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 2012* [1] (*AEO2012*), 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

The projections in *AEO2012* are generated using the NEMS, developed and maintained by the Office of Energy Analysis (OEA) 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 (DOE), and other Federal agencies. NEMS is also used by other nongovernment groups, such as the Electric Power Research Institute, Duke University, Georgia Institute of Technology, and OnLocation, Incorporated. 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 is approximately 25 years, extending to 2035, the period in which the structure of the economy and the nature of energy markets are sufficiently understood that it is possible to represent considerable structural and regional detail. Because of the diverse nature of energy supply, demand, and conversion in the United States, NEMS supports regional modeling and analysis in order to represent the regional differences in energy markets, to provide policy impacts at the regional level, and to portray transportation flows. To represent regional differences in energy markets, the component modules of NEMS function at the regional level: the nine 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 the five Petroleum Administration for Defense Districts (PADDs) for refineries. Maps illustrating the regional formats used in each module are included in this report. Only selected regional results are presented in *AEO2012*, which predominant focuses 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 annually through the projection horizon. 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 (CO_2) emissions, as well as emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury from the electricity generation sector.

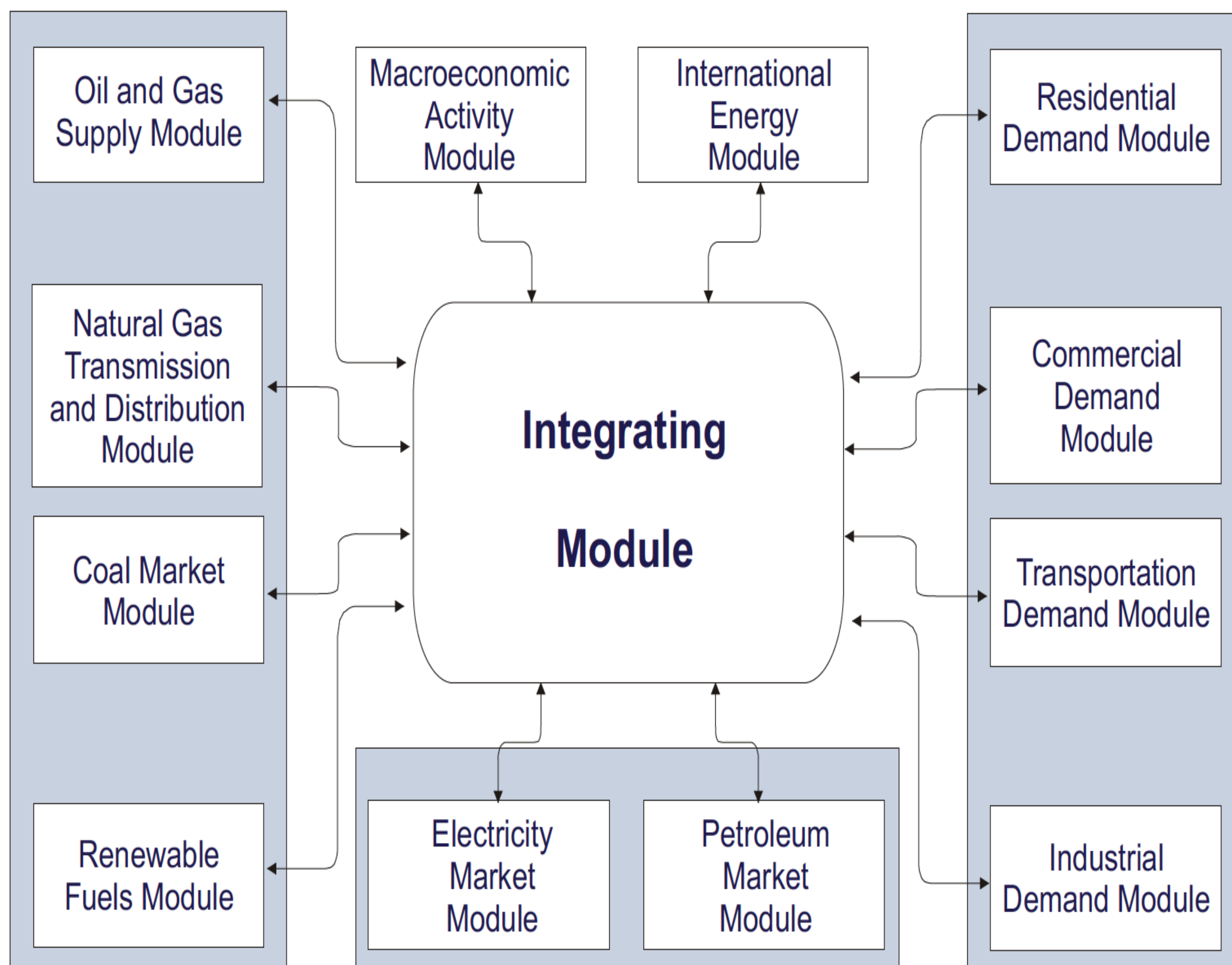
The integrating module of NEMS controls the execution of each of the component modules. To facilitate modularity, the components do not pass information to each other directly but communicate through a central data storage location. This modular design provides the capability to execute modules individually, 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 *AEO2012* generally represents current legislation and environmental regulations, including recent government actions, for which implementing regulations were available as of December 31, 2011, such as: the Mercury and Air Toxics Standards (MATS) [3] issued by the U.S. Environmental Protection Agency (EPA) in December 2011; the Cross-State Air Pollution Rule (CSAPR) [4] as finalized by the EPA in July 2011; the new fuel efficiency standards for medium- and heavy-duty

