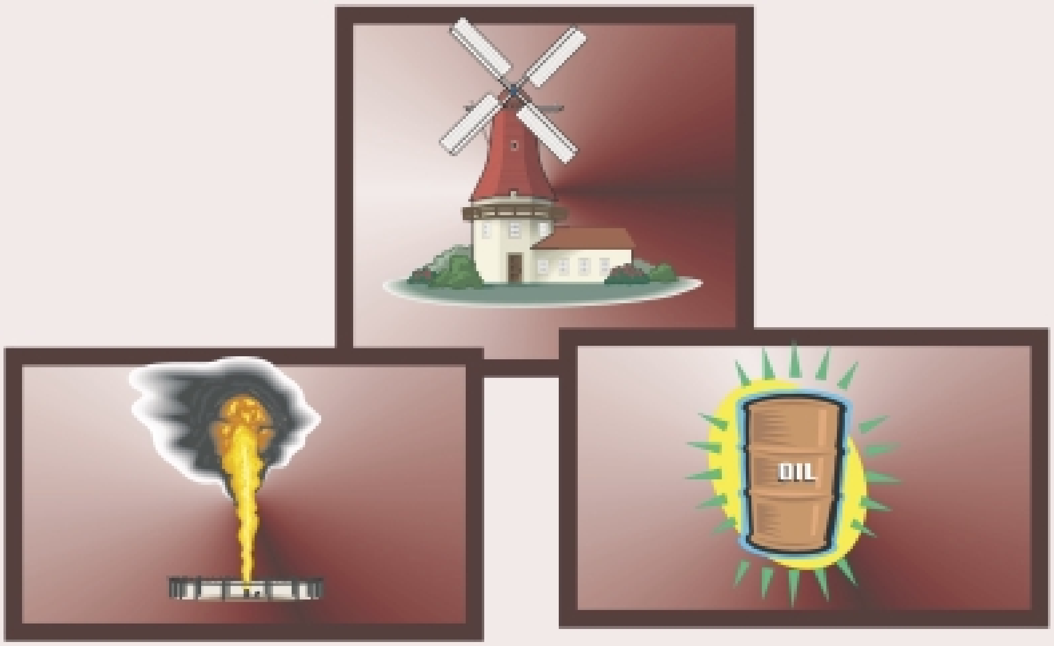
DOE/EIA-0554(2001)

Assumptions to the Annual Energy Outlook 2001 (AEO2001)



With Projections to 2020

December 2000

www.eia.doe.gov

eia

Contents

Introduction

This report presents the major assumptions of the National Energy Modeling System (NEMS) used to generate the projections in the *Annual Energy Outlook 2001*[1] (*AEO2001*), 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 *AEO2001* 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, other DOE offices, and other government agencies.

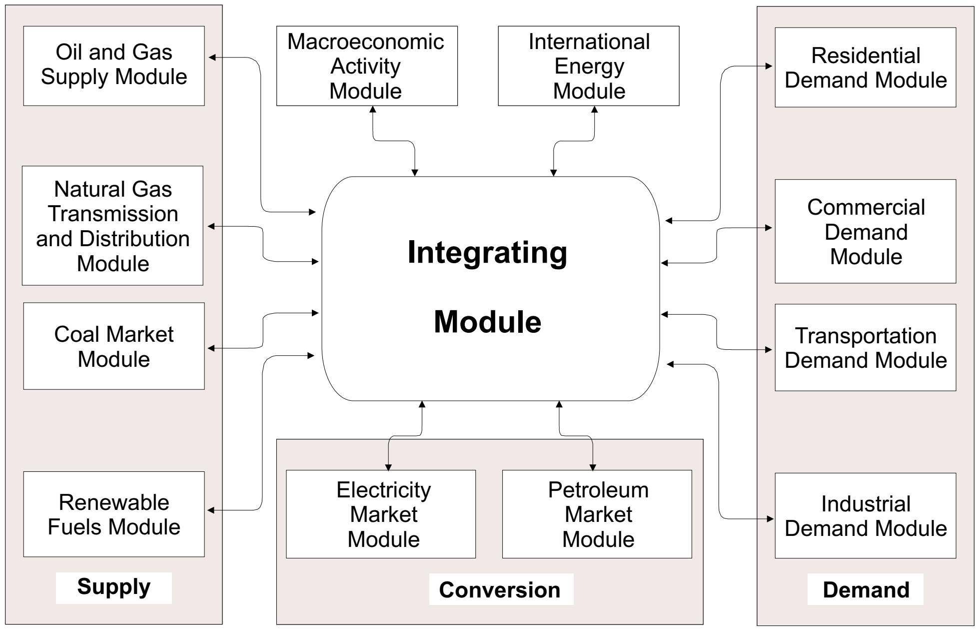
The time horizon of NEMS is approximately 20 years, the midterm period in which the structure of the economy and the nature of energy markets are sufficiently understood that it is possible to represent considerable structural and regional detail. Because of the diverse nature of energy supply, demand, 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 *AEO2001,* 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 is a kernel regression representation of the Standard and Poor's DRI U.S. 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 analysis of impacts of interregional constraints in the interstate natural gas pipeline network and the identification of pipeline and storage capacity expansion requirements. Peak and off-peak periods are represented for natural gas transmission, and core and noncore markets are represented at the burner tip. The key components of pipeline and distributor tariffs are included in the pricing algorithms.

Petroleum Market Module

The Petroleum Market Module forecasts prices of petroleum products, crude oil and product import activity, and domestic refinery operations, including fuel consumption, subject to the demand for petroleum products, availability and price of imported petroleum, and domestic production of crude oil, natural gas liquids, and alcohol fuels. The module represents refining activities for three regions— Petroleum Administration for Defense District (PADD) 1, PADD 5, and an aggregate of PADDs 2, 3, and 4. The module uses the same crude oil types as the International Module. It explicitly models the requirements of CAAA90 and the costs of automotive fuels, such as oxygenated and reformulated gasoline, and includes oxygenate production and blending for reformulated gasoline. *AEO2001* reflects a ban or limit on the gasoline blending component methyl tertiary butyl ether(MTBE) in the eight states that have passed legislation. Because the *AEO2001* reference case assumes current laws and regulations, it assumes that the Federal oxygen requirement for reformulated gasoline in Federal nonattainment areas will remain intact. A new regulation that requires the sulfur content of all gasoline in the United States to be reduced to an annual average of 30 parts per million (ppm) between the years 2004 and 2007 is also explicitly modeled. Costs include capacity expansion for refinery processing units based on a 15-percent hurdle rate and a 15-percent return on investment. End-use prices are based on the marginal costs of production, plus markups representing product distribution costs, State and Federal taxes, and environmental costs.

Coal Market Module

The Coal Market Module 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 2001*

The *AEO2001* 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 2.1 percent from 1999 through 2020 and the labor force at 0.9 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 2.3 and 1.2 percent per year, respectively, resulting in GDP growth of 3.5 percent annually. The average annual growth in productivity, the labor force, and GDP is 1.8, 0.7 and 2.5 percent, respectively, in the low economic growth case.

- **World Oil Markets** - In the reference case, the average world oil price increases to $22.41 per barrel (in real 1999 dollars) in 2020. Reflecting uncertainty in world markets, the price in 2020 reaches $15.10 per barrel in the low oil price case and $28.42 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 July 1, 2000, 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, and new standards for the sulfur content of gasoline. Pending legislation and sections of existing legislation for which funds have not been appropriated are not reflected in these forecasts.

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 1. Summary of *AEO2001* 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 2.5 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 3.5 percent, compared to the reference case growth of 3.0 percent.	Fully integrated
Low World Oil Price	World oil prices are $15.10 per barrel in 2020, compared to $22.41 per barrel in the reference case.	Fully integrated
High World Oil Price	World oil prices are $28.42 per barrel in 2020, compared to $22.41 per barrel in the reference case.	Fully integrated
Residential: 2001 Technology	Future equipment purchases based on equipment available in 2001. Building shell efficiencies fixed at 2001 levels.	Standalone
Residential: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Existing building shell efficiencies increase by 26 percent from 1997 values by 2020.	Standalone
Residential: Best Available Technology	Future equipment purchases and new building shells based on most efficient technologies available. Existing building shell efficiencies increase by 26 percent from 1997 values by 2020.	Standalone
Commercial: 2001 Technology	Future equipment purchases based on equipment available in 2001. Building shell efficiencies fixed at 2001 levels.	Standalone
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.	Standalone
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.	Standalone
Industrial: 2001 Technology	Efficiency of plant and equipment fixed at 2001 levels.	Standalone
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment.	Standalone
Transportation: 2001 Technology	Efficiencies for new equipment in all modes of travel are fixed at 2001 levels.	Standalone
Transportation: High Technology	Reduced costs and improved efficiencies are assumed for advanced technologies.	Standalone
Consumption: 2001 Technology	Combination of the residential, commercial, industrial, and transportation 2001 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 30 years of operation.	Partially integrated
Electricity: High Nuclear	Increases in operating costs are smaller than in the reference case.	Partially integrated
Electricity: Advanced Nuclear Cost 4-Year	New nuclear capacity is assumed to have lower capital costs than in the reference case and the same (4-year) construction lead time.	Partially integrated

Table 1. Summary of *AEO2001* Cases (Continued)

Cases	Description	Integration Mode
Electricity: Advanced Nuclear Cost 3-Year	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
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 fossil generating technologies are assumed not to improve over time from 1999.	Partially integrated
Electricity: High Fossil Technology	Costs and/or efficiencies for advanced fossil-fired generating technologies are assumed to improve from reference case values.	Partially integrated
Renewables: High Renewables	Lower costs and higher efficiencies are assumed for new renewable generating technologies	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: Low Resource	Inferred reserves, technically recoverable undiscovered resources, and unconventional unproved resources are reduced.	Fully integrated
Oil and Gas: High Resource	Inferred reserves, technically recoverable undiscovered resources, and unconventional unproved resources are increased.	Fully integrated
Oil and Gas: MTBE Ban	MTBE blended with gasoline is banned from all gasoline by 2004. The Federal requirement for 2.0 percent oxygen in reformulated gasoline is waived.	Standalone
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

Table 2 presents the carbon dioxide coefficients at full combustion, the combustion fractions, and the adjusted carbon dioxide emission factors used for *AEO2001*.

Methane emissions from energy-related activities are now estimated in NEMS. Most of these emissions occur as methane is released 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 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	19.36	0.990	19.17
Liquefied Petroleum Gas			
Used as Fuel	17.18	0.995	17.09
Used as Feedstock	16.88	0.200	3.38
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 1998 average is 25.50.

Source: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1999*, DOE/EIA-0573(99), (Washington, DC, October 2000).

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				
	1999	5.842				
	2000	5.908				
	2005	6.250				
	2010	6.613				
	2015	6.996				
	2020	7.401				

Source: Emissions factors and data sources from Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1999*, DOE/EIA-0573(99), (Washington, DC, October 2000).

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 1999*, DOE/EIA-0573(99), (Washington, DC, October 2000).

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	82.87			
Buses	43.02			
Motorcycles	1094.15			
Light-Duty Trucks	65.45			
Other Trucks	22.04			

Source: Emissions factors and data sources from Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1999*, DOE/EIA-0573(99), (Washington, DC, October 2000).

Notes and Sources

[1] Energy Information Administration, *Annual Energy Outlook 2001* (AEO2001), DOE/EIA-0383(2001), (Washington, DC, December 2000).

[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(2001), (Washington, DC, December 2000), plus *Macroeconomic Activity Module (MAM): Kernel Regression Documentation of the National Energy Modeling System 1999*, DOE/EIA-M065(99), Washington, DC, 1999).

Key Assumptions

The output of the Nation's economy, measured by GDP, is expected to increase by 3.0 percent between 1999 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 3 indicates, the rate of growth of GDP is slower in the latter half of the forecast period due to a slowdown in the expansion of the labor force. 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 *AEO2001*. Total population is expected to grow annually by 0.8 percent between 1999 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	1999-2005	2005-2010	2010-2015	2015-2020	1999-2020
GDP (Billion Chain-Weighted $1992)					
High Growth	4.3	3.3	3.2	2.9	3.5
Reference	3.6	2.9	2.9	2.4	3.0
Low Growth	3.0	2.5	2.4	1.8	2.5
Labor Force					
High Growth	1.6	1.3	0.9	0.7	1.2
Reference	1.2	1.1	0.8	0.6	0.9
Low Growth	1.0	0.9	0.5	0.3	0.7
Productivity					
High Growth	2.8	2.0	2.2	2.2	2.3
Reference	2.4	1.9	2.2	1.8	2.1
Low Growth	2.1	1.6	1.9	1.5	1.8

Source: Energy Information Administration, *AEO2001* National Energy Modeling System runs: aeo2001.d101600a; lm2001.d101600a; and hm2001.d101600a.

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, productivity growth remains relatively constant throughout 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 *AEO2001* 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 Standard and Poor's DRI.[4]   The DRI forecasts used in *AEO2001* are the February 2000 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 3.5 percent between 1999 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 2.5 percent 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 Standard and Poor's DRI February 2000 T250200 and February TO250299 and TP250299.

International Energy Module

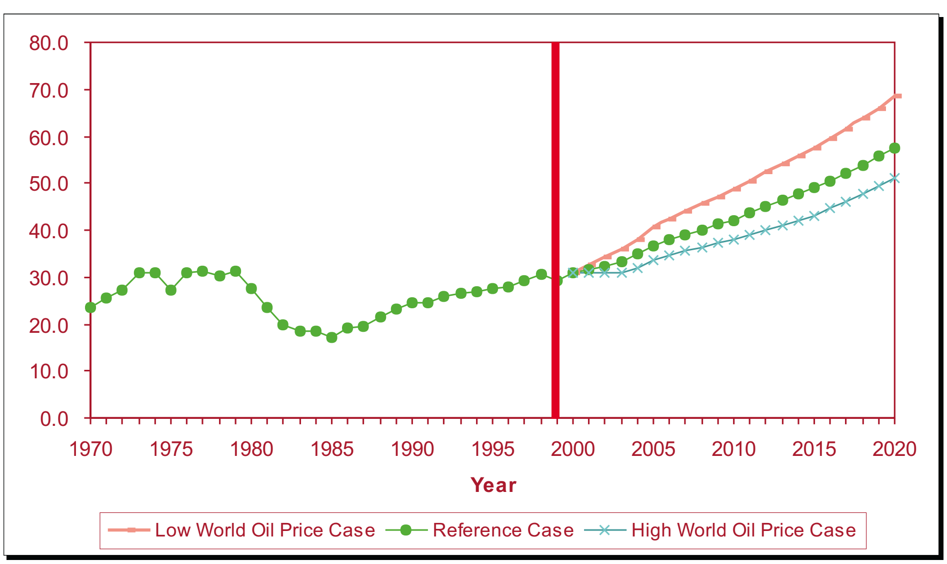
The International Energy Module determines changes in the world oil price and the supply prices of crude oils and petroleum products for import to the United States in response to changes in U.S. import requirements. A market clearing method is used to determine the price at which worldwide demand for 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 OPEC is a key factor influencing the world oil price projections incorporated into *AEO2001*. 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 802 billion barrels, almost 79 percent of the world's estimated total, at the end of 1999.[5] For the *AEO2001* 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 2002. 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 input for all three world oil price case projections. Non-OPEC production depends upon world oil prices, so

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

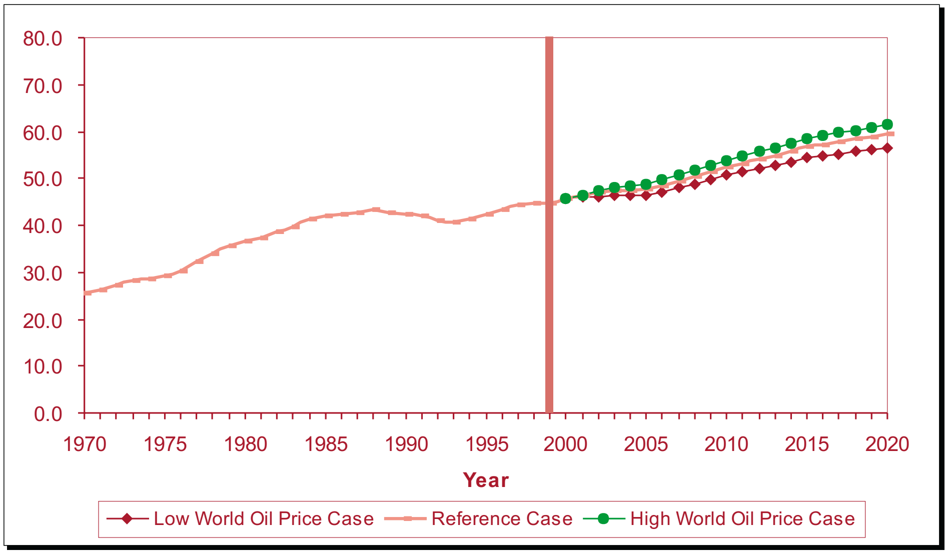


OPEC = Organization of Petroleum Exporting Countries.

