Assumptions

to the

Annual Energy Outlook 1998

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Contents

Introduction

This paper presents the major assumptions of the National Energy Modeling System (NEMS) used to generate the projections in the *Annual Energy Outlook 1998*[1] (*AEO98*), 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

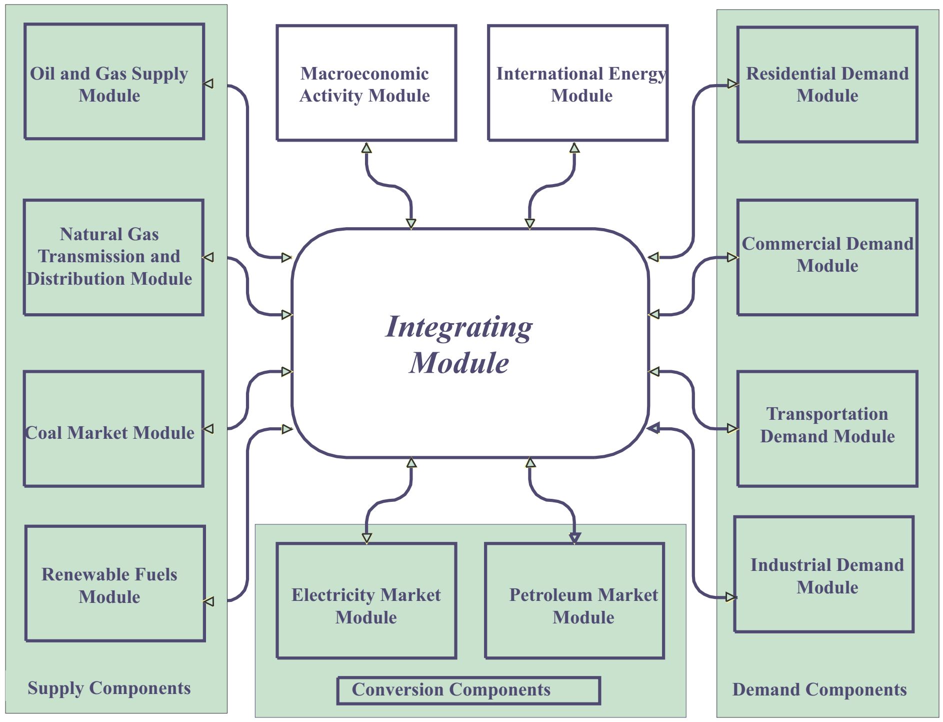
The projections in the *AEO98* were produced with the National Energy Modeling System. NEMS is developed and maintained by the Office of Integrated Analysis and Forecasting of the Energy Information Administration (EIA) to provide projections of domestic energy-economy markets in the midterm time period and perform policy analyses requested by decisionmakers and analysts in the U.S. Congress, the Department of Energy's Office of Policy and International Affairs, other DOE offices, and other government agencies.

The time horizon of NEMS is approximately 20 years, the midterm period in which the structure of the economy and the nature of energy markets are sufficiently understood that it is possible to represent considerable structural and regional detail. Because of the diverse nature of energy supply, demand, and conversion in the United States, NEMS supports regional modeling and analysis in order to represent the regional differences in energy markets, to provide policy impacts at the regional level, and to portray transportation flows. The level of regional detail for the end-use demand modules is the nine Census divisions. Other regional structures include production and consumption regions specific to oil, gas, and coal supply and distribution, the North American Electric Reliability Council regions and subregions for electricity, and aggregations of the Petroleum Administration for Defense Districts (PADD) for refineries. Only national results are presented in the *AEO98*, with the regional and other detailed results available on the EIA CD-ROM and EIA Home Page.

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.

Figure 1. National Energy Modeling System



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 the provisions of the Climate Change Action Plan (CCAP), which are separately described under each module.

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 response surface representation of the DRI/McGraw-Hill Quarterly Model.

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.

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, and compressed natural gas 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 four primary submodules — capacity planning, fuel dispatching, finance and pricing, and demand-side management. Nonutility generation and transmission and trade are represented in the planning and dispatching submodules. The levelized fuel cost of uranium fuel for nuclear generation is directly incorporated into the 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 includes submodules that provide explicit representation of the supply of biomass (including wood and energy crops), municipal solid waste (including landfill gas), wind energy, solar thermal electric and photovoltaic energy, and geothermal energy. It contains natural resource supply estimates and provides costs and performance criteria to the EMM. The EMM represents market penetration of renewable technologies used for centralized electricity generation, and the end-use demand modules incorporate market penetration of selected off-grid electric and non-marketed non-electric renewables.

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 tight gas formations, Devonian shale, and coalbeds. This framework analyzes cash flow and profitability to compute investment and drilling in each of the supply sources, subject to the prices for crude oil and natural gas, the domestic recoverable resource base, and technology. Oil and gas production functions are computed at a level of 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. 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 capacity expansion requirements. There is an explicit representation of core and noncore markets for natural gas transmission and distribution, and 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 in three regions. The first region includes Petroleum Administration for Defense District (PADD) I, the second includes PADDs II, III, IV, and the third includes PADD V. The module uses the same crude oil types as the International Energy Module. It explicitly models the requirements of the CAAA90 and the costs of new automotive fuels, such as oxygenated and reformulated gasoline, and includes oxygenated production and blending for reformulated gasoline. Costs include capacity expansion for refinery processing units. End-use prices are based on the marginal costs of production, plus markups representing product distribution costs, State and Federal taxes, and environmental costs. State taxes are assumed to increase with inflation. On the other hand, Federal taxes are assumed to remain constant at nominal 1997 levels, not increasing with inflation.

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 mine production, labor productivity, and factor input costs. Twelve coal types are represented, differentiated by thermal grade, 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 four 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 1998*

The *AEO98* presents five fully integrated 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 1.1 percent from 1996 through 2020 and the labor force at 0.8 percent per year, yielding a growth in real GDP of 1.9 percent per year. In the high economic growth case, productivity and the labor force grow at 1.4 and 1.0 percent per year, respectively, resulting in GDP growth of 2.4 percent annually. The average annual growth in productivity, the labor force, and GDP are 0.8, 0.5, and 1.3 percent, respectively, in the low economic growth case.

- **World Oil Markets** - In the reference case, the average world oil price increases to $22.32 per barrel (in real 1996 dollars) in 2020. Reflecting uncertainty in world markets, the price in 2020 reaches $14.43 per barrel in the low oil price case and $28.71 per barrel in the high oil price case.

In addition to the five fully integrated 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 prepared assuming Federal, State, and local laws and regulations in effect on July 1, 1997, 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, and the Tax Payer Relief Act of 1997. Pending legislation and sections of existing legislation for which funds have not been appropriated are not reflected in these forecasts.

The projections include analysis of the provisions of the CCAP developed in 1993, which consists of forty-four actions to achieve carbon stabilization in the United States by 2000, relative to 1990. Thirteen of the actions not related to the combustion of energy fuels or to carbon dioxide and are not incorporated in the analysis. Since funding for many of the CCAP programs has been curtailed in budget negotiations, their full impact is not reflected in these projections. In addition, since some of the energy savings associated with CCAP programs are already in the baseline, the full projected impacts were reduced.

Emissions

Carbon emissions from energy use are dependent on the carbon content of the fuel and the fraction of the fuel consumed in combustion. The product of the carbon content at full combustion and the combustion fraction yields an adjusted carbon emission factor for each fuel. The emissions factors are expressed in millions of metric tons of carbon emitted per quadrillion Btu of energy use, or equivalently, in kilograms of carbon per million Btu. The adjusted emissions factors are multiplied by energy consumption to arrive at the carbon 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 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 emitted by renewable sources is considered balanced by the carbon sequestration that occurred in its creation. Therefore, following convention, net emissions of carbon from renewable sources is taken as zero, and no emission coefficient is reported. Renewable fuels include hydroelectric power, biomass, photovoltaic, geothermal, ethanol, and wind energy.

Table 2 presents the carbon coefficients at full combustion, the combustion fractions, and the adjusted carbon emission factors used for *AEO98*.

Table 1 . Summary of AEO98 Cases

Case Name	Description
Residential: 1998 Technology	Future equipment purchases based on equipment available in 1998. Building shell efficiencies fixed at 1998 levels.
Residential: Advanced Technology Cost Reduction	Cost of best technologies reduced by 35 percent by 2020. Building shell efficiencies increase by 50 percent from reference values by 2020.
Residential: Best Available Technology	Future equipment purchases based on most efficient technologies available. Building shell efficiencies increase by 50 percent from reference values by 2020.
Commercial: 1998 Technology	Future equipment purchases based on equipment available in 1998. Building shell efficiencies fixed at 1998 levels.
Commercial: Advanced Technology Cost Reduction	Cost of best technologies reduced by 35 percent by 2020. Building shell efficiencies increase by 50 percent from reference values by 2020.
Commercial: Best Available Technology	Future equipment purchases based on most efficient technologies available. Building shell efficiencies increase by 50 percent from reference values by 2020.
Industrial: 1998 Technology	Efficiency of plant and equipment fixed at 1998 levels.
Industrial: High Technology	Energy intensity declines at an annual rate of 1.5 percent, compared to 1.1 percent in the reference case.
Transportation: 1998 Technology	Efficiencies for new equipment in all modes of travel are fixed.
Transportation: Advanced Technology	Reduced costs and improved efficiencies are assumed for advanced technologies.
End-Use Demand: 1998 Technology	Combination of the residential, commercial, industrial, and transportation 1998 technology cases.
End-Use Demand: High Technology	Combination of the residential and commercial advanced technology cost reduction cases, the industrial high technology case, and the transportation advanced technology case.
Electricity: Low Nuclear	All reactors retire after 30 years of operation.
Electricity: High Nuclear	Each reactor operates 10 years longer than assumed in the reference case.
Electricity: High Demand	Electricity demand increases at an annual rate of 2.0 percent, compared to 1.4 in the reference case.
Electricity: Low Fossil Technology	No new advanced fossil-fired generating technologies are assumed. Costs for conventional fossil-fired technologies are lower than in the reference case.
Electricity: High Fossil Technology	Costs and efficiencies for advanced fossil-fired technologies are assumed to improve from reference case values.
Electricity: Competitive Pricing	Competitive pricing is phased in over 10 years in all regions of the country.

Table 1. Summary of AEO98 Cases (Cont'd)

Case Name	Description
Electricity: Low Gas Price Competitive Pricing	Competitive pricing combined with the rapid oil and gas technology case assumptions.
Electricity: High Gas Price Competitive Pricing	Competitive pricing combined with the slow oil and gas technology case assumptions.
Electricity: 5 - Percent Renewable Portfolio Standard	Nonhydroelectric renewable generation increases to 5 percent of total generation by 2020.
Electricity: 10-Percent Renewable Portfolio Standard	Nonhydroelectric renewable generation increases to 10 percent of total generation by 2020.
Renewables: High Technology	Lower costs and higher efficiencies are assumed for new renewable generating technologies.
Oil and Gas: Slow Technology	Cost, finding rate, and resource base growth parameters adjusted for slower improvement.
Oil and Gas: Rapid Technology	Cost, finding rate, and resource base growth parameters adjusted for more rapid improvement.
Oil and Gas: Moderate Resource	Expansion of oil and natural gas inferred reserves and shallow Gulf of Mexico resources adjusted for slower improvement.
Oil and Gas: High Reformulated Gasoline	Reformulated gasoline demand increases by 10 percent in Census divisions 1 through 7 (areas east of the Rocky Mountains).
Coal: Low Mining Cost	Productivity increases at an annual rate of 3.3 percent, compared to the reference case growth of 2.0 percent. Real wages decrease by 0.5 percent annually, compared to constant real wages in the reference case.
Coal: High Mining Cost	Productivity increases at an annual rate of 0.8 percent, compared to the reference case growth of 2.0 percent. Real wages increase by 0.5 percent annually, compared to constant real wages in the reference case.

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

Fuel Type	Carbon Coefficient at Full Combustion	Combustion Fraction	Adjusted Emissions Factor
Petroleum			
Motor Gasoline	19.38	0.990	19.19
Liquefied Petroleum Gas			
Used as Fuel	16.87	0.995	16.79
Used as Feedstock	17.11	0.200	3.42
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	3.84
Kerosene	19.72	0.990	12.92
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	25.53	0.990	25.28
Industrial Other	25.63	0.950	25.38
Electric Utility[1]	25.74	0.990	25.49
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 emission for coal varies throughout the forecast. The 1996 average is 25.74.

Source: Energy Information Administration, Emissions of Greenhouse Gases in the United States 1996, DOE/EIA-0573(96), (Washington, DC, October 1997).

[1] Energy Information Administration, *Annual Energy Outlook 1998* (AEO98), DOE/EIA-0383(97), (Washington, DC, December 1997).

[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*, DOE/EIA-0581(96), (Washington, DC, March 1996). The 1998 version of the report will be available February 1998.

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, (Washington, DC, February 1994).

Key Assumptions

The output of the Nation's economy, measured by GDP, is expected to increase by 1.9 percent between 1996 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 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 *AEO98*. Total population is expected to grow by 0.8 percent between 1996 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 2005 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 3. Growth in Gross Domestic Product, Labor Force, and Productivity
(Percent per Year)

Assumptions	1996-2000	2020-2005	2005-2010	2010-2015	2015-2020	1996-2020
GDP (Billion Chain-Weighted ($1992)						
High Growth	3.0	2.6	2.6	2.1	1.8	2.4
Reference	2.5	2.1	2.1	1.6	1.3	1.9
Low Growth	2.0	1.6	1.5	1.0	0.7	1.3
Labor Force						
High Growth	1.8	1.3	1.1	0.7	0.5	1.0
Reference	1.5	1.0	0.9	0.5	0.3	0.8
Low Growth	1.2	1.2	0.7	0.2	-0.01	0.5
Productivity						
High Growth	1.3	1.3	1.4	1.4	1.3	1.3
Reference	1.0	1.1	1.2	1.1	1.0	1.1
Low Growth	0.8	0.8	0.9	0.8	0.7	0.8

Source: Energy Information Administration, *AEO98* National Energy Modeling System runs: aeo98b.d100197a; lmac98.d100197a; and hmac98.d100197a.

The productivity of labor is the second major reason for economic growth and combines 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 1.9 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. The Federal deficit is expected to diminish over time, helping lead a recovery in private investment and spending on research and development. 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 in the range of 1 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 *AEO98* 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 Data Resources, Inc. (DRI).[4] The DRI forecasts used in *AEO98* are the Trend Growth scenario and the Optimistic and Pessimistic growth projections. EIA has used DRI's forecasts directly, apart from an adjustment to incorporate EIA's world oil price assumptions. The three economic growth cases have been modified by EIA to incorporate the world oil price assumptions for the *AEO98* reference case. With this change, the DRI projections are used as the starting point for the macroeconomic forecasts within the NEMS simulations for the *AEO98*. The macroeconomic activity module incorporates energy price feedback impacts on the aggregate economy.

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 2.4 percent between 1996 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 1.3 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 DRI/McGraw-Hill's August 1997 Summer Long-Term Forecasts, Trend, Optimistic and Pessimistic Growth Cases. See DRI/McGraw-Hill, *Review of the U.S. Economy,* August 1997 (Lexington, MA, 1997).

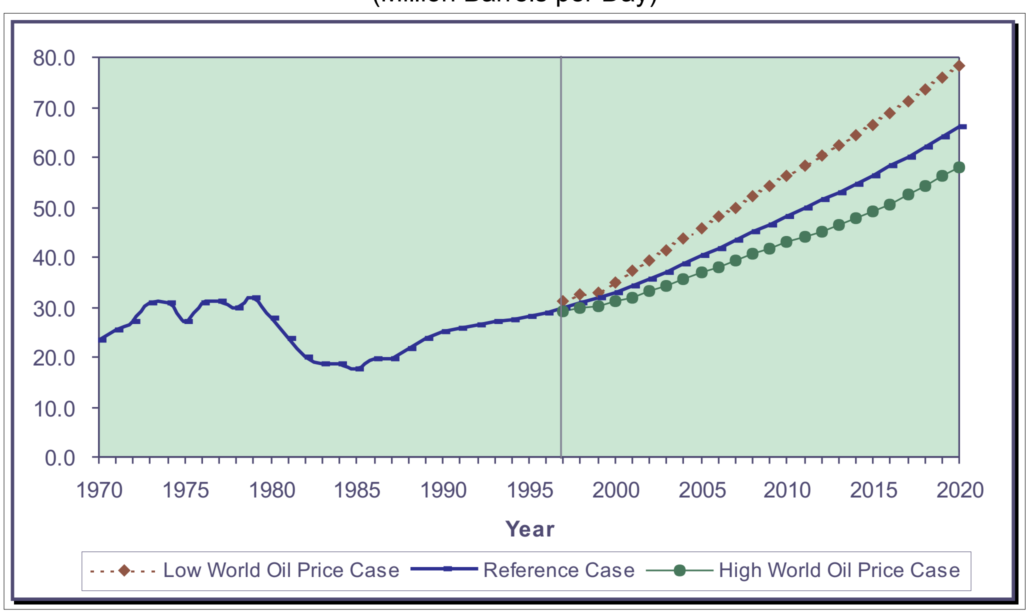
International Energy Module

The International Energy Module determines changes in the world oil price and the supply prices of 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, (Washington, DC, April 1994).

Key Assumptions

The level of oil production by countries in the OPEC is a key factor influencing the world oil price projections incorporated into *AEO98*. Non-OPEC production, worldwide regional economic growth rates and the associated regional demand for oil are additional factors affecting the world oil price.

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



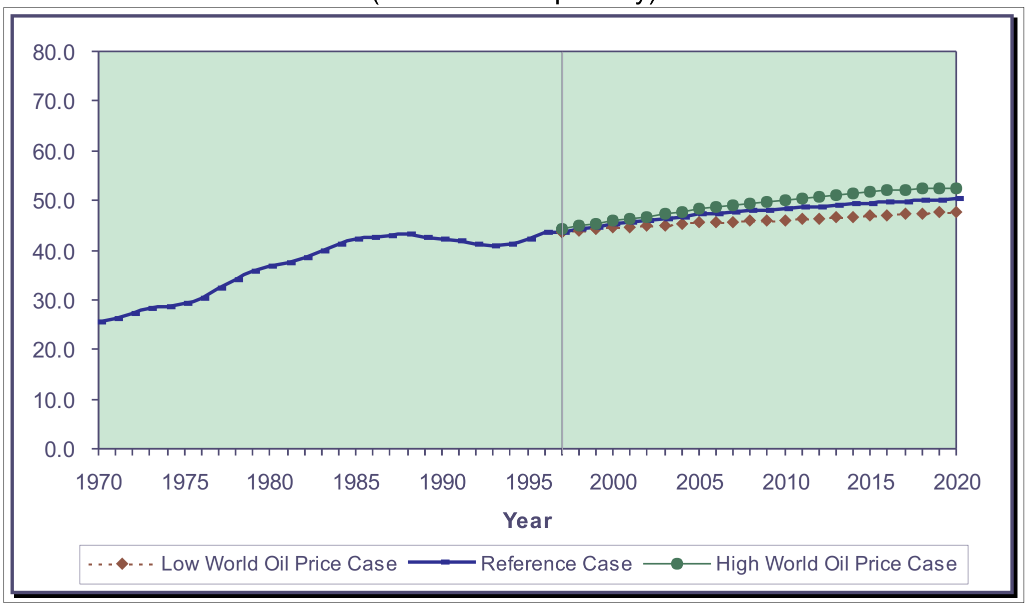
OPEC=Organization of Petroleum Exporting Countries.

Source:Energy Information Administration, *AEO98* National Energy Modeling System runs: lwop98.d100197c; aeo98b.d100197a; and hwop98.d100197a.

OPEC oil production is assumed to increase throughout the forecast, making OPEC the source for 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 — reaching almost 790 billion barrels, over 77 percent of the world's total, at the end of 1996.[5] For the *AEO98* 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. Non-OPEC oil production is expected to follow a gradually rising path — with an increase of more than 0.6 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 the values of world oil prices, so the final forecast solutions of the levels of non-OPEC production for the three oil prices 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.

Source: Energy Information Administration. *AEO98* National Energy Modeling System runs: lwop98.d100197c; aeo98b.d100197a; and hwop98.d100197a.

The assumed growth rates for GDP for various regions in the world are shown in Table 4. This set of growth rates for GDP was assumed for all three price cases. The GDP growth rate assumptions are from selected issues of The WEFA Group, *World Economic Outlook*. The WEFA GDP growth rates have been used for all regions of the world except for the developing countries, for which the GDP growth rates have been assumed to be about 1 percentage point per year lower than the WEFA values.

The WEFA GDP forecasts are made with limited consideration of prospective energy market conditions. EIA's analysis indicates that economic growth by the developing countries at the rates suggested by WEFA would put upward pressures on energy production and prices (particularly for oil) that could not be sustained by the market. These high economic growth rates would lead to oil prices high enough to retard economic growth. The 1-percentage-point reduction in economic growth rates for developing countries provides a better balance between sustainable economic growth rates and growth in energy production.

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 5 for the three oil price cases by regions of the world. The different rates of growth for oil consumption in the three price cases reflect the different levels in consumption calculated for the different oil prices.

Economic growth and oil consumption in the Former Soviet Union (FSU) are expected to reverse the downward trends exhibited over the past half-dozen years. After 1997, oil consumption in the FSU is expected to begin gradually rising and almost double by the end of the forecast period. After 1997, oil production in the FSU also recovers and the FSU remains a net exporter through 2020. In contrast, China is expected to remain a net importer of oil through 2020.

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 in the range of prices assumed for *AEO98*, as well as values for worldwide petroleum production over this price range. The refinery technology incorporated in the model is updated using the most recently available Oil & Gas Journal Database.[7]

Table 4. Average Annual Regional Gross Domestic Product Growth Rates, 1996-2020
(Percent per Year)

Region	Gross Domestic Product
Organization for Economic Cooperation and Development	2.7
Other Developing Countries	4.4
Eurasia	5.5
China	7.4
Former Soviet Union	4.3
Eastern Europe	3.1
Total World	3.3

Source: The WEFA Group, World Economic Outlook, (August 1996), Volume 1, and EIA, World Energy Projection System (1997).

Table 5. Average Annual Regional Growth Rates for Oil Demand, 1996-2020
(Percent per Year)

Region	Low Price	Reference	High Price
Organization for Economic Cooperation and Development	1.5	1.1	0.9
Organization of Petroleum Exporting Countries	2.3	2.3	2.3
Other Developing Countries	3.7	3.3	3.1
Eurasia	3.9	3.5	3.4
China	5.2	4.8	4.6
Former Soviet Union	3.0	2.8	2.6
Eastern Europe	2.0	1.9	1.8
Total World	2.4	2.1	1.9

Source: Energy Information Administration, *AEO98* National Energy Modeling System runs: lwop98.d100197c; aeo98b.d100197a; and hwop98.d100197a.

[5] EIA, *International Energy Outlook 1997*, DOE/EIA-0484(97) (Washington DC, April 1997).

[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, 1996).

