Assumptions to the Annual Energy Outlook 2005

With Projections to 2025

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Contents

Introduction

This report presents the major assumptions of the National Energy Modeling System (NEMS) used to generate the projections in the *Annual Energy Outlook 2005*[1] (*AEO2005*), including general features of the model structure, assumptions concerning energy markets, and the key input data and parameters that are most significant in formulating the model results. Detailed documentation of the modeling system is available in a series of documentation reports.[2] A synopsis of NEMS, the model components, and the interrelationships of the modules is presented in *The National Energy Modeling System: An Overview*[3], which is updated once every two years.

The National Energy Modeling System

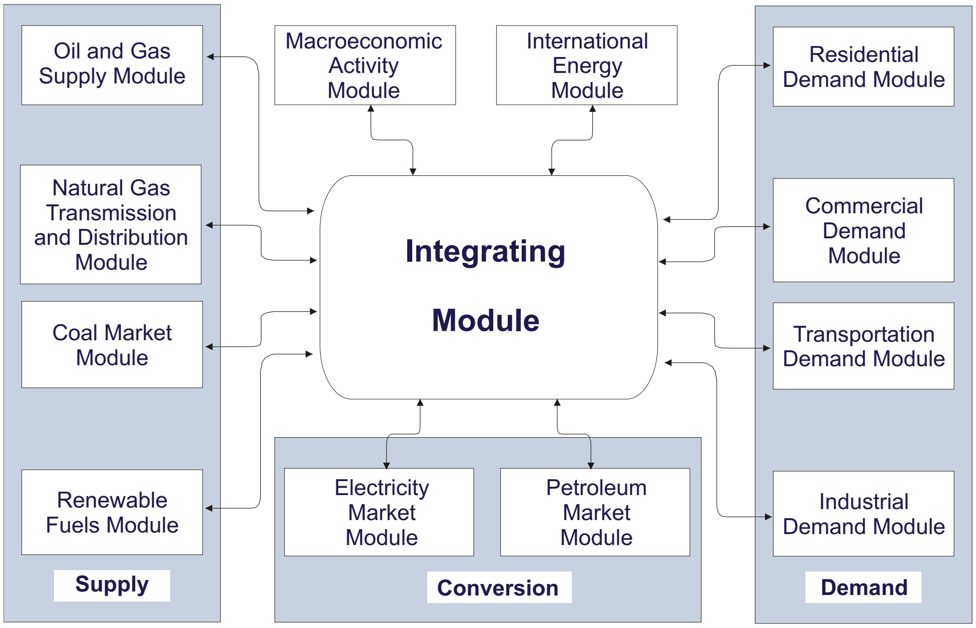
The projections in the *AEO2005* were produced with the National Energy Modeling System. NEMS is developed and maintained by the Office of Integrated Analysis and Forecasting of the Energy Information Administration (EIA) to provide projections of domestic energy-economy markets in the midterm time period and perform policy analyses requested by decisionmakers in the U.S. Congress, the Administration, including DOE Program Offices, and other government agencies.

The time horizon of NEMS is approximately 20 years, the midterm period in which the structure of the economy and the nature of energy markets are sufficiently understood that it is possible to represent considerable structural and regional detail. Because of the diverse nature of energy supply, demand, and conversion in the United States, NEMS supports regional modeling and analysis in order to represent the regional differences in energy markets, to provide policy impacts at the regional level, and to portray transportation flows. The level of regional detail for the end-use demand modules is the nine Census divisions. Other regional structures include production and consumption regions specific to oil, gas, and coal supply and distribution, the North American Electric Reliability Council regions and subregions for electricity, and the Petroleum Administration for Defense Districts (PADD) for refineries. Maps illustrating the regional formats used in each module are included in this report. Only national results are presented in the *AEO2005,* with the regional and other detailed results available on the EIA Forecasting Home Page. (http://www.eia.doe.gov/oiaf/aeo/index.html)

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. NEMS is organized and implemented as a modular system (Figure 1). The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes a macroeconomic and an international oil module. 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 such as economic activity, domestic production activity, and international petroleum supply availability.

The integrating module of NEMS controls the execution of each of the component modules. To facilitate modularity, the components do not pass information to each other directly but communicate through a central data storage location. This modular design provides the capability to execute modules individually, thus allowing decentralized development of the system and independent analysis and testing of individual modules. This modularity allows use of the methodology and level of detail most appropriate for each energy sector. NEMS solves by calling each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. Solution is reached annually through the midterm horizon. Other variables are also evaluated for convergence such as petroleum product imports, crude oil imports, and several macroeconomic indicators.

Figure 1. National Energy Modeling System



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Each NEMS component also represents the impact and cost of legislation and environmental regulations that affect that sector and reports key emissions. NEMS reflects all current legislation and environmental regulations that are defined sufficiently to be modeled as of October 31, 2004. The potential impacts of pending or proposed legislation, regulations, or standards—or of sections of legislation that have been enacted but that require funds or implementing regulations that have not been provided or specified—are not reflected in the sectors. A list of the Federal and selected State legislation and regulations included in the *AEO*, including how they are incorporated, is provided in Appendix A.

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. This section provides brief summaries of each of the modules.

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 Industry Model, and National Employment Model. In addition, EIA has constructed a Regional Economic and Industry Model to forecast regional economic drivers and a Commercial Floorspace Model to forecast 13 floorspace types in 9 Census Divisions. For AEO2005, bulk chemicals are disaggregated into organic and inorganic chemicals, resins, and agricultural chemicals. In addition, the accounting framework for industrial output has changed from the Standard Industrial Classification (SIC) system to the North American Industry Classification System (NAICS), which has reclassified the components of gross industrial output and moved some manufacturing activities into services.

International Energy Module

The International Energy Module represents 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. A world oil supply/demand balance is created, including estimates for 16 oil consumption regions and 18 oil production regions. The oil production estimates include both conventional and nonconventional supply recovery technologies.

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. The modules also include forecasts of distributed generation. Both modules incorporate changes to "normal" heating and cooling degree-days by Census division based on State-level population projections. The Residential Demand Module projects that the average square footage of both new construction and existing structures is increasing, based on trends in the size of new construction and the remodeling of existing homes.

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. As noted in the description of the macroeconomic module, the value of shipments is now based on NAICS rather than SIC. The industries are classified into three groups—energy-intensive manufacturing, non-energy-intensive manufacturing, 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. Bulk chemicals have been further disaggregated to organic, inorganic, resins and other petroleum products. 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 CAAA and other legislative proposals, and the module includes a component to explicitly assess the penetration of alternative-fuel vehicles. The air transportation module explicitly 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. For airfreight 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 represents 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 CAAA 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 *AEO2005*.

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 hydroelectricity, biomass (wood, energy crops, and biomass co-firing), geothermal, landfill gas, solar thermal electricity, solar photovoltaics, and wind energy. The RFM contains natural resource supply estimates representing the regional opportunities for renewable energy development. Investment tax credits for renewable fuels are incorporated, as currently legislated in the Energy Policy Act of 1992. They provide a 10-percent tax credit for business investment in solar energy (thermal non-power uses as well as power uses) and geothermal power. The credits have no expiration date. Production tax credits for wind and some types of biomass fueled plants are also represented. These provide a 1.8 cent per kilowatt-hour tax credit for electricity produced in the first 10 years of plant operation. New plants that come online prior to January 1, 2006 are eligible to receive the credit.

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 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 capacity expansion requirements. Peak and off-peak periods are represented for natural gas transmission, and core and non-core 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 in the five Petroleum Administration for Defense Districts (PADDs). The module uses the same crude oil types as the International Energy Module. It explicitly models the requirements of CAAA and the costs of automotive fuels, such as oxygenated and reformulated gasoline, and includes oxygenate production and blending for reformulated gasoline. *AEO2005* reflects legislation that bns or limits the use of the gasoline blending component methyl tertiary butyl ether (MTBE) in Arizona, California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Maine, Michigan, Minnesota, Missouri, Nebraska, New Hampshire, New York, Ohio, South Dakota, Washington, and Wisconsin.

The Federal oxygen requirement for reformulated gasoline in Federal nonattainment areas is assumed to remain intact. The nationwide phase-in of gasoline with an annual average sulfur content of 30 ppm between 2005 and 2007 and the diesel regulations that limit the sulfur content to 15 ppm in highway diesel starting mid-2006 and in all nonroad and locomotive/marine diesel by mid-2012, are represented in *AEO2005*. Growth in demand and costs of the regulations lead to capacity expansion for refinery-processing units assuming a financing ratio of 60-percent equity and 40-percent debt, with a hurdle rate and an after-tax return on investment at about 10 percent [6]. End-use prices are based on the marginal costs of production, plus markups representing product and distribution costs, and State and Federal taxes [7]. Refinery capacity expansion at existing sites may occur in all five refining regions modeled.

Fuel ethanol and biodiesel are included in PMM because they are commonly blended into petroleum products. The PMM allows ethanol blending into gasoline at 10 percent (by volume) or less and also allows limited quantities of E85, a blend of up to 85 percent (by volume) ethanol. Ethanol is produced primarily in the Midwest from corn or other starchy crops, and it is expected to be produced from cellulosic material in other regions in the future. Biodiesel is produced from soybean oil or yellow grease, which is primarily recycled cooking oil. Soybean oil biodiesel is assumed to be blended into highway diesel, and yellow grease biodiesel is assumed to be blended into non-highway diesel.

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. U.S. coal production is represented in the CMM using 40 separate supply curves—differentiated by region, mine type, coal rank and sulfur content. The coal supply curves include a response to capacity utilization of mines, mining capacity, labor productivity, and factor input costs (mining equipment, mining labor, and fuel requirements). Projections of U.S. coal distribution are determined in the CMM through the use of a linear programming algorithm that determines the least-cost supplies of coal for a given set of coal demands by demand region and sector, accounting for transportation costs from the different supply curves, heat and sulfur content, existing coal supply contracts, and sulfur allowance costs. Over the forecast horizon, coal transportation costs in the CMM are projected to vary in response to changes in railroad productivity and the user cost of rail transportation equipment. The CMM produces projections of U.S. steam and metallurgical coal exports, in the context of world coal trade. The CMM's linear programming algorithm determines the pattern of world coal trade flows that minimizes the production and transportation costs of meeting a pre-specified set of regional world coal import demands, subject to constraints on export capacities by country and coal type and trade flows.

Cases for the *Annual Energy Outlook 2005*

Besides the reference case, the *AEO2005* presents detailed results for six alternative cases that differ from each other due to fundamental assumptions concerning the domestic economy and world oil market conditions. These alternative case include the following:

- **Economic Growth** - In the *reference case*, real GDP grows at an average annual rate of 3.1 percent from 2003 through 2025, supported by a 2.2 percent per year growth in productivity in nonfarm business and a 0.9 percent per year growth in nonfarm employment. In the *high economic growth* *case,* real GDP is projected to increase by 3.6 percent per year, with productivity and nonfarm employment growing at 2.7 percent and 1.6 percent per year, respectively. In the *low economic growth case*, the average annual growth in GDP, productivity and nonfarm employment is 2.5, 1.8 and 0.8 percent, respectively.

- **World Oil Markets** - In the *reference case*, the average world oil price increases to $30.31 per barrel (in real 2003 dollars) in 2025. Reflecting uncertainty in world markets, the price in 2025 reaches $20.99 per barrel in the *low oil price case*, $35.00 per barrel in the *October oil futures case*, $39.24 per barrel in the *high A world oil price case,* and $48.00 per barrel in the *high B world oil price case*.

In addition to these six cases, 29 additional alternative cases presented in Table 1 explore the impacts of changing key assumptions on individual sectors.

Many of the side cases were designed to examine the impacts of varying key assumptions for individual modules or a subset of the NEMS modules, and thus the full market consequences, such as the consumption or price impacts, are not captured. In a fully integrated run, the impacts would tend to narrow the range of the differences from the reference case. For example, the best available technology side case in the residential demand assumes that all future equipment purchases are made from a selection of the most efficient technologies available in a particular year. In a fully integrated NEMS run, the lower resulting fuel consumption would have the effect of lowering the market prices of those fuels with the concomitant impact of increasing economic growth, thus stimulating some additional consumption. As another example, the higher electricity demand side case results in higher electricity prices due to the need to add additional capacity to the grid. If this were a fully integrated run, the demand for electricity would be reduced as a result of higher prices, thus moderating somewhat the higher demand. The results of single model or partially integrated cases should be considered the maximum range of the impacts that could occur with the assumptions defined for the case.

All projections are based on Federal, State, and local laws and regulations in effect as of October 31, 2004 that have been specifically defined, examples of Federal and State legislation that is included are the National Appliance Energy Conservation Act of 1987; the Clean Air Act Amendments of 1990 (CAAA90), which include new standards for motor gasoline and diesel fuel and for heavy-duty vehicle emissions; the Energy Policy Act of 1992 (EPACT); the Omnibus Budget Reconciliation Act of 1993, which added 4.3 cents per gallon to the Federal tax on highway fuels; the Outer Continental Shelf Deep Water Royalty Relief Act of 1995 and subsequent provisions on royalty relief for new leases issued after November 2000 on a lease-by-lease basis; the Maritime Security Act of 2002, which amended the Deepwater Port Act of 1974 to include offshore natural gas facilities; the American Jobs Creation Act of 2004, which includes incentives and tax credit for biodiesel fuels, a modified depreciation schedule for the Alaska natural gas pipeline, and an expansion of the 1.8-cent renewable energy production tax credit to include geothermal and solar generation technologies; the Military Construction Appropriations Act of 2005, which includes provisions to support construction of the Alaska natural gas pipeline, including Federal loan guarantees during construction; the Working Families Tax Relief Act of 2004, which includes an extension of the 1.8-cent production tax credit for wind and closed-loop biomass to December 31, 2005, tax deductions for qualified clean-fuel and electric vehicles, and changes in how oil and gas well depletions is handled; the State of Alaska’s Right-Of-Way Leasing Act Amendment of 2001, which prohibit leases across State land for a “northern” or “over-the-top” natural gas pipeline route running east from the North Slope to Canada’s MacKenzie River Valley; State renewable portfolio standards, including the California renewable portfolio standards passed on September 12, 2002; and State programs for restructuring of the electricity industry.

Table 1. Summary of *AEO2005* Cases

Case name	Description	Integration mode
Reference	Baseline economic growth (3.1 percent per annum), world oil price falling to about $25 per barrel by 2010 and rising to $30.31 per barrel, and technology assumptions	Fully integrated
Low Economic Growth	Gross domestic product grows at an average annual rate of 2.5 percent from 2003 through 2025,compared with the reference case growth of 3.1 percent. Reference case assumptions otherwise.	Fully integrated
High Economic Growth	Gross domestic product grows at an average annual rate of 3.6 percent from 2003 through 2025,compared with the reference case growth of 3.1 percent. Reference case assumptions otherwise.	Fully integrated
Low World Oil Price	Reference case assumptions except that the world oil prices are $20.99 per barrel in 2025, compared with $30.31 per barrel in the reference case.	Fully integrated
October Oil Futures	World oil prices continue to rise in near term and are $35.00 per barrel in 2025, compared with $30.31 per barrel in the reference case.	Fully integrated
High A World Oil Price	Reference case assumptions except that the world oil prices are $39.24 per barrel in 2025,compared with $30.31 per barrel in the reference case.	Fully integrated
High B World Oil Price	World oil prices remain high and are $48.00 per barrel in 2025,compared with $30.31 per barrel in the reference case.	Fully integrated
Residential: 2005 Technology	Future equipment purchases based on equipment available in 2005. Existing building shell efficiencies fixed at 2005 levels.	With commercial
Residential: High Technology	Relative to the reference case,earlier availability,lower costs, and higher efficiencies assumed for more advanced equipment. Heating shell efficiency increases by 21 percent from 2002 values by 2025.	With commercial
Residential: Best Available Technology	Relative to the reference case,future equipment purchases and new building shells based on most efficient technologies available. Heating shell efficiency increases by 25 percent from 2002 values by 2025.	With commercial
Commercial: 2005 Technology	Relative to the reference case, future equipment purchases are based on equipment available in 2005. Building shell efficiencies are fixed at 2005 levels.	With residential
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
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
Residential and Commercial: SEER 12	Replaces the recently enacted SEER 13 standard with the previously set level of SEER 12.	Fully integrated
Residential and Commercial: Warmer Temperatures	Summer and winter temperatures trend to the average of the 5 warmest of the past 30 years by 2025.	Fully Integrated
Residential and Commercial: Colder Temperatures	Summer and winter temperatures trend to the average of the 5 coldest of the past 30 years by 2025.	Fully Integrated
Industrial: 2005 Technology	Efficiency of plant and equipment fixed at 2005 levels.	Standalone
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment.	Standalone

Table 1. Summary of *AEO2003* Cases (Continued)

Cases	Description	Integration Mode
Transportation: 2005 Technology	Efficiencies for new equipment in all modes of travel are fixed at 2005 levels.	Standalone
Transportation: High Technology	Reduced costs and improved efficiencies are assumed for advanced technologies.	Standalone
Transportation: AB1493 California Only	Accounts for adoption of vehicle carbon dioxide emissions standards in California.	Fully integrated
Transportation: AB1493 Extended	Accounts for adoption of vehicle carbon dioxide emissions standards in California, New York, Maine, Massachusetts, and Vermont.	Fully integrated
Integrated 2005 Technology	Baseline macroeconomic drivers, combining the the residential, commercial, industrial, and transportation 2005 technology assumptions with electricity low fossil technology and low renewable technology assumptions.	Fully integrated
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
Electricity: Advanced Nuclear Cost	New nuclear capacity is assumed to have 20 percent lower capital and operating costs in 2025 than in the reference case	Fully integrated
Electricity: Nuclear Vendor Estimate	New nuclear capacity is assumed to have lower capital costs based on vendor goals.	Fully Integrated
Electricity: High Fossil Technology	Costs and efficiencies for advanced fossil-fired generating technologies improve by 10 percent in 2025 from reference case values.	Fully Integrated
Electricity:Low Fossil Technology	New advanced fossil generating technologies are assumed not to improve over time from 2005	Fully Integrated
Electricity: Proposed Clean Air Interstate Rule (CAIR)	Limits on NOx and SO2 emissions.	Fully Integrated
Renewables: Low Renewables	New renewable generating technologies are assumed not to improve over time from 2005	Fully Integrated
Renewables: High Renewables	Levelized cost of energy for nonhydropower renewable generating technologies declines by 10 percent in 2025 from reference case values	Fully Integrated
Renewables: PTC Extension	The production tax credit (PTC) for wind expired in 2003. *AEO2005* does not assume its extension consistent with the approach generally taken toward public policy in the forecast. This scenario assumes the extension of the PTC through 2015.	Fully Integrated
Oil and Gas: Rapid Technology	Cost,finding rate,and success rate technology parameters adjusted for 50-percent more rapid improvement than in the reference case.	Fully integrated
Oil and Gas: Slow Technology	Cost, finding rate, and success rate technology parameters adjusted for 50 percent slower improvement than in the reference case.	Fully integrated
Oil and Gas: Restricted Natural Gas Supply	The slow oil and gas technology case with no Alaskan pipeline and no new U.S. LNG regasification terminals except those already under construction. Proposed expansions of existing U.S. LNG terminals are permitted to go into operation as currently scheduled.	
Oil and Gas: No nonroad Diesel Rule	No new nonroad diesel rules.	Fully integrated

Emissions

Carbon dioxide emissions from energy use are dependent on the carbon content of the fossil fuel, the fraction of the fuel consumed in combustion, and the consumption of that fuel. The product of the carbon content at full combustion and the combustion fraction yields an adjusted carbon dioxide emission factor for each fossil fuel. The emissions factors are expressed in millions of metric tons carbon equivalent of carbon dioxide emitted per quadrillion Btu of energy use, or equivalently, in kilograms carbon equivalent of carbon dioxide per million Btu. The adjusted emissions factors are multiplied by the energy consumption of that fossil fuel to arrive at the carbon dioxide emissions projections.

For fuel uses of energy, the combustion fractions are assumed to be 0.99 for liquid fuels and 0.995 for gaseous fuels. The carbon dioxide in nonfuel use of energy, such as for asphalt and petrochemical feedstocks, is assumed to be sequestered in the product and not released to the atmosphere. For energy categories that are mixes of fuel and nonfuel uses, the combustion fractions are based on the proportion of fuel use. Any carbon dioxide emitted by biogenic renewable sources, such as biomass and alcohols, is considered balanced by the carbon dioxide sequestration that occurred in its creation. Therefore, following convention, net emissions of carbon dioxide from biogenic renewable sources are taken as zero, and no emission coefficient is reported. In calculating carbon dioxide emissions for motor gasoline, the emissions from renewable blending stock (ethanol) is omitted.

Table 2 presents the carbon dioxide coefficients at full combustion, the combustion fractions, and the adjusted carbon dioxide emission factors used for *AEO2005*.

Table 2. Carbon Dioxide Emission Factors
(million metric tons carbon dioxide equivalent per quadrillion Btu)

Fuel Type	Carbon Dioxide Coefficient at Full Combustion	Combustion Fraction	Adjusted Emissions Factor
Petroleum			
Motor Gasoline	70.91	0.990	70.20
Liquefied Petroleum Gas			
Used as Fuel	63.07	0.995	62.75
Used as Feedstock	61.67	0.500	30.83
Jet Fuel	70.88	0.990	70.17
Distillate Fuel	73.15	0.990	72.42
Residual Fuel	78.80	0.990	78.01
Asphalt and Road Oil	75.61	0.000	0.00
Lubricants	74.21	0.500	37.11
Petrochemical Feedstocks	71.02	0.370	26.28
Kerosene	72.31	0.990	71.58
Petroleum Coke	102.12	0.500	51.06
Petroleum Still Gas	64.20	0.995	63.88
Other Industrial	74.43	0.990	73.68
Coal			
Residential and Commercial	95.48	0.990	94.53
Metallurgical	93.98	0.990	93.04
Industrial Other	94.38	0.990	93.44
Electric Utility[1]	95.26	0.990	94.31
Natural Gas			
Used as Fuel	53.06	0.995	52.79
Used as Feedstocks	53.06	0.774	41.07

[1]Emission factors for coal used for electricity generation are specified by coal supply region and types of coal, so the average carbon dioxide contents for coal varies throughout the forecast. The 2003 average is 93.94.

Source: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2003*, DOE/EIA-0573(2003), (Washington, DC, December 2004).

Notes and Sources

[1] Energy Information Administration, Annual Energy Outlook 2005 (AEO2005), DOE/EIA-0383(2005), (Washington, DC, February 2005).

[2] NEMS documentation reports are available on the EIA Homepage (http://www.eia.doe.gov/bookshelf.html).

[3] Energy Information Administration, The National Energy Modeling System: An Overview 2003, DOE/EIA-0581(2003), (Washington, DC, March 2003).

Macroeconomic Activity Module

The Macroeconomic Activity Module (MAM) represents the interaction between the U.S. economy as a whole and energy markets. The rate of growth of the economy, measured by the growth in gross domestic product (GDP) is a key determinant of the growth in demand for energy. Associated economic factors, such as interest rates and disposable income, strongly influence various elements of the supply and demand for energy. At the same time, reactions to energy markets by the aggregate economy, such as a slowdown in economic growth resulting from increasing energy prices, are also reflected in this module. A detailed description of the MAM is provided in the EIA publication, *Model Documentation Report: Macroeconomic Activity Module (MAM) of the National Energy Modeling System*, DOE/EIA-M065(2004), (Washington, DC, January 2005).

Key Assumptions

The output of the U.S. economy, measured by GDP, is expected to increase by 3.1 percent between 2003 and 2025 in the reference case. The growth in GDP can be explained by two key factors: the growth rate of nonfarm employment and the rate of productivity change associated with employment. As Table 3 indicates, GDP growth slows down in each of the periods identified, from 4.0 percent between 2003 and 2005, to 3.1 percent between 2005 and 2010, to 2.8 percent in the last five-year period from 2020 to 2025. The table highlights two elements of the forecast that explain these trends – nonfarm employment and productivity as measured by output per hour of nonfarm business. In the near term from 2003 through 2005, the growth in nonfarm employment is low at 1.3 percent compared with 2.4 percent in the second half of the 1990s, while the economy is currently experiencing strong productivity growth of 2.8 percent. Over the forecast period, nonfarm employment is expected to grow by 1.2 percent per year. Nonfarm employment, a measure of demand for nonfarm labor, is generally more volatile than the labor force, a measure of labor supply. The latter depends upon the forecast of population and labor force participation rate. The Census Bureau's middle series population projection is used as a basis for population growth for the AEO2005. Total population is expected to grow by 0.8 percent per year between 2003 and 2025, and the share of population over 65 is expected to increase over time. However, the share of the labor force in the population over 65 is also projected to increase in the forecast period.

Table 3. Growth in Gross Domestic Product, Nonfarm Employmemt and Productivity
(Percent per Year)

Assumptions	2003-2005	2005-2010	2010-2015	2015-2020	2020-2025	2003-2025
GDP (Billion Chain-Weighted $2000)						
High Growth	4.7	3.9	3.4	3.3	3.4	3.6
Reference	4.0	3.1	3.1	3.0	2.8	3.1
Low Growth	3.0	2.8	2.6	2.4	2.1	2.5
Nonfarm Employment						
High Growth	1.8	1.9	1.2	1.6	1.6	1.6
Reference	1.3	1.1	1.1	1.4	1.2	1.2
Low Growth	0.9	0.3	0.8	1.2	1.0	0.8
Productivity						
High Growth	3.4	2.8	2.9	2.3	2.2	2.6
Reference	2.8	2.6	2.5	1.8	1.8	2.2
Low Growth	2.2	2.4	2.0	1.3	1.4	1.8

Source: Energy Information Administration, *AEO2005* National Energy Modeling System runs: *AEO2005.d102004a; lm2005.d102004a; and hm2005.d102004a.*

To achieve the reference case's long-run 3.1 percent economic growth, there is an anticipated steady growth in labor productivity. The improvement in labor productivity reflects the positive effects of a growing capital stock as well as technological change over time. Nonfarm labor productivity is expected to diminish from its current high level to a more sustainable level between 1.8 and 2.6 percent for the remainder of the forecast period from 2005 through 2025. Business fixed investment as a share of nominal GDP is expected to grow over time. The resulting growth in the capital stock and the technology base of that capital stock helps to sustain productivity growth of 2.2 percent from the 2003 to 2025.

To reflect the uncertainty in forecasts of economic growth, the *AEO2005* forecasts use high and low economic growth cases along with the reference case to project the possible impacts on energy markets. The high economic growth case incorporates higher population, labor force and productivity growth rates than the reference case. Due to the higher productivity gains, inflation and interest rates are lower compared to the reference case. Investment, disposable income, and industrial production are increased. Economic output is projected to increase by 3.6 percent per year between 2003 and 2025. The low economic growth case assumes lower population, labor force, and productivity gains, with resulting higher prices and interest rates and lower industrial output growth. In the low economic growth case, economic output is expected to increase by 2.5 percent per year over the forecast horizon.

International Energy Module

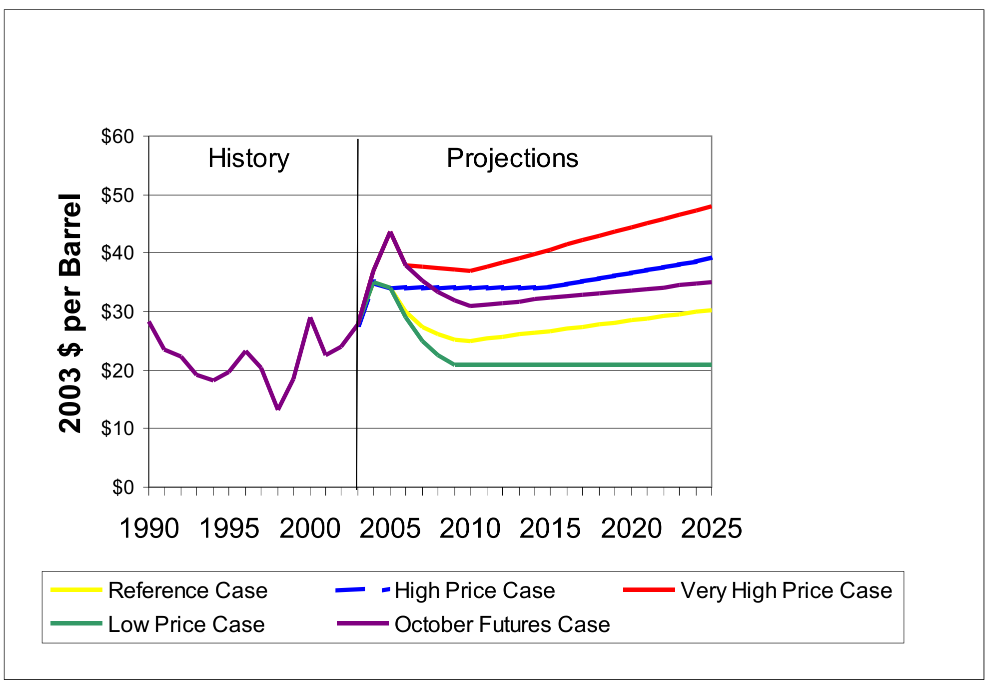
The International Energy Module determines changes in the world oil price and the supply prices of crude oils and petroleum products for import to the United States in response to changes in U.S. import requirements. A market clearing method is used to determine the price at which worldwide demand for oil is equal to the worldwide supply. The module determines new values for oil production and demand for regions outside the United States, along with a new world oil price that balances supply and demand in the international oil market. A detailed description of the International Energy Module is provided in the EIA publication, *Model Documentation Report: The International Energy Module of the National Energy Modeling System*, DOE/EIA-M071(03), (Washington, DC, May 2003).

Key Assumptions

The level of oil production by countries in the Organization of Petroleum Exporting Countries (OPEC) is a key factor influencing the world oil price projections incorporated into *AEO2004*. Non-OPEC production, worldwide regional economic growth rates and the associated regional demand for oil are additional factors affecting the world oil price.

The world oil price is the annual average U.S. refiner's acquisition cost of imported crude oil. Five distinct world oil price scenarios are represented in AEO2005, the low, reference, high, and very high world oil price cases as well as an October oil futures case. For the low, reference, high, and very high world oil price cases, prices reach $21, $30, $39, and $48 per barrel in 2025, respectively, in 2003 dollars. The reference case assumes that OPEC producers will continue to demonstrate a disciplined production approach to maintain prices within an announced target range of $25 to $31 per barrel in 2003 ollars. The low oil price case reflects a market where all oil production becomes more competitive and plentiful. The high oil price case could result from a more cohesive and market-assertive OPEC whose long-term goal might be to maintain a constant market share. The very high oil price case illustrates the possibility of sustained growth in oil prices. The October oil futures case implies that the annual oil price in 2005 will exceed the 2004 level and that prices for the remainder of the decade will not show as dramatic a decline as those in the reference case. Prices in the October oil futures case are based on quotes from the New York Mercantile Exchange (NYMEX) and reach $35 per barrel in 2025 (2003 dollars). The five price scenarios are shown in Figure 2.

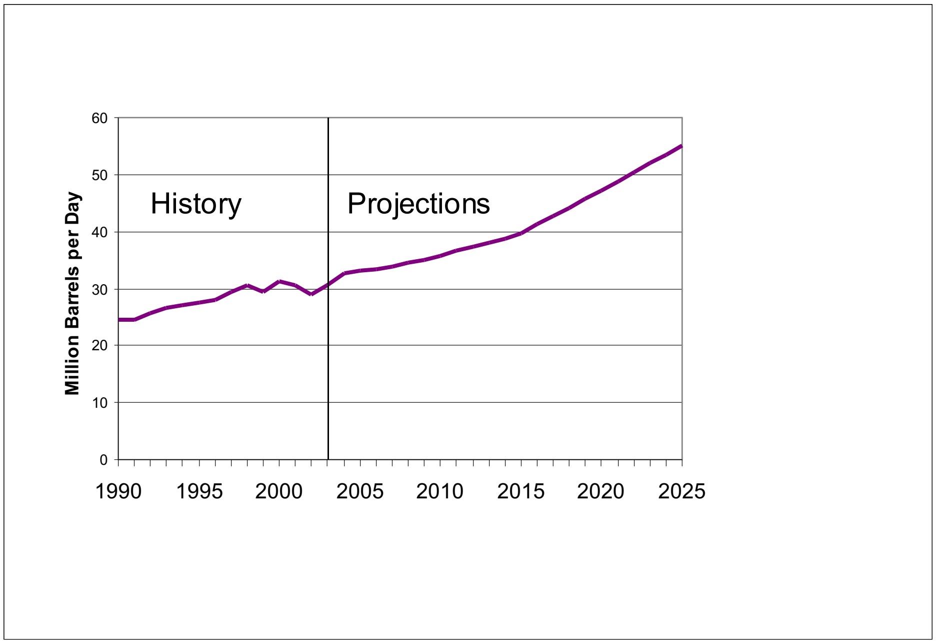
Figure 2. World Oil Prices in Five Cases, 1990-2025



Source: AEO2005 National Energy Modeling System runs AEO2005.D102004a, LW2005.D102004a, HW2005.D102004a, VHW2005.D120304a, and CF2005.D111104a.

OPEC oil production is assumed to increase throughout the reference case forecast, making OPEC the primary source for satisfying the worldwide increase in oil consumption expected over the forecast period (Figure 3). OPEC is assumed to be the source of additional production because its member nations hold a major portion of the world's total reserves—exceeding 869 billion barrels, almost 69 percent of the world's estimated total, at the end of 2003.[4] The reference case values for OPEC production are shown in Figure 3. Iraq is assumed to sell oil at approximately pre-conflict volumes until 2005. They are expected to increase production levels to over 3.5 million barrels per day by the end of the decade. By 2025, Iraq is expected to increase production capacity to more than 6 million barrels per day with likely investment help from foreign sources. Non-OPEC oil production is expected to increase by almost 1.3 percent per year over the forecast period, as advances in both exploration and extraction technologies result in an upward trend. The Non-OPEC production path for the reference case is shown in Figure 4.

Figure 3. OPEC Oil Production in the Reference Case, 1990-2025



OPEC = Organization of Petroleum Exporting Countries.

Source: Energy Information Administration. AEO2005 National Energy Modeling System run AEO2005.D102004a.

The non-U.S. oil production forecasts in the *AEO2005* begin with country-level assumptions regarding proved oil reserves. These reserve estimates are taken from PennWell Publishing Company's *Oil and Gas Journal* and are shown in Table 4.

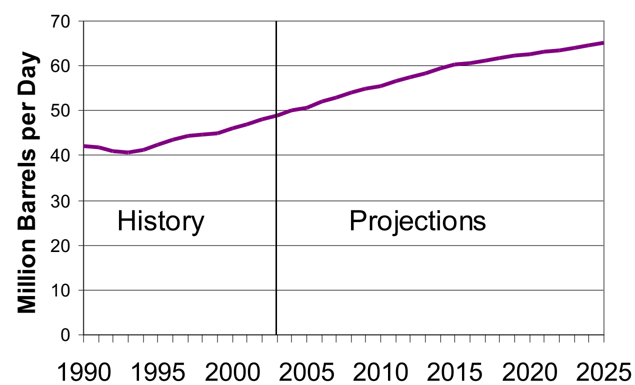
The assumed growth rates for GDP for various regions in the world are shown in Table 5. The same GDP growth rates are applied in all three world oil price cases. The GDP growth rate assumptions are from Global Insight's DRI-WEFA August 2003 World Economic Outlook.

The values for growth in oil demand calculated in the International Energy Module, which depend upon the oil price levels as well as the GDP growth rates, are shown in Table 6 for the reference case by regions.

Petroleum product imports are represented in the projections through a series of curves that present the quantity of each product that the world market is willing to supply to U.S. markets for each of the five Petroleum Administration for Defense Districts (PADDs). Curves are provided for twelve products: traditional gasoline (including aviation), reformulated gasoline, reformulated gasoline blending stocks for oxygenated blending (RBOB), traditional distillate fuel, low-sulfur No. 2 heating oil, low-sulfur diesel fuel, high- and low-sulfur residual fuel, jet fuel (including naphtha jet), liquefied petroleum gases, petrochemical feedstocks, and other petroleum products. The curves are calculated using the World Oil Refining Logistics

Demand (WORLD) Model.[5] The WORLD model uses as inputs worldwide demand for crude oil and petroleum products based on world oil prices that are close to the oil prices assumed for *AEO2005*, as well as values for worldwide petroleum production that are consistent with such prices. The refinery technology incorporated in the model is updated using the most recently available Oil & Gas Journal Database.[6]

Figure 4. Non-OPEC Oil Production in the Reference Case, 1990-2025



OPEC = Organization of Petroleum Exporting Countries.

Source: Energy Information Administration. AEO2005 National Energy Modeling System run AEO2005.D102004a.

Table 4. Worldwide Oil Reserves as of January 1, 2004
(Billion Barrels)

Region	Proved Oil Reserves
Western Hemisphere	316.1
Western‘Europe	18.2
Asia-Pacific	38.3
Eastern Europe and F.S.U.	79.3
Middle East	726.8
Africa	87.0
Total World	1265.8
Total OPEC	869.5

Source: PennWell Publishing Co., International Petroleum Encyclopedia, (Tulsa, OK, 2003).

Table 5. Average Annual Regional Gross Domestic Product Growth Rates, 2001-2025
(Percent per Year)

Region	Gross Domestic Product Growth
Industrialized Countries	2.4
Other Developing Countries	4.1
Eurasia	5.3
China	6.1
Former Soviet Union	4.2
Eastern Europe	3.9
Total World	3.0

Source: Global Insight's DRI-WEFA, World Economic Outlook, (Lexington, MA, August 2003).

Table 6. Average Annual Regional Growth Rates for Oil Demand in the Reference Case, 2002-2025
(Percent per Year)

Region	Oil Demand Growth
Industrialized Countries	1.2
Other Developing Countries	2.5
Eurasia	3.1
China	4.0
Former Soviet Union	2.1
Eastern Europe	1.7
Total World	1.9

Source: Energy Information Administration, *AEO2005* National Energy Modeling System run: aeo2005.d102004a.

Notes and Sources

[4] PennWell Publishing Co., International Petroleum Encyclopedia, (Tulsa, OK, 2004).

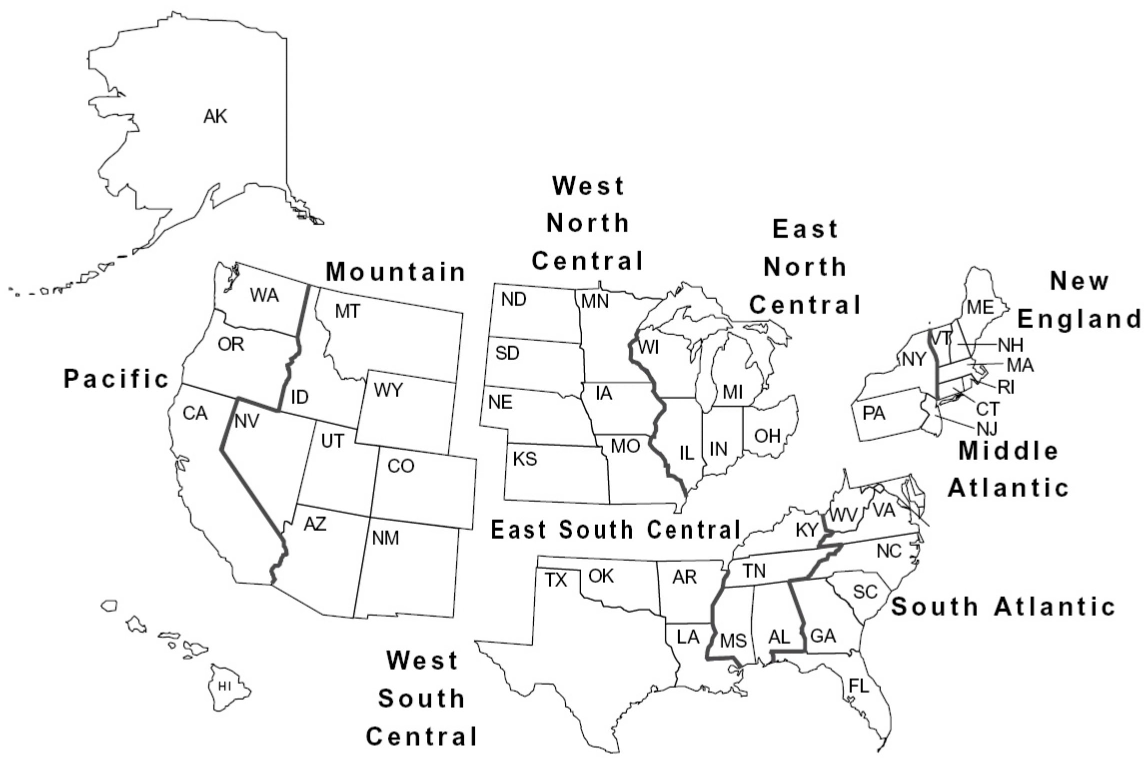
[5] EIA, EIA Model Documentation: World Oil Refining Logistics Demand Model, “WORLD” Reference Manual, DOE/EIA-M058, (Washington, DC, March 1994).

[6] Oil & Gas Journal, World Wide Refinery Survey, (data as of January 1, 2004).

Residential Demand Module

The NEMS Residential Demand Module forecasts future residential sector energy requirements based on projections of the number of households and the stock, efficiency, and intensity of use of energy-consuming equipment. The Residential Demand Module projections begin with a base year estimates of the housing stock, the types and numbers of energy-consuming appliances servicing the stock, and the "unit energy consumption" by appliance (or UEC—in million Btu per household per year). The projection process adds new housing units to the stock, determines the equipment installed in new units, retires existing housing units, and retires and replaces appliances. The primary exogenous drivers for the module are housing starts by type (single-family, multifamily and mobile homes) and Census Division and prices for each energy source for each of the nine Census Divisions (see Figure 5). The Residential Demand Module also requires projections of available equipment and their installed costs over the forecast

Figure 5. United States Census Divisions



Source:Energy Information Administration,Office of Integrated Analysis and Forecasting.

horizon. Over time, equipment efficiency tends to increase because of general technological advances and also because of Federal and/or state efficiency standards. As energy prices and available equipment changes over the forecast horizon, the module includes projected changes to the type and efficiency of equipment purchased as well as projected changes in the usage intensity of the equipment stock.

The end-use services for which equipment stocks are modeled include space conditioning (heating and cooling), water heating, refrigeration, freezers, dishwashers, clothes washers, lighting, furnace fans, cooking, and clothes drying. In addition to the major equipment-driven end-uses, the average energy consumption per household is projected for secondary heating, color televisions, personal computers, and other electric and nonelectric appliances. The module's output includes number of households, equipment stock, average equipment efficiencies, and energy consumed by service, fuel, and geographic location. The fuels represented are distillate fuel oil, liquefied petroleum gas, natural gas, kerosene, electricity, wood, geothermal, coal, and solar energy.

One of the implicit assumptions embodied in the Residential Demand Module is that, through 2025, there will be no radical changes in technology or consumer behavior. No new regulations of efficiency beyond those currently embodied in law or new government programs fostering efficiency improvements are assumed. Technologies which have not gained widespread acceptance today will generally not achieve significant penetration by 2025. Currently available technologies will evolve in both efficiency and cost. In general, at the same efficiency level, future technologies will be less expensive than those available today in real dollar terms. When choosing new or replacement technologies, consumers will behave similarly to the way they now behave. The intensity of end-uses will change moderately in response to price changes. Electric end uses will continue to expand, but at a decreasing rate.[7]

Key Assumptions

Housing Stock Submodule

A very important determinant of future energy consumption is the projected number of households. Base year estimates for 2001 are derived from the Energy Information Administration's (EIA) *Residential Energy Consumption Survey* (RECS) (Table 7). The forecast for occupied housing units is done separately for each Census Division. It is based on the combination of the previous year's surviving stock with projected housing starts provided by the NEMS Macroeconomic Activity Module. The housing stock submodule assumes a constant survival rate (the percentage of households which are present in the current forecast year, which were also present in the preceding year) for each type of housing unit; 99.7 percent for single-family units, 99.8 percent for multifamily units, and 97.5 percent for mobile home units. Projected fuel consumption is dependent not only on the projected number of housing units, but also on the type and geographic distribution of the houses. The intensity of space heating energy use varies greatly across the various climate zones in the United States. Also, fuel prevalence varies across the country—oil (distillate) is more frequently used as a heating fuel in the New England and Middle Atlantic Census Divisions than in the rest of the country, while natural gas dominates in the Midwest. An example of differences by housing type is the more prevalent use of liquefied petroleum gas in mobile homes relative to other housing types.

Table 7. 2001 Households

Census Division	Single-family Units	Multiple family Units	Mobile Home	Total Units
New England	3.397,357	2,046,038	116,755	5,560,15
Mid Atlantic	9,022,447	5,618,800	376,390	15,017,637
East North Central	12,620,969	4,323,007	721,652	17,665,629
West North Central	5,729,603	1,659,511	389,346	7,778,460
South Atlantic	14,551,319	5,122,081	1,863,493	21,536,893
East South Central	4,751,956	1,205,518	795,918	6,753,392
West South Central	8,305,719	2,685,452	908,105	11,899,276
Mountain	4,912,205	1,601,455	560,142	7,073,802
Pacific	10,440,297	4,670,139	636,826	15,747,262
United States	73,731,872	28,932,001	6,368,627	109,032,500

Source: U.S. Deoartment of Energy, Energy Information Administration, *2001 Residential Energy Consumption Survey and Global Insight Macroeconomic Model CTL0804,* modified by EIA.

Technology Choice Submodule

The key inputs for the Technology Choice Submodule are fuel prices by Census Division and characteristics of available equipment (installed cost, maintenance cost, efficiency, and equipment life). Fuel prices are determined by an equilibrium process which considers energy supplies and demands and are passed to this submodule from the integrating module of NEMS. Energy price, combined with equipment UEC (which is a function of efficiency), determines the operating costs of equipment. Equipment characteristics are exogenous to the model and are modified to reflect both Federal standards and anticipated changes in the market place. Table 8 lists capital cost and efficiency for selected residential appliances for the years 2002 and 2015.

Table 8. Installed Cost and Efficiency Ratings of Selected Equipment

Equipment Type	Relative Performance[1]	2003 Installed Cost ($2004)[2]	Efficiency[3]	2015 Installed Cost ($2004)[2]	Efficiency[3]	Approximate Hurdle Rate
Electric Heat Pump	Minimum	$3,800	10.0	$4,150	13.0	15%
	Best	$7,000	18.6	$7,000	18.6	
Natural Gas Furnace	Minimum	$1,500	0.80	$1,500	0.80	15%
	Best	$2,000	0.97	$2,000	0.97	
Room Air Conditioner	Minimum	$290	9.8	$290	9.8	140%
	Best	$760	11.7	$800	12.0	
Central Air Conditioner	Minimum	$2,000	10.0	$2,500	13.0	15%
	Best	$6,000	19.5	$6,000	19.5	
Refrigerator (23.9 cubic ft in adjusted volume)	Minimum	$600	510	$600	510	19%
	Best	$700	460	$650	400	
Electric Water Heater	Minimum	$354	0.86	$350	0.90	83%
	Best	$1,236	2.0	$1,800	2.4	
Solar Water Heater	N/A	$2,867	2.0	$2,533	2.0	83%

[1]Minimum performance refers to the lowest efficiency equipment available. Best refers to the highest efficiency equipment available.

[2]Installed costs are given in 2004 dollars in the original source document.

[3]Efficiency measurements vary by equipment type. Electric heat pumps and central air conditioners are rated for cooling performance using the Seasonal Energy Efficiency Ratio (SEER); natural gas furnaces are based on Annual Fuel Utilization Efficiency; room air conditioners are based on Energy Efficiency Ratio (EER); refrigerators are based on kilowatt-hours per year; and water heaters are based on Energy Factor (delivered Btu divided by input Btu).

Source: Navigant Consulting, *EIA Technology Forecast Updates*, Reference Number 117943, September 2004.

Table 9 provides the cost and performance parameters for representative distributed generation technologies. The *AEO2005* model also incorporates endogenous "learning" for the residential distributed generation technologies, allowing for declining technology costs as shipments increase. For fuel cell and photovoltaic systems, learning parameter assumptions for the *AEO2005* reference case result in a 13 percent reduction in capital costs each time the number of units shipped to the buildings sectors (residential and commercial) doubles.

The Residential Demand Module projects equipment purchases based on a nested choice methodology. The first stage of the choice methodology determines the fuel and technology to be used, the second stage determines the efficiency of the selected equipment type. The equipment choices for cooling, water heating, and cooking are linked to the space heating choice for new construction. Technology and fuel choice for replacement equipment uses a nested methodology similar to that for new construction, but includes (in addition to the capital and installation costs of the equipment), explicit costs for technology switching (e.g., costs for installing gas lines if switching from electricity or oil to gas, or costs for retrofitting air ducts if switching from electric resistance heat to central heating types). Also, for replacements, there is no linking of fuel choice for water heating and cooking as is done for new construction. Technology switching upon replacement is allowed for space heating, air conditioning, water heating, cooking and clothes drying.

Once the fuel and technology choice for a particular end use is determined, the second stage of the choice methodology determines efficiency. In any given year, there are several available prototypes of varying efficiency (minimum standard, medium low, medium high and highest efficiency). Efficiency choice is based on a functional form and coefficients which give greater or lesser importance to the installed capital cost (first cost) versus the operating cost. Generally, within a technology class, the higher the first cost, the lower the operating cost. For new construction, efficiency choices are made based on the costs of both the heating and cooling equipment and the building shell characteristics.

The parameters for the second stage efficiency choice are calibrated to the most recently available shipment data for the major residential appliances. Shipment efficiency data are obtained from industry associations which monitor shipments such as the Association of Home Appliance Manufacturers. Because of this calibration procedure, the model allows the relative importance of first cost versus operating cost to vary by general technology and fuel type (e.g., natural gas furnace, electric heat pump, electric central air conditioner, etc.). Once the model is calibrated, it is possible to calculate (approximately) the apparent

Table 9. Capital Cost and Performance Parameters of Residential Distributed Generation Technologies

Technology Type	Year of Introduction	Average Generating Capacity (kW)	Electrical Efficiency	Combined Efficiency (Elec. + Thermal)	Installed Capital Cost ($2003 per KW of Capacity)[1]	Service Life Years
Solar Photovoltaic	2000	2	0.14	N/A	$9,000	30
	2005	2	0.16	N/A	$8,200	30
	2010	2	0.18	N/A	$6,200	30
	2015	2	0.20	N/A	$4,534	30
	2025	2	0.22	N/A	$3,180	30
Fuel Cell	2000	10	0.30	0.696	$5,500	20
	2005	10	0.30	0.696	$5,500	20
	2010	10	0.30	0.696	$3,800	20
	2015	10	0.335	0.705	$3,000	20
	2025	10	0.335	0.717	$1,750	20

[1]Installed costs are given in 2003 dollars in the original source document.

