Assumptions
for the
Annual Energy Outlook 1996

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Introduction

This paper presents the major assumptions of the National Energy Modeling System (NEMS) used to generate the projections in the *Annual Energy Outlook 1996* (*AEO96*). In this context, assumptions include 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 listed in the Appendix.[1] A synopsis of NEMS, the model components, and the interrelationships of the modules is presented in *The National Energy Modeling System: An Overview*.

The National Energy Modeling System

The projections in the *AEO96* were produced with the National Energy Modeling System (NEMS). NEMS is developed and maintained by the Office of Integrated Analysis and Forecasting of the Energy Information Administration (EIA) to provide projections of domestic energy-economy markets in the midterm time period and perform policy analyses requested by decisionmakers and analysts in the U.S. Congress, the Department of Energy's Office of Policy, other DOE offices, other government agencies, and the private sector.

The time horizon of NEMS is 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. The *AEO96* is the first *Annual Energy Outlook* to provide projections to 2015. Because of the diverse nature of energy supply, demand, and conversion in the United States, NEMS supports regional modeling and analysis in order to represent the regional differences in energy markets, to provide policy impacts at the regional level, and to portray transportation flows. The level of regional detail for the end-use demand modules is the nine Census divisions. Other regional structures include production and consumption regions specific to oil, gas, and coal supply and distribution, the North American Electric Reliability Council regions and subregions for electricity, and the Petroleum Administration for Defense districts for refineries. Only national results are presented in the *AEO96*, with the regional and other detailed results available on the EIA CD-ROM, EIA Home Page, or diskettes.[2]

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

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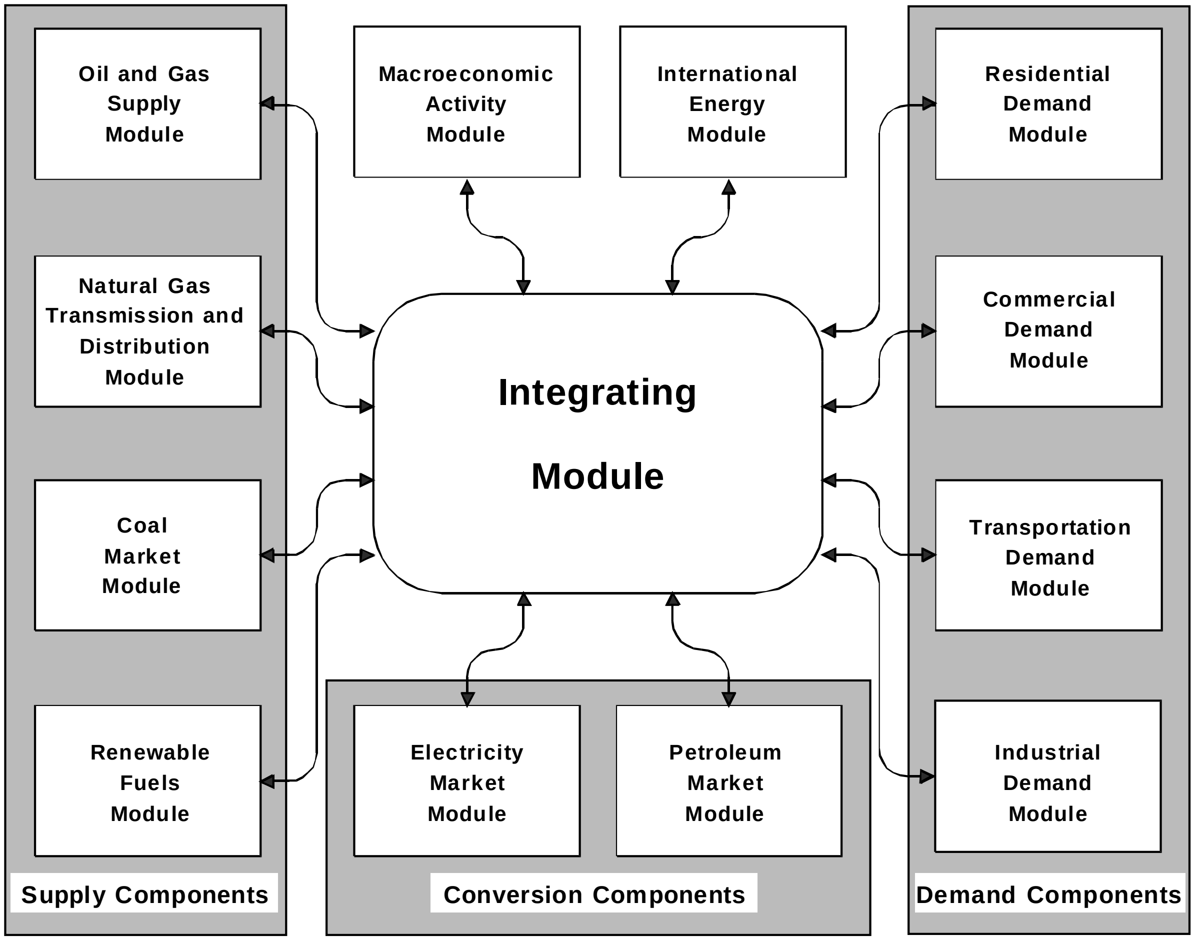
[1]NEMS documentation reports are available on the EIA CD-ROM. For ordering information, contact the National Energy Information Center (202/586-8800) or E-mail: infoctr@EIA.DOE.GOV.