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 *AEO98* 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 *AEO98* 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 1993 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 *AEO98* 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, 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, lighting, 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 (active) 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 1993 are derived from the Energy Information Administration's (EIA) *Residential Energy Consumption Survey* (RECS) (Table 6). The forecast for occupied housing units is done separately for each Census Division. It is based on the combination of the previous year's surviving stock with projected housing starts provided by the NEMS Macroeconomic Activity Module. The housing stock submodule assumes a constant survival rate (the percentage of households which are present in the current forecast year, which were also present in the preceding year) for each type of housing unit; 99.7 percent for single-family units, 99.6 percent for multifamily units, and 96.6 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 6. 1993 Households

Region	Single-family Units	Multi-family Units	Mobile Home Units	Total Units
New England	3,094,829	1,747,055	225,381	5,067,265
Mid Atlantic	8,813,412	5,279,802	317,255	14,410,469
East North Central	11,396,562	4,009,539	945,403	16,351,504
West North Central	5,175,494	1,304,775	468,787	6,949,056
South Atlantic	12,193,075	3,733,627	1,440,830	17,367,532
East South Central	4,677,828	639,879	684,169	6,001,876
West South Central	7,959,478	1,686,948	482,358	10,128,784
Mountain	3,643,727	1,060,754	654,887	5,359,368
Pacific	9,854,773	4,785,219	355,646	14,995,638
United States	66,809,178	24,247,598	5,574,716	96,631,492

Source: Energy Information Administration, *Housing Characteristics 1993*, DOE/EIA-314(93), (Washington, DC, June 1995).

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 7 lists capital cost and efficiency for selected residential appliances for the years 1995 and 2005.

Table 7. Capital Cost and Efficiency Ratings of Selected Equipment

Equipment Type	Relative Performance[1]	1995 Capital Cost ($1991)[2]	Efficiency[2]	2005 Capital Cost ($1991)[2]	Efficiency[3]	Approximate Discount Rate
Electric Heat Pump	Minimum Best	$2,909 $4,986	10.0 14.5	$2,909 $4,986	10.0 16.9	20%
Natural Gas Furnace	Minimum Best	$1,351 $3,117	0.78 0.95	$1,351 $2,597	0.78 0.96	15%
Room Air Conditioner	Minimum Best	$623 $883	8.7 12.0	$623 $883	9.7 12.5	100%
Central Air Conditioner	Minimum Best	$2,182 $3,117	10.0 14.5	$2,182 $3,168	10.0 16.9	50%
Refrigerator (18 cubic ft)	Minimum Best	$519 $675	690 550	$519 $727	483 400	19%
Electric Water Heater	Minimum Best	$ 364 $1,588	0.88 2.60	$364 $1,100	0.88 2.80	111%

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

[2]Capital costs are given in 1991 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 41615, June 1995.

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.

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] The efficiency gap literature has been drawn on as the basis for efficiency standards and Federally-Sponsored voluntary programs under the Climate Change Action Plan (CCAP) (see on page 24). 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 8.

Table 8. 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	25
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 1993 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 23), the size of new construction relative to the existing stock, people per household and shell efficiency and weather effects (space heating and cooling). The various levels of aggregated consumption (consumption by fuel, by service, etc.) are derived from these detailed equipment-specific calculations.

Equipment Efficiency

The average energy consumption of a particular technology is initially based on estimates derived from RECS 1993. 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 1993, 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 1993 indicates that new construction (post-1990) is on average roughly 20 percent larger than the existing stock of housing. The residential module uses similar estimates for each Census Division to model the size of new construction by housing type. The energy consumption for space heating, air conditioning, and lighting are assumed to increase with the square footage of the structure (all future new construction is assumed to be of the size of the post-1990 vintage stock from RECS and Bureau

Census data[10]). This results in an increase in the average size of the housing stock of 1,630 to 1,728 square feet from 1993 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. These adjustments are based on National Oceanographic and Atmospheric Administration (NOAA) data for 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 1993 through 1997. After 1997, 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 -0.15. 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 -0.15 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 elasticity parameter, the demand for the service will rise by 1.5 percent (-10 percent multiplied by -0.15). Only space heating, cooling and lighting 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, fuel type, service (heating and cooling), and Census Division. The age, 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-1993) and existing. Existing homes are characterized by the RECS 1993 survey and are assigned a shell index value of 1.0 for the base year (1993). 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). New homes are more efficient than old homes in terms of their building envelope. Based on RECS data, newer homes are roughly 10 percent more efficient than the existing stock, depending upon the heating fuel and Census Division. Over time, the shell integrity of new homes is assumed to improve as the stringency of building codes increases. The shell integrity index affects the space heating and cooling loads directly, causing a decrease in fuel consumed for these services as the shell integrity improves.

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-1994) 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 50 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.

Climate Change Action Plan

The Climate Change Action Plan (CCAP) contains many policies which are designed to reduce carbon emissions in the United States to the 1990 levels. The CCAP strategies which directly affect the residential sector are Actions 8 through 11. The Residential Demand Module for *AEO98* includes effects from Action Items 6, 7, 8, 10, and 11 (the House and Senate appropriations included no funding for Action 9). Specifically, these sections relate to Federal Efficiency Standards for several household appliances, stricter building codes, and the expansion of "Golden Carrot" demand-pull type programs. Analyses relating to CCAP programs are on an ongoing basis, as funding changes over time.

Action Item 6 includes voluntary programs sponsored by the Department of energy (DOE) and the Environmental Protection Agency (EPA) aimed at market-pull partnerships with industry. Among the programs in Action Item 6 are DOE's R&D efforts to commercialize advanced energy-efficient technologies and EPA's Energy Star Programs for residential homes, air conditioning, ductwork and lighting.

CCAP Action Items 8, 10 and 11 are policies designed to reduce energy consumption by strengthening building shell efficiency and promoting energy efficient mortgages. In *AEO98*, the shell integrity (efficiency) of new construction is assumed to increase relative to 1993 levels as stricter building codes, energy-efficient mortgages, and home energy rating systems become more widespread. The combined energy savings due to CCAP Actions 6 through 11 results in approximately 2.6 MMT of carbon emissions savings in the year 2000 and 12.3 MMT in 2010.

Residential Technology Cases

In addition to the *AEO98* reference case, three side cases were developed to examine the effect of equipment and building standards on residential energy use — a *1998 technology case,* a *best available technology case*, and an *advanced technology cost reduction 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.

The *1998 technology case* assumes that all future equipment purchases are made based only on equipment available in 1998. This case further assumes that building shell efficiencies will not improve beyond 1998 levels. In the reference case, the 2020 housing stock shell efficiency is 16 percent higher than in 1993 for heating (13 percent for cooling).

The *best available technology case* assumes that all equipment purchases from 1998 forward are based on the only the highest available efficiency in a particular simulation year. The *best available technology case* disregards the economic costs of such a scenario, and is merely designed to show how much the choice of only the highest-efficiency equipment could affect energy consumption for the explicitly-modeled end-uses. In the *best available technology case*, heating shell efficiency is assumed to increase by 21 percent (cooling shell, 17 percent).

The *advanced technology cost reduction case* assumes that the (real) capital costs of the most efficient technologies included in the reference case fall year-by-year. This contrasts with the typical reference case assumption of a technology characterized to be constant in both efficiency and cost in a "window of availability" lasting for several year periods. For the cost reduction case, costs of the most efficient technologies for a given fuel and end-use are allowed to fall by roughly 35 percent over a 10 year interval beginning in 1999. To mirror the assumptions in the 1998 and *best available technology cases*, no costs are adjusted until after 1998. The cost decline occurs faster in the first half of the interval and then tapers off. When efficient reference case technologies change in a minor way over time (either in cost or performance), the cost of the new version at time of introduction is linked to the cost reduction trend of the model which it replaces. That is, rather than being introduced at reference case values (and then allowed a cost decline), updated editions of essentially the same technology are brought in on the reduced-cost trend. Shell effects in this case are assumed to be the same as for the *best available technology case* above.

[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(98), (Forthcoming, January 1998).

[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 technlogy 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 2uality 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, *Characteristics of New Housing*, C25/95-A.

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.[11]

The commercial module forecasts consumption by fuel[12] 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[13] for eleven building categories[14] 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.[15] 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.[16]

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 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.[17]

Existing Floorspace and Attrition

Existing floorspace is based on the estimated floorspace reported in the *Commercial Buildings Energy Consumption Survey 1992* (Table 9). Over time the 1992 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*. *Gamma* controls the acceleration of the rate of retirement around the average building lifetime. The current values for the average building lifetime and *gamma* are 59 years and 5.4, respectively.[18]

Table 9. 1992 Total Floorspace by Census Division and Principal Building Activity
(Millions of Square Feet)

	Assembly	Education	Food Sales	Food Service	Health Care	Lodging	Large Office	Small Office	Merc/ Service	Ware-house	Other	Total
New England	307	609	60	93	139	160	342	364	605	292	311	3,280
Middle Atlantic	938	1,373	61	350	213	465	1,085	810	2,205	1,476	1,238	10,214
East North Central	1,280	1,530	110	289	169	405	1,213	878	1,873	1,916	1,047	10,711
West North Central	733	864	75	144	143	168	373	494	1,289	1,203	1,101	6,587
South Atlantic	1,375	1,158	114	183	226	520	1,181	938	1,635	2,119	1,149	10,600
East South Central	462	553	30	48	154	260	462	515	1,140	1,451	345	5,420
West South Central	1,781	917	106	178	113	255	559	627	1,486	1,398	1,161	8,582
Mountain	414	412	117	53	16	233	409	358	667	606	365	3,649
Pacific	1,046	1,076	96	155	130	416	1,145	1,075	1,579	1,044	1,264	9,025
United States	8,337	8,494	767	1,494	1,301	2,882	6,770	6,059	12,479	11,504	7,980	68,068

Source: Energy Information Administration, *Commercial Buildings Energy Consumption Survey 1992*, Public Use Diskettes.

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.[19]

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.[20] 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.[21] 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 *AEO98* reference case, shell improvements for new buildings are up to 30 percent more efficient than the 1992 stock of similar buildings. Over the forecast horizon, new building shells improve in efficiency by 7 percent relative to their efficiency in 1992. For existing buildings, efficiency is assumed to increase by 5 percent over the 1992 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 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 proportion of equipment in existing floorspace projected to wear out.[22] 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 choice among 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 10 below illustrates the proportions of floorspace subject to the different behavior rules for space heating technology choices in large office buildings.

Table 10. Assumed Behavior Rules for Choosing Space Heating Equipment in Large Office Buildings
(Percent)

	Unrestricted	Same Fuel	Same Technology	Total
New Equipment Decision	16	31	53	100
Replacement Decision	8	33	59	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(97) (Washington DC, January 1997), p. A-16.

Time Preferences

The time preferences of owners of commercial buildings are assumed to be distributed among six alternate time preference premiums (Table 11). Adding the time preference premiums to the 10-year Treasury Bill rate results in discount 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 *AEO98* assigns some floorspace a very high discount 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 five segments of the distribution get progressively lower, simulating increased sensitivity to the fuel costs of the equipment that is purchased.

Table 11. Assumed Distribution of Time Preference Premiums
(Percent)

Proportion of Floorspace	Time Preference Premium
33.0	1000.0
19.4	152.9
20.4	55.4
16.2	30.9
10.0	19.9
1.0	13.6
100	--

Source: Energy Information Administration. *Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M066(97) (Washington DC, January 1997), p A-52.

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; 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 12 provides a sample of the technology data for space heating in the New England Census Division.

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 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 1992. 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 1992, 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.

Table 12. Capital Cost and Efficiency Ratings of Selected Commercial Space Heating Equipment

Equipment Type	Vintage	Efficiency[1]	Capital Cost ($1987 per Mbtu/hour) [2]	Maintenance Cost ($1987 per Mbtu/hour) [2]	Service Life (Years)
Electric Heat Pump	1992	5.8	$86.95	$3.79	12
	1993	6.8	$86.34	$3.79	12
	1995	10.2	$143.90	$3.79	12
	2000	8.0	$92.40	$3.79	12
	2005	11.0	$143.90	$3.79	12
	2010-low efficiency	8.5	$92.40	$3.79	12
	2010-high efficiency	12.0	$149.96	$3.79	12
Ground-Source Heat Pump	1992	10.2	$140.13	$3.16	13
	1993	11.6	$143.91	$3.16	13
	1995	13.0	$157.80	$3.16	13
	2000	11.6	$131.29	$3.16	13
	2005	14.0	$227.23	$3.16	13
	2010 - low efficiency	13.0	$126.24	$3.16	13
	2010 - high efficiency	14.3	$201.98	$3.16	13
Electric Boiler	1992	0.94	$6.89	$0.45	25
Packaged Electric	1992	0.93	$18.63	$3.29	18
Natural Gas Furnace	1992	0.77	$12.39	$0.21	20
	1995	0.80	$12.78	$0.28	20
	2005 - low efficiency	0.80	$12.78	$0.28	20
	2005 - high efficiency	0.96	$17.36	$0.39	20
	2010	0.96	$17.09	$0.39	20
Natural Gas Boiler	1992 - low efficiency	0.68	$6.62	$0.09	20
	1992 - high efficiency	0.73	$8.58	$0.09	20
	1995	0.80	$15.45	$0.16	20
	2000	0.76	$9.91	$0.11	20
	2005	0.80	$15.45	$0.16	20
	2010 - low efficiency	0.78	$11.36	$0.12	20
	2010 - high efficiency	0.80	$15.45	$0.16	20
Natural Gas Heat Pump	1992	1.02	$201.98	$5.68	13
	2005	1.02	$145.18	$4.42	13
	2005	1.45	$138.86	$3.79	15
	2010 - engine driven	1.02	$145.18	$4.42	13
	2010 - absorption	1.45	$138.86	$3.79	15
Distillate Oil Furnace	1992 - low efficiency	0.68	$13.86	$0.23	15
	1992 - high efficiency	0.77	$14.95	$0.23	15
	1998	0.79	$16.06	$0.25	15
	2000	0.82	$16.26	$0.26	15
	2010	0.85	$16.81	$0.27	15
Distillate Oil Boiler	1992	0.56	$8.27	$0.08	20
	1992	0.72	$10.72	$0.08	20
	1995	0.77	$14.95	$0.08	20
	2005 - low efficiency	0.74	$10.91	$0.08	20
	2005 - high efficiency	0.81	$15.45	$0.08	20

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

[2]Capital and maintenance costs are given in 1987 dollars.

Source: Energy Information Administration, *Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M066(97) (Washington DC, January 1997), p. A-53.

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 otherwise been. The commercial module makes weather adjustments for the years 1993 through 1997. After 1997, 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 elasticity parameter is -0.15 for end uses affected by short-term price and efficiency rebound effects. 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 0.15 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. Based on the short-term elasticity parameter, the demand for the service will rise by 1.5 percent (-10 percent x -0.15). Currently, the services affected by the short-term price effect and efficiency rebound are space heating and cooling, water heating, ventilation and lighting.

Cogeneration

Nonutility power production applications within the commercial sector are concentrated in education, health care, office, and warehouse buildings. Historical data from Form EIA-867, *Annual Nonutility Power Producer Report*, are used to derive electricity cogeneration for the years 1990 through 1994 by Census Division, building type, and fuel. After 1994, a forecast of electricity cogeneration, as disaggregated above, is developed as follows: first, relative prices of energy sources for generation are compared with the price of electricity; second, if the price of electricity increases relative to generation fuels, then cogeneration increases based on a sensitivity parameter.[23] If the price of electricity falls relative to the prices of other fuels, then cogeneration decreases based on the same sensitivity parameter. For each year of the forecast period, all cogenerated electricity is assumed to be sold to the grid and, subsequently, a portion is bought back to meet part of the consumption necessary to satisfy service demands.

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, 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 factors of 0.78.

Climate Change Action Plan

The Climate Change Action Plan (CCAP) contains 5 Action Items which affect the commercial sector. Action Items 1, 4 and 5 are designed to stimulate investment in more efficient building shells and equipment for heating, cooling and other end uses. Action Item 2, EPA's Green Lights Program targets the retrofitting of lighting equipment. Action Item 3 was unfunded and therefore not modeled. 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). For Action Items 1, 2, 4 and 5, retrofits of equipment for space heating and air conditioning are incorporated in the distribution of premiums given in Table 11. Also, based partly on these actions, the shell efficiency of new and existing buildings is assumed to increase from 1992 through 2020. Shells for new buildings increase in efficiency by 7 percent over this period, while shells for existing buildings increase in efficiency by 5 percent. In total, the action items result in energy savings which are estimated to reduce carbon emissions by the commercial sector by 9.2 million metric tons for the year 2010.

Commercial Technology Cases

In addition to the *AEO98* reference case, three side cases were developed to examine the effect of equipment and building standards on commercial energy use — a *1998 technology case*, a *best available technology case*, and an *advanced technology cost reduction 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.

The *1998 technology case* assumes that all future equipment purchases are made based only on equipment available in 1998. This case further assumes building shell efficiency to be fixed at 1998 levels. In the reference case, existing building shells are allowed to increase in efficiency by 5 percent over 1992 levels, new building shells improve by 7 percent by 2020 relative to new buildings in 1992.

The *best available technology case* assumes that all equipment purchases from 1999 forward are based on the highest available efficiency 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 the best available technology case, building shell efficiencies are assumed to increase by 50 percent over the levels achieved in the reference case. Existing building shells, therefore, increase by 7.5 percent relative to 1992 levels and new building shells by 10.5 percent relative to their efficiency in 1992 by 2020.

The *advanced technology cost reduction case* assumes that the (real) capital costs of the most efficient technologies included in the reference case fall year-by-year. This contrasts with the typical reference case assumption of a technology characterized to be constant in both efficiency and cost in a "window of availability" lasting for several year periods. For the cost reduction case, costs of the most efficient technologies for a given fuel and end-use are allowed to fall by roughly 35 percent over a 10 year interval. To mirror the assumptions in the 1998 and *best available technology cases*, no costs are adjusted until after 1998. The cost decline occurs faster in the first half of the interval and then tapers off. When efficient reference case technologies change either in cost or performance over time, the cost of the new version at time of introduction is linked to the cost reduction trend of the version it replaces. That is, rather than being introduced at reference case values (and then allowed a cost decline), updated editions of essentially the same technology are brought in on the reduced-cost trend. Shell effects in this case are assumed to be the same as for the *best available 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.

[11] Energy Information Administration, *Commercial Buildings Characteristics 1992*, DOE/EIA-0246(92), (Washington, DC, April 1994); *Commercial Buildings Energy Consumption and Expenditures 1992*, DOE/EIA-0318(92), (Washington, DC, April 1995).

[12] 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.

[13] 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.

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

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

[16] 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(98), (Forthcoming January 1998).

[17] The floorspace from the Macroeconomic Activity Model is based on the Data Resources Incorporated (DRI) floorspace estimates which are approximately 10 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.

[18] The commercial module performs attrition for 5 vintages of floorspace developed from the CBECS 1992 stock estimate and historical floorspace additions data from F.W. Dodge data.

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

[20] "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.

[21] Based on updated estimates using CBECS 1992 data and the methodology described in *End-Use Energy Consumption Estimates for U.S. Commercial Buildings, 1992*, Belzer, D.B., and Wrench, L.E., Pacific Northwest Laboratories, PNNL-11514, Prepared for the U.S. DOE under Contract DE-AC06-76RLO-1830, (Richland, WA, March, 1997).

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

[23] The sensitivity parameter assumes that a 10 percent change in relative prices results in a 1 percent change in Cogeneration activity.

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 energy-intensive industries are modeled through the use of a detailed process flow accounting procedure, whereas the nonenergy-intensive and the nonmanufacturing industries are modeled through econometrically based equations (Table 13). 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.

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 primary 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 energy-intensive 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 a separate module of NEMS, and the projected energy consumption is included in the manufacturing total. Forecasts of refining use of 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 combines the use of a bottom-up process modeling approach with a top-down econometric 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 1991 baseline Unit Energy Consumption (UEC) estimates based on analysis of the Manufacturing Energy Consumption Survey 1991.[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 seven most energy-intensive manufacturing industries (apart from petroleum refining, which is modeled in the Petroleum Market Module of NEMS) with a detailed process flow 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 1991 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.

Table 13. 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, 322)			Construction	(SIC 15, 16, 17)
Primary Aluminum	(SIC 3334)				

SIC = Standard Industrial Classification.

Source: Office of Management and Budget, Standard Industrial Classification Manual 1987 (Springfield, VA, National Technical Information Service).

Process/Assembly Component

The Process/Assembly (PA) Component models each major manufacturing production step for the energy-intensive 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, additions to waste fiber pulping capacity are assumed to require only 93 percent as much energy as does the average existing plant (Table 14). 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. It is unlikely that new technology is employed in all new capacity additions. Many facilities will only partially incorporate the technology or will need time to debug the operating aspects of the newly installed capacity. 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 six of the energy-intensive manufacturing industries[26] are adjusted for changes in relative fuel prices. The six industries are food, paper, chemicals, glass, cement, and steel. 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.

Table 14. Coefficients for Technology Possibility Curve

Industry/ Process Unit	Old Facilities			New Facilities		
	REI 1991 (Year 1)	REI[1] 2015 (Year 24)	Slope b	REI 1991 (Year 1)	REI[1] 2015 (Year 24)	Slope b
Pulp & Paper						
Wood Preparation	1.000	0.950	-0.00269	0.840	0.831	-0.00044
Waste Production	1.000	0.974	-0.00138	0.930	0.885	-0.00205
Mechanical Pulping	1.000	0.944	-0.00305	0.840	0.822	-0.00089
Semi-Chemical	1.000	0.894	-0.00591	0.730	0.697	-0.00191
Kraft, Sulfite, misc. chemicals	1.000	0.903	-0.00537	0.730	0.600	-0.00816
Bleaching	1.000	0.910	-0.00495	0.750	0.683	-0.00390
Paper Making	1.000	0.910	-0.00495	0.750	0.560	-0.01217
Glass[1]						
Batch Preparation	1.000	0.957	-0.00229	0.882	0.882	0
Melting/Refining	1.000	0.892	-0.00602	0.850	0.448	-0.02664
Forming	1.000	0.952	-0.00257	0.818	0.744	-0.00395
Post-Forming	1.000	0.921	-0.00432	0.780	0.760	-0.00106
Cement						
Dry Process	1.000	0.982	-0.00094	0.790	0.657	-0.00768
Wet Process[2]	1.000	0.954	-0.00247	NA	NA	NA
Finish Grinding	1.000	0.943	-0.00309	0.813	0.641	-0.00989
Steel						
Coke Oven	1.000	1.000	0	0.840	0.817	-0.00116
BF/OH[3]	1.000	1.000	0	NA	NA	NA
BF/BOF	1.000	1.000	0	1.000	0.982	-0.00075
EAF	1.000	1.000	0	0.960	0.960	0
Ingot Casting/Primary Rolling	1.000	1.000	0	NA	NA	NA
Continuous Casting	1.000	1.000	0	.000	1.000	0
Hot Rolling	1.000	0.698	-0.01892	0.500	0,401	-0.00920
Cold Rolling	1.000	0.877	-0.00690	0.840	0.488	-0.02264
Aluminum						
Alumina Refinery	1.000	0965	-0.00190	0.900	0.865	-0.00164
Primary aluminum	1.000	0.936	-0.00349	0.910	0.812	-0.00477
Semi-Fabrication	1.000	0.855	-0.00826	0.610	0.506	-0.00781
Secondary Aluminum	1.000	0.817	-0.01065	0.600	0.510	-0.00675

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

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

SIC = Standard Industrial Classification.