Source: Solar Technology Specifications: *The Changing Face of Renewable Energy,* Navigant Consulting, June 2003 *PEM* 10KW Fuel Cells: *Gas-fired Distributed Generation Resource Technology Characterizations*, National Renewable Energy Laboratory, Draft final, August 2003.

discount rates based on the relative weight given to the operating cost savings versus the weight given to the higher cost of more efficient equipment. Hurdle rates in excess of 30 percent are common in the Residential Demand Module. The prevalence of such high apparent hurdle rates by consumers has led to the notion of the "efficiency gap" that is, there are many investments that could be made that provide rates of return in excess of residential borrowing rates (15 to 20 percent for example). There are several studies which document instances of apparent high discount rates.[8] Once equipment efficiencies for a technology and fuel are determined, the installed efficiency for its entire stock is calculated.

Appliance Stock Submodule

The Appliance Stock Submodule is an accounting framework which tracks the quantity and average efficiency of equipment by end use, technology, and fuel. It separately tracks equipment requirements for new construction and existing housing units. For existing units, this module calculates equipment which survives from previous years, allows certain end uses to further penetrate into the existing housing stock and calculates the total number of units required for replacement and further penetration. Air conditioning and clothes drying are the two end uses not considered to be "fully penetrated."

Once a piece of equipment enters into the stock, an accounting of its remaining life is begun. It is assumed that all appliances survive a minimum number of years after installation. A fraction of appliances are removed from the stock once they have survived for the minimum number of years. Between the minimum and maximum life expectancy, all appliances retire based on a linear decay function. For example, if an appliance has a minimum life of 5 years and a maximum life of 15 years, one tenth of the units (1 divided by 15 minus 5) are retired in each of years 6 through 15. It is further assumed that, when a house is retired from the stock, all of the equipment contained in that house retires as well; i.e., there is no secondhand market for this equipment. The assumptions concerning equipment lives are given in Table 10.

Fuel Consumption Submodule

Energy consumption is calculated by multiplying the vintage equipment stocks by their respective UECs. The UECs include adjustments for the average efficiency of the stock vintages, short term price elasticity of demand and "rebound" effects on usage (see discussion below), the size of new construction relative to the

Table 10. Minimum and Maximum Life Expectancies of Equipment

Equipment	Minimum Life	Maximum Life
Heat Pumps	7	21
Central Forced-Air Furnaces	10	25
Hydronic Space Heaters	20	30
Room Air Conditioners	8	16
Central Air Conditioners	7	21
Gas Water Heaters	4	14
Electric Water Heaters	5	22
Cooking Stoves	16	21
Clothes Dryers	11	20
Refrigerators	7	26
Freezers	11	31

Source: Lawrence Berkeley Laboratory, *Baseline Data for the Residential Sector and Development of a Residential Forecasting Database*, May 1994, and analysis of RECS 1997 data.

existing stock, people per household and shell efficiency and weather effects (space heating and cooling). The various levels of aggregated consumption (consumption by fuel, by service, etc.) are derived from these detailed equipment-specific calculations.

Equipment Efficiency

The average energy consumption of a particular technology is initially based on estimates derived from RECS 2001. Appliance efficiency is either derived from a long history of shipment data (e.g., the efficiency of conventional air-source heat pumps) or assumed based on engineering information concerning typical installed equipment (e.g., the efficiency of ground-source heat pumps). When the average efficiency is computed from shipment data, shipments going back as far as 20 to 30 years are combined with assumptions concerning equipment lifetimes. This allows for not only an average efficiency to be calculated, but also for equipment retirements to be vintaged—older equipment tends to be lower in efficiency and also tends to get retired before newer, more efficient equipment. Once equipment is retired, the Appliance Stock and Technology Choice Modules determine the efficiency of the replacement equipment. It is often the case that the retired equipment is replaced by substantially more efficient equipment.

As the stock efficiency changes over the simulation interval, energy consumption decreases in inverse proportion to efficiency. Also, as efficiency increases, the efficiency rebound effect (discussed below) will offset some of the reductions in energy consumption by increased demand for the end-use service. For example, if the stock average for electric heat pumps is now 10 percent more efficient than in 1997, then all else constant (weather, real energy prices, shell efficiency, etc.), energy consumption per heat pump would average about only 9 percent less.

Adjusting for the Size of Housing Units

Information derived from RECS 2001 indicates that new construction (post-1990) is on average roughly 26 percent larger than the existing stock of housing. Estimates for the size of each new home built in the projection period vary by type and region, and are determined by a log-trend forecast based on historical data from the Bureau of the Census.[9] For existing structures, it is assumed that about 1 percent of households that existed in 2001 add about 600 square feet to the heated floor space in each year of the projection period.[10] The energy consumption for space heating, air conditioning, and lighting is assumed to increase with the square footage of the structure. This results in an increase in the average size of the housing stock from 1,720 to 1,950 square feet from 2001 through 2025.

Adjusting for Weather and Climate

Weather in any given year always includes short-term deviations from the expected longer-term average (or climate). Recognition of the effect of weather on space heating and air conditioning is necessary to avoid inadvertently projecting abnormal weather conditions into the future. In the residential module, adjustments are made to space heating and air conditioning UECs by Census Division by their respective heating and cooling degree-days (HDD and CDD). A 10 percent increase in HDD would increase space heating consumption by 10 percent over what it would have otherwise been. Over the projection period, the residential module uses a 30-year average for heating and cooling degree - days by Census Division, adjusted by projections in state population shifts.

Short-Term Price Effect and Efficiency Rebound

It is assumed that energy consumption for a given end-use service is affected by the marginal cost of providing that service. That is, all else equal, a change in the price of a fuel will have an opposite, but less than proportional, effect on fuel consumption. The current value for the short-term elasticity parameter is -0.25.[11] This value implies that for a 1 percent increase in the price of a fuel, there will be a corresponding decrease in energy consumption of -0.25 percent. Another way of affecting the marginal cost of providing a service is through altered equipment efficiency. For example, a 10 percent increase in efficiency will reduce the cost of providing the end-use service by 10 percent. Based on the short-term efficiency rebound parameter, the demand for the service will rise by 1.5 percent (-10 percent multiplied by -0.15). Only space heating and cooling are assumed to be affected by both elasticities and the efficiency rebound effect.

Shell Efficiency

The shell integrity of the building envelope is an important determinant of the heating and cooling load for each type of household. In the NEMS Residential Demand Module, the shell integrity is represented by an index, which changes over time to reflect improvements in the building shell. The shell integrity index is dimensioned by vintage of house, type of house, fuel type, service (heating and cooling), and Census Division. The age, type, location, and type of heating fuel are important factors in determining the level of shell integrity. Housing units which heat with electricity tend to be better insulated than homes that use other fuels. The age of homes are classified by new (post-2001) and existing. Existing homes are characterized by the RECS 2001 survey and are assigned a shell index value based on the mix of homes that exist in the base year (2001). The improvement over time in the shell integrity of these homes is a function of two factors—an assumed annual efficiency improvement and improvements made when real fuel prices increase (no price-related adjustment is made when fuel prices fall). For new construction, building shell efficiency is determined by the relative costs and energy bill savings for several levels of heating and cooling equipment, in conjunction with the building shell attributes. The packages represented in NEMS range from homes that meet the International Energy Conservation Code (IECC)[12] to homes that exceed the IECC by 50 percent. Shell efficiency in new homes would increase over time if energy prices rise, or the cost of more efficient equipment falls.

Legislation and Other Federal Programs

Energy Policy Act of 1992 (EPACT)

The EPACT contains several policies which are designed to improve residential sector energy efficiency. The EPACT policies represented in the NEMS Residential Demand Module include the sections relating to window labeling programs, low-flow showerheads, and building codes. The impact of building codes is captured in the shell efficiency index for new buildings listed above. Other EPACT provisions, such as home energy efficiency ratings and energy-efficient mortgages, which allow home buyers to qualify for higher loan amounts if the home is energy-efficient, are voluntary, and their effects on residential energy consumption have not been estimated.

The window labeling program is designed to help consumers determine which windows are most energy efficient. These labels already exist for all major residential appliances. Based on analysis of RECS data, it is assumed that the window labeling program will decrease heating loads by 8 percent and cooling loads by 3 percent. Approximately 30 percent of the existing (pre-2002) housing stock is affected by this policy by 2025.

The low-flow showerhead program is designed to cut domestic hot water use for showers. It is assumed that these showerheads cut hot water use by 33 percent for shower use. Since showers account for approximately 30 percent of domestic hot water use, total hot water use decreases by 10 percent. It is further assumed that these showerheads are installed exclusively in new construction.

National Appliance Energy Conservation Act of 1987

The Technology Choice Submodule incorporates equipment standards established by the National Appliance Energy Conservation Act of 1987 (NAECA). Some of the NAECA standards implemented in the module include: a Seasonal Energy Efficiency Rating (SEER) of 10.0 for heat pumps increasing to 12.0 in 2006; an Annual Fuel Utilization Efficiency (energy output over energy input) of 0.78 for oil and gas furnaces; an Efficiency Factor of 0.86 for electric water heaters; increasing to .90 in 2004; and refrigerator standards that set consumption limits to 976 kilowatt-hours per year in 1990, 691 kilowatt-hours per year in 1993, and 510 kilowatt-hours per year in 2002.

Residential Technology Cases

In addition to the *AEO2005* reference case, three side cases were developed to examine the effect of equipment and building standards on residential energy use—a *2005 technology case,* a *best available technology case*, and a *high technology case*. These side cases were analyzed in stand-alone (not integrated with the supply modules) NEMS runs and thus do not include supply-responses to the altered residential consumption patterns of the two cases. *AEO2005* also analyzed *integrated 2005 technology* and *high technology cases*. The *integrated 2005 technology case* combines the *2005 technology cases* of the four end-use demand sectors, the *electricity low fossil technology case*, and the assumption of renewable technologies fixed at 2005 levels. The *integrated high technology case* uses the same approach, but for high technology.

The 2005 technology case assumes that all future equipment purchases are made based only on equipment available in 2005. This case further assumes that existing building shell efficiencies will not improve beyond 2005 levels. In the reference case, the 2025 housing stock shell efficiency is 10 percent higher than in 2002 for heating (5 percent for cooling).

The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than the reference case. Equipment assumptions were developed by engineering technology experts, considering the potential impact on technology given increased research and development into more advanced technologies.[13] In the *high technology case*, heating shell efficiency increases by 21 percent and cooling shell efficiency by 8 percent, relative to 2002.

The *best available technology case* assumes that all equipment purchases from 2005 forward are based on the highest available efficiency in the *high technology case* in a particular simulation year, disregarding the economic costs of such a case. This case is designed to show how much the choice of the highest-efficiency equipment could affect energy consumption. In this case, heating shell efficiency increases by 25 percent and cooling shell efficiency by 11 percent, relative to 2002.

Notes and Sources

[7] The Model Documentation Report contains additional details concerning model structure and operation. Refer to Energy Information Administration, Model Documentation Report: Residential Sector Demand Module of the National Energy Modeling System, DOE/EIA-M065(2005), (January 2005).

[8] Among the explanations often mentioned for observed high average implicit discount rates are: market failures, (i.e., cases where incentives are not properly aligned for markets to result in purchases based on energy economics alone); unmeasured technology costs (i.e., extra costs of adoption which are not included or difficult to measure like employee down-time); characteristics of efficient technologies viewed as less desirable than their less efficient alternatives (such as equipment noise levels or lighting quality characteristics); and the risk inherent in making irreversible investment decisions. Examples of market failures/barriers include: decision makers having less than complete information, cases where energy equipment decisions are made by parties not responsible for energy bills (e.g., landlord/tenants, builders/home buyers), discount horizons which are truncated (which might be caused by mean occupancy times that are less than the simple payback time and that could possibly be classified as an information failure), and lack of appropriate credit vehicles for making efficiency investments, to name a few. The use of high implicit discount rates in NEMS merely recognizes that such rates are typically found to apply to energy-efficiency investments.

[9] U.S. Bureau of Census, Series C25 Data from various years of publications.

[10] Sources: U.S. Bureau of Census, Annual Housing Survey 2001 and Professional Remodler, 2002 Home Remodeling Study.

[11] See DAHL, CAROL, *A Survey of Energy Demand Elasticities in Support of the Development of the NEMS*, October 1993.

[12] The IECC established guidelines for builders to meet specific targets concerning energy efficiency with respect to heating and cooling load.

[13] The high technology assumptions are based on Energy Information Administration, Technology Forecast Updates-Residential and Commercial Building technologies-Advanced Adoption Case (Navigant Consulting, September 2004).

Commercial Demand Module

The NEMS Commercial Sector Demand Module generates forecasts of commercial sector energy demand through 2025. The definition of the commercial sector is consistent with EIA's State Energy Data System (SEDS). That is, the commercial sector includes business establishments that are not engaged in transportation or in manufacturing or other types of industrial activity (e.g., agriculture, mining or construction). The bulk of commercial sector energy is consumed within buildings; however, street lights, pumps, bridges, and public services are also included if the establishment operating them is considered commercial. Since most of commercial energy consumption occurs in buildings, the commercial module relies on the data from the EIA Commercial Buildings Energy Consumption Survey (CBECS) for characterizing the commercial sector activity mix as well as the equipment stock and fuels consumed to provide end use services.[14]

The commercial module forecasts consumption by fuel[15] at the Census division level using prices from the NEMS energy supply modules, and macroeconomic variables from the NEMS Macroeconomic Activity Module (MAM), as well as external data sources (technology characterizations, for example). Energy demands are forecast for ten end-use services[16] for eleven building categories[17] in each of the nine Census divisions (see Figure 5). The model begins by developing forecasts of floorspace for the 99 building category and Census division combinations. Next, the ten end-use service demands required for the projected floorspace are developed. The electricity generation and water and space heating supplied by distributed generation and combined heat and power technologies are projected. Technologies are then chosen to meet the projected service demands for the seven major end uses.[18] Once technologies are chosen, the energy consumed by the equipment stock (both existing and purchased equipment) is developed to meet the projected end-use service demands.[19]

Key Assumptions

The key assumptions made by the commercial module are presented in terms of the flow of the calculations described above. The sections below summarize the assumptions in each of the commercial module submodules: floorspace, service demand, distributed generation, technology choice, and end-use consumption. The submodules are executed sequentially in the order presented, and the outputs of each submodule become the inputs to subsequently executed submodules. As a result, key forecast drivers for the floorspace submodule are also key drivers for the service demand submodule, and so on.

Floorspace Submodule

Floorspace is forecast by starting with the previous year's stock of floorspace and eliminating a portion to represent the age-related removal of buildings. Total floorspace is the sum of the surviving floorspace plus new additions to the stock derived from the MAM floorspace growth projection.[20]

Existing Floorspace and Attrition

Existing floorspace is based on the estimated floorspace reported in the *Commercial Buildings Energy Consumption Survey 1999* (Table 11). Over time, the 1999 stock is projected to decline as buildings are removed from service (floorspace attrition). Floorspace attrition is estimated by a logistic decay function, the shape of which is dependent upon the values of two parameters: average building lifetime and *gamma*. The average building lifetime refers to the median expected lifetime of a particular building type. The *gamma* parameter corresponds to the rate at which buildings retire near their median expected lifetime. The current values for the average building lifetime and *gamma* vary by building type as presented in Table 12.[21]

Table 11. 1999 Total Floorspace by Census Division and Principal Building Activity
(Millions of Square Feet)

	Assem-bly	Educa-tion	Food Sales	Food Service	Health Care	Lodging	Large Office	Small Office	Merc/ Service	Ware-house	Other	Total
New England	378	575	10	40	86	169	565	311	824	429	348	3,735
Middle Atlantic	944	1,139	212	182	291	315	1,094	490	1,801	1,314	844	8,625
East North Central	1,202	1,506	115	463	336	725	1,096	847	2,183	1,983	751	11,205
West North Central	864	744	58	95	176	215	560	555	1,227	782	281	5,556
South Atlantic	848	997	156	302	312	825	1,507	1,077	2,611	1,909	457	11,001
East South Central	781	438	101	166	103	467	331	395	1,288	963	187	5,220
West South Central	1,028	913	135	207	215	303	663	644	1,569	1,085	501	7,264
Mountain	680	758	103	104	113	545	458	389	586	520	322	4,579
Pacific	1,074	1,580	105	292	233	956	1,145	969	1,698	1,493	607	10,152
United States	7,798	8,651	994	1,851	1,865	4,521	7,418	5,678	13,786	10,477	4,298	67,338

Note: Totals may not equal sum of components due to independent rounding.

Source: Energy Information Administration, Commercial Buildings Energy Consumption Survey 1999 Public Use Data

Table 12. Floorspace Attrition Parameters

	Assem-bly	Educa-tion	Food Sales	Food Service	Health Care	Lodging	Large Office	Small Office	Merc/ Service	Ware-house	Other
Median Expected Lifetime (years)	54	66	52	52	48	52	58	58	52	66	54
gamma	2.2	3.0	1.6	1.9	2.3	2.2	1.7	1.6	2.4	1.9	2.5

Sources: Energy Information Administration, Commercial Buildings Energy Consumption Survey 1999, 1995, and 1992 Public Use Data, McGraw-Hill Construction Dodge Annual Starts - non residential building starts, and Journal of Business and Economic Statistics, April 1986, Vol. 4, No. 2.

New Construction Additions to Floorspace

The commercial module develops estimates of projected commercial floorspace additions by combining the surviving floorspace estimates with the total floorspace forecast from MAM. A total NEMS floorspace projection is calculated by applying the MAM assumed floorspace growth rate within each Census division and MAM building type to the corresponding NEMS Commercial Demand Module's building types based on the CBECS building type shares. The NEMS surviving floorspace from the previous year is then subtracted from the total NEMS floorspace projection for the current year to yield new floorspace additions.[22]

Service Demand Submodule

Once the building stock is projected, the Commercial Demand module develops a forecast of demand for energy-consuming services required for the projected floorspace. The module projects service demands for the following explicit end-use services: space heating, space cooling, ventilation, water heating, lighting, cooking, refrigeration, personal computer office equipment, and other office equipment.[23] The service demand intensity (SDI) is measured in thousand Btu of end-use service demand per square foot and differs across service, Census division and building type. The SDIs are based on a hybrid engineering and statistical approach of CBECS consumption data.[24] Projected service demand is the product of square feet and SDI for all end uses across the eleven building categories with adjustments for changes in shell efficiency for space heating and cooling.

Shell Efficiency

The shell integrity of the building envelope is an important determinant of the heating and cooling loads for each type of building. In the NEMS Commercial Demand Module, the shell efficiency is represented by an index, which changes over time to reflect improvements in the building shell. This index is dimensioned by building type and Census division and applies directly to heating. For cooling, the effects are computed from the index, but differ from heating effects, because of different marginal effects of shell integrity and because of internal building loads. In the *AEO2005* reference case, shell improvements for new buildings are up to 22 percent more efficient than the 1999 stock of similar buildings. Over the forecast horizon, new building shells improve in efficiency by 7 percent relative to their efficiency in 1999. For existing buildings, efficiency is assumed to increase by 5 percent over the 1999 stock average. The shell efficiency index affects the space heating and cooling service demand intensities causing changes in fuel consumed for these services as the shell integrity improves.

Distributed Generation and Combined Heat and Power

Nonutility power production applications within the commercial sector are currently concentrated in education, health care, office and warehouse buildings. Program driven installations of solar 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. Historical data from Form EIA-860, *Annual Electric Generator Report*, are used to derive electricity generation for 2000 through 2003 by Census division, building type and fuel. A forecast of distributed generation and combined heat and power (CHP) of electricity is developed based on the economic returns projected for distributed generation and CHP technologies. The model uses a detailed cash-flow approach to estimate the number of years required to achieve a cumulative positive cash flow (some technologies may never achieve a cumulative positive cash flow). Penetration assumptions for distributed generation and CHP technologies are a function of the estimated number of years required to achieve a positive cash flow. Table 13 provides the cost and performance parameters for representative distributed generation and CHP technologies.

The model also incorporates endogenous "learning" for new distributed generation and CHP technologies, allowing for declining technology costs as shipments increase. For fuel cell and photovoltaic systems, parameter assumptions for the *AEO2005* reference case result in a 13 percent reduction in capital costs each time the number of units shipped to the buildings sectors (residential and commercial) doubles. Doubling the number of microturbines shipped results in a 10 percent reduction in capital costs.

Technology Choice Submodule

The technology choice submodule develops projections of the results of the capital purchase decisions for equipment fueled by the three major fuels (electricity, natural gas, and distillate fuel). Capital purchase decisions are driven by assumptions concerning behavioral rule proportions and time preferences, described below, as well as projected fuel prices, average utilization of equipment (the capacity factors), relative technology capital costs, and operating and maintenance (O&M) costs.

Decision Types

In each forecast year, equipment is potentially purchased for three "decision types". Equipment must be purchased for newly added floorspace and to replace the portion of equipment in existing floorspace that is projected to wear out.[25] Equipment is also potentially purchased for retrofitting equipment that has become economically obsolete. The purchase of retrofit equipment occurs only if the annual operating costs of a current technology exceed the annualized capital and operating costs of a technology available as a retrofit candidate.

Behavioral Rules

The commercial module allows the use of three alternate assumptions about equipment choice behavior. These assumptions constrain the equipment selections to three choice sets, which are progressively more restrictive. The choice sets vary by decision type and building type:

Table 13. Capital Cost and Performance Parameters of Selected Commercial Distributed Generation Technologies

Technology Type	Year	Average Generating Capacity (kW)	Electrical Efficiency	Combined Efficiency (Elec.+Thermal)	Installed Capital Cost ($2003 per kW of Capacity)*	Service Life (Years)
Solar Photovoltaic	2003	25	0.14	N/A	$6,500	30
	2005	25	0.16	N/A	$6,000	30
	2010	25	0.18	N/A	$4,750	30
	2015	25	0.20	N/A	$3,779	30
	2020	25	0.22	N/A	$3,178	30
	2025	25	0.22	N/A	$2,650	30
Fuel Cell	2003	200	0.36	0.72	$5,200	20
	2005	200	0.36	0.72	$5,200	20
	2010	200	0.49	0.72	$2,500	20
	2015	200	0.50	0.72	$2,150	20
	2020	200	0.51	0.72	$1,800	20
	2025	200	0.52	0.73	$1,450	20
Natural Gas Engine	2003	200	0.31	0.77	$1,160	20
	2005	200	0.32	0.77	$1,130	20
	2010	200	0.33	0.77	$1,030	20
	2015	200	0.33	0.78	$ 980	20
	2020	200	0.34	0.78	$ 930	20
	2025	200	0.34	0.79	$ 915	20
Oil-Fired Engine	2003	200	0.31	0.83	$1,320	20
	2006	200	0.31	0.82	$1,240	20
	2010	200	0.31	0.82	$1.150	20
	2015	200	0.31	0.81	$1,040	20
	2020	200	0.31	0.81	$ 990	20
	2025	200	0.31	0.81	$ 990	20
Natural Gas Turbine	2003	1000	0.22	0.65	$1,910	20
	2005	1000	0.23	0.66	$1,809	20
	2010	1000	0.24	0.67	$1,679	20
	2015	1000	0.26	0.68	$1,623	20
	2020	1000	0.27	0.69	$1,567	20
	2025	1000	0.28	0.70	$1,539	20
Natural Gas Micro Turbine	2003	200	0.25	0.61	$1,926	20
	2005	200	0.30	0.63	$1,620	20
	2010	200	0.36	0.63	$1,415	20
	2015	200	0.37	0.64	$1,143	20
	2020	200	0.38	0.65	$ 870	20
	2025	200	0.39	0.68	$ 818	20

*Installed costs are given in 2003 dollars in the original source document.

Sources: National Renewable Energy Laboratory, *Gas-Fired Distributed Energy Resource Technology Characterizations: Reference Number NREL/TP-620-34783,* November 2003, Navigant Consulting, Inc., *The Changing Face of Renewable Energy*, public study (Navigant Consulting, June 2003), and ONSITE SYCOM Energy Corporation, *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector*, (Washington, DC, January 2000).

- **Unrestricted Choice Behavior -** This rule assumes that commercial consumers consider *all* types of equipment that meet a given service, across all fuels, when faced with a capital purchase decision.

- **Same Fuel Behavior -** This rule restricts the capital purchase decision to the set of technologies that consume the *same fuel* that currently meets the decision maker's service demand.

- **Same Technology Behavior -** Under this rule, commercial consumers consider only the available models of the *same technology and fuel* that currently meet service demand, when facing a capital stock decision.

Under any of the above three behavior rules, equipment that meets the service at the lowest annualized lifecycle cost is chosen. Table 14 illustrates the proportions of floorspace subject to the different behavior rules for space heating technology choices in large office buildings.

Table 14. Assumed Behavior Rules for Choosing Space Heating Equipment in Large Office Buildings
(Percent)

	Unrestricted	Same Fuel	Same Technology	Total
New Equipment Decision	21	30	49	100
Replacement Decision	8	35	57	100
Retrofit Decision	0	5	95	100

Source: Energy Information Administration, *Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M066(2005) (March 2005).

Time Preferences

The time preferences of owners of commercial buildings are assumed to be distributed among seven alternate time preference premiums (Table 15). Adding the time preference premiums to the 10-year Treasury Bill rate from MAM results in implicit discount rates, also known as hurdle rates, applicable to the assumed proportions of commercial floorspace. The effect of the use of this distribution of discount rates is to prevent a single technology from dominating purchase decisions in the lifecycle cost comparisons. The distribution used for *AEO2005* assigns some floorspace a very high discount or hurdle rate to simulate floorspace which will never retrofit existing equipment and which will only purchase equipment with the lowest capital cost. Discount rates for the remaining six segments of the distribution get progressively lower, simulating increased sensitivity to the fuel costs of the equipment that is purchased. The proportion of floorspace assumed for the 0.0 time preference premium represents an estimate of the Federally owned commercial floorspace that is subject to purchase decisions in a given year. In accordance with Executive Order 13123 signed in June 1999, the Federal sector uses a rate comparable to the 10-year Treasury Bill rate when making purchase decisions.

Table 15. Assumed Distribution of Time Preference Premiums
(Percent)

Proportion of Floorspace-All Services Except Lighting	Proportion of Floorspace-Lighting	Time Preference Premium
27.0	27.0	1000.0
25.4	25.4	152.9
20.4	20.4	55.4
16.2	16.2	30.9
10.0	8.5	19.9
0.8	2.3	13.6
0.2	0.2	0.0
100.0	100.0	--

Source: Energy Information Administration, *Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M066(2005) (March 2005).

The distribution of hurdle rates used in the commercial module is also affected by changes in fuel prices. If a fuel's price rises relative to its price in the base year (1999), the nonfinancial portion of each hurdle rate in the distribution decreases to reflect an increase in the relative importance of fuel costs, expected in an environment of rising prices. Parameter assumptions for *AEO2005* result in a 30 percent reduction in the nonfinancial portion of a hurdle rate if the fuel price doubles. If the time preference premium input by the model user results in a hurdle rate below the assumed financial discount rate for the commercial sector, 15 percent, with base year fuel prices (such as the rate given in Table 15 for the Federal sector), no response to increasing fuel prices is assumed.

Technology Characterization Database

The technology characterization database organizes all relevant technology data by end use, fuel, and Census division. Equipment is identified in the database by a technology index as well as a vintage index, the index of the fuel it consumes, the index of the service it provides, its initial market share, the Census division index for which the entry under consideration applies, its efficiency (or coefficient of performance or efficacy in the case of lighting equipment), installed capital cost per unit of service demand satisfied, operating and maintenance cost per unit of service demand satisfied, average service life, year of initial availability, and last year available for purchase. Equipment may only be selected to satisfy service demand if the year in which the decision is made falls within the window of availability. Equipment acquired prior to the lapse of its availability continues to be treated as part of the existing stock and is subject to replacement or retrofitting. This flexibility in limiting equipment availability allows the direct modeling of equipment efficiency standards. Table 16 provides a sample of the technology data for space heating in the New England Census division.

Table 16. Capital Cost and Efficiency Ratings of Selected Commercial Space Heating Equipment[1]

Equipment Type	Vintage	Efficiency[2]	Capital Cost ($2001 per Mbtu/hour) [3]	Maintenance Cost ($2001 per Mbtu/hour) [3]	Service Life (Years)
Electric Heat Pump	Current Standard	6.8	$81.39	$3.33	14
	2000- typical	7.5	$97.92	$3.33	14
	2000- high efficiency	9.8	$155.56	$3.33	14
	2005- typical	7.5	$97.22	$3.33	14
	2005- high efficiency	9.8	$155.56	$3.33	14
	2010 - typical	7.5	$97.22	$3.33	14
	2010 - high efficiency	9.8	$155.56	$3.33	14
	2020 - typical	7.8	$97.22	$3.33	14
	2020 - high efficiency	10.0	$150.00	$3.33	14
Ground-Source Heat Pump	2000- typical	3.4	$187.50	$1.46	20
	2000- high efficiency	4.0	$229.17	$1.46	20
	2005- typical	3.4	$166.67	$1.46	20
	2005- high efficiency	4.3	$229.17	$1.46	20
	2010- typical	3.4	$166.67	$1.46	20
	2010 - high efficiency	4.3	$208.33	$1.46	20
	2020 - typical	3.8	$166.67	$1.46	20
	2020 - high efficiency	4.5	$197.92	$1.46	20
Electric Boiler	Current Standard	0.98	$21.83	$0.14	21
Packaged Electric	1995	0.93	$19.77	$3.49	18
Natural Gas Furnace	Current Standard	0.80	$9.11	$1.00	15
	2000 - high efficiency	0.92	$14.82	$0.88	15
	2010 - typical	0.81	$8.70	$0.96	15
Natural Gas Boiler	Current Standard	0.80	$18.11	$0.55	25
	2000 - high efficiency	0.87	$33.82	$0.69	25
	2005 - typical	0.81	$17.87	$0.55	25
	2005 - high efficiency	0.90	$31.68	$0.67	25
Natural Gas Heat Pump	2005 - absorption	1.4	$173.61	$4.17	15
Distillate Oil Furnace	Current Standard	0.81	$14.25	$1.00	15
	2000	0.86	$23.75	$1.00	15
	2010	0.89	$22.69	$1.00	15
Distillate Oil Boiler	Current Standard	0.83	$15.76	$0.13	20
	2000 - high efficiency	0.88	$18.83	$0.12	20
	2005 - typical	0.83	$15.76	$013	20
	2005- high efficiency	0.88	$18.83	$0.12	20

[1]Equipment listed is for the New England Census division, but is also representative of the technology data for the rest of the U.S. See the source referenced below for the complete set of technology data.

[2]Efficiency measurements vary by equipment type. Electric air-source heat pumps are rated for heating performance using the Heating Seasonal Performance Factor (HSPF); natural gas and distillate furnaces are based on Thermal Efficiency; ground source and natural gas heat pumps are rated on coefficient of performance; and boilers are based on combustion efficiency.

[3]Capital and maintenance costs are given in 2004 dollars.

Source: Energy Information Administration, “EIA - Technology Forecast Updates - Residential and Commercial Building Technologies - Reference Case”, Navigant Consulting, Inc., Reference Number 117943, September 2004.

Starting with *AEO2000*, an option to allow endogenous price-induced technological change has been included in the determination of equipment costs and availability for the menu of equipment. This concept allows future technologies faster diffusion into the market place if fuel prices increase markedly for a sustained period of time. Although no price-induced change would have been expected using *AEO2005* reference case fuel prices, the option was not exercised for the *AEO2005* model runs.

End-Use Consumption Submodule

The end-use consumption submodule calculates the consumption of each of the three major fuels for the ten end-use services plus fuel consumption for combined heat and power and district services. For the ten end-use services, energy consumption is calculated as the end-use service demand met by a particular type of equipment divided by its efficiency and summed over all existing equipment types. This calculation includes dimensions for Census division, building type, and fuel. Consumption of the five minor fuels is forecast based on historical trends.

Equipment Efficiency

The average energy consumption of a particular appliance is based initially on estimates derived from CBECS 1999. As the stock efficiency changes over the model simulation, energy consumption decreases nearly, but not quite proportionally to the efficiency increase. The difference is due to the calculation of efficiency using the harmonic average and also the efficiency rebound effect discussed below. For example, if on average, electric heat pumps are now 10 percent more efficient than in 1999, then all else constant (weather, real energy prices, shell efficiency, etc.), energy consumption per heat pump would now average about 9 percent less. The Service Demand and Technology Choice Submodules together determine the average efficiency of the stocks used in adjusting the initial average energy consumption.

Adjusting for Weather and Climate

Weather in any given year always includes short-term deviations from the expected longer-term average (or climate). Recognition of the effect of weather on space heating and air conditioning is necessary to avoid projecting abnormal weather conditions into the future. In the commercial module, proportionate adjustments are made to space heating and air conditioning demand by Census division. These adjustments are based on National Oceanic and Atmospheric Administration (NOAA) data for Heating Degree Days (HDD) and Cooling Degree Days (CDD). A 10 percent increase in HDD would increase space heating consumption by 10 percent over what it would have been otherwise. The commercial module uses a 30-year average for HDD and CDD by Census division, adjusted over the projection period by projections for state population shifts.

Short-Term Price Effect and Efficiency Rebound

It is assumed that energy consumption for a given end-use service is affected by the marginal cost of providing that service. That is, all else equal, a change in the price of a fuel will have an inverse, but less than proportional, effect on fuel consumption. The current value for the short-term price elasticity parameter is -0.25 for all major end uses except refrigeration. A value of -0.1 is currently used for commercial refrigeration. A value of -0.05 is currently used for PC and non-PC office equipment and other minor uses of electricity. For example, for lighting this value implies that for a 1 percent increase in the price of a fuel, there will be a corresponding decrease in energy consumption of 0.25 percent. Another way of affecting the marginal cost of providing a service is through equipment efficiency. As equipment efficiency changes over time, so will the marginal cost of providing the end-use service. For example, a 10 percent increase in efficiency will reduce the cost of providing the service by 10 percent. The short-term elasticity parameter for efficiency rebound effects is -0.15 for affected end uses; therefore, the demand for the service will rise by 1.5 percent (-10 percent x -0.15). Currently, all services are affected by the short-term price effect and services affected by efficiency rebound are space heating and cooling, water heating, ventilation and lighting.

Legislation and Other Federal Programs

Energy Policy Act of 1992 (EPACT)

A key assumption incorporated in the technology selection process is that the equipment efficiency standards described in the EPACT constrain minimum equipment efficiencies. The effects of standards are modeled by modifying the technology database to eliminate equipment that no longer meets minimum efficiency requirements. For standards effective January 1, 1994, affected equipment includes electric heat pumps—minimum heating system performance factor of 6.8, gas and oil-fired boilers—minimum combustion efficiency of 0.8 and 0.83, respectively, gas and oil-fired furnaces—minimum thermal efficiency of 0.8 and 0.81, respectively, fluorescent lighting—minimum efficacy of 75 lumens per watt, incandescent lighting—minimum efficacy of 16.9 lumens per watt, air-cooled air conditioners—minimum energy efficiency ratio of 8.9, electric water heaters—minimum energy factor of 0.85, and gas and oil water heaters—minimum thermal efficiency of 0.78. Updated standards are effective October 29, 2003 for gas water heaters—minimum thermal efficiency of 0.8. An additional standard affecting fluorescent lamp ballasts becomes effective April 1, 2005. The standard mandates electronic ballasts with a minimum ballast efficacy factor of 1.17 for 4-foot, 2-lamp ballasts and 0.63 for 8-foot, 2-lamp ballasts.

Energy Efficiency Programs

Several energy efficiency programs affect the commercial sector. These programs are designed to stimulate investment in more efficient building shells and equipment for heating, cooling, lighting, and other end uses. The commercial module includes several features that allow projected efficiency to increase in response to voluntary programs (e.g., the distribution of time preference premiums and shell efficiency parameters). Retrofits of equipment for space heating, air conditioning and lighting are incorporated in the distribution of premiums given in Table 14. Also the shell efficiency of new and existing buildings is assumed to increase from 1999 through 2025. Shells for new buildings increase in efficiency by 7 percent over this period, while shells for existing buildings increase in efficiency by 5 percent.

Commercial Technology Cases and Alternative Renewables Cases

In addition to the *AEO2005* reference case, three side cases were developed to examine the effect of equipment and building standards on commercial energy use—a *2005 technology case*, a *high technology case*, and a *best available technology case*. These side cases were analyzed in stand-alone (not integrated with the NEMS demand and supply modules) buildings (residential and commercial) modules runs and thus do not include supply-responses to the altered commercial consumption patterns of the three cases. *AEO2005* also analyzed an *integrated high technology case*, which combines the *high technology cases* of the four end-use demand sectors, the *electricity high fossil technology case,* the *advanced nuclear cost case*, and the *high renewables case,* and an *integrated 2005 technology case*, which combines the *2005 technology cases* of the four end-use demand sectors, the *electricity low fossil technology case*, and the *low renewables case*.

The *2005 technology case* assumes that all future equipment purchases are made based only on equipment available in 2005. This case assumes building shell efficiency to be fixed at 2005 levels. In the reference case, existing building shells are allowed to increase in efficiency by 5 percent over 1999 levels, and new building shells improve by 7 percent by 2025 relative to new buildings in 1999.

The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than the reference case. Equipment assumptions were developed by engineering technology experts, considering the potential impact on technology given increased research and development into more advanced technologies. In the *high technology case*, building shell efficiencies are assumed to improve 25 percent more than in the reference case after 2005. Existing building shells, therefore, increase by 6.25 percent relative to 1999 levels and new building shells by 8.75 percent relative to their efficiency in 1999 by 2025.

The *best available technology case* assumes that all equipment purchases after 2005 are based on the highest available efficiency in the high technology case in a particular simulation year, disregarding the economic costs of such a case. It is designed to show how much the choice of the highest-efficiency equipment could affect energy consumption. Shell efficiencies in this case are assumed to improve 50 percent more than in the reference case after 2005, i.e., existing shells increase by 7.5 percent relative to 1999 levels and new building shells by 10.5 percent relative to their efficiency in 1999 by 2025.

Fuel shares, where appropriate for a given end use, are allowed to change in the technology cases as the available technologies from each technology type compete to serve certain segments of the commercial floorspace market. For example, in the *best available technology case*, the most efficient gas furnace technology competes with the most efficient electric heat pump technology. This contrasts with the reference case, in which, a greater number of technologies for each fuel with varying efficiencies all compete to serve the heating end use. In general, the fuel choice will be affected as the available choices are constrained or expanded, and will thus differ across the cases.

Two integrated cases that focus on electricity generation incorporate alternative assumptions for non-hydro renewable energy technologies, including residential and commercial photovoltaic systems. In each of these cases, assumptions regarding non-renewable technologies are not changed from the reference case.

The *low renewables case* assumes that the cost and performance characteristics for residential and commercial photovoltaic systems remain fixed at 2005 levels through the forecast horizon.

The *high renewables case* assumes that costs for residential and commercial photovoltaic systems are 10 percent lower than reference case cost estimates by 2025.

Notes and Sources

[14] Energy Information Administration, 1999 Commercial Buildings Energy Consumption Survey (CBECS) Public Use Files, web site www.eia.doe.gov/emeu/cbecs/1999publicuse/99microdat.html.

[15] The fuels accounted for by the commercial module are electricity, natural gas, distillate fuel oil, residual fuel oil, liquefied petroleum gas (LPG), coal, motor gasoline, and kerosene. Current commercial use of biomass (wood, Municipal solid waste) is also included. In addition to these fuels the use of solar energy is projected based on an exogenous forecast of projected solar photovoltaic system installations under the Million Solar Roofs program, State and local incentive programs, and the potential endogenous penetration of solar photovoltaic systems and solar thermal water heaters.

[16] The end-use services in the commercial module are heating, cooling, water heating, ventilation, cooking, lighting, refrigeration, PC and non-PC office equipment and a category denoted other to account for all other minor end uses.

[17] The 11 building categories are assembly, education, food sales, food services, health care, lodging, large offices, small offices, mercantile/services, warehouse and other.

[18] Minor end uses are modeled based on penetration rates and efficiency trends.

[19] The detailed documentation of the commercial module contains additional details concerning model structure and operation. Refer to Energy Information Administration, Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System, DOE/EIA M066(2005), (March 2005).

[20] The commercial floorspace equations of the Macroeconomic Activity Model are estimated using the F.W. Dodge Statistics and Forecasts Group database of historical floorspace estimates. The F.W. Dodge estimate for commercial floorspace in the U.S. is approximately 20 percent lower than the estimate obtained from the CBECS used for the Commercial module. See F.W. Dodge, Building Stock Database Methodology and 1991 Results, Construction Statistics and Forecasts, F.W. Dodge, McGraw-Hill.

[21] The commercial module performs attrition for 9 vintages of floorspace developed from the CBECS 1999 stock estimate and historical floorspace additions data from F.W. Dodge data.

[22] In the event that the computation of additions produce a negative value for a specific building type, it is assumed to be zero.

[23] "Other office equipment" includes copiers, fax machines, typewriters, cash registers, mainframe computers, and other miscellaneous office equipment. A tenth category denoted other includes equipment such as elevators, medical, and other laboratory equipment, communications equipment, security equipment, transformers and miscellaneous electrical appliances. Commercial energy consumed outside of buildings and for combined heat and power is also included in the "other" category.

[24] Based on updated estimates using CBECS 1999 building-level consumption data and CBECS 1995 end-use-level consumption data and the methodology described in Estimation of Energy End-Use Intensities, web site www.eia.doe.gov/emeu/cbecs/tech_end_use.html.

[25] The proportion of equipment retiring is inversely related to the equipment life.

Industrial Demand Module

The NEMS Industrial Demand Module estimates energy consumption by energy source (fuels and feedstocks) for 9 manufacturing and 6 nonmanufacturing industries. The manufacturing industries are further subdivided into the energy-intensive manufacturing industries and nonenergy-intensive manufacturing industries. The manufacturing industries are modeled through the use of a detailed process flow or end use accounting procedure, whereas the nonmanufacturing industries are modeled with substantially less detail (Table 17). The Industrial Demand Module forecasts energy consumption at the four Census region level (see Figure 5); energy consumption at the Census Division level is estimated by allocating the Census region forecast using the SEDS[26] data.

Table 17. Industry Categories

Energy-Intensive Manufacturing		Nonenergy-Intensive Manufacturing		Nonmanufacturing Industries	
Food Products	(NAICS 311)	Metal-Based Durables	(NAICS 332-336)	Agricultural Production -Crops	(NAICS 111)
Paper and Allied Products	(NAICS 322)	Balance of Manufacturing	(all remaining manufacturing NAICS)	Other Agriculture Including Livestock	(NAICS 112-115)
Bulk Chemicals				Coal Mining	(NAICS 2121)
Inorganic	(NAICS 32512 to 32518)				
Organic	(NAICS 32511, 32519)				
Resins	(NAICS 3252)				
Agricultural	(NAICS 3253				
Glass and Glass Products	(NAICS 3272)			Oil and Gas Extraction	(NAICS 211)
Cement	(NAICS 32731)			Metal and Other Nonmetallic Mining	(NAICS 2122-2123)
Iron and Steel	(NAICS 3311-3312)			Construction	(NAICS 233-235)
Aluminum	(NAICS 3313)				

NAICS = North American Industry Classification System.

Source: Office of Management and Budget, North American Industry Classification System (NAICS) - United States (Springfield, VA, National Technical Information Service).

The energy-intensive industries (food and kindred products, paper and allied products, bulk chemicals, glass and glass products, hydraulic cement, blast furnace and basic steel products, and aluminum) are modeled in considerable detail. Each industry is modeled as three separate but interrelated components consisting of the Process Assembly (PA) Component, the Buildings Component (BLD), and the Boiler/Steam/Cogeneration (BSC) Component. The BSC Component satisfies the steam demand from the PA and BLD Components. In some industries, the PA Component produces byproducts that are consumed in the BSC Component. For the manufacturing industries, the PA Component is separated into the major production processes or end uses.

Petroleum refining (North American Industry Classification System 32411) is modeled in detail in the Petroleum Market Module of NEMS, and the projected energy consumption is included in the manufacturing total. Forecasts of refining energy use, and lease and plant fuel and fuels consumed in cogeneration in the oil and gas extraction industry (North American Industry Classification System 211) are exogenous to the Industrial Demand Module, but endogenous to the NEMS modeling system.

Key Assumptions

The NEMS Industrial Demand Module primarily uses a bottom-up process modeling approach. An energy accounting framework traces energy flows from fuels to the industry's output. An important assumption in the development of this system is the use of 1998 baseline Unit Energy Consumption (UEC) estimates based on analysis of the Manufacturing Energy Consumption Survey (MECS) 1998.[27] The UECs represent the energy required to produce one unit of the industry's output. The output may be defined in terms of physical units (e.g., tons of steel) or in terms of the dollar value of shipments.

The module depicts the manufacturing industries (apart from petroleum refining, which is modeled in the Petroleum Market Module of NEMS) with a detailed process flow or end use approach. The dominant process technologies are characterized by a combination of unit energy consumption estimates and "technology possibility curves." The technology possibility curves indicate the energy intensity of new and existing stock relative to the 1998 stock over time. Rates of energy efficiency improvement assumed for new and existing plants vary by industry and process. These assumed rates were developed using professional engineering judgments regarding the energy characteristics, year of availability, and rate of market adoption of new process technologies.

Process/Assembly Component

The PA Component models each major manufacturing production step or end use for the manufacturing industries. The throughput production for each process step is computed as well as the energy required to produce it.

Within this component, the UECs are adjusted based on the technology possibility curves for each step. For example, state-of-the-art additions to waste fiber pulping capacity in 1998 are assumed to require only 93 percent as much energy as does the average existing plant (Table 18). The technology possibility curve is a means of embodying assumptions regarding new technology adoption in the manufacturing industry and the associated increased energy efficiency of capital without characterizing individual technologies. To some extent, all industries will increase the energy efficiency of their process and assembly steps. The reasons for the increased efficiency are not likely to be directly attributable to changing energy prices but due to other exogenous factors. Since the exact nature of the technology improvement is too uncertain to model in detail, the module employs a technology possibility curve to characterize the bundle of technologies available for each process step.

Fuel shares for process and assembly energy use in the manufacturing industries[28] are adjusted for changes in relative fuel prices. In each industry, two logit fuel-sharing equations are applied to revise the initial fuel shares obtained from the process-assembly component. The resharing does not affect the industry's total energy use, only the fuel shares. The methodology adjusts total fuel shares across all process stages and vintages of equipment to account for aggregate market response to changes in relative fuel prices.

The fuel share adjustments are done in two stages. The first stage determines the fuel shares of electricity and nonelectric energy. (The non-electric energy group excludes boiler fuel and feedstocks.) The second stage determines the fossil fuel shares of nonelectric energy. In each stage, a new fuel-group share, $NEWSHR_i$, is established as a function of the initial, default fuel-group shares, $DEFLTSHR_j$ and fuel-group prices indices, $PRCRAT_i$. The $DEFLTSHR_i$ are the base year shares. The price indices are the ratio of the current year price to the base year price, in real dollars.

The form of the equation results in unchanged fuel shares when the price indices are all 1, or unchanged from their 1998 levels. The implied own-price elasticity of demand is about -0.1.

Byproducts produced in the PA Component serve as fuels for the BSC Component. In the industrial module, byproducts are assumed to be consumed before purchased fuel.

Table 18. Coefficients for Technology Possibility Curve

Industry/Process Unit	Existing Facilities		New Facilities		
	REI 2025[1]	TPC[2]	REI 1998[3]	REI 2025[4]	TPC[2]
Food Products					
Process Heating	0.900	-0.0039	0.900	0.800	-0.0044
Process Cooling	0.876	-0.0049	0.850	0.750	-0.0046
Other	0.915	-0.0033	0.915	0.810	-0.0045
Paper & Allied Products					
Wood Preparation	0.922	-0.0030	0.873	0.845	-0.0012
Waste Pulping	0.942	-0.0022	0.936	0.882	-0.0022
Mechanical Pulping	0.917	-0.0032	0.868	0.834	-0.0015
Semi-chemical	0.873	-0.0050	0.876	0.747	-0.0059
Kraft, Sulfite, misc. Chemicals	0.816	-0.0075	0.876	0.632	-0.0121
Bleaching	0.871	-0.0051	0.900	0.742	-0.0071
Paper Making	0.796	-0.0084	0.900	0.592	-0.0154
Bulk Chemicals					
Process Heating	0.900	-0.0039	0.900	0.800	-0.0044
Process Cooling	0.876	-0.0049	0.850	0.751	-0.0046
Electro-Chemical	0.981	-0.0007	0.950	0.850	-0.0041
Other	0.915	-0.0033	0.913	0.808	-0.0045
Glass & Glass Products[5]					
Batch Preparation	0.940	-0.0023	0.882	0.882	0.0000
Melting/Refining	0.712	-0.0125	0.900	0.422	-0.0277
Forming	0.905	-0.0037	0.982	0.808	-0.0072
Post-Forming	0.925	-0.0029	0.968	0.850	-0.0048
Cement					
Dry Process	0.840	-0.0064	0.889	0.747	-0.0064
Wet Process[6]	0.935	-0.0025	NA	NA	NA
Finish Grinding	0.836	-0.0066	0.950	0.673	-0.0127
Iron and Steel					
Coke Oven[6]	0.915	-0.0033	0.874	0.830	-0.0019
BF/BOF	0.989	-0.0004	1.000	0.979	-0.0008
EAF	0.995	-0.0002	0.995	0.990	0.0000
Ingot Casting/Primary Rolling[6]	1.000	0.0000	NA	NA	NA
Continuous Casting[7]	1.000	0.0000	1.000	1.000	0.0000
Hot Rolling[7]	0.742	-0.0110	0.742	0.485	-0.0160
Cold Rolling[7]	0.738	-0.0112	0.924	0.474	-0.0244
Aluminum					
Alumina Refining	0.930	-0.0027	0.900	0.862	-0.0016
Primary Smelting	0.910	-0.0035	0.950	0.816	-0.0056
Secondary	0.781	-0.0091	0.750	0.561	-0.0107
Semi-Fabrication, Sheet	0.746	-0.0108	0.900	0.491	-0.0222
Semi-Fabrication, Other	0.873	-0.0050	0.950	0.748	-0.0088
Metal-Based Durables					
Process Heating	0.900	-0.0039	0.900	0.799	-0.0044
Process Cooling	0.876	-0.0049	0.851	0.751	-0.0046
Electro-Chemical	0.981	-0.0007	0.955	0.855	-0.0041
Other	0.915	-0.0033	0.915	0.810	-0.0045

Table 18. Coefficients for Technology Possiblity Curves (Continued)

Industry/Process Unit	Existing Facilities		New Facilities		
	REI 2025[1]	TPC[2]	REI 1998[3]	REI 2025[4]	TPC[2]
Balance of Manufacturing					
Process Heating	0.900	-0.0039	0.900	0.799	-0.0044
Process Cooling	0.876	-0.0049	0.851	0.751	-0.0046
Electro-Chemical	0.981	-0.0007	0.955	0.855	-0.0041
Other	0.915	-0.0033	0.915	0.810	-0.0045
Non-Manufacturing	0.973	-0.0010	0.900	0.853	-0.0020

[1]REI 2025 Existing Facilities = Ratio of 2025 energy intensity to average 1998 energy intensity for existing facilities.

