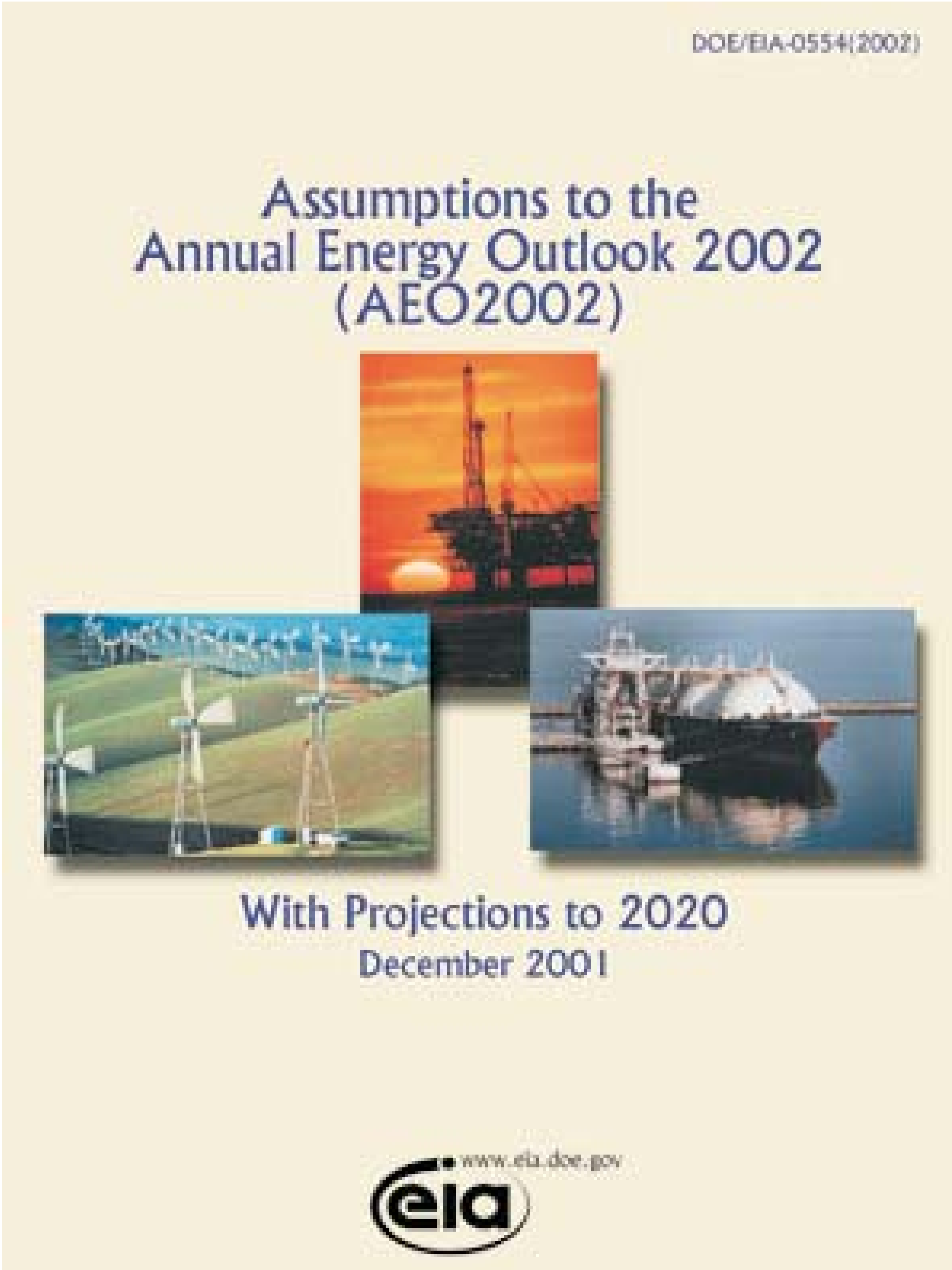
Assumptions to the Annual Energy Outlook 2002



Contents

Introduction 1
Macroeconomic Activity Module 12
International Energy Module 14
Household Expenditures Module 18
Residential Demand Module 19
Commercial Demand Module 27
Industrial Demand Module 38
Transportation Demand Module 49
Electricity Market Module 66
Oil and Gas Supply Module 80
Natural Gas Transmission and Distribution Module 89
Petroleum Market Module 93
Coal Market Module 104
Renewable Fuels Module 111

Introduction

This report presents the major assumptions of the National Energy Modeling System (NEMS) used to generate the projections in the *Annual Energy Outlook 2002*[1] (*AEO2002*), 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]

The National Energy Modeling System

The projections in the *AEO2002* 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 and analysts in the U.S. Congress, the Department of Energy's Office of Policy and International Affairs, other DOE offices, and other government agencies.

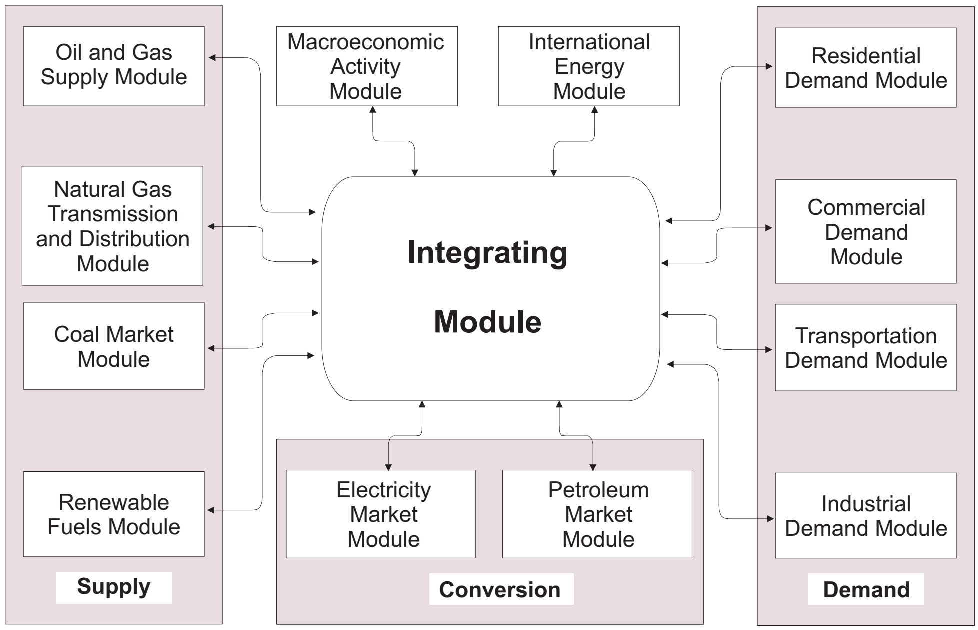
The time horizon of NEMS is approximately 20 years, the midterm period in which the structure of the economy and the nature of energy markets are sufficiently understood that it is possible to represent considerable structural and regional detail. Because of the diverse nature of energy supply, demand, 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 aggregations of the Petroleum Administration for Defense Districts (PADD) for refineries. Only national results are presented in the *AEO2002,* with the regional and other detailed results available on the EIA CD-ROM and EIA 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 macroeconomic and international modules. The primary flows of information among 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.

Each NEMS component also represents the impact and cost of legislation and environmental regulations that affect that sector. NEMS reflects all current legislation and environmental regulations, such as the Clean Air Act Amendments of 1990 (CAAA90), and the costs of compliance with other regulations. NEMS also includes an analysis of the impacts of voluntary programs to reduce energy demand and carbon dioxide emissions, which are separately described under each module.

Figure 1. National Energy Modeling System



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), interest rates, disposable income, and employment. Industrial drivers are calculated for thirty-five industrial sectors. This module uses the DRI-WEFA Macroeconomic Model of the U.S. Economy.

International Energy Module

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

Household Expenditures Module

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

Residential and Commercial Demand Modules

The Residential Demand Module forecasts consumption of residential sector energy by housing type and end use, subject to delivered energy prices, availability of renewable sources of energy, and housing starts. The Commercial Demand Module forecasts consumption of commercial sector energy by building types and nonbuilding uses of energy and by category of end use, subject to delivered prices of energy, availability of renewable sources of energy, and macroeconomic variables representing interest rates and floorspace construction. Both modules estimate the equipment stock for the major end-use services, incorporating assessments of advanced technologies, including representations of renewable energy technologies, and analyses of both building shell and appliance standards. Both modules include a representation of distributed generation.

Industrial Demand Module

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

Transportation Demand Module

The Transportation Demand Module forecasts consumption of transportation sector fuels, including petroleum products, electricity, methanol, ethanol, compressed natural gas, and hydrogen by transportation mode, vehicle vintage, and size class, subject to delivered prices of energy fuels and macroeconomic variables representing disposable personal income, GDP, population, interest rates, and the value of output for industries in the freight sector. Fleet vehicles are represented separately to allow analysis of the CAAA90 and other legislative proposals, and the module includes a component to explicitly assess the penetration of alternative-fuel vehicles.

Electricity Market Module

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

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules that provide the representation of the supply response for biomass (including wood, energy crops, and biomass co-firing), geothermal, municipal solid waste (including landfill gas), solar thermal, solar photovoltaics, and wind energy. The RFM contains natural resource supply estimates representing the regional opportunities for renewable energy development.

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil (including lease condensate), natural gas liquids, and natural gas supply within an integrated framework that captures the interrelationships among the various sources of supply—onshore, offshore, and Alaska—using both conventional and nonconventional techniques, including enhanced oil recovery and unconventional gas recovery from coalbeds and low permeability formations of sandstone and shale. This framework analyzes cash flow and profitability to compute investment and drilling in each of the supply sources, subject to the prices for crude oil and natural gas, the domestic recoverable resource base, and technology. Oil and gas production functions are computed at a level of twelve supply regions, including three offshore and three Alaskan regions. This module also represents foreign sources of natural gas, including pipeline imports and exports with Canada and Mexico and liquefied natural gas imports and exports. Crude oil production quantities are input to the Petroleum Market Module in NEMS for conversion and blending into refined petroleum products. The supply curves for natural gas are input to the Natural Gas Transmission and Distribution Module for use in determining prices and quantities.

Natural Gas Transmission and Distribution Module

The Natural Gas Transmission and Distribution Module represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas, the supply of domestic natural gas, and the availability of natural gas traded on the international market, on a seasonal basis. The module tracks the flow of natural gas in an aggregate, domestic pipeline network, connecting the domestic and foreign supply sources with twelve demand regions. This capability allows the identification of pipeline and storage capacity expansion requirements. Peak and off-peak periods are represented for natural gas transmission, and core and noncore markets are represented at the burner tip. The 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, availability and price of imported petroleum, and domestic production of crude oil, natural gas liquids, and alcohol fuels. The module represents refining activities for three regions- Petroleum Administration for Defense District (PADD) 1, PADD 5, and an aggregate of PADDs 2, 3, and 4. The module uses the same crude oil types as the International Energy Module. It explicitly models the requirements of CAAA90 and the costs of automotive fuels, such as oxygenated and reformulated gasoline, and includes oxygenate production and blending for reformulated gasoline. *AEO2002* reflects legislation that bans or limits the use of the gasoline blending component methyl tertiary butyl ether (MTBE) in the next several years in Arizona, California, Colorado, Connecticut, Iowa, Illinois, Kansas, Michigan, Minnesota, Nebraska, New York, South Dakota, and Washington. Because the *AEO2002* reference case assumes current laws and regulations, it assumes that the Federal oxygen requirement for reformulated gasoline in Federal nonattainment areas will remain intact. The "Tier 2" regulation that requires the nationwide phase-in of gasoline with a much reduced, 30 parts per million (ppm) annual average, sulfur content between 2004 and 2007 is also explicitly modeled. The new "Ultra-Low Sulfur Diesel" regulation finalized in December 2000 is also explicitly modeled. The diesel regulation requires 80 percent of the highway diesel produced between June 1, 2006, and May 31, 2010, meet a maximum sulfur content of 15 ppm and that all highway diesels meet this limit after June 1, 2010. Costs include capacity expansion for refinery-processing units based on a 10-percent hurdle rate and a 10-percent after-tax return on investment. End-use prices are based on the marginal costs of production, plus markups representing product and distribution costs, State and Federal taxes, and environmental site costs. *AEO2002* assumes that refining capacity expansion may occur on the east and west coasts, as well as the Gulf Coast.

Coal Market Module

The Coal Market Module represents mining, transportation, and pricing of coal, subject to the end-use demand for coal differentiated by physical characteristics, such as the heat and sulfur content. The coal supply curves include a response to fuel costs, labor productivity, and factor input costs. Twelve coal types are represented, differentiated by coal rank, sulfur content, and mining process. Production and distribution are computed for eleven supply and thirteen demand regions, using imputed coal transportation costs and trends in factor input costs. The Coal Market Module also forecasts the requirements for U.S. coal exports and imports. The international coal market component of the module computes trade in three types of coal for twenty import and sixteen export regions. Both the domestic and international coal markets are represented in a linear program.

Cases for the *Annual Energy Outlook 2002*

The *AEO2002* presents five cases which differ from each other due to fundamental assumptions concerning the domestic economy and world oil market conditions. Three alternative assumptions are specified for each of these two factors, with the reference case using the midlevel assumption for each.

- **Economic Growth** - In the reference case, productivity grows at an average annual rate of 2.2 percent from 2000 through 2020 and the labor force at 0.8 percent per year, yielding a growth in real GDP of 3.0 percent per year. In the high economic growth case, productivity and the labor force grow at 2.4 and 1.0 percent per year, respectively, resulting in GDP growth of 3.4 percent annually. The average annual growth in productivity, the labor force, and GDP is 1.9, 0.6 and 2.4 percent, respectively, in the low economic growth case.

- **World Oil Markets** - In the reference case, the average world oil price increases to $24.68 per barrel (in real 2000 dollars) in 2020. Reflecting uncertainty in world markets, the price in 2020 reaches $17.64 per barrel in the low oil price case and $30.58 per barrel in the high oil price case.

In addition to these five cases, additional cases presented in Table 1 explore the impacts of changing key assumptions in 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 assumed 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 slightly 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. If the end-use demand modules were executed in a full run, the demand for electricity would be reduced slightly as a result of the higher prices and resulting lower economic growth, thus moderating somewhat the input assumptions. The results of these 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 on September 1, 2001, including the additional fuels taxes in the Omnibus Budget Reconciliation Act of 1993, the CAAA90, the Energy Policy Act of 1992, the Outer Continental Shelf Deep Water Royalty Relief Act of 1995, the Tax Payer Relief Act of 1997, the Federal Highway Bill of 1998, new standards for gasoline and diesel fuel and heavy-duty vehicle emissions, and the new equipment standards announced in 2001. Pending legislation and sections of existing legislation for which funds have not been appropriated are not reflected in these forecasts.

Table 1. Summary of *AEO2002* Cases

Case name	Description	Integration mode
Reference	Baseline economic growth,world oil price,and technology assumptions	Fully integrated
Low Economic Growth	Gross domestic product grows at an average annual rate of 2.4 percent,compared to the reference case growth of 3.0 percent	Fully integrated
High Economic Growth	Gross domestic product grows at an average annual rate of 3.4 percent,compared to the reference case growth of 3.0 percent	Fully integrated
Low World Oil Price	World oil prices are $17.64 per barrel in 2020,compared to $24.68 per barrel in the reference case	Fully integrated
High World Oil Price	World oil prices are $30.58 per barrel in 2020,compared to $24.68 per barrel in the reference case	Fully integrated
Residential: 2002 Technology	Future equipment purchases based on equipment available in 2002.Existing building shell efficiencies fixed at 2002 levels	With commercial
Residential: High Technology	Earlier availability,lower costs,and higher efficiencies assumed for more advanced equipment.Heating shell efficiency increases by 8 percent from 1997 values by 2020.	With commercial
Residential: Best Available Technology	Future equipment purchases and new building shells based on most efficient technologies available.Heating shell efficiency increases by 16 percent from 1997 values by 2020.	With commercial
Commercial: 2002 Technology	Future equipment purchases based on equipment available in 2002.Building shell efficiencies fixed at 2002 levels.	With residential
Commercial: High Technology	Earlier availability,lower costs,and higher efficiencies assumed for more advanced equipment.Building shell efficiencies increase 50 percent faster than in the reference case.	With residential
Commercial: Best Available Technology	Future equipment purchases based on most efficient technologies available.Building shell efficiencies increase 50 percent faster than in the reference case.	With residential
Industrial: 2002 Technology	Efficiency of plant and equipment fixed at 2002 levels.	Standalone
Industrial: High Technology	Earlier availability,lower costs,and higher efficiencies assumed for more advanced equipment.	Standalone
Transportation: 2002 Technology	Efficiencies for new equipment in all modes of travel are fixed at 2002 levels	Standalone
Transportation: High Technology	Reduced costs and improved efficiencies are assumed for advanced technologies.	Standalone
Consumption: 2002 Technology	Combination of the residential,commercial,industrial, and transportation 2002 technology cases and electricity low fossil technology case.	Fully integrated
Consumption: High Technology	Combination of the residential,commercial,industrial, and transportation high technology cases,electricity high fossil technology case,and high renewables case.	Fully integrated
Electricity: Low Nuclear	Relative to the reference case,greater increases in operating costs are assumed to be required after 40 years of operation.	Partially integrated
Electricity: High Nuclear	No increases in operating costs due to plant aging.	Partially integrated
Electricity: Advanced Nuclear Cost	New nuclear capacity is assumed to have both lower capital costs than in the reference case and a shorter (3-year)construction lead time	Partially integrated

Table 1. Summary of *AEO2002* Cases (Continued)

Cases	Description	Integration Mode
Electricity: High Demand	Electricity demand increases at an annual rate of 2.5 percent, compared to 1.8 percent in the reference case.	Partially integrated
Electricity: Low Fossil Technology	New advanced fossil generating technologies are assumed not to improve over time from 2002.	Partially integrated
Electricity: High Fossil Technology	Costs and/or efficiencies for advanced fossil-fired generating technologies improve from reference case values.	Partially integrated
Renewables: High Renewables	Lower costs and higher efficiencies for central-station renewable generating technologies and for distributed photovoltaics,approximating U.S.Department of Energy goals for 2020.Includes greater improvements in residential and commercial photovoltaic systems,more rapid improvement in recovery of industrial biomass byproducts,and more rapid improvement in cellulosic ethanol production technology.	Fully integrated
Renewables: Production Tax Credit Extension	Production tax credit for wind and closed-loop biomass power plants assumed to be extended through 2006,with coverage expanded to open-loop biomass and landfill gas power plants.	Partially integrated
Oil and Gas:Slow Technology	Cost,finding rate,and success rate parameters adjusted for slower improvement.	Fully integrated
Oil and Gas: Rapid Technology	Cost,finding rate,and success rate parameters adjusted for more rapid improvement.	Fully integrated
Oil and Gas: Federal MTBE Ban	MTBE and other ethers blended with gasoline are banned from all gasoline starting in 2006.The Federal requirement for 2.0 percent oxygen in reformulated gasoline is not changed	Partially integrated
Coal: Low Mining Cost	Productivity increases at an annual rate of 3.7 percent, compared to the reference case growth of 2.2 percent. Real wages and real mine equipment costs decrease by 0.5 percent annually,compared to constant real wages and equipment costs in the reference case.	Partially integrated
Coal: High Mining Cost	Productivity increases at an annual rate of 0.6 percent, compared to the reference case growth of 2.2 percent. Real wages and real mine equipment costs increase by 0.5 percent annually,compared to constant real wages and equipment costs in the reference case.	Partially integrated

Emissions

Carbon dioxide emissions from energy use are dependent on the carbon dioxide content of the fuel and the fraction of the fuel consumed in combustion. The product of the carbon dioxide content at full combustion and the combustion fraction yields an adjusted carbon dioxide emission factor for each 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 energy consumption 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 renewable sources is considered balanced by the carbon dioxide sequestration that occurred in its creation. Therefore, following convention, net emissions of carbon dioxide from renewable sources are taken as zero, and no emission coefficient is reported. Renewable fuels include hydroelectric power, biomass, photovoltaic, geothermal, ethanol, and wind energy.

Table 2 presents the carbon dioxide coefficients at full combustion, the combustion fractions, and the adjusted carbon dioxide emission factors used for *AEO2002*.

Table 2. Carbon Dioxide Emission Factors
(Kilograms-carbon equivalent per million Btu)

Fuel Type	Carbon Dioxide Coefficient at Full Combustion	Combustion Fraction	Adjusted Emissions Factor
Petroleum			
Motor Gasoline	19.34	0.990	19.15
Liquefied Petroleum Gas			
Used as Fuel	17.18	0.995	17.09
Used as Feedstock	16.87	0.200	3.37
Jet Fuel	19.33	0.990	19.14
Distillate Fuel	19.95	0.990	19.75
Residual Fuel	21.49	0.990	21.28
Asphalt and Road Oil	20.62	0.000	0.00
Lubricants	20.24	0.600	12.14
Petrochemical Feedstocks	19.37	0.200	3.87
Kerosene	19.72	0.990	19.52
Petroleum Coke	27.85	0.500	13.93
Petroleum Still Gas	17.51	0.995	17.42
Other Industrial	20.31	0.990	20.11
Coal			
Residential and Commercial	26.00	0.990	25.74
Metallurgical	25.56	0.990	25.30
Industrial Other	25.63	0.990	25.38
Electric Utility[1]	25.76	0.990	25.50
Natural Gas			
Used as Fuel	14.47	0.995	14.40
Used as Feedstocks	14.47	0.774	11.20

[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 2000 average is 25.50.

Source: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2000*, DOE/EIA-0573(2000), (Washington, DC, November 2001).

Methane emissions from energy-related activities are now estimated in NEMS. Methane emissions occur in various phases of the production and transportation of coal, oil, and natural gas. Additional emissions occur as a result of incomplete combustion of fossil fuels and wood. The methane emissions from each category are calculated as a function of energy production or consumption variables projected in NEMS. The emission factors and coefficients for these calculations are displayed in Tables 3, 4, and 5.

Table 3. Coal-Related Methane Assumptions

		Northern Appalachia	Central Appalachia	Southern Appalachia	Eastern Interior	Western
Fraction of underground coal production at:						
Gassy mines		0.885	0.368	0.971	0.876	0.681
Nongassy mines		0.115	0.632	0.029	0.124	0.319
Production from mines with degasification systems (fraction of underground production)		0.541	0.074	0.810	0.067	0.056
Emission factors (kilograms methane per short ton of coal produced)						
Underground Mining						
Gassy mines		6.047	5.641	27.346	2.988	6.027
Nongassy mines		0.362	0.076	15.959	0.285	0.245
Degassified mines		4.085	37.724	22.025	0.310	0.000
Surface Mining		0.706	0.706	0.706	0.706	0.706
Post-Mining, underground-mined		1.505	1.505	1.505	1.505	1.505
Post-Mining, surface-mined		0.061	0.061	0.061	0.061	0.061
Methane recovery at active coal mines (million metric tons carbon equivalent)		United States				
	2000	4.754				
	2005	5.086				
	2010	5.442				
	2015	5.822				
	2020	6.229				

Source: Emissions factors and data sources from Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2000*, DOE/EIA-0573(2000), (Washington, DC, November 2001).

Table 4. Coefficients of Linear Equations for Natural Gas- and Oil-Related Methane Emissions

Emissions Sources	Intercept	Variable Name and Units	Coefficient	Variable Name and Units	Coefficient
Natural Gas	-38.77	Time trend (calendar year)	.02003	Dry gas production (thousand cubic feet)	.02186
Natural Gas Processing	-0.9454	Natural gas liquids production (million barrels per day)	.9350	Not applicable	
Natural Gas Transmission and Storage	2.503	Pipeline fuel use (thousand cubic feet)	1.249	Dry gas production (thousand cubic feet)	-0.06614
Natural Gas Distribution	-58.16	Time trend (calendar year)	.0297	Natural gas consumption (quadrillion Btu)	.0196
Oil production, Refining, and Transport	0.03190	Oil consumption (quadrillion Btu)	.002764	Not applicable	

Source: Derived from data used in Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2000*, DOE/EIA-0573(2000), (Washington, DC, November 2001).

Table 5. Methane Emissions Factors for Energy Combustion
(Metric tons carbon equivalent per trillion Btu)

	Residential	Commercial	Industrial	Electricity
Stationary Combustion				
Coal	3.30	57.59	13.82	3.46
Residual Fuel	0.00	9.21	16.70	4.03
Distillate Fuel	28.80	3.46	0.93	0.00
Natural Gas	5.50	6.60	7.70	0.55
Liquid Gases	6.64	6.64	7.88	0.00
Wood	5050.13	16.83	15.32	0.00
Mobile Combustion				
Passenger Cars	67.20			
Buses	39.07			
Motorcycles	1028.00			
Light-Duty Trucks	82.42			
Other Trucks	21.67			

Source: Emissions factors and data sources from Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2000*, DOE/EIA-0573(2000), (Washington, DC, November 2001).

Notes and Sources

[1] Energy Information Administration, *Annual Energy Outlook 2002* (AEO2002), DOE/EIA-0383(2002), (Washington, DC, December 2001).

[2] NEMS documentation reports are available on the EIA CD-ROM and the EIA Homepage (http://www.eia.doe.gov/bookshelf.html). For ordering information on the CD-ROM, contact STAT-USA's toll free order number: 1-800-STAT-USA or by calling (202) 482-1986.

[3] Energy Information Administration, *The National Energy Modeling System: An Overview 2000*, DOE/EIA-0581(2000), (Washington, DC, March 2000).

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(2002), (Washington, DC, January 2002).

Key Assumptions

The output of the Nation's economy, measured by GDP, is expected to increase by 3.0 percent between 2000 and 2020 in the reference case. The growth in GDP can be decomposed into two key factors: the growth rate of the labor force and the rate of productivity change associated with the labor force. As Table 6 indicates, GDP growth is slower for the first five years of the forecast period, reflecting current economic conditions and revisions in recent history. Growth in the economy recovers for the remaining of the forecast period, primarily due to continued increases in productivity growth. The growth of the labor force depends upon the forecasted population growth and the labor force participation rate. The Census Bureau's middle series population projection is used as a basis for the *AEO2002*. Total population is expected to grow annually by 0.8 percent between 2000 and 2020, with a higher rate of growth pre-2000 and a slower rate of growth post-2000. Over the forecast period, the labor force participation rate is expected to peak in 2011 and then decline as "baby boom" cohorts begin to retire. Combining population projections with labor force participation rates gives an increase in labor force earlier in the forecast horizon and then post-2000, the economy experiences slower growth as demographic trends affect future economic growth.