REI = Relative Energy Intensity.

NA = Not applicable.

BF = Blast furnace.

OH = Open hearth.

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(97) (Washington, DC, January 1997), p. D-9.

The fuel share adjustments are done in two stages. The first stage determines the fuel shares of electricity and nonelectricity energy. The latter group excludes boiler fuel and feedstocks. The second stage determines the fossil fuel shares of nonelectricity energy. In each case, 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 price indices are the ratio of the current year price to the base year price, in real dollars. The formulation is as follows:

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

The coefficients β_j are all assumed to be 0.65.

The form of the equation results in unchanged fuel shares when the price indices are all 1, or unchanged from their 1996 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 15). Energy consumption in the BLD Component for an industry is assumed to grow at the same rate as regional employment for that industry.

Boiler/Steam/Cogeneration Component

The steam demand and byproducts from the PA and BLD Components are passed to the BSC Component, which applies a heat rate and a fuel share equation (Table 16) to the boiler steam requirements to compute the required energy consumption.

The boiler fuel shares are calculated using a logit formulation. The equation is calibrated to 1991 so that the actual boiler fuel shares are produced for the relative prices that prevailed in 1991. The equation for each manufacturing industry is as follows:

$$ShareFuel_i = \frac{(P_i^{\alpha} \beta_i)}{\sum_{i=1}^{3} P_i^{\alpha} (\beta_i)}$$

where the fuels are coal, petroleum, and natural gas. The P_i are the fuel prices; α_i are sensitivity parameters; and the β_i are calibrated to reproduce the 1991 fuel shares using the relative prices that prevailed in 1991. The byproduct fuels are consumed before the quantity of purchased fuels is estimated. The boiler fuel shares are assumed to be those estimated using the 1991 MECS.[27]

Table 15. Building Component Unit Energy Consumption
(Trillion Btu/Thousand People Employed)

Industry	Lighting Electric UEC	Building Use and Energy Source		
			HVAC	
		Electric UEC	Natural Gas UEC	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-MO64, (Washington, DC, January 1997), p. D-1.

Table 16. Logit Function Parameters for Estimating Boiler Fuel Shares

Industry	Alpha	Natural Gas	Steam Coal	Oil
Food	-0.25	0.60	0.26	0.13
Paper and Allied Products	-0.25	0.47	0.34	0.20
Bulk Chemicals	-0.25	0.69	0.18	0.13
Glass and Glass Products	-0.25	0.97	0.0	0.03
Cement	-0.25	0.0	0.0	1.0
Steel	-0.25	0.57	0.22	0.22
Aluminum	-0.25	0.79	0.0	0.21
Metals-Based Durables	-0.25	0.58	0.27	0.16
Other Non-Int MFG	-0.25	0.63	0.23	0.14

Source: Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-MO64, (Washington, DC, January 1997), p. D-22.

Alpha: User-specified.

Nonenergy-Intensive Industries

The UECs for the PA Component of the nonenergy-intensive manufacturing industries are econometrically estimated. The UECs for non-manufacturing industries are held constant.

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 1991 and is assumed to retire at a fixed rate each year (Table 17). Middle vintage capital is that which is added after 1990 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-1991 capital stock.

The energy intensity of the new capital stock relative to 1990 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 14). 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.

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-867, *Annual Nonutility Power Producer Report*, consisting of data from approximately 400 cogenerators for 1989-1994.

Table 17. 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/Open Health	50.0	Metals-Based Durables	1.5
Blast Furnace/Basic Oxygen Furnace	1.0	Other MFG	2.3
Electric Arc Furnace	1.5	Other MFG	2.3
Coke Ovens	1.5		
Other Steel	2.9		

Source: Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-MO64, (Washington, DC, January 1997), p. D-19 (Corrected).

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. For the former, especially note the Open Hearth is given a 50 percent retirement rate to reflect that this technology is no longer used in the United States.

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.

Climate Change Action Plan

Several programs included in the Climate Change Action Plan (CCAP) target the industrial sector. Note that the potential impacts of the Climate Wise Program are also included in the CCAP impacts. The intent of these programs is to reduce greenhouse gas emissions by lowering industrial energy consumption. The Department of Energy (DOE) program offices estimated that full implementation of these programs would reduce industrial electricity consumption by 79 billion kilowatthours and fossil energy consumption by 359 trillion Btu by 2010. However, since the energy savings associated with the voluntary programs in the CCAP largely duplicate savings that would have occurred in their absence and since some programs were not fully funded, total CCAP energy savings were reduced. The *Annual Energy Outlook 1998* (*AEO98*) assumes that CCAP reduces electricity consumption by 41 billion kilowatthours and fossil energy consumption by 90 trillion Btu in 2010. The fossil energy is assumed to be 85 percent natural gas and 15 percent steam coal. In this situation, carbon emissions would be reduced by about 8 million metric tons (1 percent) in 2010.

High Technology and 1998 Technology Cases

From 1960 to 1994, the decline in the 10-year moving average for aggregate industrial energy intensity was 1.2 percent, with a standard deviation of 1.1 percent. Thus, a change of 1 standard deviation would approximately double the decline in intensity. The *high technology case* emulates this result by approximately doubling the projected rates of decline in energy intensity for the energy-intensive industries. Changes in aggregate energy intensity result both from changing equipment and production efficiency and from changing composition of industrial output. Since the composition of industrial output remains the same as in the reference case, aggregate intensity falls by 1.5 percent annually. This compares to a decline of 1.2 percent per year for the reference case.

The *1998 technology case* holds the energy efficiency of plant and equipment constant at the 1998 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.

[24] Energy Information Administration, *State Energy Data Report 1994, DOE/EIA-0214(94)*, (Washington, D.C., October 1996).

[25] Energy Information Administration, *Manufacturing Consumption of Energy 1991, DOE/EIA-0512(91)*, (Washington, D.C., December 1994).

[26] Primary aluminum is excluded because they use only electricity in the process and assembly component.

[27] Energy Information Administration, *Manufacturing Energy Consumption Survey: Consumption of Energy 1991, DOE/EIA-0512(91)*, (Washington, D.C., December 1994).

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, mass transit, 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 18) 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 forty-six percent by 2020.

Table 18. Macroeconomic Inputs to the Transportation Module
(Millions)

Macroeconomic Input	1995	2000	2005	2010	2015	2020
New Car Sales	8.7	7.0	6.9	7.4	7.6	7.8
New Light Truck Sales	6.1	5.7	6.0	6.4	6.6	6.7
Driving Age Population	202.1	212.8	223.8	235.4	245.8	255.6
Total Population	263.6	275.6	287.1	298.9	311.2	323.5

Source: Energy Information Administration, *AEO98* National Energy Modeling System run: aeo98b.d100197a.

Light-Duty Vehicle Assumptions

The light duty vehicle Fuel Economy Module includes 56 fuel saving technologies with data specific to car and light truck 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 19 and 20).

The vehicle sales share module holds vehicle sales shares by import and domestic manufacturers constant within a vehicle size class at 1996 level from the National Highway Traffic and Safety Administration data.[28]

Table 19. Standard 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	0.00	0	-0.08	1980	0
Unit Body	0.040	80	0.00	0	-0.05	1980	0
Material Substitution II	0.033	0	0.60	0	-0.05	1987	0
Material Substitution III	0.066	0	0.80	0	-0.10	1997	0
Material Substitution IV	0.099	0	1.00	0	-0.15	2007	0
Material Substitution V	0.132	0	1.50	0	-0.20	2017	0
Drag Reduction II	0.023	32	0.00	0	0.00	1985	0
Drag Reduction III	0.046	64	0.00	0	0.05	1991	0
Drag Reduction IV	0.069	112	0.00	0	0.01	2004	0
Drag Reduction V	0.092	176	0.00	0	0.02	2014	0
TCLU	0.030	40	0.00	0	0.00	1980	0
4-Speed Automatic	0.045	225	0.00	30	0.00	1980	0.05
5-Speed Automatic	0.065	325	0.00	40	0.00	1995	0.07
CVT	0.100	250	0.00	20	0.00	1995	0.07
6-Speed Manual	0.020	100	0.00	30	0.00	1991	0.05
Electronic Transmission I	0.005	20	0.00	5	0.00	1988	0
Electronic Transmission II	0.015	40	0.00	5	0.00	1998	0
Roller Cam	0.020	16	0.00	0	0.00	1987	0
OHC 4	0.030	100	0.00	0	0.00	1980	0.2
OHC 6	0.030	140	0.00	0	0.00	1980	0.2
OHC 8	0.030	170	0.00	0	0.00	1980	0.2
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	-0.1
4C/5V	0.100	300	0.00	45	0.00	1998	0.55
Turbo	0.050	800	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	0.1
VVT II	0.100	180	0.00	40	0.00	2008	0.15
Lean Burn	0.100	150	0.00	0	0.00	2012	0
Two Stroke	0.150	150	0.00	-150	0.00	2004	0
TBI	0.020	40	0.00	0	0.00	1982	0.05
MPI	0.035	80	0.00	0	0.00	1987	0.1
Air Pump	0.010	0	0.00	-10	0.00	1982	0
DFS	0.015	15	0.00	0	0.00	1987	0.1
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.	-0.033	0	0.00	0	0.05	1991	0
Compression Ratio Increase	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Idle Off	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Optimized Manual Transmission	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variable Displacement	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Electric Hybrid	N/A	N/A	N/A	N/A	N/A	N/A	N/A

N/A = Non Applicable

Source: Decision Analysis Corporation of Virginia, and Energy and Environment Analysis, *Changes to the Fuel Economy Module for Alternative-Fuel Vehicles*, Final Report, Subtask 12-3, prepared for the Energy Information Administration (EIA), (October 30, 1995).

Table 20. Standard 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	0.0 20	160	0.00	0	-0.08	1985	0
Unit Body	0.060	80	0.00	0	-0.05	1995	0
Material Substitution II	0.033	0	0.60	0	-0.05	1996	0
Material Substitution III	0.066	0	0.80	0	-0.10	2006	0
Material Substitution IV	0.099	0	1.00	0	-0.15	2016	0
Material Substitution V	0.132	0	1.50	0	-0.20	2026	0
Drag Reduction II	0.023	32	0.00	0	0.00	1990	0
Drag Reduction III	0.046	64	0.00	0	0.05	1997	0
Drag Reduction IV	0.069	112	0.00	0	0.01	2007	0
Drag Reduction V	0.092	176	0.00	0	0.02	2017	0
TCLU	0.030	40	0.00	0	0.00	1980	0
4-Speed Automatic	0.045	225	0.00	30	0.00	1980	0.05
5-Speed Automatic	0.065	325	0.00	40	0.00	1997	0.07
CVT	0.100	250	0.00	20	0.00	2005	0.07
6-Speed Manual	0.020	100	0.00	30	0.00	1997	0.05
Electronic Transmission I	0.005	20	0.00	5	0.00	1991	0
Electronic Transmission II	0.015	40	0.00	5	0.00	2006	0
Roller Cam	0.020	16	0.00	0	0.00	1986	0
OHC 4	0.030	100	0.00	0	0.00	1980	0.15
OHC 6	0.030	140	0.00	0	0.00	1985	0.15
OHC 8	0.030	170	0.00	0	0.00	1995	0.15
4C/4V	0.060	240	0.00	30	0.00	1990	0.30
6C/4V	0.060	320	0.00	45	0.00	1990	0.30
8C/4V	0.060	400	0.00	60	0.00	2002	0.30
Cylinder Reduction	0.030	-100	0.00	-150	0.00	1990	-0.1
4C/5V	0.080	300	0.00	45	0.00	1997	0.55
Turbo	0.050	800	0.00	80	0.00	1980	0.45
Engine Friction Reduction I	0.020	20	0.00	0	0.00	1991	0
Engine Friction Reduction II	0.035	50	0.00	0	0.00	2002	0
Engine Friction Reduction III	0.050	90	0.00	0	0.00	2012	0
Engine Friction Reduction IV	0.065	140	0.00	0	0.00	2022	0
VVT I	0.080	140	0.00	40	0.00	2006	0.1
VVT II	0.100	180	0.00	40	0.00	2016	0.15
Lean Burn	0.100	150	0.00	0	0.00	2018	0
Two Stroke	0.150	150	0.00	-150	0.00	2008	0
TBI	0.020	40	0.00	0	0.00	1985	0.05
MPI	0.035	80	0.00	0	0.00	1985	0.1
Air Pump	0.010	0	0.00	-10	0.00	1985	0
DFS	0.015	15	0.00	0	0.00	1985	0.1
Oil %w-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	1997	0
ACC II	0.010	30	0.00	0	0.00	2007	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	1992	0
Emissions Tier I	-0.010	150	0.00	10	0.00	1996	0
Emissions Tier II	-0.010	300	0.00	20	0.00	2004	0
ABS	-0.005	300	0.00	10	0.00	1990	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.	-0.033	0	0.00	0	0.05	1991	0
Compression Ratio Increase	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Idle Off	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Optimized Manual Transmission	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variable Displacement	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Electric Hybrid	N/A	N/A	N/A	N/A	N/A	N/A	N/A

N/A = Non Applicable

Source: Decision Analysis Corporation of Virginia, and Energy and Environment Analysis, *Changes to the Fuel Economy Module for Alternative-Fuel Vehicles*, Final Report, Subtask 12-3, prepared for the Energy Information Administration (EIA), (October 30, 1995).

The fuel economy module utilizes 56 new technologies for each size class and origin of manufacturer (domestic or foreign) based on the cost-effectiveness of each technology and an initial availability year. The discounted stream 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.

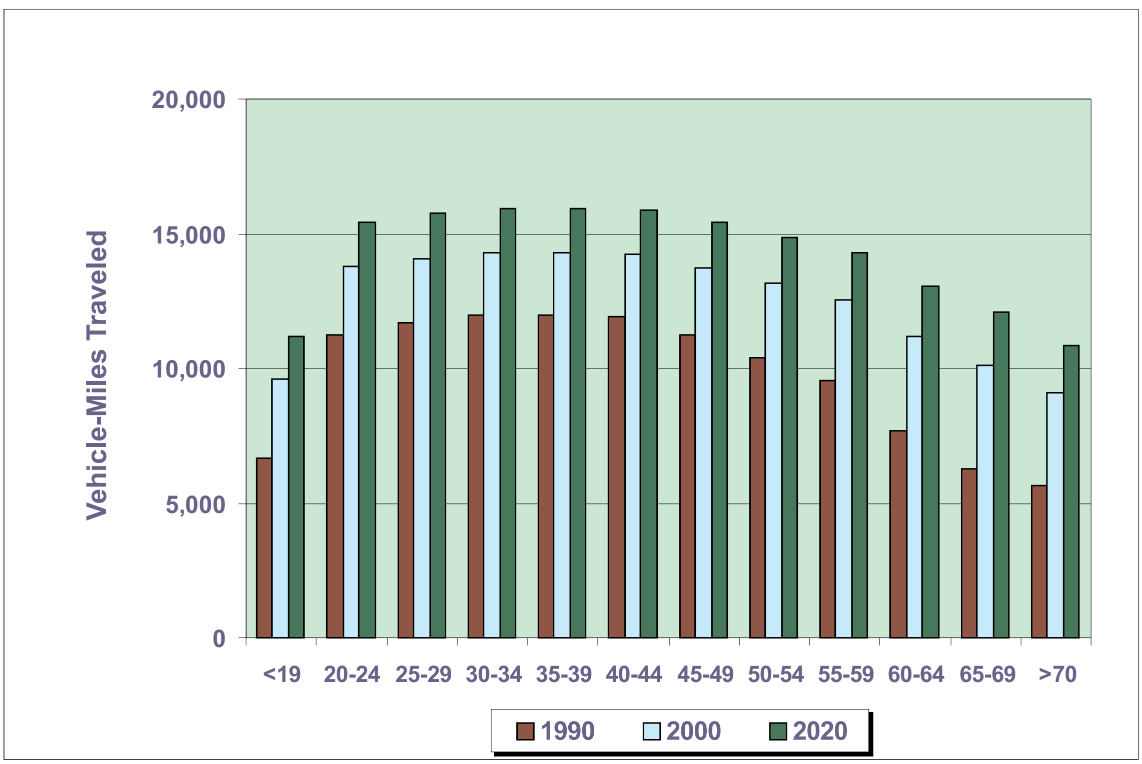
- The real discount rate remains steady at 8 percent.

- Corporate Average Fuel Efficiency standards remain constant at 1996 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 21) 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.[29,30,31,32] Degradation factors are also adjusted to reflect the percentage of reformulated gasoline consumed. 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 (Figures 4 and 5). The ratio of female to male VMT is assumed to asymptotically approach 100 percent by 2010 as compared to *AEO97* which was assumed to approach 80 percent by 2010. VMT per driver by age group was also assumed to be more uniformly distrubuted to younger and older age groups. *AEO98* assumed that all age group VMT per driver approaches one-half of the difference between itself and the maximum VMT per driver age category. Total VMT is calibrated to Federal Highway Administration VMT data [32,33]

Figure 4. VMT per Driver by Age Group
(Under New Demographic Formulation)



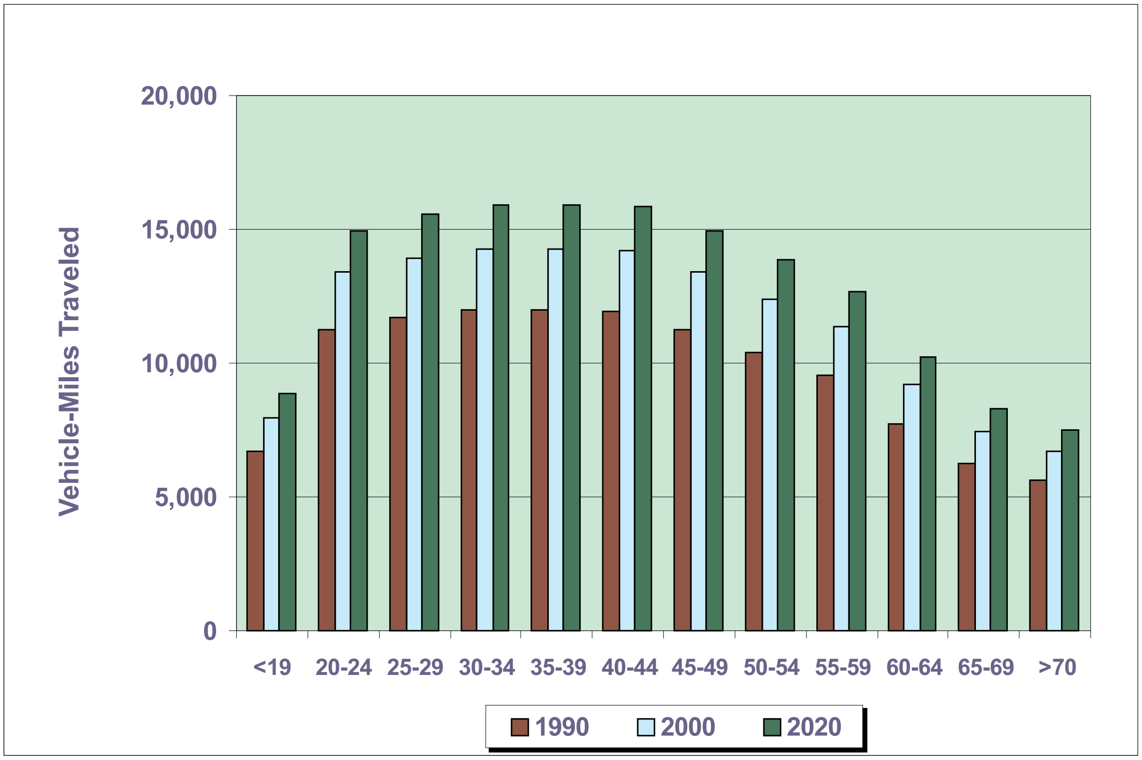
Source: 1990 values: U.S. Dept. of Transportation, *1990 National Personal Transportation Survey*, Washington D.C. February 1995; Forecast: EIA, *AEO98* National Energy Modeling System run: aeo98b.d100197a.

Table 21. Car and Light Truck Degradation Factors

	1995	2000	2005	2010	2015	2020
Cars	0.866	0.856	0.850	0.841	0.840	0.840
Light Trucks	0.815	0.805	0.799	0.789	0.789	0.789

1995-2020: Energy Information Administration, *AEO98* National Energy Modeling System run: aeo98b.d100197a.

Figure 5. VMT per Driver by Age Group
(Under Old Demographic Formulation)



Source: 1990 values: U.S. Dept. of Transportation, *1990 National Personal Transportation Survey*, Washington D.C. February 1995; Forecast: EIA, *AEO98* National Energy Modeling System run: aeo98b.d100197a.

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 22).

Table 22. 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).

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 and the Low Emission Vehicle Program.[36,37,38,39] Size class sales of alternative-fuel and conventional vehicles are held constant at anticipated levels (Table 23).[40] 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 applied from EIA surveys[34,35] (Table 24).

Table 23. 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 24. Anticipated Purchases of Alternative-Fuel Vehicles by Fleet Type and Technology Type
(Percentage)

AFV Technology	Business	Government	Utility
Ethanol	0.02	3.06	0.00
Methanol	1.62	21.98	3.37
Electric	0.90	0.19	3.10
CNG	9.46	58.73	66.94
LPG	88.00	16.04	26.58

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 1995, DOE/EIA-0585(95), (Washington, DC, December1996).*

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 three size classes.

