Major Assumptions for the Forecasts

The National Energy Modeling System

The projections in the *Annual Energy Outlook 2004* (*AEO2004*) are generated from the National Energy Modeling System (NEMS), developed and maintained by the Office of Integrated Analysis and Forecasting (OIAF) of the Energy Information Administration (EIA). In addition to its use in the development of the *AEO* projections, NEMS is also used in analytical studies for the U.S. Congress and other offices within the Department of Energy. The *AEO* forecasts are also used by analysts and planners in other government agencies and outside organizations.

The projections in NEMS are developed with the use of a market-based approach to energy analysis. 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 the midterm period, approximately 20 years into the future. In order to represent the 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, gas, and coal supply and distribution; the North American Electric Reliability Council (NERC) regions and subregions for electricity; and aggregations of the Petroleum Administration for Defense Districts (PADDs) for refineries.

NEMS is organized and implemented as a modular system. The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international modules. The primary flows of information between each of these modules are the delivered prices of energy to the end user and the quantities consumed by product, region, and sector. The delivered prices of fuel encompass all the activities necessary to produce, import, and transport fuels to the end user. The information flows also include other data on such areas as economic activity, domestic production, and international petroleum supply availability.

The integrating module 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 file. 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, permitting the use of the methodology and level of detail most appropriate for each energy sector. 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. Solution is reached annually through the midterm horizon. Other variables are also evaluated for convergence, such as petroleum product imports, crude oil imports, and several macroeconomic indicators.

Each NEMS component also represents the impacts and costs of legislation and environmental regulations that affect that sector and reports key emissions. NEMS represents current legislation and environmental regulations as of September 1, 2003, such as the Clean Air Act Amendments of 1990 (CAAA90), and the costs of compliance with other regulations, such as the new Corporate Average Fuel Economy rule for light-duty trucks, which was formally announced on April 1, 2003, and published in the *Federal Register* on April 7, 2003.

In general, the historical data used for the *AEO2004* projections were based on EIA's *Annual Energy Review 2002*, published in October 2003 [*1*]; however, data were taken from multiple sources. In some cases, only partial or preliminary data were available for 2002. Carbon dioxide emissions were calculated by using carbon dioxide coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 2002*, published in October 2003 [*2*].

Historical numbers are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Some definitional adjustments were made to EIA data for the forecasts. For example, the transportation demand sector in *AEO2004* includes electricity used by railroads, which is included in the commercial sector in EIA's consumption data publications. Footnotes in the appendix tables of this report indicate the definitions and sources of all historical data.

The *AEO2004* projections for 2003 and 2004 incorporate short-term projections from EIA's September and October 2003 *Short-Term Energy Outlook* (*STEO*). For short-term energy projections, readers are referred to the monthly updates of the *STEO* [*3*].

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 the prices of energy delivered to the consuming sectors and the quantities of end-use energy consumption.

Macroeconomic Activity Module

The Macroeconomic Activity Module provides a set of essential macroeconomic drivers to the energy modules and a macroeconomic feedback mechanism within NEMS. Key macroeconomic variables include gross domestic product (GDP), industrial output, interest rates, disposable income, prices, and employment. This module uses the following Global Insight models: Macroeconomic Model of the U.S. Economy, National Industrial Shipments Model, National Employment Model, and the Regional Disaggregation Model for macroeconomic drivers. In addition, EIA has constructed a Commercial Floorspace Model to forecast 13 floorspace types in 9 Census divisions.

International Energy Module

The International Energy Module represents the world oil markets, calculating the average world oil price and computing supply curves for five categories of imported crude oil for the Petroleum Market Module (PMM) of NEMS, in response to changes in U.S. import requirements. Fourteen international petroleum product supply curves, including curves for oxygenates, are also calculated and provided to the PMM.

Household Expenditures Module

The Household Expenditures Module provides estimates of average household direct expenditures for energy used in the home and in private motor vehicle transportation. The forecasts of expenditures reflect the projections from NEMS for the residential and transportation sectors. The projected household energy expenditures incorporate the changes in residential energy prices and motor gasoline price determined in NEMS, as well as changes in the efficiency of energy use for residential end uses and in light-duty vehicle fuel efficiency. Estimates of average expenditures for households are provided by income group and Census division.

Residential and Commercial Demand Modules

The Residential Demand Module forecasts consumption of residential sector energy by housing type and end use, based on delivered energy prices, the menu of equipment available, the availability of renewable sources of energy, and housing starts. The Commercial Demand Module forecasts consumption of commercial sector energy by building types and nonbuilding 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 effects of both building shell and appliance standards. The commercial module incorporates combined heat and power (CHP) technology. Both modules include a forecast of distributed generation.

Industrial Demand Module

The Industrial Demand Module forecasts the consumption of energy for heat and power and for feedstocks and raw materials in each of 16 industry groups, subject to the delivered prices of energy and macroeconomic variables representing employment and the value of shipments for each industry. The industries are classified into three groups—energy-intensive, non-energy-intensive, and nonmanufacturing. Of the eight energy-intensive industries, seven are modeled in the Industrial Demand Module, with components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. A representation of cogeneration and a recycling component are also included. The use of energy for petroleum refining is modeled in the Petroleum Market Module, and the projected consumption is included in the industrial totals.

Transportation Demand Module

The Transportation Demand Module forecasts consumption of transportation sector fuels, including petroleum products, electricity, methanol, ethanol, compressed natural gas, and hydrogen by transportation mode, vehicle vintage, and size class, subject to delivered prices of energy fuels and macroeconomic variables representing disposable personal income, GDP, population, interest rates, and the value of output for industries in the freight sector. Fleet vehicles are represented separately to allow analysis of CAAA90 and other legislative proposals, and the module includes a component to explicitly assess the penetration of alternative-fuel vehicles. The air transportation module was substantially revamped for *AEO2004*. The model represents the industry practice of parking aircraft to reduce operating costs and the movement of aircraft from the passenger to cargo markets as aircraft age [*4*]. For air freight shipments, the model employs narrow-body and wide-body aircraft only. The model also uses an infrastructure constraint that limits air travel growth to levels commensurate with industry-projected infrastructure expansion and capacity growth.

Electricity Market Module

The Electricity Market Module models generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, natural gas, and biofuels; costs of generation by all generation plants, including capital costs; macroeconomic variables for costs of capital and domestic investment; enforced environmental emissions laws and regulations; and electricity load shapes and demand. There are three primary submodules—capacity planning, fuel dispatching, and finance and pricing. Nonutility generation, distributed generation, and transmission and trade are modeled in the planning and dispatching submodules. The levelized fuel cost of uranium fuel for nuclear generation is directly incorporated into the Electricity Market Module.

All specifically identified CAAA90 compliance options that have been promulgated by the U.S. Environmental Protection Agency (EPA) are explicitly represented in the capacity expansion and dispatch decisions; those that have not been promulgated are not incorporated (e.g., fine particulate proposal). Several States, primarily in the Northeast, have recently enacted air emission regulations that affect the electricity generation sector. Where firm State compliance plans have been announced, regulations are represented in *AEO2004*.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing natural resource supply and technology input information for central-station, grid-connected electricity generation technologies, including biomass (wood, energy crops, and biomass co-firing), geothermal, landfill gas, solar thermal, solar photovoltaics, and wind energy. The RFM contains natural resource supply estimates representing the regional opportunities for renewable energy development. Conventional hydroelectricity is represented in the Electricity Market Module (EMM). Investment tax credits for renewable fuels are incorporated, as currently legislated in the Energy Policy Act of 1992 [*5*]. They provide a 10-percent tax credit for business investment in solar energy (thermal nonpower uses as well as power uses) and geothermal power. The credits have no expiration date.

Oil and Gas Supply Module

The Oil and Gas Supply Module models domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships between the various sources of supply: onshore, offshore, and Alaska by both conventional and nonconventional techniques, including gas recovery from coalbeds and low-permeability formations of sandstone and shale. This 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 gas production functions are computed at a level of 12 supply regions, including 3 offshore and 3 Alaskan regions. This module also represents foreign sources of natural gas, including pipeline imports and exports to Canada and Mexico, and liquefied natural gas (LNG) imports and exports.

Crude oil production quantities are input to the PMM in NEMS for conversion and blending into refined petroleum products. Supply curves for natural gas are input to the Natural Gas Transmission and Distribution Module for use in determining natural gas prices and quantities. International LNG supply sources and options for regional expansions of domestic regasification capacity are represented, based on the projected regional costs associated with gas supply, liquefaction, transportation, regasification, and natural gas market conditions.

Natural Gas Transmission and Distribution Module

The Natural Gas Transmission and Distribution Module 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 in an aggregate, domestic pipeline network, connecting the domestic and foreign supply regions with 12 demand regions. This capability allows the analysis of impacts of regional capacity constraints in the interstate natural gas pipeline network and the identification of pipeline and storage capacity expansion requirements. Peak and off-peak periods are represented for natural gas transmission, and core and noncore markets are represented at the burner tip. Key components of pipeline and distributor tariffs are included in the pricing algorithms.

Petroleum Market Module

The Petroleum Market Module (PMM) forecasts prices of petroleum products, crude oil and product import activity, and domestic refinery operations (including fuel consumption), subject to the demand for petroleum products, the availability and price of imported petroleum, and the domestic production of crude oil, natural gas liquids, and alcohol fuels. The module represents refining activities for five regions—Petroleum Administration for Defense Districts (PADD) 1 through 5. The module uses the same crude oil types as the International Energy Module. It explicitly models the requirements of CAAA90 and the costs of automotive fuels, such as oxygenated and reformulated gasoline, and includes oxygenate production and blending for reformulated gasoline. *AEO2004* reflects legislation that bans or limits the use of the gasoline blending component methyl tertiary butyl ether (MTBE) in the next several years in California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, New York, Ohio, South Dakota, Washington, and Wisconsin [*6*].

The Federal oxygen requirement for reformulated gasoline in Federal nonattainment areas is assumed to remain intact. The "Tier 2" regulation that requires the nationwide phase-in of gasoline with a greatly reduced annual average sulfur content between 2004 and 2007 and the diesel regulation that significantly limits the sulfur content of all highway diesel fuel produced after June 1, 2006, are represented in *AEO2004*. Costs of the regulation include capacity expansion for refinery-processing units based on a 10-percent hurdle rate and a 10-percent after-tax return on investment [*7*]. End-use prices are based on the marginal costs of production, plus markups representing product and distribution costs, and State and Federal taxes. Refinery capacity expansion at existing sites may occur in all five refining regions modeled.

Coal Market Module

The Coal Market Module (CMM) simulates mining, transportation, and pricing of coal, subject to the end-use demand for coal differentiated by heat and sulfur content. The coal supply curves include a response to capacity utilization of mines, mining capacity, fuel costs, labor productivity, and factor input costs (mining equipment, mining labor, and fuel requirements). Twelve coal types are represented—differentiated by coal rank, sulfur content, and mining process. Production and distribution are computed for 11 supply and 14 demand regions, using imputed coal transportation costs and trends in factor input costs. The CMM also forecasts the requirements for U.S. coal exports and imports. The international coal market component of the module computes trade in 3 types of coal for 16 export and 20 import regions. Both the domestic and international coal markets are simulated in a linear program.