Table 6. Growth in Gross Domestic Product, Labor Force, and Productivity
(Percent per Year)

Assumptions	2000-2005	2005-2010	2010-2015	2015-2020	2000-2020
GDP (Billion Chain-Weighted $1992)					
High Growth	3.1	3.9	3.5	3.2	3.4
Reference	2.5	3.4	3.2	2.8	3.0
Low Growth	1.9	3.0	2.6	2.2	2.4
Labor Force					
High Growth	1.4	1.3	0.8	0.7	1.0
Reference	1.2	1.0	0.6	0.5	0.8
Low Growth	0.9	0.8	0.3	0.2	0.6
Productivity					
High Growth	1.7	2.6	2.7	2.5	2.4
Reference	1.3	2.4	2.6	2.3	2.2
Low Growth	1.0	2.2	2.3	1.9	1.9

Source: Energy Information Administration, *AEO2002* National Energy Modeling System runs: aeo2002.d102000b; lm2002.d10201b; and hm2002.d102001b.

The productivity of labor is the second major reason for economic growth and reflects the positive effects of a growing capital stock of the economy as well as technological change occurring over time. A key to achieving the reference case's long-run 3.0 percent growth is an anticipated recovery in productivity growth. Productivity growth slowed in the 1970's, compared to the growth experienced post-World War II. There is no consensus about why productivity growth declined so much after 1973. However, between 1980 and 1990, business investment's share of GDP declined at the same time that both the Federal budget deficit and the trade deficit increased. Since 1991, the economic recovery has been led by strong gains in business investment as a result of lower interest rates. Productivity has shown recent strong gains as economic output has increased more rapidly than employment gains.

In the reference case, GDP growth is slow for the first five years, reflecting current economic uncertainty, but growth recovers later in the forecast period. Business fixed investment rises as a share of GDP. The resulting growth in the capital stock and the technology base of that capital stock helps to sustain productivity growth exceeding 2 percent. This growth in productivity offsets some of the decline in the labor force growth, but the economy continues to slow down over time.

To reflect the uncertainty in forecasts of economic growth, the *AEO2002* forecasts use high and low economic growth cases along with the reference case to project the possible energy markets. All three economic growth cases are based on forecasts prepared by DRI-WEFA.[4] The DRI forecasts used in *AEO2002* are the July 2001 Trend Growth scenario along with the February 1999 Optimistic and Pessimistic growth projections.

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 3.4 percent per year between 2000 and 2020. 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 2.4 percent per year over the forecast horizon.

The regional disaggregation of the economic variables uses regional shares based on a regional model solution. These shares change over time, but do not change as energy prices change from the projected reference price path.

[4] The underlying macroeconomic growth cases use DRI-WEFA July 2001 T250701 and February TO250299 and TP250299.

International Energy Module

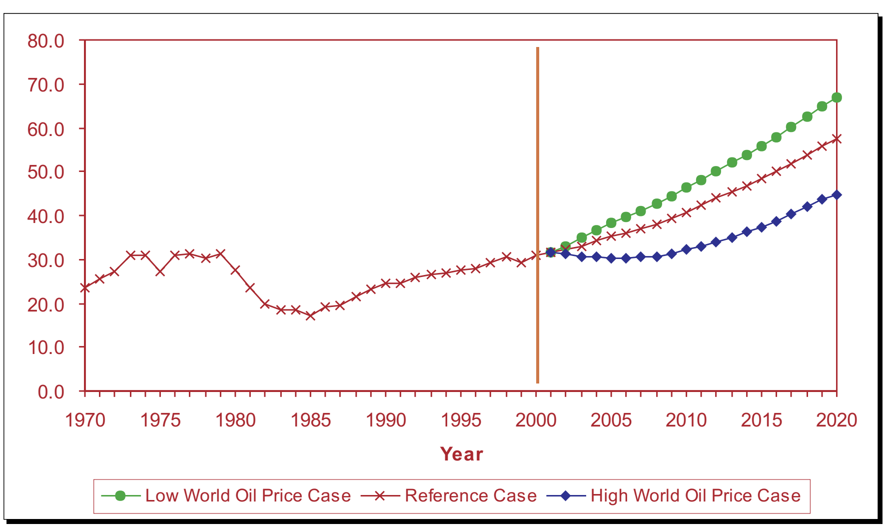
The International Energy Module determines changes in the world oil price and the supply prices of crude oils and petroleum products for import to the United States in response to changes in U.S. import requirements. A market clearing method is used to determine the price at which worldwide demand for 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(99), (Washington, DC, February 1999).

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 *AEO2002*. Non-OPEC production, worldwide regional economic growth rates and the associated regional demand for oil are additional factors affecting the world oil price.

OPEC oil production is assumed to increase throughout the forecast, making OPEC the primary source, satisfying the worldwide increase in oil consumption expected over the forecast period (Figure 2). 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 814 billion barrels, more than 79 percent of the world's estimated total, at the end of 2000.[5] For the *AEO2002* forecasts, three different OPEC production paths are the principal assumptions leading to the three world oil price path cases examined: the low oil price case, reference case, and high oil price case. The values assumed for OPEC production for the three world oil price cases are given in Figure 2. Iraq is assumed to continue selling oil only at United Nations Security Council sanction-allowed volumes until at least 2003. Once sanctions are lifted, Iraq will increase production levels to over 4 million barrels per day within 2 years. Within a decade of sanctions being lifted, 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 follow a gradually rising path—with an increase of more than 1.4 percent per year over the forecast period—as advances in both exploration and extraction technologies result in this upward trend (Figure 3). One fixed path for non-OPEC oil production is initially

Figure 2. OPEC Oil Production, 1970-2020
(Million Barrels per Day)

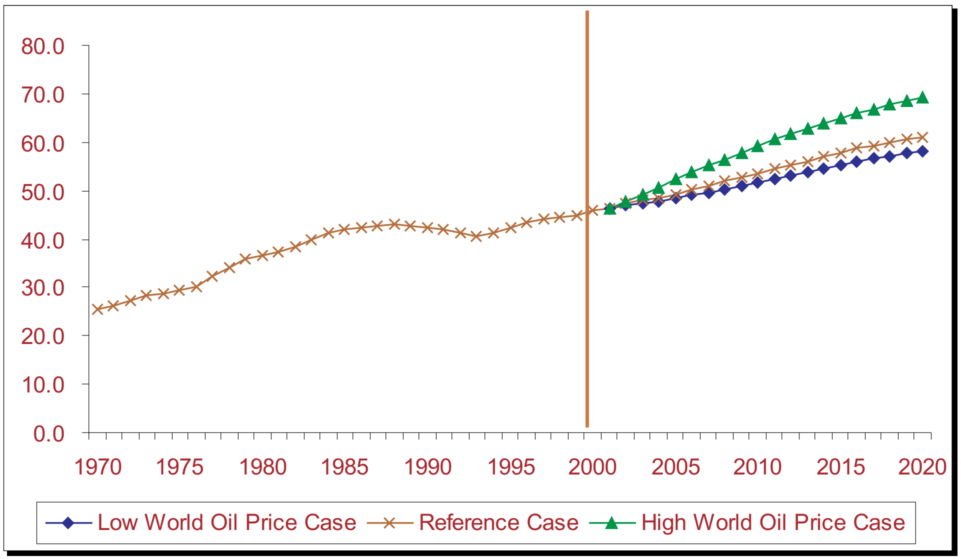


OPEC = Organization of Petroleum Exporting Countries.

Sources: Energy Information Administration. *AEO2002* National Energy Modeling System runs lw2002.d102001b, aeo2002.d102001b, and hw2002.d102001b.

input for all three world oil price case projections. Non-OPEC production depends upon world oil prices, so the final forecast solutions of the levels of non-OPEC production for the three oil price cases diverge from the initial assumptions. Production is higher in the high oil price case since more marginal wells are profitable at the higher prices. Likewise, lower world oil prices are associated with lower production levels. The final non-OPEC production paths for the three oil price cases are shown in Figure 3.

Figure 3. Non-OPEC Oil Production, 1970-2020
(Million Barrels per Day)



OPEC = Organization of Petroleum Exporting Countries.

Sources: Energy Information Administration. *AEO2002* National Energy Modeling System runs lw2002.d102001b, aeo2002.d102001b, and hw2002.d102001b.

The non-U.S. oil production forecasts in the *AEO2002* begin with country-level assumptions regarding proved oil reserves. These reserve estimates are shown in Table 7 and are compiled by PennWell Publishing Company's *Oil and Gas Journal*.

Table 7. Worldwide Oil Reserves as of January 1, 2001
(Billion Barrels)

Region	Proved Oil Reserves
Western Hemisphere	149.9
Western'Europe	17.2
Asia-Pacific	44.0
Eastern Europe and F.S.U.	59.0
Middle East	683.5
Africa	74.9
Total World	1,028.5
Total OPEC	814.4

Source: PennWell Publishing Co., International Petroleum Encyclopedia, (Tulsa, OK, 2001).

The assumed growth rates for GDP for various regions in the world are shown in Table 8. This set of growth rates for GDP was assumed for all three price cases. The GDP growth rate assumptions are from Standard & Poor's DRI third quarter 2000 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 9 for the three oil price cases by regions.

Table 8. Average Annual Regional Gross Domestic Product Growth Rates, 2000-2020
(Percent per Year)

Region	Gross Domestic Product
Organization for Economic Cooperation and Development	2.5
Other Developing Countries	4.8
Eurasia	5.9
China	7.0
Former Soviet Union	4.2
Eastern Europe	4.5
Total World	3.2

Source: Standard & Poor's DRI, World Economic Outlook, Volume 1, (Lexington, MA, Third Quarter 2000).

Table 9. Average Annual Regional Growth Rates for Oil Demand, 2000-2020
(Percent per Year)

Region	Low Price	Reference	High Price
Organization for Economic Cooperation and Development	1.5	1.1	0.9
Organization of Petroleum Exporting Countries	2.8	2.8	2.8
Other Developing Countries	4.1	3.8	3.6
Eurasia	3.8	3.6	3.4
China	4.5	4.1	3.9
Former Soviet Union	4.0	3.8	3.6
Eastern Europe	0.6	0.5	0.4
Total World	2.5	2.3	2.1

Source: Energy Information Administration, *AEO2002* National Energy Modeling System runs: lw2002.d102001b; aeo2002.d102001b; and hw2002.d102001b.

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 ten products: traditional gasoline (including aviation), reformulated gasoline, No. 2 heating oil, low-sulfur distillate oil, high- and low-sulfur residual oil, jet fuel (including naptha jet), liquefied petroleum gas, petrochemical feedstocks, and other. The curves are calculated using the World Oil Refining Logistics Demand (WORLD) Model.[6] The WORLD model uses as inputs worldwide demand for crude oil and petroleum products for world oil prices that are close to the oil prices assumed for *AEO2002*, 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.[7]

Notes and Sources

[5] PennWell Publishing Co., International Petroleum Encyclopedia, (Tulsa, OK, 2001).

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

[7] Oil & Gas Journal, *World Wide Refinery Survey*, (data as of January 1, 2001).

Household Expenditures Module

The Household Expenditures Module (HEM) constructs household energy expenditure profiles using historical survey data on household income, population and demographic characteristics, and consumption and expenditures for fuels for various end-uses. These data are combined with NEMS forecasts of household disposable income, fuel consumption, and fuel expenditures by end-use and household type. The HEM disaggregation algorithm uses these combined results to forecast household fuel consumption and expenditures by income quintile and Census Division.

Key Assumptions

The historical input data used to develop the HEM version for the *AEO2002* consists of recent household survey responses, aggregated to the desired level of detail. Two surveys performed by the Energy Information Administration are included in the *AEO2002* HEM database, and together these input data are used to develop a set of baseline household consumption profiles for the direct fuel expenditure analysis. These surveys are the 1997 Residential Energy Consumption Survey (RECS) and the 1991 Residential Transportation Energy Consumption Survey (RTECS).

HEM uses the consumption forecast by NEMS for the residential and transportation sectors as inputs to the disaggregation algorithm that results in the direct fuel expenditure analysis. Household end-use and personal transportation service consumption are obtained by HEM from the NEMS Residential and Transportation Demand Modules. Household disposable income is adjusted with forecasts of total disposable income from the NEMS Macroeconomic Activity Module.

The fundamental assumptions underlying HEM's processing of the historical and NEMS forecast data to obtain its results are:

- Individual households are assumed not to migrate between income quintiles throughout the analysis period.

- All households within a household segment are assumed to consume the average quantity of fuel for that segment. Distributions about, or deviations from, the average are not explicitly modeled.

- The change in average household consumption between forecast year y and survey base year y_0 is captured from the NEMS run at the finest available level of detail, and the same proportional change is assumed to occur in each HEM subsegment of the analysis.

Application of the HEM algorithm produces a direct household fuel expenditure forecast at the finest level of disaggregation; namely, by fuel, end-use service, housing type and vintage, ethnicity, disposable income quintile, Census Division, and year. Results obtained are summed across end-uses to yield total direct fuel expenditures as a function of disposable income for each household segment. The consolidation of these high-resolution results into national average household expenditure results requires a weighted averaging in order to obtain the desired aggregations. The weighing scheme used requires the proportions of households of each type and vintage headed by householders of each ethnicity and income quintile. The survey data provides these historical subsegment proportions, and for the *AEO2002* they are assumed to remain constant throughout the forecast period.

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. The Residential Demand Module also requires projections of available equipment over the forecast 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 2020, 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 not achieve significant penetration by 2020. Currently available technologies will evolve in both efficiency and cost. In general, for the same real cost, future technologies will be less expensive than those available today. 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.[8]

Key Assumptions

Housing Stock Submodule

A very important determinant of future energy consumption is the projected number of households. Base year estimates for 1997 are derived from the Energy Information Administration's (EIA) *Residential Energy Consumption Survey* (RECS) (Table 10). 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; 99.6 percent for single-family units, 99.3 percent for multifamily units, and 96.5 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 10. 1997 Households

Region	Single-family Units	Multi-family Units	Mobile Home Units	Total Units
New England	3,759,905	1,434,960	114,801	5,309,666
Mid Atlantic	9,990,266	4,063,826	370,168	14,424,260
East North Central	12,541,488	3,616,338	748,928	16,906,754
West North Central	5,905,676	893,549	353,749	7,152,974
South Atlantic	13,638,587	3,566,115	1,488,834	18,693,536
East South Central	4,785,180	769,795	788,963	6,343,938
West South Central	8,231,512	1,899,383	708,128	10,839,023
Mountain	4,476,532	1,039,756	663,026	6,179,314
Pacific	10,406,761	4,144,606	1,080,339	15,631,706
United States	73,735,907	21,428,328	6,316,936	101,481,171

Source: Energy Information Administration, *A Look at Residential Energy Consumption in 1997*, DOE/EIA-314(97), (Washington, DC, November 1999).

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 11 lists capital cost and efficiency for selected residential appliances for the years 2001 and 2005.

Table 11. Installed Cost and Efficiency Ratings of Selected Equipment

Equipment Type	Relative Performance[1]	2001 Installed Cost ($2001)[2]	Efficiency[3]	2015 Installed Cost ($2001)[2]	Efficiency[3]	Approximate Hurdle Rate
Electric Heat Pump	Minimum	$2,930	10.0	$3,500	12.0	15%
	Best	$5,600	18.0	$5,600	18.0	
Natural Gas Furnace	Minimum	$1,300	0.80	$1,300	0.80	15%
	Best	$2,700	0.97	$1,950	0.97	
Room Air Conditioner	Minimum	$540	8.7	$540	9.7	140%
	Best	$760	11.7	$760	12.0	
Central Air Conditioner	Minimum	$2,080	10.0	$2,300	12.0	25%
	Best	$3,500	18.0	$3,500	18.0	
Refrigerator (18 cubic ft)	Minimum	$600	690	$600	478	19%
	Best	$950	515	$950	400	
Electric Water Heater	Minimum	$337	0.86	$500	0.90	83%
	Best	$1,200	2.60	$1,100	2.6	
Solar Water Heater	N/A	$3,200	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 2001 dollars.

[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: Arthur D. Little, *EIA Technology Forecast Updates*, Reference Number 8675309, October 2001.

Table 12 provides the cost and performance parameters for representative distributed generation technologies. The *AEO2002* 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, parameter assumptions for the *AEO2002* 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.

Table 12. 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 ($1999 per KW of Capacity)	Service Life Years
Solar Photovoltaic	2000	2	0.14	N/A	$7.370	30
	2005	2	0.16	N/A	$6,253	30
	2010	2	0.18	N/A	$5,136	30
	2015	2	0.20	N/A	$3,814	30
Fuel Cell	2000	5	0,36	0.73	$3,674	20
	2002	5	0.378	0.73	$3,282	20
	2006	5	0.401	0.73	$2,834	20
	2010	5	0.43	0.74	$2,329	20
	2015	5	0.473	0.74	$1,713	20

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

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. For new construction, home heating fuel and technology choices are determined based on life-cycle costs assuming a 20 percent discount rate. 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 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.[9] 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 13.

Table 13. Minimum and Maximum Life Expectancies of Equipment

Equipment	Minimum Life	Maximum Life
Heat Pumps	8	16
Central Forced-Air Furnaces	18	29
Hydronic Space Heaters	20	30
Room Air Conditioners	12	19
Central Air Conditioners	8	16
Water Heaters	12	19
Cooking Stoves	16	21
Clothes Dryers	6	30
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.

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 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 1997. 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 New Construction

Information derived from RECS 1997 indicates that new construction (post-1980) is on average roughly 17 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.[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 1,663 to 1,787 square feet from 1997 through 2020.

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 other wise been. The residential module makes weather adjustments for the years 1997 through 2000. After 2000, long term weather patterns are assumed to occur. The residential module uses 30-year averages of HDD and CDD as normal weather conditions.

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. 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-1997) and existing. Existing homes are characterized by the RECS 1997 survey and are assigned a shell index value based on the mix of homes that exist in the base year (1997). 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 Model Energy Code (MEC) to homes that exceed the MEC 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 analyzed 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 25 percent of the existing (pre-1998) housing stock is affected by this policy by 2015.

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 15 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 .88 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 483 kilowatt-hours per year in 2002.

Residential Technology Cases

In addition to the *AEO2002* reference case, three side cases were developed to examine the effect of equipment and building standards on residential energy use—a *2002 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. *AEO2002* also analyzed an integrated *high technology case* (*consumption high technology*), which combines the *high technology cases* of the four end-use demand sectors, *electricity high fossil technology case* and *the high renewables case*.

The 2002 technology case assumes that all future equipment purchases are made based only on equipment available in 2002. This case further assumes that building shell efficiencies will not improve beyond 2002 levels. In the reference case, the 2020 housing stock shell efficiency is 4 percent higher than in 1997 for heating (2 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.[11] In the *high technology case*, heating shell efficiency increases by 8 percent and cooling shell efficiency by 4 percent, relative to 1997.

The *best available technology case* assumes that all equipment purchases from 2002 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. It is merely designed to show how much the choice of the highest-efficiency equipment could affect energy consumption. In this case, heating shell efficiency increases by 16 percent and cooling shell efficiency by 6 percent, relative to 1997.

Notes and Sources

[8] 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(2002), (December 2001).

[9] 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.

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

[11] The high technology assumptions are based on Energy Information Administration, *Technology Forecast Updates-Residential and Commercial Building technologies-Advanced Adoption Case* (Arthur D. Little, Inc., October 2001).

Commercial Demand Module

The NEMS Commercial Sector Demand Module generates forecasts of commercial sector energy demand through 2020. 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.[12]

The commercial module forecasts consumption by fuel[13] at the Census division level using prices from the NEMS energy supply modules, 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[14] for eleven building categories[15] in each of the nine Census divisions. 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. Technologies are then chosen to meet the projected service demands for the seven major end uses.[16] Once technologies are chosen, the energy consumed by the equipment stock (both previously existing and purchased equipment) chosen to meet the projected end-use service demands is developed.[17]

Key Assumptions

The key assumptions made by the commercial module are presented in terms of the flow of the calculations described above. Each section below will summarize the assumptions in each of the commercial module submodules: floorspace, service demand, technology choice, and end-use consumption. The four 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 certain 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 Macroeconomic Activity Module's floorspace projection.[18]

Existing Floorspace and Attrition

Existing floorspace is based on the estimated floorspace reported in the *Commercial Buildings Energy Consumption Survey 1995* (Table 14). Over time, the 1995 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* are 59 years and 5.4, respectively.[19]

New Construction Additions to Floorspace

The commercial module develops estimates of projected commercial floorspace additions by combining the surviving floorspace estimates with the DRI-WEFA total floorspace forecast from MAM. A total NEMS floorspace projection is calculated by applying DRI-WEFA assumed floorspace growth rate within each Census division and DRI-WEFA building type to the corresponding NEMS Commercial Demand Module's building types based on the CBECS building types 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.[20]

Table 14. 1995 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	290	567	11	38	70	150	211	351	820	308	324	3,140
Middle Atlantic	846	1,363	68	127	248	199	1,026	656	2,019	1,172	1,020	8,743
East North Central	1,028	1,336	43	417	250	642	869	747	1,994	1,624	705	9,655
West North Central	563	661	25	57	155	267	358	426	1,209	420	528	4,669
South Atlantic	906	932	107	173	270	729	1,099	1,045	2,103	1,543	568	9,475
East South Central	670	379	50	105	137	324	260	335	1,325	1,032	300	4,917
West South Central	797	1,004	129	164	208	261	482	563	1,436	861	533	6,438
Mountain	707	547	85	58	87	383	435	411	456	522	164	3,855
Pacific	934	951	124	213	217	663	1,016	881	1,366	999	516	7,881
United States	6,741	7,740	642	1,352	1,642	3,618	5,756	5,414	12,728	8,481	4,658	58,772

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

Source: Energy Information Administration, Commercial Buildings Energy Consumption Survey 1995 Public Use Data.

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.[21] 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.[22] 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 *AEO2002* reference case, shell improvements for new buildings are up to 24 percent more efficient than the 1995 stock of similar buildings. Over the forecast horizon, new building shells improve in efficiency by 6 percent relative to their efficiency in 1995. For existing buildings, efficiency is assumed to increase by 4 percent over the 1995 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.

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 a portion of equipment in existing floorspace projected to wear out.[23] Equipment is also potentially purchased for retrofitting equipment which 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:

- **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 15 illustrates the proportions of floorspace subject to the different behavior rules for space heating technology choices in large office buildings.

Table 15. 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(2002) (December 2001).

Time Preferences

The time preferences of owners of commercial buildings are assumed to be distributed among seven alternate time preference premiums (Table 16). Adding the time preference premiums to the 10-year Treasury Bill rate 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 *AEO2002* 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 16. 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(2002) (December 2001).

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 (1995), 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 *AEO2002* 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 16 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 17 provides a sample of the technology data for space heating in the New England Census division.

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 *AEO2002* reference case fuel prices, the option was not exercised for the *AEO2002* 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 Cogeneration 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

Table 17. 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	$23.46	$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.

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

[3]Capital and maintenance costs are given in 2001 dollars.

Source: Energy Information Administration, "Technology Forecast Updates - Residential and Commercial Building Technologies - Reference Case", Arthur D. Little, Inc., Reference Number 8675309, October 2001.

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 1995. 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 1995, 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 makes weather adjustments for the years 1996 through 2001. After 2001, long term weather patterns are assumed based on 30-year averages of HDD and CDD.

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.

Distributed Generation and Cogeneration

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 news releases and the Utility PhotoVoltaic Group web site. Historical data from Form EIA-860B, *Annual Electric Generator Report - Nonutility*, are used to derive electricity cogeneration for 1996 by Census division, building type and fuel. After 1996, a forecast of distributed generation and cogeneration of electricity is developed based on the economic returns projected for distributed generation and cogeneration 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 cogeneration technologies are a function of the estimated number of years required to achieve a positive cash flow. Table 18 provides the cost and performance parameters for representative distributed generation technologies.

The model also incorporates endogenous "learning" for new distributed generation technologies, allowing for declining technology costs as shipments increase. For fuel cell and photovoltaic systems, parameter assumptions for the *AEO2002* 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 7 percent reduction in capital costs.

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 coefficient of performance of 1.64, furnaces and boilers—minimum annual fuel utilization efficiency of 0.8, fluorescent lighting—minimum efficacy of 75 lumens per watt, incandescent lighting—minimum efficacy of 16.9 lumens per watt, air conditioners—minimum seasonal energy efficiency ratio of 10.5, electric water heaters—minimum energy factor of 0.85, and gas and oil water heaters—minimum energy factor 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 16. Also, the shell efficiency of new and existing buildings is assumed to increase from 1995 through 2020. Shells for new buildings increase in efficiency by 6 percent over this period, while shells for existing buildings increase in efficiency by 4 percent.

Commercial Technology Cases and High Renewables Case

In addition to the *AEO2002* reference case, three side cases were developed to examine the effect of equipment and building standards on commercial energy use—a 2002 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) commercial model runs and thus do not include supply-responses to the altered commercial consumption patterns of the three cases. *AEO2002* 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* and the *high renewables case*.

The *2002 technology case* assumes that all future equipment purchases are made based only on equipment available in 2002. This case further assumes building shell efficiency to be fixed at 2002 levels. In the reference case, existing building shells are allowed to increase in efficiency by 4 percent over 1995 levels, and new building shells improve by 6 percent by 2020 relative to new buildings in 1995.

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 50 percent faster than in the *reference case* after 2002. Existing building shells, therefore, increase by 5.6 percent relative to 1995 levels and new building shells by 7.9 percent relative to their efficiency in 1995 by 2020.

