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Chapter 1. Introduction

This report presents the major assumptions of the National Energy Modeling System (NEMS) used to generate the projections in the *Annual Energy Outlook 2016* [1] (AEO2016), including general features of the model structure, assumptions concerning energy markets, and the key input data and parameters that are the most significant in formulating the model results. Detailed documentation of the modeling system is available in a series of documentation reports [2].

The National Energy Modeling System

Projections in AEO2016 are generated using NEMS [3], developed and maintained by the Office of Energy Analysis of the U.S. Energy Information Administration (EIA). In addition to its use in developing the Annual Energy Outlook (AEO) projections, NEMS is used to complete analytical studies for the U.S. Congress, the Executive Office of the President, other offices within the U.S. Department of Energy (DOE), and other federal agencies. NEMS is also used by nongovernmental groups, such as the Electric Power Research Institute, Duke University, and the 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 2050. 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 within the 5 Petroleum Administration for Defense Districts (PADDs). Complete regional and detailed results are available on the EIA Analysis and Projections Home Page (www.eia.gov/analysis/).

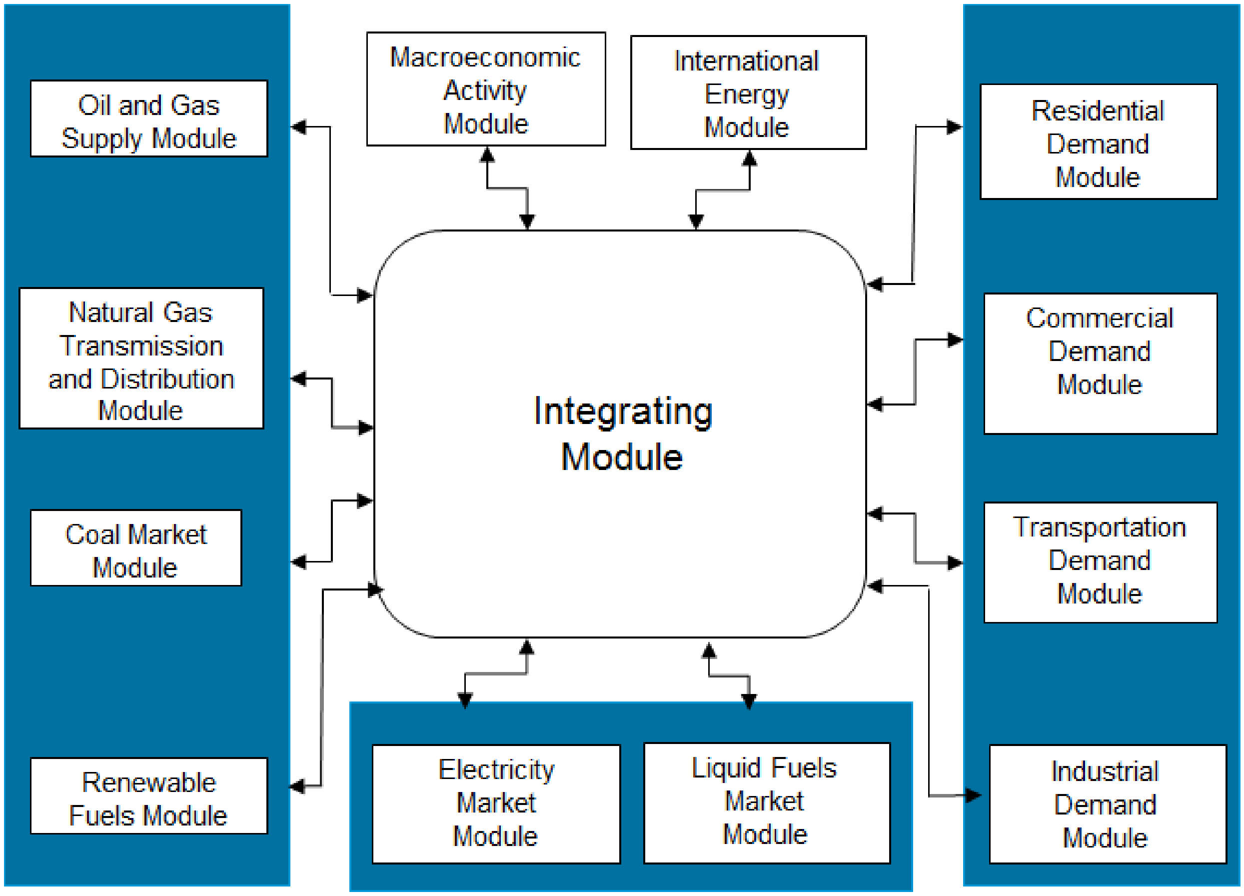
NEMS is organized and implemented as a modular system (Figure 1.1). The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. The modular design also permits the use of the methodology and level of detail most appropriate for each 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 2016 through 2050. Other variables, such as petroleum product imports, crude oil imports, and several macroeconomic indicators, are also evaluated for convergence.

Each NEMS component represents the effects and costs of legislation and environmental regulations that affect that sector. NEMS accounts for all combustion-related carbon dioxide (CO2) emissions, as well as emissions of sulfur dioxide (SO2), nitrogen oxides (NOX), and mercury from the electricity generation sector.

The integrating module of NEMS controls the execution of each of the component modules. To facilitate modularity, the components do not pass information to each other directly but communicate through a central data storage location. This modular design provides the capability to execute modules individually, thus allowing decentralized development of the system and independent analysis and testing of individual modules that appropriately reflect each energy 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 the end of February 2016, as discussed in the Legislation and Regulations section of the AEO. The potential effects of proposed federal and state legislation, regulations, or standards—or of sections of legislation that have been enacted but require funds and implementing regulations that have not been provided or specified—are not reflected in NEMS. Environmental Protection Agency's (EPA) Clean Power Plan (CPP), is included in the Reference case of AEO2016. However, because of the continuing uncertainty surrounding its implementation, a No CPP case is also included. A list of the specific federal and selected state legislation and regulations included in the AEO, including how they are incorporated, is provided in Appendix A.

Figure 1.1. National Energy Modeling System



Source: U.S. Energy Information Administration, Office of Energy Analysis.

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. This section provides brief summaries of each of the modules.

Macroeconomic Activity Module

The Macroeconomic Activity Module (MAM) provides a set of macroeconomic drivers to the energy modules and receives energy-related indicators from the NEMS energy components as part of the macroeconomic feedback mechanism within NEMS. Key macroeconomic variables used in the energy modules include gross domestic product (GDP), disposable income, value of industrial shipments, new housing starts, sales of new light-duty vehicles (LDV), interest rates, and employment. Key energy indicators fed back to the MAM include aggregate energy prices and costs. The MAM uses the following models from IHS Global Insight: Macroeconomic Model of the U.S. Economy, National Industry Model, and National Employment Model. In addition, EIA has constructed a Regional Economic and Industry Model to project regional economic drivers, and a Commercial Floorspace Model to project 13 floorspace types in 9 Census divisions. The accounting framework for industrial value of shipments uses the North American Industry Classification System (NAICS).

International Energy Module

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

Residential and Commercial Demand Modules

The Residential Demand Module (RDM) 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 (CDM) projects energy consumption in the commercial sector by Census division, building type, and category of end use, based on delivered prices of energy, availability of renewable sources of energy, and changes in commercial floorspace.

The RDM estimates the equipment stock for major end-use services, while the CDM estimates service demand met by major end-use equipment. Both incorporate assessments of advanced technologies, representations of renewable energy technologies, projections of distributed generation including commercial combined heat and power (CHP), and the effects of both building shell and appliance standards. The modules incorporate changes to heating and cooling degree days by Census division, based on a 30-year historical trend and state-level population projections. The RDM projects an increase in the average square footage of both new construction and existing structures, based on trends in new construction and remodeling, and commercial floorspace increases as a result of projected growth within the MAM of NEMS.

Industrial Demand Module

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

There were several major modeling changes in AEO2016. The major modeling changes include converting iron and steel and paper submodules to a technology choice model. The second change was to incorporate current motor regulations in the motor stock model. Also, individual industries were calibrated so that summed individual industry energy consumption equals total industrial energy consumption (excluding refining) within -0.2%/+0.01%. Finally, a limited energy-efficiency side case, including the technology choice modules only, was implemented.

The iron and steel and paper submodules use technology choice. Instead of the aggregate energy intensity evolving according to technology possibility curves, the iron and steel and paper models allow technology choice for each process. In previous years, the cement and lime, aluminum, and glass industries were converted to technology choice. All process flow models now use a technology choice approach.

Data updates include incorporating 2012 Economic Census data for the nonmanufacturing industries. Also, natural gas feedstock calibration was incorporated for the first time based on GlobalData projections of methanol and ammonia and nitrogenous fertilizer projections to 2018.

Transportation Demand Module

The Transportation Demand Module (TDM) projects consumption of energy by mode and fuel type in the transportation sector, subject to delivered energy prices and macroeconomic variables such as GDP, as well as other factors such as technology adoption. Transportation modes include LDV heavy-duty vehicles (HDV), air, marine, and rail. Fuel types include motor gasoline, distillate, jet fuel, and alternate fuels such as ethanol (E85) and compressed and liquefied natural gas (CNG/LNG). The LDV travel component uses fuel prices, personal income, and 10 age and gender population groups to generate projections. The TDM considers legislation and regulations, such as the Energy Policy Act of 2005 (EPACT2005), the Energy Improvement and Extension Act of 2008 (EIEA2008), and the American Recovery and Reinvestment Act of 2009 (ARRA2009), which contain tax credits for the purchase of alternatively-fueled vehicles. Representations of LDV Corporate Average Fuel Economy (CAFE) and Greenhouse Gas (GHG) emissions standards, HDV fuel consumption and GHG emissions standards, and biofuels consumption reflect requirements enacted by U.S. National Highway Traffic Safety Administration (NHTSA) and the EPA, as well as provisions in the Energy Independence and Security Act of 2007 (EISA2007). TDM also considers the Clean Air Act provision that provides the state of California the authority to set vehicle criteria emission standards that exceed federal standards

The air transportation component of the TDM represents air travel in 13 domestic and foreign regional markets (United States, Canada, Central America, South America, Europe, Africa, Middle East, Commonwealth of Independent States, China, Northeast Asia, Southeast Asia, Southwest Asia, and Oceania) and includes the industry practice of parking aircraft in both domestic and international markets to reduce operating costs, as well as the industry practice of moving 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 TDM projects energy consumption for freight trucks (HDV including buses, vocational vehicles, and tractor trailers), freight and passenger rail, and international and domestic marine vessels by fuel and Census division, as well as marine fuel choices and demand for ocean-going vessels operating within the North American and Caribbean Emission Control Areas (ECAs). Freight trucks, freight rail, and domestic and international marine are subject to macroeconomic drivers such as the value and type of industrial shipments. Passenger rail projections are subject to personal income and fuel prices.

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, the cost and performance of future generation capacity, expected fuel prices, expected financial parameters, expected electricity demand, and expected environmental regulations 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. The submodule also determines inter-regional trade 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 electricity prices for each sector.

All final regulations, as of February 2016, issued by the EPA for compliance with the Clean Air Act Amendments of 1990 are explicitly represented in the capacity expansion and dispatch decisions, including the CO2 performance standards for new power plants and the CPP, which restricts CO2 emissions from existing plants. All financial incentives for power generation expansion and dispatch specifically identified in EPACT2005 and revised through later amendments have been implemented. Several states, primarily in the Northeast, had previously enacted air emission regulations for CO2 that affect the electricity generation sector, and those regulations continue to be represented in AEO2016. The AEO2016 Reference case imposes a limit on CO2 emissions for specific covered sectors, including the electric power sector, in California, as represented in California's AB 32. The AEO2016 Reference case assumes implementation of the Cross State Air Pollution Rule (CSAPR), after the Supreme Court lifted the stay in October 2014 and upheld CSAPR as a replacement to the Clean Air Interstate Rule, both of which were developed to reduce emissions that contribute to ozone and fine particle pollution. Reductions in mercury emissions from coal- and oil-fired power plants also are reflected through the inclusion of the Mercury and Air Toxics Standards for power plants, finalized by the EPA on December 16, 2011.

Because regulators and the investment community have continued to push energy companies to invest in technologies that are less GHG-intensive, the AEO2016 Reference case continues to apply 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, and pollution control retrofits. Although any new coal-fired plant is assumed to be compliant with new source performance standards, this would only require 30% capture of CO2 emissions and would still be considered high emitting relative to other new sources, and will continue to face financial risk if carbon emission controls are further strengthened.

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 contains renewable resource supply estimates representing the regional opportunities for renewable energy development.

Investment tax credits (ITCs) for renewable fuels are incorporated, as currently enacted. The ITC includes business investment in solar energy (thermal nonpower uses as well as power uses) and geothermal power (available only to those projects not accepting the production tax credit [PTC] for geothermal power). For solar facilities this includes a 30% tax credit for technologies commencing construction before December 31, 2019. At that time the ITC begins to phase down in value annually until December 31, 2021, where it remains as a permanent 10% tax credit. For geothermal electric plants, the ITC is permanently at 10%. The availability of the ITC to individual homeowners is reflected in the RDM and CDM.

The PTC for wind, geothermal, landfill gas, and some types of hydroelectric and biomass-fueled plants are represented in AEO2016 based on the laws enacted in December 2015. These laws provide a credit of up to 2.3 cents/kilowatthour (kWh) for electricity produced in the first 10 years of plant operation. For AEO2016, the tax credit is phased down for wind plants and expires for other technologies commencing construction after December 31, 2016. Starting in 2017, the tax credit value for wind plants decreases by 20% annually until it expires at the end of 2019. As part of ARRA2009, plants eligible for the PTC may instead elect to receive a 30% ITC or an equivalent direct grant. AEO2016 also accounts for new renewable energy capacity resulting from state renewable portfolio standards.

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 6 onshore, 3 offshore, and in 3 regions not Alaska.

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 LFMM for conversion and blending into refined petroleum products. Supply curves for natural gas are used as inputs to the Natural Gas

Transmission and Distribution Module (NGTDM) for determining natural gas wellhead prices and domestic production.

Natural Gas Transmission and Distribution Module

The NGTDM represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas and the availability of domestic natural gas and natural gas traded on the international market. The NGTDM balances natural gas supply and demand, tracks the flows of natural gas, and determines the associated capacity expansion requirements in an aggregate pipeline network, connecting domestic and limited foreign supply sources with 12 lower 48 states regions.

The 12 lower 48 states regions align with the 9 Census divisions, with 3 subdivided, and Alaska handled separately. The flow of natural gas is determined for both a peak and off-peak period in the year, assuming a historically based seasonal distribution of natural gas demand. Key components of pipeline and distributor tariffs are included in separate pricing algorithms. The primary outputs of the module are delivered natural gas prices by region and sector, supply prices, and realized domestic natural gas production. The module also projects natural gas pipeline imports and exports to Canada and Mexico, as well as LNG imports and exports.

Liquids Fuels Market Module

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

PADD I – East Coast
PADD II – Interior
PADD II – Great Lakes
PADD III – Gulf Coast
PADD III – Interior
PADD IV – Mountain
PADD V – California
PADD V – Other
Maritime Canada/Caribbean

The LFMM models the costs of automotive fuels, such as conventional and reformulated gasoline, and includes production of biofuels for blending in gasoline and diesel. Fuel ethanol and biodiesel are included in the LFMM because they are commonly blended into petroleum products. The module allows ethanol blending into gasoline at 10% by volume, 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 are also 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 standards (RFS) specified in the EISA2007, which mandates the use of 36 billion ethanol-equivalent gallons of 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 United States), are based on a well-known technology that converts starch and sugar into ethanol. Ethanol from cellulosic sources is a relatively new technology with only a few commercial 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 (IDM, 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 2 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 1.1 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 the specific 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/barrel 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.

- The historical record shows substantial variability in oil prices, and there is arguably even more uncertainty about long-term prices. 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, while 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 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-Organization for Economic Cooperation and Development 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 Organization of the Petroleum Exporting Countries 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 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, PTCs 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 CHP 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 DOE's multiyear plan, and introduces new standards for products currently not covered by DOE. Efficiency levels for the updated residential appliance standards are based on current ENERGY STAR guidelines 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 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 LFMM. 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, and on Bandwidth Analysis by DOE. 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% ITC for industrial CHP is extended through 2040, modifying capacity limitations on the ITC by increasing the cap on CHP equipment from 15 megawatt (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 TDM was used as part of two AEO2016 alternative cases.

- In the Extended Policies case, the TDM 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 TDM 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 TDM 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 CO2 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/megawatthour) within each EMM 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 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 is assumed to be 50% lower than in the Reference case. Rates of technology improvement that reduce costs and increase productivity in the United States are also 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 CPP regulations that reduce CO2 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.

Table 1.1. Summary of AEO2016 cases

Case name	Description
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.
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.
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.
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.

Table 1.1. Summary of AEO2016 cases (cont.)

Case name	Description
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 Light-Duty Vehicle (LDV) and Heavy-Duty Vehicle (HDV) fuel economy standards in the transportation sector. This case also includes the extension of EPA's Clean Power Plan (CPP)regulations that reduce carbon dioxide (CO_2) emissions from electric power generation after 2030. Partial projection tables in Appendix D.
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.
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.
Electricity: No CPP	Assumes that the CPP is not enforced, and that no federal requirements are in place to reduce CO_2 emissions from existing power plants.
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.
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.
Electricity: CPP Extended	Assumes that the CPP CO_2 emissions targets continue to decline after 2030, reaching a 45% reduction below 2005 levels in 2040.
Electricity: CPP Hybrid	Assumes that regions can vary their CPP compliance method, with the Northeast and California regions choosing mass-based caps and the remaining regions using average rate-based standards.

Table 1.1. Summary of AEO2016 cases (cont.)

Case name	Description
Electricity: CPP Allocation to Generators	Assumes the same CPP compliance as in the Reference case, except that the CO2 allowances are allocated to generators instead of being allocated to load entities, resulting in higher retail price impacts.
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).
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.
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.
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.

Carbon dioxide emissions

CO2 emissions from energy use are dependent on the carbon content of the fossil fuel, the fraction of the fuel consumed in combustion, and the consumption of that fuel. The product of the carbon content at full combustion and the combustion fraction yields an adjusted CO2 factor for each fossil fuel. The emissions factors are expressed in millions of metric tons of carbon dioxide emitted per quadrillion British thermal unit (Btu) of energy use, or equivalently, in kilograms of CO2 per million Btu. The adjusted emissions factors are multiplied by the energy consumption of the fossil fuel to arrive at the CO2 emissions projections.

For fuel uses of energy, all of the carbon is assumed to be oxidized, so the combustion fraction is equal to 1.0 (in keeping with international conventions). Previously, a small fraction of the carbon content of the fuel was assumed to remain unoxidized. The carbon in nonfuel use of energy, such as for asphalt and petrochemical feedstocks, is assumed to be sequestered in the product and not released to the atmosphere. For energy categories that are mixes of fuel and nonfuel uses, the combustion fractions are based on the proportion of fuel use. In calculating CO2 emissions for motor gasoline, the direct emissions from renewable blending stock (ethanol) is omitted. Similarly, direct emissions from biodiesel are omitted from reported CO2 emissions.

Any CO2 emitted by biogenic renewable sources, such as biomass and alcohols, is considered balanced by the CO2 sequestration that occurred in its creation. Therefore, following convention, net emissions of CO2 from biogenic renewable sources are assumed to be zero in reporting energy-related CO2 emissions however, to illustrate the potential for these emissions in the absence of any offsetting sequestration, as might occur under related land use change, the CO2 emissions from biogenic fuel use are calculated and reported separately.

Table 1.2 presents the assumed CO2 coefficients at full combustion, the combustion fractions, and the adjusted CO2 emission factors used for AEO2016.

Table 1.2. Carbon dioxide emission factors

million metric tons carbon dioxide equivalent per quadrillion Btu

Fuel Type	Carbon Dioxide Coefficient at Full Combustion	Combustion Fraction	Adjusted Emission Factor
Petroleum			
Propane			
Used as fuel	63.07	1.000	63.07
Used as feedstock	61.07	0.200	12.61
Ethane used as feedstock	59.58	0.200	11.92
Butane used as feedstock	64.94	0.200	12.98
Isobutane used as feedstock	65.08	0.200	13.02
Natural gasoline used as feedstock	66.88	0.300	21.12
Motor gasoline (net of ethanol)	71.26	1.000	71.26
Jet fuel	70.88	1.000	70.88
Distillate fuel (net of biodiesel)	73.15	1.000	73.15
Residual fuel	78.80	1.000	78.80
Asphalt and road oil	75.61	0.000	0.00
Lubricants	74.21	0.500	37.11
Petrochemical feedstocks	71.02	0.410	29.11
Kerosene	72.31	1.000	72.31
Petroleum coke	101.09	0.956	97.64
Petroleum still gas	64.20	1.000	64.20
Other industrial	74.54	1.000	74.54
Coal			
Residential and commercial	95.33	1.000	95.33
Metallurgical	93.72	1.000	93.72
Coke	117.81	1.000	117.81
Industrial other	93.98	1.000	93.98
Electric utility[1]	95.52	1.000	95.52
Natural gas			
Used as fuel	53.06	1.000	53.06
Used as feedstock	53.06	0.437	23.21
Biogenic energy sources			
Biomass	93.81	1.000	93.81
Biogenic waste	90.64	1.000	90.64
Biofuels heats and coproducts	93.81	1.000	93.81
Ethanol	68.42	1.000	68.42
Biodiesel	72.73	1.000	72.73
Liquids from biomass	73.15	1.000	73.15
Green liquids	73.15	1.000	73.15

[1]Emission factors for coal used for electric power generation within NEMS are specified by coal supply region and types of coal, so the average CO2 content for coal varies throughout the projection. The value of 95.52 shown here is representative of recent history.

Source: U.S. Energy Information Administration, Monthly Energy Review, February 2016, DOE/EIA-0035(2014/11), (Washington, DC, February 2016).

Notes and sources

[1] U.S. Energy Information Administration, *Annual Energy Outlook 2016* (AEO2016), DOE/EIA-0383(2016) (Washington, DC, September 2016).

[2] NEMS documentation reports are available on the EIA Homepage (http://www.eia.gov/reports/index.cfm#/KNEMS Documentation).

[3] 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/outlooks/aeo/nems/overview/pdf/0581(2009).pdf.

Chapter 2. Macroeconomic Activity Module

The Macroeconomic Activity Module (MAM) represents interactions between the U.S. economy and energy markets. How fast the economy grows, as measured by either growth in gross domestic product or industrial shipments, is a key determinant of growth in the demand for energy. Associated economic factors, such as interest rates and disposable income, strongly influence various elements of the supply and demand for energy. At the same time, reactions to energy markets by the aggregate economy, such as a slowdown in economic growth resulting from increasing energy prices, are also reflected in this module. A detailed description of the MAM is provided in the EIA publications, *Model Documentation Report: Macroeconomic Activity Module (MAM) of the National Energy Modeling System* (Washington, DC, May 2014) and *Update to Industrial drivers in the AEO2015 as a result of new input-output data* (Washington, DC, May 2015).

Key assumptions

The output of the U.S. economy, measured by GDP, is expected to increase by 2.2% per year between 2015 and 2040 in the Reference case. Two key factors help explain the growth in GDP: the growth rate of nonfarm employment and the rate of productivity change associated with employment. As Table 2.1 indicates, in the Reference case, real GDP grows by 2.6% per year from 2015-20, 2.2% from 2020-30, and 2.1% from 2030 to 2040. Both the High and Low Economic Growth cases differ by 0.6 percentage points compared with the Reference case from 2015 to 2040. Non-farm employment shows higher growth from 2015-20 in the Reference case and then returns to its long-run trend growth of 0.7% from 2015-40. In the High Economic Growth case, nonfarm employment growth differs by 0.3 percentage points compared with the Reference case growth of 0.7% from 2015 to 2040, while the Low Economic Growth case differs by only 0.1%, reaching 1.0% and 0.6% in the High Economic Growth and Low Economic Growth cases, respectively. In the Reference case, productivity (measured as output per hour in nonfarm business) grows by 1.7% from 2015 to 2040, showing slower growth as compared to the 1.9% growth experienced from 1980 to 2015. Nominal business fixed investment as a share of nominal GDP is expected to grow over the projection. The resulting growth in the capital stock and the technology base of that capital stock helps sustain productivity growth of 1.7% from 2015 to 2040.

The U.S. Census Bureau's middle series population projection is used as a basis for population growth in AEO2016. Total population is expected to grow by 0.7% per year between 2015 and 2040, and the share of population over 65 is expected to increase over time. However, the share of the labor force in the population over 65 is also projected to increase in the projection period.

To achieve the Reference case's long-run 2.2% GDP growth, there is an anticipated steady growth in labor productivity. The improvement in labor productivity reflects the positive effects of a growing capital stock as well as technological change over time. Nonfarm labor productivity growth is expected to remain between 0.8 and 2.0% throughout the projection period of 2015 to 2040.

Table 2.1. Growth in gross domestic product, nonfarm employment and productivity

Assumptions	2015-2020	2020-2030	2030-2040	2015-2040
Real GDP (Billion Chain-weighted $2009)				
High Economic Growth	3.6%	2.8%	2.6%	2.8%
Reference	2.6%	2.2%	2.1%	2.2%
Low Economic Growth	1.5%	1.7%	1.7%	1.6%
Nonfarm Employment				
High Economic Growth	1.6%	0.9%	0.7%	1.0%
Reference	1.2%	0.7%	0.6%	0.7%
Low Economic Growth	0.6%	0.5%	0.6%	0.6%
Productivity				
High Economic Growth	2.1%	2.0%	2.0%	2.0%
Reference	1.6%	1.8%	1.7%	1.7%
Low Economic Growth	1.0%	1.4%	1.3%	1.3%

Source: U.S. Energy Information Administration, AEO2016 National Energy Modeling system runs: AEO2016.d032416A, LM2016.d032516A, and HM2016.d032516A.

To reflect uncertainty in the projection of U.S. economic growth, the AEO2016 uses High and Low Economic Growth cases to project the possible impacts of alternative economic growth assumptions on energy markets. The High Economic Growth case incorporates higher population, labor force and productivity growth rates than the Reference case. Due to the higher productivity gains, inflation and interest rates are lower than the Reference case. Investment, disposable income and industrial production are greater. Economic output is projected to increase by 2.8% per year between 2015 and 2040. The Low Economic Growth case assumes lower population, labor force, and productivity gains, with resulting higher prices and interest rates and lower industrial output growth. In the Low Economic Growth case, economic output is expected to increase by 1.6% per year over the projection horizon.

Chapter 3. International Energy Module

The National Energy Modeling System International Energy Module (IEM) simulates the interaction between U.S. and global petroleum markets. It uses assumptions of economic growth and expectations of future U.S. and world crude-like liquids production and consumption to estimate the effects of changes in U.S. liquid fuels markets on the international petroleum market. For each year of the forecast, the IEM computes Brent prices, provides a supply curve of world crude-like liquids, and generates a worldwide oil supply-demand balance with regional detail. The IEM also provides, for each year of the projection period, endogenous assumptions for petroleum products for import and export in the United States.

Changes in the oil price (Brent) are computed in response to:

1. The difference between projected U.S. total crude-like liquids production and the expected U.S. total crude-like liquids production at the current oil price (estimated using the current oil price and the exogenous U.S. total crude-like liquids supply curve for each year).

and

2. The difference between projected U.S. total crude-like liquids consumption and the expected U.S. total crude-like liquids consumption at the current oil price (estimated using the current oil price and the exogenous U.S. total crude-like liquids demand curve).

Key assumptions

AEO2016 considers a number of factors related to the uncertainty of future oil prices, including changes in worldwide demand for petroleum products, OPEC investment and production decisions, non-OPEC petroleum liquid fuels supply, and supplies of other liquid fuels.

In the AEO2016 Reference case, the growth in U.S. crude oil production, combined with the fall in world oil prices, contributes to a decrease in the oil price to $37 (2015 dollars) per barrel in 2016. Oil prices rise steadily after 2016 in response to growth in demand from countries outside of the Organization for Economic Cooperation and Development (OECD) even if downward pressure from increases in U.S. oil production keeps the oil price below $80 per barrel through 2020. Growth in demand from non-OECD countries will push the oil price to $136 per barrel in 2040. The AEO2016 Reference case also assumes that the OPEC market share of liquids production will increase from 39% in 2015 to 42% in 2040.

In the AEO2016 Low Oil Price case, the oil price drops to $35 per barrel in 2016 followed by a slow increase to $73 per barrel in 2040. This is in response to higher upstream investment by OPEC and lower non-OECD demand. In the AEO2016 Low Oil Price case, OPEC countries increase their liquids production to obtain an increase in market share from 39% in 2015 to 47% in 2040.

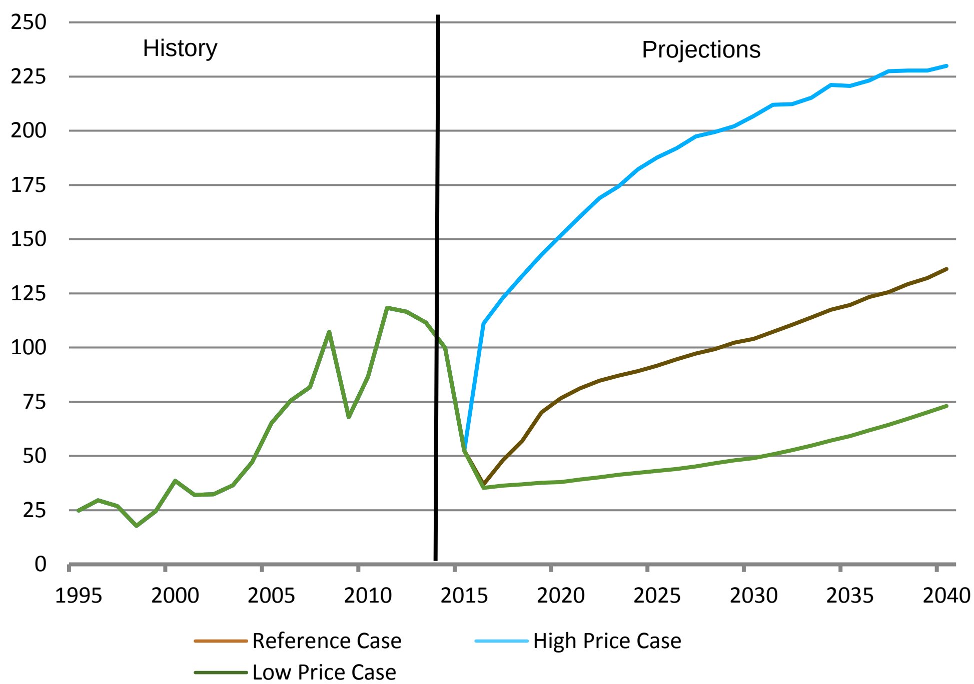
In the AEO2016 High Oil Price case, the oil price increases to $111 per barrel in 2016 and to $230 per barrel in 2040. This is in response to significantly lower OPEC production and higher non-OECD demand, higher demand for petroleum products, and a more limited supply of other liquid fuels than in the Reference case. Also, U.S. production is significantly greater, resulting in lower net imports of crude oil. In the AEO2016 High Oil Price case, OPEC countries' share of world liquids production decreases to 36% by 2025 and 34% by 2040.

OPEC oil production in the AEO2016 Reference case is assumed to increase throughout the 2016-2040 projection period (Figure 3.1), at a rate that enables the organization to achieve a 42% market share of the world's total petroleum and other liquids in 2040. OPEC is assumed to be an important source of additional production because its member nations hold a major portion of the world's total proved reserves—around 1,200 billion barrels, about 73% of the world's estimated total, at the beginning of 2014. [4]

Non-U.S., non-OPEC oil production projections in the AEO2016 are developed in two stages. Projections of liquids production before 2016 are based largely on a project-by-project assessment of major fields, including volumes and expected schedules, with consideration given to the decline rates of active projects, planned exploration and development activity, and country- specific geopolitical situations and fiscal regimes. Incremental production estimates from existing and new fields after 2016 are estimated based on country-specific consideration of economics and ultimate technically recoverable resource estimates. The non-OPEC production path for the AEO2016 Reference case is shown in Figure 3.3.

Figure 3.1. World oil prices in three cases, 1995-2040

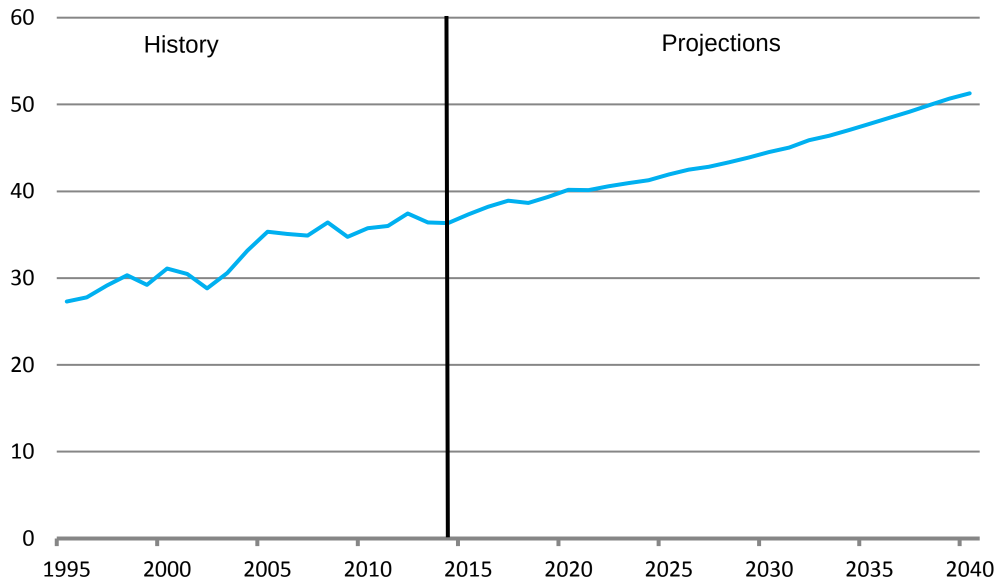
million barrels per day



Source: U.S. Energy Information Administration. AEO2016, National Energy Modeling System runs REF2016.D032416A, HIGHPRICE.D041916A, LOWPRICE.D041916A

Figure 3.2. OPEC total liquids production in the Reference case, 1995-2040

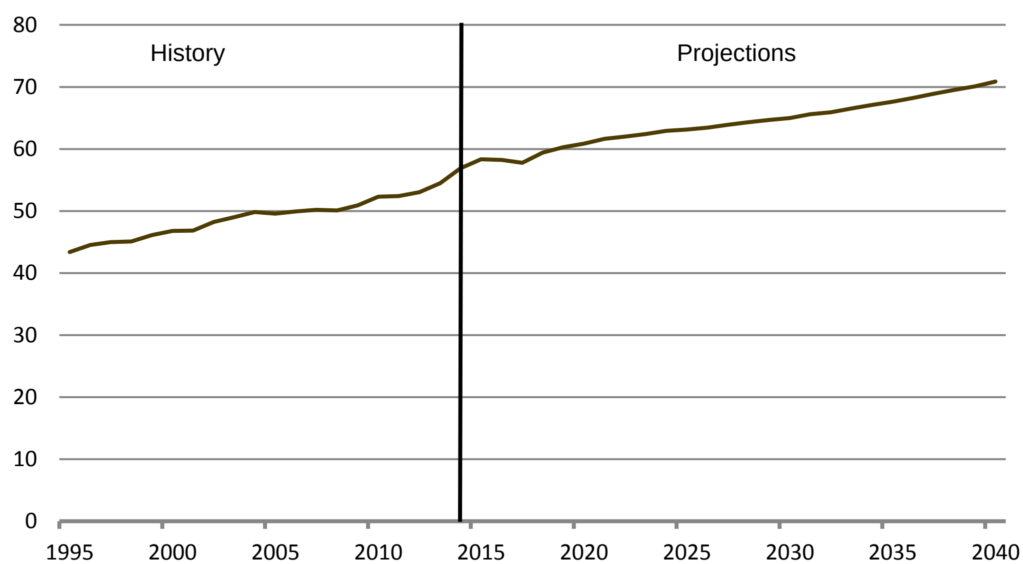
million barrels per day



OPEC = Organization of Petroleum Exporting Countries
Source: U.S. Energy Information Administration. AEO2016 National Energy Modeling System run REF2016.D032416A

Figure 3.3. Non-OPEC total liquids production in the Reference case, 1995-2040

million barrels per day



OPEC = Organization of Petroleum Exporting Countries
Source: U.S. Energy Information Administration. AEO2016 National Energy Modeling System run REF2016.D032416A

The non-U.S. oil production projections in AEO2016 are limited by country-level assumptions regarding technically recoverable oil resources. Inputs to these resource estimates include the USGS World Petroleum Assessment of 2000 and oil reserves published in the Oil & Gas Journal by PennWell Publishing Company, a summary of which is shown in Table 3.1.

The AEO2016 Reference case growth rates for GDP for various regions in the world are shown in Table 3.2. The GDP growth rate assumptions for non-U.S. countries/regions are taken from Oxford Economic Model (February 2014).

The values for growth in total liquids demand in the International Energy Module, which depend upon the oil price levels as well as GDP growth rates, are shown in Table 3.3 for the Reference case by region.

Table 3.1. Worldwide oil reserves as of January 1, 2014

million barrels

Region	Proved Oil Reserves
Western Hemisphere	544.9
Western Europe	11.1
Asia-Pacific	46.0
Eastern Europe and Former Soviet Union (F.S.U.)	120.0
Middle East	798.6
Africa	126.7
Total World	1,647.4
Total OPEC	1,200.8

Source: Pennwell Corporation, Oil and Gas Journal, Vol 112. 12 (Dec. 1, 2014).

Table 3.2. Average annual real gross domestic product rates, 2010-40

2005 purchasing power parity weights and prices

Region	Average Annual Percentage Change
OECD	2.2%
OECD Americas	2.4%
OECD Europe	2.1%
OECD Asia	1.3%
Non-OECD	4.6%
Non-OECD Europe and Eurasia	2.9%
Non-OECD Asia	5.1%
Middle East	3.8%
Africa	4.9%
Central and South America	3.3%
Total World	3.6%

Source: U.S. Energy Information Administration, Derived from Oxford Economic Model (February 2014).

Table 3.3. Average annual growth rates for total liquids demand in the Reference case, 2010-40

percent per year

Region	Demand Growth
OECD	0.03%
OECD Americas	0.16%
OECD Europe	0.05%
OECD Asia	-0.45%
Non-OECD	1.92%
Non-OECD Europe and Eurasia	0.11%
Non-OECD Asia	2.60%
Middle East	1.32%
Africa	2.23%
Central and South America	0.99%
Total World	1.08%

Source: U.S. Energy Information Administration, National Energy Modeling System run REF2016.d032416A.

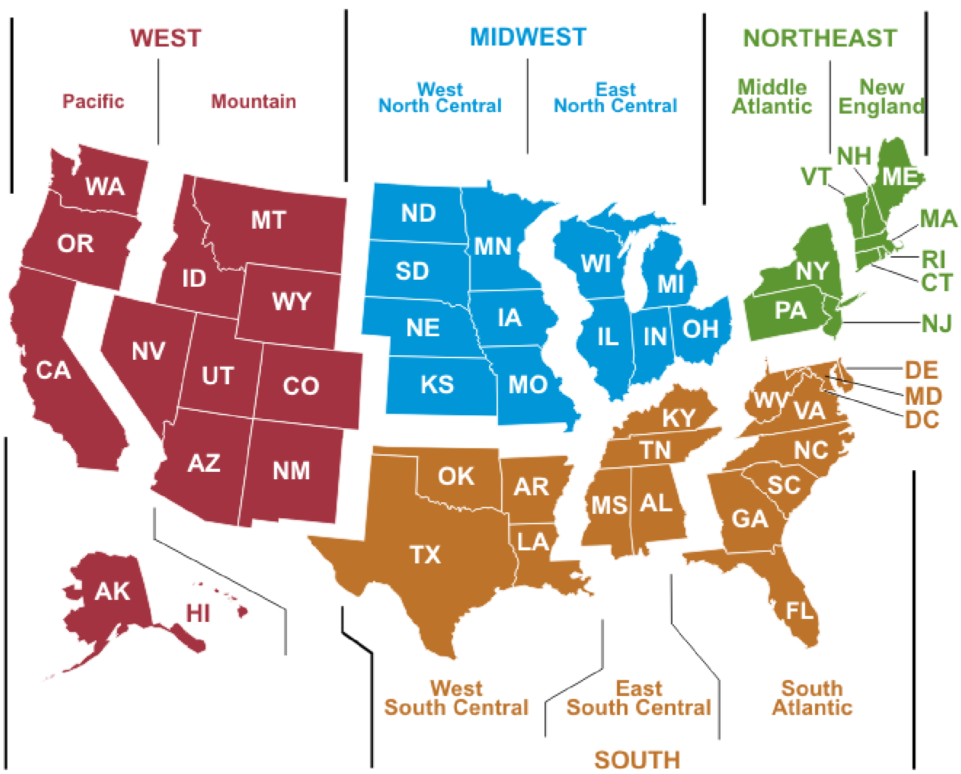
Notes and sources

[4] PennWell Corporation, Oil and Gas Journal, Vol. 111.12 (December 1, 2014).

Chapter 4. Residential Demand Module

The NEMS Residential Demand Module projects future residential sector energy requirements based on projections of the number of households and the stock, efficiency, and intensity of energy-consuming equipment. The Residential Demand Module projections begin with a base year estimate of the housing stock, the types and numbers of energy-consuming appliances servicing the stock, and the “unit energy consumption” (UEC) by appliance (in million Btu per household per year). The projection process adds new housing units to the stock, determines the equipment installed in new units, retires existing housing units, and retires and replaces appliances. The primary exogenous drivers for the module are housing starts by type (single-family, multifamily and mobile homes) and by Census division, and prices for each energy source for each of the nine Census divisions (see Figure 4.1).

Figure 4.1. United States Census Divisions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

The Residential Demand Module also requires projections of available equipment and their installed costs over the projection horizon. Over time, equipment efficiency tends to increase because of general technological advances and also because of federal and/or state efficiency standards. As energy prices and available equipment change over the projection horizon, the module includes projected changes to the type and efficiency of equipment purchased as well as projected changes in the usage intensity of the equipment stock.

The end-use equipment for which stocks are modeled include those major end uses that often span several fuels, such as space conditioning (heating and cooling) equipment, water heaters, refrigerators, freezers, dishwashers, clothes washers, cookstoves, clothes dryers, light bulbs, furnace fans, as well as several miscellaneous electric loads: televisions and related equipment (set-top boxes, home theater systems, DVD players, and video game consoles), computers and related equipment (desktops, laptops, monitors, networking equipment), rechargeable electronics, ceiling fans, coffee makers, dehumidifiers, microwaves, pool heaters and pumps, home security systems, and portable electric spas. In addition to the modeled end uses previously listed, the average energy consumption per household is projected for other electric and nonelectric uses. The fuels represented are distillate fuel oil, liquefied petroleum gas, natural gas, kerosene, electricity, wood, geothermal, and solar energy. The module's output includes number of households, equipment stock, average equipment efficiencies, and energy consumed by service, fuel, and geographic location.

One of the implicit assumptions embodied in the residential sector Reference case projections is that, through 2040, there will be no radical changes in technology or consumer behavior. No new regulations of efficiency beyond those currently embodied in law or new government programs fostering efficiency improvements are assumed. Technologies that have not gained widespread acceptance today will generally not achieve significant penetration by 2040. Currently available technologies will evolve in both efficiency and cost. In general, future technologies at the same efficiency level will be less expensive, in real dollar terms, than those available today. When choosing new or replacement technologies, consumers will behave similarly to the way they now behave, and the intensity of end uses will change moderately in response to price changes. [5]

Key assumptions

Housing Stock Submodule

An important determinant of future energy consumption is the projected number of households. Base year estimates for 2009 are derived from the U.S. Energy Information Administration's (EIA) Residential Energy Consumption Survey (RECS) (Table 4.1). The projection for occupied households is done separately for each Census division. It is based on the combination of the previous year's surviving stock with projected housing starts provided by the NEMS Macroeconomic Activity Module. The Housing Stock Submodule assumes a constant survival rate (the percentage of households which are present in the current projection year, which were also present in the preceding year) for each type of housing unit: 99.7% for single-family units, 99.5% for multifamily units, and 96.6% for mobile home units.

Table 4.1. 2009 Households

Census	Single-Family Units	Multifamily Units	Mobile Homes	Total Units
New England	3,374,597	2,052,063	84,437	5,511,097
Middle Atlantic	9,287,267	5,536,739	435,344	15,259,350
East North Central	13,077,414	4,217,199	558,802	17,853,414
West North Central	6,153,386	1,406,903	503,817	8,064,106
South Atlantic	15,162,865	4,656,262	2,405,757	22,224,884
East South Central	5,480,023	945,846	658,471	7,084,340
West South Central	9,095,440	2,822,348	853,143	12,770,931
Mountain	5,983,945	1,258,517	662,813	7,905,276
Pacific	10,937,616	5,226,838	778,377	16,942,832
United States	78,552,553	28,122,715	6,940,961	113,616,230

Source: U.S. Energy Information Administration, 2009 Residential Energy Consumption Survey.

Projected fuel consumption is dependent not only on the projected number of housing units, but also on the type and geographic distribution of the houses. The intensity of space heating energy use varies greatly across the various climate zones in the United States. Also, fuel prevalence varies across the country—oil (distillate) is more frequently used as a heating fuel in the New England and Middle Atlantic Census divisions than in the rest of the country, while natural gas dominates in the Midwest. An example of differences by housing type is the more prevalent use of liquefied petroleum gas in mobile homes relative to other housing types.

Technology Choice Submodule

The key inputs for the Technology Choice Submodule are fuel prices by Census division and characteristics of available equipment (installed cost, maintenance cost, efficiency, and equipment life). The Integrating Module of NEMS estimates fuel prices through an equilibrium simulation that balances supply and demand and passes the prices to the Residential Submodule.

Prices combined with equipment UEC (a function of efficiency) determine the operating costs of equipment. Equipment characteristics are exogenous to the model and are modified to reflect both federal standards and anticipated changes in the market place. Table 4.2 lists capital costs and efficiency for selected residential appliances for the years 2010 and 2020.

Table 4.2. Installed cost and efficiency ratings of selected equipment

Equipment Type	Relative Performance[1]	2013 Installed Cost (2013$)	2013 Efficiency[2]	2020 Efficiency[2]	Approximate Hurdle Rate
Electric Heat Pump (heating component)	Minimum	$3,150	7.7	8.2	
	Best	$4,500	9.8	11.7	25%
Natural Gas Furnace	Minimum	$1,900	0.80	0.80	
	Best	$2,950	0.98	0.98	15%
Room Air Conditioner	Minimum	$385	9.8	10.8	
	Best	$565	11.5	11.9	42%
Central Air Conditioner[3]	Minimum	$2,100	13.0	13.0	
	Best	$5,100	24.0	24.0	25%
Refrigerator[4]	Minimum	$580	541	406	
	Best	$930	349	349	10%
Electric Water Heater	Minimum	$615	0.90	0.95	
	Best	$2,170	2.45	2.75	50%
Solar Water Heater	N/A	$7,520	N/A	N/A	30%

[1]Minimum performance refers to the lowest-efficiency equipment available. Best refers to the highest-efficiency equipment available.

[2]Efficiency measurements vary by equipment type. Electric heat pumps are based on Heating Seasonal Performance Factor (HSPF); natural gas furnaces are based on Annual Fuel Utilization Efficiency (AFUE); central air conditioners are based on Seasonal Energy Efficiency Ratio (SEER); room air conditioners are based on Energy Efficiency Ratio (EER); refrigerators are based on kilowatt-hours per year; and water heaters are based on Energy Factor (delivered Btu divided by input Btu).

[3]Values are for northern regions of United States.

[4]Reflects a refrigerator with a top-mounted freezer with 20.6 cubic feet nominal volume.

Source: EIA - Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case, prepared for U.S. Energy Information Administration, Navigant Consulting, Inc., March 2014.

Table 4.3 provides the cost and performance parameters for representative distributed generation technologies. The model also incorporates endogenous "learning" for the residential distributed generation technologies, allowing for declining technology costs as shipments increase. For fuel cell and photovoltaic systems, learning parameter assumptions for the Reference case result in a 13% reduction in capital costs each time the installed capacity in buildings doubles (in the case of photovoltaics, utility-scale capacity is also included for learning). Capital costs for small wind, a relatively mature technology, decline only 3% with each doubling of shipments.

Table 4.3. Capital cost and performance parameters of selected residential distributed generation technologies

Technology Type	Year of Introduction	Average Generating Capacity (kW_{DC})	Electrical Efficiency	Combined Efficiency (Elec. + Thermal)	Installed Capital Cost (2015 $ per kW_{DC})[1]	Service Life (Years)
Solar Photovoltaic	2010	5	0.145	N/A	$6,674	30
	2015	5	0.170	N/A	$4,042	30
	2025	5	0.232	N/A	$2,387	30
	2035	5	0.279	N/A	$2,170	30
Fuel Cell	2010	5	0.359	0.855	$20,545	20
	2015	5	0.400	0.620	$11,989	20
	2025	5	0.410	0.620	$9,995	20
	2035	5	0.420	0.630	$8,374	20
Wind	2010	5	0.13	N/A	$7,983	30
	2015	5	0.13	N/A	$8,400	30
	2025	5	0.13	N/A	$7,559	30
	2035	5	0.13	N/A	$6,777	30

[1]The original source documents presented solar photovoltaic costs in 2008 dollars, fuel cell and wind costs in 2010 dollars.

Source: EIA analysis, as well as technology-specific reports: Solar photovoltaic: Photovoltaic (PV) Cost and Performance Characteristics for Residential and Commercial Applications (ICF International, 2010). Fuel cell: Commercial and Industrial CHP Technology Cost and Performance Data Analysis for EIA (SENTECH Incorporated, 2010). Wind: The Cost and Performance of Distributed Wind Turbines, 2010-35 (ICF International, 2010).

The Residential Demand Module projects equipment purchases based on a nested choice methodology. The first stage of the choice methodology determines the fuel and technology to be used. The equipment choices for cooling and water heating are linked to the space heating choice for new construction. Technology and fuel choice for replacement equipment uses a nested methodology similar to that for new construction, but includes (in addition to the capital and installation costs of the equipment) explicit costs for fuel or technology switching (e.g., costs for installing gas lines if switching from electricity or oil to gas, or costs for adding ductwork if switching from electric resistance heat to central heating types). Also, for replacements, there is no linking of fuel choice for water heating and cooking as is done for new construction. Technology switching across fuels upon replacement is allowed for space heating, air conditioning, water heating, cooking, and clothes drying.

Once the fuel and technology choice for a particular end use is determined, the second stage of the choice methodology determines efficiency. In any given year, there are several available prototypes of varying efficiency (minimum standard, some intermediate levels, and highest efficiency). Efficiency choice is based on a functional form and coefficients which give greater or lesser importance to the installed capital cost (first cost) versus the operating cost. Generally, within a technology class, the higher the first cost, the lower the operating cost. For new construction, efficiency choices are made based on the costs of both the heating and cooling equipment and the building shell characteristics.

Once equipment efficiencies for a technology and fuel are determined, the installed efficiency for its entire stock is calculated.

Appliance Stock Submodule

The Appliance Stock Submodule is an accounting framework that tracks the quantity and average efficiency of equipment by end use, technology, and fuel. It separately tracks equipment requirements for new construction and existing housing units. For existing units, this module calculates the number of units that survive from previous years, allows certain end uses to further penetrate into the existing housing stock and calculates the total number of units required for replacement and further penetration. Air conditioning, dishwashing, and clothes drying are three major end uses not considered to be “fully penetrated.”

Once a piece of equipment enters into the stock, an accounting of its remaining life begins. The decay function is based on Weibull distribution shape parameters that approximate linear decay functions. The estimated maximum and minimum equipment lifetimes used to inform the Weibull shape parameters are shown in Table 4.4. Weibull shapes allow some retirement before the listed minimum lifetime, as well as allow some equipment to survive beyond its listed maximum lifetime. It is assumed that, when a house is retired from the stock, all of the equipment contained in that house retires as well; i.e., there is no second-hand market for this equipment.

Table 4.4. Minimum and maximum life expectancies of equipment

Equipment	Minimum Life	Maximum Life
Heat Pumps	7	21
Central Forced-Air Furnaces	10	25
Hydronic Space Heaters	20	30
Room Air Conditioners	8	16
Central Air Conditioners	7	21
Gas Water Heaters	4	14
Electric Water Heaters	10	22
Cooking Stoves	16	21
Clothes Dryers	11	20
Refrigerators	7	26
Freezers	11	31

Source: Lawrence Berkeley National Laboratory, Baseline Data for the Residential Sector and Development of a Residential Forecasting Database, May 1994, and analysis of RECS 2001 data.

Fuel Consumption Submodule

Energy consumption is calculated by multiplying the vintage equipment stocks by their respective UECs. The UECs include adjustments for the average efficiency of the stock vintages, short-term price elasticity of demand and “rebound” effects on usage (see discussion below), the size of new construction relative to the existing stock, people per household, shell efficiency and weather effects (space heating and cooling). The various levels of aggregated consumption (consumption by fuel, by service, etc.) are derived from these detailed equipment-specific calculations.

Equipment efficiency

The average energy consumption for most technology types is initially based on estimates derived primarily from RECS 2009. As the stock efficiency changes over the projection period, energy consumption decreases in inverse proportion to efficiency. Also, as efficiency increases, the efficiency rebound effect (discussed below) will offset some of the reductions in energy consumption by increased demand for the end-use service. For example, if the stock average for electric heat pumps is now 10% more efficient than in 2005, then all else constant (weather, real energy prices, shell efficiency, etc.), energy consumption per heat pump would average about 9% less.

Miscellaneous electric loads (MELs)

Unlike the technology choice submodule's accounting framework, the energy consumption projection of several miscellaneous electric loads (MELs) is characterized by assumed changes in per-unit consumption multiplied by assumed changes in the number of units. In this way, stock and UEC concepts are projected, but without the decision-making parameters or investment calculations of the technology choice submodule. The UECs of certain MELs may be further modified beyond their input assumption by factors such as income, square footage, and/or degree days, where relevant.

Adjusting for the size of housing units

Estimates for the size of each new home built in the projection period vary by type and region, and are determined by a projection based on historical data from the U.S. Bureau of the Census [6]. For existing structures, it is assumed that about 1% of households that existed in 2009 add about 600 square feet to the heated floor space in each year of the projection period [7]. The energy consumption for space heating, air conditioning, and lighting is assumed to increase with the square footage of the structure. This results in an increase in the average size of a housing unit from 1,644 to 1,855 square feet from 2009 through 2040.

Adjusting for weather and climate

Weather in any given year always includes short-term deviations from the expected longer-term average (or climate). Recognition of the effect of weather on space heating and air conditioning is necessary to avoid inadvertently projecting abnormal weather conditions into the future. The residential module adjusts space heating and air conditioning UECs by Census division using data on heating and cooling degree days (HDD and CDD). Short-term projections are informed by the National Oceanic and Atmospheric Administration's (NOAA) 15-month outlook from their Climate Prediction Center [8], which often encompasses the first forecast year. Projections of degree days beyond that are informed by a 30-year linear trend of each state's degree days, which are then population-weighted to the Census division level. In this way, the projection accounts for projected population migrations across the nation and continues any realized historical changes in degree days at the state level.

Short-term price effect and efficiency rebound

It is assumed that energy consumption for a given end-use service is affected by the marginal cost of providing that service. That is, all else equal, a change in the price of a fuel will have an opposite, but less than proportional, effect on fuel consumption. The current value for the short-term elasticity parameter for non-electric fuels is -0.15 [9]. This value implies that for a 1% increase in the price of a fuel, there will be a corresponding decrease in energy consumption of -0.15%. Changes in equipment efficiency affect the marginal cost of providing a service. For example, a 10% increase in efficiency will reduce the cost of providing the end-use service by 10%. Based on the short-term elasticity, the demand for the service will rise by 1.5%(-10% multiplied by -0.15). Only space heating, cooling, and lighting are assumed to be affected by both elasticities and the efficiency rebound effect. For electricity, the short-term elasticity parameter is set to -0.30 to account for successful deployment of smart grid projects funded under the American Recovery and Reinvestment Act of 2009.

Shell efficiency

The shell integrity of the building envelope is an important determinant of the heating and cooling load for each type of household. In the NEMS Residential Demand Module, the shell integrity is represented by an index, which changes over time to reflect improvements in the building shell. The shell integrity index is dimensioned by vintage of house, type of house, fuel type, service (heating and cooling), and Census division. The age, type, location, and type of heating fuel are important factors in determining the level of shell integrity. Homes are classified by age as new (post-2009) or existing. Existing homes are represented by the most recent RECS survey and are assigned a shell index value based on the mix of homes that exist in the base year. The improvement over time in the shell integrity of these homes is a function of two factors: an assumed annual efficiency improvement and improvements made when real fuel prices increase. No price-related adjustment is made when fuel prices fall. For new construction, building shell efficiency is determined by the relative costs and energy bill savings for several levels of heating and cooling equipment, in conjunction with the building shell attributes. The packages represented in NEMS range from homes that meet the International Energy Conservation Code (IECC) [10] to homes that are built with the most efficient shell components. Shell efficiency in new homes increases over time when energy prices rise, or the cost of more-efficient equipment falls, all else equal.

Legislation and regulations

The Clean Power Plan

The Clean Power Plan (CPP) rule, issued under Section 111(d) of the Clean Air Act, allows states to comply with emissions targets by incentivizing energy efficiency in their buildings. In the NEMS residential model, the effects of incentivizing energy efficiency are modeled using subsidies for energy efficient heating, cooling, water heating, lighting, and refrigeration technologies. For residential building shells, a 15% subsidy for energy efficient building shells is assumed in either 2020 or 2025, depending on the census division. These subsidies are accumulated with an assumed 50% added for administrative costs and sent to the power sector along with the accumulated energy savings for emission credits.

Consolidated Appropriations Act of 2016 (H.R. 2029)

The H.R.2029 legislation passed in December 2015 extended the investment tax credit (ITC) provisions of the Energy Policy Act of 2005 for renewable energy technologies. The five-year ITC extension for solar energy systems allows for a 30% tax credit through 2019, then decreasing to 26% in 2020, and 22% in 2021.

American Recovery and Reinvestment Act of 2009 (ARRA2009)

The ARRA2009 legislation passed in February 2009 provides energy-efficiency funding for federal agencies, State Energy Programs, and block grants, as well as a sizable increase in funding for weatherization. To account for the impact of this funding, it is assumed that the total funding is aimed at increasing the efficiency of the existing housing stock. The assumptions regarding the energy savings for heating and cooling are based on evaluations of the impact of weatherization programs over time. Further, it is assumed each house requires a $2,600 investment to achieve the heating and cooling energy savings estimated by Oak Ridge National Laboratory [11] and that the efficiency measures last approximately 20 years. Assumptions for funding amounts and timing were revised downward and further into the future based on analysis of the weatherization program by the Inspector General of the U.S. Department of Energy [12].

The ARRA2009 provisions remove the cap on the 30% tax credit for ground-source heat pumps, solar PV, solar thermal water heaters, and small wind turbines through 2016. Additionally, the cap for the tax credits for other energy-efficiency improvements, such as windows and efficient furnaces, was increased to $1,500 through the end of 2010. Several tax credits were extended at reduced credit levels through the end of 2011 as part of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010. These tax credits were further extended through the end of 2013 as part of the American Taxpayer Relief Act of 2012, but since those tax credits were not in existence during 2012 and thus were not part of consumers' decision-making process, these tax credits were only modeled only for 2013, not for 2012.

Successful deployment of smart grid projects based on ARRA2009 funding could stimulate more rapid investment in smart grid technologies, especially smart meters on buildings and homes, which would make consumers more responsive to electricity price changes. To represent this, the price elasticity of demand for residential electricity was increased for the services that have the ability to alter energy intensity (e.g., lighting).

Energy Improvement and Extension Act of 2008 (EIEA2008)

EIEA2008 extends and amends many of the tax credits that were made available to residential consumers in EPACT2005. The tax credits for energy-efficient equipment can now be claimed through 2016, while the $2,000 cap for solar technologies has been removed. Additionally, the tax credit for ground-source (geothermal) heat pumps was increased to $2,000. The production tax credits for dishwashers, clothes washers, and refrigerators were extended by one to two years, depending on the efficiency level and product. See the EPACT2005 section below for more details about product coverage.

Energy Independence and Security Act of 2007 (EISA2007)

EISA2007 contains several provisions that impact projections of residential energy use. Standards for general service incandescent light bulbs are phased in over 2012-2014, with a more restrictive standard specified in 2020. It is estimated that these standards require 29% less watts per bulb in the first phase-in, increasing to 67% in 2020. General service incandescent bulbs become substandard in the 2012-2014 period and during this time halogen bulbs serve as the incandescent option. These halogen bulbs then become substandard in the 2020 specification, reducing general service lighting options to compact fluorescent and light-emitting diode (LED) technologies.

Energy Policy Act of 2005 (EPACT2005)

The passage of EPACT2005 in August 2005 provides additional minimum efficiency standards for residential equipment and provides tax credits to producers and purchasers of energy-efficient equipment and builders of energy-efficient homes. The standards contained in EPACT2005 include: 190-watt maximum for torchiere lamps in 2006; dehumidifier standards for 2007 and 2012; and ceiling fan light kit standards in 2007. For manufactured homes that are 30% better than the latest code, a $1,000 tax credit can be claimed in 2006 and 2007. Likewise, builders of homes that are 50% better than code can claim a $2,000 credit over the same period. The builder tax credits and production tax credits are assumed to be passed through to the consumer in the form of lower purchase cost. EPACT2005 includes production tax credits for energy-efficient refrigerators, dishwashers, and clothes washers in 2006 and 2007, with dollar amounts varying by type of appliance and level of efficiency met, subject to annual caps. Consumers can claim a 10% tax credit in 2006 and 2007 for several types of appliances specified by EPACT2005, including: energy-efficient gas, propane, or oil furnaces or boilers, energy-efficient central air conditioners, air and ground source heat pumps, water heaters, and windows. Lastly, consumers can claim a 30% tax credit in 2006 and 2007 for purchases of solar PV, solar water heaters, and fuel cells, subject to a cap.

Notes and sources

[5] The Model Documentation Report contains additional details concerning model structure and operation. Refer to Energy Information Administration, Model Documentation Report: Residential Sector Demand Module of the National Energy Modeling System, DOE/EIA-M067(2014) (August 2014). http://www.eia.gov/forecasts/aeo/nems/documentation/residential/pdf/m067(2014).pdf.

[6] U.S. Bureau of Census, Series C25 Data from various years of publications.

[7] U.S. Bureau of Census, Annual Housing Survey 2001 and Professional Remodeler, 2002 Home Remodeling Study.

[8] National Oceanic and Atmospheric Administration, National Weather Service, Experimental Monthly Degree Day Forecast, http://www.cpc.ncep.noaa.gov/pacdir/DDdir/ddforecast.txt. Explanation of forecast available at http://www.cpc.ncep.noaa.gov/pacdir/DDdir/N1.html.

[9] See Dahl, Carol, A Survey of Energy Demand Elasticities in Support of the Development of the NEMS, October 1993.

[10] The IECC established guidelines for builders to meet specific targets concerning energy efficiency with respect to heating and cooling load.

[11] Oak Ridge National Laboratory, Estimating the National Effects of the U.S. Department of Energy's Weatherization Assistance Program with State-Level Data: A Metaevaluation Using Studies from 1993 to 2005, September 2005.

[12] U.S. Department of Energy, Office of Inspector General, Office of Audit Services, Special Report: Progress in Implementing the Department of Energy's Weatherization Assistance Program under the American Recovery and Reinvestment Act, February 2010.

Chapter 5. Commercial Demand Module

The NEMS Commercial Demand Module (CDM) generates projections of commercial sector energy demand through 2040. The definition of the commercial sector is consistent with EIA's State Energy Data System (SEDS). That is, the commercial sector includes business establishments that are not engaged in transportation, manufacturing, or other types of industrial activity (e.g., agriculture, mining, or construction). The bulk of commercial sector energy is consumed within buildings; however, street lights, pumps, bridges, and public services are also included if the establishment operating them is considered commercial.

Because most of commercial energy consumption occurs in buildings, the commercial module relies on the data from the EIA Commercial Buildings Energy Consumption Survey (CBECS) for characterizing the commercial sector activity mix as well as the equipment stock and fuels consumed to provide end-use services [13].

The CDM projects consumption by fuel [14] at the Census division level using prices from the NEMS energy supply modules, macroeconomic variables from the NEMS Macroeconomic Activity Module (MAM), and external data sources for technology characterizations and other inputs. Energy demands are projected for 10 end-use services [15] for 11 building categories [16] in each of the 9 Census divisions (see Figure 5.1). The model begins by developing projections of floorspace for the 99 building category and Census division combinations. Next, the ten end-use service demands required for the projected floorspace are developed. The electricity generation and water and space heating supplied by distributed generation (DG) and combined heat and power (CHP) technologies are projected. Technologies are then chosen to meet the projected service demands for the seven major end uses. Once technologies are chosen, the energy consumed by the equipment stock (both existing and purchased equipment) is developed to meet the projected end-use service demands [17]. Minor end uses are modeled in less detail. Annual energy consumption of select miscellaneous end-use loads (MELs) are derived by combining existing and projected equipment stock, energy consumption per device, and hours of use where applicable.