Major Assumptions for the *Annual Energy Outlook 2004*

Table G1 provides a summary of the cases used to derive the *AEO2004* forecasts. For each case, the table gives the name used in this report, a brief description of the major assumptions underlying the projections, a designation of the mode in which the case was run in NEMS (either fully integrated, partially integrated, or standalone), and a reference to the pages in the body of the report and in this appendix where the case is discussed.

Assumptions for domestic macroeconomic activity are presented in the "Market Trends" section. The resulting GDP growth rates between 2002 and 2025 in the three macroeconomic growth cases are 2.4, 3.0, and 3.5 percent per year in the low economic growth, reference and high economic growth cases, respectively. The following section describes the key regulatory, programmatic, and resource assumptions that factor into the projections. More detailed assumptions for each sector are available at web site www.eia.doe.gov/oiaf/aeo/assumption/. Regional results and other details of the projections are available at web site www.eia.doe.gov/ oiaf/aeo/ supplement/.

World Oil Market Assumptions

World oil price. The world oil price is the annual average U.S. refiner's acquisition cost of imported crude oil. Three distinct world oil price scenarios are represented in *AEO2004*, reaching $17, $27, and $35 per barrel in 2025, respectively, in the low world oil price, reference, and high world oil price cases in 2002 dollars. The reference case represents EIA's current judgment regarding the expected behavior of the

Table G1. Summary of the *AEO2004* cases

Case name	Description	Integration mode	Reference in text	Reference in Appendix G
Reference	Baseline economic growth, world oil price, and technology assumptions.	Fully integrated	—	—
Low Economic Growth	Gross domestic product grows at an average annual rate of 2.4 percent from 2002 through 2025, compared to the reference case growth of 3.0 percent.	Fully integrated	p. 67	—
High Economic Growth	Gross domestic product grows at an average annual rate of 3.5 percent from 2002 through 2025, compared to the reference case growth of 3.0 percent.	Fully integrated	p. 67	—
Low World Oil Price	World oil prices are $19.04 per barrel in 2025, compared to $26.57 per barrel in the reference case.	Fully integrated	p. 68	—
High World Oil Price	World oil prices are $33.05 per barrel in 2025, compared to $26.57 per barrel in the reference case.	Fully integrated	p. 68	—
Residential: 2004 Technology	Future equipment purchases based on equipment available in 2004. Existing building shell efficiencies fixed at 2004 levels.	With commercial	p. 77	p. 244
Residential: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Heating shell efficiency increases by 13 percent from 2001 values by 2025.	With commercial	p. 77	p. 244
Residential: Best Available Technology	Future equipment purchases and new building shells based on most efficient technologies available. Heating shell efficiency increases by 18 percent from 2001 values by 2025.	With commercial	p. 77	p. 244
Commercial: 2004 Technology	Future equipment purchases based on equipment available in 2004. Building shell efficiencies fixed at 2004 levels.	With residential	p. 78	p. 245
Commercial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Heating shell efficiencies for new and existing buildings increase by 8.75 and 6.25 percent, respectively, from 1999 values by 2025.	With residential	p. 78	p. 245
Commercial: Best Available Technology	Future equipment purchases based on most efficient technologies available. Heating shell efficiencies for new and existing buildings increase by 10.5 and 7.5 percent, respectively, from 1999 values by 2025.	With residential	p. 78	p. 245
Industrial: 2004 Technology	Efficiency of plant and equipment fixed at 2004 levels.	Standalone	p. 79	p. 246
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment.	Standalone	p. 79	p. 246
Transportation: 2004 Technology	Efficiencies for new equipment in all modes of travel are fixed at 2004 levels.	Standalone	p. 79	p. 248
Transportation: High Technology	Reduced costs and improved efficiencies are assumed for advanced technologies.	Standalone	p. 79	p. 248
Integrated 2004 Technology	Combination of the residential, commercial, industrial, and transportation 2004 technology cases, electricity low fossil technology case, and assumption of renewable technologies fixed at 2004 levels.	Fully integrated	p. 104	—
Integrated High Technology	Combination of the residential, commercial, industrial, and transportation high technology cases, electricity high fossil technology case, high renewables case, and advanced nuclear cost case.	Fully integrated	p. 104	—

Table G1. Summary of the *AEO2004* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix G
Electricity: Advanced Nuclear Cost	New nuclear capacity is assumed to have 10 percent lower capital and operating costs in 2025 than in the reference case.	Fully integrated	p. 87	p. 250
Electricity: Nuclear AP1000 Case	New nuclear capacity is assumed to have lower capital costs, based on vendor goals for the AP1000 reactor.	Fully integrated	p. 87	p. 250
Electricity: Nuclear Vendor Estimate Case	New nuclear capacity is assumed to have lower capital costs, based on vendor goals for the AP1000 and CANDU reactors.	Fully integrated	p. 58	p. 250
Electricity: High Demand	Electricity demand increases at an annual rate of 2.5 percent, compared to 1.8 percent in the reference case.	Partially integrated	p. 88	p. 251
Electricity: Low Fossil Technology	New advanced fossil generating technologies are assumed not to improve over time from 2004.	Partially integrated	p. 87	p. 251
Electricity: High Fossil Technology	Costs and efficiencies for advanced fossil-fired generating technologies improve by 10 percent in 2025 from reference case values.	Partially integrated	p. 87	p. 251
Electricity: DOE Fossil Goals	Costs and/or efficiencies for advanced fossil-fired generating technologies improve from reference case values, based on Department goals.	Partially integrated	p. 87	p. 252
Renewables: Low Renewables	New renewable generating technologies are assumed not to improve over time from 2004.	Fully Integrated	p. 86	p. 254
Renewables: High Renewables	Levelized cost of energy for nonhydropower renewable generating technologies declines by 10 percent in 2025 from reference case values.	Fully Integrated	p. 86	p. 253
Renewables: DOE Goals	Lower costs and higher efficiencies for central-station renewable generating technologies and for distributed photovoltaics, approximating U.S. Department of Energy goals for 2025. Includes greater improvements in residential and commercial photovoltaic systems, more rapid improvement in recovery of industrial biomass byproducts, and more rapid improvement in cellulosic ethanol production technology.	Fully integrated	p. 86	p. 254
Oil and Gas: Slow Technology	Cost, finding rate, and success rate parameters adjusted for 50-percent slower improvement than in the reference case.	Fully integrated	p. 91	p. 254
Oil and Gas: Rapid Technology	Cost, finding rate, and success rate parameters adjusted for 50-percent more rapid improvement than in the reference case.	Fully integrated	p. 91	p. 254
Coal: Low Mining Cost	Productivity increases at an annual rate of 2.9 percent, compared to the reference case growth of 1.3 percent. Real wages and real mine equipment costs decrease by 0.5 percent annually, compared to constant real wages and equipment costs in the reference case.	Fully integrated	p. 100	p. 258
Coal: High Mining Cost	Productivity decreases at an annual rate of 0.6 percent, compared to the reference case growth of 1.3 percent. Real wages and real mine equipment costs increase by 0.5 percent annually, compared to constant real wages and equipment costs in the reference case.	Fully integrated	p. 100	p. 258

Organization of Petroleum Exporting Countries (OPEC) in the mid-term, where production is adjusted to keep world oil prices in the $22 to $28 per barrel range. Since OPEC, particularly the Persian Gulf nations, is expected to be the dominant supplier of oil in the international market over the mid-term, the organization's production choices will significantly affect world oil prices. The low world oil price case could result from a future market where all oil production becomes more competitive and plentiful. The high price case could result from a more cohesive and market-assertive OPEC with lower production goals and other nonfinancial (geopolitical) considerations.

World oil demand. Demand outside the United States is assumed to be for total petroleum with no specificity as to individual refined products or sectors of the economy. The forecast of petroleum demand within a region uses a Koyck-lag formulation and is a function of world oil price and GDP. Estimates of regional GDPs are from EIA's *International Energy Outlook 2003*.

World oil supply. Supply outside the United States is assumed to be total liquids and includes production of crude oils (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, refinery gains, alcohol, and liquids produced from coal and other sources. The forecast of oil supply is a function of the world oil price, estimates of proved oil reserves, estimates of ultimately recoverable oil resources, and technological improvements that affect exploration, recovery, and cost. Estimates of proved oil reserves are provided by the *Oil & Gas Journal* [*8*] and represent country-level assessments as of January 1, 2003. Estimates of ultimately recoverable oil resources are provided by the United States Geological Survey (USGS) [*9*] and are part of its "Worldwide Petroleum Assessment 2000." Technology factors are derived from the DESTINY forecast software [*10*] and are a part of the International Energy Services of Petroconsultants, Inc.

Buildings sector assumptions

The buildings sector includes both residential and commercial structures and commercial nonbuilding applications. The National Appliance Energy Conservation Act of 1987 (NAECA) and the Energy Policy Act of 1992 (EPACT), both of which are incorporated in *AEO2004*, contain provisions that affect future buildings sector energy use. The most significant are minimum equipment efficiency standards, which require that new heating, cooling, and other specified energy-using equipment meet minimum energy efficiency levels, which change over time. The manufacture of equipment that does not meet the standards is prohibited. Federal mandates, such as Executive Order 13123, "Greening the Government Through Efficient Energy Management" (signed in June 1999) and Executive Order 13221, "Energy-Efficient Standby Power Devices" (signed in July 2001), are expected to affect future energy use in Federal buildings.

Residential sector assumptions. The NAECA minimum standards [*11*] for the major types of equipment in the residential sector are:

- Central air conditioners and heat pumps—a 10.0 minimum seasonal energy efficiency ratio for 1992, increasing to 12.0 in 2006
- Room air conditioners—an 8.7 energy efficiency ratio in 1990, raised to 9.7 in 2003
- Gas/oil furnaces—a 0.78 annual fuel utilization efficiency in 1992
- Refrigerators—a standard of 976 kilowatthours per year in 1990, 691 kilowatthours per year in 1993, and 483 kilowatthours per year in 2002
- Electric water heaters—a 0.88 energy factor in 1990, increasing to 0.90 in 2004
- Natural gas water heaters—a 0.54 energy factor in 1990, raised to 0.59 in 2004.

The *AEO2004* version of the NEMS Residential Demand Module is based on EIA's 2001 Residential Energy Consumption Survey (RECS) [*12*]. This survey provides most of the housing stock characteristics, appliance stock information (equipment type and fuel), and energy consumption estimates used to initialize the residential module. The projected effects of equipment turnover and the choice of various levels of equipment energy efficiency are based on tradeoffs between higher equipment costs for the more efficient equipment versus lower annual energy costs. Equipment characterizations range from minimum efficiency standards to the best available equipment with the highest energy efficiency. These characterizations include equipment made available through various green programs, such as the EPA's Energy Star Programs [*13*].

A combined heating, ventilation, and air conditioning (HVAC)/shell module is used to model building shells in new construction. The module combines specific heating and cooling equipment with appropriate levels of shell efficiency to represent the least expensive ways to meet selected overall efficiency levels. The levels include:

- The current average new house, defined by the post-1990 housing stock in RECS 2001 and data obtained from results of the 2002 McGraw-Hill Dodge Survey of New Home Builders
- The International Energy Conservation Code (IECC 2000)
- Energy Star Homes using upgraded HVAC equipment and/or shell integrity (combined energy requirements for HVAC must be 30 percent lower than IECC 2000)
- The PATH home (Partnership for Advancing Technology in Housing) [*14*]
- A shell intermediate to Energy Star and PATH set to save 40 percent of HVAC energy.