Table 18. Capital Cost and Performance Parameters of Selected Commercial Distributed Generation Technologies

Technology Type	Year of Introduction	Average Generating Capacity (kW)	Electrical Efficiency	Combined Efficiency (Elec.+Thermal)	Installed Capital Cost ($1999 per kW of Capacity)	Service Life (Years)
Solar Photovoltaic	2000	10	0.14	N/A	$7,870	30
	2005	10	0.16	N/A	$5,700	30
	2010	10	0.18	N/A	$5,529	30
	2015	10	0.20	N/A	$4,158	30
	2020	10	0.22	N/A	$3,178	30
Fuel Cell	2000	200	0.36	0.73	$3,674	20
	2002	200	0.38	0.73	$3,282	20
	2006	200	0.40	0.73	$2,834	20
	2010	200	0.43	0.74	$2,329	20
	2015	200	0.47	0.74	$1,713	20
	2020	200	0.50	0.74	$1,433	20
Natural Gas Engine	2000	200	0.28	0.75	$1,390	20
	2002	200	0.29	0.76	$1,320	20
	2006	200	0.29	0.77	$1,240	20
	2010	200	0.30	0.78	$1,150	20
	2015	200	0.30	0.79	$1,040	20
	2020	200	0.31	0.80	$ 990	20
Oil-Fired Engine	2000	200	0.31	0.83	$1,390	20
	2002	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
Natural Gas Turbine	2000	1000	0.22	0.72	$1,600	20
	2002	1000	0.23	0.72	$1,555	20
	2006	1000	0.24	0.72	$1,503	20
	2010	1000	0.25	0.73	$1,444	20
	2015	1000	0.27	0.73	$1,373	20
	2020	1000	0.28	0.73	$1,340	20
Natural Gas Micro Turbine	2000	100	0.26	0.59	$1,970	20
	2002	100	0.27	0.60	$1,785	20
	2006	100	0.29	0.61	$1,574	20
	2010	100	0.31	0.62	$1,337	20
	2015	100	0.34	0.64	$1.047	20
	2020	100	0.36	0.65	$ 915	20

Sources: US Department of Energy, Office of Energy Efficiency and Renewable Energy, and Electric Power Research Institute, Renewable Energy Technology Characterizations, EPRI-TR-109496, (Washington DC, December 1997), and ONSITE SYCOM Energy Corporation, *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector*, (Washington, DC, January 200).

The *best available technology case* assumes that all equipment purchases after 2002 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 merely designed to show how much the choice of the highest-efficiency equipment could affect energy consumption.   Shell effects in this case are assumed to be the same as for the *high technology case* above.

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.

The high renewables case assumes greater improvements in residential and commercial photovoltaic systems than in the reference case. The high renewables assumptions result in capital cost estimates for 2020 that approximate DOE's Office of Energy Efficiency and Renewable Energy technology characterizations for distributed photovoltaic technologies[24], about 30 percent lower than reference case cost estimates for commercial photovoltaic systems in 2020. The assumptions were used in the integrated high renewables case which focuses on electricity generation.

Notes and Sources

[12] Energy Information Administration, *A Look at Commercial Buildings in 1995: Characteristics, Energy Consumption, and Energy Expenditures*, DOE/EIA-0625(95), (Washington, DC, October 1998).

[13] 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. 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.

[14] 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.

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

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

[17] 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(2002), (December 2001).

[18] The floorspace from the Macroeconomic Activity Model is based on the DRI-WEFA floorspace estimates which are approximately 15 percent lower than the estimate obtained from the CBECS used for the Commercial module. The DRI-WEFA estimate is developed using the F.W. Dodge data on commercial floorspace. See F.W. Dodge, Building Stock Database Methodology and 1991 Results, Construction Statistics and Forecasts, F.W. Dodge, McGraw-Hill.

[19] The commercial module performs attrition for 9 vintages of floorspace developed from the CBECS 1995 stock estimate and historical floorspace additions data from F.W. Dodge data.

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

[21] “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 cogeneration is also included in the “other” category.

Notes and Sources

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

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

[24] For current DOE technology characterizations for photovoltaic systems see web site www.eren.doe.gov/pv/pvmenu.cgi?site=pv&idx=2&body=newsinfo.html

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 distinction between the two sets of manufacturing industries pertains to the level of modeling. 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 19). The Industrial Demand Module forecasts energy consumption at the four Census region levels; energy consumption at the Census Division level is allocated by using the SEDS[25] data.

Table 19. Industry Categories

Energy-Intensive Manufacturing		Nonenergy-Intensive Manufacturing		Nonmanufacturing Industries	
Food and Kindred Products	(NAICS 311)	Metals-Based Durables	(NAICS 332-336)	Agricultural Production -Crops	(NAICS 111)
Paper and Allied Products	(NAICS 322)	Other Manufacturing	(all remaining manufacturing NAICS)	Other Agriculture Including Livestock	(NAICS112-115)
Bulk Chemicals	(NAICS 32B)			Coal Mining	(NAICS 2121)
Glass and Glass Products	(NAICS 3272)			Oil and Gas Mining	(NAICS 211)
Hydraulic Cement	(NAICS 32731)			Metal and Other Nonmetallic Mining	(NAICS 2122-2123)
Blast Furnaces and Basic Steel	(NAICS 331111)			Construction	(NAICS 233-235)
Aluminum	(NAICS 3313)				

NAICS = North American Industry Classification System.

32B = Includes the following NAICS codes: 325110, 325120, 325181, 325188, 325192, 325199, 325211, 325212, 325222, 325311, 325312.

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 oil and gas lease and plant fuel and fuels consumed in cogeneration (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.[26] The UEC represents 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 output.

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 improvements 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 Process/Assembly (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 UEC is adjusted based on the technology possibility curves for each step. For example, state-of-the-art additions to waste fiber pulping capacity are assumed to require only 93 percent as much energy as does the average existing plant (Table 20). 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[27] 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 nonelectricity energy. (Non-electric energy group excludes boiler fuel and feedstocks.) The second stage determines the fossil fuel shares of nonelectricity 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 2000 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 20. Coefficients for Technology Possibility Curve

Industry/ Process Unit	Old Facilities		New Facilities		
	REI 2020	TPC	REI 1998	REI 2020	TPC
Food & Kindred Products					
Process Heating	0.918	-0.0039	0.900	0.818	-0.0044
Process Cooling	0.897	-0.0049	0.850	0.768	-0.0046
Machine Drive	0.918	-0.0039	0.960	0.861	-0.0049
Other	0.929	-0.0033	0.915	0.828	-0.0045
Paper & Allied Products					
Wood Preparation	0.937	-0.0030	0.873	0.851	-0.0012
Waste Pulping	0.952	-0.0022	0.936	0.893	-0.0022
Mechanical Pulping	0.932	-0.0032	0.868	0.840	-0.0015
Semi-chemical	0.896	-0.0050	0.876	0.770	-0.0059
Kraft, Sulfite, misc. Chemicals	0.847	-0.0075	0.876	0.670	-0.0121
Bleaching	0.894	-0.0051	0.900	0.769	-0.0071
Paper Making	0.831	-0.0084	0.900	0.640	-0.0154
Bulk Chemicals					
Process Heating	0.918	-0.0039	0.900	0.818	-0.0044
Process Cooling	0.897	-0.0049	0.850	0.768	-0.0046
Machine Drive	0.918	-0.0039	0.960	0.861	-0.0049
Electro-Chemical	0.984	-0.0008	0.950	0.868	-0.0041
Other	0.929	-0.0033	0.915	0.828	-0.0045
Glass & Glass Products					
Batch Preparation	0.952	-0.0023	0.882	0.882	0.0000
Melting/Refining	0.758	-0.0125	0.900	0.485	-0.0277
Forming	0.921	-0.0037	0.982	0.838	-0.0072
Post-Forming	0.938	-0.0029	0.968	0.870	-0.0048
Hydraulic Cement					
Dry Process	0.868	-0.0064	0.889	0.716	-0.0098
Wet Process	0.947	-0.0025	NA	NA	NA
Finish Grinding	0.865	-0.0066	0.950	0.718	-0.0127
Blast Furnaces & Basic Steel					
Coke Oven	0.930	-0.0033	0.874	0.838	-0.0019
BF/BOF	0.992	-0.0004	1.000	0.984	-0.0008
EAF	0.996	-0.0002	0.990	0.990	0.0000
Ingot Casting/Primary Rolling	1.000	0.0000	NA	NA	NA
Continuous Casting	1.000	0.0000	1.000	1.000	0.0000
Hot Rolling	0.785	-0.0110	0.750	0.527	-0.0160
Cold Rolling	0.781	-0.0112	0.924	0.537	-0.0244
Aluminum					
Alumina Refining	0.943	-0.0027	0.900	0.868	-0.0016
Primary Smelting	0.925	-0.0035	0.950	0.840	-0.0056
Secondary	0.817	-0.0091	0.750	0.593	-0.0107
Semi-Fabrication, Sheet	0.787	-0.0108	0.900	0.549	-0.0222
Semi-Fabrication, Other	0.897	-0.0050	0.950	0.783	-0.0088
Metal Based Durables					
Process Heating	0.918	-0.0039	0.900	0.818	-0.0044
Process Cooling	0.997	-0.0049	0.850	0.768	-0.0046
Machine Drive	0.918	-0.0039	0.960	0.861	-0.0049
Electro-Chemical	0.984	-0.0008	0.950	0.868	-0.0041
Other	0.929	-0.0033	0.915	0.828	-0.0045

Table 20. Coefficients for Technology Possiblity Curves (Continued)

Industry/ Process Unit	Old Facilities		New Facilities		
	REI 2020	TPC	REI 1998	REI 2020	TPC
Other Non-Intensive Manufacturing					
Process Heating	0.918	-0.0039	0.900	0.818	-0.0044
Process Cooling	0.897	-0.0049	0.850	0.768	-0.0046
Machine Drive	0.918	-0.0039	0.960	0.861	-0.0049
Electro-Chemical	0.984	-0.0008	0.950	0.868	-0.0041
Other	0.929	-0.0033	0.915	0.828	-0.0045
Non-Manufacturing	0.978	-0.0010	0.900	0.861	-0.0020

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

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

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

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

REI 2020 Existing Facilities = Ratio of 2020 energy intensity to average 1998 energy intensity for existing facilities.

REI 2020 New Facilities = Ratio of 2020 energy intensity for a new state-of-the-art facility to the average 1998 intensity for existing facilities.

TPC = annual rate of change between 1998 and 2020.

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(2002) (Washington, DC, December 2001).

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, air conditioning, space heating 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 21). Energy consumption in the BLD Component for an industry is estimated based on regional employment and output growth for that industry.

Boiler/Steam/Cogeneration 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 22) 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-cogeneration 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-cogeneration 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 relative prices that prevailed in 1998.

The byproduct fuels are consumed before the quantity of purchased fuels is estimated. The boiler fuel shares are based on the 1998 MECS.[28]

Table 21. Building Component Energy Consumption (Trillion Btu)

		Building Use and Energy Source					
Industry	Region	Lighting Electricity Consump-ton	HVAC Electricity Consump-ton	HVAC Natural Gas Consump-tion	HVAC Steam Consump-tion	Facility Support Total Consump-tion	Onsite Transportation Total Consump-tion
Food & Kindred 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
Hydraulic 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
Blast Furnaces & 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
Other Non-Intensive 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

UEC = Unit Energy Consumption.

HVAC = Heating, Ventilation, Air Conditioning.

Source: Energy Information Administration, *Model Documentation Report: Industrial Demand Module of the National Energy Modeling System*, DOE/EIA-M064(2002), (Washington, DC, December 2001).

Table 22. Logit Function Parameters for Estimating Boiler Fuel Shares

Industry	Region	Alpha	Natural Gas	Steam Coal	Oil
Food & Kindred Products	1	-0.25	0.84	0.04	0.12
	2	-0.25	0.63	0.36	0.01
	3	-0.25	0.80	0.10	0.10
	4	-0.25	0.77	0.17	0.06
Paper & Allied Products	1	-0.25	0.30	0.18	0.53
	2	-0.25	0.50	0.47	0.03
	3	-0.25	0.52	0.35	0.13
	4	-0.25	0.87	0.09	0.04
Bulk Chemicals	1	-0.25	0.61	0.01	0.38
	2	-0.25	0.55	0.22	0.23
	3	-0.25	0.63	0.09	0.26
	4	-0.25	0.44	0.51	0.05
Glass & Glass Products	1	-0.25	0.99	0.00	0.01
	2	-0.25	0.99	0.00	0.01
	3	-0.25	0.99	0.00	0.01
	4	-0.25	0.99	0.00	0.01
Hydraulic Cement	1	-0.25	0.05	0.95	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
Blast Furnaces & Basic 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	0.17
	2	-0.25	0.74	0.24	0.02
	3	-0.25	0.85	0.03	0.12
	4	-0.25	0.97	0.00	0.03
Other Non-Intensive Manufacturing	1	-0.25	0.06	0.23	0.17
	2	-0.25	0.68	0.28	0.04
	3	-0.25	0.69	0.24	0.07
	4	-0.25	0.80	0.17	0.03

Alpha: User-specified.

Source: Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-064(2002), (Washington, DC, 2001).

Cogeneration

Cogeneration (the simultaneous generation of electricity and useful steam) has been a standard practice in the industrial sector for many years. The cogeneration estimates in the module are based on the assumption that the historical relationship between industrial steam demand and cogeneration will continue in the future. The data source is Form EIA-860B, "*Annual Electric Generator Report-Nonutility,*" and its predecessor forms.

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 cogeneration. The technical potential for onsite cogeneration 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 23.

Table 23. Cost Characteristics of Industrial Cogeneration Systems

System	Size (kilowatts)	Installed Cost ($1999 per kilowatt)		O&M Cost ($1999 per kilowatthour)	
		1999	2020	1999	2020
1 Engine	800	975	690	0.0107	0.009
2 Engine	3000	850	710	0.0103	0.009
3 Gas Turbine	1000	1600	1340	0.0096	0.008
4 Gas Turbine	5000	1075	950	0.0059	0.0049
5 Gas Turbine	10000	965	830	0.0055	0.0046
6 Gas Turbine	25000	770	675	0.0049	0.0043
7 Gas Turbine	40000	700	625	0.0042	0.004
8 Combined Cycle	100000	690	620	0.0036	0.003

Source: Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System,* DOE/EIA-MO64(2002) (Washington, DC, December 2001).

Technology

The amount of energy consumption reported by the industrial module is also a function of 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 in production prior to 1999 and is assumed to retire at a fixed rate each year (Table 24). Middle vintage capital is that which is added after 1998 but not including the year of the

Table 24. Retirement Rates

Industry	Retirement Rate (percent)	Industry	Retirement Rate (percent)
Food and Kindred Products.	1.7	Glass and Glass Products	1.3
Pulp and Paper.	2.3	Hydraulic Cement	1.2
Bulk Chemicals	1.7		
Blast Furnace and Basic Steel Products		Aluminum	1.0
Blast Furnace/Basic Oxygen Furnace . .	1.0	Metal-Based Durables.	1.3
Electric Arc Furnace	1.5		
Coke Ovens	1.5	Other Non-Intensive Manufacturing.	1.3
Other Steel	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(2002), (Washington, DC, December 2001).

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.

Legislation

Energy Policy Act of 1992 (EPACT)

EPACT and the Clean Air Act Amendments of 1990 (CAAA90) contain several implications for the industrial module. These implications fall into three categories: coke oven standards; efficiency standards for boilers, furnaces, and electric motors; and industrial process technologies. The industrial module assumes the leakage standards for coke oven doors do not reduce the efficiency of producing coke or increase unit energy consumption. 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. The standards for electric motors call for a 10-percent efficiency increase. The industrial module incorporates a 10-percent savings for state-of-the-art motors increasing to 20-percent savings in 2015. Given the time lag in the legislation and the expected lifetime of electric motors, no further adjustments are necessary to meet the EPACT standards for electric motors. The industrial module incorporates the necessary reductions in unit energy consumption for the energy-intensive industries.

High Technology, 2002 Technology Cases, and High Renewables

The high *technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment. (Table 25)[29] The *high technology case* also assumes that the rate at which biomass byproducts will be recovered from industrial processes increases from 0.2 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, primary energy intensity declines by 1.7 percent annually compared with the reference case, in which primary energy intensity is projected to decline 1.5 percent annually.

The *2002 technology case* holds the energy efficiency of plant and equipment constant at the 2002 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.

AEO2002 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,* 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 0.2 percent per year to 1.0 percent per year. The availability of additional biomass leads to an increase in biomass-based cogeneration.

Table 25. Coefficients for Technology Possibility Curves, High Technology Case

Industry/ Process Unit	Old Facilities		New Facilities		
	REI 2020	TPC	REI 1998	REI 2020	TPC
Food & Kindred Products					
Process Heating	0.858	-0.0069	0.900	0.672	-0.0132
Process Cooling	0.858	-0.0069	0.850	0.635	-0.0132
Machine Drive	0.858	-0.0069	0.960	0.717	-0.0132
Other	0.858	-0.0069	0.915	0.683	-0.0132
Paper & Allied Products					
Wood Preparation	0.870	-0.0063	0.873	0.804	-0.0037
Waste Pulping	0.917	-0.0039	0.936	0.831	-0.0054
Mechanical Pulping	0.903	-0.0046	0.868	0.815	-0.0028
Semi-chemical	0.846	-0.0076	0.876	0.674	-0.0119
Kraft, Sulfite, misc. Chemicals	0.760	-0.0124	0.876	0.473	-0.0276
Bleaching	0.817	-0.0092	0.900	0.597	-0.0185
Paper Making	0.737	-0.0138	0.900	0.410	-0.0351
Bulk Chemicals					
Process Heating	0.871	-0.0063	0.900	0.685	-0.0123
Process Cooling	0.871	-0.0063	0.850	0.647	-0.0123
Machine Drive	0.871	-0.0063	0.960	0.731	-0.0123
Electro-Chemical	0.871	-0.0063	0.950	0.723	-0.0123
Other	0.871	-0.0063	0.915	0.697	-0.0123
Glass & Glass Products					
Batch Preparation	0.881	-0.0057	0.882	0.684	0.0115
Melting/Refining	0.757	-0.0126	0.900	0.482	-0.0280
Forming	0.889	-0.0053	0.982	0.730	-0.0134
Post-Forming	0.837	-0.0080	0.968	0.593	-0.0220
Hydraulic Cement					
Dry Process	0.823	-0.0088	0.889	0.609	-0.0171
Wet Process	0.823	-0.0088	NA	NA	NA
Finish Grinding	0.823	-0.0088	0.950	0.679	-0.0152
Blast Furnaces & Basic Steel					
Coke Oven	0.652	-0.0192	0.874	0.557	-0.0203
BF/BOF	0.922	-0.0037	1.000	0.729	-0.0143
EAF	0.834	-0.0082	0.990	0.687	-0.0165
Ingot Casting/Primary Rolling	1.000	0.0000	NA	NA	NA
Continuous Casting	0.944	-0.0026	1.000	0.891	-0.0053
Hot Rolling	0.500	-0.0310	0.750	0.137	-0.0743
Cold Rolling	0.457	-0.0349	0.924	0.046	-0.1278
Aluminum					
Alumina Refining	0.884	-0.0056	0.900	0.868	-0.0016
Primary Smelting	0.847	-0.0075	0.950	0.636	-0.0180
Secondary	0.718	-0.0149	0.750	0.438	-0.0241
Semi-Fabrication, Sheet	0.739	-0.0137	0.900	0.420	-0.0341
Semi-Fabrication, Other	0.753	-0.0128	0.950	0.418	-0.0367
Metal Based Durables					
Process Heating	0.845	-0.0076	0.900	0.659	-0.0141
Process Cooling	0.845	-0.0076	0.850	0.622	-0.0141
Machine Drive	0.845	-0.0076	0.960	0.703	-0.0141
Electro-Chemical	0.845	-0.0076	0.950	0.695	-0.0141
Other	0.845	-0.0076	0.915	0.670	-0.0141

Table 25. Coefficients for Technology Possibility Curves, High Technology Case (Continued)

Industry/ Process Unit	Old Facilities		New Facilities		
	REI 2020	TPC	REI 1998	REI 2020	TPC
Other Non-Intensive Manufacturing					
Process Heating	0.850	-0.0073	0.900	0.661	-0.0139
Process Cooling	0.850	-0.0073	0.850	0.624	-0.0139
Machine Drive	0.850	-0.0073	0.960	0.705	-0.0139
Electro-Chemical	0.850	-0.0073	0.950	0.698	-0.0139
Other	0.850	-0.0073	0.915	0.672	-0.0139
Non-Manufacturing	0.957	-0.0020	0.900	0.824	-0.0040

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

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

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

REI 1998 New Facilities = For new facilities, the ratiio of State-of-the-art energy intensity to average 1998 energy intensity for existing facilities.

REI 2020 Existing Facilities = Ratio of 2020 energy intensity to average 1998 energy intensity for existing facilities.

REI 2020 New Facilities = Ratio of 2020 energy intensity for a new State-of-the-art facility to the average 1998 intensity for existing facilities.

TPC = annual rate of change between 1998 and 2020.

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(2002) (Washington, DC, December 2001).

Notes and Sources

[25] Energy Information Administration, *State Energy Data Report 1999, DOE/EIA-0214(99)*, (Washington, D.C., May 2001).

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

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

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

[29] 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 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, light trucks, industry sport utility vehicles and vans), commercial light trucks (8501-10,000 lbs), freight trucks (>10,000 lbs), 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 26) 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 is assumed to approach fifty percent by 2020.

Table 26. Macroeconomic Inputs to the Transportation Module
(Millions)

Macroeconomic Input	1999	2000	2005	2010	2015	2020
New Car Sales	8.7	9.0	8.3	8.2	9.5	9.7
New Light Truck Sales	7.0	7.8	7.7	8.1	8.4	8.6
Real Disposable Income (billion 1996 Chain-Weighted Dollars)	6,320	6,539	7,593	8,742	10,202	11,698
Real GDP (billion 1996 Chain-Weighted Dollars)	8,857	9,224	10,418	12,312	14,399	16,525
Driving Age Population	211.0	213.1	224.8	236.6	246.7	256.5
Total Population	273.2	275.7	288.1	300.2	312.7	325.3

Source: Energy Information Administration, *AEO2002* National Energy Modeling System run: aeo2002.d102001b.

Light-Duty Vehicle Assumptions

The light duty vehicle Fuel Economy Module includes 58 fuel saving technologies with data specific to cars and light trucks 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 (Tables 27 and 28).

The vehicle sales share module holds vehicle sales shares by import and domestic manufacturers constant within a vehicle size class at the 1999 level from the National Highway Traffic and Safety Administration data.[30]

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 Fuel Economy Module.[31]

The Fuel Economy Module utilizes 58 new texchnologies 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

Table 27. 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.)	First Year Introduced	Fractional Horsepower Change
Front Wheel Drive	0.060	160	0.00	0	-0.08	1980	0
Unit Body	0.040	80	0.00	0	-0.05	1980	0
Material Substitution II	0.033	0	0.60	0	-0.05	1987	0
Material Substitution III	0.066	0	0.80	0	-0.10	1997	0
Material Substitution IV	0.099	0	1.00	0	-0.15	2007	0
Material Substitution V	0.132	0	1.50	0	-0.20	2017	0
Drag Reduction II	0.023	32	0.00	0	0.00	1985	0
Drag Reduction III	0.046	64	0.00	0	0.05	1991	0
Drag Reduction IV	0.069	112	0.00	0	0.01	2004	0
Drag Reduction V	0.092	176	0.00	0	0.02	2014	0
TCLU	0.030	40	0.00	0	0.00	1980	0
4-Speed Automatic	0.045	225	0.00	30	0.00	1980	0.05
5-Speed Automatic	0.065	325	0.00	40	0.00	1995	0.07
CVT	0.100	250	0.00	20	0.00	1995	0.07
6-Speed Manual	0.020	100	0.00	30	0.00	1991	0.05
Electronic Transmission I	0.005	20	0.00	5	0.00	1988	0
Electronic Transmission II	0.015	40	0.00	5	0.00	1998	0
Roller Cam	0.020	16	0.00	0	0.00	1987	0
OHC 4	0.030	100	0.00	0	0.00	1980	0.20
OHC 6	0.030	140	0.00	0	0.00	1980	0.20
OHC 8	0.030	170	0.00	0	0.00	1980	0.20
4C/4V	0.080	240	0.00	30	0.00	1988	0.45
6C/4V	0.080	320	0.00	45	0.00	1991	0.45
8C/4V	0.080	400	0.00	60	0.00	1991	0.45
Cylinder Reduction	0.030	-100	0.00	-150	0.00	1988	-0.10
4C/5V	0.100	300	0.00	45	0.00	1998	0.55
Turbo	0.050	500	0.00	80	0.00	1980	0.45
Engine Friction Reduction I	0.020	20	0.00	0	0.00	1987	0
Engine Friction Reduction II	0.035	50	0.00	0	0.00	1996	0
Engine Friction Reduction III	0.050	90	0.00	0	0.00	2006	0
Engine Friction Reduction IV	0.065	140	0.00	0	0.00	2016	0
VVT I	0.030	50	0.00	40	0.00	1996	0.05
VVT II	0.080	180	0.00	40	0.00	2008	0.15
Lean Burn	0.100	150	0.00	0	0.00	2099	0
Two Stroke	0.150	150	0.00	-150	0.00	2099	0
TBI	0.020	40	0.00	0	0.00	1982	0.05
MPI	0.035	80	0.00	0	0.00	1987	0.10
Air Pump	0.010	0	0.00	-10	0.00	1982	0
DFS	0.015	15	0.00	0	0.00	1987	0.10
Oil 5W-30	0.005	2	0.00	0	0.00	1987	0
Oil Synthetic	0.015	5	0.00	0	0.00	1997	0
Tires I	0.010	16	0.00	0	0.00	1992	0
Tires II	0.020	32	0.00	0	0.00	2002	0
Tires III	0.030	48	0.00	0	0.00	2012	0
Tires IV	0.040	64	0.00	0	0.00	2018	0
ACC I	0.005	15	0.00	0	0.00	1992	0
ACC II	0.010	30	0.00	0	0.00	1997	0
EPS	0.015	40	0.00	0	0.00	2002	0
4WD Improvements	0.030	100	0.00	0	-0.05	1995	0
Air Bags	-0.010	300	0.00	35	0.00	1987	0
Emissions Tier I	-0.010	150	0.00	10	0.00	1994	0
Emissions Tier II	-0.010	300	0.00	20	0.00	2003	0
ABS	-0.005	300	0.00	10	0.00	1987	0
Side Impact	-0.005	100	0.00	20	0.00	1996	0
Roof Crush	-0.003	100	0.00	5	0.00	2001	0
Increased Size/Wt.	-0.067	0	0.00	0	0.10	2001	0
GDI/4-cyl	0.170	450	0.00	0	0.00	2006	0
GDI/6-cyl	0.170	650	0.00	0	0.00	2006	0

N/A = Non Applicable

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

Source: Energy and Environment Analysis, *Changes to the Fuel Economy Module Final Report, prepared for the Energy Information Administration (EIA),* (June 2000).