Key assumptions

The key assumptions made by the commercial module are presented in terms of the flow of the calculations described above. The sections below summarize the assumptions in each of the CDM Submodules: floorspace, service demand, distributed generation, technology choice, and end-use consumption. The submodules are executed sequentially in the order presented, and the outputs of each submodule become the inputs to subsequently executed submodules. As a result, key projection drivers for the floorspace submodule are also key drivers for the service demand submodule, and so on.

Floorspace Submodule

Floorspace is projected by starting with the previous year's stock of floorspace and eliminating a portion to represent the age-related removal of buildings. Total floorspace is the sum of the surviving floorspace and new additions to the stock derived from the MAM floorspace growth projection [18].

Existing floorspace and attrition

Existing floorspace is based on the estimated floorspace reported in the 2003 Commercial Buildings Energy Consumption Survey (Table 5.1). Over time, the 2003 stock is projected to decline as buildings are removed from service (floorspace attrition). Floorspace attrition is estimated by a logistic decay function, the shape of which is dependent upon the values of two parameters: average building lifetime and gamma. The average building lifetime refers to the median expected lifetime of a particular building type. The gamma parameter corresponds to the rate at which buildings retire near their median expected lifetime. The current values for the average building lifetime and gamma vary by building type as presented in Table 5.2 [19].

New construction additions to floorspace

The commercial module develops estimates of projected commercial floorspace additions by combining the surviving floorspace estimates with the total floorspace projection from MAM. A total NEMS floorspace projection is calculated by applying the MAM assumed floorspace growth rate within each Census division and MAM building type to the corresponding NEMS CDM building types based on the CBECS building type shares. The NEMS surviving floorspace from the previous year is then subtracted from the total NEMS floorspace projection for the current year to yield new floorspace additions [20].

Service demand Submodule

Once the building stock is projected, the CDM develops a projection of demand for energy-consuming services required for the projected floorspace. The module projects service demands for the following explicit end-use services: space heating, space cooling, ventilation, water heating, lighting, cooking, refrigeration, personal computer office equipment, and other office equipment [21]. The service demand intensity (SDI) is measured in thousand Btu of end-use service demand per square foot and differs across service, Census division, and building type. The SDIs are based on a hybrid engineering and statistical approach of CBECS consumption data [22]. Projected service demand is the product of square feet and SDI for all end uses across the eleven building categories with adjustments for changes in shell efficiency for space heating and cooling.

Table 5.1. 2003 Total floorspace by Census division and principal building activity

millions of square feet

	Assembly	Education	Food Sales	Food Service	Health Care	Lodging	Large Office	Small Office	Merc/ Service	Warehouse	Other	Total
New England	431	299	75	45	48	374	282	320	819	411	351	3,452
Middle Atlantic	1,243	1,384	163	127	310	797	1,523	1,065	1,641	1,112	1,177	10,543
East North Central	1,355	1,990	218	248	316	549	1,297	1,129	2,148	2,023	1,152	12,424
West North Central	772	552	102	206	123	595	219	704	1,045	994	369	5,580
South Atlantic	1,161	2,445	223	433	469	939	1,173	1,065	3,391	1,836	865	13,999
East South Central	546	341	67	99	134	368	195	371	985	390	223	3,719
West South Central	965	1,198	197	232	235	387	195	371	985	390	223	3,719
Mountain	411	640	64	32	94	438	230	535	1,087	506	168	4,207
Pacific	809	1,027	146	232	176	649	1,028	915	2,051	1,066	515	8,613
Total United States	7,693	9,874	1,255	1,654	1,905	5,096	6,861	6,605	15,242	10,078	5,395	71,658

Note: Totals may not equal sum of components due to independent rounding.

Source: U.S. Energy Information Administration, 2003 Commercial Buildings Energy Consumption Survey Public Use Data.

Table 5.2. Floorspace attrition parameters

	Assembly	Education	Food Sales	Food Service	Health Care	Lodging	Large Office	Small Office	Merc/ Service	Ware-house	Other
Median Expected Lifetime (years)	55	62	55	50	55	53	65	58	50	58	60
Gamma	2.2	2.1	2.3	2.0	2.5	2.1	2.0	2.0	2.2	2.0	2.3

Source: U.S. Energy Information Administration, Commercial Buildings Energy Consumption Survey 2003, 1999, 1995, 1992, and 1989 Public Use Data, 1986 Nonresidential Buildings Energy Consumption Survey, McGraw-Hill Construction Dodge Annual Starts- non-residential building starts, Northwest Energy Efficiency Alliance, Assessment of the Commercial Building Stock in the Pacific Northwest, KEMA-XENERGY, Inc., March 2004, and public information on demolitions.

Shell efficiency

The shell integrity of the building envelope is an important determinant of the heating and cooling loads for each type of building. In the NEMS Commercial Demand Module, the shell efficiency is represented by separate heating and cooling factors that change over time to reflect improvements in the building shell. The factors, dimensioned by building type and Census division, affect the space heating and cooling service demand intensities causing changes in fuel consumed for these services as the shell integrity improves. In the AEO2016 Reference case, building shells for new construction built in 2003 are up to 49% more efficient with respect to heating and up to 30% more efficient with respect to cooling relative to the average shell for existing buildings of the same type. Over the projection horizon, new building shells improve in efficiency by 26% relative to their efficiency in 2003. For existing buildings, efficiency is assumed to increase by 6.9% over the 2003 stock average.

Distributed generation and combined heat and power

Program-driven installations of solar photovoltaic systems are based primarily on information from the GTM Research and the Solar Energy Industries Association (SEIA) quarterly report on U.S. solar market trends. Historical data from Form EIA-860, Annual Electric Generator Report, are used to derive electricity generation by Census division, building type, and fuel. A projection of distributed generation (DG) and combined heat and power (CHP) of electricity is developed based on the economic returns projected for DG and CHP technologies. The model uses a detailed cash-flow approach to estimate the internal rate of return for an investment. Penetration assumptions for distributed generation and CHP technologies are a function of the estimated internal rate of return relative to purchased electricity. Table 5.3 provides the cost and performance parameters for representative distributed generation and CHP technologies.

The model also incorporates endogenous learning for new DG and CHP technologies, allowing for declining technology costs as shipments increase. For fuel-cell and photovoltaic systems, parameter assumptions for the AEO2016 Reference case result in a 13% reduction in capital costs each time the installed capacity in the residential and commercial building sectors doubles (in the case of photovoltaics, utility-scale capacity is also included for learning). Doubling the installed capacity of microturbines results in a 10% reduction in capital costs and doubling the installed capacity of distributed wind systems results in a 3% reduction.

Technology Choice Submodule

The technology choice submodule develops projections of major end-use equipment to meet projected service demands using the three major fuels: electricity, natural gas, and distillate fuel. Capital purchase decisions are driven by assumptions concerning behavioral rule proportions and time preferences, described below, as well as projected fuel prices, average annual utilization of equipment (capacity factors), relative technology capital costs, and operating and maintenance (O&M) costs.

Decision types

In each projection year, equipment is potentially purchased for three decision types. Equipment must be purchased for newly added floorspace and to replace the portion of equipment in existing floorspace that is projected to wear out [23]. Equipment is also potentially purchased for retrofitting equipment that has become economically obsolete. The purchase of retrofit equipment occurs only if the annual operating costs of a current technology exceed the annualized capital and operating costs of a technology available as a retrofit candidate.

Table 5.3. Capital cost and performance parameters of selected commercial distributed generation technologies

Technology Type	Year of Introduction	Average Generating Capacity (kW_{DC})	Electrical Efficiency	Combined Efficiency (Elec. + Thermal)	Installed Capital Cost (2015 $ per kW_{DC})*	Service Life (Years)
Solar Photovoltaic	2015	40	0.17	N/A	$3,436	30
	2020	40	0.20	N/A	$2,339	30
	2030	40	0.26	N/A	$1,763	30
	2040	40	0.28	N/A	$1,715	30
Fuel Cell	2015	200	0.36	0.58	$5,458	20
	2020	200	0.36	0.58	$4,800	20
	2030	200	0.37	0.58	$3,662	20
	2040	200	0.38	0.60	$2,795	20
Natural Gas Engine	2015	373	0.33	0.85	$2,176	20
	2020	373	0.33	0.85	$2,204	20
	2030	373	0.33	0.85	$2,176	20
	2040	373	0.33	0.85	$1,137	20
Oil-fired Engine	2015	340	0.33	0.77	$2,016	20
	2020	340	0.33	0.77	$2,043	20
	2030	340	0.33	0.77	$2,016	20
	2040	340	0.33	0.77	$1,980	20
Natural Gas Turbine	2015	1210	0.24	0.86	$2,224	20
	2020	1222	0.25	0.86	$2,254	20
	2030	1247	0.25	0.87	$2,223	20
	2040	1272	0.26	0.87	$2,185	20
Natural Gas Microturbine	2015	250	0.26	0.62	$3,404	20
	2020	253	0.26	0.62	$3,404	20
	2030	258	0.27	0.63	$3,403	20
	2040	263	0.27	0.64	$3,344	20
Wind	2015	100	0.13	0.00	$5,900	30
	2020	100	0.13	0.00	$5,521	30
	2030	100	0.13	0.00	$4,847	30
	2040	100	0.13	0.00	$4,235	30

* The original source documents presented solar photovoltaic costs in 2008 dollars and all other technologies in 2010 dollars. Costs for solar photovoltaic, fuel cell, microturbine, and wind technologies include learning effects.

Sources: U.S. Energy Information Administration, Commercial and Industrial CHP Technology Cost and Performance Data Analysis for EIA SENTECH, Inc., and SAIC, Inc., June 2010; U.S. Energy Information Administration, Photovoltaic (PV) Cost and Performance Characteristics for Residential and Commercial Applications Final Report, ICF International, August 2010; U.S. Energy Information Administration, Review of Distributed Generation and Combined Heat and Power Technology Performance and Cost Estimates and Analytic Assumptions for National Energy Modeling System Draft Report, Leidos, January 2016; and U.S. Energy Information Administration, The Cost and Performance of Distributed Wind Turbines, 2010-35 Final Report, ICF International, August 2010.

Behavioral rules

The commercial module allows the use of three alternate assumptions about equipment choice behavior. These assumptions constrain the equipment selections to three choice sets, which are progressively more restrictive. The choice sets vary by decision type and building type:

- Unrestricted Choice Behavior - This rule assumes that commercial consumers consider all types of equipment that meet a given service, across all fuels, when faced with a capital purchase decision.
- Same Fuel Behavior - This rule restricts the capital purchase decision to the set of technologies that consume the same fuel that currently meets the decision maker’s service demand.
- Same Technology Behavior - Under this rule, commercial consumers consider only the available models of the same technology and fuel that currently meet service demand when facing a capital stock decision.

Under any of the above three behavior rules, equipment that meets the service at the lowest annualized lifecycle cost is chosen. Table 5.4 illustrates the proportions of floorspace subject to the different behavior rules for space heating technology choices in large office buildings.

Time preferences

Commercial building owners’ time preferences regarding current versus future expenditures are assumed to be distributed among seven alternate time preference premiums. Adding the risk-adjusted time preference premiums to the 10-year Treasury note rate from the MAM results in implicit discount rates, also known as hurdle rates, applicable to the assumed proportions of commercial floorspace. The effect of the use of this distribution of discount rates is to prevent a single technology from dominating purchase decisions in the lifecycle cost comparisons. The distribution used for AEO2016 assigns some floorspace a very high discount or hurdle rate to simulate floorspace which will never retrofit existing equipment and which will only purchase equipment with the lowest capital cost. Discount rates for the remaining six segments of the distribution get progressively lower, simulating increased sensitivity to the fuel costs of the equipment that is purchased. The share of floorspace assigned to each rate in the distribution varies by end-use service. Table 5.5 illustrates the distribution of time preference premiums for space heating and lighting in 2016. The proportion of floorspace assumed for the 0.0 time preference premium represents an estimate of the federally-owned commercial floorspace that is subject to purchase decisions in a given year. The federal sector is expected to purchase energy-efficient equipment to meet the federal buildings performance standards of the Energy Policy Act of 2005 (EPAct2005) and the Energy Independence and Security Act of 2007 (EISA2007) whenever cost-effective. For federal purchase decisions relating to energy conservation, cost-effectiveness is determined using a discount rate based on long-term Treasury bond rates, approximated in the commercial module by the 10-year Treasury note rate. For lighting, the proportion of floorspace assumed for the 0.0 time preference premium is increased to include all federal floorspace starting in 2009 to represent the EISA2007 provision that all federal buildings be equipped with energy-efficient lighting fixtures and bulbs to the maximum extent feasible, including when replacing bulbs in existing fixtures.

Table 5.4. Assumed behavior rules for choosing space heating equipment in large office buildings

percent

	Unrestricted	Same Fuel	Same Technology	Total
New Equipment Decision	21	30	49	100
Replacement Decision	7	31	62	100
Retrofit Decision	1	4	95	100

Source: U.S. Energy Information Administration, Model Documentation Report: Commercial Demand Module of the National Energy Modeling System, DOE/EIA-M066(2014) (August 2014).

Table 5.5. Assumed distribution of risk-adjusted time preference premiums for space heating and lighting equipment in 2015

percent

Time Preference Premium	Proportion of Floorspace-space Heating (2016)	Proportion of Floorspace-Lighting (2016)
1000.0	26.5	26.4
100.0	22.6	22.5
45.0	19.6	19.3
25.0	19.2	19.3
15.0	10.5	8.5
6.5	1.3	1.3
0.0	0.3	2.7
--	100.0	100.0

Source: U.S. Energy Information Administration, Model Documentation Report: Commercial Demand Module of the National Energy Modeling System, DOE/EIA-M066(2014) (August 2014).

The distribution of hurdle rates used in the commercial module is also affected by changes in fuel prices. If a fuel's price rises relative to its price in the base year (2003), the nonfinancial portion of each hurdle rate in the distribution decreases to reflect an increase in the relative importance of fuel costs, expected in an environment of rising prices. Parameter assumptions for AEO2016 result in a 30% reduction in the nonfinancial portion of a hurdle rate if the fuel price doubles. If the risk-adjusted time preference premium input by the model user results in a hurdle rate below the assumed financial discount rate–15% for the commercial sector–with base year fuel prices (such as the 0.0 rate given in Table 5.5), no response to increasing fuel prices is assumed.

Technology characterization menu

The technology characterization menu organizes all relevant major end-use equipment data. Equipment is indexed by technology, vintage, fuel, end-use service provided, and Census division (or building type for ventilation, lighting, and refrigeration end uses). Initial market share, efficiency (coefficient of performance or efficacy in the case of lighting equipment), installed capital cost per unit of service demand satisfied, operating and maintenance cost per unit of service demand satisfied, average service life, year of initial availability, and last year available for purchase are also characterized. Equipment may only be selected to satisfy service demand if the year in which the decision is made falls within the window of availability.

Equipment acquired prior to the lapse of its availability continues to be treated as part of the existing stock and is subject to replacement or retrofitting. This flexibility in limiting equipment availability allows the direct modeling of equipment efficiency standards. Table 5.6 provides a sample of the technology data for space heating in the New England Census division.

An option has been included to allow endogenous price-induced technological change in the determination of equipment costs and availability for the menu of equipment. This concept allows future technologies faster diffusion into the marketplace if fuel prices increase markedly for a sustained period of time. The option was not exercised for the AEO2016 model runs.

End-Use Consumption Submodule

The end-use consumption submodule calculates the consumption of each of the three major fuels (electricity, natural gas, and distillate fuel oil) for the ten end-use services plus fuel consumption for CHP and district services. For the ten end-use services, energy consumption is calculated as the end-use service demand met by a particular type of equipment divided by its efficiency, summed over all existing equipment types. This calculation includes dimensions for Census division, building type, and fuel. Consumption of the five minor fuels (residual fuel oil, liquefied petroleum gas, motor gasoline, kerosene, and coal) is projected based on historical trends.

Equipment efficiency

The average energy consumption of a particular appliance is based initially on estimates derived from the 2003 CBECS. As the stock efficiency changes over the model simulation, energy consumption decreases nearly as much as, but not quite proportionally to, the increase in efficiency. The difference is due to the calculation of efficiency using the harmonic average and also the efficiency rebound effect discussed below. For example, if on average, electric heat pumps are now 10% more efficient than in 2003, then all else constant (weather, real energy prices, shell efficiency, etc.), energy consumption per heat pump would now average about 9% less. The service demand and technology choice submodules together determine the average efficiency of the stocks used in adjusting the initial average energy consumption.

Adjusting for weather and climate

Recognition of the effect of weather on space heating and air conditioning is necessary to avoid projecting abnormal weather conditions into the future. In the CDM, proportionate adjustments are made to space heating and air conditioning demand by Census division. These adjustments are based on National Oceanic and Atmospheric Administration (NOAA) heating degree day (HDD) and cooling degree day (CDD) data. Short-term projections are informed by NOAA's 15-month outlook from their Climate Prediction Center [24], which often encompasses the first forecast year. Projections of degree days beyond that are informed by a 30-year linear trend of each state's degree days, which are then population-weighted to the Census division level. In this way, the CDM accounts for projected population migrations across the nation and continues any realized historical changes in degree days at the state level. A 10% increase in HDD would increase space heating consumption by 10% over what it would have been, while a 10% increase in CDD would increase cooling consumption by about 12.5%.

Table 5.6. Capital cost and efficiency ratings of selected commercial space heating equipment[1]

Equipment Type	Vintage	Efficiency[2]	Capital Cost (2013$ per MBtu/ hour)[3]	Maintenance Cost (2013$ per MBtu/ hour)[3]	Service Life (Years)
Rooftop Air-Source Heat Pump	2003 installed base	3.10	$67.78	$1.47	15
	2013 current standard/typical	3.30	$81.39	$1.47	15
	2013 high	3.40	$102.78	$1.47	15
	2020 typical	3.30	$80.28	$1.47	15
	2020 high	3.40	$102.78	$1.47	15
Ground-Source Heat Pump	2003 installed base	3.40	$545.83	$3.13	25
	2013 typical	3.60	$514.58	$3.13	25
	2013 mid	3.70	$530.21	$3.13	25
	2013 high	4.00	$571.88	$3.13	25
	2020 typical	3.80	$514.88	$3.13	25
	2020 high	4.20	$571.88	$3.13	25
	2030 typical	4.00	$514.58	$3.13	25
	2030 high	4.40	$571.88	$3.13	25
Electric Boiler	2003 installed base	0.94	$16.68	$0.26	15
	2012 installed base	0.94	$21.13	$0.26	15
Electric Resistance Heater	2003 installed base	0.98	$21.76	$0.01	18
Natural Gas Heat Pump	2003 Installed base (residential type)	1.30	$218.33	$2.67	15
	2013 typical (engine-driven rooftop)	1.40	$300.00	$4..92	15
	2020 typical (engine-driven rooftop)	1.40	$300.00	$4.92	15
	2030 typical (engine-driven rooftop)	1.40	$300.00	$4.92	15
Natural Gas Furnace	2003 installed base	0.71	$8.46	$1.13	15
	2013 current standard/typical	0.78	$9.21	$1.03	15
	2013 high	0.88	$11.78	$2.66	15
	2020 typical	0.79	$10.95	$1.03	15
	2020 high	0.88	$11.78	$2.66	15
	2030 typical	0.79	$10.95	$1.03	15
	2030 high	0.89	$11.78	$2.66	15
Natural Gas Boiler	2003 installed base	0.76	$29.36	$0.79	30
	2013 current standard/typical	0.80	$31.64	$0.75	30
	2013 mid-range	0.85	$33.97	$071	30
	2013 high	0.98	$32.33	$0.61	30
	2020 typical	0.82	$32.62	$0.73	30
	2020 high	0.98	$32.33	$0.61	30
	2030 typical	0.83	$33.06	$0.72	30

Table 5.6. Capital cost and efficiency ratings of selected commercial space heating equipment[1] (cont.)

Equipment Type	Vintage	Efficiency[2]	Capital Cost (2013$ per MBtu/ hour)[3]	Maintenance Cost (2013$ per MBtu/ hour)[3]	Service Life (Years)
Distillate Oil Furnace	2003 installed base	0.76	$14.46	$1.05	15
	2013 typical	0.80	$14.40	$1.01	15
	2020 typical	0.80	$14.40	$1.01	15
Distillate Oil Boiler	2003 installed base	0.79	$17.83	$0.17	30
	2013 current standard	0.82	$19.82	$0.17	30
	2013 typical	0.83	$20.68	$0.17	30
	2013 high	0.89	$30.90	$0.15	30
	2020 typical	0.83	$20.68	$0.17	30
	2020 high	0.89	$30.90	$0.15	30

[1]Equipment listed is for the New England Census division, but is also representative of the technology data for the rest of the United States. See the source reference below for the complete set of technology data.

[2]Efficiency metrics vary by equipment type. Electric rooftop air-source heat pumps, ground-source and natural gas heat pumps are rated for heating performance using coefficient of performance (COP); natural gas and distillate furnaces and boilers reflect thermal efficiency.

Source: U.S. Energy Information Administration, "EIA - Technology Forecast Updates - Residential and Commercial Building Technologies - Reference Case," Navigant Consulting, Inc., March 2014.

Short-term price effect and efficiency rebound

It is assumed that energy consumption for a given end-use service is affected by the marginal cost of providing that service. That is, all else equal, a change in the price of a fuel will have an inverse, but less than proportional, effect on fuel consumption. The current value for the short-term price elasticity parameter is -0.25 for all major end uses except refrigeration. A value of -0.10 is currently used for commercial refrigeration. A value of -0.05 is currently used for personal computers (PC) and non-PC office equipment and other minor uses of electricity. For example, for lighting, this value implies that for a 1.0% increase in the price of a fuel, there will be a corresponding decrease in energy consumption of 0.25%. Another way of affecting the marginal cost of providing a service is through equipment efficiency. As equipment efficiency changes over time, so will the marginal cost of providing the end-use service. For example, a 10% increase in efficiency will reduce the cost of providing the service by 10%. The short-term elasticity parameter for efficiency rebound effects is -0.15 for affected end uses; therefore, the demand for the service will rise by 1.5% (-10% x -0.15). Currently, all services are affected by the short-term price effect and services affected by efficiency rebound are space heating and cooling, water heating, ventilation and lighting.

Legislation and regulations

The Clean Power Plan

The Clean Power Plan (CPP) rule, issued under Section 111(d) of the Clean Air Act, allows states to comply with emissions targets by incentivizing energy efficiency in buildings. In the NEMS commercial model, the effects of incentivizing energy efficiency are modeled using subsidies for energy efficient heating, cooling, water heating, ventilation, lighting, and refrigeration technologies. These subsidies are accumulated with an assumed 50% added for administrative costs and sent to the power sector along with the accumulated energy savings for emission credits.

Consolidated Appropriations Act of 2016 (H.R. 2029)

The H.R.2029 legislation passed in December 2015 extends the investment tax credit (ITC) provisions of the Energy Policy Act of 2005 for renewable energy technologies. The five year ITC extension for solar energy systems allows for a 30% tax credit through 2019, then decreasing to 26% in 2020, 22% in 2021, then remaining at 10% from 2022 and after. The credit is directly incorporated into the cash-flow approach for projecting distributed generation by commercial photovoltaic systems and factored into the installed capital cost assumptions for solar water heaters.

American Recovery and Reinvestment Act of 2009 (ARRA2009)

The ARRA2009 legislation passed in February 2009 provides energy-efficiency funding for federal agencies, State Energy Programs, and block grants. To account for the impact of this funding, states are assumed to adopt and enforce the ASHRAE 90.1-2007 standard by 2018 for building shell measures, and all public buildings (federal, state, and local) are assumed to use the 10-year Treasury note rate for purchase decisions related to both new construction and replacement equipment while stimulus funding is available. A percentage of the State Energy Program and Conservation Block Grant funding is assumed to be used for solar photovoltaic and small wind turbine installations. Additional stimulus funding is applied to fuel cell installations.

The ARRA2009 provisions remove the cap on the 30% business investment tax credit (ITC) for wind turbines. The ITC is still available for systems installed through 2016. These credits are directly incorporated into the cash-flow approach for distributed generation systems.

Energy Improvement and Extension Act of 2008 (EIEA2008)

The EIEA2008 legislation passed in October 2008 extends the ITC provisions of the Energy Policy Act of 2005 and expands the credit to include additional technologies. The ITCs of 30% for solar energy systems and fuel cells and 10% for microturbines are extended through 2016. The cap on the fuel cell credit has been increased from $500 to $1,500 per half kilowatt of capacity. The EIEA2008 provisions expand the ITC to include a 10% credit for CHP systems and ground-source heat pumps and a 30% credit for wind turbines with the wind credit capped at $4,000. The expanded credits are available for systems installed through 2016. These credits are directly incorporated into the cash-flow approach for distributed generation systems, including CHP, and factored into the installed capital cost assumptions for solar water heaters and ground-source heat pumps effective in 2009 and 2010, and bans the manufacture or import of mercury vapor lamp ballasts effective January 1, 2008.

Energy Independence and Security Act of 2007 (EISA2007)

The EISA2007 legislation passed in December 2007 provides standards for specific explicitly modeled commercial equipment. The EISA2007 requires specific energy-efficiency measures in commercial walk-in coolers and walk-in freezers effective January 1, 2009, with an additional update effective in 2017. Incandescent and halogen lamps must meet standards for maximum allowable wattage based on lumen output starting in 2012 and metal halide lamp fixtures using lamps between 150 and 500 watts are required to have a minimum ballast efficiency ranging from 88% to 94%, depending on ballast type, effective January 1, 2009. Additional requirements become effective in 2017.

The EISA2007 requirement for federal buildings to use energy-efficient lighting fixtures and bulbs to the maximum extent possible is represented by adjusting the proportion of the commercial sector assumed to use the 10-year Treasury note rate as an implicit discount or hurdle rate for lighting.

Energy Policy Act of 2005 (EPACT2005)

The passage of the EPACT2005 in August 2005 provides additional minimum efficiency standards for commercial equipment. Some of the standards for explicitly modeled equipment, effective January 1, 2010, include an increased Energy Efficiency Rating (EER) for small package air conditioning and heating equipment; daily electricity consumption limits by volume for commercial refrigerators, freezers, and refrigerator-freezers; and electricity consumption limits per 100 pounds of ice produced based on equipment type and capacity for automatic ice makers. The EPACT2005 adds standards for medium-base compact fluorescent lamps effective January 1, 2006, for ballasts for Energy Saver fluorescent lamps effective in 2009 and 2010, and bans the manufacture or import of mercury vapor lamp ballasts effective January 1, 2008.

Several efficiency standards in the EPACT2005 pertain to equipment not explicitly represented in the NEMS Commercial Demand Module. For low-voltage dry-type transformers, effects of the standard are included in estimating the share of projected miscellaneous electricity use attributable to transformer losses. For illuminated exit signs, traffic signals, and commercial premise spray valves, assumed energy reductions are calculated based on per-unit savings relative to a baseline unit and the estimated share of installed units and sales that already meet the standard. Total projected reductions are phased in over time to account for stock turnover. Under the EPACT2005 standards, illuminated exit signs and traffic signal modules must meet ENERGY STAR program requirements as of January 1, 2006. The requirements limit input power demand to 5 watts or less per face for exit signs. Nominal wattages for traffic signal modules are limited to 8 to 15 watts, based on module type. Effective January 1, 2007, low-voltage dry-type distribution transformers are required to meet the National Electrical Manufacturers Association Class I Efficiency Levels with minimum efficiency levels ranging from 97% to 98.9% based on output. Commercial pre-rinse spray valves [25] must have a maximum flow rate of 1.6 gallons per minute, effective January 1, 2006, with energy reductions attributed to hot water use.

The EPACT2005 expands the business investment tax credit to 30% for solar property installed in 2006 and 2007. ITCs of 30% for fuel cells and 10% for microturbine power plants are also available for property installed in 2006 and 2007. The EPACT2005 tax credit provisions were extended in December 2006 to cover equipment installed in 2008. These credits are directly incorporated into the cash-flow approach for distributed generation systems and factored into the installed capital cost assumptions for solar hot water heaters.

Energy Policy Act of 1992 (EPACT1992)

A key assumption incorporated in the technology selection process is that the equipment efficiency standards described in the EPACT1992 constrain minimum equipment efficiencies. The effects of standards are modeled by modifying the technology database to eliminate equipment that no longer meets minimum efficiency requirements. Some of the EPACT1992 standards implemented in the module include: gas and oil-fired boilers—minimum combustion efficiency of 0.80 and 0.83, respectively, amended to minimum thermal efficiency of 0.80 and 0.81, respectively, in 2012; gas and oil-fired furnaces—minimum thermal efficiency of 0.80 and 0.81, respectively; electric water heaters—minimum energy factor of 0.85; and gas and oil water heaters—minimum thermal efficiency of 0.80 and 0.78, respectively. A fluorescent lamp ballast standard effective in 2005 mandates electronic ballasts with a minimum ballast efficacy factor of 1.17 for 4-foot, 2-lamp ballasts and 0.63 for 8-foot, 2-lamp ballasts. Fluorescent lamps and incandescent reflector lamb bulbs must meet amended standard levels for minimum average lamp efficacy in 2012. Recent updates for commercial refrigeration equipment include maximum energy consumption standards for refrigerated vending machines and display cases based on volume.

The 10% Business Investment Tax Credit for solar energy property included in EPACT1992 is directly incorporated into the cash-flow approach for projecting distributed generation by commercial photovoltaic systems. For solar water heaters, the tax credit is factored into the installed capital cost assumptions used in the technology choice submodule.

Energy efficiency programs

Several energy efficiency programs affect the commercial sector. These programs are designed to stimulate investment in more efficient building shells and equipment for heating, cooling, lighting, and miscellaneous end-use loads (MELs). The commercial module includes several features that allow projected efficiency to increase in response to voluntary programs (e.g., the distribution of risk-adjusted time preference premiums and shell efficiency parameters). Retrofits of equipment for space heating, air conditioning and lighting are incorporated in the distribution of premiums given in Table 5.5. Also, the shell efficiency of new and existing buildings is assumed to increase from 2003 through 2040. Shells for new buildings increase in efficiency by 26.0% over this period, while shells for existing buildings increase in efficiency by 6.9%.

Notes and sources

[13] U.S. Energy Information Administration, 2003 Commercial Buildings Energy Consumption Survey (CBECS) Public Use Files, http://www.eia.gov/consumption/commercial/data/2003/index.cfm?view=microdata

[14] The fuels accounted for by the commercial module are electricity, natural gas, distillate fuel oil, residual fuel oil, liquefied petroleum gas (LPG), coal, motor gasoline, and kerosene. Current commercial use of biomass (wood, municipal solid waste) is also included. In addition to these fuels, the use of solar energy is projected based on an exogenous estimate of existing solar photovoltaic system installations, projected installations due to state and local incentive programs, and the potential endogenous penetration of solar photovoltaic systems and solar thermal water heaters. The use of wind energy is projected based on an estimate of existing distributed wind turbines and the potential endogenous penetration of wind turbines in the commercial sector.

[15] The end-use services in the commercial module are heating, cooling, water heating, ventilation, cooking, lighting, refrigeration, PC and non-PC office equipment and a category denoted “miscellaneous end-use loads (MELs)” to account for all other minor end uses.

[16] The 11 building categories are assembly, education, food sales, food services, health care, lodging, large offices, small offices, mercantile/services, warehouse, and other.

[17] The detailed documentation of the commercial module contains additional details concerning model structure and operation. Refer to U.S. Energy Information Administration, Model Documentation Report: Commercial Demand Module of the National Energy Modeling System, DOE/EIA M066(2014) (August 2014).

[18] The commercial floorspace equations of the Macroeconomic Activity Model are estimated using the McGraw-Hill Construction Research & Analytics database of historical floorspace estimates. The McGraw-Hill Construction estimate for commercial floorspace in the United States is approximately 16% lower than the estimate obtained from the CBECS used for the Commercial module. See F.W. Dodge, Building Stock Database Methodology and 1991 Results, Construction Statistics and Forecasts, F.W. Dodge, McGraw-Hill.

[19] The commercial module performs attrition for nine vintages of floorspace developed using stock estimates from the previous five CBECS and historical floorspace additions data from McGraw-Hill Construction data.

[20] In the event that the computation of additions produces a negative value for a specific building type, it is assumed to be zero.

[21] “Other office equipment” includes copiers, fax machines, scanners, multi-function devices, data center servers, and other miscellaneous office equipment. A tenth category denoted “miscellaneous end-use loads (MELs)” includes equipment such as elevators, escalators, medical and other laboratory equipment, laundry, communications equipment, security equipment, transformers, and miscellaneous electrical appliances. Commercial energy consumed outside of buildings and for combined heat and power is also included in the “MELs” category.

Notes and sources (cont.)

[22] Based on 2003 CBECS end-use-level consumption data developed using the methodology described in Estimation of Energy End-Use Intensities, http://www.eia.gov/consumption/commercial/estimation-enduse-consumption.cfm .

[23] The proportion of equipment retiring is inversely related to the equipment life.

[24] National Oceanic and Atmospheric Administration, National Weather Service, Experimental Monthly Degree Day Forecast, http://www.cpc.ncep.noaa.gov/pacdir/DDdir/ddforecast.txt. Explanation of forecast is available at http://www.cpc.ncep.noaa.gov/pacdir/DDdir/N1.html.

[25] Commercial pre-rinse spray valves are handheld devices used to remove food residue from dishes and flatware before cleaning.

Chapter 6. Industrial Demand Module

The NEMS Industrial Demand Module (IDM) estimates energy consumption by energy source (fuels and feedstocks) for 15 manufacturing and 6 non-manufacturing industries. The manufacturing industries are subdivided further into the energy-intensive manufacturing industries and non-energy-intensive manufacturing industries (Table 6.1). The manufacturing industries are modeled through the use of a detailed process-flow or end-use accounting procedure. The non-manufacturing industries are modeled with less detail because processes are simpler and there is less available data. The petroleum refining industry is not included in the IDM, as it is simulated separately in the Liquid Fuels Market Module (LFMM) of NEMS. The IDM calculates energy consumption for the four Census Regions (Table 6.2) and disaggregates regional energy consumption to the nine Census Divisions based on fixed shares from the U.S. Energy Information Administration (EIA) *State Energy Data System* [26].

Table 6.1. Industry categories and NAICS codes

Energy-Intensive Manufacturing		Non-Energy-Intensive Manufacturing		Non-Manufacturing	
Food products	(NAICS 311)	Metal-based durables			
Paper and allied products	(NAICS 322)	Fabricated metal products	(NAICS 332)	Agricultural crop production	(NAICS 111)
Bulk chemicals		Machinery	(NAICS 333)		
Inorganic	(NAICS 32512-32518)	Computer and electronic products	(NAICS 334)	Other agricultural production	(NAICS 112, 113, 115)
Organic	(NAICS 32511, 32519)	Electrical equipment and appliances	(NAICS 335)	Coal mining	(NAICS 2121)
Resins	(NAICS 3252)	Transportation equipment	(NAICS 336)	Oil and gas extraction	(NAICS 211)
Agricultural Chemicals	(NAICS 3253)	Other Wood Products	(NAICS 321)	Metal and other non-metallic mining	(NAICS 2122-2123)
Glass and glass products	(NAICS 3272, 327993)	Plastic and rubber products	(NAICS 326)	Construction	(NAICS 23)
Cement and Lime	(NAICS 32731, 32741)	Balance of manufacturing	(NAICS 31-33 not already classified)		
Iron and Steel	(NAICS 3311-3312, 324199)				
Aluminum	(NAICS 3313)				

NAICS = North American Industry Classification System (2007).

Source: Office of Management and Budget, North American Industry Classification system (NAICS) - United States (Springfield, VA, National Technical Information Service).

Table 6.2. Census regions, Census divisions, and states

Census Region	Census Divisions	States
1 (East)	1,2	CT, ME, MA, NH, NJ, NY, PA, RI, VT
2 (Midwest)	3, 4	IL, IN, IA, KS, MI, MN, MO, ND, NE, OH, SD, WI
3 (South)	5, 6, 7	AL, AR, DE, DC, FL, GA, KY, LA, MD, MS, NC, OK, SC, TN, TX, VA, WV
4 (West)	8, 9	AZ, AK, CA, CO, HI, ID, MT, NV, NM, OR, UT, WA, WY

The energy-intensive manufacturing industries, consisting of food products, paper and allied products, bulk chemicals, glass and glass products, cement and lime, iron and steel, and aluminum, are modeled in considerable detail. Most industries are modeled as three separate but interrelated components: the Process and Assembly (PA) Component, the Buildings (BLD) Component, and the Boiler, Steam, and Cogeneration (BSC) Component. The BSC Component satisfies the steam demand from the PA and BLD Components. In some industries, the PA Component produces byproducts that are consumed in the BSC Component. The iron and steel industry as well as the paper industry use a more sophisticated process flow model which incorporates the BSC within the PA component. For the manufacturing industries, the PA Component is separated into the major production processes or end uses. Petroleum refining (NAICS 32411) is modeled in detail in the LFMM of NEMS, and the projected energy consumption is reported in the manufacturing total.

Projections of refining energy use, lease and plant fuel, and fuels consumed in cogeneration in the oil and gas extraction industry (NAICS 211) are exogenous to the IDM, but endogenous to the NEMS modeling system

Key assumptions - Manufacturing

The IDM primarily uses a bottom-up modeling approach. An energy accounting framework traces energy flows from fuels to the industry's output. An important assumption in the development of this system is the use of 2010 baseline Unit Energy Consumption (UEC) estimates based on analysis and interpretations of the 2010 Manufacturing Energy Consumption Survey (MECS), which is conducted by EIA on a four-year survey cycle [27]. The UECs represent the energy required to produce one unit of the industry's output. A unit of output may be defined in terms of physical units (e.g., tons of steel) or in dollar value of shipments.

The IDM depicts the manufacturing industries, except for petroleum refining, with either a detailed process-flow or end-use approach. Generally, industries with homogeneous products use a process-flow approach, and those with heterogeneous products use an end-use approach. Industries that use a process-flow approach are paper, glass, cement and lime, iron and steel, and aluminum. Industries that use an end-use approach are food, bulk chemicals, the five metal-based durables industries, wood, plastic and rubber products, and balance of manufacturing. The dominant process technologies are characterized by a combination of UEC estimates and Technology Possibility Curves (TPC). The TPC represents the annual rate of change from the base year to the end year of the projection. For end-use industries the TPC depicts the assumed average annual rate of change in energy intensity of either a process step or an energy end use (e.g., heating or cooling). The TPCs for new and existing plants vary by industry, vintage and process. These assumed rates were developed using professional engineering judgments regarding the energy characteristics, year of availability, and rate of market adoptions of new process technologies.

Process and/assembly component for end-use models

For industries modelled using an end-use approach, the PA component models each major manufacturing production step or end-use for the manufacturing industries. The throughput production for each process step is computed, as well as the energy required to produce it. The unit energy consumption (UEC) is defined as the amount of energy to produce a unit of output; it measures the energy intensity of the process or end use.

The module distinguishes the UECs by three vintages of capital stock. The amount of energy consumption reflects the assumption that new vintage stock will consist of state-of-the-art technologies that have different efficiencies from the existing capital stock. Consequently, the amount of energy required to produce a unit of output using new capital stock is often less than that required by the existing capital stock. The old vintage consists of capital existing in 2010 and surviving after adjusting for assumed retirements each year (Table 6.3). New production capacity is assumed to be added in a given projection year such that sufficient surviving and new capacity is available to meet the level of an industry's output as determined in the NEMS Regional Macroeconomic Module. Middle vintage capital is that which is added after 2010 up through the year prior to the current projection year.

Table 6.3. Retirement rates

Industry	Retirement Rate (percent)	Industry	Retirement Rate (percent)
Food Products	1.7	Wood Products	1.3
Bulk Chemicals	1.7	Plastics and Rubber Products	1.3
Metal-based Durables	1.3	Balance of Manufacturing	1.3

Source: SAIC, IDM Base Year Update with MECS 2006 Data, unpublished data prepared for the Office of Integrated Analysis and Forecasting, Energy Information Administration, Washington, DC, August 2010.

To simulate technological progress and adoption of more energy-efficient technologies, the UECs are adjusted each projection year based on the assumed TPC for each step. The TPCs are derived from assumptions about the relative energy intensity (REI) of productive capacity by vintage (new capacity relative to existing stock in a given year) or over time (new or surviving capacity in 2040 relative to the 2010 stock). Over time, the UECs for new capacity change, and the rate of change is given by the TPC. The UECs of the surviving 2010 capital stock are also assumed to change over time, but not as rapidly as for new capital stock because of retrofitting.

The concepts of REIs and TPCs are a means of embodying assumptions regarding new technology adoption in the manufacturing industry and the associated change in energy consumption of capital without characterizing individual technologies in detail. This approach reflects the assumption that industrial plants will change energy consumption as owners replace old equipment with new, sometimes more efficient equipment, add new capacity, add new products, or upgrade their energy management practices. The reasons for the increased efficiency are not likely to be directly attributable to technology choice decisions, changing energy prices, or other factors readily subject to modeling. Instead, the module uses the REI and TPC concepts to characterize intensity trends for bundles of technologies available for major process steps or end use.

Table 6.4. Technology Possibility Curves and Relative Energy Intensities for end-use models

Industry/Process Unit	Existing Facility Reference REI 2040[1]	Existing Facility Reference TPC%	New Facility REI 2010[2]	New Facility Reference REI 2040[3]	New Facility Reference TPC%
Food Products-Milling					
Process Heating-Electricity	0.900	-0.351	0.900	0.800	-0.392
Process Heating-Steam	0.810	-0.701	0.900	0.711	-0.784
Process Cooling-Electricity	0.900	-0.351	0.900	0.800	-0.392
Process Cooling-Natural Gas	0.900	-0.351	0.900	0.800	-0.392
Other-Electricity	0.900	-0.351	0.900	0.800	-0.392
Other-Natural Gas	0.950	-0.171	0.950	0.850	-0.370
Food Products-Dairy					
Process Heating-Electricity	0.980	-0.067	0.970	0.950	-0.069
Process Heating-Steam	0.930	-0.242	0.950	0.850	-0.370
Process Cooling-Electricity	0.900	-0.351	0.900	0.800	-0.392
Process Cooling-Natural Gas	0.980	-0.067	0.970	0.950	-0.069
Other-Electricity	0.930	-0.242	0.960	0.850	-0.405
Other-Natural Gas	0.980	-0.067	0.970	0.950	-0.069
Food Products-Animal Processing					
Process Heating-Electricity	0.980	-0.067	0.970	0.950	-0.069
Process Heating-Steam	0.950	-0.171	0.950	0.900	-0.180
Process Cooling-Electricity	0.930	-0.242	0.950	0.850	-0.370
Process Cooling-Natural Gas	0.980	-0.067	0.970	0.950	-0.069
Other-Electricity	0.950	-0.171	0.980	0.900	-0.283
Other-Natural Gas	0.980	-0.067	0.970	0.950	-0.069
Food Products-Other					
Process Heating-Electricity	0.980	-0.067	0.970	0.950	-0.069
Process Heating-Steam	0.930	-0.242	0.950	0.850	-0.370
Process Cooling-Electricity	0.930	-0.242	0.950	0.850	-0.370
Process Cooling-Natural Gas	0.980	-0.067	0.970	0.950	-0.069
Other-Electricity	NA	-0.171	NA	NA	-0.125
Other-Natural Gas	0.980	-0.067	0.970	0.950	-0.069

Table 6.4. **Technology Possibility Curves and Relative Energy Intensities for end-use models** (cont.)

Industry/Process Unit	Existing Facility Reference REI 2040[1]	Existing Facility Reference TPC%	New Facility REI 2010[2]	New Facility Reference REI 2040[3]	New Facility Reference TPC%
Bulk Chemicals-Inorganic					
Process Heating-Electricity	0.893	-0.376	0.900	0.793	-0.420
Process Heating-Steam	0.798	-0.751	0.900	0.699	-0.840
Process Cooling-Electricity	0.867	-0.476	0.850	0.743	-0.446
Process Cooling-Natural Gas	0.893	-0.376	0.900	0.793	-0.420
Electro-Chemicals	0.979	-0.072	0.950	0.843	-0.396
Other-Electricity	0.908	-0.321	0.915	0.803	-0.434
Other-Natural Gas	0.893	-0.376	0.900	0.793	-0.420
Bulk Chemicals-Organic					
Process Heating-Electricity	0.893	-0.376	0.900	0.793	-0.420
Process Heating-Steam	0.635	-1.502	0.720	0.433	-1.679
Process Cooling-Electricity	0.867	-0.476	0.850	0.743	-0.446
Process Cooling-Natural Gas	0.798	-0.751	0.720	0.559	-0.840
Electro-Chemicals	0.979	-0.072	0.950	0.843	-0.396
Other-Electricity	0.908	-0.321	0.915	0.803	-0.434
Other-Natural Gas	0.798	-0.751	0.720	0.559	-0.840
Bulk Chemicals-Resin and Synthetic Rubber					
Process Heating-Electricity	0.893	-0.376	0.900	0.793	-0.420
Process Heating-Steam	0.635	-1.502	0.720	0.433	-1.679
Process Cooling-Electricity	0.867	-0.476	0.850	0.743	-0.446
Process Cooling-Natural Gas	0.798	-0.751	0.720	0.559	-0.840
Electro-Chemicals	0.979	-0.072	0.950	0.843	-0.396
Other-Electricity	0.908	-0.321	0.915	0.803	-0.434
Other-Natural Gas	0.798	-0.751	0.720	0.559	-0.840
Bulk Chemicals-Agricultural Chemicals					
Process Heating-Electricity	0.893	-0.376	0.900	0.793	-0.420
Process Heating-Steam	0.798	-0.751	0.900	0.699	-0.840
Process Cooling-Electricity	0.867	-0.476	0.850	0.743	-0.446
Process Cooling-Natural Gas	NA	-0.376	NA	NA	-0.420
Electro-Chemicals	.979	-0.072	0.950	0.843	-0.396
Other-Electricity	.908	-0.321	0.915	0.803	-0.434
Other-Natural Gas	.893	-0.376	0.900	0.793	-0.420

Table 6.4. Technology Possibility Curves and Relative Energy Intensities for end-use models (cont.)

Industry/Process Unit	Existing Facility Reference REI 2040[1]	Existing Facility Reference TPC%	New Facility REI 2010[2]	New Facility Reference REI 2040[3]	New Facility Reference TPC%
Fabricated Metals					
Process Heating-Electricity	0.712	-1.127	0.675	0.406	-1.679
Process Cooling-Electricity	0.650	-1.427	0.638	0.371	-1.784
Process Cooling-Natural Gas	0.712	-1.127	0.675	0.406	-1.679
Electro-Chemical Process	0.937	-0.216	0.713	0.441	-1.586
Other-Electricity	0.748	-0.962	0.686	0.406	-1.737
Machinery					
Process Heating-Electricity	0.712	-1.427	0.675	0.314	-2.519
Process Cooling-Electricity	0.650	-1.427	0.638	0.283	-2.676
Process Cooling-Natural Gas	0.712	-1.127	0.675	0.314	2.519
Electro-Chemical Process	0.937	-0.216	0.713	0.346	2.379
Other-Electricity	0.748	-0.962	0.686	0.311	-2.606
Computers and Electronics					
Process Heating-Electricity	0.798	-0.751	0.720	0.559	-0.840
Process Cooling-Electricity	0.751	-0.952	0.680	0.520	-0.892
Process Cooling-Natural Gas	NA	-0.751	NA	NA	-0.840
Electro-Chemical Process	0.958	-0.144	0.760	0.599	-0.793
Other-Electricity	0.824	-0.641	0.732	0.563	-0.869
Electrical Equipment					
Process Heating-Electricity	0.798	-0.751	0.720	0.559	-0.840
Process Heating-Steam	NA	-1.502	NA	NA	-1.679
Process Cooling-Electricity	0.751	-0.952	0.680	0.520	-0.892
Process Cooling-Natural Gas	0.798	-0.751	0.720	0.559	-0.840
Electro-Chemical Process	0.958	-0.144	0.760	0.599	-0.793
Other-Electricity	0.824	-0.641	0.732	0.563	-0.869
Transportation Equipment					
Process Heating-Electricity	0.854	-0.526	0.765	0.625	-0.672
Process Heating-Steam	0.728	-1.052	0.765	0.510	-1.343
Process Cooling-Electricity	0.818	-0.666	0.723	0.583	-0.714
Process Cooling-Natural Gas	0.854	-0.526	0.765	0.625	-0.672
Electro-Chemical Process	0.970	-0.101	0.808	0.667	-0.634
Other-Electricity	0.874	-0.449	0.778	0.631	-0.695

Table 6.4. Technology Possibility Curves and Relative Energy Intensities for end-use models (cont.)

Industry/Process Unit	Existing Facility Reference REI 2040[1]	Existing Facility Reference TPC%	New Facility REI 2010[2]	New Facility Reference REI 2040[3]	New Facility Reference TPC%
Wood Products					
Process Heating-Electricity	0.712	-1.127	0.630	0.379	-1.679
Process Heating-Steam	0.505	-2.253	0.630	0.226	-3.358
Process Cooling-Electricity	0.650	-1.427	0.595	0.347	-1.784
Process Cooling-Natural Gas	0.712	-1.127	0.670	0.379	-1.679
Electro-Chemical Process	0.937	-0.216	0.655	0.412	-1.586
Other-Electricity	0.748	-0.962	0.641	0.379	-1.737
Plastic Products					
Process Heating-Electricity	0.798	-0.751	0.675	0.524	-0.840
Process Heating-Steam	0.635	-1.052	0.675	0.406	-1.679
Process Cooling-Electricity	0.751	-0.952	0.638	0.487	-0.892
Process Cooling-Natural Gas	0.798	-0.751	0.675	0.524	-0.840
Electro-Chemical Process	0.958	-0.144	0.713	0.561	-0.793
Other-Electricity	0.824	-0.641	0.686	0.528	-0.869
Balance of Manufacturing					
Process Heating-Electricity	0.844	-0.563	0.675	0.551	-0.672
Process Heating-Steam	0.712	-1.127	0.675	0.450	-1.343
Process Cooling-Electricity	0.807	-0.714	0.638	0.514	-0.714
Process Cooling-Natural Gas	0.844	-0.563	0.675	0.551	-0.672
Electro-Chemical Process	0.968	-0.108	0.713	0.589	-0.634
Other-Electricity	0.844	-0.563	0.675	0.551	-0.672

[1]REI 2040 Existing Facilities = Ratio of 2040 energy intensity to average 2010 energy intensity for existing facilities.
[2]REI 2010 New Facilities = For new facilities, the ratio of state-of-the-art energy intensity to average 2010 energy intensity for existing facilities.
[3]REI 2040 New Facilities = Ratio of 2040 energy intensity for a new state-of-the-art facility to the average 2010 intensity for existing facilities.
Source: SAIC, IDM Base Year Update with MECS 2010 Data, unpublished data prepared for the Industrial Team, Office of Energy Consumption and Efficiency Analysis, Energy Information Administration, Washington, DC, July 2013.

Electric Motor Stock Model

One exception to the general approach in the PA component in the end-use models is the use of an electric motor technology model. Machine drive electricity consumption in the bulk chemicals industry, the food industry, the five metal-based durables industries, wood, plastics and rubber products, and balance of manufacturing is calculated by a motor stock model [28]. The beginning stock of motors is modified over the projection horizon as motors are added to accommodate growth in shipments for each sector, as motors are retired and replaced, and as failed motors are rewound. When an old motor fails, an economic choice is made on whether to repair or replace the motor. When a new motor is added, either to accommodate growth or as a replacement, the motor must meet the minimum efficiency standard and a premium efficiency motor is also available. Table 6.5 provides the beginning stock efficiency for seven motor size groups in each of the three industry groups, as well as efficiencies for replacement motors. All replacement motors are assumed to be premium high efficiency motors because of current regulations.

Table 6.5. Cost and performance parameters for industrial motor choice model

Industrial Sector Horsepower Range	Average Efficiency	Replacement Motor Efficiency	Rewind Cost (2002$)	Replacement Cost (2002$)
Food				
1-5 hp	81.3	89.5	230	442
6 - 20 hp	87.1	93.0	427	1047
21 - 50 hp	90.1	94.5	665	1889
51 - 100 hp	92.7	95.4	1258	5398
101 - 200 hp	93.5	96.2	2231	10,400
201 - 500 hp	93.8	96.2	4363	20,942
> 500 hp	93.0	96.2	5726	28,115
Bulk Chemicals				
1-5 hp	82.0	89.5	230	442
6 - 20 hp	87.4	93.0	427	1047
21 - 50 hp	90.4	94.5	665	1889
51 - 100 hp	92.4	95.4	1258	5398
101 - 200 hp	93.5	96.2	2231	10,400
201 - 500 hp	93.3	96.2	4363	20,942
> 500 hp	93.2	96.2	5726	28,115
Metal-Based Durables[a]				
1-5 hp	82.2	89.5	230	442
6-20 hp	87.3	93.0	427	1047
21-50 hp	90.1	94.5	665	1889
51-100 hp	92.4	95.4	1258	5398
101-200 hp	93.5	96.2	2231	10,400
201-500 hp	94.5	96.2	4363	20,942
>500 hp	94.4	96.2	5726	28,115
Balance of Manufacturing[b]				
1-5 hp	81.8	89.5	230	442
6-20 hp	86.6	93.0	427	1047
21-50 hp	89.9	94.5	665	1889
51-100 hp	92.1	95.4	1258	5398
101-200 hp	93.2	96.2	2231	10,400
201-500 hp	93.1	96.2	4363	20,942
>500 hp	93.1	96.2	5726	28,115

[a]The metal-based durables group includes five sectors that are modeled separately: Fabricated Metals; Machinery; Computers and Electronics; Electrical Equipment; and Transportation Equipment.

[b]The balance of manufacturing group includes three sectors that are modeled separately: Wood Products; Plastic and Rubber Products; and All Other Manufacturing.

Source: U.S. Energy Information Administration, Model Documentation Report, Industrial Sector Demand Module of the National Energy Modeling System (Washington, DC, September 2013).

Note: The efficiencies listed in this table are operating efficiencies based on average part-loads. Because the average part-load is not the same for all industries, the listed efficiencies for the different motor sizes vary across industries.

Petrochemical feedstock requirement

This subroutine estimates feedstock requirements for the major petrochemical intermediates such as ethylene, propylene, and butadiene. The primary feedstocks used to produce these chemicals are natural gas liquids (NGL) (ethane, propane, butane) and petrochemical (oil-based) feedstocks (gas oil, naphtha) [29]. Biomass is a potential raw material source, but it is assumed that there will be no biomass-based capacity over the projection period because of economic barriers. The type of feedstock not only determines the source of feedstock but also the energy for heat and power requirements to produce the chemicals.

To determine the relative amounts of feedstock (NGL or oil-based) baseline intensities, feedstock consumption intensities are derived from the 2010 MECS. Feedstock consumption of both types grows or declines with organic chemicals shipment value. It should be noted that there is no change in the feedstock intensity over time, i.e., all feedstock TPCs are assumed to be zero. Unlike most other processes represented in manufacturing PA components, chemical yields are governed by basic chemical stoichiometry which allows for specific yields under set conditions of pressure and temperature. For the projected LPG feedstock quantities, a further subdivision is made into refinery-produced propylene and ethane. All ethane produced by the NEMS Oil & Gas Supply Module is absorbed by the chemical model. The remaining balance of LPG feedstock requirement is a mixture of pentanes plus, butane, and propane. The historical (baseline) feedstock consumption values for 2015 were obtained from Table 6.6, which displays EIA's assessment of historical annual feedstock consumption for chemicals.

Table 6.6. Feedstock use of fossil fuels, 2001-2015

quadrillion Btu

Year	Hydrocarbon Gas Liquids Feedstocks[1]	Petrochemical Feedstocks	Other Feedstocks[2]	Natural Gas[3]
2001	1.78	1.16	0.27	0.70
2002	1.88	1.21	0.28	0.68
2003	1.83	1.31	0.28	0.61
2004	1.92	1.53	0.28	0.54
2005	1.78	1.41	0.29	0.48
2006	1.85	1.42	0.30	0.40
2007	1.86	1.31	0.27	0.43
2008	1.70	1.12	0.28	0.47
2009[a]	1.85	0.90	0.35	0.48
2010	1.99	0.94	0.36R	0.51
2011	2.12	0.88	0.39R	0.55
2012	2.16	0.74	0.36R	0.58
2013	2.27R	0.74	0.37R	0.59
2014	231	0.69	0.38	0.63
2015[P]	2.33	0.65	0.37	0.68

[1]Includes natural gasoline -- hydrocarbon gas liquids were previously called natural gas liquids and natural gasoline is pentanes plus.

[2]Distillate fuel oil, residual fuel oil, waxes, still gas not burned as a refinery fuel and miscellaneous products.

[3]U.S. Energy Information Administration (EIA) has altered the methodology for the natural gas estimates. The estimates are based on data for methanol and ammonia production that are used to move the MECS values for nonfuel uses of natural gas in non-MECS years.

P=Preliminary.

R=Revised

Notes: Estimates of consumption for non-combustion use shown in this table are included in total energy consumption (see Table 1.3). See Note 2, "Non-Combustion Use of Fossil Fuels," at end of section. Because of changes in methodology, data series may be revised annually. Estimates of non-combustion use in this table are considered industrial uses with the exception of approximately half of the lubricants which are considered transportation use. Totals may not equal sum of components due to independent rounding. Web Pages: See http://www.eia.gov/totalenergy/data/annual/#summary for all data beginning in 1980.

For related information, see http://www.eia.gov/environment/.

Sources: Petroleum Products: 1980—EIA, Energy Data Reports, Petroleum Statement, Annual and Sales of Liquefied Petroleum Gases and Ethane in 1980. 1981 forward—EIA, Petroleum Supply Annual, annual reports, and unpublished data. Natural Gas: 1980—Bureau of the Census, 1980 Survey of Manufactures, Hydrocarbon, Coal, and Coke Materials Consumed. 1981 forward—U.S. Department of Commerce. Coal: 1980 forward—EIA estimates based on the methodology underlying the nonfuel emissions calculations in EIA's Emissions of Greenhouse Gases in the United States 2008. Percent of Total Energy Consumption: Derived by dividing total nonfuel by total energy consumption on Table 1.3.

Process/assembly component for process-flow models

Five energy-intensive industries are modelled using a process-flow approach instead of the end-use approach. Those industries are the cement and lime industry, the aluminum industry, the glass industry, the iron and steel industry, and the paper industry. The new modules use a suite of detailed technology choices for each process flow. Instead of the aggregate energy intensity evolving according to TPCs, the process-flow models use technology choice for each process flow. Energy requirements for each technology is obtained from technology estimates (e.g. expenditures, energy coefficients, and utility needs) from the Consolidated Impacts Modeling System (CIMS) database which is prepared by the Pacific Northwest National Laboratory. Depending on the industry, this data is calibrated using inputs from the U.S. Geological Survey (USGS) of the U.S. Department of the Interior, the Portland Cement Association and the latest MECS released by EIA [30, 31, 32].

The process-flow models calculate surviving capacity based retirement and needed capacity based on shipments and surviving capacity. The baseline capacity (as of year 2008 or 2009) is assumed to retire at a linear rate over a fixed period of time (20 years). Incremental, or added, capacity is assumed to retire according to a logistic survival function. The exact shape of the “S” curve can be obtained by parameters adjusted by the analyst. New capital equipment information (capital and operating costs, energy use, and emissions) were obtained from the CIMS database. Each step of the process flow allows for multiple technology choices whose fuel type and efficiency are known at the national level, as regional fuel breakouts are fixed using available EIA data.

Combined cement and lime industry

For the cement process flow, each step (raw material grinding, kiln – both rotation and burner, finished grinding) allows for multiple technology choices whose fuel type and efficiency are known at the national level, as regional fuel breakouts are fixed using available EIA data.

Cement has both dry and wet mill processes. Some technologies are available to both processes, while others are available to only one process. The technology choices within each group are:

1. Raw materials grinding: ball mill, roller mill
2. Kilns (rotators): rotary long with preheat, precalcining, and computer control (dry process only), rotary preheat with high-efficiency cooler (dry only), rotary preheat, precalcine with efficient cooler (dry process only), rotary wet standard with waste heat recovery boiler and cogeneration (wet process only)
3. Kilns (burners): standard fired by natural gas, efficient fired by natural gas, standard fired by oil, efficient fired by oil, standard fired by coal, standard fired by petroleum coke, standard fired by hazardous waste, standard fired by residue-derived fuel
4. Finish grinding: standard ball mill, finishing ball mill with high-efficiency separator, standard roller mill, finishing roller mill with high-efficiency separator

The technology slate in each of these process steps evolves over time and depends on the relative cost of equipment, cost of fuel, and fuel efficiency. Retirement of existing wet process kiln technology is assumed to be permanent; only dry process kilns can be added to replace retired wet kilns or to satisfy needed additional capacity.

The base year technology slate is determined from the latest CIMS database and calibrated for the year 2008 with dry and wet mill capacity cement fuel use data from the Portland Cement Association, the USGS, and the 2010 MECS. All new cement capacity, both for replacement and increased production, is assumed to be dry cement capacity. Existing wet capacity is assumed to retire at a linear rate over 20 years with no replacement. Imported clinker, additives, and fly-ash are assumed to make constant percentage contributions to the finished product and thus “displace” a certain amount of domestic clinker production, and therefore energy use.

Lime energy consumption is estimated separately from cement but presented together as the consolidated cement and lime energy consumption. Energy consumption and technology evolution in the lime industry are driven by the same methods implemented for cement, with different, industry-specific equipment choices. Lime shipments are now explicitly provided by the Macroeconomic Activity Module (MAM), rather than estimated as a percentage of the non-metallic minerals sector.

Aluminum industry

For the aluminum industry model, each step (alumina production, anode production, and electrolysis for primary aluminum production, and melting for secondary production), allows for multiple technology choices whose fuel type and efficiency are known, as well as other operating characteristics. Technology shares are known at the national level, with regional fuel breakouts based on fixed allocations using available EIA data.

The aluminum industry has both primary and secondary production processes, which vary greatly in their energy demands. As such, the extent of these processes are based on the aluminum industry’s projected production and its historical share of production processes attenuated by relevant regional energy prices. Therefore, the fraction of total throughput from each aluminum production process varies over the model projections. However, it is assumed based on expert judgment that no new primary aluminum plants will be built in the United States before 2040, although capacity expansion of existing primary smelters may occur.

Some technologies are available to both processes, while others are available to only one process. The technology choices within each production processing group are:

1. Primary smelting (Hall-Heroult electrolysis cell) is represented as smelting in four pre-bake anode technologies that denote standard and retrofitted choices and one inert anode wetted cathode choice.
2. Anode production, used in primary production only, is represented by three natural gas-fired furnaces under various configurations in forming and baking pre-bake anodes and the formation of Söderberg anodes. Note that anodes are a major requirement for the Hall-Heroult process.
3. Alumina production (Bayer Process) is used in primary production only and selects between existing natural gas facilities and those with retrofits.
4. Secondary production selects between two natural gas-fired melters – i.e., a standard and a melter with high efficiency

The technology slate in each of these process steps evolves over time and depends on the relative cost of equipment, cost of fuel, and fuel efficiency. The base year technology slate is determined from the latest CIMS database and calibrated for the base year 2010 MECS and the USGS. All new capacities for aluminum production, both for replacement and increased production needs, are now assumed to be either pre-existing primary production or new secondary production, based on historical trend data and projected energy prices. Similar to the energy-intensive technology of the cement industry, the lifespan of existing and new production capacity is assumed to be 20 and 30 years, respectively. In addition, production that has been idled is allowed to re-enter production before new equipment is built.

Glass industry

For the glass industry model, each step of the three glass product processes modeled in the IDM (flat glass, pressed and blown glass, glass containers) allows for multiple technology choices whose fuel type and efficiency are known, as well as other operating characteristics.

For flat glass (NAICS 327211) the process steps include batch preparation, furnace, form & finish, and tempering. For pressed and blown glass (NAICS 327212), the process steps include preparation, furnace, form & finish, and fire polish. For glass containers (NAICS 327213), the process steps include preparation, furnaces, and form & finish. For fiberglass (“mineral wool” – NAICS 327993), the process steps include preparation, furnaces, and form & finish. The final category (“glass from glass products” – NAICS 327215) was not modeled as a process flow with technology choice but instead endowed with fuel-specific UECs which evolved over time via TPC. Below is a summary list of technologies used in the glass sub-module. Not all of the technologies below are available to all processes.

1. The preparation step (collection, grinding, and mixing of raw materials including cullet) uses either a standard set of grinders/motors or an advanced set that is computer-controlled.
2. The furnaces, which melt the glass, are air-fueled or oxy-fueled burners which employ natural gas. Electric boosting furnace technology is also available. Direct electric (or Joule) heating is available for fiberglass production.
3. The form & finish process is done for all glass products and the technologies can be selected from high-pressure gas-fired computer-controlled or basic technology.
4. There is no known technology choice for the tempering step (flat glass) or the polish (blown glass). Placeholders for more-efficient future technology choices were implemented, but their introduction into these processes was rather limited.

As with the other sub-modules, the technology slate in each of these process steps evolves over time and depends on the relative cost of equipment, cost of fuel, and fuel efficiency. Oxy-fueled burners were added as a retrofit to the burner technologies, and their additive impact is determined by the relative price of natural gas vs. electricity.