vehicles (HDVs) published by the EPA and the National Highway Traffic Safety Administration (NHTSA) in September 2011 [5]; California's cap-and-trade program authorized by Assembly Bill (AB) 32, the Global Warming Solutions Act of 2006 [6]; the EPA policy memo regarding compliance of surface coal mining operations in Appalachia [7], issued on July 21, 2011; and the American Recovery and Reinvestment Act (ARRA) [8], which was enacted in mid-February 2009.

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. However, many pending provisions are examined in alternative cases included in *AEO2012* or in other analyses 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 light-duty vehicles (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 liquids production and consumption, by year, to project the interaction of U.S. and international liquids markets. The IEM computes world oil prices, provides a world crude-like liquids supply curve, generates a worldwide oil supply/demand balance for each year of the projection period, and computes initial estimates of crude oil and light and heavy petroleum product imports to the United States by PADD regions. 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 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 conventional and unconventional supply recovery technologies.

In interacting with the rest of NEMS, the IEM changes the oil price—which is defined as the price of light, low-sulfur crude oil delivered to Cushing, Oklahoma (PADD 2)—in response to changes in expected production and consumption of crude oil and product liquids in the United States.

Residential and Commercial Demand Modules

The Residential Demand Module projects energy consumption in the residential sector by housing type and end use, based on delivered energy prices, the menu of equipment available, the availability and cost of renewable sources of energy, and housing starts. The Commercial Demand Module projects energy consumption in the commercial sector by building type and non-building uses of energy and by category of end use, based on delivered prices of energy, availability of renewable sources of energy, and macroeconomic variables representing interest rates and floorspace construction.

Both modules estimate the equipment stock for the major end-use services, incorporating assessments of advanced technologies, including representations of renewable energy technologies, and the effects of both building shell and appliance standards, including the 2009 and 2010 consensus agreements reached between manufacturers and environmental interest groups. The Commercial Demand Module incorporates combined heat and power (CHP) technology. The modules also include projections of distributed generation (DG). Both modules incorporate changes to “normal” heating and cooling degree-days by Census division, based on a 10-year average 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. Of the eight energy-intensive manufacturing industries, seven are modeled in the IDM, including energy-consuming components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. Energy demand for petroleum refining (the eighth energy-intensive manufacturing industry) is modeled in the Petroleum Market Module (PMM), 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. The base year for the bulk chemical industry has been updated to 2006 in keeping with updates to EIA's 2006 Manufacturing Energy Consumption Survey (MECS) [10]. *AEO2012* also includes an upgraded representation for the cement and lime industries and agriculture. Instead of assuming that technological development for a particular process occurs on a predetermined (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 technological change, and therefore energy intensity, to respond to economic, regulatory, and other conditions. For subsequent AEOs, other industries represented in the IDM projections will be similarly upgraded.