Similar to the choice of end-use equipment, the choice of HVAC/shell efficiency level among the available alternatives is based on a tradeoff between estimated higher initial capital costs for the more efficient combinations and lower estimated annual energy costs.

In addition to the *AEO2004* reference case, three cases using the Residential and Commercial Demand Modules of NEMS were developed to examine the effects of equipment and building shell efficiencies. For the residential sector:

- The *2004 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2004. Existing building shell efficiencies are assumed to be fixed at 2004 levels.
- The *high technology case* assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment [*15*]. Heating shell efficiency is projected to increase by 13 percent over 2001 levels by 2025.
- The *best available technology case* assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year, regardless of cost. Heating shell efficiency is projected to increase by 18 percent over 2001 levels by 2025.

Commercial sector assumptions. The definition of the commercial sector for *AEO2004* is based on building characteristics and energy consumption data from the 1999 Commercial Buildings Energy Consumption Survey (CBECS) [*16*]. Minimum equipment efficiency standards for the commercial sector are mandated in the EPACT legislation [*17*]. Minimum standards for representative equipment types are:

- Small central air conditioning heat pumps—a 9.7 seasonal energy efficiency rating (January 1994)
- Natural-gas-fired forced-air furnaces—a 0.8 thermal efficiency standard (January 1994)
- Natural-gas-fired storage water heaters—a 0.80 thermal efficiency standard (October 2003)
- Fluorescent lamps—a 75.0 lumens per watt lighting efficacy standard for 4-foot F40T12 lamps (November 1995) and an 80.0 lumens per watt efficacy standard for 8-foot F96T12 lamps (May 1994) [*18*]
- Fluorescent lamp ballasts—a standard mandating electronic ballasts with a 1.17 ballast efficacy factor for 4-foot ballasts holding two F40T12 lamps and a 0.63 ballast efficacy for 8-foot ballasts holding two F96T12 lamps (April 2005 for new lighting systems, June 2010 for replacement ballasts).

Improvements to existing building shells are based on assumed annual efficiency increases. New building shell efficiencies relative to the efficiencies of existing construction vary for each of the 11 building types. The effects of shell improvements are modeled differentially for heating and cooling. For space heating, existing and new shells improve by 5 percent and 7 percent, respectively, by 2025 relative to the 1999 averages.

Among the energy efficiency programs recognized in the *AEO2004* reference case are the expansion of the EPA Energy Star Buildings program and improvements to building shells from advanced insulation methods and technologies. The EPA green programs are designed to facilitate cost-effective retrofitting of equipment by providing participants with information and analysis as well as participation recognition. Retrofitting behavior is captured in the commercial module through discount parameters for controlling cost-based equipment retrofit decisions in various market segments. To model programs that target particular end uses, the *AEO2004* version of the commercial module includes end-use-specific segmentation of discount rates. Federal buildings are assumed to participate in energy efficiency programs and to use the 10-year Treasury Bond rate as a discount rate in making equipment purchase decisions, pursuant to the directives in Executive Order 13123.

In addition to the *AEO2004* reference case, three cases using the Residential and Commercial Demand Modules of NEMS were developed to examine the effects of equipment and building shell efficiencies. For the commercial sector:

- The *2004 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2004. Building shell efficiencies are assumed to be fixed at 2004 levels.
- The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than the reference case [*19*]. Heating shell efficiencies for new and existing buildings are assumed to increase by 8.75 and 6.25 percent, respectively, from 1999 values by 2025—a 25-percent improvement relative to the reference case.
- The *best available technology* case assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year in the high technology case, regardless of cost. Heating shell efficiencies for new and existing buildings are assumed to increase by 10.5 and 7.5 percent, respectively, from 1999 values by 2025—a 50-percent improvement relative to the reference case.

Buildings renewable energy. The forecast for wood consumption in the residential sector is based on the RECS. The RECS data provide a benchmark for British thermal units (Btu) of wood energy use in 2001. Wood consumption is then computed by multiplying the number of homes that use wood for main and secondary space heating by the amount of wood used. Ground source (geothermal) heat pump energy consumption is also based on the latest RECS; however, the measure of geothermal energy consumption is represented by the amount of primary energy displaced by using a geothermal heat pump in place of an electric resistance furnace. Residential and commercial solar thermal energy consumption for water heating is represented by displaced primary energy relative to an electric water heater. Residential and commercial solar photovoltaic systems are discussed in the distributed generation section that follows.

Buildings distributed generation. Distributed generation includes photovoltaics and fuel cells for both the residential and commercial sectors, as well as microturbines and conventional combined heat and power technologies for the commercial sector. The forecast of distributed generation is developed on the basis of economic returns projected for investments in distributed generation technologies. The model uses a detailed cash-flow approach for each technology to estimate the number of years required to achieve a cumulative positive cash flow (although some technologies may never achieve a cumulative positive cash flow). Penetration rates are estimated by Census division and building type and vary by building vintage (newly constructed versus existing floorspace).

For purchases not related to specific programs, penetration rates are determined by the number of years required for an investment to show a positive economic return: the more quickly costs are recovered, the higher the technology penetration rate. Solar photovoltaic technology specifications for the residential and commercial sectors are based on a study published in June 2003 [*20*]. Program-driven installations of photovoltaic systems are based on information from DOE's Photovoltaic and Million Solar Roofs programs, as well as DOE and industry news releases and the National Renewable Energy Laboratory's Renewable Electric Plant Information System [*21*]. The program-driven installations incorporate some of the non-economic considerations and local incentives that are not captured in the cash flow model.

The *high renewables case* assumes greater improvements in residential and commercial photovoltaic systems than in the reference case. The high renewables assumptions result in capital cost estimates for 2025 that are approximately 10 percent lower than reference case costs for distributed photovoltaic technologies, and these costs are used in the integrated high renewables case, which focuses on electricity generation. A second, alternative high renewables case, the *DOE goals case*, was completed using assumptions that result in capital cost estimates for 2020 that approximate DOE's Office of Energy Efficiency and Renewable Energy technology characterizations for distributed photovoltaic technologies [*22*]. Like the high renewables case, the DOE goals case focuses on electricity generation.

Industrial Sector Assumptions

The manufacturing portion of the Industrial Demand Module is calibrated to EIA's 1998 Manufacturing

Energy Consumption Survey [*23*]. The nonmanufacturing portion of the module is based on information from EIA, the U.S. Department of Agriculture, and the U.S. Census Bureau [*24*]. EPACT sets efficiency standards for coke ovens and for boilers, furnaces, and electric motors. CAAA90 sets emissions limits for criteria air pollutants. The electric motor standards in EPACT set minimum efficiency levels for all motors up to 200 horsepower purchased after 1998 [*25*]. It has been estimated that electric motors account for about 60 percent of industrial process electricity use [*26*].

The industrial model includes a motor stock model for the Food, Bulk Chemicals, Metal-Based Durables, and Balance of Manufacturing sectors. When new motors are purchased, either an EPACT minimum efficiency motor or a premium efficiency motor is installed, depending on prevailing electricity prices. For *AEO2004*, the motor stock model was modified to include an explicit economic choice on whether to replace or repair motors when they fail. The cost and performance characteristics of the motor options have been updated based on the Motor Master + 4.0 database [*27*]. Combined heat and power (CHP), the simultaneous generation of electricity and useful steam, has been a standard practice in the industrial sector for many years. A separate model within NEMS evaluates additions to natural-gas-fired CHP, based on technical potential and prevailing electricity and natural gas prices. The cost and performance characteristics for CHP systems have also been updated for *AEO2004*.

High technology, 2004 technology, and high renewables cases. The *high technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*28*]. The high technology case also assumes a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes, at 1.0 percent per year as compared with 0.1 percent per year in the reference case. The same assumption is also incorporated in the integrated high renewable case, which focuses on electricity generation. While the choice of 1 percent recovery is an assumption of the high technology case, it is based on the expectation that there would be higher recovery rates and substantially increased use of CHP in that case. Changes in aggregate energy intensity result both from changing equipment and production efficiency and from changing composition of industrial output. Because the composition of industrial output remains the same as in the reference case, primary energy intensity falls by 1.5 percent annually in the high technology case. In the reference case, primary energy intensity falls by 1.3 percent annually between 2002 and 2025.

The *2004 technology case* holds the energy efficiency of plant and equipment constant at the 2004 level over the forecast. In this case, primary energy intensity falls by 1.1 percent annually. Because the level and composition of industrial output are the same in the reference, high technology, and 2004 technology cases, any change in primary energy intensity in the two technology cases is attributable to efficiency changes. Both cases were run with only the Industrial Demand Module rather than as fully integrated NEMS runs. Consequently, no potential feedback effects from energy market interactions were captured.

Transportation Sector Assumptions

The transportation sector accounts for two-thirds of the Nation's oil use and has been subject to regulations for many years. The Corporate Average Fuel Economy (CAFE) standards, which mandate average miles-per-gallon standards for manufacturers, continue to be widely debated. The *AEO2004* projections assume that there will be no further increase in the CAFE standard from the current 27.5 miles per gallon standard for automobiles. The CAFE standard for light trucks was increased in *AEO2004* from 20.7 miles per gallon to 21.0 miles per gallon in 2005, 21.6 miles per gallon in 2006, and 22.2 miles per gallon in 2007, where it remains constant through the projection period. This is consistent with the new Federal CAFE standard for light trucks promulgated in April 2003 and the overall policy that only current legislation is assumed in the *AEO*.

EPACT requires that centrally fueled light-duty fleet operators—Federal and State governments and fuel providers (e.g., natural gas and electric utilities)—purchase a minimum fraction of alternative-fuel vehicles [*29*]. The legislation requires that alternative-fuel vehicles make up 75 percent of Federal and State fleet purchases in 2002. *AEO2004* assumes that they remain at that level through 2005. The municipal and private business fleet mandates, which were proposed to begin in 2003 at 20 percent and scale up to 70 percent by 2005 but were never adopted, are not included in *AEO2004*.

In addition to the EPACT requirements, the sale of zero-emission vehicles (ZEVs) required by the State of California's Low Emission Vehicle Program (LEVP) is also included in the forecast. In 1998, California modified those requirements so that 60 percent of the ZEV mandate could be met by credits earned from the sales of advanced technology vehicles, depending on their degree of similarity to electric vehicles. The remaining 40 percent of the ZEV mandate was to be achieved through the sales of "true ZEVs," which include only electric and hydrogen fuel cell vehicles [*30*]. In December 2001, further modifications were enacted that maintained progress toward the 2003 goal while recognizing technology and cost limitations on ZEV product offerings. Those modifications removed ZEV sales requirements before 2003 but maintained the 2003 required sales goal of 10 percent and required a gradual increase in ZEV sales to 16 percent by 2018.

Additional sales credits were given for the sale of true ZEVs, and partial credits were allowed for advanced technology vehicles and certain alternative-fuel vehicles. The number of vehicles included in the estimation of required ZEV sales was also increased to include light-duty and medium-duty trucks. Auto manufacturers filed a Federal suit in California in 2002 arguing that the revisions to the ZEV program are preempted by the Federal fuel economy statute of the Energy Policy and Conservation Act of 1975. In June 2002, a Federal judge granted a preliminary injunction preventing the California Air Resources Board from enforcing the ZEV regulations for model year 2003 and 2004 vehicles.