Table 28. Standard Technology Matrix For Trucks[1]

	Fractional Fuel Efficiency Change	Incremental Cost (1990 $)	Incremental Cost ($/Unit Wt.)	Incremental Weight (Lbs.)	Incremental Weight (Lbs./Unit Wt.)	First Year Introduced	Fractional Horsepower Change
Front Wheel Drive	0.020	160.00	0.00	0	-0.08	1985	0
Unit Body	0.060	80.00	0.00	0	-0.05	1995	0
Material Substitution II	0.033	0.00	0.60	0	-0.05	1996	0
Material Substitution III	0.066	0.00	0.80	0	-0.10	2006	0
Material Substitution IV	0.099	0.00	1.00	0	-0.15	2016	0
Material Substitution V	0.132	0.00	1.50	0	-0.20	2026	0
Drag Reduction II	0.023	32.00	0.00	0	0.00	1990	0
Drag Reduction III	0.046	64.00	0.00	0	0.05	1997	0
Drag Reduction IV	0.069	112.00	0.00	0	0.01	2007	0
Drag Reduction V	0.092	176.00	0.00	0	0.02	2017	0
TCLU	0.030	40.00	0.00	0	0.00	1980	0
4-Speed Automatic	0.045	225.00	0.00	30	0.00	1980	0.05
5-Speed Automatic	0.065	325.00	0.00	40	0.00	1997	0.07
CVT	0.100	250.00	0.00	20	0.00	2005	0.07
6-Speed Manual	0.020	100.00	0.00	30	0.00	1997	0.05
Electronic Transmission I	0.005	20.00	0.00	5	0.00	1991	0
Electronic Transmission II	0.015	40.00	0.00	5	0.00	2006	0
Roller Cam	0.020	16.00	0.00	0	0.00	1986	0
OHC 4	0.030	100.00	0.00	0	0.00	1980	0.15
OHC 6	0.030	140.00	0.00	0	0.00	1985	0.15
OHC 8	0.030	170.00	0.00	0	0.00	1995	0.15
4C/4V	0.060	240.00	0.00	30	0.00	1990	0.30
6C/4V	0.060	320.00	0.00	45	0.00	1990	0.30
8C/4V	0.060	400.00	0.00	60	0.00	2002	0.30
Cylinder Reduction	0.030	-100.00	0.00	-150	0.00	1990	-0.10
4C/5V	0.080	300.00	0.00	45	0.00	1997	0.55
Turbo	0.050	500.00	0.00	80	0.00	1980	0.45
Engine Friction Reduction I	0.020	20.00	0.00	0	0.00	1991	0
Engine Friction Reduction II	0.035	50.00	0.00	0	0.00	2002	0
Engine Friction Reduction III	0.050	90.00	0.00	0	0.00	2012	0
Engine Friction Reduction IV	0.065	140.00	0.00	0	0.00	2022	0
VVT I	0.030	80.00	0.00	40	0.00	2001	0.10
VVT II	0.080	230.00	0.00	40	0.00	2006	0.15
Lean Burn	0.100	150.00	0.00	0	0.00	2099	0
Two Stroke	0.150	150.00	0.00	-150	0.00	2099	0
TBI	0.020	40.00	0.00	0	0.00	1985	0.05
MPI	0.035	80.00	0.00	0	0.00	1985	0.10
Air Pump	0.010	0.00	0.00	-10	0.00	1985	0
DFS	0.015	15.00	0.00	0	0.00	1985	0.10
Oil 5W-30	0.005	2.00	0.00	0	0.00	1987	0
Oil Synthetic	0.015	5.00	0.00	0	0.00	1997	0
Tires I	0.010	16.00	0.00	0	0.00	1992	0
Tires II	0.020	32.00	0.00	0	0.00	2002	0
Tires III	0.030	48.00	0.00	0	0.00	2012	0
Tires IV	0.040	64.00	0.00	0	0.00	2018	0
ACC I	0.005	15.00	0.00	0	0.00	1997	0
ACC II	0.010	30.00	0.00	0	0.00	2007	0
EPS	0.015	40.00	0.00	0	0.00	2002	0
4WD Improvements	0.030	100.00	0.00	0	-0.05	2002	0
Air Bags	-0.010	300.00	0.00	35	0.00	1992	0
Emissions Tier I	-0.010	150.00	0.00	10	0.00	1996	0
Emissions Tier II	-0.010	300.00	0.00	20	0.00	2004	0
ABS	-0.005	300.00	0.00	10	0.00	1990	0
Side Impact	-0.005	100.00	0.00	20	0.00	1996	0
Roof Crush	-0.003	100.00	0.00	5	0.00	2001	0
Increased Size/Wt.	-0.100	0.00	0.00	0	0.15	2001	0
GDI/4-cyl	0.170	450.00	0.00	0	0.00	2005	0
GDI/6-cyl	0.170	650.00	0.00	0	0.00	2005	0

N/A = Non Applicable

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

Source: Energy and Environment Analysis, *Changes to the Fuel Economy Module*, Final Report, prepared for the Energy Information Administration (EIA), (June 2000).

The discounted stream 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 4-year payback period.
- The real discount rate remains steady at 8 percent.
- Corporate Average Fuel Efficiency standards remain constant at 1998 levels.
- Expected future fuel prices are calculated based on an extrapolation of the growth rate between fuel prices 3 years and 5 years prior to the present year. This assumption is founded upon an assumed lead time of 3 to 5 years to significantly modify the vehicles offered by a manufacturer.

Degradation factors (Table 29) 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.[32] Degradation factors are also adjusted to reflect the percentage of reformulated gasoline consumed.

Table 29. Car and Light Truck Degradation Factors

	1998	2000	2005	2010	2015	2020
Cars	0.790	0.780	0.786	0.794	0.802	0.810
Light Trucks	0.813	0.813	0.810	0.807	0.803	0.800

Source: Energy Information Administration, *Transportation Sector Model of the National Energy Modeling System, Model Documentation 2002*, DOE/EIA-M070(2002), (Washington, DC, January 2002).

The vehicle miles traveled (VMT) module forecasts VMT as a function of the cost of driving per mile, income per capita, ratio of female to male VMT, and growth in the driving population. Coefficients were re-estimated for *AEO2002.* The ratio of female to male VMT is assumed to asymptotically approach 68 percent by 2020. Total VMT is calibrated to Federal Highway Administration VMT data.[33,34] The fuel price elasticity rises from -0.04 to -0.2 as fuel prices rise above reference case levels in each year.

- The share of light truck sales (Class 1 and Class 2 trucks) is assumed to reach a maximum of 50 percent of total sales by 2020. However, the light truck share will gradually decline to 46 percent if fuel prices rise to approximately $1.55 per gallon. The size class sales shares will also gravitate to 25 percent for subcompacts, 40 percent for compacts, 25 percent for mid size, and 10 percent for luxury if fuel prices exceed reference case levels of approximately $1.55 per/gallon.

Commercial Light-Duty Fleet Assumptions

With the current focus of transportation legislation on commercial fleets and their composition, the Transportation Demand Module has been redesigned to divide commercial light-duty fleets into three types of fleets: business, government, and utility. Based on this classification, commercial light-duty fleet vehicles vary in survival rates and duration in the fleet, before being combined with the personal vehicle stock (Table 30). Sales shares of fleet vehicles by fleet type also remain constant over the forecast period. Automobile fleets are divided into the following shares: business (87.39 percent), government (7.42 percent), and utilities (5.19 percent). Light truck fleets are divided into the following shares: business (83.50 percent), government (14.1 percent), and utilities (2.40 percent)[35,36]. Both car (23.70 percent) and light truck (28.57 percent) fleet sales are assumed to be a constant fraction of total car and light truck sales.

Alternative-fuel shares of fleet sales by fleet type are initially set according to historical shares (business (0.36 percent), government (2.21 percent), utility (2.64 percent))[37,38] then compared to a minimum constraint level of sales based on legislative initiatives, such as the Energy Policy Act of 1992 and the Low Emission Vehicle Program.[39,40] Size class sales shares of vehicles are held constant at anticipated levels (Table 31).[41] Individual sales shares of alternative-fuel fleet vehicles by technology type are assumed to remain at anticipated levels for utility, government, and for business fleets in accordance with the technology shares implied from EIA surveys[42,43] (Table 32).

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

Table 30. 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 Vehicles in the United States: Composition, Operating Characteristics, and Fueling Practices*, prepared for the Department of Energy, Office of Transportation Technologies and Office of Policy, Planning, and Analysis (Oak Ridge, TN, May 1992).

Table 31. Commercial Fleet Size Class Shares by Fleet and Vehicle Type, 1992
(Percentage)

Fleet Type by Size Class	Automobiles	Light Trucks
Business Fleet		
Small	4.55	37.34
Medium	71.59	37.90
Large	23.86	24.76
Government Fleet		
Small	4.35	21.34
Medium	56.52	44.39
Large	39.13	34.27
Utility Fleet		
Small	16.67	30.03
Medium	70.00	38.51
Large	13.33	31.46

Source: Oak Ridge National Laboratory, *Fleet Vehicles in the United States: Composition, Operating Characteristics, and Fueling Practices*, unpublished final report prepared for the Department of Energy, Office of Transportation Technologies and Office of Policy, Planning, and Analysis, (Oak Ridge, TN, May 1992).

Table 32. Anticipated Purchases of Alternative-Fuel Vehicles by Fleet Type and Technology Type
(Percentage)

AFV Technology	Business	Government	Utility
Ethanol	0.02	33.14	0.0
Methanol	1.62	13.92	3.36
Electric	0.90	1.54	2.29
CNG	9.46	32.92	67.87
LPG	88.00	16.48	28.86

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.[44] The distribution of vehicles by vintage, and vehicle scrappage rates is derived from R.L. Polk company registration data.[45],[46] Vehicle travel by vintage was constructed using vintage distribution curves and estimates of average annual travel by vehicle.[47],[48]

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 currently 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).

Alternative-Fuel Vehicle Technology Choice Assumptions

The Alternative-Fuel Vehicle (AFV) technology choice module 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.[49] The technology sets include:

- Conventional fuel capable (gasoline, disel, bi-fuel and flex-fuel),
- Hybrid (gasoline and disel),
- 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)[50]

The vehicles 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.[51] 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, AFV fuel efficient technology attributes are calculated relative to conventional gasoline miles per gallon. It is assumed that many fuel efficiency improvements to conventional vehicles will be transferred to alternative-fuel vehicles. Specific individual alternative-fuel technological improvements are also dependent upon the AFV technology type, cost, research and development, and availability over time. Make and model availability estimates are assumed values according to a logistic curve based on the initial technology introduction date and are based on current offerings. Coefficients summarizing consumer valuation of vehicle attributes were derived from assumed economic valuation compared to vehicle price elasticities. Initial AFV vehicle stocks are set according to EIA surveys.[52,53] 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 size class, 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 distilate regional shares.[54] 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.[55],[56] 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.[57]

New freight truck fuel economy is dependent on the market penetration of various emission control technologies and advanced engine components.[58] 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 are 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 by 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.[59]

Initial freight truck stocks by vintage are obtained from R.L. Polk Co. and are distributed by fuel type using VIUS data.[60] Vehicle scrappage rates were also estimated using R.L. Polk Co. Data.[61]

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. Specific NEMS coal production from the Coal Market Module is also 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.[62],[63] Initial freight rail efficiencies are based on the freight model from Argonne National Laboratory.[64] The distribution of rail fuel consumption by fuel type remains constant and is based on historical data.[65] Regional freight rail consumption estimates are distributed according to the *State Energy Data Report 1999*.[66]

Freight Domestic and International Shipping Assumptions

The freight domestic shipping module also converts industrial output by SIC code measured in dollars, to a volumetric equivalent by SIC code.[67],[68] 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.[69] Regional domestic and international shipping consumption estimates are distributed according to the *State Energy Data Report* residual oil regional shares.[70]

Air Travel Demand Assumptions

The air travel demand module calculates the ticket price for travel as a function of fuel cost. Similar to the light-duty vehicle module, the air travel fuel price elasticity rises from -0.05 to -0.2 if jet fuel prices exceed reference case levels. A demographic index based on the propensity to fly was introduced into the air travel demand equation.[71] The propensity to fly was made a function of the age and gender distribution over the forecast period[72],[73] The air travel demand module assumes that these relationships between the groups and their propensity to fly remain constant over time. International revenue passenger miles are based on historical data.[74] The revenue ton miles of air freight are based on merchandise exports and gross domestic product.

Aircraft Stock/Efficiency Assumptions

The aircraft stock and efficiency module consists of a stock model of both wide and narrow body planes by vintage. The shifting of passenger load between narrow and wide body aircraft is assumed to occur at a constant historical annual 1-percent rate.[75] The available seat-miles per plane, which measure the carrying capacity of the airplanes by aircraft type, remain constant and are based on holding the seat-miles and the number of planes constant within an aircraft type.[76] The difference between the seat-miles demanded and the available seat-miles represents newly purchased aircraft. Aircraft purchases in a given year cannot exceed historical annual growth rates, a constraint that sets an upper limit on the application of new aircraft to meet the gap between seat-miles demanded and available seat-miles. With a constraint on new aircraft purchases, it is assumed that when the gap exceeds historical aircraft sales levels, planes that have been temporarily stored or retired will be 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 34)[77] Fuel efficiency of new aircraft acquisitions represents, at a minimum, a 5-percent improvement over the stock efficiency of surviving airplanes.[78] 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.

Legislation

Energy Policy Act of 1992 (EPACT)

Fleet alternative-fuel vehicle sales necessary to meet the EPACT regulations were 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 33). Business fleet EPACT mandates are not included in the projections for AFV sales pending a decision on a proposed rulemaking.

Because the commercial fleet model operates on three fleet type representations (business, government, and utility), the federal and state mandates were weighted by fleet vehicle stocks to create a composite mandate for both. The same combining methodology was used to create a composite mandate for electric utilities and fuel providers based on fleet vehicle stocks.[79],[80] Fleet vehicle stocks by car and light truck were 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.[81],[82] 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 were included and 63 percent were included for government fleets.[83] EPACT covered fleets were to only include those fleets that could be centrally fueled, which was 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 was assumed that 90 percent of all fleets were within this category except for business fleets, which were assumed to be 75 percent.[84]

Table 33. EPACT Legislative Mandates for Percentage AFV Purchases by Fleet Type, Year

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).

Low Emission Vehicle Program (LEVP)

The LEVP, which began in California, was later instituted in New York and Massachusetts, and most recently by Maine and Vermont has now been rolled back to begin in 2003 at the original 10 percent mandate for California, Massachusetts and New York. All of the ULEV sales were assumed to meet the ULEV air standards with reformulated gasoline and a heated catalytic converter.

On November 5, 1998, the California Air Resources Board (CARB) amended the original LEVP to include ZEV credits for advanced technology vehicles. According to CARB these advanced technology vehicles must be capable of achieving "extremely low levels of emissions on the order of the power plant emissions that occur from charging battery-powered electric vehicles, and some that demonstrate other ZEV-like characteristics such as inherent durability and partial zero-emission range."[85]

There are three components to calculating the ZEV credit, a baseline ZEV allowance, a zero-emission vehicle-miles traveled (VMT) allowance, and a low fuel-cycle emission allowance. Using these advanced vehicles in place of ZEV's in order to comply with the LEVP mandates requires assessment of each vehicle characteristic relative to the three criteria allowances.

The baseline ZEV allowance potentially can provide up to .2 credits if the advanced technology vehicle meets the: a) Super Ultra Low Emission Vehicle (SULEV) standards contained in the originial LEVP proposal; b) on-board diagnostics requirements (OBD) which illuminates indicators on the dashboard when vehicles are out of emissions compliance levels; c) 150,000 mile emission equipment warranty; and d) evaporative emissions requirements in California which prevent emissions during refueling. SULEV emissions standards approximate the emissions from powerplants associated with recharing electric vehicles.

The second criteria, zero-emission VMT allowance, will allow a maximum .6 credit if the vehicle is capable of some all-electric operation which was fueled by off-vehicle sources (i.e. no on-board fuel reformers), or if the vehicle has ZEV-like equipment on-board such as regenerative braking, advanced batteries, or an advanced electric drivetrain.

An emission allowance was also made for low fuel-cycle vehicle fuels used in the advanced technology vehicles. A maximum of .2 credit is provided for vehicles which use fuel that has less than or equal to .01 nonmethane organic gases (NMOG) grams per mile emissions based on the grams per gallon and the fuel efficiency of the vehicle.

Overall, large volume manufacturers can apply ZEV credits up to a maximum of 60 percent of the original 10 percent ZEV mandate; the original ZEV mandate required that all (100 percent) of the 10 percent of all light-duty vehicle sales must be ZEVs (defined only as dedicated electric vehicles) beginning with the 2003 model year. The remaining 40 percent of the ZEV mandates must still come from electric vehicles, or variants of cell vehicles, which have extremely low emissions such as a hydrogen fuel cell vehicle.

In September of 2000, further modifications were proposed for the ZEV mandate. The proposal was designed to maintain progress towards the 2003 goal while recognizing technology and cost limited ZEV product offerings. The CARB proposal removed ZEV sales requirements prior to 2003, but maintained the 2003 required ZEV sales goal of 10 percent and requires a gradual increase of ZEV sales to 16 percent by year 2018. Additionally, the number of vehicles included in the estimation of required ZEV sales has been increased to include small light duty trucks.

The proposal also provides manufacturers flexibility in meeting the goal through increased vehicle credits and greater allowances for partial ZEVs (PZEVs) and advanced technology ZEVs (AT-PZEVs). Prior to 2006, ZEVs earn 1.25 credits per vehicle and PZEVs get a phase-in multiplier of 4, 2, and 1.3 per vehicle for years 2004 through 2006, respectively. Extra credits will also be allowed for ZEVs with extended range and/or reduced fueling times.

The AFV sales module compares these legislatively mandated sales to the results from the AFV logit market-driven sales shares. The legislatively mandated sales serve as a minimum constraint to AFV sales.

According to the EPA federal register, EPA's Tier II proposed regulations for light-duty vehicles below 6000 pounds must meet a sales weighted average of 0.07 grams/mile nitrogen oxides (NOx) emissions standard by 2004 and approximately a 0.01 to 0.02 grams/mile standard for particulates.[86] The previous Clean Air Act 1990 Tier I emissions standards were set at 0.6 grams per mile for NOx and 0.1 grams per mile for particulates.[87] EPA has estimated the costs to consumers range from $100 per car to $200 per light truck.[88] However, recently the U.S. Circuit Court ruling determined that EPA was not authorized to set new standards without indicating the benefits of the new regulations.

In the National Research Council's (NRC) Fifth Annual Review of Partnership for a New Generation of Vehicles (PNGV)[89], the NRC committee commented,"..the most difficult technical challenge facing the CIDI (compression ignition direct injection diesel) engine program will be meeting the standards for NOx and particulate emissions. In addition, meeting an even more stringent research objective (0.01 grams/mile) for particulate matter instead of the 0.04 grams/mile PNGV target would require additional technological breakthroughs."

The NRC has stated their concern that the Tier II regulations may affect the commercial viability of many advanced vehicles. Meeting the Tier II proposed standards may: require trading-off emissions levels for fuel economy by redesigning engines; add significant cost to a technology due to exhaust catalyst systems and their potential lack of effectiveness; stifle development of diesel technologies as a result of the unknown health effects of particulates; and result in new specifications for diesel fuel or development of advanced low emission fuels.

High Technology and 2002 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.[90] 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.[91]

The *2002 technology case* assumes that new fuel efficiency technologies are held constant at 2002 levels over the forecast. As a result, the energy use in the transportation sector was 5.9 percent higher (2.34 quadrillion Btu) than in the reference case by 2020. 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.

The air model in the *high technology case* assumed efficiency from new aircraft could improve by 40 percent from the 1992 level based on the conclusion from the Aeronautics and Space Engineering Board of the National Research Council.[92]

Table 34. Future New Aircraft Technology Improvement List

Proposed Technology	Introduction Year	Jet Fuel Price Necessary For Cost-Effectiveness (1987 dollars per gallon)	Seat-Miles per Gallon Gain Over 1990 (percent)	
			Narrow Body	Wide Body
Engines				
Ultra-high Bypass	1995	$.69	10	10
Propfan	2000	$1.36	23	0
Thermodynamics	2010	$1.22	20	20
Aerodynamics				
Hybrid Laminar Flow	2020	$1.53	15	15
Advanced Aerodynamics	2000	$1.70	18	18
Other				
Weight Reducing Materials	2000	-	15	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 Laboratory.

Table 35. High Technology Matrix For Trucks

	Fractional Fuel Efficiency Change	Incremental Cost (1990 $)	Incremental Cost ($/Unit Wt.)	Incremental Weight (Lbs.)	Incremental Weight (Lbs./ Unit Wt.)	First Year Introduced	Fractional Horsepower Change
Front Wheel Drive	0.020	160.00	0.00	0	-0.08	1985	0
Unit Body	0.060	80.00	0.00	0	-0.05	1995	0
Material Substitution II	0.033	0.00	0.30	0	-0.05	1987	0
Material Substitution III	0.066	0.00	0.40	0	-0.10	2003	0
Material Substitution IV	0.099	0.00	0.50	0	-0.15	2003	0
Material Substitution V	0.132	0.00	0.75	0	-0.20	2007	0
Drag Reduction II	0.023	32.00	0.00	0	0.00	1985	0
Drag Reduction III	0.046	64.00	0.00	0	0.05	1991	0
Drag Reduction IV	0.069	112.00	0.00	0	0.01	1997	0
Drag Reduction V	0.092	176.00	0.00	0	0.02	2003	0
TCLU	0.030	40.00	0.00	0	0.00	1980	0
4-Speed Automatic	0.045	225.00	0.00	30	0.00	1980	0.05
5-Speed Automatic	0.065	325.00	0.00	40	0.00	1995	0.07
CVT	0.100	250.00	0.00	20	0.00	1995	0.07
6-Speed Manual	0.020	100.00	0.00	30	0.00	1991	0.05
Electronic Transmission I	0.005	20.00	0.00	5	0.00	1988	0
Electronic Transmission II	0.015	40.00	0.00	5	0.00	1998	0
Roller Cam	0.020	16.00	0.00	0	0.00	1987	0
OHC 4	0.030	67.50	0.00	0	0.00	1980	0.2
OHC 6	0.030	82.50	0.00	0	0.00	1985	0.2
OHC 8	0.030	97.50	0.00	0	0.00	1980	0.2
4C/4V	0.080	187.50	0.00	30	0.00	1988	0.45
6C/4V	0.080	247.50	0.00	45	0.00	1990	0.45
8C/4V	0.080	307.50	0.00	60	0.00	1991	0.45
Cylinder Reduction	0.030	-100.00	0.00	-150	0.00	1988	-0.1
4C/5V	0.010	300.00	0.00	45	0.00	1997	0.55
Turbo	0.080	300.00	0.00	80	0.00	1980	0.45
Engine Friction Reduction I	0.020	20.00	0.00	0	0.00	1987	0
Engine Friction Reduction II	0.035	50.00	0.00	0	0.00	1996	0
Engine Friction Reduction III	0.050	90.00	0.00	0	0.00	2006	0
Engine Friction Reduction IV	0.065	140.00	0.00	0	0.00	2016	0
VVT I	0.080	100.00	0.00	40	0.00	1998	0.1
VVT II	0.120	130.00	0.00	40	0.00	2006	0.15
Lean Burn	0.100	175.00	0.00	0	0.00	2012	0
Two Stroke	0.150	0.00	0.00	-150	0.00	2004	0
TBI	0.020	40.00	0.00	0	0.00	1982	0.05
MPI	0.035	80.00	0.00	0	0.00	1985	0.1
Air Pump	0.010	0.00	0.00	-10	0.00	1982	0
DFS	0.015	15.00	0.00	0	0.00	1985	0.1
Oil 5W-30	0.005	2.00	0.00	0	0.00	1987	0
Oil Synthetic	0.015	5.00	0.00	0	0.00	1997	0
Tires I	0.010	5.00	0.00	0	0.00	1992	0
Tires II	0.020	10.00	0.00	0	0.00	2002	0
Tires III	0.030	15.00	0.00	0	0.00	2012	0
Tires IV	0.040	20.00	0.00	0	0.00	2018	0
ACC I	0.005	5.00	0.00	0	0.00	1992	0
ACC II	0.010	13.00	0.00	0	0.00	1997	0
EPS	0.015	40.00	0.00	0	0.00	2002	0
4WD Improvements	0.030	100.00	0.00	0	-0.05	1995	0
Air Bags	-0.010	300.00	0.00	35	0.00	1987	0
Emissions Tier I	-0.010	150.00	0.00	10	0.00	1994	0
Emissions Tier II	-0.010	300.00	0.00	20	0.00	2003	0
ABS	-0.005	300.00	0.00	10	0.00	1987	0
Side Impact	-0.005	100.00	0.00	20	0.00	1996	0
Roof Crush	-0.003	100.00	0.00	5	0.00	2001	0
Increased Size/Wt.	0.075	0.00	0.00	0	0.05	2001	0
GDI/4-cyl	0.170	450.00	0.00	0	0.00	2005	0.02
GDI/6-cyl	0.170	650.00	0.00	0	0.00	2005	0

Source: Energy and Enviromental Analysis, *Changes to the Fuel Economy Module, Final Report, 12-3, prepared for Energy Information Administration (EIA), (June 1998).*