[2]TPC = annual rate of change between 1998 and 2025.

[3]REI 1998 New Facilities = For new facilities, the ratio of state-of-the-art energy intensity to average 1998 energy intensity for existing facilities.

[4]REI 2025 New Facilities = Ratio of 2025 energy intensity for a new state-of-the-art facility to the average 1998 intensity for existing facilities.

[5]REIs and TPCs apply to virgin and recycled materials.

[6]No new plants are likely to be built with these technologies.

[7]Net shape casting is projected to reduce the energy requirements for hot and cold rolling rather than for the continuous casting step.

NA = Not applicable.

BF = Blast furnace.

BOF = Basic oxygen furnace.

EAF = Electric arc furnace.

Source: Energy Information Administration, *Model Documentation Report*, *Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M064(2005) (Washington, DC, 2005).

Machine drive electricity consumption in the food, bulk chemicals, metal-based durables, and balance of manufacturing sectors is calculated by a motor stock model. The beginning stock of motors is modified over the forecast horizon as motors are added to accommodate growth in shipments for each sector, as motors are retired and replaced, and as failed motors are rewound. When an old motor fails, an economic choice is made on whether to repair or replace the motor. When a new motor is added, either to accommodate growth or as a replacement, an economic choice is made between purchasing a motor which meets the EPACT minimum for efficiency or a premium efficiency motor. Table 19 provides the beginning stock efficiency for seven motor size groups in each of the four industries, as well as efficiencies for EPACT minimum and premium motors. There is no premium motor option for the largest size group because the Motor Master database does not provide characteristics for premium motors larger than 350 horsepower.[29] As the motor stock changes over the forecast horizon, the overall efficiency of the motor population changes as well.

Buildings Component

The total buildings energy demand by industry for each region is a function of regional industrial employment and output. Building energy consumption was estimated for building lighting, hvac (heating,ventilation, and air conditioning), facility support, and onsite transportation. Space heating was further divided to estimate the amount provided by direct combustion of fossil fuels and that provided by steam (Table 20). Energy consumption in the BLD Component for an industry is estimated based on regional employment and output growth for that industry.

Boiler/Steam/Combined Heat and Power Component

The steam demand and byproducts from the PA and BLD Components are passed to the BSC Component, which applies a heat rate and a fuel share equation (Table 21) to the boiler steam requirements to compute the required energy consumption.

The boiler fuel shares apply only to the fuels that are used in non-combined heat and power (CHP) boilers. The portion of the steam demand that is met with cogenerated steam reduces the amount of boiler fuel that would otherwise be required. The non-CHP boiler fuel shares are calculated using a logit formulation. The equation is calibrated to 1998 so that the actual boiler fuel shares are produced for the relativ prices that prevailed in 1998.

Table 19. Cost and Performance Parameters for Industrial Motor Choice Model

Industrial Sector Horsepower Range	1998 Stock Efficiency (%)	EPACT Minimum Efficiency (%)	EPACT Minimum Cost (2002$)	Premium Efficiency (%)	Premium Cost (2002$)
Food					
1 - 5 hp	81.3	86.7	327	88.9	351
6 - 20 hp	87.1	91.4	901	92.7	947
21 - 50 hp	90.1	92.6	1,448	93.7	1,618
51 - 100 hp	92.7	94.4	3,338	95.1	3,430
101 - 200 hp	93.5	94.6	6,734	95.9	7,670
201 - 500 hp	93.8	93.4	12,147	96.1	13,560
> 500 hp	93.0	94.8	19,148	na	na
Bulk Chemicals					
1 - 5 hp	82.0	86.9	327	89.1	351
6 - 20 hp	87.4	91.6	901	92.9	947
21 - 50 hp	90.4	92.7	1,448	93.8	1,618
51 - 100 hp	92.4	94.4	3,338	95.2	3,430
101 - 200 hp	93.5	94.7	6,734	96.0	7,670
201 - 500 hp	93.3	93.6	12,147	96.1	13,560
> 500 hp	93.2	94.9	19,148	na	na
Metal-Based Durables					
1 - 5 hp	81.9	86.8	327	88.9	351
6 - 20 hp	87.0	91.5	901	92.8	947
21 - 50 hp	90.0	92.6	1,448	93.8	1,618
51 - 100 hp	92.0	94.4	3,338	95.1	3,430
101 - 200 hp	93.5	94.6	6,734	95.9	7,670
201 - 500 hp	93.7	93.5	12,147	96.1	13,560
> 500 hp	93.0	94.8	19,148	na	na
Balance of Manufacturing					
1 - 5 hp	82.9	86.8	327	88.9	351
6 - 20 hp	88.3	91.5	901	92.8	947
21 - 50 hp	90.3	92.6	1,448	93.8	1,618
51 - 100 hp	92.7	94.4	3,338	95.1	3,430
101 - 200 hp	94.3	94.6	6,734	95.9	7,670
201 - 500 hp	94.3	93.5	12,147	96.1	13,560
> 500 hp	92.9	94.8	19,148	na	na

Source: Energy Information Administration, *Model Documentation Report, Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M064(2005) (Washington, DC, 2005).

Note: The efficiencies listed in this table are operating efficiencies based on average part-loads. Because the average part-load is not the same for all industires, the listed efficiencies for the different motor sizes vary across industries.

The byproduct fuels are consumed before the quantity of purchased fuels is estimated. The boiler fuel shares are based on the 1998 MECS.[30]

Combined Heat and Power

Combined heat and power (CHP) plants, which are designed to produce electricity and useful heat, have been used in the industrial sector for many years. The CHP estimates in the module are based on the assumption that the historical relationship between industrial steam demand and CHP will continue in the future.

Table 20. 1998 Building Component Energy Consumption (Trillion Btu)

		Building Use and Energy Source					
Industry	Region	Lighting Electricity Consumption	HVAC Electricity Consumption	HVAC Natural Gas Consumption	HVAC Steam Consumption	Facility Support Total Consumptiion	Onsite Transportation Total Consumption
Food Products	1	1.5	1.7	2.5	1.9	0.9	0.4
	2	6,5	7.3	12.1	9.1	4.4	1.8
	3	5.6	6.3	7.7	5.8	2.9	2.6
	4	2.5	2.8	5.6	4.2	1.9	1.3
Paper & Allied Products	1	2.4	2.7	1.5	0.3	0.7	1.7
	2	4.0	4.5	3.4	0.6	1.3	1.0
	3	7.6	8.5	8.8	1.6	2.8	3.0
	4	3.0	3.4	3.3	0.6	1.1	1.0
Bulk Chemicals	1	1.1	1.6	0.4	0.0	0.4	0.0
	2	3.3	4.8	1.5	0.0	1.2	0.0
	3	10.2	14.7	18.3	0.0	4.9	0.0
	4	1.0	1.5	1.0	0.0	0.4	0.0
Glass & Glass Products	1	0.4	0.6	1.5	0.0	0.0	0.0
	2	0.5	0.8	1.6	0.0	0.0	0.0
	3	0.8	1.2	2.3	0.0	0.0	0.0
	4	0.2	0.4	0.6	0.0	0.0	0.0
Cement	1	0.1	0.1	0.0	0.0	0.0	0.1
	2	0.2	0.2	0.0	0.0	0.0	0.5
	3	0.4	0.4	0.0	0.0	0.0	0.5
	4	0.2	0.2	0.0	0.0	0.0	0.3
Iron & Basic Steel	1	0.9	0.7	1.9	0.0	0.5	0.5
	2	2.5	2.1	10.8	0.0	2.2	1.5
	3	2.0	1.7	4.4	0.0	1.1	1.2
	4	0.5	0.4	1.0	0.0	0.3	0.2
Aluminum	1	0.3	0.3	0.4	0.0	0.2	0.2
	2	0.9	1.1	1.0	0.0	0.4	0.1
	3	1.4	1.8	3.2	0.0	1.0	0.1
	4	1.4	1.7	0.4	0.0	0.4	0.1
Metal-Based Durables	1	12.4	15.7	28.1	10.8	5.2	3.4
	2	39.1	49.4	100.1	38.4	14.4	7.5
	3	25.2	31.8	45.0	17.3	11.3	7.1
	4	13.9	17.6	19.6	7.5	4.6	1.8
Balance of Manufacturing	1	10.0	13.6	18.7	15.5	3.9	6.2
	2	22.0	29.8	38.1	31.5	8.4	3.6
	3	37.1	50.3	53.4	44.2	13.0	11.5
	4	9.4	12.8	21.7	17.9	4.1	3.7

HVAC = Heating, Ventilation, Air Conditioning.

Source: Energy Information Administration, *Model Documentation Report: Industrial Demand Module of the National Energy Modeling System*, DOE/EIA-M064(2005), (Washington, DC, 2005).

Table 21. Logit Function Parameters for Estimating Boiler Fuel Shares

Industry	Region	Alpha	Natural Gas	Steam Coal	Oil
Food Products	1	-0.25	0.84	0.04	0.12
	2	-0.25	0.63	0.36	0.02
	3	-0.25	0.80	0.10	0.10
	4	-0.25	0.77	0.17	0.06
Paper & Allied Products	1	-0.25	0.29	0.18	0.53
	2	-0.25	0.50	0.47	0.03
	3	-0.25	0.52	0.35	0.12
	4	-0.25	0.87	0.09	0.04
Bulk Chemicals	1	-0.25	0.50	0.01	0.49
	2	-0.25	0.45	0.21	0.33
	3	-0.25	0.54	0.10	0.36
	4	-0.25	0.38	0.53	0.08
Glass & Glass Products	1	-0.25	1.00	0.00	0.00
	2	-0.25	1.00	0.00	0.00
	3	-0.25	1.00	0.00	0.00
	4	-0.25	1.00	0.00	0.00
Cement	1	-0.25	0.04	0.96	0.00
	2	-0.25	0.31	0.69	0.00
	3	-0.25	0.40	0.60	0.00
	4	-0.25	0.56	0.44	0.00
Iron & Steel	1	-0.25	0.98	0.01	0.01
	2	-0.25	0.69	0.14	0.17
	3	-0.25	0.86	0.06	0.08
	4	-0.25	0.97	0.01	0.02
Aluminum	1	-0.25	1.00	0.00	0.00
	2	-0.25	1.00	0.00	0.00
	3	-0.25	1.00	0.00	0.00
	4	-0.25	1.00	0.00	0.00
Metal-Based Durables	1	-0.25	0.68	0.15	0.16
	2	-0.25	0.74	0.24	0.02
	3	-0.25	0.85	0.03	0.08
	4	-0.25	0.97	0.00	0.03
Balance of Manufacturing	1	-0.25	0.59	0.24	0.18
	2	-0.25	0.67	0.30	0.04
	3	-0.25	0.67	0.25	0.08
	4	-0.25	0.79	0.17	0.04

Alpha: User-specified.

Source: Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-064(2005), (Washington, DC, 2005).

In 2002, EIA comprehensively reviewed and revised how it collects, estimates, and reports fuel use for facilities producing electricity. The review addressed both inconsistent reporting of the fuels used for electric power across historical years and changes in the electric power marketplace that have been inconsistently represented in various EIA survey forms and publications. These changes were first reflected in the *Annual Energy Review 2001*, DOE/EIA-0384(2001), (Washington, DC, November 2002), and are discussed in detail in Appendix H of that publication.

The projection for additions to fossil-fueled cogeneration is based on assessing capacity that could be added to generate the industrial steam requirements that are not already met by existing CHP. The technical potential for onsite CHP is primarily based on supplying thermal requirements. Capacity additions are then determined by the interaction of payback periods and market penetration rates. Installed cost for the cogeneration systems is given in Table 22.

Table 22. Cost Characteristics of Industrial CHP Systems

	Size	Installed Cost ($2003 per kilowatt)[1]		O&M Cost ($2003 per kilowatthour)[1]	
System	(kilowatts)	2003	2020	2003	2020
1 Engine	1000	940	840	0.013	0.008
2 Engine	3000	935	830	0.009	0.008
3 Gas Turbine	1000	1910	NA	0.0096	NA
4 Gas Turbine	5000	1024	840	0.0059	0.005
5 Gas Turbine	10000	930	790	0.0055	0.005
6 Gas Turbine	25000	800	705	0.0049	0.004
7 Gas Turbine	40000	702	660	0.0042	0.004
8 Combined Cycle	100000	692	655	0.0036	0.003

[1]Costs are given in 2003 dollars in original source document.

NA = The 1000 kilowatt gas turbine is not expected to be a viable option in the future.

Source: Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System,* DOE/EIA-MO64(2005) (Washington, DC, 2005).

Technology

The amount of energy consumption reported by the industrial module is also a function of the vintage of the capital stock that produces the output. It is assumed that new vintage stock will consist of state-of-the-art technologies that are more energy efficient than the average efficiency of the existing capital stock. Consequently, the amount of energy required to produce a unit of output using new capital stock is less than that required by the existing capital stock. Capital stock is grouped into three vintages: old, middle, and new. The old vintage consists of capital added in 1998 and earlier and is assumed to retire at a fixed rate each year (Table 23). Middle vintage capital is that which is added after 1998 but not including the year of the forecast. New production capacity is built in the forecast years when the capacity of the existing stock of capital in the industrial model cannot produce the output projected by the NEMS Regional Macroeconomic Model. Capital additions during the forecast horizon are retired in subsequent years at the same rate as the pre-1999 capital stock.

The energy intensity of the new capital stock relative to 1998 capital stock is reflected in the parameter of the technology possibility curve estimated for the major production steps for each of the energy-intensive industries. These curves are based on engineering judgment of the likely future path of energy intensity changes (Table 20). The energy intensity of the existing capital stock also is assumed to decrease over time, but not as rapidly as new capital stock. The net effect is that over time the amount of energy required to produce a unit of output declines. Although total energy consumption in the industrial sector is projected to increase, overall energy intensity is projected to decrease.

Table 23. Retirement Rates

Industry	Retirement Rate (percent)	Industry	Retirement Rate (percent)
Food Products	1.7	Glass and Glass Products	1.3
Pulp and Paper	2.3	Cement	1.2
Bulk Chemicals	1.7	Aluminum	
Iron & Steel		Metal-Based Durables	
Blast Furnace and Basic Stell Products	1.5	Other Non-Intensive Manufacturing	
Electric Arc Furnace	1.5		
Coke Ovens	2.5		
Other Stell	2.9		

Note: Except for the Blast Furnace and Basic Steel Products Industry, the retirement rate is the same for each process step or end-use within an industry.

Source: Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-MO64(2005), (Washington, DC, 2005).

Legislation

Energy Policy Act of 1992 (EPACT)

EPACT contains several implications for the industrial module. These implications concern efficiency standards for boilers, furnaces, and electric motors. The industrial module uses heat rates of 1.25 (80 percent efficiency) and 1.22 (82 percent efficiency) for gas and oil burners respectively. These efficiencies meet the EPACT standards. EPACT mandates minimum efficiencies for all motors up to 200 horsepower purchased after 1998. The choices offered in the motor model are all at least as efficient as the EPACT minimums.

Clean Air Act Amendments of 1990 (CAAA90)

The CAAA90 contains numerous provisions that affect industrial facilities. Three major categories of such provisions are as follows: process emissions, emissions related to hazardous or toxic substances, and SO2 emissions.

Process emissions requirements were specified for numerous industries and/or activities (40 CFR 60). Similarly, 40 CFR 63 requires limitations on almost 200 specific hazardous or toxic substances. These specific requirements are not explicitly represented in the NEMS industrial model because they are not directly related to energy consumption projections.

Section 406 of the CAAA90 requires the Environmental Protection Agency (EPA) to regulate industrial SO_2 emissions at such time that total industrial SO_2 emissions exceed 5.6 million tons per year (42 USC 7651). Since industrial coal use, the main source of SO_2 emissions, has been declining, EPA does not anticipate that specific industrial SO_2 regulations will be required (Environmental Protection Agency, *National Air Pollutant Emission Trends: 1990-1998*, EPA-454/R-00-002, March 2000, Chapter 4). Further, since industrial coal use is not projected to increase, the industrial cap is not expected be a factor in industrial energy consumption projections.

High Technology, 2005 Technology, Advanced Nuclear, and High Renewables Cases

The *high technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment. (Table 24)[31] The *high technology case* also assumes that the rate at which biomass byproducts will be recovered from industrial processes increases from 0.1 percent per year to 1.0 percent per year. The availability of additional biomass leads to an increase in biomass-based cogeneration. Changes in aggregate energy intensity result both from changing equipment and production efficiency and from changes in the composition of industrial output. Since the composition of industrial output remains the same as in the reference case, delivered energy intensity declines by 1.6 percent annually compared with the reference case, in which delivered energy intensity is projected to decline 1.3 percent annually.

The *2005 technology case* holds the energy efficiency of plant and equipment constant at the 2005 level over the forecast. Both cases were run with only the Industrial Demand Module rather than as a fully integrated NEMS run, (i.e., the other demand models and the supply models of NEMS were not executed). Consequently, no potential feedback effects from energy market interactions were captured.

AEO2005 also analyzed an integrated high technology case (*consumption high technology*), which combines the *high technology cases* of the four end-use demand sectors, the *electricity high fossil technology case,* the *advanced nuclear case,* and *the high renewables case*.

The *high renewables case* assumes that the rate at which biomass byproducts will be recovered from industrial processes increases from 0.1 percent per year to 1.0 percent per year. The availability of additional biomass leads to an increase in biomass-based CHP.

Table 24. Coefficients for Technology Possibility Curves, High Technology Case

	Existing Facilities		New Facilities		
Industry/Process Unit	REI 2025[1]	TPC[2]	REI 1998[3]	REI 2025[4]	TPC[2]
Food Products					
Process Heating	0.829	-0.0069	0.900	0.629	-0.0132
Process Cooling	0.829	-0.0069	0.850	0.594	-0.0132
Other	0.829	-0.0069	0.915	0.639	-0.0132
Paper & Allied Products					
Wood Preparation	0.843	-0.0063	0.873	0.790	-0.0037
Waste Pulping	0.900	-0.0039	0.936	0.809	-0.0054
Mechanical Pulping	0.883	-0.0046	0.868	0.805	-0.0028
Semi-chemical	0.814	-0.0076	0.876	0.634	-0.0119
Kraft, Sulfite, misc. Chemicals	0.714	-0.0124	0.876	0.411	-0.0276
Bleaching	0.779	-0.0092	0.900	0.544	-0.0185
Paper Making	0.687	-0.0138	0.900	0.343	-0.0351
Bulk Chemicals					
Process Heating	0.843	-0.0063	0.900	0.644	-0.0123
Process Cooling	0.843	-0.0063	0.850	0.609	-0.0123
Electro-Chemical	0.843	-0.0063	0.950	0.680	-0.0123
Other	0.843	-0.0063	0.915	0.654	-0.0123
Glass & Glass Products[5]					
Batch Preparation	0.857	-0.0057	0.882	0.645	0.0115
Melting/Refining	0.710	-0.0126	0.900	0.418	-0.0280
Forming	0.866	-0.0053	0.982	0.682	-0.0134
Post-Forming	0.805	-0.0080	0.968	0.531	-0.0220

Table 24. Coefficients for Technology Possibility Curves, High Technology Case (Continued)

Industry/Process Unit	Existing Facilities		New Facilities		
	REI 2025[1]	TPC[2]	REI 1998[3]	REI 2025[4]	TPC[2]
Cement					
Dry Process	0.788	-0.0088	0.889	0.558	-0.0171
Wet Process[6]	0.788	-0.0088	NA	NA	NA
Finish Grinding	0.823	-0.0072	0.950	0.628	-0.0152
Iron & Steel					
Coke Oven[6]	0.592	-0.0192	0.874	0.502	-0.0203
BF/BOF	0.905	-0.0037	1.000	0.678	-0.0143
EAF	0.801	-0.0082	0.990	0.632	-0.0165
Ingot Casting/Primary Rolling[6]	1.000	0.0000	NA	NA	NA
Continuous Casting[7]	0.932	-0.0026	1.000	0.867	-0.0053
Hot Rolling[7]	0.427	-0.0310	0.750	0.093	-0.0743
Cold Rolling[7]	0.383	-0.0349	0.924	0.023	-0.1278
Aluminum					
Alumina Refining	0.859	-0.0056	0.900	0.678	-0.0104
Primary Smelting	0.816	-0.0075	0.950	0.582	-0.0180
Secondary	0.667	-0.0149	0.750	0.388	-0.0241
Semi-Fabrication, Sheet	0.689	-0.0137	0.900	0.353	-0.0341
Semi-Fabrication, Other	0.706	-0.0128	0.950	0.346	-0.0367
Metal-Based Durables					
Process Heating	0.814	-0.0076	0.900	0.614	-0.0141
Process Cooling	0.814	-0.0076	0.851	0.580	-0.0141
Electro-Chemical	0.814	-0.0076	0.955	0.651	-0.0141
Other	0.814	-0.0076	0.915	0.624	-0.0141
Other Non-Intensive Manufacturing					
Process Heating	0.821	-0.0073	0.900	0.617	-0.0139
Process Cooling	0.821	-0.0073	0.851	0.583	-0.0139
Electro-Chemical	0.821	-0.0073	0.955	0.655	-0.0139
Other	0.821	-0.0073	0.915	0.625	-0.0139
Non-Manufacturing	0.947	-0.0020	0.900	0.808	-0.0040

[1]REI 2025 Existing Facilities = Ratio of 2025 energy intensity to average 1998 energy intensity for existing facilities.
[2]TPC = annual rate of change between 1998 and 2025.
[3]REI 1998 New Facilities = For new facilities, the ratiio of State-of-the-art energy intensity to average 1998 energy intensity for existing facilities.
[4]REI 2025 New Facilities = Ratio of 2025 energy intensity for a new State-of-the-art facility to the average 1998 intensity for existing facilities.
[5] REIs and TPCs apply to virgin and recycled materials.
[6]No new plants are likely to be built with these technologies.
[7]Net shape casting is projected to reduce the energy requirements for hot and cold rolling rather than for the continuous casting step.
NA = Not applicable.
BF = Blast furnace.
BOF = Basic oxygen furnace.
EAF = Electric arc furnace.

Source: Energy Information Administration, *Model Documentation Report*, *Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M064(2005) (Washington, DC, 2005).

Notes and Sources

[26] Energy Information Administration, State Energy Data Report 2001, DOE/EIA-0214(2001), (Washington, D.C., November 2004).

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

[28] Aluminum is excluded due to its almost exclusive reliance on electricity in the process and assembly component.

[29] U.S., Department of Energy (2003). Motor Master+ 4.0 software database; available online: http://mm3.energy.wsu.edu/mmplus/default.stm.

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

[31] These assumptions are based in part on Arthur D. Little, Industrial Model: Update on Energy Use and Industrial Characteristics (September 2001).

Transportation Demand Module

The NEMS Transportation Demand Module estimates energy consumption across the nine Census Divisions (see Figure 5) and over ten fuel types. Each fuel type is modeled according to fuel-specific technology attributes applicable by transportation mode. Total transportation energy consumption is the sum of energy use in eight transport modes: light-duty vehicles (cars and light trucks), commercial light trucks (8,501-10,000 lbs gross vehicle weight), freight trucks (>10,000 lbs gross vehicle weight), freight and passenger airplanes, freight rail, freight shipping, and miscellaneous transport such as mass transit. Light-duty vehicle fuel consumption is further subdivided into personal usage and commercial fleet consumption.

Key Assumptions

Macroeconomic Sector Inputs

Macroeconomic sector inputs used in the NEMS Transportation Demand Module (Table 25) consist of the following: gross domestic product (GDP), industrial output by Standard Industrial Classification code, personal disposable income, new car and light truck sales, total population, driving age population, total value of imports and exports, and the military budget. The share of total vehicle sales that represent light truck sales increase to about sixty percent by 2025.

Table 25. Macroeconomic Inputs to the Transportation Module
(Millions)

Macroeconomic Input	2003	2005	2010	2015	2020	2025
New Car Sales	8.1	8.3	8.1	7.9	8.1	8.3
New Light Truck Sales	7.8	8.1	9.1	9.7	10.6	11.8
Real Disposable Income (billion 2000 Chain-Weighted Dollars)	7,734	8,250	9,594	11,192	12,783	14,990
Real GDP (billion 2000 Chain-Weighted Dollars)	10,381	11,221	13,084	15,216	17,634	20,292
Driving Age Population	226.5	231.7	244.1	254.5	265.3	276.5
Total Population	291.4	296.8	310.1	323.5	337.0	350.6

Source: Energy Information Administration, *AEO2005* National Energy Modeling System run: aeo2005.d102004a.

Light-Duty Vehicle Assumptions

The light duty vehicle Manufacturers Technology Choice Model (MTCM) includes 63 fuel saving technologies with data specific to cars and light trucks (Tables 26 and 27) including incremental fuel efficiency improvement, incremental cost, first year of introduction, and fractional horsepower change. These assumed technology characterizations are scaled up or down to approximate the differences in each attribute for 6 Environmental Protection Administration (EPA) size classes of cars and light trucks.

The vehicle sales share module holds the share of vehicle sales by import and domestic manufacturers constant within a vehicle size class at 1999 levels based on National Highway Traffic and Safety Administration data.[32]

EPA size class sales shares are projected as a function of income per capita, fuel prices, and average predicted vehicle prices based on endogeous calculations within the MTCM.[33]

The MTCM utilizes 63 new technologies for each size class and origin of manufacturer (domestic or foreign) based on the cost-effectiveness of each technology and an initial availability year. The discounted stream

Table 26. Standard Technology Matrix For Cars[1]

	Fractional Fuel Efficiency Change	Incremental Cost (1990$)	Incremental Cost ($/Unit Wt.)	Incremental Weight (Lbs.)	Incremental Weight (Lbs./Unit Wt.)	Introduction Year	Fractional Horse-power Change
Unit Body Construction	4	100	0	0	-6	1980	0
Material Substitution II	3.3	0	0.4	0	-5	1990	0
Material Substitution III	6.6	0	0.6	0	-10	1998	0
Material Substitution IV	9.9	0	0.9	0	-15	2006	0
Material Substitution V	13.2	0	1.2	0	-20	2014	0
Drag Reduction II	2.3	40	0	0	0	1988	0
Drag Reduction III	4.4	85	0	0	0.2	1992	0
Drag Reduction IV	6.3	145	0	0	0.5	2002	0
Drag Reduction V	8	225	0	0	1	2010	0
Roll-Over Technology	-1.5	100	0	0	2.2	2005	0
Side Impact Technology	-1.5	100	0	0	2.2	2005	0
Adv Low Loss Torque Converter	2	25	0	0	0	1999	0
Early Torque Converter Lockup	0.5	8	0	0	0	2002	0
Aggressive Shift Logic	2	60	0	0	0	1999	0
4-Speed Automatic	4.5	285	0	10	0	1980	0
5-Speed Automatic	6.5	435	0	20	0	1995	0
6-Speed Automatic	8	570	0	30	0	2004	0
6-Speed Manual	2	100	0	20	0	1995	0
CVT	10.5	615	0	-25	0	1998	0
Automated Manual Trans	8	100	0	0	0	2006	0
Roller Cam	2	16	0	0	0	1980	0
OHC/AdvOHV-4 Cylinder	3	80	0	0	0	1980	10
OHC/AdvOHV-6 Cylinder	3	100	0	0	0	1987	10
OHC/AdvOHV-8 Cylinder	3	120	0	0	0	1986	10
4-Valve/4-Cylinder	8	205	0	10	0	1988	17
4-Valve/6-Cylinder	8	280	0	15	0	1992	17
4 Valve/8-Cylinder	8	320	0	20	0	1994	17
5 Valve/6-Cylinder	8	300	0	18	0	1998	20
VVT-4 Cylinder	2.5	45	0	10	0	1994	5
VVT-6 Cylinder	2.5	115	0	20	0	1993	5
VVT-8 Cylinder	2.5	115	0	20	0	1993	5
VVL-4 Cylinder	4	170	0	25	0	1997	10
VVL-6 Cylinder	4	260	0	40	0	2000	10
VVL-8 Cylinder	4	330	0	50	0	2000	10
Camless Valve Actuation-4cyl	7.5	450	0	35	0	2009	13
Camless Valve Actuation-6cyl	7.5	600	0	55	0	2008	13
Camless Valve Actuation-8cyl	7.5	750	0	75	0	2007	13
Cylinder Deactivation	4.5	250	0	10	0	2004	0
Turbocharging/ Supercharging	6	650	0	-100	0	1980	15
Engine Friction Reduction I	2	25	0	0	0	1992	3
Engine Friction Reduction II	3.5	63	0	0	0	2000	5
Engine Friction Reduction III	5	114	0	0	0	2008	7
Engine Friction Reduction IV	6.5	177	0	0	0	2016	9
Stoichiometric GDI/4-Cylinder	7	300	0	20	0	2006	10
Stoichiometric GDI/6-Cylinder	7	450	0	30	0	2006	10
Lean Burn GDI	5	250	0	20	0	2006	0
5W-30 Engine Oil	1	22.5	0	0	0	1998	0
5W-20 Engine Oil	2	37.5	0	0	0	2003	0
OW-20 Engine Oil	3.1	150	0	0	0	2030	0
Electric Power Steering	2	140	0	0	0	2004	0
Improved Alternator	0.3	15	0	0	0	2005	0
Improved Oil/Water Pump	0.5	10	0	0	0	2000	0
Electric Oil/Water Pump	1	50	0	0	0	2007	0
Tires II	2	30	0	-8	0	1995	0
Tires III	4	75	0	-12	0	2005	0
Tires IV	6	135	0	-16	0	2015	0
Front Wheel Drive	6	250	0	0	-6	1980	0
Four Wheel Drive Improvements	2	100	0	0	-1	2000	0
42V-Launch Assist and Regen	3	600	0	80	0	2005	-5
42V-Engine Off at Idle	4.5	800	0	45	0	2005	0
Tier 2 Emissions Technology	-1	120	0	20	0	2006	0
Increased Size/Weight	-1.7	0	0	0	2.55	2001	0

[1] Fractional changes refer to the percentage change from the 1990 values.

Sources: Energy and Environment Analysis, *Documentation of Technology included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (September, 2002). National Research Council, *Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards* (Copyright 2002).

Table 27. Standard Technology Matrix For Light Trucks[1]

	Fractional Fuel Efficiency Change	Incremental Cost (1990$)	Incremental Cost ($/UnitWt.)	Incremental Weight (Lbs.)	Incremental Weight (Lbs./UnitWt.)	Introduction Year	Fractional Horse-power Change
Unit Body Construction	4	100	0	0	-6	1980	0
Material Substitution II	3.3	0	0.4	0	-5	1994	0
Material Substitution III	6.6	0	0.6	0	-10	2002	0
Material Substitution IV	9.9	0	0.9	0	-15	2010	0
Material Substitution V	13.2	0	1.2	0	-20	2018	0
Drag Reduction II	2.3	40	0	0	0	1992	0
Drag Reduction III	4.4	85	0	0	0.2	1998	0
Drag Reduction IV	6.3	145	0	0	0.5	2006	0
Drag Reduction V	8	225	0	0	1	2014	0
Roll-Over Technology	-1.5	100	0	0	2.2	2006	0
Side Impact Technology	-1.5	100	0	0	2.2	2006	0
Adv Low Loss Torque Converter	2	25	0	0	0	2005	0
Early Torque Converter Lockup	0.5	8	0	0	0	2006	0
Aggressive Shift Logic	2	60	0	0	0	2006	0
4-Speed Automatic	4.5	285	0	10	0	1980	0
5-Speed Automatic	6.5	435	0	20	0	1999	0
6-Speed Automatic	8	570	0	30	0	2008	0
6-Speed Manual	2	100	0	20	0	2000	0
CVT	10.5	615	0	-25	0	2008	0
Automated Manual Trans	8	100	0	0	0	2010	0
Roller Cam	2	16	0	0	0	1985	0
OHC/AdvOHV-4 Cylinder	3	80	0	0	0	1980	10
OHC/AdvOHV-6 Cylinder	3	100	0	0	0	1990	10
OHC/AdvOHV-8 Cylinder	3	120	0	0	0	1990	10
4-Valve/4-Cylinder	7	205	0	10	0	1998	17
4-Valve/6-Cylinder	7	280	0	15	0	2000	17
4 Valve/8-Cylinder	7	320	0	20	0	2000	17
5 Valve/6-Cylinder	7	300	0	18	0	2010	20
VVT-4 Cylinder	2.5	45	0	10	0	1998	5
VVT-6 Cylinder	2.5	115	0	20	0	1997	5
VVT-8 Cylinder	2.5	115	0	20	0	1997	5
VVL-4 Cylinder	4	170	0	25	0	2002	10
VVL-6 Cylinder	4	260	0	40	0	2001	10
VVL-8 Cylinder	4	330	0	50	0	2006	10
Camless Valve Actuation-4cyl	7.5	450	0	35	0	2014	13
Camless Valve Actuation-6cyl	7.5	600	0	55	0	2012	13
Camless Valve Actuation-8cyl	7.5	750	0	75	0	2011	13
Cylinder Deactivation	4.5	250	0	10	0	2004	0
Turbocharging/Supercharging	6	650	0	-100	0	1987	15
Engine Friction Reduction I	2	25	0	0	0	1992	3
Engine Friction Reduction II	3.5	63	0	0	0	2000	5
Engine Friction Reduction III	5	114	0	0	0	2010	7
Engine Friction Reduction IV	6.5	177	0	0	0	2016	9
Stoichiometric GDI/4-Cylinder	7	300	0	20	0	2008	10
Stoichiometric GDI/6-Cylinder	7	450	0	30	0	2010	10
Lean Burn GDI	5	250	0	20	0	2010	0
5W-30 Engine Oil	1	22.5	0	0	0	1998	0
5W-20 Engine Oil	2	37.5	0	0	0	2003	0
OW-20 Engine Oil	3.1	150	0	0	0	2030	0
Electric Power Steering	2	140	0	0	0	2005	0
Improved Alternator	0.3	15	0	0	0	2005	0
Improved Oil/Water Pump	0.5	10	0	0	0	2000	0
Electric Oil/Water Pump	1	50	0	0	0	2008	0
Tires II	2	30	0	-8	0	1995	0
Tires III	4	75	0	-12	0	2005	0
Tires IV	6	135	0	-16	0	2015	0
Front Wheel Drive	2	250	0	0	-3	1984	0
Four Wheel Drive Improvements	2	100	0	0	-1	2000	0
42V-Launch Assist and Regen	3	600	0	80	0	2005	-5
42V-Engine Off at Idle	4.5	800	0	45	0	2005	0
Tier 2 Emissions Technology	-1	160	0	20	0	2006	0
Increased Size/Weight	-2.5	0	0	0	3.75	2001	0
Variable Compression Ratio	4	450	0	25	0	2015	0

[1]Fractional changes refer to the percentage change from the 1990 values.
Sources: Energy and Environment Analysis, *Documentation of Technology included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (September, 2002). National Research Council, *Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards* (Copyright 2002).

of fuel savings is compared to the marginal cost of each technology. The fuel economy module assumes the following:

- All fuel saving technologies have a 3-year payback period.
- The real discount rate remains steady at 15 percent.
- Corporate Average Fuel Efficiency standards remain constant at 27.5 mpg for cars and rise from a level of 20.7 mpg in 2004 to 22.2 mpg in 2007 for light trucks, and then remain constant throughout the forecast period.
- Expected future fuel prices are calculated based on an extrapolation of the growth rate between a five year moving average of fuel price 3 years and 4 years prior to the present year. This assumption is founded upon an assumed lead time of 3 to 4 years to significantly modify the vehicles offered by a manufacturer.

Degradation factors (Table 28) used to convert Environmental Protection Agency-rated fuel economy to actual "on the road" fuel economy are based on application of a logistic curve to the projections of three factors: increases in city/highway driving, increasing congestion levels, and rising highway speeds.[34] Degradation factors are also adjusted to reflect the percentage of reformulated gasoline consumed.

Table 28. Car and Light Truck Degradation Factors

	2000	2005	2010	2015	2020	2025
Cars	74.5	76.1	77.7	79.4	81.0	81.0
Light Trucks	81.3	80.9	80.6	80.3	80.0	80.0

Source: Energy Information Administration, *Transportation Sector Model of the National Energy Modeling System, Model Documentation 2004*, DOE/EIA-M070(2004), (Washington, DC, 2004).

The vehicle miles traveled (VMT) module forecasts VMT as a function of the cost of driving per mile, and disposable personal income per capita. Coefficients were re-estimated for *AEO2005*. Based on output from the model, the fuel price elasticity rises to a maximum of -0.4 as fuel prices rise above reference case levels in each year.

Commercial Light-Duty Fleet Assumptions

With the current focus of transportation legislation on commercial fleets and their composition, the Transportation Demand Module is designed to divide commercial light-duty fleets into three types: business, government, and utility. Based on this classification, commercial light-duty fleet vehicles vary in survival rates and duration in fleet use before being sold for use as personal vehicles (Table 29). While the total number of vehicles sold to fleets can vary over time, the share of total fleet sales by fleet type is held constant in the Transportation Demand Module. Of total automobile sales to fleets, 91.1 percent are used in business fleets, 6.4 percent in government fleets, and 2.4 percent in utility fleets. Of total light truck sales to fleets, 56.8 percent are used in business fleets, 12.3 percent in government fleets, and 31.0 percent in utility fleets.[35] Both the automobile and light truck shares by fleet type are held constant from 2002 through 2025. The share of total automobile and light truck sales to fleets varies historically over time. In 2000, 19.1 percent of all automobiles sold and 17.5 percent of all light trucks sold were for fleet use. In the Transportation Demand Module, the share of total automobile sales to fleet varies through 2008, but is held constant thereafter, while the share of total light truck sales remains constant over the entire forecast period.

Alternative-fuel shares of fleet sales by fleet type are held constant at year 2000 levels (business (4.78 percent), government (7.91 percent), utility (0.84 percent)),[36] but compared to a minimum level of sales based on legislative initiatives, such as the Energy Policy Act of 1992 and the Low Emission Vehicle Program.[37,38] Size class sales shares of vehicles are held constant at anticipated levels (Table 30).[39] Individual sales shares of alternative-fuel fleet vehicles by technology type are assumed to remain constant for utility, government, and for business fleets[40] (Table 31).

Annual VMT per vehicle by fleet type stays constant over the forecast period based on the Oak Ridge National Laboratory fleet data.

Table 29. The Average Length of Time Vehicles Are Kept Before they are Sold to Others
(Months)

Vehicle Type	Business	Utility	Government
Cars	35	68	81
Light Trucks	56	60	82
Medium Trucks	83	86	96
Heavy Trucks	103	132	117

Source: Oak Ridge National Laboratory, *Fleet Characteristics and Data Issues*, Stacy Davis and Lorena Truett, final report prepared for the Department of Energy, Energy Information Administration, Office of Integrated Analysis and Forecasting, (Oak Ridge, TN, January 2003).

Table 30. Commercial Fleet Size Class Shares by Fleet and Vehicle Type
(Percentage)

Fleet Type by Size Class	Automobiles	Light Trucks
Business Fleet		
Mini	0.04	3.77
Subcompact	25.32	11.91
Compact	23.18	37.87
Midsize	41.93	7.92
Large	9.45	3.58
2-seater	0.08	34.96
Government Fleet		
Minl	0.03	7.76
Subcompact	7.64	42.29
Compact	9.08	9.16
Midsize	29.03	18.86
Large	54.21	0.21
2-seater	0.01	21.72
Utility Fleet		
Mini	0.04	13.50
Subcompact	25.32	42.68
Compact	23.18	5.43
Midsize	41.93	26.14
Large	9.45	1.14
2-seater	0.08	11.11

Source: Oak Ridge National Laboratory, *Fleet Characteristics and Data Issues*, Stacy Davis and Lorena Truett, final report prepared for the Department of Energy, Energy Information Administration, Office of Integrated Analysis and Forecasting, (Oak Ridge, TN, January 2003).

Table 31. Purchases of Alternative-Fuel Vehicles by Fleet Type and Technology Type
(Percentage)

Technology	Business	Government	Utility
Ethanol	72.6	54.0	26.8
Methanol	0.0	0.0	0.0
Electric	1.1	3.0	1.1
CNG	4.6	8.5	17.3
LPG	21.7	34.5	54.7

Sources: Energy Information Administration, *Describing Current and Potential Markets for Alternative Fuel Vehicles*, DOE/EIA-0604(96), (Washington, DC, March 1996). Energy Information Administration, *Alternatives to Traditional Transportation Fuels* http://www.eia.doe.gov/cneaf/solar.renewables/alt_trans_fuel98/table14.html.

Fleet fuel economy for both conventional and alternative-fuel vehicles is assumed to be the same as the personal new vehicle fuel economy and is subdivided into six EPA size classes for cars and light trucks.

The Light Commercial Truck Model

The Light Commercial Truck Module of the NEMS Transportation Model is constructed to represent light trucks that weigh 8,501 to 10,000 pounds gross vehicle weight (Class 2B vehicles). These vehicles are assumed to be used primarily for commercial purposes.

The module implements a twenty-year stock model that estimates vehicle stocks, travel, fuel efficiency, and energy use by vintage. Historic vehicle sales and stock data, which constitute the baseline from which the forecast is made, are taken from a recent Oak Ridge National Laboratory study.41 The distribution of vehicles by vintage, and vehicle scrappage rates is derived from R.L. Polk company registration data.42,43 Vehicle travel by vintage was constructed using vintage distribution curves and estimates of average annual travel by vehicle.44,45

The growth in light commercial truck VMT is a function of industrial output for agriculture, mining, construction, trade, utilities, and personal travel. These industrial groupings were chosen for their correspondence with output measures being forecast by NEMS. The overall growth in VMT reflects a weighted average based upon the distribution to total light commercial truck VMT by sector. Forecasted fuel efficiencies are assumed to increase at the same annual growth rate as light-duty trucks (<8,500 pounds gross vehicle weight).

Consumer Vehicle Choice Assumptions

The Consumer Vehicle Choice Module (CVCM) utilizes a nested multinomial logit (NMNL) model that predicts sales shares based on relevant vehicle and fuel attributes. The nesting structure first predicts the probability of fuel choice for multi-fuel vehicles within a technology set. The second level nesting predicts penetration among similar technologies within a technology set (i.e., gasoline versus diesel hybrids). The third level choice determines market share among the different technology sets.46 The technology sets include:

- Conventional fuel capable (gasoline, diesel, bi-fuel and flex-fuel),
- Hybrid (gasoline and diesel),
- Dedicated alternative fuel (CNG, LPG, methanol, and ethanol),
- Fuel cell (gasoline, methanol, and hydrogen), and
- Electric battery powered (lead acid, nickel-metal hydride, lithium polymer)47

The vehicle attributes considered in the choice algorithm include: price, maintenance cost, battery replacement cost, range, multi-fuel capability, home refueling capability, fuel economy, acceleration and luggage space. With the exception of maintenance cost, battery replacement cost, and luggage space, vehicle attributes are determined endogenously.48 The fuel attributes used in market share estimation include availability and price. Vehicle attributes vary by six EPA size classes for cars and light trucks and fuel availability varies by Census division. The NMNL model coefficients were developed to reflect purchase decisions for cars and light trucks separately.

Where applicable, CVCM fuel efficient technology attributes are calculated relative to conventional gasoline miles per gallon. It is assumed that many fuel efficiency improvements in conventional vehicles will be transferred to alternative-fuel vehicles. Specific individual alternative-fuel technological improvements are also dependent upon the CVCM technology type, cost, research and development, and availability over time. Make and model availability estimates are assumed according to a logistic curve based on the initial technology introduction date and current offerings. Coefficients summarizing consumer valuation of vehicle attributes were derived from assumed economic valuation compared to vehicle price elasticities. Initial CVCM vehicle stocks are set according to EIA surveys.[49] A fuel switching algorithm based on the relative fuel prices for alternative fuels compared to gasoline is used to determine the percentage of total VMT represented by alternative fuels in bi-fuel and flex-fuel alcohol vehicles.

Freight Truck Assumptions

The freight truck module estimates vehicle stocks, travel, fuel efficiency and energy use for three size classes; light medium (Class 3), heavy medium (Classes 4 through 6), and heavy (Classes 7 and 8). Within these size classes, the stock model structure is designed to estimate energy use by four fuel types (diesel, gasoline, LPG, and CNG) and twenty vehicle vintages. Fuel consumption estimates are reported regionally (by Census division) according to the State Energy Data Report distillate regional shares.[50] The module uses projections of dollars of industrial output to estimate growth in freight truck travel. Industrial output is converted to an equivalent measure of volume output using freight adjustment coefficients.[51,52] These freight adjustment coefficients vary by NEMS Standard Industrial Classification (SIC) code, gradually diminishing their deviation over time toward parity. Freight truck load factors (ton-miles per truck) by SIC code are constants formulated from historical data.[53]

New freight truck fuel economy is dependent on the market penetration of various emission control technologies and advanced engine components.[54] For the advanced engine components, market penetration is determined as a function of technology cost effectiveness and introduction year. Cost effectiveness is calculated as a function of fuel price, vehicle travel, fuel economy improvement and incremental capital cost. Emissions control equipment is assumed to enter the market to meet regulated emission standards.

Heavy truck freight travel is estimated by size class and fuel type and is based on matching projected freight travel demand (measured by industrial output) to the travel supplied by the current fleet. Travel by vintage and size class is then adjusted so that total travel meets total demand. Initial heavy vehicle travel by vintage and size class was derived using Vehicle Inventory and Use Survey (VIUS) data.[55]

Initial freight truck stocks by vintage are obtained from R.L. Polk Co. and are distributed by fuel type using VIUS data.[56] Vehicle scrappage rates were also estimated using R.L. Polk Co. data.[57]

Freight and Transit Rail Assumptions

The freight rail module receives industrial output by SIC code measured in real 1987 dollars and converts these dollars into an adjusted volume equivalent. Coal production from the NEMS Coal Market Module is used to adjust coal rail travel. Freight rail adjustment coefficients, which are used to convert dollars into volume equivalents, remain constant and are based on historical data.[58,59] Initial freight rail efficiencies are based on the freight model from Argonne National Laboratory.[60] The distribution of rail fuel consumption by fuel type remains constant and is based on historical data.[61] Regional freight rail consumption estimates are distributed according to the *State Energy Data Report 1999*.[62]

Freight Domestic and International Shipping Assumptions

The freight domestic shipping module converts industrial output by SIC code measured in dollars, to a volumetric equivalent by SIC code.[63,64] These freight adjustment coefficients are based on analysis of historical data and remain constant throughout the forecast period. Domestic shipping efficiencies are based on the freight model by Argonne National Laboratory. The energy consumption in the freight international shipping module is a function of the total level of imports and exports. The distribution of domestic and international shipping fuel consumption by fuel type remains constant throughout the analysis and is based on historical data.65 Regional domestic and international shipping consumption estimates are distributed according to residual oil regional shares in the *State Energy Data Report.*66

Air Travel Demand Assumptions

The air travel demand module calculates the domestic and international ticket prices for travel as a function of fuel cost. The ticket price is constrained to be no lower than the lowest cost per mile, adjusted by load factor. Domestic and international revenue passenger miles are based on historic data,67 per capita income, and ticket price. The revenue ton miles of air freight are based on merchandise exports, gross domestic product, and fuel cost.68

Airport capacity constraints based on the *FAA's Airport Capacity Benchmark Report 2001* are incorporated into the air travel demand module using airport capacity measures.69 Airport capacity is defined by the maximum number of flights per hour airports can routinely handle, the amount of time airports operate at optimal capacity, and passenger load factors. Capacity is expected to increase over time due to planned infrastructure improvements. If the projected demand in air travel exceeds the capacity constraint, demand is reduced to match the constraint.

Aircraft Stock/Efficiency Assumptions

The aircraft stock and efficiency module consists of a stock model of wide body, narrow body, and regional jets by vintage. Total aircraft supply for a given year is based on the initial supply of aircraft for model year 2003, new passenger sales, and the survival rate by vintage (Table 32).70 New passenger sales are a function of revenue passenger miles and gross domestic product.

Older planes, wide and narrow body planes over 25 years of age are placed as cargo jets according to a cargo percentage varying from 50 percent of 25 year old planes to 100 percent of those aircraft 30 years and older. The available seat-miles per plane, which measure the carrying capacity of the airplanes by aircraft type, vary over time, with wide bodies remaining constant and narrow bodies increasing.71 The difference between the seat-miles demanded and the available seat-miles represents potential newly purchased planes. If demand is less than supply, then passenger aircraft is parked, starting with twenty nine year old aircraft, at a pre-defined rate. Aircraft continues to be parked until equilibrium is reached. If supply is less than demand planes that have been temporarily stored, or parked, are brought back into service.