Iron and Steel industry

The iron and steel industry includes the following major process steps: coke making, iron making, steel making, steel casting, and steel forming. Steel manufacturing plants can be classified as integrated or non-integrated. The classification is dependent upon the number of the major process steps that are performed in the facility. Integrated plants perform all the process steps, whereas non-integrated plants, in general, perform only the last three steps.

For the IDM, a process flow was developed to separate the process into five steps around which unit energy consumption values were estimated. Below is a summary list of steps and technologies:

1. Coke ovens convert metallurgical coal into coke.
2. Iron is produced in the blast furnace (BF), which is then charged into a basic oxygen furnace (BOF) or open hearth (OH) to produce raw steel.
3. The electric arc furnace (EAF) is used to produce raw steel from an all-scrap (recycled materials) charge, sometimes supplemented with direct reduced iron or hot briquetted iron.
4. The raw steel is cast into blooms, billets or slabs using continuous casting, or more rarely, ingots. Some ingot or cast steel is sold directly (e.g., forging-grade billets).
5. The majority is further processed ('hot rolled') into various mill products. Some of these are sold as hot rolled mill products, while others are further cold rolled to impart surface finish or other desirable properties.

Pulp and Paper industry

The paper and allied products industry's principal processes involve the conversion of wood fiber to pulp, and then paper and board to consumer products that are generally targeted at the domestic marketplace. The industry produces a full line of paper and board products, as well as dried pulp, which is sold as a commodity product to domestic and international paper and board manufacturers. Below is a summary list of steps and technologies.

1. Wood preparation involves removing the bark and chipping the whole tree into small pieces.
2. Pulping is the process by which fibrous cellulose in the wood is removed from the surrounding lignin. Pulping can be conducted with a chemical process or a mechanical process.
3. Pulp washing is the process of washing the pulp with water to remove the cooking chemicals and lignin from the fiber.
4. Drying, liquor evaporation, effluent treatment, and other miscellaneous steps are part of the pulping process. Prior to heat drying, pulps are sent to a pressing section to squeeze out as much water as possible though mechanical means. The pulp is compressed between two rotating rolls where the extent of water removal is dependent on the design of the machine and its running speed. When the pressed pulp leaves the pressing section, it has about 65% moisture content. There are various techniques for drying, each with a different energy footprint.
5. Bleaching is required to produce white paper stock.
6. Paperboard, newsprint, coated paper, uncoated paper, and tissue paper are final products. Production of final products requires drying, finishing, and stock prep.

Buildings component

The total buildings energy demand by industry for each region is a function of regional industrial employment and output. Building energy consumption was estimated for building lighting, HVAC (heating, ventilation, and air conditioning), facility support, and on-site transportation. Space heating was further divided to estimate the amount provided by direct combustion of fossil fuels and that provided by steam (Table 6.7). Energy consumption in the BLD Component for an industry is estimated based on regional employment and output growth for that industry using the 2010 MECS as a basis.

Table 6.7. 2010 Building component energy consumption

trillion Btu

Industry	Region	Lighting Electricity Consumption	HVAC Electricity Consumption	HVAC Natural Gas Consumption	HVAC Steam Consumption	Facility Support Total Consumption	Onsite Transportation Total Consumption
			Building Use and Energy Source				
Food Products	1	2.1	2.1	3.3	2.1	1.7	0.9
	2	9.7	9.7	14.8	4.9	7.4	0.9
	3	6.8	6.8	8.7	5.5	4.4	1.6
	4	3.5	3.5	7.4	4.7	3.8	3.0
Paper & Allied Products	1	1.2	1.3	2.8	0.0	0.3	0.9
	2	3.7	4.0	3.3	0.0	0.3	0.9
	3	6.8	7.4	7.1	0.0	0.7	2.0
	4	3.2	3.4	2.2	0.0	0.3	0.9
Bulk Chemicals	1	0.8	1.0	3.7	0.0	2.8	5.2
	2	2.9	3.5	5.8	0.0	3.9	5.6
	3	7.7	9.3	15.0	0.0	9.0	9.7
	4	0.9	1.0	3.7	0.0	2.8	5.0
Glass & Glass Products	1	0.4	0.5	3.8	0.0	3.2	3.4
	2	0.7	0.9	4.1	0.0	3.3	3.4
	3	0.9	1.2	4.5	0.0	3.4	3.5
	4	0.3	0.4	3.4	0.0	3.1	3.4
Cement	1	0.1	0.1	0.6	0.0	0.6	1.1
	2	0.3	0.3	0.6	0.0	0.6	1.1
	3	0.4	0.4	0.7	0.0	0.7	1.1
	4	0.2	0.2	0.5	0.0	0.5	0.6
Iron & Steel	1	0.8	0.8	1.9	0.0	0.7	0.6
	2	2.7	2.7	8.7	0.0	1.9	2.4
	3	3.1	3.1	3.6	0.0	1.0	1.7
	4	0.4	0.4	1.0	0.0	0.6	0.6
Aluminum	1	0.2	0.2	0.5	0.0	0.2	0.2
	2	0.8	0.8	1.0	0.0	0.3	0.3
	3	0.8	8.8	2.6	0.0	0.7	0.8
	4	0.3	0.3	0.4	0.0	0.1	0.2
Metal-Based Durables	1	1.8	1.5	5.1	2.9	0.6	1.4
Fabricated Metal Products	2	6.6	5.6	16.3	9.1	1.2	1.5
	3	5.2	4.4	8.8	5.0	0.8	1.7
	4	1.4	1.2	2.6	1.5	0.2	0.3
Machinery	1	1.6	2.3	4.2	0.7	0.2	0.2
	2	4.8	6.8	20.7	3.6	0.9	0.9
	3	3.1	4.3	8.6	1.5	0.5	0.7
	4	0.6	0.8	0.5	0.1	0.1	0.2

Table 6.7. 2010 Building component energy consumption (cont.)

Industry	Region	Lighting Electricity Consumption	HVAC Electricity Consumption	HVAC Natural Gas Consumption	HVAC Steam Consumption	Facility Support Total Consumption	Onsite Transportation Total Consumption
		Building Use and Energy Source					
Computers & Electronic Products	1	2.2	5.6	4.2	2.5	0.9	0.8
	2	2.0	4.9	4.4	2.7	0.9	0.8
	3	4.2	10.5	4.4	2.7	0.9	0.8
	4	4.1	10.2	9.4	5.7	1.2	0.8
Transportation Equipment	1	1.6	2.0	4.8	0.4	0.6	0.2
	2	10.5	13.1	23.1	2.1	2.0	1.2
	3	6.1	7.6	10.1	0.9	1.1	0.8
	4	2.5	3.1	3.9	0.4	0.3	0.2
Electrical Equipment	1	0.7	1.0	1.7	1.3	0.5	0.5
	2	1.1	1.6	2.6	2.1	0.4	0.4
	3	2.1	3.1	4.0	3.1	0.6	0.4
	4	0.2	0.3	0.1	0.1	0.1	0.4
Other Non-Intensive Manufacturing							
Wood Products	1	0.2	0.2	0.8	2.5	0.5	0.4
	2	0.6	0.5	1.6	4.9	0.7	1.7
	3	2.4	1.8	2.7	8.4	0.7	2.1
	4	0.8	0.6	1.3	4.0	0.3	4.2
Plastic Products	1	0.8	0.9	1.8	0.0	0.2	0.3
	2	4.5	5.6	7.7	0.0	0.5	0.7
	3	5.5	6.8	10.3	0.0	0.7	0.8
	4	2.5	3.0	2.1	0.0	0.2	0.2
Balance of Manufacturing	1	5.5	9.1	13.4	0.0	0.9	1.2
	2	10.5	17.4	20.6	0.0	1.7	2.1
	3	15.7	26.0	28.1	0.0	2.6	3.4
	4	4.5	7.5	9.5	0.0	0.6	0.8

HVAC = Heating, Ventilation, Air Conditioning.

Source: SAIC, IDM Base Year Update with MECS 2010 Data, unpublished data prepared for the Industrial Team, Office of Energy Consumption and Efficiency Analysis, Energy Information Administration, Washington, DC, July 2013.

Boiler, steam, and cogeneration component

With the exception of the iron and steel and pulp and paper industries, the steam demand and byproducts from the PA and BLD Components are passed to the BSC Component, which applies a heat rate and a fuel share equation (Table 6.8) to the boiler steam requirements to compute the required energy consumption. The iron and steel and pulp and paper industries have independent BSC and cogeneration related modeling that is calculated as part of the PA step.

The boiler fuel shares apply only to the fuels that are used in boilers for steam-only applications. Fuel use for the portion of the steam demand associated with combined heat and power (CHP) is described in the next section. Some fuel switching for the remainder of the boiler fuel use is assumed and is calculated with a logit-sharing equation where fuel shares are a function of fuel prices. The equation is calibrated to 2010 so that the 2010 fuel shares are produced for the relative prices that prevailed in 2010.

The byproduct fuels, production of which is estimated in the PA Component, are assumed to be consumed without regard to price, independent of purchased fuels. The boiler fuel share equations and calculations are based on the 2010 MECS and information from the Council of Industrial Boiler Owners. [33]

Table 6.8. 2010 Boiler fuel component and logit parameter

trillion Btu

	Region	Alpha	Natural Gas	Coal	Oil	Renewables
Food Products	1	-2.0	33	1	3	1
	2	-2.0	147	131	3	31
	3	-2.0	85	14	6	31
	4	-2.0	74	18	3	8
Bulk Chemicals	1	-2.0	17	0	7	8
	2	-2.0	164	43	6	52
	3	-2.0	705	60	13	352
	4	-2.0	21	44	4	5
Glass & Glass Products	1	-2.0	1	0	2	1
	2	-2.0	1	0	2	1
	3	-2.0	1	0	2	1
	4	-2.0	0	0	2	1
Cement	1	-2.0	0	0	0	1
	2	-2.0	0	0	0	5
	3	-2.0	0	0	0	3
	4	-2.0	0	0	0	1
Aluminum	1	-2.0	1	0	0	0
	2	-2.0	3	0	0	1
	3	-2.0	8	0	1	1
	4	-2.0	1	0	0	0
Metal-Based Durables						
Fabricated Metal Products	1	-2.0	4	0	0	0
	2	-2.0	12	0	0	0
	3	-2.0	6	0	0	0
	4	-2.0	2	0	0	0
Machinery	1	-2.0	1	0	0	1
	2	-2.0	4	0	1	1
	3	-2.0	2	0	0	0
	4	-2.0	0	0	0	0

Table 6.8. 2010 Boiler fuel component and logit parameter (cont.)

trillion Btu

	Region	Alpha	Natural Gas	Coal	Oil	Renewables
Computer & Electronic Products	1	-2.0	3	0	1	0
	2	-2.0	3	0	1	0
	3	-2.0	3	0	1	0
	4	-2.0	7	0	1	0
Electrical Equipment	1	-2.0	1	0	1	0
	2	-2.0	2	0	0	0
	3	-2.0	3	0	0	0
	4	-2.0	0	0	0	0
Transportation Equipment	1	-2.0	3	8	2	1
	2	-2.0	17	-5	1	3
	3	-2.0	7	1	2	1
	4	-2.0	3	0	0	0
Other Non-Intensive Manufacturing						
Wood Products	1	-2.0	0	0	1	79
	2	-2.0	1	0	2	31
	3	-2.0	4	0	2	188
	4	-2.0	2	0	2	54
Plastic Products	1	-2.0	3	2	1	0
	2	-2.0	16	0	0	0
	3	-2.0	21	0	1	0
	4	-2.0	4	0	0	0
Balance of Manufacturing	1	-2.0	35	-10	0	3
	2	-2.0	54	29	0	42
	3	-2.0	74	42	0	128
	4	-2.0	25	7	0	0

Alpha: User-specified.

Source: U.S. Energy Information Administration, Model Documentation Report, Industrial Sector Demand Module of the National Energy Modeling System, (Washington, DC 2014).

Combined heat and power

CHP plants, which are designed to produce both electricity and useful heat, have been used in the industrial sector for many years. The CHP estimates in the module are based on the assumption that the historical relationship between industrial steam demand and CHP will continue in the future, and that the rate of additional CHP penetration will depend on the economics of retrofitting CHP plants to replace steam generated from existing non-CHP boilers. The technical potential for CHP is primarily based on supplying thermal requirements (i.e., matching thermal loads). Capacity additions are then determined by the interaction of CHP investment payback periods (with the time value of money included) derived using operating hours reported in EIA's published statistics, market penetration rates for investments with those payback periods, and regional deployment for these systems as characterized by the "collaboration coefficients" in Table 6.9. Assumed installed costs for the CHP systems are given in Table 6.10.

Table 6.9. Regional collaboration coefficients for CHP deployment

Census Region	Collaboration Coefficient
Northeast	1.46
Midwest	1.34
South	0.33
West	1.06

Source: Calculated from American Council for an Energy-Efficient Economy, “Challenges Facing Combined Heat and Power Today: A State-by-State Assessment," September 2011, www.aceee.org/research-report/ie111 and Energy Information Administration, Office of Energy Analysis.

Table 6.10. Cost characteristics of industrial CHP systems

trillion Btu

System	Size Kilowatts (kW)	Reference 2010	Installed Cost 2005$ per KWh)[1] Reference: 2035
Engine	1,000	1,440	576
	2,000	1,260	396
Gas turbine	3,510	1,719	1,496
	5,670	1,152	1,023
	14,990	982	869
	25,000	987	860
	40,000	875	830
Combined cycle	100,000	723	684

[1]Costs are given in 2005 dollars in original source document.

Source: U.S. Energy Information Administration, Model Documentation Report, Industrial Sector Demand Module of the National Energy Modeling System (Washington, DC, September 2013).

Key assumptions - non-Manufacturing

The non-manufacturing sector consists of three industries: agriculture, mining and construction. These industries all use electricity, natural gas, diesel fuel, and gasoline. The mining industry also uses coal, natural gas liquids (NGL), and residual fuel oil, and the construction industry also uses other petroleum in the form of asphalt and road oil. Except for oil and gas extraction, almost all of the energy use in the non-manufacturing sector takes place in the process and assembly step. Oil and gas extraction uses a significant amount of residual fuel oil in the BSC component. Table 6.10 shows the baseline unit energy consumption values for the non-manufacturing subsectors in 2010.

The non-manufacturing sector consists of three industries: agriculture, mining and construction. These industries use electricity, natural gas, hydrocarbon gas liquids (HGL), diesel fuel, and gasoline. The mining industry also uses coal and residual fuel oil, and the construction industry also uses other petroleum in the form of asphalt and road oil. Except for oil and gas extraction, almost all of the energy use in the non-manufacturing sector takes place in the process and assembly step. Oil and gas extraction uses a significant amount of residual fuel oil in the BSC component.

Unlike the manufacturing sector, the non-manufacturing sector does not have a single source of data for energy consumption estimates. Instead, UECs for the non-manufacturing sector are derived from various sources of data collected by a number of government agencies.

Non-manufacturing data was revised using EIA and Census Bureau sources to provide more realistic projections of diesel and gasoline for off-road vehicle use, allocate natural gas, HGL use, and electricity. Sources used are EIA's Fuel Oil and Kerosene Sales (FOKS) [34] for distillate consumption, Agricultural Resource Management Survey (ARMS) [35] and the Census Bureau's Census of Mining [36] and Census of Construction. [37] Combining these sources, there is now more consumption of distillate and less consumption of motor gasoline. Also, the use of HGL is now accounted for in the agriculture and in the construction industries. Nonmanufacturing consumption is no longer dictated solely by the SEDS–MECS difference as it has been in previous years.

Agriculture Sector

U.S. agriculture consists of three major sub-sectors:

- crop production, which is dependent primarily on regional environments and crops demanded;
- animal production, which is largely dependent on food demands and feed accessibility;
- all remaining agricultural activities, which are primarily composed of forestry and logging.

These sub-industries have historically been tightly coupled due to competing use of land area. For example, crops produced for animal feed cannot be consumed by humans; forests provide the feedstock of the paper and wood industries but in turn do not allow the growth of crops or limit or prevent grazing of animals. Forestry and logging are not modelled within NEMS.

Baseline energy consumption data for the two agriculture sectors (crops and other agriculture) are based on data from the Census of Agriculture and a special tabulation from the National Agricultural Statistics Service (USDA-NASS). Expenditures for four energy sources are collected from crop farms and livestock farms as part of the Agricultural Resource Management Survey (ARMS). These data are converted from dollar expenditures to energy quantities using fuel prices from NASS and EIA.

Mining Sector

The mining sector comprises of three sectors: coal mining, metal and nonmetal mining, and oil and gas extraction. Energy use is based on what equipment is used at the mine and onsite vehicles used. All mines use extraction equipment and lighting, but only coal and metal and nonmetal mines use grinding and ventilation. As with the agriculture module described above, TPCs are influenced by efficiency changes in buildings and transportation equipment.

Coal mining production is obtained from the Coal Market Module (CMM). Currently, it is assumed that 70% of the coal is mined at the surface and the rest is mined underground. As these shares evolve, however, so does the energy consumed, since surface mines use less energy overall than underground mining. Moreover, the energy consumed for coal mining depends on coal mine productivity, which is also obtained from the CMM. Diesel fuel and electricity are the predominant fuels used in coal mining. Electricity used for coal grinding is calculated using the raw grinding process step from the cement sub-module. In metal and non-metal mining, energy use is similar to coal mining. Output used for metal and non-metal mining is derived from the MAM'S variable for "other" mining which also provides the shares of each.

For oil and natural gas extraction, production is derived from the Oil and Gas Supply Module (OGSM). Energy use depends upon the fuel extracted as well as whether the well is conventional or unconventional (e.g., extraction from tight and shale formations), percentage of dry wells, and well depth. Oil and gas extraction also includes fuel consumed for liquefied natural gas liquefaction, although at present this amount is very trivial.

Construction Sector

The construction sector uses diesel fuel, gasoline, electricity and HGL as energy sources. Construction also uses asphalt and road oil as a nonfuel energy source. Asphalt and road oil use is tied to state and local government real investment in highways and streets, and this investment is derived from the MAM. TPCs for diesel and gasoline fuels are directly tied to the Transportation Demand Module's heavy-and medium-duty vehicle efficiency projections. For non-vehicular construction equipment, TPCs are a weighted average of vehicular TPCs and highway investment.

Legislation and regulations

Energy Improvement and Extension Act of 2008

Under EIEA2008 Title I, "Energy Production Incentives," Section 103 provides an Investment Tax Credit (ITC) for qualifying Combined Heat and Power (CHP) systems placed in service before January 1, 2017. Systems with up to 15 megawatts of electrical capacity qualify for an ITC up to 10% of the installed cost. For systems between 15 and 50 megawatts, the percentage tax credit declines linearly with the capacity, from 10% to 3%. To qualify, systems must exceed 60% fuel efficiency, with a minimum of 20% each for useful thermal and electrical energy produced. The provision was modeled in AEO2015 by adjusting the assumed capital cost of industrial CHP systems to reflect the applicable credit.

The Energy Independence and Security Act of 2007 (EISA2007)

Under EISA2007, the motor efficiency standards established under the Energy Policy Act of 1992 (EPACT1992) are superseded for purchases made after 2011. Section 313 of EISA2007 increases or creates minimum efficiency standards for newly manufactured and imported general purpose electric motors. The efficiency standards are raised for general purpose, integral-horsepower induction motors with the exception of fire pump motors. Minimum standards were created for seven types of poly-phase, integral-horsepower induction motors and National Electrical Manufacturers Association (NEMA) design "B" motors (201-500 hp) that were not previously covered by EPACT standards. In 2013, the Energy Policy and Conservation Act was amended (Public Law 113-67) and efficiency standards were revised in a subsequent DOE rulemaking (10 CFR 431.25). For motors manufactured after June 1, 2016, efficiency standards for current regulated motor types [38] were expanded to include 201-500 hp motors. Also, special and definite purpose motors of from 1-500 hp and NEMA design "A" motors from 201-500 hp became subject to efficiency standards. The 2014 regulations were modelled in the AEO2016 by modifying the specifications for new motors in electric motor technology choice module.

Energy Policy Act of 1992 (EPACT1992)

EPACT1992 contains several implications for the industrial module. These implications concern efficiency standards for boilers, furnaces, and electric motors. The industrial module uses heat rates of at least 1.25 (80% efficiency) and 1.22 (82% efficiency) for gas and oil burners, respectively. These efficiencies meet the EPACT1992 standards. EPACT1992 mandates minimum efficiencies for all motors up to 200 hp purchased after 1998. The choices offered in the motor efficiency assumptions are all at least as efficient as the EPACT minimums.

Clean Air Act Amendments of 1990 (CAAA1990)

he CAAA1990 contains numerous provisions that affect industrial facilities. Three major categories of such provisions are as follows: process emissions, emissions related to hazardous or toxic substances, and sulfur dioxide (SO2) emissions. Process emissions requirements were specified for numerous industries and/or activities (40 CFR 60). Similarly, 40 CFR 63 requires limitations on almost 200 specific hazardous or toxic substances. These specific requirements are not explicitly represented in the NEMS industrial model because they are not directly related to energy consumption projections.

Section 406 of the CAAA1990 requires the U.S. Environmental Protection Agency (EPA) to regulate industrial SO2 emissions at such time that total industrial SO2 emissions exceed 5.6 million tons per year (42 USC 7651). Since industrial coal use, the main source of SO2 emissions, has been declining, EPA does not anticipate that specific industrial SO2 regulations will be required (Environmental Protection Agency, National Air Pollutant Emission Trends: 1990-1998, EPA-454/R-00-002, March 2000, Chapter 4). Further, since industrial coal use is not projected to increase, the industrial cap is not expected be a factor in industrial energy consumption projections. (Emissions due to coal-to-liquids CHP plants are included with the electric power sector because they are subject to the separate emission limits of large electricity generating plants.)

Maximum Achievable Control Technology for Industrial Boilers (Boiler MACT)

Section 112 of the Clean Air Act (CAA) requires the regulation of air toxics through implementation of the National Standards for Hazardous Air Pollutants (NESHAP) for industrial, commercial, and institutional boilers. The final regulations, known as Boiler MACT, are modeled in AEO2015. Pollutants covered by Boiler MACT include the hazardous air pollutants (HAP), hydrogen chloride (HCl), mercury (HG), dioxin/furan, carbon monoxide (CO), and particulate matter (PM). Generally, industries comply with the Boiler MACT regulations by including regular maintenance and tune-ups for smaller facilities and emission limits and performance tests for larger facilities. Boiler MACT is modeled as an upgrade cost in the MAM. These upgrade costs are classified as “nonproductive costs” which are not associated with efficiency improvements. The effect of these costs in the MAM is a reduction in shipments coming into the IDM.

California Assembly Bill 32: Emissions cap-and-trade as part of the Global Warming Solutions Act of 2006 (AB32)

AB32 established a comprehensive, multi-year program to reduce Greenhouse Gas (GHG) emissions in California, including a cap-and-trade program. In addition to the cap-and-trade program, AB32 also authorizes the low carbon fuel standard (LCFS); energy efficiency goals and programs in transportation, buildings; and industry; combined heat and power goals; and renewable portfolio standards.

For AEO2015, the cap-and-trade provisions were modeled for industrial facilities, refineries, and fuel providers. GHG emissions include both non-CO2 and specific non-CO2 GHG emissions. The allowance price, representing the incremental cost of complying with AB32 cap-and-trade, is modeled in the NEMS Electricity Market Module via a region-specific emissions constraint. This allowance price, when added to market fuel prices, results in higher effective fuel prices in the demand sectors. Limited banking and borrowing, as well as a price containment reserve and offsets, have been modeled in NEMS. AB32 is not modeled explicitly in the IDM, but enters the module implicitly through higher effective fuel prices and macroeconomic effects of higher prices, all of which affect energy demand and emissions. In June 2014, AB32 regulations were clarified and revised [39], but these revisions were not added to the IDM because they did not materially affect model calculation or results.

Notes and sources

[26] U.S. Energy Information Administration, State Energy Data System, based on energy consumption by state through 2011, as downloaded in August, 2013, from www.eia.gov/state/seds/.

[27] U. S. Energy Information Administration, Manufacturing Energy Consumption Survey 2010, http://www.eia.gov/consumption/manufacturing/index.cfm.

[28] U.S. Department of Energy (2007). Motor Master+ 4.0 software database; available at updated link http://www1.eere.energy.gov/manufacturing/downloads/MM41Setup.exe.

[29] In NEMS, hydrocarbon gas liquids (HGL), which comprise natural gas liquids (NGL) and olefins, are reported as Liquefied Petroleum Gas (LPG).

[30] Roop, Joseph M., "The Industrial Sector in CIMS-US," Pacific Northwest National Laboratory, 28th Industrial Energy Technology Conference, May, 2006.

[31] U.S. Department of the Interior, U.S. Geological Survey, Minerals Yearbook, cement data was made available under a non-disclosure agreement, http://minerals.usgs.gov/minerals/pubs/commodity/cement/myb1-2012-cemen.pdf.

[32] Portland Cement Association, U.S. and Canadian Portland Cement Industry Plant Information Summary, cement data was made available under a non-disclosure agreement, http://www.cement.org .

[33] Personal correspondence with the Council of Industrial Boiler Owners.

[34] U.S. Energy Information Administration, Fuel Oil and Kerosene Survey (FOKS), http://www.eia.gov/dnav/pet/pet_cons_821usea_dcu_nus_a.htm.

[35] Agriculture Research Management Survey (ARMS), United States Dept. of Agriculture, Economic Research Service, http://ers.usda.gov/data-products/arms-farm-financial-and-crop-production-practices.aspx.

Notes and sources (cont.)

[36] U.S. Census Bureau, 2012 Economic Census Mining: Industry Series: Selected Supplies, Minerals Received for Preparation, Purchased Machinery, and Fuels Consumed by Type for the United States: 2012 (Washington, DC: February 27, 2015) available at: https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=ECN_2012_US_21SM1&prodType=table

[37] U.S. Census Bureau, 2012 Economic Census; Construction: Industry Series: Detailed Statistics by Industry for the United States: 2012 (Washington, DC: January 12, 2015) available at: https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=ECN_2012_US_23SG01&prodType=table

[38] Federal Register 79 FR 103 pp. 30934-31014, Washington, DC: May 29, 2014. Available at http://www.gpo.gov/fdsys/pkg/FR-2014-05-29/pdf/2014-11201.pdf

[39] California Air Resources Board "California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10, Article 5 §95800 - §96022" Sacramento, CA: June 14, 2014. Available at http://www.arb.ca.gov/cc/capandtrade/capandtrade/unofficial_c&t_012015.pdf

Chapter 7. Transportation Demand Module

The NEMS Transportation Demand Module (TDM) estimates transportation energy consumption across the nine Census Divisions and over ten fuel types. Each fuel type is modeled according to fuel-specific and associated technology attributes applicable by transportation mode. Total transportation energy consumption is reported as the sum of energy use in eight transport modes: light-duty vehicles (cars and light trucks), commercial light trucks (8,501-10,000 pounds gross vehicle weight), freight trucks (greater than 10,000 pounds gross vehicle weight), buses, freight and passenger aircraft, freight and passenger rail, maritime freight shipping, and miscellaneous transport such as recreational boating. Light-duty vehicle fuel consumption is further subdivided into personal usage and commercial fleet consumption.

Key assumptions

By submodules and their components, key assumptions on transportation demand and energy consumption address light-duty vehicles, commercial light trucks, freight transportation, and air travel.

Light-duty vehicle submodule

The light-duty vehicle Manufacturers Technology Choice Component (MTCC) includes 86 advanced technology input assumptions specific to cars and light trucks (Tables 7.1 and 7.2) that include incremental fuel economy improvement, incremental cost, incremental weight change, first year of introduction or commercial availability, and fractional horsepower change.

The vehicle Regional Sales Component holds the share of vehicle sales by manufacturers constant within a vehicle size class at 2010 levels based on National Highway Traffic Safety Administration (NHTSA) data [40]. U. S. Environmental Protection Agency (EPA) size class sales shares are projected as a function of income per capita, fuel prices, and average predicted vehicle prices based on endogenous calculations within the MTCC [41].

The MTCC uses 86 technologies for each size class and manufacturer to make an economic analysis based on the cost-effectiveness of each technology and an initial year of availability -- i.e., comparing relative costs and outcomes (effects) of different courses of action. A discounted stream of fuel savings (outcomes) is calculated for each technology, which is compared with the marginal cost to determine cost effectiveness and market penetration. The fuel economy calculations assume the following:

- The financial parameters used to determine technology economic effectiveness are evaluated based on the need to improve fuel economy to meet CAFE standards versus consumer willingness to pay for fuel economy improvement beyond those minimum requirements.
- Fuel economy standards for light-duty vehicles reflect current law through model year 2025, according to NHTSA model year 2011 final rulemaking, joint EPA and NHTSA rulemaking for 2012 through 2016, and joint EPA and NHTSA rulemaking for 2017 through 2025. CAFE standards enacted for model years 2022 through 2025 will undergo a midterm evaluation by NHTSA and could be subject to change. For model years 2026 through 2040, fuel economy standards are held constant at model year 2025 levels with fuel economy improvements still possible based on continued improvements in economic effectiveness.

- Expected future fuel prices are calculated based on an extrapolation of the growth rate between a five-year moving average of fuel prices 3 years and 4 years prior to the present year. This assumption is founded upon an assumed lead time of 3 to 4 years to significantly modify the vehicles offered by a manufacturer.

Table 7.1. Standard technology matrix for cars[1]

	Fuel Efficiency Change %	Incremental Cost 2000$	Incremental Cost ($/UnitWt.)	Absolute Incremental Weight (lbs.)	Per Unit Incremental Weight (lbs./UnitWt.)	Introduction Year	Horsepower Change %
Unit Body Construction	4.0	99.91	0.00	0	-6	1980	0
Mass Reduction I	1.0	0.00	0.06	0	-1.5	2005	0
Mass Reduction II	2.6	0.00	0.14	0	-3.5	2009	0
Mass Reduction III	5.4	0.00	0.42	0	-10	2011	0
Mass Reduction IV	8.4	0.00	0.62	0	-15	2099	0
Mass Reduction V	11.6	0.00	0.72	0	-20	2099	0
Aerodynamics I	2.4	48.17	0.00	0	0.5	2000	0
Aerodynamics II	4.9	203.29	0.00	0	1	2011	0
6 Speed Manual	2.2	255.59	0.00	20	0	1995	0
Aggressive Shift Logic I	2.5	32.44	0.00	0	0	1999	0
Aggressive Shift Logic II	6.7	27.18	0.00	0	0	2017	0
Early Torque Converter Lockup	0.5	29.49	0.00	0	0	2002	0
High Efficiency Gearbox	1.6	200.63	0.00	0	0	2017	0
5 Speed Automatic	1.4	103.91	0.00	20	0	1995	0
6 Speed Automatic	2.2	270.05	0.00	30	0	2003	0
7 Speed Automatic	5.1	401.04	0.00	40	0	2009	0
8 Speed Automatic	8.0	532.83	0.00	50	0	2010	0
Dual Clutch Automated Manual	5.5	56.75	0.00	-10	0	2004	0
CVT	8.4	250.98	0.00	-25	0	1998	0
Low Friction Lubricants	0.7	3.20	0.00	0	0	2003	0
Engine Friction Reduction I-4 cyl	2.0	47.16	0.00	0	0	2000	1.25
Engine Friction Reduction I-6 cyl	2.6	71.14	0.00	0	0	2000	1.25
Engine Friction Reduction I-8 cyl	2.8	94.32	0.00	0	0	2000	1.25
Engine Friction Reduction II-4 cyl	3.6	100.71	0.00	0	0	2017	2.25
Engine Friction Reduction II-6 cyl	4.7	147.87	0.00	0	0	2017	2.25
Engine Friction Reduction II-8 cyl	5.1	195.03	0.00	0	0	2017	2.25
Cylinder Deactivation-6 cyl	6.5	187.06	0.00	10	0	2004	0
Cylinder Deactivation-8 cyl	6.9	209.97	0.00	10	0	2004	0
VVT I-OHV Intake Cam Phasing-6 cyl	2.6	43.90	0.00	20	0	2051	1.25
VVT I-OHV Intake Cam Phasing-8 cyl	2.7	43.90	0.00	30	0	2051	1.25
VVT I-OHC Intake Cam Phasing-4 cyl	2.1	43.90	0.00	10	0	1993	1.25
VVT I-OHC Intake Cam Phasing-6 cyl	2.6	88.76	0.00	20	0	1993	1.25
VVT I-OHC Intake Cam Phasing-8 cyl	2.7	88.76	0.00	30	0	1993	1.25
VVT II-OHV Coupled Cam Phasing-6 cyl	5.4	43.90	0.00	20	0	2009	1.25
VVT II-OHV Coupled Cam Phasing-8 cyl	5.8	43.90	0.00	30	0	2009	1.25
VVT II-OHC Coupled Cam Phasing-4 cyl	4.3	43.90	0.00	10	0	2009	1.25
VVT II-OHC Coupled Cam Phasing-6 cyl	5.4	88.76	0.00	20	0	2009	1.25
VVT II-OHC Coupled Cam Phasing-8 cyl	5.8	88.76	0.00	30	0	2009	1.25
VVT III-OHV Dual Cam Phasing-6 cyl	5.4	99.26	0.00	25	0	2051	1.56
VVT III-OHV Dual Cam Phasing-8 cyl	5.8	99.26	0.00	37.5	0	2051	1.56
VVT III-OHC Dual Cam Phasing-4 cyl	4.3	90.67	0.00	12.5	0	2009	1.56
VVT III-OHC Dual Cam Phasing-6 cyl	5.4	195.65	0.00	25	0	2009	1.56
VVT III-OHC Dual Cam Phasing-8 cyl	5.8	195.65	0.00	37.5	0	2009	1.56
VVL I-OHV Discrete-6 cyl	5.5	225.24	0.00	40	0	2000	2.5

Table 7.1. Standard technology matrix for cars[1] (cont.)

	Fuel Efficiency Change %	Incremental Cost 2000$	Incremen-tal Cost ($/UnitWt.)	Absolute Incremen-tal Weight (lbs.)	Per Unit Incremen-tal Weight (lbs./UnitWt.)	Introduc-tion Year	Horsepower Change %
VVL I-OHV Discrete-8 cyl	5.9	322.59	0.00	50	0	2000	2.5
VVL I-OHC Discrete-4 cyl	4.3	155.57	0.00	25	0	2000	2.5
VVL I-OHC Discrete-6 cyl	5.5	225.24	0.00	40	0	2000	2.5
VVL I-OHC Discrete-8 cyl	5.9	322.59	0.00	50	0	2000	2.5
VVL II-OHV Continuous-6 cyl	7.0	1,150.07	0.00	40	0	2011	2.5
VVL II-OHV Continuous-8 cyl	7.5	1,256.96	0.00	50	0	2011	2.5
VVL II-OHC Continuous-4 cyl	5.4	232.88	0.00	25	0	2011	2.5
VVL II-OHC Continuous-6 cyl	7.0	427.58	0.00	40	0	2011	2.5
VVL II-OHC Continuous-8 cyl	7.5	466.71	0.00	50	0	2011	2.5
Stoichiometric GDI-4 cyl	1.5	264.37	0.00	20	0	2006	2.5
Stoichiometric GDI-6 cyl	1.5	397.99	0.00	30	0	2006	2.5
Stoichiometric GDI-8 cyl	1.5	478.16	0.00	40	0	2006	2.5
OHV to DOHC TBDS-I4	21.6	1,383.90	0.00	-100	0	2009	3.75
OHV to DOHC TBDS I-V6	20.2	2,096.84	0.00	-100	0	2009	3.75
SOHC to DOHC TBDS I-I4	21.6	827.47	0.00	-100	0	2009	3.75
SOHC to DOHC TBDS I-V6	20.2	1,605.80	0.00	-100	0	2009	3.75
DOHC TBDS I-I3	17.5	915.28	0.00	-100	0	2009	3.75
DOHC TBDS I-I4	21.6	747.30	0.00	-100	0	2009	3.75
DOHC TBDS I-V6	20.2	1,530.88	0.00	-100	0	2009	3.75
OHV to DOHC TBDS II-I4	26.3	1,586.36	0.00	-100	0	2012	3.75
OHV to DOHC TBDS II-V6	24.5	2,445.33	0.00	-100	0	2012	3.75
SOHC to DOHC TBDS II-I4	26.3	1,046.15	0.00	-100	0	2012	3.75
SOHC to DOHC TBDS II-V6	24.5	1,968.59	0.00	-100	0	2012	3.75
DOHC TBDS II-I3	21.2	1,130.47	0.00	-100	0	2012	3.75
DOHC TBDS II-I4	26.3	968.31	0.00	-100	0	2012	3.75
DOHC TBDS II-V6	24.5	1895.85	0.00	-100	0	2012	3.75
OHV to DOHC TBDS III-I4 (from V6)	32.6	2,031.83	0.00	-100	0	2017	3.75
OHV to DOHC TBDS III-I4 (from V8)	30.7	1,601.81	0.00	-200	0	2017	3.75
SOHC to DOHC TBDS III-I4 (from V6)	32.6	1,565.84	0.00	-100	0	2017	3.75
SOHC to DOHC TBDS III-I4 (from V8)	30.7	1,380.40	0.00	-200	0	2017	3.75
DOHC TBDS III-I3 (from I4)	27.1	1,634.58	0.00	-100	0	2017	3.75
DOHC TBDS III-I4 (from V6)	32.6	1,498.70	0.00	-100	0	2017	3.75
DOHC TBDS III-I4 (from V8)	30.7	1,302.07	0.00	-200	0	2017	3.75
Electric Power Steering	1.3	107.15	0.00	0	0	2004	0
Improved Accessories I	0.7	87.49	0.00	0	0	2005	0
12V Micro Hybrid w/EPS and IACC	7.0	640.24	0.00	45	0	2005	0
Improved Accessories II	2.5	128.69	0.00	0	0	2012	0
Mild Hybrid w/EPS and IACC II	11.0	2,902.00	0.00	80	0	2012	-2.5
Tires I	2.0	5.60	0.00	-12	0	2005	0
Tires II	4.0	58.35	0.00	-15	0	2017	0
Low Drag Brakes	0.8	59.15	0.00	0	0	2000	0
Secondary Axle Disconnect	1.3	96.34	0.00	0	-1	2012	0

[1]Fractional changes refer to the percentage change from the base technology.

Sources: U.S. Energy Information Administration, Energy and Environment Analysis, Documentation of Technology included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks (September 2002).

National Research Council, Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards (Copyright 2002).

National Highway Traffic Safety Administration, Corporate Average Fuel Economy for MY 2011-2015 Passenger Cars and Light Trucks (April 2008).

U.S. Environmental Protection Agency, Interim Report: New Powertrain Technologies and Their Projected Costs (October 2005).

U.S. Environmental Protection Agency and Department of Transportation National Highway Traffic Safety Administration, “2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Final Rule,” Federal Register Vol. 77, No. 199, October 15, 2012. 40 CFR Parts 85, 86, 600, 49 CFR Parts 523, 531, 533, et al. and 600.

Table 7.2. Standard technology matrix for light trucks[1]

	Fuel Efficiency Change %	Incremental Cost 2000$	Incremental Cost ($/UnitWt.)	Absolute Incremental Weight (lbs.)	Per Unit Incremental Weight (lbs./ UnitWt.)	Introduction Year	Horsepower Change %
Unit Body Construction	4.0	100.00	0.00	0	-6	1980	0
Mass Reduction I	1.0	0.00	0.06	0	-1.5	2005	0
Mass Reduction II	2.6	0.00	0.14	0	-7.5	2009	0
Mass Reduction III	5.4	0.00	0.42	0	-10	2011	0
Mass Reduction IV	8.4	0.00	0.62	0	-15	2016	0
Mass Reduction V	11.6	0.00	0.72	0	-20	2020	0
Aerodynamics I	2.4	48.17	0.00	0	0.5	2000	0
Aerodynamics II	4.9	203.29	0.00	0	1	2011	0
6 Speed Manual	2.0	255.59	0.00	20	0	1995	0
Aggressive Shift Logic I	2.3	32.44	0.00	0	0	1999	0
Aggressive Shift Logic II	6.3	27.18	0.00	0	0	2017	0
Early Torque Converter Lockup	0.5	29.49	0.00	0	0	2002	0
High Efficiency Gearbox	1.6	200.63	0.00	0	0	2017	0
5 Speed Automatic	1.3	103.91	0.00	20	0	1995	0
6 Speed Automatic	2.0	270.05	0.00	30	0	2003	0
7 Speed Automatic	5.0	401.04	0.00	40	0	2009	0
8 Speed Automatic	8.0	532.83	0.00	50	0	2014	0
Dual Clutch Automated Manual	4.9	182.24	0.00	-10	0	2004	0
CVT	7.8	250.98	0.00	-25	0	1998	0
Low Friction Lubricants	0.7	3.20	0.00	0	0	2003	0
Engine Friction Reduction I-4 cyl	2.0	47.16	0.00	0	0	2000	1.25
Engine Friction Reduction I-6 cyl	2.6	71.14	0.00	0	0	2000	1.25
Engine Friction Reduction I-8 cyl	2.5	94.32	0.00	0	0	2000	1.25
Engine Friction Reduction II-4 cyl	3.6	100.71	0.00	0	0	2017	2.25
Engine Friction Reduction II-6 cyl	4.7	147.87	0.00	0	0	2017	2.25
Engine Friction Reduction II-8 cyl	4.4	195.03	0.00	0	0	2017	2.25
Cylinder Deactivation-6 cyl	6.4	187.06	0.00	10	0	2004	0
Cylinder Deactivation-8 cyl	6.0	209.97	0.00	10	0	2004	0
VVT I-OHV Intake Cam Phasing-6 cyl	2.6	43.90	0.00	20	0	2051	1.25
VVT I-OHV Intake Cam Phasing-8 cyl	2.5	43.90	0.00	30	0	2051	1.25
VVT I-OHC Intake Cam Phasing-4 cyl	2.1	43.90	0.00	10	0	1993	1.25
VVT I-OHC Intake Cam Phasing-6 cyl	2.6	88.76	0.00	20	0	1993	1.25
VVT I-OHC Intake Cam Phasing-8 cyl	2.5	88.76	0.00	30	0	1993	1.25
VVT II-OHV Coupled Cam Phasing-6 cyl	5.4	43.90	0.00	20	0	2009	1.25
VVT II-OHV Coupled Cam Phasing-8 cyl	5.1	43.90	0.00	30	0	2009	1.25
VVT II-OHC Coupled Cam Phasing-4 cyl	4.3	43.90	0.00	10	0	2009	1.25
VVT II-OHC Coupled Cam Phasing-6 cyl	5.4	88.76	0.00	20	0	2009	1.25
VVT II-OHC Coupled Cam Phasing-8 cyl	5.1	88.76	0.00	30	0	2009	1.25
VVT III-OHV Dual Cam Phasing-6 cyl	5.4	99.26	0.00	25	0	2051	1.56
VVT III-OHV Dual Cam Phasing-8 cyl	5.1	99.26	0.00	37.5	0	2051	1.56
VVT III-OHC Dual Cam Phasing-4 cyl	4.3	90.67	0.00	12.5	0	2009	1.56
VVT III-OHC Dual Cam Phasing-6 cyl	5.4	195.65	0.00	25	0	2009	1.56
VVT III-OHC Dual Cam Phasing-8 cyl	5.1	195.65	0.00	37.5	0	2009	1.56
VVL I-OHV Discrete-6 cyl	5.5	225.24	0.00	40	0	2000	2.5
VVL I-OHV Discrete-8 cyl	5.2	322.59	0.00	50	0	2000	2.5
VVL I-OHC Discrete-4 cyl	4.2	155.57	0.00	25	0	2000	2.5
VVL I-OHC Discrete-6 cyl	5.5	225.24	0.00	40	0	2000	2.5
VVL I-OHC Discrete-8 cyl	5.2	322.59	0.00	50	0	2000	2.5
VVL II-OHV Continuous-6 cyl	7.0	1,150.07	0.00	40	0	2011	2.5
VVL II-OHV Continuous-8 cyl	6.5	1,256.96	0.00	50	0	2011	2.5
VVL II-OHC Continuous-4 cyl	5.3	232.88	0.00	25	0	2011	2.5
VVL II-OHC Continuous-6 cyl	7.0	427.58	0.00	40	0	2011	2.5
VVL II-OHC Continuous-8 cyl	6.5	466.71	0.00	50	0	2011	2.5
Stoichiometric GDI-4 cyl	1.5	264.37	0.00	20	0	2006	2.5

Table 7.2. Standard technology matrix for light trucks[1] (cont.)

	Fuel Efficiency Change %	Incremental Cost 2000$	Incremental Cost ($/UnitWt.)	Absolute Incremental Weight (Lbs.)	Per Unit Incremental Weight (Lbs./ UnitWt.)	Introduction Year	Horsepower Change %
Stoichiometric GDI-6 cyl	1.5	397.99	0.00	30	0	2006	2.5
Stoichiometric GDI-8 cyl	1.5	478.16	0.00	40	0	2006	2.5
OHV to DOHC TBDS-I4	21.6	1,383.90	0.00	-100	0	2009	3.75
OHV to DOHC TBDS I-V6	20.2	2,096.84	0.00	-100	0	2009	3.75
SOHC to DOHC TBDS I-I4	21.6	827.47	0.00	-100	0	2009	3.75
SOHC to DOHC TBDS I-V6	20.2	1,605.80	0.00	-100	0	2009	3.75
DOHC TBDS I-I3	17.5	915.28	0.00	-100	0	2009	3.75
DOHC TBDS I-I4	21.6	747.30	0.00	-100	0	2009	3.75
DOHC TBDS I-V6	20.2	1,530.88	0.00	-100	0	2009	3.75
OHV to DOHC TBDS II-I4	26.3	1,586.36	0.00	-100	0	2012	3.75
OHV to DOHC TBDS II-V6	24.5	2,445.33	0.00	-100	0	2012	3.75
SOHC to DOHC TBDS II-I4	26.3	1,046.15	0.00	-100	0	2012	3.75
SOHC to DOHC TBDS II-V6	24.5	1,968.59	0.00	-100	0	2012	3.75
DOHC TBDS II-I3	21.2	1,130.47	0.00	-100	0	2012	3.75
DOHC TBDS II-I4	26.3	968.31	0.00	-100	0	2012	3.75
DOHC TBDS II-V6	24.5	1,895.85	0.00	-100	0	2012	3.75
OHV to DOHC TBDS III-I4 (from V6)	32.6	2,031.83	0.00	-100	0	2017	3.75
OHV to DOHC TBDS III-I4 (from V8)	30.7	1,601.81	0.00	-200	0	2017	3.75
SOHC to DOHC TBDS III-I4 (from V6)	32.6	1,565.84	0.00	-100	0	2017	3.75
SOHC to DOHC TBDS III-I4 (from V8)	30.7	1,380.40	0.00	-200	0	2017	3.75
DOHC TBDS III-I3 (from I4)	27.1	1,634.58	0.00	-100	0	2017	3.75
DOHC TBDS III-I4 (from V6)	32.6	1,498.70	0.00	-100	0	2017	3.75
DOHC TBDS III-I4 (from V8)	30.7	1,302.07	0.00	-200	0	2017	3.75
Electric Power Steering	1.0	107.15	0.00	0	0	2004	0
Improved Accessories I	0.7	87.49	0.00	0	0	2005	0
12V Micro Hybrid w/EPS and IACC	6.7	697.79	0.00	45	0	2005	0
Improved Accessories II	2.4	128.69	0.00	0	0	2012	0
Mild Hybrid w/EPS and IACC II	10.6	2,902.00	0.00	80	0	2012	-2.5
Tires I	2.0	5.60	0.00	-12	0	2005	0
Tires II	4.0	58.35	0.00	-15	0	2017	0
Low Drag Brakes	0.8	59.15	0.00	0	0	2000	0
Secondary Axle Disconnect	1.4	96.34	0.00	0	-1	2012	0

[1]Fractional changes refer to the percentage change from the base technology.

Sources: U.S. Energy Information Administration, Energy and Environment Analysis, Documentation of Technology included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks (September 2002).

National Research Council, Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards (Copyright 2002).

National Highway Traffic Safety Administration, Corporate Average Fuel Economy for MY 2011-2015 Passenger Cars and Light Trucks (April 2008).

U.S. Environmental Protection Agency, Interim Report: New Powertrain Technologies and Their Projected Costs (October 2005).

Environmental Protection Agency and Department of Transportation National Highway Traffic Safety Administration, “2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Final Rule,” Federal Register Vol. 77, No. 199, October 15, 2012. 40 CFR Parts 85, 86, 600, 49 CFR Parts 523, 531, 533, et al. and 600.

Levels of shortfall, expressed as degradation factors, are used to convert new vehicle tested fuel economy values to “on-road” fuel economy values (Table 7.3) [42]. The degradation factors represent adjustments made to tested fuel economy values to account for the difference between fuel economy performance realized in the CAFE test procedure and fuel economy realized under normal driving conditions.

Table 7.3. Car and light truck degradation factors

	2005	2010	2015	2020	2030	2040
Cars	79.8	81.7	81.7	81.7	81.7	81.7
Light Trucks	80.6	80.0	80.0	80.0	80.0	80.0

Source: U.S. Energy Information Administration, Transportation Demand Module of the National Energy Modeling System, Model Documentation 2014, DOE/EIA-M070(2014), (Washington, DC, 2012).

The light-duty Vehicle Miles Traveled (VMT) Component uses fuel prices, personal income, and population to generate projections of demand for personal travel (i.e., VMT). Population distribution assumptions are taken from the U.S. Bureau of the Census and are divided into 13 age categories, as well as by gender. Licensing rates by these 13 age categories are also used, taken from the U.S. Department of Transportation's Federal Highway Administration (FHWA). Licensing rates are then projected for each age category using the population estimates from the U.S. Bureau of the Census. These licensing rate projections are then aggregated into five age categories, and applied to the historical VMT per licensed driver taken from FHWA, in order to project the VMT per licensed driver, using the below VMT coefficients (Table 7.4).

Table 7.4. Vehicle miles traveled equation coefficients, by age and gender cohorts

	15-19	20-34	35-54	55-64	65 or more
BETACOST					
Male	-0.0601	-0.0614	-0.0498	-0.0517	-0.0425
Female	-0.0355	-0.0573	-0.0406	-0.0462	-0.0262
ALPHA					
Male	-0.0976	1.2366	1.1304	0.7469	1.3053
Female	1.3265	0.6564	0.4824	-2.1454	-0.8364
BETAVMT					
Male	0.7417	0.6469	0.6429	0.7568	0.7363
Female	0.8551	0.7178	0.7609	0.7464	0.8205
BETAINC					
Male	0.0850	0.0000	0.0000	0.0000	-0.0765
Female	-0.1094	0.0117	0.0003	0.2564	0.0866
BETAVPLD					
Male	-0.2398	0.2522	0.4447	0.3894	0.7451
Female	0.4174	0.4223	0.6079	0.3551	0.5912
BETAEMP					
Male	0.2503	0.2368	0.0445	0.0000	-0.2556
Female	-0.2044	-0.0084	-0.2653	-0.1826	-0.4553

Source: U.S. Energy Information Administration, AEO2016 National Energy Modeling System run REF2016.032416A.

Commercial light-duty fleet assumptions

The Transportation Demand Module separates commercial light-duty fleets into three types: business, government, and utility. Based on these classifications, commercial light-duty fleet vehicles vary in survival rates and duration of in-fleet use before sale for use as personal vehicles. The average length of time fleet passenger cars are kept before being sold for personal use is 3 years for business use, 6 years for government use, and 5 years for utility use. Of total passenger car sales to fleets in 2009, 75.1% are used in business fleets, 9.6% in government fleets, and 15.3% in utility fleets. Of total light truck sales to fleets in 2009, 47.3% are used in business fleets, 15.1% in government fleets, and 37.6% in utility fleets [43]. Both the automobile and light truck shares by fleet type are held constant from 2009 through 2040. In 2009, 18.2% of all automobiles sold and 16.9% of all light trucks sold were for fleet use. The share of total automobile and light truck sales slowly declines over the forecast period based on historic trends.

Alternative-fuel shares of fleet vehicle sales by fleet type are held constant at 2005 levels (Table 7.5). Size class sales shares of vehicles are also held constant at 2005 levels (Table 7.6) [44]. Individual sales shares of new vehicles purchased by technology type are assumed to remain relatively constant for utility, government, and business fleets (Table 7.7) [45].

Annual vehicle miles traveled (VMT) per vehicle by fleet type stays constant over the projection period based on the Oak Ridge National Laboratory fleet data.

Fleet fuel economy for both conventional and alternative-fuel vehicles is assumed to be the same as the personal new vehicle fuel economy and is subdivided into six EPA size classes for cars and light trucks.

Table 7.5. Percent of fleet alternative fuel vehicles by fleet type by size class, 2005

	Mini	Subcompact	Compact	Midsize	Large	2-Seater
Car						
Business	0.0	10.5	10.7	42.7	36.1	0.0
Government	0.0	2.8	40.0	2.8	54.4	0.0
Utility	0.0	7.9	34.7	12.3	45.1	0.0
	Small Pickup	**Large Pickup**	**Small Van**	**Large Van**	**Small Utility**	**Large Utility**
Light Truck						
Business	7.9	35.1	7.9	26.8	5.5	16.8
Government	6.7	50.8	28.4	4.6	1.6	7.8
Utility	8.2	52.1	6.0	32.7	0.3	0.7

Source: U.S. Energy Information Administration, “Archive--Alternative Transportation Fuels (ATF) and Alternative Fueled Vehicles (AFV),” http://www.eia.gov/renewable/afv/archive/

Table 7.6. Commercial fleet size class shares by fleet and vehicle type, 2005

percentage

	Mini	Subcompact	Compact	Midsize	Large	2-Seater
Car						
Business	3.1	23.4	26.6	36.2	9.9	0.8
Government	0.2	4.6	20.6	28.6	46.0	0.0
Utility	1.5	12.5	10.0	59.2	16.4	0.4
	Small Pickup	**Large Pickup**	**Small Van**	**Large Van**	**Small Utility**	**Large Utility**
Light Truck						
Business	2.5	8.4	23.3	8.1	14.2	43.6
Government	6.7	43.6	10.4	17.1	3.8	18.4
Utility	7.3	38.7	11.8	18.9	7.2	16.1

Source: Oak Ridge National Laboratory, "Fleet Characteristics and Data Issues," Stacy Davis and Lorena Truett, final report prepared for the U. S. Department of Energy, U. S. Energy Information Administration, Office of Energy Analysis (Oak Ridge, TN, January 2003).

Table 7.7. Share of new vehicle purchases by fleet type and technology type, 2009

percentage

Technology	Business	Government	Utility
Cars			
Gasoline	99.10	72.78	95.52
Ethanol Flex	0.46	26.20	2.11
Electric	0.00	0.02	0.07
CNG/LNG Bi-Fuel	0.14	0.56	1.08
LPG Bi-Fuel	0.16	0.11	0.40
CNG/LNG	0.08	0.33	0.63
LPG	0.08	0.01	0.19
Light Trucks			
Gasoline	71.71	59.46	98.22
Ethanol Flex	16.29	35.09	0.49
Electric	0.04	0.07	0.05
CNG/LNG Bi-Fuel	1.28	2.29	0.51
LPG Bi-Fuel	7.93	2.55	0.31
CNG/LNG	1.54	0.49	0.24
LPG	1.22	0.05	0.18

Source: U.S. Energy Information Administration, Archive - Alternative Transportation Fuels (ATF) and Alternative Fueled Vehicles (AFV), http://www.eia.gov/renewable/afv/archive/index.cfm .

The light commercial truck component

The Light Commercial Truck Component of the NEMS Transportation Demand Module represents light trucks that have an 8,501 to 10,000 pound gross vehicle weight rating (GVW) (Class 2b vehicles). These vehicles are assumed to be used primarily for commercial purposes. The component implements a twenty-year stock model that estimates vehicle stocks, travel, fuel economy, and energy use by vintage. Historic vehicle sales and stock data, which constitute the baseline from which the projection is made, are taken from an Oak Ridge National Laboratory study [46]. The distribution of vehicles by vintage, and vehicle scrappage rates are derived from analysis of registration data from R.L. Polk & Co. and Polk data a foundation of IHS market automotive solutions [47],[48]. Vehicle travel by vintage was constructed using vintage distribution curves and estimates of average annual travel by vehicle [49],[50]. As defined in NEMS, light commercial trucks are a subset of Class 2 vehicles (vehicles weighing 6,001 to 10,000 pounds GVW) and are often referred to as Class 2b vehicles (8,500 to 10,000 pounds GVW). Class 2a vehicles (6,001 to 8,500 pounds GVW) are addressed in the Light-Duty Vehicle Submodule.

The growth in light commercial truck VMT is a function of industrial output for agriculture, mining, construction, total manufacturing, utilities, and personal travel. The overall growth in VMT reflects a weighted average based on the distribution of total light commercial truck VMT by sector. Projected fuel efficiencies are assumed to increase at the same annual growth rate as conventional gasoline light-duty trucks (less than or equal to 8,500 pounds gross vehicle weight).

Consumer vehicle choice assumptions

The Consumer Vehicle Choice Component (CVCC) utilizes a nested multinomial logit (NMNL) model that predicts sales shares based on relevant vehicle and fuel attributes. The nesting structure first predicts the probability of fuel choice for multi-fuel vehicles within a technology set. The second-level nesting predicts penetration among similar technologies within a technology set (e.g., gasoline versus diesel hybrids). The third-level choice determines market share among the different technology sets [51]. The technology sets include:

- Conventional fuel capable (gasoline, diesel, bi-fuel compressed natural gas (CNG) and liquefied natural gas (LNG), bi-fuel liquefied petroleum gas (LPG), and flex-fuel)
- Hybrid (gasoline and diesel)
- Plug-in hybrid (10-mile all-electric range and 40-mile all-electric range)
- Dedicated alternative fuel (CNG, LNG, and LPG)
- Fuel cell (gasoline, methanol, and hydrogen)
- Electric battery powered (100-mile range and 200-mile range) [52]

The vehicle attributes considered in the choice algorithm include: vehicle price, maintenance cost, battery replacement cost, range, multi-fuel capability, home refueling capability, fuel economy, acceleration and luggage space. With the exceptions of maintenance cost, battery replacement cost, and luggage space, vehicle attributes are determined endogenously [53]. Battery costs for plug-in hybrid electric and all-electric vehicles are based on a production-based function over several technology phase periods. The fuel attributes used in market share estimation include availability and price. Vehicle attributes vary by six EPA size classes for cars and light trucks, and fuel availability varies by Census division. The NMNL model coefficients were developed to reflect purchase decisions for size classes, cars, and light trucks separately.

Where applicable, CVCC fuel-efficient technology attributes are calculated relative to conventional gasoline miles per gallon. It is assumed that many fuel efficiency improvements in conventional vehicles will be transferred to alternative-fuel vehicles. Specific individual alternative-fuel technological improvements are also dependent upon the CVCC technology type, cost, research and development, and availability over time. Make and model availability estimates are assumed according to a logistic curve based on the initial technology introduction date and current offerings. Coefficients summarizing consumer valuation of vehicle attributes were derived from assumed economic valuation compared with vehicle price elasticities. Initial CVCC vehicle sales shares are calibrated to data from R.L. Polk & Co. and Polk data a foundation of IHS market automotive solutions fleet data from Bobit Publishing Company, and sales data from Wards Auto [54]. A fuel-switching algorithm based on the relative fuel prices for alternative fuels compared with gasoline is used to determine the percentage of total fuel consumption represented by alternative fuels in bi-fuel and flex-fuel alcohol vehicles.

Freight transport submodule

Freight transport includes Freight Truck, Rail Freight, and Waterborne Freight components.

Freight truck component

The Freight Truck Component estimates vehicle stocks, travel, fuel efficiency, and energy use for three size classes of trucks: light-medium (Class 3), heavy-medium (Classes 4-6), and heavy (Classes 7-8). The three size classes are further broken down into 13 subclasses for fuel economy classification purposes (Table 7.8). These subclasses include two breakouts for light-medium size class, including pickup/van and vocational, one breakout for heavy-medium, including vocational, and ten breakouts for heavy. The ten subclasses parse the heavy size class into class 7 or class 8, day cab or sleeper cab, and low, mid, or high roof. Within the size classes, the stock model structure is designed to cover 34 vehicle vintages and to estimate energy use by four fuel types: diesel, gasoline, LPG, and natural gas (CNG and LNG). Fuel consumption estimates are reported regionally (by Census Division) according to the distillate fuel shares from the State Energy Data System [55]. The technology input data are specific to the different types of trucks and include the year of introduction, incremental fuel efficiency improvement, and capital cost (Table 7.9).

Table 7.8. Vehicle technology category for technology matrix for freight trucks

Vehicle category	Class	Type	Roof[1]
1	3	Pickup and Van	-
2	3	Vocational	-
3	4-6	Vocational	-
4	7-8	Vocational	-
5	7	Tractor - day cab	low
6	7	Tractor - day cab	mid
7	7	Tractor - day cab	high
8	8	Tractor - day cab	low
9	8	Tractor - day cab	mid
10	8	Tractor - day cab	high
11	8	Tractor - sleeper cab	low
12	8	Tractor - sleeper cab	mid
13	8	Tractor - sleeper cab	high

[1]Applies to Class 7 and 8 day and sleeper cabs only.

Source: U.S. Energy Information Administration, Transportation Demand Module of the National Energy Modeling System, Model Documentation 2014, DOE/EIA-M070(2014), (Washington, DC, 2012).

Table 7.9. Standard technology matrix for freight trucks

Technology Type	Vehicle Category	Introduction Year	Capital Costs (2009$)	Incremental Fuel Economy Improvement (%)
Aerodynamics I: streamlined bumper, grill, windshield, roof	1	2010	58	1.5
Aerodynamics I: conventional features; general aerodynamic shape, removal of classic non-aerodynamic features	5,8,11	1995	1000	4.1
Aerodynamics I	7,10,13	1995	1000	4.6
Aerodynamics II: SmartWay features; streamlined shape, bumper grill, hood, mirrors, side fuel tank and roof fairings, side gap extenders	5,8	2004	1126	1.5
Aerodynamics II	7,10	2004	1126	3.1
Aerodynamics II	11	2004	1155	4.2
Aerodynamics II	13	2004	1506	4.2
Aerodynamics III: underbody airflow, down exhaust, lowered ride height	7	2014	2303	4.2
Aerodynamics III	10	2014	2489	5.0
Aerodynamics III	13	2014	2675	5.8
Aerodynamics IV: skirts, boat tails, nose cone, vortex stabilizer, pneumatic blowing	5-13	1995	5500	13.0
Tires I: low rolling resistance	1	2010	7	1.5
Tires I	2,3	2010	162	2.6
Tires I	4, 8-13	2010	194	2.0
Tires I	5-7	2010	130	2.0
Tires II: super singles	5-13	2000	150	5.3
Tires III: single wide tires on trailer	5-13	2000	800	3.1
Weight Reduction I	1	2010	127	1.6
Weight Reduction I: aluminum dual tires or super singles	5-13	2010	650	1.0
Weight Reduction II: weight reduction 15%	3-13	2018	6200	3.0
Weight Reduction III: weight reduction 20%	3-13	2022	11000	3.5
Accessories I: Electric/electrohydraulic improvements; electric power steering or electrohydraulic power steering	1	2010	115	1.5
Accessories II: Improved accessories; electrified water, oil, fuel injection, power steering pump, air compressor	1	2010	93	1.5
Accessories III: Auxiliary Power Unit	11-13	2000	5400	5.8
Transmission I: 8-speed Automatic from 6-speed automatic	1	2000	280	1.7
Transmission II: 6-Manual from 4-speed automatic	1	1995	150	1.0
Transmission III: Automated Manual Transmission	2-13	2000	5000	3.5
Diesel Engine I: after treatment improvements	1	2010	119	4.0
Diesel Engine I	2	2010	117	2.6
Diesel Engine II: low-friction lubricants	1-13	2005	4	0.5
Diesel Engine III: variable valve actuation	2	2010	0	1.0
Diesel Engine III	3-13	2005	300	1.0
Diesel Engine IV: engine friction reduction, improved bearings to allow lower-viscosity oil	1-2	2010	116	1.0
Diesel Engine IV	3-13	2010	250	1.0
Diesel Engine V: improved turbo efficiency	2-13	2010	18	1.5
Diesel Engine VI: improved water, oil, fuel pump; pistons; valve train friction reduction	2	2010	213	1.3
Diesel Engine VI	3, 5-8	2010	186	1.3
Diesel Engine VI: improved water, oil, and fuel pump; pistons	4, 9-13	2010	150	1.3
Diesel Engine VII: improved cylinder head, fuel rail and injector, EGR cooler	2	2010	42	4.7
Diesel Engine VII	3-13	2010	31	4.7
Diesel Engine VIII: turbo mechanical compounding	5-13	2017	1000	3.9
Diesel Engine IX: low temperature EGR, improved turbochargers	1	2010	184	5.0
Diesel Engine X: sequential downsizing/turbocharging	5-13	2010	1200	2.5
Diesel Engine XI: waste heat recovery, Organic Rankine Cycle (bottoming cycle)	3-13	2019	10000	8.0
Diesel Engine XII: electric turbo compounding	4-13	2020	8000	7.6

Table 7.9. Standard technology matrix for freight trucks (cont.)