Table 36. High Technology Matrix For Cars

	Fractional Fuel Efficiency Change	Incremental Cost (1990 $)	Incremental Cost/ ($/Unit Wt.)	Incremental Weight (Lbs.)	Incremental Weight (Lbs./ Unit Wt.)	First Year Introduced	Fractional Horsepower Change
Front Wheel Drive	0.060	160.00	0.00	0	-0.08	1980	0
Unit Body	0.040	80.00	0.00	0	-0.05	1980	0
Material Substitution II	0.033	0.00	0.30	0	-0.05	1987	0
Material Substitution III	0.066	0.00	0.90	0	-0.10	1997	0
Material Substitution IV	0.099	0.00	1.90	0	-0.15	2003	0
Material Substitution V	0.132	0.00	75.0	0	-0.20	2007	0
Drag Reduction II	0.023	32.00	0.00	0	0.00	1985	0
Drag Reduction III	0.046	64.00	0.00	0	0.05	1991	0
Drag Reduction IV	0.069	112.00	0.00	0	0.01	2002	0
Drag Reduction V	0.092	176.00	0.00	0	0.02	2003	0
TCLU	0.030	40.00	0.00	0	0.00	1980	0
4-Speed Automatic	0.045	225.00	0.00	30	0.00	1980	0.05
5-Speed Automatic	0.065	325.00	0.00	40	0.00	1995	0.07
CVT	0.100	250.00	0.00	20	0.00	1995	0.07
6-Speed Manual	0.020	100.00	0.00	30	0.00	1991	0.05
Electronic Transmission I	0.005	20.00	0.00	5	0.00	1988	0
Electronic Transmission II	0.015	40.00	0.00	5	0.00	1998	0
Roller Cam	0.020	16.00	0.00	0	0.00	1987	0
OHC 4	0.030	100.00	0.00	0	0.00	1980	0.20
OHC 6	0.030	140.00	0.00	0	0.00	1980	0.20
OHC 8	0.030	170.00	0.00	0	0.00	1980	0.20
4C/4V	0.080	240.00	0.00	30	0.00	1988	0.45
6C/4V	0.080	320.00	0.00	45	0.00	1991	0.45
8C/4V	0.080	400.00	0.00	60	0.00	1991	0.45
Cylinder Reduction	0.030	-100.00	0.00	-150	0.00	1988	-0.10
4C/5V	0.100	400.00	0.00	45	0.00	1998	0.55
Turbo	0.080	300.00	0.00	80	0.00	1980	0.45
Engine Friction Reduction I	0.020	20.00	0.00	0	0.00	1987	0
Engine Friction Reduction II	0.035	50.00	0.00	0	0.00	1996	0
Engine Friction Reduction III	0.050	90.00	0.00	0	0.00	2006	0
Engine Friction Reduction IV	0.065	120.00	0.00	0	0.00	2016	0
VVT I	0.030	50.00	0.00	40	0.00	1996	0.10
VVT II	0.080	130.00	0.00	40	0.00	2006	0.15
Lean Burn	0.120	75.00	0.00	0	0.00	2012	0
Two Stroke	0.150	0.00	0.00	-150	0.00	2004	0
TBI	0.020	40.00	0.00	0	0.00	1982	0.05
MPI	0.035	80.00	0.00	0	0.00	1987	0.10
Air Pump	0.010	0.00	0.00	-10	0.00	1982	0
DFS	0.015	15.00	0.00	0	0.00	1987	0.10
Oil %w-30	0.005	2.00	0.00	0	0.00	1987	0
Oil Synthetic	0.015	5.00	0.00	0	0.00	1997	0
Tires I	0.010	5.00	0.00	0	0.00	1992	0
Tires II	0.033	10.00	0.00	0	0.00	2002	0
Tires III	0.048	15.00	0.00	0	0.00	2012	0
Tires IV	0.053	20.00	0.00	0	0.00	2018	0
ACC I	0.007	5.00	0.00	0	0.00	1992	0
ACC II	0.017	13.00	0.00	0	0.00	1997	0
EPS	0.015	40.00	0.00	0	0.00	2002	0
4WD Improvements	0.030	100.00	0.00	0	-0.05	1995	0
Air Bags	-0.010	300.00	0.00	35	0.00	1987	0
Emissions Tier I	-0.010	150.00	0.00	10	0.00	1994	0
Emissions Tier II	-0.010	300.00	0.00	20	0.00	2003	0
ABS	-0.005	300.00	0.00	10	0.00	1987	0
Side Impact	-0.005	100.00	0.00	20	0.00	1996	0
Roof Crush	-0.003	100.00	0.00	5	0.00	2001	0
Increased Size/Wt.	-0.033	0.00	0.00	0	0.05	2001	0
GDI/4-cyl	0.170	450.00	0.00	0	0.00	2005	0
GDI/6-cyl	0.170	650.00	0.00	0	0.00	2005	0

Source: Energy and Environmental Analysis, *NEMS Fuel Economy Model LDV High Technology Update, Final Documentation, prepared for Energy Information Administration, (June 1998).*

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Electricity Market Module

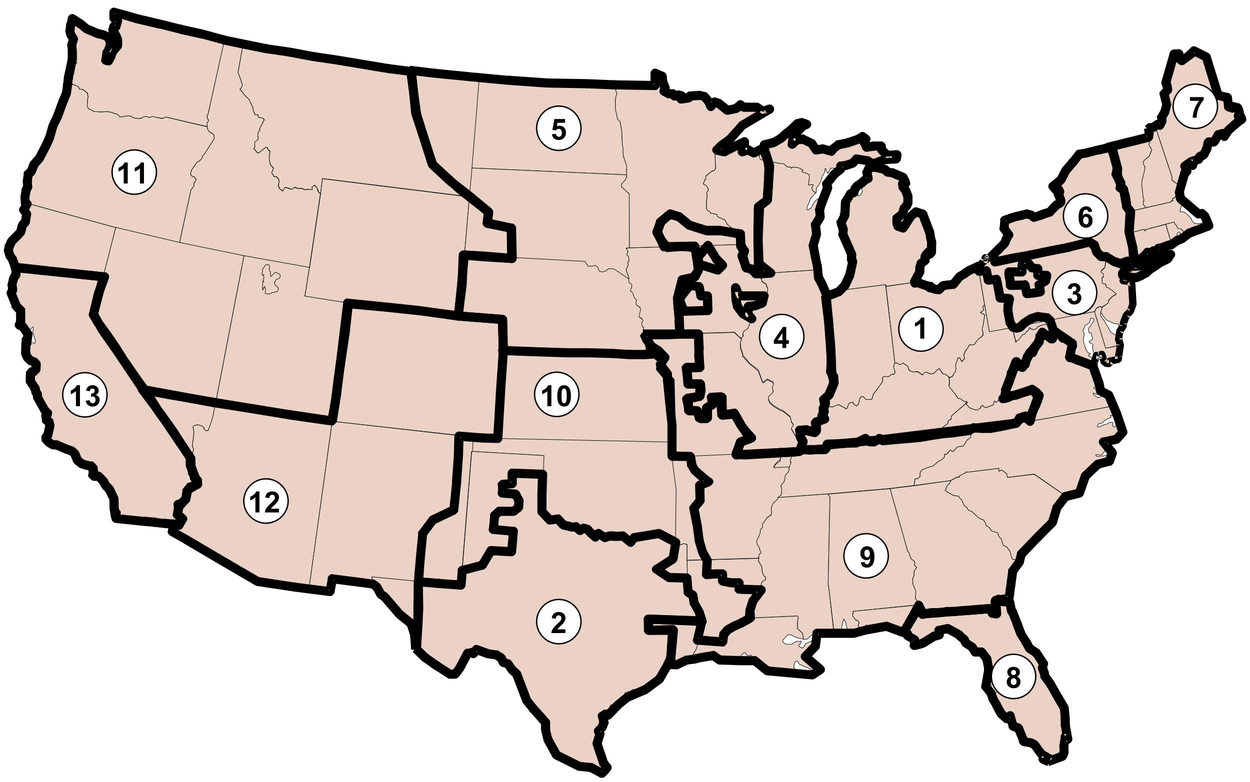
The NEMS Electricity Market Module (EMM) represents the capacity planning, dispatching, and pricing of electricity. It is composed of four submodules—electricity capacity planning, electricity fuel dispatching, load and demand-side management, and electricity finance and pricing. It includes nonutility 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 2002*, DOE/EIA-M068(2002) January 2002.

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 abut 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 Councils shown in Figure 4.

Figure 4. Electricity Market Model Supply Regions



1 East Central Area Reliability Coordination Agreement
2 Electric Reliability Council of Texas
3 Mid-Atlantic Area Council
4 Mid-America Interconnected Network
5 Mid-Continent Area Power Pool
6 New York
7 New England
8 Florida Reliability Coordinating Council
9 Southeastern Electric Reliability Council
10 Southwest Power Pool
11 Northwest Power Pool
12 Rocky Mountain, Arizona, New Mexico, Southern Nevada
13 California

Model Parameters and Assumptions

Generating Capacity Types

The capacity types represented in the EMM are shown in Table 37. Assumptions for the renewable technologies are discussed in a later chapter.

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
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
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 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 *(Middletown, U.S.A*). Differences in plant costs due to regional distinctions are calculated by applying regional multipliers (Table 39) 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 used for the capacity choice decision.

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

Technology	Online Years[1]	Size (mW)	Leadtimes (Years)	Overnight Costs in 2001 ($2000/kW)	Contingency Factors: Project Contingency Factor	Contingency Factors: Technological Optimism Factor[2]	Total Overnight Cost including Contingencies in 2001[3] (2000 $/kW)	Variable O&M[4] ($2000 mills/kWh)	Fixed O&M[4] ($2000/kW)	Heatrate in 2001 (Btu/kWhr)	Heatrate in 2010 (Btu/kWr)
Conventional Pulverized Coal	2005	400	4	1,046	1.07	1.00	1,119	3.38	23.41	9,386	9,087
Integrated Coal-Gasification Combined Cycle	2005	428	4	1,250	1.07	1.00	1,338	0.80	32.67	7,869	6,968
Conventional Gas/Oil Combined Cycle	2004	250	3	435	1.05	1.00	456	0.52	15.61	7,618	7,000
Adv Gas/Oil Combined Cycle	2004	400	3	546	1.08	1.00	590	0.52	14.46	6,870	6,350
Conv Combustion Turbine[5]	2002	160	2	323	1.05	1.00	339	0.10	6.45	11,380	10,600
Adv Combustion Turbine	2003	120	2	451	1.05	1.00	474	0.10	9.16	9,020	8,000
Fuel Cells	2004	10	3	1,810	1.05	1.10	2,091	2.08	14.98	5,744	5,361
Advanced Nuclear	2005	600	4	1,772	1.10	1.10	2,144	0.42	57.23	10,400	10,400
Generic Distributed Generation[6] - Base	2004	2	3	593	1.05	1.00	623	15.11	4.02	10,991	9,210
Generic Distributed Generation[6] - Peak	2003	1	2	533	1.05	1.00	559	23.10	12.56	10,620	10,500
Biomass	2005	100	4	1,536	1.07	1.05	1,725	2.90	44.95	8,911	8,911
MSW - Landfill Gas	2004	30	3	1,336	1.07	1.00	1,429	0.01	96.31	13,648	13,648
Geothermal [7,8]	2006	50	4	1,663	1.05	1.00	1,746	0.00	70.07	32,173	32,173
Wind	2004	50	3	918	1.07	1.00	982	0.00	25.54	10,280	10,280
Solar Thermal[8]	2004	100	3	2,157	1.07	1.10	2,539	0.00	47.87	10,280	10,280
Solar Photovoltaic[8]	2003	5	2	3,317	1.05	1.10	3,831	0.00	9.85	10,280	10,280

[1]Online year represents the first year that a new unit could be completed, given an order date of 2001.

[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 2001.

[4]O&M = Operation and maintenance.

[5]Combustion turbine units can be built by the model prior to 2003 if necessary to meet a given region's reserve margin.

[6]The costs shown here are slightly different from costs shown in Table 41 because of updated adjustments for inflation. The unit size shown here is higher than that shown in Table 41 to reflect the minimum size that can be represented meaningfully in the model. The lead times are also different from those shown in Table 41 because lead times presented here include site acquisition, site preparation, and permitting for plants that are larger in size.

[7]Because geothermal 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.

[8]Capital costs for geothermal and solar technologies are net of (reduced by) the ten percent investment tax credit.

Source: Values are derived 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 National Laboratories.

Table 39. Regional Multipliers for Construction of Fossil-Fueled, Nuclear, and Renewable[1] Generating Technologies

EMM Region	NE, NY	MAAC	STV	MAPP, ECAR, MAIN	SPP
	1.043	0.996	0.96	1.004	0.997
EMM Region	**RA**	**NWP**	**FL**	**CNV**	**ERCOT**
	1.003	1.026	0.961	1.058	0.986

[1]Regional multipliers are not applied to geothermal technologies because costs are site specific.

Source: Argonne National Laboratory, *Cost and Performance Database for Electric Power Generating Technologies*..

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. For each generating technology available for new capacity in a region, the overnight cost used by the model is calculated using the base cost, technological optimism and contingency factors for the technology from Table 38, the regional factors from Table 39, and the learning parameters from Table 40.

Table 40. Learning Parameters for New Generating Technologies[1]

Technology	Period 1 Learning Rate	Period 2 Learning Rate	Period 3 Learning Rate	Period 1 Doublings	Period 2 Doublings	Minimum Total Learning by 2020
Conventional Pulverized Coal	-	-	0.01	-	-	0.05
Integrated Coal-Gasification Combined Cycle	-	0.05	0.01	-	5	0.10
Conv Gas/Oil Combined Cycle	-	-	0.01	-	-	0.05
Adv Gas/Oil Combined Cycle	-	0.05	0.01	-	5	0.10
Conv Combustion Turbine	-	-	0.01	-	-	0.05
Adv Combustion Turbine	-	0.05	0.01	-	5	0.10
Fuel Cells	0.1	0.05	0.01	3	5	0.20
Adv Nuclear	-	0.05	0.01	-	5	0.10
Biomass	0.1	0.05	0.01	3	5	0.20
MSW - Landfill Gas	-	-	0	-	-	0.05
Geothermal	-	0.05	0.01	-	5	0.10
Wind	-	0.05	0.01	-	5	0.20
Solar Thermal	0.1	0.05	0.01	3	5	0.20
Photovoltaic	0.1	0.05	0.01	3	5	0.20

[1]Distributed technologies are not included in this learning methodology, but are assumed to receive exogenously specified reductions in costs.

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 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 has the nonlinear form:

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

where C is the cumulative capacity for the technology.

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 technology Table 41. 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 technologies receive a minimal amount of learning, even if new capacity additions are not projected. This could represent cost reductions due to future international development or increased research and development.

International Learning. In *AEO2002*, 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 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.

AEO2002 includes 1,811 megawatts of advanced coal gasification combined-cycle capacity, 5,244 megawatts of advanced combined-cycle natural gas capacity, 47 megawatts of wind capacity and 11 megawatts of biomass capacity to be built outside the United States from 2000 through 2003.

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). This includes a generic representation of micro-turbines, frame type combustion turbines operating on natural gas, and three types of reciprocating engines. The cost of the generic technology is the sum of an assumed share of each of the technologies mentioned above multiplied by its respective costs. The lowest costs are for the diesel cycle/compression ignition engines operated with natural gas. This technology represents 40 percent of the generic technology for peaking distributed generators. 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). The technologies in the generic mix include heavy-duty micro-turbines, combustion turbines, compression ignition engines, and fuel cells. The cost of the base-load technology is calculated in the same fashion as is done for the peaking technology. Combustion turbines and engines make up about one-half of the base-load technology.

Table 41 shows the characteristics for the generic technologies for 2000 and 2010. The capital cost for the baseload generator is about 27 percent more expensive than for a peaking generator in 2010. However, the operations and maintenance costs are less for the base-load distributed generator. Because of the small size of distributed generators, it is unlikely that they would obtain the lower natural gas prices available to larger high-volume central generators. In order to account for uncertainty in the

Table 41. Characteristics of Generic Distributed Generators

	Generic Peak In 2000	Generic Peak In 2010	Generic Base-load In 2000	Generic Base-load In 2010
Typical size (megawatts)	0.4	0.4	2.47	1.6
Construction lead time (years)	0.2	0.2	0.5	0.5
Overnight costs for initial versions ($1999/kW)	Not estimated	700	Not estimated	2000
Overnight costs for mature versions ($1999/kW)	531	440	591	560
Variable O & M (1999 mills/kWh)	23	15.5	15	10.4
Fixed O & M ($1999/year-KW)	12.5	12.5	4.0	6.3
Heat Rate (Btu/kWh)	10,620	10,500	10,991	9,210

Source: Distributed Utility Associates, *Assessing Market Acceptance and Penetration for Distributed Generation in the United States,* June 7, 1999.

delivered costs of natural gas it was assumed that distributed generators would pay a premium of 2 dollars per million Btu above the price incurred by larger-scale electricity producers.

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.

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.

Reserve margins—the percentage of capacity required in excess of peak demand needed for unforeseeable outages—are also assumed for each regulated EMM region. A 13 percent reserve margin is assumed for MAPP and STV, 9 percent for FL, and 15 percent for NWP. In the other regions where competition has replaced regulation in all or a majority of the region, the EMM determines the reserve margin by equating 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 operating 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 $8 per kilowatt (kW) for oil and gas steam plants, $6/kW for combined-cycle plants, and combustion turbines, $15/kW for coal plants and $30/kW for nuclear plants. These costs are added to existing plants regardless of their age. Beyond 30 years of age an additional $5/KW capital charge for fossil plants, and $50/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. Individual plants are assumed to be able to replace up to five percent of their total fuel consumption with biomass, assuming sufficient residue fuel is available within the State where the plant is located.

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 and operating assumptions for the advanced nuclear technology represented in the NEMS are based on Westinghouse's advanced passive reactor design (AP600). It is one of three new designs that have received design certification from the Nuclear Regulatory Commission (NRC), a necessary step to new nuclear construction. The other two designs (General Electric's Advanced Boiling Water reactor and ABB/Combustion engineering's System 80+) are not significantly different from current designs; they are based on larger sizes (over 1 gigawatt) and do not include passive safety features. The AP600 design is based on a smaller size (600 megawatts) and includes passive safety features, both of which make it more attractive to investors. Westinghouse is in a pre-application stage for approval of a larger unit of the same design, the AP1000. They expect to gain cost efficiencies from the larger size, lowering the cost per kilowatt. Research and development on more revolutionary designs is continuing, both in the United States and abroad. However, until the designs are approved by the NRC, there are too many uncertainties to be included as a future option within the forecast period.

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 NERC and WSCC 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 2000*. They are locked in for the term of the contract. Contracts that are scheduled to expire by 2010 are assumed not to be renewed. Because there is no information available about expiration dates for contracts that go beyond 2010, they are assumed to be phased out by 2020. 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 2000*. 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 is assumed to return to fully regulated pricing in 2002, after beginning to transition to completition 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 Southwest Power Pool, and the Rocky Mountain Power Area/ Arizona are a weighted average of both competitive and regulated prices. Some of the States in each of these regions have not taken action to deregulate their pricing of electricity, and in those States prices are assumed to continue to be based on traditional cost-of-service pricing. The price for the region will be 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 or where states representing less than half of regional electricity sales 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 four 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 *AEO2002*. The key trends are discussed below:

- Reduced General and Administrative Expenses (G&A) - Over the 1990 through 1999 period, utilities have reduced their employment at fossil steam plants at a rate of 4 percent per year. This trend has been incorporated by reducing total G&A expenditures at a rate of 2.5 percent annually through 2005. No further reductions are assumed to occur after 2005.

- Reduced Fossil Plant Operations Expenditures (O&M) - Again, over the 1990 through 1999 period, utility fossil plant operation and maintenance costs (all operating costs other than fuel) fell at a rate of about 3 percent annually. As with G&A, this trend has been incorporated by reducing fossil O&M expenditures at a rate of 2.5 percent annually through 2005. No further reductions are assumed to occur after 2005.

Demand-Side Management

Improvements in energy efficiency induced by rising energy prices, new appliance standards, and utility demand-side management programs are represented in the end-use demand models. Appliance choice decisions are a function of the relative costs and performance characteristics of a menu of technology options. In 1999, utilities reported spending over $1.4 billion on demand-side management programs.[92]

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 adaptive expectations, in which future prices are extrapolated from recent historical trends.[93] For each projection year, coal prices are assumed to decrease one percent annually from that year's projected price until the end of the subsequent 20 year period. For each oil product, future prices are estimated by applying a constant markup to an external forecast of world oil prices. The markups are calculated by taking the differences between the regional product prices and the world oil price for the previous forecast year. For natural gas, expected wellhead prices are based on a nonlinear function that relates the expected price to the expected cumulative domestic gas production. Delivered prices are developed by applying a constant markup, which represents the difference between the delivered and wellhead prices from the prior forecast year.

The approach for natural gas was developed to have the following properties:

1. The natural gas wellhead price should be upward sloping as a function of cumulative gas production.

2. The rate of change in wellhead prices should increase as fewer economical reserves remain to be discovered and produced.

The approach assumes that at some point in the future a given target price, PF, results when cumulative gas production reaches a given level, QF. The target values for PF and QF were assumed to be $7.00 per thousand cubic feet (1995 dollars) and 2000 trillion cubic feet (tcf), respectively. Gas hydrates are included in the resource base at a level of 60 tcf, and geopressurized aquifers are included at 500 tcf. The future annual production is assumed to be constant at the prior year's level. There is also the flexibility to assume a different path in the short term and longer term by choosing an inflection price at which new competitors would enter the market.

The expected wellhead gas price equation is of the following form:

$$P_k = A * Q_k^{exp} + B$$

where P is the wellhead price for year k, Q_k is the cumulative production from 1991 to year k, and A and B are determined each year such that the price equation will intersect the future target point (PF, QF). The exponent, exp, is assumed to be 0.70 as long as P_k is below an assumed inflection price of $3.50. Above this price, the exponent is assumed to be 1.30. The cumulative production calculation assumes that future growth in production will be equal to most recent 3 year average growth rate.

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. The costs for FGD equipment average approximately $400 per kilowatt, in 2000 dollars, including cost estimates for very small, possibly uneconomic plants. The average cost for units 500 megawatts or greater is $234/kw, although the costs vary widely across the regions. It is also assumed that the market for trading emission allowances is allowed to operate without regulation and that the States do not further regulate the selection of coal to be used.

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 (Table 43). 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. All of these NO_x limits are incorporated in EMM.

Table 43. NO_x Emissions Standards
(Pounds per million Btu)

Boiler Type	# Boilers	Phase I Limit	Phase II Limit
Group 1 Boilers			
Dry Bottom Wall-Fired	284	0.50	0.45
Tangential	296	0.45	0.38
Group 2 Boilers			
Cell Burners	35	NA	0.68
Cyclones	88	NA	0.94
Wet Bottom Wall-Fired	38	NA	0.86
Vertically Fired	29	NA	0.80
Fluidized Bed	5	NA	0.29

NA = Not Applicable.

Source: Environmental Protection Agency, Nitrogen Oxide Emission Reduction Program.

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.

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.[94] 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 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.

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

State	Emissions Cap
Alabama	30.60
Connecticut	5.20
Delaware	5.00
District of Columbia	0.20
Illinois	36.60
Indiana	51.80
Kentucky	38.80
Maryland	13.00
Massachusetts	14.70
Michigan	29.50
New Jersey	8.20
New York	31.20
North Carolina	32.70
Ohio	51.50
Pennsylvania	46.00
Rhode Island	1.60
South Carolina	19.80
Tennessee	26.20
Virginia	21.00
West Virginia	24.05

Source: U.S. Environmental Protection Agency, Federal Register, Vol. 65, number 207 (October 27, 1998).

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

High Electricity Demand Case

The *high electricity demand case* assumes that electricity demand grows at 2.5 percent annually between 2000 and 2020. In the reference case, electricity demand is projected to grow 1.8 percent annually between 2000 and 2020. No attempt was made to determine the changes needed in the end-use sectors to result in the stronger demand growth.

The *high electricity demand case* is a partially integrated run. The end-use demand modules are not operated, but all of the electricity end-use demands from the reference case are multiplied by the same factor to achieve the higher growth rate. Using the higher electricity demand and all other reference case demand projections as inputs, the EMM, Macroeconomic Activity, Petroleum Marketing, International Energy, Oil and Gas, Natural Gas Transmission and Distribution, Coal Market, and Renewable Fuels Modules are allowed to interact.

Low and High Fossil Cases

The *low fossil case* assumes that the costs of advanced 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 2002 levels. Capital costs of conventional generating technologies are the same as those assumed in the reference case (Table 45).

Table 45. Cost and Performance Characteristics for Fossil-Fueled Generating Technologies: Three Cases

	Total Overnight Cost in 2000 (Reference)	Total Overnight Cost including contingencies and learning effects[1]			Heatrate in 2000 (Reference)	Heat Rate		
		Reference	High Fossil	Low Fossil		Reference	High Fossil	Low Fossil
	(2000$/kW)	(2000$/kW)	(2000$/kW)	(2000$/kW)	Btu/kWhr	Btu/kWhr	Btu/kWhr	Btu/kWhr
Pulverized Coal	1119				9419			
2005		1110	1110	1110		9253	9253	9253
2010		1083	1083	1083		9087	9087	9087
2015		1068	1080	1062		9087	9087	9087
2020		1056	1075	1047		9087	9087	9087
Integrated Coal Gasification Combined-Cycle	1338				7969			
2005		1315	1208	1332		7469	7379	7769
2010		1287	1000	1332		6968	6728	7769
2015		1260	976	1332		6968	6077	7769
2020		1221	951	1332		6968	5687	7769
Conv Combined Cycle	456				7687			
2005		453	453	453		7343	7343	7343
2010		448	448	448		7000	7000	7000
2015		443	443	443		7000	7000	7000
2020		438	438	438		7000	7000	7000
Adv. Combined Cycle	590				6927			
2005		572	572	587		6639	6384	6812
2010		526	516	587		6350	5672	6812
2015		505	499	587		6350	4960	6812
2020		493	485	587		6350	4960	6812
Conv. Combustion Turbine	339				11467			
2005		336	336	336		11033	11033	11033
2010		333	333	333		10600	10600	10600
2015		329	329	329		10600	10600	10600
2020		326	326	326		10600	10600	10600
Adv. Combustion Turbine	474				9133			
2005		446	446	472		8567	8117	8907
2010		384	384	472		8000	6800	8907
2015		365	363	472		8000	6800	8907
2020		362	361	472		8000	6800	8907

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

Source: AEO2002 National Energy Modeling System runs: AEO2002.D102001B, HFOSS02.D102301B, LFOSS02.D102401A.

In the *high fossil case*, efficiencies of advanced fossil generating technologies are higher than the reference case, based on the Department of Energy, Office of Fossil Energy's Vision 21 program goals, while efficiencies of conventional technologies are the same as used in the reference case. The costs of integrated coal-gasification combined-cycle are also assumed to be lower than in the reference case.