Technological availability, economic viability, and efficiency characteristics of new aircraft are based on the technologies listed in the Oak Ridge National Laboratory Air Transport Energy Use Model (Table 33).72 Fuel efficiency of new aircraft acquisitions represents, at a minimum, a 5-percent improvement over the stock efficiency of surviving airplanes.73 Maximum growth rates of fuel efficiency for new aircraft are based on a future technology improvement list consisting of an estimate of the introduction year, jet fuel price, and an estimate of the proposed marginal fuel efficiency improvement. Regional shares of all types of aircraft fuel are assumed to be constant and are consistent with the *State Energy Data Report* estimate of regional jet fuel shares.74

Table 32. 2003 Passenger and Cargo Aircraft Supply and Survival Rate

Aircraft Type	New	1-10	11-20	21-30	>30	Total
	Age of Aircraft (years)					
Passenger						
Narrow Body	157	1651	1560	657	428	4,453
Wide Body	32	372	305	220	20	949
Regional Jets	279	919	71	9	12	1,290
Cargo						
Narrow Body	0	49	45	163	292	549
Wide Body	6	141	119	139	19	424
Survival Curve (fraction)	**New**	**5**	**10**	**20**	**30**	
Narrow Body	1.0000	0.9998	0.9992	0.9911	0.9256	
Wide Body	1.0000	0.9980	0.9954	0.9754	0.8892	
Regional Jets	1.0000	0.9967	0.9942	0.9816	0.9447	

Source: Jet Information Services, 2002 World Jet Inventory, data tables (2002).

Table 33. Future New Aircraft Technology Improvement List

Proposed Technology	Introduction Year	Jet Fuel Price Necessary For Cost-Effectiveness (2003 dollars per gallon)	Seat-Miles per Gallon Gain Over 1990 (percent)
Engines			
Ultra-high Bypass	2008	$0.68	10
Propfan	2000	$1.67	23
Thermodynamics	2010	$1.50	20
Aerodynamics			
Hybrid Laminar Flow	2020	$1.87	15
Advanced Aerodynamics	2000	$2.09	18
Other			
Weight Reducing Materials	2000	-	15

Source: Greene, D.L., *Energy Efficiency Improvement Potential of Commercial Aircraft to 2010*, ORNL-6622, 6/1990., and from data tables in the Air Transportation Energy Use Model (ATEM), Oak Ridge National

Legislation

Energy Policy Act of 1992 (EPACT)

Fleet alternative-fuel vehicle sales necessary to meet the EPACT regulations are derived based on the mandates as they currently stand and the Commercial Fleet Vehicle Module calculations. Total projected AFV sales are divided into fleets by government, business, and fuel providers (Table 34). Business fleet EPACT mandates are not included in the projections for AFV sales pending a decision on a proposed rulemaking.

Table 34. EPACT Legislative Mandates for AFV Purchases by Fleet Type and Year
(Percent)

Year	Municipal & Business	Federal	State	Fuel Providers	Electric Utilities
1996	-	25	-	-	-
1997	-	33	10	30	-
1998	-	50	15	50	30
1999	-	75	25	70	50
2000	-	75	50	90	70
2001	-	75	75	90	90
2002	20	75	75	90	90
2003	40	75	75	90	90
2004	60	75	75	90	90
2005	70	75	75	70	90

Source: EIA, *Alternatives to Traditional Transportation Fuels 1994*, DOE/EIA-0585(94), (Washington, D.C, February 1996).

Because the commercial fleet model operates on three fleet type representations (business, government, and utility), the federal and state mandates are weighted by fleet vehicle stocks to create a composite mandate for both. The same combining methodology is used to create a composite mandate for electric utilities and fuel providers based on fleet vehicle stocks.[75] Fleet vehicle stocks by car and light truck are disaggregated to include only fleets of 50 or more (in accordance with EPACT) by using a fleet size distribution function based on The Fleet Factbook and the Truck and Inventory Use Survey.[76,77] To account for the EPACT regulations which stipulate that "covered" fleets (which refer to fleets bound by the EPACT mandates) include only fleets in the metropolitan statistical areas (MSA's) of 250,000 population or greater, 90 percent of the business and utility fleets are included and 63 percent are included for government fleets.[78] EPACT covered fleets only include those fleets that can be centrally fueled, which is assumed to be 50 percent of the fleets for all fleet types, and only fleets of 50 or more that had 20 vehicles or more in those MSA's of 250,000 or greater population. It is assumed that 90 percent of all fleets are within this category except for business fleets, which are assumed to be 75 percent.[79]

Low Emission Vehicle Program (LEVP)

The LEVP was originally passed into legislation in 1990 in the State of California. It began as the implementation of a voluntary opt-in pilot program under the purview of Clean Air Act Amendments of 1990 (CAAA90), which included a provision that other States could opt in to the California program to achieve lower emissions levels than would otherwise be achieved through CAAA90. New York, Massachusetts, Maine, and Vermont have elected to adopt the California LEVP.

The LEVP is an emissions-based policy, setting sales mandates for 6 categories of low-emission vehicles: low-emission vehicles (LEVs), ultra-low-emission vehicles (ULEVs), super-ultra low emission vehicles (SULEVs), partial zero-emission vehicles (PZEVs), advanced technology partial zero emission vehicles (AT-PZEVs), and zero-emission vehicles (ZEVs). The LEVP requires that in 2005 10 percent of a manufacturer's sales are ZEVs, increasing to 11 percent in 2009, 12 percent in 2012, 14 percent in 2015, and 16 percent in 2018 where it remains constant thereafter. In December 2001 California Air Resources Board (CARB) amended the LEVP to allow ZEV credits for partial zero emission vehicles (PVEVs), advanced technology partial zero emission vehicles (AT-PZEVs), phase-in credits for pure ZEVs, and additional credits for high fuel economy vehicles. Auto manufactures filed federal suits in both California and

New York in 2002 arguing that the revisions to the ZEV program are pre-empted by the federal fuel economy statute enacted by the Energy Policy and Conservation Act of 1975.

In April 2003, CARB proposed further amendments to the ZEV mandates in response to the suit filed by the auto manufacturers. Due the changes proposed in the amendment (Resolution 03-4), the auto manufacturers agreed to settle litigation with California. The proposed mandate places a greater emphasis on emissions reductions from PZEVs and AT-PZEVs and requires that manufacturers produce a minimum number of fuel cell and electric vehicles. The mandate still requires the minimum ZEV sales goals, but includes phase-in multipliers for pure ZEVs and allows 20 percent of the sales requirement to be met with AT-PZEVs and 60 percent of the requirement to be met with PZEVs. AT-PZEVs and PZEVs are allowed 0.2 credits per vehicle. EIA assumes that credit allowances for PZEVs will be met with conventional vehicle technology, that hybrid vehicles will be sold to meet the AT-PZEV allowances, and that battery electric and hydrogen fuel cell vehicles will be sold to meet the pure ZEV requirements. Given the auto manufacturers response to the proposed amendments, AEO 2004 incorporates the proposed mandates in the forecast as if they were enacted law.

The vehicle sales module compares the legislatively mandated sales to the results from the consumer driven sales shares. If the consumer driven sales shares are less than the legislatively mandated sales requirements, then the legislative requirements serve as a minimum constraint for the hybrid, electric, and fuel cell vehicle sales.

High Technology and 2005 Technology Cases

In the *high technology case*, the conventional fuel saving technology characteristics came from a study by the American Council for an Energy Efficient Economy.80 Tables 35 and 36 summarize the High Technology matrix for cars and light trucks. High technology case assumptions for heavy trucks reflect the optimistic values, with respect to efficiency improvement, for advanced engine and emission control technologies as reported by ANL.81

The *2005 technology case* assumes that new fuel efficiency technologies are held constant at 2004 levels over the forecast. As a result, the energy use in the transportation sector was 5.8 percent higher (2.31 quadrillion Btu) than in the reference case by 2025. 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, or fuel economy was captured.

Table 35. High Technology Matrix For Cars

	Fractional Fuel Efficiency Change	Incremental Cost (1990$)	Incremental Cost ($/Unit Wt.)	Incremental Weight (Lbs.)	Incremental Weight (Lbs./Unit Wt.)	Introduction Year	Fractional Horse-power Change
Unit Body Construction	4	100	0	0	-6	1980	0
Material Substitution II	3.3	0	0.4	0	-5	1990	0
Material Substitution III	6.6	0	0.5	0	-10	1998	0
Material Substitution IV	9.9	0	0.5	0	-15	2006	0
Material Substitution V	13.2	0	1.1	0	-20	2014	0
Drag Reduction II	1.6	0	0	0	0	1988	0
Drag Reduction III	3.2	0	0	0	0.2	1992	0
Drag Reduction IV	6.3	145	0	0	0.5	2002	0
Drag Reduction V	8	225	0	0	1	2010	0
Roll-Over Technology	-1.5	100	0	0	2.2	2005	0
Side Impact Technology	-1.5	100	0	0	2.2	2005	0
Adv Low Loss Torque Converter	2	25	0	0	0	1999	0
Early Torque Converter Lockup	1	8	0	0	0	2002	0
Aggressive Shift Logic	3.5	65	0	0	0	1999	0
4-Speed Automatic	4.5	285	0	10	0	1980	0
5-Speed Automatic	8	410	0	20	0	1995	0
6-Speed Automatic	9.5	495	0	30	0	2004	0
6-Speed Manual	2	80	0	20	0	1995	0
CVT	11.5	365	0	-25	0	1998	0
Automated Manual Trans	8	100	0	0	0	2006	0
Roller Cam	2	16	0	0	0	1980	0
OHC/AdvOHV-4 Cylinder	3	60	0	0	0	1980	10
OHC/AdvOHV-6 Cylinder	3	80	0	0	0	1987	10
OHC/AdvOHV-8 Cylinder	3	100	0	0	0	1986	10
4-Valve/4-Cylinder	8.8	185	0	10	0	1988	17
4-Valve/6-Cylinder	8.8	260	0	15	0	1992	17
4 Valve/8-Cylinder	8.8	320	0	20	0	1994	17
5 Valve/6-Cylinder	9	300	0	18	0	1998	20
VVT-4 Cylinder	2.5	30	0	10	0	1994	5
VVT-6 Cylinder	2.5	90	0	20	0	1993	5
VVT-8 Cylinder	2.5	90	0	20	0	1993	5
VVL-4 Cylinder	7.5	150	0	25	0	1997	10
VVL-6 Cylinder	7.5	205	0	40	0	2000	10
VVL-8 Cylinder	7.5	290	0	50	0	2000	10
Camless Valve Actuation-4cyl	12	450	0	35	0	2009	13
Camless Valve Actuation-6cyl	12	600	0	55	0	2008	13
Camless Valve Actuation-8cyl	12	750	0	75	0	2007	13
Cylinder Deactivation	9	250	0	10	0	2004	0
Turbocharging/ Supercharging	5	475	0	-100	0	1980	15
Engine Friction Reduction I	2	25	0	0	0	1992	3
Engine Friction Reduction II	3.5	63	0	0	0	2000	5
Engine Friction Reduction III	5	114	0	0	0	2008	7
Engine Friction Reduction IV	6.5	177	0	0	0	2016	9
Stoichiometric GDI/4-Cylinder	7	300	0	20	0	2006	10
Stoichiometric GDI/6-Cylinder	7	450	0	30	0	2006	10
Lean Burn GDI	6	250	0	20	0	2006	0
5W-30 Engine Oil	1	10.5	0	0	0	1998	0
5W-20 Engine Oil	2	20	0	0	0	2003	0
OW-20 Engine Oil	3.1	80	0	0	0	2030	0
Electric Power Steering	2	50	0	0	0	2004	0
Improved Alternator	0.3	15	0	0	0	2005	0
Improved Oil/Water Pump	0.5	10	0	0	0	2000	0
Electric Oil/Water Pump	1	50	0	0	0	2007	0
Tires II	1.5	15	0	-8	0	1995	0
Tires III	3	35	0	-12	0	2005	0
Tires IV	6	90	0	-16	0	2015	0
Front Wheel Drive	6	250	0	0	-6	1980	0
Four Wheel Drive Improvements	2	100	0	0	-1	2000	0
42V-Launch Assist and Regen	5	400	0	80	0	2005	-5
42V-Engine Off at Idle	6	500	0	45	0	2005	0
Tier 2 Emissions Technology	-1	120	0	20	0	2006	0
Increased Size/Weight	-1.7	0	0	0	2.55	2001	0
Variable Compression Ratio	4	350	0	25	0	2015	0

Source: Energy and Environmental Analysis, *Documentation of Technology included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (September, 2002). National Research Council, *Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards* (Copyright 2002).

Table 36. High Technology Matrix For Light Trucks

	Fractional Fuel Efficiency Change	Incremental Cost (1990$)	Incremental Cost ($/Unit Wt.)	Incremenal Weight (Lbs.)	Incremental Weight (Lbs./Unit Wt.)	Introduction Year	Fractional Horse-power Change
Unit Body Construction	4	100	0	0	-6	1980	0
Material Substitution II	3.3	0	0.4	0	-5	1994	0
Material Substitution III	6.6	0	0.5	0	-10	2002	0
Material Substitution IV	9.9	0	0.5	0	-15	2010	0
Material Substitution V	13.2	0	1.1	0	-20	2018	0
Drag Reduction II	1.6	0	0	0	0	1992	0
Drag Reduction III	3.2	0	0	0	0.2	1998	0
Drag Reduction IV	6.3	145	0	0	0.5	2006	0
Drag Reduction V	8	225	0	0	1	2014	0
Roll-Over Technology	-1.5	100	0	0	2.2	2006	0
Side Impact Technology	-1.5	100	0	0	2.2	2006	0
Adv Low Loss Torque Converter	2	25	0	0	0	2005	0
Early Torque Converter Lockup	1	8	0	0	0	2006	0
Aggressive Shift Logic	3.5	65	0	0	0	2006	0
4-Speed Automatic	4.5	285	0	10	0	1980	0
5-Speed Automatic	8	410	0	20	0	1999	0
6-Speed Automatic	9.5	495	0	30	0	2008	0
6-Speed Manual	2	80	0	20	0	2000	0
CVT	11.5	365	0	-25	0	2008	0
Automated Manual Trans	8	100	0	0	0	2010	0
Roller Cam	2	16	0	0	0	1985	0
OHC/AdvOHV-4 Cylinder	3	60	0	0	0	1980	10
OHC/AdvOHV-6 Cylinder	3	80	0	0	0	1990	10
OHC/AdvOHV-8 Cylinder	3	100	0	0	0	1990	10
4-Valve/4-Cylinder	8.8	185	0	10	0	1998	17
4-Valve/6-Cylinder	8.8	260	0	15	0	2000	17
4 Valve/8-Cylinder	8.8	320	0	20	0	2000	17
5 Valve/6-Cylinder	9	300	0	18	0	2010	20
VVT-4 Cylinder	2.5	30	0	10	0	1998	5
VVT-6 Cylinder	2.5	90	0	20	0	1997	5
VVT-8 Cylinder	2.5	90	0	20	0	1997	5
VVL-4 Cylinder	7.5	150	0	25	0	2002	10
VVL-6 Cylinder	7.5	205	0	40	0	2001	10
VVL-8 Cylinder	7.5	290	0	50	0	2006	10
Camless Valve Actuation-4cyl	12	450	0	35	0	2014	13
Camless Valve Actuation-6cyl	12	600	0	55	0	2012	13
Camless Valve Actuation-8cyl	12	750	0	75	0	2011	13
Cylinder Deactivation	9	250	0	10	0	2004	0
Turbocharging/Supercharging	5	475	0	-100	0	1987	15
Engine Friction Reduction I	2	25	0	0	0	1992	3
Engine Friction Reduction II	3.5	63	0	0	0	2000	5
Engine Friction Reduction III	5	114	0	0	0	2010	7
Engine Friction Reduction IV	6.5	177	0	0	0	2016	9
Stoichiometric GDI/4-Cylinder	7	300	0	20	0	2008	10
Stoichiometric GDI/6-Cylinder	7	450	0	30	0	2010	10
Lean Burn GDI	6	250	0	20	0	2010	0
5W-30 Engine Oil	1	10.5	0	0	0	1998	0
5W-20 Engine Oil	2	20	0	0	0	2003	0
OW-20 Engine Oil	3.1	80	0	0	0	2030	0
Electric Power Steering	2	50	0	0	0	2005	0
Improved Alternator	0.3	15	0	0	0	2005	0
Improved Oil/Water Pump	0.5	10	0	0	0	2000	0
Electric Oil/Water Pump	1	50	0	0	0	2008	0
Tires II	1.5	15	0	-8	0	1995	0
Tires III	3	35	0	-12	0	2005	0
Tires IV	6	90	0	-16	0	2015	0
Front Wheel Drive	6	250	0	0	-3	1984	0
Four Wheel Drive Improvements	2	100	0	0	-1	2000	0
42V-Launch Assist and Regen	5	400	0	80	0	2005	-5
42V-Engine Off at Idle	6	500	0	45	0	2005	0
Tier 2 EmissionsTechnology	-1	160	0	20	0	2006	0
Increased Size/Weight	-1.7	0	0	0	3.75	2001	0
Variable Compression Ratio	4	350	0	25	0	2015	0

Source: Energy and Enviromental Analysis, *Documentation of Technology included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (September, 2002). National Research Council, *Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards* (Copyright 2002).

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Electricity Market Module

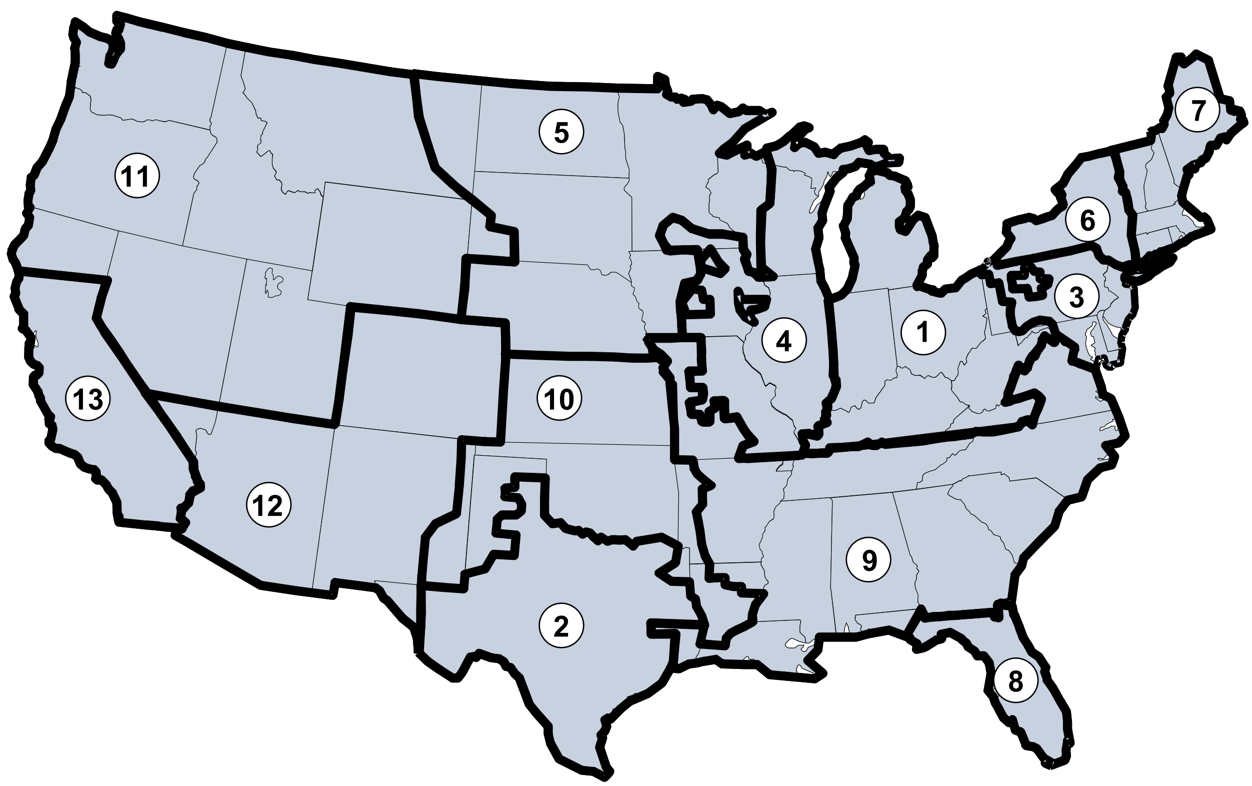
The NEMS Electricity Market Module (EMM) represents the capacity planning, dispatching, and pricing of electricity. It is composed of four submodules—electricity capacity planning, electricity fuel dispatching, load and demand-side management, and electricity finance and pricing. It includes nonutility capacity and generation, and electricity transmission and trade. A detailed description of the EMM is provided in the EIA publication, *Electricity Market Module of the National Energy Modeling System 2005*, DOE/EIA-M068(2005).

Based on fuel prices and electricity demands provided by the other modules of the NEMS, the EMM determines the most economical way to supply electricity, within environmental and operational constraints. There are assumptions about the operations of the electricity sector and the costs of various options in each of the EMM submodules. This section describes the model parameters and assumptions used in EMM. It includes a discussion of legislation and regulations that are incorporated in EMM as well as information about the climate change action plan. The various electricity and technology cases are also described.

EMM Regions

The supply regions used in EMM are based on the North American Electric Reliability Council regions and subregions shown in Figure 6.

Figure 6. Electricity Market Model Supply Regions



1 East Central Area Reliability Coordination Agreement (ECAR)
2 Electric Reliability Council of Texas (ERCOT)
3 Mid-Atlantic Area Council (MAAC)
4 Mid-America Interconnected Network (MAIN)
5 Mid-Continent Area Power Pool (MAPP)
6. New York (NY)
7. New England (NE)
8 Florida Reliability Coordinating Council (FL)
9 Southeastern Electric Reliability Council (SERC)
10 Southwest Power Pool (SPP)
11 Northwest Power Pool (NWP)
12. Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada (RA)
13 California (CA)

Model Parameters and Assumptions

Generating Capacity Types

The capacity types represented in the EMM are shown in Table 37.

Table 37. Generating Capacity Types Represented in the Electricity Market Module

Capacity Type
Existing coal steam plants[1]
High Sulfur Pulverized Coal with Wet Flue Gas Desulfurization
Advanced Coal - Integrated Coal Gasification Combined Cycle
Advanced Coal with carbon sequestration
Oil/Gas Steam - Oil/Gas Steam Turbine
Combined Cycle - Conventional Gas/Oil Combined Cycle Combustion Turbine
Advanced Combined Cycle - Advanced Gas/Oil Combined Cycle Combustion Turbine
Advanced Combined Cycle with carbon sequestration
Combustion Turbine - Conventional Combustion Turbine
Advanced Combustion Turbine - Steam Injected Gas Turbine
Molten Carbonate Fuel Cell
Conventional Nuclear
Advanced Nuclear - Advanced Light Water Reactor
Generic Distributed Generation - Baseload
Generic Distributed Generation - Peak
Conventional Hydropower - Hydraulic Turbine
Pumped Storage - Hydraulic Turbine Reversible
Geothermal
Municipal Solid Waste
Biomass - Integrated Gasification Combined-Cycle
Solar Thermal - Central Receiver
Solar Photovoltaic - Single Axis Flat Plate
Wind

[1]The EMM represents 32 different types of existing coal steam plants, based on the different possible configuration of No_x, particulate and SO_2 emission control devices, as well as future options for controlling mercury.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

New Generating Plant Characteristics

The cost and performance characteristics of new generating technologies are inputs to the electricity capacity planning submodule (Table 38). These characteristics are used in combination with fuel prices from the NEMS fuel supply modules and foresight on fuel prices, to compare options when new capacity is needed. Heat rates for fossil-fueled technologies are assumed to decline linearly through 2010.

The overnight costs shown in Table 38 are the cost estimates to build a plant in a typical region of the country. Differences in plant costs due to regional distinctions are calculated by applying regional multipliers that represent variations in the cost of labor. The base overnight cost is multiplied by a project contingency factor and a technological optimism factor (described later in this chapter), resulting in the total construction cost for the first-of-a-kind unit used for the capacity choice decision.

Table 38. Cost and Performance Characteristics of New Central Station Electricity Generating Technologies

Technology	Online Year[1]	Size (mW)	Leadtimes (Years)	Base Overnight Costs in 2004 ($2003/kW)	Contingency Factors: Project Contingency Factor	Contingency Factors: Technological Optimism Factor[2]	Total Overnight Cost in 2004[3] (2003 $/kW)	Variable O&M[5] ($2003 mills/kWh)	Fixed O&M[5] ($2003/kW)	Heatrate in 2004 (Btu/kWhr)	Heatrate nth-of-a-kind (Btu/kWr)
Scrubbed Coal New	2008	600	4	1,134	1.07	1.00	1,213	4.06	24.36	8,844	8,600
Integrated Coal-Gasification Combined Cycle (IGCC)	2008	550	4	1,310	1.07	1.00	1,402	2.58	34.21	8,309	7,200
IGCC with Carbon Sequestration	2010	380	4	1,820	1.07	1.03	2,006	3.93	40.26	9,713	7,920
Conv Gas/Oil Comb Cycle	2007	250	3	540	1.05	1.00	567	1.83	11.04	7,196	6,800
Adv Gas/Oil Comb Cycle (CC)	2007	400	3	517	1.08	1.00	558	1.77	10.35	6,752	6,333
ADV CC with Carbon Sequestration	2010	400	3	992	1.08	1.04	1,114	2.60	17.60	8,613	7,493
Conv Combustion Turbine[5]	2006	160	2	376	1.05	1.00	395	3.16	10.72	10,817	10,450
Adv Combustion Turbine	2006	230	2	356	1.05	1.00	374	2.80	9.31	9,183	8,550
Fuel Cells	2007	10	3	3,679	1.05	1.10	4,250	42.40	5.00	7,930	6,960
Advanced Nuclear	2013	1000	6	1,694	1.10	1.05	1,957	0.44	60.06	10,400	10,400
Distributed Generation -Base	2007	2	3	769	1.05	1.00	807	6.30	14.18	9,950	8,900
Distributed Generation -Peak	2006	1	2	924	1.05	1.00	970	6.30	14.18	11,200	9,880
Biomass	2008	80	4	1,612	1.07	1.02	1,757	2.96	47.18	8,911	8,911
MSW - Landfill Gas	2007	30	3	1,402	1.07	1.00	1,500	0.01	101.07	13,648	13,648
Geothermal [6,7]	2008	50	4	2,960	1.05	1.00	3,108	0.00	104.98	45,335	36,468
Conventional Hydropower[6]	2008	500	4	1,319	1.10	1.00	1,451	4.60	12.35	10,338	10,338
Wind	2007	50	3	1,060	1.07	1.00	1,134	0.00	26.81	10,280	10,280
Solar Thermal[7]	2007	100	3	2,515	1.07	1.10	2,960	0.00	50.23	10,280	10,280
Photovoltaic[7]	2006	5	2	3,868	1.05	1.10	4,467	0.00	10.34	10,280	10,280

[1]Online year represents the first year that a new unit could be completed, given an order date of 2004.

[2]The technological optimism factor is applied to the first four units of a new, unproven design, it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

[3]Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2004.

[4]O&M = Operations and maintenance.

[5]Combustion turbine units can be built by the model prior to 2006 if necessary to meet a given region's reserve margin.

[6]Because geothermal and hydro cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.

[7]Capital costs for geothermal and solar technologies are shown before the 10 percent investment tax credit is applied.

Sources: The values shown in this table are developed by the Energy Information Administration, Office of Integrated Analysis and Forecasting, from analysis of reports and discussions with various sources from industry, government, and the Department of Energy Fuel Offices and National Laboratories. They are not based on any specific technology model, but rather, are meant to represent the cost and performance of typical plants under normal operating conditions for each plant type. Key sources reviewed are listed in the 'Notes and Sources' section at the end of the chapter.

Technological Optimism and Learning

Overnight costs for each technology are calculated as a function of regional construction parameters, project contingency, and technological optimism and learning factors.

The technological optimism factor represents the demonstrated tendency to underestimate actual costs for a first-of-a-kind, unproven technology. As experience is gained (after building 4 units) the technological optimism factor is gradually reduced to 1.0.

The learning function in NEMS is determined at a component level. Each new technology is broken into its major components, and each component is identified as revolutionary, evolutionary or mature. Different learning rates are assumed for each component, based on the level of experience with the design component (Table 39). Where technologies use similar components, these components learn at the same rate as these units are built. For example, it is assumed that the underlying turbine generator for a combustion turbine, combined cycle and integrated coal-gasification combined cycle unit is basically the same. Therefore construction of any of these technologies would contribute to learning reductions for the turbine component.

The learning function has the nonlinear form:

$$OC(C) = a^*C^{-b},$$

where C is the cumulative capacity for the technology component.

Table 39. Learning Parameters for New Generating Technology Components

Technology Component	Period 1 Learning Rate	Period 2 Learning Rate	Period 3 Learning Rate	Period 1 Doublings	Period 2 Doublings	Minimum Total Learning by 2025
Pulverized Coal	-	-	1%	-	-	5%
Combustion Turbine - conventional	-	-	1%	-	-	5%
Combustion Turbine - advanced	-	10%	1%	-	5	10%
HRSG[1]	-	-	1%	-	-	5%
Gasifier	-	10%	1%	-	5	10%
Carbon Capture/Sequestration	20%	10%	1%	3	5	20%
Balance of Plant - IGCC	-	-	1%	-	-	5%
Balance of Plant - Turbine	-	-	1%	-	-	5%
Balance of Plant - Combined Cycle	-	-	1%	-	-	5%
Fuel Cell	10%	5%	1%	3	5	10%
Advanced Nuclear	5%	3%	1%	3	5	10%
Fuel prep - Biomass IGCC	20%	10%	1%	3	5	20%
Distributed Generation - Base	-	5%	1%	-	5	10%
Distributed Generation - Peak	-	5%	1%	-	5	10%
Geothermal	-	8%	1%	-	5	10%
Municipal Solid Waste	-	-	1%	-	-	5%
Hydropower	-	-	1%	-	-	5%
Wind	-	-	1%	-	-	1%
Solar Thermal	20%	10%	1%	3	5	20%
Solar PV	15%	8%	1%	3	5	20%

[1]HRSG = Heat Recovery Steam Generator

Note: Please see the text for a description of the methodology for learning in the Electricity Market Module.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

The progress ratio (*pr*) is defined by speed of learning (e.g., how much costs decline for every doubling of capacity). The reduction in capital cost for every doubling of cumulative capacity (f) is an exogenous parameter input for each component (Table 39). Consequently, the progress ratio and *f* are related by:

$$pr = 2^{-b} = (1 - f)$$

The parameter “b” is calculated by (b =-(ln(1-*f*)/ln(2)). The parameter “a” can be found from initial conditions. That is,

$$a = OC(C0)/C0^{-b}$$

where C0 is the cumulative initial capacity. Thus, once the rates of learning (f) and the cumulative capacity (C0) are known for each interval, the corresponding parameters (a and b) of the nonlinear function are known. Three learning steps were developed, to reflect different stages of learning as a new design is introduced to the market. New designs with a significant amount of untested technology will see high rates of learning initially, while more conventional designs will not have as much learning potential. All design components receive a minimal amount of learning, even if new capacity additions are not projected. This represents cost reductions due to future international development or increased research and development.

Once the learning rate by component is calculated, a weighted average learning factor is calculated for each technology. The weights are based on the share of the initial cost estimate that is attributable to each component (Table 40). For technologies that do not share components, this weighted average learning rate is calculated exogenously, and input as a single component. These technologies may still have a mix of revolutionary components and more mature components, but it is not necessary to include this detail in the model unless capacity from multiple technologies would contribute to the component learning.

Table 40. Component Cost Weights for New Technologies

Technology	Combustion Turbine-conventional	Combustion Turbine-advanced	HRSG	Gasifier	Carbon Capture/ Sequestration	Balance of Plant-IGCC	Balance of Plant-Turbine	Balance of Plant-Combined Cycle	Fuelprep Biomass IGCC
Integrated Coal_Gasification Comb Cycle (IGCC)	0%	15%	20%	41%	0%	24%	0%	0%	0%
IGCC with carbon sequestration	0%	10%	15%	30%	30%	15%	0%	0%	0%
Conv Gas/Oil Comb Cycle	30%	0%	40%	0%	0%	0%	0%	30%	0%
Adv Gas/Oil Comb Cycle (CC)	0%	30%	40%	0%	0%	0%	0%	30%	0%
Adv CC with carbon sequestration	0%	20%	25%	0%	40%	0%	0%	15%	0%
Conv Comb Turbine	50%	0%	0%	0%	0%	0%	50%	0%	0%
Adv Comb Turbine	0%	50%	0%	0%	0%	0%	50%	0%	0%
Biomass	0%	12%	16%	33%	0%	20%	0%	0%	19%

Note: All unlisted technologies have a 100% weight with the corresponding component. Components are not broken out for all technologies unless there is overlap with other technologies.

HRSG = Heat Recovery Steam Generator.

Source: Market Based Advanced Coal Power Systems, May 1999, DOE/FE-0400

Table 41 shows the capacity credit toward component learning for the various technologies. It was assumed that for all combined-cycle technologies, the turbine unit contributed two-thirds of the capacity, and the steam unit one-third. Therefore, building one gigawatt of gas combined cycle would contribute 0.67 gigawatts toward turbine learning, and 0.33 gigawatts toward steam learning. All non-capacity components, such as the balance of plant category, contribute 100 percent toward the component learning.

International Learning. In *AEO2005*, capital costs for all new electricity generating technologies (fossil, nuclear, and renewable) decrease in response to foreign and domestic experience. Foreign units of new technologies are assumed to contribute to reductions in capital costs for units that are installed in the United States to the extent that (1) the technology characteristics are similar to those used in U.S. markets, (2) the design and construction firms and key personnel compete in the U.S. market, (3) the owning and operating

Table 41. Component Capacity Weights for New Technologies

Technology	Combustion Turbine-conventional	Combustion Turbine-advanced	HRSG	Gasifier	Carbon Capture/ Sequestration	Balance of Plant-IGCC	Balance of Plant-Turbine	Balance of Plant-Combined Cycle	Fuelprep Biomass IGCC
Integrated Coal_Gasification Comb Cycle (IGCC)	0%	67%	33%	100%	0%	100%	0%	0%	0%
IGCC with carbon sequestration	0%	67%	33%	100%	100%	100%	0%	0%	0%
Conv Gas/Oil Comb Cycle	67%	0%	33%	0%	0%	0%	0%	100%	0%
Adv Gas/Oil Comb Cycle (CC)	0%	67%	33%	0%	0%	0%	0%	100%	0%
Adv CC with carbon sequestration	0%	67%	33%	0%	100%	0%	0%	100%	0%
Conv Comb Turbine	100%	0%	0%	0%	0%	0%	100%	0%	0%
Adv Comb Turbine	0%	100%	0%	0%	0%	0%	100%	0%	0%
Biomass	0%	67%	33%	100%	0%	100%	0%	0%	100%

HRSG = Heat Recovery Steam Generator.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

firm competes actively in the U.S. market, and (4) there exists relatively complete information about the status of the associated facility. If the new foreign units do not satisfy one or more of these requirements, they are given a reduced weight or not included in the domestic learning effects calculation.

AEO2005 includes 1,938 megawatts of advanced coal gasification combined-cycle capacity, 5,244 megawatts of advanced combined-cycle natural gas capacity, 11 megawatts of biomass capacity and 47 megawatts of wind capacity to be built outside the United States from 2000 through 2003. The learning function also includes 7,200 megawatts of advanced nuclear capacity, representing two completed units and four additional units under construction in Asia.

Distributed Generation

Distributed generation is modeled in the end-use sectors as well as in the EMM, which is described in the appropriate chapters. This section describes the representation of distributed generation in the EMM only. Two generic distributed technologies are modeled. The first technology represents peaking capacity (capacity that has relatively high operating costs and is operated when demand levels are at their highest). The second generic technology for distributed generation represents base load capacity (capacity that is operated on a continuous basis under a variety of demand levels). See Table 38 for costs and performance assumptions. It is assumed that these plants reduce the costs of transmission upgrades that would otherwise be needed.

Representation of Electricity Demand

The annual electricity demand projections from the NEMS demand modules are converted into load duration curves for each of the EMM regions (based on North American Electric Reliability Council regions and subregions) using historical hourly load data. However, unlike traditional load duration curves where the demands for an entire period would be ordered from highest to lowest, losing their chronological order, the load duration curves in the EMM are segmented into the 9 time periods shown in Table 42. The summer and winter peak periods are represented in the model by 2 vertical slices each (a peak slice and an off-peak slice) while the remaining 7 periods are represented by 1 vertical slice each, resulting in a total of 11 vertical slices. The time periods shown were chosen to accommodate intermittent generating technologies (i.e., solar and wind facilities) and demand-side management programs.

Reserve margins—the percentage of capacity required in excess of peak demand needed for unforeseeable outages—are currently assumed for all EMM regions. Target reserve margins range from 6 to 18 percent,

Table 42. Load Segments in the Electricity Market Module

Season	Months	Period	Hours
Summer	June-September	Daytime	0700-1800
		Morning/Evening	0500-0700 and 1800-2400
		Night	0000-0500
Winter	December-March	Daytime	0800-1600
		Morning/Evening	0500-0800 and 1600-2400
		Night	0000-0500
Off-peak	April-May	Daytime	0700-1700
	October-November	Morning/Evening	0500-0700 and 1700-2400
		Night	0000-0500

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

and were set based on an off-line analysis comparing the marginal cost of capacity and the cost of unserved energy.

Fossil Fuel-Fired and Nuclear Steam Plant Retirement

Fossil-fired steam plant retirements and nuclear retirements are calculated endogenously within the model. Plants are assumed to retire when it is no longer economical to continue running them. Each year, the model determines whether the market price of electricity is sufficient to support the continued operation of existing plants. If the expected revenues from these plants are not sufficient to cover the annual going forward costs, the plant is assumed to retire if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, operations and maintenance costs and annual capital additions, which are plant specific based on historical data. The average capital additions for existing plants are $11 per kilowatt (kW) for oil and gas steam plants, $6 per kW for combined-cycle plants, and combustion turbines, $15 per kW for coal plants and $18 per kW for nuclear plants (in 2003 dollars). These costs are added to existing plants regardless of their age. Beyond 30 years of age an additional $5 per kW capital charge for fossil plants, and $27 per kW charge for nuclear plants is included in the retirement decision to reflect further investment to address impacts of aging. Age related cost increases are due to capital expenditures for major repairs or retrofits, decreases in plant performance, and/or increased maintenance costs to mitigate the effects of aging.

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 $105 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 the total output using biomass fuel, assuming sufficient residue 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 supply.

New Nuclear Plant Orders

A new nuclear technology competes with other fossil-fired and renewable technologies as new generating capacity is needed to meet increasing demand, or replace retiring capacity, throughout the forecast period. The cost assumptions for new nuclear units are based on an analysis of recent cost estimates for nuclear designs available in the United States and worldwide. The capital cost assumptions in the reference case represent the expense of building a new single unit nuclear plant of approximately 1,000 megawatts at a new “Greenfield” site. Since no new nuclear plants have been built in the US in many years, there is a great deal of uncertainty about the true costs of a new unit. The estimate used for *AEO2005* is an average of the construction costs incurred in completed advanced reactor builds in Asia, adjusting for expected learning from other units still under construction.

It is also important to note that there is a great deal of uncertainty about how the nuclear technology will evolve over the next 20 years. Currently, two conventional light water reactors along with the smaller, passively safe, Westinghouse AP600 power plant have had their designs certified by the NRC. A larger version of the Westinghouse design is also under review with the NRC. Additionally, the process to certify a number of more revolutionary reactor designs is just beginning. Thus, it is quite possible that within the next 20 years there will be wide range of designs that have been licensed by the NRC and could be built. Rather than attempting to “pick the winners” the cost estimates used here are more general, and do not deal with any one design.

Nuclear Uprates

The AEO2004 nuclear power forecast also assumes capacity increases at existing units. Nuclear plant operators can increase the rated capacity at plants through power uprates, which are license amendments that must be approved by the U.S. Nuclear Regulatory Commission (NRC). Uprates can vary from small (less than 2 percent) increases in capacity, which require very little capital investment or plant modifications, to extended uprates of 15-20 percent, requiring significant modifications. Historically, most uprates were small, and the AEO forecasts accounted for them only after they were implemented and reported, but recent surveys by the NRC and EIA have indicated that more extended power uprates are expected in the near future. The NRC approved 8 applications for power uprates in 2003, and another 12 were approved or pending in 2004. *AEO2005* 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 3.5 gigawatts between 2004 and 2025. Table 43 provides a summary of projected uprate capacity additions by region. In cases where the NRC did not specifically identify the unit expected to uprate, EIA assumed the units with the lowest operating costs would be the next likely candidates for power increases.

Table 43. Nuclear Upratres by EMM Region
(gigawatts)

Region	
East Central Area Reliability Coordination Agreement	0.00
Electric Reliability Council of Texas	0.42
Mid-Atlantic Area Council	0.54
Mid-America Interconnected Network	0.48
Mid-Continent Area Power Pool	0.00
New York	0.00
New England	0.00
Florida Reliability Coordinating Council	0.02
Southeastern Electric Reliability Council	2.05
Southwest Power Pool	0.01
Northwest Power Pool	0.01
Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada	0.00
California	0.00
Total	3.51

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, based on Nuclear Regulatory Commission survey, http://www.nrc.gov/reactors/operating/licensing/power-uprates.html

Interregional Electricity Trade

Both firm and economy electricity transactions among utilities in different regions are represented within the EMM. In general, firm power transactions involve the trading of capacity and energy to help another region satisfy its reserve margin requirement, while economy transactions involve energy transactions motivated by the marginal generation costs of different regions. The flow of power from region to region is constrained by the existing and planned capacity limits as reported in the National Electriic Reliability Council and Western Electric Coordinating Council Summer and Winter Assessment of Reliability of Bulk Electricity Supply in North America. Known firm power contracts are obtained from NERC's *Electricity Supply and Demand Database 2004*. They are locked in for the term of the contract. Contracts that are scheduled to expire by 2013 are assumed not to be renewed. Because there is no information available about expiration dates for contracts that go beyond 2013, they are assumed to be phased out by 2022. In addition, in certain regions where data show an established commitment to build plants to serve another region, new plants are permitted to be built to serve the other region's needs. This option is available to compete with other resource options.

Economy transactions are determined in the dispatching submodule by comparing the marginal generating costs of adjacent regions in each time slice. If one region has less expensive generating resources available in a given time period (adjusting for transmission losses and transmission capacity limits) than another region, the regions are allowed to exchange power.

International Electricity Trade

Two components of international firm power trade are represented in the EMM—existing and planned transactions, and unplanned transactions. Existing and planned transactions are obtained from the North American Electric Reliability Council's *Electricity Supply and Demand Database 2004*. Unplanned firm power trade is represented by competing Canadian supply with U.S. domestic supply options. Canadian supply is represented via supply curves using cost data from the Department of Energy report *Northern Lights: The Economic and Practical Potential of Imported Power from Canada*, (DOE/PE-0079).

International economy trade is determined endogenously based on surplus energy expected to be available from Canada by region in each time slice. Canadian surplus energy is determined using Canadian electricity supply and demand projections as reported in the Canadian National Energy Board report *Energy Supply and Demand to 2025.*

Electricity Pricing

The reference case assumes a transition to full competitive pricing in New York, New England, Mid-Atlantic Area Council, and Texas. California returned to return to almost fully regulated pricing in 2002, after beginning a transition to competition in 1998. In addition electricity prices in the East Central Area Reliability Council, the Mid-American Interconnected Network (Illinois, plus parts of Missouri, Michigan and Wisconsin), the Southeastern Electric Reliability Council, the Southwest Power Pool, the Northwest Power Pool, and the Rocky Mountain Power Area/Arizona are a weighted average of both competitive and regulated prices. Since some States in each of these regions have not taken action to deregulate their pricing of electricity, prices in those States are assumed to continue to be based on traditional cost-of-service pricing. The price for the region is a weighted average of the competitive price and the regulated price, with the weight based on the percent of the region that has taken action to deregulate. The reference case assumes that State-mandated price freezes or reductions during a specified transition period will occur based on the terms of the legislation. In general, the transition period is assumed to occur over a ten-year period from the effective date of restructuring, with a gradual shift to marginal cost pricing. In regions where none of the states in the region have introduced competition, electricity prices are assumed to remain regulated. The cost-of-service calculation is used to determine electricity prices in regulated regions.

The price of electricity to the consumer is comprised of the price of generation, transmission, and distribution including applicable taxes. Transmission and distribution are considered to remain regulated in the *AEO*; that is, the price of transmission and distribution is based on the average cost for each customer class. In the competitive regions, the generation component of price is based on marginal cost, which is defined as the cost of the last (or most expensive) unit dispatched. The marginal cost includes fuel, operating and maintenance, taxes, and a reliability price adjustment, which represents the value of capacity in periods of high demand. Therefore, the price of electricity in the regulated regions consists of the average cost of generation, transmission, and distribution for each customer class. The price of electricity in the four regions with a competitive generation market consists of the marginal cost of generation summed with the average costs of transmission and distribution. In the seven partially competitive regions the price is a combination of cost-of-service pricing and marginal pricing weighted by the share of sales.

In recent years, the move towards competition in the electricity business has led utilities to make efforts to reduce costs to improve their market position. These cost reduction efforts are reflected in utility operating data reported to the Federal Energy Regulatory Commission (FERC) and these trends have been incorporated in the *AEO2005*.

Both General and Administrative (G&A) expenses and Operations and Maintenance (O&M) expenses have shown declines in recent years. The O&M declines show variation based on the plant type. A regression analysis of recent data was done to determine the trend, and the resulting function was used to project declines throughout the forecast.

The analysis of G&A costs used data from 1992 through 2001, which had a 15 percent overall decline in G&A costs, and a 1.8 percent average annual decline rate. The *AEO2005* forecast assumes a further decline of 18 percent by 2025 based on the results of the regression analysis. The O&M cost data was available from 1990 through 2001, and showed average annual declines of 2.1 percent for all steam units, 1.8 percent for combined cycle and 1.5 percent for nuclear. The *AEO2005* assumes further declines in O&M expenses for these plant types, for a total decline through 2025 of 17 percent for combined cycle, 15 percent for steam and 8 percent for nuclear.

Fuel Price Expectations

Capacity planning decisions in the EMM are based on a life cycle cost analysis over a 20-year period. This requires foresight assumptions for fuel prices. Expected prices for coal, natural gas and oil are derived using rational expectations, or 'perfect foresight'. In this approach, expectations for future years are defined by the realized solution values for these years in a prior run. The expectations for the world oil price and natural gas wellhead price are set using the resulting prices from a prior run. The markups to the delivered fuel prices are calculated based on the markups from the previous year within a NEMS run. Coal prices are determined using the same coal supply curves developed in the Coal Market Module. The supply curves produce prices at different levels of coal production, as a function of labor productivity, and costs and utilization of mines. Expectations for each supply curve are developed in the EMM based on the actual demand changes from the prior run throughout the forecast horizon, resulting in updated mining utilization and different supply curves.

The perfect foresight approach generates an internally consistent scenario for which the formation of expectations is consistent with the projections realized in the model. The NEMS model involves iterative cycling of runs until the expected values and realized values for variables converge between cycles.

Legislation and Regulations

Clean Air Act Amendments of 1990 (CAAA90)

It is assumed that electricity producers comply with the CAAA90, which mandate a limit of 8.95 million tons 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. It is 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.

As specified in the CAAA90, EPA has developed a two-phase nitrogen oxide (NOx) program, with the first set of standards for existing coal plants applied in 1996 while the second set was implemented in 2000. Dry bottom wall-fired, and tangential fired boilers, the most common boiler types, referred to as Group 1 Boilers, were required to make significant reductions beginning in 1996 and further reductions in 2000. Relative to their uncontrolled emission rates, which range roughly between 0.6 and 1.0 pounds per million Btu, they are required to make reductions between 25 and 50 percent to meet the Phase I limits and further reductions to meet their Phase II limits. The EPA did not impose limits on existing oil and gas plants, but some states have additional NO_x regulations. All new fossil units are required to meet standards. In pounds per million Btu, these limits are 0.11 for conventional coal, 0.02 for advanced coal, 0.02 for combined cycle, and 0.08 for combustion turbines. These NO_x limits are incorporated in EMM.

In addition, the EPA has issued rules to limit the emissions of NOx, specifically calling for capping emissions during the summer season in 22 Eastern and Midwestern states. After an initial challenge, these rules have been upheld, and emissions limits have been finalized for 19 states and the District of Columbia (Table 44). Within EMM, electric generators in these 19 states must comply with the limit either by reducing their own emissions or purchasing allowances from others who have more than they need.

The costs of adding flue gas desulfurization equipment (FGD) to remove sulfur dioxide (SO_2) and selective catalytic reduction (SCR) equipment to remove nitrogen oxides (NO_x) are given below for 300, 500, and 700-megawatt coal plants. FGD units are assumed to remove 95 percent of the SO_2, while SCR units are assumed to remove 90 percent of the NO_x. The costs per megawatt of capacity decline with plant size and are shown in Table 45.

Table 44. Summer Season NO_x Emissions Budgets for 2004 and Beyond
(Thousand tons per season)

State	Emissions Cap
Alabama	29.02
Connecticut	2.65
Delaware	5.25
District of Columbia	0.21
Illinois	32.37
Indiana	47.73
Kentucky	36.50
Maryland	14.66
Massachusetts	15.15
Michigan	32.23
New Jersey	10.25
New York	31.04
North Carolina	31.82
Ohio	48.99
Pennsylvania	47.47
Rhode Island	1.00
South Carolina	16.77
Tennessee	25.81
Virginia	17.19
West Virginia	26.86

Source: U.S. Environmental Protection Agency, Federal Register, Vol. 65, number 42 (March 2, 2002) pages 11222-11231.

Power Plant Mercury Emissions Assumptions

The Electricity Market Module (EMM) of the National Energy Modeling System (NEMS) represents 35 coal plant configurations and assigns a mercury emissions modification factor (EMF) to each configuration Each configuration represents different combinations of boiler types, particulate control devices, sulfur dioxide

Table 45. Coal Plant Retrofit Costs
(2003 Dollars)

Coal Plant Size (MW)	FGD Capital Costs ($/KW)	SCR Capital Costs ($/KW)
300	274	113
500	209	98
700	174	89

Note: The model was run for each individual plant assuming a 1.3 retrofit factor for FGDs and 1.6 factor for SCRs.

Source: CUECOST3.xls model (as updated 2/9/2000) developed for the Environmental Protection Agency by Raytheon Engineers and Constructors, Inc. EPA Contract number 68-D7-0001.

(SO_2) control devices, nitrogen oxide (NO_x) control devices, and mercury control devices. An EMF represents the amount of mercury that was in the fuel that remains after passing through all the plant's systems. For example, an EMF of 0.60 means that 40 percent of the mercury that was in the fuel is removed by various parts of the plant. Table 46 provides the assumed EMFs for existing coal plant configurations without mercury specific controls.