In April 2003, the California Air Resources Board proposed amendments to the LEVP in response to the Federal suit filed by auto manufacturers [*31*]. As a result of the proposed amendments, the auto manufacturers agreed to settle litigation with the California Air Resources Board and have indicated initial agreement with the proposed amendments. The amendments place a greater emphasis on emissions reductions from partial zero emission vehicles (PZEVs) and advanced technology partial emission vehicles (AT-PZEVs), and require that manufacturers produce a minimum number of electric and fuel cell vehicles. Credits earned from the sales of PZEVs can be used to meet up to 60 percent of the ZEV sales requirement and credits earned from AT-PZEVs can be used to meet up to 20 percent of the requirement. PZEVs and AT-PZEVs are allowed 0.2 credits per vehicle. The *AEO2004* projections assume that California, Massachusetts, New York, Maine, and Vermont will formally begin implementing the LEVP mandates in 2005.

Technology choice. Conventional light-duty (less than 8,500 pounds gross vehicle weight) vehicle technologies are chosen by consumers and penetrate the market based on the assumption of cost-effectiveness, which compares the capital cost to the discounted stream of fuel savings from the technology. There are approximately 63 fuel-saving technologies, which vary by capital cost, date of availability, marginal fuel efficiency improvement, and marginal horsepower effect [*32*]. The projections assume that the regulations for alternative-fuel and advanced technology vehicles represent minimum requirements for alternative-fuel vehicle sales; in the model, consumers are allowed to purchase more of the vehicles if their cost, fuel efficiency, range, and performance characteristics make them desirable. Technology choice captures the manufacturers' response to the market.

Many consumers do not place a significant value on high-efficiency vehicles. This is reflected in the model by assuming a 3-year payback period, with the real discount rate remaining steady at 15 percent. Expected future fuel prices are calculated based on extrapolation of the growth rate between a 5-year moving average of fuel prices 3 years and 4 years before the present year. This assumption is based on a lead time of 3 to 4 years for significant modification of the vehicles offered by a manufacturer.

For freight trucks, technology choice is based on several technology characteristics, including capital cost, marginal improvement in fuel efficiency, payback period, and discount rate, which are used to calculate a fuel price at which the technologies become cost-effective [*33*]. When technologies are mutually exclusive, the more cost-effective technology will gain market share relative to the less cost-effective technology. Efficiency improvements for both rail and ship are based on recent historical trends [*34*].

As in the case of freight trucks, fuel efficiency improvements for new aircraft are also determined by a trigger fuel price, the time the technology becomes commercially available, and the projected marginal fuel efficiency improvement. The advanced technologies are ultra-high bypass, propfan, thermodynamics, hybrid laminar flow, advanced aerodynamics, and weight-reducing materials [*35*].

Travel. Projections of vehicle-miles traveled for personal travel [*36*] and ton-miles traveled for freight travel [*37*] are based on the assumption that modal shares (for example, personal automobile travel versus mass transit) remain stable over the forecast and follow recent historical patterns. Important factors affecting the forecast of vehicle-miles traveled for light-duty vehicles are personal disposable income per capita and the cost of driving. Travel by freight truck, rail, and ship is based on the growth in industrial output by sector and the historical relationship between freight travel and industrial output [*38*]. Both rail and ship travel are also based on projected coal production and distribution.

Air travel is estimated for domestic travel, international travel, and dedicated air freight shipments by U.S. carriers. Depending on the market segment, the demand for air travel is based on projected disposable personal income, GDP, merchandise exports, and ticket price as a function of jet fuel prices. Load factors, which represent the percentage of seats occupied per plane and are used to convert air travel (expressed in revenue-passenger miles and revenue-ton miles) to seat-miles of demand, increase slightly over the forecast period. For passenger travel, domestic and international air travel is modeled specific to aircraft type (regional, narrow body and wide body) such that regional aircraft are used exclusively for domestic travel, while narrow body aircraft serve both domestic and international markets, and wide body aircraft primarily serve the international market. In addition, the model captures the industry practice of parking aircraft to reduce operating costs and moving aircraft from the passenger to cargo markets as aircraft age. For air freight shipments, the model employs narrow body and wide body aircraft only. The model also utilizes an infrastructure constraint that limits air travel growth to levels commensurate with industry-projected infrastructure expansion and capacity growth.

2004 technology case. The *2004 technology case* assumes that new fuel efficiency levels are held constant at 2004 levels through the forecast horizon for all modes of travel.

High technology case. For the *high technology case*, light-duty conventional and alternative-fuel vehicle characteristics reflect more optimistic assumptions for incremental fuel economy improvements and costs [*39*]. In the air travel sector, the high technology case reflects lower costs for improved thermodynamics, advanced aerodynamics, and weight reduction materials, which provides a 25-percent improvement in new aircraft efficiency compared to the reference case by 2025. In the freight truck sector, the high technology case assumes more optimistic incremental fuel efficiency improvements for engine and emission control technologies [*40*]. More optimistic assumptions for fuel efficiency improvements are also made for the rail and shipping sectors.

Both cases were run with only the Transportation Demand Module rather than as fully integrated NEMS runs. Consequently, no potential macroeconomic feedback on travel demand was captured, nor were changes in fuel prices incorporated.

Electricity Assumptions

Characteristics of generating technologies. The costs (including capital costs and operating and maintenance costs) and performance (efficiency) of new generating technologies are important factors in determining the future mix of capacity. Fossil fuel, renewable, and nuclear technologies are represented and include those currently available as well as those that are expected to be commercially available within the horizon of the forecast. It is assumed that the selection of new plants to be built is based on least cost, subject to environmental constraints. The incremental costs associated with each option are evaluated and used as the basis for selecting plants to be built. Details about each of the generating plant options are described in the detailed assumptions, which are available at web site www.eia.doe.gov/oiaf/aeo/assumption/.

Regulation of electricity markets. It is assumed that electricity producers comply with CAAA90, which mandates a limit of 9.48 million short tons of sulfur dioxide (SO_2) emissions per year from 2001 through 2009 and 8.95 million tons per year by 2010. Electricity producers are assumed to comply with the limits on sulfur dioxide emissions by retrofitting units with flue gas desulfurization (FGD) equipment, transferring or purchasing sulfur emission allowances, operating high-sulfur coal units at a lower capacity utilization rate, or switching to low-sulfur fuels. Electricity producers are assumed to comply with the limits on nitrogen oxides (NO_x) by installing selective catalytic reduction (SCR) equipment. FGD units are assumed to remove 95 percent of the SO_2 and SCR units are assumed to remove 90 percent of the NO_x. The costs per kilowatt to add FGD or SCR equipment decline as the capacity of the coal plant increases. Capital costs for retrofitting with FGD equipment are estimated to decline from $270 per kilowatt (2002 dollars) for a 300-megawatt plant to $206 per kilowatt for a 500-megawatt plant and $171 per kilowatt for a 700-megawatt plant. Capital costs for installing SCR equipment are estimated to decline from $111 per kilowatt for a 300-megawatt plant to $97 per kilowatt for a 500-megawatt plant and $88 per kilowatt for a 700-megawatt plant [*41*].

In the reference, high, and low economic growth, and high and low world oil price cases, generators are projected to meet the annual SO_2 caps based on additions of 23 gigawatts of planned retrofits and 2 to 10 gigawatts of unplanned retrofits of FGD equipment at existing coal-fired power plants, combined with the drawdown of banked SO_2 emission allowances amounting to 9.2 million tons at the end of 2001. Announced retrofits by Duke Power and Progress Energy in response to North Carolina's Clean Smokestacks Bill account for nearly one-half of the planned retrofits included. The remaining are based on other factors, including compliance strategies developed by generators in response to CAAA90, agreements that generators have reached with the U.S. Department of Justice in litigation related to New Source Review, and other State and local environmental issues.

The EPA has issued rules to limit emissions of NO_x, specifically calling for capping emissions during the summer season in 22 eastern and midwestern States. After an initial challenge, the rules have been upheld, and emissions limits have been finalized for 19 States and the District of Columbia, starting in 2004. *AEO2004* assumes that electricity generators in those 19 States and the District of Columbia comply with the limits either by reducing their own emissions or by purchasing allowances from others. *AEO2004* also assumes that generators comply with the NO_x limits through a combination of combustion and post-combustion controls. In the reference case, installed and planned post-combustion control equipment amounts to 42 gigawatts of SCR equipment and 5 gigawatts of selective noncatalytic reduction (SNCR) equipment. The facilities in which the equipment is installed are located in 12 States, and their actions are in response to the EPA rules. Additional unplanned retrofits are projected in the reference case—52 gigawatts of SCR and 25 gigawatts of SNCR—between 2002 and 2025.

The reference case assumes a transition to full competitive pricing in New York, New England, the Mid-Atlantic Area Council, and Texas. In addition, electricity prices in the East Central Area Reliability Council, the Mid-America Interconnected Network, the Southeastern Electric Reliability Council, the Southwest Power Pool, the Northwest Power Pool, and the Rocky Mountain Power Area/Arizona (Arizona, New Mexico, Colorado, and eastern Wyoming) regions are assumed to be partially competitive. Some of the States in each of these regions have not taken action to deregulate their pricing of electricity, and in those States prices are assumed to continue to be based on traditional cost-of-service pricing. In California, a return to almost total cost-of-service regulation is now assumed.

In many deregulated States the legislation has mandated price freezes or reductions over a specified transition period. *AEO2004* includes such agreements in the electricity price forecast. In general, the transition period is assumed to be a 10-year period from the beginning of restructuring in each region, during which time prices gradually shift to competitive prices. The transition period reflects the time needed for the establishment of competitive market institutions and recovery of stranded costs as permitted by regulators. *AEO2004* assumes that the competitive price in deregulated regions is the marginal cost of generation.

Competitive cost of capital. The cost of capital is calculated as a weighted average of the costs of debt and equity. The cost of equity is an implied investor's opportunity cost, or the required rate of return on any risky investment. *AEO2004* assumes a ratio of 45 percent debt and 55 percent equity. The yield on debt represents that of a BBB corporate bond, calculated by applying a 1.25-percent premium to the annual AA utility bond rate projected by the Macroeconomic Activity Module. The cost of equity is calculated to be representative of unregulated industries similar to the electricity generation sector. It is assumed that the capital invested in a new plant must be recovered over a 20-year plant life rather than the traditional 30-year life.

Representation of Climate Challenge participation agreements. As a result of the Climate Challenge Program, many electricity generators have announced efforts to reduce their greenhouse gas emissions voluntarily. These efforts cover a wide variety of programs, including increasing demand-side management investments, repowering (fuel switching) fossil plants, restarting nuclear plants that have been out of service, planting trees, and purchasing emissions offsets from international sources.

To the degree possible, each of the participation agreements was examined to determine whether the commitments made were addressed in the normal reference case assumptions or whether they should be addressed separately. Programs such as tree planting and emissions offset purchasing are not addressed, but the other programs are, for the most part, captured in *AEO2004*. For example, electricity generators annually report to EIA their plans (over the next 10 years) to bring a plant back on line, repower a plant, extend a plant's life, cancel a previously planned plant, build a new plant, or switch fuel at a plant. Data for these programs are included in the *AEO2004* input data. However, because many of the agreements do not identify the specific plants where action is planned, it is not possible to determine which of the specified actions, together with their greenhouse gas emissions savings, should be attributed to the Climate Challenge Program and which are the result of normal business operations.

