Appendix G

Major Assumptions for the Forecasts

The National Energy Modeling System

The projections in the *Annual Energy Outlook 1999* (*AEO99*) are generated with the National Energy Modeling System (NEMS), developed and maintained by the Office of Integrated Analysis and Forecasting 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 the energy supply and demand, accounting for the economic competition between the various energy fuels and sources. The time horizon of NEMS is the midterm period, approximately 20 years in the future. In order to represent the regional differences in energy markets, the component models of NEMS function at the regional level: the 9 Census divisions for the end-use demand models; production regions specific to oil, gas, and coal supply and distribution; the North American Electric Reliability Council regions and subregions for electricity; and aggregations of the Petroleum Administration for Defense Districts 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 activity, 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. This modularity allows 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 impact and cost of legislation and environmental regulations that affect that sector and reports key emissions. NEMS represents current legislation and environmental regulations as of July 1, 1998, such as the Clean Air Act Amendments of 1990 (CAAA90), the Ozone Transport Rule (OTR), and the costs of compliance with other regulations.

In general, the *AEO99* projections were prepared by using the most current data available as of July 31, 1998. At that time, most 1997 data were available, but only partial 1998 data were available. Carbon emissions were calculated by using carbon coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 1997*, published in October 1998 [*1*].

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 *AEO99* includes electricity used by railroads, which is included in the commercial sector in EIA's consumption data publications. Also, the *State Energy Data Report* classifies energy consumed by independent power producers, exempt wholesale generators, and cogenerators as industrial consumption, whereas *AEO99* includes cogeneration in the industrial sector and other nonutility generators in the electricity sector. Footnotes in the appendix tables of this report indicate the definitions and sources of all historical data.

The *AEO99* projections for 1998 and 1999 incorporate short-term projections from the September update of EIA's *Short-Term Energy Outlook* (*STEO*), Third Quarter 1998 [*2*], published in July 1998. For short-term energy projections, readers are referred to the monthly updates of the *STEO*.

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), interest rates, disposable income, and employment. Industrial drivers are calculated for 35 industrial sectors. This module is a kernel regression representation of the DRI/McGraw-Hill U.S. Macroeconomic Model of the U.S. Economy.

International Module

The International Module represents the world oil markets, calculating the average world oil price and computing supply curves for 5 categories of imported crude oil for the Petroleum Market Module of NEMS, in response to changes in U.S. import requirements. International petroleum product supply curves, including curves for oxygenates, are also calculated.

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 the changes in the efficiency of energy use for residential end-uses and in light-duty vehicle fuel efficiency. Average expenditures estimates are provided for households 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, subject to delivered energy prices, 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, subject to 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.

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 output for each industry. The industries are classified into three groups—energy-intensive, non-energy-intensive, and nonmanufacturing. Of the 8 energy-intensive industries, 7 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 alternatively-fueled vehicles.

Electricity Market Module

The Electricity Market Module represents generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, and natural gas; costs of generation by centralized renewables; macroeconomic variables for costs of capital and domestic investment; and electricity load shapes and demand. There are three primary submodules—capacity planning, fuel dispatching, and finance and pricing. Nonutility generation and transmission and trade are represented 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 CAAA90 and OTR compliance options are explicitly represented in the capacity expansion and dispatch decisions. Both new generating technologies and renewable technologies compete directly in these decisions.

Renewable Fuels Module

The Renewable Fuels Module includes submodules that provide explicit representation of the supply of biomass (including wood and energy crops), municipal solid waste (including landfill gas), wind energy, solar thermal electric and photovoltaic energy, and geothermal energy. It contains natural resource supply estimates and provides cost and performance criteria to the Electricity Market Module. The Electricity Market Module represents market penetration of renewable technologies used for centralized electricity generation, and the end-use demand modules incorporate market penetration of selected off-grid electric and nonmarketed nonelectric renewables.

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships between the various sources of supply: onshore, offshore, and Alaska by both conventional and nonconventional techniques, including enhanced oil recovery and unconventional gas recovery from tight gas formations, shale, and coalbeds. This framework analyzes cash flow and profitability to compute investment and drilling in each of the supply sources, subject to the prices for crude oil and natural gas, the domestic recoverable resource base, and 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 with Canada and Mexico and liquefied natural gas imports and exports. Crude oil production quantities are input to the Petroleum Market Module 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 prices and quantities.

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 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, availability and price of imported petroleum, and domestic production of crude oil, natural gas liquids, and alcohol fuels. The module represents refining activities for three regions—Petroleum Administration for Defense District (PADD) 1, PADD 5, and an aggregate of PADDs 2, 3, and 4. The module uses the same crude oil types as the International Module. It explicitly models the requirements of CAAA90 and the costs of new automotive fuels, such as oxygenated and reformulated gasoline, and includes oxygenate production and blending for reformulated gasoline. Costs include capacity expansion for refinery processing units. End-use prices are based on the marginal costs of production, plus markups representing product distribution costs, State and Federal taxes, and environmental costs.

Coal Market Module

The Coal Market Module simulates mining, transportation, and pricing of coal, subject to the end-use demand for coal differentiated by physical characteristics, such as the heat and sulfur content. The coal supply curves include a response to fuel costs, labor productivity, and factor input costs. Twelve coal types are represented, differentiated by coal rank, sulfur content, and mining process. Production and distribution are computed for 11 supply and 13 demand regions, using imputed coal transportation costs and trends in factor input costs. The Coal Market Module also forecasts the requirements for U.S. coal exports and imports. The international coal market component of the module computes trade in 4 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 1999*

Table G1 provides a summary of the cases used to derive the *AEO99* 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 the NEMS model (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 on world oil markets and domestic macroeconomic activity are primary drivers to the forecasts presented in *AEO99*. These assumptions are presented in the “Market Trends” section. The following section describes the key regulatory, programmatic, and resource assumptions that factor into the projections. More detailed assumptions for each sector will be available via the EIA Home Page on the Internet and on the EIA CD-ROM, along with regional results and other details of the projections.

Buildings sector assumptions

The buildings sector includes both residential and commercial structures. Both the National Appliance Energy Conservation Act of 1987 (NAECA), the Energy Policy Act of 1992 (EPACT), and the Climate Change Action Plan (CCAP) contain provisions which impact future buildings sector energy use. The provisions with the most significant effect are minimum equipment efficiency standards. These standards 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.