Table 46. Mercury Emission Modification Factors

Configuration			EIA EMFs			EPA EMFs		
SO_2 Control	Particulate Control	NO_x Control	Bit Coal	Sub Coal	Lignite Coal	Bit Coal	Sub Coal	Lignite Coal
None	BH	—	0.11	0.27	1.00	0.11	0.26	1.00
Wet	BH	None	0.05	0.27	0.64	0.03	0.27	1.00
Wet	BH	SCR	0.10	0.27	0.64	0.10	0.15	0.56
Dry	BH	—	0.05	0.75	1.00	0.05	0.75	1.00
None	CSE	—	0.64	0.97	1.00	0.64	0.97	1.00
Wet	CSE	None	0.34	0.73	0.58	0.34	0.84	0.56
Wet	CSE	SCR	0.10	0.73	0.58	0.10	0.34	0.56
Dry	CSE	—	0.64	0.65	1.00	0.64	0.65	1.00
None	HSE/Oth	—	0.90	0.94	1.00	0.90	0.94	1.00
Wet	HSE/Oth	None	0.58	0.80	1.00	0.58	0.80	1.00
Wet	HSE/Oth	SCR	0.42	0.76	0.64	0.10	0.75	1.00
Dry	HSE/Oth	—	0.60	0.85	1.00	0.60	0.85	1.00

Notes: SO_2 Controls - Wet = Wet Scrubber and Dry = Dry Scrubber, Particulate Controls, BH - fabric filter/baghouse. CSE = cold side electrostatic precipitator, HSE = hot side electrostatic precipitator, NO_x Controls, SCR = selective catalytic reduction, — = not applicable, Bit = bituminous coal, Sub = subbituminous coal. The NO_x control system is not assumed to enhance mercury removal unless a wet scrubber is present, so it is left blank in such configurations.

Sources: EPA, EMFs. http://www.epa.gov/clearskies/technical.html EIA EMFs not from EPA: Lignite EMFs, Mercury Control Technologies for Coal-Fired Power Plants, presented by the Office of Fossil Energy on July 8, 2003. Bituminous coal mercury removal for a Wet/HSE/Oth/SCR configured plant, Table EMF1, Analysis of Mercury Control Cost and Performance, Office of Fossil Energy & National Energy Technology Laboratory, U.S. Department of Energy, January 2003, Washington, DC.

Mercury Control Options

To reduce mercury, power companies can change their fuels, redispatch their units, change the configuration of their units or add mercury specific controls. To represent this, the EMM allows plants to alter their configuration by adding equipment, such as an SCR to remove NO_x or an SO_2 scrubber. They can also add activated carbon injection systems specifically designed to remove mercury. Activated carbon can be injected in front of existing particulate control devices or a supplemental fabric filter can be added with activated carbon injection capability.

The equipment to inject activated carbon in front of an existing particulate control device is assumed to cost approximately $4 (2003 dollars) per kilowatt of capacity, while the cost of a supplemental fabric filter with activated carbon injection (often referred as a COPAC unit) is approximately $58 per kilowatt of capacity.[82] The amount of activated carbon required to meet a given percentage removal target is given by the following equations.[83]

For a unit with a CSE, using subbituminous coal, and simple activated carbon injection:

- Hg Removal (%) = 65 – (65.286 / (ACI + 1.026))

For a unit with a CSE, using bituminous coal, and simple activated carbon injection:

- Hg Removal (%) = 100 – (469.379 / (ACI + 7.169))

For a unit with a CSE, and a supplemental fabric filter with activated carbon injection:

- Hg Removal (%) = 100 – (28.049 / (ACI + 0.428))

For a unit with a HSE/Other, and a supplemental fabric filter with activated carbon injection:

- Hg Removal (%) = 100 – (43.068 / (ACI + 0.421))

ACI = activated carbon injected in pounds per million actual cubic feet.

Planned SO_2 Scrubber and NO_x Control Equipment Additions

In recent years, in response to state emission reduction programs and compliance agreements with the Environmental Protection Agency, some companies have announced plans to add scrubbers to their plants to reduce sulfur dioxide and particulate emissions. Where firm commitments appear to have been made these plans have been represented in NEMS. Based on EIA analysis of announced plans, 21.6 gigawatts of capacity are assumed to add these controls (Table 47). The greatest number of retrofits is expected to occur in the Southeastern Electric Reliability Council because of the Clean Smokestacks bill passed by the North Carolina General Assembly.

Table 47. Planned SO_2 Scrubber Additions Represented by Region

Region	Capacity (Gigawatts)
East Central Area Reliability Coordination Agreement	4.2
Electric Reliability Council of Texas	0.0
Mid-Atlantic Area Council	0.6
Mid-America Interconnected Network	0.0
Mid-Continent Area Power Pool	0.6
New York	0.1
New England	0.8
Florida Reliability Coordinating Council	0.0
Southeastern Electric Reliability Council	15.3
Southwest Power Pool	0.0
Northwest Power Pool	0.0
Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada	0.0
California	0.0
Total	21.6

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, based on public announcements and reports to Form EIA-767, "Annual Steam-Electric Plant Operation and Design Data".

Companies are also announcing plans to retrofit units with controls to reduce NOx emissions to comply with emission limits in certain states. In the reference case planned post-combustion control equipment amounts to 27.4 gigawatts of selective catalytic reduction (SCR) and another 2.7 gigawatts of selective non-catalytic reduction (SNCR) equipment. These plants are located in thirteen States (Alabama, Georgia, Indiana, Kentucky, Michigan, Minnesota, North Carolina, New Jersey, Ohio, South Carolina, Tennessee, Texas and West Virginia) primarily in response to EPA rules.

Energy Policy Act of 1992 (EPACT)

The provisions of the EPACT include revised licensing procedures for nuclear plants and the creation of exempt wholesale generators (EWGs).

The Public Utility Holding Company Act of 1935 (PUHCA)

Prior to the passage of EPACT, PUHCA required that utility holding companies register with the Securities and Exchange Commission (SEC) and restricted their business activities and corporate structures.[84] Entities that wished to develop facilities in several States were regulated under PUHCA. To avoid the stringent SEC regulation, nonutilities had to limit their development to a single State or limit their ownership share of projects to less than 10 percent. EPACT changed this by creating a class of generators that, under certain conditions, are exempt from PUHCA restrictions. These EWGs can be affiliated with an existing utility (affiliated power producers) or independently owned (independent power producers). In general, subject to State commission approval, these facilities are free to sell their generation to any electric utility, but they cannot sell to a retail consumer. These EWGs are represented in NEMS.

FERC Orders 888 and 889

FERC has issued two related rules (Orders 888 and 889) designed to bring low cost power to consumers through competition, ensure continued reliability in the industry, and provide for open and equitable transmission services by owners of these facilities. Specifically, Order 888 requires open access to the transmission grid currently owned and operated by utilities. The transmission owners must file nondiscriminatory tariffs that offer other suppliers the same services that the owners provide for themselves. Order 888 also allows these utilities to recover stranded costs (investments in generating assets that are unrecoverable due to consumers selecting another supplier). Order 889 requires utilities to implement standards of conduct and an Open Access Same-Time Information System (OASIS) through which utilities and non-utilities can receive information regarding the transmission system. Consequently, utilities are expected to functionally or physically unbundle their marketing functions from their transmission functions.

These orders are represented in EMM by assuming that all generators in a given region are able to satisfy load requirements anywhere within the region. Similarly, it is assumed that transactions between regions will occur if the cost differentials between them make it economic to do so.

Electricity and Technology Cases

Low and High, Fossil Technology Cases

The *low fossil case* assumes that the costs of advanced fossil generating technologies (integrated coal-gasification combined-cycle, advanced natural gas combined-cycle and turbines) will remain at current costs during the projection period, that is, no learning reductions are applied to the cost. Operating efficiencies for advanced technologies are assumed to be constant at 2005 levels. Capital costs of conventional generating technologies are the same as those assumed in the reference case (Table 48).

In the *high fossil case*, capital costs, heat rates and operating costs for the advanced coal and gas technologies are assumed to be ten 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 ten percent. Heat rates for advanced fossil technologies, in the high fossil case, fall to 16 to 22 percent below initial levels, while capital costs are reduced by 22 percent to 26 percent between 2004 and 2025.

Table 48. Cost and Performance Characteristics for Fossil-Fueled Generating Technologies: Three Cases

	Total Overnight Cost in 2004 Reference (2003 $/kW)	Total Overnight Cost[1]			Heatrate in 2004 (Reference) Btu/kWhr	Heat Rate		
		Reference (2003 $/kW)	High Fossil (2003 $/kW)	Low Fossil (2003 $/kW)		Reference BTU/kWhr	High Fossil Btu/kWhr	Low Fossil Btu/kWhr
Pulverized Coal	1213				8844			
2010		1196	1196	1196		8670	8670	8670
2015		1181	1181	1180		8600	8600	8600
2020		1158	1167	1158		8600	8600	8600
2025		1142	1153	1141		8600	8600	8600
Advanced Coal	1402				8309			
2010		1365	1306	1398		7517	7003	8309
2015		1321	1215	1398		7200	6480	8309
2020		1267	1123	1398		7200	6480	8309
2025		1148	1033	1398		7200	6480	8309
Conventional Combined Cycle	567				7196			
2010		559	559	559		6857	6357	6857
2015		552	552	552		6800	6800	6800
2020		546	546	546		6800	6800	6800
2025		539	539	539		6800	6800	6800
Advanced Gas Technology	558				6752			
2010		543	527	557		6393	5850	6692
2015		521	497	557		6333	5700	6692
2020		497	466	557		6333	5700	6692
2025		485	436	557		6333	5700	6692
Conventional CombustionTurbine	395				10817			
2010		390	390	390		10450	10450	10450
2015		385	385	385		10450	10450	10450
2020		380	380	380		10450	10450	10450
2025		376	376	376		10450	10450	10450
Advanced CombustionTurbine	374				9183			
2010		360	348	373		8550	7695	9078
2015		338	324	373		8550	7695	9078
2020		316	300	373		8550	7695	9078
2025		305	275	373		8550	7695	9078

[1]Total overnight cost (including project contingency, technological optimism and learning factors, but excluding regional multipliers), for projects initiated in the given year.

Source: AEO2005 National Energy Modeling System runs: AEO2005.D102004A, HFOSS05.D102104A, LFOSS05.D102104A.

The *low and high fossil technology cases* are fully-integrated runs, allowing feedback from the end-use demand and fuel supply modules.

Advanced Nuclear Cost Cases

For nuclear power plants, two advanced nuclear cost cases analyze the sensitivity of the projections to lower costs for new plants. The cost assumptions for the *advanced nuclear cost case* reflect a twenty percent reduction in the capital and operating cost 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 case therefore assumes a 28 percent reduction between 2005 and 2025. The *Nuclear vendor estimate case* assumptions are consistent with estimates from British Nuclear Fuel Limited (BNFL) for the manufacture of their

Advanced Pressurized Water Reactor (AP1000), as provided to DOE's Office of Nuclear Energy's Near-Term Deployment Working Group. In this case, the overnight capital cost of a new advanced nuclear unit is assumed to be $1,604 per kilowatt initially, declining to $1,097 per kilowatt for plants coming on line in 2025 (in year 2003 dollars)—18 percent lower initially than assumed in the reference case and 38 percent lower in 2025 (Table 49). Cost and performance characteristics for all other technologies are as assumed in the reference case

Table 49. Cost Characteristics for Advanced Nuclear Technology: Two Cases

		Total Overnight Cost[1]		
Advanced Nuclear	Overnight Cost in 2004 (Reference) (2003$/kW)	Reference Case (2003$/kW)	Advanced Nuclear (2003$/KW)	Nuclear Vendor Estimate (2003$/kW)
	1957			
2010		1901	1818	1604
2015		1854	1679	1435
2020		1808	1543	1225
2025		1761	1410	1097

[1]Total overnight cost (including project contingency, technological optimism and learning factors, but excluding regional multipliers), for projects initiated in the given year.

Source: AEO2005 National Energy Modeling System runs: AEO2005.D102004A, ADVNUC20.D102104A, ADVNUC5A.D110804A.

Notes and Sources

[82] These costs were developed using the National Energy Technology Laboratory Mercury Control Performance and Cost Model, 1998.

[83] U.S. Department of Energy, Analysis of Mercury Control Cost and Performance, Office of Fossil Energy & National Energy Technology Laboratory, January 2003.

[84] A registered utility holding company is defined as any company that owns or controls 10% of the voting securities of a public utility company. PUHCA defines a public utility company as any company that owns or operates generation, transmission, or distribution facilities for the sale of electricity to the public.

Sources referenced in Table 38

Fossil technology cost and performance characteristics were developed utilizing reviews performed by A2H Energy Services and Booz Allen Hamilton (BAH) in May 2004. A2H and BAH reviewd the parameters utilized in the Annual Energy Outlook 2004 (AEO2004) and provided recommended changes where needed. The averages of the AE2004 values and the recommended values were used.

Aiken, Richard, Booz Allen Hamilton, Review of Fossil Energy Cost and Performance Assumptions in the Electricity Market Module of the National Energy Modeling System, May 2004.

DeLallo, Michael, Independent Expert (PEER) Review Program for the Energy Information Administration, May 17, 2004.

McGraw-Hill Companies, Top Plants, Power Magazine, Vol. 146, No. 5, August 2002

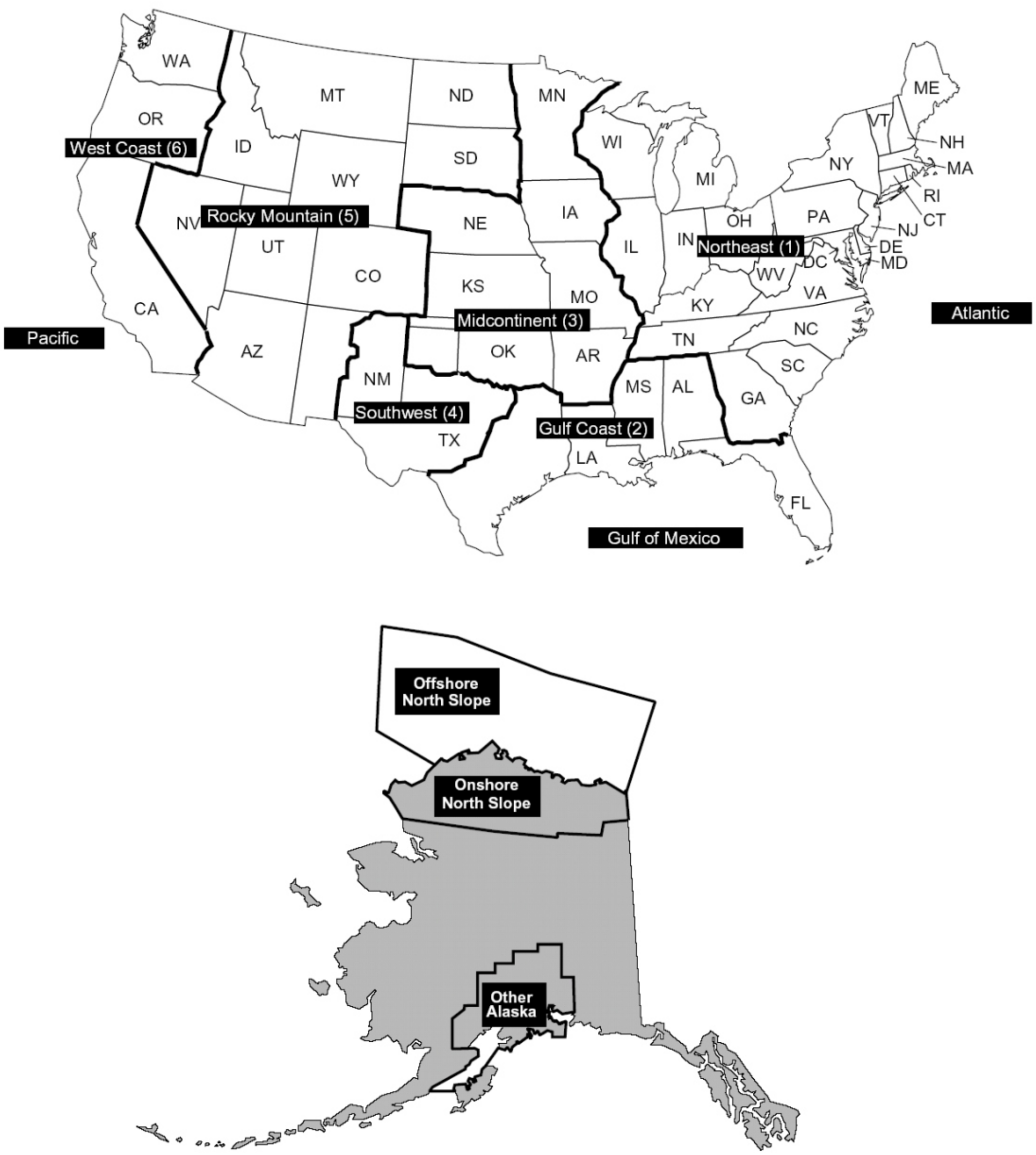
A Roadmap to Deploy New Nuclear Power Plants in the United States by 2010 (RDNN), available at the following link: http://www.nuclear.gov/Nuclear2010/NucPwr2010_PI.html

“New Fuel for the CANDU - And a new CANDU, too!”; NUKEM Market Report, June 2002.

Oil and Gas Supply Module

The NEMS Oil and Gas Supply Module (OGSM) constitutes a comprehensive framework with which to analyze oil and gas supply on a regional basis (Figure 7). A detailed description of the OGSM is provided in the EIA publication, *Model Documentation Report: The Oil and Gas Supply Module (OGSM)*, DOE/EIA-M063(2005), (Washington, DC, 2005). The OGSM provides crude oil and natural gas short-term supply parameters to both the Natural Gas Transmission and Distribution Module and the Petroleum Market Module. The OGSM simulates the activity of numerous firms that produce oil and natural gas from domestic fields throughout the United States, acquire natural gas from foreign producers for resale in the United States, or sell U.S. gas to foreign consumers.

Figure 7. Oil and Gas Supply Model Regions



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

OGSM encompasses domestic crude oil and natural gas supply by both conventional and nonconventional recovery techniques. Nonconventional recovery includes unconventional gas recovery from low permeability formations of sandstone and shale, and coalbeds. Foreign gas transactions may occur via either pipeline (Canada or Mexico) or transport ships as liquefied natural gas (LNG).

Primary inputs for the module are varied. One set of key assumptions concerns estimates of domestic technically recoverable oil and gas resources. Other factors affecting the projection include the assumed rates of technological progress, supplemental gas supplies over time, and natural gas import and export capacities.

Key Assumptions

Domestic Oil and Gas Technically Recoverable Resources

Domestic oil and gas technically recoverable resources[85] consist of proved reserves,[86] inferred reserves,[87] and undiscovered technically recoverable resources.[88] OGSM resource assumptions are based on estimates of technically recoverable resources from the United States Geological Survey (USGS) and the Minerals Management Service (MMS) of the Department of the Interior.[89] Supplemental adjustments to the USGS nonconventional resources are made by Advanced Resources International (ARI), an independent consulting firm. While undiscovered resources for Alaska are based on USGS estimates, estimates of recoverable resources are obtained on a field-by-field basis from a variety of sources including trade press. Published estimates in Tables 50 and 51 reflect the removal of intervening reserve additions between the date of the latest available assessment and January 1, 2003.

Lower 48 Offshore

Most of the Lower 48 offshore oil and gas production comes from the deepwater of the Gulf of Mexico (GOM). Production from current producing fields and industry announced discoveries largely determine the short-term oil and natural gas production projection.

For currently producing fields, a 2-percent exponential decline is assumed for production except for natural gas production from fields in shallow water, which uses a 30-percent exponential decline. Fields that began production after 2001 are assumed to remain at their peak production level for 2 years before declining.

The assumed field size and year of initial production of the major announced deepwater discoveries that were not brought into production by 2003 are shown in Table 52. A field that is announced as an oil field is assumed to be 100 percent oil and a field that is announced as a gas field is assumed to be 100 percent gas. If a field is expected to produce both oil and gas, 70 percent is assumed to be oil and 30 percent is assumed to be gas. Production is assumed to

- ramp up to a peak level in 2 to 4 years depending on the size of the field,
- remain at the peak level until the ratio of cumulative production to initial resource reaches 20 percent for oil and 30 percent for natural gas,
- and then decline at an exponential rate of 20-30 percent.

The discovery of new fields (based on MMS's field size distribution) is assumed to follow historical patterns. Production from these fields is assumed to follow the same profile as the announced discoveries (as described in the previous paragraph).

Table 50. Crude Oil Technically Recoverable Resources
(Billion barrels)

Crude Oil Resource Category	As of January 1, 2003
Undiscovered	49.77
Onshore	19.23
Northeast	1.47
Gulf Coast	4.73
Midcontinent	1.10
Southwest	3.25
Rocky Moutain	5.68
West Coast	3.00
Offshore	30.54
Deep (>200 meters Water Depth)	28.14
Shallow (0-200 meters Water Depth)	2.40
Inferred Reserves	44.77
Onshore	36.61
Northeast	0.68
Gulf Coast	0.64
Midcontinent	3.58
Southwest	14.27
Rocky Mountain	9.74
West Coast	7.71
Offshore	8.16
Deep (>200 meters Water Depth)	4.26
Shallow (0-200 meters Water Depth)	3.90
Total Lower 48 States Unproved	94.54
Alaska	24.27
Total U.S. Unproved	118.81
Proved Reserves	24.01
Total Crude Oil	142.82

Note: Resources in areas where drilling is officially prohibited are not included in this table. The Alaska value is not explicitly utilized in the OGSM, but is included here to complete the table. The Alaska value does not include resources from the Arctic Offshore Outer Continental shelf.

Source: Conventional Onshore, State Offshore, and Alaska - U.S. Geological Survey (USGS); Federal (Outer Continental Shelf) Offshore - Minerals Management Service (MMS); Proved Reserves - EIA, Office of Oil and Gas. Table values reflect removal of intervening reserve additions between the date of the latest available assessment and January 1, 2003.

Table 51. Natural Gas Technically Recoverable Resources
(trillion cubic feet)

Natural Gas Resource Category	As of January 1, 2003
Nonassociated Gas	
Undiscovered	260.58
Onshore	115.12
Northeast	5.43
Gulf Coast	59.02
Midcontinent	15.32
Southwest	11.07
Rocky Mountain	18.10
West Coast	6.19
Offshore	145.46
Deep (>200 meters water depth)	86.59
Shallow (0-200 meters water depth)	58.87
Inferred Reserves	236.87
Onshore	188.32
Northeast	2.54
Gulf Coast	94.71
Midcontinent	62.10
Southwest	18.12
Rocky Mountain	10.15
West Coast	0.70
Offshore	48.55
Deep (>200 meters water depth)	5.96
Shallow (0-200 (meters water depth)	42.59
Unconventional Gas Recovery	487.59
• Tight Gas	321.04
Northeast	59.25
Gulf Coast	63.82
Midcontinent	12.60
Southwest	9.72
Rocky Mountain	175.15
West Coast	0.50
• Shale	85.98
Northeast	30.01
Gulf Coast	0.00
Midcontinent	0.00
Southwest	42.39
Rocky Mountain	14.34
West Coast	0.00
• Coalbed	79.81
Northeast	8.79
Gulf Coast	2.13
Midcontinent	6.04
Southwest	0.00
Rocky Mountain	62.85
West Coast	0.00
Associated-Dissolved Gas	133.76
Total Lower 48 Unproved	1118.80
Alaska	31.73
Total U.S. Unproved	1150.53
Proved Reserves	186.95
Total Natural Gas	1337.47

Sources and Notes for this table are listed in the 'Notes and Sources' section at the end of chapter.

Table 52. Assumed Size and Initial Production Year of Major Announced Deepwater Discoveries

Field/Project Name	Block	Oil/Gas	Water Depth (feet)	Year of Discovery	Field Size Class	Field Size (MMBOE)	Start Year of Production
Coulomb – Na Kika	MC657	gas	7591	1987	12	89.3	2004
Devil's Tower	MC773	oil	5610	1999	12	89.3	2004
Front Runner	GC339	oil	3330	2001	15	690.6	2004
Llano	GB385	oil/gas	2700	1998	12	89.3	2004
Marco Polo	GC608	oil	4320	2000	12	89.3	2004
Raptor	EB668	gas	3710	2003	13	182.1	2004
Red Hawk	GB877	gas	5334	2001	13	182.1	2004
Rigel	MC252	gas	5225	1998	11	44.8	2004
Tomahawk	EB623	gas	3650	2003	11	44.8	2004
Champlain	AT063	oil/gas	4457	2000	12	89.3	2005
Entrada	GB782	oil/gas	4600	2000	15	690.6	2005
Holstein	GC644	oil	4344	1999	14	371.7	2005
K2/Timon	GC562	oil	4006	1999	13	182.1	2005
Mad Dog	GC826	oil/gas	4428	1998	16	1,418.9	2005
Merganser	AT037	gas	7900	2001	11	44.8	2005
Thunder Horse	MC778	oil	6050	1999	16	1,418.9	2005
Triton/Poseiden	MC728	oil	5567	2002	12	89.3	2005
Atlantis	GC699	oil	6130	1998	16	1,418.9	2006
Balboa	EB597	oil/gas	3352	2001	10	22.9	2006
Blind Faith	MC696	oil	6989	2001	15	690.6	2006
Constitution	GS680	oil	5071	2003	14	371.7	2006
Hawkes	MC509	oil	4174	2001	11	44.8	2006
Shenzi	GC653	oil	4394	2002	14	371.7	2006
Thunder Horse North	MC776	oil	5660	2000	15	690.6	2006
Trident	AC903	oil	9743	2001	14	371.7	2006
Tubular Bells	MC725	oil	4334	2003	12	89.3	2006
GB244	GB244	oil/gas	2130	2001	11	44.8	2006
Great White	AC857	oil	8009	2002	15	690.6	2007
Hornet	GC379	oil/gas	2076	2001	14	371.7	2007
Neptune	AT575	oil/gas	6220	1995	14	371.7	2007
Spiderman	DC621	gas	8087	2004	14	371.7	2007
Tahiti	GC640	oil	4017	2002	15	690.6	2007
Vortex	AT261	oil/gas	8334	2002	13	182.1	2007
Atlas	LL050	gas	8934	2003	12	89.3	2008
Jubilee	AT349	gas	8825	2003	13	182.1	2008
Lorien	GC199	oil	2315	2003	12	89.3	2008
St. Malo	WR678	oil	7036	2003	15	690.6	2008
Sturgis	AT183	oil/gas	3710	2003	12	89.3	2008
Cascade	WR206	oil	8143	2002	15	690.6	2009
Chinook	WR469	oil	8831	2003	14	371.7	2009
Puma	GC823	oil	4129	2004	14	371.7	2009

Source: Energy Information Administration, Office of Integrating Analysis and Forecasting. The discovery year, initial production year and field sizes are based on industry announcements. If an initial production year was not specified, the field was assumed to start production 5 years after discovery.

Alaskan Crude Oil and Natural Gas from Arctic Areas

Alaska crude oil production is determined by the estimates of available resources in undeveloped areas and the time and expense required to begin production in these areas. Alaska production includes existing producing fields, fields that have been discovered but are not currently being produced, and fields that are projected to exist, based upon the region's geology. The first category of field includes expansion fields in the Prudhoe Bay region, accounting for 800 million barrels of oil. These fields are relatively small, and development of these fields began in 2002 and continues throughout the forecast. The estimated size of these expansion fields corresponds to projections made by the State of Alaska and other analysis by EIA.

Fields in the second category include fields in the National Petroleum Reserve Alaska, or NPR-A. In 1999, 2002, and 2004, northeastern portions of the NPR-A were leased by the Federal government for oil and gas exploration and production. According to a recent USGS assessment[90] NPR-A is estimated to contain a mean resource level of 10.6 billion barrels. These resources are assumed not be brought into production until 2007. Finally, a total of roughly 800 million barrels of additional resources are projected to be developed in other fields yet to be discovered, both on the North Slope of Alaska and offshore in the Beaufort Sea. These fields are expected to be smaller than recent finds like the Alpine field. Oil and gas exploration and production currently are not permitted in the Alaska National Wildlife Refuge. The AEO2005 projections for Alaska oil and gas production presume that this prohibition remains in effect throughout the forecast period.

The outlook for natural gas production from the North Slope of Alaska is affected strongly by the unique circumstances regarding its transport to market. Unlike virtually all other identified deposits of natural gas in the United States, North Slope gas lacks a means of economic transport to major commercial markets. The lack of viable marketing potential at present has led to the use of Prudhoe Bay gas to maximize crude oil recovery in that field. Recent high natural gas prices and the passage of legislation in support of a major Alaska pipeline from the North Slope into Alberta, Canada, raised the potential economic viability of such a project. The primary assumptions associated with estimating the cost of North Slope Alaskan gas in Alberta, as well as for MacKenzie Delta gas into Alberta, are shown in Table 53. A simple calculation is performed to estimate a regulated, levelized, tariff for each pipeline. Additional items are added to account for the wellhead price, treatment costs, pipeline fuel costs, and a risk premium to reflect market price uncertainty.

Table 53. Primary Assumptions for Natural Gas Pipelines from Alaska and MacKenzie Delta into Alberta, Canada

	Alaska to Alberta	MacKenzie Delta to Alberta
Initial flow into Alberta	3.9 Bcf per day	1.1 Bcf per day
Expansion potential	22 percent	58 percent
Initial capitalization	14.2 billion (2003 dollars)	5.0 billion (2003 dollars)
Cost of Debt (premium over AA bond rate)	0.0 percent	1.0 percent
Cost of equity (premium over AA bond rate)	5.0 percent	8.0 percent
Debt fraction	80 percent	70 percent
Depreciation period	15 years	15 years
Minimum wellhead price	$0.83 (2003 dollars per Mcf)	$1.03 (2003 dollars per Mcf)
Treatment and fuel costs	$0.42 (2003 dollars per Mcf)	$0.41 (2003 dollars per Mcf)
Risk Premium	$0.35 (2003 dollars per Mcf)	$0.39 (2003 dollars per Mcf)
Additional cost for expansion	$0.67 (2003 dollars per Mcf)	$0.08 (2003 dollars per Mcf)
Construction period	4 years	3 years
Planning period	5 years	2 years
Earliest start year	2014	2010

Note: The MacKenzie risk premium partially reflects the potential of capital cost overruns, whereas this is represented for the Alaska pipeline by using an initial capitalization that is 20 percent bigger than the expected estimate.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Alaska pipeline data are partially based on information from British Petroleum/ExxonMobil/Conoco Phillips and reflect assumed impact on Alaska pipeline finances as a result of the American Jobs Creation Act of 2004 and the Military Construction Appropriations Act, 2004.

For the Alaska pipeline the uncertainty associated with the initial capitalization is captured by applying a value that is 20 percent higher than the expected value. Finally, for comparison purposes, a price differential of $0.62 (2003 dollars per Mcf) is assumed between the price in Alberta and the average lower 48 price. The resulting cost of Alaska gas, relative to the lower 48 wellhead price, is approximately $3.43 (2003 dollars per Mcf), with some variation across the forecast due to changes in gross domestic product. Construction of an Alaska-to-Alberta pipeline is forecast to commence if the assumed total costs for Alaska gas in the lower 48 States exceeds the average lower 48 gas price in each of the previous 2 years, on average over the previous 5 years (with greater weight applied to more recent years), and as expected to average over the next 3 years. An adjustment is made if prices were declining over the previous 5 years. Once the assumed 4-year construction period is complete, expansion can occur if the price exceeds the initial trigger price by $0.67 (2003 dollars per Mcf). When the Alaska to Alberta pipeline is built in the model, additional pipeline capacity is added to bring the gas across the border into the United States. For accounting purposes, the model assumes that all of the Alaska gas will be consumed in the United States and that sufficient economical supplies are available at the North Slope to fill the pipeline over the depreciation period.

Supplemental Natural Gas

The projection for supplemental gas supply is identified for three separate categories: synthetic natural gas (SNG) from liquids, SNG from coal, and other supplemental supplies (propane-air, coke oven gas, refinery gas, biomass air, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas). SNG from the currently operating Great Plains Coal Gasification Plant is assumed to continue through the forecast period, at an average historical level of 50.0 billion cubic feet per year. Other supplemental supplies are held at a constant level of 22.4 billion cubic feet per year throughout the forecast because this level is consistent with historical data and it is not believed to change significantly in the context of a reference case forecast. Synthetic natural gas from liquid hydrocarbons in Hawaii is assumed to continue over the forecast at the average historical level of 2.7 billion cubic feet per year.

Natural Gas Imports and Exports

U.S. natural gas trade with Mexico is determined endogenously based on various assumptions about the natural gas market in Mexico. U.S. natural gas exports from the United States to Canada are set exogenously in NEMS at 324 billion cubic feet per year, post 2003. Canadian production and U.S. import flows from Canada are determined endogenously within the model and can be constrained by pipeline capacities.

It is assumed that Mexican natural gas production grows at an average annual rate of 2.0 percent through 2025 and that consumption grows at an average annual rate of 3.9 percent. It is further assumed that domestic production will be supplemented by LNG from receiving terminals constructed on both the east and west coasts of Mexico that serve only the Mexican market. Receiving terminal(s) in Baja California, Mexico, that serve both Mexico and the United States can be constructed if the regional LNG price exceeds a trigger price. The difference between production and consumption in any year is assumed is either imported from, or exported to, the United States. Adjustments to these figures are made endogenously within the model to reflect response to price fluctuations within the market.

Canadian consumption and production in Eastern Canada are set exogenously in the model and are shown in Table 54. Production in the Western Canadian Sedimentary Basin (WCSB) is calculated endogenously to the model using annual supply curves based on beginning-of-year proved reserves and an expected production-to-reserve ratio. Reserve additions are set equal to the product of successful natural gas wells (based on an econometric estimation) and a finding rate (set as a function of the number of successful wells drilled and the assumed economically recoverable resource base). The unconventional and conventional WCSB economically recoverable resource base estimates assumed in the model for the beginning of 2004 are 70 trillion cubic feet and 96 trillion cubic feet, respectively.[91] For conventional gas, the initial resource level is assumed to grow by 0.5 percent per year throughout the projection period to reflect improvements in and penetration of technology. Production from unconventional sources is established based on an assumed production path which varies in response to the level of remaining resources and the solution price in the previous forecast year.

Table 54. Exogenously Specified Canadian Production and Consumption
(billion cubic feet per year)

Year	Consumption	Production Eastern Canada
2000	3,301	142
2005	3,308	182
2010	3,900	355
2015	4,300	800
2020	4,600	830
2025	4,900	730

Source: Consumption - EIA, International Energy Outlook 2004, DOE/EIA-0484(2004); Production - Based on projections from *Canada's Energy Future, Scenarios for Supply and Demand to 2025*, National Energy Board, Calgery, Alberta, 2003.

Natural gas production from the frontier areas (e.g., MacKenzie Delta) is assumed to be sufficient to fill a pipeline over the projection period should one be built connecting the area to markets in the south. The basic methodology used to represent the decision to build a MacKenzie pipeline is similar to the process used for an Alaska-to-lower 48 pipeline, using the primary assumed parameters listed in Table 53. One exception is that the uncertainty associated with the initial capitialization is captured in the risk premium.

Annual U.S. exports of liquefied natural gas (LNG) to Japan are assumed to be constant at 64.9 billion cubic feet per year through March of 2009, when the export license expires. LNG imports are determined endogenously within the model. The model provides for the construction of new facilities should gas prices be high enough to make construction economic — the prices upon existing the facility that are needed to trigger new LNG construction in the United States and the Bahamas vary by region and, at the beginning of the forecast, range from $3.21 to $4.62/Mcf (2003 dollars).

Currently there are four LNG facilities in operation, located at Everett, Massachusetts; Lake Charles, Louisiana; Cove Point, Maryland; and Elba Island, Georgia. These four facilities including expansions currently in progress have a combined design capacity of 4,435 million cubic feet per day (1,619 billion cubic feet per year) and an assumed combined sustainable sendout of 1.2 trillion cubic feet per year. Further expansion is triggered when the regional LNG tailgate[92] price meets or exceeds a trigger price as determined in the model.

The model also has a provision for the construction of new facilities in all United States coastal regions, in eastern Canada, and in Baja California, Mexico. Supplies from a Baja California, Mexico, facility are assumed to enter the United States as pipeline imports from Mexico destined for Southwestern markets. As with expansion of existing facilities, construction is triggered when the regional LNG tailgate price meets or exceeds a trigger price. The trigger price for construction of a Baja California, Mexico, LNG facility is $3.16. LNG is represented similarly in eastern Canada, with the trigger price for construction at the terminal set at $4.71.

Since LNG does not compete with wellhead prices, trigger prices are compared with regional prices in the vicinity of the LNG facility (i.e., the tailgate price) rather than with wellhead prices. With the exception of the Canada and Baja facilities, the individual trigger prices represent the least cost feasible combination of production, liquefaction, and transportation costs to the facility plus the regasification cost at the facility. Regasification costs at new facilities include capital costs for construction of the facility. A range of cost components used in determining trigger prices at new facilities are shown in Table 55.

The production costs reflect assumed market prices entering the liquefaction facility for various stranded gas[93] locations and average about $0.56 Mcf (2003 dollars). Different supply factors are estimated based on the existing and potential upstream projects for each supply source, and are applied to the average supply cost to arrive at the production cost by source.[94]

Table 55. LNG Cost Components
(2003 dollars per mcf)

	Low		High	
2003 Production	$0.34	Nigeria	$1.17	Peru
2003 Liquefaction	$1.44	All facilities	$1.44	All facilities
Shipping	$0.34	Venezuala to the Bahamas	$1.87	Qatar to Gulf Mexico
Regasification	$0.30	Gulf of Mexico	$0.96	Florida
Risk Premium	$0.46	All new facilities	$0.46	All new facilities

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Gas supply costs are based on a March 31, 2003 report produced under contract to EIA by the Gas Technology Institute (GTI), using a conversion factor of 1,100 Btus/cf. Regasification costs are based on Project Technical Liaison, Inc. estimates. Shipping costs are based on various sources, including www.dataloy.com for transportation distances, the GTI Report, and EIA judgement. Liquefaction costs are based on data from Bear Sterns and Wood MacKenzie.

Liquefaction costs are estimated based on a declining liquefaction capital cost function for one train (3.33 million metric tons of LNG or 159 Bcf per year) starting at $270 per ton of plant capacity in 2003 and gradually declining to $221 per ton in 2025. The capital cost is to be amortized over a 20-year period with a 18 percent average cost of equity, 8.5 percent cost of debt, 60 percent debt fraction, and 30 percent corporate tax rate, resulting in a nominal 11.2 percent cost of capital (after taxes). These liquefaction costs are adjusted to account for individual plant factors such as the plant's age and location. The liquefaction plant utilization rate is assumed to be 89 percent.

LNG shipment costs from a supply source to a receiving terminal are a function of the distance between these two locations, an average per unit-mile shipment cost, and a port cost. The per unit-mile shipment cost is computed as a function of the return on invested capital for the tanker, number of round trips per year, distance between a supply source and an LNG terminal, average tanker capacity, estimated fuel cost, and administrative and general expenses for the tanker serving that route. Taxes are embedded in the administrative and general expenses.

Costs were calculated using the shipment costs for 10 selected routes based on distances, an assumed average capital cost for all the newly built tankers, an average rate of return on the invested capital, tanker fuel costs, administrative and general expenses, an assumed average tanker capacity per trip, and the assumed number of round trips per year for a tanker serving a particular route. The estimated shipment costs, in 2003 dollars/Mcf, were divided by the route distances, and then averaged. These calculations provide a result of $0.000184/Mcf-mile in 2003 dollars (i.e., roughly $0.18/Mcf per 1,000 nautical miles). This average per unit-mile cost is applied to the various source/destination combinations, based on the distance of each combination, to calculate initial transportation costs for those terminals. Finally, an assumed $0.05/Mcf port cost is added to each of these transportation costs to arrive at the final shipment costs.

The capacity for a generic regasification plant was assumed to be 1.5 Bcf per day with five storage tanks with capacity of 150,000 cubic meters in the Gulf region, 1 Bcf per day with four storage tanks in California, and 500 MMcf per day with two storage tanks for all other regions. Regasification plant costs were developed for each of these generic sized terminals, assuming a non-seismically active site with no requirement for dredging or piling. Capital costs and operation and maintenance costs for these generic facilities were estimated at $669 million and $38 million dollars for the 1.5 Bcf per day facility, $550 million and $27 million dollars for the 1 Bcf per day facility, and $395 million and $18 million dollars for the 500 MMcf per day facility, respectively. A 10.7 percent weighted cost of capital was assumed, with a 20-year economic life. Using a cost recovery method, the resulting per unit regasification costs for the 1.5 Bcf per day, 1 Bcf per day, and the 500 MMcf per day generic plants were $0.30 per Mcf, $0.44 per Mcf, and $0.61 per Mcf, respectively, in 2003 dollars. The generic costs were adjusted to account for region-specific costs associated with land purchase; labor; risk premiums; and site-specific permitting and special land and waterway preparation and/or acquisitions. Multipliers to account for these and other general construction and operating cost differences across the United States were developed and range from 1.0 to 1.50.

While technological improvements are expected to continue to place some downward pressure on costs throughout the supply chain, growing demand for natural gas in the international market is likely to exert upward pressure on international natural gas prices. In order to represent this phenomenon a 5 percent annual growth factor was applied to the shipping costs. In reality it is expected that all segments of the supply chain are likely to be in the position to demand a higher price if demand increases at expected rates and if the capacity to supply stays in check.

It is assumed that LNG facilities are developed with an initial design capacity along with a capability for future expansion. For existing terminals, original capital expenditures are considered sunk costs. Costs were additionally determined for expansion beyond documented expansion capability at existing facilities under the assumption that if prices reached sustained levels at which new facilities would be constructed, additional expansion at existing facilities would likely be considered. The costs of expansion at existing facilities within a region are in general lower that those for the construction of new facilities. Initial capacity from new facilities is assumed to vary from 90 Bcf/year to 365 Bcf/year capacity in the Gulf Coast. If market prices warrant, additional capacity can be added in a region either through expansion or construction of new facilities.

Legislation and Regulations

The Minerals Management Service published its final rule on the “Oil and Gas and Sulphur Operations in the Outer Continental Shelf–Relief or Reduction in Royalty Rates–Deep Gas Provisions” on January 26, 2004, effective March 1, 2004. The rule grants royalty relief for natural gas production from wells drilled to 15,000 feet or deeper on leases issued before January 1, 2001, in the shallow waters (less than 200 meters) of the Gulf of Mexico. Production of gas from the completed deep well must begin before 5 years after the effective date of the final rule. The minimum volume of production with suspended royalty payments is 15 billion cubic feet for wells drilled to at least 15,000 feet and 25 billion cubic feet for wells drilled to more than 18,000 feet. In addition, unsuccessful wells drilled to a depth of at least 18,000 feet would receive a royalty credit for 5 billion cubic feet of natural gas. The ruling also grants royalty suspension for volumes of not less than 35 billion cubic feet from ultra-deep wells on leases issued before January 1, 2001.

Section 116 of the Military Construction Appropriations and Emergency Hurricane Supplemental Appropriations Act, 2004 (H.R.4837) gives the Secretary of Energy the authority to issue Federal loan guarantees for an Alaska natural gas transportation project, including the Canadian portion, that would carry natural gas from northern Alaska, through the Canadian border south of 68 degrees north latitude, into Canada, and to the lower-48 States. This authority would expire 2 years after the final certificate of public convenience and necessity is issued. In aggregate the loan guarantee would not exceed: (1) 80 percent of total capital costs (including interest during construction); (2) $18 billion dollars (indexed for inflation at the time of enactment); or (3) a term of 30 years. The Act also promotes streamlined permitting and environmental review, an expedited court review process, and protection of rights-of-way for the pipeline. The loan guarantee was represented in the model by lowering the cost of debt by a percentage point and increasing the debt fraction fro 70 percent to 80 percent.

Section 706 of the American Jobs Creation Act of 2004 (H.R.4520) provides a 7-year cost-of-investment recovery period for the Alaska natural gas pipeline, as opposed to the currently allowed 15-year recovery period, for tax purposes. The provision would be effective for property placed in service after 2013, or treated as such. The provision was represented in the model by lowering the cost of equity by 3 percentage points.

Section 707 of the American Jobs Creation Act would extend the 15-percent tax credit currently applied to costs related to enhanced oil recovery to construction costs for a gas treatment plant that supplies natural gas to a 2 trillion Btu per day pipeline, lies in Northern Alaska, and produces carbon dioxide for injection into hydrocarbon-bearing geological formations. A gas treatment plan on the North Slope that feeds gas into an Alaska pipeline to Canada is expected to satisfy this requirement. The provision would be effective for costs incurred after 2004. The provision was represented in the model by lowering the rate charge for natural gas treatment by $0.05 per Mcf.

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 a number of parameters representing technological penetration in the reference case were adjusted to reflect a more rapid and a slower penetration rate. In the reference case, the underlying assumption is that technology will continue to penetrate at historically observed rates. Since technologies are represented somewhat differently in different submodules of the Oil and Gas Supply Module, the approach for representing rapid and slow technology penetration varied as well. For instance, the effects of technological progress on conventional oil and natural gas parameters in the reference case, such as finding rates, drilling, lease equipment and operating costs, and success rates, were adjusted upward and downward by 50 percent (Table 56), for the rapid and slow technology cases, respectively. The approach taken in unconventional natural gas is discussed below.

In the Canadian supply submodule, successful natural gas wells for conventional gas and production levels for unconventional gas in the WCSB are assumed to be progressively greater in the rapid technology case and lesser in the slow technology case across the forecast horizon. By 2025, the number of successful natural gas wells are approximately 12 percent higher and lower in the rapid and slow technology cases than in the reference case directly due to differences in assumed technological improvements. Potential production rates from conventional new discoveries are adjusted upward and downward by 25 percent in the rapid and slow technology cases, respectively. The resource base levels for the WCSB were assumed not to vary across technology cases. The technology parameter on production from unconventional natural gas wells is adjusted upward and downward by 50 percent under the rapid and slow technology cases, resulting in production levels approximately 15 percent higher or lower directly due to assumed technological improvements. Finally, the minimum supply prices deemed necessary to trigger the Alaska and MacKenzie Delta natural gas pipelines are progressively decreased or increased over the forecast in the rapid and slow technology cases, respectively, downward or upward from 0.0 to 12.5 percent by 2025. All other parameters in the model were kept at their reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of LNG and natural gas trade between the United States and Mexico.

The Unconventional Gas Recovery Supply Submodule (UGRSS) relies on Technology Impacts and Timing functions to capture the effects of technological progress on costs and productivity in the development of gas from deposits of coalbed methane, gas shales, and tight sands. The numerous research and technology initiatives are combined into 11 specific "technology groups," that encompass the full spectrum of key disciplines — geology, engineering, operations, and the environment. The technology groups utilized for the *Annual Energy Outlook 2005* are characterized for three distinct technology cases — Slow Technological Progress, Reference Case, and Rapid Technological Progress — that capture three different futures for technology progress. The 11 technology groups are listed in Table 57. Table 58 provides a description of their treatment under the different technology cases.

Table 56. Assumed Annual Rates of Technological Progress for Conventional Crude Oil and Natural Gas Sources
(percent/year)

Category	Slow	Reference	Rapid
Lower 48 Onshore			
Costs			
Drilling	0.45	0.89	1.34
Lease Equipment	0.38	0.76	1.14
Operating	0.26	0.52	0.78
Finding Rates			
New Field Discoveries	0.00	0.00	0.00
Known Fields	1.105	2.21	3.32
Success Rates			
Exploratory	0.25	0.50	0.75
Developmental	0.25	0.50	0.75
Lower 48 Offshore			
Exploration success rates	0.40	0.80	1.20
Delay to commence first exploration and between exploration (years)	0.30	0.60	0.90
Exploration and Development drilling costs	0.60	1.20	1.80
Operating costs	0.60	1.20	1.80
Time to construct production facility (years)	0.30	0.60	0.90
Production facility construction costs	0.60	1.20	1.80
Initial constant production rate	0.30	0.60	0.90
Production Decline rate	0.00	0.00	0.00
Alaska			
Costs			
Drilling	0.50	1.00	1.50
Lease Equipment	0.50	1.00	1.50
Operating	0.50	1.00	1.50
Finding Rates	1.50	3.00	4.50

Source: The values shown in this table are developed by the Energy Information Administration, Office of Integrated Analysis and Forecasting from econometric analysis for onshore costs and discussions with various industry and Government sources for offshore and Alaska costs. Onshore drilling cost data are based on the American Petroleum Institute's *Joint Association Survey on Drilling Costs*. Onshore lease equipment and operating costs are based on the Energy Information Administration's *Costs and Indices for Domestic Oil & Gas Field Equipment and Production Operations*.

Table 57. Technology Types and Impacts

Technology Group	Technology Type	Impact
1	Basin assessments	Increase the available resource base by a) accelerating the time that hypothetical plays in currently unassessed areas become available for development and b) increasing the play probability for hypothetical plays – that portion of a given area that is likely to be productive.
2	Play specific, extended reservoir characterizations	Increase the pace of new development by accelerating the pace of development of emerging plays, where projects are assumed to require extra years for full development compared to plays currently under development.
3	Advanced well performance diagnostics and remediation	Expand the resource base by increasing reserve growth for already existing reserves.
4	Advanced exploration and natural fracture detection R&D	Increases the success of development by a) improving exploration/development drilling success rates for all plays and b) improving the ability to find the best prospects and areas.
5	Geology technology modeling and matching	Matches the “best available technology” to a given play with the result that the expected ultimate recovery (EUR) per well is increased.
6	More effective, lower damage well completion and stimulation technology	Improves fracture length and conductivity, resulting in increased EUR’s per well.
7	Targeted drilling and hydraulic fracturing R&D	Results in more efficient drilling and stimulation which lowers well drilling and stimulation costs.
8	New practices and technology for gas and water treatment	Result in more efficient gas separation and water disposal which lowers water and gas treatment operation and maintenance costs.
9	Advanced well completion technologies, such as cavitation, horizontal drilling, and multi-lateral wells:	Defines applicable plays, thereby accelerating the date such technologies are available and introduces and improved version of the particular technology, which increases EUR per well.
10	Other unconventional gas technologies, such as enhanced coalbed methane and enhanced gas shales recovery	Introduce dramatically new recovery methods that a) increase EUR per well and b) become available at dates accelerated by increase R&D, with c) increased operation and maintenance costs (in the case of coalbed methane) for the incremental gas produced.
11	Mitigation of environmental constraints	Removes development constraints in environmentally sensitive basins, resulting in an increase in basin areas available for development.