Fossil steam and nuclear plant retirement assumptions. Fossil steam plants and nuclear plants are retired when it is no longer economical to run them. In each forecast year the model determines whether the market price of electricity is sufficient to support the continued operation of existing plants. If the revenue a plant receives is not sufficient to cover its forward costs (including fuel, operations and maintenance costs, and assumed annual capital additions) the plant is retired. Beyond age 30, the forward costs also include capital expenditures assumed to be needed to address aging-related issues. For fossil plants the aging-related costs are assumed to be $5 per kilowatt, in year 2002 dollars. For nuclear plants the aging-related costs are assumed to be $37 per kilowatt. Aging-related cost increases result from increased capital costs, decreases in performance, and/or increased maintenance expenditures to mitigate the effects of aging.

Nuclear power. There are no nuclear units actively under construction in the United States. In NEMS, new nuclear plants are competed against other options when new capacity is needed. The cost assumptions for new nuclear units are based on an analysis of the realized costs of nuclear plants recently constructed overseas, since no advanced reactors have been built yet in the United States.

The capital cost assumptions in the reference case are meant to represent the expense of building a new single-unit nuclear plant of approximately 1,000 megawatts. Because no new nuclear plants have been built in the United States in many years, there is a great deal of uncertainty about the true costs of a new unit. The estimate used for *AEO2004* is an average of the actual costs incurred in completed advanced reactor builds in Asia, adjusting for expected learning from other units still under construction. The average nuclear capacity factor in 2002 was 90 percent, the highest annual average ever in the United States. The average annual capacity factor reaches a national average of 91 percent by 2011. Capacity factor assumptions are developed at the unit level, and improvements or decrements are based on the age of the reactor.

The *AEO2004* nuclear power forecast assumes capacity increases at existing units. The U.S. Nuclear Regulatory Commission (NRC) approved 18 applications for power uprates in 2002, and another 9 were approved or pending in 2003. *AEO2004* assumes that all of those uprates will be implemented, as well as others expected by the NRC over the next 15 years, for a capacity increase of 3.9 gigawatts between 2003 and 2025.

For nuclear power plants, several advanced nuclear cases analyze the sensitivity of the projections to lower costs for new plants. The cost assumptions for the *advanced nuclear cost case* reflect a 10-percent reduction in the capital and operating costs for the advanced nuclear technology in 2025, relative to the reference case. Since the reference case assumes some learning occurs regardless of new orders and construction, the reference case already projects a 10-percent reduction in capital costs between 2005 and 2025. The advanced nuclear cost case therefore assumes a 19-percent reduction between 2005 and 2025. The *nuclear AP1000 case* assumptions are consistent with estimates from British Nuclear Fuel Limited (BNFL) for the manufacture of its Advanced Pressurized Water Reactor (AP1000), as provided to the Near-Term Deployment Working Group of DOE's Office of Nuclear Energy, Science, and Technology. In this case, the overnight capital cost of a new advanced nuclear unit is assumed initially to be $1,580 per kilowatt, declining to $1,081 per kilowatt for plants coming on line in 2025 (in year 2002 dollars)—18 percent lower than assumed in the reference case in 2002 and 38 percent lower in 2025. A final case, the *nuclear vendor estimate case* (discussed in "Issues in Focus"), uses cost assumptions based on the average of estimates for the AP1000 and Atomic Energy Canada Limited's CANDU reactor, now being marketed to the United States. In this case, the overnight cost is $1,555 per kilowatt initially, falling to $1,149 per kilowatt for plants coming online in 2025. Cost and performance characteristics for all other technologies are as assumed in the reference case.

Biomass co-firing. Coal-fired power plants are allowed to co-fire with biomass fuel if it is economical. Co-firing requires a capital investment for boiler modifications and fuel handling. This expenditure ranges from about $100 to $240 per kilowatt of biomass capacity, depending on the type and size of the boiler. A coal-fired unit modified to allow co-firing can generate up to 15 percent of its total output using biomass fuel, assuming sufficient fuel supplies are available. Larger units are required to pay additional transportation costs as the level of co-firing increases, due to the concentrated use of the regional biomass supply.

Distributed generation. AEO2004 assumes the availability of two generic technologies for distributed electricity generation. To determine the levels of capacity and generation for distributed technologies projected to be used in the forecast, the model compares their costs with the "avoided costs" of electricity producers. The avoided costs are the costs electricity producers would incur if they added the least expensive conventional central-station generators rather than distributed generators, as well as the costs of additional transmission and distribution equipment that would be required if the distributed generators were not added. Because there are currently no reliable estimates of the transmission and distribution costs that can be avoided by adding distributed generators, regional estimates were developed for the transmission and distribution investments that would be needed for each kilowatt of central-station generating capacity added. It was then assumed that 75 percent of such "growth-related" transmission and distribution costs could be avoided by adding distributed generators.

International learning. Capital costs for all new electricity generating technologies are assumed to decrease in response to domestic as well as foreign experience, to the extent that the new foreign plants reflect technologies and firms competing in the United States. In its learning function, *AEO2004* includes 1,938 megawatts of advanced coal gasification combined-cycle capacity (including the 127-megawatt Fife plant that entered service in Scotland in 2001) and 5,244 megawatts of advanced combined-cycle natural gas capacity operating or under construction outside the United States from 2000 through 2003. A small amount of international biomass integrated gasification combined cycle and wind capacity is also assumed to be on line in that time period. The learning function also includes 7,200 megawatts of advanced nuclear capacity, representing two completed units and four additional units under construction in Asia. Experience indicates that the small amount of learning attributed to international renewable energy installations is already adequately incorporated in U.S. domestic learning functions, and that because installations taking place in the United States are lowering projected capital costs, no additional accounting for new international renewable energy capacity is required.

High electricity demand case. The *high electricity demand case* assumes that the demand for electricity grows by 2.5 percent annually between 2002 and 2025, compared with 1.8 percent in the reference case. No attempt was made to determine changes in the end-use sectors that would result in the stronger demand growth. The high electricity demand case is partially integrated, with no feedback from the Macroeconomic Activity, International, or end-use demand modules. Rapid growth in electricity demand also leads to higher prices. The price of electricity in 2025 is 7.1 cents per kilowatthour in the high demand case, as compared with 6.9 cents in the reference case. Higher fuel prices, especially for natural gas, and higher capital costs for alternative technologies are the key factors leading to higher electricity prices.

High and low fossil technology cases. The high and low fossil technology cases are partially integrated cases, with no feedback from the Macroeconomic Activity, International, or end-use demand modules. In the *high fossil technology case*, capital costs, heat rates and operating costs for the advanced coal and gas technologies are assumed to be 10-percent lower than reference case levels in 2025. Since learning occurs in the reference case, costs and performance in the high case are reduced from initial levels by more than 10 percent. Heat rates in the high fossil case fall to roughly 20 percent below initial levels, while capital costs are reduced by 20 to 25 percent between 2003 and 2025. In the *low fossil technology case*, capital costs and heat rates for coal gasification combined-cycle units and advanced combustion turbine and combined-cycle units do not decline during the forecast period and remain fixed at the 2004 values assumed in the reference case.

In the *DOE fossil goals case*, capital costs and heat rates for the advanced coal and gas technologies are assumed to be lower and decline faster than in the reference case, and in most instances are lower than the high fossil technology case. The values used in the DOE goals case for capital costs and heat rates were based on the DOE's Vision 21 program. The capital costs and heat rates for renewable, nuclear, and other fossil technologies are assumed to be the same as in the reference case. Details about annual capital costs, operating and maintenance costs, plant efficiencies, and other factors used in the high fossil technology, low fossil technology, and DOE goals cases are described in the detailed assumptions, which are available at web site www.eia.doe.gov/oiaf/aeo/assumption/.

Renewable Fuels Assumptions

Energy Policy Act of 1992. The EPACT 10-year renewable electricity production tax credit (PTC) of 1.5 cents per kilowatthour (now adjusted for inflation to 1.8 cents) for new wind and some biomass plants originally expired on June 30, 1999. It was first extended through December 31, 2001, and then retroactively extended from December 31, 2001 through December 31, 2003, by the Job Creation and Worker Assistance Act of 2002 (P.L. 107-147). *AEO2004* applies the credit to all wind plants built through 2003. ("Closed loop" biomass plants are assumed to be commercially available beginning in 2010 and thus are not available to take advantage of the credit until 2010.) *AEO2004* assumes that the 10-percent investment tax credit for solar and geothermal technologies that generate electric power will be continued through 2025.

Renewable capacity additions. In addition to new unplanned generation capacity using renewable resources as determined by NEMS, *AEO2004* includes 4,362 megawatts of new "planned" central-station generating capacity using renewable resources as announced by utilities and independent power producers or identified by EIA to be built from 2003 through 2015. No planned builds were assumed after 2015. Of the total planned capacity builds, 3,132 megawatts result from State mandates, State renewable portfolio standards (RPS), State goals and other objectives or requirements, and 1,229 megawatts result from commercial builds and voluntary programs, such as green power programs and utility testing and demonstration projects using renewable technologies.

Because of demand and regulatory uncertainties, *AEO2004* does not assume that all new renewable capacity implied by State RPS and other mandates will be built; the assumptions for planned renewable capacity include primarily the near-term requirements about which the States and utilities are relatively certain. States and utilities are sometimes unable to quantify the amount of new capacity that will result from the RPS. Further, actual RPS implementation for some States is proceeding more slowly than initially expected, suggesting caution in expectations for the near term. Moreover, RPS implementation itself is often uncertain, because many of the RPS programs are set to be reevaluated, often by 2007. Given the legal alternatives (such as fines and exemptions) and technology choices (including conservation), the prospect of RPS reevaluation and redirection after 2007 may slow or inhibit compliance. Finally, even if the new capacity is eventually built, the specific technologies that will be chosen, the years in which they will be built, and their sizes and locations are uncertain.

Estimating supplemental additions of new renewable capacity for *AEO2004* is further complicated by reported transmission constraints thwarting wind development, by uncertainty about post-2003 extension of the PTC, by uncertain financial positions of utilities in the West that serve California markets, by uncertain demand for renewables in light of potential overbuilding of natural gas capacity, and by uncertainty about States' adherence to RPS mandates when economic growth is slow. As a result, the State RPS estimates should be considered relatively certain estimates of new capacity likely to be built in the near term and not as measure of the full potential consequences of the RPS over the entire forecast period. Using publicly available information and working with State agencies, EIA confirms projections of mandated renewable energy capacity; however, limited resources preclude confirming the status of every new renewable energy plant.

In addition to supplemental additions based on known plans, the projection includes minimum expectations for new central-station solar energy capacity assumed to be installed for reasons other than least-cost electricity supply, based on historical rates of addition of new capacity. *AEO2004* estimates include 75.5 megawatts of central-station solar thermal-electric and 332.5 megawatts of central-station photovoltaic (PV) generating capacity to be installed from 2003 through 2025.