Residential assumptions. The NAECA minimum standards [*3*] 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
- Room air conditioners—an 8.7 energy efficiency ratio in 1990, increasing to 9.7 in 2001
- Gas/oil furnaces—a 0.78 annual fuel utilization efficiency in 1992
- Refrigerators—a standard of 976 kilowatthours per year in 1990, decreasing to 691 kilowatthours per year in 1993 and to 483 kilowatthours per year in 2002
- Electric water heaters—a 0.88 energy factor in 1990
- Natural gas water heaters—a 0.54 energy factor in 1990.

Table G1. Summary of the *AEO99* 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 1.5 percent, compared to the reference case growth of 2.1 percent.	Fully integrated	p. 45	
High Economic Growth	Gross domestic product grows at an average annual rate of 2.6 percent, compared to the reference case growth of 2.1 percent.	Fully integrated	p. 45	
Low World Oil Price	World oil prices are $14.57 per barrel in 2020, compared to $22.73 per barrel in the reference case.	Partially integrated	p. 46	
High World Oil Price	World oil prices are $29.35 per barrel in 2020, compared to $22.73 per barrel in the reference case.	Partially integrated	p. 46	
Residential: 1999 Technology	Future equipment purchases based on equipment available in 1999. Building shell efficiencies fixed at 1999 levels.	Standalone	p. 57	p. 220
Residential: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment.	Standalone	p. 57	p. 220
Residential: Best Available Technology	Future equipment purchases and new building shells based on most efficient technologies available. Existing building shell efficiencies increase by 30 percent from 1993 values by 2020.	Standalone	p. 57	p. 220
Commercial: 1999 Technology	Future equipment purchases based on equipment available in 1999. Building shell efficiencies fixed at 1999 levels.	Standalone	p. 58	p. 221
Commercial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment.	Standalone	p. 58	p. 221
Commercial: Best Available Technology	Future equipment purchases based on most efficient technologies available. Building shell efficiencies increase by 50 percent from reference values by 2020.	Standalone	p. 58	p. 221
Industrial: 1999 Technology	Efficiency of plant and equipment fixed at 1999 levels.	Standalone	p. 59	p. 222
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment.	Standalone	p. 59	p. 222
Transportation: 1999 Technology	Efficiencies for new equipment in all modes of travel are fixed at 1999 levels.	Standalone	p. 59	p. 223
Transportation: High Technology	Reduced costs and improved efficiencies are assumed for advanced technologies.	Standalone	p. 59	p. 223
Consumption: 1999 Technology	Combination of the residential, commercial, industrial, and transportation 1999 technology cases and electricity low fossil technology case.	Fully integrated	p. 40	
Consumption: High Technology	Combination of the residential, commercial, industrial, and transportation high technology cases and electricity high fossil technology case.	Fully integrated	p. 40	

Table G1. Summary of the *AEO99* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix G
Electricity: Low Nuclear	Higher capital investments are assumed after 30 to 40 years of operation.	Partially integrated	p. 65	p. 225
Electricity: High Nuclear	No capital investments are required for license renewal.	Partially integrated	p. 65	p. 225
Electricity: High Demand	Electricity demand increases at an annual rate of 2.0 percent, compared to 1.4 percent in the reference case.	Partially integrated	p. 65	p. 225
Electricity: Low Fossil Technology	New generating technologies are assumed not to improve over time from 1997.	Fully integrated	p. 66	p. 225
Electricity: High Fossil Technology	Costs and efficiencies for advanced fossil-fired generating technologies are assumed to improve from reference case values.	Fully integrated	p. 66	p. 225
Electricity: Competitive Pricing	Competitive pricing is phased in over 10 years in all regions of the country.	Fully integrated	p. 28	p. 226
Electricity: 5.5-Percent Renewable Portfolio Standard	Nonhydroelectric renewable generation increases to 5.5 percent of total generation for the period 2010-2015.	Fully integrated	p. 23	p. 226
Renewables: High Renewables	Lower costs and higher efficiencies are assumed for new renewable generating technologies	Fully integrated	p. 68	p. 227
Oil and Gas: Slow Technology	Cost, finding rate, and success rate parameters adjusted for slower improvement.	Fully integrated	p. 74	p. 228
Oil and Gas: Rapid Technology	Cost, finding rate, and success rate parameters adjusted for more rapid improvement.	Fully integrated	p. 74	p. 228
Oil and Gas: Automakers' National Low-Sulfur Gasoline	Starting in 2004, sulfur levels of all gasoline in the United States meet a 40 ppm annual average standard.	Standalone	p. 29	p. 230
Oil and Gas: API/NPRA Regional Reduced-Sulfur Gasoline	Starting in 2004, gasoline in Federal reformulated gasoline areas, in 23 States, and in East Texas meets a 150 ppm annual average standard. California gasoline continues to meet the current 40 ppm standard, and gasoline in all other areas of the country meets a 300 ppm standard. In 2010, the areas that were using 150 ppm gasoline are assumed to switch to 40 ppm gasoline.	Standalone	p. 29	p. 230
Coal: Low Mining Cost	Productivity increases at an annual rate of 3.8 percent, compared to the reference case growth of 2.3 percent. Real wages decrease by 0.5 percent annually, compared to constant real wages in the reference case.	Partially integrated	p. 80	p. 230
Coal: High Mining Cost	Productivity increases at an annual rate of 1.2 percent, compared to the reference case growth of 2.3 percent. Real wages increase by 0.5 percent annually, compared to constant real wages in the reference case.	Partially integrated	p. 80	p. 230

Improvements to existing building shells are based on both energy prices and assumed annual efficiency increases. New building shell efficiencies relative to existing construction vary by main heating fuel and assumed annual increases. The effects of shell improvements are modeled differentially for heating and cooling. For space heating, existing and new shells improve by 15 percent and 26 percent, respectively, by 2020 relative to the 1993 stock average. For space cooling, the corresponding increases are 13 percent and 25 percent for existing and new buildings. Building codes relevant to CCAP are represented by an increase in the shell integrity of new construction over time.