A generalized representation of CHP is included. A revised methodology for CHP systems, implemented for *AEO2012*, 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 updated appraisal incorporating historical rather than assumed capacity factors and regional acceptance rates for new CHP facilities. The evaluation of CHP systems still uses a discount rate, which is equal to the projected 10-year Treasury bill rate plus a risk premium.

Transportation Demand Module

The Transportation Demand Module projects consumption of energy in the transportation sector — including petroleum products, electricity, methanol, ethanol, compressed natural gas, and hydrogen — by transportation mode, subject to delivered energy prices and macroeconomic variables such as disposable personal income, GDP, population, interest rates, and industrial shipments. The Transportation Demand Module includes legislation and regulations, such as the Energy Policy Act of 2005, the Energy Improvement and Extension Act of 2008, and the American Recovery and Reinvestment Act of 2009, which contain tax credits for the purchase of alternatively fueled vehicles. Fleet vehicles are also modeled, allowing for analysis of legislative proposals specific to those markets. Representations of LDV Corporate Average Fuel Economy (CAFE) and greenhouse gas (GHG) emissions standards, HDV fuel consumption and greenhouse gas emissions standards, and biofuels consumption in the module 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 explicitly 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 in regional, narrow-body, and wide-body aircraft. 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.

Electricity Market Module

There are three primary submodules of the Electricity Market Module: 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 (CAAA90) are explicitly represented in the capacity expansion and dispatch decisions. All financial incentives for power generation expansion and dispatch specifically identified in EPACT2005 have been implemented. Several States, primarily in the Northeast, have enacted air emission regulations for CO_2 that affect the electricity generation sector, and those regulations are represented in *AEO2012*. The *AEO2012* Reference case also imposes a limit on power sector CO_2 emissions for plants serving California, to represent the power sector impacts of California's AB 32. The *AEO2012* Reference case reflects the CSAPR as finalized by the EPA on July 6, 2011, requiring reductions in emissions from power plants that contribute to ozone and fine particle pollution in 28 States. 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 *AEO2012* Reference case through a 3-percentage-point increase in the cost of capital when evaluating investments in new coal-fired power plants and new coal-to-liquids (CTL) plants without carbon capture and storage (CCS) and for pollution control retrofits.

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 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 CO_2 flooding, steam flooding, polymer flooding, and profile modification) are explicitly represented. Natural gas resources include high-permeability carbonate and sandstone, tight gas, shale gas, and coalbed methane.

Domestic crude oil production quantities are used as inputs to the PMM 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 an off-peak period in the year, assuming a historically based seasonal distribution of natural gas demand. Key components of pipeline and distributor tariffs are included in separate pricing algorithms. An algorithm is included to project the addition of compressed natural gas 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 liquefied natural gas (LNG) imports and exports. For *AEO2012*, LNG exports and re-exports were set exogenously and assumed to reach and maintain a total level of 903 billion cubic feet per year by 2020.

Petroleum Market Module

The PMM projects prices of petroleum products, crude oil and product import activity, and domestic refinery operations, subject to demand for petroleum products, availability and price of imported petroleum, and domestic production of crude oil, natural gas liquids, and biofuels—ethanol, biodiesel, biomass-to-liquids (BTL), CTL, and gas-to-liquids (GTL). Costs, performance, and first dates of commercial availability for the advanced alternative liquids technologies [12] are reviewed and updated annually.

The module represents refining activities in the five PADDs, as well as a less—detailed representation of refining activities in the rest of the world. It 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 PMM, because they are commonly blended into petroleum products. The module allows ethanol blending into gasoline at 10 percent or less by volume (E10), 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.

The PMM includes representation of the Renewable Fuels Standard (RFS) included in EISA2007, which mandates the use of 36 billion gallons of ethanol equivalent renewable fuel annually by 2022. Both domestic and imported ethanol 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—defined as plants 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 PMM.

