

Introduction

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This report presents the major assumptions of the National Energy Modeling System (NEMS) used to generate the projections in the *Annual Energy Outlook 2013* [1] (*AEO2013*), 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 the *AEO2013* are generated using the NEMS, 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 also used to complete analytical studies for the U.S. Congress, the Executive Office of the President, other offices within the U.S. Department of Energy, and other Federal agencies. NEMS is also used by other nongovernment groups, such as the Electric Power Research Institute, Duke University, and Georgia Institute of Technology. In addition, the *AEO* projections are used by analysts and planners in other government agencies and nongovernment 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 among the various energy fuels and sources. The time horizon of NEMS extends to 2040. To represent regional differences in energy markets, the component modules of NEMS function at the regional level: the 9 Census divisions for the end-use demand modules; production regions specific to oil, natural gas, and coal supply and distribution; 22 regions and subregions of the North American Electric Reliability Corporation for electricity; and 8 refining regions that are a subset of the 5 Petroleum Administration for Defense Districts (PADDs). Maps illustrating the regional formats used in each module are included in this report. Only selected regional results are presented in *AEO2013*, which predominantly focus on the national results. Complete regional and detailed results are available on the EIA Analyses and Projections Home Page (www.eia.gov/analysis/).

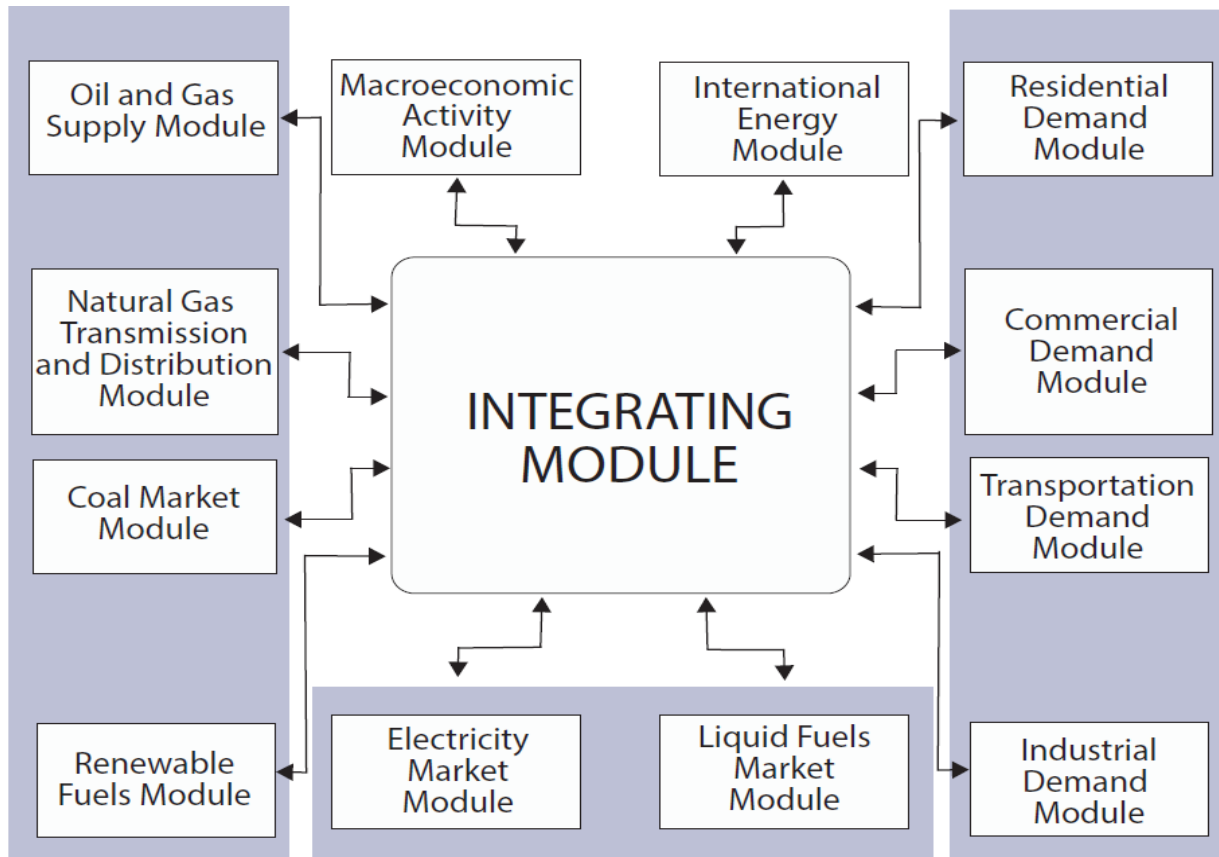
NEMS is organized and implemented as a modular system (Figure 1). The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. The modular design also permits the use of the methodology and level of detail most appropriate for each energy 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 the activities necessary to produce, import, and transport fuels to end users. The information flows also include other data on 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, thus achieving an economic equilibrium of supply and demand in the consuming sectors. A solution is reached for each year from 2012 through 2040. Other variables, such as petroleum product imports, crude oil imports, and several macroeconomic indicators, also are evaluated for convergence. Each NEMS component represents the impacts 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 (NO_x), 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. This modularity allows use of the methodology and level of detail most appropriate for each energy sector. NEMS solves by calling each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. Solution is reached annually through the projection horizon. Other variables are also evaluated for convergence such as petroleum product imports, crude oil imports, and several macroeconomic indicators.