Sources: Energy Information Administration. AEO2001 National Energy Modeling System runs lw2001.d101600a, aeo2001.d101600a, and hw2001.d101600a.

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. *AEO2001* National Energy Modeling System runs lw2001.d101600a, aeo2001.d101600a, and hw2001.d101600a.

The non-U.S. oil production forecasts in the AEO2001 begin with country-level assumptions regarding proved oil reserves. These reserve estimates are shown in Table 4 and are compiled by PennWell Publishing Company's Oil and Gas Journal.

Table 7. Worldwide Oil Reserves as of January 1, 2000
(Billion Barrels)

Region	Proved Oil Reserves
Western Hemisphere	143.9
Western'Europe	18.6
Asia-Pacific	44.0
Eastern Europe and F.S.U.	59.0
Middle East	675.6
Africa	74.9
Total World	1,016.0
Total OPEC	802.5

Source: PennWell Publishing Co., International Petroleum Encyclopedia, (Tulsa, OK, 2000).

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 1999 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, 1999-2020
(Percent per Year)

Region	Gross Domestic Product
Organization for Economic Cooperation and Development	2.2
Other Developing Countries	4.5
Eurasia	5.5
China	6.2
Former Soviet Union	4.7
Eastern Europe	4.4
Total World	2.9

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, 1999-2020
(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	3.2	3.2	3.2
Other Developing Countries	3.5	3.2	3.0
Eurasia	3.9	3.6	3.4
China	4.8	4.4	4.1
Former Soviet Union	3.8	3.5	3.4
Eastern Europe	0.9	0.7	0.6
Total World	2.4	2.1	1.9

Source: Energy Information Administration, *AEO2001* National Energy Modeling System runs: lw2001.d101600a; aeo2001.d101600a; and hw2001.d101600a.

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 *AEO2001*, 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, 2000).

[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, 2000).

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 *AEO2001* 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 *AEO2001* 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 *AEO2001* 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 1998 and 2005.

Table 11. Installed Cost and Efficiency Ratings of Selected Equipment

Equipment Type	Relative Performance[1]	1998 Installed Cost ($1998)[2]	Efficiency[3]	2015 Installed Cost ($1998)[2]	Efficiency[3]	Approximate Discount Rate
Electric Heat Pump	Minimum	$4,100	10.0	$4,100	10.0	25%
	Best	$5,500	17.7	$5,200	18.0	
Natural Gas Furnace	Minimum	$1,350	0.80	$1,300	0.78	15%
	Best	$2,700	0.96	$1,600	0.96	
Room Air Conditioner	Minimum	$450	8.7	$450	9.7	140%
	Best	$760	11.7	$760	12.0	
Central Air Conditioner	Minimum	$2,500	10.0	$2,500	10.0	30%
	Best	$3,600	18.0	$3,200	18.0	
Refrigerator (18 cubic ft)	Minimum	$530	690	$530	478	19%
	Best	$850	518	$700	400	
Electric Water Heater	Minimum	$350	0.86	$350	0.86	83%
	Best	$1,025	2.60	$800	2.20	
Solar Water Heater	N/A	$2,600	2.0	$2,600	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 1998 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 37125, September 1998.

Table 12 provides the cost and performance parameters for representative distributed generation technologies. The AEO 2001 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 AEO2001 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	$7.870	30
	2005	2	0.16	N/A	$6,700	30
	2010	2	0.18	N/A	$5,529	30
	2015	2	0.20	N/A	$4,158	30
Fuel Cell	2000	5	0,36	0.73	$3,674	20
	2002	5	0.38	0.73	$3,282	20
	2006	5	0.40	0.73	$2,834	20
	2010	5	0.43	0.74	$2,329	20
	2015	5	0.47	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. Discount rates in excess of 30 percent are common in the Residential Demand Module. The prevalence of such high apparent discount 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 on page 24), the size of new construction relative to the existing stock, people per household and shell efficiency and weather effects (space heating andcooling). 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 are assumed to increase with the square footage of the structure. This results in an increase in the average size of the housing stock of 1,663 to 1,763 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, proportionate 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; 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; 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 *AEO2001* reference case, three side cases were developed to examine the effect of equipment and building standards on residential energy use—a *2001 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. *AEO2001* 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 2001 technology case assumes that all future equipment purchases are made based only on equipment available in 2001. This case further assumes that building shell efficiencies will not improve beyond 2001 levels. In the reference case, the 2020 housing stock shell efficiency is 6 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 24 percent and cooling shell efficiency by 9 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 32 percent and cooling shell efficiency by 9 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(2001), (December 2000).

[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., September 1998).

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 Data Resources, Inc. (DRI) total floorspace forecast from MAM. A total NEMS floorspace projection is calculated by applying DRI's assumed floorspace growth rate within each Census Division and DRI 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 *AEO2001* 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(2001) (December 2000).

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 *AEO2001* 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(2001) (December 2000).

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 *AEO2001* 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 12 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 *AEO2001* reference case fuel prices, the option was not exercised for the *AEO2001* 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 ($1998 per Mbtu/hour) [3]	Maintenance Cost ($1998 per Mbtu/hour) [3]	Service Life (Years)
Electric Heat Pump	Current Standard	6.8	$97.62	$2.86	12
	1998- typical	7.5	$104.76	$2.86	12
	1998- high efficiency	9.4	$130.95	$2.86	12
	2005- typical	8.0	$104.76	$2.86	12
	2005- high efficiency	9.5	$128.57	$2.86	12
	2015 - typical	8.5	$100.00	$2.86	12
	2015 - high efficiency	10.0	$123.81	$2.86	12
Ground-Source Heat Pump	1998- typical	3.4	$166.67	$1.35	20
	1998- high efficiency	4.0	$250.00	$1.35	20
	2005- typical	3.4	$145.83	$1.35	20
	2005- high efficiency	4.1	$225.00	$1.35	20
	2015- typical	3.8	$135.42	$1.35	20
	2015 -high efficiency	4.2	$197.92	$1.35	20
Electric Boiler	Current Standard	0.98	$22.37	$0.12	21
Packaged Electric	1995	0.93	$25.28	$4.46	18
Natural Gas Furnace	Current Standard	0.80	$11.69	$0.94	20
	1998- high efficiency	0.92	$13.78	$0.82	20
	2015 - typical	0.81	$12.35	$0.93	20
Natural Gas Boiler	Current Standard	0.80	$10.79	$0.35	25
	1998 - high efficiency	0.90	$15.60	$0.47	25
	2005- typical	0.81	$10.54	$0.35	25
	2005- high efficiency	0.90	$12.88	$0.41	25
Natural Gas Heat Pump	1998- engine driven	4.1	$229.17	$4.69	13
	2005- engine driven	4.1	$166.67	$3.65	13
	2005- absorption	1.4	$173.61	$4.17	15
Distillate Oil Furnace	Current Standard	0.81	$13.43	$0.94	15
	1998	0.83	$21.80	$0.94	15
	2000	0.86	$22.07	$0.94	15
	2010	0.89	$22.82	$0.94	15
Distillate Oil Boiler	Current Standard	0.83	$16.67	$0.09	20
	1998- high efficiency	0.87	$23.33	$0.09	20
	2005- typical	0.83	$16.50	$0.09	20
	2005- high efficiency	0.87	$22.33	$0.09	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 1998 dollars.

Source: Energy Information Administration, *Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M066(2001) (December 2000).

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 NOAA data for HDD and 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 2000. After 2000, 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 AEO2001 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. 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 12. 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

In addition to the *AEO2001* reference case, three side cases were developed to examine the effect of equipment and building standards on commercial energy use—a 2001 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. *AEO2001* 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 *2001 technology case* assumes that all future equipment purchases are made based only on equipment available in 2001. This case further assumes building shell efficiency to be fixed at 2001 levels. In the reference case, existing building shells are allowed to increase in efficiency by 4 percent over 1995 levels, 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 2001. Existing building shells, therefore, increase by 5.5 percent relative to 1995 levels and new building shells by 8.2 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	$6,700	30
	2010	10	0.18	N/A	$5,529	30
	2015	10	0.20	N/A	$4,158	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
Natural Gas Engine	2000	100	0.28	0.75	$1,390	20
	2002	100	0.29	0.76	$1,320	20
	2006	100	0.29	0.77	$1,240	20
	2010	100	0.30	0.78	$1,150	20
	2015	100	0.30	0.79	$990	20
Oil-Fired Engine	2000	100	0.31	0.83	$1,390	20
	2002	100	0.31	0.82	$1,320	20
	2006	100	0.31	0.82	$1,240	20
	2010	100	0.31	0.82	$1,150	20
	2015	100	0.31	0.81	$1,040	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
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

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 2000).

The *best available technology case* assumes that all equipment purchases after 2001 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.

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 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(2001), (December 2000).

[18] The floorspace from the Macroeconomic Activity Model is based on the Data Resources Incorporated (DRI) floorspace estimates which are approximately 15 percent lower than the estimate obtained from the CBECS used for the Commercial module. The DRI forecast 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, and other miscellaneous office equipment. A tenth category denoted other includes equipment such as elevators, medical, and other laboratory equipment, communications equipment, security equipment, 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.

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[24] data.

Table 19. Industry Categories

Energy-Intensive Manufacturing		Nonenergy-Intensive Manufacturing		Nonmanufacturing Industries	
Food and Kindred Products	(SIC 20)	Metals-Based Durables	(SIC 34, 35, 36, 37, 38)	Agricultural Production -Crops	(SIC 01)
Paper and Allied Products	(SIC 26)	Other Manufacturing	(all remaining manufacturing SIC)	Other Agriculture Including Livestock	(SIC 02, 07, 08, 09)
Bulk Chemicals	(SIC 281, 282, 286, 287)			Coal Mining	(SIC 12)
Glass and Glass Products	(SIC 321, 322, 329)			Oil and Gas Mining	(SIC 13)
Hydraulic Cement	(SIC 324)			Metal and Other Nonmetallic Mining	(SIC 10, 14)
Blast Furnaces and Basic Steel	(SIC 331)			Construction	(SIC 15, 16, 17)
Aluminum	(SIC 3334, 3353)				

SIC = Standard Industrial Classification.

Source: Office of Management and Budget, Standard Industrial Classification Manual 1987 (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 (Standard Industrial Classification 2911) 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 (Standard Industrial Classification 1311) 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 1994 baseline Unit Energy Consumption (UEC) estimates based on analysis of the Manufacturing Energy Consumption Survey 1994.[25] 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 1994 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[26] 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 formulation is as follows:

$$NEWSHR_i = \frac{DEFLTSHR_i \cdot e^{\beta_i (1 - PRCRAT_i)}}{\sum_{j=1}^{N} DEFLTSHR_i \cdot e^{\beta_j (1 - PRCRAT_j)}}$$

The coefficients β_j are all assumed to be 0.05.

Table 20. Coefficients for Technology Possibility Curve

Industry/ Process Unit	Old Facilities		New Facilities		
	REI 2020	TPC	REI 1994	REI 2020	TPC
Food	0.892	-0.0044	0.900	0.792	-0.0049
Pulp & Paper					
Wood Preparation	0.909	-0.0037	0.840	0.830	-0.0004
Waste Pulping	0.938	-0.0025	0.930	0.882	-0.0021
Mechanical Pulping	0.904	-0.0039	0.840	0.821	-0.0009
Semi-Chemical	0.870	-0.0054	0.794	0.756	-0.0019
Kraft, Sulfite, misc. chemicals	0.784	-0.0093	0.730	0.590	-0.0082
Bleaching	0.879	-0.0050	0.852	0.769	-0.0039
Paper Making	0.763	-0.0104	0.750	0.546	-0.0122
Bulk Chemicals	0.892	-0.0044	0.900	0.792	-0.0049
Glass[1]					
Batch Preparation	0.936	-0.0025	0.882	0.882	0
Melting/Refining	0.783	-0.0094	0.877	0.577	-0.0160
Forming	0.912	-0.0035	0.921	0.831	-0.0040
Post-Forming	0.871	-0.0053	0.780	0.759	-0.0011
Cement					
Dry Process	0.815	-0.0078	0.790	0.646	-0.0077
Wet Process[2]	0.954	-0.0025	NA	NA	NA
Finish Grinding	0.899	-0.0041	0.813	0.813	0
Steel[3]					
Coke Oven	0.904	-0.0039	0.840	0.820	-0.0009
BF/BOF	0.899	-0.0041	1.000	0.799	-0.0086
EAF	0.919	-0.0033	0.960	0.841	-0.0051
Ingot Casting/Primary Rolling[2]	1.000	0	NA	NA	NA
Continuous Casting	1.000	0	1.000	1.000	0
Hot Rolling	0.672	-0.0152	0.500	0.381	-0.0104
Cold Rolling	0.768	-0.0101	0.840	0.550	-0.0162
Aluminum					
Primary aluminum	0.898	-0.0041	0.910	0.804	-0.0048
Semi-Fabrication	0.734	-0.0118	0.610	0.497	-0.0078
Metal-Based Durables	0.916	-0.0034	0.900	0.792	-0.0049
Other Manufacturing	0.923	-0.0031	0.900	0.792	-0.0049
Non-manufacturing	0.974	-0.0010	0.900	0.854	-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.

[4]SIC = Standard Industrial Classification.

REI 1994 New Facilities = For new facilities, the ratiio of State-of-the-art energy intensity to average 1994 energy intensity for existing facilities.

REI 2020 Existing Facilities = Ratio of 2020 energy intensity to average 1994 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 1994 intensity for existing facilities.

TPC = annual rate of change between 1994 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(2001), (Washington, DC, December 2000).

The form of the equation results in unchanged fuel shares when the price indices are all 1, or unchanged from their 1999 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.

Buildings Component

The total buildings energy demand by industry for each region is the product of the building UEC and regional industrial employment. Building UEC's were derived by first estimating energy requirements for building lighting, air conditioning, and space heating, where 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 assumed to grow at the same rate as regional employment for that industry.

Table 21. Building Component Unit Energy Consumption
(Trillion Btu/Thousand People Employed)

Industry	Building Use and Energy Source			
	Lighting Electric UEC	HVAC Electric UEC	HVAC Natural Gas UEC	HVAC Steam UEC
Food & Kindred Products	0.007	0.009	0.014	0.045
Paper & Allied Products	0.0131	0.016	0.023	0.0082
Bulk Chemicals	0.0159	0.0299	0.68	0.0058
Glass and Glass Products	0.0133	0.019	0.044	0.004
Hydraulic Cement	0.029	0.029	0.029	0.0568
Blast Furnaces & Basic Steel	0.0123	0.0184	0.0674	0.011
Primary Aluminum	0.0187	0.0266	0.0062	0.0053
Metal Based Durables	0.0083	0.0125	0.0153	0.0019
Other Non-Intensive MFG Fabricated Metals	0.007	0.0103	0.0134	0.0036

UEC = Unit Energy Consumption.

HVAC = Heating, Ventilation, Air Conditioning.

Source: Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M064(2001), (Washington, DC, December 2000).

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 1994 so that the actual boiler fuel shares are produced for the relative prices that prevailed in 1994. The equation for each manufacturing industry is as follows:

$$ShareFuel_i \quad \frac{P_i \quad _i}{\sum_{i=1}^{3} P_i \quad (\; _i)}$$

where the fuels are coal, petroleum, and natural gas. The P_i are the fuel prices; a sensitivity parameter; and the $_i$ are the 1994 fuel shares. The byproduct fuels are consumed before the quantity of purchased fuels is estimated. The boiler fuel shares are based on the 1994 MECS.[27]

Table 22. Logit Function Parameters for Estimating Boiler Fuel Shares

Industry	Alpha	Natural Gas	Steam Coal	Oil
Food	-0.25	0.63	0.03	0.34
Paper and Allied Products	-0.25	0.45	0.31	0.24
Bulk Chemicals	-0.25	0.55	0.08	0.37
Glass and Glass Products	-0.25	0.91	0.0	0.09
Cement	-0.25	0.05	0.95	0.0
Steel	-0.25	0.47	0.15	0.38
Aluminum	-0.25	0.15	0.85	0.0
Metals-Based Durables	-0.25	0.35	0.40	0.25
Other Non-Int MFG	-0.25	0.58	0.04	0.38

Alpha: User-specified.