Source: Advanced Resources International.

Table 58. Assumed Rates of Technological Progress for Unconventional Gas Recovery

Technology Group	Item	Type of Deposit	Technology Case: Slow	Reference	Rapid
1	Year Hypothetical Plays Become Available	All Types-Non DOE	NA	NA	2016
		All Types-DOE	2016	2016	2016
2	Decrease in Extended Portion of Development Schedule for Emerging Plays (per year)	All Types - Non DOE	0.83%	1.67%	2.50%
		All Types - DOE	1.25%	2.50%	3.75%
3	Expansion of Existing Reserves (per year -declining 0.1% per year; eg., 3.0, 2.0...)	Tight Sands	1.0%	2.0%	3.0%
		Coalbed Methane & Gas Shales	2.0%	4.0%	6.0%
4	Increase in Percentage of Wells Drilled Successfully (per year)	All Types	0.1%	0.2%	0.3%
	Year that Best 30 Percent of Basin is Fully Identified	All Types	2048	2022	2013
5	Increase in EUR per Well (per year)	All Types	0.13%	0.25%	0.38%
6	Increase in EUR per Well (per year)	All types	0.13%	0.25%	0.38%
7	Decrease in Drilling and Stimulation Costs per Well (per year)	All types	NA	NA	NA
8	Decrease in Water and Gas Treatment O&M Costs per Well (per year)	All Types	NA	NA	NA
9	Year Advanced Well Completion Technologies Become Available	Coalbed Methane &	NA	NA	NA
		Tight Sands & Gas Shales	NA	2016	2009
	Increase in EUR per well (total increase)	Coalbed Methane	NA	NA	NA
		Tight Sands	NA	10%	15%
		Gas Shales	NA	20%	30%
10	Year Advanced Recovery Technologies Become Available	Coalbed Methane & Tight Sands	NA	NA	2016
		Gas Shales	NA	NA	NA
	Increase in EUR per well (total increase)	Coalbed Methane	NA	NA	45%
		Tight Sands	NA	NA	15%
		Gas Shales	NA	NA	NA
	Increase in Costs (1998 dollars/Mcf) for Incremental CBM production	Coalbed Methane	NA	NA	0.75
		Tight Sands	NA	NA	0.00
		Gas Shales	NA	NA	NA
11	Proportion of Areas Currently Restricted that Become Available for Development (per year)	All types	0.5%	1%	1.5%

EUR = Estimated Ultimate Recovery.
O&M = Operation & Maintenance.
CBM = Coalbed Methane.
NA = Not applicable.
DOE = Those plays in the Rocky Mountain basins assessed as part of Department of Energy sponsored basin studies.
Source: Reference Technology Case, Advanced Resources, International; Slow and Rapid Technology Cases, Energy Information Administration, Office of Integrated Analysis and Forecasting.

Notes and Sources

[85] Technically recoverable resources are resources in accumulations producible using current recovery technology but without reference to economic profitability.

[86] Proved reserves are the estimated quantities that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

[87] Inferred reserves are that part of expected ultimate recovery from known fields in excess of cumulative production plus current reserves.

[88] Undiscovered resources are located outside oil and gas fields in which the presence of resources has been confirmed by exploratory drilling; they include resources from undiscovered pools within confirmed fields when they occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions.

[89] Donald L. Gautier and others, U.S. Department of Interior, U.S. Geological Survey, 1995 National Assessment of the United States Oil and Gas Resources, (Washington, D.C., 1995); U.S. Department of Interior, Minerals Management Service, an Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf, OGS Report MMS 96-0034 (June 1996); and 2003 estimates of conventionally recoverable hydrocarbon resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 2003.

[90] U.S. Geological Survey, 2002 Petroleum Resource Assessment of the National Petroleum Reserve in Alaska (NPRA): Play Maps and Technically Recoverable Resource Estimates, Open- File Report 02-207 (May 2002).

[91] For unconventional -- Average undiscovered resources under the National Energy Board's Supply Push and Techno-vert scenarios in "Canada's Energy Future, scenarios for Supply and Demand to 2025," 2003. For conventional -- "Canada's Conventional Natural Gas Resources - A Status Report," April 2004.

[92] Tailgate LNG prices represents the price when natural gas exists the regasification facility.

[93] Gas reserves that have been located but are isolated from potential markets, commonly referred to as "stranded" gas, are likely to provide most of the natural gas for LNG in the future. Reserves that can be linked to sources of demand via pipeline are unlikely candidates to be developed for LNG.

[94] Largely based on information from Gas Technology Institute, "Liquefied Natural Gas (LNG) Methodology Enhancements in NEMS," Report submitted to Energy Information Administration, March 31, 2003.

Notes and Sources for Table 51

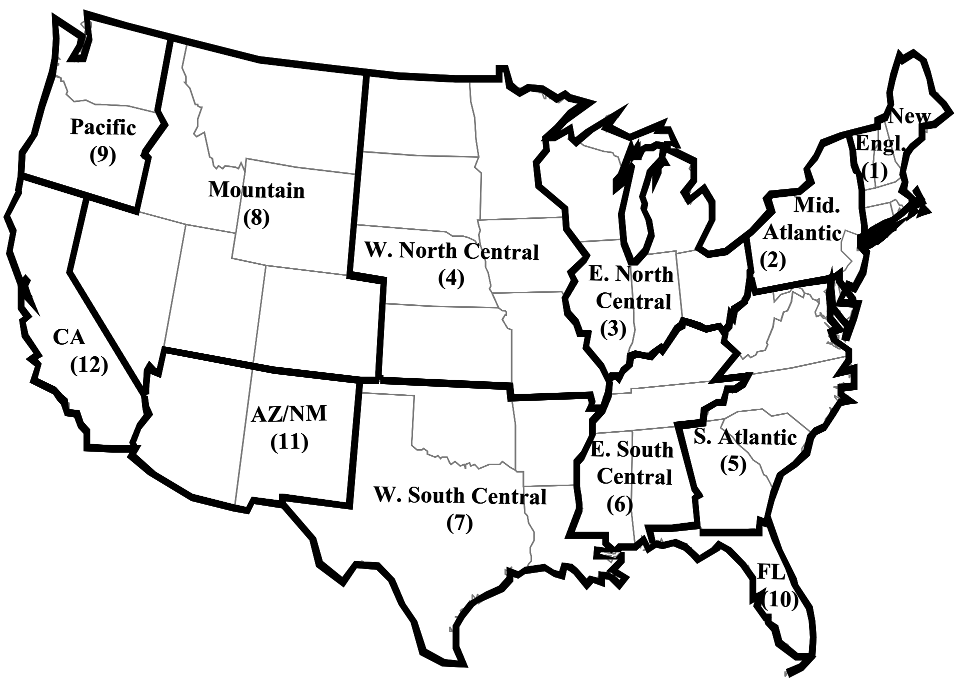
Note: Resources in areas where drilling is officially prohibited are not included in this table. Also, the Associated-Dissolved Gas and the Alaska values are not explicitly utilized in the OGSM, but are included here to complete the table. The Alaska value does not include stranded Arctic gas.

Source: Onshore, State Offshore, and Alaska - U.S. Geological Survey (USGS) with adjustments to Unconventional Gas Recovery resources by Advanced Resources, International; Federal (Outer Continental Shelf) Offshore - Minerals Management Service (MMS); Proved Reserves -- EIA, Office of Oil and Gas. Table values reflect removal of intervening reserve additions between the date of the latest available assessment and January 1, 2003.

Natural Gas Transmission and Distribution Module

The NEMS Natural Gas Transmission and Distribution Module (NGTDM) derives domestic natural gas production, wellhead and border prices, end-use prices, and flows of natural gas through the regional interstate network, for both a peak (December through March) and off peak period during each forecast year. These are derived by solving for the market equilibrium across the three main components of the natural gas market: the supply component, the demand component, and the transmission and distribution network that links them. In addition, natural gas flow patterns are a function of the pattern in the previous year, coupled with the relative prices of gas supply options as translated to the represented market centers within each of the NGTDM regions (Figure 8). The major assumptions used within the NGTDM are grouped into five general categories. They relate to (1) the classification of demand into core and noncore transportation service classes, (2) the pricing of transmission and distribution services, (3) pipeline and storage capacity expansion and utilization, and (4) the implementation of recent regulatory reform. A complete listing of NGTDM assumptions and in-depth methodology descriptions are presented in *Model Documentation: Natural Gas Transmission and Distribution Model of the National Energy Modeling System, Model Documentation 2005,* DOE/EIA-M062(2005) (Washington, DC, 2005).

Figure 8 . Natural Gas Transmission and Distribution Model Regions



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Key Assumptions

Demand Classification

Customers demanding natural gas are classified as either core or noncore customers, with core customers assumed to transport their gas under firm (or near firm) transportation agreements and noncore customers assumed to transport their gas under interruptible or short-term capacity release transportation agreements. A distinction is made between core and noncore customers because the price differentials can be significant and it allows for a different algorithm to be used in setting the prices. All residential, commercial, and transportation (vehicles using compressed natural gas) end-use customers are assumed to be core customers. Industrial customers fall into both categories, with industrial boilers and refineries assumed to be noncore and all other industrial users assumed to be core. Likewise, customers in the electric generator sector are assumed to be both core and noncore. Gas steam and gas combined-cycle units are considered to be core; and the remaining units are classified as noncore.

End-use sector specific load patterns are based on recent historical patterns and do not change over the forecast, with the exception of the electric generation sector[95] (i.e., there is no representation of changes in load patterns from new technologies like natural gas cooling.) However, pipeline load factors do change over the forecast as the composition of end-use consumption changes across sectors and as more pipeline and storage capacity becomes available.

Pricing of Services

Transportation rates for interstate pipeline services (both between NGTDM regions and within a region) are calculated assuming that the costs of new pipeline capacity will be rolled into the existing rate base. While cost-of-service still forms the basis for pricing these services, an adjustment to the tariffs is made based on changes in utilization to reflect a more market-based approach. Capital expenditures for refurbishment are generally relatively small, are offset by retirements, and are therefore not considered, nor are potential future expenditures for pipeline safety (refurbishment costs include any expenditures for repair and/or replacement of existing pipe).

End-use prices for residential, commercial, and core industrial customers are derived by adding a markup to the average regional market price of natural gas in both peak and off-peak periods. (Prices are reported on an annual basis and represent quantity-weighted averages of the two seasons.) These markups include the cost of service provided by intraregional interstate pipelines, intrastate pipelines, and local distributors. The intrastate tariffs are accounted for endogenously through historical model benchmarking. Distributor tariffs represent the difference between the regional end-use and citygate price, independent of whether or not a customer class typically purchases gas through a local distributor. The distribution tariffs are initially based on average historical values (Table 59). For residential, commercial, and core industrial customers,

Table 59. Base Level Annual Distributor Markup for Local Transportation Service
(2002 dollars per thousand cubic feet)

Region	Residential	Commercial	Core Industrial
New England	5.37	2.86	-0.19
Mid Atlantic	4.68	2.51	0.07
East North Central	2.60	2.05	0.18
West North Central	3.00	1.84	-0.34
South Atlantic	4.62	2.93	0.42
East South Central	3.86	2.82	0.76
West South Central	3.64	1.88	0.33
Mountain	3.11	2.27	1.23
Pacific	4.45	3.02	0.54
Florida	9.35	3.92	1.70
Arizona/New Mexico	4.95	2.75	1.07
California	4.12	3.43	1.01

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived from Form EI-857, “Monthly Report of Natural Gas Purchases and Deliveries to Consumers” for residential, commercial, and citygate, and from various Manufacturing Energy Consumption Surveys for core industrial.

distributor tariffs are adjusted throughout the forecast in response to changes in consumption levels and other explanatory variables, such as the cost of labor and capital. Although the markups in Table 59 represent annual averages, the model uses separate markups for the peak and offpeak periods.

End-use prices for noncore industrial and electric generator customers are similarly established by adding a markup to the regional natural gas market price. These markups are endogenously derived as the difference between estimated historical end-use prices,[96] and the NGTDM regional market price. For noncore industrial customers, these markups are held constant throughout the forecast. For electric generator customers, these markups are adjusted each forecast year by a fraction (0.27) of the annual percentage change in the associated electric generator consumption. This adjustment is intended to reflect anticipated additional infrastructure devoted to serving electric generation consumption growth.

The vehicle natural gas (VNG) sector is divided into fleet and non-fleet vehicles. The distributor tariffs for natural gas to fleet vehicles are set to *EIA's Natural Gas Annual* historical end-use prices minus citygate prices plus Federal and State VNG taxes (Table 60). The price to non-fleet vehicles is based on the industrial sector firm price plus an assumed $4.35 (2003 dollars per thousand cubic feet) dispensing charge plus Federal and State taxes, held constant in nominal dollars. It is assumed that the retailer will lower the dispensing charge by up to 20 percent if needed to be competitive with gasoline prices.

Table 60. Vehicle Natural Gas (VNG) Pricing
(nominal dollars per thousand cubic feet)

Modified Census Divisions	Total Federal and State VNG Tax[1]
New England	0.81
Middle Atlantic	2.71
East North Central	2.05
West North Central	2.07
South Atlantic (excludes Florida)	1.67
East South Central	1.71
West South Central	1.75
Mountain (excludes Arizona and New Mexico)	1.70
Pacific (excludes California)	2.40
Florida	1.00
Arizona and New Mexico	0.59
California	1.04

[1]Assuming a $0.4844 (nominal dollars per thousand cubic feet) Federal tax.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, based on the Federal tax published in the Department of the Treasury, "Excise Taxes for 2003," Publication 510, February 2003; and State taxes posted at Hart Energy Networks Motor Fuels Information Center at www.hartenergynetwork.com/motorfuels/state/doc/glance/glnctax.htm.

Capacity Expansion and Utilization

For the first 2 forecast years, announced pipeline and storage capacity expansions (that are deemed highly likely to occur) are used to establish limits on flows and storage in the model. Subsequently, pipeline and storage capacity is added when increases in demand, coupled with anticipated price impacts, warrant such additions (i.e., flow is allowed to exceed current capacity if the demand still exists given the adjusted tariff, thus indicating an expansion). When the decision to add capacity is made, a representation is incorporated that captures the average capital costs for pipeline and storage expansion and the resulting tariff. Once it is determined that an expansion will occur, the associated capital costs are estimated based on costs of recent expansions in that area and are used in the revenue requirement calculations in future years.

It is assumed that pipelines and local distribution companies build and subscribe to a portfolio of pipeline and storage capacity to serve a region-specific colder-than-normal winter demand level, currently set at 30 percent for all pipeline areas. Maximum pipeline capacity utilization in the peak period is set at 99 percent. In the off-peak period, the maximum is assumed to vary between 75 and 99 percent of the design capacity. The overall level and profile of consumption as well as the availability and price of supplies generally cause realized pipeline utilization levels to be lower than the maximum. For each sector, consumption is disaggregated into peak and off-peak periods based on average historical patterns. The model methodology represents net injections of natural gas into storage in the off-peak period and net withdrawals during the peak period. Total annual net storage withdrawals equal zero in all years of the forecast.

Legislation and Regulation

The methodology for setting reservation fees for transportation services is consistent with FERC's alternative ratemaking and capacity release position in that it allows flexibility in the rates pipelines charge. The methodology is market-based in that prices for transportation services will respond positively to increased demand for services while prices will decline (reflecting discounts to retain customers) should the demand for services decline. The Pipeline Safety Improvement Act of 2002 is not explicitly represented, but is expected to raise transportation costs by an insignificant amount.

Notes and Sources

[95] The fraction of the annual natural gas consumption by electric generators in the peak period is assumed to grow by 0.5 percent a year throughout the forecast period.

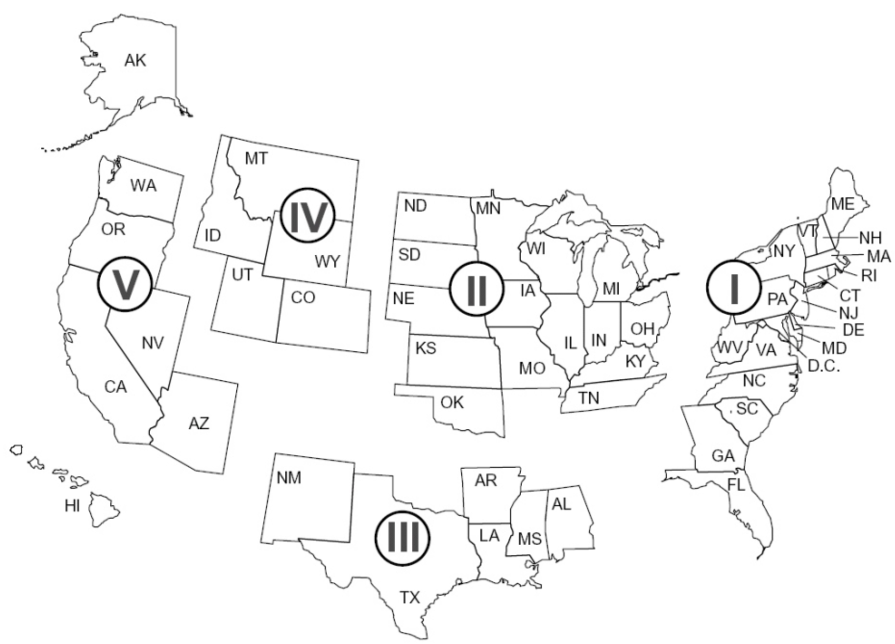
[96] Historical core and noncore industrial prices were based on data from various Energy Information Administration Manufacturing Energy Consumption Surveys. Year-to-year estimates are set as a function of regional industrial prices, as sold through local distribution companies and published in EIA's Natural Gas Annual, and regional supply prices from the same source.

Petroleum Market Module

The NEMS Petroleum Market Module (PMM) forecasts petroleum product prices and sources of supply for meeting petroleum product demand. The sources of supply include crude oil (both domestic and imported), petroleum product imports, other refinery inputs including alcohols, ethers, and bioesters natural gas plant liquids production, and refinery processing gain. In addition, the PMM estimates capacity expansion and fuel consumption of domestic refineries.

The PMM contains a linear programming representation of U.S. refining activities in the five Petroleum Area Defense Districts (PADDs) (Figure 9). The PADDs are created by aggregating individual refineries into one linear programmming representation for each region. This representation provides the marginal costs of production for a number of traditional and new petroleum products. In order to interact with other NEMS modules with different regional representations, certain PMM inputs and outputs are converted from PADD regions to other regional structures and vice versa. The linear programming results are used to determine end-use product prices for each Census Division (shown in Figure 5) using the assumptions and methods described below.

Figure 9. Petroleum Administration for Defense Districts



Source:Energy Information Administration,Office of Integrated Analysis and Forecasting.

Key Assumptions

Product Types and Specifications

The PMM models refinery production of the products shown in Table 61.

The costs of producing different formulations of gasoline and diesel fuel that are required by State and Federal regulations are determined within the linear programming representation by incorporating specifications and demands for these fuels. The PMM assumes that the specifications for these fuels will remain the same as currently specified, except that the sulfur content of all gasoline and diesel fuel will be phased down to reflect EPA regulations.

Table 61. Petroleum Product Categories

Product Category	Specific Products
Motor Gasoline	Conventional Unleaded, Oxygenated, Reformulated
Jet Fuel	Kerosene-type
Distillates	Kerosene, Heating Oil, Low-Sulfur-Diesel, Ultra-Low-Sulfur-Diesel
Residual Fuels	Low Sulfur, High Sulfur
Liquefied Petroleum Gases	Propane, Liquefied Petroleum Gases Mixed
Petrochemical Feedstocks	Petrochemical Naptha, Petrochemical Gas Oil, Propylene, Aromatics
Others	Lubricating Products and Waxes, Asphalt/Road Oil, Still Gas Petroleum Coke, Special Naphthas, Aviation Gasoline

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Motor Gasoline Specifications and Market Shares

The PMM models the production and distribution of three different types of gasoline: conventional, oxygenated, and reformulated (Phase 2). The following specifications are included in PMM to differentiate between conventional and reformulated gasoline blends (Table 62): oxygen content, Reid vapor pressure (Rvp), benzene content, aromatic content, sulfur content, olefin content, and the percent evaporated at 200 and 300 degrees Fahrenheit (E200 and E300). The sulfur specification for gasoline is reduced to reflect recent regulations requiring the average annual sulfur content of all gasoline used in the United States to be phased-down to 30 parts per million (ppm) between the years 2004 and 2007.[97] PMM assumes that RFG has an average annual sulfur content of 135 ppm in 2000 and meets the 30 ppm requirement in 2004. The regional assumptions for phasing-down the sulfur in conventional gasoline account for less stringent sulfur requirements for small refineries and refineries in the Rocky Mountain region. The 30 ppm annual average standard is not fully realized in conventional gasoline until 2008 due to allowances for small refineries. The sulfur specifications assumed for each region and type are provided in Table 63.

Table 62. Year Round Gasoline Specifications by Petroleum Administration for Defense Districts (PADD)

PADD	Reid Vapor Pressure (Max PSI)	Oxygen Weight Percent (Min)	(Max)	Aromatics Volume Percent (Max)	Benzene Volume Percent (Max)	2006 Sulfur PPM (Max)	Olefin Volume Percent (Max)	Percent Evaporated at 200°	Percent Evaluated at 300°
Conventional									
PADD I	9.6	—	—	26.0	1.1	43.4	11.6	47.1	82.0
PADD II	10.2	—	—	26.1	1.1	60.0	11.6	47.1	81.9
PADD III	9.9	—	—	26.1	1.1	60.0	11.6	47.1	81.9
PADD IV	10.8	—	—	26.1	1.1	44.2	11.6	47.1	81.9
PADD V	9.2	—	—	26.7	1.1	33.7	11.6	45.7	81.4
Reformulated									
PADD I	8.5	2.0	2.1	20.7	0.6	30.0	11.9	50.2	84.6
PADD II	9.5	2.0	2.1	18.5	0.8	30.0	7.1	50.8	85.2
PADD III	8.6	2.0	2.1	19.8	0.6	30.0	11.2	51.6	83.9
PADD V									
Nonattainment	7.9	2.0	2.1	22.0	0.70	20.0	6.0	49.0	90.0
CARB (attainment)	7.9	—	1.2	22.0	0.70	20.0	6.0	49.0	90.0

Max = Maximum.

Min = Minimum.

PADD = Petroleum Administration for Defense District.

PPM = Parts per million by weight.

PSI = Pounds per Square Inch.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived using U.S. EPA's Complex Model, and updated with U.S. EPA's 2002 gasoline projection survey (http://www.epa.gov/otag/regs/fuels/rfg/properf/rfgper.htm).

Conventional gasoline must comply with antidumping requirements aimed at preventing the quality of conventional gasoline from eroding as the reformulated gasoline program is implemented. Conventional gasoline must meet the Complex Model compliance standards which cannot exceed average 1990 levels of toxic and nitrogen oxide emissions.[98]

Table 63. Gasoline Sulfur Content Assumptions, by Region and Gasoline Type, Parts per Million (PPM)

	2004	2005	2006	2007	2008-2025
Conventional					
PADD I	143.4	90.0	43.4	41.7	30
PADD II	167.7	111.0	60.0	33.2	30
PADD III	170.5	114.5	60.0	32.4	30
PADD IV	140.0	90.0	44.2	44.2	30
PADD V	122.8	70.0	33.7	33.7	30
Reformulated					
PADD I-IV	30	30	30	30	30
PADD V	20	20	20	20	20

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived from Form EI-810 “Monthly Refinery Report” and U.S. Environmental Protection Agency, “Tier 2” Motor Vehicle Emissions Standards and Gasoline Sulfur Control requirements, February 2000, (Washington, DC).

Oxygenated gasoline, which has been required during winter in many U.S. cities since October of 1992, requires an oxygenated content of 2.7 percent by weight. Oxygenated gasoline is assumed to have specifications identical to conventional gasoline with the exception of a higher oxygen requirement. Some areas that require oxygenated gasoline will also require reformulated gasoline. For the sake of simplicity, the areas of overlap are assumed to require gasoline meeting the reformulated specifications.

Cellulosic biomass feedstock supplies and costs are taken from the NEMS Renewable Fuels Model. Capital and operating costs for biomass ethanol are derived from an Oak Ridge National Laboratory report.[99]

Reformulated gasoline has been required in many areas in the United States since January 1995. In 1998, the EPA began certifying reformulated gasoline using the “complex model,” which allows refiners to specify reformulated gasoline based on emissions reductions from their company; 1990 baseline or the EPA’s 1990 baseline. The PMM reflects “Phase 2” reformulated gasoline requirements which began in 2000. The PMM uses a set of specifications that meet the “complex model” requirements, but it does not attempt to determine the optimal specifications that meet the “complex model.” (Table 62).

The Clean Air Act Amendments of 1990 (CAAA90) provided for special treatment of California that would allow different specifications for oxygenated and reformulated gasoline in that State. In 1992, California requested a waiver from the winter oxygen requirements of 2.7 percent to reduce the requirement to a range of 1.8 to 2.2 percent. The PMM assumes that PADD V refiners have met the California Air Resources Board (CARB) Phase 3 specifications since 2003. The CARB Phase 3 specifications reflect the removal of the oxygen requirement designed to complement the State ban of the oxygenate, methyl tertiary butyl ether (MTBE) in 2003. Without a waiver from the U.S. EPA, a minimum oxygen content will still be required in the areas of California covered by the Federal reformulated gasoline program (Los Angeles, San Diego, Sacramento, and San Joaquin Valley). *AEO2005* assumes that the oxygen requirement remains intact in these areas because no waiver had been granted at the time of the development of the forecast.

AEO2005 reflects legislation which bans or limits the use of MTBE in 19 additional States: Arizona, Colorado, Connecticut, Illinois, Iowa, Kansas, Maine, Michigan, Minnesota, Nebraska, New Hampshire, New York, South Dakota, Wisconsin, Washington, Indiana, Kentucky, Ohio, and Missouri. Since the oxygen requirement on RFG is assumed to continue in these States, the MTBE ban is modeled as a requirement to produce ethanol blended RFG. Ethanol blends were assumed to account for the following market percentages:

— 29.0 percent of RFG in New England
— 36.5 percent of RFG in Mid-Atlantic

— 99.0 percent of RFG in Mountain
— 100.0 percent of RFG(with 2.0 percent oxygen requirement) in Pacific
— 100.0 percent of oxygenated gasoline in West North Central
— 100.0 percent of oxygenated gasoline in Mountain
— 100.0 percent of oxygenated gasoline in Pacific

Rvp limitations are effective during summer months, which are defined differently in different regions. In addition, different Rvp specifications apply within each refining region, or PADD. The PMM assumes that these variations in Rvp are captured in the annual average specifications, which are based on summertime Rvp limits, wintertime estimates, and seasonal weights.

Within the PMM, total gasoline demand is disaggregated into demand for conventional, oxygenated, and reformulated gasoline by applying assumptions about the annual market shares for each type. The shares are able to change over time based on assumptions about the market penetration of new fuels. In *AEO2005,* the annual market shares for each region reflect actual 2001 market shares and are held constant throughout the forecast. (See Table 64 for *AEO2005* market share assumptions.)

Table 64. Market Share for Gasoline Types by Census Division

Gasoline Type/Year	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West Slouth Central	Mountain	Pacific
Conventional Gasoline	19	42	83	56	82	94	71	63	19
Oxygenated Gasoline (2.7% oxygen)	0	0	0	10	0	0	1	17	6
Reformulated Gasoline (2.0% oxygen)	81	58	17	34	18	6	28	20	75*

*Note: 59 percent is assumed to continue the 2.0 percent Federal oxygen requirement. 15 percent is the result of State requirements.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived from EIA-782C, “Monthly Report of Prime Supplier Sales of Petroleum Products Sold for Local Consumption,” January-December 2002.

Diesel Fuel Specifications and Market Shares

In order to account for diesel desulfurization regulations related to CAAA90, low-sulfur diesel is differentiated from other distillates. In NEMS, Census Division 9 is required to meet CARB standards. Both Federal and CARB standards, currently limit sulfur to 500 ppm.

AEO2005 incorporates the “ultra-low-sulfur diesel” (ULSD) regulation finalized in December 2000. ULSD is highway diesel that contains no more than 15 ppm sulfur at the pump. The ULSD regulation includes a phase-in period under the “80/20” rule, that 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. As NEMS is an annual average model, only a portion of the production of highway diesel in 2006 is subject to the 80/20 rule and the 100 percent requirement does not cover all highway diesel until 2011.

NEMS models ULSD as containing 7.5 ppm sulfur at the refinery gate in 2006, phasing down to 7ppm sulfur by 2010. This lower sulfur limit at the refinery reflects the general consensus that refiners will need to produce diesel with a sulfur content below 10 ppm to allow for contamination during the distribution process.

Revamping (retrofitting) existing units to produce ULSD will be undertaken by refineries representing two-thirds of highway diesel production; the remaining refineries will build new units. The capital cost of the revamp is assumed to be 50 percent of the cost of adding a new unit.

The capital costs for new distillate hydrotreaters reflected in *AEO2005* are $1,243 to $2,437 (2002 dollars) per barrel per day (Inside Battery Limit). The lower estimate is for a 30,000 barrel per day unit utilizing Conoco Philips Z-sorb desulfurization tehnology. The higher estimate is for a 30,000 barrel per day unit processing higher sulfur feed streams with greater aromatics improvement.

The amount of ULSD downgraded to a lower value product because of sulfur contamination in the distribution system is assumed to be 10 percent at the start of the program, declining to 4.4 percent at full implementation. The decline reflects the expectation that the distribution system will become more efficient at handling ULSD with experience.

A revenue loss is assumed to occur when a portion of ULSD that is put into the distribution system is contaminated and must be sold as lower value product. The amount of the revenue loss is estimated offline based on earlier NEMS results and is included in *AEO2005* ULSD price projections as a distribution cost. The revenue loss associated with the 10 percent downgrade assumption for 2007 is 0.7 cents per gallon. The revenue loss estimate declines to 0.2 cents per gallon after 2010 when the downgrade assumption declines to 4.4 percent.

The capital and operating costs associated with ULSD distribution are based on assumptions used by the EPA in the Regulatory Impact Analysis (RIA) of the rule.[100]Capital costs of 0.7 cents per gallon are assumed for additional storage tanks to handle ULSD during the transition period. These capital expenditures are assumed to be fully amortized by 2011. Additional operating costs for distribution of highway diesel of 0.2 cents per gallon are assumed for the entire forecast. Another 0.2 cents per gallon is assumed for the cost of lubricity additives. Lubricity additives are needed to compensate for the reduction of aromatics and high-molecular-weight hydrocarbons stripped away by the severe hydrotreating used in the desulfurization process.

Demand for highway-grade diesel, both 500 ppm and ULSD combined, is assumed to be equivalent to total transportation distillate demand. Historically, highway-grade diesel supplies have nearly matched total transportation distillate sales, although some highway-grade diesel has gone to nontransportation uses such as construction and agriculture.

The energy content of ULSD is assumed to decline by 0.5 percent because undercutting and severe desulfurization will result in a lighter stream composition than that for 500 ppm diesel.

AEO2005 incorporates the “nonroad locomotive and marine” (NRLM) diesel regulation finalized in May 2004. The PMM model has been revised to reflect the nonroad rule and re-calibrated for market shares of highway, NRLM diesel, and other distillate (mostly heating oil, but excluding jet fuel and kerosene). The nonroad rule follows the highway diesel rule closely and represents an incremental tightening of the entire diesel pool. The demand for high sulfur distillate will diminish over time while the demand for ULSD (both highway and NRLM) will increase over time.

The final rule is implemented in multiple steps and requires sulfur content for all nonroad locomotive and marine (NRLM) diesel fuel produced by refiners to be reduced to 500 ppm starting mid-2007 and establishes a new ultra-low-sulfur diesel (ULSD) limit of 15 ppm for nonroad diesel by mid-2010. For locomotive and marine diesel, the action establishes a ULSD limit of 15 ppm in mid-2012.

The price for commercial and industrial distillate fuel with the rule in place is higher after 2010 to remove sulfur from the most difficult distillate streams. Commercial distillate prices are generally 2-cents-per-gallon higher with peaks approaching 3-cents-per-gallon. Prices for industrial distillate exhibit considerable variance (0.4-to-9-cents-per-gallon) during rule implementation with maximum differentials approaching 10-cents-per-gallon. While nonroad diesel is a relatively small portion of commercial distillate, nonroad diesel dominates industrial distillate. Consequently, the price impact on industrial distillate is larger than for commercial distillate.

For the transportation sector, indications are that the nonroad diesel price will be about 2-cents-per-gallon higher by 2010-2012 because of the NRLM diesel sulfur reduction. The transportation diesel price will be almost 3 cents-per-gallon higher by 2014 when locomotive and marine diesel fuel is required to reduce sulfur content to 15 ppm.

The electric utility sector is least permanently affected by the nonroad diesel rule due to fuel switching to other competing fuels such as natural gas and coal.

EPA estimates place the added cost of ULSD for nonroad use in the range of about 7-cents-per-gallon; however, EPA expects these costs to be offset by reduced engine maintenance expenses, thereby reducing the net incremental impact to about 4-cents-per-gallon.[101]The EPA estimates assume complete turnover of nonroad diesel engines by 2030. These somewhat longer-term results focusing on the nonroad diesel market differ from EIA calculated composite impacts of 2-to 4-cents-per-gallon for all diesel during the 2007-2014 implementation years.

End-Use Product Prices

End-use petroleum product prices are based on marginal costs of production plus production-related fixed costs plus distribution costs and taxes. The marginal costs of production are determined by the model and represent variable costs of production including additional costs for meeting reformulated fuels provisions of the CAAA90. Environmental costs associated with controlling pollution at refineries are implicitly assumed in the annual update of the refinery investment costs for the processing units.

The costs of distributing and marketing petroleum products are represented by adding fixed distribution costs to the marginal and refinery fixed costs of products. The distribution costs are applied at the Census Division level (Table 65) and are assumed to be constant throughout the forecast and across scenarios.

Distribution costs for each product, sector, and Census Division represent average historical differences between end-use and wholesale prices. The distribution costs for kerosene are the average difference between end-use prices of kerosene and wholesale distillate prices. Distribution costs for E85 are assumed to be equal to distribution costs for gasoline.

Table 65. Petroleum Product End-Use Markups by Sector and Census Division
(2003 dollars per gallon)

	Census Division								
Sector/Product	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Residential Sector									
Distillate Fuel Oil	0.40	0.48	0.34	0.27	0.45	0.31	0.21	0.29	0.42
Kerosene	0.17	0.31	0.44	0.26	0.32	0.40	0.23	0.19	0.08
Liquefied Petroleum Gases	0.92	0.98	0.54	0.36	0.83	0.69	0.61	0.57	0.84
Commercial Sector									
Distillate Fuel Oil	0.16	0.13	0.06	0.03	0.07	0.04	0.04	0.04	0.07
Gasoline	0.16	0.13	0.14	0.15	0.13	0.17	0.17	0.16	0.17
Kerosene	0.16	0.26	0.46	0.27	0.30	0.42	0.20	0.21	0.10
Liquefied Petroleum Gases	0.57	0.58	0.49	0.35	0.57	0.46	0.38	0.49	0.62
Low-Sulfur Residual Fuel Oil	0.00	0.03	0.02	0.01	0.00	0.03	-0.01	0.03	0.10
Utility Sector									
Distillate Fuel Oil	0.02	0.03	0.02	0.01	0.02	0.06	0.03	0.07	0.02
High-Sulfur Residual Fuel Oil[2]	0.00	0.03	0.09	-0.04	0.01	-0.06	0.07	0.01	0.08
Low-Sulfur Residual Fuel Oil[3]	-0.01	0.00	0.08	-0.07	0.01	-0.11	0.11	0.23	0.19
Transportation Sector									
Distillate Fuel Oil	0.30	0.23	0.19	0.17	0.19	0.21	0.18	0.19	0.25
E85[1]	0.21	0.17	0.19	0.20	0.18	0.23	0.22	0.18	0.15
Gasoline	0.25	0.23	0.22	0.24	0.20	0.25	0.26	0.21	0.13
High-Sulfur Residual Fuel Oil[2]	-0.02	0.04	0.12	-0.04	0.00	-0.08	0.06	0.29	0.05
Jet Fuel	-0.02	-0.01	-0.02	-0.04	-0.03	0.00	0.00	-0.02	0.00
Liquefied Petroleum Gases	0.52	0.53	0.60	0.33	0.52	0.40	0.32	0.42	0.55
Industrial Sector									
Asphalt and Road Oil	0.23	0.18	0.29	0.17	0.16	0.09	0.19	0.36	0.18
Distillate Fuel Oil	0.16	0.14	0.14	0.11	0.11	0.09	0.10	0.08	0.13
Gasoline	0.16	0.13	0.14	0.16	0.13	0.18	0.17	0.16	0.14
Kerosene	0.10	0.11	0.15	0.18	0.15	0.17	0.08	0.13	0.11
Liquefied Petroleum Gases	0.45	0.49	0.55	0.29	0.49	0.39	0.24	0.29	0.55
Low-Sulfur Residual Fuel Oil	0.00	0.00	0.03	0.02	0.01	-0.01	0.01	0.09	0.10

[1]85 percent ethanol and 15 percent gasoline.

[2]Negative values indicate that average end-use sales prices were less than wholesale prices. This often occurs with residual fuel which is produced as a byproduct when crude oil is refined to make higher value products like gasoline and heating oil.

Sources: Markups based on data from Energy Information Administration (EIA), Form EIA-782A, *Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report*; EIA, Form EIA-782B, *Resellers'/Retailers' Monthly Petroleum Report Product Sales Report*; EIA, Form FERC-423, *Monthly Report of Cost and Quality of Fuels for Electric Plants*; EIA, Form EIA-759 *Monthly Power Plant Report; EIA, State Energy Data Report 2000, Consumption (March 2003); EIA, State Energy Data 2000: Prices and Expenditures* (March 2003).

State and Federal taxes are also added to transportation fuels to determine final end-use prices (Tables 66 and 67). Recent tax trend analysis indicated that State taxes increase at the rate of inflation, therefore, State taxes are held constant in real terms throughout the forecast. This assumption is extended to local taxes which are assumed to average 2 cents per gallon.[102] Federal taxes are assumed to remain at current levels in accordance with the overall *AEO2005* assumption of current laws and regulation. Federal taxes are deflated as follows:

$$\text{Federal Tax}_{\text{product, year}} = \text{Current Federal Tax}_{\text{product}} / \text{GDP Deflator}_{\text{year}}$$

Table 66. State and Local Taxes on Petroleum Transportation Fuels by Census Division
(2003 dollars per gallon)

	Census Division								
Year/Product	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Gasoline[1]	0.25	0.21	0.24	0.21	0.19	0.21	0.22	0.24	0.22
Diesel	0.24	0.22	0.22	0.20	0.20	0.17	0.19	0.22	0.20
Liquefied Petroleum Gases	0.11	0.11	0.16	0.17	0.16	0.16	0.12	0.13	0.05
E85[2]	0.27	0.19	0.16	0.17	0.14	0.17	0.20	0.14	0.13
Jet Fuel	0.04	0.04	0.00	0.03	0.05	0.02	0.01	0.04	0.03

[1]Tax also applies to gasoline consumed in the commercial and industrial sectors.

[2] 85 percent ethanol and 15 percent gasoline.

Source: Gasoline, diesel and E85 aggregated from Petroleum Marketing Monthly DE/EIA-0380(2004/09), Table EN1, (Washington, DC, September 2004). LPG aggregated from Federal Highway Administration, Tax Rates on Motor Fuel, Jet fuel from EIA, Office of Oil and Gas.

Table 67. Federal Taxes
(Nominal dollars per gallon)

Product	Tax
Gasoline	0.18
Diesel	0.24
Jet Fuel	0.04
Liquefied Petroleum Gases	0.14
M85[1]	0.09
E85[2]	0.13

[1]85 percent methanol and 15 percent gasoline.

[2] 85 percent ethanol and 15 percent gasoline.

Sources: Omnibus Budget Reconciliation Act of 1993 (H.R. 2264); Tax Payer Relief Act of 1997 (PL 105-34) and *Clean Fuels Report* (Washington, DC, April 1998).

Crude Oil Quality

In the PMM, the quality of crude oil is characterized by average gravity and sulfur levels. Both domestic and imported crude oil are divided into five categories as defined by the ranges of gravity and sulfur shown in Table 68.

Table 68. Crude Oil Specifications

Crude Oil Categories	Sulfur (percent)	Gravity (degrees API)
Low Sulfur Light	0 - 0.5	25 - 60
Medium Sulfur Heavy	0.35 - 1.1	26 - 40
High Sulfur Light	> 1.1	>32
High Sulfur Heavy	> 1.1	24 - 33
High Sulfur Very Heavy	> 0.9	< 23

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived from EI-810, "Monthly Refinery Report" data.

A "composite" crude oil with the appropriate yields and qualities is developed for each category by averaging the characteristics of specific crude oil streams that fall into each category. While the domestic and foreign categories are the same, the composite crudes for each category may differ because different crude streams make up the composites. For domestic crude oil, estimates of total regional production are made first, then shared out to each of the five categories based on historical data. For imported crude oil, a separate supply curve is provided for each of the five categories.

Capacity Expansion

PMM allows for capacity expansion of all processing units including distillation capacity, vacuum distillation, hydrotreating, coking, fluid catalytic cracking, hydrocracking, alkylation, and methyl tertiary butyl ether manufacture. Capacity expansion occurs by processing unit, starting from base year capacities established by PADD using historical data.

Expansion occurs in NEMS when the value received from the additional product sales exceeds the investment and operating costs of the new unit. The investment costs assume a10-percent hurdle rate in the decision to invest and a 10-percent rate of return over a 15-year financial plant life. Expansion through 2004 is determined by adding to the existing capacities of units planned and under construction that are expected to begin operating during this time. Capacity expansion plans are done every 3 years. The PMM looks ahead in 2002 and determines the optimal capacities given the estimated demands and prices expected in the 2005 forecast year. The PMM then allows one-third of that capacity to be built in each of the forecast years 2003, 2004, and 2005. At the end of 2005 the cycle begins anew, looking ahead to 2008.

Capacity expansion of ethanol plants are not modeled explicitly, but as a variable in computing ethanol supply curves. A more detailed description of this process can be found in Appendix I of the PMM documentation, NEMS Petroleum Market Model Documentation, DOE/EIA-M059(Washington, DC, 2004).

Strategic Petroleum Reserve Fill Rate

AEO2005 assumes no additions for the Strategic Petroleum Reserve (SPR) during the forecast period. Any SPR draw is assumed to be in the form of a swap with a zero net annual change.

Biofuels Supply

The PMM provides supply functions on an annual basis through 2025 for ethanol produced from both corn and cellulosic biomass to produce transportation fuel. It also assumes that small amounts of vegetable oil and animal fats are processed into biodiesel, a blend of methyl esters suitable for fueling diesel engines.

- Corn feedstock supplies and costs are provided exogenously to NEMS. Feedstock costs reflect credits for co-products (livestock feed, corn oil, etc.). Feedstock supplies and costs reflect the competition between corn and its co-products and alternative crops, such as soybeans and their co-products.

- Current U.S ethanol production capacity is aggregated by Census Division in the PMM. Cellulose ethanol demonstration plants are modeled in Census Divisions 2 and 7. However, the majority of cellulose ethanol growth is projected in Census Divisions 3 and 4 using corn stover as feedstock, and in Census Division 9 with rice straw and forest residue as the primary feedstock.

- The tax subsidy to ethanol is 51 cents per gallon of ethanol (5.1 cents per gallon subsidy to gasohol at a 10-percent volumetric blending portion) is applied within the model. The tax subsidy is held constant in nominal terms, decreasing with inflation throughout the forecast. The subsidy is assumed not to expire during the forecast period.

Interregional transportation is assumed to be by rail, ship, barge, and truck and the associated costs are included in PMM. A subsidy is offered by the Department of Agriculture's Commodity Credit Corporation for the production of biodiesel. Based on data through the third quarter of 2002, biodiesel output is projected to grow by 8.2 million gallons per year until the subsidy expires at the end of 2006. Thereafter, biodiesel output is projected to grow by 1.8 percent per year.

Gas-To-Liquids, Coal-To-Liquids, and Gasification Technologies

If prices for lower sulfur distillates reach a high enough level to make gas-to-liquids (GTL) facilities economic, it is assumed that they 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 $2.88 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 feed is assumed to cost $0.83 per thousand cubic feet (2002 dollars).

It is also assumed that coal-to-liquids (CTL) facilities will be built when low-sulfur distillate prices are high enough to make them economic. 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 fuels per day and 696 megawatts of capacity for electricity cogeneration sold to the grid.[103] A CTL facility of this size is assumed to cost over $2 billion in initial capital investment. CTL facilities could be built near existing refineries. For the East Coast, potential CTL facilities could be built near the Delaware River basin; for the Central region, near the Illinois River basin or near Billings, Montana; and for the West Coast, in the vicinity of Puget Sound in Washington State. The CTL yields are assumed to be similar to those from a GTL facility, because both involve the Fischer-Tropsch process to convert syngas ($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 *AEO2005* high world oil price cases.

Gasification of petroleum coke (petcoke) and heavy oil (asphalt, vacuum resid, etc.) is represented in *AEO2005*. The PMM assumes petcoke to be the primary feedstock for gasification, which in turn could be converted to either combined heat and power (CHP) or hydrogen production based on refinery economics. A typical gasification facility is assumed to have a capacity of 2,000 ton-per-day (TPD) which includes the main gasifier and other integrated units in the refinery such as air separation unit (ASU), syngas clean-up, sulfur recovery unit (SRU), and two downstream process options - CHP or hydrogen production. Currently, there is more than 5,000 TPD gasification capacity in the Nation, producing CHP and hydrogen. Additional gasification capacity is projected to be built in the *AEO2005* forecast, primarily for CHP production.

Combined Heat and Power (CHP)

Electricity consumption in the refinery is a function of the throughput of each unit. Sources of electricity consist of refinery power generation, utility purchases, refinery CHP, and merchant CHP. Power generators and CHP plants are modeled in the PMM linear program as separate units which are allowed to compete along with purchased electricity. Both the refinery and merchant CHP units provide estimates of capacity, fuel consumption, and electricity sales to the grid based on historical parameters.

Refinery sales to the grid are estimated using the following percentages which are based on 2002 data:

Region	Percent Sold To Grid
PADD I	67.0
PADD II	0.9
PADD III	2.2
PADD IV	0.9
PADD V	45.4

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived using EIA-860B, "Annual Electric Generators Report-Nonutility".

The PMM sells electricity back to the grid in these percentages at a price equal to the average price of electricity.

Merchant CHP plants are defined as non-refiner owned facilities located near refineries to provide energy to the open market and to the neighboring refinery. These sales occur at a price equal to the average of the generation price and the industrial price of electricity for each PMM region. Electricity prices are obtained from the Electricity Market Model.

Short-term Methodology

Petroleum balance and price information for the years 2004 and 2005 are projected at the U.S. level in the *Short-term Energy Outlook, (STEO*). The PMM adopts the *STEO* results for 2004 and 2005, using regional estimates derived from the national *STEO* projections.

Legislation and Regulations

The Tax Payer Relief Act of 1997 reduced excise taxes on liquefied petroleum gases and methanol produced from natural gas. The reductions set taxes on these products equal to the Federal gasoline tax on a Btu basis.

Title II of CAAA90 established regulations for oxygenated and reformulated gasoline and reduced-sulfur (500 ppm) on-highway diesel fuel, which are explicitly modeled in the PMM. Reformulated gasoline represented in the PMM meets the requirements of phase 2 of the Complex Model, except in the Pacific region where it meets CARB 3 specifications. The reformulated gasoline in areas of the Pacific region covered by the Federal RFG program continue to require 2.0 percent oxygen.

AEO2005 reflects legislation which bans or limits the use of the gasoline blending component MTBE in the following states: Arizona, California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Maine, Michigan, Minnesota, Missouri, Nebraska, New Hampshire, New York, Ohio, South Dakota, Washington, and Wisconsin.

AEO2005 reflects "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements finalized by EPA in February 2000. This regulation requires that the average annual sulfur content of all gasoline used in the United States be phased-down to 30 ppm between the years 2004 and 2007. The 30 ppm annual average standard is not fully realized in conventional gasoline until 2008 due to allowances for small refineries.

AEO2005 reflects Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements finalized by the EPA in December 2000. Between June 2006 and June 2010, this regulation requires that 80 percent of highway diesel supplies contain no more than 15 ppm sulfur while the remaining 20 percent of highway diesel supplies contain no more than 500 ppm sulfur. After June 2010, all highway diesel is required to contain no more than 15 ppm sulfur at the pump.

AEO2005 reflects nonroad locomotive and marine (NRLM) diesel requirements finalized by the EPA in May 2004. Between June 2007 and June 2010, this regulation requires that nonroad diesel supplies contain no more than 15 ppm sulfur. For locomotive and marine diesel, the action establishes a NRLM limit of 15 ppm in mid-2012.

Public Law 104-58 lifted the ban on exporting Alaskan crude oil in November 1995. In the years following there were some exports from this region, however since 2000 there have been no significant crude exports from Alaska. Consequently, AEO2005 assumes that all US crude exports during the forecast period come from the lower 48 states. Alaskan exports are only assumed to occur if there is a constraint along the Trans-Alaska Pipeline System.

Notes and Sources

[97] U.S. Environmental Protection Agency, “Tier 2” Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements, February 2000, (Washington, DC).

[98] Federal Register, Environmental Protection Agency, 40 CFR Part 80, Regulation of Fuels and Fuel Additives: Standards for Reformulated and Conventional Gasoline, Rules and Regulations, p. 7800, (Washington, DC, February 1994).

[99] M. Walsh, R. Perlock, D. Becker, A Turhollow, and R. Graham, "Evolution of the Fuel Ethanol Industry: Feedstock Availability and Price", Oak Ridge National Laboratory (June 5, 1997).

[100] U.S. Environmental Protection Agency, Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements, EPA420-R-00-026 (Washington, DC, December 2000).

[101] Environmental Protection Agency, Clean Air Nonroad Diesel Rule Facts and Figures, EPA 420-F-04-037, May 2004: http://www.epa.gov/nonroad-diesel/2004fr/420f04037.htm.

