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 2017* [1.1] (AEO2017), 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. The AEO is now on a biennial schedule with a full report every other year. AEO2017 is an abridged report and contains fewer side cases than the prior AEO. Detailed documentation of the modeling system is available in a series of documentation reports [1.2]. Important changes since the most recent documentation will be featured in this report and as such no additional formal documentation will be provided until the next long report in AEO2018.

The National Energy Modeling System

Projections in AEO2017 are generated using NEMS [1.3], 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 currently 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/).

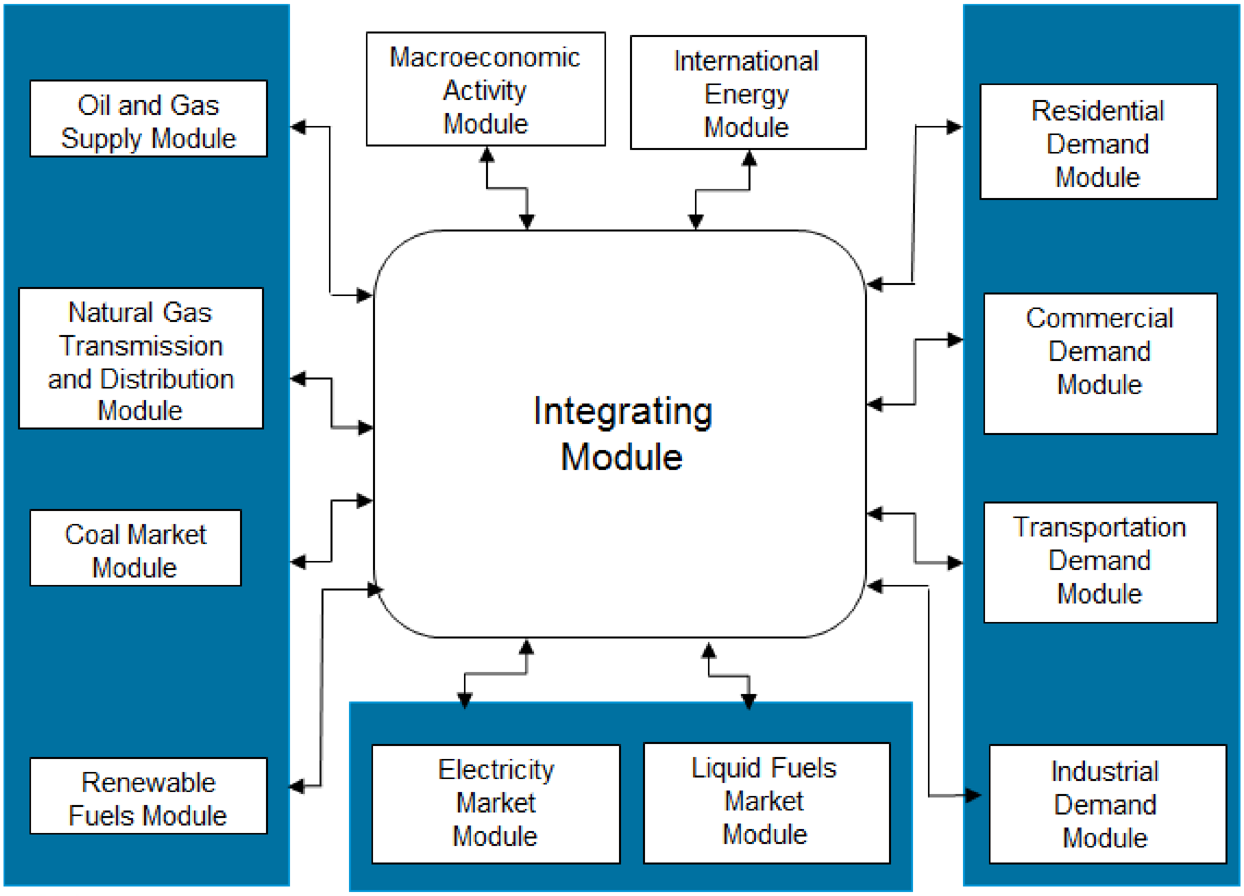
NEMS is organized and implemented as a modular system (Figure 1.1). The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. The modular design also permits the use of the methodology and level of detail most appropriate for each 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 2017 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 AEO2017 generally represents current legislation and environmental regulations, including recent government actions for which implementing regulations were available as of the end of September 2016. 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. The U.S. Environmental Protection Agency's (EPA) Clean Power Plan (CPP), is included in the Reference case of AEO2017. 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 of this document.

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, 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 the 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 that are 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 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 Macroeconomic Activity Module of NEMS.