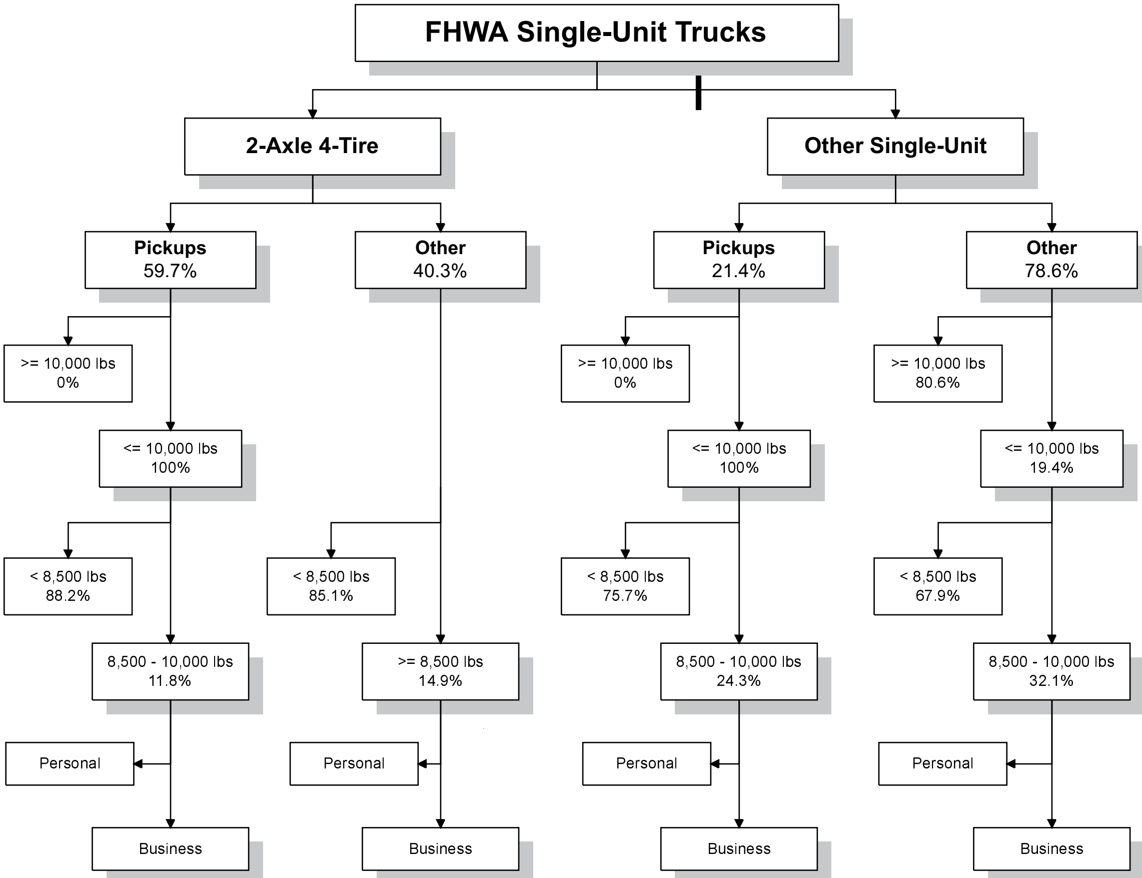
The Light Commercial Truck Module

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 6). 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 7). Finally, the TIUS microdata set is used to construct a characterization of these Light Commercial Trucks, comprising 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 25 and 26). 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.

Over the forecast period 1996-2020 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 of light-duty trucks (<8500 lbs.).

Figure 6. Distribution of FHWA Single-Unit Truck Stocks



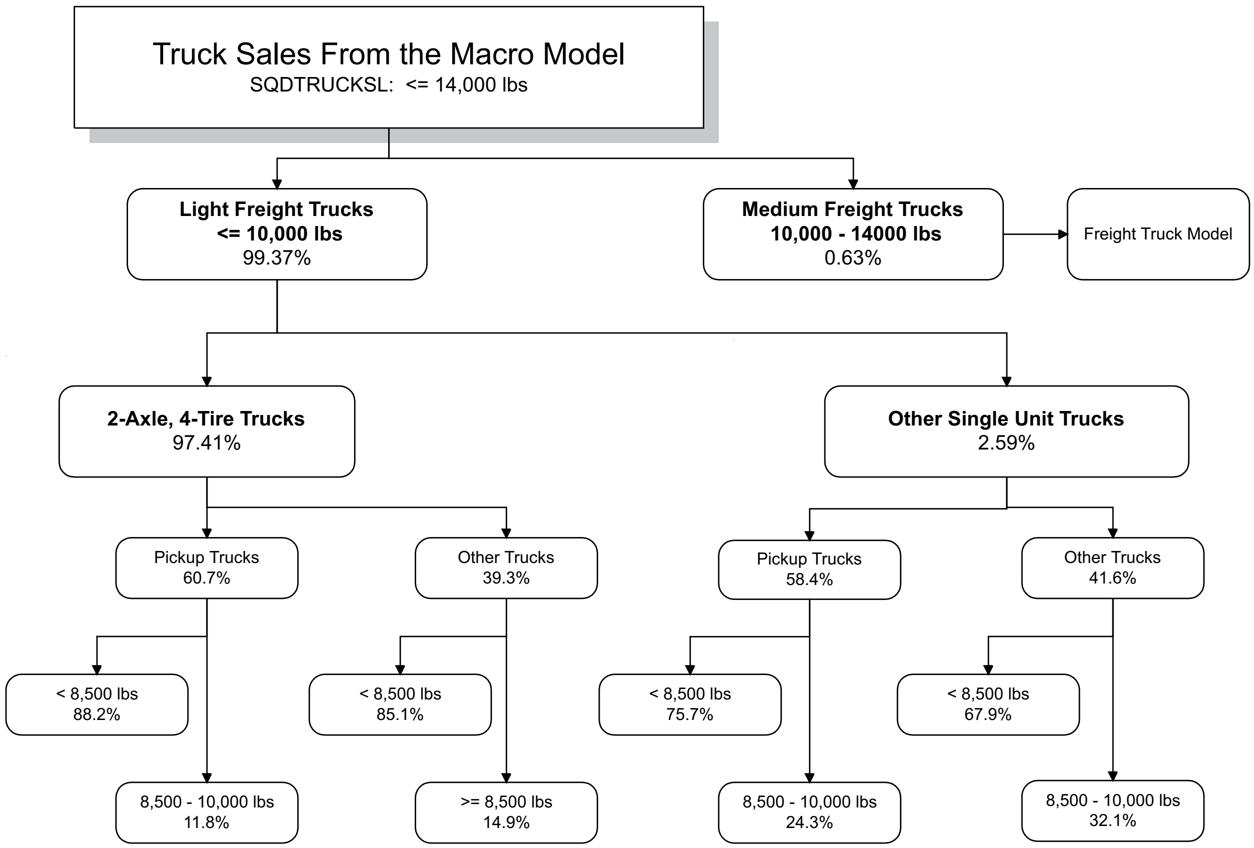
Source: U.S. Dept. Of Transportation, Federal Highway Administration, Highway Statistics 1995, Nov. 1996; U.S. Dept. Of Commerce, Bureau of the Census, Truck Inventory and Use Survey 1992, TC-92-T-52, (Washington DC., May 1995).

Table 25. Anticipated Annual Miles, by Major Use (1992 TIUS) (Aggregated for NEMS)

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: 1992 TIUS- 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, TC-92-T-52, (Washington DC., May 1995).

Figure 7. 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, TC-92-T-52, (Washington DC., May 1995).

Table 26. Average Miles Per Gallon: Biweighted Mean Iterated

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: 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

The alternative-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), diesel ICE, ethanol flex, ethanol neat, methanol flex, methanol neat, electric dedicated (uses only electricity), electric hybrid with small ICE, compressed natural gas (CNG), CNG bi-fuel, LPG, LPG bi-fuel, gas turbine gasoline, gas turbine CNG, fuel cell methanol, and fuel cell liquid hydrogen.

Listed in Table 27 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, vehicle price and vehicle range, all other attributes are exogenously set, based on offline analysis.[41,42,43]

Table 27. Alternative-Fuel Vehicle Attribute Inputs For Three Stage Logit Model

Small Vehicle Size Class	Year	Gasoline	Ethanol Flex	Methanol Flex	CNG	Electric Vehicle Hybrid	Dedicated Electric Vehicle
Vehicle Price (thousand 1990 dollars)	1995	12.80	14.24	14.23	17.41	31.58[1]	22.16[1]
	2015	14.48	15.64	15.93	18.84	14.82[1]	18.13[1]
Vehicle MPG (miles/gallon)	1995	30.41	27.62	27.88	27.59	39.14	34.67
	2015	37.38	32.47	32.71	33.46	42.63	59.10
Vehicle Range (100 miles)	1995	3.09	3.09	2.50	2.99	3.09	0.80
	2015	3.09	3.09	2.98	3.09	3.09	0.80
Fuel Availability Relative to Gasoline	1995	1.00	1.00	1.00	0.02	0.05	0.05
	2015	1.00	1.00	1.00	0.22	1.00	1.00
Commercial Availability Indexed To Gasoline	1995	1.00	0.007	0.007	0.001	0.000	0.007
	2015	1.00	0.999	0.999	0.993	0.999	0.999

[1]Electric vehicle battery replacement cost included.

CNG = Compressed natural gas.

MPG = Miles per gallon.

Sources: Vehicle prices, fuel efficiency, and range: Decision Analysis Corporation of Virginia, and Energy and Environmental Analysis, *Changes to the Fuel Economy Module for Alternative-Fuel Vehicles*, Final Report, Subtask 12-3, Prepared for EIA, (October 1995).

Fuel and Commercial availability: Department of Energy, Office of Transportation Technologies and Energy Efficiency and Renewable Energy, *Alternative-Fuel Vehicle Model*, 1994.

Vehicle attributes vary by three size classes, and fuel availability varies by Census Division. It is assumed that the logit model coefficients can be used for both estimates for future sales shares of both cars and light trucks separately. 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 technologies 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 handled dependent upon the AFV technology type, cost, research and development, and availability over time. Commercial availability estimates are assumed values according to a logistic curve based on the initial technology introduction date and were constructed in cooperation with the Office of Energy Efficiency and Renewable Energy of the Department of Energy (DOE). Coefficients summarizing consumer valuation of vehicle attributes were derived from a stated preference survey conducted in California [44] and are assumed to be representative of the United States. Initial AFV vehicle stocks are set according to EIA surveys.[34,35]

AFV sales are also a function of the number of makes and models within a vehicle size class.[45] Conventional vehicle offerings are held constant at 1994 levels.[46] Market-driven sales are assumed to begin in the year 2003, after the legislative AFV mandates have established necessary infrastructure for the private market.

Freight Truck Assumptions

The freight stock truck module converts industrial output in dollar terms to an equivalent measure of volume by using a freight adjustment coefficient. These freight truck adjustment coefficients vary by NEMS Standard Industrial Classification (SIC) code, gradually diminishing their deviation over time and are estimated from historical freight data. Freight truck load factors (ton-miles per truck) by SIC code are constants formulated from historical load[47,48] factors.[49] All freight trucks are subdivided into medium, and heavy-duty trucks. Freight truck fuel efficiency growth rates relative to fuel prices are tied to historical growth rates by size class and are also dependent on the maximum penetration, introduction year, fuel trigger price (based on cost-effectiveness), and fuel economy improvement of the technologies including alternative fuel technologies (Table 28).[49] 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 according to the *State Energy Data Report* distillate regional shares.[50]

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

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. Freight rail adjustment coefficients, which are used to convert dollars into volume equivalents, remain constant and are based on historical data.[47,51] Initial freight rail efficiencies are based on the freight model from Argonne National Laboratory.[52] The distribution of rail fuel consumption by fuel type remains constant and is based on historical data (Table 28).[49] Regional freight rail consumption estimates are distributed according to the *State Energy Data Report 1994*.[50]

Table 28. Technology Characteristics for the Freight Truck Model
(Percent)

	Fuel Economy Improvement		Maximum Penetration		Introduction Year	Fuel Trigger Price ($1987 per MMBtu)
	Medium	Large	Medium	Large		
Existing Technologies						
Aerodynamic Features	5%	13%	40%	100%	n/a	n/a
Radial Tires	4%	1%	90%	100%	n/a	n/a
Axle or Drive Ratio to Maximize Fuel Economy	6%	10%	50%	100%	n/a	n/a
Fuel Economy Engine with Low RPM, Turbo Change, etc.	7%	9%	80%	100%	n/a	n/a
Variable Fan Drive	3%	5%	40%	100%	n/a	n/a
New Technologies						
Improved Tires & Lubricants	5%	5%	80%	80%	1992	$9.00
Electronic Engine Controls	4%	4%	70%	70%	1992	$9.00
Electronic Transmission Controls	4%	4%	75%	75%	1992	$9.00
Advanced Drag Reduction	n./a	25%	n/a	45%	2005	$9.25
Turbocompound Diesel Engine	n/a	10%	n/a	25%	2005	$9.50
Heat Engine-LE 55	n/a	50%	n/a	50%	2005	$10.25

Source: Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 15* (Oak Ridge, TN, May 1995).

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.[47] These freight adjustment coefficients are based on analysis of historical data[53] 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.[48] Regional domestic and international shipping consumption estimates are distributed according to the *State Energy Data Report* residual oil regional shares.

Air Travel Demand Assumptions

The air travel demand module calculates the ticket price for travel as a function of fuel cost. A demographic index based on the propensity to fly was introduced into the air travel demand equation.[54] The propensity to fly was made a function of the age and sex group distribution over the forecast period.[55,56] 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 calculated as a percentage of domestic revenue passenger miles based on an extrapolation of historical data, which asymptotically approaches 56 percent by 2020.[57] The revenue ton miles of air freights 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 occurs at a constant historical annual 1-percent rate.[58] 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.[58] 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.[59] Fuel efficiency of new aircraft acquisitions represents, at a minimum, a 5-percent improvement over the stock efficiency of surviving airplanes.[58] 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 (Table 29). 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.

Table 29. Future New Aircraft Technology Improvement List

Proposed Technology	Introduction Year	Jet Fuel Price Necessary For Cost-Effectiveness (1987 dollars per MBtu)	Seat-Miles per Gallon Gain Over 1990 (percent)	
			Narrow Body	Wide Body
Engines				
Ultra-high Bypass	1995	5.11	10	10
Propfan	2000	10.08	23	0
Aerodynamics				
Hybrid Laminar Flow	2020	11.34	15	15
Advanced Aerodynamics	2000	12.60	18	18
Other				
Weight Reducing Materials	2000	-	15	15
Thermodynamics	2010	9.04	20	20

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.

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 30). Although inclusion of the business fleet is dependent upon a rulemaking by the Secretary of Energy, the assumption is that fuel displacement goals set in EPACT can only be reached by inclusion of the business fleet. It is assumed that business fleet EPACT mandates do not take effect until the year 2002 based on the late mandated schedule of proposed rulemaking.

Because the commercial fleet model operates on three fleet type representations (business, government, and utility), the federal and state mandates were weighted by fleet vehicle stocks to create a composite mandate for both. The same combining methodology was used to create a composite mandate for electric utilities and fuel providers based on fleet vehicle stocks.[34,35] 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.[36,37] To account for the EPACT regulations which stipulate that "covered" fleets (which refers 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.[38] 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.[38]

Table 30. 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).

Table 31. EPACT Alternative-Fuel Fleet Sale Estimates

Vehicle Type	Fleet Type	1995	2000	2005	2010	2015
Automobiles	Government	0	57,065	73,572	73,990	75,470
	Business	0	0	77,376	76,132	76,251
	Fuel Provider	0	76,614	88,218	88,720	90,495
Light Trucks	Government	0	68,021	104,660	106,988	107,361
	Business	0	0	22,234	22,729	22,808
	Fuel Provider	0	19,304	23,738	24,266	24,351

Source: Energy Information Administration (EIA),*AEO98* National Energy Modeling System run: aeo98b.d100197a.

Low Emission Vehicle Program (LEVP)

The LEVP, which began in California, which was originally instituted in New York and Massachusetts, has now been rolled back to begin in 2003 at the original 10 percent mandate for California and Massachusetts. It is assumed that New York will retain the original LEVP mandates. The following Zero Emission Vehicle (ZEV) sales percentage numbers (Table 32) come from the California Air Resources Board.[60] All of the ULEV sales were assumed to meet the ULEV air standards with reformulated gasoline and a heated catalytic converter.

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.

Table 32. Original and Revised California Low Emission Vehicle Program Legislatively Mandated Alternative-Fuel Vehicle Sales (Percentage)

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.

Climate Change Action Plan

There were four programs implemented from the Climate Change Action Plan (CCAP) transportation policies — 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 2.35 percent in 2010, representing a decline in consumption of approximately 273 trillion Btu which increases to 3.47 percent VMT reduction by 2020. The fuel economy tire labeling program improved fuel efficiency by 4 percent among vehicles that switched to low rolling resistance tires, and resulted in a reduction in fuel consumption of 1 trillion Btu by 2010. Total reductions of carbon emissions from CCAP reach 5.3 million metric tons per year by 2010.

Advanced Technology and 1998 Technology Cases

In the advanced technology case, the light-duty vehicle assumptions are presented in Table 33 and are based on the yearly U.S. Department of Energy Office of Energy Efficiency and Renewables OTT Program Analysis. In the *advanced 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 7.3 percent lower (2.65 quadrillion Btu) than in the reference case by 2020.[61]

Table 33. Alternative-Fuel Large Car Vehicle Assumptions Relative to Conventional Gasoline Vehicle

Technology	Year of Introduction	Year of Maturity	Vehicle Cost Ratio	Fuel Economy Ratio	Relative Vehicle Range
Advanced Diesel	2007	2012	Intro: 1.1 Mat.:1.05	Intro: 1.3 Mat.: 1.3	Intro: 1.0 Mat.: 1.0
Hybrid	2005	2010	Intro: 1.3 Mat.: 1.1	Intro: 1.5 Mat.: 1.75	Intro: 0.95 Mat.: 0.95
Fuel Cell	2009	2013	Intro: 1.4 Mat.: 1.2	Intro: 2.5 Mat.: 2.5	Intro: 0.8 Mat.: 0.8
Natural Gas	1998	2002	Intro: 1.2 Mat.: 1.07	Intro: 1.0 Mat.: 1.0	Intro: 0.75 Mat.: 0.75
Flex Alcohol	2005	2005	Intro: 1.0 Mat.: 1.0	Intro: 1.08 Mat.: 1.08	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 98,* June 17, 1997.

The *1998 technology case* assumes that new fuel efficiency technologies are held constant at 1998 levels over the forecast. As a result, the energy use in the transportation sector was 3.7 percent higher (1.35 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 *advanced technology case* were constructed in accordance with the asssumptions from a Department of Energy (DOE) interlab study.[62] The following technologies were made commercially available within the forecast period: advanced drag reduction, turbocompound diesel engine, heat engine CLE-55, and reduced empty weight technologies. Additionally, shorter market penetration periods, and technology prices were made cost-effective at $6/MMBtu for diesel fuel, instead of the range of $8-10.50/MMBtu in the *AEO98* reference case.

The air model assumptions for the *advanced technology case* were also constructed to replicate the assumptions in the DOE interlab study. Aircraft load factors were increased to 70% for domestic and international travel. Efficiency improvements were approximately 40% higher than the 1996 levels for new aircraft by 2020, which is the equivalent of a 1.3% annual growth rate.

Table 34. 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	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	0.30	0	-0.05	1987	0
Material Substitution III	0.066	0	0.40	0	-0.10	1997	0
Material Substitution IV	0.099	0	0.50	0	-0.15	2003	0
Material Substitution V	0.132	0	0.75	0	-0.20	2007	0
Drag Reduction II	0.023	32	0.00	0	0.00	1985	0
Drag Reduction III	0.046	64	0.00	0	0.05	1991	0
Drag Reduction IV	0.069	112	0.00	0	0.01	1997	0
Drag Reduction V	0.092	176	0.00	0	0.02	2003	0
TCLU	0.030	40	0.00	0	0.00	1980	0
4-Speed Automatic	0.045	225	0.00	30	0.00	1980	0.05
5-Speed Automatic	0.065	325	0.00	40	0.00	1995	0.07
CVT	0.100	250	0.00	20	0.00	1995	0.07
6-Speed Manual	0.020	100	0.00	30	0.00	1991	0.05
Electronic Transmission I	0.005	20	0.00	5	0.00	1988	0
Electronic Transmission II	0.090	60	0.00	5	0.00	1998	0
Roller Cam	0.020	16	0.00	0	0.00	1987	0
OHC 4	0.030	45	0.00	0	0.00	1980	0.2
OHC 6	0.030	55	0.00	0	0.00	1980	0.2
OHC 8	0.030	65	0.00	0	0.00	1980	0.2
4C/4V	0.080	125	0.00	30	0.00	1988	0.45
6C/4V	0.080	165	0.00	45	0.00	1991	0.45
8C/4V	0.080	205	0.00	60	0.00	1991	0.45
Cylinder Reduction	0.030	-100	0.00	-150	0.00	1988	-0.1
4C/5V	0.100	300	0.00	45	0.00	1998	0.55
Turbo	0.080	300	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	120	0.00	0	0.00	2016	0
VVT I	0.080	100	0.00	40	0.00	1998	0.1
VVT II	0.100	130	0.00	40	0.00	2008	0.15
Lean Burn	0.120	75	0.00	0	0.00	2012	0
Two Stroke	0.150	0	0.00	-150	0.00	2004	0
TBI	0.020	40	0.00	0	0.00	1982	0.05
MPI	0.035	80	0.00	0	0.00	1987	0.1
Air Pump	0.010	0	0.00	-10	0.00	1982	0
DFS	0.015	15	0.00	0	0.00	1987	0.1
Oil %w-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	5	0.00	0	0.00	1992	0
Tires II	0.033	10	0.00	0	0.00	2002	0
Tires III	0.048	15	0.00	0	0.00	2012	0
Tires IV	0.053	20	0.00	0	0.00	2018	0
ACC I	0.010	5	0.00	0	0.00	1992	0
ACC II	0.017	13	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.	-0.033	0	0.00	0	0.05	1991	0
Compression Ratio Increase	0.010	0	0.00	0	0.00	1995	0.02
Idle Off	0.110	260	0.00	0	0.00	1997	0
Optimized Manual Transmission	0.120	60	0.00	0	0.00	1997	0
Variable Displacement	0.030	65	0.00	0	0.00	1999	0
Electric Hybrid	0.660	1785	0.00	0	0.00	2001	0

Source: Decision Analysis Corporation of Virginia, and Energy and Environmental Analysis, *NEMS Fuel Economy Model LDV High Technology Update, Final Documentation, Subtask, 9-2*, prepared for Energy Information Administration, (June 17, 1996).