Technology Type	Vehicle Category	Introduction Year	Capital Costs (2009$)	Incremental Fuel Economy Improvement (%)
Gasoline Engine I: low friction lubricants	1-13	2010	4	0.5
Gasoline Engine II: coupled cam phasing	2-4	2010	46	2.6
Gasoline Engine III: engine friction reduction; low tension piston rings, roller cam followers, piston skirt design, improved crankshaft design, and bearings; costing	1-2	2010	116	2.0
Gasoline III	3-4	2010	95	2.0
Gasoline Engine IV: stoichiometric gasoline direct injection V8	1	2006	481	1.5
Gasoline Engine IV	2	2010	481	1.5
Gasoline Engine IV	3-4	2014	450	1.5
Gasoline Engine V: turbocharging and downsizing SGDI V8 to V6	1-4	2006	1743	2.1
Gasoline Engine VI: lean burn GDI	1-4	2020	450	1.5
Gasoline Engine VII: HCCI	1-4	2035	685	12.0
Hybrid System I: 42V engine off at idle	1-2	2005	1500	7.0
Hybrid System I	3-4	2005	1500	4.5
Hybrid System II: dual mode hybrid	1-2	2008	12000	25.0
Hybrid System II: electric, ePTO, or hydraulic	3-4	2009	26667	30.0
Hybrid System II: 4 kWh battery, 50 kW motor generator	5-13	2012	26000	5.5

Sources: Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles, U.S. Environmental Protection Agency and U.S. Department of Transportation, Final Rules, Federal Register, Vol. 76, No. 179 (September 2011).
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The Freight Truck Component uses projections of industrial output to estimate growth in freight truck travel. Regional heavy-duty freight truck vehicle travel is determined using a ton-mile per dollar of industrial output measure that is converted to freight vehicle miles traveled using shares developed from the Freight Analysis Framework (FAF) [56] with GIS-based regionalization between origin/destination points [587. Freight truck ton-miles, by Census division and industrial commodity, and historical truck vehicle miles traveled are developed using U. S. Department of Transportation and Federal Highway Administration data [58],[59].

Fuel economy of new freight trucks is dependent on the market penetration of advanced technology components [60]. For the advanced technology components, market penetration is determined as a function of technology type, cost effectiveness, and introduction year. Cost effectiveness is calculated as a function of fuel price, vehicle travel, fuel economy improvement, and incremental capital cost.

Heavy truck freight travel is estimated by class size and fuel type based on matching projected freight travel demand (measured by industrial output) to the travel supplied by the current fleet. Travel by vintage and size class is then adjusted so that total travel meets total demand.

Initial heavy vehicle travel, by vintage and size class, is derived by EIA using Vehicle Inventory and Use Survey (VIUS) data [61]. Initial freight truck stocks by vintage are obtained from analysis of R. L. Polk & Co. and Polk data and are distributed by fuel type using VIUS data. Vehicle scrappage rates are also estimated by EIA using R. L. Polk & Co. and Polk data a foundation of IHS market automotive solutions.

Freight rail

The Rail Freight Component uses the industrial output by NAICS code measured in real 2009 dollars and a ton-mile per dollar output measure to project rail ton-miles by Census division and commodity developed from the FAF [62]. Coal production from the NEMS Coal Market Module is used to adjust coal-based rail travel. Freight rail historical ton-miles are developed from U.S. Department of Transportation data [63]. Historic freight rail efficiencies are based on historical data taken from the U.S. Department of Transportation [64]. The distribution of rail fuel consumption by fuel type is based on the cost-effectiveness of LNG as compared with diesel considering fuel costs and incremental locomotive costs [65].

Domestic and international waterborne freight

Similar to the previous component, the domestic freight shipping within the Waterborne Freight Component uses the industrial output by NAICS code measured in real 2005 dollars and a ton-mile per dollar output measure to project domestic marine ton-miles by Census division and industrial commodity to develop domestic marine travel [66, 67].

Domestic shipping efficiencies are taken from the Transportation Energy Data Book [68]. The energy consumption in the international shipping within the Waterborne Freight Component is a function of the total level of imports and exports. The distribution of domestic and international shipping fuel consumption by fuel type is based on historical data through 2013 and allows for LNG as a marine fuel starting in 2013 based on fuel economics [69]. Historic regional domestic shipping fuel share estimates are distributed according to regional shares in the State Energy Data System (SEDS) [70].

Marine fuel choice for ocean-going vessels within Emission Control Areas (ECA)

The North American ECAs generally extend 200 nautical miles (nm) from the U.S. and Canadian ports (50 nm for the U.S. Caribbean ECA), and their requirements went into effect on January 1, 2015. The new requirements mandate that existing ships either burn fuel containing a maximum of 0.1% sulfur or to use scrubbers to remove the sulfur emissions. New ships will be built with engines and controls to handle alternative fuels and meet the ECA limits.

Compliance options, modeled as a logit choice function based on marine fuel prices, associated with travel in the ECAs for new vessels include using exhaust controls (e.g., scrubbers and selective catalytic reduction), changing fuels to marine gas oil (MGO) or liquefied natural gas (LNG), or installing engine-based controls (e.g., exhaust gas recirculation). Other technologies (e.g., biofuels and water injection) are also under development by industry but have not yet reached wide-scale adoption; hence they are modeling options for consideration in future NEMS programs, not in the current program.

Ship efficiency improvements, shipping demand changes, and fuel price fluctuations will also drive future fuel consumption predictions within the North American and U.S. Caribbean ECAs. Details on assumptions for baseline fuel estimates and technology choice options were outlined in a report released by EIA, as well methodology and assumptions for projecting fuel demand within North American ECAs [71].

Air travel submodule

The Air Travel Submodule is a 13-region world demand and supply model for passenger and freight (i.e., cargo) transport (Table 7.10). For each region, demand is computed for domestic route travel (both takeoff and landing occur in the same region) and international route travel (either takeoff or landing is in the region but not both). Once the demand for aircraft is projected, the Aircraft Fleet Efficiency Component shifts parked aircraft between regions to satisfy the projected demand for air travel.

Table 7.10. Thirteen regions for the world model

Region Number	Region	Major Countries in Region
1	United States	United States
2	Canada	Canada
3	Central America	Mexico
4	South America	Brazil
5	Europe	France, Germany
6	Africa	South Africa
7	Middle East	Egypt
8	CIS	Russia
9	China	China
10	Northeast Asia	Japan, Korea
11	Southeast Asia	Vietnam
12	Southwest Asia	India
13	Oceania	Australia, New Zealand

Source: Jet Information Services, 2013 World Jet Inventory, data tables (2013).

Air travel demand

The Air Travel Demand Component calculates the domestic and international per capita revenue passenger miles (RPM-PC) for each region. Domestic and international revenue passenger miles are based on the historical data in Table 7.11 [72], per capita income for the United States, per capita GDP for the non-U.S. regions, and ticket prices. The revenue ton miles of air freight for the United States are based on merchandise exports, gross domestic product, and fuel cost. For the non-U.S. regions, revenue ton-miles are based on GDP growth in the region [73].

Airport capacity constraints based on the Federal Aviation Administration (FAA) Airport Capacity Benchmark Report 2004 are incorporated into the Air Travel Demand Component using airport capacity measures [74]. Airport capacity is defined by the maximum number of flights per hour airports can routinely handle, the amount of time airports operate at optimal capacity, and passenger load factors. Capacity expansion is expected to be delayed due to the economic environment and fuel costs.

Aircraft stock efficiency

The Aircraft Fleet Efficiency Component consists of a world regional stock model of wide body, narrow body, and regional jets by vintage. Total aircraft supply for a given year is based on the initial supply of aircraft for model year 2009, new passenger aircraft sales, and the survival rate by vintage (Table 7.12) [75]. New passenger aircraft sales are a function of revenue passenger miles and gross domestic product.

Table 7.11. 2013 Regional population, GDP, per capita GDP, domestic and international RPM and per capita RPM

Region	Population (million)	GDP (2005$)	GDP per Capita
United States	317.0	11,651	36,752.78
Canada	35.3	1,274	36,115.40
Central America	166.0	2,181	13,136.93
South America	443.2	5,033	11,355.94
Europe	649.7	16,041	24,689.83
Africa	1076.3	4,374	4,063.54
Middle East	220.9	2,562	11,597.03
Russia	252.5	3,752	14,856.79
China	1,463.9	12,124	8,282.08
Northeast Asia	176.1	5,508	31,277.72
Southeast Asia	778.6	4,350	5,587.67
Southwest Asia	1,502.7	5,580	3,713.48
Oceania	29.6	866	29,300.60
Region	**RPM (billion)**	**RPM per Capita (thousand)**	
Domestic			
United States	602.5	1,900.7	
Canada	31.4	890.6	
Central America	23.2	139.6	
South America	93.6	211.2	
Europe	453.4	697.8	
Africa	34.1	31.7	
Middle East	54.8	248.1	
Russia	75.1	297.5	
China	292.6	199.9	
Northeast Asia	66.0	374.6	
Southeast Asia	105.8	135.9	
Southwest Asia	43.2	28.8	
Oceania	62.9	2,126.4	
International			
United States	263.6	832.1	
Canada	62.5	1,770.6	
Central America	79.0	476.0	
South America	66.7	150.5	

Table 7.11. 2013 Regional population, GDP, per capita GDP, domestic and international RPM and per capita RPM (cont.)

Region	RPM (billion)	RPM per Capita (thousand)
Europe	411.6	633.5
Africa	65.9	61.2
Middle East	154.0	696.9
Russia	100.3	397.0
China	115.8	79.1
Northeast Asia	131.6	747.4
Southwest Asia	150.9	193.8
Southwest Asia	70.0	46.6
Oceania	54.5	1,845.0

Source: Global Insight 2005 chain-weighted dollars, Boeing Current Market Outlook 2013.

Table 7.12. 2013 Regional passenger and cargo aircraft supply

Passenger and Cargo Aircraft Type	New	Age of Aircraft (years) 1-10	11-20	21-30	30 or more	Total
Passenger						
Narrow Body						
United States	154	1019	1588	886	42	3756
Canada	6	127	94	49	4	297
Central America	21	190	60	64	19	374
South America	49	329	159	109	53	778
Europe	139	1705	890	307	9	3,059
Africa	11	149	150	136	36	559
Middle East	30	319	119	85	11	600
Russia	33	265	333	242	44	1,081
China	235	1250	274	36	0	1,795
Northeast Asia	49	205	106	10	2	374
Southeast Asia	135	533	167	123	10	1007
Southwest Asia	40	254	44	31	0	394
Oceania	21	197	51	10	0	279
Wide Body						
United States	20	88	323	171	3	618
Canada	4	23	28	25	0	81
Central America	3	9	9	5	0	28
South America	9	60	42	6	2	120

Table 7.12. 2013 Regional passenger and cargo aircraft supply (cont.)

		Age of Aircraft (years)				
Passenger and Cargo Aircraft Type	**New**	**1-10**	**11-20**	**21-30**	**30 or more**	**Total**
Europe	38	327	366	89	0	831
Africa	9	60	39	34	6	154
Middle East	46	310	157	72	0	608
Russia	9	41	89	35	0	178
China	57	195	109	4	0	365
Northeast Asia	23	177	137	20	0	357
Southeast Asia	50	227	158	31	0	473
Southwest Asia	7	53	36	14	0	114
Oceania	8	65	33	25	0	131
Regional Jets						
United States	49	1,222	1,024	177	3	2,476
Canada	14	152	96	146	16	433
Central America	13	80	68	57	0	218
South America	38	190	98	63	3	392
Europe	38	635	531	249	0	1,453
Africa	7	152	145	98	3	415
Middle East	1	98	76	38	0	216
Russia	18	98	122	98	1	352
China	15	137	46	1	0	199
Northeast Asia	7	59	26	3	0	95
Southeast Asia	35	121	103	67	2	338
Southwest Asia	3	52	32	0	0	88
Oceania	10	108	132	107	0	357
Cargo						
Narrow Body						
United States	0	3	68	108	109	288
Canada	0	0	5	2	26	33
Central America	0	1	3	6	9	19
South America	0	0	2	6	46	54
Europe	0	0	18	87	5	110
Africa	0	0	4	16	45	65
Middle East	0	0	1	6	9	16
Russia	1	8	6	3	4	22
China	0	2	36	23	0	61
Northeast Asia	0	0	0	1	0	1
Southeast Asia	0	0	1	13	19	33

Table 7.12. 2013 Regional passenger and cargo aircraft supply (cont.)

Passenger and Cargo Aircraft Type	New	Age of Aircraft (years) 1-10	11-20	21-30	30 or more	Total
Southwest Asia	0	0	1	5	6	12
Oceania	0	0	0	11	3	14
Wide Body						
United States	15	101	194	200	89	599
Canada	0	0	0	3	4	7
Central America	0	2	1	3	3	9
South America	3	8	7	4	5	27
Europe	10	48	54	40	19	171
Africa	0	2	2	1	2	7
Middle East	12	17	11	18	13	71
Russia	2	7	8	7	4	28
China	8	47	20	15	2	92
Northeast Asia	6	25	17	10	0	58
Southeast Asia	0	22	29	5	0	56
Southwest Asia	0	0	0	2	3	5
Oceania	0	1	0	0	0	1
Regional Jets						
United States	0	0	5	37	0	42
Canada	0	0	2	8	0	10
Central America	0	0	4	2	0	6
South America	0	0	0	3	0	3
Europe	0	0	18	93	0	111
Africa	0	0	3	6	1	10
Middle East	0	0	0	2	0	2
Russia	0	0	0	2	0	2
China	0	0	0	0	0	0
Northeast Asia	0	0	0	0	0	0
Southeast Asia	0	0	0	5	0	5
Southwest Asia	0	0	3	0	0	3
Oceania	0	0	0	8	0	8
Survival Curve (fraction)	**New**	**5**	**10**	**20**	**40**	
Narrow Body	1.000	0.9998	0.9994	0.9970	0.8000	
Wide Body	1.000	0.9983	0.9961	0.9870	0.7900	
Regional Jets	1.000	0.9971	0.9950	0.9830	0.7800	

Source: Jet Information Services, 2013 World Jet Inventory (2013).

Wide- and narrow-body passenger planes over 25 years of age are placed as cargo jets according to a cargo percentage varying from 50% of 25-year-old planes to 100% of those aircraft 30 years and older. The available seat-miles per plane, which measure the carrying capacity of the airplanes by aircraft type, increase gradually over time. Domestic and international travel routes are combined into a single regional demand for seat-miles and passed to the Aircraft Fleet Efficiency Component, which adjusts the initial aircraft stock to meet that demand. For each region, starting with the United States, the initial stock is adjusted by moving aircraft between regions.

Technological availability, economic viability, and efficiency characteristics of new jet aircraft are assumed to grow at a fixed rate. Fuel-efficiency of new aircraft acquisitions represents an improvement over the stock efficiency of surviving airplanes. Generic sets of new technologies (Table 7.13) are introduced in different years and with a set of improved efficiencies over the base year (2007). Regional shares of all types of aircraft fuel use are assumed to be constant and are consistent with the SEDS estimate of regional jet fuel shares.

Table 7.13. Standard technology matrix for air travel

Technology	Introduction Year	Fractional Efficiency Improvement	Jet Fuel Trigger Price (1987$/gallon)
Technology #1	2008	0.03	1.34
Technology #2	2014	0.05	1.34
Technology #3	2020	0.09	1.34
Technology #4	2025	0.13	1.34
Technology #5	2018	0.17	1.34
Technology #6	2018	0.00	1.34

Source: Jet Information Services, 2013 World Jet Inventory, data tables (2013).

Legislation and regulations

Light-Duty Vehicle Combined Corporate Average Fuel Economy (CAFE) Standards

The AEO2016 Reference case includes the attribute-based CAFE standards for LDVs for model year (MY) 2011, the joint attribute-based CAFE and vehicle GHG emissions standards for MY 2012 through MY 2016 and for MY 2017 through 2025. CAFE standards are then held constant in subsequent model years, although the fuel economy of new LDVs continues to rise modestly over time.

Heavy-Duty Vehicle Combined Corporate Average Fuel Economy Standards

On September 15, 2011, EPA and NHTSA jointly announced a final rule, called the HD National Program [76], which for the first time establishes greenhouse gas (GHG) emissions and fuel consumption standards for on-road heavy-duty trucks and their engines. The AEO2016 Reference case incorporates the standards for heavy-duty vehicles (HDVs) with gross vehicle weight rating (GVWR) above 8,500 pounds (Classes 2b through 8). The HD National Program standards begin for MY 2014 vehicles and engines and are fully phased in by MY 2018. AEO2016 models standard compliance among 13 HDV regulatory classifications that represent the discrete vehicle categories set forth in the rule. On August 16, 2016, EPA and NHTSA jointly adopted a second round of standards for medium- and heavy-duty vehicles. This second round of vehicle standards is not included in AEO2016 Reference case, instead it is included as an AEO2016 side case.

Energy Independence and Security Act of 2007 (EISA2007)

A fuel economy credit trading program is established based on EISA2007. Currently, CAFE credits earned by manufacturers can be banked for up to 3 years and can only be applied to the fleet (car or light truck) from which the credit was earned. Starting in model year 2011, the credit trading program allows manufacturers whose automobiles exceed the minimum fuel economy standards to earn credits that can be sold to other manufacturers whose automobiles fail to achieve the prescribed standards. The credit trading program is designed to ensure that the total oil savings associated with manufacturers that exceed the prescribed standards are preserved when credits are sold to manufacturers that fail to achieve the prescribed standards.

While the credit trading program began in 2011, EISA2007 allows manufacturers to apply credits earned to any of the three model years prior to the model year the credits are earned, and to any of the five model years after the credits are earned. The transfer of credits within a manufacturer's fleet is limited to specific maximums. For model years 2011 through 2013, the maximum transfer is 1.0 mpg; for model years 2014 through 2017, the maximum transfer is 1.5 mpg; and for model years 2018 and later, the maximum credit transfer is 2.0 mpg. NEMS currently allows for sensitivity analysis of CAFE credit banking by manufacturer fleet, but does not model the trading of credits across manufacturers. AEO2016 does not consider trading of credits since this would require significant modifications to NEMS and detailed technology cost and efficiency data by manufacturer, which are not readily available.

The CAFE credits specified under the Alternative Motor Fuels Act (AMFA) through 2019 are extended. Prior to passage of this Act, the CAFE credits under AMFA were scheduled to expire after model year 2010. Currently, 1.2 mpg is the maximum CAFE credit that can be earned from selling alternative fueled vehicles. EISA2007 extends the 1.2 mpg credit maximum through 2014 and reduces the maximum by 0.2 mpg for each following year until it is phased out by model year 2020. NEMS does model CAFE credits earned from alternative fuel vehicle sales.

American Recovery and Reinvestment Act of 2009 and Energy Improvement and Extension Act of 2008

ARRA Title I, Section 1141, modified the EIEA2008 Title II, Section 205, tax credit for the purchase of new, qualified plug-in electric drive motor vehicles. According to the legislation, a qualified plug-in electric drive motor vehicle must draw propulsion from a traction battery with at least 4 kWh of capacity and be propelled to a significant extent by an electric motor which draws electricity from a battery that is capable of being recharged from an external source of electricity.

The tax credit for the purchase of a plug-in electric vehicle is $2,500, plus, starting at a battery capacity of 5 kWh, an additional $417 per kWh battery credit up to a maximum of $7,500 per vehicle. The tax credit eligibility and phase-out are specific to an individual vehicle manufacturer. The credits are phased out once a manufacturer's cumulative sales of qualified vehicles reach 200,000. The phase-out period begins two calendar quarters after the first date in which a manufacturer's sales reach the cumulative sales maximum after December 31, 2009 [i]. The credit is reduced to 50% of the total value for the first two calendar quarters of the phase-out period and then to 25% for the third and fourth calendar quarters before being phased out entirely thereafter. The credit applies to vehicles with a gross vehicle weight rating of less than 14,000 pounds.

ARRA also allows a tax credit of 10% against the cost of a qualified electric vehicle with a battery capacity of at least 4 kWh subject to the same phase-out rules as above. The tax credits for qualified plug-in electric drive motor vehicles and electric vehicles are included in AEO2016.

Energy Policy Act of 1992 (EPACT1992)

Fleet alternative-fuel vehicle sales necessary to meet the EPACT regulations are derived based on the mandates as they currently stand and the Commercial Fleet Vehicle Component calculations. Total projected AFV sales are divided into fleets by government, business, and fuel providers (Table 7.14).

Table 7.14. EPACT legislative mandates for AFV purchases by fleet type and year

Year	Federal	State	Fuel Providers	Electric Utilities
2005	75	75	70	90

Source: U.S. Energy Information Administration, Energy Efficiency and Renewable Energy (Washington, DC, 2005), http://www1.eere.energy.gov/vehiclesandfuels/epact/statutes_regulations.html.

Because the commercial fleet model operates on three fleet type representations (business, government, and utility), the federal and state mandates are weighted by fleet vehicle stocks to create a composite mandate for both. The same combining methodology is used to create a composite mandate for electric utilities and fuel providers based on fleet vehicle stocks [77].

Emission 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. 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) [78]. 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. The ECAs extend up to 200 nautical miles from coasts of the United States, Canada, and the French territories, but do 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 [79].

Low-Emission Vehicle Program (LEVP)

The LEVP was originally passed into legislation in 1990 in the State of California. It began as the implementation of a voluntary opt-in pilot program under the purview of Clean Air Act Amendments of 1990 (CAAA1990), which included a provision that other states could opt in to the California program to achieve lower emissions levels than would otherwise be achieved through CAAA1990. Fourteen states have elected to adopt the California LEVP. The program was amended in 1998 to expand to cover more vehicles, increase stringency, and add ZEV credits.

The LEVP is a fleet-averaged, emissions-based policy for smog-forming pollutants, setting sales mandates for six categories of low-emission vehicles: low-emission vehicles (LEVs), ultra-low-emission vehicles (ULEVs), super-ultra-low-emission vehicles (SULEVs), partial zero-emission vehicles (PZEVs), advanced technology partial zero-emission vehicles (AT-PZEVs), and zero-emission vehicles (ZEVs). The LEVP was amended multiple times, most recently in 2014, to cover more vehicles, increase stringency, and add ZEV credits.

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 model year (MY) 2018 and later [80]. The ZEV program affects model year 2018 and later vehicles, requiring automakers to earn credits for alternative fuel vehicles based on a percentage of their sales in California. Nine other states (Connecticut, Maine, Massachusetts, Rhode Island, Vermont, New Jersey, New York, Maryland, and Oregon) have adopted California's ZEV program. The ZEV sales requirement is administered through credits that are earned for selling specific types of vehicles, such as but not limited to battery electric and plug-in hybrid electric vehicles. The value of the credits for vehicles sold within each category depends on certain vehicle characteristics including, for example, the electric driving range of electric vehicles. The total percentage requirement starts at 4.5% for model year 2018 sales and increases to 22% for model year 2025 sales. Full ZEVs are required to make up 16% of the required credits by model year 2025, mandating the sale of vehicles powered by electricity or hydrogen fuel cells.

Notes and sources

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Chapter 8. Electricity Market Module

The NEMS Electricity Market Module (EMM) represents the capacity planning, dispatching, and pricing of electricity. It is composed of four submodules: electricity load and demand, electricity capacity planning, electricity fuel dispatching, and electricity finance and pricing. It includes nonutility capacity and generation, and electricity transmission and trade. A detailed description of the EMM is provided in the forthcoming EIA publication, Electricity Market Module of the National Energy Modeling System 2016, DOE/EIA-M068(2016).

Based on fuel prices and electricity demands provided by the other modules of NEMS, the EMM determines the most economical way to supply electricity, within environmental and operational constraints. There are assumptions about the operations of the electricity sector and the costs of various options in each of the EMM Submodules. This section describes the model parameters and assumptions used in the EMM. It includes a discussion of legislation and regulations that are incorporated in the EMM, as well as information about the climate change action plan.

EMM regions

The supply regions used in the EMM were developed for the *Annual Energy Outlook 2011*, and correspond to the North American Electric Reliability Corporation (NERC) regions in place at that time, divided into subregions, as shown in Figure 8.1.

Figure 8.1. Electricity Market Model Supply Regions

1.	ERCT	ERCOT 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

Model parameters and assumptions

Generating capacity types

The capacity types represented in the EMM are shown in Table 8.1.

Table 8.1. Generating capacity types represented in the Electricity Market Module

Capacity Type
Existing coal steam plants[1]
Ultra Supercritical Coal (USC)[2]
Advanced Coal - Integrated Coal Gasification Combined Cycle (IGCC)[2]
USC with 30% Carbon Sequestration
Oil/Gas Steam - Oil/Gas Steam Turbine
Combined Cycle - Conventional Gas/Oil Combined Cycle Combustion Turbine
Advanced Combined Cycle - Advanced Gas/Oil Combined Cycle Combustion Turbine
Advanced Combined Cycle with carbon sequestration
Combustion Turbine - Conventional Combustion Turbine
Advanced Combustion Turbine - Steam Injected Gas Turbine
Molten Carbonate Fuel Cell
Conventional Nuclear
Advanced Nuclear - Advanced Light Water Reactor
Generic Distributed Generation - Baseload
Generic Distributed Generation - Peak
Conventional Hydropower - Hydraulic Turbine
Pumped Storage - Hydraulic Turbine Reversible
Geothermal
Municipal Solid Waste
Biomass - Fluidized Bed
Solar Thermal - Central Tower
Solar Photovoltaic – Single Axis Tracking
Wind
Wind Offshore

[1] The EMM represents 32 different types of existing coal steam plants, based on the different possible configuration of NOx, particulate and SO2 emission control devices, as well as future options for controlling mercury and carbon. (See Table 8.10.).
[2] The AEO2016 assumes new coal plants without CCS cannot be built, due to emission standards for new plants. These technologies exist in the modeling framework, but are not assumed available to be built in the projections.
Source: U.S. Energy Information Administration.

New generating plant characteristics

The cost and performance characteristics of new generating technologies are inputs to the electricity capacity planning submodule (Table 8.2). These characteristics are used in combination with fuel prices from the NEMS fuel supply modules and foresight on fuel prices to compare options when new capacity is needed. Heat rates for new fossil-fueled technologies are assumed to decline linearly through 2025.

For AEO2016, EIA commissioned an external consultant to update current cost estimates for certain utility-scale electric generating plants [81]. This report used a consistent methodology, similar to the one used to develop the estimates for previous AEOs, but accounted for more recent data and experience, and also included alternative designs not previously considered. Updated costs were used for coal with carbon capture and sequestration (CCS), the combined cycle (without CCS) technologies, the combustion turbine technologies, advanced nuclear, onshore wind and solar photovoltaic (PV). Costs for other technologies are consistent with AEO2015 assumptions. A cost adjustment factor, based on the producer price index for metals and metal products, allows the overnight costs to fall in the future if this index drops, or rise further if it increases.

The overnight costs shown in Table 8.2, except as noted below, represent the estimated cost of building a plant before adjusting for regional cost factors. Overnight costs exclude interest during plant construction and development. Technologies with limited commercial experience may include a “Technological Optimism” factor to account for the tendency during technology research and development to underestimate the full engineering and development costs for new technologies.

All technologies demonstrate some degree of variability in cost based on project size, location, and access to key infrastructure (such as grid interconnections, fuel supply, and transportation). For wind in particular, the cost favorability of the lowest-cost regions compound the underlying variability in regional cost and create a significant differential between the unadjusted costs and the capacity-weighted average national costs as observed from recent market experience. To correct for this, Table 8.2 shows a weighted average cost for wind based on the regional cost factors assumed for wind in the AEO2016 and the actual regional distribution of wind builds that occurred in 2014.

Table 8.3 presents a full listing of the overnight costs for each technology and electricity region (Figure 6), if the resource or technology is available to be built in the given region. The regional costs reflect the impact of locational adjustments, including one to address ambient air conditions for technologies that include a combustion turbine and one to adjust for additional costs associated with accessing remote wind resources. Temperature, humidity, and air pressure can impact the available capacity of a combustion turbine, and EIA’s modeling addresses this through an additional cost multiplier by region. Unlike most other generation technologies where fuel can be transported to the plant, wind generators must be located in areas with the best wind resources. As sites near existing transmission, with access to a road network, or otherwise located on lower-development-cost lands are utilized, additional costs may be incurred to access sites with less favorable characteristics. EIA represents this through a multiplier applied to the wind plant capital costs that increases as the best sites in a given region are developed.

Table 8.2. Cost and performance characteristics of new central station electricity generating technologies

Technology	First Available Year[1]	Size (MW)	Lead time (years)	Base Overnight Cost in 2015 (2015 $/kW)	Contingency Factors: Project Contingency Factor[2]	Contingency Factors: Techno-logical Optimism Factor[3]	Total Overnight Cost in 2015[4,10] (2015 $/kW)	Variable O&M[5] (2015 $/MWh)	Fixed O&M (2015 $/ kW/yr.)	Heatrate[6] in 2015 (Btu/ kWh)	nth-of-a-kind Heatrate (Btu/ kWh)
Coal with 30% carbon sequestration (CCS)	2019	650	4	4,649	1.07	1.03	5,098	6.95	68.49	9,750	9,221
Conv Gas/Oil Comb Cycle	2018	702	3	911	1.05	1.00	956	3.42	10.76	6,600	6,350
Adv Gas/Oil Comb Cycle (CC)	2018	429	3	1,000	1.08	1.00	1,080	1.96	9.78	6,300	6,200
Adv CC with CCS	2018	340	3	1,898	1.08	1.04	2,132	6.97	32.69	7,525	7,493
Conv Comb Turbine[7]	2017	100	2	1,026	1.05	1.00	1,077	3.42	17.12	9,960	9,600
Adv Comb Turbine	2017	237	2	632	1.05	1.00	664	10.47	6.65	9,800	8,550
Fuel Cells	2018	10	3	6,217	1.05	1.10	7,181	44.21	0.00	9,500	6,960
Adv Nuclear	2022	2,234	6	5,288	1.10	1.05	6,108	2.25	98.11	10,449	10,449
Distributed Generation-Base	2018	2	3	1,448	1.05	1.00	1,520	7.98	17.94	9,004	8,900
Distributed Generation - Peak	2017	1	2	1,739	1.05	1.00	1,826	7.98	17.94	10,002	9,880
Biomass	2019	50	4	3,498	1.07	1.01	3,765	5.41	108.63	13,500	13,500
Geothermal[8,9]	2019	50	4	2,559	1.05	1.00	2,687	0.00	116.12	9,541	9,541
MSW Landfill Gas	2018	50	3	7,954	1.07	1.00	8,511	9.00	403.97	14,360	18,000
Conventional Hydropower[9]	2019	500	4	2,191	1.10	1.00	2,411	2.62	14.70	9,541	9,541
Wind[10]	2018	100	3	1,536	1.07	1.00	1,644	0.00	45.98	9,541	9,541
Wind Offshore	2019	400	4	4,605	1.10	1.25	6,331	0.00	76.10	9,541	9,541
Solar Thermal[8]	2018	100	3	3,895	1.07	1.00	4,168	0.00	69.17	9,541	9,541
Photovoltaic[8,11]	2017	150	2	2,362	1.05	1.00	2,480	0.00	21.33	9,541	9,541

[1]Represents the first year that a new unit could become operational.

[2]A contingency allowance is defined by the American Association of Cost Engineers as the "specific provision for unforeseeable elements of costs within a defined project scope; particularly important where previous experience has shown that unforeseeable events which will increase costs are likely to occur."

[3]The technological optimism factor is applied to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

[4]Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2015.

[5]O&M = Operations and maintenance.

[6]For hydro, wind, solar and geothermal technologies, the heat rate shown represents the average heat rate for conventional thermal generation as of 2014. This is used for purposes of calculating primary energy consumption displaced for these resources, and does not imply an estimate of their actual energy conversion efficiency.

[7] Combustion turbine units can be built by the model prior to 2017 if necessary to meet a given region's reserve margin.

[8]Capital costs are shown before investment tax credits are applied.

[9]Because geothermal and hydro cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.

[10]Wind's total overnight cost of $1644/kW represents the average input value across all 22 electricity market regions, as weighted by the wind capacity installed during 2014 in each region to account for the substantial regional variation in wind costs (as shown in Table 8.3). The input value used for AEO 2016 was $1837/kW, and represents the cost of building a 100 MW wind plant excluding regional factors. Region-specific factors contributing to the substantial regional variation in cost include differences in typical project size across regions, accessibility of resources, and variation in labor and other construction costs throughout the country.

[11]Costs and capacities are expressed in terms of net AC power available to the grid for the installed capacity.

Sources: For the AEO2016 cycle, EIA updated cost estimates for certain electric generating technologies, based on a draft report provided by external consultants. This report will be provided on the EIA website when finalized. Costs were updated for coal with CCS, the combined cycle (without CCS) technologies, the combustion turbine technologies, advanced nuclear, onshore wind and solar PV. Costs for other technologies are consistent with AEO2015 assumptions.

Table 8.3. Total overnight capital costs of new electricity generating technologies by region

2015 $/kW

Technology	1 (ERCT)	2 (FRCC)	3 (MROE)	4 (MROW)	5 (NEWE)	6 (NYCW)	7 (NYLI)	8 (NYUP)	9 (RFCE)	10 (RFCM)	11 (RFCW)
Coal with 30% CCS	4,760	5,001	4,841	4,887	5,119	N/A	N/A	4,802	5,478	4,951	5,134
Conv Gas/Oil Comb Cycle	875	904	913	933	1,062	1,541	1,541	1,080	1,131	955	979
Adv Gas/Oil Comb Cycle (CC)	1,035	1,056	1,026	1,068	1,200	1,644	1,644	1,219	1,267	1,071	1,116
Adv CC with CCS	1,991	2,065	2,073	2,051	2,184	3,111	3,111	2,195	2,333	2,089	2,147
Conv Comb Turbine	1,035	1,075	1,024	1,066	1,119	1,517	1,517	1,104	1,185	1,067	1,092
Adv Comb Turbine	645	666	640	666	720	1,028	1,028	714	774	666	686
Fuel Cells	6,728	6,893	7,217	7,000	7,245	8,703	8,703	7,145	7,374	7,173	7,159
Adv Nuclear	5,857	5,943	6,150	6,020	6,364	N/A	N/A	6,462	6,529	6,102	6,224
Distributed Generation - Base	1,353	1,392	1,491	1,486	1,737	2,482	2,482	1,759	1,819	1,543	1,559
Distributed Generation - Peak	1,754	1,822	1,735	1,806	1,896	2,571	2,571	1,871	2,008	1,809	1,851
Biomass	3,471	3,569	3,837	3,644	3,878	4,620	4,620	3,893	4,010	3,746	3,803
Geothermal	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
MSW – Landfill Gas	7,830	8,077	8,579	8,241	8,587	10,724	10,724	8,502	8,792	8,485	8,460
Conventional Hydropower	N/A	N/A	N/A	3,047	3,292	N/A	N/A	2,604	N/A	N/A	2,597
Wind	1,617	N/A	2,204	1,819	2,465	N/A	2,241	2,241	2,241	2,204	2,204
Wind Offshore	5,780	8,357	6,369	6,400	6,496	8,110	8,110	6,274	6,496	6,300	6,369
Solar Thermal	3,551	3,776	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Photovoltaic[1]	2,135	2,269	2,376	2,437	2,559	N/A	3,469	2,433	2,574	2,453	2,443

Technology	12 (SRDA)	13 (SRGW)	14 (SRSE)	15 (SRCE)	16 (SRVC)	17 (SPNO)	18 (SPSO)	19 (AZNM)	20 (CAMX)	21 (NWPP)	22 (RMPA)
Coal with 30% CCS	4,798	5,206	4,816	4,744	4,627	5,027	4,886	5,653	5,782	5,247	5,739
Conv Gas/Oil Comb Cycle	873	991	898	877	851	947	913	1,043	1,204	994	1,119
Adv Gas/Oil Comb Cycle (CC)	1,033	1,129	1,060	1,053	1,013	1,095	1,072	1,280	1,378	1,175	1,320
Adv CC with CCS	2,007	2,207	2,021	1,977	1,935	2,122	2,059	2,413	2,490	2,206	2,395
Conv Comb Turbine	1,048	1,113	1,077	1,030	1,019	1,089	1,067	1,244	1,237	1,128	1,295
Adv Comb Turbine	654	696	683	643	640	680	668	788	799	710	954
Fuel Cells	6,793	7,303	6,764	6,807	6,692	7,030	6,908	7,080	7,504	7,102	6,879
Adv Nuclear	5,894	6,199	5,876	5,906	5,839	6,034	5,961	6,065	N/A	6,126	6,108
Distributed Generation - Base	1,359	1,570	1,386	1,377	1,327	1,480	1,427	1,520	1,889	1,534	1,600
Distributed Generation - Peak	1,777	1,886	1,826	1,745	1,727	1,845	1,808	2,108	2,097	1,912	2,195
Biomass	3,502	3,829	3,483	3,517	3,438	3,663	3,599	3,765	4,051	3,773	3,524
Geothermal	N/A	N/A	N/A	N/A	N/A	N/A	N/A	3,982	2,742	2,687	N/A
MSW - Landfill Gas	7,941	8,672	7,872	7,941	7,753	8,298	8,102	8,358	8,979	8,358	8,060
Conventional Hydropower	3,138	2,217	3,138	1,330	1,940	N/A	2,637	N/A	2,432	2,411	2,801
Wind	2,388	2,204	2,388	2,388	2,388	1,516	1,378	1,980	1,984	1,980	1,516
Wind Offshore	6,331	N/A	5,818	N/A	5,717	N/A	N/A	N/A	6,604	6,433	N/A
Solar Thermal	N/A	N/A	N/A	N/A	N/A	N/A	3,822	4,093	4,660	4,118	3,839
Photovoltaic[1]	2,210	2,500	2,170	2,192	2,081	2,383	2,284	2,403	2,765	2,443	2,326

Table shows overnight capital costs for projects initiated in 2015. Costs include contingency factors and regional cost and ambient conditions multipliers. Interest charges are excluded. The costs are shown before investment tax credits are applied.

N/A: plant type cannot be built in the region due to lack of resources, sites or specific state legislation.

[1]PV represents a ground-mounted utility-scale system. Roof-top or other distributed PV can be built in NYCW, but the ability to site larger, ground-mounted plants may be limited in the densely populated region.

Region map: Figure 6.

Technological optimism and learning

Overnight costs for each technology are calculated as a function of regional construction parameters, project contingency, and technological optimism and learning factors.

The technological optimism factor represents the demonstrated tendency to underestimate actual costs for a first-of-a-kind, unproven technology. As experience is gained (after building four units) the technological optimism factor is gradually reduced to 1.0.

The learning function in NEMS is determined at a component level. Each new technology is broken into its major components, and each component is identified as revolutionary, evolutionary, or mature. Different learning rates are assumed for each component, based on the level of experience with the design component (Table 8.4). Where technologies use similar components, these components learn at the same rate as these units are built. For example, it is assumed that the underlying turbine generator for a combustion turbine, combined cycle, and integrated coal-gasification combined cycle unit is basically the same. Therefore construction of any of these technologies would contribute to learning reductions for the turbine component.

The learning function, OC, has the nonlinear form:

$$OC(C) = a*C^{-b},$$

where C is the cumulative capacity for the technology component.

Table 8.4. Learning parameters for new generating technology components

Technology Component	Period 1 Learning Rate (LR1)	Period 2 Learning Rate (LR2)	Period 3 Learning Rate (LR3)	Period 1 Doublings	Period 2 Doublings	Minimum Total Learning by 2035
Pulverized Coal	-	-	1%	-	-	5%
Combustion Turbine - conventional	-	-	1%	-	-	5%
Combustion Turbine - advanced	-	10%	1%	-	5	10%
HRSG[1]	-	-	1%	-	-	5%
Gasifier	-	10%	1%	-	5	10%
Carbon Capture/Sequestration	20%	10%	1%	3	5	20%
Balance of Plant - IGCC	-	-	1%	-	-	5%
Balance of Plant - Turbine	-	-	1%	-	-	5%
Balance of Plant - Combined Cycle	-	-	1%	-	-	5%
Fuel Cell	20%	10%	1%	3	5	20%
Advanced Nuclear	5%	3%	1%	3	5	10%
Fuel prep - Biomass	-	10%	1%	-	5	10%
Distributed Generation - Base	-	5%	1%	-	5	10%
Distributed Generation - Peak	-	5%	1%	-	5	10%
Geothermal	-	8%	1%	-	5	10%
Municipal Solid Waste	-	-	1%	-	-	5%
Hydropower	-	-	1%	-	-	5%
Wind	-	-	1%	-	-	5%
Wind Offshore	20%	10%	1%	3	5	20%
Solar Thermal	20%	10%	1%	3	5	10%
Solar PV - Module	-	10%	1%	-	5	10%
Balance of Plant - Solar PV	-	14%	1%	-	5	10%

[1]HRSG = Heat Recovery Steam Generator

Note: Please see the text for a description of the methodology for learning in the Electricity Market Module.

Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis.

The progress ratio (pr) is defined by speed of learning (i.e., how much costs decline for every doubling of capacity). The reduction in capital cost for every doubling of cumulative capacity (LR) is an exogenous parameter input for each component (Table 8.4). The progress ratio and LR are related by:

$$pr = 2^{-b} = (1 - LR)$$

The parameter “b” is calculated from the second equality above (b =-(ln(1-LR)/ln(2))). The parameter “a” is computed from initial conditions, i.e.,

$$a = OC(C_0)/Co^{-b}$$

where C_0 is the initial cumulative capacity. Once the rates of learning (LR) and the cumulative capacity (C_0) are known for each interval, the parameters (a and b) can be computed. Three learning steps were developed to reflect different stages of learning as a new design is introduced into the market. New designs with a significant amount of untested technology will see high rates of learning initially, while more conventional designs will not have as much learning potential. Costs of all design components are adjusted to reflect a minimal amount of learning, even if new capacity additions are not projected. This represents cost reductions due to future international development or increased research and development.

Once the learning rates by component are calculated, a weighted average learning factor is calculated for each technology. The weights are based on the share of the initial cost estimate that is attributable to each component (Table 8.5). For technologies that do not share components, this weighted average learning rate is calculated exogenously, and input as a single component.

These technologies may still have a mix of revolutionary components and more mature components, but it is not necessary to include this detail in the model unless capacity from multiple technologies would contribute to the component learning. In the case of the solar PV technology, it is assumed that the module component accounts for 30% of the cost, and that the balance of system components accounts for the remaining 70%. Because the amount of end-use PV capacity (existing and projected) is significant relative to total solar PV capacity, and because the technology of the module component is common across the end-use and electric power sectors, the calculation of the learning factor for the PV module component also takes into account capacity built in the residential and commercial sectors.

Table 8.6 shows the capacity credit toward component learning for the various technologies. It was assumed that for all combined-cycle technologies, the turbine unit contributed two-thirds of the capacity, and the steam unit one-third. Therefore, building one gigawatt of gas combined cycle would contribute 0.67 gigawatts (GW) toward turbine learning, and 0.33 GW toward steam learning. Components that do not contribute to the capacity of the plant, such as the balance of plant category, receive 100% capacity credit for any capacity built with that component. For example, when calculating capacity for the “Balance of plant - CC” component, all combined cycle capacity would be counted 100%, both conventional and advanced.

Table 8.5. Component cost weights for new technologies

Technology	Pulverized Coal	Combus-tion Turbine-conven-tional	Combustion Turbine - advanced	HRSG	Gasifier	Carbon Capture/ Sequestion	Balance of Plant -IGCC	Balance of Plant-Turbine	Balance of Plant-Combined Cycle	Fuel Prep Biomass
Coal with carbon sequestration	75%	0%	0%	0%	0%	25%	0%	0%	0%	0%
Conv Gas/Oil Comb	0%	30%	0%	40%	0%	0%	0%	0%	30%	0%
Adv Gas/Oil Comb Cycle (CC)	0%	0%	30%	40%	0%	0%	0%	0%	30%	0%
Adv CC with carbon sequestration	0%	0%	20%	25%	0%	40%	0%	0%	15%	0%
Conv Comb Turbine	0%	50%	0%	0%	0%	0%	0%	50%	0%	0%
Adv Comb Turbine	0%	0%	50%	0%	0%	0%	0%	50%	0%	0%
Biomass	50%	0%	0%	0%	0%	0%	0%	0%	0%	50%

Note: All unlisted technologies have a 100% weight with the corresponding component. Components are not broken out for all technologies unless there is overlap with other technologies.

HRSG = Heat Recovery Steam Generator.

Source: Market-Based Advanced Coal Power Systems, May 1999, DOE/FE-0400.

Table 8.6. Component capacity weights for new technologies

Technology	Pulverized Coal	Combustion Turbine-conven-tional	Combus-tion Turbine-advanced	HRSG	Gasifier	Carbon Capture/ Seques-tration	Balance of Plant-IGCC	Balance of Plant-Turbine	Balance of Plant-Combined Cycle	Fuel Prep Biomass
Coal with Carbon sequestration	100%	0%	0%	0%	0%	100%	0%	0%	0%	0%
Conv Gas/Oil Comb Cycle	0%	67%	0%	33%	0%	0%	0%	0%	100%	0%
Adv Gas/Oil Comb Cycle (CC)	0%	0%	67%	33%	0%	0%	0%	0%	100%	0%
Adv CC with carbon sequestration	0%	0%	67%	33%	0%	100%	0%	0%	100%	0%
Conv Comb Turbine	0%	100%	0%	0%	0%	0%	0%	100%	0%	0%
Adv Comb Turbine	0%	0%	100%	0%	0%	0%	0%	100%	0%	0%
Biomass	50%	0%	0%	0%	0%	0%	0%	0%	0%	100%

HRSG = Heat Recovery Steam Generator.
Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis.

Distributed generation

Distributed generation is modeled in the end-use sectors (as described in the appropriate chapters) as well as in the EMM. This section describes the representation of distributed generation in the EMM only. Two generic distributed technologies are modeled. The first technology represents peaking capacity (capacity that has relatively high operating costs and is operated when demand levels are at their highest). The second generic technology for distributed generation represents base load capacity (capacity that is operated on a continuous basis under a variety of demand levels). See Table 8.2 for costs and performance assumptions. It is assumed that these plants reduce the costs of transmission upgrades that would otherwise be needed.

Demand storage

The EMM includes the option to build a new demand storage technology to simulate load shifting, through programs such as smart meters. This is modeled as a new technology build, but with operating characteristics similar to pumped storage. The technology is able to decrease the load in peak slices, but must generate to replace that demand in other time slices. There is an input factor that identifies the amount of replacement generation needed, where a factor of less than 1.0 can be used to represent peak shaving rather than purely shifting the load to other time periods. This plant type is limited to operating only in the peak load slices, and it is assumed that this capacity is limited to 3.5% of peak demand on average in 2040, with limits varying from 2.2% to 6.8% of peak across the regions.

Coal-to-gas conversion

Since the AEO2015, the EMM includes the representation of conversion of existing coal plants to burn natural gas. In recent years, a number of companies have announced plans to retrofit their coal plants to operate as single cycle steam plants, to reduce emissions from the plant or to take advantage of low natural gas prices [82]. AEO2016 includes explicit representation of conversions of 8.8 GW by changing the plant type and fuel source for specific units, based on announced plans. Additionally, the EMM was revised to include the option to convert additional coal plants to gas-fired steam plants if economic.

The modeling structure for coal-to-gas conversions was based on EPA's modeling for the Base Case v5.13 [83]. For this modeling, coal-to-gas conversion refers to the modification of an existing boiler to allow it to fire natural gas. It does not refer to the addition of a gas turbine, the replacement of a coal boiler with a new natural gas combined cycle plant, or to the gasification of coal for use in a combustion turbine. There are two components of cost for the retrofit option – boiler modification costs and the cost of extending natural gas lateral pipeline spurs from the boiler to a natural gas main pipeline.

Allowing natural gas firing in a coal boiler typically involves installation of new gas burners as well as modifications to the boiler and possibly environmental equipment. EPA's estimates were developed by engineering staff and discussions with industry engineers, and were designed to be applicable across the existing coal fleet. In the EMM, costs were estimated for eligible coal plants identified by EPA, which excluded units under 25 MW as well as units with fluidized bed combustion or stoker boilers. There is no capacity penalty for conversion to gas, but there is a 5% heat rate penalty to reflect reduced efficiency due to lower stack temperature and the corresponding higher moisture loss when gas is combusted instead of coal. Fixed O&M costs are assumed to be reduced by 33% for the converted plant due to reduced needs for operators, maintenance materials, and maintenance staff. Variable O&M costs are reduced by 25% due to reduced waste disposal and other costs. The incremental capital cost is described by the following functions:

For pulverized-coal-fired boilers:

$$\text{Cst per kW} = 267 * (75 / \text{CAP})^{0.35}$$

For cyclone boilers:

$$\text{Cst per kW} = 374 * (75 / \text{CAP})^{0.35}$$

Where CAP is the capacity of the unit in megawatts and the calculated cost is in 2011 dollars per kW.

EIA used EPA's assumptions regarding natural gas pipeline requirements, which were based on a detailed assessment for every coal boiler in the United States, to determine gas volumes needed, distance to the closest pipeline, and size of the lateral pipeline required to get unit-specific costs. The resulting cost per kW of boiler capacity varies widely, from $4/kW to $3,584/kW, with an average cost of $193/kW (in 2015 dollars).

Representation of electricity demand

The annual electricity demand projections from the NEMS demand modules are converted into load duration curves for each of the EMM regions (based on North American Electric Reliability Corporation regions and subregions) using historical hourly load data. The load duration curve in the EMM is made up of nine time slices. First, the load data is split into three seasons: winter (December through March), summer (June through September), and fall/spring. Within each season the load data is sorted from high to low, and three load segments are created: a peak segment representing the top 1% of the load, and then two off-peak segments representing the next 49% and 50%, respectively. The seasons were defined to account for seasonal variation in supply availability.

Reserve margins (the percentage of capacity in excess of peak demand required to adequately maintain reliability during unforeseeable outages) are established for each region by its governing body–public utility commission, NERC region, or Independent System Operators (ISOs)/Regional Transmission Operators (RTOs). The reserve margin values from the AEO2016 Reference case are set based on these regional Reference Margins reported to NERC, and range from 14% to 17% [84].

Operating reserves

In addition to the planning reserve margin requirement, system operators typically require a specific level of operating reserves–generators available within a short period of time to meet demand in case a generator goes down or there is another disruption to supply. These reserves can be provided through plants that are already operating but not at full capacity (spinning reserves) as well as through capacity not currently operating but that can be brought online quickly (non-spinning reserves). This is particularly important as more intermittent generators are added to the grid, because technologies like wind and solar have uncertain availability that can be difficult to predict. Since AEO2014, the capacity and dispatch submodules of the EMM have been updated to include explicit constraints requiring spinning reserves in each load slice. The amount of spinning reserves required is computed as a percentage of the load height of the slice plus a percentage of the distance between the load of the slice and the seasonal peak. An additional requirement is calculated that is a percentage of the intermittent capacity available in that time period to reflect the greater uncertainty associated with the availability of intermittent resources. All technologies except for storage, intermittents, and distributed generation can be used to meet spinning reserves. Different operating modes are developed for each technology type to allow the model to choose between operating a plant to maximize generation versus contributing to spinning reserves, or a combination of both. Minimum levels of generation are required if a plant is contributing to spinning reserves, and vary by plant type, with plant types typically associated with baseload operation having higher minimums than those that can operate more flexibly to meet intermediate or peak demand.

Fossil fuel-fired and nuclear steam plant retirement

Fossil-fired steam plant retirements and nuclear retirements are calculated endogenously within the model. Generating units are assumed to retire when it is no longer economical to continue running them. Each year, the model determines whether the market price of electricity is sufficient to support the continued operation of existing plant generators. A generating unit is assumed to retire if the expected revenues from the generator are not sufficient to cover the annual going-forward costs and if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, operations and maintenance costs, and annual capital additions, which are unit-specific and based on historical data. The average capital additions for existing plants are $8 per kilowatt (kW) for oil and gas steam plants, $17 per kW for coal plants, and $23 per kW for nuclear plants (in 2015 dollars). These costs are added to the estimated costs at existing plants regardless of their age. Beyond 30 years of age an additional $7 per kW capital charge for fossil plants and $34 per kW charge for nuclear plants is included in the retirement decision to reflect further investment to address the impacts of aging. Age-related cost increases are attributed to capital expenditures for major repairs or retrofits, decreases in plant performance, and/or increases in maintenance costs to mitigate the effects of aging.

EIA assumes all retirements reported as planned during the next ten years on the Form EIA-860 will occur. Additionally, the AEO2016 nuclear projection assumes a decrease of 3.0 GW by 2020 to reflect existing nuclear units that appear at risk of early closure due to a combination of high operating costs and low electricity prices.

Biomass co-firing

Coal-fired power plants are assumed to co-fire with biomass fuel if it is economical. Co-firing requires a capital investment for boiler modifications and fuel handling. This expenditure is assumed to be $526 per kW of biomass capacity. A coal-fired unit modified to allow co-firing can generate up to 15% of the total output using biomass fuel, assuming sufficient residue supplies are available.

Nuclear uprates

The AEO2016 nuclear power projection assumes capacity increases at existing units. Nuclear plant operators can increase the rated capacity at plants through power uprates, which are license amendments that must be approved by the U.S. Nuclear Regulatory Commission (NRC). Uprates can vary from small (less than 2%) increases in capacity, which require very little capital investment or plant modification, to extended uprates of 15-20%, requiring significant modifications. Recently, several companies have canceled previously planned extended uprates due to lower demand projections and low electricity prices [85]. AEO2016 assumes that only those uprates reported to EIA as planned modifications on the Form EIA-860 will take place in the Reference case, representing 0.1 GW of additional capacity.

Interregional electricity trade

Both firm and economy electricity transactions among utilities in different regions are represented within the EMM. In general, firm power transactions involve the trading of capacity and energy to help another region satisfy its reserve margin requirement, while economy transactions involve energy transactions motivated by the marginal generation costs of different regions. The flow of power from region to region is constrained by the existing and planned capacity limits as reported in the NERC and Western Electricity Coordinating Council Summer and Winter Assessment of Reliability of Bulk Electricity Supply in North America, as well as information obtained from the Open Access Same-Time Information System (OASIS). Known firm power contracts are compiled from the Federal Energy Regulatory Commission (FERC) Form 1, "Electric Utility Annual Report" as well as information provided in the latest available Summer and Winter Assessments and individual ISO reports. The EMM includes an option to add interregional transmission capacity. In some cases it may be more economical to build generating capacity in a neighboring region, but additional costs to expand the transmission grid will be incurred as well. Explicitly expanding the interregional transmission capacity may also make the transmission line available for additional economy trade.

Economy transactions are determined in the dispatching submodule by comparing the marginal generating costs of adjacent regions in each time slice. If one region has less-expensive generating resources available in a given time period (adjusting for transmission losses and transmission capacity limits) than another region, the regions are assumed to exchange power.

International electricity trade

Two components of international firm power trade are represented in the EMM—existing and planned transactions, and unplanned transactions. Data on existing and planned transactions are compiled from the FERC Form 1 and provincial reliability assessments. Unplanned firm power trade is represented by competing Canadian supply with U.S. domestic supply options. Canadian supply is represented via supply curves using cost data from the Department of Energy report, “Northern Lights: The Economic and Practical Potential of Imported Power from Canada” (DOE/PE-0079). International economy trade is determined endogenously based on surplus energy expected to be available from Canada by region in each time slice. Canadian surplus energy was determined using a mini-dispatch model that utilizes Canadian provincial plant data, load curves, demand forecasts, and fuel prices to determine the excess electricity supply by year, load slice, supply step, step cost, and Canadian province.

Electricity pricing

Electricity pricing is projected for 22 electricity market regions for fully competitive, partially competitive and fully regulated supply regions. The price of electricity to the consumer comprises the price of generation, transmission, and distribution, including applicable taxes.

Transmission and distribution are considered to remain regulated in the AEO; that is, the price of transmission and distribution is based on the average cost to build, operate and maintain these systems using a cost of service regulation model. The price of electricity in the regulated regions consists of the average cost of generation, transmission, and distribution for each customer class.

In the competitive regions, the energy component of price is based on marginal cost, which is defined as the cost of the last (or most expensive) unit dispatched. The competitive generation price includes the marginal energy cost (fuel and variable operations and maintenance costs), taxes, and a capacity payment. The capacity payment is calculated as a combination of levelized costs for combustion turbines and the marginal value of capacity calculated within the EMM. The capacity payment is calculated for all competitive regions and should be viewed as a proxy for additional capital recovery that must be procured from customers rather than the representation of a specific market. The capacity payment also includes the costs associated with meeting the spinning reserves requirement discussed earlier. The total cost for both reserve margin and spinning reserve requirements in a given region is calculated within the EMM, and allocated to the sectors based on their contribution to overall peak demand.

The price of electricity in the regions with a competitive generation market consists of the competitive cost of generation summed with the average costs of transmission and distribution. The price for mixed regions reflects a load-weighted average of the competitive price and the regulated price, based on the percent of electricity load in the region subject to deregulation. In competitively supplied regions, a transition period is assumed to occur (usually over a 10-year period) from the effective date of restructuring, with a gradual shift to marginal cost pricing.

The Reference case assumes a transition to full competitive pricing in the three New York regions and in the ReliabilityFirst Corporation/East region, and a 95% transition to competitive pricing in New England (Vermont being the only fully-regulated state in that region). Eight regions fully regulate their electricity supply, including the Florida Reliability Coordinating Council, four of the SERC Reliability Corporation subregions–Delta (SRDA), Southeastern (SRSE), Central (SRCE) and Virginia-Carolina (SRVC), the Southwest Power Pool Regional Entities (SPNO and SPSO), and the Western Electricity Coordinating Council/Rockies (RMPA). The Texas Reliability Entity, which in the past was considered fully competitive by 2010, is now only 88% competitive, since many cooperatives have declined to become competitive or allow competitive energy to be sold to their customers. California returned to almost fully regulated pricing in 2002, after beginning a transition to competition in 1998, with only 10% competitive supply sold currently in the Western Electricity Coordinating Council (WECC)/California region. All other regions reflect a mix of both competitive and regulated prices.

There have been ongoing changes to pricing structures for ratepayers in competitive states since the inception of retail competition. The AEO has incorporated these changes as they have been incorporated into utility tariffs. These have included transition period rate reductions and freezes instituted by various states, and surcharges in California relating to the 2000-2001 energy crisis in the state. Since price freezes have ended, many costs related to the transition to competition are now explicitly added to the distribution portion and sometimes the transmission portion of the customer bill, regardless of whether or not the customer bought generation service from a competitive or regulated supplier. There have also been unexpected costs relating to unforeseen events that have been included in the calculation of electricity prices. For instance, as a result of volatile fuel markets, state regulators have sometimes had a hard time enticing retail suppliers to offer competitive supply to residential and smaller commercial and industrial customers. Subsequent state legislation has led to generation service supplied by regulator or utility-run auction or competitive bid for the market energy price plus an administration fee.

Typical charges that all customers must pay on the distribution portion of their bill (depending on where they reside) include transition charges (including persistent stranded costs), public benefits charges (usually for efficiency and renewable energy programs), administrative costs of energy procurement, and nuclear decommissioning costs. Costs added to the transmission portion of the bill include the Federally Mandated Congestion Charges (FMCC), a bill pass-through associated with the Federal Energy Regulatory Commission passage of Standard Market Design (SMD) to enhance reliability of the transmission grid and control congestion. Additional costs not included in historical data sets have been added in adjustment factors to the transmission and distribution capital, operations and maintenance costs, which impact the cost of both competitive and regulated electricity supply. Since most of these costs, such as transition costs, are temporary in nature, they are gradually phased out throughout the projection.

Electricity distribution prices are adjusted for two aspects related to the Clean Power Plan (CPP), a state level program to reduce CO2 emissions, described in more detail in the Legislation and Regulations section below. The CPP is expected to induce incremental energy efficiency (EE) due to programs implemented by the end-use sectors but affecting consumers costs. The residential and commercial modules pass the costs associated with the incremental EE programs to the EMM, where they are added to the distribution component of electricity price. Additionally, as the CPP is implemented in the AEO2016 Reference case, a CO2 emissions cap is in place which results in CO2 allowances being allocated. If allowances are allocated to load-serving entities, as assumed in the Reference case, the costs of purchasing the allowances (by generators) is reflected in the generation price, but distribution prices are reduced to reflect the revenues that the load-serving entities receive from the sale of the allowances and rebate back to consumers.

Fuel price expectations

Capacity planning decisions in the EMM are based on a life-cycle cost analysis over a 30-year period. This requires foresight assumptions for fuel prices. Expected prices for coal, natural gas, and oil are derived using rational expectations, or perfect foresight. In this approach, expectations for future years are defined by the realized solution values for these years in a prior run. The expectations for the world oil price and natural gas wellhead price are set using the resulting prices from a prior run. The markups to the delivered fuel prices are calculated based on the markups from the previous year within a NEMS run. Coal prices are determined using the same coal supply curves developed in the Coal Market Module. The supply curves produce prices at different levels of coal production, as a function of labor productivity, and costs and utilization of mines. Expectations for each supply curve are developed in the EMM based on the actual demand changes from the prior run throughout the projection horizon, resulting in updated mining utilization and different supply curves.

The perfect foresight approach generates an internally consistent scenario for which the formation of expectations is consistent with the projections realized in the model. The NEMS model involves iterative cycling of runs until the expected values and realized values for variables converge between cycles.

Nuclear fuel prices

Nuclear fuel prices are calculated through an offline analysis which determines the delivered price to generators in mills per kilowatthour. To produce reactor-grade uranium, the uranium (U308) must first be mined, and then sent through a conversion process to prepare for enrichment. The enrichment process takes the fuel to a given purity of U235, typically 3-5% for commercial reactors in the United States. Finally, the fabrication process prepares the enriched uranium for use in a specific type of reactor core. The price of each of the processes is determined, and the prices are summed to get the final price of the delivered fuel. The analysis uses forecasts from Energy Resources International for the underlying uranium prices.

Legislation and regulations

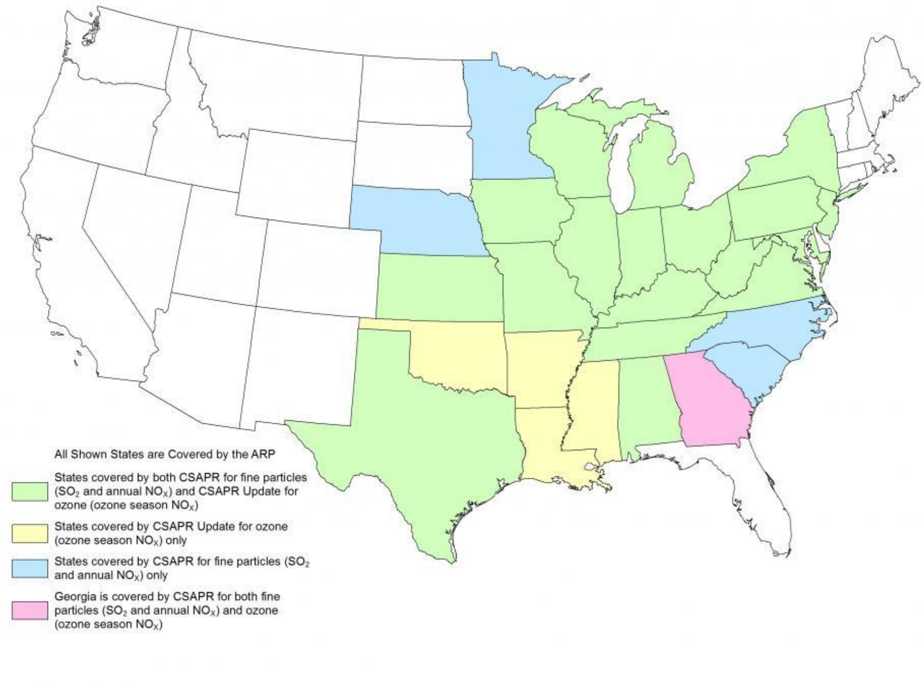
Clean Air Act Amendments of 1990 (CAAA1990) and Cross State Air Pollution Rule (CSAPR)

The AEO2016 includes the implementation of the Cross State Air Pollution Rule (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 the Clean Air Interstate Rule. EPA realigns the CSAPR schedule to comply with the Court's ruling, with Phase 1 beginning in December 2014 and more stringent Phase II targets taking effect in January 2016. Although CSAPR remains in place, the courts remanded CSAPR back to EPA in June 2015 for additional refinement affecting the Phase II implementation of NOx emission limits. The AEO2016 assumes the original targets are still in place.

Under CSAPR, 27 states must restrict emissions of sulfur dioxide and/or 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 (Figure 8.2). CSAPR permits allowance trading between states within a group (approximated in NEMS by trade between coal demand regions) but not between groups.

As specified in CAAA1990, EPA developed a two-phase nitrogen oxide (NOx) program, with the first set of standards for existing coal plants applied in 1996 while the second set was implemented in 2000. Dry bottom wall-fired and tangential-fired boilers, the most common boiler types, are referred to as Group 1 Boilers, and were required to make significant reductions beginning in 1996 and further reductions in 2000. Relative to their uncontrolled emission rates, which range roughly between 0.6 and 1.0 pounds per million Btu, they are required to make reductions between 25% and 50% to meet the Phase I limits and further reductions to meet the Phase II limits. EPA did not impose limits on existing oil and gas plants, but some states have instituted additional NOx regulations. All new fossil units are required to meet current standards. In pounds per million Btu, these limits are 0.11 for conventional coal, 0.02 for advanced coal, 0.02 for combined cycle, and 0.08 for combustion turbines. These NOx limits are incorporated in EMM.