The version of NEMS used for *AEO2013* generally represents current legislation and environmental regulations, including recent government actions for which implementing regulations were available as of September 30, 2012, such as: the new light-duty vehicle (LDV) greenhouse gas (GHG) and corporate average fuel economy (CAFE) standards for model years 2017 to 2025 [3] released in October 2012; the Clean Air Interstate Rule (CAIR), which was reinstated as binding legislation after the Cross-State Air Pollution Rule (CSAPR) [4] was vacated on August 21, 2012; updated handling of the U.S. Environmental Protection Agency's (EPA) National Emissions Standards for Hazardous Air Pollutants for industrial boilers and process heaters [5] based on regulations released in March 2011; the Mercury and Air Toxics Standards [6] issued by the EPA in December 2011; California's cap-and-trade program authorized by Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006 [7], issued in September 2006; and the California Low Carbon Fuel Standard (LCFS) [8] finalized in January 2010.

The potential impacts of proposed federal and state legislation, regulations, or standards—or of sections of legislation that have been enacted but require funds or implementing regulations that have not been provided or specified—are not reflected in NEMS. Many of the pending provisions, however, are examined in alternative cases included in *AEO2013* or in other analysis completed by EIA. 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. 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 LDVs, 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. The IEM computes Brent and West Texas Intermediate (WTI) prices, 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 and exogenous assumptions for petroleum products for import and export in the United States. In interacting with the rest of NEMS, the IEM changes Brent and WTI prices in response to changes in expected production and consumption of crude oil and other liquids in the United States.

Residential and Commercial Demand Modules

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

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

Industrial Demand Module

The Industrial Demand Module (IDM) projects the consumption of energy for heat and power, as well as the consumption of feedstocks and raw materials in each of 21 industry groups, subject to the delivered prices of energy and macroeconomic estimates of employment and the value of shipments for each industry. As noted in the description of 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 eighth energy-intensive manufacturing industry) is modeled in the Liquid Fuels Market Module (LFMM) as described below, but the projected consumption is reported under the industrial totals.