Other CCAP programs which could have a major impact on residential energy consumption are the Environmental Protection Agency's (EPA) Green Programs. These programs, which are cooperative efforts between the EPA and home builders and energy appliance manufacturers, encourage the development and production of highly energy-efficient housing and equipment. At fully funded levels, residential CCAP programs are estimated by program sponsors to reduce carbon emissions by approximately 28 million metric tons by the year 2010. For the reference case, carbon reductions are estimated to be 11.5 million metric tons, primarily because of differences in the estimated penetration of energy-saving technologies.

In addition to the *AEO99* reference case, three cases using only the residential module of NEMS were developed to examine the effects of equipment and building shell efficiencies on residential sector energy use:

- The *1999 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 1999. Building shell efficiencies are assumed to be fixed at 1999 levels.

- 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. Existing building shell efficiencies are assumed to increase by 30 percent over 1993 levels by 2020.

- The *high technology case* assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment [*4*].

Commercial assumptions. Minimum equipment efficiency standards for the commercial sector are mandated in the EPACT legislation [*5*]. Minimum standards for representative equipment types are:

- Central air-conditioning heat pumps—a 9.7 seasonal energy efficiency rating (January 1994)
- Gas-fired forced-air furnaces—a 0.8 annual fuel utilization efficiency standard (January 1994)
- Fluorescent lamps—a 75.0 lumens per watt lighting efficacy standard for 4-foot F40T12 lamps (November 1995) and a 80.0 lumens per watt efficiency standard for 8-foot F96T12 lamps (May 1994).

Improvements to existing building shells are based on assumed annual efficiency increases. New building shell efficiencies relative to 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 4 percent and 6 percent, respectively, by 2020 relative to the 1995 averages.

The CCAP programs recognized in the *AEO99* reference case include the expansion of the EPA Green Lights and Energy Star Buildings programs 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 via discount parameters for controlling cost-based equipment retrofit decisions for various market segments. To model programs such as Green Lights, which target particular end uses, the *AEO99* version of the commercial module includes end-use-specific segmentation of discount rates. At fully funded levels, commercial CCAP programs are estimated by program sponsors to reduce carbon emissions by approximately 25 million metric tons by the year 2010. For the reference case, carbon reductions are estimated to be 13.0 million metric tons in 2010, primarily because of differences in the estimated penetration of energy-saving technologies.

The definition of the commercial sector for *AEO99* is based on data from the 1995 Commercial Buildings Energy Consumption Survey (CBECS) [*6*]. Parking garages and commercial buildings on multibuilding manufacturing sites were included in earlier CBECS, but eliminated from the target building population for the 1995 CBECS. In addition, the data provided by any CBECS are estimates based on reported data from representatives of a randomly chosen subset of the entire population of commercial buildings. As a result, the estimates always differ from the true population values and vary from survey to survey. Differences between the estimated values and the actual population value errors are both nonsampling errors that would be expected to occur in all possible samples and sampling errors that occur because the survey estimate is calculated from a randomly chosen subset of the entire population [*7*].

Due to the change in the target population and the variability caused by the nonsampling and sampling errors, the estimates of commercial floorspace for the 1995 CBECS are lower than estimates found in previous CBECS. For example, the 1995 CBECS reports 13 percent less commercial floorspace in the United States than the 1992 CBECS reported. The most notable effect on *AEO99* projections is seen in commercial energy intensity. Commercial energy use per square foot reported in *AEO99* is significantly higher than in previous *AEO*s, not because energy consumption is higher, but because the 1995 floorspace estimates are lower. The variability between CBECS surveys also results in different estimates of the amount of each major fuel used to provide end-use services such as space heating, lighting, etc., affecting the *AEO99* projections for fuel consumption within each end use. For example, the 1995 CBECS end-use intensities report more fuel used for heating and less for cooling than the end-use intensities based on the 1992 CBECS.

In addition to the *AEO99* reference case, three cases using only the commercial module of NEMS were developed to examine the effects of equipment and building shell efficiencies on commercial sector energy use:

- The *1999 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 1999. Building shell efficiencies are assumed to be fixed at 1999 levels.
- The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than the reference case [*8*]. Building shell efficiencies are assumed to improve at a rate that is 50 percent faster than the rate of improvement in 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. Building shell efficiencies are assumed to improve at a 50 percent faster rate than in the reference case.

Industrial sector assumptions

The manufacturing portion of the industrial sector has been recalibrated to be consistent with the data in EIA's *Manufacturing Consumption of Energy 1994* [*9*]. Compared to the building sector, there are relatively few regulations which target industrial sector energy use. The electric motor standards in EPACT require a 10-percent increase in efficiency above 1992 efficiency levels for motors sold after 1999 [*10*]. These standards have been incorporated into the Industrial Demand Module through the analysis of efficiencies for new industrial processes. These standards are expected to lead to significant improvements in efficiency since it has been estimated that electric motors account for about 60 percent of industrial process electricity use.

Climate Change Action Plan. Several programs included in the CCAP target the industrial sector. Note that the potential impacts of the Climate Wise Program are also included in the CCAP impacts. The intent of these programs is to reduce greenhouse gas emissions by lowering industrial energy consumption. For their annual update, the program offices estimated that full implementation of these programs would reduce industrial electricity consumption by 20 billion kilowatthours and nonelectric consumption by 193 trillion Btu by 2000. However, since the energy savings associated with the voluntary programs in the CCAP are, to a large extent, already contained in the *AEO99* baseline, total CCAP energy savings were reduced. Consequently, CCAP is assumed to reduce electricity consumption by 9 billion kilowatthours and non-electric energy consumption by 48 trillion Btu. The non-electric energy is assumed to be 85 percent natural gas, based on the fuel shares for nonboiler, nonfeedstock industrial energy use.

For 2010, the program offices estimated electricity savings of 79 billion kilowatthours and fossil fuel savings of 359 trillion Btu. For the reason cited above, these estimates for *AEO99* were revised to 41 billion kilowatthours for electricity and 90 trillion Btu for fossil fuels. In this situation, carbon emissions would be reduced by about 7 million metric tons (1 percent) in 2010.