Figure 8.2. Cross State Air Pollution Rule



Source: U.S. Environmental Protection Agency, https://www.epa.gov/airmarkets

Table 8.7 shows the average capital costs for environmental control equipment utilized by NEMS for existing coal plants as retrofit options in order to remove sulfur dioxide (SO2), nitrogen oxides (NOX), mercury and/or hydrogen chloride (HCl). In the EMM, plant-specific costs are calculated based on the size of the unit and other operating characteristics. The table reflects the capacity-weighted averages of all plants falling into each size category. FGD units are assumed to remove 95% of the SO2, while SCR units are assumed to remove 90% of the NOX. The EMM also includes an option to install a dry sorbent injection (DSI) system, which is assumed to remove 70% of the SO2. However, the DSI option is only available under the mercury and air toxics rule discussed in the next section, as its primary benefit is for reducing hydrogen chloride (HCl).

Clean Power Plan with New Source Performance Standards for power generation

Under the Clean Air Act (CAA) Sections 111(b) and 111(d), EPA developed rules to constrain carbon emissions from power plants in October 2015. Section 111(b) sets carbon pollution standards for new, modified, and reconstructed power plants [86]. Section 111(d) sets performance standards for existing fossil fuel-fired plants and implemented through the Clean Power Plan (CPP) [87]. Final rules to support the performance standards and model trading rules were in effect by October 2015. However, on February 9, 2016, the U.S. Supreme Court issued a stay in enforcement of the existing plant rule, pending hearings of legal challenges by states and affected industries [88]. Given the high degree of uncertainty surrounding the actual state of “current law” in the case, the AEO2016 Reference case includes the CPP, and an alternative No CPP case, assuming that the CPP is not enforced, also is included.

To model the provisions of the performance standards for new plants, the AEO2016 assumes that the only coal technology allowed to be built in the future includes 30% carbon capture to ensure the ability to meet the standard of 1,400 lb CO2 per MWh. New coal plants without carbon capture and storage technology cannot be built. The new natural gas combined-cycle plants modeled in previous AEOs were already below the 1,000 lb CO2/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, which are also covered by the rule.

The CPP sets interim and final CO2 emission performance rates for two subcategories of fossil fuel-fired EGUs: existing fossil steam units (interim/final rate, 1,534/1,305 lb CO2/MWh net) and existing stationary CTs (interim/final rate, 832/731 lb CO2/MWh net). The interim target must be met in 2022 and the final target in 2030, and EPA provides a phased-in approach over three steps during the implementation period.

States have significant flexibility in implementation of the CPP rule. EPA developed both rate-based and mass-based state-specific standards that are an equivalent quantitative expression of the source specific rates, and the states may 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 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 due to energy efficiency can be used as zero-emitting compliance options to offset emissions from affected generators.

The EMM was revised to represent both average rate-based or mass-based goals, with the option controlled by user input. Because the EMM is not a state-level model, EIA represents the CPP using EMM regions as compliance regions, implicitly assuming some level of state cooperation. EPA’s state- level targets are mapped to EMM region using a generation-based weighting. Additional levels of cooperation across EMM regions can also be modeled. For the AEO2016 Reference case, EIA assumed that all regions opted to meet a mass-based target and that trading was only done within EMM regions. EPA developed two different mass-based targets, one covering only existing sources and another including new sources. EIA assumed the target including new sources was implemented, as this satisfies EPA’s requirement to show that leakage of emissions to new sources will not occur as a result of implementation of the CPP. Other methods to limit leakage have not yet been well specified.

Under a mass-based program, an assumption must be made regarding the distribution of the initial allowances, which could be allocated to generators or load-serving entities, or sold through auction. The EMM was revised to represent any of these assumptions, with the impact flowing through to retail prices. The AEO2016 Reference case assumes allowances are allocated to load-serving entities, which provide the revenue back to consumers through lower distribution prices.

Mercury regulation

The Mercury and Air Toxics Standards (MATS) were finalized in December 2011 to fulfill EPA’s requirement to regulate mercury emissions from power plants. MATS also regulate other hazardous air pollutants (HAPS) such as hydrogen chloride (HCl) and fine particulate matter (PM2.5). MATS applies to coal- and oil-fired power plants with a nameplate capacity greater than 25 megawatts. The standards are scheduled to take effect in 2015, but allow for a one-year waiver to comply, and require that all qualifying units achieve the maximum achievable control technology (MACT) for each of the three covered pollutants. For AEO2016, EIA assumes that all coal-fired generating units with a capacity greater than 25 megawatts will comply with the rule beginning in 2016, due to the large number of plants requesting the one-year extension. All power plants are required to reduce their mercury emissions to 90% below their uncontrolled emissions levels.

Because the EMM does not explicitly model HCl or PM2.5, specific control technologies are assumed to be used to achieve compliance. In order to meet the HCl requirement, units must have either flue gas desulfurization (FGD) scrubbers or dry sorbent injection (DSI) systems in order to continue operating. A full fabric filter (FF) is also required to meet the PM2.5 limits and to improve the effectiveness of the DSI technology. When plants alter their configuration by adding equipment such as an SCR to remove NOx or an SO2 scrubber, removal of mercury is often a resulting cobenefit. The EMM considers all combinations of controls and may choose to add NOx or SO2 controls purely to lower mercury if it is economic to do so. Plants can also add activated carbon injection systems specifically designed to remove mercury. Activated carbon can be injected in front of existing particulate control devices or a supplemental fabric filter can be added with activated carbon injection capability.

The equipment to inject activated carbon in front of an existing particulate control device is assumed to cost approximately $6 (2015 dollars) per kilowatt of capacity [89]. The costs of a supplemental fabric filter with activated carbon injection (often referred as a COPAC unit) are calculated by unit, with average costs shown in Table 8.7. The amount of activated carbon required to meet a given percentage removal target is given by the following equations [90].

For a unit with a cold side electrostatic precipitator (CSE), using subbituminous coal, and simple activated carbon injection:

- Hg Removal (%) = 65 - (65.286 / (ACI + 1.026))

For a unit with a CSE, using bituminous coal, and simple activated carbon injection:

- Hg Removal (%) = 100 - (469.379 / (ACI + 7.169))

For a unit with a CSE, and a supplemental fabric filter with activated carbon injection:

- Hg Removal (%) = 100 - (28.049 / (ACI + 0.428))

For a unit with a hot side electrostatic precipitator (HSE) or other particulate control, and a supplemental fabric filter with activated carbon injection:

- Hg Removal (%) = 100 - (43.068 / (ACI + 0.421))

ACI = activated carbon injection rate in pounds per million actual cubic feet of flue gas

Table 8.7. Coal plant retrofit costs

2015 dollars per kW

Coal Plant Size (MW)	FGD Capital Costs	DSI Capital Costs	FF Capital Costs	SCR Capital Costs
<100	929	155	266	402
100 - 299	650	80	197	266
300 - 499	514	48	166	217
500 - 699	457	35	152	203
>=700	410	30	139	185

Source: Documentation for EPA Base Case v4.10 using the Integrated Planning Model, August 2010, EPA Contract EP-W-08-018, Appendices to Chapter 5.

Power plant mercury emissions assumptions

The EMM represents 35 coal plant configurations and assigns a mercury emissions modification factor (EMF) to each configuration. Each configuration represents different combinations of boiler types, particulate control devices, sulfur dioxide (SO2) control devices, nitrogen oxide (NOx) control devices, and mercury control devices. An EMF represents the amount of mercury that was in the fuel that remains after passing through all the plant’s systems. For example, an EMF of 0.60 means that 40% of the mercury that was in the fuel is removed by various parts of the plant. Table 8.8 provides the assumed EMFs for existing coal plant configurations without mercury-specific controls.

Table 8.8. Mercury emission modification factors

	Configuration		EIA EMFs			EPA EMFs		
SO2 Control	Particulate Control	NOx Control	Bit Coal	Sub Coal	Lignite Coal	Bit Coal	Sub Coal	Lignite Coal
None	BH	--	0.11	0.27	0.27	0.11	0.26	1.00
Wet	BH	None	0.05	0.27	0.27	0.03	0.27	1.00
Wet	BH	SCR	0.10	0.27	0.27	0.10	0.15	0.56
Dry	BH	--	0.05	0.75	0.75	0.50	0.75	1.00
None	CSE	--	0.64	0.97	0.97	0.64	0.97	1.00
Wet	CSE	None	0.34	0.73	0.73	0.34	0.84	0.56
Wet	CSE	SCR	0.10	0.73	0.73	0.10	0.34	0.56
Dry	CSE	--	0.64	0.65	0.65	0.64	0.65	1.00
None	HSE/Oth	--	0.90	0.94	0.94	0.90	0.94	1.00
Wet	HSE/Oth	None	0.58	0.80	0.80	0.58	0.80	1.00
Wet	HSE/Oth	SCR	0.42	0.76	0.76	0.10	0.75	1.00
Dry	HSE/Oth	--	0.60	0.85	0.85	0.60	0.85	1.00

Notes: SO2 Controls - Wet = Wet Scrubber and Dry = Dry Scrubber, Particulate Controls, BH - fabric filter/baghouse. CSE = cold side electrostatic precipitator, HSE = hot side electrostatic precipitator, NOx Controls, SCR = selective catalytic reduction.
— = not applicable, Bit = bituminous coal, Sub = subbituminous coal. The NOx control system is not assumed to enhance mercury removal unless a wet scrubber is present, so it is left blank in such configurations. Sources: EPA, EMFs. www.epa.gov/clearskies/technical.html . EIA EMFs not from EPA: Lignite EMFs, Mercury Control Technologies for Coal-Fired Power Plants, presented by the Office of Fossil Energy on July 8, 2003. Bituminous coal mercury removal for a Wet/HSE/Oth/SCR configured plant, Table EMF1, Analysis of Mercury Control Cost and Performance, Office of Fossil Energy & National Energy Technology, U.S. Department of Energy, January 2003, Washington, DC.

Planned SO2 Scrubber and NOx control equipment additions

EIA assumes that all planned retrofits, as reported on the Form EIA-860, will occur as currently scheduled. For AEO2016, this includes 14.5 GW of planned SO2 scrubbers (Table 8.9) and 0.3 GW of planned selective catalytic reduction (SCR) added after 2014.

Carbon capture and sequestration retrofits

The EMM includes the option of retrofitting existing coal plants for carbon capture and sequestration (CCS). The modeling structure for CCS retrofits within the EMM was developed by the National Energy Technology Laboratory[91] and uses a generic model of retrofit costs as a function of basic plant characteristics (such as heat rate). The costs have been adjusted to be consistent with costs of new CCS technologies. The CCS retrofits are assumed to remove 90% of the carbon input. The addition of the CCS equipment results in a capacity derate of around 30% and reduced efficiency of 43% at the existing coal plant. The costs depend on the size and efficiency of the plant, with the capital costs averaging $1,679 per kilowatt, and ranging from $1,222 to $2,386 per kilowatt. It was assumed that only plants greater than 500 megawatts and with heat rates below 12,000 Btu per kilowatthour would be considered for CCS retrofits.

Table 8.9. Planned SO2 scrubber additions by EMM region

Regions	gigawatts
Texas Reliability Entity	0.0
Florida Reliability Coordinating Council	0.0
Midwest Reliability Council - East	1.2
Midwest Reliability Council - West	1.4
Northeast Power Coordinating Council/New England	0.0
Northeast Power Coordinating Council/NYC-Westchester	0.0
Northeast Power Coordinating Council/Long Island	0.0
Northeast Power Coordinating Council/Upstate	0.0
ReliabilityFirst Corporation/East	0.0
ReliabilityFirst Corporation/Michigan	1.7
ReliabilityFirst Corporation/West	4.8
SERC Reliability Corporation/Delta	0.0
SERC Reliability Corporation/Gateway	1.2
SERC Reliability Corporation/Southeastern	1.0
SERC Reliability Corporation/Central	0.0
SERC Reliability Corporation/Virginia-Carolina	0.0
Southwest Power Pool/North	1.3
Southwest Power Pool/South	1.6
Western Electricity Coordinating Council/Southwest	0.0
Western Electricity Coordinating Council/California	0.0
Western Electricity Coordinating Council/Northwest Power Pool Area	0.0
Western Electricity Coordinating Council/Rockies	0.5
Total	14.5

Source: U.S. Energy Information Administration, Form EIA-860, “Annual Electric Generator Report.”

Heat rate improvement retrofits

Since the AEO2015, the EMM includes the capability to evaluate the potential for making heat rate improvements at existing coal-fired generators. A generator with a lower heat rate can generate the same quantity of electricity while consuming less fuel, and therefore reducing corresponding emissions of SO2, NOx, mercury, and CO2. Improving heat rates at power plants can lower fuel costs and help achieve compliance with environmental regulations. Heat rate improvement is a planning activity as it considers the tradeoff between the investment expenditures and the savings in fuel and/or environmental compliance costs. The amount of potential increase in efficiency can vary depending on the type of equipment installed at a unit, as well as the beginning configuration of the plant. The EMM represents 32 configurations of existing coal-fired plants based on different combinations of particulate, sulfur dioxide (SO2), nitrogen oxide (NOx), mercury, and carbon emission controls (Table 8.10). These categories form the basis for evaluating the potential for heat rate improvements.

EIA entered into a contract with Leidos, Inc. to develop a methodology to evaluate the potential for heat rate improvement at existing coal-fired generating plants [92]. Leidos performed a statistical analysis of the heat rate characteristics of coal-fired generating units modeled by EIA in the EMM. Specifically, Leidos developed a predictive model for coal-fired electric generating unit heat rates as a function of various unit characteristics. Leidos employed statistical modeling techniques to create the predictive models.

For the EMM plant types, the coal-fired generating units were categorized according to quartiles, based on observed versus predicted heat rates. Units in the first quartile (Q1), which perform better than predicted, were generally associated with the least potential for heat rate improvement. Units in the fourth quartile (Q4), representing the least-efficient units relative to predicted values, were generally associated with the highest potential for heat rate improvement. Leidos developed a matrix of heat rate improvement options and associated costs, based on a literature review and the application of engineering judgment.

Little or no coal-fired capacity exists for the EMM plant types with mercury and carbon control configurations; therefore, estimates were not developed for those plant types. These plant types were ultimately assigned the characteristics of the plants with the same combinations of particulate, SO2, and NOx controls. Plant types with relatively few observations were combined with other plant types having similar improvement profiles. As a result, nine unique plant type combinations were developed for the purposes of the quartile analysis and for each of these combinations Leidos created a minimum and a maximum potential for heat rate improvement along with the associated costs to achieve those improved efficiencies.

Leidos used the minimum and maximum characteristics as a basis for developing estimates of mid-range cost and heat rate improvement potential. The mid-range estimates were used as the default values in the EMM (Table 8.11)

Table 8.10. Existing pulverized coal plant types in the NEMS Electricity Market Module

Plant Type	Particulate Controls	SO2 Controls	NOx Controls	Mercury Controls	Carbon Controls
B1	BH	None	Any	None	None
B2	BH	None	Any	None	CCS
B3	BH	Wet	None	None	None
B4	BH	Wet	None	None	CCS
B5	BH	Wet	SCR	None	None
B6	BH	Wet	SCR	None	CCS
B7	BH	Dry	Any	None	None
B8	BH	Dry	Any	None	CCS
C1	CSE	None	Any	None	None
C2	CSE	None	Any	FF	None
C3	CSE	None	Any	FF	CCS
C4	CSE	Wet	None	None	None
C5	CSE	Wet	None	FF	None
C6	CSE	Wet	None	FF	CCS
C7	CSE	Wet	SCR	None	None
C8	CSE	Wet	SCR	FF	None
C9	CSE	Wet	SCR	FF	CCS
CX	CSE	Dry	Any	None	None
CY	CSE	Dry	Any	FF	None
CZ	CSE	Dry	SCR	FF	CCS
H1	HSE/Oth	None	Any	None	None
H2	HSE/Oth	None	Any	FF	None
H3	HSE/Oth	None	Any	FF	CCS
H4	HSE/Oth	Wet	None	None	None
H5	HSE/Oth	Wet	None	FF	None
H6	HSE/Oth	Wet	None	FF	CCS
H7	HSE/Oth	Wet	SCR	None	None
H8	HSE/Oth	Wet	SCR	FF	None
H9	HSE/Oth	Wet	SCR	FF	CCS
HA	HSE/Oth	Dry	Any	None	None
HB	HSE/Oth	Dry	Any	FF	None
HC	HSE/Oth	Dry	Any	FF	CCS

Notes: Particulate Controls, BH – baghouse, CSE = cold side electrostatic precipitator,
HSE/Oth = hot side electrostatic precipitator/other/none;
SO2 Controls - wet = wet scrubber, Dry = dry scrubber;
NOx Controls, SCR = selective catalytic reduction;
Mercury Controls - FF = fabric filter;
Carbon Controls - CCS = carbon capture and storage

Table 8.11. Heat rate improvement (HRI) potential and cost (capital, fixed O&M) by plant type and quartile as used for input to NEMS

Plant type and quartile combination	Count of Total Units	Percentage HRI Potential	Capital Cost (million 2014 $/MW)	Average Fixed O&M Cost (2014 $/MW-yr)
B1-Q1	32	(s)	0.01	200
B1-Q2	15	1%	0.10	2,000
B1-Q3	18	4%	0.20	4,000
B1-Q4	20	6%	0.90	20,000
B3-Q1	13	(s)	0.01	300
B3-Q2	24	1%	0.05	1,000
B3-Q3	16	6%	0.20	3,000
B3-Q4	15	9%	0.60	10,000
B5C7-Q1	16	(s)	(s)	80
B5C7-Q2	42	1%	0.03	700
B5C7H7-Q3	84	7%	0.10	2,000
B5C7H7-Q4	59	10%	0.20	4,000
B7-Q1	27	(s)	(s)	70
B7-Q2	25	1%	0.04	800
B7-Q3Q4	30	7%	0.30	5,000
C1H1-Q1	148	(s)	0.01	200
C1H1-Q2	117	1%	0.10	2,000
C1H1-Q3	72	4%	0.40	8,000
C1H1-Q4	110	7%	1.00	30,000
C4-Q1	15	(s)	(s)	80
C4-Q2	27	1%	0.04	900
C4-Q3	32	6%	0.20	2,000
C4-Q4	39	10%	0.30	5,000
CX-Q1Q2Q3Q4	15	7%	0.20	4,000
H4-Q1Q2Q3	13	3%	0.20	3,000
IG-Q1	3	(s)	(s)	60
TOTAL SET	**1,027**	**4%**	**0.30**	**6,000**

(s) = less than 0.05% for HRI potential or less than 0.005 million $/MW for capital cost.

Source: U.S. Energy Information Administration/Leidos Corporation.

State air emissions regulation

AEO2016 continues to model the Northeast Regional Greenhouse Gas Initiative (RGGI), which applies to fossil-fuel powered plants over 25 megawatts in the northeastern United States. The state of New Jersey withdrew from the program at the end of 2011, leaving nine states in the accord. The rule caps CO2 emissions from covered electricity generating facilities and requires that they account for each ton of CO2 emitted with an allowance purchased at auction. Because the baseline and projected emissions were calculated before the economic recession that began in 2008, the actual emissions in the first years of the program have been less than the cap, leading to excess allowances and allowance prices at the floor price. As a result, in February 2013 program officials announced a tightening of the cap starting in 2014. Beginning with AEO2014, the EMM applies these revised targets, which reflect a cap that is 45% of the original target for 2014.

The California Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006, authorized the California Air Resources Board (CARB) to set California's GHG reduction goals for 2020 and establish a comprehensive, multi-year program to reduce GHG emissions in California. As one of the major initiatives for AB 32, CARB designed a cap-and-trade program that started on January 1, 2012, with the enforceable compliance obligations beginning in 2013 for the electric power sector and industrial facilities. Fuel providers must comply starting in 2015. The AB 32 cap-and-trade provisions are incorporated in NEMS through an emission constraint in the EMM that also accounts for the emissions determined by the other sectors. Within the power sector, emissions from plants owned by California utilities but located out of state as well as emissions from electricity imports into California count toward the emission cap, and estimates of these emissions are included in the EMM constraint. An allowance price is calculated and added to fuel prices for the affected sectors. Limited banking and borrowing of allowances as well as an allowance reserve and offsets have been modeled, as specified in the Bill, providing some compliance flexibility and cost containment.

Energy Policy Acts of 1992 (EPACT1992) and 2005 (EPACT2005)

The provisions of EPACT1992 include revised licensing procedures for nuclear plants and the creation of exempt wholesale generators (EWGs). EPACT1992 also implemented a permanent 10% investment tax credit for geothermal and solar facilities, and introduced a production tax credit for eligible renewable technologies (subsequently extended and expanded). EPACT2005 provides a 20% investment tax credit for Integrated Coal-Gasification Combined Cycle capacity and a 15% investment tax credit for other advanced coal technologies. These credits are limited to 3 GW in both cases. These credits have been fully allocated and are not assumed to be available for new, unplanned capacity built within the EMM. EPACT2005 also contains a production tax credit (PTC) of 1.8 cents (nominal) per kWh for new nuclear capacity beginning operation by 2020. This PTC is specified for the first 8 years of operation, and is limited to $125 million annually and 6 GW of new capacity. However, this credit may be shared to additional units if more than 6 GW are under construction by January 1, 2014. EPACT2005 extended the PTC for qualifying renewable facilities by 2 years, or through December 31, 2007. It also repealed the Public Utility Holding Company Act (PUHCA).

Renewable electricity tax credits

The investment and energy production tax credits initiated in EPACT92 and amended in EPACT2005 have been further amended through a series of Acts, which have been incorporated in previous AEOs. A history of these tax credits is described in AEO2016 Legislation and Regulations LR3 - Impact of a Renewable Energy Tax Credit extension and phaseout [93]. The AEO2016 reflects the most recent changes implemented through the 2016 Consolidated Appropriation Act passed in December 2015. Solar projects under construction before the end of 2019 receive an investment tax credit of 30%, and the credit is phased down over two years, and then is reduced to 10% for plants under construction after 2021.

The production tax credit (PTC) is a per-kWh tax credit available for qualified wind, geothermal, closed-loop and open-loop biomass, landfill gas, municipal solid waste, hydroelectric, and marine and hydrokinetic facilities. The value of the credit, originally 1.5 cents/kWh, is adjusted for inflation annually and is available for 10 years after the facility has been placed in service. For AEO2016, wind, poultry litter, geothermal, and closed-loop biomass resources receive a tax credit of 2.3 cents/kWh; all other renewable resources receive a 1.1 cent/kWh (that is, one-half the value of the credit for other resources) tax credit. EIA assumes that biomass facilities obtaining the PTC will use open-loop fuels, as closed- loop fuels are assumed to be unavailable and/or too expensive for widespread use during the period that the tax credit is available. The PTC has been recently extended by the 2016 Consolidated Appropriation Act passed in December 2015 for wind projects through 2016. The PTC is scheduled to phase down in value for wind projects as follows: 80% of the current PTC if construction begins in 2017; 60% of the current PTC if construction begins in 2018; and 40% of the current PTC if construction begins in 2019.

The investment and production tax credits are exclusive of one another, and thus may not both be claimed for the same geothermal facility (which is eligible to receive either).

American Recovery and Reinvestment Act (ARRA)

Smart grid expenditures

ARRA provides $4.5 billion for smart grid demonstration projects. While somewhat difficult to define, smart grid technologies generally include a wide array of measurement, communications, and control equipment employed throughout the transmission and distribution system that will enable real-time monitoring of the production, flow, and use of power from the generator to the consumer. Among other things, these smart grid technologies are expected to enable more-efficient use of the transmission and distribution grid, lower line losses, facilitate greater use of renewables, and provide information to utilities and their customers that will lead to greater investment in energy efficiency and reduced peak load demands. The funds provided will not fund a widespread implementation of smart grid technologies, but could stimulate more rapid investment than would otherwise occur.

Several changes were made throughout NEMS to represent the impacts of the smart grid funding provided in ARRA. In the electricity module, it was assumed that line losses would fall slightly, peak loads would fall as customers shifted their usage patterns, and customers would be more responsive to pricing signals. Historically, line losses, expressed as the percentage of electricity lost, have been falling for many years as utilities make investments to replace aging or failing equipment.

Smart grid technologies also have the potential to reduce peak demand through the increased deployment of demand response programs. It is assumed that the Federal expenditures on smart grid technologies will stimulate efforts that reduce peak demand from what they otherwise would be, with the amount of total peak load reduction growing from 2.2% initially to 3.5% by 2040, although the shifts vary by region. Load is shifted to offpeak hours, so net energy consumed remains largely constant.

FERC Orders 888 and 889

The Federal Energy Regulatory Commission (FERC) issued two related rules (Orders 888 and 889) designed to bring low-cost power to consumers through competition, ensure continued reliability in the industry, and provide for open and equitable transmission services by owners of these facilities.

Specifically, Order 888 requires open access to the transmission grid currently owned and operated by utilities. The transmission owners must file nondiscriminatory tariffs that offer other suppliers the same services that the owners provide for themselves. Order 888 also allows these utilities to recover stranded costs (investments in generating assets that are unrecoverable due to consumers selecting another supplier). Order 889 requires utilities to implement standards of conduct and an Open Access Same-Time Information System (OASIS) through which utilities and non-utilities can receive information regarding the transmission system. As a result, utilities have functionally or physically unbundled their marketing functions from their transmission functions.

These orders are represented in EMM by assuming that all generators in a given region are able to satisfy load requirements anywhere within the region. Similarly, it is assumed that transactions between regions will occur if the cost differentials between them make such transactions economical.

Notes and sources

[81] Capital Cost Estimates for Utility Scale Electricity Generating Plants, November 2016, http://www.eia.gov/analysis/studies/powerplants/capitalcost/.

[82] Numerous press announcements regarding coal to gas conversions, for example, “NRG closing Romeoville coal plant, converting Joliet plant to natural gas,” August 7, 2014, http://thetimesweekly.com/news/2014/aug/07/nrg-closing-romeoville-coal-plant-converting-jolie/.

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[84] North American Electric Reliability Corporation, 2013 Summer Reliability Assessment (Atlanta, GA: May 2013), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013SRA_Final.pdf.

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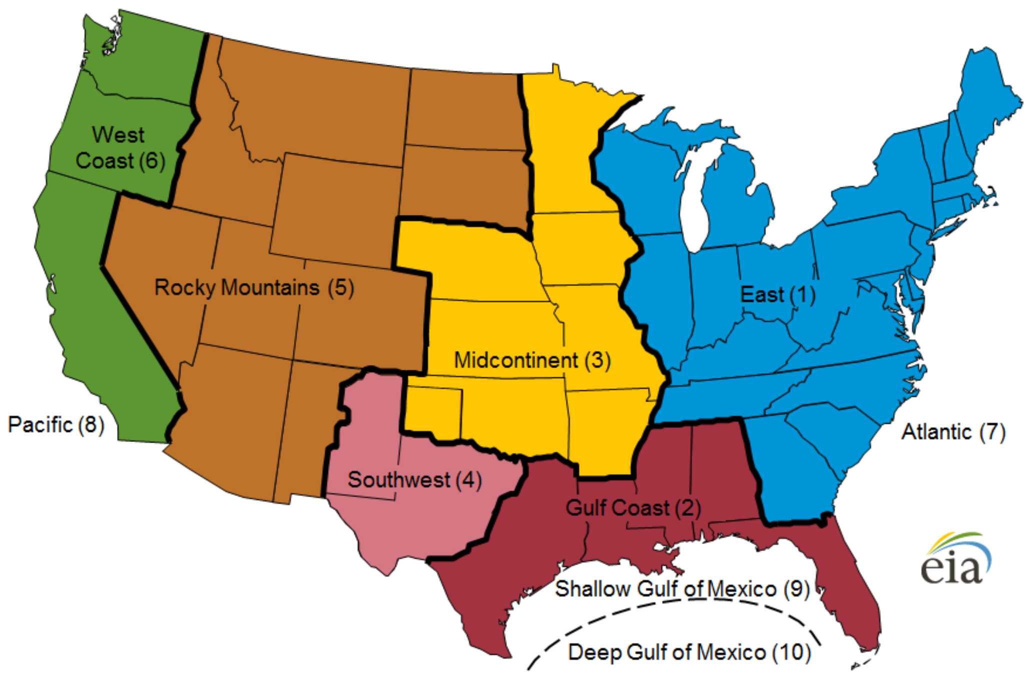
[92] Analysis of Heat Rate Improvement Potential at Coal-Fired Power Plants, May 2015, Leidos, Inc. http://www.eia.gov/analysis/studies/powerplants/heatrate/pdf/heatrate.pdf

[93] U.S. Energy Information Administration, *Annual Energy Outlook 2016*, Legislation and Regulations LR3, DOE/EIA-0383(2016) (Washington, DC, August 2016), http://www.eia.gov/forecasts/aeo/section_legs_regs.cfm

Chapter 9. Oil and Gas Supply Module

The NEMS Oil and Gas Supply Module (OGSM) constitutes a comprehensive framework with which to analyze crude oil and natural gas exploration and development on a regional basis (Figure 9.1). The OGSM is organized into 4 submodules: Onshore Lower 48 Oil and Gas Supply Submodule, Offshore Oil and Gas Supply Submodule, Oil Shale Supply Submodule [94], and Alaska Oil and Gas Supply Submodule. A detailed description of the OGSM is provided in the EIA publication, Oil and Gas Supply Module of the National Energy Modeling System: Model Documentation 2016, DOE/EIA-M063 (2016), (Washington, DC, 2016). The OGSM provides crude oil and natural gas short-term supply parameters to both the Natural Gas Transmission and Distribution Module and the Petroleum Market Module. The OGSM simulates the activity of numerous firms that produce oil and natural gas from domestic fields throughout the United States.

Figure 9.1. Oil and Gas Supply Model regions



Source: U.S. Energy Information Administration.

OGSM encompasses domestic crude oil and natural gas supply by several recovery techniques and sources. Crude oil recovery includes improved oil recovery processes such as water flooding, infill drilling, and horizontal drilling, as well as enhanced oil recovery processes such as CO2 flooding, steam flooding, and polymer flooding. Recovery from highly fractured, continuous zones (e.g., Austin chalk and Bakken shale formations) is also included. Natural gas supply includes resources from low-permeability tight sand formations, shale formations, coalbed methane, and other sources.

Key assumptions

Domestic oil and natural gas technically recoverable resources

The outlook for domestic crude oil production is highly dependent upon the production profile of individual wells over time, the cost of drilling and operating those wells, and the revenues generated by those wells.

Every year EIA re-estimates initial production (IP) rates and production decline curves, which determine estimated ultimate recovery (EUR) per well and total technically recoverable resources (TRR) [95].

A common measure of the long-term viability of U.S. domestic crude oil and natural gas as an energy source is the remaining technically recoverable resource, consisting of proved reserves [96] and unproved resources [97]. Estimates of TRR are highly uncertain, particularly in emerging plays where few wells have been drilled. Early estimates tend to vary and shift significantly over time as new geological information is gained through additional drilling, as long-term productivity is clarified for existing wells, and as the productivity of new wells increases with technology improvements and better management practices. TRR estimates used by EIA for each AEO are based on the latest available well production data and on information from other federal and state governmental agencies, industry, and academia. Published estimates in Tables 9.1 and 9.2 reflect the removal of intervening reserve additions and production between the date of the latest available assessment and January 1, 2014.

The resources presented in the tables in this chapter are the starting values for the model. Technology improvements in the model add to the unproved TTR, which can be converted to reserves and finally production. The tables in this chapter do not include these increases in TRR.

Table 9.1. Technically recoverable U.S. crude oil resources as of January 1, 2014

billion barrels

	Proved Reserves	Unproved Resources	Total Technically Recoverable Resources
Lower 48 Onshore	**28.1**	**151.1**	**179.2**
East	0.4	4.7	5.2
Gulf Coast	6.1	33.6	39.7
Midcontinent	1.9	14.6	16.5
Southwest	8.0	53.9	61.9
Rocky Mountain/Dakotas	9.0	39.8	48.8
West Coast	2.7	4.4	7.1
Lower 48 Offshore	**5.6**	**52.5**	**58.1**
Gulf (currently available)	5.0	40.3	45.3
Eastern/Central Gulf (unavailable until 2022)	0.0	3.7	3.7
Pacific	0.5	6.1	6.6
Atlantic	0.0	2.5	2.5
Alaska (Onshore and Offshore)	**2.9**	**34.0**	**36.9**
Total U.S.	**36.5**	**237.6**	**274.2**

Note: Crude oil resources include lease condensates but do not include natural gas plant liquids or kerogen (oil shale). Resources in areas where drilling is officially prohibited are not included in this table. The estimate of 7.3 billion barrels of crude oil resources in the Northern Atlantic, Northern and Central Pacific, and within a 50-mile buffer off the Mid and Southern Atlantic Outer Continental Shelf (OCS) is also excluded from the technically recoverable volumes because leasing is not expected in these areas by 2040.

Source: Onshore and State Offshore - U.S. Energy Information Administration; Alaska - U.S. Geological Survey (USGS); Federal (Outer Continental Shelf) Offshore - Bureau of Ocean Energy Management (formerly the Minerals Management Service); Proved Reserves - U.S. Energy Information Administration. Table values reflect removal of intervening reserve additions between the date the latest available assessment and January 1, 2014.

Table 9.2. Technically recoverable U.S. dry natural gas resources as of January 1, 2014

trillion cubic feet

	Proved Reserves	Unproved Resources	Total Technically Recoverable Resources
Lower 48 Onshore	**322.2**	**1,548.9**	**1,871.1**
Tight Gas	81.3	251.1	332.4
East	2.4	51.1	53.5
Gulf Coast	12.8	50.8	63.6
Midcontinent	7.8	12.1	19.8
Southwest	14.0	37.9	51.9
Rocky Mountain/Dakotas	44.0	99.2	143.1
West Coast	0.4	0.0	0.4
Shale Gas & Tight Oil	141.1	827.4	968.5
East	68.7	438.8	507.4
Gulf Coast	33.9	172.6	206.5
Midcontinent	13.4	62.0	75.5
Southwest	24.8	84.2	109.0
Rocky Mountain/Dakotas	0.3	56.3	56.6
West Coast	0.0	13.5	13.5
Coalbed Methane	6.1	119.5	125.6
East	1.5	4.1	5.6
Gulf Coast	1.4	2.2	3.6
Midcontinent	1.3	38.3	39.6
Southwest	0.4	5.8	6.2
Rocky Mountain/Dakotas	1.5	58.9	60.3
West Coast	0.0	10.3	10.3
Other	93.8	350.9	444.6
East	12.8	31.2	44.0
Gulf Coast	11.2	125.6	136.8
Midcontinent	17.9	51.5	69.4
Southwest	18.5	71.6	90.1
Rocky Mountain/Dakotas	32.0	59.2	91.2
West Coast	1.4	11.8	13.3
Lower 48 Offshore	**8.7**	**316.2**	**324.9**
Gulf (currently available)	8.4	261.8	270.2
Eastern/Central Gulf (unavailable until 2022)	0.0	21.5	21.5
Pacific	0.3	9.3	9.7
Atlantic	0.0	23.6	23.6
Alaska (Onshore and Offshore)	**7.3**	**271.1**	**278.4**
Total U.S.	**338.3**	**2,136.2**	**2,474.4**

Note: Resources in other areas where drilling is officially prohibited are not included. The estimate of 32.9 trillion cubic feet of natural gas resources in the Northern Atlantic, Northern and Central Pacific, and within a 50-mile buffer off the Mid and Southern Atlantic OCS is also excluded from the technically recoverable volumes because leasing is not expected in these areas by 2040.

Source: Onshore and State Offshore - U.S. Energy Information Administration; Alaska - U.S. Geological Survey (USGS); Federal (Outer Continental Shelf) Offshore - Bureau of Ocean Energy Management (formerly the Minerals Management Service); Proved Reserves - U.S. Energy Information Administration. Table values reflect removal of intervening reserve additions between the date the latest available assessment and January 1, 2014.

The remaining unproved TRR for a continuous-type shale gas or tight oil area is the product of (1) area with potential, (2) well spacing (wells per square mile), and (3) EUR per well. The play-level unproved technically recoverable resource assumptions for tight oil, shale gas, tight gas, and coalbed methane are summarized in Tables 9.3-9.4. The model uses a distribution of EUR per well in each play and often in sub-play areas. Table 9.5 provides an example of the distribution of EUR per well for each of the Bakken areas. The Bakken is subdivided into five areas: Central Basin, Eastern Transitional, Elm Coulee-Billings Nose, Nesson-Little Knife, and Northwest Transitional [97]. Because of the significant variation in well productivity within an area, the wells in each Bakken area are further delineated by county. This level of detail is provided for select plays in Appendix 2.C of the AEO2016 Documentation for the OGSM. The USGS periodically publishes tight and shale resource assessments that are used as a guide for selection of key parameters in the calculation of the TRR used in the AEO. The USGS seeks to assess the recoverability of shale gas and tight oil based on the wells drilled and technologies deployed at the time of the assessment. AEO2015 introduced a contour map based approach for incorporating geology parameters into the calculation of resources, recognizing that geology can vary significantly within counties. This new approach was only applied to the Marcellus play.

The AEO TRRs incorporate current drilling, completion, and recovery techniques, requiring adjustments to some of the assumptions used by the USGS to generate their TRR estimates, as well as the inclusion of shale gas and tight oil resources not yet assessed by the USGS. If well production data are available, EIA analyzes the decline curve of producing wells to calculate the expected EUR per well from future drilling.

The underlying resource for the Reference case is uncertain, particularly as exploration and development of tight oil continues to move into areas with little to no production history. Many wells drilled in tight or shale formations using the latest technologies have less than two years of production history, so the impact of recent technological advancement on the estimate of future recovery cannot be fully ascertained. Uncertainty also extends to the areal extent of formations and the number of layers that could be drilled within formations. Alternative resource cases are discussed at the end of this chapter.

Lower 48 onshore

The Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS) is a play-level model used to analyze crude oil and natural gas supply from onshore lower 48 sources. The methodology includes a comprehensive assessment method for determining the relative economics of various prospects based on financial considerations, the nature of the resource, and the available technologies. The general methodology relies on a detailed economic analysis of potential projects in known fields, enhanced oil recovery projects, and undiscovered resources. The projects which are economically viable are developed subject to the availability of resource development constraints which simulate the existing and expected infrastructure of the oil and gas industries. For crude oil projects, advanced secondary or improved oil recovery techniques (e.g., infill drilling and horizontal drilling) and enhanced oil recovery (e.g., CO_2 flooding, steam flooding, and polymer flooding) processes are explicitly represented. For natural gas projects, the OLOGSS represents supply from shale formations, tight sands formations, coalbed methane, and other sources.

The OLOGSS evaluates the economics of future crude oil and natural gas exploration and development from the perspective of an operator making an investment decision. An important aspect of the economic calculation concerns the tax treatment. Tax provisions vary with the type of producer (major, large independent, or small independent). The economics of potential projects reflect the tax treatment provided by current laws for large independent producers. Relevant tax provisions are assumed unchanged over the life of the investment. Costs are assumed constant over the investment life but vary across region, fuel, and process type. Operating losses incurred in the initial investment period are carried forward and used against revenues generated by the project in later years.

Table 9.3. U.S. unproved technically recoverable tight/shale oil and gas resources by play (as of January 1, 2014)

				Average EUR		Technically Recoverable Resources		
Region/Basin	Play	Area with Potential[1] (mi²)	Average Spacing (wells/mi²)	Crude Oil[2] (MMb/well)	Natural Gas (Bcf/well)	Crude Oil (b)	Natural Gas (Tcf)	NGPL (b)
East								
Appalachian	Bradford-Venango-Elk	18,128	8.1	0.003	0.063	0.5	9.2	0.0
Appalachian	Clinton-Medina-Tuscarora	26,549	8.0	0.002	0.118	0.4	25.0	0.0
Appalachian	Devonian	51,387	6.3	0.000	0.101	0.1	32.6	0.9
Appalachian	Marcellus Foldbelt	869	4.3	0.000	0.168	0.0	0.6	0.0
Appalachian	Marcellus Interior	25,200	4.3	0.007	1.934	0.8	209.4	11.6
Appalachian	Marcellus Western	2,688	5.5	0.000	0.287	0.0	4.2	0.2
Appalachian	Utica-Gas Zone Core	12,988	5.0	0.005	2.263	0.3	146.9	3.8
Appalachian	Utica-Gas Zone Extension	20,019	3.0	0.006	0.624	0.3	37.6	1.8
Appalachian	Utica-Oil Zone Core	2,161	5.0	0.062	0.109	0.7	1.2	0.0
Appalachian	Utica-Oil-Zone Extension	7,389	3.0	0.031	0.129	0.7	2.9	0.0
Illinois	New Albany	3,058	8.0	0.000	0.117	0.0	2.9	0.2
Michigan	Antrim Shale	13,177	8.0	0.000	0.106	0.0	11.1	0.9
Michigan	Berea Sand	7,473	8.0	0.000	0.105	0.0	6.3	0.1
Gulf Coast								
Black Warrior	Floyd-Neal/Conasauga	1,402	2.0	0.000	1.520	0.0	4.3	0.0
TX-LA-MS Salt	Cotton Valley	3,670	8.0	0.025	1.483	0.7	43.6	0.8
TX-LA-MS Salt	Haynesville-Bossier-LA	2,105	6.0	0.004	4.266	0.0	53.7	0.0
TX-LA-MS Salt	Haynesville-Bossier-TX	1,568	6.0	0.001	2.837	0.0	26.6	0.0
Western Gulf	Austin Chalk-Giddings	2,457	6.0	0.051	0.269	0.7	4.0	0.5
Western Gulf	Austin Chalk-Outlying	10,066	6.0	0.063	0.234	3.8	14.1	0.8
Western Gulf	Buda	8,610	4.0	0.068	0.302	2.4	10.4	0.2
Western Gulf	Eagle Ford-Dry Zone	3,897	6.0	0.090	1.163	2.1	27.1	2.6
Western Gulf	Eagle Ford-Oil Zone	8,204	5.6	0.174	0.096	8.0	4.4	1.2
Western Gulf	Eagle Ford-Wet Zone	3,009	8.7	0.199	0.762	5.2	19.9	2.7
Western Gulf	Olmos	5,497	4.0	0.011	1.106	0.3	24.3	0.0
Western Gulf	Pearsall	1,200	6.0	0.003	0.769	0.0	5.5	0.0
Western Gulf	Tuscaloosa	7,453	4.0	0.111	0.088	3.3	2.6	0.1
Western Gulf	Vicksburg	324	8.0	0.027	0.929	0.1	2.4	0.1
Western Gulf	Wilcox Lobo	730	8.0	0.008	0.825	0.0	4.8	0.1
Western Gulf	Woodbine	1,161	4.0	0.106	0.019	0.5	0.1	0.0
Midcontinent								
Anadarko	Cana Woodford-Dry Zone	794	4.0	0.022	2.130	0.1	6.8	0.0
Anadarko	Cana Woodford-Oil Zone	420	6.0	0.071	0.981	0.2	2.5	0.1
Anadarko	Cana Woodford-Wet Zone	1,069	4.0	0.160	1.311	0.7	5.6	0.5
Anadarko	Cleveland	735	4.3	0.044	0.333	0.1	1.0	0.0
Anadarko	Granite Wash	3,545	4.0	0.063	0.729	0.9	10.4	0.6
Anadarko	Red Fork	523	4.0	0.010	0.324	0.0	0.7	0.0
Arkoma	Carney	798	4.0	0.000	0.330	0.0	1.1	0.0
Arkoma	Fayetteville-Central	2,008	8.0	0.000	1.949	0.0	31.3	0.0
Arkoma	Fayetteville-West	773	8.0	0.000	0.716	0.0	4.4	0.0
Arkoma	Woodford-Arkoma	588	8.0	0.002	1.287	0.0	6.1	0.5
Black Warrior	Chattanooga	629	8.0	0.000	0.865	0.0	4.4	0.0

Table 9.3. U.S. unproved technically recoverable tight/shale oil and gas resources by play (as of January 1, 2014) (cont.)

Region/Basin	Play	Area with Potential[1] (mi²)	Average Spacing (wells/mi²)	Average EUR: Crude Oil[2] (MMb/ well)	Average EUR: Natural Gas (Bcf/well)	Technically Recoverable Resources: Crude Oil (b)	Technically Recoverable Resources: Natural Gas (Tcf)	NGPL (b)
Southwest								
Fort Worth	Barnett-Core	351	8.0	0.000	1.590	0.0	4.5	0.2
Fort Worth	Barnett-North	1,646	8.0	0.005	0.468	0.1	6.2	0.2
Fort Worth	Barnett-South	5,368	8.0	0.002	0.192	0.1	8.2	0.3
Permian	Abo	2,812	4.0	0.059	0.244	0.7	2.7	0.1
Permian	Avalon/Bone Spring	3,982	4.2	0.128	0.356	2.1	6.0	0.4
Permian	Barnett-Woodford	2,618	4.0	0.001	1.028	0.0	10.8	1.5
Permian	Canyon	6,567	8.0	0.014	0.207	0.7	10.9	0.0
Permian	Spraberry	13,289	6.4	0.167	0.251	14.2	21.4	2.1
Permian	Wolfcamp	17,500	4.0	0.099	0.388	6.9	27.2	2.2
Rocky Mountain/Dakotas								
Denver	Muddy	3,842	8.0	0.009	0.116	0.3	3.6	0.0
Denver	Niobrara	7,461	5.0	0.012	0.073	0.4	2.7	0.1
Greater Green River	Hilliard-Baxter-Mancos	4,469	8.0	0.004	0.443	0.2	15.8	0.9
Greater Green River	Tight Oil Plays	724	11.0	0.112	0.015	0.9	0.1	0.0
Montana Thrust Belt	Tight Oil Plays	494	11.0	0.111	0.075	0.6	0.4	0.0
North Central Montana	Bowdoin-Greenhorn	958	4.0	0.000	0.151	0.0	0.6	0.0
Paradox	Fractured Interbed	1,171	1.6	0.543	0.434	1.0	0.8	0.0
Powder River	Tight Oil Plays	19,685	3.0	0.035	0.040	2.1	2.4	0.1
San Juan	Dakota	1,818	8.0	0.002	0.277	0.0	4.0	0.0
San Juan	Lewis	1,479	3.0	0.000	2.200	0.0	9.8	0.0
San Juan	Mesaverde	724	8.0	0.002	0.488	0.0	2.8	0.0
San Juan	Pictured Cliffs	101	4.0	0.000	0.183	0.0	0.1	0.0
Southwestern Wyoming	Fort Union-Fox Hills	1,888	8.0	0.006	0.605	0.1	9.1	0.7
Southwestern Wyoming	Frontier	2,835	8.0	0.019	0.319	0.4	7.2	0.0
Southwestern Wyoming	Lance	2,243	8.0	0.021	1.109	0.4	19.9	3.6
Southwestern Wyoming	Lewis	3,698	8.0	0.016	0.558	0.5	16.5	0.4
Southwestern Wyoming	Tight Oil Plays	885	11.0	0.111	0.015	1.1	0.1	0.0
Uinta-Piceance	Iles-Mesaverde	4,275	8.0	0.000	0.363	0.0	12.4	0.0
Uinta-Piceance	Mancos	1,549	8.0	0.001	0.341	0.0	4.2	0.0
Uinta-Piceance	Tight Oil Plays	85	16.0	0.050	0.111	0.1	0.2	0.0
Uinta-Piceance	Wasatch-Mesaverde	1,908	8.0	0.022	0.445	0.3	6.8	0.0
Uinta-Piceance	Williams Fork	1,598	8.8	0.003	0.716	0.0	10.1	0.0
Williston	Bakken Central	4,275	3.0	0.206	0.161	2.6	2.0	0.4
Williston	Bakken Eastern Transitional	2,751	3.1	0.263	0.089	2.3	0.8	0.2
Williston	Bakken Elm Coulee-Billings Nose	1,896	2.0	0.131	0.116	0.5	0.4	0.0
Williston	Bakken Nesson-Little Knife	3,397	3.2	0.255	0.631	2.8	6.9	1.5
Williston	Bakken Northwest Transitional	2,860	2.0	0.077	0.018	0.4	0.1	0.0
Williston	Bakken Three Forks	22,142	3.5	0.182	0.099	14.1	7.6	0.8
Williston	Gammon	2,060	2.0	0.000	0.440	0.0	1.8	0.0
Williston	Judith River-Eagle	1,451	4.0	0.000	0.149	0.0	0.9	0.0
Wind River	Fort Union-Lance	709	8.0	0.020	0.910	0.1	5.2	0.2
West Coast								
Columbia	Basin Central	1,091	8.0	0.000	1.400	0.0	12.2	0.0
San Joaquin/Los Angeles	Monterey/Santos	3,141	2.4	0.026	0.165	0.2	1.3	0.0
					Total Tight/Shale	**89.2**	**1,078.5**	**46.6**

EUR = estimated ultimate recovery

NGPL=Natural Gas Plant Liquids

[1]Area of play that is expected to have unproved technically recoverable resources remaining.

[2]Includes lease condensates.

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Table 9.4. U.S. unproved technically recoverable coalbed methane resources by play (as of January 1, 2014)

			Average EUR			Technically Recoverable Resources		
Region/Basin	Play	Area with Potential[1] (mi²)	Average Spacing (wells/mi²)	Crude Oil[2] (MMb/ well)	Natural Gas (Bcf/well)	Crude Oil (b)	Natural Gas (Tcf)	NGPL (b)
East								
Appalachian	Central Basin	1,302	8	0.000	0.176	0.0	1.8	0.0
Appalachian	North Appalachian Basin - High	359	12	0.000	0.125	0.0	0.5	0.0
Appalachian	North Appalachian Basin – Mid/Low	490	12	0.000	0.080	0.0	0.5	0.0
Illinois	Central Basin	1,277	8	0.000	0.120	0.0	1.2	0.0
Gulf Coast								
Black Warrior	Extention Area	148	8	0.000	0.080	0.0	0.1	0.0
Black Warrior	Main Area	690	12	0.000	0.206	0.0	1.7	0.0
Cahaba	Cahaba Coal Field	264	8	0.000	0.179	0.0	0.4	0.0
Midcontinent								
Forest City	Central Basin	23,110	8	0.022	0.172	4.0	31.8	0.0
Midcontinent	Arkoma	2,718	8	0.000	0.216	0.0	4.7	0.0
Midcontinent	Cherokee	3,436	8	0.000	0.065	0.0	1.8	0.0
Southwest								
Raton	Southern	1,925	8	0.000	0.375	0.0	5.8	0.0
Rocky Mountain/Dakotas								
Greater Green River	Deep	1,620	4	0.000	0.600	0.0	3.9	0.0
Greater Green River	Shallow	644	8	0.000	0.204	0.0	1.1	0.0
Piceance	Deep	1,534	4	0.000	0.600	0.0	3.7	0.0
Piceance	Divide Creek	135	8	0.000	0.179	0.0	0.2	0.0
Piceance	Shallow	1,865	4	0.000	0.299	0.0	2.2	0.0
Piceance	White River Dome	201	8	0.000	0.410	0.0	0.7	0.0
Powder River	Big George/Lower Fort Union	1,570	16	0.000	0.260	0.0	6.5	0.0
Powder River	Wasatch	206	8	0.000	0.056	0.0	0.1	0.0
Powder River	Wyodak/Upper Fort Union	6,162	20	0.000	0.136	0.0	16.8	0.0
Raton	Northern	343	8	0.000	0.350	0.0	1.0	0.0
Raton	Purgatoire River	174	8	0.000	0.311	0.0	0.4	0.0
San Juan	Fairway NM	169	4	0.000	1.142	0.0	0.8	0.0
San Juan	North Basin	1,353	4	0.000	0.280	0.0	1.5	0.0
San Juan	North Basin CO	1,673	4	0.000	1.515	0.0	10.1	0.0
San Juan	South Basin	1,030	4	0.000	0.199	0.0	0.8	0.0
San Juan	South Menefee NM	373	5	0.000	0.095	0.0	0.2	0.0
Uinta	Ferron	227	8	0.000	0.776	0.0	1.4	0.0
Uinta	Sego	341	4	0.000	0.306	0.0	0.4	0.0
Wind River	Mesaverde	418	2	0.000	2.051	0.0	1.7	0.0
Wyoming Thrust Belt	All Plays	5,200	2	0.000	0.454	0.0	5.4	0.0
West Coast								
Western Washington	Bellingham	441	2	0.000	2.391	0.0	2.1	0.0
Western Washington	Southern Puget Lowlands	1,102	2	0.000	0.687	0.0	1.5	0.0
Western Washington	Western Cascade Mountains	2,152	2	0.000	1.559	0.0	6.7	0.0
				Total Coalbed Methane	**4.0**	**119.5**	**0.0**	0.0

EUR = estimated ultimate recovery

NGPL = Natural Gas Plant Liquids.

[1]Area of play that is expected to have unproved technically recoverable resources remaining.

[2]Includes lease condensates.

Source: U.S. Energy Information Administration, Office of Energy Analysis

Table 9.5. Distribution of crude oil EURs in the Bakken

Play Name	State	County	Number of potential wells	EUR (Mb/well)
Bakken Central Basin	MT	Daniels	112	117
Bakken Central Basin	MT	McCone	313	117
Bakken Central Basin	MT	Richland	616	153
Bakken Central Basin	MT	Roosevelt	2,915	171
Bakken Central Basin	MT	Sheridan	442	47
Bakken Central Basin	ND	Divide	21	241
Bakken Central Basin	ND	Dunn	155	268
Bakken Central Basin	ND	McKenzie	4,459	239
Bakken Central Basin	ND	Williams	3,670	231
Bakken Eastern Transitional	ND	Burke	1,382	127
Bakken Eastern Transitional	ND	Divide	646	121
Bakken Eastern Transitional	ND	Dunn	2,113	310
Bakken Eastern Transitional	ND	Hettinger	4	169
Bakken Eastern Transitional	ND	McLean	1,045	254
Bakken Eastern Transitional	ND	Mercer	135	13
Bakken Eastern Transitional	ND	Mountrail	3,010	346
Bakken Eastern Transitional	ND	Stark	194	169
Bakken Eastern Transitional	ND	Ward	57	169
Bakken Elm Coulee-Billings Nose	MT	McCone	67	163
Bakken Elm Coulee-Billings Nose	MT	Richland	1,583	152
Bakken Elm Coulee-Billings Nose	ND	Billings	819	50
Bakken Elm Coulee-Billings Nose	ND	Golden Valley	131	84
Bakken Elm Coulee-Billings Nose	ND	McKenzie	1,192	162
Bakken Nesson-Little Knife	ND	Billings	574	109
Bakken Nesson-Little Knife	ND	Burke	308	172
Bakken Nesson-Little Knife	ND	Divide	602	157
Bakken Nesson-Little Knife	ND	Dunn	3,151	281
Bakken Nesson-Little Knife	ND	Hettinger	110	223
Bakken Nesson-Little Knife	ND	McKenzie	1,958	291
Bakken Nesson-Little Knife	ND	Mountrail	1,056	310
Bakken Nesson-Little Knife	ND	Slope	172	223
Bakken Nesson-Little Knife	ND	Stark	1,099	326
Bakken Nesson-Little Knife	ND	Williams	1,975	198
Bakken Northwest Transitional	MT	Daniels	1,550	82
Bakken Northwest Transitional	MT	McCone	97	82
Bakken Northwest Transitional	MT	Roosevelt	787	82
Bakken Northwest Transitional	MT	Sheridan	1,714	69
Bakken Northwest Transitional	MT	Valley	603	1
Bakken Northwest Transitional	ND	Divide	628	115
Bakken Northwest Transitional	ND	Williams	340	144

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Technological Improvement

The OLOGSS uses a simplified approach to modeling the impact of technology advancement on U.S. crude oil and natural gas costs and productivity to better capture a continually changing technological landscape. This approach incorporates assumptions regarding ongoing innovation in upstream technologies and reflects the average annual growth rate in natural gas and crude oil resources plus cumulative production from 1990 between AEO2000 and AEO2015.

Areas in tight oil, tight gas, and shale gas plays are divided into two productivity tiers with different assumed rates of technology change. The first tier ("Tier 1") encompasses actively developing areas and the second tier ("Tier 2") encompasses areas not yet developing. Once development begins in a Tier 2 area, this area is converted to Tier 1 so technological improvement for continued drilling will reflect the rates assumed for Tier 1 areas. This conversion captures the effects of diminishing returns on a per well basis from decreasing well spacing as development progresses, the quick market penetration of technologies, and the ready application of industry practices and technologies at the time of development. The specific assumptions for the annual average rate of technological improvement are shown in Table 9.6.

Table 9.6. Onshore lower 48 technology assumptions

annual average rate of technological improvement

Crude Oil and Natural Gas Resource Type	Drilling Cost	Lease Equipment & Operating Cost	EUR-Tier 1	EUR-Tier 2
Tight oil	-1.00%	-0.50%	1.00%	3.00%
Tight gas	-1.00%	-0.50%	1.00%	3.00%
Shale gas	-1.00%	-0.50%	1.00%	3.00%
All other	-0.25%	-0.25%	0.25%	0.25%

Source: U.S. Energy Information Administration, Office of Energy Analysis.

CO2 enhanced oil recovery

For CO2 miscible flooding, the OLOGSS incorporates both industrial and natural sources of CO2. The industrial sources of CO2 are:

- Hydrogen plants
- Ammonia plants
- Ethanol plants
- Cement plants
- Refineries (hydrogen)
- Fossil fuel power plants
- Natural gas processing
- Coal/biomass to liquids (CBTL)

The volume and cost of CO2 available from fossil fuel power plants and CBTL are determined in the Electricity Market Module and the Liquid Fuels Market Module, respectively. Technology and market constraints prevent the total volumes of CO2 from the other industrial sources (Table 9.7) from becoming immediately available. The development of the CO2 market is divided into two periods: 1) development phase and 2) market acceptance phase. During the development phase, the required capture equipment is developed, pipelines and compressors are constructed, and no CO2 is available. During the market acceptance phase, the capture technology is being widely implemented and volumes of CO2 first become available. The number of years in each development period is shown in Table 9.8.

CO2 is available from planned Carbon Sequestration and Storage (CSS) power plants funded by American Recovery and Reinvestment Act of 2009 (ARRA) starting in 2016.

Table 9.7. Maximum volume of CO2 available

billion cubic feet

OGSM Region	Natural Plants	Hydrogen Plants	Ammonia Plants	Ethanol Plants	Cement Plants	Refineries (hydrogen)	Natural Gas Processing
East	0	3	0	52	94	17	23
Gulf Coast	292	0	78	0	86	114	114
Midcontinent	16	0	0	175	48	1	0
Southwest	657	0	0	68	74	0	0
Rocky Mountains/Dakotas	80	0	3	32	38	77	18
West Coast	0	0	0	4	48	93	40

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Table 9.8. CO2 availability assumptions

Source Type	Development Phase (years)	Market Acceptance Phase (years)	Ultimate Market Acceptance
Natural	0	10	100%
Hydrogen plants	4	10	100%
Ammonia plants	2	10	100%
Ethanol plants	4	10	100%
Cement plants	7	10	100%
Refineries (hydrogen)	4	10	100%
Natural Gas Processing	2	10	100%

Source: U.S. Energy Information Administration, Office of Energy Analysis.

The cost of CO2 from natural sources is a function of the oil price. For industrial sources of CO2, the cost to the producer includes the cost to capture, compress to pipeline pressure, and transport to the project site via pipeline within the region (Table 9.9). Inter-regional transportation costs add $0.40 per Mcf for every region crossed.

Table 9.9. Industrial CO2 capture and transportation costs by region

$/Mcf

OGSM Region	Hydrogen Plants	Ammonia Plants	Ethanol Plants	Cement Plants	Refineries (hydrogen)	Natural Gas Processing
East	$2.44	$2.10	$2.23	$4.29	$2.44	$1.92
Gulf Coast	$1.94	$2.10	$2.23	$4.29	$1.94	$1.92
Midcontinent	$2.07	$2.10	$2.23	$4.29	$2.07	$1.92
Southwest	$2.02	$2.10	$2.23	$4.29	$2.02	$1.92
Rocky Mountains/Dakotas	$2.03	$2.10	$2.23	$4.29	$2.03	$1.92
West Coast	$2.01	$2.10	$2.23	$4.29	$2.01	$1.92

Source: U.S. Energy Information Administration. Office of Energy Analysis.

Lower 48 offshore

Most of the Lower 48 offshore oil and gas production comes from the deepwater Gulf of Mexico (GOM). Production from currently producing fields and industry-announced discoveries largely determine the near-term oil and natural gas production projection.

For currently producing oil fields, a 10-15% exponential decline is assumed for production. Currently producing natural gas fields use a 30% exponential decline. Fields that began production after 2008 are assumed to remain at their peak production level for 2 years before declining.

The assumed field size and year of initial production of the major announced deepwater discoveries that were not brought into production by 2014 are shown in Table 9.10. A field that is announced as an oil field is assumed to be 100% oil and a field that is announced as a gas field is assumed to be 100% gas. If a field is expected to produce both oil and gas, 70% is assumed to be oil and 30% is assumed to be gas.

Production is assumed to:

- ramp up to a peak level in 3 years
- remain at the peak level until the ratio of cumulative production to initial resource reaches 10%
- then decline at an exponential rate of 30% for natural gas fields and 25% for oil fields

The discovery of new fields (based on BOEM'S field size distribution) is assumed to follow historical patterns. Production from these fields is assumed to follow the same profile as the announced discoveries (as described in the previous paragraph). Advances in technology for the various activities associated with crude oil and natural gas exploration, development, and production can have a profound impact on the costs associated with these activities. The specific technology levers and values for the offshore are presented in Table 9.11.

Leasing is assumed to be available in 2022 in the Eastern Gulf of Mexico, in 2018 in the Mid-and South Atlantic, in 2023 in the South Pacific, and after 2035 in the North Atlantic, Florida straits, Pacific Northwest, and North and Central California.

Table 9.10. Assumed size and initial production year of major announced deepwater discoveries

Field/Project Name	Block	Water Depth (feet)	Year of Discovery	Field Size Class	Field Size (MMBoe)	Start Year of Production
Silvertip	AC815	9,280	2004	12	90	2015
Gotcha	AC865	7,844	2006	12	90	2019
Vicksburg	DC353	7,457	2009	14	357	2019
Gettysburg	DC398	5,000	2014	11	44	2024
Cardamom Deep	GB427	2,720	2009	13	176	2015
Bushwood	GB506	2,700	2009	12	90	2019
North Platte	GB959	4,400	2012	15	693	2022
Katmai	GC040	2,100	2014	11	44	2024
Stampede-Pony	GC468	3,497	2006	14	357	2018
Stampede-Knotty Head	GC512	3,557	2005	14	357	2018
Holstein Deep	GC643	4,326	2014	14	357	2016
Anchor	GC807	5,183	2015	16	1,393	2025
Parmer	GC823	3,821	2012	11	44	2022
Heidelberg	GC903	5,271	2009	14	357	2016
Guadalupe	KC010	4,000	2014	12	90	2024
Gila	KC093	4,900	2013	15	693	2017
Tiber	KC102	4,132	2009	15	693	2017
Kaskida	KC292	5,894	2006	15	693	2020
Leon	KC642	1,865	2014	14	357	2024

Table 9.11. Assumed size and initial production year of major announced deepwater discoveries (cont.)

Field/Project Name	Block	Water Depth (feet)	Year of Discovery	Field Size Class	Field Size (MMBoe)	Start Year of Production
Lucius	KC874	7,168	2009	14	357	2015
Hadrian North	KC919	7,000	2010	14	357	2020
Hadrian South	KC964	7,983	2009	13	176	2015
Diamond	LL370	9,975	2008	11	44	2018
Cheyenne East	LL400	9,187	2011	9	12	2020
Amethyst	MC026	1,200	2014	11	44	2017
Otis	MC079	3,800	2014	11	44	2018
Horn Mountain Deep	MC126	5,400	2015	12	90	2017
Mandy	MC199	2,478	2010	12	90	2020
Marmalard	MC300	6,148	2012	11	44	2015
Appomattox	MC392	7,290	2009	14	357	2017
Son of Bluto 2	MC431	6,461	2012	11	44	2017
Rydberg	MC525	7,500	2014	12	90	2019
Big Bend	MC698	7,273	2012	12	90	2015
Deimos South	MC762	3,122	2010	12	90	2015
Kaikias	MC768	4,575	2014	12	90	2024
Kodiak	MC771	5,006	2008	13	176	2018
Dantzler	MC782	6,580	2013	12	90	2015
West Boreas	MC792	3,094	2009	12	90	2015
Gunflint	MC948	6,138	2008	12	90	2016
Vito	MC984	4,038	2009	13	176	2020
Phobos	SE039	8,500	2013	12	90	2018
Big Foot	WR029	5,235	2006	13	176	2018
Shenandoah	WR052	5,750	2009	15	693	2017
Yucatan North	WR095	5,860	2013	12	90	2020
Yeti	WR160	5,895	2015	13	176	2025
Stones	WR508	9,556	2005	16	1,393	2018
Julia	WR627	7,087	2007	12	90	2018

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Table 9.12. Offshore exploration and production technology levels

Technology Level	Total Improvement over 30 years (%)
Exploration success rates	30
Delay to commence first exploration and between exploration and development	15
Exploration & development drilling costs	30
Operating cost	30
Time to construct production facility	15
Production facility construction costs	30
Initial constant production rate	15
Decline rate	0

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Alaska crude oil production

Projected Alaska oil production includes both existing producing fields and undiscovered fields that are expected to exist, based upon the region's geology. The existing fields category includes the expansion fields around the Prudhoe Bay and Alpine Fields for which companies have already announced development schedules. Projected North Slope oil production also includes the initiation of oil production in the Point Thomson Field in 2016. Alaska crude oil production from the undiscovered fields is determined by the estimates of available resources in undeveloped areas and the net present value of the cash flow calculated for these undiscovered fields based on the expected capital and operating costs, and on the projected prices.