There are several updates and upgrades in the representations of select industries. *AEO2013* includes an upgraded representation for the aluminum industry. Instead of assuming that technological development for a particular process occurs on a predetermined or exogenous path based on engineering judgment, these upgrades allow IDM technological change to be modeled endogenously, while using more detailed process representation. The upgrade allows for explicit technological change, and therefore energy intensity, to respond to economic, regulatory, and other conditions. The combined cement and lime industry was upgraded in the *Annual Energy Outlook 2012 (AEO2012)*. For subsequent AEOs other energy-intensive industries will be similarly upgraded.

The bulk chemicals model has been enhanced in several respects: baseline natural gas liquids (NGL) feedstock data were aligned with Manufacturing Energy Consumption Survey 2006 data; an updated propane pricing mechanism reflecting natural gas price influences was used to allow for price competition between liquid petroleum gases feedstock and petroleum-based (naphtha) feedstock; and propylene supplied by the refining industry is now specifically accounted for in the LFMM.

Nonmanufacturing models were significantly revised as well. The construction and mining models were augmented to better reflect NEMS assumptions regarding energy efficiencies in (off-road) vehicles and buildings, as well as coal, oil, and natural gas extraction productivity. The agriculture model was similarly augmented in *AEO2012*. The IDM also includes a generalized representation of CHP. The methodology for CHP systems simulates the utilization of installed CHP systems based on historical utilization rates and is driven by end-use electricity demand. To evaluate the economic benefits of additional CHP capacity, the model also includes an appraisal incorporating historical capacity factors and regional acceptance rates for new CHP facilities.

There are also enhancements to the IDM to account for regulatory changes. This includes California's AB 32 that allows for representation of a cap-and-trade program developed as part of California's GHG reduction goals for 2020. Another regulatory update is included for the handling of National Emissions Standards for Hazardous Air Pollutants for industrial boilers, to address the maximum degree of emission reduction using maximum achievable control technology.

Transportation Demand Module

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

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

The Transportation Demand Module projects energy consumption for freight and passenger rail and marine vessels by mode and fuel, subject to macroeconomic variables such as the value and type of industrial shipments.

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 transmission and pricing of electricity. The finance and pricing submodule uses capital costs, fuel costs, macroeconomic parameters, environmental regulations, and load shapes to estimate generation costs for each technology.

All specifically identified options promulgated by the EPA for compliance with the Clean Air Act Amendments of 1990 are explicitly represented in the capacity expansion and dispatch decisions. All financial incentives for power generation expansion and dispatch specifically identified in EPACT2005 have been implemented. Several States, primarily in the northeast, have enacted air emission regulations for CO₂ that affect the electricity generation sector, and those regulations are represented in *AEO2013*. The *AEO2013* Reference case also 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 *AEO2013* Reference case reinstates the CAIR after the court vacated CSAPR in August 2012. CAIR incorporates a cap and trade program for annual emissions of SO₂ and annual and seasonal emissions of NO_x from fossil power plants. 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.

Although currently there is no Federal legislation in place that restricts GHG emissions, regulators and the investment community have continued to push energy companies to invest in technologies that are less GHG-intensive. The trend is captured in the *AEO2013* Reference case through a 3-percentage-point increase in the cost of capital, when evaluating investments in new coal-fired power plants, new coal-to-liquids (CTL) plants without carbon capture and storage, and pollution control retrofits.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing renewable resource supply and technology input information for central-station, grid-connected electricity generation technologies, including conventional hydroelectricity, biomass (dedicated biomass plants and co-firing in existing coal plants), geothermal, landfill gas, solar thermal electricity, solar photovoltaics, and both onshore and offshore wind energy. The RFM contains renewable resource supply estimates representing the regional opportunities for renewable energy development. Investment tax credits (ITCs) for renewable fuels are incorporated, as currently enacted, including a permanent 10-percent ITC for business investment in solar energy (thermal nonpower uses

as well as power uses) and geothermal power (available only to those projects not accepting the production tax credit [PTC] for geothermal power). In addition, the module reflects the increase in the ITC to 30 percent for solar energy systems installed before January 1, 2017. The extension of the credit to individual homeowners under EIEA2008 is reflected in the Residential and Commercial Demand Modules.