Source: Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M064(2001), (Washington, DC, December 2000).

Cogeneration

Cogeneration (the generation of electricity and 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 are determined with a new modeling approach developed for the *Annual Energy Outlook 2001*. The new approach 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 traditional 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

	Size	Installed Cost ($1999 per kilowatt)		O&M Cost ($1999 per kwh)	
System	(kilowatts)	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(2001) (Washington, DC, December 2000).

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 1995 and is assumed to retire at a fixed rate each year (Table 24). Middle vintage capital is that which is added after 1994 but not including the year of the forecast. New production capacity is built in the forecast years when the capacity of the existing stock of capital in the industrial model cannot produce the output forecasted by the NEMS Regional Macroeconomic Model. Capital additions during the forecast horizon are retired in subsequent years at the same rate as the pre-1995 capital stock.

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	1.9	Glass and Glass Products	1.3
Blast Furnace and Basic Steel Products		Primary Aluminum	2.1
Blast Furnace/Basic Oxygen Furnace . .	1.0	Metal-Based Durables.	1.5
Electric Arc Furnace	1.5		
Coke Ovens	1.5		
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(2001), (Washington, DC, December 2000).

The energy intensity of the new capital stock relative to 1994 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 15). 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 and 2001 Technology Cases

The high *technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment.[28] 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, aggregate intensity declines by 1.5 percent annually compared with the reference case, in which aggregate intensity is projected to decline 1.4 percent annually.

AEO2001 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 *2001 technology case* holds the energy efficiency of plant and equipment constant at the 2001 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.

Notes and Sources

[24] Energy Information Administration, *State Energy Data Report 1997, DOE/EIA-0214(97)*, (Washington, D.C., September 1999).

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

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

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

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

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 25) consist of the following: gross domestic product (GDP), industrial output by Standard Industrial Classification code, personal disposable income, new car and light truck sales, total population, driving age population, total value of imports and exports, and the military budget. The share of total vehicle sales that represent light truck sales is assumed to approach fifty percent by 2020.

Light-Duty Vehicle Assumptions

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

Macroeconomic Input	1999	2000	2005	2010	2015	2020
New Car Sales	8.7	8.9	8.0	7.5	8.0	8.1
New Light Truck Sales	7.0	7.4	7.4	7.2	7.9	8.0
Real Disposable Income (billion 1996 Chain-Weighted Dollars)	6,363	6,551	7,702	8,928	10,361	11,842
Real GDP (billion 1996 Chain-Weighted Dollars)	8,876	9,338	10,960	12,667	14,635	16,515
Driving Age Population	210.9	213.1	224.8	236.6	246.7	256.5
Total Population	273.1	275.6	288.0	300.2	312.6	325.2

Source: Energy Information Administration, *AEO2001* National Energy Modeling System run: aeo2001.d101600a.

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 EPA size classes of cars and light trucks (Tables 26 and 27).

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.[29]

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.[30]

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 26. Standard Technology Matrix For Cars[1]

	Fractional Fuel Efficiency Change	Incremental Cost (1990 $)	Incremental Cost ($/Unit Wt.)	Incremental Weight (Lbs.)	Incremental Weight (Lbs./Unit Wt.)	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	0.099	0	1.50	0	-0.20	2017	0
Drag Reduction II	0.132	32	0.00	0	0.00	1985	0
Drag Reduction III	0.023	64	0.00	0	0.05	1991	0
Drag Reduction IV	0.046	112	0.00	0	0.01	2004	0
Drag Reduction V	0.069	176	0.00	0	0.02	2014	0
TCLU	0.092	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	0.080	140	0.00	40	0.00	1998	0.10
VVT II	0.100	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	2002	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	1000	0.00	0	0.00	2005	0
GDI/6-cyl	0.170	1200	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).

Table 27. 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	0.080	140.00	0.00	40	0.00	2006	0.10
VVT II	0.100	180.00	0.00	40	0.00	2016	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 %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	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	1000.00	0.00	0	0.00	2005	0
GDI/6-cyl	0.170	1200.00	0.00	0	0.00	2005	0
Gasoline Hybrid	0.450	0.00	75.00	0	0.05	2001	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 28) used to convert Environmental Protection Agency-rated fuel economy to actual "on the road" fuel economy are based on application of a logistic curve to the projections of three factors: increases in city/highway driving, increasing congestion levels, and rising highway speeds.[31] Degradation factors are also adjusted to reflect the percentage of reformulated gasoline consumed.

Table 28. Car and Light Truck Degradation Factors

	1998	2000	2005	2010	2015	2020
Cars	0.853	0.853	0.848	0.843	0.836	0.831
Light Trucks	0.806	0.805	0.801	0.797	0.790	0.785

Source: Energy Information Administration, Transportation Sector Model of the National Energy Modeling System, Model Documentation 2001, DOE/EIA-M070(2001), (Washington, DC, forthcoming January 2001).

- 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 age distribution of the driving population (Figure 4). Coefficients were re-estimated for *AEO2001* to adjust for the change in the definition of income to include stock equity and software, and chain-weighting of income. The ratio of female to male VMT is assumed to asymptotically approach 65 percent by 2020. VMT per driver by age group was also assumed to be more uniformly distributed to older age groups. Total VMT is calibrated to Federal Highway Administration VMT data.[32,33] 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 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/gal. 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 approximately $1.55/gal.

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 29). 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%), government (7.42%), and utilities (5.19%). Light truck fleets are divided into the following shares: business (83.50%), government (14.1%), and utilities(2.40%)[34,35]. Both car (23.70%) and light truck (28.57%) 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%), government (2.21%), utility (2.64%))[36,37] 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.[38,39] Size class sales shares of vehicles are held constant at anticipated levels (Table 30).[40,41]

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 31).

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

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

Source: Oak Ridge National Laboratory, *Fleet 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 30. 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 31. 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.

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

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.

Figure 4. VMT per Driver by Age-Group
(Vehicles-Miles Traveled)

Source: 1990 values: U.S. Dept. of Transportation, Summary of Travel Trends: *1995 National Personal Transportation Survey*, draft, prepared by Oak Ridge National Laboratory Washington D.C. 1999; Forecast: EIA, *AEO2001* National Energy Modeling System run: aeo2001.d1001600a.

The Light Commercial Truck Module

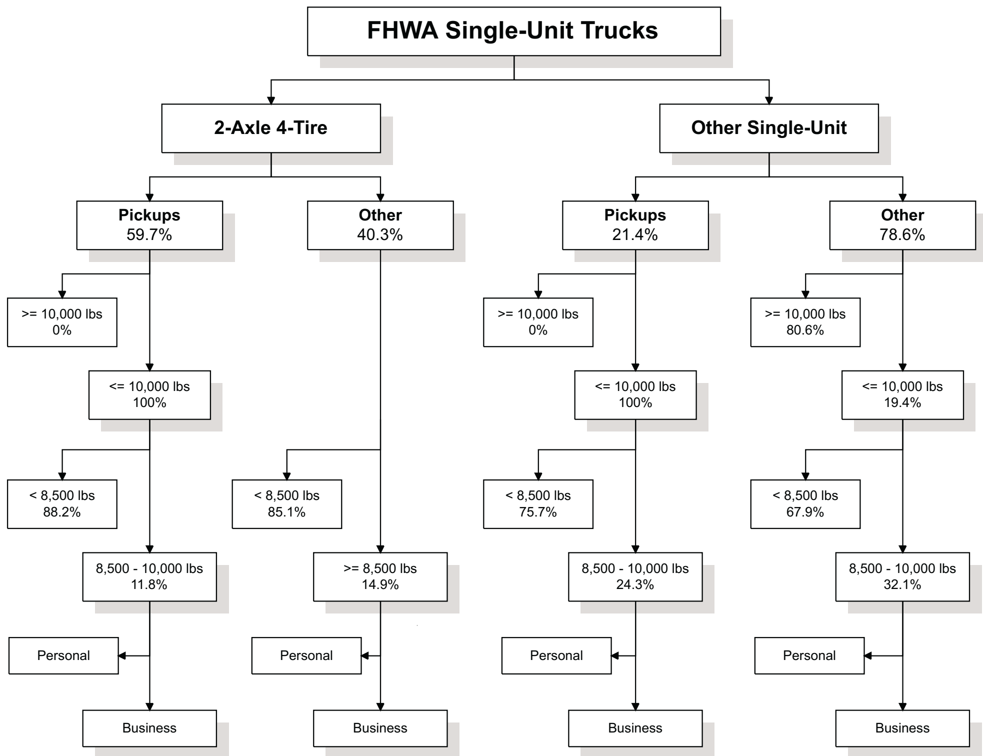
The Light Commercial Truck Module of the NEMS Transportation Model is constructed to represent trucks that weight 8501 lbs. to 10,000 lbs. These vehicles are assumed to be used for commercial freight purposes.

The primary source of data for this model is the microdata file of the 1992 Truck Inventory and Use Survey (TIUS), which provides numerous details on truck stock and usage patterns at a high level of disaggregation. The data derived from this source are used to allocate and sort the summary truck data presented in the Federal Highway Administration's annual publication of highway statistics, which constitute the baseline from which the NEMS forecast is made (Figure 5). TIUS data are also used to distribute estimated sales of trucks, obtained from the Macroeconomic Model, among the affected models according to their weight class (Figure 6). Finally, the TIUS microdata set is used to construct a characterization of these Light Commercial Trucks.

Truck characterizations comprised of their average annual miles of travel, fuel economy, and distribution among several aggregate industrial groupings chosen for their correspondence with output measures currently being forecast by NEMS (Tables 32 and 33). It is expected that projected growth in industrial output will provide a useful proxy for the growth in demand for the services of light commercial trucks.

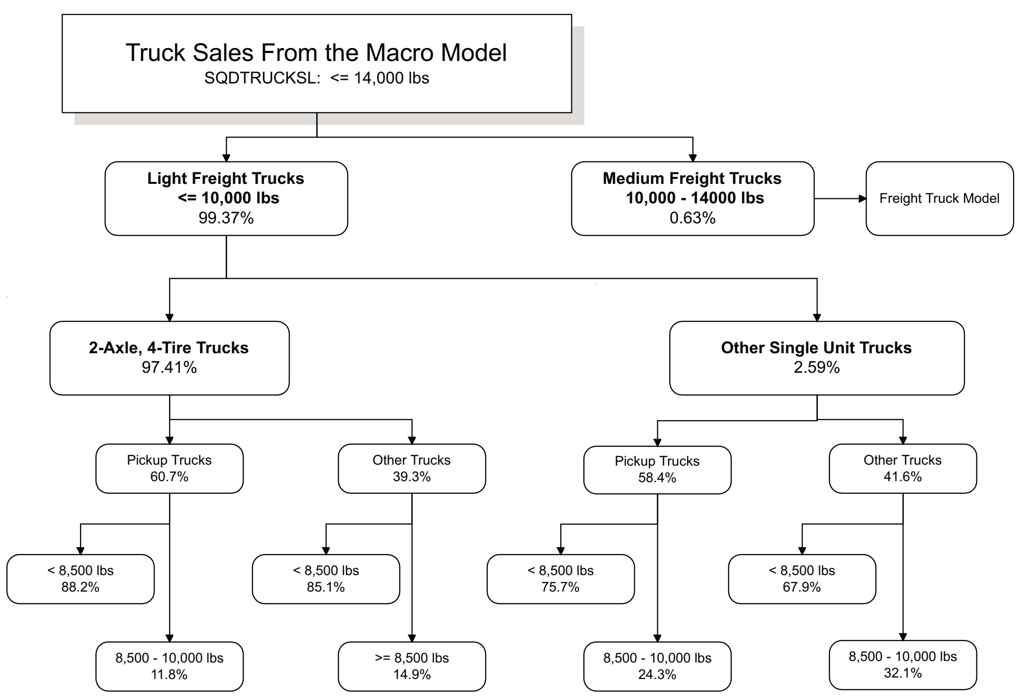
VMT for light commercial trucks is a function of industrial output for agriculture, mining, construction, trade, utilities, and personal VMT. Forecasted fuel efficiencies are assumed to increase at the same annual growth rate as light-duty trucks (<8500 lbs.).

Figure 5. Distribution of FHWA Single-Unit Truck Stocks



Source: U.S. Dept. Of Transportation, Federal Highway Administration, Highway Statistics 1995, Nov. 1996; U.S. Dept. Of Commerce, Bureau of the Census, Truck Inventory and Use Survey 1992,

Figure 6. Distribution of Light Truck Sales



Source: U.S. Dept. Of Transportation, Federal Highway Administration, Highway Statistics 1995, Nov. 1996; U.S. Dept. Of Commerce, Bureau of the Census, Truck Inventory and Use Survey 1992,

Table 32. Annual Miles by Major Use, 1992

Major Use	Single-Unit Trucks, 6,000 - 10,000 lbs.			
	2 Axle, 4 Tire		Other Single-Unit	
	Pickup	Other	Pickup	Other
Agriculture	11,920	8,569	15,197	7,054
Mining	20,231	24,871	18,520	17,786
Construction	15,909	15,195	13,043	10,074
Trade	13,313	15,394	10,009	11,832
Utilities	13,023	13,776	9,947	9,996
Personal	9,980	10,148	8,429	5,852

Source: Estimated from U.S. Dept. Of Commerce, Bureau of the Census, Truck Inventory and Use Survey 1992, TC-92-T-52, (Washington DC., May 1995).

Table 33. Average Miles Per Gallon, 1992

Major Use	2 Axle, 4 Tire			
	Pickup	Other	Pickup	Other
Agriculture	12.77	8.75	11.79	8.66
Mining	13.12	11.92	12.00	10.10
Construction	13.45	11.79	12.58	8.92
Trade	13.55	11.57	12.71	8.98
Utilities	13.33	10.25	13.57	8.65
Personal	13.67	13.99	12.29	10.78

Source: Estimated from U.S. Dept. Of Commerce, Bureau of the Census, Truck Inventory and Use Survey 1992, TC-92-T-52, (Washington, DC., May 1995).

Alternative-Fuel Vehicle Technology Choice Assumptions

Fuel vehicle (AFV) technology choice module utilizes a discrete choice specification, which uses vehicle attributes as inputs and forecasts vehicle sales shares among the following 16 light-duty technologies: gasoline internal combustion engine (ICE), direct injection diesel ICE, ethanol flex, ethanol neat, methanol flex, methanol neat, electric dedicated (uses only electricity), diesel electric hybrid, gasoline electric hybrid, compressed natural gas (CNG), CNG bi-fuel, LPG, LPG bi-fuel, fuel cell gasoline, fuel cell methanol, and fuel cell liquid hydrogen.[44] Direct injection gasoline technologies are included in the conventional gasoline ICE technologies.

Listed in Table 34 are a few examples of the input variables that correspond to the vehicle attributes used in the analysis. With the exception of vehicle fuel economy, fuel price, vehicle price, vehicle range, 0-60 second acceleration times, and fuel availability, all other attributes are exogenously set, based on offline analysis.[45]

Vehicle attributes vary by six EPA size classes for cars and light trucks, and fuel availability varies by Census Division. The logit model coefficients vary by three car sizes and four light truck sizes. Vehicle prices are assumed to follow exponential curves of economies of scale in production dependent upon the volumes and cost curves which vary by AFV technologies. 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.[46,47] A fuel switching algorithm based on the relative fuel prices for AF compared to gasoline is used to determine the percentage of total VMT represented by AF in bi-fuel and flex-fuel alcohol vehicles. An upper limit of 5 percent and a lower limit of 25 percent is assumed for the percentage of the vehicle-miles traveled using the alternative fuel.

Table 34 . Alternative-Fuel Vehicle Attribute Inputs For Compact Cars For Two Stage Logit Model

Vehicle Attributes	Year	Gasoline	Ethanol Flex	CNG Bi-fuel Flex	Gasoline Electric Hybrid	Diesel Electric Hybrid	Fuel Cell Gasoline
Vehicle Price (thousand 1990 dollars)	1999	14.50	16.30	19.50	26.20	N/A	N/A
	2020	16.10	17.80	21.10	16.60	18.1	22.0
Vehicle MPG (miles/gallon)	1999	29.68	29.94	29.64	43.03	N/A	N/A
	2020	33.54	33.76	33.22	41.58	5.52	49.81
Vehicle Range (100 miles)	1999	4.54	3.31	2.27	5.68	N/A	N/A
	2020	5.01	3.66	2.51	6.27	6.52	5.01
Fuel Availability Relative to Gasoline	1999	1.00	1.00	1.00	1.0	0.84	1.00
	2020	1.00	1.00	1.00	1.0	0.84	1.00
Make and Model Availability Indexed To Gasoline	1999	1.00	0.015	0.001	0.000*	N/A	N/A
	2020	1.00	0.015	0.001	0.001	0.000*	0.000*

[1]Electric vehicle battery replacement cost included.