Table 35. High Technology Matrix For Trucks

	Fractional Fuel Efficiency Change	Incremental Cost (1990 $)	Incremental Cost ($/Unit Wt.)	Incremental Weight (Lbs.)	Incremental Weight (Lbs./Unit Wt.)	First Year Introduced	Fractional Horsepower Change
Front Wheel Drive	0.020	160	0.00	0	-0.08	1985	0
Unit Body	0.060	80	0.00	0	-0.05	1995	0
Material Substitution II	0.033	0	0.30	0	-0.05	1987	0
Material Substitution III	0.066	0	0.40	0	-0.10	1997	0
Material Substitution IV	0.099	0	0.50	0	-0.15	2003	0
Material Substitution V	0.132	0	0.75	0	-0.20	2007	0
Drag Reduction II	0.023	32	0.00	0	0.00	1985	0
Drag Reduction III	0.046	64	0.00	0	0.05	1991	0
Drag Reduction IV	0.069	112	0.00	0	0.01	1997	0
Drag Reduction V	0.092	176	0.00	0	0.02	2003	0
TCLU	0.030	40	0.00	0	0.00	1980	0
4-Speed Automatic	0.045	225	0.00	30	0.00	1980	0.05
5-Speed Automatic	0.065	325	0.00	40	0.00	1995	0.07
CVT	0.100	250	0.00	20	0.00	1995	0.07
6-Speed Manual	0.020	100	0.00	30	0.00	1991	0.05
Electronic Transmission I	0.005	20	0.00	5	0.00	1988	0
Electronic Transmission II	0.090	60	0.00	5	0.00	1998	0
Roller Cam	0.020	16	0.00	0	0.00	1987	0
OHC 4	0.030	45	0.00	0	0.00	1980	0.2
OHC 6	0.030	55	0.00	0	0.00	1980	0.2
OHC 8	0.030	65	0.00	0	0.00	1980	0.2
4C/4V	0.080	125	0.00	30	0.00	1988	0.45
6C/4V	0.080	165	0.00	45	0.00	1991	0.45
8C/4V	0.080	205	0.00	60	0.00	1991	0.45
Cylinder Reduction	0.030	-100	0.00	-150	0.00	1988	-0.1
4C/5V	0.100	300	0.00	45	0.00	1998	0.55
Turbo	0.080	300	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	120	0.00	0	0.00	2016	0
VVT I	0.080	100	0.00	40	0.00	1998	0.1
VVT II	0.120	130	0.00	40	0.00	2008	0.15
Lean Burn	0.100	75	0.00	0	0.00	2012	0
Two Stroke	0.150	0	0.00	-150	0.00	2004	0
TBI	0.020	40	0.00	0	0.00	1982	0.05
MPI	0.035	80	0.00	0	0.00	1987	0.1
Air Pump	0.010	0	0.00	-10	0.00	1982	0
DFS	0.015	15	0.00	0	0.00	1987	0.1
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	5	0.00	0	0.00	1992	0
Tires II	0.033	10	0.00	0	0.00	2002	0
Tires III	0.048	15	0.00	0	0.00	2012	0
Tires IV	0.053	20	0.00	0	0.00	2018	0
ACC I	0.040	5	0.00	0	0.00	1992	0
ACC II	0.017	13	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.	-0.033	0	0.00	0	0.05	1991	0
Compression Ratio Increase	0.010	0	0.00	0	0.00	1995	0.02
Idle Off	0.110	260	0.00	0	0.00	1997	0
Optimized Manual Transmission	0.120	60	0.00	0	0.00	1997	0
Variable Displacement	0.030	65	0.00	0	0.00	1999	0
Electric Hybrid	0.660	1785	0.00	0	0.00	2001	0

Source: Decision Analysis Corporation of Virginia, and Energy and Enviromental Analysis, *Changes to the Fuel Economy Module for Alternative-Fuel Vehicles*, Final Report, Subtask 12-3, prepared for Energy Information Administration (EIA), (October 30, 1995).

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Electricity Market Module

The NEMS Electricity Market Module (EMM) represents the planning, operations, and pricing of electricity in the United States. It is composed of four primary submodules — electricity capacity planning, electricity fuel dispatching, load and demand-side management, and electricity finance and pricing. In addition, nonutility generation and supply and electricity transmission and trade are represented in the planning and dispatching submodules.

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. The major assumptions are summarized below.

Key Assumptions

Capacity Types

Twenty-six capacity types are presented in the EMM (Table 36).

Table 36. 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
New High Sulfur Pulverized Coal with Wet Flue Gas Desulfurization
New Advanced Coal - Integrated Coal Gasification Combined Cycle
Oil/Gas Steam - Oil/Gas Steam Turbine
Combined Cycle - Conventional Gas/Oil Combined Cycle Combustion Turbine
New 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
Advanced Nuclear Advanced Light Under Reactor
Conventional Hydropower - Hydraulic Turbine
Pipeline Hydropower - Hydraulic Turbine
Pumped Storage - Hydraulic Turbine Reversible
Geothermal - Dual Flash
Geothermal - Binary
Municipal Solid Waste - Mass Burn
Biomass - Integrated Gasification Combined-Cycle
Solar Thermal - Central Receiver
Solar Photovoltaic - Fixed-Flat Plate
Wind

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

New Generating Plant Characteristics

The operational characteristics of new generating technologies are the most important inputs to the electricity capacity planning submodule. The key characteristics for these technologies are summarized in Table 37. These characteristics are used, in combination with fuel price foresight from the NEMS Integrating Module, to compare resource options when new capacity is needed. Heat rates for fossil-fueled technologies decline linearly between 1995 and 2010. The assumptions for nuclear technologies are described later in this section.

The overnight costs listed for each technology in Table 37 are the base costs estimated to build a plant in *Middletown, U.S.A*. Differences in plant costs due to regional distinctions are calculated by applying regional multipliers (Table 38 and 39) to the cost of labor, factory equipment, and site material for each new generating technology.

Table 37. Cost and Performance Characteristics of New Fossil and Nuclear Generating Technologies

Technology	Year Available	Size (mW)	Leadtime (Year)	First Electricity Date	Overnight Capital Costs[1] First-of-a-kind ($1996 per kW)	Overnight Capital Costs[1] Nth-of-a-kind ($1996 per kW)	Variable O&M (1996 Mills/ kWh)	Fixed O&M ($1996 per kW)	Heatrate First-of-a-kind (Btu/kWhr)	Heatrate Nth-of-a-kind (Btu/kWhr)
Pulverized Coal (95% Scrubber)	2000	400	4	2001	1,079	1,079	3.25	22.5	9,585	9,087
Advanced Coal (IGCC)	2000	380	4	2001	1,833	1,206	1.87	24.2	8,470	7,308
Oil/Gas Steam (Conventional)	1996	300	2	1998	991	991	0.5	30.0	9,500	9,500
Combined-Cycle (Conventional, F-Frame)	1998	250	3	2000	440	440	2.0	15.0	8,030	7,000
Combined-Cycle (Advanced, G-&H-Frame)	1999	400	3	2000	572	400	2.0	13.8	6,985	6,350
Combustion Turbine (Conventional)	1996	160	2	1999	325	325	5.0	4.0	11,900	10,600
Combustion Turbine (Advanced Turbine Sys.)	1998	120	2	1999	458	320	5.0	5.7	9,700	8,000
Fuel Cell (Molten Carbonate)	1998	10	2	2003	2,189	1,440	2.0	14.4	6,000	5,361
Nuclear (Evolutionary Adv. Reactor)	2005	1,300	5	2010	2,356	1,550	0.4	55.0	10,400	10,400
Biomass	2000	100	4	2002	2,243	1,476	5.2	43.0	8,911	8,224
Geothermal[2]	1996	50	4	1996	NA	2,025	0.0	95.7	32,391	N/A
Municipal Solid Waste[3]	1996	30	1	1995	6,403	5,289	5.4	0.0	16,000	16,000
Solar Thermal[4]	1999	100	3	2000	2,903	1,910[5]	0.0	46.0	N/A	N/A
Solar Photovoltaic	1999	5	2	1997	4,556	3,185[5]	0.0	9.7	N/A	N/A
Wind	1996	50	3	1997	1,235	965	0.0	25.6	N/A	N/A

[1]Overnight capital cost plus project contingencies.

[2]Because geothermal cost and performance parameters are specific for each of the 51 sites in the database, the value shown is an average for the capacity built in 2000.

[3]Because municipal solid waste (MSW) does not compete with other technologies in the model, these values are used only in calculating the average costs of electricity.

[4]Solar thermal is assumed to operate economically only in Electricity Market Module regions 2, 5, and 10-13, that is, West of the Mississippi River, because of its requirement for significant direct, normal insolation.

[5]Capital costs for solar technologies are net of (reduced by) the 10 percent investment tax credit.

O&M = Operation and maintenance.

Sources: Most 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 National Laboratories, with the following specific sources — **Solar Thermal**: California Energy Commission Memorandum, *Technology Characterization for ER94*, August 6, 1993. **Photovoltaic**: *Technical Assessment Guide-Electric Power Research Institute* (EPRI-TAG1993). **MSW**: EPRI-TAG 1993.

Table 38. Regional Multipliers for New Construction, Fossil-Fueled and Nuclear Generating Technologies

EMM Region	NE, NY	MAAC	STV	MAPP, ECAR MAIN	SPP
Factory Equipment	1.09	1.01	0.95	1.01	1.03
Site Labor	1.33	0.97	0.69	1.03	0.98
Site Material	1.08	0.97	0.93	1.00	1.00
EMM Region	**RA**	**NWP**	**FL**	**CNY**	**ERCOT**
Factory Equipment	1.05	0.99	0.90	1.01	1.02
Site Labor	1.02	1.20	0.70	1.45	0.89
Site Material	1.03	1.00	0.80	1.01	0.98

Note: See Part II, Detailed Tables, Tables 54 through 66 for regional descriptions. Source: Argonne National Laboratory, *Cost and Performance Database for Electric Power Generating Technologies*.

Table 39. Regional Multipliers for New Construction, Renewable Energy Technologies

EMM	Number/Region	Multiplier
1	ECAR	1.01;
2	ERCOT	1.00; 0.98 for MSW
3	MAAC	1.00; 0.99 for MSW
4	MAIN	1.01
5	MAPP	1.01
6	NY	1.12; 1.16 for MSW
7	NE	1.12; 1.16 for MSW
8	FL	0.86; 0.83 for MSW
9	STV	0.91; 0.87 for MSW
10	SPP	1.02; 1.01 for MSW
11	NWP	1.02; 1.00 for geothermal; 1.05 for MSW
12	RA	1.04; 1.00 for geothermal
13	CNV	1.07; 1.00 for geothermal; 1.13 for MSW

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

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 nine different time slices (Table 40). The time periods shown were mainly 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 EMM region. Fifteen percent reserve margins are assumed for NWP and NY, fourteen percent for CNV and RA, and thirteen percent for ECAR, ERCOT, MAAC, MAIN, MAPP, SPP and STV, eight percent for NE, and four percent for FL.

Table 40. Load Segments for 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
Offpeak	April-May	Daytime	0700-1700
	October-November	Morning/Evening	0500-0700, 1700-2400
		Night	0000-0500

Note: Both 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.

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

Fossil Fuel-Fired Steam Plant Life Extension/Retirement

Fossil-fired steam plant retirements are calculated exogenously to the model. Plants where the total operational costs (fuel and operation and maintenance costs) exceed 4 cents per kilowatt-hour are marked for retirement. These plants are then ranked in order from the highest to lowest operational costs and retired in equal numbers of plants into the next decade.

Approximately 127 gigawatts of total capacity are retired from 1996 through 2020, of which 75 gigawatts are fossil plants. These include 29 gigawatts of coal, 18 gigawatts of oil, 28 gigawatts of gas, and 52 gigawatts of nuclear retirements. No retirement of nonutility units are assumed.

Table 41. Capital Cost of Life Extension
(1987 Dollars per Kilowatt)

Fuel Type	Cost
Coal	216
Gas	112
Oil	146

Source: Energy Information Administration, *Estimating the Capital Cost of Life Extension for Fossil-Fuel Steam Plants*, DOE/EIA-0509, (Washington, DC, July 1988).

Nuclear Power Plant Orders and Retirements

There are no nuclear units actively under construction in the United States, and the *AEO98* does not assume any new units become operational in the forecast period.

The licensing status as of year end 1996 defines unit operating life. This information includes the recoupment of construction time for those plants whose licenses have been redefined by the Nuclear Regulatory Commission. The majority of nuclear units are assumed to operate until the expiration of their license. However, recent experience has indicated that utilities will retire units before their license expiration date for a variety of reasons, including either operating costs or costs to refurbish the unit that are excessively high. Therefore, the *AEO98* assumes that 24 currently operating reactors will retire before their licenses expire. The units chosen to retire early are among the first generation of plants to come on line, and generally have high operating costs, or have not made equipment repairs, such as steam generator replacement, which are likely to be required for extended operation. The early retirement dates vary from two to ten years before the license expiration date. A total of 52 gigawatts of nuclear capacity are retired through 2020.

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 on the April 1995, *Coordinated Bulk Power Supply Program Report*, (DOE Form OE-411). Known firm power contracts are locked in for the term of the contract. 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. The price for the economy transactions is assumed to be set by splitting the difference between the exporting and importing region's marginal generation costs.

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 regional publications of the *Coordinated Bulk Power Supply Program Report*, (DOE Form OE-411). 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 1993-2010*.

Electricity Finance and Pricing

The reference case assumes a transition to competitive pricing in California, New York, and the New England states. Although other states such as Pennsylvania, New Jersey, Oklahoma, Wisconsin, and Montana have decided to allow consumers to choose their electricity suppliers, the regional configuration of these suppliers assumed in the reference case prevents representation of competitive markets in the regions in which these states are located. Nevertheless, the reference case assumes that: in California, the price of electricity will remain constant between 1996 and 2001 for commercial and industrial consumers while residential customers will enjoy a 10 percent reduction in current prices by 1998; the market will transition from a regulated to a competitive market between 2002 and 2007; and California markets will be fully competitive by 2008. Similarly, in New York and New England the transition period is assumed to occur from 1998 through 2007 with full competitive pricing of electricity beginning in 2008.

The price of electricity to the consumer is comprised of the price of generation, transmission and distribution. 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 California, New York, and New England 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 operating costs, maintenance and general and administrative (G&A) costs, 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 three regions with a competitive generation market consists of the marginal cost of generation summed with the average costs of transmission and distribution.

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 beginning to show in utility operating data reported to the Federal Energy Regulatory Commission (FERC) and trends reflected there have been incorporated in the *AEO98*. The key trends are discussed below:

- Reduced General and Administrative Expenses (G&A) - Over the 1990 through 1994 period, utilities have reduced their employment by 65,000, a reduction of nearly 3 percent annually. This trend has been incorporated by reducing G&A expenditures at a rate of 2.5 percent annually over the next 10 years.

- Reduced Fossil Plant Operations Expenditures (O&M) - Again, over the 1990 through 1994 period, utility fossil plant operation and maintenance costs (all operating costs other than fuel) have been falling at a rate of nearly 3 percent annually. As with G&A, this trend has been incorporated by reducing fossil O&M expenditures at a rate of 2.5 percent annually over the next 10 years.

- Reduced Nuclear Operations and Maintenance Expenditures - In the *AEO98* nuclear O&M expenditures are reduced over time to reflect the impact of older more expensive plants retiring in the later years of the forecast. In 2020 nuclear capacity is 52 gigawatts below the 1996 level and nuclear O&M expenditures are reduced 5 percent to reflect this.

Demand-Side Management

Improvements in energy efficiency induced by growing energy prices, new appliance standards, and utility demand-side management programs are represented in the end-use demand models. Appliance choice decisions are a function of the relative costs and performance characteristics of a menu of technology options. In 1995 utilities reported spending over $2.42 billiion on demand-side management programs. These expenditures are expected to decrease slightly to over $2.25 billion by the year 2000.[63]

Fuel Price Expectations

Capacity planning decisions for the electric power industry are based on a lifecycle cost analysis over a 30-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.[64] 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 30 year period or until the cumulative decrease based on the annual one percent reduction equals or exceeds 0.75. If the cumulative increase equals or exceeds 0.75 then coal prices are assumed to remain constant from that year to the end of the 30 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 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 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 $6.00 per thousand cubic feet (1995 dollars) and 2000 trillion cubic feet, respectively. Gas hydrates are included in the resource base. The future annual production is assumed to be constant at the prior year's level.

The wellhead gas price equation is of the following form:

$$P_k = A * Q_k^{0.75} + B$$

where P is the wellhead price for year k, Q 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).

Externality Costs

Externality costs of 40.8, 27.73, 17.72, 15.45, 11.69, and 9.83 mills per kilowatthour (1987 dollars) for pulverized coal, advanced coal, gas combined-cycle, advanced gas combined-cycle, gas combustion turbine and steam-injected combustion turbine, respectively, were assumed for the California/Nevada (CNV) region. Externality costs for these respective technologies for the New York (NY) region are assumed to 8.28, 5.41, 3.62, 3.13, 2.13 and 1.79 mills per kilowatthour (1987 dollars). Four other states-Minnesota, Nevada, Oregon, and Wisconsin-also specify externality costs for new construction. However, these States are located in EMM regions that include States or parts of States with no externality costs. As a result, no externality costs were assumed for these multistate regions. The costs used for NY and CNV are based on values extracted from a bulletin board (EPRINET) originating from the Electric Power Research Institute.

Technological Optimism and Learning Factors

Overnight costs are calculated for each new generating technology by applying the regional cost multipliers from Table 38 to the base overnight cost in Table 37. For advanced generating technologies these costs are assumed to be fifth-of-a-kind costs (the overnight cost for the fifth unit constructed). Technological optimism factors (Table 42) are applied to the first-of-a-kind unit (the first unit constructed of that technology) and decrease linearly until the fifth unit is constructed. In addition, overnight costs for advanced generating technologies decrease by 10 percent for each doubling of capacity for the first through the fifth unit, decrease by 5 percent for each doubling of capacity for the sixth through the fortieth unit, and decrease by 2.5 percent for each doubling of capacity past the forty-first unit. In the case of conventional generating technologies, no technological optimism factors are applied. Construction costs as computed from the regional multipliers and the base overnight costs are assumed to be the cost per kilowatt for the first forty units constructed. Costs then decrease by 2.5 percent for each doubling of capacity for past forty units.

Table 42. Technological Optimism and Learning Factors for New Generating Technologies

Technology	Optimism Factor	Learning Factor Units 1 to 5	Learning Factor Units 6 to 40	Learning Factor Units 41 to...
Pulverized Coal (95% Scrubber)	1.00	0.025	0.025	0.025
Advanced Coal (IGCC)	1.19	0.100	0.050	0.025
Oil-Gas Steam (Conventional)	1.00	0.025	0.025	0.025
Combined-Cycle (Conventional, F-Frame)	1.00	0.025	0.025	0.025
Combined-Cycle (Advanced, G- & H-Frame)	1.12	0.100	0.050	0.025
Combustion Turbine (Conventional)	1.00	0.025	0.025	0.025
Combustion Turbine (Advanced Turbine Sys.)	1.12	0.100	0.050	0.025
Fuel Cell (Molten Carbonate)	1.19	0.100	0.050	0.025
Nuclear (Passive Safety PWR-AP600)	1.19	0.100	0.050	0.025
Biomass	1.19	0.100	0.050	0.025
Geothermal	N/A	0.100	0.050	0.025
Municipal Solid Waste	N/A	N/A	N/A	N/A
Solar Thermal	1.19	0.100	0.050	0.025
Solar Photovoltaic	1.12	0.100	0.050	0.025
Wind	1.00	0.100	0.050	0.025

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

In *AEO98*, 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 reducd weight or not included in the learning effects calculation.

International learning effects (reduced value) this year include 1,229 megawatts advanced combined cycle, 88 megawatts advanced combustion turbine, 101 megawatts geothermal, 48 megawatts wind, and 2 megawatts biomass integrated combined cycle capacity in operation, under construction, or under contract for construction outside the United States. Table 43 shows identified offshore units contributing to U.S. learning in *AEO98*; weights reducing the capacity for U.S. learning effects are displayed in the table 43.[65]

Table 43. Current and Planned International Generating Capacity, New Technologies, as of May 1, 1997

New Technology	Plant Name	Country	Unweighted Net Summer Capability	Year Online	Weight
Current Capacity					
Advanced Clean Coal (Gasification)	--	--	--	--	--
Advanced Combined Cycle	--	--	--	--	--
Advanced Combustion Turbine	BIRR	Switzerland	265.0	1996	0.33
Molten Carbonate Fuel Cell	--	--	--	--	--
Nuclear (AP600)[1]	--	--	--	--	--
Solar Thermal (Grid-Connected)	--	--	--	--	--
Solar Photovoltaic (Grid-Connected)	--	--	--	--	--
Wind	Miyako Island	Japan	1.2	1996	0.5
	Moerdijk	Neitherlands	4.0	1996	0.5
Geothermal	Malitbog 1	Philippines	72.0	1996	0.165[2]
Biomass Integrated Combined Cycle	Varmamo	Sweden	6.0	1993	0.33
Planned Capacity					
Advanced Clean Coal (Gasification)	--	--	--	--	--
Advanced Combined Cycle	Rocksavage	United Kingdom	720	1997	0.33
	T Point	Japan	330	1997	0.50
	Poryong	South Korea	2,020	1997	0.165
	RDK4S	Germany	360	1998	0.33
	Taranaki	New Zealand	360	1998	0.33
	Dock Sud	Argentina	775	1999	0.33
Advanced Combustion Turbine	--	--	--	--	--
Molten Carbonate Fuel Cell	--	--	--	--	--
Nuclear (AP600)[1]	--	--	--	--	--
Solar Thermal (Grid-Connected)	--	--	--	--	--
Solar Photovoltaic (Grid-Connected)	Two unnamed sites	India	0.20	1998	0.50
Wind	Tetouan	Morocco	50.4	1997	0.5
	Huitengxile	China	5.4	1998	0.5
	Carrickbrock	Ireland	15.0	1998	0.5

[1]Because of unique safety and other requirements imposed on U.S. equipment, no nuclear plants installed outside the United States are considered sufficiently equivalent to U.S. nuclear plants (AP600) to convey any significant learning effects.

[2]On the basis of information obtained from contacts with industry personnel, no currently operating geothermal units outside the United States are considered “new”; however, discovery and drilling techniques are improving, markets are competitive, and firms operating in the U.S. Market continue to be involved in all phases of international geothermal development. EIA assigns this limited learning a weight of 0.165.

[3]Because 483 megawatts are slated to enter service in 1997, and their weighted value (80.5 megawatts) exceeds one unit (50 megawatts), geothermal is credited with 50 megawatts for 1997.

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

Legislation

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 short tons of sulfur dioxide emissions by 2000. 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 $144 per kilowatt, in 1987 dollars, although the costs vary widely across the regions. It is also assumed that the market for trading emission allowances is allowed to operate without regulation and that the States do not further regulate the selection of coal to be used.

Utilities are assumed to comply with the mandates set forth in the CAAA90 with respect to the SO_2 and NO_x standards. It is assumed that utilities will comply with CAAA90 and reduce their emissions of sulfur dioxide (SO_2) by 10 million tons over the forecast period. Consequently, the forecast assumes that the cost associated with purchasing an SO_2 allowance (dollars per ton of SO_2) is equivalent to the marginal cost of compliance (dollars per ton of SO_2 removed).

As specified in the CAAA90, EPA has developed a two-phase NOx program, with the first set of standards taking force in 1996 while the second set is to be implemented in 2000 (Table 44). Dry bottom wall-fired, and tangential fired boilers, the most common boiler types, referred to as Group 1 Boilers, are 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 of between 25 and 50 percent to meet the Phase I limits and further reductions to meet their Phase II limits. Both Phase I and Phase II NO_x limits are incorporated in the NEMS.

Table 44. 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

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).

EPACT allows the issuance of a combined construction and operating license for nuclear plants; however, it also allows for a post-construction hearing and judicial review. The uncertainty associated with waste, regulatory, and financial issues is sufficiently large to require their resolution or some manner of financial protection for investors before investments in nuclear power would take place. Unresolved, these conditions would lead to investments in alternative capacity additions or a delay in capital investment. Therefore, no newly ordered nuclear plants are assumed to become operational by 2020.

EPACT reformed 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.[66] 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.