PTCs for wind, geothermal, landfill gas, and some types of hydroelectric and biomass-fueled plants also are represented, based on the laws in effect on October 31, 2012. They provide a credit of up to 2.2 cents per kilowatt-hour for electricity produced in the first 10 years of plant operation. For *AEO2013*, new wind plants coming on line before January 1, 2013, are eligible to receive the PTC; other eligible plants must be in service before January 1, 2014. The law has subsequently been amended to extend the PTC for wind by an additional year. Furthermore, eligible plants of any type will qualify if construction begins prior to the expiration date, regardless of when the plant enters commercial service. This change was made after the completion of *AEO2013* and is not reflected in the analysis. As part of ARRA2009, plants eligible for the PTC may instead elect to receive a 30-percent ITC or an equivalent direct grant. *AEO2013* also accounts for new renewable energy capacity resulting from state renewable portfolio standard programs, mandates, and goals.

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 formations of sandstone and shale. 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 3 Alaskan 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 at the play level. Crude oil resources include conventional, structurally reservoirized resources 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 quantities are used as inputs to the LFMM in NEMS for conversion and blending into refined petroleum products. Supply curves for natural gas are used as inputs to the Natural Gas Transmission and Distribution Module (NGTDM) for determining natural gas wellhead prices and domestic production.

Natural Gas Transmission and Distribution Module

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

The 12 Lower 48 regions align with the 9 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. An algorithm is included to project the addition of CNG retail fueling capability. The module also accounts for foreign sources of natural gas, including 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 activity, as well as domestic refinery operations, subject to demand for petroleum products, availability and price of imported petroleum, and domestic production of crude oil, NGL, 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 [9] are reviewed and updated annually.

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

- Region 1. PADD I - East Coast
- Region 2. PADD II - Interior
- Region 3. PADD II - Great Lakes

- Region 4. PADD III – Gulf Coast
- Region 5. PADD III – Interior
- Region 6. PADD IV – Mountain
- Region 7. PADD V – California
- Region 8. PADD V – Other
- Region 9. Maritime Canada/Caribbean

The 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 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 percent by volume, 15 percent by volume (E15) in states that lack explicit language capping ethanol volume or oxygen content, and up to 85 percent by volume (E85) for use in flex-fuel vehicles. Crude 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 provided by the IEM.

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

The LFMM includes representation of the renewable fuels standard (RFS) specified in EISA2007, which mandates the use of 36 billion gallons of ethanol equivalent renewable fuel by 2022. Both domestic and imported biofuels count toward the RFS. Domestic ethanol production is modeled for three feedstock categories: corn, cellulosic plant materials, and advanced feedstock materials. Starch-based ethanol plants are numerous (more than 190 are now in operation, with a total maximum sustainable nameplate capacity of more than 14 billion gallons annually), and they are based on a well-known technology that converts starch and sugar into ethanol. Ethanol from cellulosic sources is a new technology with only a few small pilot plants in operation. Ethanol from advanced feedstocks—produced at ethanol refineries that ferment and distill grains other than corn, and reduce GHG emissions by at least 50 percent—is also a new technology modeled in the LFMM.

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

Two California-specific policies are also represented in the LFMM: the LCFS and the AB 32 cap-and-trade program. The LCFS requires the carbon intensity (amount of GHG per unit of energy) of transportation fuels sold for use in California to decrease according to a schedule published by the California Air Resources Board. California's AB 32 cap-and-trade program is established to help California achieve its goal of reducing 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 capacity utilization of mines, mining capacity, 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 period, 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 world coal import demands, subject to constraints on export capacities and trade flows. The international coal market component of the module computes trade in 3 types of coal 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 2013 cases

In preparing projections for *AEO2013*, EIA evaluated a wide range of trends and issues that could have major implications for U.S. energy markets between now and 2040. Besides the Reference case, *AEO2013* presents detailed results for five alternative cases that differ from each other due to fundamental assumptions concerning the domestic economy and world oil market conditions. These alternative cases include the following:

Economic Growth -

- In the Reference case, population grows by 0.9 percent per year, nonfarm employment by 1.0 percent per year, and labor productivity by 1.9 percent per year from 2011 to 2040. Economic output as measured by real GDP increases by 2.5 percent per year from 2011 through 2040, and growth in real disposable income per capita averages 1.4 percent per year.
- The Low Economic Growth case assumes lower growth rates for population (0.8 percent per year) and labor productivity (1.4 percent per year), resulting in lower nonfarm employment (0.8 percent per year), higher prices and interest rates, and lower growth in industrial output. In the Low Economic Growth case, economic output as measured by real GDP increases by 1.9 percent per year from 2011 through 2040, and growth in real disposable income per capita averages 1.2 percent per year.
- The High Economic Growth case assumes higher growth rates for population (1.0 percent per year) and labor productivity (2.1 percent per year), resulting in higher nonfarm employment (1.1 percent per 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 (2.9 percent per year) than in the Reference case (2.5 percent). Disposable income per capita grows by 1.6 percent per year, compared with 1.4 percent in the Reference case.

Price Cases – For *AEO2013*, the benchmark oil price is being re-characterized to represent Brent crude oil instead of WTI crude oil. This change, which is being made to better reflect the marginal price refineries pay for imported light, sweet crude oil, used to produce petroleum product for consumers. EIA will continue to report the WTI price, as it is a critical reference point for evaluation of the growing production in the mid-continent. EIA will also continue to report the Imported Refiner Acquisition Cost (IRAC).

The historical record shows substantial variability in oil prices, and there is arguably even more uncertainty about future prices in the long term. *AEO2013* 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 demand by countries outside the Organization for Economic Cooperation and Development (OECD) for petroleum and other liquid fuels due to different levels of economic growth. The Low and High Oil Price cases also reflect different assumptions about decisions by members of the Organization of the Petroleum Exporting Countries (OPEC) regarding the preferred rate of oil production and about the future finding and development costs and accessibility to conventional structurally reservoir oil resources outside the United States.

- In the Reference case, real oil prices (in 2011 dollars) rise from \$109 per barrel in 2011 to \$163 per barrel in 2040. The Reference case represents EIA's current judgment regarding exploration and development costs and accessibility of oil resources. It also assumes that OPEC producers will choose to maintain their share of the market and will schedule investments in incremental production capacity so that OPEC's oil production will represent between 40 and 43 percent of the world's total petroleum and other liquids production over the projection period.
- In the Low Oil Price case, crude oil prices are \$75 per barrel (2011 dollars) in 2040. The low price results from lower demand for petroleum and other liquid fuels in the non-OECD nations. Lower demand is derived from lower economic growth relative to the Reference case. In this case, GDP growth in the non-OECD countries is lower on average relative to the Reference case in each projection year, beginning in 2013. The OECD projections are affected only by the price impact. On the supply side, OPEC countries increase their oil production to obtain a 49-percent share of total world petroleum and other liquids production in 2040, and oil resources outside the United States are more accessible and/or less costly to produce (as a result of technology advances, more attractive fiscal regimes, or both) than in the Reference case.
- In the High Oil Price case, oil prices reach about \$237 per barrel (2011 dollars) in 2040. The high prices result from higher demand for petroleum and other liquid fuels in the non-OECD nations. Higher demand is measured by higher economic growth relative to the Reference case. In this case, GDP growth in the non-OECD countries is higher on average relative to the Reference case in each projection year, beginning in 2013. The OECD projections are affected only by the price impact. On the supply side, OPEC countries reduce their market share to between 37 and 40 percent and oil resources outside the United States are less accessible and/or more costly to produce than in the Reference case.

In addition to these cases, 22 additional alternative cases presented in Table 1.1 explore the impact of changing key assumptions on individual sectors.