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

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 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 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.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing renewable resource supply and technology input information for central-station, grid-connected electricity generation technologies, including conventional hydroelectricity, biomass (dedicated biomass plants and co-firing in existing coal plants), geothermal, landfill gas, solar thermal electricity, solar photovoltaics (PV), and both onshore and offshore wind energy. The RFM contains renewable resource supply estimates representing the regional opportunities for renewable energy development. Investment tax credits (ITCs) for renewable fuels are incorporated, as currently enacted, including a permanent 10-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. They provide a credit of up to 2.2 cents per kilowatthour for electricity produced in the first 10 years of plant operation. For *AEO2012*, 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. As part of the ARRA, plants eligible for the PTC may instead elect to receive a 30-percent ITC or an equivalent direct grant. *AEO2012* also accounts for new renewable energy capacity resulting from State renewable portfolio standard (RPS) programs, mandates, and goals.

Cases for the Annual Energy Outlook 2012

In preparing projections for *AEO2012*, EIA evaluated a wide range of trends and issues that could have major implications for U.S. energy markets between now and 2035. Besides the Reference case, *AEO2012* 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, real GDP grows at an average annual rate of 2.5 percent from 2010 through 2035, supported by a 1.9-percent-per-year growth in productivity in nonfarm business, a 1.0-percent-per-year growth in nonfarm employment, and population growth of 0.9 percent per year. In the High Economic Growth case, real GDP is projected to increase by 3.0 percent per year, with population growth of 1.0 percent per year and productivity and nonfarm employment growing at 2.2 percent and 1.2 percent per year, respectively. In the Low Economic Growth case, the average annual growth in GDP, population, productivity, and nonfarm employment is 2.0, 0.8, 1.5 and 0.8 percent per year, respectively.
- Price Cases - The oil price in *AEO2012* is defined as the average price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, and is similar to the price for light, sweet crude oil traded on the New York Mercantile Exchange, referred to as West Texas Intermediate (WTI). *AEO2012* also includes a projection of the U.S. annual average refiner acquisition cost of imported crude oil, which is more representative of the average cost of all crude oils used by domestic refiners. The historical record shows substantial variability in oil prices, and there is arguably even more uncertainty about future prices in the long term. *AEO2012* 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 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 of conventional oil resources outside the United States.

- In the Reference case, real oil prices rise from $93 per barrel (2010 dollars) in 2011 to $145 per barrel in 2035. 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 conventional oil production will represent about 40 percent of the world's total liquids production over the projection period.

- In the Low Oil Price case, crude oil prices are only $62 per barrel (2010 dollars) in 2035, compared with $145 per barrel in the Reference case. In the Low Oil Price case, the low price results from lower demand for 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 reduced by 1.5 percentage points relative to Reference case in each projection year, beginning in 2015. The OECD projections are affected only by the price impact. On the supply side, OPEC countries increase their conventional oil production to obtain a 46-percent share of total world liquids production, and oil resources outside the U.S. 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 $200 per barrel (2010 dollars) in 2035. In the High Oil Price case, the high prices result from higher demand for 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 region is raised by 0.1 to 1.0 percentage point relative to the Reference case in each projection year, starting in 2012. GDP growth rates for China and India are raised by 1.0 percentage point relative to the Reference case in 2012, declining to 0.3 percentage point above the Reference case in 2035. GDP growth rates for most other non-OECD regions average about 0.5 percentage point above the Reference case in each projection year. The OECD projections are affected only by the price impact. On the supply side, OPEC countries are assumed to reduce their market share somewhat, and oil resources outside the United States are assumed to be less accessible and/or more costly to produce than in the Reference case.

In addition to these cases, 25 additional alternative cases presented in Table 1.1 explore the impact of changing key assumptions on individual sectors.