Renewable resources. All central-station electricity generating technologies, including those using renewable energy resources, compete in NEMS based on their relative costs. Intermittent renewables (solar and wind) compete during time periods when they are assumed to be available but decrease in value as they contribute increasing shares of a region's total electricity supply, because they can contribute less additionally to meeting a region's reliability needs. As wind power provides increasing shares of a region's total generation, new wind plants alone cannot provide significant additional reliable capacity and therefore either must be used as fuel-saving nonfirm substitutes for the operation of existing capacity or must have backup capacity to ensure firm power delivery.

The delivered cost of electricity from renewables depends both on the availability of adequate renewable resources and on the capital costs of the technologies using them. Costs of renewable energy resources tend to increase as more of them are used and the best sites are exhausted; at the same time, costs of renewable energy technologies are assumed to decline with experience and mass production. As a result, depending upon the assumed rates of resource cost increases and the assumed rate of decline in capital costs, a region's delivered electricity cost from renewable energy resources may decrease or increase as a function of the changing cost of each input.

Although conventional hydroelectricity is the largest source of renewable energy in U.S. electricity markets today, the lack of available new sites, environmental and other restrictions, and costs are assumed to halt the expansion of U.S. hydroelectric power. Solar, wind, and geothermal resources are theoretically very large, but economically accessible resources are less available.

Solar energy (direct normal insolation) for thermal applications is considered economical only in drier regions west of the Mississippi River. Photovoltaics can be economical in all regions, although conditions are also superior in the West. Wind energy resource potential, while large, is constrained by wind quality differences, distance from markets, power transmission costs, alternative land uses, and environmental objections. The geographic distribution of available wind resources is based on work by the Pacific Northwest Laboratory and the National Renewable Energy Laboratory [*42*], enumerating winds among average annual wind-power classes. Geothermal energy is limited geographically to regions in the western United States with hydrothermal resources of hot water and steam. Although the potential for biomass is large, transportation costs limit the amount of the resource that is economically productive, because biomass fuels have a low Btu content per weight of fuel.

The *AEO2004* reference case incorporates upward-sloping supply curves for geothermal and wind technologies, in recognition of the higher costs of consuming increasing proportions of a region's resources. Capital costs are assumed to increase in response to (1) declining natural resource quality, such as rough or steep terrain or turbulent winds, (2) increasing costs of upgrading the existing transmission and distribution network, and (3) market conditions that increase wind power costs in competition with other land uses, such as for crops, recreation, or environmental or cultural preferences.

AEO2004 includes a revision to the treatment of wind energy for capacity planning and dispatch. This change reflects the additional costs imposed on the power grid by increasing levels of wind penetration. For *AEO2004*, the marginal capacity credit for wind decreases toward zero with increasing penetration, which ensures the availability of adequate firm capacity within a region to satisfy reliability requirements. In addition, surplus wind generation (such as during low-load periods) is assumed to be curtailed and does not contribute to cost-recovery for wind operations during curtailed periods. Penetration of wind and other intermittent generation resources is initially limited to 20 percent of a region's total generation but is allowed to increase over time to 40 percent. These limits reflect the need for a system with large intermittent generation to adjust to new and significantly different operational requirements and recognizes the uncertainties associated with operating a system that has high intermittency.

High renewables case. For the *high renewables case*, the levelized costs of energy for nonhydroelectric generating technologies using renewable resources are assumed to decline, to 10 percent below the reference case costs for the same technologies in 2025. For most renewable resources, lower costs are accomplished by reducing the capital costs of new plant construction. To reflect recent trends in wind energy cost reductions, however, it is assumed that wind plants ultimately achieve the 10-percent cost reduction through performance improvement (an increased capacity factor) rather than capital cost reductions. Biomass supplies are also assumed to be 10-percent greater for each supply step.

The *DOE goals case*, like the high renewables case, assumes improved performance and lower capital costs than the reference case for central-station nonhydroelectric generating technologies using renewable resources (other than landfill gas), in order to approximate published projections of cost and performance targets from DOE's Office of Energy Efficiency and Renewable Energy [*43*]. Differences from the reference case are not uniform, but instead reflect differences existing between the two cases in 2025. The DOE goals case also incorporates reduced operations and maintenance costs, improvements in capacity factors for wind technologies, increased biomass supplies, and lower capital costs for residential and commercial photovoltaic systems.

Annual limits are placed on the development of geothermal sites for both high renewable cases, because they require incremental development to assure that the resource is viable. The annual limits on capacity additions at geothermal sites were raised from 25 megawatts per year through 2015 to 50 megawatts per year for all forecast years. All other cases are assumed to retain the 25-megawatt limit through 2015. Other generating technologies and forecast assumptions remain unchanged from those in the reference case. In both the high renewables case and the DOE goals case, the rate of improvement in the recovery of biomass byproducts from industrial processes is also increased. More rapid improvement in cellulosic ethanol production technology is also assumed in both the high renewables case and the DOE goals case, and cellulosic ethanol production is assumed to capture a higher share of the renewable transportation fuels market, resulting in increased cellulosic ethanol supply compared with the reference case.

Low renewables case. In the *low renewables case*, capital costs, operations and maintenance costs, and performance levels for wind, solar, biomass, and geothermal resources are assumed to remain constant at 2004 levels through 2025.

Oil and Gas Supply Assumptions

Domestic oil and gas technically recoverable resources. The levels of available oil and gas resources assumed for *AEO2004* are based on estimates of the technically recoverable resource base from the U.S. Geological Survey (USGS) and the Minerals Management Service (MMS) of the Department of the Interior [*44*], with supplemental adjustments to the USGS nonconventional resources by Advanced Resources International (ARI), an independent consulting firm.

Technological improvements affecting recovery and costs. Productivity improvements are simulated by assuming that drilling, success rates, and finding rates will improve and the effective cost of supply activities will be reduced. The assumed increase in recovery is due to the recent development and deployment of technologies such as three-dimensional seismology and horizontal drilling and completion techniques.

For conventional oil and gas, drilling, operating, and lease equipment costs are expected to decline due exclusively to technological progress, at econometrically estimated rates that vary somewhat by cost and fuel categories, ranging roughly from 0.3 to 1.9 percent. The technological impacts work against increases in costs associated with drilling to greater depths, higher drilling activity levels, and rig availability. As a direct result of technological progress, success rates are assumed to improve by 0.5 percent per year, and finding rates are expected to improve by 2.8 percent per year. For nonconventional gas, these costs are expected to remain at current levels.

Rapid and slow technology cases. Two alternative cases were created to assess the sensitivity of the projections to changes in the assumed rates of progress in oil and natural gas supply technologies. To create these cases, conventional oil and natural gas reference case parameters for the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and success rates were adjusted by plus or minus 50 percent. For unconventional gas, a number of key exploration and production technologies were also adjusted by plus or minus 50 percent in the rapid and slow technology cases. Key Canadian supply parameters were also adjusted to simulate the assumed impacts of rapid and slow oil and gas technology penetration on Canadian supply potential.

All other parameters in the model were kept at the reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of liquefied natural gas and natural gas trade between the United States and Mexico. Specific detail by region and fuel category is presented in *Assumptions to the Annual Energy Outlook 2004*, which is available at web site www.eia.doe.gov/oiaf/aeo/assumption/.

Leasing and drilling restrictions. The projections of crude oil and natural gas supply assume that current restrictions on leasing and drilling will continue to be enforced throughout the forecast period. At present, drilling is prohibited along the entire East Coast, the west coast of Florida, and the West Coast except for the area off Southern California. In Alaska, drilling is prohibited in a number of areas, including the Arctic National Wildlife Refuge. The projections also assume that coastal drilling activities will be reduced in response to the restrictions of CAAA90, which require that offshore drilling sites within 25 miles of the coast, with the exception of areas off Texas, Louisiana, Mississippi, and Alabama, meet the same clean air requirements as onshore drilling sites.

Gas supply from Alaska, MacKenzie Delta, and LNG imports. Due to the relative economics, the assumption in the model is that a pipeline from the MacKenzie Delta to Alberta would be constructed first, followed by one from Alaska, with potential expansions following thereafter. The timing of both systems is based on estimates of the cost to bring the gas to market in the United States, relative to the average lower 48 wellhead price.

A natural gas pipeline from Alaska into Alberta, Canada, is assumed to carry an initial capitalization of $13.2 billion (2002 dollars) and be depreciated over 15 years. The initial capitalization includes an expected cost of $ 11.6 billion plus an additional 20 percent to account for the uncertainty in realized capital costs. The expected cost for a pipeline from the MacKenzie Delta into Alberta is $3.6 billion. It is assumed that the Alaska pipeline will require 4 years to construct (3 years for the MacKenzie pipeline), will not be completed before 2013 (2009 for MacKenzie), will deliver 3.9 billion cubic feet of dry natural gas per day once fully operational (1.5 billion for MacKenzie), and can be expanded by 23 percent, if economical. The wellhead price of natural gas from Alaska to be delivered through the pipeline is assumed to be $0.81 per thousand cubic feet in 2002 dollars ($1.00 for MacKenzie). Gas treatment and pipeline fuel costs are accounted for as well.

A market price risk premium totaling $0.34 per thousand cubic feet is assumed, above and beyond the expected cost of delivery into Alberta and on to the lower 48 States. For MacKenzie, a capital cost and market price risk premium totaling $0.39 per thousand cubic feet is assumed. Those assumptions imply that an average price in the lower 48 States of around $3.69 (2002 dollars) per thousand cubic feet ($3.41 for MacKenzie) would need to be maintained on average over a 5-year (2-year for MacKenzie) planning period for construction to commence. Falling prices during the planning period can delay the construction period, depending on the severity of the decline.

The four existing liquefied natural gas (LNG) receiving facilities in Massachusetts, Maryland, Louisiana, and Georgia are in operation and have a combined design capacity of about 1.2 trillion cubic feet per year. All four facilities are in the process of expanding, and additional capacity of approximately 650 billion cubic feet per year is expected to be in place by 2006. This will bring the total U.S. design capacity to approximately 1.8 trillion cubic feet per year. Assumed maximum load factors effectively reduce the total available LNG from existing facilities to a maximum of 1.4 trillion cubic feet per year over the forecast period. It is assumed that existing facilities will not expand beyond current plans.

The model has a provision for the construction of new facilities in all U.S. coastal regions and in Baja California, Mexico. Construction in a region is triggered when the regional price of natural gas meets or exceeds the cost (per thousand cubic feet) of producing, liquefying, transporting, and regasifying the LNG, plus a risk premium of $0.45 (in 2002 dollars) per thousand cubic feet. The risk premium is applied only in making the decision to go ahead with a project, and is not reflected in subsequent costs of LNG to the consumer. The regasification component is based on the assumed cost of constructing a generic terminal in the region with adjustments to account for region-specific parameters such as cost of land and labor costs. New facilities are assumed to range in size from 250 million cubic feet per day to 1 billion cubic feet per day, depending on location. Regional prices at the LNG tailgate (including relevant transportation charges), which trigger construction range from $3.62 (2002 dollars) per thousand cubic feet along the Gulf Coast in Texas and Louisiana to $4.57 per thousand cubic feet in California. The effect of technological progress on reducing some of the component costs is assumed to be offset by increases in other components, such as production costs.