Table 1.1. Summary of AEO2013 cases

Case name	Description
Reference	Real GDP grows at an average annual rate of 2.5 percent from 2011 to 2040. Crude oil price rise to about \$163 per barrel (2011 dollars) in 2040.
Low Economic Growth	Real GDP grows at an average annual rate of 1.9 percent from 2011 to 2040. Other energy market assumptions are the same as in the Reference case.
High Economic Growth	Real GDP grows at an average annual rate of 2.9 percent from 2011 to 2040. Other energy market assumptions are the same as in the Reference case.
Low Oil Price	Low prices result from a combination of low demand for petroleum and other liquid fuels in the non-OECD nations and higher global supply. Lower demand is measured by lower economic growth relative to the Reference case. On the supply side, OPEC increases its market share to 49 percent, and the costs of other liquids production technologies are lower than in the Reference case. Crude oil prices fall to \$75 per barrel in 2040.
High Oil Price	High prices result from a combination of higher demand for petroleum and other liquids in the non-OECD nations and lower global supply. Higher demand is measured by higher economic growth relative to the Reference case. Non-OPEC petroleum production expands more slowly in the short and middle term relative to the Reference case. Crude oil price rises to \$237 per barrel (2011 dollars) in 2040.
No Sunset	Begins with the Reference case and assumes extension of all existing energy policies and legislation that contain sunset provisions, except those requiring additional funding (e.g., loan guarantee programs) and those that involve extensive regulatory analysis, such as CAFE improvements and periodic updates of efficiency standards.
Extended Policies	Begins with the No Sunset case and assumes an increase in the capacity limitations on the ITC and extension of the program. The case includes additional rounds of efficiency standards for residential and commercial products, as well as new standards for products not yet covered; adds multiple rounds of national building codes by 2026; and increases LDV fuel economy standards in the transportation sector to 57.7 miles per gallon in 2040.
Electricity: Low Nuclear	Assumes that all nuclear plants are limited to a 60-year life (45 gigawatts of retirements), uprates are limited to the 1.3 gigawatt that has been reported to EIA, and planned additions are the same as in the Reference case..
Electricity: High Nuclear	Assumes that all nuclear plants are life-extended beyond 60 years (except for one announced retirement) and uprates are the same as in the Reference case. New plants include those under construction and plants that have a scheduled U.S. Nuclear Regulatory Commission or Atomic Safety and Licensing Board hearing.
Electricity: Small Modular Reactor	Assumes that the characteristics of the new advanced nuclear technology are based on a small modular design rather than the AP1000.
Renewable Fuels: Low Renewable Technology Cost	Costs for new nonhydropower renewable generating technologies are 20 percent lower than in the Reference case through 2040. Capital costs for new BTL technologies and biodiesel production technologies are reduced by 20 percent relative to the Reference case through 2040.
Oil and Gas: Low Oil and Gas Resource	Estimated ultimate recovery (EUR) per shale gas, tight gas, and tight oil well is 50 percent lower than in the Reference case.
Oil and Gas: High Oil and Gas Resource	Shale gas, tight gas, and tight oil well EURs are 100 percent higher than in the Reference case, and the maximum well spacing is assumed to be 40 acres. Also includes kerogen development, tight oil resources in Alaska, and 50 percent higher undiscovered resources in lower 48 offshore and Alaska than in the Reference case.
Liquids Market: Low/No Net Import	Uses AEO2013 Reference case oil price, with assumed greater improvement in vehicle efficiency and lower vehicle technology costs; post-2025 increase in CAFE standards by 1.4 percent per year through 2040; lower vehicle miles traveled (VMT); expanded market availability of LNG/CNG in heavy-duty trucks, rail, and marine; higher GTL market penetration; optimistic battery case (AEO2012) assumptions for electric drivetrain vehicles costs; and greater availability of domestic petroleum supply (consistent with the High Oil and Gas Resource case). Also assumes increased market penetration of biomass pyrolysis oils, CTL, and BTL production. Also, initial assumptions associated with E85 availability and maximum penetration of E15 are set to be more optimistic.