Table 1.1. Summary of *AEO2012* cases

Case name	Description
Reference	Baseline economic growth (2.5 percent per year from 2010 through 2035), oil price, and technology assumptions. Light, sweet crude oil prices rise to about $145 per barrel (2010 dollars) in 2035. Assumes RFS target to be met as soon as possible.
Low Economic Growth	Real GDP grows at an average annual rate of 2.0 percent from 2010 to 2035. Other energy market assumptions are the same as in the Reference case.
High Economic Growth	Real GDP grows at an average annual rate of 3.0 percent from 2010 to 2035. 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. In this case, GDP growth in the non-OECD is reduced by 1.5 percentage points in each projection year relative to Reference case assumptions, beginning in 2015. On the supply side, OPEC increases its market share to 46 percent, and the costs of other liquids production technologies are lower than in the Reference case. Light, sweet crude oil prices fall to $62 per barrel in 2035.
High Oil Price	High prices result from a combination of higher demand for liquid fuels in the non-OECD nations and lower global supply. Higher demand is measured by higher economic growth relative to the Reference case. In this case, GDP growth rates for China and India are raised by 1.0 percentage point relative to the Reference case in 2012 and decline to 0.3 percentage point above the Reference case in 2035. GDP growth rates for other non-OECD regions average about 0.5 percentage point above the Reference case. OPEC market share remains at about 40 percent throughout the projection, and non-OPEC conventional production expands more slowly in the short to middle term relative to the Reference case. Light, sweet crude oil prices rise to $200 per barrel (2010 dollars) in 2035.
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 but excludes extension of tax credits for blenders and for other biofuels that were included in the No Sunset case. Assumes expansion of the maximum industrial ITC and CHP credits 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 through 2035.
Transportation: CAFE Standards	Explores energy and market impacts assuming that LDV CAFE and greenhouse gas emissions standards proposed for model years 2017-2025 are enacted.
Transportation: High Technology Battery	Explores the impact of significant improvement in vehicle battery and nonbattery system cost and performance on new LDV sales, energy consumption, and GHG emissions.
Transportation: HDV Reference	Incorporates revised CNG and LNG pricing assumptions and HDV market acdeptance relative to the *AEO2012* Reference case.
Transportation: HD NGV, Potential	Using the HDV Reference case, explores energy and market issues associated with the expansion of natural gas refueling infrastructure for the HDV market.
Electricity: Low Nuclear	Assumes that all nuclear plants are limited to a 60-year life (31 gigawatts of retirements), uprates are limited to the 1 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 NRC or Atomic Safety and Licensing Board hearing and use a currently certified design (e.g., AP1000).
Electricity: Reference 05	Includes CSAPR and MATS as in the Reference case, with reduced 5-year environmental investment recovery.
Electricity: Low Gas Price 05	Includes CSAPR and MATS as in the Reference case, with reduced 5-year environmental investment recovery combined with the High Estimated Ultimate Recovery (EUR) case.

Table 1.1. Summary of *AEO2012* cases (cont.)

Case name	Description
Renewable Fuels: Low Renewable Technology Cost	Costs for new nonhydropower renewable generating technologies start 20 percent lower in 2012 and decline to 40 percent lower than Reference case levels in 2035. Capital costs of renewable liquid fuel technologies start 20 percent lower in 2012 and decline to approximately 40 percent lower than Reference case levels in 2035.
Petroleum: LFMM	Changes in the refining industry in the past and prospective future are discussed in the context of the development of the Liquids Fuels Market Module (LFMM) developed for NEMS. Provides overview of large-scale trends and highlights of specific issues that may require further analysis.
Oil and Gas: Low EUR	Estimated ultimate recovery (EUR) per tight oil or shale gas well is 50 percent lower than in the Reference case.
Oil and Gas: High EUR	EUR per tight oil and shale gas well is assumed to be 50 percent higher than in the Reference case.
Oil and Gas: High Technically Recoverable Resources (TRR)	The well spacing for all tight oil and shale gas plays is assumed to be 8 wells per square mile (i.e., each well has an average drainage area of 80 acres) and the EUR for tight oil and shale gas wells is assumed to be 50 percent higher than in the Reference case.
Coal: Low Coal Cost	Regional productivity growth rates for coal mining are approximately 2.8 percent per year higher than in the Reference case, and coal mining wages, mine equipment, and coal transportation rates in 2035 are between 21 and 25 percent lower than in the Reference case.
Coal: High Coal Cost	Regional productivity growth rates for coal mining are approximately 2.8 percent per year lower than in the Reference case, and coal mining wages, mine equipment, and coal transportation rates in 2035 are between 25 and 27 higher than in the Reference case.
Integrated 2011 Demand Technology	Referred to in text as the 2011 Demand Technology. Assumes future equipment purchases in the residential and commercial sectors are based only on the range of equipment available in 2011. Energy efficiency of new industrial plant and equipment is held constant at the 2012 level over the projection period.
Integrated Best Available Demand Technology	Assumes 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 for each fuel, regardless of cost.
Integrated High Demand Technology	Assumes earlier availability, lower costs, and higher efficiencies for more advanced residential and commercial equipment. For new residential and commercial construction, building shell efficiencies are assumed to meet ENERGY STAR requirements after 2016. 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.
Integrated 2011 Technology	Combination of the Integrated 2011 Demand Technology case with the assumption that costs of new power plants do not improve from 2012 levels throughout the projection.
Integrated High Technology	Combination of the Integrated High Demand Technology case and the Low Renewable Technology Cost case. Also assumes that costs for new nuclear and fossil-fired power plants are lower than Reference case levels, by 20 percent in 2012 and 40 percent in 2035.
No GHG Concern	No GHG emissions reduction policy is enacted, and market investment decisions are not altered in anticipation of such a policy.
GHG15	Applies a fee for CO_2 emissions throughout the economy, starting at $15 in 2013 and rising by 5 percent per year through 2035. Fee is set to target the same reduction in CO_2 emissions as in the *AEO2011* GHG Price Economywide case.
GHG25	Applies a fee for CO_2 emissions throughout the economy, starting at $25 in 2013 and rising by 5 percent per year through 2035. Fee is set at the same dollar amount as in the *AEO2011* GHG Price Economywide case.