The *low and high fossil* runs are partially-integrated runs, i.e., the reference case values for the Macroeconomic Activity, Petroleum Market, International Energy, and end-use demand modules are used and are not affected by changes in generating capacity mix. Conversely, the Oil and Gas Supply, Natural Gas Transmission and Distribution, Coal Market, and Renewable Fuels Modules are allowed to interact with the EMM in the *low and high fossil cases*.

Low and High Nuclear Cases

Two alternative cases were developed to incorporate the effects of uncertainty about the aging process for nuclear power plants. This uncertainty exists because there is currently no information about the costs of 40 or 50-year old nuclear power plants. In the high nuclear capacity case, it was assumed that there would be no age-related costs. The high nuclear case considers the possibility that costs would not increase beyond current levels due to aging and nuclear units are more likely to operate beyond current licenses. In the low nuclear capacity case, the age-related costs after age 30 were assumed to be the same as the reference case ($50/kw), but costs would increase to $100/kw after 40 years. This low nuclear case is intended to address the impacts that degraded performance and/or higher costs of older plants have on their competitiveness over the next decade.

The *low and high nuclear cases* are partially-integrated model runs, i.e., the reference case values for the Macroeconomic Activity, Petroleum Market, and International Energy modules are used and are not affected by changes in nuclear capacity. Conversely, the Oil and Gas Supply, Natural Gas Transmission and Distribution, Coal Market, and Renewable Fuels Modules interact with the EMM in the high and low nuclear cases.

Advanced Nuclear Cost Case

An advanced nuclear cost case was used to analyze the sensitivity of the projections to lower costs and construction times for new plants. The cost assumptions are consistent with the goals for “Generation III” nuclear plants endorsed by the Department of Energy’s Office of Nuclear Energy. In this case, the overnight capital cost, without contingencies, of a new advanced nuclear unit is assumed to be $1500/kilowatt initially, and to fall to $1200/kilowatt by 2015. The overnight cost with the ten percent project contingency is shown in Table 46. The case assumed a 3-year lead time, the goal of the Office of Nuclear Energy. The cost and performance characteristics for all other technologies are as assumed in the reference case.

Table 46. Cost Characteristics for Advanced Nuclear Technology: Two Cases

Advanced Nuclear	Overnight Cost in 2000 (Reference) (2000$/kW)	Total Overnight Cost[1] Reference Case (2000$/kW)	Total Overnight Cost[1] Adv Nuclear Case (2000$/kW)
	2144		
2005		2108	1650
2010		2063	1484
2015		2019	1320
2020		1974	1320

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

Source: AEO2002 National Energy Modeling System runs: AEO2002.D102001B, ADVNUC02.D102301B.

Notes and Sources

[92] Energy Information Administration, *Electric Power Annual 1999*, Volume II, DOE/EIA-0348(99)/2 (Washington, DC, October 2000).

[93] Energy Information Administration, *Integrating Module of the National Energy Modeling System: Model Documentation*, DOE/EIA-M057(2002), (Washington, DC, December 2001).

[94] A registered utility holding company is defined as any company that owns or controls 10 percent 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.

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. 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(2002), (Washington, DC, January 2002). 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.

OGSM encompasses domestic crude oil and natural gas supply by both conventional and nonconventional recovery techniques. Nonconventional recovery includes enhanced oil recovery and 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 major factors affecting the projection include the assumed rates of technological progress, projections for enhanced oil recovery production, 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[95] consist of proved reserves,[96] inferred reserves,[97] and undiscovered technically recoverable resources.[98] 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.[99] 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 47 and 48 reflect the removal of intervening reserve additions between the dates of the USGS (1/1/94) and MMS (1/1/95, 1/1/99) estimates and 1/1/00.

Alaskan Crude Oil and Natural Gas

Alaskan 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. Alaskan 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 projected to be relatively small, and development of these fields is projected to begin as early as 2002 and continue 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. This area was partially reopened for development in 1999. Based on USGS assessment of the opened areas of NPR-A, the area available for development is expected to have resources of 1.7 billion barrels. These resources are assumed not able to be brought into production until after 2010. 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.

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 raised the potential economic viability of a major Alaskan pipeline from the North Slope into Alberta, Canada. While several routes have been proposed, the model allows for the construction of a more generic pipeline, should the economic stimulus be sufficient. A natural gas pipeline from Alaska into Alberta, Canada is assumed to carry an initial capitalization of 10 billion dollars in 2001 dollars, deliver 4 billion cubic feet per day when first constructed, take four years to construct, and not to be completed before 2008. The wellhead price in Alaska for natural gas to be delivered along such a line, is assumed to be $0.80 per thousand cubic feet in 2000 dollars. A risk premium of $0.35 was assumed above and beyond the expected cost of delivery into Alberta. On average the price in Alberta would need to be maintained for three years at wellhead prices above $3.00 per thousand cubic feet (in 2000 dollars) for construction to commence, depending on the gross domestic product forecast. This translates into a lower-48 average wellhead price of around $3.50 per thousand cubic feet. If the Alaska to Alberta pipeline is build in the model, additional pipeline is added to bring the gas across the border into the United States. For accounting purposes, the model assumes that all of the Alaskan gas will be consumed in the United States. If market prices increase by an additional $0.50 beyond the initial trigger price, then it is assumed that the capacity on the pipeline will be increased by 50 percent.

Table 47. Crude Oil Technically Recoverable Resources
(Billion barrels)

Crude Oil Resource Category	As of January 1, 2000
Undiscovered	48.32
Onshore	16.45
Offshore	31.87
Deep (>200 meter W.D.)	28.81
Shallow (0-200 meter W.D.)	3.06
Inferred Reserves	47.47
EOR	12.69
Other Onshore	31.34
Offshore	3.44
Deep (>200 meter W.D.)	0.35
Shallow (0-200 meter W.D.)	3.08
Total Lower 48 States Unproved	95.79
Alaska	16.89
Total U.S. Unproved	112.69
Proved Reserves	23.17
Total Crude Oil	135.85

WD= Water Depth

Note: Resources in areas where drilling is officially prohibited are not included in this table. Also, the EOR and Alaska values are not explicitly utilized in the OGSM, but are included here to complete the table. The Alaska value does not include resources from the Arctic Offshore Outer Continental shelf. Resource values in Table 53 vary from comparable values in the AEO2001 Assumptions Document crude oil resource table because of : (1) an accounting for net reserve additions and production in 1999, (2) the use of a more refined methodology for estimating the share of resources existing in areas where drilling is officially prohibited, (3) new offshore resource estimates from the Minerals Management Service, and (4) the exclusion of natural gas liquids - the listed Lower 48 Crude Oil Onshore undiscovered resource value in the AEO2001 document had erroneously included Natural Gas Liquids. The latter error existed only in the AEO2001 Assumptions Document Resource Table, not in the actual resource inputs utilized for the AEO2001.

Source: Conventional (non-EOR) Onshore, State Offshore, and Alaska - U.S. Geological Survey (USGS); Federal (Outer Continental Shelf) Offshore - Minerals Management Service (MMS) EOR - Energy Information Administration (EIA), Office of Integrated Analysis and Forecasting (OIAF); Proved Reserves - EIA, Office of Oil and Gas. Table values reflect removal of intervening reserve additions between the dates of the USGS (1/1/94) and MMS (1/1/95, 1/1/99) estimates and 1/1/00.

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 57.3 billion cubic feet per year. Other supplemental supplies are held at a constant level of 48.0 billion cubic feet per year throughout the forecast because this level is consistent with historical data and there is no reason to believe this will change significantly in the context of a reference case forecast. Synthetic natural gas from liquid hydrocarbons is assumed to continue over the forecast at the average historical level of 7.3 billion cubic feet per year.

Natural Gas Imports and Exports

Table 48. Natural Gas Technically Recoverable Resources
(Trillion cubic feet)

Natural Gas Resource Category	As of January 1, 2000
Nonassociated Gas	
Undiscovered	247.71
Onshore	121.61
Offshore	126.10
Deep (>200 meters W.D.)	81.56
Shallow (0-200 meters W.D)	44.52
Inferred Reserves	232.70
Onshore	183.03
Offshore	47.68
Deep (>200 meters W.D.)	7.72
Shallow (0-200 (meters W.D.)	39.96
Unconventional Gas Recovery	369.59
• Tight Gas	253.83
• Shale	55.42
• Coalbed	60.35
Associated-Dissolved Gas	140.89
Total Lower 48 Unproved	990.89
Alaska	32.32
Total U.S. Unproved	1023.21
Proved Reserves	167.41
Total Natural Gas	1190.62

WD = Water Depth

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. Resource values in Table 54 vary from comparable values in the AEO2001 Assumptions Document natural gas resource table because of: (1) an accounting for net reserve additions and production in 1999, (2) the use of a more refined methodology for estimating the share of resources existing in areas where drilling is officially prohibited, (3) new offshore resources estimates from the Minerals Management Service, and (4) the elimination of a double-counting of Lower-48 Associated-Dissolved Gas undiscovered resource values - the listed Lower 48 Nonassociated Gas undiscovered resource values in the AEO2001 document had erroneously contained Associated-Dissolved Gas. The latter error existed only in the AEO2001 Assumptions Document resource table, not in the actual resource inputs utilized for the AEO2001.

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 dates of the USGS (1/1/94) and MMS (1/1/99) estimates and 1/1/00.

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 to NEMS at 80 billion cubic feet per year. Canadian production and U.S. import flows from Canada are determined endogenously within the model and are constrained by pipeline capacities.

Canadian consumption and production outside of the Western Canadian Sedimentary Basin (WCSB) are set exogenously in the model and are shown in Table 49. Production in the WCSB is calculated endogenously to the model. In doing so, the natural gas finding rates are set across the forecast period by establishing an initial historical average finding rate of 1.30 billion cubic feet per well and assuming an annual decline of 1.5 percent.

Annual U.S. exports of LNG to Japan are assumed to be a constant at 65.0 billion cubic feet in each year after 2000. 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 needed to trigger new LNG construction vary by region and are slightly above $4.00 (the exact triggers are dependent on a number of variables, such as sources of LNG).

Table 49. Exogenously Specified Canadian Production and Consumption
(Billion cubic feet per year)

Year	Consumption	Production Eastern Canada	Production Northern Frontier
2000	2,545	120	0
2005	3,069	320	0
2010	3,345	530	0
2015	3,635	760	0
2020	3,908	960	0

Source: Consumption derived from National Energy Board, *Canadian Energy-Supply and Demand to 2025* (Calgary, Alberta: 1999). Production from EIA/OIAF.

Currently, only two LNG import terminals are in operation: the Distrigas facility in Everett, Massachusetts, and the Trunkline facility in Lake Charles, Louisiana. Maximum sustainable LNG import capacity at these two facilities in 2000 is assumed to be 332 billion cubic feet. Two additional facilities, one at Cove Point, Maryland and the other at Elba Island, Georgia, currently mothballed, are assumed to reopen by 2002, adding an additional 385 billion cubic feet of sustainable capacity. It is assumed that additional expansion at these 4 facilities could add another 274 billion cubic feet of sustainable capacity. A maximum utilization rate of 90 percent is assumed.

Offshore Royalty Relief

The Outer Continental Shelf Deep Water Royalty Act (Public Law 104-58) gave the Secretary of Interior the authority to suspend royalty requirements on new production from qualifying leases and required that royalty payments be waived automatically on new leases sold in the 5 years following its November 28, 1995, enactment. The volume of production on which no royalties were due for the 5 years was assumed to be 17.5 million barrels of oil equivalent (BOE) in water depths of 200 to 400 meters, 52.5 million BOE in water depths of 400 to 800 meters, and 87.5 million BOE in water depths greater than 800 meters. In any year during which the arithmetic average of the closing prices on the New York Mercantile Exchange for light sweet crude oil exceeded $28 per barrel or for natural gas exceeded $3.50 per million Btu, any production of crude oil or natural gas was subject to royalties at the lease stipulated royalty rate. Although automatic relief expired on November 28, 2000, the act provided the MMS the authority to include royalty suspensions as a feature of leases sold in the future. In September 2000, the MMS issued a set of proposed rules and regulations that provide a framework for continuing deep water royalty relief on a lease by lease basis. In the model it is assumed that relief will be granted roughly the same levels as provided during the first 5 years of the act.

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 25 percent (Table 50), for the rapid and slow technology cases, respectively. The approaches taken in the representation of enhanced oil

Table 50. Assumed Annual Rates of Technological Progress on Costs, Finding Rates, and Success Rates for Conventional Sources

Category	Natural Gas			Crude Oil		
	Slow	Reference	Rapid	Slow	Reference	Rapid
Costs						
Drilling						
Onshore						
Deep	1.96	2.61	3.26	1.96	2.61	3.26
Shallow	0.67	0.89	1.11	0.67	0.89	1.11
Offshore	1.13	1.50	1.88	1.13	1.50	1.88
Alaska	0.75	1.00	1.25	0.75	1.00	1.25
Lease Equipment						
Onshore	0.90	1.20	1.50	0.90	1.20	1.50
Offshore	1.13	1.50	1.88	1.13	1.50	1.88
Alaska	0.75	1.00	1.25	0.75	1.00	1.25
Operating						
Onshore	0.41	0.54	0.68	0.41	0.54	0.68
Offshore	1.13	1.50	1.88	1.13	1.50	1.88
Alaska	0.75	1.00	1.25	0.75	1.00	1.25
Finding Rates						
New Field Wildcats	5.60	7.47	9.33	0.00	0.00	0.00
Other Exploratory	2.27	3.02	3.78	2.80	3.73	4.67
Developmental	1.66	2.21	2.76	0.33	0.45	0.56
Success Rates						
Developmental	5.00	6.67	8.34	5.00	6.67	8.34
Exploratory	6.38	8.50	10.63	6.38	8.50	10.63

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

recovery and unconventional natural gas are discussed below. In the Canadian supply submodule, the decline in the finding rate in the WCSB (set at 1.5 percent per year in the reference case) was adjusted for the technology cases, with a greater differential the further out in the forecast. In the rapid technoogy case the finding rate declines initially (similar to the reference case) and then increases to 2020, with an average annual increase of 0.2 percent per year. In the slow technology case the decline averages 3.2 percent per year. Similarly the forecasted wells for the WCSB were increased and decreased for the rapid and slow technology cases, respectively, with a greater differential the further out in the forecast. By 2020, the forcasted wells were adjusted up or down by 6.25 percent in the two cases. 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.

Enhanced Oil Recovery

Two impacts of technological improvements are modeled to determine the economics for development of inferred enhanced oil recovery (EOR) reserves: (1) an overall reduction in the costs of drilling, completion and equipping production wells due to incremental improvements in drilling equipment and procedures, reservoir characterization, completion methods, and operation refinement; and (2) the field-specific penetration of horizontal well technology, which represents a quantum improvement in recovery efficiency. The specific parameters for modeling the slow, reference, and rapid technology cases are shown in Table 51.

Table 51. Assumed Rates of Technological Progress on Enhanced Oil Recovery Techniques

Item	Slow Technology	Reference Technology	Rapid Technology
Decline in D,C,&E Costs (per year)	2%	2%	3%
Start Penetration of Horizontal Wells	NA	1995	1995
Horizontal Technology Penetration Period (years)	None	40	20
Horizontal Technology Penetration Rate (per year)	0%	2.5%	5%
Maximum Penetration of Inferred Reserve Base	0%	90%	90%

D, C, & E = drilling, completion, and equipping.

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

Table 52. Assumed Rates of Technological Progress for Gas Miscible EOR Methods
(Percent)

Region	Slow Technology	Reference Technology	Rapid Technology
2 - Gulf Coast	0	2.5	3.5
3 - Midcontinent	1	2	3
4 - Southwest	1	2	3
5 - Rocky Mountain	1	2	3

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

The remaining undiscovered recoverable resource determined to be technically amenable to gas miscible EOR methods is set for each region at the beginning of the forecast assuming current technology. This value is assumed to increase over the forecast period with advancements in technology (Table 52).

Unconventional Gas

The Unconventional Gas Recovery Supply Submodule (UGRSS) relies on the 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 2002* 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 presented below. Their treatment under the different technology cases are described in Table 53.

Unconventional Gas Recovery Technology Groups

1. Basin Assessments: 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: Extended reservoir characterizations increase the pace of new development by accelerating the pace of development for 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: 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: 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 Modelling and Matching: Geology/technology modelling 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: Improved drilling and completion technology improves fracture length and conductivity, resulting in increased EUR's per well.

7. Targeted Drilling and Hydraulic Fracturing R&D: 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: 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 (O&M) costs.

9. Advanced Well Completion Technologies such as Cavitation, Horizontal Drilling, and Multi-lateral Wells: R&D in advanced well completion technologies a) defines applicable plays, thereby accelerating the date such technologies are available and b) introduces an 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: Other unconventional gas technologies introduce dramatically new recovery methods that a) increase EUR per well and b) become available at dates accelerated by increased R&D with c) increased operation and maintenance (O&M) costs (in the case of Coalbed Methane) for the incremental gas produced.

11. Mitigation of Environmental Constraints: Environmental mitigation removes development constraints in environmentally sensitive basins, resulting in an increase in basin areas available for development.

Table 53. 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	2023	2016	2012
2	Decrease in Extended Portion of Development Schedule for Emerging Plays (per year)	Coalbed Methane & Gas Shales	3.75%	5.0%	6.25%
		Tight Sands	4.69%	6.25%	7.81%
3	Expansion of Existing Reserves (per year -declining 0.1% per year; eg., 3.0, 2.0...)	Coalbed Methane & Gas Shales	2.25%	3.0%	3.75%
		Tight Sands	1.50%	2.0%	2.5%
4	Increase in Percentage of Wells Drilled Successfully (per year)	All Types	0.19%	0.25%	0.31%
	Year that Best 30 Percent of Basin is Fully Identified	All Types	2024	2017	2013
5	Increase in EUR per Well (per year)	All Types	0.19%	0.25%	0.31%
6	Increase in EUR per Well (per year)	All types	0.38%	0.50%	0.63%
7	Decrease in Drilling and Stimulation Costs per Well (per year)	All types	0.38%	0.50%	0.63%
8	Decrease in Water and Gas Treatment O&M Costs per Well (per year)	All Types	0.75%	1.0%	1.25%
9	Year Advanced Well Completion Technologies Become Available	Coalbed Methane & Tight Sands	2016	2011	2008
		Gas Shales	NA	NA	2016
	Increase in EUR per well (total increase)	Coalbed Methane	15%	20%	25%
		Tight Sands	7.5%	10%	12.5%
		Gas Shales	NA	NA	5%
10	Year Advanced Recovery Technologies Become Available	Coalbed Methane Tight Sands	2021 NA	2015 NA	2011 2016
	Increase in EUR per well (total increase)	Coalbed Methane	22.5%	30.00%	37.50%
		Tight Sands	7.5%	10.00%	12.50%
		Gas Shales	NA	NA	NA
	Increase in Costs ($1998/Mcf) for Incremental CBM production	Coalbed Methane	1.25	1.00	0.75
		Tight Sands & Gas Shales	NA	NA	NA
11	Proportion of Areas Currently Restricted that Become Available for Development (per year)	All types	0.75%	1%	1.25%

Source: EUR = Estimated Ultimate Recovery.

O&M = Operation & Maintenance.

CBM = Coalbed Methane.

Source: Reference Technology Case-Advanced Resources, International; Slow and Rapid Technology Cases, Energy Information Administration, Office of Integrated Analysis and Forecasting.

Notes and Sources

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

[96] *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.

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

[98] 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.

[99] 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 2000 Assessment of Conventionally Recoverable Hydrocarbon Resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 2001, OGS Report MMS 2001-087 (October 2001).

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 "hubs." 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 2002,* DOE/EIA-M062(2002) (Washington, DC, January 2002).

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.[100] 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[101] (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). Existing gross plant in service is only based on new capacity additions.

End-use prices for residential, commercial, and core industrial customers are derived by adding a markup to the regional hub price of natural gas in both peak and off-peak periods. (Prices are only 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 purchase gas through a local distributor. The distribution tariffs are initially based on average historical values (Table 54). For residential, commercial, and core industrial customers, distributor tariffs are adjusted throughout the forecast in response to changes in consumption levels and cost of labor and capital. Although the markups in Table 54 represent annual averages, the model actually uses separate markups for the peak and offpeak periods.

Table 54. Base Level Annual Distributor Markup for Local Transportation Service
(1999 Dollars per thousand cubic feet)

Region	Residential	Commercial	Core Industrial
New England	5.04	2.62	-0.22
Mid Atlantic	4.60	1.11	0.64
East North Central	2.31	1.75	0.08
West North Central	2.81	1.69	-0.10
South Atlantic	4.36	2.59	0.49
East South Central	3.78	2.66	0.01
West South Central	3.49	1.91	0.36
Mountain	2.68	1.82	0.85
Pacific	3.40	2.18	1.92
Florida	8.28	2.95	-1.38
Arizona/New Mexico	4.05	2.07	0.72
California	4.37	3.80	1.28

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 the *Manufacturing Energy Consumption Survey Consumption of Energy 1994*, (Form EIA-846) for core industrial.

End-use prices for noncore industrial and electric generator customers are established by adding a markup to the natural gas market price at the corresponding core or noncore segment at the regional market hub. These markups are endogenously derived as the difference between estimated historical end-use prices[102], and the NGTDM regional hub 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 (0.12 for core, 0.02 for noncore) of the annual percentage change in the associated electric generator consumption. This adjustment is intended to reflect anticipated additional infrastructure devoted to serving core 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 minus citygate prices plus Federal and State VNG taxes (Table 55). The price to non-fleet vehicles is based on the industrial sector firm price plus an assumed $4.14 (2000 dollars per thousand cubic feet) dispensing charge plus Federal and State taxes, set 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 55. Vehicle Natural Gas (VNG) Pricing
(Nominal dollars per thousand cubic feet)

Modified Census Divisions	Total Federal and State VNG Tax[1]
New England	2.16
Middle Atlantic	2.52
East North Central	1.81
West North Central	1.53
South Atlantic (excludes Florida)	1.81
East South Central	0.75
West South Central	1.60
Mountain (excludes Arizona and New Mexico)	0.85
Pacific (excludes California)	2.40
Florida	1.13
Arizona and New Mexico	0.27
California	0.70

[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 Information Resources, Inc., publication *Octane Week*, August 9, 1993, and State taxes posted at the Department of Energy website titled "Alternative Fuels Data Center" at www.afdc.doe.gov.

Capacity Expansion and Utilization

For the first 2 forecast years of the model, 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 simple representation is incorporated to capture 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 5 percent for all pipeline area. 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. In current form, time of use pricing can not be modeled.

Additions to underground storage capacity are constrained to capture limitations of geology in each of the market regions. The constraints limit total storage additions to be less than an expansion factor times the 1990 storage capacity. 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, which would be expected under normal weather conditions.

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 model also reflects current legislation and regulation.

Notes and Sources

[100] The electric generator end-use category includes gas consumption by any facility whose sole purpose is electricity generation (including independent power producers). Natural gas consumption by cogenerators (producers of electricity as a by-product of another process) is included in industrial end-use consumption.

[101] Natural gas consumption by electric generators is established in the Electricity Market Module of NEMS on a seasonal basis. These values are used as a basis for adjusting the related load patterns throughout the forecast.

[102] Historical core and noncore industrial prices were based on data from the Energy Information Administration, *Manufacturing Consumption of Energy 1994*, (Washington, DC, 1997).

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 alcohol and ethers, 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 refining activities in three U.S. regions. This representation provides the marginal costs of production for a number of traditional and new petroleum products. The linear programming results are used to determine end-use product prices for each Census Division using the assumptions and methods described below.[103]

Key Assumptions

Product Types and Specifications

The PMM models refinery production of the products shown in Table 56.

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 new fuels will remain the same as specified in current legislation, except that the sulfur content of all gasoline will be phased down to less than 10 percent of recent levels to reflect new regulations published by EPA in February 2000.[104]

Table 56. Petroleum Product Categories

Product Category	Specific Products
Motor Gasoline	Traditional Unleaded, Oxygenated, Reformulated
Jet Fuel	Kerosene-type
Distillates	Kerosene, Heating Oil, Highway 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

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

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 57): 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. PMM assumes that RFG has an average annual sulfur content of 135 ppm in 2000 and will meet the 30 ppm requirement in 2004. The reduction in sulfur content between now and 2004 is assumed to reflect incentives for "early reduction". 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 58.

Table 57. Year Round Gasoline Specifications by Petroleum Administration for Defense Districts (PADD)

PADD	Reid Vapor Pressure (Max PSI)	Oxygen Weight Percent (Min)	Oxygen Weight Percent (Max)	Aromatics Volume Percent (Max)	Benzene Volume Percent (Max)	Initial Sulfur PPM (Max)	Olefin Volume Percent (Max)	Percent Evaporated at 200°	Percent Evaluated at 300°
Conventional									
PADD I	9.65	—	—	28.6	1.5	338.4	10.8	41.0	83.0
PADD II-IV	9.83	—	—	28.6	1.5	338.4	10.8	41.0	83.0
PADD V	9.7	—	—	28.6	1.5	338.4	10.8	41.0	83.0
Reformulated									
PADD I-IV	8.55	2.0	2.1	25.0	0.66	135.0	12.0	49.0	87.0
PADD V through 2002	7.90	1.7	1.8	25.0	0.72	25.0	6.0	49.0	85.0
PADD V									
Nonattainment	7.90	2.0	2.1	22.0	0.70	15.0	4.0	49.0	85.0

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.

Table 58. Gasoline Sulfur Content Assumptions, by Region and Gasoline Type, Parts per Million (PPM)

	2000	2001	2002	2003	2004	2005	2006	2007	2008-2020
Conventional									
PADD I	-338.4	-289.7	-240.9	-192.2	-143.4	-117.3	-53.4	-41.7	-30
PADD II-I	-338.4	-282.4	-226.4	-170.5	-114.5	-88.7	-34.8	-32.4	-30
PADD V	-338.4	-284.5	-230.6	-176.7	-122.8	-95.6	-37.4	-33.7	-30
Reformulated									
PADD I	-135	-108.75	-82.5	-56.25	-30	-30	-30	-30	-30
PADD II-I	-135	-108.75	-82.5	-56.25	-30	-30	-30	-30	-30
PADD V	-25	-25	-25	-15	-15	-15	-15	-15	-15

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).

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.[105]

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.

Reformulated gasoline has been required in many areas in the U.S. 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 II” 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 57).