CNG = Compressed natural gas.

MPG = Miles per gallon.

N/A = Not Available Commercially.

* = Less than .001

Sources: Vehicle prices, fuel efficiency, and range: Energy and Environmental Analysis, Updates to the *Fuel Economy Module Final Report*, Prepared for EIA, (June 2000).

Freight Truck Assumptions

The freight truck stock module converts industrial output in dollar terms to an equivalent measure of volume by using a freight adjustment coefficient.[48,49]These freight truck adjustment coefficients vary by NEMS Standard Industrial Classification (SIC) code, gradually diminishing their deviation over time toward parity and are estimated from historical freight data. Freight truck load factors (ton-miles per truck) by SIC code are constants formulated from historical load factors.[50] All freight trucks are subdivided into medium and heavy-duty trucks. New freight truck fuel efficiency is dependent on the maximum penetration, introduction year, cost-effectiveness based on fuel price and capital costs, and fuel economy improvement of the technologies including alternative fuel technologies (Table 35).[51] VMT freight estimates by size class and technology are based on matching freight needs as measured by the growth in industrial output by SIC code to VMT levels associated with truck stocks and new vehicles. Fuel consumption by freight trucks is regionalized by Census Division according to the *State Energy Data Report* distillate regional shares.[52]

Initial freight trucks are obtained by the Federal Highway Administration (FHWA) and are distributed by Truck and Inventory Use Survey (TIUS) shares.

Table 35. Diesel Technology Characteristics for the Freight Truck Model

	Fuel Economy Improvement (%)		Maximum Penetration (%)		Introduction Year		Capital Cost (1998 dollars)	
	Medium	Large	Medium	Large	Medium	Large	Medium	Large
Existing Technologies								
Advanced Tires: Radials	2	2	70	70	--	--	$150	$450
Drag Reduction	3	5	65	65	--	--	$500	$1,000
New Technologies								
Advanced Transmissions	2	1	40	40	2001	2001	$2,500	$2,500
Lightweight Materials	1	1	30	30	2002	2002	$3,000	$3,000
Synthetic Gear Lube	2	2	60	60	2001	2001	$40	$60
Advanced Tires: Low Resistance	4	4	70	70	2001	2001	$300	$900
Advanced Drag Reduction	4	7	65	65	2001	2002	$ 600	$1,200
Electronic Engine Control	4	4	95	95	2001	2001	$1,000	$1,000
Advanced Engine	9	9	90	90	2009	2009	$1,000	$1,000
Turbocompounding	0	5	0	90	N/A	2001	N/A	$2,000
Hybrid Powertrain	54	0	20	0	2006	N/A	$6,000	N/A
Port-Injection	0	1	0	100	N/A	2001	N/A	$300

Source: Argonne National Laboratories, Frank Stodolsky, Anant Vyas, Roy Cuenca. "*Heavy-and Medium-Duty Truck Fuel Economy and Market Penetration Analysis*", prepared for Energy Information Administration, August 6, 1999.

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 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.[53],[54] Initial freight rail efficiencies are based on the freight model from Argonne National Laboratory.[55] The distribution of rail fuel consumption by fuel type remains constant and is based on historical data.[56] Regional freight rail consumption estimates are distributed according to the *State Energy Data Report 1997*.[57]

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.[58],[59] 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.[60] Regional domestic and international shipping consumption estimates are distributed according to the *State Energy Data Report* residual oil regional shares.[61]

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.[62] The propensity to fly was made a function of the age and gender distribution over the forecast period[63],[64] 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.[65] 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.[66] 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.[67] 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. (See Table 39 on page 59)[68] Fuel efficiency of new aircraft acquisitions represents, at a minimum, a 5-percent improvement over the stock efficiency of surviving airplanes.[69] 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 36). Business fleet EPACT mandates are not included in the projections for AFV sales pending a decision on a proposed rulemaking.

Table 36. 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).

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.[70,71] 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.[72,73] 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.[74] 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.[75]

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. The following Zero Emission Vehicle (ZEV) sales percentage numbers (Table 37) come from the California Air Resources Board.[76] All of the ULEV sales were assumed to meet the ULEV air standards with reformulated gasoline and a heated catalytic converter.

Table 37. Original and Revised California Low Emission Vehicle Program Legislatively Mandated Alternative-Fuel Vehicle Sales
(Percentage of all sales)

Vehicle	1997	1998	1999	2000	2001	2002	2003
Original							
Zero Emission Vehicles	--	2	2	2	5	5	10
Revised							
Zero Emission Vehicles	--	--	--	--	--	--	10

Source: California Air Resources Board, *Proposed Regulations for Low Emission Vehicles and Clean Fuels, Staff Report*, August 13, 1990.

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."[77]

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 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.

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 NOx emissions standard by 2004 and approximately a 0.01 to 0.02 grams/mile standard for particulates.[78] The previous Clean Air Act 1990 Tier I emissions standards were set at 0.6 grams/mile for NOx and 0.1 grams/mile for particulates.[79] EPA has estimated the costs to consumers range from $100 per car to $200 per light-truck.[80] 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)[81], 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.

Energy Efficiency Programs

There are four energy efficiency programs related to transportation—reform Federal subsidy for employer-provided parking, adopt a transportation system efficiency strategy, promote telecommuting, and develop fuel economy labels for tires. The combined effect of the Federal subsidy, system efficiency, and telecommuting policies was a reduction in VMT of 1.6 percent in 2010, representing a decline in consumption of approximately 310 trillion Btu with a net carbon dioxide reduction of 6.0 million metric tons carbon equivalent. The fuel economy tire labeling program improved fuel efficiency by 4 percent among vehicles that switched to low rolling resistance tires in pre-1999 vehicles. Therefore there are no new fuel or carbon dioxide savings from this program.

High Technology and 2001 Technology Cases

In the *high technology case*, the light-duty vehicle assumptions for alternative fuel vehicles are presented in Table 38 and are based on the yearly U.S. Department of Energy Office of Energy Efficiency and Renewables Office of Transportation Technologies (OTT) Program Analysis[82] The conventional fuel saving technology characteristics come from a study by the American Council For an Energy Efficient Economy.[83] In the *high technology case,* fuel efficiency improvements from new technology more than offset the increasing travel in each transportation mode. As a result, the total energy consumption in the transportation sector was 10.2 percent lower (3.95 quadrillion Btu) than in the reference case by 2020. Tables 40 and 41 summarize the High Technology matrix for cars and trucks.

The *2001 technology case* assumes that new fuel efficiency technologies are held constant at 2001 levels over the forecast. As a result, the energy use in the transportation sector was 6.7 percent higher (2.59 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.

Freight trucks in the *high technology case* were constructed in accordance with the assumptions from a Department of Energy (DOE) study.[84] The following technologies were made commercially available and cost effective within the forecast period: advanced transmissions, light weight materials, synthetic gear lube, advanced hires, advanced drag reduction, electronic engine controls, advanced engine, turbo

Table 38. Advanced Technology Alternative-Fuel Large Car Vehicle Assumptions Relative to Conventional Gasoline Vehicle, 2020
(Thousands)

Technology	Year of Introduction	Year of Maturity	Vehicle Cost Ratio	Fuel Economy Ratio	Relative Vehicle Range
Advanced Diesel	2004	2017	Intro:1.11 Mat.:1.04	Intro: 1.35 Mat.: 1.35	Intro: 1.14 Mat.: 1.20
Diesel Hybrid	2003	2020	Intro: 1.40 Mat.: 1.16	Intro: 1.5 Mat.: 2.00	Intro: 1.20 Mat.: 1.20
Fuel Cell	2007	2019	Intro: 1.50 Mat.: 1.26	Intro: 2.10 Mat.: 2.20	Intro: 1.00 Mat.: 1.00
Natural Gas	2000	2006	Intro: 1.11 Mat.: 1.03	Intro: 1.0 Mat.: 1.0	Intro: 0.66 Mat.: 0.75
Flex Alcohol	1998	1998	Intro: 1.0 Mat.: 1.0	Intro: 1.0 Mat.: 1.0	Intro: 1.0 Mat.: 1.0

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewables, Office of Transportation Technologies, *OTT Program Analysis Methodology: Quality Metrics 2000,* November 1, 1998.

compounding, hybrid powertrain, port-injection, and reduced empty travel. Additionally, maximum market penetration periods are reached earlier, and technology prices were made more cost-effective.

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.[85]

Table 39. 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 40. 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	0.60	0	-0.05	1986	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	0.2
OHC 6	0.030	140.00	0.00	0	0.00	1985	0.2
OHC 8	0.030	170.00	0.00	0	0.00	1995	0.2
4C/4V	0.060	240.00	0.00	30	0.00	1990	0.45
6C/4V	0.060	320.00	0.00	45	0.00	1990	0.45
8C/4V	0.060	400.00	0.00	60	0.00	2002	0.45
Cylinder Reduction	0.030	-100.00	0.00	-150	0.00	1990	-0.1
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	0.080	140.00	0.00	40	0.00	2006	0.1
VVT II	0.100	180.00	0.00	40	0.00	2016	0.15
Lean Burn	0.150	150.00	0.00	0	0.00	2018	0
Two Stroke	0.150	150.00	0.00	-150	0.00	2008	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	0.1
Air Pump	0.010	0.00	0.00	-10	0.00	1985	0
DFS	0.015	15.00	0.00	0	0.00	1985	0.1
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	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.	-0.033	0.00	0.00	0	0.05	1991	0
GDI/4-cyl	0.170	1000.00	0.00	0	0.00	2005	0.02
GDI/6-cyl	0.170	1200.00	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 41. 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	0.60	0	-0.05	1987	0
Material Substitution III	0.066	0.00	0.80	0	-0.10	1997	0
Material Substitution IV	0.099	0.00	1.00	0	-0.15	2007	0
Material Substitution V	0.132	0.00	15.0	0	-0.20	2017	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	2004	0
Drag Reduction V	0.092	176.00	0.00	0	0.02	2014	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	300.00	0.00	45	0.00	1998	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	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	140.00	0.00	40	0.00	1998	0.10
VVT II	0.100	180.00	0.00	40	0.00	2008	0.15
Lean Burn	0.100	150.00	0.00	0	0.00	2012	0
Two Stroke	0.150	150.00	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	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	1992	0
ACC II	0.010	30.00	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	2002	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	1991	0
GDI/4-cyl	0.170	1000.00	0.00	0	0.00	2005	0
GDI/6-cyl	0.170	1200.00	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).*

Notes and Sources

[29] U.S. Department of Transportation, National Highway Traffic and Safety Administration, Mid-Model Year Fuel Economy Reports from Automanufacturers, (1999).

[30] Goldberg, Pinelopi Koujianou, Product Differentiation and Oligopoly In International Markets: The Case of The U.S. Automobile Industry," Econometrica, Vol. 63, No.4 (July, 1995), 891-951.

[31] Maples, John D., The Light-Duty Vehicle MPG Gap: Its Size Today and Potential Impacts in the Future, University of Tennessee Transportation Center, Knoxville, TN, (May 28, 1993, Draft); Decision Analysis Corporation of Virginia, Fuel Efficiency Degradation Factor, Final Report, Prepared for Energy Information Administration (EIA), (Vienna, VA, August 3, 1992); U.S. Department of Transportation, Federal Highway Administration, New Perspectives in Commuting, (Washington, DC, July 1992); U.S. Department of Transportation, Federal Highway Administration, Highway Statistics 1998, FHWA-PL-99-017, (Washington, DC, November 1, 1999); and Green, Tamara, "Re-estimation of Annual Energy Outlook 2000 Degradation Factors," prepared for the Energy Information Administration, unpublished paper, August 18, 1999, Washington, D.C.

[32] U.S. Department of Transportation, *op.cit*., Note 31.

[33] Decision Analysis Corporation of Virginia, NEMS Transportation Sector Model: Re-estimation of VMT Model, Prepared for Energy Information Administration (EIA), (Vienna, VA, June 30, 1995).

[34] Energy Information Administration, Describing Current and Potential Markets for Alternative Fuel Vehicles, DOE/EIA-0604(96), (Washington, DC, March 1996).

[35] Energy Information Administration, Alternatives to Traditional Transportation Fuels http://www.eia.doe.gov/cneaf/solar.renewables/alt_trans_fuel98/table14.html.

[36] Bobbit, The Fleet Fact Book, Redondo Beach, (California, 1995).

[37] U.S. Department of Commerce, Bureau of Census, Vehicle Inventory and Use Survey Data 1997, EC-97-TV-US, (Washington, DC, October 1999).

[38] U.S. Department of Energy, Office of Policy, Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector, Technical Report Fourteen: Market Potential and Impacts of Alternative-Fuel Use in Light-Duty Vehicles: A 2000/2010 Analysis, (Washington, DC, 1995).

[39] California Resources Board, Proposed Regulations for Low-Emission Vehicles and Fuels, Staff Report, (August 13, 1990).

[40] 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).

[41] *Ibid*.

[42] Energy Information Administration, *op.cit*., Note 34.

[43] Energy Information Administration, *op.cit*., Note 35.

Notes and Sources

[44] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, prepared by Interlaboratory Working Group, Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy Technologies by 2010 and Beyond, (Washington DC, 1998).

[45] U.S. Department of Energy, Office of Transportation Technologies and Energy Efficiency and Renewable Energy, Alternative-Fuel Vehicle Model, 1998; and Energy and Environmental Analysis, Changes to the Fuel Economy Module, Final Report, Prepared for Energy Information Administration (EIA), (June 1998).

[46] Energy Information Administration, *op.cit*., Note 34.

[47] Energy Information Administration, *op.cit*., Note 35.

[48] Decision Analysis Corporation of Virginia, Re-estimation of Freight Adjustment Coefficients, Report Prepared for Energy Information Administration (EIA), (February 28, 1995).

[49] Reebie Associates, TRANSEARCH Freight Commodity Flow Database, (Greenwich, CT, 1992).

[50] U.S. Department of Commerce, Bureau of Census, *op.cit*., Note 37.

[51] U.S. Department of Energy, Office of Heavy Vehicle, Technologies (OHVT), OHVT Technology Roadmap, DOE/OSTI-11690, (October 1997).

[52] Energy Information Administration, State Energy Data Report 1997, DOE/EIA-0214(97), (Washington, DC, September 1999).

[53] Decision Analysis Corporation of Virginia, *op.cit.*, Note 48.

[54] Reebie Associates, *op.cit.,* Note 49.

[55] Argonne National Laboratory, Transportation Energy Demand Through 2010, (Argonne, IL, 1992).

[56] U.S. Department of Transportation, Federal Railroad Administration, 1989 Carload Waybill Statistics; Territorial Distribution, Traffic and Revenue by Commodity Classes, (September 1991 and prior issues).

[57] Energy Information Administration, *op.cit*., Note 52.

[58] Decision Analysis Corporation of Virginia, *op.cit*., Note 48.

[59] Reebie Associates, *op.cit*., Note 49.

[60] Army Corps of Engineers, Waterborne Commerce of the United States, (Waterborne Statistics Center: New Orleans, LA, 1993).

[61] Energy Information Administration, *op.cit*., Note 52.

[62] Transportation Research Board, Forecasting Civil Aviation Activity: Methods and Approaches, Appendix A, Transportation Research Circular Number 372, (June 1991).

[63] Decision Analysis Corporation of Virginia, Re-estimation of NEMS Air Transportation Model, Prepared for the Energy Information Administration (EIA), (Vienna, VA, 1995).

Notes and Sources

[64] Air Transport Association of America, Air Travel Survey, (Washington DC, 1990).

[65] U.S. Department of Transportation, Air Carrier Traffic Statistics Monthly, (December 1999).

[66] U.S. Department of Transportation, Federal Aviation Administration, FAA Aviation Forecasts Fiscal Years 1997-2009, (Washington, DC, March 1998, and previous editions).

[67] *Ibid*.

[68] Oak Ridge National Laboratory, Energy Efficiency Improvement of Potential Commercial Aircraft to 2010, ORNL-6622, (Oak Ridge, TN, June 1990), Oak Ridge National Laboratory, Air Transport Energy Use Model, Draft Report, (Oak Ridge, TN, April 1991).

[69] Ibid.

[70] Energy Information Administration, *op.cit*., Note 34.