Climate Change Action Plan

As a result of the Climate Challenge Program (CCAP) many utilities have announced efforts to voluntarily reduce their greenhouse gas emissions between now and 2000. These efforts cover a wide variety of programs including increasing DSM investments, repowering (fuel-switching) of fossil plants, restarting of nuclear plants that have been out-of-service, planting trees, and purchasing emission offsets from international sources. To the degree possible, each one of the participation agreements was examined to determine if the commitments made were addressed in the normal reference case assumptions or whether they were addressable in NEMS. Programs like tree planting and emission offset purchasing are not addressable in NEMS. With regard to the other programs, they are, for the most part, captured in NEMS. For example, utilities annually report to EIA their plans (over the next 10 years) to bring a plant back on line, repower a plant, life extend a plant, cancel a previously planned plant, build a new plant, or switch fuel at a plant. Additionally, reduced transmission losses due to improved transformer efficiencies are incorporated. These data are inputs to NEMS. Thus, programs that would affect these areas are reflected in NEMS input data. However, because many of the agreements do not identify the specific plants where action is planned, it is not possible to determine which of the specified actions, together with their greenhouse gas emission savings, should be attributed to the Climate Challenge Program and which are just the result of normal business operations.

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

High Electricity Demand Case

The *high electricity demand case* assumes that electricity demand grows at 2.0 percent annually between 1996 and 2020, comparable to the annual growth rate of 1.8 percent between 1990 and 1996. In the reference case, electricity demand is projected to grow 1.4 percent annually between 1996 and 2020. No attempt was made to determine the changes necessary in the end-use sectors needed to result in the stronger demand growth.

The *high electricity demand case* is a partially integrated run, i.e., the Macroeconomic Activity, Petroleum Marketing, International Energy, and end-use demand modules use the reference case values and are not affected by the higher electricity demand growth. Conversely, the Oil and Gas, Natural Gas Transmission and Distribution, Coal Market, and Renewable Fuels Modules are allowed to interact with the EMM in the high electricity demand case.

Low and High Fossil Cases

The *low fossil case* assumes that no advanced generating technologies (integrated coal-gasification combined-cycle, advanced natural gas combined-cycle and turbines, and fuel cells) will come online during the projection period. Capital costs of conventional generating technologies are higher than those assumed in the reference case (Table 45). In the *high fossil case*, efficiencies of advanced generating technologies are higher than the reference case, while efficiencies of conventional technologies were the same as used in the reference case. Cost and performance parameters for advanced generating technologies in the *high fossil case* and for conventional technologies in the *low fossil case* were provided to EIA by the Office of Fossil Energy, Department of Energy (DOE).

Table 45. Cost and Performance Characteristics for Advanced Generating Technologies

Technology	Fifth-of-a-Kind Reference (1996$/kW)	First-of-a-Kind Reference (1996$/kW)	Overnight Costs			Heat Rate		
			Reference (1996$/kW)	High Fossil (1996$/kW)	Low Fossil (1996$/kW)	Reference (Btu/kWh)	High Fossil (Btu/kWh)	Low Fossil (Btu/kWh)
Pulverized Cell	$1,079	$1,079						
2000			$1,079	$1,079	$1,262	9,419	9,419	8,530
2005			$1,059	$1,065	$1,158	9,253	9,253	8,322
2010			$1,053	$1,056	$1,105	9,087	9,087	8,124
2015			$1,040	$1,044	$1,105	9,087	9,087	8,124
2020			$1,029	$1,040	$1,105	9,087	9,087	8,124
Integrated Coal Gasification Combined-Cycle	$1,206	$1,833						
2000			$1,644	$1,470	N/A	8,470	7,308	N/A
2005			$1,644	$1,287	N/A	7,889	7,064	N/A
2010			$1,644	$1,103	N/A	7,308	6,204	N/A
2015			$1,644	$1,051	N/A	7,308	5,249	N/A
2020			$1,644	$1,051	N/A	7,308	5,249	N/A
Conv. Comb.-Cycle	$440	$440						
2000			$299	$299	$403	7,687	7,687	6,985
2005			$297	$296	$403	7,343	7,343	6,985
2010			$296	$294	$403	7,000	7,000	6,985
2015			$296	$292	$403	7,000	7,000	6,985
2020			$295	$291	$403	7,000	7,000	6,985
Adv.Comb.-Cycle	$400	$572						
2000			$300	$411	N/A	6,927	5,884	N/A
2005			$261	$411	N/A	6,639	5,688	N/A
2010			$256	$375	N/A	6,350	5,538	N/A
2015			$253	$375	N/A	6,350	4,254	N/A
2020			$251	$375	N/A	6,350	4,254	N/A
Conv. Comb. Turbine	$325	$325						
2000			$437	$437	$567	11,467	11,467	9,596
2005			$431	$432	$567	11,033	11,033	9,596
2010			$431	$430	$567	10,600	10,600	9,596
2015			$431	$427	$567	10,600	10,600	9,596

Table 45. Cost and Performance Characteristics for Advanced Generating Technologies Generating Technologies (Cont'd.)

Technology	Fifth-of-a-Kind Reference (1996$/kW)	First-of-a-Kind Reference (1996$/kW)	Overnight Costs			Heat Rate		
			Reference (1996$/kW)	High Fossil (1996$/kW)	Low Fossil (1996$/kW)	Reference (Btu/kWh)	High Fossil (Btu/kWh)	Low Fossil (Btu/kWh)
2020			$431	$427	$567	10,600	10,600	9,596
Adv. Comb. Turbine	$320	$458						
2000			$442	$609	N/A	9,133	8,865	N/A
2005			$330	$556	N/A	8,567	8,699	N/A
2010			$324	$556	N/A	8,000	8,533	N/A
2015			$318	$529	N/A	8,000	8,500	N/A
2020			$315	$529	N/A	8,000	8,500	N/A
Fuel Cell	$1,440	$2,189						
2000			$2,185	$1,348	N/A	6,000	5,900	N/A
2005			$2,185	$1,348	N/A	5,681	5,900	N/A
2010			$2,185	$1,142	N/A	5,361	5,700	N/A
2015			$2,185	$1,029	N/A	5,361	4,900	N/A
2020			$2,185	$1,029	N/A	5,361	4,900	N/A

N/A = Not Applicable.

Source: *AEO98* National Energy Modeling System runs: aeo98b.d100197a,htecel.d100297a, ltecel.d100297a.

The *low and high fossil* runs are partially-integrated runs, i.e., the Macroeconomic Activity, Petroleum Market, International Energy, and end-use demand modules use the reference case values and are not effected 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

The *low and high nuclear cases* assume different nuclear retirement schedules. The l*ow nuclear case* assumes each unit retires 10 years before its license expires, while the *high nuclear case* assumes 10 additional years of operation after the reference case retirement date. These alternate cases model situations where either the majority of the plants retire early, or a substantial number of units renew their licenses. These cases do not attempt to pick which units will or will not perform in the future, but only to look at the aggregate effects on the electricity industry if nuclear units, on the average, have a longer or shorter lifetime than projected in the reference case.

The *high and low nuclear cases* are partially-integrated model runs, i.e., the Macroeconomic Activity, Petroleum Market, and International Energy modules use the reference case outputs 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.

High Renewables Case

For the *high renewables case*, EIA incorporates approximations of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy's August 1997, draft technology assumptions of lower capital and operating costs and higher efficiencies (capacity factors) for new renewable energy generating technologies than used in the reference case.[67] EIA also assumes that 305 megawatts geothermal capacity at the Geysers (California) expected to retire before 2020 will continue producing through 2020. Finally, EIA assumes that the share of landfill gas used for energy production rises to 50 percent by 2020, rather than to 40 percent, as assumed in the reference case. All other technologies and other NEMS modeling characteristics remain unchanged from the reference case.

Renewable Portfolio Standard Cases

Two cases were run in which a minimum level of nonhydroelectric renewable generation was required. In the first case, the minimum percentage of renewable generation (defined as generation from wind, biomass, geothermal, solar thermal, photovoltaic, and landfill gases divided by total sales multiplied by 100) increased from 2 percent to 5 percent over the period 2000 through 2020 inclusive. In the second case, the minimum percentage of renewable generation increased from 2 percent to 10 percent from 2000 to 2020 inclusive. Both cases were fully integrated runs, in which all the modules were used. As in the reference case, New York, California, and New England use marginal-cost-based pricing for electricity, while other regions were assumed to use the average cost methodology for electricity prices.

Competitive Pricing Cases

The three competitive pricing cases assume that all regions of the country will gradually move toward marginal-cost-based pricing, as discussed in the "Issues in Focus" section of the *Annual Energy Outlook 1998 (AEO98).* Competitive pricing is phased in over 10 years (1998-2007) by computing a weighted average of the traditional average-cost-based price and a price based on marginal costs. The weighting factor changes over time — initially weighting the average-cost-based price more heavily, then decreasing the weight over the phase-in period — until the price is based solely on marginal costs. Other than the pricing methodology, the reference competitive case is based on the assumptions of the *AEO98* reference case. The two additional competitive scenarios have assumptions corresponding to the rapid and slow technology cases developed for the oil and gas supply sector. These cases incorporate alternative assumptions about improvement in natural gas recovery and distribution technology, and they lead to different gas price projections. Therefore, the cases are referred to as the *low gas price competitive case* and the *high gas price competitive case*. All competitive pricing cases are fully integrated runs, allowing feedback between the demand and supply models.

[63] Form EIA-861, *Annual Electric Utility Report*, 1995.

[64] Energy Information Administration, *NEMS Integrating Module Documentation Report,* DOE/EIA-DOE/EIA-0581(96), (Washington, DC, May 1995).

[65] For additional information on international learning, see "*The Impact of International Learning on Technology Cost,*" in Energy Information Administration, Issues in Midterm Analysis and Forecasting 1997, DOE/EIA-0607(97) (Washington, DC, July 1997), pp 57-66.

[66] 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.

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

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(98), (Washington, DC, January 1998). 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 tight gas formations, Devonian 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 economically recoverable oil and gas resources and the assumed expansion of the resource target due to the development and penetration of new technology. Other major factors affecting the projection include 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 Economically Recoverable Resources and Technology

Domestic oil and gas economically recoverable resources[68] consist of proved reserves,[69] inferred reserves,[70] and undiscovered economically recoverable resources.[71] OGSM employs regional estimates that are derived by EIA staff using analysis from the United States Geological Survey (USGS) and the Minerals Management Service (MMS) of the Department of the Interior, and the National Petroleum Council.[72] Published estimates were adjusted to remove intervening reserve additions resulting in estimates consistent with beginning-of-year 1990.

The initial economically recoverable oil and gas resource volumes in both known and undiscovered fields are projected to increase through 2020 in all cases. Ultimate recovery from the initial stock of inferred reserves in all cases but the moderate technology resource case, is assumed to expand over the period of the forecast, exceeding the published estimates from the USGS and MMS. For the reference case, economically recoverable resources for currently undiscovered fields are assumed, with two exceptions, to increase by 2020 to the level of current technically recoverable volume estimates released by the USGS and MMS (Tables 46, 47, and 48). One exception is coalbed methane. Economically recoverable resources of coalbed methane in the reference case are assumed to increase 20 percent higher than the volume estimated by the USGS to be recoverable under existing technology. The other exception concerns economically recoverable resources in the shallow waters of the Gulf of Mexico. These resources in the reference case are assumed to achieve about 40 percent higher than the volume estimated by the MMS to be technically recoverable under existing technology. These adjustments to the USGS and MMS estimates are based on nontechnical considerations that support domestic supply growth to the levels necessary to meet projected demand levels.

Table 46. Crude Oil Economically Recoverable Resources
(Billion Barrels)

Crude Oil Resource Category	1990 Level	Reference		Slow Technologogical Progress		RapidTechnologogical Progress		Moderate Resource	
		2020 Level	Technology Improvement Rate	2020 Level	Technology Improvement Rate	2020 Level	Technology Improvement Rate	2020 Level	Technology Improvement Rate
Undiscovered	30.09	38.37	—	34.97	—	42.34	—	36.65	—
Onshore	17.42	22.05	0.8%	20.10	0.5%	24.56	1.2%	22.05	0.8%
Offshore	12.67	16.33	0.8%	14.87	0.5%	17.78	1.1%	14.60	0.5%
Deep (>200 meter W.D.)	4.96	5.64	0.4%	5.08	0.1%	6.21	0.7%	5.64	0.4%
Shallow (0-200 meter W.D.)	7.71	10.68	1.1%	9.79	0.8%	11.57	1.4%	8.96	0.5%
Inferred Reserves	51.75	52.74	—	52.74	—	52.74	—	51.75	—
EOR	12.70	12.70	—	12.70	—	12.70	—	12.70	—
Other Onshore	36.10	36.10	—	36.10	—	36.10	—	36.10	—
Offshore	2.95	3.93	—	3.93	—	3.93	—	2.95	—
Deep (>200 meter W.D.)	0.12	0.12	—	0.12	—	0.12	—	0.12	—
Shallow (0-200 meter W.D.)	2.83	3.82	1.0%	3.82	1.0%	3.82	1.0%	2.83	—
Total Lower 48 States Unproved	81.84	91.11	—	87.70	—	95.08	—	88.40	—
Alaska	10.53	10.53	—	10.53	—	10.53	—	10.53	—
Total U.S. Unproved	92.37	101.64	—	98.23	—	105.61	—	98.93	—
Proved Reserves	26.25	26.25	—	26.25	—	26.25	—	26.25	—
Total Crude Oil	118.62	127.89	—	124.48	—	131.86	—	125.18	—

[a]The 1990 levels of conventional inferred resources implicitly reflect some allowance for the future influence of technological innovation and penetration due to their methodological derivation. Further, the analytic method for enhanced oil recovery (EOR) does not readily yield 1990 resource estimates based on 1990 technology. Hence, the *AEO98* 1990 resource estimates for EOR that are based on 1990 technology also include additional resource recovery due to more advanced technology assumptions.

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

Table 47. Lower 48 Onshore Technically Recoverable Resources by Fuel (Under Existing Technology)
(Crude Oil; Billion Barrels; Natural Gas; Trillion cubic feet)

Undiscovered		Unconventional Gas	
Crude Oil	22.05	Tight Sands	306.26
Shallow Gas	70.09	Devonian	53.90
Deep Gas	97.16	Coalbed Methane	59.07

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

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-2005 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 increases 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 2005 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 $3.89 in 1996 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 $5.21, in 1996 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.

Table 48. Natural Gas Economically Recoverable Resources
(Trillion Cubic Feet)

Natural Gas Resource Category	1990 Level	Reference		Slow Technology Progress		Rapid Technology Progress		Moderate Resource	
		2020 Level	Technology Improvement Rate	2020 Level	Technology Improvement Rate	2020 Level	Technology Improvement Rate	2020 Level	Technology Improvement Rate
Nonassociated Gas									
Undiscovered	248.45	330.98	—	301.31	—	363.75	—	308.06	—
Onshore	126.20	167.25	—	151.89	—	185.65	—	167.25	—
Deep (>10,000 ft)	73.66	97.16	0.9%	87.44	0.6%	106.87	1.2%	97.16	0.9%
Shallow (0-10,000 ft)	52.54	70.09	1.0%	64.45	0.7%	78.77	1.4%	70.09	1.0%
Offshore	122.26	163.79	1.0%	149.41	0.7%	178.10	1.3%	140.81	0.5%
Deep (>200 meters W.D.)	35.92	44.41	0.7%	39.97	0.4%	48.85	1.0%	44.41	0.7%
Shallow (0-200 meters W.D)	86.34	119.32	1.1%	109.45	0.8%	129.25	1.4%	96.40	0.4%
Inferred Reserves	259.73	309.47	—	290.45	—	318.98	—	259.73	—
Onshore	219.58	257.13	—	238.11	—	278.83	—	219.58	—
Deep (>10,000 ft)	107.94	145.49	1.0%	126.47	0.5%	167.19	1.5%	107.94	—
Shallow (0-10,000 ft)	111.64	111.64	—	111.64	—	111.64	—	111.64	—
Offshore	40.15	52.34	—	52.34	—	52.34	—	40.15	—
Deep (>200 meters W.D.)	5.08	5.08	—	5.08	—	5.08	—	5.08	—
Shallow (0-200 (meters W.D.)	35.06	47.26	1.0%	47.26	1.0%	47.26	1.0%	35.06	—
Unconventional Gas Recovery	226.41	409.88	—	343.25	—	477.30	—	409.88	—
• Tight Gas	157.29	306.26	2.2%	257.41	1.7%	359.17	2.8%	306.26	2.2%
• Devonian	14.08	34.16	3.0%	23.36	1.7%	41.69	3.7%	34.16	3.0%
• Coalbed	55.04	69.45	0.8%	62.48	0.4%	76.44	1.1%	69.45	0.8%
Assc-Dissolved Gas	124.30	124.30	—	124.30	—	124.30	—	124.3	—

Table 48. Natural Gas Economically Recoverable Resources (Cont'd)
(Trillion Cubic Feet)

Natural Gas Resource Category	1990 Level	Reference 2020 Level	Reference Technology Improvement Rate	Slow Technoglogy Progress 2020 Level	Slow Technoglogy Progress Technology Improvement Rate	Rapid Technology Progress 2020 Level	Rapid Technology Progress Technology Improvement Rate	Moderate Resource 2020 Level	Moderate Resource Technology Improvement Rate
Total Lower 48 States Unproved	858.99	1,174.63	—	1,059.30	—	1,296.52	—	1,101.97	—
Alaska	11.46	11.46	—	11.46	—	11.46	—	11.46	—
Total U.S. Unproved	870.35	1,186.09	—	1,070.77	—	1,307.98	—	1,113.43	—
Proved Reserves	169.35	169.35	—	169.35	—	169.35	—	169.35	—
Total Natural Gas	1,039.70	1,355.44	—	1,240.12	—	1,477.33	—	1,282.78	—

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

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.

Projected SNG production from liquids is based on an econometrically derived equation, with the independent variable being the regional average market price for natural gas. SNG from the currently operating Great Plains Coal Gasification Plant is assumed to continue through 2008, at 57.67 billion cubic feet per year. In all cases, it is assumed that in midyear 2009 the Great Plains facility will stop producing natural gas when the current purchase contract expires and natural gas production is not economical. At that time, the facility is assumed to be more profitable. Other supplemental supplies are held at a constant level of 44.04 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.

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. U.S. import flows from Canada are determined endogenously within the model but are constrained by assumed pipeline capacities. Exogenously specified projections of pipeline import and export values from Canada and Mexico are shown in Table 49.

Table 49. U.S. Natural Gas Imports and Exports
(Billion Cubic Feet per Year)

Year	Canada Imports[1]	Canada Exports	Mexico Imports	Mexico Exports
2000	5,313	51	20	151
2005	5,313	51	20	157
2010	5,516	51	20	166
2015	5,920	51	20	171
2020	6,170	51	20	194

[1]Canadian "import" figures represent design capacity, not actual flow projections, because flows are not an assumption. Canadian import flows are determined endogenously within the model.

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

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

Canadian production and exports to the United States are determined endogenously within the model. Natural gas exports to Canada from the United States are assumed to be a constant 51 billion cubic feet in each projection year because this is the current level and there is no forecast for pipeline expansion for exports. The Canadian economically recoverable resource base estimate used in the model for the beginning of year 1990 is 304 trillion cubic feet for gas, derived from figures published by the National Energy Board. This quantity was assumed to increase at a rate of 2 percent each projection year to reflect improvements in and penetration of technology.

Annual U.S. exports of LNG were assumed to be a constant at 67.6 billion cubic feet in each projection year. LNG imports are determined endogenously within the model. The outlook for LNG imports was based on a 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 contracts with a responsible purchaser. LNG import capacity in 1996 is 0.3 trillion cubic feet. The outlook for LNG imports also includes an implicit assumption that no major operational or institutional difficulties arise that are not resolved expeditiously.

Currently, only two LNG import terminals are in operation: the Distrigas facility in Everett, Massachusetts, and the Trunkline facility in Lake Charles, Louisiana. The other two existing import terminals, at Cove Point, Maryland, and at Elba Island, Georgia, are not expected to reopen for tanker imports in the projection period.

Offshore Royalty Relief

The Outer Continental Shelf Deep Water Royalty Act (Public Law 104-58) gives the Secretary of Interior the authority to suspend royalty requirements on new production from qualifying leases and requires that royalty payments be waived on new leases sold in the five years following November 28, 1995. The volume of production on which no royalties are due is 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 exceeds $28 per barrel or natural gas exceeds $3.50 per million Btu, any production of crude oil or natural gas will be subject to royalties at the lease stipulated royalty rate.

Climate Change Action Plan

The natural gas production forecasts incorporate the expected results of the Climate Change Action Plan (CCAP) — Action Item 35, entitled *Launch Coalbed Methane Outreach Program*. Under Action Item 35, 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 50.

The annual production increases resulting (linear interpolations for interim year) from CCAP Action Item 35 are added to baseline forecasts of coalbed methane 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*.[73]

Table 50. Production from Mines Reached by CCAP Action Item 35

Year	Production (billion cubic feet)
1996	8.7
1997	13.9
1998	17.4
1999	17.4
2000	24.0
2005	26.1
2010	29.2
2015	33.4
2020	36.0

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

Rapid, Slow, and Moderate 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 theses cases, oil and natural gas reference case parameters for the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and growth in the undiscovered economic resource base were adjusted. The two cases were created by varying parameters that represent the effects of technological progress on U.S. drilling lease equipment, and operational cost from their statistically estimated values by one standard deviation (based on the standard error associated with each estimated parameter).

Statistically estimated values for U.S. finding rates were similarly varied (although additional transformations of these statistically estimated values, based on analyst judgment, were subsequently required prior to their use as parameters within the *AEO98* analytic framework). Parameters for growth in the U.S. undiscovered economic resource base (which are not statistically derived) were also varied, in proportion to the changes in the technological progress parameters affecting finding rates (reserves found per well). The specific variations in economically recoverable resources used in the analysis are shown in Tables 46 and 47.

Assumptions relating to natural gas trade with Canada were also adjusted. Similar to the United States, adjustments were made to costs, resources, and finding rates used in deriving the Canadian natural gas supply curves to reflect different rates of technological progress. Additionally, exogenously determined pipeline capacities at the U.S.-Canada border were adjusted to allow import volumes to change across the cases. Upper bounds on capacities were changed to give import volumes the same market share they achieved in the reference case.

All other parameters in the model were kept at their reference case values, including success rates, 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. Specific details by region and resource category are presented in the Supplementary Tables to the Annual Energy Outlook 1998, which are available to download from the EIA FTP site: ftp://ftp.eia.doe.gov/pub/forecasting/aeo98/sup98tables/.

A moderate technology resource case was created to isolate the sensitivity of the *AEO98* projections to a change in the assumed rate of expansion on the resources. The resource assumptions for this case vary from the reference case in two ways: (1) the initial inferred reserve resource is not expanded, and (2) the undiscovered economically recoverable resources in the shallow region of the Gulf of Mexico expand to the technically recoverable level, growing at roughly 0.1 percent per year. These assumptions result in Lower 48 unproved oil and gas resources given 2020 technology that are lower than the reference case values by 3.4 percent and 6.8 percent (Tables 46 and 48), respectively.