High technology and 1999 technology cases. The *high technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*11*]. Changes in aggregate energy intensity result both from changing equipment and production efficiency and from changing composition of industrial output. Since the composition of industrial output remains the same as in the reference case, aggregate intensity falls by only 1.4 percent annually, even though the intensity decline for some individual industries doubles. In the reference case, aggregate intensity falls by 1.0 percent annually between 1997 and 2020.

The *1999 technology case* holds the energy efficiency of plant and equipment constant at the 1999 level over the forecast.

Both cases were run with only the Industrial Demand Module rather than as a fully integrated NEMS run. Consequently, no potential feedback effects from energy market interactions were captured.

Transportation sector assumptions

The transportation sector accounts for the 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 projections appearing in this report assume that there will be no further increase in the CAFE standards from the current 27.5 miles per gallon standard for automobiles and 20.7 miles per gallon for light trucks and sport utility vehicles. This assumption is consistent with the overall policy that only current legislation is assumed.

EPACT requires that centrally-fueled automobile fleet operators—Federal, State, and local governments, and fuel providers (e.g., gas and electric utilities)—purchase a minimum fraction of alternative-fuel vehicles [*12*]. Federal fleet purchases of alternative-fuel vehicles must reach 50 percent of their total vehicle purchases by 1998 and 75 percent by 1999. Purchases of alternative-fuel vehicles by State governments must realize 25 percent of total purchases by 1999 and 75 percent by 2001. Private fuel-provider companies are required to purchase 50 percent alternative-fuel vehicles in 1998, increasing to 90 percent by 2000. Fuel provider exemptions for electric utilities are assumed to follow the electric utility provisions beginning in 1998 at 30 percent and reaching 90 percent by 2001. It is assumed that the municipal and private business fleet mandates begin in 2002 at 20 percent and scale up to 70 percent by 2005.

In addition to these requirements, the State of California has delayed the Low Emission Vehicle Program, which now requires that 10 percent of all new vehicles sold by 2003 meet the "zero emissions requirements." At present, only electric-dedicated vehicles meet these requirements. Originally, Massachusetts and New York adopted this program. The projections currently assume that California, Massachusetts, and New York have formally delayed the Low Emission Vehicle Program to 2003, based on the recent court decision to overturn the original 1998 starting date.

The projections assume that these regulations represent minimum requirements for alternative-fuel vehicle sales; consumers are allowed to purchase more of these vehicles, should vehicle cost, fuel efficiency, range, and performance characteristics make them desirable.

Projections for both personal travel [*13*] and freight travel [*14*] are based on the assumption that modal shares, for example, personal automobile travel versus mass transit, remain stable over the forecast and track recent historical patterns. Important factors affecting the forecast of vehicle-miles traveled are personal disposable income per capita; the ratio of miles driven by females to males in the total driving population, which increases from 56 percent in 1990 to 100 percent by 2010; and the aging of the population, which will slow the growth in vehicle-miles traveled. These projections incorporate recent data which indicate that retirees are driving far more than retirees of a decade ago.

Climate Change Action Plan. There are four CCAP programs that focus on transportation energy use: (1) reform Federal subsidy for employer-provided parking; (2) adopt a transportation system efficiency strategy; (3) promote telecommuting; and (4) develop fuel economy labels for tires. The combined assumed effect of the Federal subsidy, system efficiency, and telecommuting policies in the *AEO99* reference case is a 1.6-percent reduction in vehicle-miles traveled (270 trillion Btu) by 2010, with a net carbon reduction of 6.5 million metric tons. The fuel economy tire labeling program improved new fuel efficiency by 4 percent among vehicles that switched to low rolling resistance tires, and resulted in a reduction in fuel consumption of 1 trillion Btu by 2010 and a carbon reduction of 19,000 metric tons.

1999 technology case. The *1999 technology case* assumes that new fuel efficiency levels are held constant at 1999 levels through the forecast horizon for all modes of travel.

High technology case. The *high technology case* assumes the cost and performance criteria from the efficiency case in the U.S. Department of Energy (DOE) interlaboratory study, *Scenarios of U.S. Carbon Reductions* for air, freight, marine, and rail travel. Light-duty alternative-fuel vehicle characteristics originate from the DOE Office of Energy Efficiency and Renewable Energy, and conventional light-duty vehicle fuel-saving technology characteristics are from the American Council for an Energy-Efficient Economy [*15*]. The case includes new technologies including a high-efficiency advanced light-duty direct injection diesel vehicle with attributes similar to gasoline engines; electric and electric hybrid (gasoline and diesel) vehicles with higher efficiencies, lower costs, and earlier introduction dates than in the reference case, and fuel cell gasoline light-duty vehicles. In the freight sector, the case assumes technologies including advanced drag reduction, reduced weight, and engines such as the advanced turbocompound diesel engines and the lean burn diesel LE-55 engine all with shorter market penetration periods and lower cost-effectiveness criteria—from a range of $8 to $10.50 to a range of $5 to $7 per million Btu of the fuel type. The case also assumes increasing load factors and an increase in efficiency of 18 percent above the 1997 level for aircraft.

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

Electricity assumptions

Characteristics of generating technologies. The costs and performance of new generating technologies are important factors in determining the future mix of capacity. There are 26 fossil, renewable, and nuclear generating technologies included in these projections. Technologies represented include those currently available as well as those that are assumed to be commercially available within the horizon of the forecast. Capital cost estimates and operational characteristics, such as efficiency of electricity production, are used for decisionmaking where 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 via the EIA Home Page on the Internet and on the EIA CD-ROM.

Regulation of electricity markets. It is assumed that electricity producers comply with CAAA90, which mandates a limit of 8.95 million short tons of sulfur dioxide emissions by 2010. Utilities are assumed to comply with the limits on sulfur 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. The costs for FGD equipment average approximately $192 per kilowatt, in 1997 dollars, although the costs vary widely across the regions. It is also assumed that the market for trading emission allowances is allowed to operate without regulation and that the States do not further regulate the selection of coal to be used. Utilities are also assumed to comply with the NO_x emission caps established by the OTR.