[71] Energy Information Administration, *op.cit*., Note 35.

[72] Bobbit, *op.cit*., Note 36.

[73] U.S. Department of Commerce, Bureau of Census, *op.cit*., Note 37.

[74] U.S. Department of Energy, Office of Policy, *op.cit*., Note 38.

[75] U.S. Department of Energy, Office of Policy, *op.cit.*, Note 38.

[76] California Air Resources Board, Proposed Regulations for Low Emission Vehicles and Clean Fuels, Staff Report, (August 13, 1990).

[77] State of California Air Resources Board, Staff Report: Initial Statement of Reasons, Proposed Amendments to California Exhaust and Evaporative Emissions Standards and Test Procedures For Passenger Cars, Light-Duty Trucks and Medium-Duty Vehicles -"LEV II" and Proposed Amendments to California Motor Vehicle Certification, Assembly-Line and In-Use Test Requirements -"CAP 2000," Mobile Source Control Division, El Monte, CA, September 18, 1998.

[78] Http://www.epa.gov/fedrgstr/EPA-AIR/1999/May/Day-13/a11384a.htm.

[79] U.S. EPA, Office of Mobile Sources, Exhaust Emission Certification Standards, EPA 420-B-98-001, March 24, 1998.

[80] Http://www.epa.gov/oms/tr2home.htm.

[81] National Research Council, Review of the Research Program of the Partnership for a New Generation of Vehicles: Fifth Report, National Academy Press, Washington, D.C., 1999.

[82] U.S. Department of Energy, Office of Energy Efficiency and Renewables, Office of Transportation Technologies, OTT Program Analysis Methodology: Quality Metrics 2000, (November 1, 1998).

[83] DeCicco, John, and Marc Ross, An Updated Assessment of the Near-Term Potential for Improving Automotive Fuel Economy, American Council for an Energy Efficient Economy, November 1993.

Notes and Sources

[84] U.S. Department of Energy, Office of Heavy Vehicle, Technologies, *op.cit*., Note 51.

[85] National Research Council, Aeronautics and Space Engineering Board, 1992. Aeronautical Technologies for the Twenty-First Century, National academy Press, Washington, D.C.

Electricity Market Module

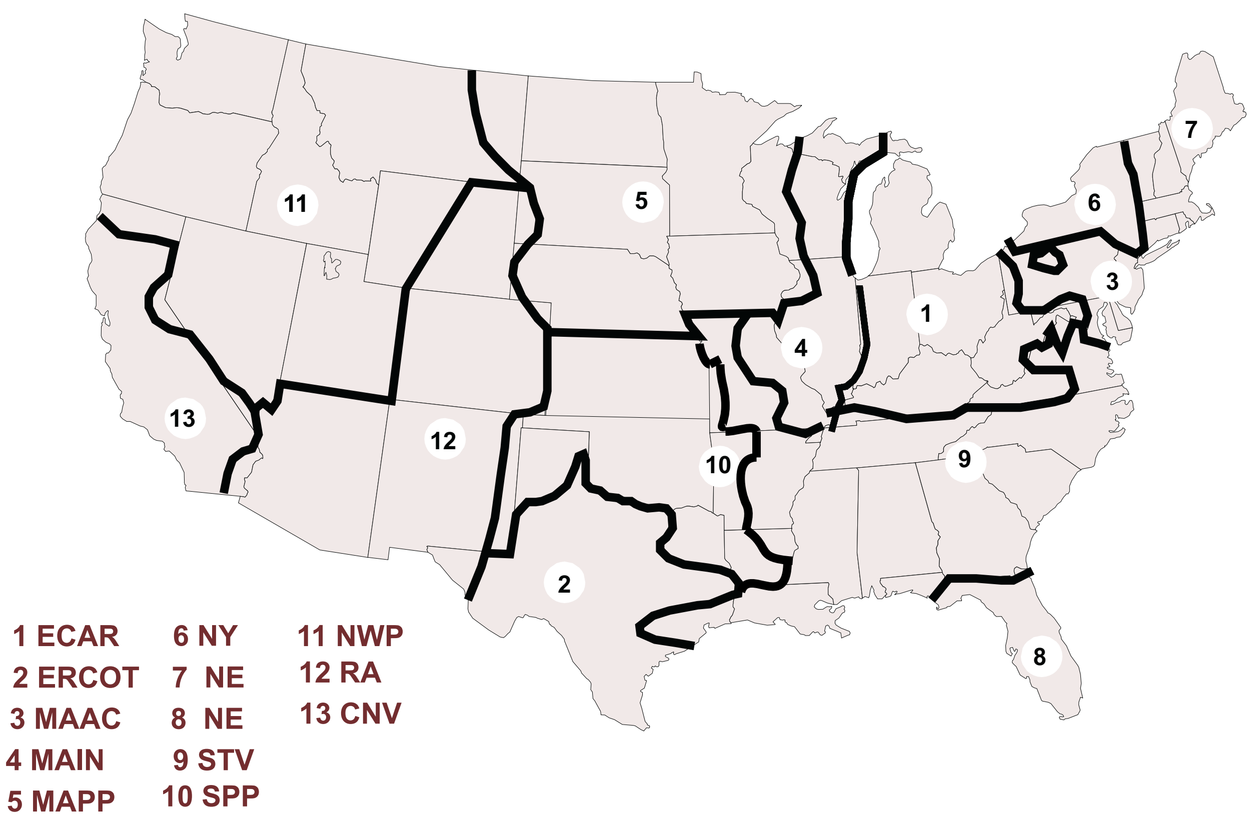
The NEMS Electricity Market Module (EMM) represents the capacity planning, dispatching, and pricing of electricity. It is composed of four submodules—electricity capacity planning, electricity fuel dispatching, load and demand-side management, and electricity finance and pricing. It includes nonutility 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 2001*, DOE/EIA-M068(2001) January 2001.

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 7.

Figure 7. Electricity Market Model Supply Regions



Model Parameters and Assumptions

Generating Capacity Types

The 29 capacity types represented in the EMM are shown in Table 42. Assumptions for the ten renewable technologies are discussed in the next chapter.

Table 42. Generating Capacity Types Represented in the Electricity Market Module

Capacity Type
Coal Steam pre-1965; Unscrubbed coal - Sulfur dioxide <=1.20 pounds per million Btu
Coal Steam pre-1965; Unscrubbed coal - Sulfur dioxide <=3.34 pounds per million Btu
Coal Steam pre-1965; Unscrubbed coal - Sulfur dioxide >=3.34 pounds per million Btu
Coal Steam post-1965; Unscrubbed coal - Sulfur dioxide <= 1.20 pounds per million Btu
Coal Steam post-1965; Unscrubbed coal - Sulfur dioxide <= 3.34 pounds per million Btu
Coal Steam post-1965; Unscrubbed coal - Sulfur dioxide >=3.34 pounds per million Btu
Coal Steam with Scrubber
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 - Dual Flash
Geothermal - Binary
Municipal Solid Waste - Mass Burn
Muncipal Solid Waste - Landfill Gas
Biomass - Integrated Gasification Combined-Cycle
Solar Thermal - Central Receiver
Solar Photovoltaic - Single Axis Flat Plate
Wind

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 43). 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 43 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 44) 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 43. Cost and Performance Characteristics of New Electricity Generating Technologies

Technology	Online Years[1]	Size (mW)	Leadtimes (Years)	Overnight Costs in 2000 ($1999/kW)	Contingency Factors: Project Contingency Factor	Contingency Factors: Technological Optimism Factor[2]	Total Overnight Cost including contingencies in 2000[3] (1999 $/kW)	Variable O&M[4] ($1999 mills/kWh)	Fixed O&M[4] ($1999/kW)	Heatrate in 2000 (Btu/kWhr)	Heatrate in 2010 (Btu/kWhr)
Conventional Pulverized Coal	2005	400	4	1,021	1.07	1.00	1,092	3.30	22.85	9,419	9,087
Integrated Coal-Gasification Combined Cycle	2005	428	4	1,220	1.07	1.00	1,306	0.78	31.89	7,969	6,968
Conventional Gas/Oil Combined Cycle	2004	250	3	424	1.05	1.00	445	0.51	15.24	7,687	7,000
Adv Gas/Oil Combined Cycle	2004	400	3	533	1.08	1.00	576	0.51	14.12	6,927	6,350
Conv Combustion Turbine[5]	2003	160	2	315	1.05	1.00	331	0.10	6.30	11,467	10,600
Adv Combustion Turbine	2003	120	2	440	1.05	1.00	462	0.10	8.94	9,133	8,000
Fuel Cells	2004	10	3	1,767	1.05	1.10	2,041	2.03	14.63	5,787	5,361
Advanced Nuclear	2005	600	4	1,729	1.10	1.15	2,188	0.41	55.86	10,400	10,400
Generic Distributed Generation[6] - Base	2004	2	3	579	1.05	1.00	608	14.75	3.92	10,991	9,210
Generic Distributed Generation[6] - Peak	2003	1	2	520	1.05	1.00	546	22.55	12.26	10,620	10,500
Biomass	2005	100	4	1,464	1.07	1.10	1,723	2.83	43.88	8,911	8,911
MSW - Landfill Gas	2004	30	3	1,304	1.07	1.00	1,395	0.01	94.01	13,648	13,648
Geothermal [7,8]	2005	50	4	1,626	1.05	1.00	1,708	0.00	70.69	31,241	30,862
Wind	2004	50	3	919	1.07	1.00	983	0.00	26.00	10,280[9]	10,280[9]
Solar Thermal[8]	2004	100	3	2,394	1.07	1.15	2,946	0.00	46.72	10,280[9]	10,280[9]
Solar Photovoltaic[8]	2003	5	2	3,681	1.05	1.10	4,252	0.00	9.85	10,280[9]	10,280[9]

[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 changes are also excluded. These represent costs of new projects initiated in 2000.

[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 45 because of updated adjustments for inflation. The unit size shown here is higher than that shown in Table 45 to reflect the minimum size that can be represented meaningfully in the model. The lead times are also different from those shown in Table 45 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.

[9]Heat rates for solar and wind technologies are fossil-fuel average heat rates.

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 44. 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 43 and the learning parameters from Table 45.

Table 45. 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 *AEO2001*, 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.

AEO2001 includes 2,524 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. For the end-use sectors see pages 33 and 42. 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 46 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

Table 46. 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.

gas prices available to larger high-volume central generators. In order to account for uncertainty in the delivered costs of natural gas it was assumed that distributed generators would pay a premium of 20 cents 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 9 time periods represented by 11 time slices. The summer and winter peak periods are represented by 2 vertical slices each (a peak slice and an off-peak slice). The remaining 7 periods are represented by 1 vertical slice each, resulting in a total of 11 vertical slices. (Table 47) The time periods shown were chosen to accommodate intermittent generating technologies (i.e., solar and wind facilities) and demand-side management programs.

Reserve margins—the percentage of capacity required in excess of peak demand needed for unforeseeable outages—are 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

Table 47. Load Segments in the Electricity Market Module

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

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

marginal cost of capacity and the cost of unserved energy.

Fossil Fuel-Fired Steam Plant Maintenance/Retirement

Fossil-fired steam plant retirements are calculated endogenously within the model. Fossil 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 capital additions for existing plants are $10 per kilowatt (kW) for oil and gas steam plants, $4/kW for combined-cycle plants, $5/kW for combustion turbines, and $16/kW for coal plants. These costs are added to existing plants regardless of their age.

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.

Nuclear Power Plant Retirements

The cost of operating nuclear power plants is assumed to increase as they age. 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. In particular, it is assumed that total operating costs per kilowatt (kW) of capacity and plant output would remain unchanged until a plant is 30 years old. At that point, operating costs begin to increase by $.25 per kilowatt of installed capacity per year for 10 years. At age 40, costs increase by $13.50 per kilowatt of capacity per year for the next 10 years, and after age 50, costs increase by about $25.00 per kilowatt per year.[86] The cost increases from year 30 to year 40 are less than that assumed in AEO 2000. However, the cost increases from years 40 to year 50 are similar to that used in AEO 2000. The age related cost increases of $13.50 per kW of capacity per year that have been assumed are consistent with costs derived in a statistical analysis of nuclear power plant operating costs and performance using a sample of plants that are newer vintages.[87]

The age related cost increases for plants that incurred major capital expenditures over the last 10 years were assumed to be 50 and 75 percent of that used for plants that did not incur such expenditures for years 30-40, and 40-50, respectively. This adjustment was made for the entire fleet of plants regardless of its vintage. An adjustment was also made to account for the fact that, if a plant continues to operate, a portion of the decommissioning costs (about $30 million) would be deferred.

The present value of these cost increases was computed over a 20-year period using a real discount rate of 7.3 percent. The discount rates and the 20-year period are consistent with the method used to compute the cost of new capacity. These costs were then compared to the total (capital and operating) levelized cost of the least cost alternative (generally natural gas-fired combined cycle technologies). If the present value of the operating costs was greater than the levelized cost of the least cost alternative, the nuclear plant would be retired.

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. 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 2025.*

Electricity Pricing

The reference case assumes a transition to full competitive pricing in California, New York, New England, Mid-Atlantic Area Council, and Texas. 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 five 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 *AEO2001*. The key trends are discussed below:

- Reduced General and Administrative Expenses (G&A) - Over the 1990 through 1997 period, utilities have reduced their employment in coal steam plants at a rate of 3.6 percent per year. This trend has been incorporated by reducing 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 1997 period, utility fossil plant operation and maintenance costs (all operating costs other than fuel) fell at a rate of about 3.6 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 1998, utilities reported spending over $1.4 billion on demand-side management programs.[88]

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.[89] 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 $6.50 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.

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 $195 per kilowatt, in 1999 dollars, although the costs vary widely across the regions. It is also assumed that the market for trading emission allowances is allowed to operate without regulation and that the States do not further regulate the selection of coal to be used.

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 48). 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 48. 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 49). 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.[90] 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

Table 49. Summer Season NO_x Emissions Budgets for 2003 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).

transmission services by owners of these facilities. Specifically, Order 888 requires open access to the transmission grid currently owned and operated by utilities. The transmission owners must file nondiscriminatory tariffs that offer other suppliers the same services that the owners provide for themselves. Order 888 also allows these utilities to recover stranded costs (investments in generating assets that are unrecoverable due to consumers selecting another supplier). Order 889 requires utilities to implement standards of conduct and a Open Access Same-time Information System (OASIS) through which utilities and non-utilities can receive information regarding the transmission system. Consequently, utilities are expected to functionally or physically unbundle their marketing functions from their transmission functions.

These orders are represented in 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 1999 and 2020. In the reference case, electricity demand is projected to grow 1.8 percent annually between 1999 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, and fuel cells) will remain at the initial cost 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 1995 levels. Capital costs of conventional generating technologies are the same as those assumed in the reference case (Table 50).

Table 50. Cost and Performance Characteristics for Fossil-Fueled Generating Technologies: Three Cases

	Overnight Cost including contingencies in 2000	Overnight Cost including contingencies and learning effects[1]			Heatrate in 2000	Heat Rate		
	(Reference)	Reference Case	High Fossil Case	Low Fossil Case[2]	(Reference)	Reference Case	High Fossil Case	Low Fossil[2] Case
	(1999$/kW)	(1999$/kW)	(1999$/kW)	(1999$/kW)	Btu/kWhr	Btu/kWhr	Btu/kWhr	Btu/kWhr
Conventional Pulverized Coal	1092				9419			
2005		1079	1079	1079		9253	9253	9253
2010		1065	1065	1065		9087	9087	9087
2015		1051	1051	1051		9087	9087	9087
2020		1038	1038	1038		9087	9087	9087
Integrated Coal Gasification Combined-Cycle	1306				7969			
2005		1273	1114	1306		7469	7079	8470
2010		1199	989	1306		6968	6383	8470
2015		1191	964	1306		6968	5687	8470
2020		1172	940	1306		6968	5687	8470
Conv Combined Cycle	445				7687			
2005		440	440	440		7343	7343	7343
2010		434	434	434		7000	7000	7000
2015		429	429	429		7000	7000	7000
2020		423	423	423		7000	7000	7000
Adv. Combined Cycle	576				6927			
2005		551	548	576		6639	6193	6985
2010		499	494	576		6350	5534	6985
2015		478	474	576		6350	4874	6985
2020		466	458	576		6350	4874	6985
Conv. Combustion Turbine	331				11467			
2005		326	326	326		11033	11033	11033
2010		323	323	323		10600	10600	10600
2015		318	318	318		10600	10600	10600
2020		314	314	314		10600	10600	10600
Adv. Combustion Turbine	462				9133			
2005		435	435	462		8567	7767	9700
2010		375	375	462		8000	6800	9700
2015		356	351	462		8000	6800	9700
2020		353	349	462		8000	6800	9700
Fuel Cells	2041				5787			
2005		1939	1321	2041		5574	5521	6000
2010		1392	1288	2041		5361	5281	6000
2015		1254	1257	2041		5361	5281	6000
2020		1245	1226	2041		5361	5281	6000

[1]Excludes regional multipliers.