Table 51. Assumed Average Annual Rates of Technological Progress on Costs and Finding Rates
(Percent)

Category	Natural Gas			Crude Oil		
	Slow Technological Progress	Reference	Rapid Technological Progress	Slow Technological Progress	Reference	Rapid Technological Progress
Costs						
Drilling						
• Onshore	1.09	1.32	1.55	1.09	1.32	1.55
• Offshore	1.95	2.35	2.74	1,395	2.35	2.74
• Alaska	0.77	1.00	1.23	0.77	1.00	1.23
Lease Equipment						
• Onshore	0.99	1.26	1.53	0.99	1.26	1.53
• Offshore	1.00	1.40	1.80	1.00	1.40	1.80
• Alaska	0.73	1.00	1.27	0.73	1.00	1.27
Operating						
• Onshore	0.38	0.81	1.24	0.38	0.81	1.24
• Offshore	0.20	0.60	1.00	0.20	0.60	1.00
• Alaska	0.57	1.00	1.43	0.57	1.00	1.43
Finding Rates						
New Field Wildcats						
Onshore						
• Regions 1&6	1.18	2.08	2.98	0.88	1.62	2.36
• Regions 2-5	2.36	4.16	5.96	1.75	3.23	4.71
Offshore	4.98	10.15	15.40	6.53	9.55	13.05
Other Exploratory						
Onshore						
• Regions 1&6	0.89	1.56	2.33	0.66	1.22	2.13
• Regions 2-5	1.77	3.12	4.47	1.31	2.42	3.53
Offshore	2.49	5.08	7.70	3.27	4.78	6.53
Developmental						
Onshore						
• Regions 1&6	0.66	1.17	1.68	0.50	0.92	1.34
• Regions 2-5	1.33	2.34	3.35	0.99	1.82	2.65
Offshore	2.49	5.08	7.70	3.27	4.78	6.53

Note: Onshore regions 1 and 6 are the Northeast and West Coast oil and gas supply regions. Regions 2 through 5 include the remaining onshore regions (Gulf Coast, Midcontinent, Southwest, and Rocky Mountain regions).

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

[68] *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.

[69] *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.

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

[71] *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.

[72] 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 1976); Larry W. Cooke, United States Department of the Interior, Minerals Management Service, *Estimates of Undiscovered, Economically Recoverable Oil and Gas Resources for the Outer Continental Shelf, Revised as of January 1990*, OCS Report MMS 91-0051, July 1991; National Petroleum Council, Committee on Natural Gas, *The Potential for Natural Gas in the United States, Volume II, Source and Supply*, (Washington, DC, December 1992).

[73] 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. These are derived by obtaining a least-cost 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. 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, (4) the implementation of recent regulatory reform, and (5) the implementation of provisions of the Climate Change Action Plan (CCAP). A complete listing of NGTDM assumptions and in-depth methodology descriptions are presented in *Model Documentation Report: Natural Gas Transmission and Distribution Model of the National Energy Modeling System*, DOE/EIA-MO62/1, January 1998.

Key Assumptions

Demand Classification

Customers demanding natural gas are classified as either core or noncore customers, with core customers transporting their gas under firm (or near firm) transportation agreements and noncore customers transporting their gas under interruptible or short-term capacity release transportation agreements. 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.[74] The noncore category is subdivided into services that are considered to be competitive with distillate fuel oil and services that are considered to be competitive with residual fuel oil. The classification is based on the type of utility boiler (Table 52).

Table 52. Electric Utility Natural Gas Demand Classification

Service Category	Plant Type
Core	Gas Steam Units Gas Combined-Cycle Unit
NonCore	
• Competitive With Distillate Fuel Oil	Gas Turbine Units Dual-Fired Turbine Units Coal Plants With Gas Startup
• Competitive With Residual Fuel Oil	Dual-Fired Steam Units

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

End-use sector specific load patterns do not change over the forecast. (There is no representation of the impacts of demand-side management programs or 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 changes across sectors and as more pipeline and storage capacity becomes available.

Pricing of Services

Firm 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 (however, the test for determining whether or not to build new capacity is done based on incremental rates). 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. If the actual flow (F1) is less than the flow (F2) used in the cost-of-service rate calculation, the tariff is scaled by the factor F1/F2, with a minimum allowed scale factor of 0.5. The cost-of-service rate before scaling reflects an adjustment to the revenue requirement that credits a portion of the revenue from interruptible and release capacity services to holders of firm capacity (to account for capacity release).

Noncore transmission service rates are competitively priced with a price floor equal to the variable cost of delivering natural gas (generally compressor station fuel plus a few cents). Capital expenditures for refurbishment in operations and maintenance costs are not considered, nor are potential future expenditures for pipeline safety (refurbishment costs include any expenditures for repair and/or replacement of existing pipe). Reductions in operations and maintenance costs, and total administrative and general costs, as a result of efficiency improvements, are accounted for based on a frontier analysis, and an assumption that firms will approach the frontier at a rate of 4 percent per year.

End-use prices for residential, commercial, and core industrial customers are derived by adding a markup to the regional hub price of natural gas associated with core service. 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. The distribution tariffs are initially based on 1996 historical data (Table 53), but they are adjusted throughout the forecast in response to changes in consumption levels and cost of labor and capital, and assumed industry efficiency improvements. It is assumed that independent of changes in costs related to the cost of capital and labor and consumption levels, the cost of providing distribution services will decline 1 percent per year through 2015 as a result of efficiency improvements.

End-use prices for noncore industrial and electric generator customers are established by adding a markup to the natural gas market price for the corresponding core or noncore segment at the regional market hub. These markups are endogenously derived as the difference between estimated historical 1996 end-use prices,[75] and the NGTDM regional core or noncore hub price, and held constant throughout the forecast. End-use prices for core electric generator customers are similarly established with markups initially based on 1996 end-use prices. However, these markups are adjusted each forecast year by a fraction (0.05) of the annual percentage change in the core electric generator consumption. This adjustment is intended to reflect anticipated addtional 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 54). The price to non-fleet vehicles is based on the industrial sector firm price plus an assumed $3.98 (1996 dollars per thousand cubic feet) dispensing charge plus Federal and State taxes. 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 53. Base Year Average 1996 Annual Distributor Markup for Local Transportation Service
(1996 Dollars per Thousand Cubic Feet)

Region	Residential	Commercial	Core Industrial	Core Electric Generators
New England	4.81	2.64	0.41	-1.42
Mid Atlantic	4.36	2.97	1.13	-0.55
East North Central	2.11	1.65	0.37	-1.62
West North Central	2.58	1.80	0.08	-0.56
South Atlantic	3.70	2.37	0.13	-0.74
East South Central	2.77	2.12	-0.34	-0.69
West South Central	2.93	1.60	0.15	-0.42
Mountain	2.16	1.40	0.28	-0.35
Pacific	3.55	2.51	1.57	-0.09
Florida	7.83	2.87	-1.03	-0.42
Arizona/New Mexico	3.42	1.91	0.67	-0.46
California	3.98	3.52	0.96	0.22

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived from Form EIA-176, *Annual Report of Natural and Supplemental Gas Supply and Disposition* for residential, commercial, citygate and from the *Manufacturing Energy Consumption Survey Consumption of Energy 1991*, (Form EIA-846) for core industrial, derived from Form FERC-423, *Monthly Report of Cost and Quality of Fuels for Electric Plants* for core electric generators.

Table 54. Vehicle Natural Gas (VNG) Pricing

Modified Census Divisions	Total Federal and State VNG Tax[1] (1996 dollars per thousand cubic feet)
New England	2.44
Middle Atlantic	0.75
East North Central	1.67
West North Central	1.53
South Atlantic (excludes Florida)	1.72
East South Central	1.51
West South Central	1.42
Mountain (excludes Arizona and New Mexico)	1.20
Pacific (excludes California)	1.95
Florida	1.05
Arizona and New Mexico	0.63
California	0.59

[1]Assuming a $0.52 (1996 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 published in Energy Information Administration, *Alternatives to Traditional Transportation Fuels 1995,* DOE/EIA-0585(95), December 1996, Table 15.

Capacity Expansion and Utilization

The model methodology assumes that pipeline and storage capacity is available 2 years from the final decision to add new capacity. Average capital costs for pipeline expansion (1996 dollars per Mcf-mile per day) are assumed to be $1.66 for compression, $1.86 for looping, and $2.39 for new pipe. The average costs were regionalized by applying regional cost factors reflecting differences in terrain and labor costs.

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 (percentages vary from 5 to 15 percent, with lower percentages in areas with warmer weather). With the exception of import arcs, annual maximum pipeline capacity utilization is assumed to be limited to between 83 and 90 percent of the design capacity (with the exceptions of capacity into Florida, which is assumed to be 96 percent of 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. Within the Capacity Expansion Submodule, consumption is represented for peak and offpeak periods based on historically based sectoral splits, held constant throughout the forecast period.

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 by firm and interruptible classes into storage in the off-peak period and net withdrawals during the peak period. Total annual net storage withdrawals equal zero in all years of the forecast.

Legislation and Regulation

The Federal Energy Regulatory Commission (FERC) is receptive to alternative ratemaking and wishes to provide an atmosphere that fosters efficient capacity release.

The methodology for pricing firm pipeline 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.

Climate Change Action Plan

The Climate Change Action Plan (CCAP) initiatives to increase the natural gas share of total energy use through Federal regulatory reform (Action 23) are reflected in the methodology for the pricing of pipeline services. Provisions of the CCAP to expand the Natural Gas Star program (Action 32) are assumed to recover 35 billion cubic feet of natural gas per year by the year 2000 that otherwise might be lost to fugitive emissions. This is phased in by recovering an additional 7 billion cubic feet per year from 1997 through 2000, and by recovering the full 35 billion cubic feet from 2000 through the end of the forecast period.

[74] 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 indusrial end-use consumption.

[75] Historical core and noncore industrial prices were based on data from the *Manufacturing Consumption of Energy 1991*, 1994.

Petroleum Market Module

The NEMS Petroleum Market Module (PMM) forecasts petroleum product prices and sources of supply for meeting petroleum product demand. The sources of supply include crude oil (both domestic and imported), petroleum product imports, other refinery inputs including alcohols 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.[76]

Key Assumptions

Product Types and Specifications

The PMM models refinery production of the products shown in Table 55.

Table 55. 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, Liquified 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 costs of producing new formulations of gasoline and diesel fuel that will be phased in as a result of the Clean Air Act Amendments of 1990 (CAAA90) 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.

Motor Gasoline Specifications and Market Shares

The PMM models the production and distribution of three different types of gasoline: traditional, oxygenated and reformulated. The following specifications are included in PMM to differentiate between traditional and reformulated gasoline blends (Table 56): octane, oxygen content, Reid vapor pressure (Rvp), benzene content, aromatic content, sulfur content, olefin content, and the percent evaporated at 200 and 300 degrees farenheit (E200 and E300).

Traditional gasoline must comply with antidumping requirements aimed at preventing the quality of traditional gasoline from eroding as the reformulated gasoline program is implemented. Starting in 1998, traditional gasoline must meet the Complex Model compliance standards which cannot exceed average 1990 levels of toxic and nitrogen oxide emissions.[77] Traditional gasoline during the 1998-2020 time period is assumed to have “1990 baseline” specifications.

Oxygenated gasoline, which has been required during winter in many U.S. cities since October of 1992, requires a oxygenated content of 2.7 percent by weight. Oxygenated gasoline is assumed to have specifications identical to traditional 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 (Table 56). Beginning in 1998, the EPA will only certify reformulated gasoline using the "complex model," which allows refiners to specify reformulated gasoline based on emissions reductions from their companies 1990 baseline or the EPA's 1990 baseline. 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." Specifications such as Rvp, aromatics, sulfur, and olefin content change in the year 2000 reflecting further emissions reductions required by CAAA90 (Table 56).

Table 56. Year Round Gasoline Specifications by Petroleum Administration for Defense Districts (PADD)

PADD	Reid Vapor Pressure (Max)	Oxygen Weight Percent (Min)	Oxygen Weight Percent (Max)	Aromatics Volume Percent (Max)	Benzene Volume Percent (Max)	Sulfur PPM (Max)	Olefin Volume Percent (Max)	Percent Evaporated at 200°	Percent Evaluated at 300°
Traditional									
PADD I-V									
1998-2020	10.0	—	—	28.6	1.6	338.4	10.8	41.0	83.0
Reformulated									
PADD I-IV									
1998-1999	8.7	2.1	2.7	25.0	0.95	305.0	12.0	49.0	87.0
2000-2020	8.5	2.1	2.7	25.0	0.95	135.0	12.0	49.0	87.0
PADD V									
1998-1999	8.2	1.8	2.2	25.0	1.0	40.0	6.0	49.0	91.0
2000-2020	7.9	1.8	2.2	25.0	1.0	40.0	6.0	49.0	91.0

Max = Maximum.

Min = Minimum.

PADD = Petroleum Administration for Defense District.

PPM = Parts per million by weight.

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

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 specifications. Starting in 1996, the specifications for reformulated gasoline in PADD V are the same as California standards.

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 traditional, 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 *AEO98,* the annual market shares for each region reflect actual 1996 market shares and are held constant throughout the forecast. The Census Division 8 market shares were adjusted because Phoenix recently joined the Federal reformulated gasoline program in the summer of 1997. (See Table 57 for *AEO98* market share assumptions.) Census Division 4 market shares were adjusted to reflect a statewide requirement for oxygenated gasoline in Minnesota beginning in 1997.

Table 57. Market Share for Gasoline Types by Census Division
(Percentage)

Gasoline Type/Year	Census Division								
	1	2	3	4	5	6	7	8	9
Traditional Gasoline	13	43	83	81	82	95	74	67	27
Oxygenated Gasoline (2.7% oxygen)	0	0	0	19	0	0	1	19	7
Reformulated Gasoline (2.0% oxygen)	87	57	17	0	18	5	26	14	65

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

Diesel Fuel Specifications and Market Shares

In order to account for diesel desulfurization regulations, low-sulfur diesel is differentiated from other distillates. Diesel fuel in Census Divisions 1 through 8 is assumed to meet Federal requirements, while diesel fuel in Census Division 9 is assumed to meet California Air Resources Board (CARB) standards.

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 1996, (on line: http://www.eia.doe.gov/oil_gas/fok/1996/fokframe96.html, November 3, 1997)*. Since about 20 percent of current demand in the transportation sector is off highway, 80 percent of transportation demand for distillate fuel is assumed to be low sulfur. Consumption of low-sulfur distillate outside of the transportation sector is assumed to be zero.

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[78] (Table 58) are reflected as fixed costs (associated operation and maintenance costs prior to 1996 are excluded). 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.

Table 58. Summary of Refinery Site Environmental Costs by Petroleum Administration for Defense Districts (PADD)
(1996 Dollars per Barrel)

Cost Category	PADD I	PADD II	PADD III	PADD IV	PADD V
Environmental Costs	0.63	0.64	0.50	0.93	0.71

PADD = Petroleum Administration for Defense District.

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

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 59) and are assumed to be constant throughout the forecast and across scenarios.

Table 59. Petroleum Product End-Use Markups by Sector and Census Division
(1996 Dollars per Gallon)

Sector/Product	Census Division 1	2	3	4	5	6	7	8	9
Residential Sector									
Distillate Fuel Oil	0.37	0.42	0.30	0.27	0.41	0.30	0.18	0.27	0.37
Kerosene	0.51	0.57	0.47	0.40	0.50	0.36	0.41	0.53	0.91
Liquefied Petroleum Gases	0.82	0.87	0.51	0.33	0.74	0.62	0.54	0.52	0.82
Commercial Sector									
Distillate Fuel Oil	0.18	0.15	0.08	0.06	0.09	0.07	0.08	0.07	0.10
Gasoline	0.15	0.14	0.13	0.15	0.13	0.16	0.17	0.15	0.13
Kerosene	0.27	0.21	0.20	0.12	0.18	0.23	0.20	0.15	0.23
Liquefied Petroleum Gases	0.63	0.61	0.43	0.37	0.58	0.36	0.22	0.40	0.56
Low-Sulfur Residual Fuel Oil	0.02	0.06	0.04	0.00	0.04	0.04	-0.01	-0.03	0.10
Utility Sector									
Distillate Fuel Oil	0.04	0.07	0.06	0.05	0.04	0.11	0.07	0.08	0.11
High-Sulfur Residual Fuel Oil	-0.01	0.02	0.12	0.03	0.00	-0.03	0.06	0.01	0.07
Low-Sulfur Residual Fuel Oil	0.00	0.01	0.17	0.03	0.01	0.15	0.08	0.10	0.19
Transportation Sector									
Distillate Fuel Oil	0.25	0.19	0.13	0.13	0.15	0.13	0.15	0.15	0.20
Ethanol	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Gasoline	0.14	0.13	0.13	0.17	0.13	0.16	0.17	0.15	0.13
High-Sulfur Residual Fuel Oil	-0.02	0.03	0.12	-0.01	-0.01	-0.07	0.04	0.22	0.09
Jet Fuel	0.02	0.03	0.01	0.00	-0.02	0.04	0.03	-0.01	0.04
Liquefied Petroleum Gases	0.68	0.61	0.52	0.36	0.55	0.37	0.18	0.37	0.53
Methanol	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Industrial Sector									
Asphalt and Road Oil	0.22	0.16	0.26	0.28	0.17	0.15	0.23	0.30	0.28
Distillate Fuel Oil	0.16	0.15	0.14	0.13	0.14	0.12	0.13	0.12	0.15
Gasoline	0.15	0.13	0.13	0.17	0.13	0.16	0.17	0.16	0.14
Kerosene	0.27	0.21	0.20	0.12	0.18	0.23	0.20	0.15	0.23
Liquefied Petroleum Gases	0.59	0.55	0.48	0.31	0.54	0.30	0.08	0.28	0.55
Low-Sulfur Residual Fuel Oil	0.01	0.03	0.05	0.00	0.03	0.05	-0.01	0.01	0.07

Note: Use conversion factors listed in Table 1 of the *Annual Energy Outlook 1998* 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 1994*, DOE/EIA-0214(94), (Washington, DC, October 1996); EIA, *State Energy Price and Expenditures Report 1994*, DOE/EIA-0376(94), (Washington, DC, June 1996); and EIA, *Petroleum Marketing Monthly March 1997*, DOE/EIA-0380(97/03), (Washington, DC, March 1997).

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

State and Federal taxes are also added to transportation fuels to determine final end-use prices (Tables 60 and 61). 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. Federal taxes are assumed to remain at current levels in accordance with the overall *AEO98* 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 60. State-Level Taxes on Petroleum Transportation Fuels by Census Division
(1996 Dollars per Gallon)

	Census Division								
Year/Product	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**
Gasoline[1]	0.26	0.19	0.21	0.19	0.16	0.18	0.19	0.20	0.23
Diesel	0.20	0.20	0.22	0.20	0.17	0.16	0.19	0.17	0.22
Liquefied Petroleum Gases	0.15	0.13	0.16	0.17	0.16	0.16	0.15	0.12	0.05
Methanol	0.25	0.14	0.18	0.14	0.15	0.16	0.19	0.20	0.12
Ethanol	0.25	0.18	0.16	0.19	0.15	0.16	0.19	0.20	0.12
Jet Fuel	0.03	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.

Source: Aggregated from Federal Highway Administration, *Monthly Motor Fuel Reported by States*, (Washington, DC, March 1997). *Clean Fuels Report* (Washington, DC, April 1997).

Table 61. Federal Taxes
(1996 Dollars per Gallon)

Product	Tax
Gasoline	0.18
Diesel	0.24
Jet Fuel	0.04
Liquefied Petroleum Gases	0.13
Methanol	0.09
Ethanol	0.13

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 1997).

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 62.

Table 62. 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.

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, an estimate of total production is 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.

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 is determined when the value received from the additional product sales exceeds the investment and operating costs of the new unit. The investment costs assume a 15-percent rate of return over a 15-year plant life. Expansion through 1998 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 three years. For example, after the model has reached a solution for forecast year 2000, the PMM looks ahead and determines the optimal capacities given the demands and prices existing in the 2003 forecast year. The PMM then allows 50 percent of that capacity to be built in forecast year 2001, 25 percent in 2002, and 25 percent in 2003. At the end of 2003, the cycle begins anew, looking ahead to 2006.

Strategic Petroleum Reserve Fill Rate

AEO98 assumes no additions for the Strategic Petroleum Reserve during the forecast period. Additions to the Strategic Petroleum Reserve have not been included in recent budgets.

Short-term Methodology

Petroleum balance and price information for the years 1997 and 1998 are projected at the U.S. level in the *Short-term Energy Outlook, 3rd Quarter 1997* (*STEO*). The PMM assumes the STEO results for these years, using regional estimates derived from the national STEO projections.

Biofuels (Ethanol) Supply Submodule

Background

The Biofuels (Ethanol) Supply Submodule provides supply functions on an annual basis through 2020 for ethanol produced from corn 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. Only ethanol produced from corn is currently modeled.[79]

- Most production is projected to come from Petroleum Administration for Defense District II, where most of the corn is grown. This is not an assumption of the model, but rather a result of the exogenous projections of feedstock costs and quantities. However, it is assumed that the supply will approximate reality to the point that it includes most of the production.

- 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. 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 costs are included in the Petroleum Market Model and are not part of the Biofuels Supply submodule.

Legislation

The PMM reflects recent national and regional legislative and regulatory changes that will affect future petroleum supply and product prices. It incorporates taxes imposed by the 1993 Budget Reconciliation Act and the 1997 Tax Payer Relief Act as well as costs resulting from environmental legislation.

The Budget Reconciliation Act imposes a tax increase of 4.3 cents per gallon on transportation fuels including gasoline, diesel, liquefied petroleum gases, and jet fuel. Except for jet fuel, the tax began on October 1, 1993. Jet fuel was granted a 2-year delay and was enacted in 1996.

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.

With a goal of reducing tailpipe emissions in areas failing to meet Federal air quality standards (nonattainment areas), Title II of the Clean Air Act Admendments of 1990 (CAAA90) established regulations for gasoline formulation. Starting in November 1992, gasoline sold during the winter in the initial 39 carbon monoxide nonattainment areas was required to be oxygenated.[80] Starting in 1995, gasoline sold in major U.S. cities that are considered the most severe ozone nonattainment areas must be reformulated to reduce volatile organic compounds (which contribute to ozone formation) and toxic air pollutants, as well as meet a number of other new specifications. Additional areas with less severe ozone problems have chosen to "opt in" to the reformulated gasoline requirement. In 1998 reformulated gasoline will be required to meet a performance based definition, "The Complex Model". In 2000 the performance measures will become more stringent.

Title II of the CAAA90 also established regulations on the sulfur and aromatics content of diesel fuel, which took effect October 1, 1993. All diesel fuel sold for use on highways now contains less sulfur and meets new aromatics or cetane level standards.

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.[81] 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.

The PMM also assumed that the ban on exporting Alaskan crude oil would be lifted. This legislation was passed and signed into law (PL 104-58) in November 1995. The PMM allowsfor exports of Alaska North slope (ANS) crude oil up to 150 thousand barrels per day if the estimated target price is greater than the ANS value in PADD V. The target prices were assumed to decline as ANS exports increased.