An LNG facility in Baja California, Mexico, with a capacity of 1 billion cubic feet per day and expansion potential of an additional 1 billion cubic feet per day, is assumed to be constructed at a tailgate price of $3.10 (in 2002 dollars) per thousand cubic feet, with half of its capacity available for export to the United States and the other half reserved for use within Mexico. A liquefaction plant in Kenai, Alaska, has been producing and exporting LNG to Japan for the past 30 years, and this is expected to continue throughout the forecast at a level of approximately 65 billion cubic feet per year. Exports to Mexico are determined based on projected production and consumption within Mexico. Consumption in Mexico is projected to grow at an average annual rate of 6.1 percent per year over the forecast period. Production is expected to grow at a slower rate, with the shortfall met by a combination of pipeline imports from the United States and LNG imports.

Natural gas transmission and distribution assumptions. Transportation rates for pipeline services are calculated with the assumption that the costs of new pipeline capacity will be rolled into the existing ratebase. The rates based on cost of service are adjusted according to pipeline utilization, to reflect a more market-based approach. In determining interstate pipeline tariffs, potential future expenditures for pipeline safety necessary to comply with the Pipeline Safety Improvement Act of 2002 are not considered.

Distribution markups to core customers (not including electricity generators) change over the forecast in response to changes in consumption levels and in the costs of capital and labor. Markups to electricity generators are a direct function of changes in consumption levels alone. The natural gas vehicle sector is divided into fleet and nonfleet vehicles. The distributor tariffs for natural gas to fleet vehicles are based on historical differences between end-use and citygate prices from EIA's *Natural Gas Annual* plus Federal and State taxes on natural gas used by vehicles. The price to nonfleet vehicles is based on the industrial sector firm price plus an assumed dispensing charge of $4.29 (2002 dollars) per thousand cubic feet plus taxes.

Petroleum Market Assumptions

Gasoline demand. Demands for conventional, reformulated, and oxygenated gasolines are disaggregated from composite gasoline consumption on the basis of their 2002 market shares in each Census division. Reformulated gasoline (RFG) is consumed in the 10 serious ozone nonattainment areas required by CAAA90 and in areas that voluntarily opted into the program [*45*]. RFG projections also reflect a Statewide requirement in California and State law in Phoenix, Arizona. In total, RFG is assumed to account for about 33 percent of annual gasoline sales throughout the *AEO2004* forecast. The estimated market shares for oxygenated gasoline assume continued wintertime participation of carbon monoxide nonattainment areas and statewide participation in Minnesota. Oxygenated gasoline represents about 4.6 percent of gasoline demand in the forecast. Conventional gasoline makes up the balance (62.4 percent) of gasoline demand.

RFG specifications. RFG must meet the EPA's "Complex Model 2" requirements beginning in 2000. Gasoline currently sold in the United States slightly exceeds the quality implied in the Complex Model 2 specifications (i.e., "over-compliance"). In addition to assuming Complex Model 2 compliance for the RFG, *AEO2004* also reflects the over-compliance nature of gasoline in general by adopting the EPA survey of RFG properties in 2002 [*46*]. The RFG specifications used for the West Coast represent the California Air Resources Board (CARB) statewide gasoline requirements, first implemented in 1996, which will be tightened in 2004 [*47*]. The U.S. 9th Circuit Court of Appeals recently ruled that the EPA must reconsider a request by California to waive the Federal oxygen requirement in Federal nonattainment areas, including Los Angeles, San Diego, Sacramento, and San Joaquin Valley. Because those areas contain about 80 percent of California's population and EPA is appealing the Court's ruling, *AEO2004* assumes that 80 percent of RFG in the State will continue to require 2.0 percent oxygen by weight after MTBE is banned.

State MTBE bans. AEO2004 includes constraints that model legislation banning or limiting the use of the gasoline blending component MTBE in the next few years in 17 States: California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, New York, Ohio, South Dakota, Washington, and Wisconsin [*48*]. Of the 17 States, only California, New York, Connecticut, Missouri, and Kentucky still sold MTBE-blended RFG in 2003. *AEO2004* assumes that ethanol will replace MTBE as the oxygenate for RFG in those five States, blending at 5.7 percent per volume ethanol in California's RFG (due to stricter CARB gasoline specifications), and 10 percent per volume ethanol in RFG in all other States where MTBE will soon be banned.

Low-sulfur fuel requirements. AEO2004 reflects "Tier 2" Motor Vehicle Emissions Standards and

Gasoline Sulfur Control Requirements finalized by the EPA in February 2000. The regional assumptions for phasing down the sulfur content of conventional gasoline include less stringent sulfur requirements for small refineries and refineries in the Rocky Mountain region as allowed by EPA. The 30-ppm annual average standard is not fully realized in conventional gasoline until 2008 due to allowances for small refineries.

AEO2004 also incorporates the "ultra-low-sulfur diesel" (ULSD) regulation finalized in December 2000. By definition, ULSD is highway diesel that contains no more than 15 ppm sulfur at the pump; however, there is general consensus that refiners will need to produce ULSD somewhat below 10 ppm in order to allow for contamination during the distribution process. *AEO2004* assumes that ULSD at the refinery gate will contain a maximum of 7 ppm sulfur. The new regulation contains the "80/20" rule, which requires the production of 80 percent ULSD and 20 percent 500 ppm highway diesel between June 2006 and June 2010, and a 100-percent requirement for ULSD thereafter. Because NEMS is an annual average model, the full impact of the 80/20 rule cannot be seen until 2007, and the impact of the 100-percent requirement cannot be seen until 2011. No change in the sulfur level of nonroad diesel fuel is assumed, because the EPA has not yet formally adopted nonroad diesel standards.

Gas-to-liquids. If prices for lower sulfur distillates reach a high level, it is assumed that gas-to-liquids (GTL) facilities will be built on the North Slope of Alaska to convert stranded natural gas into distillates, to be transported on the Trans-Alaskan Pipeline System (TAPS) to Valdez and shipped to markets in the lower 48 States. The facilities are assumed to be built incrementally, no earlier than 2005, with output volumes of 50,000 barrels per day, at a cost of $21,750 per barrel of daily capacity (2002 dollars). Operating costs are assumed to be $4.04 per barrel. Transportation costs to ship the GTL product from the North Slope to Valdez along the TAPS range from $2.78 to $4.50 per barrel, depending on total oil flow on the pipeline and the potential need for GTL to maintain the viability of the TAPS line if Alaskan oil production declines. Initially, the natural gas feedstock is assumed to cost $0.83 per thousand cubic feet (2002 dollars).

Coal-to-liquids. It is also assumed that coal-to-liquids (CTL) facilities will be built when low-sulfur distillate prices are high. One CTL facility is capable of processing 16,400 tons of bituminous coal per day, with a production capacity of 33,200 barrels of synthetic petroleum fuel per day and 696 megawatts of capacity for electricity cogeneration sold to the grid [*49*]. The CTL yields are assumed to be similar to those from a GTL facility, because both involve the Fischer-Tropsch process to convert syngas ($CO + H_2$) to liquid hydrocarbons. The primary yields would be distillate and kerosene, with additional yields of naphthas and liquefied petroleum gases. Petroleum products from CTL facilities are assumed to be competitive when distillate prices rise above the cost of CTL production (adjusted for credits from the sale of cogenerated electricity). CTL capacity is projected to be built only in the *AEO2004* high world oil price case.

Petroleum coke gasification. Gasification of petroleum coke (petcoke) and heavy oil (asphalt, vacuum residual, etc.) are represented in *AEO2004* [*50*]. The primary feedstock for gasification is assumed to be petcoke. Petcoke can be used for combined heat and power (CHP) electric and steam generation or for hydrogen production, based on the particular refinery economics. A typical gasification facility is assumed to have a capacity of 2,000 tons per day, which includes the main gasifier and other integrated units in the refinery such as an air separation unit (ASU), syngas clean-up, a sulfur recovery unit (SRU), and two downstream process options—CHP or hydrogen production. Currently, more than 5,000 tons per day of gasification capacity operates in the United States, producing combined heat and power (CHP) and hydrogen. Additional gasification capacity is projected in the *AEO2004* forecast, primarily for CHP production.

Ethanol and biodiesel. Fuel ethanol production is modeled in the Petroleum Market Module (PMM). Ethanol is produced in dedicated plants from corn or cellulose feedstocks. Most ethanol is produced from corn in the Midwest (Census divisions 3 and 4). Commercial cellulosic ethanol production from corn stover is assumed to be producible in the Midwest. Cellulosic ethanol may be produced from wood products in Census divisions 2, 3, 4, 7, and 9. Ethanol is blended into gasoline at up to 10 percent by volume to provide oxygen, octane, and gasoline volume. Ethanol is also sold as E85, a blend of up to 85 percent ethanol and at least 15 percent gasoline by volume. The historical annual average of the ethanol content in E85 is about 74 percent, due to the lower blending ratios for E85 in the fall and winter months for drivability purposes [*51*]. Ethanol can also be used to make ethyl-tertiary-butyl ether (ETBE), another potential gasoline oxygenate. The PMM is capable of modeling ETBE, but it is expected to cause water contamination problems similar to those caused by MTBE and is therefore not in widespread use.

Biodiesel production is also modeled in the PMM. Biodiesel is the collective name for methyl esters of vegetable oil or animal fat, which are suitable for fueling diesel engines. Payments are offered by the Department of Agriculture's Commodity Credit Corporation for production of biodiesel. Based on data through the third quarter of 2002, biodiesel output is projected to grow by 8.9 million gallons per year until 2006 (biodiesel output was 15.3 million gallons in 2002), when the payments will no longer be offered. Thereafter, biodiesel output is projected to grow at 1.8 percent per year.

Transportation fuel taxes. State taxes on gasoline, diesel, jet fuel, and E85 are assumed to increase with inflation, as has occurred historically. Federal taxes, which have increased sporadically in the past, are assumed to stay at 2002 nominal levels (a decline in real terms). Extension of the excise tax exemption for blending corn-based ethanol with gasoline, passed in the Federal Highway Bill of 1998, is incorporated in the projections. The bill extends the tax exemption through 2007 but reduces the current exemption of 52 cents per gallon by 1 cent per gallon in 2005. It is assumed that the tax exemption will be extended beyond 2007 through 2025 at the nominal level of 51 cents per gallon (a decline in real terms).

High renewables case. The *high renewables case* uses more optimistic assumptions about the availability of renewable energy sources. The supply curve for cellulosic ethanol is shifted in each forecast year relative to the reference case, making larger quantities available at any given price earlier than are available in the reference case. Commercialization of cellulosic ethanol follows the same path from year to year but begins in 2006 rather than 2010.

Coal Market Assumptions

Productivity. Technological advances in the coal industry, such as improvements in coal haulage systems at underground mines, contribute to increases in productivity, as measured in average tons of coal per miner per hour. Productivity improvements are assumed to continue at a reduced rate over the forecast horizon. Rates of improvement are developed based on econometric estimates using historical data by region and by mine type (surface and underground). On a national basis, labor productivity is assumed to improve on average at a rate of 1.3 percent per year over the *AEO2004* forecast period, decreasing from an estimated annual improvement rate of 1.4 percent between 2002 and 2010 to a rate of 1.3 percent between 2010 and 2025. By comparison, productivity in the U.S. coal industry improved at an average rate of 5.9 percent per year between 1980 and 2002. Some reasons why future productivity improvements are expected to be lower than historical levels include increasing strip ratios, thinner coal seams and lower coal yields, longer trucking hauls, and tougher permitting standards. Sulfur dioxide emissions limits from electricity generators, as mandated in CAAA90, are explicitly modeled in the Coal Market Module.