[2]In the Low Fossil Case, heat rates for advanced technologies are held constant at 1995 levels.

Source: AEO2001 National Energy Modeling System runs: AEO2001.D101600A, HFOSS01.D101800B, LFOSS01.D101700A.

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 and fuel cells 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, the age related cost increases were assumed to be 25 percent of the cost used in the reference case ($.06 per kilowatt per year after age 30, $3.37 per kilowatt per year after age 40 and $6.25 per kilowatt per year after age 50). The high nuclear case considers the possibility that costs would be less than expected and nuclear units are more likely to operate beyond current licenses. In the low nuclear capacity case, the cost increases from ages 30-40 were assumed to be about $5.00 per kilowatt of capacity per year. Given this assumption, on a per kilowatt hour basis, the cost of the average 40 year old plant is similar to the average cost experienced in the early 1990's. The cost increases from years 40-60 were the same as the costs used in the reference case. 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. In both the high and low nuclear capacity cases, these adjustments were made for all plants regardless of vintage including units that underwent a major repair.

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 Cases

A pair of advanced nuclear cost cases was used to analyze the sensitivity of the projections to lower costs and construction times for new plants. The cost assumptions for the two cases 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 51. One case assumed a 4-year construction time, as in the Reference case, and the other 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 51. Cost Characteristics for Advanced Nuclear Technology: Two Cases

	Overnight Cost in 2000 (Reference) (1999$/kW)	Overnight Cost including project contingencies and learning effects[1]	
		Reference Case (1999$/kW)	Adv Nuclear Case (1999$/kW)
	2188		
2005		2133	1650
2010		2078	1484
2015		2023	1320
2020		1969	1320

[1]Excludes regional multipliers.

Source: AEO2001 National Energy Modeling System runs: AEO2001.D101600A, ADVNUC1.D101700A.

Notes and Sources

[86] For example, assume that the total operating costs at year 30 was $100.00 per kilowatt. Then at ages 31,32, ..40, the operating costs would be $100.25, $100.50, ..$102.50, respectively. At ages 41,42, ..50, costs would be $116.00, $129.50, ..237.50, respectively.

[87] Energy Information Administration, An Analysis of Nuclear Plant Operating Costs: A 1995 update, SR/OIAF/95-01, Washington, DC, April 1995.

[88] Form EIA-861, Annual Electric Utility Report, 1998.

[89] Energy Information Administration, Integrating Module of the National Energy Modeling System: Model Documentation, DOE/EIA-M057(2001), (Washington, DC, December 2000).

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

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(2001), (Washington, DC, January 2001). 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, the start date, and threshold price for the Alaskan Natural Gas Transportation System (ANGTS), 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[91] consist of proved reserves,[92] inferred reserves,[93] and undiscovered technically recoverable resources.[94] 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. Supplemental adjustments to the USGS nonconventional resources are made by Advanced Resources International (ARI), an independent consulting firm, and adjustments to the deep resources in the Gulf of Mexico are made based on estimates in a report to the National Petroleum Council.[95] 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 52 and 53 reflect the removal of intervening reserve additions between the dates of the USGS (1/1/94) and MMS (1/1/95) estimates and 1/1/99.

Alaskan Natural Gas

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. This use is expected to delay extraction of gas for market until the post-2009 period. The estimates for gas from the North Slope that will be transported to lower 48 States markets through ANGTS are dependent on the capacity of this system. ANGTS is projected to flow gas to market in two phases, and it is assumed that production will be available to fully utilize the capacity in both phases, if constructed. Operational capacity for the first phase is 767 billion cubic feet per year delivered to the U.S./Canadian border. Annual capacity is assumed to increase to 1,150 billion cubic feet upon the completion of the second phase. Operation for each phase is assumed to begin at midyear; thus only half of the capacity is available for the first year of operation, with full capacity available in each year thereafter. It is assumed that ANGTS will not begin operation until 2009 at the earliest, to support oil recovery in the Prudhoe Bay field. Each phase of ANGTS is brought on line in OGSM when the appropriate border-crossing price is reached for gas delivered to the lower 48 States. The price for phase one is $4.06 in 1999 dollars per thousand cubic feet. When this price is reached, ANGTS is brought on line in the following year, with a total flow of 383 billion cubic feet, reaching the full capacity of 767 billion cubic feet in subsequent years. If a higher threshold price of $5.44, in 1999 dollars per thousand cubic feet is reached, then phase two will begin the following year. The flow will increase by 192 billion cubic feet, to 959 billion cubic feet, and in each subsequent year the flow will be 1,150 billion cubic feet. This methodology is applied in all the cases. Although other options have been proposed for Alaska North Slope gas, including gas-to-liquids (GTL), liquefied natural gas (LNG), and transportation to the lower-48 via pipeline systems other than ANGTS, these options are not at present included in the NEMS.

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 2009, at an average historical level of 57.3 billion cubic feet per year. In all cases, it is assumed that in 2010 the Great Plains facility will stop producing natural gas when the current purchase contract expires and natural gas production is assumed not to be economical. 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 6.8 billion cubic feet per year.

Table 52. Crude Oil Technically Recoverable Resources
(Billion barrels)

Crude Oil Resource Category	As of January 1, 1999
Undiscovered	53.42
Onshore	25.03
Offshore	28.39
Deep (>200 meter W.D.)	27.43
Shallow (0-200 meter W.D.)	0.96
Inferred Reserves	50.64
EOR	12.70
Other Onshore	33.37
Offshore	4.57
Deep (>200 meter W.D.)	2.32
Shallow (0-200 meter W.D.)	2.25
Total Lower 48 States Unproved	104.06
Alaska	17.13
Total U.S. Unproved	121.19
Proved Reserves	22.37
Total Crude Oil	143.56

WD= Water Depth

Note: Resources in restricted areas (where drilling is 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.

Source: Conventional (non-EOR) Onshore, State Offshore, and Alaska - U.S. Geological Survey (USGS); Federal (Outer Continental Shelf) Offshore - Minerals Management Services (MMS) with adjustments to MMS Deep Water resources in the Gulf of Mexico based on estimates from the National Petroleum Council (NPC); EOR - Energy Information Administration (EIA), Office of

Table 53. Natural Gas Technically Recoverable Resources
(Trillion cubic feet)

Natural Gas Resource Category	As of January 1, 1999
Nonassociated Gas	
Undiscovered	319.04
Onshore	167.46
Deep (>10,000 ft)	84.90
Shallow (0-10,000 ft)	82.56
Offshore	151.58
Deep (>200 meters W.D.)	118.04
Shallow (0-200 meters W.D)	33.54
Inferred Reserves	243.73
Onshore	191.88
Deep (>10,000 ft)	26.42
Shallow (0-10,000 ft)	165.46
Offshore	51.85
Deep (>200 meters W.D.)	9.72
Shallow (0-200 (meters W.D.)	42.13
Unconventional Gas Recovery	392.61
• Tight Gas	277.95
• Shale	52.79
• Coalbed	61.87
Associated-Dissolved Gas	129.20
Total Lower 48 Unproved	1084.57
Alaska	32.52
Total U.S. Unproved	1117.09
Proved Reserves	164.04
Total Natural Gas	1281.14

WD = Water Depth

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

Source: Onshore, State Offshore, and Alaska - U.S. Geological Survey (USGS) with adjustments to Unconventional Gas Recovery resources by Advanced Resources, International, Federal (Outer Continental Shelf) Offshore - Minerals Management Services (MMS) with adjustments to MMS Deep Water resources in the Gulf of Mexico based on estimates from the National Petroleum Council (NPC); 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) estimates and 1/1/99.

Natural Gas Imports and Exports

U.S. natural gas trade with Mexico and natural gas exports from the United States to Canada are determined exogenously to NEMS. U. S. exports of LNG are also exogenously determined. Canadian production and U.S. import flows from Canada are determined endogenously within the model and are constrained by pipeline capacities. Exogenously specified projections of pipeline import and export values from Canada and Mexico are shown in Table 54.

Canadian consumption and production outside of the Western Canadian Sedimentary Basin (WCSB) are set exogenously in the model and are shown in Table 55. These values are reflective of a recent forecast produced by Canada's National Energy Board. 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 1.57 billion cubic feet per well and assuming an annual decline of 1.8 percent.

Annual U.S. exports of LNG are assumed to be a constant at 64.5 billion cubic feet in each year after 2000. LNG imports are determined endogenously within the model. The outlook for LNG imports was based on a contracts with a responsible purchaser. The outlook for LNG imports also includes an implicit assumption that no major operational or institutional difficulties arise that are not resolved expeditiously.

Table 54. U.S. Natural Gas Imports and Exports
(Billion cubic feet per year)

	Canada	Mexico	
Year	Exports	Imports	Exports
2000	44	15	92
2005	44	41	217
2010	44	71	320
2015	44	96	423
2020	44	121	523

Note: Imports are imports to the United States. Exports are exports from the United States.

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

Table 55. Exogenously Specified Canadian Production and Consumption
(Billion cubic feet per year)

Year	Consumption	Production Eastern Canada	Production Northern Frontier
2000	2,711	170	0
2005	3,069	230	0
2010	3,345	395	0
2015	3,635	525	0
2020	3,908	555	450

Source: Derived from National Energy Board, *Canadian Energy-Supply and Demand to 2025* (Calgary, Alberta: 1999)

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 1999 is assumed to be 352 billion cubic feet. Two additional facilities, one at Cove Point, Maryland and the other at Elba Island, Georgia, currently mothballed, are assumed to reopen in 2003, adding an additional 529 billion cubic feet of sustainable capacity. It is further assumed that according to announced plans, Elba Island will receive one to two shipments (less than 5 bcf) to test the facility prior to fully reactivating it.

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.

combination of influences, including available gasification capacity, announced plans by each company, tanker availability, expected utilization rates, projected gas prices and liquefaction capacity, and long-term

Launch Coalbed Methane Outreach Program

The natural gas production forecasts incorporate the expected results of the *Launch Coalbed Methane Outreach Program* (LCMOP). Under the LCMOP, the Department of Energy (DOE) and the Environmental Protection Agency (EPA) created a program to raise the awareness among key coal companies and State agencies of the potential for cost-effective methane emissions reduction.

Estimates of the production resulting from this program through 2020 have been obtained from EPA. These production projections are presented in Table 56.

Table 56. Production from Mines Reached by the LCMOP
(Billion cubic feet)

Year	Production
2000	23.7
2005	26.4
2010	29.1
2015	31.8
2020	34.6

Source: Environmental Protection Agency.

The annual production increases resulting (linear interpolations for interim year) from the LCMOP are added to baseline forecasts of coalbed methane (CBM) production from the OGSM. The additional production is allocated regionally based on sharing factors derived from analysis in the EPA report, *Opportunities to Reduce Anthropogenic Methane Emissions in the United States.*[96]

High and Low Resources Cases

To demonstrate the sensitivity of the underlying oil and gas resource base on the *AEO2001* results, high and low resource cases were created by simply adjusting the oil and gas resource base a percentage across all regions. As in the other *AEO2001* cases, resources in areas restricted from exploration and development are not included in the resource base. For conventional onshore and offshore resources, both the undiscovered technically recoverable resource and the inferred reserve estimates were adjusted plus or minus 20 percent. Even more uncertainty surrounds the estimates for unconventional gas resources, so the unproved resource estimates for unconventional gas recovery was adjusted plus or minus 40 percent in the high and low resource cases. Thus, the assumed level of technically recoverable natural gas resources are 1,583 trillion cubic feet in the high resource case and 979 trillion cubic feet in the low resource case compared to 1,281 trillion cubic feet in the reference case. Technically recoverable crude oil resources are 165 billion barrels in the high resource case, 144 billion barrels in the reference case, and 122 billion barrels in the low resource case. The recoverable volumes for these cases were specified to exhibit significant variation in this key assumption without exceeding a reasonable range. Results of the high and low resource cases should not be construed as extreme cases that are expected to bound most, if not all, feasible projections.

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 57), for the rapid and slow technology cases, respectively. The approaches taken in the representation of enhanced oil recovery and unconventional natural gas are discussed below. In the Canadian supply submodule, the decline in the finding rate in the WCSB (set at 1.8 percent per year in the reference case) was set at 0.9 and 2.7 percent in the rapid and slow technology cases, respectively, from 2000 forward. 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.

Table 57. Assumed Annual Rates of Technological Progress on Costs, Finding Rates, and Success Rates for Conventional Sources
(Percent)

	Natural Gas			Crude Oil		
Category	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	5.18	6.91	8.64	4.12	5.49	6.86
Other Exploratory	5.02	6.69	8.36	3.15	4.20	5.25
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.

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 58.

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 59).

Table 58. 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%

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

Table 59. 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.

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 2001* 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 60.

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 60. 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%

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

[91] *Economically recoverable resources* are those volumes considered to be of sufficient size and quality for their production to be commercially profitable by current conventional or nonconventional technologies, under specified economic conditions.

[92] *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.

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

[94] *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.

[95] Donald L. Goutier 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); Committee on Natural Gas, Peter I. Bijur, Chair, A Report to the National Petroleum Council, Natural Gas: *Meeting the Challenges of the Nation's Growing Natural Gas Demand*, Volume II, (December 1999).

[96] United States Environmental Protection Agency, *Opportunities to Reduce Anthropogenic Emissions in the United States: Report to Congress,* EPA430-R-93-012, (Washington, DC, October 1993).

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 2001, DOE/EIA-M062(2001),* scheduled for release in January 2001.

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.[97] 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[98] (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. The flow of gas in the peak period is based on reservation and usage charges; while the off-peak flows are just based on usage fees. 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 61). 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. In addition, a decline rate of 1 percent per year is applied (independent of changes in costs related to the cost of capital and labor and consumption levels) to account for capital depreciation combined with efficiency improvements. Although the markups in Table 61 represent annual averages, the model actually uses separate markups for the peak and offpeak periods.

Table 61. Base Level Annual Distributor Markup for Local Transportation Service
(1999 Dollars per thousand cubic feet)

Region	Residential	Commercial	Core Industrial
New England	5.58	3.04	-0.17
Mid Atlantic	5.31	2.65	0.94
East North Central	2.83	2.35	0.34
West North Central	2.82	1.64	-0.01
South Atlantic	3.87	2.58	-0.06
East South Central	3.57	2.48	-0.11
West South Central	3.46	1.87	0.16
Mountain	2.87	2.00	0.71
Pacific	3.70	2.60	2.30
Florida	8.63	3.10	-0.97
Arizona/New Mexico	4.02	1.99	0.42
California	4.10	3.30	0.98

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[99], 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 (0.09 for core, 0.03 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 62). The price to non-fleet vehicles is based on the industrial sector firm price plus an assumed $4.04 (1999 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 62. 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.

The Natural Gas Star program is assumed to recover 35 billion cubic feet of natural gas per year from 2002 through the end of the forecast period that otherwise might be lost to fugitive emissions.

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

[97] 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.

[98] 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.

[99] Historical core and noncore industrial prices were based on data from the Energy Information Administration, *Manufacturing Consumption of Energy 1994*, 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.[100]

Key Assumptions

Product Types and Specifications

The PMM models refinery production of the products shown in Table 63.

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.[101]

Table 63. Petroleum Product Categories

Product Category	Specific Products
Motor Gasoline	Traditional Unleaded, Oxygenated, Reformulated
Jet Fuel	Kerosene-type
Distillates	Kerosene, Heating Oil, Highway 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 64): 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 65.

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

Table 64. 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-V	9.6	—	—	28.6	1.6	338.4	10.8	41.0	83.0
PADD V	9.2	—	—	28.6	1.6	338.4	10.8	41.0	83.0
Reformulated									
PADD I-IV	8.5	2.0	2.1	25.0	0.95	135.0	12.0	49.0	87.0
PADD V through 2002	7.9	1.7	1.8	25.0	0.72	25.0	6.0	49.0	85.0
PADD V Post 2002									
Nonattainment	7.9	2.0	2.1	22.0	0.70	15.0	4.0	49.0	85.0
CARB (attainment)	7.9	—	1.2	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 65. 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)

gasoline must meet the Complex Model compliance standards which cannot exceed average 1990 levels of toxic and nitrogen oxide emissions.[102]

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 64).