The discovery of new Alaskan oil fields is determined by the number of new wildcat exploration wells drilled each year and by the average wildcat success rate. The North Slope and South-Central wildcat well success rates are based on the success rates reported to the Alaska Oil and Gas Conservation Commission for the period of 1977 through 2008.

New wildcat exploration drilling rates are determined differently for the North Slope and South-Central Alaska. North Slope wildcat well drilling rates were found to be reasonably well correlated with prevailing West Texas Intermediate crude oil prices. Consequently, an ordinary least squares statistical regression was employed to develop an equation that specifies North Slope wildcat exploration well drilling rates as a function of prevailing West Texas Intermediate crude oil prices. In contrast, South-Central wildcat well drilling rates were found to be uncorrelated to crude oil prices or any other criterion. However, South-Central wildcat well drilling rates on average equaled just over three wells per year during the 1977 through 2008 period, so three South-Central wildcat exploration wells are assumed to be drilled every year in the future.

On the North Slope, the proportion of wildcat exploration wells drilled onshore relative to those drilled offshore is assumed to change over time. Initially, only a small proportion of all the North Slope wildcat exploration wells are drilled offshore. However, over time, the offshore proportion increases linearly, so that after 20 years, 50% of the North Slope wildcat wells are drilled onshore and 50% are drilled offshore. The 50/50 onshore/offshore wildcat well apportionment remains constant through the remainder of the projection in recognition of the fact that offshore North Slope wells and fields are considerably more expensive to drill and develop, thereby providing an incentive to continue drilling onshore wildcat wells even though the expected onshore field size is considerably smaller than the oil fields expected to be discovered offshore.

The size of the new oil fields discovered by wildcat exploration drilling is based on the expected field sizes of the undiscovered Alaska oil resource base, as determined by the U.S. Geological Survey (USGS) for the onshore and state offshore regions of Alaska, and by the Bureau of Ocean Energy Management (BOEM) (formerly known as the U.S. Minerals Management Service) for the federal offshore regions of Alaska. The undiscovered resource assumptions for the offshore North Slope were revised in light oil Shell's disappointing results in the Chukchi Sea, the cancellation of two potential Arctic offshore lease sales scheduled under BOEM's 2012-2017 five-year leasing program, and companies relinquishing of Chukchi Sea leases.

It is assumed that the largest undiscovered oil fields will be found and developed first and in preference to the small and midsize undiscovered fields. As exploration and discovery proceed and as the largest oil fields are discovered and developed, the discovery and development process proceeds to find and develop the next largest set of oil fields. This large to small discovery and development process is predicated on the fact that developing new infrastructure in Alaska, particularly on the North Slope, is an expensive undertaking and that the largest fields enjoy economies of scale, which make them more profitable and less risky to develop than the smaller fields.

Oil and gas exploration and production currently are not permitted in the Arctic National Wildlife Refuge. The projections for Alaska oil and gas production assume that this prohibition remains in effect throughout the projection period.

Three uncertainties are associated with the Alaska oil projections:

- whether the heavy oil deposits located on the North Slope, which exceed 20 billion barrels of oil-in-place, will be producible in the foreseeable future at recovery rates exceeding a few percent
- the oil production potential of the North Slope shale formations is unknown at this time
- the North Slope offshore oil resource potential, especially in the Chukchi Sea, is untested

In June 2011, Alyeska Pipeline Service Company released a report regarding potential operational problems that might occur as Trans-Alaska Pipeline System (TAPS) throughput declines from the current production levels. Although the onset of TAPS low flow problems could begin at around 550,000 barrels per day (b/d), absent any mitigation, the severity of the TAPS operational problems is expected to increase significantly as throughput declines. As the types and severity of problems multiply, the investment required to mitigate those problems is expected to increase significantly. Because of the many and diverse operational problems expected to occur below 350,000 b/d of throughput, considerable investment might be required to keep the pipeline operational below this threshold. Thus, North Slope fields are assumed to be shut down, plugged and abandoned when the following two conditions are simultaneously satisfied: 1) TAPS throughput would have to be at or below 350,000 b/d and two) total North Slope oil production revenues would have to be at or below $5.0 billion per year.

Legislation and regulations

The Outer Continental Shelf Deep Water Royalty Act (Public Law 104-58) gave the Secretary of the Interior the authority to suspend royalty requirements on new production from qualifying leases and required that royalty payments be waived automatically on new leases sold in the five years following its November 28, 1995 enactment. The volume of production on which no royalties were due for the five years was assumed to be 17.5 million barrels of oil equivalent (BOE) in water depths of 200 to 400 meters, 52.5 million BOE in water depths of 400 to 800 meters, and 87.5 million BOE in water depths greater than 800 meters. In any year during which the arithmetic average of the closing prices on the New York Mercantile Exchange for light sweet crude oil exceeded $28 per barrel or for natural gas exceeded $3.50 per million Btu, any production of crude oil or natural gas was subject to royalties at the lease-stipulated royalty rate. Although automatic relief expired on November 28, 2000, the act provided the Minerals Management Service (MMS) the authority to include royalty suspensions as a feature of leases sold in the future. In September 2000, the MMS issued a set of proposed rules and regulations that provide a framework for continuing deep water royalty relief on a lease-by-lease basis. In the model it is assumed that relief will be granted at roughly the same levels as provided during the first five years of the Act.

Section 345 of the Energy Policy Act of 2005 provides royalty relief for oil and gas production in water depths greater than 400 meters in the Gulf of Mexico from any oil or gas lease sale occurring within five years after enactment. The minimum volumes of production with suspended royalty payments are:

1. 5,000,000 BOE for each lease in water depths of 400 to 800 meters;
2. 9,000,000 BOE for each lease in water depths of 800 to 1,600 meters;
3. 12,000,000 BOE for each lease in water depths of 1,600 to 2,000 meters; and
4. 16,000,000 BOE for each lease in water depths greater than 2,000 meters.

The water depth categories specified in Section 345 were adjusted to be consistent with the depth categories in the Offshore Oil and Gas Supply Submodule. The suspension volumes are 5,000,000 BOE for leases in water depths of 400 to 800 meters; 9,000,000 BOE for leases in water depths of 800 to 1,600 meters; 12,000,000 BOE for leases in water depths of 1,600 to 2,400 meters; and 16,000,000 for leases in water depths greater than 2,400 meters. Examination of the resources available at 2,000 to 2,400 meters showed that the differences between the depths used in the model and those specified in the bill would not materially affect the model result.

The MMS published its final rule on the "Oil and Gas and Sulphur Operations in the Outer Continental Shelf Relief or Reduction in Royalty Rates Deep Gas Provisions" on January 26, 2004, effective March 1, 2004. The rule grants royalty relief for natural gas production from wells drilled to 15,000 feet or deeper on leases issued before January 1, 2001, in the shallow waters (less than 200 meters) of the Gulf of Mexico. Production of gas from the completed deep well must begin before five years after the effective date of the final rule. The minimum volume of production with suspended royalty payments is 15 billion cubic feet for wells drilled to at least 15,000 feet and 25 billion cubic feet for wells drilled to more than 18,000 feet. In addition, unsuccessful wells drilled to a depth of at least 18,000 feet would receive a royalty credit for 5 billion cubic feet of natural gas. The ruling also grants royalty suspension for volumes of not less than 35 billion cubic feet from ultra-deep wells on leases issued before January 1, 2001.

Section 354 of the Energy Policy Act of 2005 established a competitive program to provide grants for cost-shared projects to enhance oil and natural gas recovery through CO2 injection, while at the same time sequestering CO2 produced from the combustion of fossil fuels in power plants and large industrial processes.

From 1982 through 2008, Congress did not appropriate funds needed by the MMS to conduct leasing activities on portions of the federal Outer Continental Shelf (OCS) and thus effectively prohibited leasing. Further, a separate Executive ban in effect since 1990 prohibited leasing through 2012 on the OCS, with the exception of the Western Gulf of Mexico and portions of the Central and Eastern Gulf of Mexico. When combined, these actions prohibited drilling in most offshore regions, including areas along the Atlantic and Pacific coasts, the eastern Gulf of Mexico, and portions of the central Gulf of Mexico. In 2006, the Gulf of Mexico Energy Security Act imposed yet a third ban on drilling through 2022 on tracts in the Eastern Gulf of Mexico that are within 125 miles of Florida, east of a dividing line known as the Military Mission Line, and in the Central Gulf of Mexico within 100 miles of Florida.

On July 14, 2008, President Bush lifted the Executive ban and urged Congress to remove the Congressional ban. On September 30, 2008, Congress allowed the Congressional ban to expire. Although the ban through 2022 on areas in the Eastern and Central Gulf of Mexico remains in place, the lifting of the Executive and Congressional bans removed regulatory obstacles to development of the Atlantic and Pacific OCS.

On March 20, 2015, the Bureau of Land Management (BLM) released regulations applying to hydraulic fracturing on federal and Indian lands (the "Fracking Rule"). Key components of the rule include: validation of well integrity and strong cement barriers between the wellbore and water zones through which the wellbore passes; public disclosure of chemicals used in hydraulic fracturing; specific standards for interim storage of recovered waste fluids from hydraulic fracturing; and disclosure of more detailed information on the geology, depth, and location of preexisting wells to the BLM. The impact of this regulation is expected to be minimal since many of the provisions are consistent with current industry practices and state regulations. However, in June 2016, this regulation was struck down in federal court. BLM is currently appealing the court decision.

Oil and gas supply alternative cases

Oil and Natural Gas Resource and Technology cases

Estimates of technically recoverable tight/shale crude oil and natural gas resources are particularly uncertain and change over time as new information is gained through drilling, production, and technology experimentation. Over the last decade, as more tight/shale formations have gone into production, the estimate of technically recoverable tight oil and shale gas resources has increased. However, these increases in technically recoverable resources embody many assumptions that might not prove to be true over the long term and over the entire tight/shale formation. For example, these resource estimates assume that crude oil and natural gas production rates achieved in a limited portion of the formation are representative of the entire formation, even though neighboring well production rates can vary by as much as a factor of three within the same play. Moreover, the tight/shale formation can vary significantly across the petroleum basin with respect to depth, thickness, porosity, carbon content, pore pressure, clay content, thermal maturity, and water content. Additionally, technological improvements and innovations may allow development of crude oil and natural gas resources that have not been identified yet, and thus are not included in the Reference case.

The sensitivity of the AEO2016 projections to changes in assumptions regarding domestic crude oil and natural gas resources and technological progress is examined in two cases. These cases do not represent a confidence interval for future domestic oil and natural gas supply, but rather provide a framework to examine the effects of higher and lower domestic supply on energy demand, imports, and prices. Assumptions associated with these cases are described below.

Low Oil and Gas Resource and Technology case

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 technological improvement that reduce costs and increase productivity in the United States are also 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.

High Oil and Gas Resource and Technology 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, to more than 17 million barrels per day (b/d) in 2040 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 than in 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.

Notes and sources

[94] The current development of tight oil plays has shifted industry focus and investment away from the development of U.S. oil shale (kerogen) resources. Considerable technological development is required prior to the large-scale in-situ production of oil shale being economically feasible. Consequently, the Oil Shale Supply Submodule assumes that large-scale in-situ oil shale production is not commercially feasible in the Reference case prior to 2040.

[95] Technically recoverable resources are resources in accumulations producible using current recovery technology but without reference to economic profitability.

[96] Proved reserves are the estimated quantities that analysis of geological and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Notes and sources (cont.)

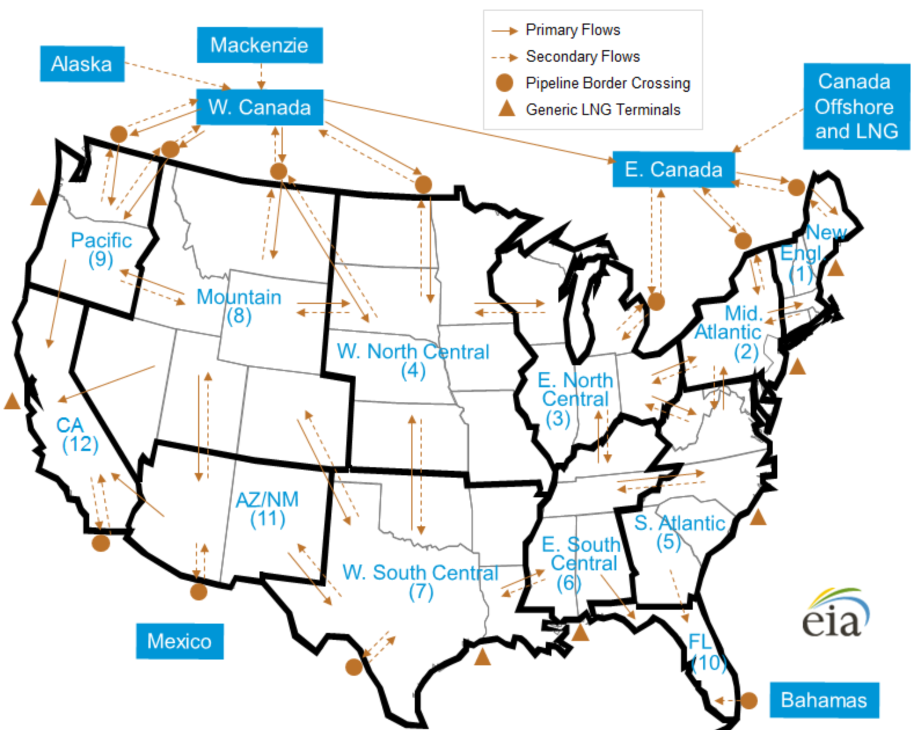
[97] Unproved resources include resources that have been confirmed by exploratory drilling and undiscovered resources, which are located outside oil and gas fields in which the presence of resources has been confirmed by exploratory drilling; they include resources from undiscovered pools within confirmed fields when they occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions.

[98] The Bakken areas are consistent with the USGS Bakken formation assessment units shown in Figure 1 of Fact Sheet 2013-3013, Assessment of Undiscovered Oil Resources in the Bakken and Three Forks Formations, Williston Basin Province, Montana, North Dakota, and South Dakota, 2013 at http://pubs.usgs.gov/fs/2013/3013/fs2013-3013.pdf.

Chapter 10. Natural Gas Transmission and Distribution Module

The NEMS Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS) derives domestic natural gas production, wellhead and border prices, end-use prices, and flows of natural gas through a regional interstate representative pipeline network, for both a peak (December through March) and off-peak period during each projection year. These are derived by solving for the market equilibrium across the three main components of the natural gas market: the supply component, the demand component, and the transmission and distribution network that links them. Natural gas flow patterns are a function of the pattern in the previous year, coupled with the relative prices of the supply options available to bring gas to market centers within each of the NGTDM regions (Figure 10.1). The major assumptions used within the NGTDM are grouped into five general categories structural components of the model, capacity expansion pricing of transmission and distribution services, supplemental natural gas, and imports and exports. A complete listing of NGTDM assumptions and in-depth methodology descriptions are presented in Model Documentation: Natural Gas Transmission and Distribution Module of the National Energy Modeling System, Model Documentation 2014, DOE/EIA-M062 (2014) (Washington, DC, 2014).

Figure 10.1. Natural Gas Transmission and Distribution regions



Source: U.S. Energy Information Administration

Key assumptions

Structural components

The primary and secondary region-to-region flows represented in the model are shown in Figure 10.1. Primary flows are determined, along with non-associated gas production levels, as the model equilibrates supply and demand. Associated-dissolved gas production is determined in the Oil and Gas Supply Module (OGSM). Secondary flows are established before the equilibration process and are largely set exogenously. In the Northeast, where secondary flows are expected to grow significantly, secondary flows are endogenously set based in part on price differentials between sending and receiving regions.

Liquefied natural gas (LNG) imports and domestically-produced natural gas exports are also not directly part of the equilibration process, but are set at the beginning of each NEMS iteration in response to the price from the previous iteration and projected future prices, respectively. LNG re-exports are set exogenously to the model. Flows and production levels are determined for each season, linked by seasonal storage.

When required, annual quantities (e.g., consumption levels) are split into peak and off-peak values based on historical averages. When multiple regions are contained in a Census Division, regional end-use consumption levels are approximated using historical average shares. Supply curves and electric generator gas consumption are provided by other NEMS modules for subregions of the NGTDM regions, reflective of how their internal regions overlap with the NGTDM regions. Pipeline and storage capacity are added as warranted by the relative volumes and prices. Regional pipeline fuel and lease and plant fuel consumption are established by applying a historically based factor to the flow of gas through a region and the production in a region, respectively.

Prices within the network, including at the borders and the wellhead, are largely determined during the equilibration process when supply and demand are balanced and prices are set. Delivered prices for each sector are set by adding an endogenously estimated markup (e.g., a distributor tariff) to either the regional representative city gate price or the regional market hub price.

Capacity expansion

For the first two projection years, announced pipeline and storage capacity expansions (which are deemed highly likely to occur) are used to establish limits on flows and seasonal storage in the model. Subsequently, pipeline and storage capacity is added when increases in consumption, coupled with an anticipated price increase, warrant such additions (i.e., flow is allowed to exceed current capacity if the demand still exists given an assumed increased tariff). Once it is determined that an expansion will occur, the associated capital costs are applied in the revenue requirement calculations in future years. Capital costs are assumed based on average costs of recent comparable expansions for compressors, looping, and new pipeline.

It is assumed that pipeline and local distribution companies build and subscribe to a portfolio of interstate pipeline and storage capacity to serve a region-specific colder-than-normal winter demand level, set at 30% above the daily average. Maximum pipeline capacity utilization in the peak period is set at 99%. In the off-peak period, the maximum is assumed to vary between 75% and 99% of the design capacity. The overall level and profile of consumption, as well as the availability and price of supplies, mostly cause realized pipeline utilization levels to be lower than the maximum.

Pricing of transmission and distribution services

Transport rates between regions are set for the purposes of determining natural gas flows through the representative pipeline network based on historical observed differentials between regional spot prices. Ultimately regional city gate prices reflect the addition of reservation charges along each of the connecting routes and within a region. Per-unit pipeline reservation charges are initially based on a regulated cost-of-service calculation and an assumed flow rate, and are dynamically adjusted based on the realized utilization rate. Reservation rates for interstate pipeline services (both between NGTDM regions and within a region) are calculated assuming that the costs of new pipeline capacity will be rolled into the existing rate base.

For the industrial and electric generator sectors, delivered natural gas prices are based on regional prices which do not directly include any pipeline reservation fees (i.e., spot prices), with an added markup based on averaged historical values. For the residential and commercial customers, delivered natural gas prices are based on regional city gate prices with an added econometrically estimated distributor markup, set as a function of the sectoral consumption, as well as the number of gas burning households and commercial floorspace, respectively. For the industrial sector, distributor markups are estimated separately for energy-intensive and non-energy-intensive industrial customers as a function of consumption. Prices are originally set on a seasonal basis and are averaged with quantity-weights to derived annual prices.

The natural gas used in the transportation sector, excluding pipeline fuel use, is distinguished by fuel category (compressed natural gas and LNG), customer category (private refueling station (fleet) and public retail station), and transport mode (vehicle, train, and ship). All transport modes are assumed to see the same price with the exception that: 1) vehicles are assumed to pay the state and federal motor fuels taxes for either compressed natural gas (CNG) or LNG, 2) ships are assumed to pay the same price as vehicles minus the state motor fuels tax, and 3) trains are assumed to pay the same price as vehicles minus both the state and federal motor fuels tax, with the LNG price for trains further lowered to account for assumed lower infrastructure costs. The use by rail and ship is further disaggregated in the NEMS Transportation Sector Module, but no further distinction is made on the prices.

The price for delivered dry natural gas to a liquefaction plant is approximated by using the price for delivered dry natural gas to electric generators. The retail price for LNG into a vehicle/train/ship is therefore equal to the sum of: the price to electric generators, the assumed price to liquefy and transport the LNG to a station, the retail price markup at the station, and the excise taxes. Table 10.1 shows the national average state excise tax, while in the model these taxes vary by region. The markup for the retail price of CNG at a station off of the regional city gate price is based on posted rates published in Department of Energy's Office of Energy Efficiency & Renewable Energy publications of "Clean Cities Alternative Fuel Price Report." These markups are adjusted for any change in the state and federal excise tax seen historically versus what are assumed in the projection period. CNG for fleets is assumed to have a lower infrastructure and operating cost and is therefore assigned a lower price ($0.53 1987$ per million cubic feet or $0.14 2015$/diesel gallon equivalent (dge) less) than at a retail station. The values used throughout the projection period for these components and the primary assumptions behind them are shown in Table 10.1.

Table 10.1. Assumptions for setting CNG and LNG fuel prices

Year	CNG fleet	CNG retail	LNG fleet	LNG retail
Retail markup after dry gas pipeline delivery, with no excise tax (2015$/dge)	0.86	1.01	1.51	1.72
Capacity (dge/day)	1,600	1,100	4,000	4,000
Usage (percent of capacity)	80	60	80	60
Capital cost (million 2015$)	0.87	0.54	1.08	1.08
Capital recovery (years)	5	10	5	10
Weighted average cost of capital (rate)	0.10	0.15	0.10	0.15
Operating cost (2015$/dge)	0.37	0.55	0.44	0.64
Charge for liquefying and delivering LNG (2015$/dge)	--	--	0.81	0.81
Federal excise tax (nominal$/dge)	0.21	0.21	0.25	0.25
State excise tax (nominal$/dge)	0.17	0.17	0.18	0.18
Fuel loss for liquefying and delivering LNG (percent of input volumes)	--	--	10	10
Fuel loss at station (percent of input volumes)	0.5	0.5	1.0	2.0

dge=diesel gallon equivalent.
Source: U.S. Energy Information Administration, Office of Petroleum, Natural Gas, and Biofuels Analysis, U.S. Tax Code and State Tax Codes.

The retail markup above the cost of dry gas for LNG for rail was assumed at $0.98 2015$/dge (compared to $1.51/dge for fleet vehicles as shown in Table 10.1), with the assumption that liquefaction would occur at the refueling point and cost $0.58/dge (compared to $0.81/dge for vehicles), operating costs would be $0.23/dge (compared to $0.44/dge for fleet vehicles), and capital cost recovery for additional equipment beyond the liquefiers would be $0.17/dge (compared to $0.25/dge for fleet vehicles, not shown in table).

Supplemental natural gas

The projection for supplemental gas supply is identified for three separate categories: pipeline quality synthetic natural gas (SNG) from coal or coal-to-gas (CTG), SNG from liquids, and other supplemental supplies (propane-air, coke oven gas, refinery gas, biomass air, air injected for British Thermal Unit (Btu) stabilization, and manufactured gas commingled and distributed with natural gas). The third category, other supplemental supplies, are held at a constant level of 8.5 billion cubic feet per year throughout the projection because this level is consistent with historical data and it is not believed to change significantly in the context of a Reference case. SNG from liquid hydrocarbons in Hawaii is assumed to continue over the projection at the average historical level of 2.6 billion cubic feet per year. SNG production from coal at the currently operating Great Plains Coal Gasification Plant is also assumed to continue through the projection period at an average historical level of 51.0 billion cubic feet per year. It is assumed that additional CTG facilities will not be economic to build.

Natural gas imports and exports

U.S. natural gas trade with Mexico is determined endogenously based on various assumptions about the natural gas market in Mexico. Natural gas consumption levels in Mexico are set exogenously based on preliminary projections from the International Energy Outlook 2016 and are provided in Table 10.2, along with initially assumed Mexico natural gas production and LNG import levels targeted for markets in Mexico. Adjustments to production are made endogenously within the model to reflect a response to price fluctuations within the market and reflect laws concerning foreign investment at the time of the projection. Domestic production is assumed to be supplemented by LNG from receiving terminals constructed on both the east and west coasts of Mexico. Maximum LNG import volumes targeted for markets in Mexico are set exogenously and will be realized if endogenously determined LNG imports into North America are sufficient. The difference between production plus LNG imports and consumption in Mexico in any year is assumed to be either imported from, or exported to, the United States.

Table 10.2. Exogenously specified Mexico natural gas consumption, production, and LNG imports

Billion cubic feet per year

	Consumption	Initial Dry Production	Initial LNG Imports
2015	2,672	1,373	200
2020	3,098	1,225	0
2025	3,383	1,531	0
2030	3,804	1,995	0
2035	4,352	2,644	0
2040	4,929	3,347	0

Source: U.S. Energy Information Administration, Office of Petroleum, Natural Gas, and Biofuels Analysis, based on U.S. Energy Information Administration, International Energy Outlook 2016 DOE/EIA-0484(2016), preliminary.

Note: Excludes any LNG imported to Mexico for export to the United States.

Similarly to Mexico, Canada is modeled through a combination of exogenously and endogenously specified components. Western Canadian production, U.S. import flows from Canada, and U.S. export flows to Canada are determined endogenously within the model. Canadian natural gas production in Eastern Canada, consumption, and LNG exports are set exogenously in the model and are shown in Table 10.3. Production from conventional and tight formations in the Western Canadian Sedimentary Basin (WCSB) is set endogenously to the model using annual supply curves based on an expected production level equal to the beginning-of-year proved reserves multiplied by a historical production-to-reserve ratio, assumed to decline by 1% each year. A baseline projection of successful conventional/tight gas wells is set exogenously with an associated baseline price projection, and is used to establish successful gas wells in the projection as the projected price varies from the base. Conventional/tight reserve additions are set equal to the product of successful natural gas wells and a finding rate (set at an historical level and assumed to decline 2% each year).

Table 10.3. Exogenously specified Canada natural gas consumption, production, and LNG exports

billion cubic feet per year

Year	Consumption	Production Eastern Canada	LNG Exports
2015	3,640	120	0
2020	3,832	67	0
2025	4,180	29	0
2030	4,658	12	0
2035	5,134	0	1,007
2040	5,576	0	2,230

Source: Consumption and LNG exports – Based on U.S. Energy Information Administration, International Energy Outlook 2016, DOE/EIA-0484(2016), preliminary; Production - Energy Information Administration, Office of Petroleum, Natural Gas, and Biofuels Analysis.

The remaining marketable (technically and economically recoverable) gas resource estimates for coalbed methane and shale gas are assumed in the model at 35 and 222 trillion cubic feet, respectively, as of the beginning of 2013. [99] Production from coalbed and shale sources is established based on an assumed production path which varies in response to the level of remaining resources and the solution price in the previous projection year. LNG imports to Canada are set in conjunction with the LNG import volumes for the Lower 48 states.

LNG imports to the United States and Canada are determined endogenously within the model using Atlantic/Pacific and peak/off-peak supply curves derived from model results generated by EIA's International Natural Gas Model (INGM). Prices from the previous model iteration are used to establish the total level of U.S./Canadian LNG imports in the peak and off-peak periods and in the Atlantic and Pacific regions. First, assumed LNG imports that are consumed in Mexico are subtracted (presuming the volumes are sufficient). Then, the remaining levels are allocated to the model regions based on the previous year's import levels, the available regasification capacity, and the relative prices. Regasification capacity is limited to facilities currently in existence and those already under construction, which is fully sufficient to accommodate import levels projected by the model. LNG import volumes into New England have an assumed minimum of 62 billion cubic feet per year.

LNG exports of domestically produced natural gas from the Lower 48 states and Alaska are set endogenously in the model. The five projects that were under construction when AEO2016 was developed were assumed to come online in the indicated year: Sabine Pass, LA, 2016; Cove Point, MD, 2018; Hackberry, LA, 2018; Freeport, TX, 2019; and Corpus Christi, TX, 2019. Beyond these, the model assesses the relative economics of a generic 200 billion cubic feet train in operation over the next 20 years in each viable coastal region by comparing a model-generated estimate of the expected market price in Europe and Asia over the next 20 years against the expected price of natural gas in each coastal region plus assumed charges for liquefaction, shipping, and regasification (shown in Table 10.4). A present value of the differential is set using a discount rate of 10%. The model limits the annual liquefaction capacity builds to three trains per year. Once it is determined that a train is economically viable, the train is added over three years in the region showing the greatest positive economic potential. Once a facility is built, it is assumed to operate at its design capacity throughout the projection period unless the competing price in Asia or Europe falls below the delivered price of U.S. LNG in the region, excluding assumed reservation charges (i.e., "sunk" costs) for liquefaction.

Table 10.4. Charges related to LNG exports

2015 dollars per million Btu

	South Atlantic	West South Central	Washington/Oregon	Alaska
Liquefaction & Pipe Fee	3.58	3.25	4.45	7.59
Shipping to Europe	1.06	1.39	4.19	3.96
Shipping to Asia	2.85	2.77	1.25	0.98
Regasification	0.11	0.11	0.11	0.11
Fuel charge (percent)*	15	15	15	15

*Percent increase in market price of natural gas charged by liquefaction facility to cover fuel-related expenses, largely fuel used in the liquefaction process.

Other constraining assumptions are considered, such as earliest start year and maximum export capacity in each region. The projected market prices of LNG in Europe (National Balancing Point) and Asia (Japan) are based on the assumed values shown in Table 10.5, projected Brent oil prices, and the level of North American LNG exports. Annual U.S. exports of LNG to Japan via Alaska's existing Kenai facility are assumed to have ended in 2014. LNG re-exports are assumed to end in 2016.

Table 10.5. International natural gas volume drivers for world LNG Europe and Asia market price projections

2010 dollars per million Btu

	Flexible LNG*	Consumption OECD Europe	Consumption Japan	Consumption S. Korea	Consumption China	Production China
2015	4,362	18,194	5,070	1,979	5,807	5,264
2020	5,821	19,319	5,188	2,107	9,109	7,200
2025	7,273	20,740	5,674	2,189	13,649	11,103
2030	8,577	22,519	5,760	2,350	17,665	14,195
2035	10,097	23,849	5,919	2,687	22,549	16,681
2040	11,452	25,487	5,982	2,981	27,236	18,667

*Flexible LNG is a baseline projection of the volumes of LNG sold in the spot market or effectively available for sale at flexible destinations, based on U.S. Energy Information Administration, International Energy Outlook 2013, DOE/EIA-0484(2013), and U.S. Energy Information Administration, Office of Petroleum, Natural Gas, and Biofuels Analysis.

Source: U.S. Energy Information Administration, International Energy Outlook 2016, DOE/EIA-0484(2016), preliminary.

Legislation and regulations

The methodology for setting reservation fees for transportation services is initially based on a regulated rate calculation, but is ultimately consistent with the Federal Energy Regulatory Commission's alternative ratemaking and capacity release position in that it allows some flexibility in the rates pipelines ultimately charge. The methodology is market-based, meaning that rates for transportation services will respond positively to increased demand for services while rates will decline should the demand for services decline.

Section 312 of the Energy Policy Act of 2005 authorizes the Federal Energy Regulatory Commission to allow natural gas storage facilities to charge market-based rates if it was believed that they would not exert market power. Storage rates are allowed to vary in the model from regulation-based rates, depending on market conditions.

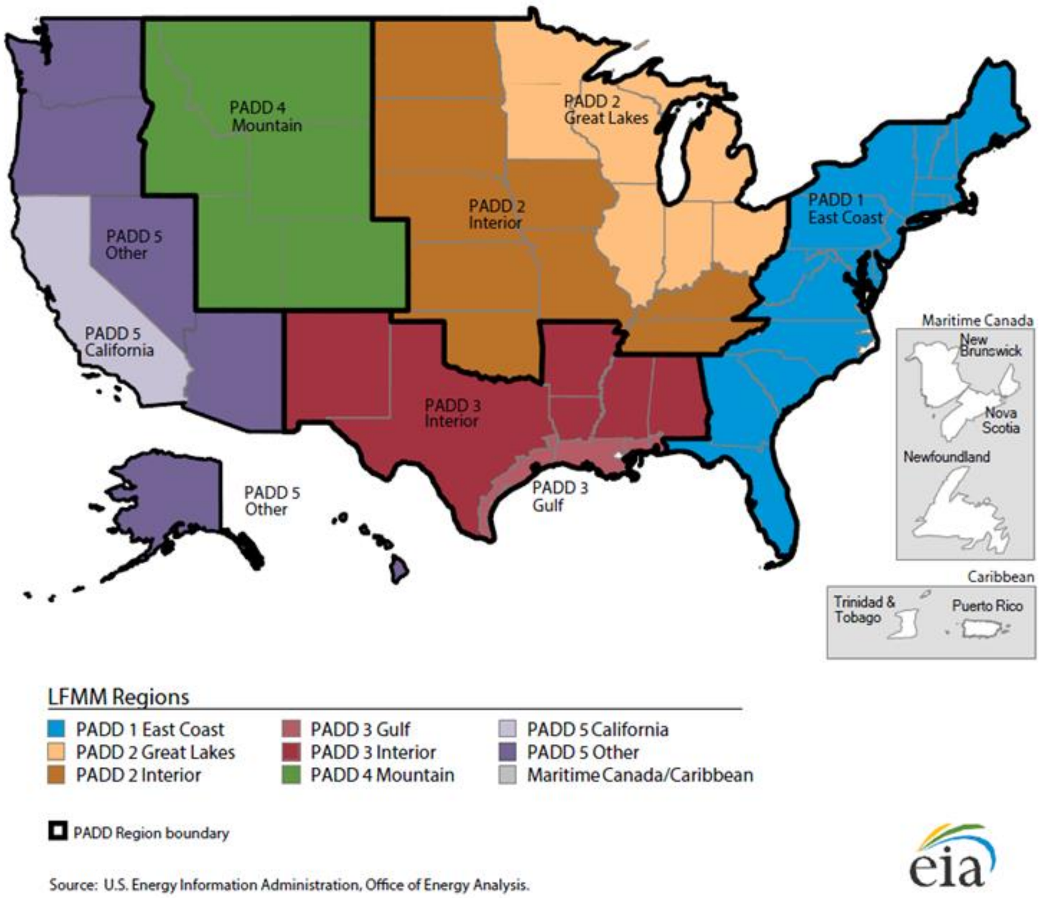
Notes and sources

[99] Coalbed and shale gas remaining marketable gas resources in the Western Canadian Resource Base from the Appendices of National Energy Board of Canada's "Canada's Energy Future 2013 – Energy Supply and Demand Projections to 2035 – An Energy Market Assessment," November 2013.

Chapter 11. Liquid Fuels Market Module

The NEMS Liquid Fuels Market Module (LFMM) projects petroleum product prices and sources of liquid fuels supply for meeting petroleum product demand. The sources of liquid fuels supply include petroleum-based fuels, such as crude oil (both domestic and imported), petroleum product imports, and unfinished oil imports. It also includes non-petroleum-based inputs, including alcohols, ethers, esters, corn, biomass, natural gas, and coal. In addition, liquid fuels supply includes natural gas plant liquids production and refinery processing gain. The LFMM also projects capacity expansion and fuel consumption at domestic refineries.

Figure 11.1. Liquid Fuels Market Module Regions



The LFMM contains a linear programming (LP) representation of U.S. petroleum refining activities, biofuels production activities, and other nonpetroleum liquid fuels production activity in eight U.S. regions. It also represents refining activity in the non-U.S. Maritime Canada/Caribbean refining region, which predominantly serves U.S. markets. In order to better represent policy, import/export patterns, and biofuels production, the eight U.S. regions are defined by subdividing three of the five Petroleum Administration for Defense Districts (PADDs) (Figure 11.1). The LP model also represents supply curves for crude imports and exports, petroleum product imports and exports, biodiesel imports, and advanced ethanol imports from Brazil. The nine LFMM regions and import/export curves are connected in the LP via crude and product transport links. In order to interact with other NEMS modules with different regional representations, certain LFMM inputs and outputs are converted from sub-PADD regions to other regional structures and vice versa. For example, the LP model converts end-use product prices from the LFMM regions (excluding the Maritime Canada/Caribbean region) into prices for the nine U.S. Census Divisions (shown in Figure 4.1) using the assumptions and methods described below.

Key assumptions

Product types and specifications

The LFMM models refinery production of the products shown in Table 11.1.

The LFMM assumes no change in the state and federal specifications for the products listed below. The costs of producing different formulations of gasoline and diesel fuel required under current regulations are determined within the LP representation of refineries.

Table 11.1. Petroleum product categories

Product Category	Specific Products
Motor Gasoline	Conventional, Reformulated (including CARB gasoline)
Jet Fuel	Kerosene-type
Distillates	Kerosene, Heating Oil, Low Sulfur, Ultra-Low Sulfur and CARB Diesel
Residual Fuels	Low Sulfur, High Sulfur
Liquefied Petroleum Gases	Ethane, Propane, Propylene, normal-Butane and iso-Butane
Petrochemical Feedstock	Petrochemical Naphtha, Petrochemical Gas Oil, Aromatics
Others	Lubricating Products and Waxes, Asphalt/Road Oil, Still Gas
	Petroleum Coke, Special Naphthas, Aviation Gasoline

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Motor gasoline specifications and market shares

The LFMM models the production and distribution of two different types of gasoline: conventional and reformulated. The following specifications are included in the LFMM to differentiate between conventional and reformulated gasoline blends (Table 11.2): Reid vapor pressure (RVP), benzene content, aromatic content, sulfur content, olefins content, and the percent evaporated at 200 and 300 degrees Fahrenheit (E200 and E300). The LFMM incorporates the EPA Tier 3 program requirement that the sulfur content of delivered gasoline be no greater than 10 parts per million (PPM) by January 1, 2017. [100]

Table 11.2. Year-round gasoline specifications by Petroleum Administration for Defense District (PADD)

PADD/Type	Reid Vapor Pressure (Max PSI)	Aromatics Volume Percent (Max)	Benzene Volume Percent (Max)	Sulfur[1] PPM (Max)	Olefin Volume Percent (Max)	Percent Evaporated at 200° (Min)	Percent Evaporated at 300° (Min)
Conventional							
PADD I	10.11	24.23	0.62	22.48/5.0	10.8	45.9	81.7
PADD II	10.11	24.23	0.62	22.48/5.0	10.8	45.9	81.7
PADD III	10.11	24.23	0.62	22.48/5.0	10.8	45.9	81.7
PADD IV	10.11	24.23	0.62	22.48/5.0	10.8	45.9	81.7
PADD V	10.11	24.23	0.62	22.48/5.0	10.8	45.9	81.7
Reformulated							
PADD I	8.8	21.0	0.62	23.88/5.0	10.36	54.0	81.7
PADD II	8.8	21.0	0.62	23.88/5.0	10.36	54.0	81.7
PADD III	8.8	21.0	0.62	23.88/5.0	10.36	54.0	81.7
PADD IV	8.8	21.0	0.62	23.88/5.0	10.36	54.0	81.7
PADD V							
Nonattainment	8.8	21.0	0.62	23.88/5.0	10.36	54.0	81.7
CARB (attainment)	7.7	23.12	0.58	10/5.0	6.29	42.9	86.3

[1]Values reflect sulfur levels “prior to / after” January 1, 2017, to meet EPA final ruling: “EPA Sets Tier 3 Motor Vehicle Emission and Fuel Standards,” http://www.epa.gov/otaq/documents/tier3/420f14009.pdf.

Max = maximum, Min = minimum, PADD = Petroleum Administration for Defense District. PPM = parts per million by weight, PSI = pounds per square inch.

Benzene volume percent changed to 0.62 for all regions and types in 2011 to meet the MSAT2 ruling.

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Reformulated gasoline must meet the Complex Model II compliance standards, which cannot exceed average 1990 levels of toxic and nitrogen oxide emissions [101]. Reformulated gasoline has been required in many areas in the United States since January 1995. In 1998, EPA began certifying reformulated gasoline using the “Complex Model,” which allows refiners to specify reformulated gasoline based on emissions reductions from their companies’ respective 1990 baselines or EPA’s 1990 baseline. The LFMM reflects “Phase 2” reformulated gasoline requirements which began in 2000. The LFMM uses a set of specifications that meet the “Complex Model” requirements, but it does not attempt to determine the optimal specifications that meet the “Complex Model.”

Cellulosic biomass feedstock supplies and costs are provided by the NEMS Renewable Fuels Model. Initial capital costs for biomass cellulosic ethanol were obtained from a research project reviewing cost estimates from multiple sources [102]. Operating costs and credits for excess electricity generated at biomass ethanol plants were obtained from a survey of literature [103].

Corn supply prices are estimated from the USDA baseline projections to 2019 [104]. Operating costs of corn ethanol plants are obtained from USDA survey of ethanol plant costs [105]. Energy requirements are obtained from a study of carbon dioxide emissions associated with ethanol production [106].

AEO2015 assumes a minimum 10% blend of ethanol in domestically consumed motor gasoline. Federal reformulated gasoline (RFG) and conventional gasoline can be blended with up to 15% ethanol (E15) in light-duty vehicles of model year 2001 and later. Reformulated and conventional gasoline can also be blended with 16% biobutanol. Actual levels will depend on the ethanol and biobutanol blending value and relative cost-competitiveness with other gasoline blending components. In addition, current state regulation, along with marketplace constraints, limit the full penetration of E15 in the projection. The Energy Independence and Security Act of 2007 (EISA2007) defines a requirements schedule for having renewable fuels blended into transportation fuels by 2022.

RVP limitations are in effect during summer months, which are defined differently by consuming region. In addition, different RVP specifications apply within each PADD. The LFMM assumes that these variations in RVP are captured in the annual average specifications, which are based on summertime RVP limits, wintertime estimates, and seasonal weights.

Within the LFMM, total gasoline demand is disaggregated into demand for conventional and reformulated gasoline by applying assumptions about the annual market shares for each type. In AEO2015 the annual market shares for each region reflect actual 2010 market shares and are held constant throughout the projection (see Table 11.3 for AEO2015 market share assumptions).

Table 11.3. Percent in market share for gasoline types by Census Division

Gasoline Type	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Conventional Gasoline	18	41	81	88	81	95	72	86	25
Reformulated Gasoline	82	59	19	12	19	5	28	14	75

Note: Data derived from EIA-782C, “Monthly Report of Prime Supplier Sales of Petroleum Products Sold for Local Consumption,” January-December 2010.

Note: As of January 2007, Oxygenated Gasoline is included within Conventional Gasoline.

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Diesel fuel specifications and market shares

In order to account for ultra-low sulfur diesel (ULSD, or highway diesel) regulations related to the Clean Air Act Amendments of 1990 (CAAA90), ULSD is differentiated from other distillates. In NEMS, the California portion of the Pacific Region (Census Division 9) is required to meet California Air Resources Board (CARB) standards. Both Federal and CARB standards currently limit sulfur to 15 parts per million (ppm).

AEO2016 incorporates the "nonroad, locomotive, and marine" (NRLM) diesel regulation finalized in May 2004 for large refiners and importers. The final NRLM rule established a new ULSD limit of 15 ppm for nonroad diesel by mid-2010. For locomotive and marine diesel, the rule established an ULSD limit of 15 ppm in mid-2012.

Demand for ULSD in LFMM is assumed to be the sum of total transportation distillate demand, 85% of industrial distillate demand, and 49% of commercial distillate demand. LFMM also differentiates ultra-low sulfur fuel oil demands as mandated in some states – New York, New Jersey, Maine, and Vermont.

End-use product prices

End-use petroleum product prices are based on marginal costs of production, plus production-related fixed costs, plus distribution costs and taxes. The marginal costs of production are determined within the LP and represent variable costs of production, including additional costs for meeting reformulated fuels provisions of CAAA90. Environmental costs associated with controlling pollution at refineries are implicitly assumed in the annual update of the refinery investment costs for the processing units.

The costs of distributing and marketing petroleum products are represented by adding product-specific distribution costs to the marginal refinery production costs (product wholesale prices). The distribution costs are derived from a set of base distribution markups (Table 11.4).

State and federal taxes are also added to transportation fuels to determine final end-use prices (Tables 11.5 and 11.6). Tax trend analysis indicates that state taxes increase at the rate of inflation; therefore, state taxes are held constant in real terms throughout the projection. This assumption is extended to local taxes, which are assumed to average 1% of motor gasoline prices [107]. Federal taxes are assumed to remain at current levels in accordance with the overall AEO2016 assumption of current laws and regulations. Federal taxes are not held constant in real terms, but are deflated as follows:

$$\text{Federal Tax}_{\text{product, year}} = \text{Current Federal Tax}_{\text{product}} / \text{GDP Deflator}_{\text{year}}$$

Crude oil quality

In the LFMM, the quality of crude oil is characterized by average gravity and sulfur levels. Both domestic and imported crude oil are divided into eleven categories as defined by the ranges of gravity and sulfur shown in Table 11.7.

A "composite" crude oil with the appropriate yields and qualities is developed for each category by averaging the characteristics of specific crude oil streams in the category. Each category includes both domestic and foreign crude oil, which are both used to determine category characteristics. For each category's domestic crude oil volumes, estimates of total regional production are made first. Each region's production is then divided among each of the eleven categories based on that region's distribution of average API gravity and sulfur content. For AEO2016, in accordance with the Consolidated Appropriations Act, 2016 [108], all crude types are allowed to be exported from the U.S. For imported crude oil, a separate supply curve is provided (by the IEM) for each category.

Table 11.4. Petroleum product end-use markups by sector and Census Division

2015 dollars per gallon

			Census Division						
Sector/Product	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Residential Sector									
Distillate Fuel Oil	0.78	0.91	0.48	0.41	0.87	0.86	0.75	0.58	0.88
Kerosene	0.19	0.63	0.50	0.51	0.57	0.79	0.63	0.22	0.00
Liquefied Petroleum Gases	0.98	1.03	0.51	0.47	0.87	0.93	0.79	0.56	0.90
Commercial Sector									
Distillate Fuel Oil	0.44	0.44	0.09	0.07	0.34	0.36	0.34	0.43	0.42
Gasoline	0.17	0.17	0.16	0.15	0.15	0.17	0.14	0.20	0.21
Kerosene	0.19	0.67	0.50	0.53	0.52	0.80	0.54	0.13	0.00
Liquefied Petroleum Gases	0.14	0.25	0.14	0.14	-0.25	0.21	0.25	0.11	-0.03
Low-Sulfur Residual Fuel Oil[1]	0.00	0.02	0.00	0.00	0.19	-0.03	0.31	0.00	0.00
Utility Sector									
Distillate Fuel Oil	0.17	0.53	0.08	-0.04	0.29	0.31	0.27	0.50	0.37
Residual Fuel Oil[1]	0.00	0.39	0.00	0.00	0.09	-0.07	0.32	0.00	0.58
Transportation Sector									
Distillate Fuel Oil	0.58	0.49	0.52	0.52	0.52	0.65	0.66	0.52	0.52
E85[2]	0.16	0.15	0.12	0.11	0.12	0.13	0.10	0.17	0.16
Gasoline	0.20	0.19	0.16	0.15	0.16	0.17	0.13	0.22	0.21
High-Sulfur Residual Fuel Oil[1]	0.00	0.23	-0.03	-0.49	0.01	-0.35	-0.59	0.00	1.08
Jet Fuel	0.12	0.03	0.07	0.13	0.06	0.05	0.08	0.10	0.04
Liquefied Petroleum Gases	0.06	0.19	0.71	0.72	0.38	0.70	0.57	0.39	0.37
Industrial Sector									
Asphalt and Road Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate Fuel Oil	0.31	0.35	0.20	0.17	0.38	0.42	0.38	0.47	0.46
Gasoline	0.20	0.19	0.16	0.15	0.16	0.18	0.13	0.21	0.21
Kerosene	0.00	0.17	0.02	0.03	0.20	0.37	0.09	0.36	0.00
Liquefied Petroleum Gases	0.52	0.71	0.16	0.16	0.43	0.05	-0.38	0.01	0.07
Low-Sulfur Residual Fuel Oil[1]	0.00	0.06	0.00	0.00	0.18	0.20	0.25	-0.14	0.00

[1]Negative values indicate that average end-use sales prices were less than wholesale prices. This often occurs with residual fuel which is produced as a byproduct when crude oil is refined to make higher-value products like gasoline and heating oil.

[2]E85 refers to a blend of 85% ethanol (renewable) and 15 % motor gasoline (non-renewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74% is used.

Note: Data from markups based on Form EIA-782A, Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report; EIA, Form EIA-782B, Resellers'/Retailers' Monthly Petroleum Report Product Sales Report; Form FERC-423, Monthly Report of Cost and Quality of Fuels for Electric Plants prior to 2008; Form EIA-923, Power Plant Operations Report starting in 2008; EIA Form EIA-759 Monthly Power Plant Report; EIA, State Energy Data Report 2013, Consumption (July 2015); EIA, State Energy Data 2013: Prices and Expenditures (July 2015).

Sources: U.S. Energy Information Administration (EIA), Office of Energy Analysis.

Table 11.5. State and local taxes on petroleum transportation fuels by Census Division

2015 dollars per gallon

	Census Division								
Year/Product	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East south Central	West South Central	Mountain	Pacific
Gasoline[1]	0.33	0.28	0.27	0.26	0.23	0.24	0.24	0.25	0.25
Diesel	0.29	0.34	0.24	0.23	0.23	0.20	0.20	0.24	0.33
Liquefied Petroleum Gases	0.14	0.14	0.20	0.22	0.20	0.20	0.15	0.16	0.07
E85[2]	0.23	0.24	0.18	0.18	0.15	0.16	0.16	0.17	0.28
Jet Fuel	0.07	0.06	0.00	0.04	0.08	0.08	0.03	0.05	0.03

[1]Tax also applies to gasoline consumed in the commercial and industrial sectors.

[2]E85 refers to a blend of 85% ethanol (renewable) and 15% motor gasoline (non-renewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74% is used.

Source: American Petroleum Institute, "September 2015 State Motor Fuel Taxes by State," September 2015, http://www.api.org/oil-and-natural-gas/consumer-information/motor-fuel-taxes

Table 11.6. Federal taxes

nominal dollars per gallon

Product	Tax
Gasoline	0.180
Diesel	0.242
Jet Fuel	0.043
E85[1]	0.200

[1]74% ethanol and 26% gasoline.

Note: IRS Internal Revenue Bulletin 2006-43 available on the web at www.irs.gov/pub/irs-irbs/irb06-43.pdf.

Sources: Omnibus Budget Reconciliation Act of 1993 (H.R. 2264); Tax Payer Relief Act of 1997 (PL 105-34), Clean Fuels Report (Washington, DC, April 1998) and Energy Policy Act of 2005 (PL 109-58).

Table 11.7. Crude oil specifications

Crude oil categories	a.k.a.	Sulfur (%)	Gravity (degrees API)
API 50+	Light Sweet	<0.5	API≥50
API 40-50	Light Sweet	<0.5	40≤API<50
API 35-40 sweet	Light Sweet	<0.5	35≤API<40
API 35+ sour	Light Sour	≥0.5	API≥35
API 27-35 Med-sour	Medium Med-sour	<1.1	27≤API<35
API 27-35 sour	Medium Sour	≥1.1	27≤API<35
API<27 sweet	Heavy Sweet	<1.1	API<27
API<27 sour	Heavy Sour	≥1.1	API<27
California		1.1-2.6	API<27
Syncrude		<0.5	API≥35
DilBit/SynBit		>1.1	API<27

Note: Sources include U.S. Energy Information Administration, "U.S. Crude Oil Production Forecast- Analysis of Crude Types,"
Dilbit/Synbit definition = Bitumen diluted with lighter petroleum products or synthetic crude
May 29, 2014, (http://www.eia.gov/analysis/petroleum/crudetypes/

Sources: U.S. Energy Information Administration.

Capacity expansion

The LFMM allows for capacity expansion of all processing unit types. This includes distillation units like the atmospheric distillation unit (ADU), vacuum distillation unit (VDU), and condensate splitters, as well as secondary processing units like the hydrotreating, coking, fluid catalytic cracking, hydrocracking, and alkylation units. Capacity expansion occurs by processing unit, starting from regional capacities established using historical data.

Expansion occurs in LFMM when the value received from the sale of products that could be produced with new processing capacity exceeds the investment and operating costs of adding this new capacity, plus the cost of purchasing additional feedstock. The investment costs assume a financing ratio of 60% equity and 40% debt, with a hurdle rate and an after-tax return on investment ranging from 6% for building new refinery processing units to over 13% for higher-risk projects like the construction of a coal-to-liquids plant.

The LFMM models capacity expansion using a three-period planning approach similar to that used in the NEMS Electricity Market Module (EMM). The first two periods contain a single planning year (current year and next year, respectively), and the third period represents a net present value of the next 19 years in the projection. The second and third planning periods are used to establish an economic plan for capacity expansion for the next NEMS model year. In period 2, product demands and legislative requirements must be met. Period 3 acts like a leverage in the capacity expansion decision for period 2, and is controlled by the discount rate assumptions. Larger discount rates increase the net present value (NPV) of revenue and expenditures in earlier periods and decrease the NPV of revenue and expenditure in later periods. The LFMM uses multiple discount rates for the NPV calculation to represent various categories of risk. For AEO2016, the LFMM uses an 18% discount rate.

Capacity expansion is also modeled for production of corn and cellulosic ethanol, biobutanol, biomass pyrolysis oil, biodiesel, renewable diesel, coal-to-liquids, gas-to-liquids, and biomass-to-liquids. All process unit capacity that is expected to begin operating in the future is added to existing capacities in their respective start year. The retirement and replacement of existing refining capacity is not explicitly represented in the LFMM.

Capacity utilization of a process unit is the ratio of the actual throughput for a unit to the total capacity for that unit. The throughput for an atmospheric distillation unit (ADU) typically is a blend of crude oils, but historically has included unfinished oil imports at some refineries. Therefore, historical ADU capacity utilization at these refineries includes both crude oil and unfinished oil imports. Since the LFMM only processes unfinished oil imports in secondary units, downstream from the ADU, an assumption was made to include a historical percentage of the unfinished oils imported to the refinery as part of the throughput when calculating the ADU capacity utilization reported in AEO2016.

Non-petroleum fuel technology characteristics

The LFMM explicitly models a number of liquid fuels technologies that do not require petroleum feedstock. These technologies produce both fuel-grade products for blending with traditional petroleum products, and alternative feedstock for the traditional petroleum refinery (Table 11.8).

Table 11.8. Alternative fuel technology product type

Technology	Product Type	Feedstock	Product Yield (percent by volume)
Biochemical			
Corn Ethanol	Fuel Grade	corn	100% ethanol
Advanced Grain Ethanol	Fuel Grade	grain	100% ethanol
Cellulosic Ethanol	Fuel Grade	stover	100% ethanol
Biobutanol	Fuel Grade	corn	biobutanol
Thermochemical Catalytic			
Methyl Ester Biodiesel	Fuel Grade	yellow or white grease	100% biodiesel
Non-Ester Renewable Diesel	Fuel Grade	yellow or white grease	98% renewable diesel, 2% renewable naphtha
Pyrolysis	Fuel Grade	agriculture residue, forest residue, or urban wood waste	60% distillate, 40% naphtha
Thermochemical Fischer-Tropsch			
Gas-to-Liquids (GTL)	Fuel Grade/Refinery Feed	natural gas	52% diesel, 23% kerosene, 24.5% naphtha, 0.5% LPG
Coal-to-Liquids (CTL)	Fuel Grade/Refinery Feed	coal	51% diesel, 21% kerosene, 28% naphtha
Biomass-to-Liquids (BTL)	Fuel Grade/Refinery Feed	biomass	22% diesel, 46% kerosene, 32% naphtha

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Estimates of capital and operating costs corresponding to specified nameplate capacities for these technologies are shown in Table 11.9. The cost data are defined assuming a 2020 base year, and are deflated to 2015 dollars using the GDP deflator in NEMS.

Overnight capital cost is defined as the anticipated cost of completing a project from start to finish, including working capital, but excluding time-related costs such as accrued interest and depreciation of assets (i.e., the lump sum cost of a project as if it were completed overnight). Since some components of technologies have not yet been proven at a commercial scale, a technology optimism factor is applied to the assumed first-of-a-kind overnight capital cost, a multiplier that increases the first-of-a-kind plant cost (e.g., 1.2 for BTL). The multiplier is an estimate of the underestimated construction errors (redos) and underestimated costs in building the first full-scale commercial plant. As experience is gained (after building the first 4 units), the technological optimism factor is gradually reduced to 1.0, after which the overnight capital cost may be reduced due to learning.

The learning function has the nonlinear form:

$$OC(C) = a*C-b,$$

where C is the cumulative capacity (or number of standard-sized units) for each technology component and OC represents the overnight capital cost expected with cumulative capacity C of the technology.

The learning function in NEMS is determined at a component level. Each new technology is broken into its major components, and each component is identified as revolutionary, evolutionary or mature. Different learning rates are assumed for each component, based on the level of construction experience with the component. In the case of the LFMM, the second and third phases of a technology will have only evolutionary/revolutionary (fast) and mature (slower) learning components, depending on the mix (percent) of new and mature processes that compose a particular technology.

The progress ratio (pr) is related by the speed of learning or learning rate (LR) (e.g., how much costs decline for every doubling of capacity). The reduction in capital cost for every doubling of cumulative capacity (i.e., LR) is an exogenous input parameter for each component. The progress ratio and LR are related by:

$$pr = 2^{-b} = (1 - LR).$$

The parameter "b" is calculated from the second half of the equality above:

$$b = -(\ln(1-LR)/\ln(2)).$$

The parameter "a" is computed from initial overnight cost and capacity conditions of the nonlinear learning curve:

$$a = OC\,(C0)/Co^{-b}$$

Note that Co is the cumulative capacity or number of units built as of the beginning of the current time period/year.

As a new technology matures, the capital cost is expected to decline, reflecting the principle of "learn by doing" and manufacturing experience. This principle is implemented in the LFMM similar to the methodology used in the EMM. The learning occurs in three phases. The first phase is represented by the linear phase out of optimism (and some revolutionary learning) over the first four plants (such that the optimism factor for the fifth and later plant is 1.0). The non-linear learning function shown above is used for the second (up to 32 plants built) and third (beyond 32 plants) phases.

Each technology was assessed to determine the mix of technological maturity of each component (revolutionary/evolutionary or mature). This was used to define what percent (m) of the cost would decline slowly (slow for mature) versus quickly (fast for evolutionary/revolutionary) due to learning. Next, for each learning category (fast and slow), a rate of learning (f) is assumed (i.e., a percent reduction in overnight capital cost for every doubling of cumulative capacity).

The overall learning factor is the weighted combination of the fast and slow learning factors (OC), weighted by the percentage that each component represents of the technology. Model parameters for both optimism (1^{st} of a kind) and learning (after the 4^{th} unit is built) are shown in Table 11.10 for applicable technologies.

Table 11.9. Non-petroleum fuel technology characteristics[1]

AEO2016 2020 Basis (2015$)	Nameplate Capacity[2] b/sd	Overnight Capital Cost[3] $/b/sd	Thermal Efficiency[4] %	Utilization Rate[5] %	Cost of Capital[6] (WACC) %	Fixed O&M Cost[7] $/d/b/sd	Non-Feedstock Variable O&M Cost[7] $/b
Biochemical							
Corn Ethanol	6,800	$25,500	49%	100%	12%	$6	$7
Advanced Grain Ethanol	3,400	$60,900	49%	100%	12%	$19	$3
Cellulosic Ethanol	4,400	$160,200	28%	85%	12%	$34	$1
Biobutanol (retrofit of corn ethanol plant)	6,500	$13,300	62%	90%	12%	$2	$7
Thermochemical Catalytic							
Methyl Ester Biodiesel (FAME)	1,200	$27,700	21%	100%	12%	$21	$7
Non-Ester Renewable Diesel (NERD)	2,100	$39,300	21%	95%	12%	$23	$7
Pyrolysis	5,200	$326,000	60%	90%	12%	$59	$6
Thermochemical Fischer-Tropsch							
Gas-to-Liquids (GTL)[8]	48,000	$177,100	55%	85%	12%	$29	$9
Coal-to-Liquids (CTL)	48,000	$210,800	49%	85%	12%	$34	$12
Biomass-to-Liquids (BTL)	6,000	$368,200	38%	85%	12%	$62	$7

[1]This table is based on the AEO2016 Reference case projections for year 2020.
[2]Nameplate capacity is the expected size of a unit based on historical builds and engineering estimations. Capacity amounts provided on an output basis.
[3]Overnight capital cost is given in unit costs, relative to nameplate capacity and is defined as the cost of a project with no interest incurred, or the lump sum cost of a project as if it were completed overnight. It excludes additional costs from optimism on the 1st unit, and cost reductions on the nth unit due to learning effects (see Table 11.10).
[4]Thermal efficiency represents the ratio of the combustive energy of the products to the combustive energy of the feedstock used to produce the products.
[5]Utilization rate represents the expected annual production divided by the plant capacity divided by 365 days.
[6]Cost of Capital is the weighted average cost of capital (WACC) during construction and lifetime operations. This term is used with the plant lifetime and overnight capital cost to compute an amortized unit capital cost ($/b/sd for a year).
[7]Fixed and Non-Feedstock variable operations and maintenance (O&M) costs impact the annual costs ($/year) and units costs ($/b)
[8]While these costs are for a Gulf Coast facility, the costs in other regions, particularly Alaska, are expected to be much higher.
b/sd = barrels per stream day.
$/b/sd = dollars per barrel per stream day
Note 1: For all technologies listed, length of construction is assumed to be 4 years and plant lifetime is assumed to be 20 years; where, length of construction impacts the interest that accrues during construction, and plant lifetime impacts the amortized cost of capital.
Note 2: Values from this table come from analysis of reports and discussions with various sources from industry, government, and the Department of Energy Fuel Offices and National Laboratories. They are meant to represent the cost and performance of typical plants under normal operating conditions for each technology.
Key sources reviewed are listed in “Notes and Sources” at the end of the chapter.
Source: U.S. Energy Information Administration.

Table 11.10. Non-petroleum fuel technology learning parameters

Technology Type	Cumulative Plants (k)	Phase 1 1st of a Kind Optimism	Phase 2 5th of a Kind Fast[1]	 Slow[1]	Phase 3 32nd of a Kind Fast[1]	 Slow[1]
Cellulosic Ethanol	Optimism Factor and Revolutionary Learning	1.20	1.0	1.0	1.0	1.0
	Learning Type Fraction (m)	--	33%	67%	33%	67%
	Learning Rate (f)	--	0.25	0.10	0.10	0.05
Pyrolysis	Optimism Factor and Revolutionary Learning	1.20	1.0	1.0	1.0	1.0
	Learning Type Fraction (m)	--	33%	67%	33%	67%
	Learning Rate (f)	--	0.25	0.10	0.10	0.05
Biomass-to-Liquids (BTL)	Optimism Factor and Revolutionary Learning	1.20	1.0	1.0	1.0	1.0
	Learning Type Fraction (m)	--	15%	85%	15%	85%
	Learning Rate (f)	--	0.10	0.01	0.10	0.01
Coal-to-Liquids (CTL)	Optimism Factor and Revolutionary Learning	1.15	1.0	1.0	1.0	1.0
	Learning Type Fraction (m)	--	15%	85%	15%	85%
	Learning Rate (f)	--	0.10	0.01	0.10	0.01
Gas-to-Liquids (GTL)	Optimism Factor and Revolutionary Learning	1.10	1.0	1.0	1.0	1.0
	Learning Type Fraction (m)	--	10%	90%	10%	90%
	Learning Rate (f)	--	0.10	0.01	0.10	0.01

[1]Fast = evolutionary/revolutionary learning; slow = mature learning.

Source: U.S. Energy Information Administration, Office of Energy Analysis, analyst judgement.

Biofuels supply

Supply functions for corn, non-corn grain, and cellulosic biomass feedstocks are provided on an annual basis through 2040 for the production of ethanol (blended into transportation fuel). Supply functions for soy oil, other seed-based oils, and grease are provided on an annual basis through 2040 for the production of biodiesel and renewable diesel.

- Corn feedstock supplies and costs are provided exogenously to NEMS. Feedstock costs reflect credits for co-products (livestock feed, corn oil, etc.). Feedstock supplies and costs reflect the competition between corn and its co-products and alternative crops, such as soybeans and their co-products.

- Biodiesel and renewable diesel feedstock supplies and costs are provided exogenously to NEMS.
- Cellulosic (biomass) feedstock supply and costs are provided by the Renewable Fuels Module in NEMS.
- To model the Renewable Fuels Standard in EISA2007, several assumptions were required.
    - The penetration of cellulosic ethanol into the market is limited before 2023 to several planned projects with aggregate nameplate capacity of approximately 60 million gallons per year. Planned capacity through 2019 for pyrolysis and biomass-to-liquids (BTL) processes is approximately 75 million gallons per year.
    - Methyl ester biodiesel production contributes 1.5 credits towards the advanced mandate.
    - Renewable diesel fuel and cellulosic diesel fuel, including that from Pyrolysis oil, and Fischer-Tropsch diesel contribute 1.7 credits toward the cellulosic mandate.
    - Cellulosic drop-in gasoline contributes 1.54 credits toward the cellulosic mandate.
    - Imported Brazilian sugarcane ethanol counts towards the advanced renewable mandate.
    - Separate biofuel waivers can be activated for each of the four RFS fuel categories.
    - Biodiesel and BTL diesel are assumed to be compatible with diesel engines without significant infrastructure modification (either vehicles or delivery infrastructure).
    - Ethanol is assumed to be consumed as E10, E15 or E85, with no intermediate blends. The cost of placing E85 pumps at the most economic stations is spread over diesel and gasoline.
    - To accommodate the ethanol requirements in particular, transportation modes are expanded or upgraded for E10, E15 and E85, and it is assumed that most ethanol originates from the Midwest, with nominal transportation costs of a few cents per gallon.
    - For E85 dispensing stations, it is assumed the average cost of a retrofit and new station is about $158,000 per station (2015 dollars). Interregional transportation is assumed to be by rail, ship, barge, and truck, and the associated costs are included in the LFMM.
    - Potential RFS target reductions by EPA are provided exogenously to NEMS.