Coal transportation costs. Transportation rates are escalated or de-escalated over the forecast period to reflect projected changes in input factor costs. The escalators used to adjust the rates year by year are generated endogenously from a regression model based on the current-year diesel price, employee wage cost index, user cost of capital for transportation equipment, and a producer time trend.

Coal exports. Coal exports are modeled as part of a linear program that provides annual forecasts of U.S. steam and coking coal exports in the context of world coal trade. The linear program determines the pattern of world coal trade flows that minimizes the production and transportation costs of meeting a specified set of regional world coal import demands.

Coal imports. Projections of annual U.S. coal imports, specified by demand region and economic sector, are developed exogenously. The forecast is based primarily on the capability and plans of existing coal-fired generating plants to import coal and announced plans to expand coal import infrastructure. Projections of coal imports do not vary across the alternative *AEO2004* cases. Total sulfur dioxide emissions from imports and domestically produced coal are subject to the restrictions on emissions specified in CAAA90.

High and low mining cost cases. Two alternative mining cost cases examine the impacts of different labor productivity, labor cost, and equipment cost assumptions. The annual growth rates for productivity were increased and decreased by region and mine type, based on historical variations in labor productivity.

The high and low mining cost cases were developed by adjusting the *AEO2004* reference case productivity path by one standard deviation, corresponding to an adjustment of 1.9 percent in the annual growth rates of coal mine labor productivity which are specified by region and mine type. The resulting national average productivities in 2025 (in short tons per hour) were 13.1 in the *high mining cost case* and 5.94 in the *low mining cost case*, compared with 9.19 in the reference case. These are fully integrated cases, with feedback from the Macroeconomic Activity, International, supply, conversion, and end-use demand modules.

In the reference case, labor wage rates for coal mine production workers and equipment costs are assumed to remain constant in real terms over the forecast period. In the low and high mining cost cases, wages and equipment costs are assumed to decline and increase by 0.5 percent per year in real terms, respectively.

Notes

[*1*] Energy Information Administration, *Annual Energy Review 2002*, DOE/EIA-0384(2001) (Washington, DC, October 2003).

[*2*] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2002*, DOE/EIA-0573(2001) (Washington, DC, October 2003).

[*3*] Energy Information Administration, *Short-Term Energy Outlook*, web site www.eia.doe.gov/emeu/steo/pub/contents.html. Portions of the preliminary information were also used to initialize the PMM projection.

[*4*] Jet Information Services, Inc., *World Jet Inventory Year-End 2002* (Woodinville, WA, March 2003), and personal communications with Bill Francoins at Jet Information Services and Thomas C. Hoang at Boeing.

[*5*] National Energy Policy Act of 1992, P.L. 102-486, Title III, Section 303, and Title V, Sections 501 and 507.

[*6*] Maine has passed legislation that provides a goal of phasing out MTBE, although at this time no MTBE is used in Maine.

[7] The hurdle rate for petroleum coke gasification is assumed to be 15 percent because of the higher economic risk involved in this technology.

[*8*] "Worldwide Look at Reserves and Production," *Oil & Gas Journal* (December 23, 2002), pp. 114-115.

[*9*] U.S. Geological Survey, *World Petroleum Assessment 2000: Description and Results*, Data Series DDS-60, Version 1.1 (Washington, DC, June 2000).

[*10*] Petroconsultants, Inc., "DESTINY: International Forecast Software, Petroleum Exploration and Production Database" (Houston, TX, 1996).

[*11*] Lawrence Berkeley Laboratory, *U.S. Residential Appliance Energy Efficiency: Present Status and Future Direction*; and U.S. Department of Energy, Office of Codes and Standards.

[*12*] Energy Information Administration, 2001 *Residential Energy Consumption Survey*, web site www.eia.doe.gov/emeu/recs/contents.html.

[*13*] For additional information on green programs see web site www.energystar.gov.

[*14*] For further information see web site www.pathnet.org/about/about.html.

[*15*] High technology assumptions are based on Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Arthur D. Little, Inc., October 2001).

[*16*] Energy Information Administration, 1999 CBECS Public Use Data Files (October 2002), web site www.eia.doe.gov/emeu/cbecs/.

[*17*] National Energy Policy Act of 1992, P.L. 102-486, Title I, Subtitle C, Sections 122 and 124.

[*18*] Efficiency typically refers to the ratio of energy delivered to energy consumed. In the case of lighting, the measure used is efficacy, which is the ratio of light delivered (in lumens) to energy consumed.

[*19*] High technology assumptions are based on Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Arthur D. Little, Inc., October 2001).

[*20*] Navigant Consulting, Inc., *The Changing Face of Renewable Energy* (June 2003).

[*21*] The National Renewable Energy Laboratory's Renewable Electric Plant Information System is available at web site www.eere.energy.gov/repis/.

[*22*] For current DOE technology characterizations for photovoltaic systems see web site www.eren.doe.gov/power/pdfs/techchar.pdf.

[*23*] Energy Information Administration, *1998 Manufacturing Energy Consumption Survey*, web site www.eia.doe.gov/emeu/mecs/mecs98/datatables/contents.html.

[*24*] The data sources and methodology used to develop the nonmanufacturing portion of the Industrial Demand Module are described in Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M064(2002) (Washington, DC, December 2001).

[*25*] National Energy Policy Act of 1992, P.L. 102-486, Title II, Subtitle C, Section 342.

[*26*] S.R. Nadal et al., *Energy-Efficient Motor Systems: A Handbook on Technology, Program, and Policy Opportunities*, 2nd Edition (Washington, DC: American Council for an Energy-Efficient Economy, 2002).

[*27*] U.S. Department of Energy, Motor Master+ 4.0 software database (2003), web site http://mm3.energy.wsu.edu/mmplus/default.stm.

[*28*] These assumptions are based in part on Energy Information Administration, *Industrial Model—Updates on*

Energy Use and Industrial Characteristics (Arthur D. Little, Inc., September 2001).

[*29*] National Energy Policy Act of 1992, P.L. 102-486, Title III, Section 303, and Title V, Sections 501 and 507.

[*30*] California Air Resources Board, Resolution 01-1 (January 25, 2001).

[*31*] California Air Resources Board, Resolution 03-4 (April 24, 2003).

[*32*] Energy Information Administration, *Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (Energy and Environmental Analysis, September 2002).

[*33*] A. Vyas, C. Saricks, and F. Stodolsky, *Projected Effect of Future Energy Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks* (Argonne, IL: Argonne National Laboratory, 2001).

[*34*] S. Davis, *Transportation Energy Databook No. 22*, prepared for the Office of Transportation Technologies, U.S. Department of Energy (Oak Ridge, TN: Oak Ridge National Laboratory, September 2002).

[*35*] D. Greene, *Energy Efficiency Improvement Potential of Commercial Aircraft to 2010*, ORNL-6622 (Oak Ridge, TN: Oak Ridge National Laboratory, June 1990), and Oak Ridge National Laboratory, Air Transportation Energy Use Model.

[*36*] Vehicle-miles traveled are the miles traveled yearly by light-duty vehicles.

[*37*] Ton-miles traveled are the miles traveled and their corresponding tonnage for freight modes, such as trucks, rail, air, and shipping.

[*38*] U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC97TV (Washington, DC, October 1999); Federal Highway Administration, *Highway Statistics 1998* (Washington, DC, November 1999); and S. Davis, *Transportation Energy Databook No. 19*, prepared for the Office of Transportation Technologies, U.S. Department of Energy (Oak Ridge, TN: Oak Ridge National Laboratory, September 1999).

[*39*] Energy Information Administration, *Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (Energy and Environmental Analysis, September 2002).

[*40*] A. Vyas, C. Sarícks, and F. Stodolsky, *Projected Effect of Future Energy Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks* (Argonne, IL: Argonne National Laboratory, 2001).

[*41*] The source of the cost data is the CUECOST3.xls model, as updated February 9, 2000, which was developed for the U.S. Environmental Protection Agency by Raytheon Engineers and Constructors, Inc., EPA Contract Number 68-D7-0001. The EPA model estimates costs for adding SCRs, FGDs, and SNCRs for plants based on a number of design parameters. For retrofits, a retrofit factor is assigned to reflect the additional costs of retrofitting an existing plant rather than adding it as part of a Greenfield plant. The EPA model was run for each individual plant assuming a 1.3 retrofit factor for FGDs and 1.6 for SCRs, based on historical evidence.

[*42*] Pacific Northwest Laboratory, *An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States*, PNL-7789, prepared for the U.S. Department of Energy under Contract DE-AC06-76RLO 1830 (August 1991); and M.N. Schwartz, O.L. Elliott, and G.L. Gower, *Gridded State Maps of Wind Electric Potential. Proceedings, Wind Power 1992* (Seattle, WA, October 19-23, 1992). Also, National Renewable Energy Laboratory, "Subtask A: Incorporation of Existing Validated Wind Data into NEMS," draft final report to EIA (November 2003).

[*43*] Based on technology characterizations from National Renewable Energy Laboratory, *2003 Power Technologies Databook*, web site www.nrel.gov/analysis/power_databook/. Cost and performance projections in the Databook are sourced to U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, publications and documents.

[*44*] D.L. Goutier et al., *1995 National Assessment of the United States Oil and Gas Resources* (Washington, DC: U.S. Department of the Interior, U.S. Geological Survey, 1995); U.S. Department of the Interior, Minerals Management Service, *An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf*, OCS Report MMS 96-0034 (Washington, DC, June 1997); U.S. Department of the Interior, Minerals Management Service, *2000 Assessment of the Conventionally Recoverable Hydrocarbon Resources of the Gulf of Mexico and Atlantic Outer Continental Shelf, as of January 1, 1999*, OCS Report MMS 2001-087 (New Orleans, LA, October 2001); National Petroleum Council, *Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand* (Washington, DC, December 1999).

[*45*] Required areas: Baltimore, Chicago, Hartford, Houston, Los Angeles, Milwaukee, New York City, Philadelphia, San Diego, Sacramento and San Joaquin Valley. Opt-in areas are in the following States: Connecticut, Delaware, Kentucky, Massachusetts, Maryland, Missouri, New Hampshire, New Jersey, New York, Rhode Island, Texas, Virginia, and the District of Columbia. Excludes areas that "opted-out" prior to June 1997.

[*46*] U.S. Environmental Protection Agency, Office of Transportation and Air Quality, *Information on Reformulated Gasoline (RFG) Properties and Emissions Performance by Area and Season*, web site www.epa.gov/otaq/regs/fuels/rfg/properf/rfgperf.htm.

[*47*] California Air Resource Board, "California Phase 3 Reformulated Gasoline," web site www.arb.ca.gov/fuels/gasoline/carfg3/carfg3.htm.

[*48*] The State of Maine has passed legislation that provides a goal of phasing out MTBE.

[*49*] Based on the methodology described in D. Gray and G. Tomlinson, *Coproduction: A Green Coal Technology*, Technical Report MP 2001-28 (Mitretek, March 2001).

[*50*] National Energy Technology Laboratory, *Refinery Technology Profiles—Gasification and Supporting Technologies* (June 2003).

[*51*] National Ethanol Vehicles Coalition, *E85 Blending, Tax Incentives, and Pump Pricing*. A copy of the report may be obtained by calling (877) 485-8595.