Table 1.1. Summary of AEO2013 cases (cont.)

Case name	Description
Liquids Market: High Net Imports	Uses AEO2013 Reference case oil price, with assumed lower improvement in vehicle efficiency (driven by limits on technology improvement and non-enforcement of CAFE standards), higher VMT, no change in LNG/CNG market availability, no change in GTL penetration, no change in biofuel market penetration from the Reference case, and lower availability of domestic petroleum supply (consistent with the Low Oil and Gas Resource case).
Coal: Low Coal Cost	Regional productivity growth rates for coal mining are approximately 2.5 percent per year higher than in the Reference case, and coal mining wages, mine equipment, and coal transportation rates in 2040 are lower than in the Reference case.
Coal: High Coal Cost	Regional productivity growth rates for coal mining are approximately 2.5 percent per year lower than in the Reference case, and coal mining wages, mine equipment, and coal transportation rates in 2040 are higher than in the Reference case.
Integrated 2012 Demand Technology	Referred to in text as “2012 Demand Technology.” Assumes future equipment purchases in the residential and commercial sectors are based only on the range of equipment available in 2012. Building shell efficiency is held constant at 2012 levels. Energy efficiency of new industrial plant and equipment held constant at the 2013 level over the projection period.
Integrated Best Available Demand Technology	Referred to in the text as “Best Available Demand Technology.” Assumes that all future equipment purchases in the residential and commercial sectors are made from a menu of technologies that includes only the most efficient models available in a particular year, regardless of cost. Residential building shells for new construction are built to the most efficient specifications after 2012, and existing residential shells have twice the improvement of the Reference case. New and existing commercial building shell efficiencies improve 50 percent more than in the Reference case by 2040. Industrial and transportation sector assumptions are the same as in the Reference case.
Integrated High Demand Technology	Referred to in the text as “High Demand Technology.” Assumes earlier availability, lower costs, and higher efficiencies for more advanced residential and commercial equipment. For new residential construction, building shell efficiencies are assumed to meet ENERGY STAR requirements after 2016. Existing residential shells exhibit 50 percent more improvement than in the Reference case after 2012. New and existing commercial building shells are assumed to improve 25 percent more than in the Reference case by 2040. For the industrial sector, assumes earlier availability, lower costs, and higher efficiency for more advanced equipment and a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes. In the transportation sector, the characteristics of conventional and alternative-fuel LDVs reflect more optimistic assumptions about incremental improvements in fuel economy and costs. Freight trucks are assumed to see more rapid improvement in fuel efficiency for engine and emissions control technologies. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail, and shipping sectors.
No GHG Concern	No GHG emissions reduction policy is enacted, and market investment decisions are not altered in anticipation of such a policy.
GHG10	Applies a price for CO ₂ emissions throughout the economy, starting at \$10 per metric ton in 2014 and rising by 5 percent per year through 2040.
GHG15	Applies a fee for CO ₂ emissions throughout the economy, starting at \$15 per metric ton in 2014 and rising by 5 percent per year through 2040.
GHG25	Applies a fee for CO ₂ emissions throughout the economy, starting at \$25 per metric ton in 2014 and rising by 5 percent per year through 2040.
GHG10 and Low Gas Prices	Combines GHG10 and High Oil and Gas Resource cases.
GHG15 and Low Gas Prices	Combines GHG15 and High Oil and Gas Resource cases.
GHG25 and Low Gas Prices	Combines GHG25 and High Oil and Gas Resource cases.

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 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 *AEO2013*.