Non-petroleum fossil fuel supply

Gas-to-liquids (GTL) facilities convert natural gas into distillates, and are assumed to be built if the prices for lower-sulfur distillates reach a high enough level to make them economic. The earliest start date for a GTL facility is set at 2020.

It is also assumed that coal-to-liquids (CTL) facilities will be built when low-sulfur distillate prices are high enough to make them economic. A 48,000-barrel-per-day CTL facility is assumed to cost over $7.5 billion in initial capital investment (2015 dollars). These facilities could be built near existing refineries. For the East Coast, potential CTL facilities could be built near the Delaware River basin; for the Central region, near the Illinois River basin or near Billings, Montana; and for the West Coast, in the vicinity of Puget Sound in Washington State. It is further assumed that the earliest build date for CTL facilities is 2025.

Combined heat and power (CHP)

Electricity consumption at the refinery and other liquid fuels production facilities is a function of the throughput of each unit. Sources of electricity consist of refinery power generation, utility purchases, and CHP from other liquid fuels producers (including cellulosic/advanced ethanol, coal- and biomass-to-liquids). Power generators and CHP plants are modeled in the LFMM linear program as separate units, and are allowed to compete along with purchased electricity. Operating characteristics for these electricity producers are based on historical parameters and available data. Sales to the grid or own-use decisions are made on an economic basis within the LP solution. The price for electricity sales to the grid is set to the marginal energy price for baseload generation (provided by the EMM).

Short-term methodology

Petroleum balance and price information for 2016 and 2017 is projected at the U.S. level in the Short-Term Energy Outlook, (STEO). The LFMM adopts the STEO results for 2016 and 2017, using regional estimates derived from the national STEO projections.

Legislation and regulation

The Tax Payer Relief Act of 1997 reduced excise taxes on liquefied petroleum gases and methanol produced from natural gas. The reductions set taxes on these products equal to the federal gasoline tax on a Btu basis.

Title II of CAAA90 established regulations for oxygenated and reformulated gasoline and on-highway diesel fuel. These are explicitly modeled in the LFMM. Reformulated gasoline represented in the LFMM meets the requirements of Phase 2 of the Complex Model, except in the Pacific region where it meets CARB 3 specifications.

AEO2016 reflects "Tier 3 Vehicle Emissions and Fuel Standards" which states that the average annual sulfur content of federal gasoline will not contain more than 10 ppm by January 1, 2017. For projection years prior to 2017, AEO2016 reflects the "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements which requires that the average annual sulfur content of all gasoline used in the United States be 30 ppm.

AEO2016 reflects Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements. All highway diesel is required to contain no more than 15 ppm sulfur at the pump.

AEO2016 reflects nonroad locomotive and marine (NRLM) diesel requirements that nonroad diesel supplies contain no more than 15 ppm sulfur. For locomotive and marine diesel, the action establishes a NRLM limit of 15 ppm in mid-2012.

AEO2016 represents major provisions in the Energy Policy Act of 2005 (EPACT05) concerning the petroleum industry, including removal of the oxygenate requirement in RFG.

AEO2016 includes provisions outlined in the Energy Independence and Security Act of 2007 (EISA2007) concerning the petroleum industry, including a Renewable Fuels Standard (RFS) increasing total U.S. consumption of renewable fuels. In order to account for the possibility that RFS targets might be unattainable at reasonable cost, LFMM includes a provision for purchase of waivers. The price of a cellulosic waiver is specified in EISA2007. The non-cellulosic LFMM RFS waivers function as maximum allowed RIN prices. LFMM also assumes that EPA will reduce RFS targets as allowed by the EISA2007 statute.

AEO2016 includes the EPA Mobil Source Air Toxics (MSAT 2) rule which includes the requirement that all gasoline products (including reformulated and conventional gasoline) produced at a refinery during a calendar year will need to contain no more than 0.62 percent benzene by volume. This does not include gasoline produced or sold in California, which is already covered by the current California Phase 3 Reformulated Gasoline Program.

AEO2016 includes California's Low Carbon Fuel Standard which aims to reduce the Carbon Intensity (CI) of gasoline and diesel fuels in that state by about 10% respectively from 2012 through 2020.

AEO2016 incorporates the cap-and-trade program within the California Assembly Bill (AB 32), the Global Warming Solutions Act of 2006. The program started January 1, 2012, with enforceable compliance obligations beginning in 2013. Petroleum refineries are given allowances (calculated in the LFMM) in the cap-and-trade system based on the volumetric output of aviation gasoline, motor gasoline, kerosene-type jet fuel, distillate fuel oil, renewable liquid fuels, and asphalt. Suppliers of Reformulated Blend Stock for Oxygenate Blending (RBOB) and Distillate Fuel Oil #1 and #2 are required to comply starting in 2015 if the emissions from full combustion of these products are greater than or equal to 25,000 metric tons CO_2 equivalent ($MTCO_2e$) in any year 2011-2014.

AEO2016 includes mandates passed by New York, New Jersey, Maine, and Vermont that aim to lower the sulfur content of all heating oil to ultra-low sulfur diesel over different time schedules. It also includes transition to a 2% biodiesel content in the case of Maine and Connecticut.

The International Maritime Organization's "MARPOL Annex 6" rule covering cleaner marine fuels and ocean ship engine emissions is not explicitly represented in LFMM, but is reflected in the impact on transportation demands, which are provided to the LFMM from the Transportation Demand Module (TDM) in NEMS.

The AEO2016 Reference Case does not extend the $1.00-per-gallon biodiesel excise tax credit or the $1.01-per-gallon cellulosic biofuels production tax credit over the projection.

Notes and sources

[100] U.S. Environmental Protection Agency (EPA), “EPA Sets Tier 3 Vehicle Emission and Fuel Standards,” http://www.epa.gov/otaq/documents/tier3/420f14009.pdf.

[101] Federal Register, U.S. Environmental Protection Agency, 40 CFR Part 80, Regulation of Fuels and Fuel Additives: Standards for Reformulated and Conventional Gasoline, Rules and Regulations, p. 7800, (Washington, DC, February 1994).

[102] Marano, John, “Alternative Fuels Technology Profile: Cellulosic Ethanol”, March 2008.

[103] Ibid.

[104] U.S. Department of Agriculture, “USDA Agricultural Baseline Projections to 2019,” February 2009, www.ers.usda.gov/publications/oce-usda-agricultural-projections/oce-2010-1.aspx.

[105] Shapouri, Hosein and Gallagher, Paul. USDA’s 2002 Ethanol Cost-of-Production Survey, July 2005.

[106] U.S. Department of Agriculture. 2008 Energy Balance for the Corn-Ethanol Industry, June 2010.

[107] American Petroleum Institute, How Much We Pay for Gasoline: 1996 Annual Review, May 1997.

[108] *Consolidated Appropriations Act, 2016*, H.R.2029, 114th Congress (2015-2016), *Division O – Other Matters, Title I – Oil Exports, Safety Valve, and Maritime Security*, became Public Law No: 114-113 on 12/18/2015; https://www.congress.gov/bill/114th-congress/house-bill/2029.

Chapter 12. Coal Market Module

The NEMS Coal Market Module (CMM) provides projections of U.S. coal production, consumption, exports, imports, distribution, and prices. The CMM comprises three functional areas: coal production, coal distribution, and coal exports. A detailed description of the CMM is provided in the EIA publication, Coal Market Module of the National Energy Modeling System 2014, DOE/EIA-M060 (2014) (Washington, DC, 2014).

Key assumptions

Coal production

The CMM generates a different set of supply curves for each year of the projection. Combinations of 14 supply regions, nine coal types (unique groupings of thermal grade and sulfur content), and two mine types (underground and surface), result in 41 separate supply curves. Supply curves are constructed using an econometric formulation that relates the mine mouth prices of coal for the supply regions and coal types to a set of independent variables. The independent variables include: capacity utilization of mines, mining capacity, labor productivity, the user cost of capital of mining equipment, the cost of factor inputs (labor and fuel), and other mine supply costs.

The key assumptions underlying the coal production modeling are:

- As capacity utilization increases, higher mine mouth prices for a given supply curve are projected. The opportunity to add production capacity is allowed within the modeling framework if capacity utilization rises to a pre-determined level, typically in the 80% range. Likewise, if capacity utilization falls, mining capacity may be retired. The amount of capacity that can be added or retired in a given year depends on the supply region, the capacity utilization level, and the mining process (underground or surface). The volume of capacity expansion permitted in a projection year is based upon historical patterns of capacity additions.
- Between 1980 and 2000, U.S. coal mining productivity increased at an average rate of 6.6% per year, from 1.93 to 6.99 short tons per miner per hour. The major factors underlying these gains were inter-fuel price competition, structural change in the industry, and technological improvements in coal mining [111]. Between 2000 and 2014, growth in overall U.S. coal mining productivity has been negative, declining at a rate of 1.5% per year to 5.65 short tons per miner-hour in 2014. In all regions but one (Alaska/Washington) productivity in coal producing basins represented in the CMM has declined from the productivity level in 2000. In the Central Appalachian coal basin, which has been mined extensively, productivity declined by almost 50% between 2000 and 2014, corresponding to an average decline of 4.5% per year. While productivity declines have been more moderate at the relatively highly-productive mines in Wyoming's Powder River Basin, coal mining productivity in this region still fell by 30% between 2000 and 2014, corresponding to an average rate of decline of 2.7% per year. Of the top coal producing regions showing declines, the Eastern Interior has shown the best overall performance, with coal mining productivity declining by only 2.0% between 2000 and 2014, or 0.1% per year. The Eastern Interior region, which has a substantial amount of thick,

underground-minable coal reserves, is currently experiencing a resurgence in coal mining activity, with several coal companies operating highly-productive longwall mines.

- Over the projection period, labor productivity is expected to decline in most coal supply regions, reflecting the trend of the previous decade. Higher stripping ratios and the added labor needed to maintain more extensive underground mines offset productivity gains achieved from improved equipment, automation, and technology. Productivity in some areas of the coalfields in the eastern U.S. is projected to decline as operations move from mature coalfields to marginal reserve areas. Regulatory restrictions on surface mines and fragmentation of underground reserves limit the benefits that can be achieved by Appalachian producers from economies of scale.

- In the CMM, different rates of productivity improvement are assumed for each of the 41 coal supply curves used to represent U.S. coal supply. These estimates are based on recent historical data and expectations regarding the penetration and impact of new coal mining technologies. Data on labor productivity are provided on a quarterly and annual basis by individual coal mines and preparation plants on the U.S. Department of Labor, Mine Safety and Health Administration's Form 7000-2, "Quarterly Mine Employment and Coal Production Report," and the U.S. Energy Information Administration's Form EIA-7A, "Annual Survey of Coal Production and Preparation". In the Reference case, overall U.S. coal mining labor productivity declines at rate of 0.7% per year between 2014 and 2040. Reference case projections of coal mining productivity by region are provided in Table 12.1.

Table 12.1. Coal mining productivity by region

short tons per miner hour

Supply Region	2014	2020	2025	2030	2035	2040	Average Annual Growth 14-40
Northern Appalachia	3.43	3.28	3.08	2.89	2.75	2.61	-1.0%
Central Appalachia	2.20	1.74	1.49	1.28	1.20	1.07	-2.7%
Southern Appalachia	1.88	1.60	1.46	1.33	1.24	1.17	-1.8%
Eastern Interior	4.64	4.98	5.11	5.27	5.41	5.56	0.7%
Western Interior	2.73	2.38	2.24	2.11	2.04	1.99	-1.2%
Gulf Lignite	6.94	6.40	6.09	5.79	5.57	5.38	-1.0%
Dakota Lignite	11.53	11.53	10.96	10.42	10.03	9.69	-0.7%
Western Montana	16.58	13.67	15.01	15.64	14.32	13.08	-0.9%
Wyoming, Northern Powder River Basin	29.35	27.30	25.57	23.95	22.89	21.99	-1.1%
Wyoming, Southern Powder River Basin	34.32	31.92	29.90	28.01	26.77	25.71	-1.1%
Western Wyoming	6.36	7.37	7.01	6.67	6.44	6.25	-0.1%
Rocky Mountain	6.12	5.01	4.42	3.89	3.56	3.29	-2.4%
Arizona/New Mexico	8.01	7.53	7.20	6.88	6.66	6.46	-0.8%
Alaska/Washington	5.42	5.84	5.96	6.08	6.15	6.22	0.5%
U.S. Average	5.65	5.90	5.68	5.54	4.93	4.70	-0.7%

Source: U.S. Energy Information Administration, AEO2016 National Energy Modeling System run REF2016.D032416A.

- In the AEO2016 Reference case, the wage rate for U.S. coal miners increases by 0.9% per year and mine equipment costs are assumed to remain constant in 2013 dollars (i.e., increase at the general rate of inflation) over the projection period.

Coal distribution

The coal distribution submodule of the CMM determines the least-cost (mine mouth price plus transportation cost) supplies of coal by supply region for a given set of coal demands in each demand sector using a linear programming algorithm. Production and distribution are computed for 14 supply (Figure 12.1) and 16 demand regions (Figure 12.2) for 49 demand subsectors.

The projected levels of coal-to-liquids, industrial steam, coking, and commercial/institutional coal demand are provided by the liquid fuel market, industrial, and commercial demand modules, respectively. Electricity coal demands are projected by the Electricity Market Module (EMM). Coal imports and coal exports are projected by the CMM based on non-U.S. supply availability, endogenously determined U.S. import demand, and exogenously determined world coal import demands (non-U.S.).

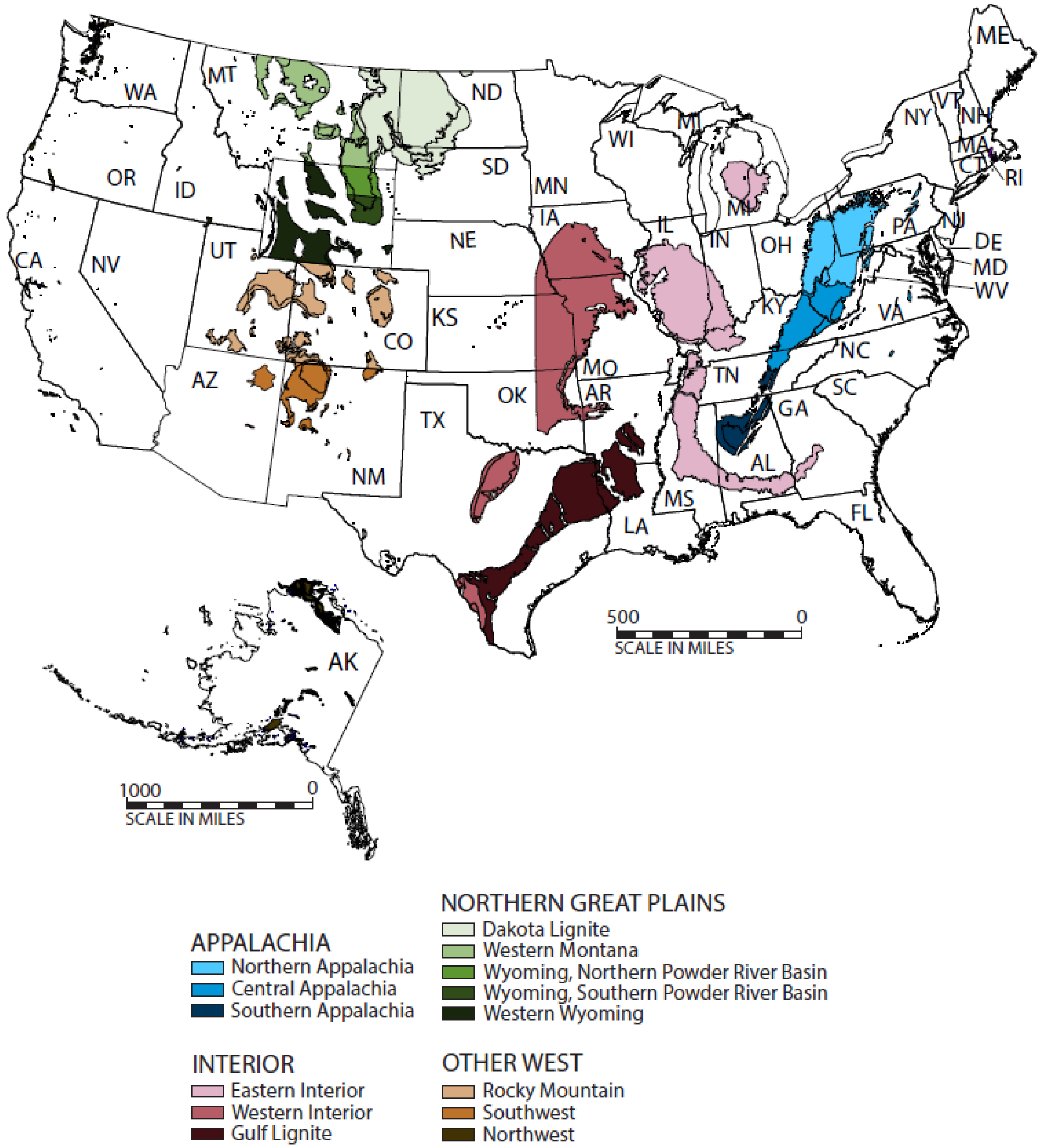
Transportation rates between coal supply and demand regions are determined by applying annual, projected regional transportation price indices to a two-tier rate structure. The first tier is representative of the historical average transportation rate which is estimated for a base year using recent EIA survey data. The second tier captures costs associated with changing patterns of coal demand for electricity generation. Regional fuel surcharges are then added to the indexed transportation rates to reflect the impact of higher diesel fuel costs.

The key assumptions underlying the coal distribution modeling are as follows:

- Base-year (2014) transportation costs are estimates of average transportation costs for each origin-destination pair without differentiation by transportation mode (rail, truck, barge, and conveyor). These costs are computed as the difference between the average delivered price for a demand region (by sector and for export) and the average mine mouth price for a supply curve. Delivered price data are from 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-923, “Power Plant Operations Report”, and the U.S. Bureau of the Census, “Monthly Report EM-545”. Mine mouth price data are from Form EIA-7A, “Coal Production and Preparation Report”.

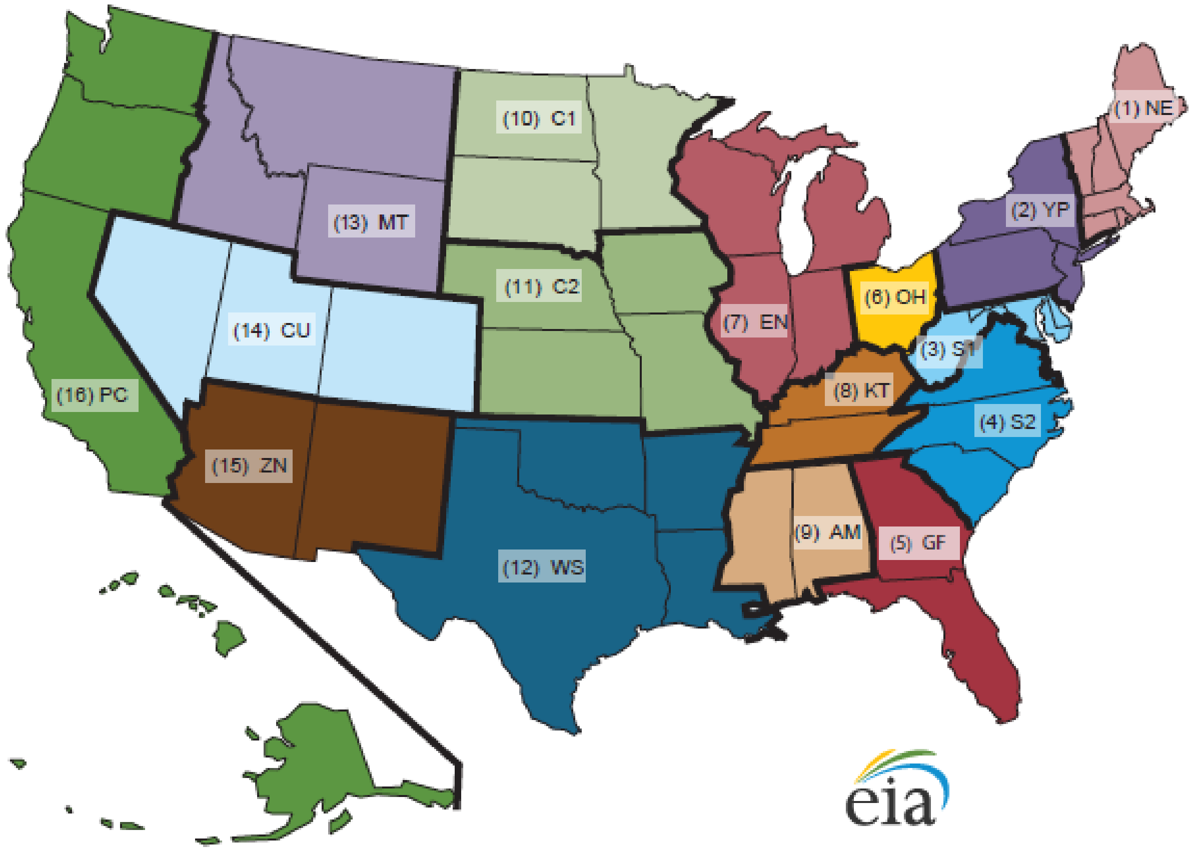
For the electricity sector only, a two-tier transportation rate structure is used for those regions which, in response to changing patterns of coal demand, may expand their market share beyond historical levels. The first-tier rate is representative of the historical average transportation rate. The second-tier transportation rate is used to capture the higher cost of expanded shipping distances in large demand regions. The second tier is also used to capture costs associated with the use of subbituminous coal at units that were not originally designed for its use. This cost is estimated at $0.10 per million Btu (2000 dollars) [110].

Figure 12.1. Coal Supply Regions



Source: U.S. Energy Information Administration

Figure 12.2. Coal Demand Regions



Region	Code	Content	Region	Code	Content
1	NE	CT, MA, ME, NH, RI, VT	9	AM	AL, MS
2	YP	NY, PA, NJ	10	C1	MN, ND, SD
3	S1	WV, MD, DC, DE	11	C2	IA, NE, MO,KS
4	S2	VA, NC, SC	12	WS	TX, LA, OK, AR
5	GF	GA, FL	13	MT	MT, WY, ID
6	OH	OH	14	CU	CO, UT, NV
7	EN	IN, IL, MI, WI	15	ZN	AZ, NM
8	KT	KY, TN	16	PC	AK, HI, WA, OR, CA

Source: U.S. Energy Information Administration

- Coal transportation costs, both first- and second-tier rates, are modified over time by two regional (east and west) transportation indices. The indices, calculated econometrically, are measures of the change in average transportation rates for coal shipments on a tonnage basis, which occurs between successive years for coal shipments. An east index is used for coal originating from coal supply regions located east of the Mississippi River, while a west index is used for coal originating from coal supply regions located west of the Mississippi River. The indices are universally applied to all domestic coal transportation movements within the CMM. In the AEO2016 Reference case, both eastern and western coal transportation rates are projected to remain near their 2014 levels in 2014 dollars. The transportation rate indices for six AEO2016 cases are shown in Table 12.2.
- The east index is negatively correlated with improvements in railroad productivity, and positively correlated with the user cost of capital for railroad equipment and the national average diesel fuel price. The user cost of capital for railroad equipment is calculated from the producer price index (PPI) for railroad equipment, and accounts for the opportunity cost of money used to purchase equipment, depreciation occurring as a result of use of the equipment (assumed at 10%), less any capital gain associated with the worth of the equipment. In calculating the user cost of capital, three percentage points are added to the cost of borrowing in order to account for the possibility that a national level program to regulate greenhouse gas emissions may be implemented in the future. An increase in national ton-miles (total tons of coal shipped multiplied by the average distance) increases PPI and, consequently, the user cost of capital. Diesel fuel is removed from the equation for the east in the projection period in order to avoid double-counting the influence of diesel fuel costs with the impact of the fuel surcharge program.
- The west index is negatively correlated with improvements in railroad productivity, and positively correlated with increases in investment and the western share of national coal consumption. The investment variable is analogous to the user cost of capital of railroad equipment variable applied in the east, and similarly increases with an increase in national ton-miles (total tons of coal shipped multiplied by the average distance).
- For both the east and the west, any related financial savings due to productivity improvements are assumed to be retained by the railroads and are not passed on to shippers in the form of lower transportation rates. For this reason, transportation productivity is held flat for the projection period for both regions.

Table 12.2. Transportation rate multipliers

constant dollar index, 2014=1.000

Scenario	Region:	2014	2020	2025	2030	2035	2040
Reference	East	1.0000	1.0834	1.0592	1.0471	1.0381	1.0331
	West	1.0000	1.0149	1.0185	1.0199	1.0136	1.0135
Low Oil Price	East	1.0000	1.0801	1.0567	1.0443	1.0362	1.0318
	West	1.0000	1.0149	1.0185	1.0199	1.0136	1.0135
High Oil Price	East	1.0000	1.0858	1.0642	1.0496	1.0385	1.0328
	West	1.0000	1.0149	1.0185	1.0200	1.0137	1.0137
Low Economic Growth	East	1.0000	1.0944	1.0691	1.0509	1.0377	1.0293
	West	1.0000	1.0148	1.0185	1.0199	1.0136	1.0136
High Economic Growth	East	1.0000	1.0793	1.0579	1.0449	1.0349	1.0297
	West	1.0000	1.0149	1.0185	1.0199	1.0136	1.0135
High Resource	East	1.0000	1.0826	1.0593	1.0472	1.0378	1.0332
	West	1.0000	1.0145	1.0182	1.0195	1.0129	1.0125

Source: Projections: U.S. Energy Information Administration, National Energy Modeling System runs REF2016.D021915A, LOWPRICE.D041916A, HIGHPRICE. D041916A, LOWMACRO.D032516A, HIGHMACRO.D032516A, and HIGHRESOURCE.D022516A. Based on methodology described in Coal Market Module of the National Energy Modeling System 2014, DOE/EIA-M060 (2014) (Washington, DC, 2014).

- Major coal rail carriers have implemented fuel surcharge programs in which higher transportation fuel costs have been passed on to shippers. While the programs vary in their design, the Surface Transportation Board (STB), the regulatory body with limited authority to oversee rate disputes, recommended that the railroads agree to develop some consistencies among their disparate programs and likewise recommended closely linking the charges to actual fuel use. The STB cited the use of a mileage-based program as one means to more closely estimate actual fuel expenses.
- For AEO2016, representation of a fuel surcharge program is included in the coal transportation costs. For the west, the methodology is based on BNSF Railway Company’s mileage-based program. The surcharge becomes effective when the projected nominal distillate price to the transportation sector exceeds $1.25 per gallon. For every $0.06 per gallon increase above $1.25, a $0.01 per carload mile is charged. For the east, the methodology is based on CSX Transportation’s mileage-based program. The surcharge becomes effective when the projected nominal distillate price to the transportation sector exceeds $2.00 per gallon. For every $0.04 per gallon increase above $2.00, a $0.01 per carload mile is charged. The number of tons per carload and the number of miles vary with each supply and demand region combination and are a pre-determined model input. The final calculated surcharge (in constant dollars per ton) is added to the escalator-adjusted transportation rate. For every projection year, it is assumed that 100% of all coal shipments are subject to the surcharge program.

- Coal contracts in the CMM represent a minimum quantity of a specific electricity coal demand that must be met by a unique coal supply source prior to consideration of any alternative sources of supply. Base-year (2014) coal contracts between coal producers and electricity generators are estimated on the basis of receipts data reported by generators on the Form EIA-923, “Power Plant Operations Report”. Coal contracts are specified by CMM supply region, coal type, demand region, and whether or not a unit has flue gas desulfurization equipment. Coal contract quantities are reduced over time on the basis of contract duration data from information reported on the Form EIA-923, “Power Plant Operations Report”, historical patterns of coal use, and information obtained from various coal and electric power industry publications and reports.
- Coal-to-liquids (CTL) facilities are assumed to be economic when low-sulfur distillate prices reach high enough levels. These plants are assumed to be co-production facilities with generation capacity of 832 megawatts (MW) (295 MW for the grid and 537 MW to support the conversion process) and the capability of producing 48,000 barrels of liquid fuels per day. The technology assumed is similar to an integrated gasification combined cycle, first converting the coal feedstock to gas, and then subsequently converting the syngas to liquid hydrocarbons using the Fisher-Tropsch process. Of the total amount of coal consumed at each plant, 40% of the energy input is retained in the product with the remaining energy used for conversion and for the production of power sold to the grid. For AEO2016, coal-biomass-to-liquids (CBTL) are not modeled. CTL facilities produce distillate fuel oil (about 72%) and paraffinic naphtha used in plastics production and blend-able naphtha used in motor gasoline (together about 28% of the total by volume). CTL facilities are not economic in the AEO2016 Reference case in any forecast year

Coal imports and exports

Coal imports and exports are modeled as part of the CMM’s linear program that provides annual projections of U.S. steam and metallurgical coal exports, in the context of world coal trade. The CMM projects steam and metallurgical coal trade flows from 17 coal-exporting regions of the world to 20 import regions for two coal types (steam and metallurgical). It includes five U.S. export regions and four U.S. import regions. The linear program determines the pattern of world coal trade flows that minimizes the production and transportation costs of meeting U.S. import demand and a pre-specified set of regional coal import demands. It does this subject to constraints on export capacity and trade flows.

The key assumptions underlying coal export modeling are:

- Coal buyers (importing regions) tend to spread their purchases among several suppliers in order to reduce the impact of potential supply disruptions, even though this may add to their purchase costs. Similarly, producers choose not to rely on any one buyer and instead endeavor to diversify their sales.
- Coking coal is treated as homogeneous. The model does not address quality parameters that define coking coals. The values of these quality parameters are defined within small ranges and affect world coking coal flows very little.

The data inputs for coal trade modeling are:

- World steam and metallurgical coal import demands for the AEO2016 cases (Tables 12.3 and 12.4). U.S. coal exports are determined, in part, by these estimates of world coal import demand. The assumed demands for AEO2016 are based on the projections made in IEO2016.
- Step-function coal export supply curves for all non-U.S. supply regions. The curves provide estimates of export prices per metric ton, inclusive of minemouth and inland freight costs, as well as the capacities for each of the supply steps.
- Ocean transportation rates (in dollars per metric ton) for feasible coal shipments between international supply regions and international demand regions. The rates take into account typical vessel sizes and route distances in thousands of nautical miles between supply and demand regions.

Table 12.3. World steam coal import demand by import region[1]

million metric tons of coal equivalent

	2013	2020	2025	2030	2035	2040
The Americas	32.3	25.1	23.7	22.7	22.4	22.1
United States[2]	5.8	0.0	0.0	0.0	0.0	0.0
Canada	4.5	2.7	1.6	0.9	0.9	0.9
Mexico	3.4	3.3	3.3	3.2	3.2	3.1
South America	18.6	19.1	18.8	18.6	18.3	18.1
Europe	161.3	163.8	161.9	157.6	149.5	140.5
Scandinavia	6.3	6.6	5.9	5.0	4.6	4.1
U.K./Ireland	39.8	17.1	14.4	12.6	10.8	8.0
Germany/Austria/Poland	39.2	38.8	37.8	36.8	32.4	26.9
Other NW Europe	17.0	18.9	17.8	16.5	15.3	14.5
Iberia	13.4	15.3	13.2	11.4	10.5	9.1
Italy	12.9	14.6	14.4	14.1	12.2	10.4
Med/E Europe	32.7	52.4	58.3	61.1	63.8	67.5
Asia	610.6	512.9	527.4	542.1	562.0	580.6
Japan	98.0	96.5	93.5	90.3	88.9	86.6
East Asia	124.9	152.4	151.0	152.2	157.9	165.0
China/Hong Kong	210.5	117.4	114.8	112.3	107.2	100.5
ASEAN	49.3	60.0	79.3	94.9	113.0	131.2
Indian Sub	127.8	86.7	88.8	92.4	95.0	97.2
TOTAL	**804.1**	**701.7**	**712.9**	**722.4**	**733.9**	**743.2**

[1]Import Regions: United States: East Coast, Gulf Coast, Northern Interior, Non-Contiguous; Canada: Eastern, Interior; South America: Argentina, Brazil, Chile, Puerto Rico; Scandinavia: Denmark, Finland, Norway, Sweden; Other NW Europe: Belgium, France, Luxembourg, Netherlands; Iberia: Portugal, Spain; Med/E. Europe: Algeria, Bulgaria, Croatia, Egypt, Greece, Israel, Malta, Morocco, Romania, Tunisia, Turkey; East Asia: North Korea, South Korea, Taiwan; ASEAN: Malaysia, Philippines, Thailand, Vietnam; Indian Sub: Bangladesh, India, Iran, Pakistan, Sri Lanka.
[2]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
Notes: One “metric ton of coal equivalent” equals 27.78 million Btu. Totals may not equal sum of components due to independent rounding.

Table 12.4. World metallurgical coal import demand by import region[1]

million metric tons of coal equivalent

	2013	2020	2025	2030	2035	2040
The Americas	22.8	19.2	21.6	23.1	26.1	28.0
United States[2]	0.8	1.0	1.0	1.0	1.0	1.0
Canada	3.3	3.1	3.0	2.9	2.8	2.7
Mexico	3.7	1.2	1.7	2.2	2.8	3.3
South America	15.0	13.9	15.9	17.0	19.5	21.1
Europe	56.0	55.0	55.1	54.1	53.9	54.0
Scandinavia	3.2	2.7	2.7	2.7	2.7	2.7
U.K./Ireland	7.2	7.0	7.0	7.0	7.0	7.0
Germany/Austria/Poland	11.6	13.2	12.2	11.2	11.2	11.2
Other NW Europe	12.4	12.1	11.9	11.7	11.4	11.3
Iberia	3.2	1.7	1.7	1.7	1.7	1.7
Italy	5.3	4.0	5.0	5.0	5.0	5.0
Med/E Europe	13.0	14.2	14.4	14.6	14.8	15.0
Asia	227.3	230.7	249.4	253.0	257.0	266.9
Japan	75.4	76.9	76.5	74.8	71.3	66.0
East Asia	39.0	44.1	50.4	55.6	60.1	64.5
China/Hong Kong	72.0	51.2	53.3	41.7	30.1	27.2
ASEAN[3]	0.0	0.0	0.0	0.0	0.0	0.0
Indian Sub	40.8	58.6	69.3	81.0	95.5	109.1
TOTAL	**306.0**	**304.9**	**326.1**	**330.2**	**337.0**	**348.8**

[1]Import Regions: United States: East Coast, Gulf Coast, Northern Interior, Non-Contiguous; Canada: Eastern, Interior; South America: Argentina, Brazil, Chile, Puerto Rico; Scandinavia: Denmark, Finland, Norway, Sweden; Other NW Europe: Belgium, France, Luxembourg, Netherlands; Iberia: Portugal, Spain; Med/E. Europe: Algeria, Bulgaria, Croatia, Egypt, Greece, Israel, Malta, Morocco, Romania, Tunisia, Turkey; East Asia: North Korea, South Korea, Taiwan; ASEAN: Malaysia, Philippines, Thailand, Vietnam; Indian Sub: Bangladesh, India, Iran, Pakistan, Sri Lanka.
[2]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[3]Malaysia, Philippines, Thailand, and Vietnam are not expected to import significant amounts of metallurgical coal in the projection.
Notes: One “metric ton of coal equivalent” equals 27.78 million Btu. Totals may not equal sum of components due to independent rounding.

Coal quality

Each year, the values of base year coal production–heat, sulfur, and mercury content–and carbon dioxide emission factors for each coal source in CMM are calibrated to survey data. Surveys used for this purpose are the Form EIA-923, a survey of the origin, cost, and quality of fossil fuels delivered to generating facilities, the Form EIA-3, which records the origin, cost, and quality of coal delivered to U.S. manufacturers, transformation and processing plants, and commercial and institutional users, and the Form EIA-5, which records the origin, cost, and quality of coal delivered to domestic coke plants. Estimates of coal quality for the export sector are based on coal quality data collected on EIA surveys for domestic shipments. Mercury content data for coal by supply region and coal type, in units of pounds of mercury per trillion Btu, shown in Table 12.5, were derived from shipment-level data reported by electricity generators to the U.S. Environmental Protection Agency in its 1999 Information Collection Request. Carbon dioxide emission factors for each coal type, based on data published by the U.S. Environmental Protection Agency, are shown in Table 12.5 in units of pounds of carbon dioxide emitted per million Btu [111].

Table 12.5. Production, heat content, sulfur, mercury and carbon dioxide emission factors by coal type and region

Coal Supply Region	States	Coal Rank and Sulfur Level	Mine Type	2014 Production (million short tons)	2014 Heat Content (million Btu per short ton)	2014 Sulfur Content (pounds per million Btu)	Mercury Content (pounds per trillion Btu)	CO2 (pounds per million Btu)
Northern Appalachia	PA, OH, MD, WV (North)	Metallurgical	Underground	15.4	28.62	1.10	N/A	204.7
		Mid-Sulfur Bituminous	All	16.3	24.94	1.40	11.17	204.7
		High-Sulfur Bituminous	All	93.2	24.85	2.68	11.67	204.7
		Waste Coal (Gob and Culm)	Surface	3.9	10.70	4.11	63.90	204.7
Central Appalachia	KY (East), WV (South), VA, TN (North)	Metallurgical	Underground	49.2	28.71	0.68	N/A	206.4
		Low-Sulfur Bituminous	All	8.4	24.90	0.51	5.61	206.4
		Mid-Sulfur Bituminous	All	53.2	23.64	1.15	7.58	206.4
Southern Appalachia	AL, TN (South)	Metallurgical	Underground	13.6	28.66	0.49	N/A	204.7
		Low-Sulfur Bituminous	All	0.3	24.81	0.52	3.87	204.7
		Mid-Sulfur Bituminous	All	5.1	24.52	1.26	10.15	204.7
East Interior	IL, IN, KY(West), MS	Mid-Sulfur Bituminous	All	6.7	22.70	1.25	5.60	203.1
		High-Sulfur Bituminous	All	113.1	22.76	2.79	6.35	203.1
		Mid-Sulfur Lignite	Surface	2.6	10.59	0.93	14.11	216.5
West Interior	IA, MO, KS, AR, OK, TX (Bit)	High-Sulfur Bituminous	Surface	0.8	23.50	1.82	21.55	202.8
Gulf Lignite	TX (Lig), LA	Mid-Sulfur Lignite	Surface	31.6	13.60	1.23	14.11	212.6
		High-Sulfur Lignite	Surface	8.5	12.63	1.92	15.28	212.6
Dakota Lignite	ND, MT (Lig)	Mid-Sulfur Lignite	Surface	29.4	13.29	1.28	8.38	219.3
Western Montana	MT (Bit & Sub)	Low-Sulfur Bituminous	Underground	0.4	20.59	0.38	5.06	215.5
		Low-Sulfur Subbituminous	Surface	16.8	18.40	0.38	5.06	215.5
		Mid-Sulfur Subbituminous	Surface	13.3	17.00	0.81	5.47	215.5

Table 12.5. Production, heat content, sulfur, mercury and carbon dioxide emission factors by coal type and region (cont.)

Coal Supply Region	States	Coal Rank and Sulfur Level	Mine Type	2014 Production (million short tons)	2014 Heat Content (million Btu per short ton)	Sulfur Content (pounds per million Btu)	Mercury Content (pounds per trillion Btu)	CO2 (pounds per million Btu)
Wyoming, Northern PRB	WY (Northern Powder River Basin	Low-Sulfur Subbituminous	Surface	129.6	16.84	0.37	7.08	214.3
		Mid-Sulfur Subbituminous	Surface	2.3	16.36	0.77	7.55	214.3
Wyoming, Southern PRB	WY (Southern Powder River Basin)	Low-Sulfur Subbituminous	Surface	247.3	17.62	0.28	5.22	214.3
Rocky Mountain	CO, UT	Metallurgical	Surface	0.0	28.71[1]	0.48[1]	N/A	209.6
		Low-Sulfur Bituminous	Underground	29.2	22.71	0.51	3.82	209.6
		Low-Sulfur Subbituminous	Surface	5.0	20.19	0.50	2.04	212.8
Southwest	AZ, NM	Low-Sulfur Bituminous	Surface	8.2	21.53	0.55	4.66	207.1
		Mid-Sulfur Subbituminous	Surface	13.0	17.76	0.93	7.18	209.2
		Mid-Sulfur Bituminous	Underground	6.2	18.23	0.90	7.18	207.1
Northwest	WA, AK	Low-Sulfur Subbituminous	Surface	0.6	23.44	0.57	6.99	216.1

N/A = not available.

[1] No production in 2014, displayed values from 2013.

Source: U.S. Energy Information Administration, 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-7A, "Coal Production and Preparation Report", and Form EIA-923, "Power Plant Operations Report". U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM-545." U.S. Environmental Protection Agency, Emission Standards Division, Information Collection Request for Electric Utility Steam Generating Unit, Mercury Emissions Information Collection Effort (Research Triangle Park, NC, 1999). U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008, ANNEX 2 Methodology and Data for Estimating CO2 Emissions from Fossil Fuel Combustion, EPA 430-R-10-006 (Washington, DC, April 2010), Table A-37, http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/archive.html.

Legislation and regulations

The AEO2016 is based on current laws and regulations in effect as of the end of February, 2016. The AEO2016 Legislation and Regulations chapter discusses in detail many rulings and environmental regulations that indirectly affect coal use. This includes the US EPA's Clean Power Plan (CPP), which requires states to reduce carbon emissions from existing power plants. The implementation of this program could significantly impact coal use, but will occur through electricity markets, therefore the modeling and assumptions related to the CPP are discussed in the Electricity chapter of this report. The CMM is capable of modeling compliance with emissions limits established by the Clean Air Act Amendments of 1990 (CAAA90). Specifically, two US EPA rules currently impacting coal markets represented in the CMM are the Mercury Air Toxics Standard (MATS) and the Cross-State Air Pollution Rule (CSAPR).

MATS, finalized in December 2011, sets emissions limits for mercury, other heavy metals, and acid gases from coal and oil power plants that are 25 MW or greater. Since generators are expected to request one-year extensions for compliance, MATS is assumed to be fully in place by 2016 rather than 2015 as stated in the regulation. Retrofit decisions in the Electric Market Model (EMM) are the primary means of compliance for MATS but the CMM also includes transportation cost adders for removing mercury using activated carbon injection.

The CSAPR [112] rule replaced the prior Clean Air Interstate Rule (CAIR) [113] cap-and-trade program at the start of 2015. CSAPR requires fossil fuel-fired electric generating units in 27 states to restrict emissions of sulfur dioxide and nitrogen oxide, which are precursors to the formation of fine particulate matter (PM2.5) and ozone. The CMM sets regional limits (constraints) throughout the projection for SO2 based on annual allowance set by EPA under CSAPR. The sulfur content for US coal produced in 2014 is displayed in Table 12.5 along with heat content, mercury content, and average CO2 emissions.

The Energy Improvement and Extension Act of 2008 (EIEA) and Title IV, under Energy and Water Development, of the American Recovery and Revitalization Act of 2009 (ARRA), contain provisions affecting the cost of mining coal and coal-related research and development. EIEA was passed in October 2008 as part of the Emergency Economic Stabilization Act of 2008. Subtitle B provides investment tax credits for various projects sequestering CO2. Subtitle B of EIEA, which extends the payment of current coal excise taxes for the Black Lung Disability Trust Fund program of $1.10 per ton on underground-mined coal and $0.55 per ton on surface-mined coal from 2013 to 2018, is also represented in the AEO2016. Prior to the enactment of EIEA, contribution rates for the Black Lung Disability Trust Fund were to be reduced in 2014 to $0.50 per ton on underground-mined coal and to $0.25 per ton on surface- mined coal. Lignite production is not subject to the Black Lung Disability Trust Fund program's coal excise taxes.

Title IV under ARRA provides $3.4 billion for additional research and development on fossil energy technologies. This includes $800 million to fund projects under the Clean Coal Power Initiative (CCPI) program, focusing on projects that capture and sequester greenhouse gases or use captured carbon dioxide for enhanced oil recovery (EOR). The Hydrogen Energy California (HECA) project in Kern County, California and the Texas Clean Energy Project (TCEP) in Penwell, Texas include efforts to use captured carbon dioxide for EOR.

Title XVII of the Energy Policy Act of 2005 (EPACT2005) authorized loan guarantees for projects that avoid, reduce, or sequester greenhouse gasses. EPACT05 also provided a 20% investment tax credit for Integrated Coal-Gasification Combined Cycle (IGCC) capacity and a 15% investment tax credit for other advanced coal technologies. EIEA allocated an additional $1.25 billion in investment tax credits for IGCC and other advanced, coal-based generation technologies. For the AEO2016, all of the EPACT 2005 and EIEA investment tax credits are assumed to have been fully allocated and, therefore, not available for new, unplanned capacity builds in the NEMS Electricity Market Module.

Beginning in 2008, electricity generating units of 25 megawatts or greater were required to hold an allowance for each ton of CO2 emitted in nine Northeastern States as part of the Regional Greenhouse Gas Initiative (RGGI). The States currently participating in RGGI include Connecticut, Maine, Maryland, Massachusetts, Rhode Island, Vermont, New York, New Hampshire, and Delaware. RGGI is modeled in AEO2016 as an emissions reduction program for the Central Atlantic region.

The AEO2016 continues to include a representation of California Assembly Bill 32 (AB32), the California Global Warming Solutions Act of 2006. The bill authorized the California Air Resources Board (CARB) to set California's overall GHG emissions reduction goal to its 1990 level by 2020 and establish a comprehensive, multi-year program to reduce GHG emissions in California, including a cap-and-trade program. The cap-and-trade program features an enforceable cap on GHG emissions that will decline over time. An allowance price, representing the incremental cost of complying with AB32 cap-and-trade, is modeled in the NEMS Electricity Market Module via a region-specific emissions constraint. This allowance price increases the effective delivered price of coal, reducing its ability to compete with other generating sources such as natural gas which emits less CO2 per unit of electricity produced.

In accordance with California Senate Bill 1368 (SB 1368), which established a greenhouse gas emission performance standard for electricity generation, the AEO2016 prohibits builds of new coal-fired generating capacity without carbon capture and storage (CCS) for satisfying electricity demand in California. SB 1368 limits the generating emissions rate for all power plants that California utilities build, invest in, or sign a long-term contract with to be no more than 1,100 pounds of CO2 per megawatthour, which is the approximate emissions rate for a new natural gas combined-cycle power plant [114]. The methodology to represent SB 1368 includes the modeling of the expiration of contracts for imported coal-fired generation from the Four Corners, Navajo, Reid Gardner, San Juan, and Boardman plants and the retirement of the Intermountain plant in 2025.

Notes and sources

[109] Flynn, Edward J., "Impact of Technological Change and Productivity on The Coal Market," U.S. Energy Information Administration (Washington, DC, October 2000), http://www.eia.gov/oiaf/analysispaper/pdf/coal.pdf ; and U.S. Energy Information Administration, The U.S. Coal Industry, 1970-1990: Two Decades of Change, DOE/EIA-0559 (Washington, DC, November 1992).

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[113] U .S. Environmental Protection Agency, “Clean Air Interstate Rule (CAIR)” (Washington, DC: February 21, 2016), https://archive.epa.gov/airmarkets/programs/cair/web/html/index.html.

[114] California Energy Commission, SB 1368 Emission Performance Standards, http://www.energy.ca.gov/emission_standards/index.html.

Chapter 13. Renewable Fuels Module

The NEMS Renewable Fuels Module (RFM) provides natural resources supply and technology input information for projections of new central-station U.S. electricity generating capacity using renewable energy resources. The RFM has six submodules representing various renewable energy sources: biomass, geothermal, conventional hydroelectricity, landfill gas (LFG), solar (thermal and Photovoltaic), and wind [115].

Some renewables, such as landfill gas LFG from municipal solid waste (MSW) and other biomass materials, are fuels in the conventional sense of the word, while others, such as water, wind, and solar radiation, are energy sources that do not involve the production or consumption of a fuel. Commercial market penetration of renewable technologies varies widely.

The submodules of the RFM interact primarily with the Electricity Market Module (EMM). Because of the high level of integration with the EMM, the final outputs (levels of consumption and market penetration over time) for renewable energy technologies are largely dependent upon the EMM. Because some types of biomass fuel can be used for either electricity generation or for the production of liquid fuels, such as ethanol, there is also some interaction with the Liquid Fuels Market Module (LFMM), which contains additional representation of some biomass feedstocks that are used primarily for liquid fuels production.

Projections for residential and commercial grid-connected photovoltaic systems are developed in the end-use demand modules and not in the RFM; see the Distributed Generation and Combined Heat and Power description in the “Commercial Demand Module” and “Residential Demand Module” sections of the report. Descriptions for biomass energy production in industrial settings, such as the pulp and paper industries, can be found in the “Industrial Demand Module” section of the report.

Key assumptions

Nonelectric renewable energy uses

In addition to projections for renewable energy used in central station electricity generation, AEO2016 contains projections of nonelectric renewable energy consumption for industrial and residential wood heating, solar residential and commercial hot water heating, biofuels blending in transportation fuels, and residential and commercial geothermal (ground-source) heat pumps. Assumptions for these projections are found in the Residential Demand, Commercial Demand, Industrial Demand, and LFMM sections of this report. Additional minor renewable energy applications occurring outside of energy markets, such as direct solar thermal industrial applications, direct lighting, off-grid electricity generation, and heat from geothermal resources used directly (for example, district heating and greenhouses) are not included in the projections.

Electric power generation

The RFM considers only grid-connected central station electricity generation systems. The RFM submodules that interact with the EMM are the central station grid-connected biomass, geothermal, conventional hydroelectricity, LFG, solar (thermal and photovoltaic), and wind submodules, which provide specific data or estimates that characterize the respective resources. A set of technology cost and performance values is provided directly to the EMM and is central to the build and dispatch decisions of the EMM. The technology cost and performance values are summarized in Table 8.2 in the chapter discussing the EMM.

Capital costs

Chapter 8 describes the methodology used to determine initial capital costs and cost-learning assumptions. Regional variation in costs for wind is based on EIA analysis of the actual variation in the installation cost of recently built wind projects. For hydropower and geothermal resources, costs are based on site-specific supply curves as described in the hydropower and geothermal sections of this document.

Capital costs for renewable technologies are affected by several factors. Capital costs for technology to exploit some resources, especially geothermal, hydroelectric, and wind power resources, are assumed to be dependent on the quality, accessibility, and/or other site-specific factors in the areas with exploitable resources. These factors can include additional costs associated with reduced resource quality, the need to build or upgrade transmission capacity from remote resource areas to load centers or local impediments to permitting, equipment transport, and construction in good resource areas due to siting issues, inadequate infrastructure, or rough terrain.

Short-term cost adjustment factors increase technology capital costs as a result of a rapid U.S. buildup in a single year, reflecting limitations on the infrastructure (for example, limits on manufacturing, resource assessment, and construction expertise) to accommodate unexpected demand growth. These factors, which are applied to all new electric generation capacity, are a function of past production rates and are further described in "The Electricity Market Module of the National Energy Modeling System: Model Documentation 2014" report, available at www.eia.gov/forecasts/aeo/nems/documentation/electricity/pdf/m068(2014).pdf.

Also assumed to affect all new capacity types are costs associated with construction commodities. Through much of 2000 to 2008, the installed cost for most new plants was observed to increase. Although several factors contributed to this cost escalation, some of which may be more or less important to specific types of new capacity, much of the overall cost increase was correlated with increases in the cost of construction materials, such as bulk metals, specialty metals, and concrete. Capital costs are specifically linked to the projections for the metals producer price index found in the Macroeconomic Module of NEMS. Independent of the other two factors, capital costs for all electric generation technologies, including renewable technologies, are assumed to decline as a function of growth in installed capacity for each technology.

For a description of NEMS algorithms lowering generating technologies' capital costs as more units enter service (learning), see "Technological optimism and learning" in the EMM chapter of this report. A detailed description of the RFM is provided in the EIA publication, Renewable Fuels Module of the National Energy Modeling System, Model Documentation 2014, DOE/EIA-M069(2014) Washington, DC, 2014, available at www.eia.gov/forecasts/aeo/nems/documentation/renewable/pdf/m069(2014).pdf.

Solar Submodule

Background

The solar submodule currently includes both solar thermal (also referred to as concentrating solar power or CSP) and photovoltaic (PV) technologies. The representative solar thermal technology assumed for cost estimation is a 100-megawatt central-receiver tower without integrated energy storage, while the representative solar PV technology is a 150-megawatt array of flat plate PV modules using single-axis tracking. PV is assumed to be available in all EMM regions, while CSP is available only in the Western regions with the arid atmospheric conditions that result in the most cost-effective capture of direct sunlight. Cost estimates for PV are based on a report by Leidos Engineering, LLC entitled "EOP III Task 10388, Subtask 4 and Task 10687 Subtask 2.3.1 – Review of Power Plant Cost and Performance Assumptions for NEMS: Technology Documentation Report," published in 2016, http://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf. The cost estimates for CSP are based on the SAIC report entitled "EOP III Task 1606, Subtask 4 – Review of Power Plant Cost and Performance Assumptions for NEMS: Technology Documentation Report," published in 2013 and available at http://www.eia.gov/analysis/studies/powerplants/capitalcost/archive/2013/pdf/updated_capcost.pdf. Technology-specific performance characteristics are obtained from information provided by the National Renewable Energy Laboratory (NREL).

Assumptions

- Only grid-connected (utility and nonutility) generation is included. Projections for distributed solar PV generation are included in the commercial and residential modules.
- NEMS represents the investment tax credit (ITC) for solar electric power generation by tax-paying entities. The ITC provides a credit to federal income tax liability as a percentage of initial investment cost for a qualified renewable generating facility. The recently passed Consolidated Appropriations Act of 2016 extended the availability of the ITC such that solar projects under construction before the end of 2019 qualify to receive the full 30% ITC, while those starting construction in 2020 and 2021 qualify for credits of 26% and 22% ITC, respectively. Utility-scale solar projects beginning construction after 2021 receive 10% ITC. EIA assumes a two-year lead time for utility-scale solar production, and thus assumes that plants entering service by [2020] will receive the full 30% credit, and that plants entering service after [2022] will receive only the 10% credit.
- Existing capacity and planned capacity additions are based on EIA survey data from the Form EIA-860, "Annual Electric Generator Report" and Form EIA-860M, "Monthly Update to the Annual Electric Generator Report." Planned capacity additions under construction or having an expected completion date prior to 2018were included in the model's planned capacity additions, according to respondents' planned completion dates.
- Capacity factors for solar technologies are assumed to vary by time of day and season of the year, such that nine separate capacity factors are provided for each modeled region, three for time of day and three for each of three broad seasonal groups (summer, winter, and spring/fall). Regional capacity factors vary from national averages based on climate and latitude.

- Solar resources are well in excess of conceivable demand for new capacity; energy supplies are considered unlimited given solar irradiance within regions (at specified daily, seasonal, and regional capacity factors). Therefore, sub-regional variations of solar resources are not estimated in NEMS. In the regions where CSP technology is not modeled, the level of direct, normal insolation (the kind needed for that technology) is assumed to be insufficient to make that technology commercially viable through the projection horizon.

Wind Energy Power Submodule

Background

Because of limits to windy land areas, wind is considered a finite resource, so the submodule calculates maximum available capacity by NEMS EMM (Electricity Market Module) regions. The minimum economically viable average wind speed is about 15 miles-per-hour at a hub-height of 80 meters (m), and wind speeds are categorized by annual average wind speed based on a classification system originally from the Pacific Northwest Laboratory (see http://rredc.nrel.gov/wind/pubs/atlas/tables/1-1T.html). The RFM tracks wind capacity by resource quality and costs within a region, and moves to the next best wind resource when one category is exhausted. Wind resource data on the amount and quality of wind per EMM region come from NREL [116]. The technological performance, cost, and other wind data used in NEMS are based on a report by Leidos Engineering, LLC entitled "EOP III Task 10388, Subtask 4 and Task 10687 Subtask 2.3.1 – Review of Power Plant Cost and Performance Assumptions for NEMS: Technology Documentation Report", published in 2016. To access, please see http://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf. Maximum wind capacity, capacity factors, and incentives are provided to the EMM for capacity planning and dispatch decisions. These form the basis on which the EMM decides how much power generation capacity is available from wind energy. The fossil-fuel heat rate equivalents for wind are used for primary energy consumption calculation purposes only.

Assumptions

- Only grid-connected (utility and nonutility) generation is included. Projections for distributed wind generation are included in the commercial and residential modules.
- In the wind energy submodule, wind supply costs are affected by factors such as average wind speed, distance from existing transmission lines, resource degradation, transmission network upgrade costs, and other market factors.
- Available wind resource is reduced by excluding all windy lands not suited for the installation of wind turbines because of excessive terrain slope (greater than 20%) reservation of land for non-intrusive uses (such as national parks, wildlife refuges, etc.) inherent incompatibility with existing land uses (such as urban areas, areas surrounding airports and water bodies, including offshore locations) and insufficient contiguous windy land to support a viable wind plant (less than 5 square-kilometer of windy land in a 100 square-kilometer area). Half of the wind resource located on military reservations, U.S. Forest Service land, state forested land, and all non-ridge-crest forest areas is excluded from the available resource base to account for the uncertain ability to site projects at such locations. These assumptions are detailed in Appendix 3-E of the "The Renewable Fuels Module of the National Energy Modeling System: Model

Documentation", DOE/EIA-MO69 (2014), Washington, DC, 2014. To access please see http://www.eia.gov/forecasts/aeo/nems/documentation/renewable/pdf/m069(2014).pdf

- Capital costs for wind technologies are assumed to increase in response to: (1) declining natural resource quality, such as terrain slope, terrain roughness, terrain accessibility, wind turbulence, wind variability, or other natural resource factors, as the best sites are utilized, (2) increasing costs of upgrading existing local and network distribution and transmission lines to accommodate growing quantities of remote wind power, and (3) market conditions, such as the increasing costs of alternative land uses, including aesthetic or environmental reasons. Capital costs are left unchanged for some initial share, then increased by 10%, 25%, 50%, and finally 100%, to represent the aggregation of these factors.
- Proportions of total wind resources in each category vary by EMM region. For all EMM regions combined, about 0.9% of windy land (106 GW of 11,600 GW in total resource) is available with no cost increase, 3.3% (387 GW) is available with a 10% cost increase, 2% (240 GW) is available with a 25% cost increase, and over 90% is available with a 50% or 100% cost increase.
- Because of downwind turbulence and other aerodynamic effects, the model assumes an average spacing between turbine rows of 5 rotor diameters and a lateral spacing between turbines of 10 rotor diameters. This spacing requirement determines the amount of power that can be generated from wind resources, about 6.5 megawatts per square kilometer of windy land, and is factored into requests for generating capacity by the EMM.
- Capacity factors for each wind class are calculated as a function of overall wind market growth. EIA implements an algorithm increasing the capacity factor within a wind class as more units enter service (learning). The capacity factors for each wind class were increased for AEO2016 and are assumed to start at 48% and are limited to 55% for a Class 6 site. However, despite increasing performance, as better wind resources are depleted, the modeled capacity factors decline, corresponding with the use of less-desirable sites.
- Due to the Consolidated Appropriation Act of 2016 passed in December 2015, AEO2016 allows plants under construction by the end of 2015 to claim the full 2.3 cents per kilowatt-hour (cent/kWh) federal Production Tax Credit (PTC) through the end of 2016. The PTC reduces for wind projects under construction after December 31, 2016 as follows:
  - 80% of the current PTC value (1.8 cent/kWh) for projects with construction beginning in 2017 and commencing service before 2022;
  - 60% of the current PTC value (1.4 cent/kWh) for projects with construction beginning in 2018 and commencing service before 2023;
  - 40% of the current PTC value (0.9 cent/kWh) for projects with construction beginning in 2019 and commencing service before 2024;
  - No PTC for those projects that begin construction after December 2019.
- Wind plants are assumed to depreciate capital expenses using the Modified Accelerated Cost Recovery System with a 5-year tax life and 5-year double declining balance depreciation.
- Wind plants are assumed and modeled to be in-service 3 years from the start of construction.

Offshore wind

Offshore wind resources are represented as a separate technology from onshore wind resources. Offshore resources are modeled with a similar model structure as onshore wind. However, because of the unique challenges of offshore construction and the somewhat different resource quality, the assumptions with regard to capital cost, learning-by-doing cost reductions, and resource access cost differ significantly from onshore wind.

- Like onshore resources, offshore resources are assumed to have an upwardly sloping cost supply curve, in part influenced by the same factors that determine the onshore supply curve (such as distance to load centers, environmental or aesthetic concerns, variable terrain/seabed) but also explicitly by water depth.
- Because of the more difficult maintenance challenges offshore, performance for a given annual average wind power density level is assumed to be somewhat decreased by reduced turbine availability. Offsetting this, however, is the availability of resource areas with higher overall power density than is assumed available onshore. Capacity factors for offshore start at 50% and are limited to 58% for a Class 7 site.
- Cost reductions in the offshore technology result in part from learning reductions in onshore wind technology as well as from cost reductions unique to offshore installations, such as foundation design and construction techniques. Because offshore technology is significantly less mature than onshore wind technology, offshore-specific technology learning occurs at a somewhat faster rate than on-shore technology. A technological optimism factor (see EMM documentation: www.eia.gov/forecasts/aeo/nems/documentation/electricity/pdf/m068(2014).pdf) is included for offshore wind to account for the substantial cost of establishing the unique construction infrastructure required for this technology.

Geothermal Electricity Submodule

Background

Beginning in AEO2011, all geothermal supply curve data come from the NREL's updated U.S. geothermal supply curve assessment. The most recent report, released in October 2011, assigns cost estimates to the U.S. Geological Survey's (USGS) 2008 geothermal resource assessment [117]. Some data from the 2006 report, "The Future of Geothermal Energy," prepared for Idaho National Laboratory by the Massachusetts Institute of Technology, were also incorporated into the NREL report; however, this would be more relevant to deep, dry, and unknown geothermal resources, which EIA did not include in its supply curve. NREL took the USGS data and used the Geothermal Electricity Technology Evaluation Model (GETEM), a techno-economic systems analysis tool, to estimate the costs [118]. Only resources with temperatures above 110 degrees Celsius were considered. There are approximately 125 of these known, hydrothermal resources which EIA used in its supply curve. Each of these sites also has what NREL classified as "near-field enhanced geothermal energy system potential" which are in areas around the identified site that lack the permeability of fluids that are present in the hydrothermal potential. Therefore, there are 250 total points on the supply curve since each of the 125 hydrothermal sites has corresponding enhanced geothermal system (EGS) potential.

In the past, EIA cost estimates were broken down into cost-specific components. However, this level of detail was not available in the NREL data. A site-specific capital cost and fixed operations and maintenance cost were provided. Two types of technology, flash and binary cycle, are also included with capacity factors ranging from 90% to 95%. While the source of the data was changed beginning in AEO2011, the site-by-site matrix input that acts as the supply curve has been retained.

Assumptions

- Existing and identified planned capacity data are obtained directly by the EMM from Form EIA-860 and Form EIA-860M.
- The permanent investment tax credit of 10% available in all projection years, based on Energy Policy Act of 1992 (EPACT92), applies to all geothermal capital costs, except through December 2016 when the 2.3-cent/kWh PTC is available to this technology and is assumed chosen instead. Projects that began construction and are beyond the exploratory drilling phase by that date are eligible for this PTC.
- Plants are not assumed to retire unless their retirement is reported to EIA. The Geysers units are not assumed to retire but instead are assigned the 35% capacity factors reported to EIA reflecting their reduced performance in recent years.

Biomass Submodule

Background

Biomass consumed for electricity generation is modeled in two parts in NEMS. Capacity in the wood products and paper industries, the so-called captive capacity, is included in the Industrial Demand Module as cogeneration. Generation in the electricity sector is represented in the EMM. Fuel costs are calculated in NEMS and passed to EMM, while capital and operating costs and performance characteristics are assumed as shown in Table 8.2, available at http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf. Fuel costs are provided in sets of regional supply schedules. Projections for ethanol production are produced by the LFMM, with the quantities of biomass consumed for ethanol decremented from, and prices obtained from, the EMM regional supply schedules.

Assumptions

- Existing and planned capacity data are obtained from Form EIA-860 and Form EIA-860M.
- The conversion technology represented is a 50 megawatt dedicated combustion plant. The cost estimates for this technology are based on a report by Leidos Engineering, LLC entitled “EOP III Task 10388, Subtask 4 and Task 10687 Subtask 2.3.1 – Review of Power Plant Cost and Performance Assumptions for NEMS: Technology Documentation Report,” published in 2016, http://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf.
- Biomass co-firing can occur up to a maximum of 15% of fuel used in coal-fired generating plants.