The reference case assumes a transition to competitive pricing in California, New York, the New England States, the Mid-Atlantic States, and the Mid-America Interconnected Network (Illinois, plus parts of Missouri and Wisconsin). Although other States are allowing consumers to choose their electricity suppliers, the regional configuration assumed in the reference case prevents the representation of competitive markets in the regions where most States have not moved to competitive pricing. Nevertheless, the reference case assumes that, in California, electricity prices will remain constant at nominal 1997 levels between 1999 and 2001 for commercial and industrial customers, whereas residential customers will see a 10-percent reduction from 1997 prices in 1999; that there will be a transition from regulated to competitive prices between 2002 and 2007; and that the market will be fully competitive by 2008. Similarly, in the other regions for which competitive pricing is assumed, the transition period is assumed to be from 1999 through 2007, with fully competitive pricing of electricity beginning in 2008. The transition period reflects the time needed for the establishment of competitive market institutions and recovery of stranded costs as permitted by regulators. The reference case assumes that competitive prices in these regions will be the marginal cost of generation.

Competitive cost of capital. To capture the increased risks that new power plant operators are expected to face in a competitive market, the cost of capital for the generation sector is assumed to be 100 basis points higher than that for the transmission and distribution sector. In addition, 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.

Energy efficiency and demand-side management. Improvements in energy efficiency induced by growing energy prices, new appliance standards, and utility demand-side management programs are represented in the end-use demand models. Appliance choice decisions are a function of the relative costs and performance characteristics of a menu of technology options. Utilities have reported plans to spend more than $2.2 billion per year by 2000.

Representation of utility Climate Challenge participation agreements. As a result of the Climate Challenge Program, many utilities have announced efforts to voluntarily reduce their greenhouse gas emissions between now and 2000. These efforts cover a wide variety of programs, including increasing demand-side management (DSM) investments, repowering (fuel-switching) fossil plants, restarting nuclear plants that have been out-of-service, planting trees, and purchasing emission offsets from international sources.

To the degree possible, each one of the participation agreements was examined to determine whether the commitments made were addressed in the normal reference case assumptions or whether they were addressable in NEMS. Programs like tree planting and emission offset purchasing are not addressable in NEMS. With regard to the other programs, they are, for the most part, captured in NEMS. For example, utilities annually report to EIA their plans (over the next 10 years) to bring a plant back on line, repower a plant, life extend a plant, cancel a previously planned plant, build a new plant, or switch fuel at a plant. These data are inputs to NEMS. Thus, programs that would affect these areas are reflected in NEMS 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.

Nuclear power. There are no nuclear units actively under construction in the United States, and *AEO99* does not assume any new units becoming operational in the forecast period.

It is assumed that nuclear power plants will operate until some major capital expenditure is required to repair the effects of aging. The decision to either incur the costs of repairing the unit or retire the unit is based on the relative economics of the alternatives. In the reference case, it is first assumed that a retrofit costing $150 per kilowatt will be required after 30 years of operation to operate the plant for another 10 years. Plants that have already incurred a major expenditure (such as a steam generator replacement) are assumed not to need additional retrofits and to run for 40 years. For other units, the capital investment is assumed to be recovered over 10 years, and an annual payment is calculated. If the combined operating costs and capital payment costs are cheaper than building new capacity, then the plant is run through its license period. If it is not economical, the plant is retired at 30 years.

It is also assumed that nuclear licenses will be renewed if it is economical to continue running the plant. A more extensive capital investment ($250 per kilowatt) is assumed to be required to operate a nuclear unit for 20 years past its current license expiration date. If this investment, recovered over 20 years, is less expensive than building new capacity, the unit is assumed to continue operating. Otherwise, it will be retired when it reaches the expiration date on its license. For both of these investment decisions, adjustments are made for new units to capture the improvements in their designs compared with older units.

Two side cases were developed with different assumptions regarding the capital investments, which changes the retirement decisions. In the *low nuclear case*, the adjustments for the new plants were removed, making these units face higher capital investments. The *high nuclear case* assumes that fewer units need major repairs during the first 40 years of operation, and that no capital expenditures required for license renewal.

The average nuclear capacity factor in 1997 was 71 percent, a drop from 1996 due to several units being down for extended outages. The capacity factor is expected to increase throughout the forecast, to as high as 85 percent in 2020. Capacity factor assumptions are developed at the unit level, and improvements or decrements are forecast based on the age of the reactor.

Fossil-steam retirement assumptions. Fossil steam plants are retired when it is no longer economical to run them. Each year the model determines whether the market price of electricity is sufficient to support the continued operation of existing plants. If the revenue the plants receive is not sufficient to cover their forward costs (mainly fuel and operations and maintenance costs) the plant will be retired.

International learning. For *AEO99*, capital costs for all new electricity generating technologies—fossil, nuclear, and renewable—decrease in response to foreign as well as domestic experience, to the extent the new plants reflect technologies and firms also competing inside the United States. International learning effects include 1,553 megawatts advanced coal, 2,330 megawatts advanced combined cycle, 360 megawatts advanced combustion turbine, 110 megawatts geothermal, 1,250 megawatts wind, 115 megawatts grid-connected photovoltaics, and 57 megawatts biomass integrated combined cycle capacity in operation, under construction, or under contract for construction outside the United States.

High electricity demand case. The *high electricity demand case*, which is a standalone case, assumes that the demand for electricity grows by 2.0 percent annually between 1997 and 2020, compared with 1.4 percent in the reference case. No attempt was made to determine the changes necessary in the end-use sectors needed to result in the stronger demand growth. The high electricity demand case is a partially integrated run, i.e., the Macroeconomic Activity, Petroleum Marketing, International Energy, and end-use demand modules use the reference case values and are not effected by the higher electricity demand growth. Conversely, the Oil and Gas, Natural Gas Transmission and Distribution, Coal Market, and Renewable Fuels Modules are allowed to interact with the Electricity Market Module in the high electricity demand case.

High and low fossil technology cases. The high and low fossil technology cases are standalone, partially integrated cases. These cases use cost estimates for fossil-fuel-based technologies provided by the DOE Office of Fossil Energy. In the *high fossil case*, capital costs for coal gasification combined-cycle units and molten carbonate fuel cells are assumed to be lower than the reference case, and the costs for advanced combustion turbine and advanced combined-cycle units are higher than those in the reference case. In the *low fossil case*, capital costs and heat rates for advanced generating technologies remain fixed over the forecast period.