Table 59. Market Share for Gasoline Types by Census Division

	Census Division								
Gasoline Type/Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**
Conventional Gasoline	20	42	80	69	82	94	71	70	20
Oxygenated Gasoline (2.7% oxygen)	0	0	0	24	0	0	0	15	6
Reformulated Gasoline (2.0% oxygen)	80	58	20	7	18	6	29	15	74*

*Note: 59 percent is assumed to continue the 2.0 percent Federal oxygen requirement. 15 percent is not covered by this requirement.

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 2000.

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 Petroleum Administration for Defense District (PADD) V refiners must meet the California Air Resources Board (CARB) phase 2 specifications through 2002 and the recently developed “CARB3" specifications after 2002. The CARB3 specifications reflect the removal of the oxygen requirement designed to complement the State’s plans to ban the oxygenate, methyl tertiary butyl ether (MTBE) by the end of 2002. 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 the recently added San Jonquin Valley). *AEO2002* 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.

AEO2002 reflects legislation which bans or limits the use of MTBE in twelve additional States: Arizona, Colorado, Connecticut, Illinois, Iowa, Kansas, Michigan Minnesota, Nebraska, New York, and South Dakota, and Washington. 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 Census Division 1
— 36.5 percent of RFG in Census Division 2
— 97.7 percent of RFG in Census Division 8
— 100.0 percent of RFG(with 2.0 percent oxygen requirement) in Census Division 9
— 100.0 percent of oxygenated gasoline in Census Division 4
— 100.0 percent of oxygenated gasoline in Census Division 8
— 100.0 percent of oxygenated gasoline in Census Division 9

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.

Motor Gasoline Market Shares

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 *AEO2002,* the annual market shares for each region reflect actual 2000 market shares and are held constant throughout the forecast. (See Table 59 for *AEO2002* market share assumptions.)

Table 60. Summary of Refinery Site Environmental Costs by Petroleum Administration for Defense Districts (PADD)
(1998 dollars per barrel)

Cost Category	PADD I	PADD II	PADD III	PADD IV	PADD V
Environmental Costs	0.66	0.67	0.53	0.97	0.74

PADD = Petroleum Administration for Defense District.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived from estimated costs from the National Petroleum Council, U.S. Petroleum Refining-Meeting Requirement for Cleaner Fuels and Refineries, Volume 1, (Washington, DC, August 1993).

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 limit sulfur to 500 ppm.

AEO2002 also 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 ppm sulfur at the refinery gate. 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 cost for new distillate hydrotreaters reflected in *AEO2002* are $1,690 to $2,545 (2000 dollars) per barrel per day, ISBL. The lower estimate is for a 25,000 barrel per day unit processing low-sulfur streams with incidental dearomatization. The higher estimate is for a 10,000 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 that 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 *AEO2002* 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.[106] 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 supplied has 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.

No change in the sulfur level of non-road diesel is assumed because the EPA has not yet promulgated these standards.

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 (Table 60) are reflected as fixed costs (associated operation and maintenance costs prior to 1996 are excluded).[107] Assuming that refinery-related fixed costs are recovered in the prices of light products, fixed costs are allocated among the prices of liquefied petroleum gases, gasoline, distillate, kerosene, and jet fuel. These costs are based on average annual estimates and are assumed to remain constant over the forecast period.

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 61) 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 M85 are assumed to be equivalent to distribution costs for gasoline.

State and Federal taxes are also added to transportation fuels to determine final end-use prices (Tables 62 and 63). 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.[108] Federal taxes are assumed to remain at current levels in accordance with the overall *AEO2002* 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 61. Petroleum Product End-Use Markups by Sector and Census Division
(2000 dollars per gallon)

Sector/Product	Census Division 1	2	3	4	5	6	7	8	9
Residential Sector									
Distillate Fuel Oil	0.38	0.45	0.32	0.26	0.43	0.30	0.20	0.28	0.39
Kerosene	0.53	0.58	0.42	0.42	0.52	0.32	0.48	0.60	0.90
Liquefied Petroleum Gases	0.87	0.92	0.51	0.34	0.77	0.65	0.57	0.53	0.79
Commercial Sector									
Distillate Fuel Oil	0.14	0.12	0.85	0.03	0.07	0.04	0.04	0.04	0.07
Gasoline	0.14	0.13	0.14	0.14	0.13	0.17	0.17	0.16	0.16
Kerosene	0.28	0.22	0.21	0.15	0.20	0.26	0.25	0.19	0.23
Liquefied Petroleum Gases	0.54	0.35	0.46	0.33	0.54	0.43	0.34	0.46	0.58
Low-Sulfur Residual Fuel Oil	0.00	0.04	0.02	0.01	0.01	0.05	-0.01	-0.01	0.09
Utility Sector									
Distillate Fuel Oil	0.02	0.03	0.02	0.01	0.02	0.06	0.03	0.06	0.02
High-Sulfur Residual Fuel Oil[3]	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	-0.06	0.01	-0.10	0.10	0.22	0.18
Transportation Sector									
Distillate Fuel Oil	0.23	0.17	0.14	0.11	0.14	0.15	0.12	0.14	0.19
E85[1]	0.335	0.335	0.335	0.335	0.335	0.335	0.335	0.335	0.335
Gasoline	0.14	0.12	0.14	0.15	0.13	0.17	0.17	0.16	0.13
High-Sulfur Residual Fuel Oil[3]	-0.02	0.04	0.12	0.04	0.00	-0.08	0.06	0.27	0.04
Jet Fuel	0.00	-0.00	0.02	0.04	0.03	0.00	0.00	0.01	0.00
Liquefied Petroleum Gases	0.60	0.60	0.55	0.30	0.48	0.37	0.28	0.38	0.51
M85[2]	0.14	0.12	0.13	0.14	0.13	0.17	0.17	0.16	0.13
Industrial Sector									
Asphalt and Road Oil	0.21	0.16	0.26	0.17	0.15	0.09	0.19	0.35	0.17
Distillate Fuel Oil	0.16	0.14	0.13	0.10	0.10	0.08	0.10	0.09	0.12
Gasoline	0.18	0.13	0.14	0.15	0.13	0.17	0.17	0.16	0.14
Kerosene	0.28	0.23	0.21	0.14	0.19	0.25	0.25	0.23	0.23
Liquefied Petroleum Gases	0.42	0.47	0.51	0.27	0.46	0.36	0.20	0.25	0.51
Low-Sulfur Residual Fuel Oil	0.00	0.01	0.04	0.01	0.01	0.01	0.02	0.09	0.09

[1]85 percent ethanol and 15 percent gasoline.

[2]85 percent methanol and 15 percent gasoline.

[3]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 biproduct when crude oil is refined to make higher value products like gasoline and heating oil.

Note: Use conversion factors listed in Table H1 of the *Annual Energy Outlook 2002* to convert values to physical units.

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 1997*, DOE/EIA-0214(97), (Washington, DC, September 1999); EIA, *State Energy Price and Expenditures Report 1997*, DOE/EIA-0376(97), (Washington, DC, July 2000); and EIA, *Petroleum Marketing Monthly March 2001, DOE/EIA-0380(2001/03),* (Washington, DC, March 2001).

Table 62. State and Local Taxes on Petroleum Transportation Fuels by Census Division
(2000 dollars per gallon)

Year/Product	Census Division 1	2	3	4	5	6	7	8	9
Gasoline[1]	0.26	0.23	0.24	0.22	0.18	0.20	0.22	0.23	0.24
Diesel	0.21	0.26	0.25	0.20	0.18	0.16	0.20	0.22	0.23
Liquefied Petroleum Gases	0.11	0.13	0.17	0.19	0.16	0.16	0.15	0.09	0.05
M85[2]	0.25	0.18	0.19	0.15	0.13	0.17	0.20	0.14	0.12
E85[3]	0.24	0.18	0.16	0.16	0.13	0.17	0.20	0.13	0.12
Jet Fuel	0.04	0.03	0.01	0.03	0.04	0.03	0.00	0.03	0.03

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

[2] 85 percent methanol and 15 percent gasoline.

[3] 85 percent ethanol and 15 percent gasoline.

Source: Gasoline, diesel and LPG aggregated from Federal Highway Administration, Tax Rates on Motor Fuel February 1, 2000, Table MF-121T, http://www.fhwa.dot.gov/ohim/novmmfr.pdf, (Washington, DC, March 2000). M85 and E85 aggregated from Clean Fuels Report (Washington, DC, February 2000). Jet Fuel from EIA, Office of Oil and Gas.

Table 63. 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 64.

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.

Regional Assumptions

PMM reflects three refining regions: PADD I, PADD V, and a third region including PADD II-IV. Individual refineries are aggregated into one linear programming representation for each region. In order to interact with other NEMS modules with different regional representations, certain PMM inputs and outputs are converted from a PMM region to a non-PMM regional structure and vice versa.

Table 64. Crude Oil Specifications

Crude Oil Categories	Sulfur (percent)	Gravity (degrees API)
Low Sulfur Light	0 - 0.5	> 24
Medium Sulfur Heavy	0.35 - 1.1	> 24
High Sulfur Light	> 1.1	> 32
High Sulfur Heavy	> 1.1	24 - 33
High Sulfur Very Heavy	> 0.7	0 - 23

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

Cogeneration Assumptions

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 cogeneration, and merchant cogeneration. Power generators and cogenerators are modeled in the PMM linear program as separate units which are allowed to compete along with purchased electricity. Both the refinery and merchant cogeneration units provide estimates of capacity, fuel consumption, and electricity sales to grid based on historical parameters.

Refinery sales to the grid are estimated using the following percentages which are based on 1998 data:

Region	Percent Sold To Grid
1 (PADD I)	56.9
2 (PADD's II, III, and IV)	4.3
3 (PADD V)	20.1

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

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

Merchant cogenerator's are defined as non-refiner owned facilities located near refineries to provide energy to the open market and to the neighboring refinery. The PMM assumes that 66 percent of electricity from merchant cogenerators in every region is sold to the grid. 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.

Capacity Expansion Assumptions

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 plant life. Expansion through 2000 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 2005 the cycle begins anew, looking ahead to 2008.

Strategic Petroleum Reserve Fill Rate

AEO2002 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.

Short-term Methodology

Petroleum balance and price information for the year 2001 is projected at the U.S. level in the *Short-term Energy Outlook, (STEO*). The PMM assumes the *STEO* results for 2000, 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.

AEO2002 reflects legislation which bans or limits the use of the gasoline blending component MTBE in the following states: Arizona, California, Colorado, Connecticut, Illinois, Iowa, Kansas, Michigan, Minnesota, Nebraska, New York, South Dakota, and Washington.

AEO2002 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.

AEO2002 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 80 percent of highway diesel contain no more than 15 ppm sulfur while the remaining 20 percent of highway diesel 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.

A number of pieces of legislation are aimed at controlling air, water, and waste emissions from refineries themselves. The PMM incorporates related environmental investments as refinery fixed costs. The estimated expenditures are based on results of the 1993 National Petroleum Council Study.[109] These investments reflect compliance with Titles I, III, and V of CAAA90, the Clean Water Act, the Resource Conservation and Recovery Act, and anticipated regulations including the phaseout of hydrofluoric acid and a broad-based requirement for corrective action. No costs for remediation beyond the refinery site are included.

Lifting the ban on exporting Alaskan crude oil was passed and signed into law (PL 104-58) in November 1995. Alaskan exports of crude oil have represented about 60 percent of U.S. crude oil exports since November 1995 and are assumed to equal 60 percent of total U.S. crude oil exports in the forecast.

Biofuels (Ethanol) Supply

Background

The PMM provides supply functions on an annual basis through 2020 for ethanol produced from both corn and cellulosic biomass to produce transportation fuel.

Assumptions

- 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.

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.[110]

- 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 of $0.54 per gallon of ethanol (5.4 cents per gallon subsidy to gasohol at a 10-percent volumetric blending portion) is applied within the premium. This subsidy is scheduled to be reduced to 51 cents by 2007. 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, and the associated costs are included in PMM.

Methyl Tertiary Butyl Ether Ban Case

This alternative case reflects a nationwide ban on MTBE and other ethers starting in 2006. A strong political impetus for restricting the use of MTBE has developed because the chemical has made its way from leaking pipelines and storage tanks into water supplies throughout the country. Thus far, 13 States have passed legislation to ban or reduce the use of MTBE, and there have been similar proposals in other States and the U.S. Congress. The MTBE ban case assumes that bans or restrictions currently scheduled in 13 States will be implemented as planned over the next few years.

The use of MTBE began to increase as a result of the introduction of oxygenated gasoline in the fall of 1993. The MTBE ban case provides a most severe scenario in terms of gasoline blending, because the oxygen specification in RFG is assumed to remain unchanged. PMM does not account for the possible conversion of MTBE units to alkylation or iso-octane processes. Other than the ban on ethers in gasoline, the model inputs and assumptions are the same as in the *AEO2002* reference case. Imports of reformulated blendstock for oxygenate blending (RBOB) are assumed to be available.

High Renewables Case

The high renewables case uses more optimistic assumptions about renewable energy sources. The supply curve for cellulosic ethanol is shifted in each forecast year relative to the reference case, making larger quantities available at any given price than are available in the reference case.

Notes and Sources

[103] Energy Information Administration, *EIA Model Documentation: Petroleum Market Model of the National Energy Modeling System*, DOE/EIA-M059 (2002), (Washington, DC, January 2002).

[104] U.S. Environmental Protection Agency, "Tier2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements, February 2000, (Washington, DC).

[105] 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).

[106] 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).

[107] Environmental cost estimates are based on National Petroleum Council, U.S. Petroleum Refining: Meeting Requirements for Cleaner Fuels and Refineries, Volume I, (Washington, DC, August 1993). Associated operating and maintenance base costs predating 1995 are excluded as they are reflected in the refinery fixed operating cost estimates.

[108] American Petroleum Institute. "How Much We Pay for Gasoline": 1996 Annual Review, Page 4 (Washington, DC, May 1997).

[109] National Petroleum Council, *U.S. Petroleum Refining: Meeting Requirements for Cleaner Fuels and Refineries*, Volume 1, (Washington, DC, August 1993).

[110] 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).

Coal Market Module

The NEMS Coal Market Module (CMM) provides forecasts of U.S. coal production, consumption, exports, 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 2002,* DOE/EIA-M060(2002) (Washington, DC, January 2002*).*

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. Separate supply curves are developed for each of 11 supply regions and 12 coal types (unique combinations of thermal grade, sulfur content, and mine type). The modeling approach used to construct regional coal supply curves addresses the relationship between the minemouth price of coal and corresponding levels of coal production, labor productivity, and the cost of factor inputs (mining equipment, mine labor, and fuel requirements).

The key assumptions underlying the coal production modeling are:

- Mining costs are assumed to vary with changes in mine production, labor productivity, and factor input costs. Factor input costs are represented by projections of electricity prices from the Electricity Market Module (EMM) and estimates of future coal mine labor and mining equipment costs.

- Between 1979 and 2000, U.S. coal mining productivity (measured in short tons of coal produced per miner per hour) increased at an estimated average rate of 6.6 percent per year. The major factors underlying these gains were interfuel price competition, structural change in the industry, and technological improvements in coal mining.[111] 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, productivity improvements are assumed to continue, but to decline in magnitude. Different rates of improvement are assumed by region and by mine type, surface and underground. On a national basis, labor productivity increases on average at a rate of 2.2 percent a year over the entire forecast, declining from an estimated annual rate of 5.7 percent in 2000 to approximately 1.5 percent over the 2010 to 2020 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.[112]

- Between 1985 and 1993, the average hourly wage for U.S. coal miners (in 2000 dollars) declined at an average rate of 1.5 percent per year, falling from $22.12 to $19.58.[113] During this same time period the producer price index (PPI) for mining machinery and equipment (in 2000 dollars) declined by 0.6 percent per year, falling from 162.4 to 155.3.[114] In the reference case, both the wage rate for U.S. coal miners and mine equipment costs are to remain constant in 2000 dollars (i.e., increase at the general rate of inflation). This assumption reflects the more recent trend in wages and mine equipment costs that has prevailed since 1993. In 2000, the average hourly wage rate for coal miners was $19.09, and the PPI for mining machinery and equipment was 155.1.

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 in each demand region using a linear programming algorithm. Production and distribution are computed for 11 supply and 13 demand regions for 18 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 provided by the EMM, and coal export demands are provided from the CMM itself.

The key assumptions underlying the coal distribution modeling are:

- Base-year transportation costs are estimates of average transportation costs for each origin-destination pair. 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, *Coke Plant Report-Quarterly*, 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*.

Coal transportation costs are modified over time in response to projected variations in reference case fuel costs (No. 2 diesel fuel in the industrial sector), labor costs, the producer price index for transportation equipment, and a time trend. The transportation rate multipliers used for all five *AEO2002* cases are shown in Table 65.

Table 65. Transportation Rate Multipliers
(1999=1.000)

Year	Reference Case	High Oil Price	Low Oil Price	High Economic Growth	Low Economic Growth
1999	1.0000	1.0000	1.0000	1.0000	1.0000
2005	0.9358	0.9535	0.923	0.9389	0.9341
2010	0.8790	0.8949	0.8609	0.8909	0.8688
2015	0.8336	0.8468	0.8130	0.8579	0.8155
2020	0.7629	0.7747	0.7448	0.7911	0.7385

Source: Energy Information Administration. Based on methodology described in "Forecasting Annual Energy Outlook Coal Transportation Rates", *Issues in Midterm Analysis and Forecasting 1997*, DOE/EIA-0607(97), (Washington, DC, July 1997).

- 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.

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 disruption, even though this adds 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 *AEO2002* forecast cases are shown in Tables 66 and 67.

Table 66. World Steam Coal Import Demand by Import Region, 2000-2020
(Million metric tons of coal equivalent)

Import Regions[1]	2000	2005	2010	2015	2020
The Americas	33.9	41.2	42.5	42.3	42.0
United States	10.0	15.1	15.7	16.3	16.9
Canada	13.5	9.9	8.6	7.9	7.4
Mexico	4.1	8.5	9.0	9.2	9.2
South America	6.3	7.7	9.2	8.9	8.5
Europe	110.6	114.9	111.3	107.1	103.8
Scandinavia	11.3	8.5	5.6	4.4	3.6
U.K/Ireland	14.1	15.8	16.9	16.9	16.9
Germany/Austria	16.6	21.8	21.8	22.7	24.5
Other NW Europe	21.0	20.5	17.7	14.5	10.9
Iberia	14.5	11.0	11.3	11.3	9.5
Italy	10.0	8.7	8.3	7.8	7.3
Med/E Europe	23.1	28.6	29.7	29.5	31.1
Asia	170.1	208.6	240.1	253.9	268.7
Japan	70.0	80.2	90.6	92.8	94.2
East Asia	67.4	81.1	91.0	95.5	99.1
China/Hong Kong	8.6	10.8	15.3	19.8	26.1
ASEAN	15.3	27.0	32.2	33.9	36.5
Indian Sub	8.8	9.5	11.0	11.9	12.8
Total	314.6	364.7	393.9	403.3	414.5

[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.

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; and SSY Consultancy and Research, "Data Updates for the International Coal Trade Component of the National Energy Modeling System", June 1999.

- 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.

Table 67. World Metallurgical Coal Import Demand by Import Region, 2000-2020
(Million metric tons of coal equivalent)

Import Regions[1]	2000	2005	2010	2015	2020
The Americas	19.6	22.2	24.4	27.4	29.6
United States	1.3	1.1	1.1	1.0	0.9
Canada	3.9	3.9	3.8	3.6	3.7
Mexico	0.6	2.2	2.8	3.6	3.8
South America	13.8	15.0	16.7	19.2	21.2
Europe	53.9	54.9	54.4	53.7	52.9
Scandinavia	2.9	2.7	2.4	2.2	1.9
U.K/Ireland	7.6	7.6	7.6	7.1	7.1
Germany/Austria	5.1	6.9	6.9	6.9	6.9
Other NW Europe	15.1	15.1	13.2	12.2	11.2
Iberia	4.2	3.8	3.8	3.8	3.8
Italy	7.6	7.2	7.1	6.3	6.3
Med/E Europe	11.4	11.6	13.4	15.2	15.7
Asia	97.6	99.9	102.2	104.8	106.9
Japan	58.5	56.4	52.7	51.3	49.9
East Asia	26.1	28.4	31.7	33.6	35.9
China/Hong Kong	0.5	0.6	1.7	1.7	1.9
ASEAN	0.0	0.0	0.0	0.0	0.0
Indian Sub	12.5	14.5	16.1	18.2	19.2
Total	171.1	177.0	181.0	185.9	189.4

[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.

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; and SSY Consultancy and Research, "Data Updates for the International Coal Trade Component of the National Energy Modeling System", June 1999.

- 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 thousand nautical miles.

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 860B which records the quality of coal consumed at independent power producers, the Form EIA5 and 5a which record the origin, cost, and quality of coal receipts at domestic coke plants, and the Forms EIA 3 and 3a, which record 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 in Table 68, 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 emissions levels for each coal type are listed in Table 68 in pounds of carbon dioxide emitted per million Btu.[115]

Legislation

It is assumed that provisions of the Energy Policy Act of 1992 that relate to the future funding of the Health and Benefits Fund of the United Mine Workers of America will have no significant effect on estimated production costs, although liabilities of company's contributions will be redistributed. Electricity sector demand for coal, which represented 89 percent of domestic coal demand in 2000, incorporates the provisions of the Clean Air Act Amendments of 1990. It is assumed that electricity producers will be granted full flexibility to meet the specified reductions in sulfur dioxide emissions. The reference case excludes any potential environmental actions not currently mandated such as mercury reductions or other rules or regulations not finalized.

Mining Cost Cases

In the reference case, labor productivity is assumed to increase at an average rate of 2.2 percent per year through 2020, while wage rates and mine equipment costs remain constant in 2000 dollars. Two alternative cases were modeled in the NEMS CMM, assuming different growth rates for both labor productivity and miner wages. In a low mining cost sensitivity case, productivity increases at 3.7 percent per year, and real wages and mine equipment costs decline by 0.5 percent per year. In a high mining cost sensitivity case, productivity increases by 0.6 percent per year, and real wages and mine equipment costs increase by 0.5 percent per year. In the alternative cases, the annual growth rates for productivity were increased and decreased by mine type (underground and surface), based on historical variations in labor productivity during the years 1980 through 1998. Both cases were run using only the NEMS energy supply modules (Oil and Gas Supply Module, Natural Gas Transmission and Distribution Module, Coal Market Module, and Renewable Fuels Module), the Petroleum Market Module, and the Electricity Market Module, rather than as a fully integrated NEMS run. Consequently, no price-induced demand feedback in end-use coal markets was captured. In an integrated run, the demand response would tend to moderate the magnitude of the equilibrium price response.

Table 68. Production, Heat Content, and Sulfur and Carbon Dioxide Emissions by Coal Type and Region

Coal Supply Region	States	Coal Rank and Sulfur Level	Mine Type	1999 Production (Million Short tons)	Heat Content (Million Btu per Short Ton)	Sulfur Content (Pounds Per Million Btu)	Hg Content (Pounds Per Trillion Btu)	CO2 Emissions (Pounds Per Million Btu)
Northern Appalachia	PA, OH, MD, WV (North)	Metallurgical	Underground	8.4	26.80	0.76	N/A	205.4
		Low-Sulfur Bituminous	All	2.3	24.67	0.57	11.62	203.6
		Mid-Sulfur Bituminous	All	68.3	25.59	1.27	11.16	205.4
		High-Sulfur Bituminous	All	62.5	24.37	2.63	11.67	203.6
		Waste Coal (Gob and Culm)	Surface	9.6	12.43	1.74	63.90	203.6
Central Appalachia	KY(East), WV (South), VA	Metallurgical	Underground	46.8	26.80	0.61	N/A	203.8
		Low-Sulfur Bituminous	All	67.7	25.15	0.55	5.61	203.8
		Mid-Sulfur Bituminous	All	147.0	24.96	0.85	7.58	203.8
Southern Appalachia	AL, MS, TN	Metallurgical	Underground	4.0	26.80	0.55	N/A	203.3
		Low-Sulfur Bituminous	All	5.9	24.97	0.54	3.87	203.3
		Mid-Sulfur Bituminous	All	12.7	24.34	1.05	10.15	203.3
		Mid-Sulfur Lignite	Surface	*	10.59	1.10	14.11	211.4
East Interior	IL, IN, KY (West)	Mid-Sulfur Bituminous	All	31.8	23.03	1.06	5.60	202.8
		High-Sulfur Bituminous	All	72.2	22.51	2.75	6.35	202.5
West Interior	IA, MO, KS, AR, OK. TX (Bit)	High-Sulfur Bituminous	Surface	2.7	22.22	2.73	21.55	202.4
Gulf Lignite	TX (Lig), LA	Mid-Sulfur Lignite	Surface	35.9	12.83	1.14	14.11	211.4
		High-Sulfur Lignite	Surface	19.9	12.93	2.08	15.28	211.4
Dakota Lignite	ND, MT(Lig)	Mid-Sulfur Lignite	Surface	31.4	13.30	1.14	8.38	216.6
Powder River, Green River, and Hannah Basins	WY, MT(Sub)	Low-Sulfur Subbituminous	Surface	341.5	17.38	0.36	5.68	210.7
		Mid-Sulfur Subbituminous	Surface	34.8	17.51	0.80	5.82	210.7
		Low-Sulfur Bituminous	Underground	1.7	21.64	0.58	2.08	204.4
Rocky Mountain	CO, UT	Low-Sulfur Bituminous	Underground	46.9	23.25	0.41	3.82	203.0
		Low-Sulfur Subbituminous	Surface	9.5	20.62	0.39	2.04	210.6
Southwest	AZ, NM	Low-Sulfur Bituminous	Surface	21.0	21.25	0.46	4.66	205.4
		Mid-Sulfur Subbituminous	Surface	20.0	18.32	0.88	7.18	206.7
Northwest	WA, AK	Mid-Sulfur Subbituminous	Surface	5.7	15.70	0.83	6.99	207.9

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

N/A = not available.

Source: Energy Information Administration, Form EIA-3, "Quarterly Coal Consumption Report—Manufacturing Plants"; Form EIA-3A, "Annual Coal Quality Report—Manufacturing Plants"; Form EIA-5, "Coke Plant Report Quarterly"; Form EIA-5A, "Annual Coal Quality Report—Coke Plants"; Form EIA-860B, "Annual Electric Generator Report—Nonutility"; Form EIA-6A, "Coal Distribution Report—Annual"; and Form EIA-7A, "Coal Production 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).