Industrial Demand Module

The Industrial Demand Module (IDM) projects the consumption of energy for heat and power in each of 21 industries or industry groups, as well as the consumption of feedstocks in the bulk chemicals industry. 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. The one data change for AEO2017 includes simplifying the direct reduced iron (DRI) output so that 10% of total DRI output is used in blast furnaces.

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 light-duty vehicles, heavy-duty vehicles, 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 light-duty vehicle travel component uses fuel prices, personal income, and ten age and gender population groups to generate projections. The Transportation Demand Module 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 light-duty-vehicle Corporate Average Fuel Economy (CAFE) and Greenhouse Gas (GHG) emissions standards, heavy-duty vehicle fuel consumption and GHG emissions standards, and biofuels consumption reflect requirements enacted by 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 Transportation Demand Module 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.

The Transportation Demand Module projects energy consumption for freight trucks (heavy-duty vehicles 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 November 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 Clean Power Plan, 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 AEO2017. The AEO2017 Reference case imposes a limit on CO2 emissions for specific covered sectors, including the electric power sector, in California, as represented in California's SB 32. The AEO2017 Reference case continues to assume 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 AEO2017 Reference case continues to apply a 3-percentage-point increase in the cost of capital, when evaluating investments in certain 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. The AEO2017 also represents a coal technology that captures 90% of the carbon emissions, and this technology does not receive the 3 percentage point adder.

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 Residential and Commercial Demand Modules.

The PTC for wind, geothermal, landfill gas, and some types of hydroelectric and biomass-fueled plants are represented in AEO2017 based on the laws enacted in December 2015. The PTC provides a credit of up to 2.3 cents/kilowatthour (kWh) for electricity produced in the first 10 years of plant operation. For AEO2017, 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 percentage points annually until it expires at the end of 2019. AEO2017 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 six onshore, three offshore, and in three Alaska regions.

The Onshore Lower 48 Oil and Gas Supply Submodule evaluates the economics of future exploration and development projects for crude oil and natural gas plays. Crude oil resources include structurally reservoired resources (i.e., conventional) as well as highly fractured continuous zones, such as the Austin Chalk and Bakken shale formations. Production potential from advanced secondary recovery techniques (such as infill drilling, horizontal continuity, and horizontal profile) and enhanced oil recovery (such as CO2 flooding, steam flooding, polymer flooding, and profile modification) are explicitly represented. Natural gas resources include high-permeability carbonate and sandstone, tight gas, shale gas, and coalbed methane.

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

Natural Gas Transmission and Distribution Module

The Natural Gas Transmission and Distribution Module (NGTDM) represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas, the availability of domestic natural gas, and domestic natural gas traded on the international market. The module balances natural gas supply and demand, tracks the flows of natural gas, and determines the associated capacity expansion requirements in an aggregate pipeline network, connecting domestic and limited foreign supply sources with 12 demand regions representing the Lower 48 states. These regions align with the nine Census divisions, with three subdivided, and Alaska handled separately.

The flow of natural gas is determined for both a peak and off-peak period in the year, assuming a historically based seasonal distribution of natural gas demand. Key components of pipeline and distributor tariffs are included in separate pricing algorithms. The primary outputs of the module are delivered natural gas prices by region and sector, supply prices, and realized domestic natural gas production. The module also projects natural gas pipeline imports and exports to Canada and Mexico, as well as LNG imports and exports.

Liquids Fuels Market Module

The Liquid Fuels Market Module (LFMM) projects prices of petroleum products, crude oil and product import/export activity, and domestic refinery operations, subject to demand for petroleum products, availability and price of imported petroleum, environmental regulations, and domestic production of crude oil, natural gas liquids, and biofuels—ethanol, biodiesel, biomass-to-liquids (BTL), coal-to-liquids (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 Fuel Standard (RFS) specified in the Energy Independence and Security Act of 2007, 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 was 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 two types of coal (steam and metallurgical) for 17 export regions and 20 import regions. U.S. coal production and distribution are computed for 14 supply regions and 16 demand regions.

Annual Energy Outlook 2017 cases

Table 1.1 provides a summary of the cases produced as part of AEO2017. For each case, the table gives the name used in AEO2017 and a brief description. The text prior to Table 1.1 describes the various cases in more detail. Regional results and other details of the projections are available at http://www.eia.gov/outlooks/aeo/tables_ref.cfm#supplement.