In both the high and low fossil technology cases, generating technologies other than those for which capital costs were provided by DOE's Office of Fossil Energy are assumed to use the same technological optimism and learning factors as the reference case. Details about annual capital costs, operating and maintenance costs, plant efficiencies, and technological optimism and learning factors are described in the detailed assumptions which will be available via the Internet (ftp://ftp.eia.doe.gov/pub/forecasting/aeo99/aeo99asu.pdf) and on the EIA CD-ROM.

Competitive pricing case. The *competitive pricing case* assumes that all regions of the country move toward competitive pricing, as discussed in the "Issues in Focus" section of this report. Competitive pricing for most regions is phased in over 10 years (1999-2008) by computing a weighted average of the traditional average-cost-based price and a linearly increasing fraction of the prices based on marginal costs. Prices in two regions, CNV and MAIN, in which the sole or the preponderance of the States have legislatively enacted restructuring plans, are adjusted to reflect the price caps embodied in the State plans. Reserve margins are set endogenously so that the full costs of new capacity will be recovered. In the competitive pricing case, customers using certain end-use services, including commercial heating, cooling, and hot water heating and industrial shift work, are able to respond to spot, or "time-of-use," prices through changes in their demand for electricity. This is represented as a transfer of demand from peak, high-usage periods to off-peak, lower-usage periods. All other assumptions, including improvements in operations and maintenance efficiency are identical to those in the reference case.

Renewable portfolio standard case. A case was run in which a minimum level of nonhydroelectric renewable generation was required. The minimum percentage of renewable generation (defined as generation from wind, biomass, geothermal, solar thermal, photovoltaic, and landfill gases divided by total sales multiplied by 100) increased from 2 percent to 5.5 percent over the period 2000 to 2010, stays at 5.5 percent through 2015, and then is sunset.

Renewable fuels assumptions

Energy Policy Act of 1992. Under EPACT, the Renewable Fuels Module (RFM) provides a renewable electricity production credit of 1.5 cents per kilowatthour for electricity produced by wind, applied to plants becoming operational between January 1, 1994, and December 31, 1999, and continuing for 10 years [*16*]. EPACT and the RFM also include a 10 percent investment tax credit for solar and geothermal technologies that generate electric power [*17*].

Supplemental Additions. AEO99 includes 2,897 megawatts of assumed new generating capacity using renewable resources, including 2,290 megawatts of planned new capacity not reported among EIA data collections and 607 megawatts assumed by EIA to be built for reasons not incorporated in the NEMS, such as for investment, testing, for distributed applications, or in response to State mandates. Total supplementals include 288 megawatts biomass, 168 megawatts geothermal, 134 megawatts landfill gas, 627 megawatts solar photovoltaic, 162 megawatts solar thermal, and 1,518 megawatts wind.

Renewable resources. 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 nearly halt the expansion of U.S. hydroelectric power. Solar, wind, and geothermal resources are theoretically very large, but economically accessible resources are much less available.

Solar energy (direct normal insolation) for thermal applications is considered economically amenable only in drier regions, west of the Mississippi River; photovoltaics, however, can be considered 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, alternative land uses, and environmental objections. The geographic distribution of available wind resources is based on work by the Pacific Northwest Laboratory [*18*], enumerating winds among average annual wind-speed 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 thermal conversion factor (Btu content per weight of fuel). Municipal solid waste resources are limited by the amount of the waste that is managed by other methods, such as recycling or landfills, and by the impact of waste minimization as a strategy for addressing the waste problem.

For *AEO99*, EIA incorporates in NEMS recognition of higher costs (proxies for supply elasticities) for uses of biomass and wind resources as generating capacity consumes more of the available resources. Costs increase in response to (1) increasing costs as natural resource quality declines, such as from wind turbulence, more difficult land access, or declining land quality, (2) increasing costs of local and regional transmission network improvements, and (3) market conditions increasing costs of alternative land uses, including for crops, recreation, or environmental or cultural preferences. Although the effects generally apply only with very large capacity increases not experienced in *AEO99*, some wind costs in California are increased this year in response to these factors.

High renewables case. For the *high renewables case*, EIA incorporates approximations of the DOE Office of Energy Efficiency and Renewable Energy's August 1997, draft technology characterizations of lower capital and operating costs and higher efficiencies (capacity factors) for new renewable energy generating technologies than used in the reference case [*19*]. EIA also assumes that the yields for energy crops grown on pasture and crop land are nearly 20 percent higher than in the reference case. In addition, for the high renewables case, EIA assumes that additional capacity effects of State RPS programs included in the reference case will extend beyond 2010, by 2020 adding 97 megawatts of additional supplemental capacity. The additions include 39 megawatts wind, 20 megawatts biomass, 17 megawatts solar photovoltaics, 12 megawatts solar thermal, 8 megawatts municipal solid waste (landfill gas), and 2 megawatts geothermal generating capacity. All other technologies and other NEMS modeling characteristics remain unchanged.

Non-electric renewable energy. The forecast for wood consumption in the residential sector is based on the Residential Energy Consumption Survey [*20*] (RECS) and data from the *Characteristics of New Housing: 1993*, published by the Bureau of the Census [*21*]. The RECS data provide a benchmark for Btu of wood use in 1993. The Census data are used to develop the forecasts of new housing units utilizing wood. 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 consumption is also based on the latest RECS and Census data; 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. Solar thermal consumption for water heating is also represented by displaced primary energy relative to an electric water heater.

Exogenous projections of active and passive solar technologies and geothermal heat pumps in the commercial sector are based on projections from the National Renewable Energy Laboratory [*22*]. Industrial use of renewable energy is primarily the use of wood and wood byproducts in the paper and lumber industries as well as a small amount of hydropower for electricity generation.

Oil and gas supply assumptions

Domestic oil and gas technically recoverable resources. The assumed resource levels 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 with supplemental adjustments to the USGS nonconventional resources by Advanced Resources International (ARI), an independent consulting firm [*23*].

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 increase in recovery is due to the development and deployment of new technologies, such as three-dimensional seismology and horizontal drilling and completion techniques.