Notes and Sources

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

[113] U.S. Department of Labor, Bureau of Labor Statistics, Series ID: EEU1012006.

[114] U.S. Department of Labor, Bureau of Labor Statistics, Series ID: PCU3532#.

[115] 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 five submodules representing various renewable energy sources, biomass, geothermal, landfill gas, solar, and wind; a sixth renewable, conventional hydroelectric power, is represented in the Electricity Market Module (EMM).[116]

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 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 was an original source of electricity generation, 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 low-cost energy storage.

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 Cogeneration description 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 *AEO2002* 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. The RFM submodules that interact with the EMM are the central station grid-connected biomass, geothermal, landfill gas, solar (thermal and photovoltaic), and wind submodules. Most provide specific data or estimates that characterize that resource in a useful manner. In addition, a set of technology cost and performance values is provided directly to the EMM. These values are central to the build and dispatch decisions of the EMM. The values are presented in Table 38. Overnight capital costs and other extended performance characteristics are presented in Table 69.

Conventional Hydroelectricity

The Hydroelectric Power Data File in the EMM represents reported plans for new conventional hydroelectric power capacity connected to the transmission grid and reported on Form EIA-860, *Annual Electric Generator Report*, and Form EIA-867, *Annual Nonutility Power Producer Report*. It does not estimate pumped storage hydroelectric capacity, which is considered a storage medium for coal and nuclear power and not a renewable energy use. However, the EMM allows new conventional hydroelectric capacity to be built in addition to reported plans. Converting Idaho National Engineering and Environmental Laboratory information on U.S. hydroelectric potential, the EMM contains regional conventional hydroelectric supply estimates at increasing capital costs. All the capacity is assumed available at a uniform capacity factor of 45 percent. Data maintained for hydropower include the available capacity, capacity factors, and costs (capital, and fixed and variable operating and maintenance). The fossil-fuel heat rate equivalents for hydropower are provided to the report writer for energy consumption calculation purposes only. Because of hydroelectric power's position in the merit order of generation, it is assumed that all available installed hydroelectric capacity will be used within the constraints of available water supply and general operating requirements (including environmental regulations).

Table 69. Cost and Performance Characteristics for Renewable Energy Generating Technologies: Two Cases

		Total Overnight Costs[1]		Best Available Capacity Factors	
Technology/Decision Year	Overnight Costs in 2001 (Reference) ($2000/kW)	Reference ($2000/kW)	High Renewable ($2000/kW)	Reference (%)	High Renewable (%)
Biomass	1,725				
2005		1,556	1,510	80	80
2010		1,424	1,429	80	80
2015		1,376	1,379	80	80
2020		1,303	1,315	80	80
MSW - Landfill Gas[2]	1,429				
2005		1,417	1,417	90	90
2010		1,402	1,402	90	90
2015		1,387	1,387	90	90
2020		1,373	1,373	90	90
Geothermal[3]	1,746				
2005		1,695	1,506	95	95
2010		1,586	1,292	95	95
2015		1,680	1,458	95	95
2020		2,026	1,709	95	95
Wind	982				
2005		921	932	39	44
2010		907	871	41	46
2015		876	811	42	47
2020		826	750	42	48
Solar Thermal	2,539				
2005		2,454	2,906	42	52
2010		2,348	2,990	42	63
2015		2,243	2,934	42	75
2020		2,137	2,877	42	77
Photovoltaic	3,830				
2005		2,722	3,260	30	30
2010		2,404	1,686	30	30
2015		2,293	1,466	30	30
2020		2,219	1,246	30	30

[1]Overnight capital cost (i.e.excluding interest charges), plus contingency factors and learning, excluding regional multipliers.

[2]Provided to show evolution of landfill gas costs through 2020; for landfill gas, assumptions in the high renewables case are unchanged from the reference case

[3]Because geothermal cost and performance characteristics are specific for each site, the table entries represent the least cost units available in the Northwest Power Pool region, where most of the proposed sites are located.

Source: Capital Costs: AEO2002 National Energy Modeling System runs: aeo2002.d102001b, hirenew02.d102301a; capacity factors: Energy Information Administration, Office of Integrated Analysis and Forecasting, as described in text in this report for each technology.

Capital Costs

The capital costs of renewable energy technologies are modified to represent two phenomena:

- Short-term cost adjustment factors, which increase technology capital costs as a result of rapid U.S. buildup in a single year, reflect limitations on the infrastructure (for example, manufacturing, resource assessment, construction expertise) to accommodate unexpected demand growth. These short-term factors are invoked when demand for new capacity in any year exceeds 50 percent of the prior year's total U.S. capacity. For every 1 percent increase in total U.S. capacity over the previous year greater than 50 percent, capital costs rise 0.5 percent for wind, 0.33 percent for biomass, and 1 percent for solar technologies.

- For geothermal and wind, higher costs are assumed to result from large cumulative increases in these resources' use, reflecting any or all of three general longer-term costs: (1) resource degradation, (2) transmission network upgrades, and (3) market factors. Presumably best land resources are used first. Increasing resource use necessitates resort to less efficient land - less accessible, less productive, more difficult to use (e.g, land roughness, slope, terrain variability, or productivity, wind turbulence or wind variability). Second, as capacity increases, especially for intermittent technologies like wind power, existing local and long-distance transmission networks require upgrading, increasing overall costs. Third, market pressures from competing land uses increase costs as cumulative capacity increases, including competition from agricultural or other production alternatives, residential or recreational use, aesthetics, or from broader environmental preferences. As a result, for *AEO2002*, each EMM region's wind resource estimates are parceled into five cost levels, 0, 20, 50, 100 and 200 percent respectively. For geothermal, four successive increments incur neither, either, or both of 33 percent increases in the drilling and field cost portions of capital costs and doubling of the relatively small exploration cost component. The size of the resource increments varies by technology and region.

For a description of NEMS algorithms lowering generating technologies' capital costs as more units enter service (learning), see "Technological Optimism and Learning" in the Electricity Market Module section 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 2002*, DOE/EIA-M069(2002) (Washington, DC, January 2002).

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 primarily 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).[117] 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).

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 Cogeneration description in the "Commercial Demand Module" section of the report.

Assumptions

- Capacity factors for solar technologies are assumed to vary by time of day and season of 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 for such reasons 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 2020.

- NEMS represents the Energy Policy Act of 1992 (EPACT) permanent 10-percent investment tax credit for solar electric power generation by tax-paying entities.

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 13 mph, and wind speeds are categorized into three wind classes according to annual average wind speed. The RFM tracks wind capacity (megawatts) within a region and moves to the next best wind class when one category is exhausted. Wind resource data on the amount and quality of wind per EMM region come from a Pacific Northwest Laboratory study and a subsequent update.[118] The technological performance, cost, and other wind data used in NEMS are derived by EIA from consultation with industry experts.[119] 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 is constrained 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.

- Availability of wind power (among three wind classes) is based on the Pacific Northwest Laboratory Environmental and Moderate Land-Use Exclusions Scenario, in which some of the windy land area is not available for siting of wind turbines. The percent of total windy land unavailable under this scenario consists of all environmentally protected lands (such as parks and wilderness areas), all urban lands, all wetlands, 50 percent of forest lands, 30 percent of agricultural lands, and 10 percent of range and barren lands.

- Wind resources are mapped by distance from existing transmission capacity among three distance categories, accepting wind resources within (1) 0-5, (2) 5-10, and (3) 10-20 miles on either side of the transmission lines. Transmission cost factors are added to the resources further from the transmission lines.

- Capital costs for wind technologies are also 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, the increasing costs of alternative land uses, including for 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 in each category vary by EMM region.

- 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 “fuel savers” 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 and fuel costs for existing (non-wind) capacity.

- 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 windy land area and is factored into requests for generating capacity by the EMM.

- Capacity factors are assumed to increase to a national average of about 42 percent in the best wind class resulting from taller towers, more reliable equipment, and advanced control technologies. However, as better wind resources are depleted, capacity factors are assumed to go down.

- *AEO2002* includes the 1.5 (adjusted for inflation to 1.7) cent per kilowatthour Federal production tax credit (PTC) received for the first 10 years of a new wind unit’s production; the PTC is applied to all taxpayer-owned wind units entering service from 1993 through 2001. The PTC is represented in NEMS as a 2.7 cent per kilowatthour reduction in required electricity plant revenue in order to more accurately represent its after-tax market value. Although a similar Federal incentive exists for publicly-owned (non tax paying) units, all wind units are assumed owned by taxpaying entities in the RFM.

For *AEO2002*, the performance characteristics of wind turbine technology were updated to ensure consistency with current developments and reasonably expected improvements over the forecast period. Two parameters were examined: capacity factor and energy capture (energy per swept rotor area). The evaluation resulted in assumed improved performance in both factors; the estimated 2020 capacity factor for Class 6 winds improved from 30 percent to 42 percent, and the estimated 2020 energy capture improved from 1381 kilowatthours per square meter per year to 1582 kilowatthours per square meter per year. There were corresponding changes in other wind classes and years.

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 updated estimates provided in 1999 by DynCorp Corporation and subsequently adapted by EIA.[120] Hot dry rock resources are not considered cost effective until after 2020 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 (the high estimate) within each EMM region among four increasing cost categories, with the lowest cost category (the low estimate of available capacity) 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 as for other technologies. 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 an 80 percent capacity factor; both are assigned an 87 percent capacity factor for actual generation.

For *AEO2002*, the GES was modified and estimates of available supply were reduced. First, to more realistically reflect each of the 51 sites' capacity availability through 2020, the 40-year estimates included for *AEO2001* were reduced, usually to about 100 megawatts for each of four cost levels for each site. Second, annual maximum capacity builds were established for each site, reflecting industry practice of expanding development gradually. For the reference case, each site was permitted a maximum development of 25 megawatts per year through 2015 and 50 megawatts per year thereafter; for the high renewables case, the 50 megawatt annual limit applies to all years.

Assumptions

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

- The permanent investment tax credit of 10 percent available in all forecast years based on the EPACT applies to all geothermal capital costs.

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

- Capital and operating costs vary by site and year; values shown in Table 38 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, 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, these same supply schedules.

Assumptions

- Existing and planned capacity data are obtained from Forms EIA-860A and EIA-860B.

- The conversion technology represented, upon which the costs in Table 38 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 5 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. The first three are combined into a single supply schedule for each region which does not change for the full forecast period. Energy crops data are presented in yearly schedules from 2010 to 2020 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.[121] The wood

Table 70. U.S. Biomass Resources, by Region and Type, 2020
(Trillion Btu)

	Forest Resources	Urban Wood Waste/ Mill Residue	Energy Crops	Agricultural Residue	Total
1. ECAR	363	156	183	407	1,110
2. ERCOT	29	45	78	57	210
3. MAAC	44	50	19	28	142
4. MAIN	125	36	112	439	712
5. MAPP	191	39	398	946	1,573
6. NPCC/NY	40	63	59	3	165
7. NPCC/NE	81	50	38	0	170
8. SERC/FL	32	42	4	0	79
9. SERC	342	307	217	61	927
10. SPP	225	138	387	264	1,014
11. NWP	414	180	0	53	647
12. W/RA	105	30	6	54	195
13. W/CNV	43	94	0	23	161
Total US	**2,036**	**1,231**	**1,501**	**2,335**	**7,103**

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; all other biomass resources: Oak Ridge National Laboratory, personal communication with Marie Walsh, August 20, 1999.

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.[122] Agricultural residues are wheat straw and corn stover only, which make up the great majority of crop residues.[123] Energy crops data are for hybrid poplar, willow and switchgrass grown on crop land, pasture land, or on Conservation Reserve lands.[124] The maximum amount of resources in each supply category is shown in Table 70.

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).[125]

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 2000*[126].

- 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[127].

- 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.

High Renewables Case

The High Renewables case examines the effect on energy supply of using cost and performance assumptions for nonhydro, non-landfill gas renewable energy technologies approximating published goals of the relevant program offices of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy (DOE/EE). For electric power sector technologies, the High Renewables assumptions are designed to correspond to year 2020 cost and performance goals in the *Renewable Energy Technology Characterizations* document jointly published by the DOE/EE and the Electric Power Research Institute (EPRI). [128] These assumptions, summarized in Table 69, include:

- Biomass: For biomass in the high renewables case, capital costs are modified from reference case values such that they are similar to those in the EE/EPRI *Technology Characterization* costs for biomass gasification by 2020. In addition, biomass supplies are increased 10 percent across all price steps for the four types of biomass. Fixed operations and maintenance costs are reduced about 14 percent to be consistent with *Technology Characterization* costs. Biomass capacity factors are unchanged from the reference case.

- Geothermal: For geothermal in the high renewables case, EIA assumes that (1) capital costs for all 51 sites in 2000 match higher EIA rather than EE *Technology Characterization* estimates for this "base" year, (2) EIA assumptions for capital costs decline at a rate sufficient to match *Technology Characterization* estimates by 2010, meaning that high renewables case assumptions remain higher than DOE/EE assumed costs through 2009 and (3) the lowest cost geothermal site available in 2000 (Roosevelt Hot Springs), would, if available for selection in 2020 (decision year), meet the 2020 *Technology Characterization* capital cost goal in that year, about 36 percent below its current $1800 per kilowatt ($99) cost. Finally, because each of the 51 sites is separately priced, EIA applies the rates (rather than amounts) of capital cost decline necessary for Roosevelt Hot Springs to meet these requirements to all other 50 sites. Overall, each site's capital cost declines by 3 percentage points per decision year from 2000-2010, and by 0.6 percentage point per year from 2011-2020, using the capital cost weights:

Decision Year	Weight
2000	1.00
2005	0.85
2010	0.70
2015	0.67
2020	0.64

Least cost geothermal sites in any case result from the interaction of (a) baseline cost estimates for each site, (b) cost adjustment factors, and (c) increased costs as least-cost units are taken and higher cost sites are chosen. Therefore, in the high renewables case results, actual 2020 marginal capital costs by 2020 will not necessarily be lower than in the reference case but will instead show greater quantities of geothermal available and chosen before again attaining the higher marginal costs.

In the high renewables case, geothermal capacity factors and fixed operations and maintenance costs (O&M) are unchanged from the reference case.

- Photovoltaics (Central Station): For photovoltaics, EIA assumes reduced capital and operations and maintenance costs, corresponding to utility scale flat plate "Thin Film" technology in the EE/EPRI *Technology Characterizations*. Performance is assumed unchanged from the reference case.

- Solar Thermal: For solar thermal in the high renewables case, EIA assumes increased capital costs compared to the reference case, with significantly improved performance (as measured by capacity factor); in addition, operations and maintenance costs are reduced. This corresponds with the Central Receiver (Solar Power Tower) technology in the EE/EPRI *Technology Characterization*, which incorporates, at additional cost, increasing levels of thermal energy storage in the forecast years.

- Wind: EIA assumes reduced capital and operations and maintenance costs, with increased performance (as measured by capacity factor and energy capture per swept rotor area) in all wind classes. The EE/EPRI *Technology Characterizations* only specify goals for Class 4 and 6 winds, thus improvements in Class 5 winds are interpolated.

Because costs are assumed to decline (or increase, in the case of Solar Thermal) based on the exogenous cost trajectory of the *Technology Characterizations*, the normal learning function of the EMM does not apply to these capacity types. Thus cost targets are achieved regardless of actual market penetration.

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.

Legislation

Energy Policy Act of 1992 (EPACT)

The RFM includes the investment tax and energy production credits established in the EPACT for the appropriate energy types. EPACT provides a renewable electricity production tax credit (PTC) of 1.5 cents per kilowatt-hour for electricity produced by wind, applied to plants that become operational between January 1, 1994, and June 30, 1999; *AEO2002* includes extension of the PTC (adjusted for inflation to 1.7 cents) through December 31, 2001, as provided in section 507 of the Tax Relief Extension Act of 1999. The credit extends for 10 years after the date of initial operation. EPACT also includes provisions that allow an investment tax credit of 10 percent for solar and geothermal technologies that generate electric power. This credit is represented as a 10-percent reduction in the capital costs in the RFM.

Production Tax Credit

Because it is currently scheduled to expire on December 31, 2001, the PTC has no effects on wind or biomass capacity projections post 2001 for either the reference or the high renewables case. However, H.R. 4, the "Securing America's Future Energy Act of 2001" (SAFE Act), having passed the House of Representatives in early August of 2001 and currently pending in the Senate, would extend the PTC to December 31, 2006, as well as expand eligibility to facilities using open-loop biomass and landfill gas fuels. The "Legislation and Regulations" section of the *AEO2002* discusses the results of a NEMS case that extends the PTC to 2006 and also allows new biomass and landfill gas capacity to receive the tax credit.

Supplemental and Floor Capacity Additions

In addition to the reported generating capacity plans from the EIA-860A and EIA-860B and capacity projected through the use of the EMM and RFM, the *AEO2002* also includes 7,865 megawatts additional generating capacity powered by renewable resources. Summarized in Table 71 and detailed in Table 72, some of the capacity represents mandated new capacity required by state laws, EIA estimates for expected new capacity under state-enacted renewable portfolio standards (RPS), estimates of winning bids in California's renewables funding program (Assembly Bill 1890), expected new capacity under known voluntary programs, such as "green marketing" efforts, and other publicly stated plans. The additions do not include 382 megawatts of planned additional wind capacity contingent upon extension of the EPACT production tax credit beyond its current 2001 expiration; in addition, they do not include off-grid or distributed photovoltaics or hydroelectric power.

Table 71. Post-2000 Supplemental Capacity Additions (Megawatts, Net Summer Capability)

Rationale	Geothermal	Biomass	Landfill Gas	Solar Thermal	Solar Photovoltaic	Wind	Total
Mandates	0.0	71.3	47.5	0.0	0.0	130.0	248.8
RenewablePortfolio Standards	301.2	300.5	808.4	21.6	9.1	3418.5	4859.3
California AB1890[1]	214.6	18.5	113.3	0.0	0.0	1579.3	1925.7
Other Reported Plans[2]	14.0	15.1	212.3	0.0	8.3	581.3	831.0
Total	529.8	405.4	1181.5	21.6	17.4	5709.1	7864.8

[1]Partially supported by funding under California Assembly Bill 1890.

[2]Other non mandated plans, including "green marketing" efforts and other activities known to EIA.

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

The projections also include 54.5 megawatts central station thermal-electric and 250 megawatts central station photovoltaic (PV) generating capacity ("Floors") assumed by EIA to be installed for reasons in addition to least-cost electricity supply 2001-2020.

Table 72. Planned Post-2000 U.S. Central Station Generating Capacity Using Renewable Resources[1]

Technology	Plant Identification	Program[2]	State	Net Summer Capability (Megawatts)	On-Line Years
Biomass	California (various)	AB1890	California	18.5	2001-2002
	Jacobs Energy	Commercial	Illinois	0.6	2003
	Massachusetts (various)	RPS	Massachusetts	94.8	2003-2015
	Itasca/Great River Wood Waste	Commercial	Minnesota	11.4	2001
	Beck LLC	Mandate	Minnesota	47.5	2002
	St. Paul Congregation	Mandate	Minnesota	23.8	2004
	New Jersey (various)	RPS	New Jersey	186.7	2002-2016
	Texas	RPS	Texas	19	2002
	Zosell Lumber	Commercial	Washington	3	2001
Conventional Hydroelectric	California (Various)	AB1890	California	4.6	2001-2005
Geothermal	Four Mile Hill	AB1890	California	47.4	2004
	California (Various)	AB1890	California	167.2	2002-2005
	Animas	Commercial	New Mexico	0.95	2002
	Rye Patch	Commercial	Nevada	11.4	2001
	Empire	Commercial	Nevada	0.95	2002
	Nevada (Various)	RPS	Nevada	301.2	2003-2015
	Milgro-Newcastle	Commercial	Utah	0.71	2003
Landfill Gas	TriCitires	Commercial	Arizona	3.8	2001
	Pinnacle, Glenndale	RPS	Arizona	1.8	2001
	California (Various)	AB1890	California	113.3	2001-2005
	Union Mine Disposal Site	Commercial	California	1.8	2001
	San Timoteo	Commercial	California	0.95	2001
	Ox Mountain	Commercial	California	9.5	2002
	Columbus-Schatulga Road	Commercial	Georgia	2.85	2001
	Fort Dodge	Commercial	Iowa	1.9	2001
	Illinois (Various)	Commercial	Illinois	70.74	2001
	Gary	Commercial	indiana	2.85	2001
	Wheatland	Commercial	Kansas	1.9	2001
	Greater New Orleans	Commercial	Louisana	1.9	2001
	Massachusetts (Various)	Commercial	Massachusetts	11.22	2001-2002
	Fibrominn Poultry Litter	Mandate	Minnesota	47.5	2003
	New Jersey (Various)	RPS	New Jersey	365.2	2002-2016
	Seneca Meadows	Commercial	New York	5.51	2001
	Ohio (Various)	Commercial	Ohio	30.6	2001
	Pennsylvania (Various)	Commercial	Pennsylvania	21.2	2001
	Horry county	Commercial	South Carolina	2.6	2001
	Middle Point	Commercial	Tennessee	4.9	2001

Table 72. Planned Post-2000 U.S. Central Station Generating Capacity Using Renewable Resources[1] (Continued)

Technology	Plant Name	Program[2]	State	Net Summer Capacity (Megawatts)	On-Line Years
	Texas (Various)	Commercial	Texas	26	2001-2002
	Texas (Various)	RPS	Texas	435.1	2001-2020
	H.W. Hill, Part 2	Commercial	Washington	10	2005
	Wisconsin (Various)	Commercial	Wisconsin	2	2001
	Wisconsin (Various)	RPS	Wisconsin	6.3	2001
CentralStation Photovoltains	Tuscon Electric (Various)	Commercial	Arizona	4.4	2001-2002
	Los Angeles Dept Water&Power	Commercial	California	2	2002-2005
	Nevada	RPS	Nevada	9.1	2003 & 2009
	Long Island, Fala Corporation	Commercial	New York	1.5	2001
Central Station Solar Thermal	Nevada (Various)	RPS	Nevada	21.6	2003-2015
Wind	Mark Technologies	AB1890	California	25.2	2002
	Cal Wind	AB1890	California	8.7	2002
	Windland	AB1890	California	19.8	2002
	Christensen Lazar	AB1890	California	23.3	2002
	Gorman (Tenderland)	AB1890	California	40	2002
	Victory Green	AB1890	California	30	2002
	West 1&2	AB1890	California	7	2002
	Alexander 1-3	AB1890	California	14.7	2002
	Catellus 1-5	AB1890	California	35	2002
	Phoenix 2-5	AB1890	California	7.7	2002
	California (Various)	AB1890	California	1368.00	2002-2005
	Ponnequin III	Commercial	Colorado	10	2001
	New Century	Commercial	Colorado	26	2001
	Top of Iowa	RPS	Iowa	80	2001
	Alliant, Sibley	Commercial	Iowa	1.32	2001
	Compton	Commercial	Illinois	50	2001
	Montezuma, Kansas Wind	Commercial	Kansas	110	2001
	Massachusetts (various)	RPS	Massachusetts	316	2003-2015
	Wilmont	Commercial	Minnesota	1.32	2001
	NAE Wind Hybrid	Mandate	Minnesota	50	2001
	NSP Pase IV	Mandate	Minnesota	80	2002
	Mun. Egy. Agency of Nebraska	Commercial	Nebraska	10.5	2002

Table 72. Planned Post-2000 U.S. Central Station Generating Capacity Using Renewable Resources[1] (Continued)

Technology	Plant Name	Program[2]	State	Net Summer Capacity (Megawatts)	On-Line Years
	New Jersey (Various)	RPS	New Jersey	352	2002-2016
	Nevada (Various)	RPS	Nevada	817	2003-2015
	Stateline (Oregon Phase)	Commercial	Oregon	71	2001
	Condon	Commercial	Oregon	24.6	2001
	Mill Run, Fayette	Commercial	Pennsylvania	15	2001
	Somerset	Commercial	Pennsylvania	9	2001
	Prairie Winds	Commercial	South Dakota	2.6	2001
	York (Ector County)	RPS	Texas	250	2001
	Carson Cty/White Deer/Llano	RPS	Texas	79	2001
	King Mountain	RPS	Texas	280	2001
	Indian Mesa I	RPS	Texas	160	2001
	Indian Mesa II	RPS	Texas	82	2001
	Woodward Mtn/Capitol Hill	RPS	Texas	160	2001
	Trent Mesa	RPS	Texas	130	2001
	Texas (Various)	RPS	Texas	684	2002-2009
	Stateline (Washington Phase)	Commercial	Washington	200	2001
	Addison Parts 1 - 3	RPS	Wisconsin	29.7	2001
	Rock River I	Commercial	Wyoming	50	2001

[1]Includes reported information and EIA estimates for mandates, renewable portfolio standards (RPS), and California's renewables.

[2]RPS" represents state renewable portfolio standards; "AB 1890" represents California Assembly Bill 1890; "Mandate" identifies other forms of identified state legal requirements; "Commercial" identifies other new capacity, including "green marketing" efforts and other voluntary programs and plans.

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

Notes and Sources

[116] 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(2002), (Washington, DC, January 2002).

[117] Electric Power Research Institute and U.S. Department of Energy, Office of Utility Technologies, *Renewable Energy Technology Characterizations* (EPRI TR-109496, December 1997) or www.eren.doe.gov/utilities/techchar.html.

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[119] Energy Information Administration analysts discussed input values with the Electric Power Research Institute, U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, Lawrence Berkeley National Laboratory, RLA Consulting, the Zond Corporation, and others.

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[125] U.S. Environmental Protection Agency, Atmospheric Pollution Prevention Division, Energy Project Landfill Gas Utilization Software (E-PLUS) Version 1.0, EPA-430-B-97-006 (Washington, DC, January 1997).

[126] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2000*, DOE/EIA-0573(2000) (Washington, DC, November 2001).

[127] Governmental Advisory Associates, Inc., METH2000 Database, Westport, CT, January 25, 2000.

[128] Department of Energy assumptions are obtained or derived from Electric Power Research Institute and U.S. Department of Energy, Office of Utility Technologies, *Renewable Energy Technology Characterizations* (EPRI TR-109496, Dec. 1997) or www.eren.doe.gov/utilities/techchar.html.