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			
Gasoline (net of ethanol)	71.26	1.0000	71.26
Liquefied Petroleum Gas			
Used as Fuel	62.97	1.0000	62.97
Used as Feedstock	61.27	0.2000	12.25
Jet Fuel	70.88	1.0000	70.88
Distillate Fuel (net of biodiesel)	73.15	1.0000	73.15
Residual Fuel	78.80	1.0000	78.80
Asphalt and Road Oil	75.61	0.0000	0.00
Lubricants	74.21	0.5000	37.11
Petrochemical Feedstocks	71.02	0.3533	25.09
Kerosene	72.31	1.0000	72.31
Petroleum Coke	102.12	0.9014	92.05
Petroleum Still Gas	64.20	1.0000	64.20
Other Industrial	74.54	1.0000	74.54
Coal			
Residential and Commercial	95.35	1.0000	95.35
Metallurgical	93.71	1.0000	93.71
Coke	114.14	1.0000	114.14
Industrial Other	93.88	1.0000	93.98
Electric Utility ¹	95.52	1.0000	95.52
Natural Gas			
Used as Fuel	53.06	1.0000	53.06
Used as Feedstocks	53.06	0.5270	27.96
Biogenic Energy Sources			
Biomass	88.45	1.0000	88.45
Biogenic Waste	90.65	1.0000	90.65
Biofuels Heats and Coproducts	88.45	1.0000	88.45
Ethanol	65.88	1.0000	65.88
Biodiesel	73.88	1.0000	73.88
Liquids from Biomass	73.15	1.0000	73.15
Green Liquids	73.15	1.0000	73.15

¹Emission factors for coal used for electricity generation are specified by coal supply region and types of coal, so the average CO₂ content for coal varies throughout the projection. The 2009 average is 95.52.

Source: U.S. Energy Information Administration, Emissions of Greenhouse Gases in the United States 2009, DOE/EIA-0573(2009), (Washington, DC, February 2010).

Notes and sources

- [1] Energy Information Administration, *Annual Energy Outlook 2013 (AEO2013)*, DOE/EIA-0383(2013), (Washington, DC, April 2013).
- [2] NEMS documentation reports are available on the EIA Homepage (www.eia.gov/analysis/model-documentation.cfm).
- [3] U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "2017 and Later Model Year Light- Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards," *Federal Register*, Vol. 77, No. 199, 40 CFR Parts 85, 86, and 600, and 49 CFR Parts 523, 531, 533, et al. (Washington, DC: October 15, 2012), website www.gpo.gov/fdsys/pkg/FR-2012-10-15/html/2012-21972.htm.
- [4] U.S. Environmental Protection Agency, "Cross-State Air Pollution Rule (CSAPR)" (Washington, DC: January 14, 2013), website <http://epa.gov/airtransport>. CSAPR was scheduled to begin on January 1, 2012; however, the U.S. Court of Appeals for the D.C. Circuit issued a stay delaying implementation while it addresses legal challenges to the rule that have been raised by several power companies and States. CSAPR is included in *AEO2013* despite the stay, because the Court of Appeals had not made a final ruling at the time *AEO2013* was published.
- [5] U.S. Congress, "Clean Air Act: Chapter 85—Air Pollution Prevention and Control," 42 U.S.C. 7412 (2011), website www.gpo.gov/fdsys/pkg/USCODE-2011-title42/pdf/USCODE-2011-title42-chap85.pdf.
- [6] U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards (MATS)" (Washington, DC: March 27, 2012), website www.epa.gov/mats.
- [7] California Environmental Protection Agency, Air Resources Board, "Assembly Bill No. 32: Global Warming Solutions Act" (Sacramento, CA: September 27, 2006), website www.arb.ca.gov/cc/ab32/ab32.htm.
- [8] California Environmental Protection Agency, Air Resources Board, "Low Carbon Fuel Standard Program" (Sacramento, CA: January 11, 2013), website www.arb.ca.gov/fuels/lcfs/lcfs.htm. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards," website www.epa.gov/mats.
- [9] Alternative other liquids technologies include all biofuels technologies plus CTL and GTL.