Drilling, operating, and lease equipment costs are expected to decline due to technological progress, at econometrically estimated rates that vary somewhat by cost and fuel categories, ranging from roughly 0.3 to 2.0 percent. These technological impacts work against increases in costs associated with drilling to greater depths, higher drilling activity levels, and rig availability. Exploratory success rates are assumed to improve by 0.5 percent per year, and finding rates are expected to improve by 1.0 to 6.0 percent per year because of technological progress.

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 plus or minus 50 percent. A number of key exploration and production technologies were assumed to penetrate at alternate rates with varying degrees of effectiveness in the *rapid and slow technology cases*.

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 (LNG) and natural gas trade between the United States and Canada and Mexico. Specific detail by region and fuel category is presented in the supplementary tables to the *Annual Energy Outlook 1999*, which will be available in December 1998 on EIA's FTP site (ftp://ftp.eia.doe.gov/pub/forecasting/AEO99/AEO99tables).

Climate Change Action Plan (CCAP). The CCAP includes a program promoting the capture of methane from coal mining activities to reduce carbon emissions. The methane would be marketed as part of the domestic natural gas supply. This program began in 1995. The *AEO99* assumption is that it reaches a 2010 production level of 29 billion cubic feet and a level of 35 billion cubic feet by 2020.

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 requires 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 and LNG imports. The Alaska Natural Gas Transportation System is assumed to come on line no earlier than 2005 and only after the U.S.-Canada border price reaches $3.89, in 1997 dollars per thousand cubic feet. The liquefied natural gas facilities at Everett, Massachusetts, and Lake Charles, Louisiana (the only ones currently in operation) have an operating capacity of 311 billion cubic feet. The facilities at Cove Point, Maryland, and Elba Island, Georgia, are assumed to reopen when economically justified, but not before 1999. Should these facilities reopen, total liquefied natural gas operating capacity would increase to 794 billion cubic feet.

Natural gas transmission and distribution assumptions. It is assumed that industry restructuring is fully in place in the transmission segment of the industry and making considerable inroads in the distribution segment.

Transportation rates for pipeline services are calculated with the assumption that the costs of new pipeline capacity will be rolled into the existing rate base. While cost of service forms the basis for pricing these services, an adjustment is made to the resulting tariff based on the utilization of the pipeline to reflect a more market-based approach.

In determining interstate pipeline tariffs, capital expenditures for refurbishment over and above that included in operations and maintenance costs are not considered, nor are potential future expenditures for pipeline safety. (Refurbishment costs include any expenditures for repair or replacement of existing pipe.) Reductions in operations and maintenance costs and total administrative and general costs as a result of efficiency improvements are accounted for on the basis of historical trends.

Distribution markups to core customers (not including electricity generators) change over the forecast in response to changes in consumption levels, cost of capital, and assumed industry efficiency improvements. It is assumed that, independent of changes in costs related to the cost of capital and consumption levels, distributor costs for firm service customers will decline by 1 percent per year through 2015.

The vehicle natural gas (VNG) sector is divided into fleet and non-fleet 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 VNG taxes. The price to non-fleet vehicles is based on the industrial sector firm price plus an assumed $3 (1987 dollars) dispensing charge plus taxes. Federal taxes are set and held at $0.49 in 1994 nominal dollars per thousand cubic feet.

CCAP initiatives to increase the natural gas share of total energy use through Federal regulatory reform (Action 23) are reflected in the methodology for the pricing of pipeline services. Provisions of the CCAP to expand the Natural Gas Star program (Action 32) are assumed to recover 35 billion cubic feet of natural gas per year by the year 2000 that otherwise might be lost to fugitive emissions. This is phased in by recovering 21 and 28 billion cubic feet per year in 1998 and 1999, respectively. The full 35 billion cubic feet is recovered from 2000 through the end of the forecast period.

Petroleum market assumptions

The petroleum refining and marketing industry is assumed to incur large environmental costs to comply with CAAA90 and other regulations. Investments related to reducing emissions at refineries are represented as an average annualized expenditure. Costs identified by the National Petroleum Council [*24*] are allocated among the prices of liquefied petroleum gases, gasoline, distillate, and jet fuel, assuming they are recovered in the prices of light products. The lighter products, such as gasoline and distillate, are assumed to bear a greater amount of these costs because demand for these products is less price-responsive than for the heavier products.

Petroleum product prices also include additional costs resulting from requirements for new fuels, including oxygenated and reformulated gasolines and low-sulfur diesel. These additional costs are determined in the representation of refinery operations by incorporating specifications and demands for these fuels. Demands for traditional, reformulated, and oxygenated gasolines are disaggregated from composite gasoline consumption based on their 1997 market shares in each Census Division. The expected oxygenated gasoline market shares assume continued wintertime participation of carbon monoxide nonattainment areas and statewide participation in Minnesota. Oxygenated gasoline represents about 3 percent of gasoline demand in the forecast.

Reformulated gasoline (RFG) is assumed to continue to be consumed in the 10 serious ozone nonattainment areas required by CAAA90 and in areas in 13 States and the District of Columbia that voluntarily opted into the program [*25*]. An additional 63 million barrels per day of demand is assumed to reflect the June 1999 addition of St. Louis, Missouri, to the RFG program. Reformulated gasoline projections also reflect a statewide requirement in California. Phoenix, Arizona, which by State law may use either Federal RFG or California RFG, is assumed to use Federal RFG. RFG is assumed to account for about 33 percent of annual gasoline sales throughout the *AEO99* forecast, which reflects the 1997 market share with adjustments for the opt-in of St. Louis in June 1999.

Reformulated gasoline reflects the "Complex Model" definition as required by the EPA and the tighter Phase 2 requirements beginning in 2000. *AEO99* projections also reflect California's statewide requirement for severely reformulated gasoline first required in 1996. Throughout the forecast, traditional gasoline is blended according to 1990 baseline specifications, to reflect CAAA90 "antidumping" requirements aimed at preventing traditional gasoline from becoming more polluting.

AEO99 assumes that State taxes on gasoline, diesel, jet fuel, M85, and E85 increase with inflation, as they have tended to in the past. Federal taxes which have increased sporadically in the past are assumed to stay at 1997 nominal levels (a decline in real terms).