The 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 compliment 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, and Sacramento). AEO2001 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.

AEO2001 reflects legislation which bans or limits the use of MTBE in seven additional States: Arizona, Connecticut, Maine, Minnesota, Nebraska, New York, and South Dakota. 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:

— 33.8 percent of RFG in Census Division 1
— 36.3 percent of RFG in Census Division 2
— 99.9 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
— 32.9 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 *AEO2001,* the annual market shares for each region reflect actual 1999 market shares and are held constant throughout the forecast. The Census Divisions 3 and 4 market shares were adjusted because St. Louis, Missouri, joined the Federal reformulated gasoline program in the summer of 1999. (See Table 66 for *AEO2001* market share assumptions.)

Table 66. 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	43	81	69	83	94	72	73	21
Oxygenated Gasoline (2.7% oxygen)	0	0	0	23	0	0	1	14	6
Reformulated Gasoline (2.0% oxygen)	80	57	19	8	17	6	27	13	73*

*Note: 46 percent is assumed to continue the 2.0 percent Federal oxygen requirement. 27 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 1999.

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 diesel fuel in Census Divisions 1 through 8 is required to meet Federal requirements, while diesel fuel in Census Division 9 is required to meet California Air Resources Board (CARB) standards. Both Federal and CARB standards limit sulfur to 500ppm.

The PMM contains a sharing methodology to allocate distillate demands between low and high sulfur. Market shares for low-sulfur diesel and distillate fuel are estimated based on data from EIA's annual *Fuel Oil and Kerosene Sales 1999,* (on line: http://www.eia.doe.gov/oil_gas/petroleum/data_publications/fuel_oil_and_kerosene_sales/foks.html, September, 2000*)*. Since about 15 percent of current demand in the transportation sector is off highway, 85 percent of transportation demand for distillate fuel is assumed to be low sulfur. Consumption of low-sulfur distillate also occurs in the industrial sector where it is assumed to be 50 percent of the market.

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 67) are reflected as fixed costs (associated operation and maintenance costs prior to 1996 are excluded).[103] 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 68) 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.

Table 67. 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).

State and Federal taxes are also added to transportation fuels to determine final end-use prices (Tables 69 and 70). 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.[104] Federal taxes are assumed to remain at current levels in accordance with the overall *AEO2001* 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 68. Petroleum Product End-Use Markups by Sector and Census Division
(1999 dollars per gallon)

Sector/Product	Census Division 1	2	3	4	5	6	7	8	9
Residential Sector									
Distillate Fuel Oil	0.37	0.44	0.32	0.26	0.42	0.30	0.19	0.28	0.38
Kerosene	0.51	0.57	0.46	0.40	0.51	0.31	0.47	0.58	0.87
Liquefied Petroleum Gases	0.85	0.88	0.54	0.35	0.76	0.64	0.55	0.54	0.81
Commercial Sector									
Distillate Fuel Oil	0.14	0.05	0.03	0.01	0.02	0.02	0.02	0.01	0.02
Gasoline	0.14	0.13	0.13	0.15	0.13	0.17	0.17	0.16	0.16
Kerosene	0.27	0.22	0.20	0.14	0.19	0.25	0.24	0.19	0.22
Liquefied Petroleum Gases	0.61	0.61	0.44	0.37	0.57	0.42	0.28	0.43	0.58
Low-Sulfur Residual Fuel Oil	0.02	0.05	0.04	0.01	0.02	0.06	-0.01	-0.01	0.09
Utility Sector									
Distillate Fuel Oil	0.01	0.02	0.02	0.01	0.01	0.06	0.04	0.05	0.01
High-Sulfur Residual Fuel Oil[3]	0.00	0.02	0.09	-0.04	0.01	-0.05	0.06	0.01	0.08
Low-Sulfur Residual Fuel Oil[3]	0.01	0.00	0.09	-0.06	0.01	-0.07	0.06	0.21	0.17
Transportation Sector									
Distillate Fuel Oil	0.23	0.17	0.14	0.11	0.13	0.15	0.12	0.14	0.19
E85[1]	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32
Gasoline	0.14	0.12	0.13	0.14	0.13	0.17	0.17	0.16	0.13
High-Sulfur Residual Fuel Oil[3]	0.02	0.03	0.16	0.02	0.00	-0.05	0.02	0.19	0.10
Jet Fuel	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquefied Petroleum Gases	0.63	0.60	0.52	0.35	0.53	0.39	0.23	0.39	0.54
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	0.23	0.04	0.04	0.05	0.03	0.02	0.02	0.07	0.06
Distillate Fuel Oil	0.16	0.14	0.12	0.10	0.10	0.08	0.10	0.09	0.12
Gasoline	0.14	0.13	0.13	0.15	0.13	0.17	0.17	0.16	0.13
Kerosene	0.27	0.22	0.21	0.14	0.18	0.24	0.24	0.22	0.22
Liquefied Petroleum Gases	0.55	0.56	0.50	0.31	0.52	0.36	0.15	0.30	0.54
Low-Sulfur Residual Fuel Oil	0.02	0.02	0.05	0.02	0.03	0.03	0.03	0.09	0.10

[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 2001* 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 2000, DOE/EIA-0380(2000/03),* (Washington, DC, March 2000).

Table 69. State and Local Taxes on Petroleum Transportation Fuels by Census Division
(1999 dollars per gallon)

	Census Division								
Year/Product	1	2	3	4	5	6	7	8	9
Gasoline[1]	0.27	0.24	0.25	0.22	0.18	0.20	0.22	0.23	0.25
Diesel	0.21	0.27	0.26	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]	0.26	0.18	0.19	0.15	0.13	0.17	0.20	0.14	0.12
E85[3]	0.25	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 70. 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 71.

Table 71. 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.

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.

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 perecentages 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 a15-percent hurdle rate in the decision to invest and a 15-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. For example, after the model has reached a solution for forecast year 2001, the PMM looks ahead and determines the optimal capacities given the demands and prices existing in the 2004 forecast year. The PMM then allows 50 percent of that capacity to be built in forecast year 2002, 25 percent in 2003, and 25 percent in 2004. At the end of 2004, the cycle begins anew, looking ahead to 2007.

Strategic Petroleum Reserve Fill Rate

AEO2001 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 2000 is projected at the U.S. level in the *Short-term Energy Outlook, (STEO*). The PMM assumes the STEO results for 1999, 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 the Clean air Act amendments of 1990 (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.

AEO2001 reflects legislation which bans or limits the use of the gasoline blending component MTBE in the following states: Arizona, California, Connecticut, Maine, Minnesota, Nebraska, New York, and South Dakota.

AEO2001 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.

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.[105] 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.[106]

- Current U.S ethanol production capacity is aggregated by census division in the PMM. A small amount of Carribean imports into Census Division 9 is also assumed 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 the Petroleum Market Model.

Methyl Tertiary Butyl Ether Ban Case

This alternative case reflects recommendations from a Blue Ribbon Panel (BRP) of experts convened by the EPA to study problems associated with methyl tertiary butyl ether (MTBE) in water supplies. In addition to tighter controls on leaking underground storage tanks, the BRP recommend a substantial reduction in MTBE in gasoline and removal of the Federal oxygen requirement for reformulated gasoline. The BRP further noted that other ethers, such as ethyl tertiary butyl ether (ETBE) and tertiary amyl methyl ether (TAME), have similar but not identical characteristics and recommended studying the health effects and characteristics of those compounds before they are allowed to be placed in widespread use. Because of the greater scrutiny, refiners and blenders are unlikely to increase the use of these ethers significantly. As a result, the use of all ethers in gasoline was assumed to be limited in this case. Although the BRP did not specify a target level of MTBE, this case reflects a complete ban of MTBE as have numerous legislative proposals in 2000.

The use of MTBE began to increase as a result of the introduction of oxygenated gasoline in the fall of 1993. The elimination of the oxygen specification in RFG requires that other specifications be adjusted in order to maintain air quality. In order to maintain current emissions levels of air toxics, as recommended by the BRP, the MTBE ban case assumes tighter limits on benzene in RFG than does the *AEO2001* reference case (Table 72). In the MTBE ban case, gasoline consumption and crude oil price projections remain the same as in the *AEO2001* reference case. The only changes relative to the reference case are gasoline specifications and the ban on ether use beginning in the year 2004.

Although the alternative case assumes that the oxygen requirement for RFG is removed, a wintertime oxygen requirement would remain intact for Los Angeles and surrounding areas that do not meet United States air quality standards for carbon monoxide. This isolated seasonal oxygen requirement is reflected as a weighted annual average requirement for the Federal ozone nonattainment areas.

Table 72. Gasoline Specifications for MTBE Reduction Scenario

PADD	Reid Vapor Pressure (Max)	Oxygen Weight Percent (Min)	Oxygen Weight Percent (Max)	Aromatics Volume Percent (Max)	Benzene Volume Percent (Max)	Sulfur PPM 2004 (Max)	Olefin Volume Percent (Max)	Percent Evaporated at 200°	Percent Evaluated at 300°
Traditional Gasoline									
PADD I-IV	10.0	—	—	28.6	1.6	143.4	10.8	41.0	83.0
PADD V	9.2	—	—	28.6	1.6	122.8	10.8	41.0	83.0
Reformulated Gasoline									
PADD I-IV	8.5	—	2.1	25.0	0.70	30	12	50.0	87.0
PADD V									
Nonattainment	7.9	1.2	1.3	25.0	0.72	25.0	6.0	49.0	85.0
CARB (attainment)	7.9	—	1.2	25.0	0.72	25.0	6.0	49.0	85.0

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System input file gdcrdcfmtbe3.txt. Derived using U.S. Environmental Protection Agency's Complex Model.

Notes and Sources

[100] Energy Information Administration, EIA Model Documentation: Petroleum Market Model of the National Energy Modeling System, DOE/EIA-M059 (2001), January 2001.

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

[102] 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).

[103] 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.

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

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

[106] 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 2001,* DOE/EIA-M060(2001) January 2001.

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 1999, U.S. coal mining productivity (measured in short tons of coal produced per miner per hour) increased at an estimated average rate of 6.7 percent per year. The major factors underlying these gains were interfuel price competition, structural change in the industry, and technological improvements in coal mining.[107] 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 5.9 percent in 1999 to approximately 1.2 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.[108]

- Between 1985 and 1993, the average hourly wage for U.S. coal miners (in 1999 dollars) declined at an average rate of 1.5 percent per year, falling from $21.67 to $19.18.[109] During this same time period the producer price index (PPI) for mining machinery and equipment (in 1999 dollars) declined by 0.6 percent per year, falling from 159.1 to 152.1.[110] In the reference case, both the wage rate for U.S. coal miners and mine equipment costs are to remain constant in 1999 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 1999, the average hourly wage rate for coal miners was $19.34, and the PPI for mining machinery and equipment was 153.2.

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 *AEO2001* cases are shown in Table 73.

Table 73. 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	0.9574	0.9699	0.9414	0.9596	0.9696
2010	0.9127	0.9243	0.8960	0.9290	0.9045
2015	0.8559	0.8681	0.8384	0.8786	0.8407
2020	0.7933	0.8041	0.7776	0.8198	0.7699

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 utility 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, nonutility 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 *AEO2001* forecast cases are shown in Tables 74 and 75.

Table 74. World Steam Coal Import Demand by Import Region, 1999-2020
(Million metric tons of coal equivalent)

Import Regions[1]	1999	2005	2010	2015	2020
The Americas	30.2	40.9	42.9	43.6	45.2
United States	7.1	13.5	15.0	15.9	17.3
Canada	14.4	10.2	9.7	9.6	10.2
Mexico	2.5	8.5	9.0	9.2	9.2
South America	6.2	7.7	9.2	8.9	8.5
Europe	122.5	124.7	119.6	115.3	112.6
Scandinavia	10.5	11.3	8.5	4.4	3.6
U.K/Ireland	14.0	15.8	16.9	16.9	16.9
Germany	14.0	21.8	21.8	22.7	24.5
Other NW Europe	21.6	20.5	17.7	14.5	10.9
Iberia	20.3	11.0	11.3	11.3	9.5
Italy	9.6	8.7	8.3	7.8	7.3
Med/E Europe	19.2	28.6	29.7	29.5	31.1
Asia	149.1	208.6	240.1	253.9	268.7
Japan	64.3	80.2	90.6	92.8	94.2
East Asia	60.7	81.1	91.0	95.5	99.1
China/Hong Kong	6.9	10.8	15.3	19.8	26.1
ASEAN	8.8	27.0	32.2	33.9	36.5
Indian Sub	8.4	9.5	11.0	11.9	12.8
Total	288.5	364.4	394.3	404.6	417.7

[1]Import Regions: **United States:** United States; **Canada:** Canada; **Mexico:** Mexico; **South America:** Argentina, Brazil, Chile; **Scandinavia:** Denmark, Finland, Norway, Sweden; **U.K./Ireland:** Ireland, United Kingdom; **Germany:** Austria, Germany; **Other NW Europe:** Belgium, France, Luxembourg, Netherlands; **Iberia:** Portugal, Spain; **Italy:** Italy; **Med/E Europe:** Algeria, Bulgaria, Croatia, Egypt, Greece, Israel, Malta, Morocco, Romania, Tunisia, Turkey; **Japan:** Japan; **East Asia:** North Korea, South Korea, Taiwan; **China/Hong Kong:** China, Hong Kong; **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: 1999: International Energy Agency, Coal Information 2000 (Paris, France, August 2000); and Energy Information Administration, Quarterly Coal Report, DOE/EIA-0121(99/4Q) (Washington, DC, April 2000). 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.

Table 75. World Metallurgical Coal Import Demand by Import Region, 1999-2020
(Million metric tons of coal equivalent)

Import Regions[1]	1999	2005	2010	2015	2020
The Americas	20.8	21.8	24.0	27.1	29.1
United States	1.1	0.5	0.5	0.5	0.5
Canada	4.0	3.6	3.5	3.3	3.1
Mexico	0.2	2.2	2.8	3.6	3.8
South America	14.4	15.0	16.7	19.2	21.2
Europe	56.4	58.5	57.9	57.0	56.0
Scandinavia	3.2	2.7	2.4	2.2	1.9
U.K/Ireland	8.5	7.6	7.6	7.1	7.1
Germany	3.6	6.9	6.9	6.9	6.9
Other NW Europe	16.7	15.1	13.2	12.2	11.2
Iberia	4.3	3.8	3.8	3.8	3.8
Italy	7.3	7.2	7.1	6.3	6.3
Med/E Europe	8.8	11.6	13.4	15.2	15.7
Asia	97.8	99.9	102.2	104.8	106.9
Japan	60.5	56.4	52.7	51.3	49.9
East Asia	25.5	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	11.0	14.5	16.1	18.2	19.2
Total	171.0	176.6	180.6	185.6	188.9

[1]Import Regions: **United States:** United States; **Canada:** Canada; **Mexico:**; **South America:** Argentina, Brazil, Chile; **Scandinavia:** Denmark, Finland, Norway, Sweden; **U.K./Ireland:** Ireland, United Kingdom; **Germany:** Austria, Germany; **Other NW Europe:** Belgium, France, Luxembourg, Netherlands; **Iberia:** Portugal, Spain; **Italy:** Italy; **Med/E Europe:** Algeria, Bulgaria, Croatia, Egypt, Greece, Israel, Malta, Morocco, Romania, Tunisia, Turkey; **Japan:** Japan; **East Asia:** North Korea, South Korea, Taiwan; **China/Hong Kong:** China, Hong Kong; **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: 1999: International Energy Agency, Coal Information 2000 (Paris, France, August 2000); and Energy Information Administration, Quarterly Coal Report, DOE/EIA-0121(99/4Q) (Washington, DC, April 2000). 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.

- 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 content, sulfur and carbon emissions for each coal source in the Coal Market Module of the NEMS 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 FERC 867 which records the quality of coal receipts 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. Sulfur emissions levels shown below (Table 76) have been adjusted from percent by weight data (on an 'as received basis') to reflect U.S. Environmental Protection Agency assumptions about the variation in the completeness of combustion by coal rank: 95 percent for bituminous coals, 87.5 percent for sub-bituminous coals and 75 percent for lignite. These emissions are appropriate for unscrubbed boilers; depending on the type of scrubber employed, emissions from scrubbed boilers would be further reduced by between 70 and 95 percent. Carbon emissions levels for each coal type are listed in Table 76 in pounds of carbon dioxide emitted per million Btu.[111]

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 1999, 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.