Fuel supply schedules are a composite of four fuel sources: forestry materials from federal forest, forestry materials from non-federal forest, wood residues, and agricultural residues and energy crops. Feedstock potential from agricultural residues and dedicated energy crops are calculated from a version of the Policy Analysis (POLYSYS) agricultural model that uses the same oil price information as the rest of NEMS. Forestry residues are calculated from inventories conducted by the U.S. Forest Service and Oak Ridge National Laboratory. The forestry materials component is made up of logging residues, rough rotten salvageable dead wood, and excess small pole trees [119]. The wood residue component consists of primary mill residues, silvicultural trimmings, and urban wood such as pallets, construction waste, and demolition debris that are not otherwise used [120]. Agricultural residues are wheat straw, corn stover, and a number of other major agricultural crops [121]. Energy crop data are for hybrid poplar, willow, and switchgrass grown on existing cropland. POLYSYS assumes that the additional cropland needed for energy crops will displace existing pasturelands. The maximum amount of resources from forestry is fixed based on “U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry” prepared by Oak Ridge National Laboratory [122]. Urban wood waste is determined dynamically based on activity in the industry sectors that produce usable biomass feedstocks. Agricultural resource (agricultural residues and energy crops) supply is determined dynamically, and supplies available within the model at any point in time may not reflect the maximum potential for that region. In 2040, the estimated supplies of the feedstock categories are as follows: agricultural residues and energy crops are estimated at 5,061 trillion British thermal unit (Btu); wood residues are estimated at 1,211 trillion Btu; forestry materials (from public and private lands) are estimated at 1,915 trillion Btu. For 2040, supplies of 304 trillion Btu from all sectors could be available given prevailing demand in the AEO2016 Reference case.

Landfill Gas (LFG) Submodule

Background

Landfill-gas-to-electricity capacity competes with other technologies using supply curves that are based on the amount of “high,” “low,” and “very low” methane-producing landfills located in each EMM region. An average cost of electricity for each type of landfill is calculated using gas collection system and electricity generator costs and characteristics developed by EPA’s “Energy Project Landfill Gas Utilization Software” (E-PLUS) [123].

Assumptions

- Gross domestic product (GDP) and population are used as the drivers in an econometric equation that establishes the supply of landfill gas.
- Recycling is assumed to account for 50% of the waste stream in 2010 (consistent with EPA’s recycling goals).
- The waste stream is characterized into three categories: readily, moderately, and slowly decomposable material.
- Emission parameters are the same as those used in calculating historical methane emissions in EIA’s “Emissions of Greenhouse Gases in the United States 2003” [124].
- The ratio of “high,” “low,” and “very low” methane production sites to total methane production is calculated from data obtained for 156 operating landfills contained in the Governmental Advisory Associates Inc., METH2000 database [125].

- Cost of electricity for each site was calculated by assuming each site to be a 100-acre by 50-foot deep landfill and by applying methane emission factors for “high,” “low,” and “very low” methane-emitting wastes.

Conventional Hydroelectricity Submodule

The conventional hydroelectricity submodule represents U.S. potential for new conventional hydroelectric capacity of 1 megawatt or greater from new dams, existing dams without hydroelectricity, and from adding capacity at existing hydroelectric dams. Summary hydroelectric potential is derived from reported lists of potential new sites assembled from Federal Energy Regulatory Commission (FERC) license applications and other survey information, plus estimates of capital and other costs prepared by the Idaho National Engineering and Environmental Laboratory (INEEL) [126]. Annual performance estimates (capacity factors) were taken from the generally lower but site-specific FERC estimates rather than from the general estimates prepared by INEEL, and only sites with estimated costs of 10 cents per kilowatthour or lower are included in the supply. Pumped storage hydroelectric, considered a nonrenewable storage medium for fossil and nuclear power, is not included in the supply; moreover, the supply does not consider offshore or in-stream hydroelectric, efficiency or operational improvements without capital additions, or additional potential from refurbishing existing hydroelectric capacity.

In the hydroelectricity submodule, sites are first arrayed by NEMS region from least to highest cost per kilowatthour. For any year’s capacity decisions, only those hydroelectric sites whose estimated levelized costs per kilowatthour (kWh) are equal to or less than an EMM-determined avoided cost (the least cost of other technology choices determined in the previous decision cycle) are submitted. Next, the array of below-avoided-cost sites is parceled into three increasing cost groups, with each group characterized by the average capacity-weighted cost and performance of its component sites. Finally, the EMM receives from the conventional hydroelectricity submodule the three increasing-cost quantities of potential capacity for each region, providing the number of megawatts potential along with their capacity-weighted average overnight capital cost, operations and maintenance cost, and average capacity factor. After choosing from the supply, the EMM informs the hydroelectricity submodule, which decrements available regional potential in preparation for the next capacity decision cycle.

The RFM incorporates the extended PTC expiration date for incremental hydroelectric generation as enacted by the 2016 Consolidated Appropriation Act. Qualifying facilities receive the PTC if they were built within the timeframe specified by the law and its various extensions and can claim the tax credit on generation sold during their first 10 years of operation.

Legislation and regulations

Renewable electricity tax credits

The RFM includes the investment and energy production tax credits codified in EPACT92 as amended.

The ITC provides a credit to federal income tax liability as a percentage of initial investment cost for a qualified renewable generating facility. The Consolidated Appropriations Act of 2016 extended the ITC so that it provides solar projects under construction before the end of 2019 a tax credit currently valued at 30% of initial investment costs. Solar projects starting construction in 2020 and 2021 qualify for credits of 26% and 22% of initial investment costs, respectively. Utility-scale solar projects beginning construction after 2021 receive a 10% ITC. This change is reflected in the RFM, Commercial Demand Module, and Residential Demand Module.

The PTC is a per-kWh tax credit available for qualified wind, geothermal, closed-loop and open-loop biomass, landfill gas, municipal solid waste, hydroelectric, and marine and hydrokinetic facilities. The value of the credit, originally 1.5 cents/kWh, is adjusted for inflation annually and is available for 10 years after the facility has been placed in service. For AEO2016, wind, poultry litter, geothermal, and closed-loop [127] biomass resources receive a tax credit of 2.3 cents/kWh; all other renewable resources receive a 1.1 cent/kWh (that is, one-half the value of the credit for other resources) tax credit. EIA assumes that biomass facilities obtaining the PTC will use open-loop fuels, as closed- loop fuels are assumed to be unavailable and/or too expensive for widespread use during the period that the tax credit is available. The PTC has been recently extended by the 2016 Consolidated Appropriation Act passed in December 2015 for wind projects through 2016. The PTC is scheduled to phase down in value for wind projects as follows: 80% of the current PTC if begin construction in 2017; 60% of the current PTC if begin construction in 2018; and 40% of the current PTC if begin construction in 2019.

The ITC and PTC are exclusive of one another, and thus may not both be claimed for the same facility.

Further details on the PTC and ITC modeling assumptions can be found in the technology-specific sections of this document. A history of these tax credits is described in AEO2016 Legislation and Regulations LR3 - Impact of a Renewable Energy Tax Credit extension and phaseout [128].

The AEO2016 reference case also includes assumptions reflecting the regulations set in place by the Clean Power Plan (CPP). These assumptions are discussed in greater detail in the Electricity Market Module portion of the documentation. While renewables are considered to be an integral part of the CPP rule, the rule specifically applies to fossil generators.

State Renewable Portfolio Standards programs

EIA represents various state-level policies generally referred to as Renewable Portfolio Standards (RPS). These policies vary significantly among states, but typically require the addition of renewable generation to meet a specified share of state-wide generation. Any non-discretionary limitations on meeting the generation or capacity target are modeled to the extent possible. However, because of the complexity of the various requirements, the regional target aggregation, and the nature of some of the limitations, the measurement of compliance is assumed to be approximate.

Regional renewable generation targets were estimated using the renewable generation targets in each state within the region. In many cases where regional boundaries intersect state boundaries; in these cases state requirements were apportioned among relevant regions based on sales. Using state-level RPS compliance schedules and preliminary estimates of projected sales growth, EIA estimated the amount of renewable generation required in each state within a region. Required generation in each state was then summed to the regional level for each year, and a regional renewable generation share of total sales was determined, as shown in Table 13.1.

Only targets with established enforcement provisions or established state funding mechanisms were included in the calculation; non-enforceable goals were not included. Compliance enforcement provisions vary significantly among states, and most states have established procedures for waiving compliance through the use of alternative compliance payments, penalty payments, discretionary regulatory waivers, or retail price impact limits. Because of the variety of mechanisms, even within a given electricity market region, these limits are not modeled.

Table 13.1. Aggregate regional renewable portfolio standard requirements

percentage share of total values

Region[1]	2020	2030	2040
Texas Reliability Entity	4.4%	4.4%	4.4%
Midwest Reliability Organization East	13.0%	13.1%	13.1%
Midwest Reliability Organization West	7.1%	8.6%	8.6%
Northeast Power Coordinating Council / New England	17.9%	20.4%	22.4%
Northeast Power Coordinating Council / NYC Westchester	24.5%	24.6%	24.6%
Northeast Power Coordinating Council / Long Island	24.6%	24.6%	24.6%
Northeast Power Coordinating Council / Upstate New York	24.5%	24.5%	24.5%
Reliability First Corporation/ East	14.0%	15.4%	15.4%
Reliability First Corporation/Michigan	10.0%	10.0%	10.0%
Reliability First Corporation/West	7.1%	10.9%	10.9%
SERC Reliability Corporation / Delta	0.6%	0.6%	0.6%
SERC Reliability Corporation / Gateway	11.1%	17.1%	17.1%
SERC Reliability Corporation / Virginia Carolina	4.4%	5.2%	5.2%
Southwest Power Pool Regional Entity / North	2.6%	3.8%	3.8%
Southwest Power Pool Regional Entity / South	2.1%	2.2%	2.2%
Western Electricity Coordinating Council / Southwest	9.1%	11.8%	11.8%
Western Electricity Coordinating Council / California	33.0%	50.0%	50.0%
Western Electricity Coordinating Council / Northwest Power Pool Area	9.7%	11.1%	11.1%
Western Electricity Coordinating Council / Rockies	17.1%	17.1%	17.1%

[1]See chapter on the Electricity Market Module for a map of the electricity market module supply regions.
Regions not shown do not have renewable portfolio standard requirements.

Notes and sources

[115] For a comprehensive description of each submodule, see U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, Model Documentation, Renewable Fuels Module of the National Energy Modeling System, DOE/EIA-M069(2014), (Washington, DC, August 2014), http://www.eia.gov/forecasts/aeo/nems/documentation/renewable/pdf/m069(2014).pdf.

[116] Revising the Long Term Multipliers in NEMS: Quantifying the Incremental Transmission Costs Due to Wind Power, Report to EIA from Princeton Energy Resources International, LLC. May 2007.

Notes and sources (cont.)

[117] Augustine, C. ”Updated U.S. Geothermal Supply Characterization and Representation for Market Penetration Model Input,” NREL/TP-6A20-47459 (Golden, CO, October 2011), http://www.nrel.gov/docs/fy12osti/47459.pdf.

[118] The one exception applies to the Salton Sea resource area. For that site, EIA used cost estimates provided in a 2010 report on electric power sector capital costs rather than NREL.

[119] U.S. Department of Energy. “U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry”, August 2011.

[120] Ibid.

[121] De la Torre Ugarte, D. “Biomass and bioenergy applications of the POLYSYS modeling framework” Biomass and Bioenergy Vol. 18 (April 2000), pp 291-308.

[122] U.S. Department of Energy. “U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry”, August 2011.

[123] U.S. Environmental Protection Agency, Atmospheric Pollution Prevention Division, Energy Project Landfill Gas Utilization Software (E-PLUS) Version 1.0, EPA-430-B-97-006 (Washington, DC, January 1997).

[124] U.S. Energy Information Administration, “Emissions of Greenhouse Gases in the United States 2003,” DOE/EIA- 0573(2003) (Washington, DC, December 2004), www.eia.gov/oiaf/1605/archive/gg04rpt/index.html.

[125] Governmental Advisory Associates, Inc., METH2000 Database, Westport, CT, January 25, 2000.

[126] Hall, Douglas G., Richard T. Hunt, Kelly S. Reeves, and Greg R. Carroll, Idaho National Engineering and Environmental Laboratory, “Estimation of Economic Parameters of U.S. Hydropower Resources” INEEL/EXT-03-00662, (Idaho Falls, Idaho, June 2003), http://www1.eere.energy.gov/water/pdfs/doewater-00662.pdf.

[127] Closed-loop biomass are crops produced explicitly for energy production. Open-loop biomass are generally wastes or residues that are a byproduct of some other process, such as crops grown for food, forestry, landscaping, or wood milling.

[128] U.S. Energy Information Administration, *Annual Energy Outlook 2016*, Legislation and Regulations LR3, DOE/EIA-0383(2016) (Washington, DC, August 2016), accessed September 23, 2016.

Appendix A: Handling of federal and selected state legislation and regulations in the AEO

Residential sector

	Legislation	Brief description	AEO handling	Basis
A.	National Appliance Energy Conservation Act of 1987 (NAECA87)	Requires Secretary of Energy to set minimum efficiency standards for various appliance categories with periodic updates	Include categories represented in the AEO residential sector forecast	Public Law 100-12
	a. Room air conditioners	Sets standards for room air conditioners in 2014	Require new purchases of room air conditioners to meet the standard	Federal Register Notice of Final Rulemaking
	b. Central air conditioners and heat pumps	Sets standards for central air conditioners in 2015	Require new purchases of other air conditioners to meet the standard	Federal Register Notice of Final Rulemaking
	c. Water heaters	Sets standards for water heaters in 2015	Require new purchases of water heaters to meet the standard	Federal Register Notice of Final Rulemaking
	d. Refrigerators and freezers	Sets standards for water heaters in 2014	Require new purchases of refrigerators/freezers to meet the standard	Federal Register Notice of Final Rulemaking
	e. Dishwashers	Sets standards for dishwasher in 2010	Require new purchases of dishwashers to meet the standard	Federal Register Notice of Final Rulemaking
	f. Fluorescent lamp ballasts	Sets standards for fluorescent lamp ballasts in 2005	Require new purchases of fluorescent lamp ballasts to meet the standard	Federal Register Notice of Final Rulemaking
	g. Clothes washers	Sets standards for clothes washers in 2011	Require new purchases of clothes washers to meet the standard	Federal Register Notice of Final Rulemaking
	h. Furnaces	Sets standards for furnaces in 2013	Require new purchases of furnaces to meet the standard	Federal Register Notice of Final Rulemaking
	i. Clothes dryers	Sets standards for clothes dryers in 2015	Require new purchases of clothes dryers to meet the standard	Federal Register Notice of Final Rulemaking
	j. Boilers	Sets standards for boilers in 2012	Require new purchases of boilers to meet the standard	Federal Register Notice of Final Rulemaking
B.	Energy Policy Act of 1992 (EPACT92)			Public Law 102-486
	a. Building codes	For the IECC 2006, specifies whole house efficiency minimums	Assume that all states adopt the IECC 2006 code by 2017	Trend of states' adoption of codes, allowing for lead times for enforcement and builder compliance

Legislation	Brief description	AEO handling	Basis
b. Various lighting types	Sets standards for various lighting types in 2012	Require new purchases of various lighting types to meet the standards	Federal Register Notice of Final Rulemaking
C. Energy Policy Act of 2005 (EPACT05)			Public Law 109-58
a. Torchiere lamp standard	Sets standard for torchiere lamps in 2006	Require new purchases of torchiere bulbs to meet the standard	Federal Register Notice of Final Rulemaking
b. Compact fluorescent lamp standard	Sets standard for fluorescent lamps in 2006	Require new purchases of compact fluorescent bulbs to meet the standard	Federal Register Notice of Final Rulemaking
c. Ceiling fan light kit standard	Sets standard for ceiling fans and ceiling fan light kits in 2007	Reduce lighting electricity consumption by appropriate amount	Number of ceiling fan shipments and estimated kWh savings per unit determine overall savings
d. Dehumidifier standard	Sets standard for dehumidifiers in 2012	Reduce dehumidifier electricity consumption by appropriate amount	Number of dehumidifier shipments and estimated kWh savings per unit determine overall savings
e. Energy-efficient equipment tax credit	Provides tax credits to purchasers of certain energy-efficient equipment in 2006 and 2007	Reduce cost of applicable equipment by specified amount	Federal Register Notice of Final Rulemaking
f. New home tax credit	Provides $1,000 or $2,000 tax credit to builders if they construct homes that are 30% or 50%, respectively, more efficient than code in 2006 and 2007	Reduce shell package cost for these homes by specified amount	Cost reductions to consumers are assumed to be 100% of the builder's tax credit
g. Energy-efficient appliance tax credit	Provides tax credits to producers of energy-efficient refrigerators, dishwashers, and clothes washers for each unit they produce that meets certain efficiency specifications	Assume that the cost savings are passed on to the consumer, reducing the price of the appliance by the specified amount	Cost reductions to consumers are assumed to be 100% of the producer's tax credit
D. Energy Independence and Security Act of 2007 (EISA 07)			Public Law 110-140
a. General service incandescent lamp standard	Require less wattage for bulbs in 2012–2014 and 2020	Reduce wattage for new bulbs by 28% in 2013 and 67% in 2020	Federal Register Notice of Final Rulemaking
b. External power supply standard	Sets standards for external power supplies in 2008	Reduce external power supply electricity consumption by appropriate amount	Number of shipments and estimated kWh savings per unit determine overall savings
c. Manufactured housing code	Require manufactured homes to meet latest IECC in 2011	Require that all manufactured homes shipped after 2011 meet the IECC 2006	Federal Register Notice of Final Rulemaking

	Legislation	Brief description	AEO handling	Basis
E.	Energy Improvement and Extension Act of 08 (EIEA08)			Public Law 110-343
	a. Energy-efficient equipment tax credit	Purchasers of certain energy-efficient equipment can claim tax credits through 2016	Reduce the cost of applicable equipment by specified amount	Federal Register Notice of Final Rulemaking
	b. Energy-efficient appliance tax credit	Producers of energy-efficient refrigerators, clothes washers, and dishwashers receive tax credits for each unit they produce that meets certain efficiency specifications, subject to an annual cap	Assume that the cost savings are passed on to the consumer, reducing the price of the appliance by the specified amount	Cost reductions to consumer are assumed to be 100% of the producer's tax credit
F.	American Recovery and Reinvestment Act of 2009 (ARRA09)			Public Law 111-5
	a. Energy-efficient equipment tax credit	Increases cap of energy-efficient equipment specified under Section E(a) above to $1,500; removes cap for solar PV, wind, and geothermal heat pumps	Reduce the cost of applicable equipment by specified amount	Federal Register Notice of Final Rulemaking
	b. Weatherization and State Energy Programs	Increases funding for weatherization and other programs to improve the energy efficiency of existing housing stock	Apply annual funding amount to existing housing retrofits; base savings for heating and cooling on $2,600 per-home investment as specified in weatherization program evaluation	Federal Register Notice of Final Rulemaking
G.	Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010			Public Law 111-312
	a. Energy-efficient equipment tax credit	Extends tax credits for some energy-efficient equipment, generally to EISA07 amounts	Reduce the cost of applicable equipment by specified amount	

Commercial sector

	Legislation	Brief description	AEO handling	Basis
A.	National Appliance Energy Conservation Act of 1987 (NAECA87)	Requires Secretary of Energy to set minimum efficiency standards for various appliance categories with periodic updates	Include categories represented in the AEO commercial sector forecast	Public Law 100-12
	a. Room air conditioners		Change room air conditioner efficiency, including metric, from 9.8 Energy Efficiency Ratio (EER) to 10.9 Combined Energy Efficiency Ratio (CEER) in 2014	Federal Register Notice of Final Rulemaking
	b. Other residential-size air conditioners (<5.4 tons)		Set central air conditioning and heat pump efficiency to 10 SEER before 2006, 13 SEER in 2006, and 14 SEER in 2015	Federal Register Notice of Final Rulemaking
	c. Fluorescent lamp ballasts		Set standard of 0.90 power factor and minimum efficacy factor for F40 and F96 lamps based on lamp size and wattage, increasing to higher efficacy factor in 2005 that limits purchases to electronic ballasts	Federal Register Notice of Final Rulemaking
B.	Energy Policy Act of 1992 (EPACT92)			Public Law 102-486
	a. Building codes		Incorporate into commercial building shell assumptions; represent efficiency of new shell relative to existing shell in shell efficiency indices; assumes shell efficiency improves 6.9% and 15.0% by 2040 for existing buildings and new construction, respectively	Based on Science Applications International Corporation commercial shell indices for 2003 developed for EIA in 2008 and 2011
	b. Window labeling	Helps consumers determine which windows are more energy efficient	Incorporate into commercial building shell assumptions; represent efficiency of new shell relative to existing shell in shell efficiency indices; assume shell efficiency improves 6.9% and 15.0% by 2040 for existing buildings and new construction, respectively	Based on Science Applications International Corporation commercial shell indices for 2003 developed for EIA in 2008 and 2011
	c. Commercial furnaces and boilers		Set gas-fired furnace and boiler thermal efficiency to 80%; set oil furnace thermal efficiency to 81%; set oil boiler thermal efficiency to 83%	Federal Register Notice of Final Rulemaking

Legislation	Brief description	AEO handling	Basis
d. Commercial air conditioners and heat pumps		Set air-source air conditioners and heat pumps less than 135,000 Btu to 8.9 EER and greater than 135,000 Btu to 8.5 EER in 2001	Federal Register Notice of Final Rulemaking
e. Commercial water heaters		Set gas and oil thermal efficiency to 78%, increasing to 80% thermal efficiency for gas units in 2003	Federal Register Notice of Final Rulemaking
f. Lamps		Set incandescent efficacy to 16.9 lumens per watt and fluorescent efficacy to 75 and 80 lumens per watt for 4- and 8-foot lamps, respectively	
g. Electric motors	Specifies minimum efficiency levels for a variety of motor types and sizes	Model end-use services at the equipment level (motors contained in new equipment must meet the standards)	Federal Register Notice of Final Rulemaking
h. Federal energy management	Requires federal agencies to reduce energy consumption 20% by 2000 relative to 1985	Use the 10-year Treasury note rate for federal share of the commercial sector as a discount rate in equipment purchase decisions	Superseded by Executive Order 13123 , EPACT05, and EISA07
i. Business investment energy credit	Provides a permanent 10% investment tax credit for solar property	Incorporate tax credit into cash flow for solar generation systems; reduced investment cost for solar water heaters by 10%	Federal Register Notice of Final Rulemaking
C. Executive Order 13123: Greening the Government Through Efficient Energy Management	Requires federal agencies to reduce energy consumption 30% by 2005 and 35% by 2010 relative to 1985 through cost-effective life-cycle energy measures	Use the 10-year Treasury note rate for federal share of the commercial sector as a discount rate in equipment purchase decisions	Superseded by EPACT05 and EISA07

	Legislation	Brief description	AEO handling	Basis
D.	Energy Policy Act of 2005 (EPACT05)			Public Law 109-58
	a. Commercial package air conditioners and heat pumps	Sets minimum efficiency levels in 2010	Set air-cooled air conditioners/ heat pumps less than 135,000 Btu to 11.2/ 11.0 EER and heating COP of 3.3 and greater than 135,000 Btu to 11.0/ 10.6 EER and heating COP of 3.2	Federal Register Notice of Final Rulemaking
	b. Commercial refrigerators, freezers, and automatic icemakers	Sets minimum efficiency levels in 2010 and 2017 (refrigerators and freezers)	Remove refrigerator and freezer systems that do not meet standard from technology choice.	Federal Register Notice of Final Rulemaking
	c. Lamp ballasts	Bans manufacture or import of mercury vapor lamp ballasts in 2008; sets minimum efficacy level for T12 energy saver ballasts in 2009 and 2010 based on application	Remove mercury vapor lighting system from technology choice menu in 2008; set minimum efficacy of T12 ballasts at specified standard levels	Federal Register Notice of Final Rulemaking
	d. Compact fluorescent lamps	Sets standard for medium base lamps to ENERGY STAR specifications in 2006	Set efficacy level of compact fluorescent lamps at required level.	Federal Register Notice of Final Rulemaking
	e. Illuminated exit signs and traffic signals	Sets standards to ENERGY STAR specifications in 2006	Reduce miscellaneous electricity consumption by appropriate amount	Number of shipments, share of shipments that currently meet standard, and estimated kWh savings per unit determine overall savings
	f. Distribution transformers	Sets standard as National Electrical Manufacturers Association Class I Efficiency levels in 2007, with an update effective in 2016	Include effects of standard in estimating the share of miscellaneous electricity consumption attributable to transformer losses	Federal Register Notice of Final Rulemaking
	g. Pre-rinse spray valves	Sets maximum flow rate to 1.6 gallons per minute in 2006	Reduce energy use for water heating by appropriate amount	Number of shipments, share of shipments that currently meet standard, and estimated kWh savings per unit determine overall savings
	h. Federal energy management	Requires federal agencies to reduce energy consumption 20% by 2015 relative to 2003 through cost-effective life-cycle energy measures	Use the 10-year Treasury note rate as a discount rate for federal share of the commercial sector as a discount rate in equipment purchase decisions as opposed to adding risk premiums to the 10-year Treasury note rate to develop discount rates for other commercial decisions	Superseded by EISA07

	Legislation	Brief description	AEO handling	Basis
	i. Business investment tax credit for fuel cells and microturbines	Provides a 30% investment tax credit for fuel cells and a 10% investment tax credit for microturbines installed in 2006 through 2016	Incorporate tax credit into cash flow for fuel cells and microturbines	Extended through 2008 by Public Law 109-432 and through 2016 by EIEA08
	j. Business solar investment tax credit	Provides a 30% investment tax credit for solar property installed in 2006 through 2016	Incorporate tax credit into cash flow for solar generation systems; reduce investment cost for solar water heaters by 30%	Extended through 2008 by Public Law 109-432 and through 2016 by EIEA08
E.	Energy Independence and Security Act of 2007 (EISA07)			
	a. Commercial walk-in coolers and walk-in freezers	Requires use of specific energy efficiency measures in equipment manufactured in or after 2009, with an update effective in 2017	Remove walk-in refrigerator and freezer systems that do not meet standard from technology choice	Federal Register Notice of Final Rulemaking
	b. Incandescent and halogen lamps	Sets maximum allowable wattage based on lumen output starting in 2012	Remove incandescent and halogen general service lighting systems that do not meet standard from technology choice menu in 2012	Federal Register Notice of Final Rulemaking
	c. Metal halide lamp ballasts	Sets minimum efficiency levels for metal halide lamp ballasts starting in 2009, with an update effective in 2017	Remove metal halide lighting systems that do not meet standard from technology choice menu; set minimum system efficiency to include specified standard levels for ballasts based on type	Federal Register Notice of Final Rulemaking
	d. Federal use of energy-efficient lighting	Requires use of energy-efficient lighting fixtures and bulbs in federal buildings to the maximum extent possible starting in 2009	Increase proportion of sector using 10-year Treasury note rate for lighting purchase decisions to represent all existing and new federal floorspace in 2009	Federal Register Notice of Final Rulemaking
	e. Federal energy management	Requires federal agencies to reduce energy consumption per square foot 30% by 2015 relative to 2003 through cost-effective life-cycle energy measures	Uses the 10-year Treasury note rate for federal share of the commercial sector as a discount rate in equipment purchase decisions as opposed to adding risk premiums to the 10-year Treasury note rate to develop discount rates for other commercial decisions	Federal Register Notice of Final Rulemaking

	Legislation	Brief description	AEO handling	Basis
F.	Energy Improvement and Extension Act of 2008 (EIEA08)			Public Law 110-343
	a. Business solar investment tax credit	Extends the EPACT05 30% investment tax credit for solar property through 2016	Incorporate tax credit into cash flow for solar generation systems; reduce investment cost for solar water heaters by 30%	Federal Register Notice of Final Rulemaking
	b. Business investment tax credit for fuel cells and microturbines	Extends the EPACT05 30% investment tax credit for fuel cells and 10% investment tax credit for micro-turbines through 2016	Incorporate tax credit into cash flow for fuel cells and microturbines	Federal Register Notice of Final Rulemaking
	c. Business investment tax credit for CHP systems	Provides a 10% investment tax credit for CHP systems installed in 2009 through 2016	Incorporate tax credit into cash flow for CHP systems	Federal Register Notice of Final Rulemaking
	d. Business investment tax credit for small wind turbines	Provides a 30% investment tax credit for wind turbines installed in 2009 through 2016	Incorporate tax credit into cash flow for wind turbines	Federal Register Notice of Final Rulemaking
	e. Business investment tax credit for geothermal heat pumps	Provides a 10% investment tax credit for geothermal heat pump systems installed in 2009 through 2016	Reduce investment cost for geothermal heat pump systems by 10%	Federal Register Notice of Final Rulemaking
G.	American Recovery and Reinvestment Act of 2009 (ARRA09)			Public Law 111-5
	a. Business investment tax credit for small wind turbines	Removes the cap on the EIEA08 30% investment tax credit for wind turbines through 2016	Incorporate tax credit into cash flow for wind turbines	Federal Register Notice of Final Rulemaking
	b. Stimulus funding to federal agencies	Provides funding for efficiency improvement in federal buildings and facilities	Increase the proportion of sector using the 10-year Treasury note rate for purchase decisions to include all existing and new federal floorspace in years stimulus funding is available to account for new, replacement, and retrofit projects; assume some funding is used for solar PV, small wind turbine, and fuel cell installations	Federal Register Notice of Final Rulemaking

Legislation	Brief description	AEO handling	Basis
c. State Energy Program funding and energy efficiency and conservation block grants	Provides grants for state and local governments for energy efficiency and renewable energy purposes (State Energy Program funding conditioned on enactment of new building codes)	Increase the proportion of sector using the 10-year Treasury note rate for purchase decisions to include all public buildings in years stimulus funding is available; increase new building shell efficiency to 10% better than 2003 by 2018 for improved building codes; assume some funding is used for solar PV and small wind turbine installations	Federal Register Notice of Final Rulemaking
d. Funding for smart grid projects	Provides funding for smart grid demonstration projects	Assume smart grid technologies cause consumers to become more responsive to electricity price changes by increasing the price elasticity of demand for certain end uses	Federal Register Notice of Final Rulemaking

Industrial sector

	Legislation	Brief description	AEO handling	Basis
A.	Energy Policy Act of 1992 (EPACT92)			
	a. Motor efficiency standards	Specifies minimum efficiency levels for a variety of motor types and sizes.	Not modeled because participation is voluntary; actual reductions will depend on future, unknown commitments.	EPACT1992, Section 342 (42 USC 6313).
	b. Boiler efficiency standards	Specifies minimum combustion efficiency for package boilers larger than 300,000 Btu/hr. Natural Gas boilers: 80 percent. Oil boilers: 83 percent.	All package boilers are assumed to meet the efficiency standards. While the standards do not apply to field-erected boilers, which are typically used in steam-intensive industries, we assume they meet the standard in the AEO.	Standard specified in EPACT92. 10 CFR 431.
B.	Clean Air Act Amendments (CAAA90)			
	a. Process emissions	Numerous process emissions require-ments for specified industries and/or activities.	Not modeled because they are not directly related to energy projections.	CAAA90, 40 CFR 60.
	b. Emissions related to hazardous/toxic substances	Numerous emissions requirements relative to hazardous and/or toxic substances.	Not modeled because they are not directly related to energy projections.	CAAA90, 40 CFR 60.
	c. Industrial SO2 emissions	Sets annual limit for industrial SO2 emissions at 5.6 million tons. If limit is reached, specific regulations could be implemented.	Industrial SO2 emissions are not projected to reach the limit (Source: EPA, National Air Pollutant Emissions Trends:1990-1998, EPA-454/R-00-002, March 2000, p. 4-3.)	CAAA90, Section 406 (42 USC 7651)
	d. Industrial boiler hazardous air pollutants	Requires industrial boilers and process heaters to conduct periodic tune-ups or meet emissions limits on HAPs to comply with the Maximum Achievable Control Technology (MACT) Floor. Regulations finalized December 2012.	Costs of compliance that are not offset by efficiency gains (non-recoverable costs) modeled as an additional capital cost in the Macroeconomic Activity Module (MAM) based on proposed regulations as of September 2012.	U.S. Environmental Protection Agency, National Emissions Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers, Major Source (40 CFR 63, Subpart DDDDD) and Area Source (40 CFR 63 Part JJJJJJ)
	e. Emissions from stationary diesel engines	Requires engine manufacturers to meet the same emission standards as nonroad diesel engines. Fully effective in 2011.	New stationary engines meet the standards.	40 CFR Parts 60, 85, 89, 94, 1039, 1065, and 1068.

Legislation	Brief description	AEO handling	Basis
C. Energy Policy Act of 2005 (EPACT05)			
a. Physical energy intensity	Voluntary commitments to reduce physical energy intensity by 2.5 percent annually for 2007-2016.	Not modeled because participation is voluntary; actual reductions will depend on future, unknown commitments.	EPACT2005, Section 106 (42 USC 15811)
b. Mineral components of cement of concrete	Increase in mineral component of federally procured cement or concrete.	Not modeled.	EPACT2005, Section 108 (42 USC 6966).
c. Tax credits for coke oven	Provides a tax credit of $3.00 per barrel oil equivalent, limited to 4000 barrels per day average. Applies to most producers of coal coke or coke gas.	Not modeled because no impact on U.S. coke plant activity is anticipated.	EPACT2005, Section 1321 (26 USC 45K).
D. The Energy Independence and Security Act of 2007 (EISA2007)			
a. Motor efficiency standards	Supersedes EPACT1992 Efficiency Standards no later than 2011.	Motor purchases must meet the EPAct1992 standards through 2010; afterwards purchases must meet the EISA2007 standards. Motors manufactured after June 1, 2016 are required to comply with higher efficiency standards.	EISA2007. 10 CFR Part 431 as amended
E. The Energy Improvement and Extension Act of 2008 (EIEA2008)			
e. Combined heat and power tax incentive	Provides an investment tax credit for up to 15 megawatts of capacity in combined heat and power systems of 50 megawatts or less through 2016.	Costs of systems adjusted to reflect the credit.	EIEA2008, Title I, Sec. 103

Transportation sector

	Legislation	Brief description	AEO handling	Basis
A.	Energy Policy Act of 1992 (EPACT92)	Increases the number of alternative fuel vehicles and alternative fuel use in federal, state, and fuel-provided fleets	Assumes federal, state and fuel-provided fleets meet the mandated sales requirements.	Energy Policy Act of 1992, Public Law 102-486-Oct. 24, 1992.
B.	California's Advanced Clean Cars program (ACCP) includes Zero Emission Vehicle (ZEV) Program and the Low Emission Vehicle Program (LEVP)	The Clean Air Act provides the state of California the authority to set vehicle criteria emission standards that exceed federal standards. A part of that program mandates the sale of zero-emission vehicles by manufacturers. Other nonattainment states are given the option of opting into the federal or California emission standards.	Incorporates the ACCP which includes the Low Emission Vehicle Program as amended on March 22, 2012, and the Zero Emission Vehicle Program from July 10, 2014. Assumes the states of California, Connecticut, Maine, Massachusetts, New Jersey, New York, Rhode Island, Vermont, Oregon, and Washington adopt the ZEV Program and that the proposed sales requirements for hybrid, electric, and fuel cell vehicles are met.	Section 177 of the Clean Air Act, 42 U.S.C. sec. 7507 (1976) and CARB, California Exhaust Emissions Standards and Test Procedures for Passenger Cars, Light-Duty Trucks, and Medium-Duty Vehicles, August 4, 2005, as amended March 22, 2012. Zero-Emission Vehicle Standards for 2018 and subsequent model year Passenger Cars, Light-Duty Trucks, and Medium-Duty Vehicles, July 10, 2014.
C.	Corporate Average Fuel Economy (CAFE) Standard for Light Duty Vehicles	Requires manufacturers to produce vehicles that meet a minimum federal average fuel economy standard, promulgated jointly for model years 2012-2016 and 2017-2025 with an average greenhouse emissions standard; cars and light trucks are regulated separately.	CAFE standards are increased for model years 2011 through 2016 to meet the final CAFE rulemakings for model year 2011 and 2012 to 2016, respectively. CAFE standards are increased for model years 2017 to 2025 to meet final CAFE joint rulemakings for model year 2017 to 2021 and to meet augural CAFE standards for model year 2022 to 2025, which will undergo a midterm evaluation to finalize. CAFE standards are held constant through the end of the projection.	Energy Policy Conservation Act of 1975; Title 49 USC, Chapter 329; Energy Independence and Security Act of 2007, Title 1, Section 102; Average Fuel Economy Standards Passenger Cars and Light Trucks Model Year 2011; Federal Register, Vol. 74, No. 59, March 2009; Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards, Final Rule, Federal Register, Vol. 75, No. 88, May 2010; 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards Federal Register, Vol. 77, No. 199, October 2012.
D.	Electric, Hybrid, and Alternative Fuel Vehicle Tax Incentives	Federal tax incentives are provided to encourage the purchase of electric, hybrid and/or alternative fuel vehicles. For example, tax incentives for hybrid vehicles in the form of a $2,000 income tax deduction.	Incorporates the federal tax incentives for hybrid and electric vehicles.	IRS Technical Publication 535; Business Expenses.

	Legislation	Brief description	AEO handling	Basis
E.	Plug-in Hybrid Vehicle Tax Credit	EIEA2008 grants a tax credit of $2,500 for PHEVs with at least 4kWh of battery capacity, with larger batteries earning an additional $417 per kWh up to a maximum of $7,500 for light-duty PHEVs. The credit will apply until 250,000 eligible PHEVs are sold or until 2015, whichever comes first.	Incorporates the federal tax credits for PHEVs.	Energy Improvement and Extension Act of 2008, H.R.6049.
F.	State Electric, Hybrid, and Alternative Fuel Vehicle Tax and Other Incentives	Approximately 20 states provide tax and other incentives to encourage the purchase of electric, hybrid and/or alternative fuel vehicles. The tax incentives are in the form of income reductions, tax credits, and exemptions. Other incentives include use of HOV lanes and exemptions from emissions inspections and licensing fees. The incentives offered and the mix varies by state. For example, Georgia offers a tax credit of $5,000 for electric vehicles and Oklahoma offers a tax credit of $1,500 for hybrid and alternative fuel vehicles.	Does not incorporate state tax and other incentives for hybrid, electric, and other alternative fuel vehicles.	State laws in Arizona, Arkansas, California, Colorado, Delaware, Florida, Georgia, Iowa, Kansas, Louisiana, Maine, Maryland, Michigan, New Hampshire, New York, Oklahoma, Pennsylvania, Utah, Virginia, and Washington
G.	Heavy-Duty (HD) National Program; Greenhouse Gas Emissions and Fuel Consumption Standards for Heavy-Duty Vehicles	Requires on-road heavy-duty vehicle manufacturers to produce vehicles that meet a minimum federal average greenhouse gas emission standard, issued by the EPA, for model years 2014-2018. NHTSA established voluntary fuel consumption standards for MY 2014-2015, and mandatory fuel consumption standards for MY 2016 and beyond for onroad heavy-duty trucks and their engines; vocational and combination engines are regulated separately.	HD National program standards begin for MY 2014 as set by the GHG emissions portion of the rule with the assumption that the vehicles comply with the voluntary portion of the rule for fuel consumption. The model allows for both the engine and chassis technologies to meet the standards to finalize. CAFE standards are held constant through the end of the projection.	Section 202 of the Clean Air Act Title 49 USC, Chapter 32902[k]; Energy Independence and Security Act of 2007, Title 1, Section 102; Federal Register, Vol. 76, No. 179, September 2011.

	Legislation	Brief description	AEO handling	Basis
H.	The International Convention for the Prevention of Pollution from Ships (MARPOL) Annex VI	Sets limits on sulfur oxides and oxides of nitrogen emissions from ship exhausts and prohibits deliberate emissions of ozone depleting substances. First entered into force on May 19, 2005. New requirements added on January 1, 2015, mandating a maximum of 0.1% sulfur fuel use or exhaust scrubber use in Emission Control Areas (ECA), from a previous 1% limit.	MARPOL Annex VI fuel sulfur mandates reflected in domestic and international shipping fuel choices starting in 2015.	MARPOL 73/78, (33 U.S.C 1901(a) (4) & (5), 1902(a)(1)&(5), and 1907 (a), as amended by the Maritime Pollution Prevention Act of 2008 (MPPA), Pub.L. 110-280, 122 Stat 2611).

Electric power generation

	Legislation	Brief description	AEO handling	Basis
A.	Clean Air Act Amendments of 1990 (CAAA90)	Established a national limit on electricity generator emissions of sulfur dioxide to be achieved through a cap-and-trade program.	Sulfur dioxide cap-and-trade program is explicitly modeled, choosing the optimal mix of options for meeting the national emissions cap.	Clean Air Act Amendments of 1990, Title IV, Sections 401 through 406, Sulfur Dioxide Reduction Program, 42 U.S.C.7651a through 7651e.
		Requires the EPA to establish National Ambient Air Quality Standards (NAAQS). In 1997, EPA is currently determining which areas of the country are not in compliance with the new standards. Area designations were made in December 2004. States submitted their compliance plans, and have until 2009-2014 to bring all areas into compliance.	These standards are not explicitly represented, but the Cross State Air Pollution Rule is incorporated (described below) and was developed to help states meet their NAAQS.	Clean Air Act Amendment of 1990, Title I, Sections 108 and 109, National Ambient Air Quality Standards for Ozone, 40 CFR Part 50, Federal Register, Vol 68, No 3, January 8, 2003. National Ambient Air Quality Standards for Particulate Matter, 40 CFR Part 50, Federal Register, Vol 62, No. 138, July 18, 1997.
		Requires EPA to develop standards for emissions from new power plants. In October 2015, EPA specified CO2 emission rate standards for four types of new electric generating units: new fossil steam, modified fossil steam, reconstructed coal steam, and new combined-cycle combustion turbines.	The AEO2016 assumes that new fossil plants built endogenously must meet the appropriate emission standard. New coal plants must include 30% carbon capture and sequestration to achieve the emission target specified. EIA does not represent modified or reconstructed power plants.	Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 FR 64509, October 23, 2015.
		Requires EPA to require states to establish CO2 standards for existing plants once they are in place for new units. In October 2015, EPA adopted interim and final CO2 emission performance rates for fossil steam and combined cycle plants through the Clean Power Plan (CPP). States can also choose to meet EPA calculated average emission rates or emission caps, with caps specified for both existing sources only, and existing and new sources.	The AEO2016 assumes that the CPP is implemented at the electricity region level, with states choosing to cooperate within regions, and by meeting the average emission cap covering existing and new sources. In February 2016, the Supreme Court issued a stay on enforcement of the CPP, but no lower court had considered the challenges and there was no previous judgement. The AEO2016 includes a case without the CPP for comparison.	Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 FR 64661, October 23, 2015.

	Legislation	Brief description	AEO handling	Basis
B.	Cross-State Air Pollution Rule (CSAPR)	CSAPR requires States to reduce SO2 and NOx emissions from power plants. CSAPR consists of four individual cap and trade programs, covering two different SO2 groups, an annual NOx group and a seasonal NOx group. A total of 23 States are subject to annual limits, and 25 States are subject to seasonal limits.	Cap-and-trade programs for SO2 and NOX are modeled explicitly, allowing the model to choose the best method for meeting the emission caps.	Environmental Protection Agency, "Cross-State Air Pollution Rule," website epa.gov/air transport. Federal Register, Vol. 70, No. 91 (May 12, 2005), 40 CFR Parts 51, 72, 73, 74, 77, 78 and 96.
C.	Mercury and Air Toxics Standards (MATS)	MATS sets standards to reduce air pollution from coal-and oil-fired power plants greater than 25 megawatts. The rule requires plants achieve the maximum achievable control technology for mercury, hydrogen chloride (HCl) and fine particulate matter (PM 2.5).	The EMM assumes that all coal-fired generating plants above 25 megawatts will comply beginning in 2016. Plants are assumed to reduce mercury emissions by 90 percent relative to uncontrolled levels. Because the EMM does not model HCl or PM 2.5 explicitly, to meet those requirements, coal plants are required to install either an FGD or a dry sorbent injection system including a full fabric filter.	U. S. Environmental Protection Agency, "Mercury and Air Toxics Standards," website epa.gov/mats.
D.	Energy Policy Act of 1992 (EPACT92)	Created a class of generators referred to as exempt wholesale generators (EWGs), exempt from PUHCA as long as they sell wholesale power.	Represents the development of Exempt Wholesale Generators (EWGs) or what are now referred to as independent power producers (IPPs) in all regions.	Energy Policy Act of 1992, Title VII, Electricity, Subtitle A, Exempt Wholesale Generators.
E.	The Public Utility Holding Company Act of 1935 (PUHCA)	PUHCA is a federal statue which was enacted to legislate against abusive practices in the utility industry. The act grants power to the U.S. Securities and Exchange Commission (SEC) to oversee and outlaw large holding companies which might otherwise control the provision of electrical service to large regions of the country. It gives the SEC power to approve or deny mergers and acquisitions and, if necessary, force utility companies to dispose of assets or change business practices if the company's structure of activities are not deemed to be in the public interest.	It is assumed that holding companies act competitively and do not use their regulated power businesses to cross-subsidize their unregulated businesses.	Public Utility Holding Company Act of 1936.

	Legislation	Brief description	AEO handling	Basis
F.	FERC Orders 888 and 889	FERC has issued two related rules: Orders 888 and 889, designed to bring low-cost power to consumers through competition, ensure continued reliability in the industry, and provide for open and equitable transmission services by owners of these facilities. Specifically, Order 888 requires open access to the transmission grid currently owned and operated by utilities. The transmission owners must file nondiscriminatory tariffs that offer other suppliers the same services that the owners provide for themselves. Order 888 also allows these utilities to recover stranded costs (investments in generating assets that are unrecoverable due to consumers selecting another supplier). Order 889 requires utilities to implement standards of conduct and an Open Access Same-time Information System (OASIS) through which utilities and non-utilities can receive information regarding the transmission system. Consequently, utilities are expected to functionally or physically unbundle their marketing functions from their transmission functions.	These orders are represented in the forecast by assuming that all generators in a given region are able to satisfy load requirements anywhere within the region. Similarly, it is assumed that transactions between regions will occur if the cost differentials between them make it economic to do so.	Promoting Wholesale Competition Through Open Access, Non-Discriminatory Transmission Services by Public Utilities; Public Utilities and Transmitting Utilities, ORDER NO. 888 Issued April 24, 1996), 18 CFR Parts 35 and 385, Docket Nos. RM95-8-000 and RM94-7-001. Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct, ORDER NO. 889, (Issued April 24, 1996), 18 CFR Part 37, Docket No. RM95-9-000.
G.	New Source Review (NSR)	On August 28, 2003, the EPA issued a final rule defining certain power plant and industrial facility activities as routine maintenance, repair, and replacement, which are not subject to new source review (NSR). As stated by EPA, these changes provide a category of equipment replacement activities that are not subject to major NSR requirements under the routine maintenance, repair, and replacement (RMRR) exclusion.[1] Essentially this means that power plants and industrial facilities engaging in RMRR activities will not have to get preconstruction approval from the state or EPA and will not have to install best available emissions control technologies that might be required if NSR were triggered.	It is assumed that coal plants will be able to increase their output as electricity demand increases. Their maximum capacity factor is set at 75 percent. No increases in the capacity of existing plants is assumed. If further analysis shows that capacity uprates may result from the NSR rule, they will be incorporated in future AEOs. However, at this time, the NSR rule is being contested in the courts.	EPA, 40 CFR Parts 51 and 52, Deterioration (PSD) and Non-Replacement Provision of the Vol. 68, No. 207, page 61248, Prevention of Significant Attainment New Source Review (NSR): Equipment Routine Maintenance, Repair and Replacement Exclusion; Final Rule, Federal Register, October 27, 2003.

	Legislation	Brief description	AEO handling	Basis
H.	State Renewable Portfolio Standards (RPS) Laws, Mandates, and Goals	Several states have enacted laws requiring that a certain percentage of their generation come from qualifying renewable sources.	The AEO reference case represents the Renewable Portfolio Standard (RPS) or substantively similar laws from States with established enforcement provisions for their targets. As described in the Renewable Fuels Module chapter of this document, mandatory targets from the various states are aggregated at the regional level, and achievement of nondiscretionary compliance criteria is evaluated for each region.	The states with RPS or other mandates providing quantified projections are detailed in the Legislation and Regulations section of AEO2016.
I.	Regional and State Air Emissions Regulations	The Northeast Regional Greenhouse Gas Initiative (RGGI) applies to fossil-fueled power plants over 25 megawatts in the northeastern United States. New Jersey withdrew in 2011, leaving 9 states in the program. The rule caps CO2 emissions and requires they account for CO2 emitted with allowances purchased at auction. In February 2013, program officials announced a tightening of the cap beginning in 2014.	The impact of RGGI is included in the EMM, making adjustments when needed to estimate the emissions caps at the regional level used in NEMS. AEO2016 incorporates the revised target beginning in 2014.	Regional Greenhouse Gas Initiative Model rule, www.rggi.org.
		The California Assembly Bill 32 (AB32) sets GHG reduction goals for 2020 for California. A cap-and-trade program was designed to enforce the caps. The cap-and-trade program applies to multiple economic sectors including electric power plants, large industrial facilities, suppliers of transportation fuel, and suppliers of natural gas. Emissions resulting from electricity generated outside California but consumed in the state are also subject to the cap.	The EMM models the cap-and-trade program explicitly for CO2 for California through an emission constraint that accounts for emissions from the other sectors. Limited banking and borrowing of allowances as well as an allowance reserve and offsets are incorporated as specified in the Bill.	California Code of Regulations, Subchapter 10 Climate Change, Article 5, Sections 95800 to 96023, Title 17, “California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms,” (Sacramento, CA: July 2011).
J.	Energy Policy Act of 2005	Extended and substantially expanded and modified the Production Tax Credit, originally created by EPACT1992.	EPACT2005 also adds a PTC for up to 6,000 megawatts of new nuclear capacity and a $1.3 billion investment tax credit for new or repowered coal-fired power projects. The tax credits for renewables, nuclear and coal projects are explicitly modeled as specified in the law and subsequent amendments. Because the tax credits for new coal projects have been fully allocated, the EMM does not assume future coal capacity will receive any tax credits.	Energy Policy Act of 2005, Sections 1301, 1306, and 1307.

	Legislation	Brief description	AEO handling	
K.	American Recovery and Reinvestment Act of 2009	ARRA provides $4.5 billion for smart grid demonstration projects. These generally include a wide array of measurement, communications, and control equipment employed throughout the transmission and distribution system that will enable real-time monitoring of the production, flow, and use of power from generator to consumer.	In the electricity module, it was assumed that line losses would fall slightly, peak loads would fall as customers shifted their usage patterns, and customers would be more responsive to pricing signals	American Recovery and Reinvestment Act of 2009, Title IV, “Energy and Water Development”, Section 405.
		ARRA provides $800 million to fund projects under the Clean Coal Power Initiative program focusing on capture and sequestration of greenhouse gases.	It was assumed that one gigawatt of new coal with sequestration capacity would come online by 2018.	American Recovery and Reinvestment Act of 2009, Title IV, “Energy and Water Development”
L.	Consolidated Appropriations Act , 2016	As part of this Act, 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.	AEO2016 explicitly models the revised dates for these tax credits.	H.R.2029 - Consolidated Appropriations Act, 2016, Public Law 114-113, Sec. 187, December 2015.

Oil and gas supply

	Legislation	Brief description	AEO handling	Basis
A.	The Outer Continental Shelf Deep Water Royalty Relief Act (DWRRA)	Mandates that all tracts offered by November 22, 2000, in deep water in certain areas of the Gulf of Mexico must be offered under the new bidding system permitted by the DWRRA. The Secretary of the Interior must offer such tracts with a specific minimum royalty suspension volume based on water depth.	Incorporates royalty rates based on water depth.	43 U.S.C. SS 1331-1356 (2002).
B.	Energy Policy and Conservation Act Amendments of 2000	Required the USGS to inventory oil and gas resources beneath federal lands.	To date, the Rocky Mountain oil and gas resource inventory has been completed by the USGS. The results of this inventory have been incorporated in the technically recoverable oil and gas resource volumes used for the Rocky Mountain region.	Scientific Inventory of Onshore Federal Lands: Oil and Gas Resources and Reserves and the Extent and Nature of Restrictions or Impediments to their Development: The Paradox/San Juan, Uinta/ Piceance, Greater Green River, and Powder River Basins and the Montana Thrust Belt. Prepared by the Departments of Interior, Agriculture and Energy, January 2003.
C.	Section 29 Tax Credit for Nonconventional Fuels	The Alternative Fuel Production Credit (Section 29 of the IRC) applies to qualified nonconventional fuels from wells drilled or facilities placed in service between January 1, 1980 and December 31, 1992. Gas production from qualifying wells could receive a $3 (1979 constant dollars) per barrel of oil equivalent credit on volumes produced through December 31, 2002. The qualified fuels are: oil produced from shale and tar sands; gas from geopressurized brine, Devonian shale, coal seams, tight formations, and biomass; liquid, gaseous, or solid synthetic fuels produced from coal; fuel from qualified processed formations or biomass; and steam from agricultural products.	The Section 29 Tax Credit expired on December 31, 2002, and it is not considered in new production decisions. However, the effect of these credits is implicitly included in the parameters that are derived from historical data reflecting such credits.	Alternative Fuel Production Credit (Section 29 of the Internal Revenue Code), initially established in the Windfall Profit Tax of 1980.
D.	Energy Policy Act of 2005	Established a program to provide grants to enhance oil and gas recovery through CO2 injection	Additional oil resources were added to account for increased use of CO2-enhanced oil recovery.	Title III, Section 354 of the Energy Policy Act of 2005.

Natural gas transmission and distribution

	Legislation	Brief description	AEO handling	Basis
A.	Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 and other previous laws and regulations on pipeline safety.	Provides for enhanced safety, reliability and environmental protection in the transportation of energy products by pipeline.	Costs associated with previously imposed pipeline safety laws are assumed to already be reflected in historical capital and operating	P.L. 112-90, 125 Stat. 1904
B.	Energy Policy Act of 2005.	Allowed natural gas storage facilities to charge market-based rates if it was believed they would not exert market power.	Storage rates are allowed to vary from regulation-based rates depending on market conditions.	Title III, Section 312 of the Energy Policy Act of 2005.
C.	Federal Motor Fuels Excise Taxes for Compressed Natural Gas and Liquefied Natural Gas in Vehicles. Liquefied natural gas tax changed	Taxes are levied on each gasoline-gallon equivalent of compressed natural gas and each diesel-gallon equivalent of liquefied natural gas used in vehicles and ships.	Federal motor fuels excise taxes on natural gas fuel for vehicles and ships are included in retail prices and are assumed to be extended indefinitely at current	26 USC 4041.
D.	State Motor Fuels Taxes for Compressed Natural Gas and Liquefied Natural Gas in Vehicles	Taxes are levied on each gallon, gasoline-gallon equivalent, or diesel-gallon equivalent of natural gas for vehicles.	State motor fuels excise taxes on natural gas fuel for vehicles are included in retail prices and are assumed to be extended indefinitely at current	Determined by review of existing state laws.

Liquid fuels market

	Legislation	Brief description	AEO handling	Basics
A	Ultra-Low-Sulfur Diesel (ULSD) regulations under the Clean Air Act Amendment of 1990	Since mid-2012, all diesel for domestic use (highway, non-road, locomotive, marine) may contain at most 15 ppm sulfur.	Reflected in diesel specifications.	40 CFR Parts 69, 80, 86, 89, 94, 1039, 1048, 1065, and 1068.
B.	Mobile Source Air Toxics (MSAT) Controls Under the Clean Air Act Amendment of 1990	Establishes a list of 21 substances emitted from motor vehicles and known to cause serious human health effects, particularly benzene, formaldehyde, 1.3 butadiene, acetaldehyde, diesel exhaust organic gases, and diesel particulate matter. Establishes anti-backsliding and anti- dumping rules for gasoline.	Modeled by updating gasoline specifications to most current EPA gasoline survey data (2005) representing anti-backsliding requirements.	40 CFR Parts 60 and 86.
C.	Low-Sulfur Gasoline Regulations Under the Clean Air Act Amendment of 1990	Gasoline must contain an average of 30 ppm sulfur or less by 2006. Small refiners may be permitted to delay compliance until 2008.	Reflected in gasoline specifications.	40 CFR Parts 80, 85 and 86.
D.	Tier 3 Vehicle Emission and Fuel Standards Program	Gasoline must contain an average of 10 ppm sulfur or less by January 1, 2017. Small refiners may be permitted a 3 year delay.	Reflected in gasoline specifications beginning in 2017.	40 CFR Parts 79, 80, 85, et. al., final rule: http://www.gpo.gov/fdsys/pkg/FR-2014-04-28/pdf/2014-06954.pdf
E.	MTBE Bans in 25 states	25 states ban the use of MTBE in gasoline by 2007.	Ethanol assumed to be the oxygenate of choice for all motor gasoline blends.	State laws in Arizona, California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Maine, Michigan, Minnesota, Missouri, Montana, Nebraska, New Hampshire, New Jersey, New York, North Carolina, Ohio, Rhode Island, South Dakota, Vermont, Washington, and Wisconsin.
F.	Regional Clean Fuel Formations	States with air quality problems can specify alternative gasoline or diesel formulations with EPA's permission. California has long had authority to set its own fuel standards.	Reflected in PADD-level gasoline and diesel specifications.	State implementation plans required by the Clean Air Act Amendments of 1990, as approved by EPA.
G.	Federal Motor Fuels Excise Taxes	Taxes are levied on each gallon of transportation fuels to fund infrastructure and general revenue. These taxes are set to expire at various times in the future but are expected to be renewed, as they have been in the past.	Gasoline, diesel, and ethanol blend tax rates are included in end-use prices and are assumed to be extended indefinitely at current nominal rates.	26 USC 4041 Extended by American Jobs Creation Act of 2004

	Legislation	Brief description	AEO handling	Basics
H.	State Motor Fuel Taxes	Taxes are levied on each gallon of transportation fuels. The assumption that state taxes will increase at the rate of inflation supports an implied need for additional highway revenues as driving increases.	Gasoline and diesel rates are included in end-use prices and are assumed to be extended indefinitely in real terms (to keep pace with inflation).	Determined by review of existing state laws performed semi-annually by EIA's Office of Energy Statistics.
I.	Diesel Excise Taxes	Phases out the 4.3 cents excise tax on railroads between 2005 and 2007.	Modeled by phasing out.	American Jobs Creation Act of 2004, Section 241.
J. Energy Policy Act of 2005 (EPACT05)				
	a. Ethanol/biodiesel tax credit	Petroleum product blenders may claim tax credits for blending ethanol into gasoline and for blending biodiesel into diesel fuel or heating oil. The credits may be claimed against the federal motor fuels excise tax or the income tax. Most recent tax credits are $1.01 per gallon of cellulosic ethanol, and $1.00 per gallon of biodiesel. Both tax credits expire after 2014.	The tax credits are applied against the production costs of the products into which they are blended. Ethanol is used in gasoline and E85. Biodiesel is assumed to be blended into highway diesel, and nonroad diesel or heating oil.	26 USC 40, and 26 USC 6426. Tax credits extended through December 31, 2014 by Public Law 113-195) .
	b. Renewable Fuels Standard (RFS)	This section has largely been redefined by EISA07 (see below); however, EPA rulemaking completed for this law was assumed to contain guiding principles of the rules and administration of EISA07.		Energy Policy Act of 2005, Section 1501.
	c. Elimination of oxygen content requirement in reformulated gasoline	Removes the 2% oxygen requirement for reformulated gasoline (RFG) nationwide.	Oxygenate waiver already an option of the model. MTBE was phased out in 2006 resulting from the petroleum industry's decision to discontinue use.	Energy Policy Act of 2005, Section 1504.
	d. Coal gasification provisions	Investment tax credit program for qualifying advanced clean coal projects including Coal-to- Liquids Projects.	Two CTL units are available to build with lower capital costs reflecting the provision's funding.	Energy Policy Act of 2005, Section 1307.
K. Energy Independence and Security Act of 2007 (EISA07)				

	a. Renewable Fuels Standard (RFS)	Requires the use of 36 billion gallons of ethanol per year by 2022, with corn ethanol limited to 15 billion gallons. Any other biofuel may be used to fulfill the balance of the mandate, but the balance must include 16 billion gallons per year of cellulosic biofuel by 2022 and 1 billion gallons per year of biodiesel by 2012	The RFS is included in AEO2016, however it is assumed that the schedule for cellulosic biofuel is adjusted downward consistent with waiver provisions contained in the law.	40 CFR Part 80, Subpart M; AEO2016: "RFS Program: Standards for 2014, 2015, and 2016 and Biomass-Based Diesel Volume for 2017," page 4/100, https://www.gpo.gov/fdsys/pkg/FR-2015-12-14/pdf/2015-30893.pdf
L.	State Heating Oil Mandates	A number of Northeastern states passed legislation that reduces the maximum sulfur content of heating oil to between 15 and 50 ppm in different phases through 2016.	All state regulations included as legislated in AEO2014. 2013 EIA heating oil consumption data is used to calculate respective state Census Division shares for new consumption of low sulfur diesel as heating oil.	Vermont Energy Act of 2011, Maine State Legislature HP1160, NJ State Department of Environmental Protection, Amendment N.J.A.C. 7:27-9.2, New York State Senate Bill 51145C.
M	California Low Carbon Fuel Standard (LCFS)	California passed legislation which is designed to reduce the Carbon Intensity (CI) of motor gasoline and diesel fuels sold in California by 10 percent between 2012 and 2020 through the increased sale of alternative "low-carbon" fuels.	The LCFS is included in AEO2014 as legislated for gasoline and diesel fuel sold in California, and for other regulated fuels.	California Air Resources Board, "Final Regulation Order: Subarticle 7. Low Carbon Fuel Standard."
N	California Assembly Bill 32 (AB32)	The California Assembly Bill 32 (AB32), the Global Warming Solutions Act of 2006, authorized the California Air Resources Board (CARB) to set GHG reduction goals for 2020 for California. A cap-and-trade program was designed to enforce the caps. The cap-and-trade program applies to multiple economic sectors including electric power plants, large industrial facilities, suppliers of natural gas. Emissions resulting from electricity generated outside California but consumed in the State are also subject to the cap.	The AB32 cap-and-trade was more fully implemented in AEO2013, adding industrial facilities, refineries, fuel providers, and non-CO2 GHG emissions to the representation already in the electrical power sector of NEMS. Also, limited banking and borrowing, as well as an allowance reserve and offset purchases, were modeled, providing some compliance flexibility and cost containment.	California Code of Regulations, Subchapter 10 Climate Change, Article 5, Sections 95800 to 96023, Title 17, "California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms," (Sacramento, CA: July 2011)

	Legislation	Brief description	AEO handling	Basics
O	EPA ETS Waiver	EPA approved two waivers for the use of ethanol motor gasoline blends of up to 15 percent in vehicles 2001 and newer.	These two waivers were included and modeled in AEO2013 (and remain in AEO2015) based on forecasted vehicle fleets and potential infrastructure and liability setbacks.	EPA–HQ–OAR–2009–0211; FRL–9215–5, EPA–HQ– OAR–2009–0211; FRL–9258–6.
P	US Department of commerce, Bureau of Industry and Security (BIS): clarification on the export of lease condensate	Under 754.2(a), "lease condensate that has been processed through a crude oil distillate tower is not crude oil but a petroleum product" which have few export restrictions.	Processed API 50+ crude is assumed to be processed condensate, and is allowed to be exported	See FAQ#3 under the heading "FAQs – Crude Oil and Petroleum Products December 30, 2014," https://www.bis.doc.gov/index.php/policy-guidance/deemed-exports/deemed-exports-faqs
Q	US Congress, "H.R. 1314 – Bipartisan Budget Act of 2015," Title IV – Strategic Petroleum Reserve, Sec. 401-403, 114th Congress (2015-2016)	Under Sec. 401-403, requires a test drawdown, actual drawdown, and sale of crude from the Strategic Petroleum Reserve over FY2018 – FY2025.	Explicitly represents the crude withdrawals from the Strategic Petroleum Reserve (SPR) as specified by the Act	https://www.congress.gov/bill/114th-congress/house-bill/1314/text#toc-H2D8D609ED2A3417887CC3EAF49A81E15
R	US Congress, "H.R. 22 – FAST Act," Sec. 32204, Strategic Petroleum Reserve drawdown and sale, 114th Congress (2015-2016)	Under Sec. 32204, requires drawdown and sale of crude from the Strategic Petroleum Reserve over a specified timeframe.	Explicitly represents the crude withdrawals from the Strategic Petroleum Reserve (SPR) as specified by the Act.	https://www.congress.gov/bill/114th-congress/house-bill/22/text
S	US Congress, "H.R. 2029 – Consolidated Appropriations Act 2016," Division O – Other matters, Title I – Oil Exports, Safety Valve, and Maritime Security, 114th Congress (2015-2016)	Title 1, Sec. 101 ends the ban on U.S. crude oil exports; however, under extenuating circumstances, the President may restrict U.S. crude oil exports for no more than 1 year.	Any crude produced in the U.S. is allowed to be exported.	https://www.congress.gov/bill/114th-congress/house-bill/2029

Source: U.S. Energy Information Administration, Office of Energy Analysis.