Carbon dioxide emissions

Carbon dioxide 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 carbon emission 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 carbon dioxide per million Btu. The adjusted emissions factors are multiplied by the energy consumption of the fossil fuel to arrive at the carbon dioxide 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 a recent change in 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 carbon dioxide emissions for motor gasoline, the direct emissions from renewable blending stock (ethanol) is omitted. Similarly, direct emissions from biodiesel are omitted from reported carbon dioxide emissions.

Any carbon dioxide emitted by biogenic renewable sources, such as biomass and alcohols, is considered balanced by the carbon dioxide sequestration that occurred in its creation. Therefore, following convention, net emissions of carbon dioxide from biogenic renewable sources are assumed to be zero in reporting energy-related carbon dioxide 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 carbon dioxide emissions from biogenic fuel use are calculated and reported separately.

Table 1.2 presents the assumed carbon dioxide coefficients at full combustion, the combustion fractions, and the adjusted carbon dioxide emission factors used for *AEO2012*.

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

[1]Emission factors for coal used for electricity generation are specified by coal supply region and types of coal, so the average carbon dioxide 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 2012 (*AEO2012*), DOE/EIA-0383(2012), (Washington, DC, June 2012).

[2] NEMS documentation reports are available on the EIA Homepage (www.eia.gov/analysis/model-documentation.cfm).

[3] U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards," website www.epa.gov/mats.

[4] U.S. Environmental Protection Agency, "Cross-State Air Pollution Rule (CSAPR)," website 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 *AEO2012* despite the stay, because the Court of Appeals had not made a final ruling at the time *AEO2012* was published.

[5] U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles; Final Rule," Federal Register, Vol. 76, No. 179 (September 15, 2011), pp. 57106-57513, website www.gpo.gov/fdsys/pkg/FR-2011-09-15/html/2011-20740.htm.

[6] California Air Resources Board (ARB), "California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms," Article 5 95800 to 96023, website www.arb.ca.gov/cc/capandtrade/capandtrade.htm.

[7] U.S. Environmental Protection Agency, "July 21, 2011 Final Memorandum: Improving EPA Review of Appalachian Surface Coal Mining Operations Under the Clean Water Act, National Environmental Polic Act, and the Environmental Justice Executive Order," website water.epa.gov/lawsregs/guidance/wetlands/mining.cfm.

[8] For the complete text of the American Recovery and Reinvestment Act of 2009, see website www.gpo.gov/fdsys/pkg/PLAW-111pub15/html/PLAW-111pub15.htm.