Macroeconomic growth cases

In addition to the AEO2017 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 an average rate of 0.6%/year, nonfarm employment by 0.7%/year, and productivity by 1.7%/year from 2016 to 2050. Economic output as measured by real GDP increases by 2.1%/year from 2016 through 2050, and growth in real disposable income per capita averages 1.5%/year.
- The Low Economic Growth case assumes lower average annual growth rates for population (0.5%/year) and productivity (1.3%/year), resulting in lower growth in nonfarm employment (0.5%/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 2016 through 2050, and growth in real disposable income per capita averages 1.3%/year.
- The High Economic Growth case assumes higher average growth rates for population (0.8%/year) and productivity (2.0%/year), resulting in higher nonfarm employment (0.9%/year). With higher productivity gains and employment growth, inflation and interest rates are lower than in the Reference case for most years, and consequently economic output grows at a higher rate (2.6%/year) than in the Reference case (2.1%/year). Real disposable income per capita grows by 1.7%/year.

Oil price cases:

- The benchmark crude oil price in AEO2017 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 (b) and $8/b. Data tables also include 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 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. AEO2017 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 (2016 dollars) steadily rise from $43/b in 2016 to $109/b in 2040 and $117/b by 2050. The Reference case represents a trend projection for both oil supply and demand. Global supply increases throughout the projection period. Global oil production is only projected through 2040. 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 light duty vehicle (LDV) and heavy duty vehicle (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 $25/b (2016 dollars) in 2017, and remain below $50/b through 2050. Relatively low global 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 (OPEC) and non-OPEC producers. However, lower-cost supply from OPEC producers eventually begins to crowd out supply from relatively more expensive non-OPEC sources. In the Low Oil Price case, OPEC’s market share of liquids production rises steadily from 40% in 2016 to 43% in 2020 and to 48% in 2040.
- In the High Oil Price case, oil prices average about $226/b (2016 dollars) in 2040 and $241/b in 2050. A lack of global investment in the oil sector is the primary cause of higher prices, which eventually leads 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, starting in 2019, crowds out OPEC oil, and OPEC’s share of world liquids production decreases, from 39% in2016 to under 33% 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.

No Clean Power Plan case

- 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] in the Northeast and California's SB 32). There is no incentive for incremental energy efficiency in the end-use demand modules.

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 AEO2017 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 164 billion barrels, and the natural gas resource is decreased to 1,328 trillion cubic feet (Tcf), as compared with unproved resource estimates of 236 billion barrels of crude oil and 1,986 Tcf of natural gas as of January 1, 2015, 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 355 billion barrels, and the natural gas resource increases to 2,812 Tcf as compared with unproved resource estimates of 236 billion barrels of crude oil and 1,986 Tcf of natural gas in the Reference case as of the start of 2015.

Table 1.1. Summary of AEO2017 cases

Case name	Description
Reference	Real gross domestic product (GDP) grows at an average annual rate of 2.1% from 2016 to 2050. Brent crude oil prices rise to about $117/barrel (b) (2016 dollars) in 2050. Reference case projection tables are in AEO2017 Appendix A.
Low Economic Growth	Real GDP grows at an average annual rate of 1.6% from 2016 to 2050.Energy market assumptions are the same as in the Reference case. Partial projection tables are in AEO2017 Appendix B.
High Economic Growth	Real GDP grows at an average annual rate of 2.6% from 2016 to 2050. Energy market assumptions are the same as in the Reference case. Partial projection tables are in AEO2017 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 and Development (non-OECD) nations and higher global supply. Lower global 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 40% in 2016 to 43% in 2020 and 48% in 2040. Brent light, sweet crude oil prices fall to an average of $25/b (2016 dollars) in 2017, and remain below $50/b through 2050. Partial projection tables are in AEO2017 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 resources 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, from 39% in 2016 to 33% by 2040. 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. Crude oil prices are about $226/b (2016 dollars) in 2040 and $241/b in 2050. Partial projection tables are in AEO2017 Appendix C.

Table 1.1. Summary of AEO2017 cases (cont.)

Case name	Description
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 are in AEO2017 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 are in AEO2017 Appendix D.
Electricity: No CPP	Assumes that the CPP is not enforced, and that no federal requirements are in place to reduce CO2 emissions from existing power plants.

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 estimate 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 convention). 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 AEO2017.

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
Propane used as feedstock	63.07	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	0.316	21.12
Motor gasoline (net of ethanol)	71.28	1.000	71.28
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	71.01	0.410	29.11
Kerosene	72.31	1.000	72.31
Petroleum coke	101.09	0.956	97.61
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[2]			
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

[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.

[2]Biogneic sources are included for information purposes, but not counted in total energy-related carbon dioxide.

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

Notes and sources

[1.1] U.S. Energy Information Administration, *Annual Energy Outlook 2017* (AEO2017), DOE/EIA-0383(2017) (Washington, DC, January 2017). https://www.eia.gov/outlooks/aeo/

[1.2] NEMS documentation reports are available on the EIA website.

[1.3] NEMS overview and brief description of cases.