AEO99 reflects the extension of the tax credit for blending corn-based ethanol with gasoline included in the Federal Highway Bill of 1998. The bill extends the tax credit through 2007 but reduces the current credit of 54 cents per gallon by 1 cent per gallon in 2001, 2003, and 2005. *AEO99* assumes that the tax credit will be extended beyond 2007 through 2020 at the nominal level of 51 cents per gallon (a decline in real terms).

AEO99 assumes that refining capacity expansion may occur on the east and west coasts, as well as the Gulf Coast.

Automakers' national low-sulfur gasoline. The alternative case reflects the American Automobile Manufacturers Association/Association of International Automobile Manufacturers (automakers) petition to the EPA to reduce the average allowable sulfur content of gasoline in the United States to 40 ppm, which is equivalent to the current standard in the State of California. The reduced sulfur standard is assumed to be enforced in 2004 as it is associated with requirements for technology for lower emissions "Tier 2" vehicles, which are required for model year 2004. Sensitivities to gasoline supply and prices are explored.

API/NPRA regional reduced-sulfur gasoline. The alternative case reflects a proposal by the American Petroleum Institute/National Petrochemical and Refiners Association for a reduced-sulfur gasoline program beginning in 2004. The proposal is a regional plan in which all gasoline in Federal reformulated gasoline areas and in 23 States and East Texas must meet an annual average of 150 ppm. Gasoline in California would continue to meet statewide gasoline requirements, which include a 40 ppm annual average sulfur limit, while gasoline in all other parts of the country would have an annual average of 300 ppm. The "second step" of the proposal includes further reduction of sulfur in 2010 for gasoline in areas that require year-round NO_x control gasoline. The actual sulfur level and participants would be determined by an EPA study in 2006. The alternative case assumes 40 ppm gasoline requirements beginning in 2010 for the areas with the 150 ppm limit in 2004. Sensitivities to gasoline supply and prices are explored.

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 but to decline in magnitude over the forecast horizon. Different rates of improvement are assumed by region and by mine type, surface and deep. On a national basis, labor productivity is assumed to improve on average at a rate of 2.3 percent per year, declining from an annual rate of 6.2 percent in 1997 to approximately 1.3 percent over the 2010 to 2020 period.

In two alternative mining cost cases that were run to examine the impacts of different labor productivity and labor 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 *AEO99* reference case productivity path by 1 standard deviation, although productivity growth rates were adjusted gradually (with full variation from the reference case phased in by 2000). The resulting national average productivities attained in 2020 (in short tons per hour) were 14.14 in the *low mining cost case* and 7.99 in the *high mining cost case*, compared with 10.18 in the reference case.

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

With the exception of the electricity generation sector, the mining cost cases were run without allowing demands to shift in response to changing prices. If demands also had been allowed to shift in the energy end-use sectors, the price changes would be smaller, since minemouth prices vary with the levels of production required to meet demand.

Notes

[1] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1997*, DOE/EIA-0573(97) (Washington, DC, October 1998).

[2] Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202(98/3Q) (Washington, DC, July 1998), and web site www.eia.doe.gov/emeu/steo/pub/upd/sep98/index.html.

[3] 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.

[*4*] High technology assumptions are based on Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Arthur D. Little, Inc., September 1998).

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

[*6*] Energy Information Administration, 1995 CBECS Micro-Data Files, February 17, 1998, see web site www.eia.doe.gov/emeu/cbecs/.

[*7*] A detailed discussion of the Nonsampling and Sampling Errors for CBECS is provided in Appendix B of the 1995 CBECS Building Characteristics and Energy Consumption and Expenditures reports at www.eia.doe.gov/ emeu/cbecs/.

[*8*] High technology assumptions are based on Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Arthur D. Little, Inc., September 1998).

[*9*] Energy Information Administration, *Manufacturing Consumption of Energy 1994*, DOE/EIA-0512(94) (Washington, DC, December 1997).

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

[*11*] These assumptions are based in part on Arthur D. Little, "Aggressive Technology Strategy for the NEMS Model" (September 1998).

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

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

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

[*15*] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy Technologies by 2010 and Beyond*, ORNL/CON-444 (Washington, DC, September 1997); Office of Energy Efficiency and Renewable Energy, Office of Transportation Technologies, *OTT Program Analysis Methodology: Quality Metrics 99* (December 1997); and J. DeCicco and M. Ross, *An Updated Assessment of the Near-Term Potential for Improving Automotive Fuel Economy* (Washington, DC: American Council for an Energy-Efficient Economy, November 1993).

[*16*] National Energy Policy Act of 1992, P.L. 102-486, Title XIX, Section 1914.

[*17*] National Energy Policy Act of 1992, P.L. 102-486, Title XIX, Section 1916.

[*18*] 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 Schwartz, M.N.; Elliott, O.L.; and Gower, G.L.; *Gridded State Maps of Wind Electric Potential. Proceedings, Wind Power 1992*, October 19-23, 1992, Seattle.

[*19*] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, draft, *Renewable Energy Technology Characterizations*, Vol. 1, (Washington, DC, February 1997), as updated in internal revisions, Summer 1997.

[*20*] Energy Information Administration, *Household Energy Consumption and Expenditures 1993*, DOE/EIA-0321(93) (Washington, DC, 1995).

[*21*] U.S. Bureau of the Census, U.S. Department of Commerce, *Current Construction Reports, Series C25 Characteristics of New Housing: 1993* (Washington, DC, 1994).

[*22*] National Renewable Energy Laboratory, "Baseline Projections of Renewables Use in the Buildings Sector," prepared for the U.S. Department of Energy under Contract DE-AC02-83CH10093 (December 1992).

[*23*] Goutier, Donald L., et al., U.S. Department of the Interior, U.S. Geological Survey, *1995 National Assessment of the United States Oil and Gas Resources* (Washington, DC, 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); Cooke, Larry W., U.S. Department of the Interior, Minerals Management Service, *Estimates of Undiscovered, Economically Recoverable Oil and Gas Resources for the Outer Continental Shelf, Revised as of January 1990*, OCS Report MMS 91-0051 (July 1991).

[*24*] Estimated from National Petroleum Council, *U.S. Petroleum Refining—Meeting Requirements for Cleaner Fuels and Refineries*, Volume I (Washington, DC, August 1993). Excludes operation and maintenance base costs prior to 1997.

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