Mining Cost Cases

In the reference case, labor productivity is assumed to increase at an average rate of 2.2 percent a year through 2020, while wage rates and mine equipment costs remain constant in 1999 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 a year, and real wages and mine equipment costs decline by 0.5 percent a year. In a high mining cost sensitivity case, productivity increases by 0.6 percent a year, and real wages and mine equipment costs increase by 0.5 percent a 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 76. Production, Heat Content, and Sulfur and Carbon Emissions by Coal Type and Region

Coal Supply Region	Coal Rank & Sulfur Level	1998 Production (Million Short tons)	Million Btu per Short ton	Lbs SOX Emitted per million Btu	Lbs CO2 Emitted per million Btu
North Appalachia	Metallurgical[1]	6.2	26.80	1.27	205.4
	Low Sulfur Bituminous	2.7	24.71	1.06	203.6
	Mid Sulfur Bituminous	80.5	25.54	2.39	205.4
	High Sulfur Bituminous	68.3	24.28	5.11	203.6
	Waste Coal (Bituminous)	8.6	12.43	3.31	203.6
Central Appalachia	Metallurgical[1]	62.2	26.80	1.07	203.8
	Low Sulfur Bituminous	63.9	25.17	1.03	203.8
	Mid Sulfur Bituminous	150.9	24.84	1.62	203.8
Southern Appalachia	Metallurgical[1]	5.7	26.80	0.93	203.3
	Low Sulfur Bituminous	8.1	25.11	1.01	203.3
	Mid Sulfur Bituminous	11.9	24.58	2.26	203.3
	Mid Sulfur Lignite	0.0	12.94	2.03	211.4
East Interior	Mid Sulfur Bituminous	34.4	22.73	2.20	201.4
	High Sulfur Bituminous	75.8	22.45	5.23	201.4
West Interior/Gulf	High Sulfur Bituminous	2.7	24.52	5.02	202.4
	Mid Sulfur Lignite	27.5	12.83	1.71	211.4
	High Sulfur Lignite	28.0	12.93	3.12	211.4
Dakota Lignite	Mid Sulfur Lignite	30.2	13.30	1.71	216.6
Powder R., Green R. & Hannah Basins	Low Sulfur Subbituminous	314.9	17.39	0.65	210.7
	Mid Sulfur Subbituminous	40.3	17.67	1.35	210.7
	Low Sulfur Bituminous	1.7	21.54	1.10	204.4
Rocky Mountain	Low Sulfur Bituminous	45.8	23.07	0.80	203.0
	Low Sulfur Subbituminous	9.9	20.55	0.67	210.6
Southwest	Low Sulfur Bituminous	19.5	21.24	0.89	205.4
	Mid Sulfur Subbituminous	20.4	18.26	1.52	206.7
Northwest	Mid Sulfur Subbituminous	6.0	15.70	1.45	207.9

[1]The average heat content of metallurgical coal is estimated to be 26.80 million Btu per short ton in EIA, Table A5, *Annual Energy Review*, DOE/EIA-0384(99), (Washington, DC, July 2000).

Note: Coal Supply Regions are defined as follows: North Appalachia - Pennsylvania, Maryland, Ohio, Northern West Virginia; Central Appalachia - Southern West Virginia, Virginia, East Kentucky; South Appalachia - Alabama, Tennessee, Mississippi; East Interior - Illinois, Indiana, West Kentucky; West Interior/Gulf - Iowa, Missouri, Kansas, Oklahoma, Arizona, Louisiana,Texas; Dakota lignite - North Dakota, Montana (lignite only); Powder River, Green River and Hannah River Basins - Montana, Wyoming (subbituminous and bituminous); Rocky Mountain - Colorado, Utah; Southwest-Arizona, New Mexico; Northwest - Alaska, Washington.

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; and B.D. Hong and E.R. Slatick, “Carbon Dioxide Emission Factors for Coal,” Energy Information Administration, Quarterly Coal Report, January-March 1994, DOE/EIA-0121 (94/Q1) (Washington, DC, August 1995).

Notes and Sources

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

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

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

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

[111] 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).[112]

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, landfill gas (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.

Key Assumptions

Nonelectric Renewable Energy Uses

In addition to projections for renewable energy used in central station electricity generation, the *AEO2001* contains projections of nonelectric renewable energy uses for industrial and residential wood consumption, solar residential and commercial hot water heating, and residential and commercial geothermal (ground-source) heat pumps. Assumptions for their projections are found in the residential, commercial, and industrial 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 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 43. Overnight capital costs and other extended performance characteristics are presented in Table 77.

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

	Total Overnight Costs[1]			National Average Capacity Factors	
Technology	Overnight Costs in 2000 (Reference) ($1999/kW)	Reference ($1999/kW)	High Renewable ($1999/kW)	Reference (%)	High Renewable (%)
Biomass	1,723				
2005		1,624	1,582	80	80
2010		1,300	1,141	80	80
2015		1,145	983	80	80
2020		1,137	938	80	80
MSW - Landfill Gas	1,395				
2005		1,378	1,378	90	90
2010		1,360	1,360	90	90
2015		1,343	1,343	90	90
2020		1,325	1,325	90	90
Geothermal[2]	1,708				
2005		1,665	1,382	87	87
2010		1,763	1,543	87	87
2015		1,759	1,524	87	87
2020		1,759	1,521	87	87
Wind	983				
2005		934	849	32	41
2010		885	764	34	45
2015		835	679	36	46
2020		786	594	38	47
Solar Thermal	2,946				
2005		2,798	2,711	42	44
2010		2,651	2,503	42	56
2015		2,504	2,303	42	68
2020		2,328	2,082	42	77
Photovoltaic	4,252				
2005		3,021	3,271	28	21
2010		2,543	2,562	29	21
2015		2,420	1,854	30	21
2020		2,342	1,145	30	21

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

[2]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: AEO2001 National Energy Modeling System runs: aeo2001.d101600a, hirenew.d101600a; 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 and 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 30 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 30 percent, capital costs rise 0.5 percent. These factors apply to biomass, geothermal, solar, and wind technologies.

- For biomass, geothermal and wind, higher costs are assumed to result from a large cumulative increase in use of one of these resources, reflecting any or all of three general longer-term cost adjustment factors: (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 *AEO2001*, each EMM region's biomass and wind resource estimates are parceled into five cost levels. For biomass, the percentage cost increases that are applied to initial capital costs are 0, 15, 50, 75 and 100 percent for successive increments of the resource. For geothermal, four successive increments incur 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. For wind, the increases are 0, 20, 50, 100 and 200 percent respectively. The size of the resource increments vary 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 2001*, DOE/EIA-M069(2001), January 2001.

Solar Electric Submodule

Background

The Solar Electric Submodule (SOLES) currently includes 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).[113] Most other cost and performance characteristics for ST are obtained or derived from the August 6, 1993, California Energy Commission memorandum, *Technology Characterization for ER 94*; and, for PV, from the Electric Power Research Institute, *Technical Assessment Guide (TAG) 1993*. In addition, capacity factors are obtained from information provided by the National Renewable Energy Laboratory (NREL).

Assumptions

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

- In order to incorporate assumed improvements in photovoltaic technologies, all PV capacity factors are assumed to improve linearly a total of 10 percent from 2005 through 2015; for example, California's annual average capacity factor for PV increases from 24.6 percent to almost 27.1 percent by 2015.

- 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. Early years' penetration for such reasons is included as supplemental additions.

- 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 keeps track of 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.[114] The technological performance, cost, and other wind data used in NEMS are derived by EIA from consultation with industry experts.[115] 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 from the EPACT, 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.

- It is expected that wind turbine technology will improve in performance and that blade lengths will increase, as the cubic relationship between the area swept by the rotor and power generation provides a large incentive for increasing blade length. Capacity factors are assumed to increase to a national average of about 34 percent in the best wind class. However, as better wind resources are depleted, capacity factors are assumed to go down.

- *AEO2001* 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 wind units entering service from 1993 through 2001. (All wind units are assumed owned by taxpaying entities).

Geothermal-Electric Power Submodule

Background

The Geothermal-Electric Submodule (GES), simplified for *AEO2001*, 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.[116] 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, *AEO2001* new dual-flash capacity – the lower cost technology - is assigned an 95 percent capacity factor, whereas binary plants are assigned a 95 percent capacity factor; both are assigned an 87 percent capacity factor for actual generation.

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 43 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 43, 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 43 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.

- Biomass cofiring can occur up to a maximum of 5 percent of fuel used in coal-fired generating plants. Short-term and long-term cost adjustment factors are used.

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.[117] The wood residue component consists of primary mill residues, silvicultural trimmings and urban wood such as pallets, construction waste and demolition debris that are not otherwise used.[118] Agricultural residues are wheat straw and corn stover only, which make up the great majority of crop residues.[119] Energy crops data is for hybrid poplar, willow and switchgrass grown on crop land, pasture land, or on Conservation Reserve lands. Energy crop costs range from zero to over five dollars per million Btu.[120] The maximum amount of resources in each supply category is shown in Table 78.

Table 78. 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.

Landfill-gas-to-Electricity Submodule

Background

Beginning with *AEO2001*, a new submodule has been added to NEMS, to let landfill-gas-to-electricity technologies compete economically with other generation technologies. 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 electricity market module 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)[121].

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 recyclying 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 1998*[122].

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[123].

- 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.

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; *AEO2001* 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.

Supplemental 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/RFM, the *AEO2001* also includes 5,356 megawatts additional generating capacity powered by renewable resources. Summarized in Table 79 and detailed in Table 80, some of the capacity represents mandated new capacity required by state laws, EIA estimates for expected new capacity under recent state-enacted renewable portfolio standards (RPS), estimates of winning bids in California’s renewables funding program (Assembly Bill 1890 but not its August, 2000, extension), expected new capacity under known voluntary programs, such as “green marketing” efforts, and other publicly stated plans.

Table 79. Post-1999 Supplemental Capacity Additions (Megawatts, Net Summer Capability)

Rationale	Geothermal	Biomass	Landfill Gas	Solar Thermal	Solar Photovoltaic	Wind	Total
Mandates	0.0	71.3	8.4	0.0	0.0	193.2	272.9
RenewablePortfolio Standards	13.6	764.7	1087.8	36.6	27.0	2447.4	4377.1
California AB1890[1]	103.5	3.6	48.6	0.0	0.0	259.4	415.1
Other Reported Plans[2]	0.0	16.2	41.2	0.0	3.8	229.6	290.8
Total	117.1	855.8	1186.0	36.6	30.8	3129.6	5355.9

[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 and state renewable portfolio standards and other plans.

Table 80. Planned Post-1999 U.S. Generating Capacity Using Renewable Resources[1]

Technology	Plant Identification	Program[2]	State	Net Summer Capability (Megawatts)	On-Line Years
Biomass	Wheelabrator	AB1890	California	3.6	2000
	Massachusetts RPS	RPS	Massachusetts	94.8	2003-2015
	Itasca Wood Waste	Commercial	Minnesota	11.4	2001
	Northern States Power	Mandate	Minnesota	71.3	2002-2004
	New Jersey RPS	RPS	New Jersey	650.9	2003-2016
	Browning Ferris Concord	Commercial	North Carolina	4.8	2000
	Texas RPS	RPS	Texas	19.0	2002
Geothermal	Imperial Valley	AB1890	California	9.5	2000
	Salton Sea	AB1890	California	46.6	2000
	Four Mile Hill	AB1890	California	47.4	2004
	Nevada RPS	RPS	Nevada	13.6	2001-2014
Landfill Gas	Pinnacle	RPS	Arizona	1.8	2001
	Minnesota Methane	AB1890	California	8.1	2000
	Santa Cruz	AB1890	California	1.9	2001
	Browning Ferris	AB1890	California	19.0	2001
	Energy Development	AB/1890	California	11.0	2001
	San Francisco	AB1890	California	11.1	2001
	Riverside, LFG	AB1890	California	6.6	2000-2001
	Sacramento Municipal Electricity District (SMUD)	Commercial	California	7.9	2000
	Browning Ferris	Commercial	Massachusetts	5.8	2002
	New Jersey RPS	RPS	New Jersey	650.9	2003-2016
	TVA Green Energy	Commercial	Tennessee	6.2	2000
	3 Sites	Commercial	Texas	13.3	2000
	Bergstrom Airport	Commercial	Texas	3.8	2002
	Texas RPS	RPS	Texas	435.1	2001-2020
	Alliant Energy	Mandate	Wisconsin	6.2	2000
	Wisconsin Electric	Commercial	Wisconsin	4.2	2000
	Wisconsin Electric	Mandate	Wisconsin	2.2	2000
Large Grid-Connected Solar Photovoltaic	Arizona RPS	RPS	Arizona	15.7	2000-2010
	Los Angeles Department Water & Power	Commercial	California	1.1	2000-2001
	Com.Ed (Spire) City of Chicago	Commercial	Illinois	2.6	2000-2004
	Nevada RPS	RPS	Nevada	11.3	2005-2014
	Parking Lot	Commercial	Texas	0.1	2000

Table 80. Planned Post-1999 U.S. Generating Capacity Using Renewable Resources[1] (Continued)

Technology	Plant Name	Program[2]	State	Net Summer Capacity (Megawatts)	On-Line Years
Solar Thermal	Nevada RPS	RPS	Nevada	36.6	2004-2014
Wind	California AB1890 (various)	AB1890	California	259.4	2001
	Massachusetts RPS	RPS	Massachusetts	316.2	2003-2015
	17 Small Projects	Mandate	Minnesota	32.0	2000
	Northern States Power	Mandate	Minnesota	130.0	2001-2002
	Great River, Part 2	Commercial	Minnesota	2.0	2001
	New Jersey RPS	RPS	New Jersey	381.2	2003-2016
	Madison	Commercial	New York	11.5	2000
	Niagara Mohawk	Commercial	New York	4.6	2000
	Niagara Mohawk	Mandate	New York	2.0	2000
	Vansycle Ridge (BPA)	Commercial	Oregon	105.0	2001
	Gondon Wind	Commercial	Oregon	24.6	2001
	Green Mountain Power	Commercial	Pennsylvania	10.3	2000
	Pennsylvania Electric	Commercial	Pennsylvania	30.0	2001-2003
	Prairie Winds	Commercial	South Dakota	1.0	2001
	TVA Green Switch	Commercial	Tennessee	2.0	2000
	King Mountain	Commercial	Texas	20.0	2000
	Enron Pecos 1 & 2	RPS	Texas	150.0	2000-2001
	TXU McCamey	RPS	Texas	160.0	2001
	SW Public Service	RPS	Texas	40.0	2001
	Texas RPS	RPS	Texas	1400.0	2002-2009
	Alliant Energy	Mandate	Wisconsin	4.5	2000
	Wisconsin Electric	Commercial	Wisconsin	0.5	2000
	Wisconsin Electric	Mandate	Wisconsin	24.7	2000
	Medicine Bow, Part 3	Commercial	Wyoming	1.3	2000
	Foote Creek IV	Commercial	Wyoming	16.8	2000

[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 non modeled 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

[112] 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), Washington, DC, January 2001.

[113] 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.

[114] D.L. Elliott, L.L. Wendell, and G.L. Gower, *An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States*, Richland, WA: Pacific Northwest Laboratory, (August 1991); Pacific Northwest Laboratory, *An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States*, (PNL-7789), prepared for the U.S. Department of Energy under Contract DE-AC06-76RLO 1830, (August 1991), and Schwartz, N.N.; Elliot, O.L.; and Gower, GL: *Gridded State Maps of Wind Electric Potential Proceedings Wind Power 1992*, (Seattle, WA, October 19-23, 1992).

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

[116] Dyncorp Corporation, deliverable #DEL-99-548 (Contract #DE-AC01-95-ADF34277), Alexandria, Virginia, July, 1997).

[117] United States Department of Agriculture, U.S. Forest Service, *Forest Resources of the United States, 1992*, General Technical Report RM-234, (Fort Collins CO, June 1994).

[118] Antares Group Inc., *Biomass Residue Supply Curves for the U.S (updated),* prepared for the National Renewable Energy Laboratory, June 1999.

[119] Walsh, M.E., et.al., Oak Ridge National Laboratory, *The Economic Impacts of Bioenergy Crop Production on U.S. Agriculture,* (Oak Ridge, TN, May 2000). http://bioenergy.ornl.gov/papers/wagin/index.html.

[120] Graham, R.L., et.al., Oak Ridge National Laboratory, *The Oak Ridge Energy Crop County Level Database*, (Oak Ridge TN, December, 1996).

[121] 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).

[122] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1998*, DOE/EIA-0573(98) (Washington, DC, October 1999), Appendix A: Estimation Methods, pp. 88-90.

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