[102] American Petroleum Institute, *How Much We Pay for Gasoline*: 1996 Annual Review, May 1997.

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

Coal Market Module

The NEMS Coal Market Module (CMM) provides forecasts of U.S. coal production, consumption, exports, imports, distribution, and prices. The CMM comprises three functional areas: coal production, coal distribution, and coal exports. A detailed description of the CMM is provided in the EIA publication, *Coal Market Module of the National Energy Modeling System 2005,* DOE/EIA-M060(2005) (Washington, DC, 2005*).*

Key Assumptions

Coal Production

The coal production submodule of the CMM generates a different set of supply curves for the CMM for each year of the forecast. Forty separate supply curves are developed for each of 14 supply regions and 12 coal types (unique combinations of thermal grade, sulfur content, and mine type). Supply curves are constructed using an econometric formulation that relates the minemouth prices of coal for the supply regions and coal types to a set of independent variables. The independent variables include: capacity utilization of mines, mining capacity, labor productivity, the user cost of capital of mining equipment, and the cost of factor inputs (labor and fuel).

The key assumptions underlying the coal production modeling are:

- As capacity utilization increases, higher minemouth prices for a given supply curve are projected. The opportunity to add capacity is allowed within the modeling framework if capacity utilization rises to a pre-determined level, typically in the 80 percent range. Likewise, if capacity utilization falls, mining capacity may be retired. The amount of capacity that can be added or retired in a given year depends on the level of capacity utilization, the supply region, and the mining process (underground or surface). The volume of capacity expansion permitted in a forecast year is based upon historical patterns of capacity additions.

- Between 1980 and 2003, U.S. coal mining productivity increased at an estimated average rate of 5.7 percent per year from 1.93 to 6.95 short tons of coal produced per miner hour. The major factors underlying these gains were interfuel price competition, structural change in the industry, and technological improvements in coal mining.[104] Based on the expectation that further penetration of certain more productive mining technologies, such as longwall methods and large capacity surface mining equipment, will gradually level off, and as mining conditions become more difficult, productivity improvements are generally assumed to continue, but to decline in magnitude. Different rates of improvement are assumed for each of the 40 supply curves. On a national basis, labor productivity increases on average at a rate of 0.8 percent a year over the entire forecast (Table 69), declining from an estimated annual rate of 1.2 percent between 2003 and 2010 to approximately 0.6 percent over the 2010 to 2025 period. These estimates are based on recent historical data reported on Form EIA-7A, *Coal Production Report*, and expectations regarding the penetration and impact of new coal mining technologies.[105]

- In the *AEO2005* forecast scenarios, both the wage rate for U.S. coal miners and mine equipment costs are assumed to remain constant in 2003 dollars (i.e., increase at the general rate of inflation) over the forecast period. This assumption primarily reflects the recent trends in these cost variables. Although U.S. coal mining wages declined by 1.1 percent per year between 1990 and 2001 (in 2003 dollars)[106], they have remained essentially constant since then as Appalachian coal producers, faced with the first real labor shortage in years, have scrambled to hire and retain experienced miners. The producer price index (PPI) for mining machinery and equipment has remained relatively constant over the past decade, declining from 166.4 (2003 dollars) in 1990 to 165.0 in 2003.[107]

Table 69. Coal Mining Productivity by Region
(Short Tons per Miner Hour)

Supply Region	2003	2005	2010	2015	2020	2025	Average Annual Growth 03-25
Northern Appalachia	4.15	4.14	4.23	4.29	4.36	4.46	0.3%
Central Appalachia	3.62	3.58	3.49	3.41	3.34	3.29	-0.4%
Southern Appalachia	2.67	2.69	2.72	2.74	2.74	2.79	0.2%
Eastern Interior	4.54	4.57	4.65	4.71	4.75	4.79	0.2%
Western Interior	3.90	3.97	4.13	4.26	4.37	4.47	0.6%
Gulf Lignite	9.68	9.80	10.04	10.25	10.40	10.56	0.4%
Dakota Lignite	17.68	17.79	18.00	18.18	18.35	18.44	0.2%
Western Montana	24.21	24.50	23.65	20.95	21.11	21.55	-0.5%
Wyoming,Northern Power River Basin	42.57	43.30	44.74	45.92	46.89	47.79	0.5%
Wyoming,Southern Power River Basin	43.89	43.89	43.89	43.45	43.02	42.59	-0.1%
Western Wyoming	8.42	8.52	8.69	8.88	9.04	9.19	0.4%
Rocky Mountain	8.00	8.12	8.37	8.56	8.75	8.91	0.5%
Arizona/New Mexico	8.78	8.46	8.58	8.69	8.76	8.81	0.0%
Alaska/ Washington	5.06	5.09	5.12	5.12	5.12	5.12	0.1%
U.S. Average	6.95	7.18	7.55	7.88	8.08	8.28	0.8%

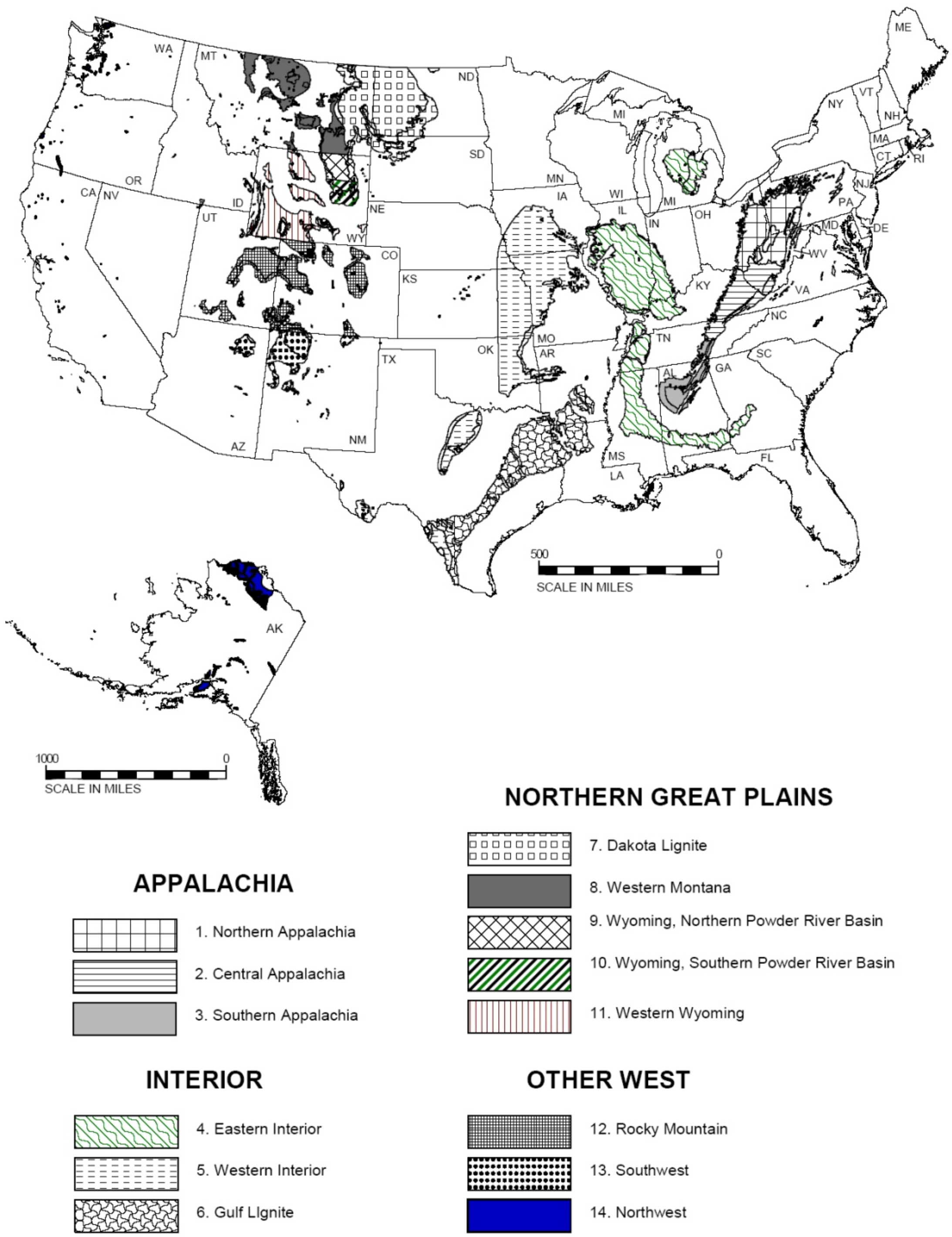
Source: Projections: Energy Information Administration, Office of Integrated and Forecasting

Coal Distribution

The coal distribution submodule of the CMM determines the least-cost (minemouth price plus transportation cost) supplies of coal by supply region for a given set of coal demands in each demand sector using a linear programming algorithm. Production and distribution are computed for 14 supply (Figure 10) and 14 demand regions (Figure 11) for 49 demand subsectors.

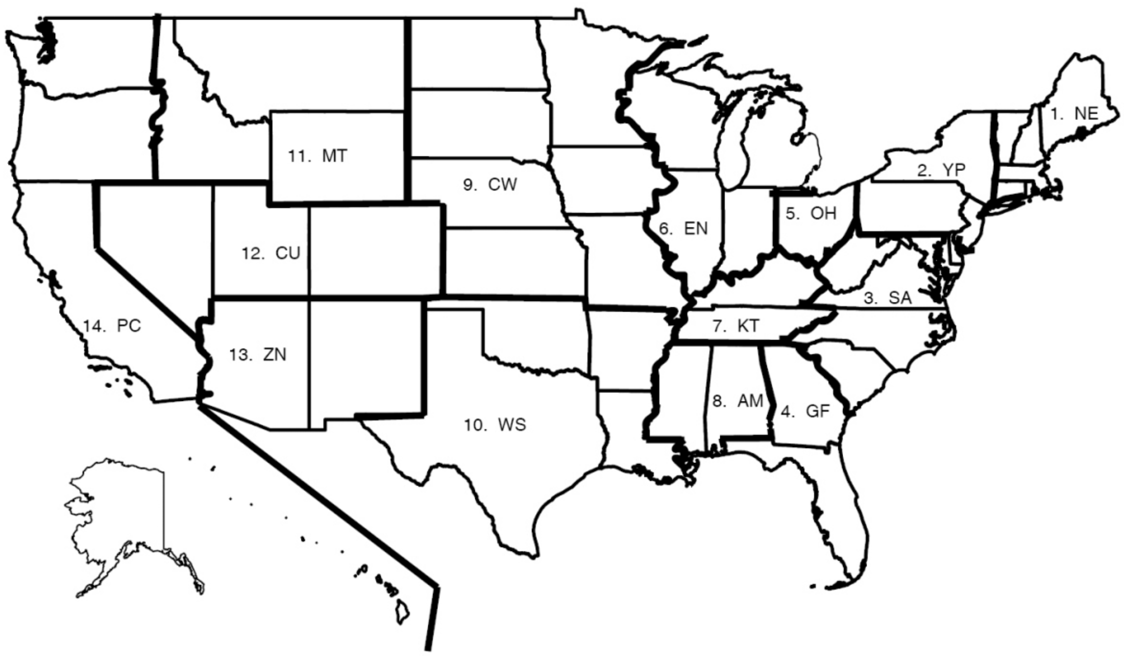
The projected levels of industrial, coking, and residential/commercial coal demand are provided by the industrial, commercial, and residential demand modules; electricity coal demands are forecasted by the EMM; coal imports are determined exogeneously, and coal export demands are forecasted by the CMM itself based on forecasted non-U.S. coal supply availability and exogenously determined world coal demand.

Figure 10. Coal Supply Regions



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 11. Coal Demand Regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. SA	WV,MD,DC,DE,VA,NC,SC
4. GF	GA,FL
5. OH	OH
6. EN	IN,IL,MI,WI
7. KT	KY,TN

Region Code	Region Content
8. AM	AL,MS
9. CW	MN,IA,ND,SD,NE,MO,KS
10. WS	TX,LA,OK,AR
11. MT	MT,WY,ID
12. CU	CO,UT,NV
13. ZN	AZ,NM
14. PC	AK,HI,WA,OR,CA

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

The key assumptions underlying the coal distribution modeling are:

- Base-year (2003) transportation costs are estimates of average transportation costs for each origin-destination pair without differentiation by transportation mode (rail, truck, barge, and conveyor). These costs are computed as the difference between the average delivered price for a demand region (by sector and for export) and the average minemouth price for a supply curve. Delivered price data are from Form EIA-3, *Quarterly Coal Consumption Report-Manufacturing Plants*, Form EIA-5, *Quarterly Coke Consumption* and *Quality Report, Coke Plants*, Form EIA-423, *Monthly Cost and Quality of Fuels for Electric Plants Report*, Federal Energy Regulatory Commission (FERC) Form 423, *Monthly Report of Cost and Quality of Fuels for Electric Plants*, and the U.S. Bureau of the Census' Monthly Report EM-545. Minemouth price data are from Form EIA-7A, *Coal Production Report*.

- For the electricity sector only, a two-tier transportation rate structure is used for those regions which, in response to rising demands or changes in demands, may expand their market share beyond historical levels. The first-tier rate is representative of the historical average transportation rate. The second-tier transportation rate is used to capture the higher cost of expanded shipping distances in large demand regions. The second tier is also used to capture costs associated with the use of subbituminous coal at units that were not originally designed for its use. This cost is estimated at $0.10 per million Btu (2000 dollars).[108]

- Coal transportation costs, both first- and second-tier rates, are modified over time by two regional (east and west) transportation indices. The indices are measures of the change in average transportation rates, on a tonnage basis, that occurs between successive years for rail and multi-mode coal shipments. An east index is used for coal originating from eastern supply regions while a west index is used for coal originating from western supply regions. The indices are calculated econometrically as a function of railroad productivity, the user cost of capital of railroad equipment, average contract duration, and average distance (west only). Although the indices are derived from railroad information, they are universally applied to all coal transportation rates within the CMM. In the *AEO2005* reference case, eastern coal transportation rates are projected to decline by 10 percent between 2003 and 2025, and western rates are projected to decline by 11 percent.

  Railroad productivity, measured in freight ton-miles per employee per year, is expected to increase at an average rate of 3 percent per year for the east and 4 percent per year for the west. The user cost of capital for railroad equipment is calculated from the PPI for railroad equipment, projected exogenously to decrease by 1 percent per year in real terms, and accounts for the opportunity cost of money used to purchase equipment, depreciation occurring as a result of use of the equipment (assumed at 10 percent), less any capital gain associated with the worth of the equipment. Contract duration is held constant at 2001 levels over the forecast reflecting the assumption that new contracts will continue to be, on average, less than 5 years in length. For the west, distance is held constant over the forecast reflecting that distance is already implicitly accounted for in the model by using the origin-destination pair transportation rate structure. The transportation rate indices for five *AEO2005* cases are shown in Table 70.

Table 70. Transportation Rate Multipliers
(Constant Dollar Index, 2003=1.000)

Year	Reference Case		High Oil Price		Low Oil Price		High Economic Growth		Low Economic Growth	
	East	West	East	West	East	West	East	West	East	West
2003	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
2005	1.0005	1.0178	1.0004	1.0177	1.0005	1.0178	1.0031	1.0197	0.9966	1.0149
2010	0.9778	0.9975	0.9784	0.9979	0.9774	0.9972	0.9856	1.0034	0.9704	0.9919
2015	0.9562	0.9644	0.9557	0.9640	0.9557	0.9640	0.9658	0.9715	0.9474	0.9578
2020	0.9292	0.9266	0.9293	0.9267	0.9288	0.9264	0.9405	0.9350	0.9193	0.9193
2025	0.9044	0.8913	0.9044	0.8913	0.9041	0.8911	0.9188	0.9018	0.8929	0.8829

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Based on methodology described in *Coal Market Module of the National Energy Modeling System, Model Documentation 2005*, DOE/EIA-060(2005), (Washington, DC, 2005).

- Coal contracts in the CMM represent a minimum quantity of a specific electricity coal demand that must be met by a unique coal supply source prior to consideration of any alternative sources of supply. Base-year (2003) coal contracts between coal producers and electricity generators are estimated on the basis of receipts data reported by electric utilities on FERC Form 423, *Monthly Report of Cost and Quality of Fuels for Electric Plants*, and by nonutility generators on Form EIA-423, *Monthly Cost and Quality of Fuels for Electric Plants Report*. Coal contracts are specified by CMM supply region, coal type, demand region, and whether or not a unit has flue gas desulfurization equipment. Coal contract quantities are reduced over time on the basis of contract duration data reported by electric utilities on FERC Form 580, "Interrogatory on Fuel and Energy Purchase Practices," historical patterns of coal use, and information obtained from various coal and electric power industry publications and reports.

- Electric generation demand received by the CMM is subdivided into "coal groups" representing demands for different sulfur and thermal heat content categories. This process allows the CMM to determine the economically optimal blend of different coals to minimize delivered cost, while meeting the sulfur emissions requirements of the Clean Air Act Amendments of 1990. Similarly, nongeneration demands are subdivided into subsectors with their own coal groups to ensure that, for example, lignite is not used to meet a coking coal demand.

- 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 the coal import infrastructure. Projections of coal imports do not vary across the alternative *AEO2005* forecast scenarios. Total sulfur dioxide emissions from imports and domestically produced coal are subject to the restrictions on emissions specified in the CAAA90.

Coal Exports

Coal exports are modeled as part of the CMM's linear program that provides annual forecasts of U.S. steam and metallurgical coal exports, in the context of world coal trade. The linear program determines the pattern of world coal trade flows that minimize the production and transportation costs of meeting a prespecified set of regional world coal import demands. It does this subject to constraints on export capacity and trade flows.

The CMM projects steam and metallurgical coal trade flows from 16 coal-exporting regions of the world to 20 import regions for three coal types (coking, bituminous steam, and subbituminous). It includes five U.S. export regions and four U.S. import regions.

The key assumptions underlying coal export modeling are:

- The coal market is competitive. In other words, no large suppliers or groups of producers are able to influence the price through adjusting their output. Producers' decisions on how much and who they supply are driven by their costs, rather than prices being set by perceptions of what the market can bear. In this situation, the buyer gains the full consumer surplus.

- Coal buyers (importing regions) tend to spread their purchases among several suppliers in order to reduce the impact of potential supply disruptions, even though this may add to their purchase costs. Similarly, producers choose not to rely on any one buyer and instead endeavor to diversify their sales.

- Coking coal is treated as homogeneous. The model does not address quality parameters that define coking coals. The values of these quality parameters are defined within small ranges and affect world coking coal flows very little.

Data inputs for coal export modeling:

- U.S. coal exports are determined, in part, by the projected level of world coal import demand. World steam and metallurgical coal import demands for the *AEO2005* forecast cases are shown in Tables 71 and 72.

- Step-function coal export supply curves for all non-U.S. supply regions. The curves provide estimates of export prices per metric ton, inclusive of minemouth and inland freight costs, as well as the capacities for each of the supply steps.

- Ocean transportation rates (in dollars per metric ton) for feasible coal shipments between international supply regions and international demand regions. The rates take into account maximum vessel sizes that can be handled at export and import piers and through canals and reflect route distances in thousands of nautical miles.

Table 71. World Steam Coal Import Demand by Import Region, 2003-2025
(Million metric tons of coal equivalent)

Import Regions[1]	2003[2]	2005	2010	2015	2020	2025
The Americas	47.1	48.4	53.5	59.1	63.0	68.4
United States	21.0	20.6	27.6	31.6	35.2	38.8
Canada	15.4	15.2	12.8	11.0	10.9	11.8
Mexico	5.7	6.8	7.3	7.4	7.9	8.8
South America	5.0	5.8	5.8	9.1	9.0	9.0
Europe	146.9	148.2	154.1	152.8	147.1	144.3
Scandinavia	14.7	10.6	8.2	6.7	5.8	5.4
U.K/Ireland	25.8	26.2	27.3	25.2	24.3	23.8
Germany/Austria	23.1	24.1	26.8	27.7	28.6	29.5
Other NW Europe	22.8	19.8	18.6	18.1	14.5	12.9
Iberia	21.3	25.2	28.2	27.3	25.5	23.7
Italy	12.8	13.1	13.1	13.1	11.4	11.1
Med/E Europe	26.4	29.2	31.9	34.7	37.0	37.9
Asia	217.9	236.5	271.3	301.6	328.5	350.7
Japan	83.0	84.9	87.4	95.2	104.8	110.8
East Asia	89.4	93.1	110.3	117.3	125.5	131.8
China/Hong Kong	15.9	17.2	23.5	29.8	33.4	37.0
ASEAN	15.2	24.2	31.4	38.8	42.5	46.1
Indian Sub	14.4	17.1	18.7	20.5	22.3	25.0
Total	411.9	433.1	478.9	513.5	538.6	563.4

[1]Import Regions: **South America:** Argentina, Brazil, Chile; **Scandinavia:** Denmark, Finland, Norway, Sweden; **Other NW Europe:** Belgium, France, Luxembourg, Netherlands; **Iberia:** Portugal, Spain; **Med/E Europe:** Algeria, Bulgaria, Croatia, Egypt, Greece, Israel, Malta, Morocco, Romania, Tunisia, Turkey; **East Asia:** North Korea, South Korea, Taiwan; **ASEAN:** Malaysia, Philippines, Thailand; **Indian Sub:** Bangladesh, India, Iran, Pakistan, Sri Lanka.

[2]The base year of the world trade forecast for coal is 2003.

Notes: One "metric ton of coal equivalent" contains 27.78 million Btu. Totals may not equal sum of components due to independent rounding.

Source: Projections: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 72. World Metallurgical Coal Import Demand by Import Region, 2003-2025
(Million metric tons of coal equivalent)

Import Regions[1]	2003[2]	2005	2010	2015	2020	2025
The Americas	20.3	22.4	24.5	26.1	27.5	27.4
United States	1.5	2.3	2.3	2.3	2.3	2.3
Canada	3.6	3.6	3.4	3.3	3.2	3.0
Mexico	1.0	1.1	1.7	2.0	2.5	2.5
South America	14.2	15.4	17.1	18.5	19.5	19.6
Europe	49.3	51.2	51.3	50.3	49.2	48.6
Scandinavia	2.8	2.8	2.4	2.2	1.9	1.6
U.K/Ireland	6.7	7.6	7.6	7.1	7.1	7.1
Germany/Austria	5.8	6.3	6.9	6.9	6.9	6.9
Other NW Europe	15.3	14.4	13.3	12.3	11.3	10.8
Iberia	4.6	4.0	3.9	3.9	3.9	3.9
Italy	6.6	6.5	6.4	6.3	6.3	6.3
Med/E Europe	7.5	9.6	10.8	11.6	11.8	12.0
Asia	115.9	116.4	121.1	124.2	125.2	128.0
Japan	71.3	65.2	62.4	60.9	59.5	57.5
East Asia	25.2	27.4	29.4	31.9	32.7	34.2
China/Hong Kong	3.1	6.7	11.5	12.0	12.5	13.0
ASEAN	0.0	0.0	0.0	0.0	0.0	0.0
Indian Sub	16.3	17.1	17.8	19.4	20.5	23.3
Total	185.5	190.0	196.9	200.6	201.9	204.0

[1]Import Regions: **South America:** Argentina, Brazil, Chile; **Scandinavia:** Denmark, Finland, Norway, Sweden; **Other NW Europe:** Belgium, France, Luxembourg, Netherlands; **Iberia:** Portugal, Spain; **Med/E Europe:** Algeria, Bulgaria, Croatia, Egypt, Greece, Israel, Malta, Morocco, Romania, Tunisia, Turkey; **East Asia:** North Korea, South Korea, Taiwan; **ASEAN:** Malaysia, Philippines, Thailand; **Indian Sub:** Bangladesh, India, Iran, Pakistan, Sri Lanka.

2 The base year of the world trade forecast for coal is 2003.

Notes: One "metric ton of coal equivalent" contains 27.78 million Btu. Totals may not equal sum of components due to independent rounding.

Source: Projections: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Coal Quality

Each year the values of base year coal production, heat, sulfur and mercury (Hg) content and carbon dioxide emissions for each coal source in CMM are calibrated to survey data. Surveys used for this purpose are the FERC Form 423, a survey of the origin, cost and quality of fossil fuels delivered to electric utilities, the Form EIA 423, a survey of the origin, cost and quality of fossil fuels delivered to non-utility generating facilities, the Form EIA-5 which records the origin, cost, and quality of coal receipts at domestic coke plants, and the Form EIA 3, which records the origin, cost and quality of coal delivered to domestic industrial consumers. Estimates of coal quality for the export and residential/commercial sectors are made using the survey data for coal delivered to coking coal and industrial steam coal consumers. Hg content data for coal by supply region and coal type, in units of pounds of Hg per trillion Btu, shown in Table 73, were derived from shipment-level data reported by electricity generators to the Environmental Protection Agency in its 1999 Information Collection Request. The database included approximately 40,500 Hg samples reported for 1,143 generating units located at 464 coal-fired facilities. Carbon dioxide emission factors for each coal type are shown in Table 73 in pounds of carbon dioxide emitted per million Btu.[109]

Table 73. Production, Heat Content, and Sulfur, Mercury and Carbon Dioxide Emission Factors by Coal Type and Region

Coal Supply Region	States	Coal Rank and Sulfur Level	Mine Type	2003 Production (Million Short tons)	Heat Content (Million Btu per Short Ton)	Sulfur Content (Pounds Per Million Btu)	Mercury Content (Pounds Per Trillion Btu)	CO_2 (Pounds Per Million Btu)
Northern Appalachia	PA, OH, MD, WV(North)	Metallurgical	Underground	2.3	27.43	0.70	N/A	205.4
		Mid-Sulfur Bituminous	All	64.3	25.23	1.28	11.17	205.4
		High-Sulfur Bituminous	All	59.2	24.79	2.45	11.67	203.6
		Waste Coal (Gob and Culm)	Surface	11.6	12.70	2.13	63.9	203.6
Central Appalachia	KY(East), WV(South), VA, TN (North)	Metallurgical	Underground	36.0	27.43	0.61	N/A	203.8
		Low-Sulfur Bituminous	All	52.2	25.33	0.54	5.61	203.8
		Mid-Sulfur Bituminous	All	142.6	24.84	0.89	7.58	203.8
Southern Appalachia	AL,TN (South)	Metallurgical	Underground	5.3	27.43	0.46	N/A	203.3
		Low-Sulfur Bituminous	All	3.0	24.70	0.55	3.87	203.3
		Mid-Sulfur Bituminous	All	11.9	24.27	1.02	10.15	203.3
East Interior	IL, IN, KY(West), MS	Mid-Sulfur Bituminous	All	30.1	22.46	1.10	5.60	202.7
		High-Sulfur Bituminous	All	58.6	22.56	2.72	6.35	202.5
		Mid-Sulfur Lignite	Surface	3.7	10.17	1.01	14.11	211.4
West Interior	IA, MO,KS, AR, OK, TX(Bit)	High-Sulfur Bituminous	Surface	2.3	23.55	2.54	21.55	202.4
Gulf Lignite	TX(Lig), LA	Mid-Sulfur Lignite	Surface	18.3	12.85	1.14	14.11	211.4
		High-Sulfur Lignite	Surface	33.2	13.13	2.38	15.28	211.4
Dakota Lignite	ND, MT(Lig)	Mid-Sulfur Lignite	Surface	31.1	13.28	1.03	8.38	216.6
Western Montana	MT (Bit and Sub)	Low-Sulfur Bituminous	Underground	*	20.90	0.48	5.06	207.5
		Low-Sulfur Subbituminous	Surface	18.2	18.78	0.37	5.06	211.3
		Mid-Sulfur Subbituminous	Surface	18.3	17.28	0.76	5.47	211.3
Northern Wyoming	WY (Northern Powder River Basin)	Low-Sulfur Subbituminous	Surface	125.9	16.90	0.40	7.08	210.6
		Mid-Sulfur Subbituminous	Surface	5.8	16.47	0.74	7.55	210.6
Southern Wyoming	WY (Southern Powder River Basin)	Low-Sulfur Subbituminous	Surface	231.7	17.61	0.32	5.22	210.6
Western Wyoming	WY (Other basins, excludingPowder River Basin)	Low-Sulfur Bituminous	Underground	0.0	18.50	0.60	2.19	204.4
		Low-Sulfur Subbituminous	Surface	7.2	19.18	0.53	4.06	210.6
		Mid-Sulfur Subbituminous	Surface	5.7	19.35	0.83	4.35	210.6
Rocky Mountain	CO, UT	Low-Sulfur Bituminous	Underground	50.2	23.10	0.48	3.82	203.0
		Low-Sulfur Subbituminous	Surface	8.7	20.60	0.39	2.04	210.6
Southwest	AZ, NM	Low-Sulfur Bituminous	Surface	18.0	21.28	0.46	4.66	205.4
		Mid-Sulfur Subbituminous	Surface	14.6	18.20	0.90	7.18	206.7
		Mid-Sulfur Bituminous	Underground	5.9	19.24	0.76	7.18	206.7
Northwest	WA, AK	Mid-Sulfur Subbituminous	Surface	7.3	15.67	1.27	6.99	207.9

N/A = not available.

*Indicates that the quantity is less than 50,000 short tons.

Source: Energy Information Administration, Form EIA-3, "Quarterly Coal Consumption Report—Manufacturing Plants"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report—Annual"; Form EIA-7A, "Coal Production Report", and Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report." Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM-545." U.S. Environmental Protection Agency, Emission Standards Division, *Information Collection Request for Electric Utility Steam Generating Unit, Mercury Emissions Information Collection Effort* (Research Triangle Park, NC, 1999). B.D. Hong and E.R. Slatick, "Carbon Dioxide Emission Factors for Coal," in Energy Information Administration, *Quarterly Coal Report*, January-March 1994, DOE/EIA-0121 (94/Q1) (Washington, DC, August 1995).

Legislation

The *AEO2005* reference forecast incorporates provisions of the Clean Air Act Amendments of 1990 as they apply to sulfur dioxide and nitrogen oxide emissions. The reference case excludes any potential environmental actions not currently mandated such as mercury reductions or other rules or regulations not finalized.

Notes and Sources

[104] Energy Information Administration, The U.S. Coal Industry, 1970-1990: Two Decades of Change, DOE/EIA-0559, (Washington, DC, November 1992).

[105] Stanley C. Suboleski, et.al., Central Appalachia: Coal Mine Productivity and Expansion, Electric Power Research Institute, EPRI IE-7117, (September 1991).

[106] U.S. Department of Labor, Bureau of Labor Statistics, Series ID: CEU1021210006.

[107] U.S. Department of Labor, Bureau of Labor Statistics, Series ID: PCU333131333131.

[108] The estimated cost of switching to subbituminous coal, $0.10 per million Btu (2000 dollars), was derived by Energy Ventures Analysis, Inc. and was recommended for use in the CMM as part of an Independent Expert Review of the Annual Energy Outlook 2002's Powder River Basin production and transportation rates. Barbaro, Ralph and Seth Schwartz. *Review of the Annual Energy Outlook 2002 Reference Case Forecast for PRB Coal*, prepared for the Energy Information Administration (Arlington, VA: Energy Ventures Analysis, Inc., August 2002)

[109] Hong, B.D. and Slatick, E.R. “Carbon Dioxide Emission Factors for Coal,” Energy Information Administration, Quarterly Coal Report, January-March 1994, DOE/EIA-121 (94/Q1) (Washington, DC, August 1995).

Renewable Fuels Module

The NEMS Renewable Fuels Module (RFM) provides natural resources supply and technology input information for forecasts of new central-station U.S. electricity generating capacity using renewable energy resources. The RFM has six submodules representing various renewable energy sources, biomass, conventional hydroelectricity, geothermal, hydroelectric power, landfill gas, solar, and wind[110].

Some renewables, such as landfill gas (LFG) from municipal solid waste (MSW) and other biomass materials, are fuels in the conventional sense of the word, while others, such as water, wind, and solar radiation, are energy sources that do not involve the production or consumption of a fuel. Renewable technologies cover the gamut of commercial market penetration, from hydroelectric power, which has been utilized for many centuries, to newer power systems using biomass, geothermal, LFG, solar, and wind energy. In some cases, they require technological innovation to become cost effective or have inherent characteristics, such as intermittency, which make their penetration into the electricity grid dependent upon new methods for integration within utility system plans or upon the availability of low-cost energy storage systems.

The submodules of the RFM interact primarily with the Electricity Market Module (EMM). Because of the high level of integration with the EMM, the final outputs (levels of consumption and market penetration over time) for renewable energy technologies are largely dependent upon the EMM.

Projections for residential and commercial grid-connected photovoltaic systems are developed in the end-use demand modules and not in the RFM; see the Distributed Generation and Combined Heat and Power descriptions in the “Commercial Demand Module” section of the report.

Key Assumptions

Nonelectric Renewable Energy Uses

In addition to projections for renewable energy used in central station electricity generation, the *AEO2005* contains projections of nonelectric renewable energy uses for industrial and residential wood consumption, solar residential and commercial hot water heating, blending in transportation fuels, and residential and commercial geothermal (ground-source) heat pumps. Assumptions for their projections are found in the residential, commercial, industrial, and petroleum marketing sections of this report. Additional minor renewable energy applications occurring outside energy markets, such as direct solar thermal industrial applications or direct lighting, off-grid electricity generation, and heat from geothermal resources used directly (e.g., district heating and greenhouses) are not included in the projections.

Electric Power Generation

The RFM considers only grid-connected central station electricity generation systems. The RFM submodules that interact with the EMM are the central station grid-connected biomass, conventional hydroelectricity, geothermal, landfill gas, solar (thermal and photovoltaic), and wind submodules, which provide specific data or estimates that characterize that resource. A set of technology cost and performance values is provided directly to the EMM and are central to the build and dispatch decisions of the EMM. The technology cost and performance values are summarized in Table 38 in the chapter discussing the EMM. Overnight capital costs are presented in Table 74 and the assumed capacity factors for new plants in Table 75.

Capital Costs

Capital costs for renewable technologies are affected by several factors. Capital costs for technology to exploit some resources, especially geothermal, hydroelectric, and wind power resources, are assumed to be dependent on the quality, accessibility, and/or other site-specific factors in the areas with exploitable resources. These factors can include additional costs associated with reduced resource quality; need to build or upgrade transmission capacity from remote resource areas to load centers; or local impediments to permitting, equipment transport, and construction in good resource areas due to sitting issues, inadequate infrastructure, or rough terrain.

Table 74. Overnight Capital Cost Characteristics for Renewable Energy Generating Technologies in Three Cases (2003$/kW)

	Year	Reference	Total Overnight Costs[1] High Renewables	Low Renewables
Geothermal[2]	2005	2,678	2,642	2,691
	2010	1,784	1,724	1,796
	2025	2,063	2,195	1,955
Hydroelectric[2,3]	2005	1,291	1,270	1,291
	2010	1,243	1,199	1,243
	2025	1,220	1,111	1,220
Landfill Gas	2005	1,398	1,392	1,402
	2010	1,382	1,346	1,402
	2025	1,332	1,205	1,402
Photovoltaic[4]	2005	3,793	3,778	3,829
	2010	3,593	3,506	3,810
	2025	2,614	2,584	3,589
Solar Thermal[4]	2005	2,466	2,457	2,490
	2010	2,348	2,291	2,490
	2025	1,983	1,784	2,478
Biomass[5]	2005	1,634	1,750	1,637
	2010	1,589	1,636	1,607
	2025	1,326	1,214	1,400
Wind	2005	1,059	1,056	1,060
	2010	1,055	1,036	1,060
	2025	1,049	975	1,060

[1]Overnight capital cost (that is, excluding interest charges), plus contingency, learning, and technological optimism factors, excluding regional multipliers. A contingency allowance is defined by the American Association of Cost Engineers as the specific provision for unforeseeable elements of costs within a defined project scope. This is particularly important where previous experience has shown that unforeseeable events which will increase costs are likely to occur.

[2]Geothermal and Hydroelectric costs are specific for each site. The table entries represent the least cost unit available in the specified year in the Northwest Power Pool region, where most of the proposed sites are located.

[3]Hydroelectric is not included in the Low Renewables case as there is no net change in capacity in the Reference case.

[4]Costs decline slightly in the Low Renewable case for photovoltaic and solar thermal technologies as technological optimism is factored into initial costs (see pg. 72 in the chapter discussing the EMM). However, there is no learning-by-doing assumed once the optimism factor has been removed.

[5]Biomass plants share significant components with similar coal-fired plants, these components continue to decline in cost in the Low Renewables case, although biomass-specific components (especially fuel handling components) do not see cost declines beyond 2004.

Source: AEO2005 National Energy Modeling System runs AEO2005.D202004A, LOREN05.D111504A, and HIREN05.D111604A.

Short-term cost adjustment factors, which increase technology capital costs as a result of a rapid U.S. buildup in a single year, reflecting limitations on the infrastructure (for example, limits on manufacturing, resource assessment, and construction expertise) to accommodate unexpected demand growth. These factors, which are applied to all new electric generation capacity, are a function of past production rates and are further described in *The Electricity Market Module of the National Energy Modeling System: Model Documentation Report*, available at http://www.eia.doe.gov/bookshelf/docs.html.

Table 75. Capacity Factors[1] for Renewable Energy Generating Technologies in Three Cases

Technology	Year	Reference	High Renewables	Low Renewables
Geothermal[2]	2005	0.86	0.86	0.86
	2010	0.95	0.95	0.95
	2025	0.95	0.90	0.95
Hydrolectric[2]	2005	0.30	0.30	0.30
	2010	0.33	0.30	0.33
	2025	0.35	0.35	0.35
Landfill Gas	2005	0.90	0.90	0.90
	2010	0.90	0.90	0.90
	2025	0.90	0.90	0.90
Photovoltaic	2005	0.24	0.24	0.24
	2010	0.24	0.24	0.24
	2025	0.24	0.24	0.24
Solar Thermal	2005	0.33	0.33	0.33
	2010	0.33	0.33	0.33
	2025	0.33	0.33	0.33
Biomass	2005	0.83	0.83	0.83
	2010	0.83	0.83	0.83
	2025	0.83	0.83	0.83
Wind[3]	2005	0.41	0.42	0.41
	2010	0.43	0.44	0.41
	2025	0.44	0.42	0.41

[1]Capacity factor for units available to be built in specified year. Capacity factor represents maximum expected annual power output as a fraction of theoretical output if plant were operated at rated capacity for a full year.

[2]Geothermal and Hydroelectric capacity factors are specific for each site. The table entries represent the least-cost unit available in the specified year in the Northwest Power Pool region.

[3]Wind capacity factors are based on regional resource availability and generation characteristics. The table entries represent the least-cost resource available in the specified year in the Northwest Power Pool region.

Source: AEO2005 National Energy Modeling System runs: AEO2005.D102004A, LOREN05.D111504A, and HIREN05.D111604A.

Independent of the other two factors, capital costs for all electric generation technologies, including renewable technologies, are assumed to decline as a function of growth in installed capacity for each technology.

For a description of NEMS algorithms lowering generating technologies' capital costs as more units enter service (learning), see "Technological Optimism and Learning" in the EMM chapter of this report. A detailed description of the RFM is provided in the EIA publication, *Renewable Fuels Module of the National Energy Modeling System, Model Documentation 2004*, DOE/EIA-M069(2004) (Washington, DC, 2004).

Solar Electric Submodule

Background

The Solar Electric Submodule (SOLES) currently includes both concentrating solar power (thermal) and photovoltaics, including two solar technologies: 50 megawatt central receiver (power tower) solar thermal (ST) and 5 megawatt single axis tracking-flat plate thin-film copper-indium-diselenide (CIS) photovoltaic (PV) technologies. PV is assumed available in all thirteen EMM regions, while ST is available only in the six Western regions where direct normal solar insolation is sufficient. Capital costs for both technologies are determined by EIA using multiple sources, including 1997 technology characterizations by the Department of

Energy's Office of Energy Efficiency and Renewable Energy and the Electric Power Research Institute (EPRI).[111] Most other cost and performance characteristics for ST are obtained or derived from the August 6, 1993, California Energy Commission memorandum, *Technology Characterization for ER 94*; and, for PV, from the Electric Power Research Institute, *Technical Assessment Guide (TAG) 1993*. In addition, capacity factors are obtained from information provided by the National Renewable Energy Laboratory (NREL).

Assumptions

- Capacity factors for solar technologies are assumed to vary by time of day and season of the year, such that nine separate capacity factors are provided for each modeled region, three for time of day and for each of three broad seasonal groups (summer, winter, and spring/fall). Regional capacity factors vary from national averages. The current reference case solar thermal annual capacity factor for California, for example, is assumed to average 40 percent; California's current reference case PV capacity factor is assumed to average 24.6 percent.

- Because solar technologies are more expensive than other utility grid-connected technologies, early penetration will be driven by broader economic decisions such as the desire to become familiar with a new technology or environmental considerations. Minimal early years' penetration is included by EIA as "floor" additions to new generating capacity (see "Supplemental and Floor Capacity Additions" below).

- Solar resources are well in excess of conceivable demand for new capacity; therefore, energy supplies are considered unlimited within regions (at specified daily, seasonal, and regional capacity factors). Therefore, solar resources are not estimated in NEMS. In the seven regions where ST technology is not modeled, the level of direct, normal insolation (the kind needed for that technology) is insufficient to make that technology commercially viable through 2025.

- NEMS represents the Energy Policy Act of 1992 (EPACT) permanent 10-percent investment tax credit for solar electric power generation by tax-paying entities. With passage of the *American Jobs Creation Act of 2004,* solar plants constructed by December 31, 2005 also qualify for a production tax credit of 1.8 cents per kilowatt-hour of electricity produced for the first five years of plant operation. This tax credit may not be used in conjunction with the Federal investment tax credit. It is assumed that for central-station photovoltaic plants – with very high initial costs and relatively low annual energy production per unit capacity – the investment tax credit will be more valuable, but for solar thermal plants – with somewhat lower initial costs and higher annual energy production – the production tax credit will be utilized instead.

Wind-Electric Power Submodule

Background

Because of limits to windy land area, wind is considered a finite resource, so the submodule calculates maximum available capacity by Electricity Market Module Supply Regions. The minimum economically viable wind speed is about 14 mph, and wind speeds are categorized into three wind classes according to annual average wind speed. The RFM tracks wind capacity (megawatts) by resource quality, distance to transmission, and other resource costs within a region and moves to the next best wind resource when one category is exhausted. For *AEO2005*, wind resource data on the amount and quality of wind per EMM region come from the National Renewable Energy Laboratory for 23 states[112] and a Pacific Northwest Laboratory study and a subsequent update for the remainder.[113] The technological performance, cost, and other wind data used in NEMS are derived by EIA from available data and in consultation with industry experts.[114] Maximum wind capacity, capacity factors, and incentives are provided to the EMM for capacity planning and dispatch decisions. These form the basis on which the EMM decides how much power generation capacity is available from wind energy. The fossil-fuel heat rate equivalents for wind are used for energy consumption calculation purposes only.

Assumptions

- Only grid-connected (utility and nonutility) generation is included. The forecasts do not include off-grid or distributed electric generation.

- In the wind submodule, wind supply costs are affected by three modeling measures, addressing (1) average wind speed, (2) distance from existing transmission lines, and (3) resource degradation, transmission network upgrade costs, and market factors.

- Available wind resource is reduced by excluding all windy lands not suited for the installation of wind turbines because of: excessive terrain slope (greater than 20 percent); reservation of land for non-intrusive uses (such as National Parks, wildlife refuges, and so forth); inherent incompatibility with existing land uses (such as urban areas, areas surrounding airports and water bodies, including offshore locations); insufficient contiguous windy land to support a viable wind plant (less than 5 square kilometers of windy land in a 100 square kilometer area). Half of the wind resource located on military reservations, U.S. Forest Service land, state forested land, and all non-ridge-crest forest areas are excluded from the available resource base to account for the uncertain ability to site projects at such locations. These assumptions are detailed in the Draft Final Report to EIA on *Incorporation of Existing Validated Wind Data into NEMS*, November 2003.

- Wind resources are mapped by distance from existing transmission capacity among three distance categories, within (1) 0-5, (2) 5-10, and (3) 10-20 miles on either side of the transmission lines. Additional transmission costs are added to the resources further from the transmission lines. Transmission costs vary by region and distance from transmission lines, ranging from $4.10 per kW to $12.30 per kW (2002$).

- Capital costs for wind technologies are assumed to increase in response to (1) declining natural resource quality, such as terrain slope, terrain roughness, terrain accessibility, wind turbulence, wind variability, or other natural resource factors, (2) increasing cost of upgrading existing local and network distribution and transmission lines to accommodate growing quantities of intermittent wind power, and (3) market conditions, such as the increasing costs of alternative land uses, including aesthetic or environmental reasons. Capital costs are left unchanged for some initial share, then increased 20, 50, 100 percent, and finally 200 percent, to represent the aggregation of these factors. Proportions of total wind resources in each category vary by EMM region. For all thirteen EMM regions, 1.2 percent of windy land is available with no cost increase, 1.8 percent is available with a 20 percent cost increase, 3.2 percent is available with a 50 percent cost increase, 3.2 percent is available with a 100 percent cost increase, and almost 91 percent of windy land is assumed to be available with a 200 percent cost increase.

- Depending on the EMM region, the cost of competing fuels, and other factors, wind plants can be built to meet system capacity requirements or as a “fuel saver” to displace generation from existing capacity. For wind to penetrate as a fuel saver, its total capital and fixed operations and maintenance costs minus applicable subsidies must be less than the variable operating costs, including fuel, of the existing (non-wind) capacity. When competing in the new capacity market, wind is assigned a capacity credit that declines based on its estimated contribution to regional reliability requirements.

- Because of downwind turbulence and other aerodynamic effects, the model assumes an average spacing between turbine rows of 5 rotor diameters and a lateral spacing between turbines of 10 rotor diameters. This spacing requirement determines the amount of power that can be generated from wind resources, about 6.5 megawatts per square kilometer of windy land, and is factored into requests for generating capacity by the EMM.

- Capacity factors are assumed to increase to a national average of 44 percent in the best wind class resulting from taller towers, more reliable equipment, and advanced technologies. Capacity factors for each wind class are calculated as a function of overall wind market growth. The capacity factors are assumed to be limited to about 48 percent for an average Class 6 site. As better wind resources are depleted, capacity factors are assumed to go down.

- *AEO2005* does not allow plants constructed after 2005 to claim the Federal Production Tax Credit (PTC), a 1.8 cent per kilowatt-hour tax incentive that is set to expire on December 31, 2005. Wind plants are assumed to depreciate capital expenses using the Modified Accelerated Cost Recovery Schedule with a 5-year tax life.

Geothermal-Electric Power Submodule

Background

The Geothermal-Electric Submodule (GES), represents the generating capacity and output potential of 51 hydrothermal resource areas in the Western United States based on estimates provided in 1999 by DynCorp Corporation and subsequently modified by EIA.[115] Hot dry rock resources are not considered cost effective until after 2025 and are therefore not modeled in the GES. Both dual flash and binary cycle technologies are represented. The GES distributes the total capacity for each site within each EMM region among four increasing cost categories, with the lowest cost category assigned the base estimated costs, the next assigned higher (double) exploration costs, the third assigned a 33 percent increase in drilling and field costs, and the highest assigned both double exploration and 33 percent increased drilling and field costs. Drilling and field costs vary from site to site but are roughly half the total capital cost (along with plant costs) of new geothermal plants; exploration costs are a relatively minor additional component of capital costs. All quantity-cost groups in each region are assembled into increasing-cost supplies. When a region needs new generating capacity, all remaining geothermal resources available in that region at or below an avoided cost level determined in the EMM are submitted (in three increasing cost subgroups) to compete with other technologies for selection as new generating supply. Geothermal capital costs decline with learning. For estimating costs for building new plants, new dual-flash capacity – the lower cost technology - is assigned an 80 percent capacity factor, whereas binary plants are assigned a 95 percent capacity factor; both are assigned an 87 percent capacity factor for actual generation.

To realistically reflect capacity availability through 2025 at each of the 51 geothermal sites, each site's potential is limited to about 100 megawatts for each of four cost levels. Second, annual maximum capacity builds are established for each site, reflecting industry practice of expanding development gradually. For the reference case, each site is permitted a maximum development of 25 megawatts per year through 2015 and 50 megawatts per year thereafter.

Assumptions

- Existing and identified planned capacity data are obtained directly by the EMM from Forms EIA-860A (utilities) and EIA-860B (nonutilities) and from supplemental additions (See Below).

- The permanent investment tax credit of 10 percent available in all forecast years based on the EPACT applies to all geothermal capital costs, except for 2005 when the 1.8 cent production tax credit is available to this technology.

- Plants are not assumed to retire unless their retirement is reported to EIA. Geysers units are not assumed to retire but instead are assigned the 35 percent capacity factors reported to EIA reflecting their reduced performance in recent years.

- Capital and operating costs vary by site and year; values shown in Table 38 in the EMM chapter are indicative of those used by EMM for geothermal build and dispatch decisions.

Biomass Electric Power Submodule

Background

Biomass consumed for electricity generation is modeled in two parts in NEMS. Capacity in the wood products and paper industries, the so-called captive capacity, is included in the industrial sector module as cogeneration. Generation by the electricity sector is represented in the EMM, with capital and operating costs and capacity factors as shown in Table 38 in the EMM chapter, as well as fuel costs, being passed to the EMM where it competes with other sources. Fuel costs are provided in sets of regional supply schedules. Projections for ethanol are produced by the Petroleum Market Module (PMM), with the quantities of biomass consumed for ethanol decremented from, and prices obtained from, the EMM regional supply schedules.

Assumptions

- Existing and planned capacity data are obtained from Form EIA-860.

- The conversion technology represented, upon which the costs in Table 38 in the EMM chapter are based, is an advanced gasification-combined cycle plant that is similar to a coal-fired gasifier. Costs in the reference case were developed by EIA to be consistent with coal gasifier costs. Short-term cost adjustment factors are used.

- Biomass cofiring can occur up to a maximum of 15 percent of fuel used in coal-fired generating plants.

Fuel supply schedules are a composite of four fuel types: forestry materials, wood residues, agricultural residues and energy crops. Energy crop data are presented in yearly schedules from 2010 to 2025 in combination with the other material types for each region. The forestry materials component is made up of logging residues, rough rotten salvable dead wood, and excess small pole trees.[116] The wood residue component consists of primary mill residues, silvicultural trimmings, and urban wood such as pallets, construction waste, and demolition debris that are not otherwise used.[117] Agricultural residues are wheat straw, corn stover, and a number of other major agricultural crops.[118] Energy crop data are for hybrid poplar, willow, and switchgrass grown on crop land, pasture land, or on Conservation Reserve Program lands.[119] The maximum amount of resources in each supply category is shown in Table 76.