[76] Energy Information Administration, *EIA Model Documentation: Petroleum Market Model of the National Energy Modeling System*, DOE/EIA-MO59, Forthcoming.

[77] 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).

[78] 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.

[79] About 95 percent of the U.S. production of fuel ethanol is derived from corn. U.S. Department of Energy, Energy Information Administration, *Estimates of U.S. Biomass Energy Consumption 1992*, p.25, (Washington, DC, May 1994).

[80] Oxygenated gasoline must contain an oxygen content of 2.7 percent by weight.

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

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, *Model Documentation: Coal Market Module of the National Energy Modeling System*, DOE/EIA-MO60.

Key Assumptions

Coal Production

The coal production area 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, 12 coal types (unique combinations of thermal grade, sulfur content, and mine type). The modeling approach used to constant regional coal supply curves addresses the relationship between the minemouth price of coal and corresponding levels of coal production 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 diesel fuel prices from the PMM and estimates of future coal mine labor costs.

- Between 1978 and 1996, U.S. coal mining productivity (measured in short tons of coal produced per miner per hour) increased at an 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.[82] 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 at a rate of 2.0 percent a year in the forecast, declining from an annual rate of 5.8 percent in 1996 to approximately 1.6 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.[83]

- Between 1985 and 1996, the average hourly wage for U.S. coal miners (in 1996 dollars) declined at an average rate of 1.2 percent per year, falling from $21.32 to $18.75.[84] In the reference case, the wage rate for U.S. coal miners, is assumed to remain constant in 1996 dollars (i.e., increase at the general rate of inflation), as it has since 1993.

Coal Distribution

The coal distribution area 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 region. 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 *AEO98* cases are shown in Table 63.

- 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 EMM 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.

Table 63. Transportation Rate Multipliers
(1996=1.000)

Year	Reference Case	High Oil Price	Low Oil Price	High Economic Growth	Low Economic Growth
1996	1.0000	1.0000	1.0000	1.0000	1.0000
2000	0.9761	0.9844	0.9622	0.9637	0.9917
2005	0.9523	0.9596	0.9409	0.9433	0.9634
2010	0.9163	0.9253	0.9042	0.9175	0.9147
2015	0.8717	0.8836	0.8569	0.8838	0.8537
2020	0.8197	0.8307	0.8004	0.8425	0.7858

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

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 coal import demands. It does this subject to constraints on export capacity, trade flows, and sulfur emissions.

The CMM projects steam and metallurgical coal trade flows from 16 coal-exporting regions of the world to 20 import regions for 4 coal types (coking, low-sulfur steam, high-sulfur 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. This means suppliers gain no producer surplus.

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 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.

- While subbituminous coal is included, use of this coal is constrained by the capacity of subbituminous coal-fired plants in an import region and the extent that it can be substituted/blended.

- 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 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 *AEO98* forecast cases are shown in Tables 64 and 65.

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 1996, 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.

Climate Change Action Plan

Provisions of the Climate Change Action Plan (CCAP) that concern coalbed methane recovery are incorporated in the Oil and Gas Supply Module.

Mining Cost Cases

In the reference case, labor productivity is assumed to increase at an average rate of 2.0 percent a year through 2020, while wage rates remain constant in 1996 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 3.3 percent a year, and real wages decline by 0.5 percent a year. In a high mining cost sensitivity case, productivity increases by only 0.8 percent a year, and real wages 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 1996. Both cases were run using only the CMM, rather than as a fully integrated NEMS run. Consequently, no price-induced demand feedback in coal markets was captured. In an integrated run, the demand response would tend to moderate the magnitude of the equilibrium price response.

Table 64. World Steam Coal Import Demand by Import Region, 2000-2020
(Million Metric Tons of Coal Equivalent)

Import Regions[1]	2000	2005	2010	2015	2020
The Americas	22.5	26.0	28.5	30.4	36.6
United States	5.8	5.9	6.0	6.1	6.2
Canada	6.9	7.0	5.5	5.4	5.7
Mexico	2.0	3.6	5.6	6.1	8.1
South America	7.8	9.5	11.4	12.8	16.6
Europe	108.6	119.7	130.8	136.5	147.4
Scandinavia	15.8	14.5	13.5	13.1	12.7
U.K/Ireland	11.4	12.3	12.8	13.2	13.7
Germany	16.4	20.1	25.5	28.3	31.9
Other NW Europe	24.2	27.3	27.9	27.5	28.4
Iberia	14.6	15.1	16.1	17.0	18.8
Italy	10.9	12.8	14.6	14.6	16.4
Med/E Europe	15.3	17.6	20.4	22.8	25.5
Asia	147.3	177.8	205.7	231.6	263.4
Japan	61.3	70.4	81.0	86.7	93.3
East Asia	56.0	62.3	67.7	72.3	81.3
China/Hong Kong	15.3	21.6	26.2	32.5	38.8
ASEAN	8.7	10.6	14.7	18.6	23.1
Indian Sub	6.0	12.9	16.1	21.5	26.9
Total	278.4	323.5	365.0	398.5	447.4

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

Table 65. World Metallurgical Coal Import Demand by Import Region, 2000-2020 (Million Metric Tons of Coal Equivalent)

Import Regions[a]	2000	2005	2010	2015	2020
The Americas	20.6	21.5	22.7	24.4	26.2
United States	0.9	0.9	0.9	0.9	0.9
Canada	5.5	5.3	5.0	4.6	4.4
Mexico	0.9	0.9	0.9	0.9	0.9
South America	13.3	14.4	15.9	18.0	20.0
Europe	51.5	51.1	49.8	48.5	46.8
Scandinavia	3.1	2.8	2.5	2.2	1.9
U.K/Ireland	7.0	6.6	6.2	5.8	5.4
Germany	3.7	5.3	5.8	6.3	6.3
Other NW Europe	16.3	15.3	14.5	13.9	13.4
Iberia	3.4	2.9	2.5	2.1	1.7
Italy	6.4	6.2	5.9	5.6	5.3
Med/E Europe	11.6	12.0	12.4	12.6	12.8
Asia	99.2	99.6	101.8	100.4	100.6
Japan	60.1	55.2	54.2	51.3	49.5
East Asia	25.5	28.8	30.6	31.2	32.3
China/Hong Kong	0.2	0.2	0.2	0.2	0.2
ASEAN	0.0	0.0	0.0	0.0	0.0
Indian Sub	13.4	15.4	16.8	17.7	18.6
Total	171.3	172.2	174.3	173.3	173.6

[a]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: Energy Information Administration, Office of Integrated Analysis and Forecasting.

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

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

[84] U.S. Department of Labor, Bureau of Labor Statistics.

Renewable Fuels Module

The NEMS Renewable Fuels Module (RFM) consists of five distinct submodules that represent the major renewable energy technologies. Although it is described here, conventional hydroelectric is included in the Electricity Market Module (EMM) and is not part of the RFM. Similarly, ethanol modeling is included in the Petroleum Market Module (PMM). Some renewables, such as 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 require the production 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 wind, solar, and geothermal energy. In some cases, they require technological innovation to become cost effective or have inherent characteristics, such as intermittence, 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 only with modules outside of the RFM and not with other RFM submodules. These interactions occur through common elements of the model 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.

The EMM represents learning effects for new technologies, which are implemented as a decrease in capital costs as a function of the level of market penetration. For *AEO98*, learning effects in the EMM occur in three phases, with capital costs declining most rapidly (usually 10 percent) for every doubling of capacity from the 1st through the 5th unit, less rapidly from the 5th through the 40th unit (usually 5 percent per doubling), and at a much slower rate thereafter per each doubling (2.5 percent). The RFM provides the 5th (nth) unit costs. In addition, unit size is provided to the EMM for renewable technologies, so that the level of market penetration can be determined.

For *AEO98*, two increasing costs are superimposed onto the capital costs of renewable energy technologies to represent two phenomena:

- Short-term supply elasticities, which increase technology capital costs as a result of rapid U.S. buildup in a single year and reflecting limitations on the infrastructure to accommodate unexpected demand growth. These short-term elasticities are invoked when demand for new capacity in any year exceeds 25 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 25 percent, capital costs rise 0.5 percent. These elasticities apply to biomass, geothermal, municipal solid waste, solar, and wind technologies.

- For biomass and wind only, increased costs resulting from a large cumulative increase in use of a given resource, reflecting any or all of three general 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, rock, 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 uses increase costs as cumulative capacity increases, including for agricultural or other production alternatives, residence or recreation, aesthetics, or from broader environmental preferences. As a result, for *AEO98*, each EMM region's biomass and wind resource estimates are parceled into three broad ranges, an initial land share incurring no cost penalty, a second share for which capital costs increase 25 to 50 percent, and a final share (the remaining resources) for which capital costs increase 100 to 200 percent over the reference case. Proportions vary by technology and region.

For an in-depth discussion of the learning functions, see the EMM section and the background section of the model summary for the Geothermal Electric Submodule. A detailed description of the RFM is provided in the EIA publication, *Model Documentation: Renewable Fuels Module of the National Energy Modeling System*, DOE/EIA-M069.

Key Assumptions

Nonelectric Renewable Energy Uses

In addition to projections for renewable energy used in electricity generation, the *AEO98* 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. Additional renewable energy applications, 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 specifically and NEMS in general consider only grid-connected electricity generation. Off-grid sources, such as off-grid applications of photovoltaic, dish-Stirling solar, and wind generation, are not included in the energy balances for the *AEO98*. The renewable submodules that interact with the EMM are the grid-connected solar (thermal and photovoltaic), wind, geothermal, biomass, and MSW 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 data are central to the build and dispatch decisions of the EMM with the exception of MSW. The values are presented in Table 37 of the EMM section.

Conventional Hydroelectric Power Data File

Background

The Hydroelectric Power Data File in the EMM represents reported plans for new conventional hydroelectric power capacity connected to the transmission grid reported on Form EIA-860, *Annual Electric Generator Report*, and Form EIA-867, *Annual Nonutility Power Producer Report*. It does not estimate additional unplanned capacity, nor estimate pumped storage hydroelectric capacity, which is considered a storage medium for coal and nuclear power and not a renewable energy use. Hydroelectric power is not competed against any other generating technologies for capacity expansion, and all the hydropower generated is assumed to be consumed. 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.

Assumption

- 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).

Solar Electric Submodule

Background

The Solar Electric Submodule (SOLES) currently includes two solar technologies: 100 megawatt central receiver (power tower) solar thermal (ST) and 5 megawatt fixed-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 technology characterization being prepared by the Department of Energy's Office of Energy Efficiency and Renewable Energy. 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); limits to learning are determined by EIA.

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). The current solar thermal annual capacity factor for the region including California, for example, is assumed to average 40 percent; California's current PVcapacity 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.

- 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). Accordingly, there is no reason to track solar resources 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 models the 10-percent investment tax credit for solar electric power generation by tax-paying entities. Because it does not distinguish publicly-owned from privately-owned facilities, and EIA assumes that most new capacity will be privately-owned, the model does not include EPACT's 1.5 cent renewable energy production incentive for publicly owned new solar capacity.

Wind-Electric Power Submodule

Background

Because of limits to windy land area, wind is considered a finite resource, so the submodule calculates a maximum available capacity by North American Electric Reliability Council (NERC) region. 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 NERC region come from a Pacific Northwest Laboratory study and a subsequent update.[85] The technological performance, cost, and other wind data used in NEMS are derived by EIA from discussions with industry experts.[86]

Maximum wind capacity, capacity factors, capital costs, fixed and variable operating and maintenance costs, 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 provided to the report writer for energy consumption calculation purposes only.

Assumptions

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

- First 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, accepting wind resources within miles on either side of the transmission lines. Transmission cost factors are added to the resources further from the transmission lines.

- For *AEO98*, capital costs for wind technologies are also assumed to increase in response to (1) declining quality of land or wind resources other than average annual wind speed, 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 50 percent, and finally 300 percent, to represent the aggregation of these factors. Proportions in each category vary by EMM region.

- Depending on the NERC 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, the total fixed (capital and fixed operations and maintenance) costs plus operating (variable operations and maintenance minus applicable subsidies from the Energy Policy Act of 1992, (EPACT) costs for new wind units 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 go down.

Geothermal-Electric Power Submodule

Background

In developing geothermal capacity growth projections, the focus is on hydrothermal resources but extraction of energy from hot dry rock resources is not included. This is because the technology probably at best be available after 2010, and reliable cost and resource data are not yet available. The Geothermal-Electric Power Submodule (GES) utilizes a process of resource accounting based on Sandia National Laboratory's 1991 geothermal resource assessment.[87] Site-specific costs, including those for drilling, steam collection, and electricity transmission to the grid, as well as site characteristics, are used in identifying available resources and capacities by EMM region. The cost and performance values are based on dual flash and binary cycle technologies. The costs from 51 sites are aggregated into a set of regional supply curves for each year. For each iteration of a model run, a value for avoided cost is obtained from the Electricity Capacity Planning Submodule to establish the level and truncate the curves and exclude the higher cost resources. Capital cost learning on the generating units which emulates what is done in the EMM is incorporated in the GES.[88]

Assumptions

- Existing and planned capacity data are accessed directly by the EMM. The data are obtained from Forms EIA-860 and EIA-867.

- An investment tax credit of 10 percent is assumed to be available in all model years.

- Plant retirements are generally assumed to occur 30 years after startup. An exception is made for wells affected by a project to bring water to parts of The Geysers site which is expected to halt the enthalpy decline. Of these (six) wells, half are assumed to be retired after 35 years, the others in 40 years.

- Capital and operating costs vary by sites and years; values shown in Table 37 of the EMM section 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 37 of the EMM section, 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.

Assumptions

- Existing and planned capacity data are accessed directly by the EMM. The data are obtained from Forms EIA-860 and EIA-867.

- The conversion technology represented, upon which the costs in Table 37 are based, is an advanced gasification-combined cycle plant that is similiar to a coal-fired gasifier. Costs in the reference case were developed by EIA to be consistent with coal gasifier costs. Co-firing with coal is a distinct possibility, but it would not add capacity and is not included.

- In place of the previously used capacity constraints, short-term and long-term elasticities have been installed. The short-term values are described in the RFM introduction. The long-term values would increase capital cost by 25 percent after reaching 15 percent of total resources and by 100 percent when reaching 50 percent of total resources. These levels were not reached in *AEO98*.

- Fuel supply schedules are a composite of two fuel types, woody resources and energy crops. Woody resources supply data are developed from U.S. Forest Service data and are contained in a single supply schedule for each region, from 1990 through 2020.[89] Reinterpretation of the data has resulted in a reduction of the resources in some regions since *AEO97*. Energy crop data are presented in yearly schedules from 2010 to 2020 for each region. These crop data are developed from The FASOM model at the U.S. Environmental Protection Agency with limitations developed from data provided by the Oak Ridge National Laboratory.[90] [91]

Municipal Solid Waste-Electric Power Submodule

Background

Municipal solid waste (MSW) combustion is treated within NEMS as a separate technology whose electricity production is determined exogenous to the EMM. The cost of producing electricity is passed to the EMM only as an input to the calculation that derives the average cost of producing electricity. Energy from MSW is a byproduct of waste disposal activity and, therefore, not competed against other technologies in model decisions regarding new capacity additions.[92]

Assumptions

- MSW is assumed to displace other energy forms lower in the merit order.

- Build decisions are based on a stepwise process involving waste disposal parameters.

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

  - The values are extrapolated from historical Environmental Protection Agency (EPA) values for MSW and factored upward by 1.47 to reflect a broader definition of materials known to be combusted. The factor 1.47 is derived from information in the Biocycle State Survey.[93]

  - The heat content of the MSW is assumed to increase from 5,114 Btu per pound in 1990 to 5,569 Btu per pound in 2000 and remain at that level for the remainder of the projection.

  - The percentage of waste combusted is assumed to remain constant at 11 percent of a growing waste stream. Using the Biocycle-base value for generation of the MSW waste steam, the percentage currently combusted is reduced from the EPA value of 15 percent to 11 percent.

  - The total energy from MSW projected for the United States is limited to the portion currently used for electricity generation (about 92 percent) and is disaggregated into regions. This regional breakdown is performed by maintaining the projected 1996 distribution of these factors as represented in the EIA database of MSW plants. Steam from MSW is represented in industrial cogeneration.

— Capacities are computed from total energy by applying an assumed heat rate of 16,000 Btu per kilowatt-hour and a combustion capacity factor of 0.78 for all regions and years.

- An estimate is made of energy produced from landfill gas. Data values are entered in a Lotus 1-2-3 file that considers existing and additional landfills and a profile of gas generation from the waste. It is assumed that the percent of the gas emitted that will be captured for energy conversion will increase from 13 percent in 1995 to 40 percent in 2020, based on an EPA estimate of a tripling of landfills that will capture the gas. The resulting generating capacity is added to the capacity for MSW combustion, is disaggregated by region and passed to the EMM.

Legislation

Energy Policy Act of 1992 (EPACT)

The RFM includes the investment tax and energy production credits called for in the EPACT for the appropriate energy types. EPACT provides a renewable electricity production credit 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. 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-860 and EIA-867 and capacity projected through the use of the RFM, the *AEO98* also includes 1,780 megawatts additional new generating capacity powered by renewable resources. The plans are summarized in Table 66. Some of the capacity represents commitments not yet reported to EIA, some represents mandated new capacity required by law, and the remainder represents minimum EIA "floor" estimates of new solar photovoltaic or solar thermal capacity assumed by EIA to be built for reasons not represented in the RFM, including other solar technologies (like dish-Stirling thermal), niche markets (such as for distributed applications), or education and testing of new technologies.

Table 66. Supplemental Capacity Plans (Megawatts)

Rationale	Geothermal	Solar Thermal	Solar Photovoltaic	Wind	Biomass	Total
Commitments	32	10	10	330	11[1]	393
Mandates	33	35	35	524	119	746
Unmodeled	0	140	500	0	0	640
Total	66	185	545	854	130[1]	1,780

[1] Includes 11 megawatts. Landfill gas-powered capacity.

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

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

The solar thermal estimates are assumed to be primarily dish-Stirling engine systems, with little new solar trough capacity expected; because central receiver capacity is modeled in SOLES, only minimal amounts are included here.

International Learning

For *AEO98*, capital costs for all new electricity generating technologies decrease in response to foreign as well as domestic experience. Additional offshore planned capacity decreasing U.S. renewable energy technology capital costs includes 101 megawatts geothermal, 48 megawatts wind, and 2 megawatts biomass integrated combined cycle capacity in operation, under construction, or under contract for construction outside the United States. For a description of international learning in EMM, see page 72.

Climate Change Action Plan

Action Item 26, "*Form Renewable Energy Market Mobilization Collaborative with Technology Demonstration*," of the Climate Change Action Plan (CCAP),[94] is designed to spur field validation of selected renewable energy technologies by supporting specified electric utility tests. The demonstrations, along with information dissemination, intend to address market barriers by increasing utility and investor confidence in the technologies. Technologies included in Action Item 26 include assistance to "ice breaker" geothermal plants, site testing advanced wind turbines, and assistance and collaboration in launching test biomass-fueled and photovoltaic electricity generating technologies.

The electricity generating capacity effects on *AEO98* of Action Item 26 are incorporated in EIA's projections for renewable technologies. The supplemental capacity additions include additions that will be cost-shared by DOE and industry. While the stated goal of this action item is "increased utility and investor experience and confidence" in renewable technologies, in general, no additional cost declines beyond those discussed above are assumed.

[85] 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).

[86] 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.

[87] Sandia National Laboratories, *Supply of Geothermal Power from Hydrothermal Sources: A Study of the Cost of Power in 20 and 40 Years*, (Albuquerque, NM, June 1991).

[88] DynCorp-Meridian Inc., *Model Documentation, Geothermal Electric Submodule of the Renewable Fuels Module of the National Energy Modeling System*, (Alexandria VA, December 1994) and DynCorp Environmental, Energy and National Security Programs Inc., *Model Documentation, Renewable Fuels Module; Modifications to the Geothermal Electricity Supply Submodule*, prepared for the Energy Information Administration, (Alexandria, VA, September 1995).

[89] 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)

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[90] Decision Analysis Corporation of Virginia, *Data Documentation for the Biomass Cost-Supply Schedule*, (Vienna VA, July 1995).

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

[92] For more details on the methodology, see the *Model Documentation on Renewable Fuels Module of the National Energy Modeling System*, DOE/EIA-M069(95), (Washington,D.C., July 1995).

[93] Biocycle, *The State of Garbage in America*, Annual Series (April 1988 - April 1997).

[94] U.S. Department of Energy, *The Climate Change Action Plan: Technical Supplement*, DOE/PO-0011, (Washington, DC, March 1994) p. 57.

List of Acronyms

AEO	*Annual Energy Outlook*
AEO97	*Annual Energy Outlook 1997*
AEO98	*Annual Energy Outlook 1998*
AFV	AFV Alternative-Fuel Vehicle
AGA	American Gas Association
ANGTS	Alaskan Natural Gas Transportation System
BEA	Bureau of Economic Analysis
BSC	Boiler/Steam/Cogeneration
Btu	British thermal unit
CAAA90	Clean Air Act Amendments of 1990
CBECS	Commercial Buildings Energy Consumption Surveys
CCAP	Climate Change Action Plan
CDD	Cooling Degree-Days
CNG	Compressed natural gas
DOE	U.S. Department of Energy
DRB	Demonstrated Reserve Base
DRI	Data Resources, Inc./McGraw Hill
EER	Energy Efficiency Ratio
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EPA	U.S. Environmental Protection Agency
EPACT	Energy Policy Act of 1992
EWG	Exempt Wholesale Generator
FAA	Federal Aviation Administration
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FSU	Former Soviet Union
GDP	Gross domestic product
GRI	Gas Research Institute
HSPF	Heating Season Performance Factor
HDD	Heating Degree-Days
IEA	International Energy Agency
ICE	Internal Combustion Engine
LEVP	Low Emissions Vehicle Program
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MSW	Municipal Solid Waste
NAECA	National Appliance Energy Conservation Act of 1987
NEMS	National Energy Modeling System
NERC	National Electric Reliability Council
NOAA	National Oceanicgraphic and Atmospheric Administration
NRC	Natural Resources Canada
O&M	Operation and Maintenance
OPEC	Organization of Petroleum Exporting Countries

PADD	Petroleum Administration for Defense Districts
PURPA	Public Utility Regulatory Policies Act of 1978
PUHCA	Public Utility Holding Company Act of 1935
PV	Photovoltaic
R&D	Research & Development
RFG	Reformulated gasoline
RECS	Residential Energy Consumption Survey
SEC	Securities and Exchange Commission
SDI	State Demand Intensity
SEDS	State Energy Data System
SEER	Seasonal Energy Efficiency Ratio
SIC	Standard Industrial Classification
SNG	Synthetic Natural Gas
TIUS	Truck Inventory and Use Survey
TVA	Tennessee Valley Authority
UEC	Unit Energy Consumption
VMT	Vehicle Miles Traveled
ZEV	Zero Emission Vehicles
WEFA	The WEFA Group (formerly the Wharton Econometric Forecasting Associates)