Landfill-Gas-to-Electricity Submodule

Background

Landfill-gas-to-electricity capacity competes with other technologies using supply curves that are based on the amount of “high”, “low”, and “very low” methane producing landfills located in each EMM region. An average cost-of-electricity for each type of landfill is calculated using gas collection system and electricity generator costs and characteristics developed by EPA’s “Energy Project Landfill Gas Utilization Software” (E-PLUS).[120]

Assumptions

- Gross domestic product (GDP) and population are used as the drivers in an econometric equation that establishes the supply of landfill gas.

- Recycling is assumed to account for 35 percent of the total waste stream by 2005 and 50 percent by 2010 (consistent with EPA’s recycling goals).

- The waste stream is characterized into three categories: readily, moderately, and slowly decomposable material.

- Emission parameters are the same as those used in calculating historical methane emissions in the EIA’s *Emissions of Greenhouse Gases in the United States 2002.*[121]

- The ratio of “high”, “low”, and “very low” methane production sites to total methane production is calculated from data obtained for 156 operating landfills contained in the Government Advisory Associates METH2000 database.[122]

- Cost-of-electricity for each site was calculated by assuming each site to be a 100-acre by 50-foot deep landfill and by applying methane emission factors for “high”, “low”, and “very low” methane emitting wastes.

Conventional Hydroelectricity

The conventional hydroelectricity submodule represents U.S. potential for new conventional hydroelectric capacity 1 megawatt or greater from new dams, existing dams without hydroelectricity, and from adding capacity at existing hydroelectric dams. Summary hydroelectric potential is derived from reported lists of

Table 76. Maximum U.S. Biomass Resources, by Coal Demand Region and Type
(Trillion Btu)

Coal Demand Region	States	Agricultural Residue	Energy Crops	Forestry Residue	Urban Wood Waste/Mill Residue	Total
1. NE	CT, MA, ME, NH, RI, VT	1	29	131	15	176
2..YP	NY, PA, NJ	29	73	89	59	250
3. SA	WV, MD, DC, DE, VA, NC, SC	63	116	408	56	643
4. GF	GA, FL	57	66	246	47	416
5. OH	OH	71	119	27	17	234
6. EN	IN, IL, MI, WI	409	307	404	47	1,167
7. KT	KY, TN	27	210	92	30	359
8. AM	AL, MS	18	211	149	19	397
9. CW	MN, IA, ND, SD, NE, MO, KS	900	1,004	523	28	2,455
10. WS	TX, LA, OK, AR	191	473	247	57	968
11. MT	MT, WY, ID	70	56	229	25	380
12. CU	CO, UT, NV	6	0	23	7	36
13. ZN	AZ, NM	6	0	23	7	36
14. PC	AK, HI, WA, OR, CA	104	0	195	83	382
Total U.S.		1,952	2,664	2,786	497	7,899

Sources: Urban Wood Wastes/Mill Residues: Antares Group Inc., *Biomass Residue Supply Curves for the U.S (updated),* prepared for the National Renewable Energy Laboratory, June 1999; Agricultural residues: James Easterly, "Biomass Suppy Curve Enhancement Regarding Agricultural Residues" prepared for EIA, September, 2004. All other biomass resources: Oak Ridge National Laboratory, personal communication with Marie Walsh, August 20, 1999.

potential new sites assembled from Federal Energy Regulatory Commission (FERC) license applications and other survey information, plus estimates of capital and other costs prepared by the Idaho National Engineering and Environmental Laboratory (INEEL).[123] For *AE02005* annual performance estimates (capacity factors) were taken from the generally lower but site specific FERC estimates rather than from the general estimates prepared by INEEL, and only sites with estimated costs 10 cents per kilowatthour or lower were included in the supply. Pumped storage hydro, considered a nonrenewable storage medium for fossil and nuclear power, is not included in the supply; moreover, the supply does not consider offshore or in-stream (non-impoundment) hydro, efficiency or operational improvements without capital additions, or additional potential from refurbishing existing hydroelectric capacity.

In the hydroelectricity submodule, sites are first arrayed by NEMS region from least to highest cost per kilowatthour. For any year's capacity decisions, only those hydroelectric sites whose estimated levelized costs per kilowatthour are equal to or less than an EMM determined avoided cost (the least cost of other technology choices determined in the previous decision cycle) are submitted. Next, the array of below-avoided cost sites is parceled into three increasing cost groups, with each group characterized by the average capacity-weighted cost and performance of its component sites. Finally, the EMM receives from the conventional hydroelectricity submodule the three increasing-cost quantities of potential capacity for each region, providing the number of megawatts potential along with their capacity-weighted average overnight capital cost, operations and maintenance cost, and average capacity factor. After choosing from the supply, the EMM informs the hydroelectricity submodule, which decrements available regional potential in preparation for the next capacity decision cycle.

Legislation

Energy Policy Act of 1992 (EPACT)

The RFM includes the investment and energy production tax credits codified in the Energy Policy Act of 1992 (EPACT) as amended in subsequent legislation. The investment tax credit provides a credit to Federal income tax liability worth 10 percent of initial investment cost for a solar, geothermal, or qualifying biomass facility. The production tax credit, which originally applied to wind and certain biomass facilities, provides a 1.8 cent tax credit for every kilowatt-hour of electricity produced for the first 10 years of operation for a facility constructed by December 31, 2005. The value of the credit, originally 1.5 cents, is adjusted annually for inflation. Various amendments to the original production tax credit allow credits for electricity produced from qualifying solar, geothermal, animal waste, certain small-scale hydroelectric, landfill gas, municipal solid waste, and additional biomass resources. Poultry litter receives a 1.8 cent tax credit for the first 10 years of facility operations. Solar and geothermal receive a 1.8 cent tax credit for the first 5 years of facility operations. All other renewable resources receive a 0.9 cent tax credit for the first 5 years of facility operations. The investment and production tax credits are exclusive of one another, and may not both be claimed for the same facility.

Alternative Renewable Technology Cases

Two cases examine the effect on energy supply using alternative assumptions for cost and performance of non-hyrdo, non-landfill gas renewable energy technologies. The Low Renewable Technology case examines the effect if technology costs were to remain at current levels. The High Renewable case examines the effect if technology energy costs were reduced by 2025 to 10 percent below Reference case values.

The Low Renewables case does not allow "learning-by-doing" effects to reduce the capital cost of biomass, geothermal, solar, or wind technologies beyond 2005 levels. The construction of the first four units of biomass integrated gasification combined cycle units, utility-scale photovoltaic plants, or solar thermal plants are still assumed to reduce the technological optimism factor associated with those technologies. All other parameters remain the same as in the Reference case.

The High Renewables case assumes that the non-hydro, non-landfill gas renewable technologies are able to reduce their overall cost-of-energy produced in 2025 by 10 percent from the Reference case. Because the cost of supply of renewable resources is assumed to increase with increasing utilization (that is, the renewable resource supply curves are upwardly sloping), the cost reduction is achieved by targeting the reduction on the "marginal" unit of supply for each technology in 2025 for the Reference case (that is, the next resource available to be utilized in the Reference case in 2025). This has the effect of reducing costs for the entire supply (that is, shifting the supply curve downward by 10 percent). As a result of the overall reduction in costs, more supply may be utilized, and a unit from higher on the supply curve may result in being the marginal unit of supply in the High Renewable case. Thus the actual market-clearing cost-of-energy for a given renewable technology may not differ by much from the Reference case, although that resource is able to supply more energy than in the Reference case. These cost reductions are achieved gradually through "learning-by-doing", and are only fully realized by 2025.

For biomass, geothermal, and solar technologies, this cost reduction is achieved by a reduction in overnight capital costs sufficient to achieve the 10 percent targeted reduction in cost-of-energy. As a result, the supply of biomass fuel is increased by 10 percent at every price level. For geothermal, the capital cost of the lowest-cost site available in the year 2000 (Roosevelt Hot Springs) is reduced such that if it were available for construction in 2025, it would have a 10 percent lower cost-of-energy in the High Renewable case than the cost-of-energy it would have in 2025 were it available for construction in the Reference case. For solar technologies (both photovoltaic and solar thermal power), the resource is assumed to be unlimited and the reductions in cost-of-energy are achieved strictly through capital cost reduction.

Observation of wind energy markets indicates that improvements in performance (as measured by capacity factor) have, in recent years, dominated reductions in capital cost as a means of reducing cost-of-energy. Therefore, in the High Renewables case, wind capital costs are assumed to decline at the same rate relative to market growth as in the Reference case, but the rate of improvement in capacity factor is increased to meet the 10 percent targeted cost reduction. Other assumptions within NEMS are unchanged from the Reference case.

For the High Renewables case, demand-side improvements are also assumed in the renewable energy technology portions of residential and commercial buildings, industrial processes, and refinery fuels modules. Details on these assumptions can be found in the corresponding sections of this report.

Supplemental and Floor Capacity Additions

Of the nearly 11 gigawatts of new nonhydroelectric renewable energy capacity projected to enter service in the electric power sector after 2003, 2.6 gigawatts of central station "supplemental additions'' were specifically added by EIA to account for identified new renewable energy projects and for limited amounts of new capacity determined to be highly likely to be built under state requirements such as renewable portfolio standards (RPS) and mandates or under voluntary goals, green power marketing programs, and other commercial ventures (summarized in Table 77 and detailed in Table 78).

For *AE02005,* expectations for new capacity from state requirements, such as RPS, are again reduced from amounts projected in *AEO2004* because of increased uncertainty for new capacity from these programs; as summarized in "State Renewable Energy Requirements and Goals: Status Through 2003," renewable

Table 77. Post-2003 Supplemental Capacity Additions (Megawatts, Net Summer Capability)

Rationale	Biomass	Conventional Hydro-electric	Geothermal	Landfill Gas	Solar Thermal	Solar Photovoltaic	Wind	Total
Mandates	0.0	0.0	0.0	39.0	0.0	0.0	1,010.3	1,049.3
RenewablePortfolio Standards[1]	8.5	0.1[2]	100.6	65.5	48.5	4.9	205.8	433.8
Goals	0.0	0.0	0.0	0.0	0.0	0.0	126.6	126.6
Other Reported[3]	21.1	0.0	0.0	30.9	0.0	0.0	993.2	1,045.2
Total	29.6	0.1	100.6	135.4	48.5	4.9	2,335.9	2,654.9

[1]Renewable Portfolio Standard; also includes both California RPS and funding under Assembly Bill 1890..

[2]Ocean Wave.

[3]Commercial and other not-known-to-be-required plans, "green marketing" projects, and other activities identified by EIA.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, based on publicly available information about specific projects, state renewable portfolio standards, mandates, goals, and commercial and other plans.

portfolio standards and other requirements have so far been met with significantly less new capacity than initially expected; as a result, for *AE02005* EIA is less certain of the new capacity that will be constructed under these programs.[124]

Further, for *AE02005* projections for new end-user-sited capacity include 29 megawatts of new photovoltaics (PV) capacity as supplemental additions, representing specifically identified expected new grid-connected end-user PV capacity known by EIA to be expected over the forecast period or emanating from state RPS and other requirements.

Finally, the projections also include generic projections of 320 megawatts of central station PV capacity and 76 megawatts of central station solar thermal generating capacity ("Floors") not specifically identified but assumed by EIA to be installed over the forecast period for reason other than least-cost electricity supply.

Table 78. Planned U.S. Central Station Generating Capacity Using Renewable Resources for 2004 and Beyond[1]

Technology	Plant Identification	Program[2]	State	Net Summer Capability (Megawatts)	On-Line Years
Biomass					
	Envir. Forest Solutions	R	Arizona	2.8	2004
	APS Biiomass I (Eager)	R	Arizona	2.9	2004
	Snowflake Gasification	R	Arizona	2.9	2005
	Port Wentworth	C	Georgia	21.1	2004
Landfill Gas (including mass-burn waste)	Los Reales (Expansion)	R	Arizona	1.9	2006
	California (various)	R	California	6.1	2004
	Buena Vista	R	California	2.4	2005
	California (various)	R	California	1.9	2006
	Mesquite Lake (Waste Tires)	R	California	28.5	2006
	Owl Creek	C	Georgia	3.8	2004
	HECO Landfill Gas	R	Hawaii	1.0	2008
	HECO (Municipal Waste)	R	Hawaii	15.2	2011
	Taylor Ridge	C	Illinois	3.8	2004
	New Paris Pike	C	Indiana	1.5	2004
	Twiss Street (Westfield)	R	Massachusetts	0.5	2004
	New York (various)	C	New York	1.4	2004
	Johnston (Massachusetts RPS)	R	Rhode Island	8.1	2004
	Central Landfill	C	Rhode Island	2.4	2004
	South Carolina (various)	C	South Carolina	6.2	2004
	Hutchins	C	Texas	2.5	2004
	Texas RPS	M	Texas	7.6	2005
	Texas RPS	M	Texas	7.6	2006
	Texas RPS	M	Texas	7.6	2007
	Texas RPS	M	Texas	7.6	2008
	Texas RPS	M	Texas	8.6	2009
	Davis County	C	Utah	1.0	2004
	Virginia (Various)	C	Virginia	8.4	2004
Geothermal	Puna (Expansion)	R	Hawaii	7.6	2006
	Rye Patch	R	Nevada	11.9	2005
	Hot Sulphur Springs	R	Nevada	23.8	2005
	Galena I (Orni I Steamboat)	R	Nevada	19.0	2006
	Desert Peak II, III	R	Nevada	38.4	2006
Central Station Photovoltaics (PV)	Springerville Expansion	R	Arizona	0.8	2004
	Springerville Expansion	R	Arizona	0.8	2005
	Springerville Expansion	R	Arizona	1.1	2007
	Springerville Expansion	R	Arizona	1.1	2008
	Springerville Expansion	R	Arizona	1.1	2009
Solar Thermal	Saguaro Power	R	Arizona	1.0	2005
	Solargenix	R	Nevada	47.5	2006

Table 78. Planned U.S. Central Station Generating Capacity Using Renewable Resources for 2004 and Beyond[1] (Continued)

Technology	Plant Identification	Program[2]	State	Net Summer Capability (Megawatts)	On-Line Years
Ocean Wave	Hawaii Pcean Wave	R	Hawaii	0.1	2004
Wind	Howling Dog Mesa	R	Arizona	15.0	2005
	Windland II	R	California	19.8	2005
	Windridge	R	California	30.0	2005
	(Unnamed) RPS	R	California	57.2	2005
	Lamar Light & Power	C	Colorado	6.0	2004
	Hawaii RD	G	Hawaii	10.6	2005
	Neppel	C	Iowa	1.5	2004
	MidAmerican	C	Iowa	310.0	2005
	Iowa Wind RFP	C	Iowa	100.0	2005
	Crescent Ridge	G	Illinois	51.0	2004
	Spearville	C	Kansas	150.0	2005
	Hull 2	R	Massachusetts	1.1	2004
	Princeton	R	Massachusetts	2.7	2005
	Small Wind (various)	M	Minnesota	28.1	2004
	Palmer II	M	Minnesota	1.7	2005
	Xcel Small (various)	M	Minnesota	31.1	2005
	Xcel Small 2006	M	Minnesota	17.0	2006
	Xcel Small 2007	M	Minnesota	17.0	2007
	Xcel Small 2008	M	Minnesota	17.0	2008
	Xcel Small 2009	M	Minnesota	17.0	2009
	Xcel Samll 2010	M	Minnesota	17.0	2010
	NPPD (Ainsworth)	C	Nebraska	60.0	2005
	Caprock Cielo	R	New Mexico	80.0	2005
	Flatrock I	C	New York	150.0	2005
	AMP Ohio/Green Mountain	C	Ohio	7.2	2004
	Weatherford	C	Oklahoma	106.5	2005
	Oregon	C	Oregon	75.0	2005
	Stonycreek	G	Pennsylvania	65.0	2005
	Buffalo Wind Energy Center	C	Tennessee	27.0	2004
	Sweetwater Wind II	M	Texas	91.5	2004
	Texas RPS 2005	M	Texas	155.0	2005
	Texas RPS 2006	M	Texas	155.0	2006
	Texas RPS 2007	M	Texas	155.0	2007
	Texas RPS 2008	M	Texas	154.0	2008
	Texas RPS 2009	M	Texas	154.0	2009

[1]includes reported information and EIA estimates for goals, mandates, renewable portfolio standards (RPS), and California Assembly Bill 1890 required renewables.

[2]"R" (RPS) represents state renewable portfolio standards; “M" (Mandate) identifies other forms of identified state legal requirements; “C" (Commercial) identifies other new capacity, not know by EIA to be required, including “green marketing” efforts and other voluntary programs and plans. Publicly available information does not always specify whether a project is mandated or a commercial build.

Note: Publicly available information does not always specify whether a project is required, commercial, or other voluntary build; EIA characterizes unspecified projects as "commercial".

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, based on publicly available information about specific projects, state renewable portfolio standards, mandates, goals, and commercial and other plans.

Notes and Sources

[110] For a comprehensive description of each submodule, see Energy Information Administration, Office of Integrated Analysis and Forecasting, Model Documentation, Renewable Fuels Module of the National Energy Modeling System, DOE/EIA-M069(2005), (Washington, DC, March 2005).

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APPENDIX A: HANDLING OF FEDERAL AND SELECTED STATE LEGISLATION AND REGULATION IN THE ANNUAL ENERGY OUTLOOK

Legislation	Brief Description	AEO Handling	Basis
Residential Sector			
A. National Appliance Energy Conservation Act of 1987	Requires Secretary of Energy to set minimum efficiency standards for 10 appliance categories	Included for categories represented in the AEO residential sector forecast	
a. Room Air Conditioners		Current standard of 9.8 EER	Federal Register Notice of Final Rulemaking,
b. Other Air Conditioners (<5.4 tons)		Current standard 10 SEER for central air conditioners and heat pumps, increasing to 13 SEER in 2006.	Federal Register Notice of Final Rulemaking,
c. Water Heaters		Electric: Current standard .90 EF. Gas: Current standard .59 EF.	Federal Register Notice of Final Rulemaking,
d. Refrigerators/Freezers		Current standard of 1.04 MEF, increasing to 1.26 MEF in 2007.	Federal Register Notice of Final Rulemaking,
e. Dishwashers		Current standard of .46 EF	Federal Register Notice of Final Rulemaking,
f. Fluorescent Lamp Ballasts		Current standard of .90 power factor	Federal Register Notice of Final Rulemaking,
g. Clothes Washers		Current standard of 1.18 EF, increasing to 1.04 MEF in 2004, further increasing to 1.26 MEF in 2007.	Federal Register Notice of Final Rulemaking,
h. Furnaces		Standard set at 78 AFUE for gas and oil furnaces.	Federal Register Notice of Final Rulemaking,
i. Clothes Dryers		Gas: Current standard 2.67 EF. Electric: Current standard 3.01 EF. The increase in MEF for clothes washers further increases the de facto standard for clothes dryers due to better extraction of water from clothes in washing process.	Federal Register Notice of Final Rulemaking,
B. Energy Policy Act of 1992 (EPACT)			
a. Window Labeling	Designed to help consumers determine which windows are most energy efficient.	Assume decrease heating loads by 8 percent and cooling loads by 3 percent.	Based in analysis of RECS data. Impacts 25 percent of existing (pre-1998) housing stock by the end of the forecast.
b. Low-Flow Showerheads	Designed to decrease domestic hot water use.	Assumed cuts hot water use for showers by 33 percent (implies 10 percent decrease in total hot water use). Only installed in new construction.	Analysis of how much domestic hot water is used for showers based on LBNL study.
c. Building Codes	For the IECC 2000, specifies whole house efficiency minimums.	Assumes that all States adopt the IECC 2000 code by 2010.	Trend of States' adoption to codes, allowing for lead times for enforcement and builder compliance.
d. Home Energy Efficiency Rates (HERS)	Rates homes based on installed efficiency of appliances and shell.	Used to determine compliance with obtaining an energy-efficient mortgage.	No final HERS rating system has been established by DOE. State agencies and mortgage lenders have developed a non-binding system, which is currently in place.
e. Energy-Efficient Mortgages	Allow homeowners to qualify for higher loan amounts if the home is energy-efficient, as scored by HERS	Efficiency of equipment represented in technology choice parameters. Efficiency of shell represented in HVAC choice.	No way to separate out these purchases from others. Assumes historical effect in the forecast, with cost-reducing learning in the shell portion of HVAC choice.

Legislation	Brief Description	AEO Handling	Basis
Commercial Sector			
A. National Appliance Energy Conservation Act of 1987	Requires Secretary of Energy to set minimum efficiency standards for 10 appliance categories	Included for categories represented in the AEO commercial sector forecast.	
a. Room Air Conditioners		Current standard of 9.8 EER	Federal Register Notice of Final Rulemaking,
b. Other Residential-size Air Conditioners (<5.4 tons)		Current standard 10 SEER for central air conditioners and heat pumps, increasing to 13 SEER in 2006.	Federal Register Notice of Final Rulemaking,
c. Fluorescent Lamp Ballasts		Current standard if .90 power factor and minimum efficacy factor for F40 and F96 lamps based on lamp size and wattage, increasing to higher efficacy factor in 2005 that limits purchases to electronic ballasts.	Federal Register Notice of Final Rulemaking,
B. Energy Policy Act of 1992 (EPACT)			
a. Building Codes		Incorporated in commercial building shell assumptions. Efficiency of new relative to existing shell represented in shell efficiency indices. Assume shell efficiency improves 5 and 7 percent by 2025 for existing buildings and new construction, respectively.	Based on Arthur D. Little commercial shell indices developed for EIA in 1998, updated to 1999 CBECS building stock.
b. Window Labeling	Designed to help consumers determine which windows are most energy efficient.	Incorporated in commercial building shell assumptions. Efficiency of new relative to existing shell represented I shell efficiency indices. Assume shell efficiency improves 5 and 7 percent by 2025 for existing buildings and new construction, respectively,	Based on Arthur D. Little commercial shell indices developed for EIA in 1998, updated to 1999 CBECS building stock.
c. Commercial Furnaces and Boilers		Gas-fired furnaces and boilers: Current standard is 0.80 thermal efficiency. Oil furnaces and boilers: Current standard is 0.81 thermal efficiency for furnaces, 0.83 thermal efficiency for boilers.	Public Law 102-486: EPACT. Federal Register Notice of Final Rulemaking,
d. Commercial Air Conditioners and Heat Pumps		Air-cooled air conditioners and heat pumps less than 135,000 Btu: Current standard of 8.9 EER. Air-cooled air conditioners and heat pumps greater than 135,000 Btu: Current standard of 8.5 EER.	Public Law 102-486: EPACT
e. Commercial Water Heaters		Natural gas and oil: EPACT standard .78 thermal efficiency, increasing to .80 thermal efficiency for gas units in 2003.	Public Law 102-486: EPACT. Federal Register Notice of Final Rulemaking.
f. Lamps		Incandescent: Current standard 16.9 lumens per watt. Fluorescent: Current standard 75 and 80 lumens per watt for 4 and 8 foot lamps, respectively.	
g. Electric Motors	Specifies minimum efficiency levels for a variety of motor types and sizes.	End-use services modeled at the equipment level. Motors contained in new equipment must meet the standards.	Public Law 102-486: EPACT.

Legislation	Brief Description	AEO Handling	Basis
h. Federal Energy Management	Requires Federal agencies to reduce energy consumption 20 percent by 2000 relative to 1985.	Superceded by Executive Order 13123.	Superceded by Executive Order 13123.
i. Business Investment Energy Credit	Provides a permanent 10 percent investment tax credit for solar property	Tax credit incorporated in cash flow for solar generation systems. Investment cost reduced 10 percent for solar water heaters.	Public Law 102-486: EPACT.
C. Executive Order 13123, "Greening the Government Through Efficient Energy Management"	Requires Federal agencies to reduce energy consumption 30 percent by 2005 and 35 percent by 2010 relative to 1985 through life-cycle cost-effective energy measures,	The Federal "share" of the commercial sector uses the 10 year treasury bond rate as a discount rate in equipment purchase decisions as opposed to adding risk premiums to the 10 year treasury bond rate to develop discount rates for other commercial decisions.	Federal Register Notice of Executive Order. Code of Federal Regulations: 10CFR 436.14 Methodological assumptions for lifecycle cost calculations.
Industrial Sector			
A. Energy Policy Act of 1992 (EPACT)			
1. Motor Efficiency Standards	Specifies minimum efficiency levels for a variety of motor types and sizes	New motors must meet the standards.	Standard specified in EPACT, 10 CFR 431
2. Boiler Efficiency Standards	Specifies minimum combustion efficiency for package boilers larger than 300,000 Btu/hr. Natural Gas boilers: 80 percent; oil boilers: 83 percent.	All package boilers are assumed to meet the efficiency standards. While the standards do not apply to field-erected boilers, which are typically used in steam-intensive industries, we assume they meet the standard in the AEO.	Standard specified in EPACT, 10 CFR 431.42
B. Clean Air Act Amendments of 1990 (CAAA90)			
1. Process Emissions	Numerous process emissions requirements for specified industries and/or activities,	Not modeled because they are not directly related to energy projections.	CAAA90, 40 CFR 60
2. Emissions related to hazardous/toxic substances	Numerous emissions requirements relative to hazardous and/or toxic substances.	Not modeled because they are not directly related to energy projections.	CAAA90, 40 CFR 63
3. Industrial SO2 emissions	Sets annual limit for industrial SO2 emissions at 5.6 million tons. If limit is reached, specific regulations could be implemented.	Industrial SO2 emissions are not projected to reach the limit (Source: EPA, National Air Pollutant Emissions Trends: 1990-1998, EPA-454/R-00-002, March 2000, p. 4-3.)	CAAA90, Section 406 (42 USC 7651)
4. Industrial boiler hazadous air pollutants	Requires industrial boilers and process heaters to meet emissions limits on HAPs to comply with the Maximum Achievable Control Technology (MACT) floor.	Not explicitly modeled because new boilers are expected to meet the standards in the absence of the rule and retrofit costs should be relatively small.	Environmental Protection Agency, "National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters," 40 CFR Part 63.
Transportation Sector			
A. Energy Policy Act of 1992 (EPACT)	Increases the number of alternative fuel vehicles and alternative fuel use in Federal, State, and fuel provider fleets.	Assumes Federal, State and fuel provider fleets meet the mandated sales requirements.	Energy Policy Act of 1992, Public Law 102-486-Oct. 24, 1992.

Legislation	Brief Description	AEO Handling	Basis
B. Low Emission Vehicle Program (LEVP)	Allows California the authority to set vehicle criteria emission standards that exceed Federal standards. In addition, this program mandates the sale of zero emission vehicles by manufacturers, States are given the optin of opting into the Federal or California emission standards.	Incorporates the LEVP program as amended on 4/24/03. Assumes California, New York, Massachusetts, Maine, and Vermont adopt the LEVP program as amended April 24, 2003 and that the proposed sales requirements for hybrid, electric, and fuel cell vehicles are met.	General Motors Corp., Daimler/Chrysler and Isuzu Motors filed suit against the ZEV mandates outlined in the July 30, 2002 amendments. Due to the changes proposed in the April 24, 2003 amendments (Resolution 03-4), the auto manufacturers agreed to settle litigation with California.
C. Light Vehicle GHG Emission Standards	California has enacted light vehicle GHG emission standards as part of the Low Emission Vehicle Program (A.B. 1493), which requires that GHG emissions from new light vehicles be significantly reduced from 2009 to 2016.	AEO does not incorporate, but is addressed in a side case.	The alliance of Automobile Manufacturers and Several California auto dealerships filed suit against A.B. 1493 on December 7, 2004.
D. Corporate Average Fuel Economy (CAFE) Standards	Requires manufacturers to produce vehicles whose average fuel economy meets a minimum Federal standard Cars and light trucks are regulated separately.	The current CAFE standard for cars is 27.5 mpg. The car standard is unchanged through 2025. The current CAFE standard for light trucks is 20.7 mpg. Increasing to 21.0 mpg in 2005, 21.6 mpg in 2006, and 22.2 mpg in 2007 and beyond.	Energy Policy Conservation Act of 1975; Title 49 United States Code, Chapter 329; and Federal Register, Vol. 68, No. 66, Monday, April 7, 2003.
E. Electric, Hybrid, and Alternative Fuel Vehicle Tax Incentives	Federal tax incentives are provided to encourage the purchase of electric, hybrid and or alternative fuel vehicles. For example, tax incentives for hybrid vehicles in the form of a $2,000 income tax deduction.	Incorporates the Federal tax incentives for hybrid and electric vehicles.	IRS Technical Publication 535; Business Expenses
F. The Working families Tax Relief Act of 2004.	The Act repeals the phase out of the credits which were allowed for qualified electric and clean fuel vehicles for property acquired in 2004 and 2005. The credit is reduced by 75 percent for vehicles acquired in 2006. This will provide an incentive to purchase electric and clean fuel vehicles.	The federal tax incentives are embodied in the code. This will provide an incentive to purchase electric and clean fuel vehicles but little impact is realized on projections of total highway energy use.	Sections 318 and 319 of the Working families Tax Relief Act of 2004.
G. State Electric, Hybrid, and Alternative Fuel Vehicle Tax and other Incentives	Approximately 20 States provide tax and other incentives to encourage the purchase of electric, hybrid and or alternative fuel vehicles. The tax incentives are in the form of income reductions, tax credits, and exemptions. Other incentives include use of HOV lanes and exemptions from emissions inspections and licensing fees. The incentives offered and the mix varies by state. For example, Georgia offers a tax credit of $5,000 for electric vehicles and Oklahoma offers a tax credit of $1,500 for hybrid and alternative fuel vehicles.	Does not incorporate State tax and other incentives for hybrid, electric, and other alternative fuel vehicle.	State laws in Arizona, Arkansas, California, Colorado, Delaware, Florida, Georgia, Iowa, Kansas, Louisiana, Maine, Maryland, Michigan, New Hampshire, New York, Oklahoma, Pennsylvania, Utah, Virginia, and Washington.
Electric Power Generation			
A. Clean Air Act Amendments of 1990	Established a national limit on electricity generator emissions of sulfur dioxide to be achieved through a cap and trade program.	Sulfur dioxide cap and trade program is explicitly modeled, choosing the optimal mix of options for meeting the national emissions cap.	Clean Air Act Amendments of 1990, Title IV, Sections 401 through 406, Sulfur Dioxide Reduction Program, 42 U.S.C. 7651a through 7651e
	Set boiler type specific nitrogen oxide emission limits for electricity generators.	Assumes each boiler installs the options necessary to comply with their nitrogen oxide emissions limit.	Clean Air Act Amendments of 1990, Title IV, Section 407, Nitrogen Oxides Emission Reduction Program, 42 U.S.C. 7651f

Legislation	Brief Description	AEO Handling	Basis
	Under section 126, Northeast states petitioned the EPA arguing that generators in other states contributed to the nitrogen oxide emissions problems in their states. EPA established a summer season nitrogen oxide emission cap and trade program coovering 22 states (three were removed by the courts) to start in May 2003 (delayed until May 2004).	The 19-state summer season nitrogen oxide cap and trade program is explicitly modeled, allowing electricity generators to choose the optimal mix of control options to meet the emission cap.	Section 126 Rule: Revised Deadlines, Federal Register: April 30, 2002 (volume 67, Number 83), Rules and Regulations, Pages 21521-21530
	Requires the EPA to establish national ambient air quality standards, In 1997, EPA set new standards for ground level ozone and fine particulates. EPA is currently determining which areas of the country are not incompliance with the new standards. Area designations will be made in December 2004. States will then have until December 2007 to submit their compliance plans, and until 2009-2014 to bring all areas into compliance.	Because state implementation plans have not been established, these revised standards are not currently repersented.	Clean Air Act Amendments of 1990, Title I, Sections 108 and 109, National Ambient Air Quality Standards for Ozone, 40 CFR Part 50, Federal Register, Vol 68, No 3, January 8, 2003. National Ambient Air Quality Standards for Particulate Matter, 40 CFR Part 50, Federal Register, Vol. 62, No. 138, July 18, 1997.
	Required the EPA to study hazardous air pollutants from electricity generation. EPA announced in December 2000 that it would regulate electricity generator mercury emissions under Section 112 of the Clean Air Act. EPA plans to issue proposed mercury emission standards in December 2003 and final standards in March 2005.		Clean Air Act Amendments of 1990, Title I, Section 112. No specific standard promulgated as of 9/1/2003.
B. Energy Policy Act of 1992 (EPACT)	Created a class of generators referred to as exempt wholesale generators (EWGs), exempt from PUCHA as long as they sell wholesale power,	Represents the development of Exempt Wholesale Generators (EWGs) or what are now referred to as independent power producers (IPPs) in all regions.	Energy Policy Act of 1992, Title VII, Electricity, Subtitle A, Exempt Wholesale Generators
	Created production tax incentives (PTC) for wind and biomass and reintroduced a permanent investment tax credit (ITC) for solar. The PTC has been reauthorized several times and currently expires as of December 31, 2005 as called for in the Working Families Tax Relief Act of 2004 (P.L. 108-357). Production Tax Credits have also been authorized for poultry litter, geothermal power, solar power, and landfill gas.	The PTCs and ITCs for renewables are explicitly modeled as atated in the law.	Energy Policy Act of 1992, Title XII, Renewable Energy, Section 1212, Renewable Energy Production Incentive, Working Families Tax Relief Act of 2004.
C. The Public Utility Holding Company Act of 1935 (PUCHA)	PUHCA is a US federal statute which was enacted to legislate against abusive practices in the utility industry. The act grants power to the US Securities and Exchange Commission (SEC) to oversee and outlaw large holding companies which might otherwise control the provision of electrical service to large regions of the country. It gives the SEC power to approve or deny mergers and acquisitions and, if necessary, force utility companies to dispose of assets or change business practices if the company's structure of activities are not deemed to be in the public interest.	It is assumed that holding companies act competitively and do not use their regulated power businesses to cross-subsidize their unregulated businesses.	Public Utility Holding Company Act of 1936

Legislation	Brief Description	AEO Handling	Basis
D. FERC Orders 888 and 889	FERC has issued two related rules Orders 888 and 889) designed to bring low cost power to consumers through competition, ensure continued reliability in the industry, and provide for open and equitable transmission services by owners of these facilities. Specifically, Order 888 requires open access to the transmission grid currently owned and operated by utilities. The transmission owners must file nondiscriminatory tariffs that offer other suppliers the same services that the owners provide for themselves. Order 888 also allows these utilities to recover stranded costs (investments in generating assets that are unrecoverable due to consumers selecting another supplier). Order 889 requires utilities to implement standards of conduct and a Open Access Same-time Information System (OASIS) through which utilities and non-utilities can receive information regarding the transmission system. Consequently, utilities are expected to functionally or physically unbundle their marketing functions from their transmission functions.	These orders are represented in the forecast by assuming that all generators in a given region are able to satisfy load requirements anywhere within the region, Similarly, it is assumed that transactions between regions will occur if the cost differentials between them make it economic to do so.	Promoting Wholesale Competition Through Open Access, Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, ORDER NO. 888 (Issued April 24, 1996), 18 CFR Parts 35 and 385, Docket Nos. RM95-8-000 and RM94-7-001. Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct, ORDER NO. 889, (Issued April 24, 1996), 18 CFR Part 37, Docket No. RM95-9-000.
E. New Source Review (NSR)	On August 27, 2003, the Environmental Protection Agency (EPA) issued a final rule defining certain power plant and industrial facility activities as routine maintenance, repair and replacement , which are not subject to new source review (NSR). As stated by EPA, "these changes provide a category of equipment replacement activities that are not subject to Major NSR requirements under the routine maintenance, repair and replacement (RMRR) exclusion."[1] Essentially this means that power plants and industrial facilities engaging in RMRR activities will not have to get preconstruction approval from the State or EPA and will not have to install best available emissions control technologies that might be required if NSR were triggered.	It is assumed that coal plants will be able to increase their output as electricity demand increases. Their maximum capacity factor is set at 84 percent. No increases in the capacity of existing plants is assumed. If further analysis shows that capacity uprates may result from the NSR rule, they will be incorporated in future AEOs. However, at this time, the NSR rule is being contested in the courts.	Environmental Protection Agency, 40 CFR Parts 51 and 52, Prevention of Significant Deterioration (PSD) and Non-Attainment New Source Review (NSR): Equipment Replacement Provision of the Routine Maintenance, Repair and Replacement Exclusion; Final Rule, Federal Register, Vol. 68, No. 207, page 61248, October 27, 2003.
F. State RPS laws, mandates, and goals	Several States have enacted laws requiring that a certain percentage of their generation come from qualifying renewable sources.	Estimates of projected new capacity, by renewable technology and forecast year, of future capacity resulting from state RPS, mandates, and goals are included for those states able to quantify expectations. Most estimates are limited to near-term years.	States with RPS or other mandates providing quantified projections are Arizona, California, Connecticut, Illinois, Massachusetts, Minnesota, Nevada, New Jersey, Pennsylvania, Texas, and Wisconsin.

Legislation	Brief Description	AEO Handling	Basis
G. State Environmental Laws	Several States have enacted laws requiring emissions reductions from their generating plants.	Where compliance plans have been announced, they have been incorporated. In total 22 gigawatts of planned SO2 scrubbers, 27 gigawatts of planned selective catalytic reduction (SCR) and 3 gigawatts of planned selective non-catalytic reduction (SNCR) are represented.	North Carolina's Clean Smoke Stacks Act, Session Law 2002-4, Senate Bill 1078, An Act to improve Air Quality in the State by Imposing Air Quality in the State by Imposing Limits on the Emission of Certain Pollutants from Certain Facilities that Burn Coal to Generate Electricity and to Provide for Recovery by Electric Utilities of the Costs of Achieving Compliance with those Limits.
Oil and Gas Supply			
A. The Outer Continental Shelf Deep Water Royalty Relief Act (DWRRA)	Mandates that all tracts offered by November 22, 2000, in deep water in certain areas of the Gulf of Mexico must be offered under the new bidding system permitted by the DWRRA. The Secretary of Interior must offer such tracts with a specific minimum royalty suspension volume based on water depth.	Incorporates royalty rates based on water depth.	43 U.S.C SS 1331-1356 (2002).
B. Energy Policy and Conservation Act Amendments of 2000	Required the USGS to inventory oil and gas resources beneath Federal lands.	To date, the Rocky Mountain oil and gas resource inventory has been completed by the USGS. The results of this inventory have been incorporated in the technically recoverable oil and gas resource volumes used for the Rocky Mountain region.	"Scientific Inventory of Onshore Federal Lands" Oil and Gas Resources and Reserves and the Extent and Nature of Restrictions or Impediments to their Development: The Paradox/San Juan, Uinta/Piceance, Greater Green River, and Powder River Basins and the Montana Thrust Belt," Prepared by the Departments of Interior, Agriculture and Energy, January 2003.
C. Hackberry Decision	Terminated open access requirements for new onshore LNG terminals and authorized them to charge market-based rather than cost-of-service rates.	This is reflected in lower risk premiums for new terminal construction.	Docket No. PL02-9, Natural Gas Markets Conference (2002).
D. Maritime Security Act of 2002 Amendments to the Deepwater Port Act of 1974	Transfers jurisdiction over offshore LNG facilities from FERC to the Maritime Administration (MARAD) and the Coast Guard, both under the Department of Transportation (DOT), provides these facilities with a new, streamlined application process, and relaxes regulatory requirements (offshore LNG facilities are no longer required to operate as common carriers or to provide open access as they did while under FERC jurisdiction).	This is reflected in lower risk premiums for new terminal construction.	P.L. 107-295.

Legislation	Brief Description	AEO Handling	Basis
E. Section 29 Tax Credit for Nonconventional Fuels	The Alternative Fuel Production Credit (Section 29 of the IRC) applies to qualified nonconventional fuels from wells drilled or facilities placed in service between January 1, 1980, and December 31, 1992. Gas production from qualifying wells could receive a 3 dollars (1979 constant dollars) per barrel of oil equivalent credit on volumes produced through December 31, 2002. The qualified fuels are: oil produced from shale and tar sands: gas from geopressurized brine, Devonian shale, coal seams, tight formations, and biomass; liquid, gaseous, or solid synthetic fuels produced from coal; fuel from qualified processed formations or biomass; and steam from agricultural products.	The Section 29 Tax Credit expired on December 31, 2002 and is not considered in new production decisions. However, the effect of these credits is implicitly included in the parameters that are derived from historical data reflecting such credits.	Alternative Fuel Production Credit (Section 29 of the Internal Revenue Code), initially established in the Windfall Profit Tax of 1980.
Natural Gas Transmission and Distribution			
A. Alaska Natural Gas Pipeline Act, Sections 101-116 of the Military Construction Hurricane Supplemental Appropriations Act, 2005.	Disallows approval for a pipeline to enter Canada via Alaska north of 68 degrees latitude. Also, provides Federal guarantees for loans and other debt obligations assigned to infrastructure in the United States or Canada related to any natural gas pipeline system that carries Alaska natural gas to the border between Alaska and Canada south of 68 degrees north latitude. This authority would expire 2 years after the final certificate of public convenience and necessity is issued. The guarantee will not exceed 1) 80 percent of the total capital costs (including interest during construction), 2) $18 billion dollars (indexed for inflation at the time of enactment), or 3) a term of 30 years.	Assumes the pipeline construction cost estimate for the "southern" Alaska pipeline route in projecting when an Alaska gas pipeline would be profitable to build. Also, when calculating the tariff associated with the Alaska pipeline, the return on debt was lowered by 1 percentage point and the percentage of capital financed by debt was increased by 10, to account for the impact of the loan guarantee.	P.L. 108-324.
B. American Jobs Creation Act of 2004, Sections 706 and 707.	Provides a 7-year cost-of-investment recovery period for the Alaska natural gas pipeline, as opposed to the currently allowed 15-year recovery period, for tax purposes. The provision would be effective for property placed in service after 2013, or treated as such. Effectively extends the 15-percent tax credit currently applied to costs related to enhanced oil recovery to construction costs for a gas treatment plant on the North Slope that would feed gas into an Alaska pipeline to Canada.	When calculating the tariff associated with the Alaska pipeline, the return on equity was lowered by 3 percentage points. Also, the charge associated with removing liquids from natural gas at the gas processing plant for the Alaska natural gas pipeline was decreased by $0.05 per Mcf.	P.L. 108-357.
C. Pipeline Safety Improvement Act of 2002	Imposes a stricter safety regime on pipeline operators designed to prevent leaks and ruptures.	Costs associated with implementing the new safety features are asumed to be a small percentage of total pipeline costs and are partially offset by benefits gained through reducing pipeline leakage. It is assumed that the Act accelerates the schedule of repair wrk that would have been done otherwise.	P.L. 107-355, 116 Stat. 2985.

Legislation	Brief Description	AEO Handling	Basis
D. FERC Order 436 (Issued in 1985)	Order 436 changed gas transmission from a merchant business, wherein the pipeline buys the gas commodity at the inlet and sold the gas commodity at the delivery point, to being a transportation business wherein the pipeline does not take title to the gas. Order 436 permitted pipelines to apply for "blanket transportation certificates," in return for becoming non-discriminatory, open-access gas transporters. Order 436 also allocated gas pipeline capacity on a "first-come, first-serve" basis, allowed pipelines to discount below the maximum rate, allowed local gas distributors to convert to transportation only contracts, and created optional expedited certificates for the construction of new facilities.	Natural gas is priced at the wellhead at a competitive rate determined by the market. The flow of gas in the system is a function of the relative costs and is set to balance supply, demand, and prices in the market. Transportation costs are based on a regulated rate calculation.	50 F. R. 42408, FERC Statutes & Regulations Paragraph 30,665 (1985)
E. FERC Order 636 (Issued in 1992)	FERC Order 636 completed the separation of pipeline merchant services from pipeline transportation services, requiring pipelines to offer separate tariffs for firm transportation, interruptible transportation, and storage services. Order 636 also permitted pipelines to resell unused firm capacity as interruptible transportation, gave shippers the "right of first refusal" at the expiration of their firm transportation contracts, adopted Straight-Fixed-Variable rate design as the presumptive rate methodology, and created a mechanism for pipelines to recover the costs incurred by prior "take-or-pay" contracts.	A straight-fixed-variable rate design is used to establish regulated rates. To reflect some of the flexibility built into the system, the actual tariffs charged are allowed to vary from the regulated rates as a function of the utilization of the pipeline. End-use prices are set separately for firm and interruptible customers for the industrial and electric generation sectors.	57 F. R. 13267, FERC Statutes and Regulations Paragraph 30,939 (1992)
Petroleum Refining			
A. Ultra-Low Sulfur Diesel (ULSD) regulations under the Clean Air Act	80 percent of highway diesel pool must contain 15 ppm sulfur or less starting in mod-2006. By mid-2011, all highway diesel mist be 15 ppm or less. All nonroad, locomotive, and marine diesel fuel produced must contain less than 500 ppm starting mid-2007. By mid-2010 nonroad diesel must contain less than 15 ppm. Locomotive and marine diesel must contain less than 15 ppm by mid-2012.	Reflected in diesel specifications	40 CFR Parts 69, 80, 86, 89, 94, 1039, 1048, 1051, 1065, and 1068
B. Mobile Source Air Toxics (MSAT) controls under the Clean Air Act.	Establishes a list of 21 substances emitted from motor vehicles and known to cause serious human health effects, particularly benzene, formaldehyde, 1.3 butadiene, acetaldehyde, diesel exhaust organic gases, and diesel particulate matter. Establishes anti-backsliding and anti-dumping rules for gasoline.	Modeled by updating gasoline specifications to most current EPA gasoline survey data (2002) representing anti-backsliding requirements.	40 CFR Parts 60 and 86
C. Low-sulfur gasoline regulations under the Clean Air Act	Gasoline must contain an average of 30 ppm sulfur or less by 2006. Small refiners may be permitted to delay compliance until 2008.	Reflected in gasoline specifications	40 CFR Parts 80, 85 and 86

Legislation	Brief Description	AEO Handling	Basis
D. MTBE Bans in 20 States	Seventeen States ban the use of MTBE in gasoline by 2004	Ethanol assumed to be the oxygenate of choice in RFG where MTBE is banned.	State laws in Arizona, California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Maine, Michigan, Minnesota, Missouri, Nebraska, New Hampshire, New York, Ohio, South Dakota, Washington, and Wisconsin.
E. Regional clean fuel formulations under the Clean Air Act Amendments of 1990	States with air quality problems can specify alternative gasoline or diesel formulations with EPA's permission. California has long had authority to set its own fuel standards.	Reflected in PADD-level gasoline and diesel specifications.	State implementation Plans required by the Clean Air Act Amendments if 1990, as approved by EPA.
F. Federal Motor Fuels Excise Taxes	Taxes are levied on each gallon of transportation fuels to fund infrastructure and general revenue, These taxes are set to expire at various times in the future but are expected to be renewed, as they have been in the past.	Gasoline, diesel, and ethanol blend tax rates are included in end-use prices and are assumed to be extended indefinitely at current nominal rates.	26 USC 4041 Extended by American Jobs Creation Act of 2004
G. State Motor Fuel Taxes	Taxes are levied on each gallon of transportation fuels. The assumption that State taxes will increase at the rate of inflation supports an implied need for additional highway revenues as driving increases.	Gasoline and diesel rates are included in end-use prices and are assumed to be extended indefinitely in real terms (to keep pace with inflation).	Determined by review of existing State laws performed semi-annually by EIA's Office of Oil and Gas.
H. Diesel Excise Taxes	Phases out the 4.3 cent excise tax on railroads between 2005 and 2007.	Modeled by phasing out.	American Jobs Creation Act of 2004, Section 241
I. Ethanol/Bio-Diesel Tax Credit	Petroleum product blenders may claim tax credits for blending ethanol into gasoline and for blending biodiesel into diesel fuel or heating oil. The credits may be claimed against the Federal motor fuels excise tax or the income tax. The tax credits are 51 cents per gallon of ethanol, 50 cents per gallon of nonvirgin biodiesel, and $1.00 per gallon of virgin biodiesel. The ethanol tax credit expires in 2010, but is expected to be renewed as it has been in the past. The biodiesel tax credits expire after 2006.	The tax credits are applied against the production costs of the products into which they are blended. Ethanol is used in gasoline and E85. Virgin biodiesel is assumed to be blended into highway diesel, and nonvirgin biodiesel is assumed to be blended into nonroad diesel or heating oil.	26 USC 40, 4041 and American Jobs Creation Act of 2004

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Abbreviations:

AEO: Annual Energy Outlook
AFUE: Average Fuel Use Efficiency
Btu: British Thermal Unit
CAFÉ: Corporate Average Fuel Economy
CBECS: Commercial Building Energy Consumption Survey
CFR: Code of Federal Regulations
DOE: Department of Energy
DOT: Department of Transportation
DWRRA: Deep Water Royalty Relief Act
EER: Energy Efficient Ratio
EF: Energy Efficiency
EIA: Energy Information Administration
EPA: Environmental Protection Agency
EPACT: Energy Policy Act of 1992
EWGs: Exempt Wholesale Generators
FERC: Federal Energy Regulatory Commission
HERS: Home Energy Efficiency Rating
HVAC: Heating, Ventilation, and Air Conditioning
IECC: International Energy Conservation Code
ITC: Investment Tax Credit
kWh: Kilowatthour
LBNL: Lawrence Berkeley National Laboratory
LEVP: Low Emission Vehicle Program
LNG: Liquified Natural Gas
MARAD: Maritime Administration
MEF: Modified Energy Factor
MSAT: Mobile Source Air Toxics
MTBE: Methyl-Tertiary-Butyl-Ether
OASIS: Open Access Same-Time Information System
PADD: Petroleum Administration for Defense Districts
P.L.: Public Law
PPM: Parts Per Million
PTC: Production Tax Credit
PUCHA: Public Utility Holding Company Act of 1935
RECS: Residential Energy Consumption Survey
RPS: Renewable Portfolio Standard
SCR: Selective Catalytic Reduction
SEER: Seasonal Energy Efficiency Rating
SO2: Sulfur Dioxide
SNCR: Selective Non-Catalytic Reduction
ULSD: Ultra-Low Sulfur Dioxide
U.S.C.: United States Code
USGS: United States Geological Survey
ZEV: Zero Emission Vehicle