[2]To obtain diskettes from the AEO96 or the supplementary tables, contact the Office of Scientific and Technical Information by telephone at 615/576-8401 or by mail at P.O. Box 62, Oak Ridge, TN 37831.

Figure 1. National Energy Modeling System



module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. Solution is reached annually through the midterm horizon. Other variables are also evaluated for convergence such as petroleum product imports, crude oil imports, and several macroeconomic indicators.

Each NEMS component also represents the impact and cost of legislation and environmental regulations that affect that sector and reports key emissions. NEMS reflects all current legislation and environmental regulations, such as the Clean Air Act Amendments of 1990, 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, 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, a macroeconomic feedback mechanism within NEMS, and a mechanism to evaluate detailed macroeconomic and interindustry impacts associated with energy events. Key macroeconomic variables include gross domestic product (GDP), interest rates, disposable income, and employment. Industrial drivers are calculated for 35 industrial sectors. This module is a response surface representation of the Data Resources, Inc., Quarterly Model of the U.S. Economy.

International Energy Module

The International Module represents the world oil markets, calculating the average world oil price and computing supply curves for five categories of imported crude oil for the Petroleum Market Module 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 macroeconomic variables representing population, disposable personal income, interest rates, 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 GDP, employment, 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 35 industries, subject to the delivered prices of energy and macroeconomic variables representing GDP, interest rates, employment and labor cost, 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, buildings, and process/assembly use of energy. A representation of cogeneration and a recycling component are also included. The use of energy for petroleum refining is modeled in the Petroleum Market Module, and the projected consumption is included in the industrial totals.

Transportation Demand Module

The Transportation Demand Module forecasts consumption of transportation sector fuels, including petroleum products, electricity, methanol, ethanol, 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 Clean Air Act Amendments 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 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 load 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 Electricity Market Module. All Clean Air Act compliance options are explicitly represented in the capacity expansion and dispatch decisions. Both new generating technologies and renewable technologies compete directly in these decisions. The competition between utility and nonutility generation and several options for wholesale pricing are included.

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil (including lease condensate) natural gas liquids, and natural gas production 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 12 supply regions, including 3 offshore and 3 Alaskan regions. This module also represents foreign sources of natural gas, including pipeline imports and exports with Canada and Mexico, and liquefied natural gas imports. The crude oil supply curves 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.

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 12 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 for the five Petroleum Administration for Defense districts, using the same crude oil types as the International Energy Module. It explicitly models the requirements of the Clean Air Act Amendments of 1990 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.

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 capacity utilization and fuel costs, as well as reserve depletion, labor productivity, and factor input costs. Twenty-eight coal types are represented, differentiated by thermal grade, sulfur content, and mining process. Production and distribution are computed for 16 supply and 23 demand regions, using imputed coal transportation costs and trends in factor input costs. The Coal Market Module also forecasts the requirements for U.S. coal exports and imports. The international coal market component of the module computes trade in 4 types of coal for 20 import and 16 export regions. Both the domestic and international coal markets are represented in a linear program.

Renewable Fuels Module

The Renewable Fuels Module includes submodules representing wood, municipal solid waste, wind energy, solar thermal electric and photovoltaic energy, and geothermal energy. It provides costs and performance criteria to the Electricity Market Module and also interacts with the Petroleum Market Module to represent the production and pricing of alcohol fuels derived from renewable sources. The Electricity Market Module represents market penetration of renewable technologies used for centralized electricity generation, and the end-use demand modules incorporate market penetration of selected off-grid electric and nonmarketed nonelectric renewables.

Cases for the *Annual Energy Outlook 1996*

The *AEO96* presents five cases which differ from each other due to fundamental assumptions concerning the domestic economy and world oil market conditions. Three alternative assumptions are specified for each of these two factors, with the Reference Case using the midlevel assumption for each.

- **Economic Growth**. In the Reference Case, productivity grows at an average annual rate of 0.9 percent from 1994 through 2015 and the labor force at 1.0 percent per year, yielding a growth in real GDP of 2.0 percent per year. In the High Economic Growth Case, productivity and the labor force grow at 1.2 and 1.3 percent per year, respectively, resulting in GDP growth of 2.5 percent annually. The average annual growth in productivity, the labor force, and GDP are 0.7, 0.8, and 1.5 percent, respectively, in the Low Economic Growth Case.

- **World Oil Markets**. In the Reference Case, the average world oil price remains below $20 per barrel (in real 1994 dollars) through 2001 and then gradually increases to $25.43 per barrel in 2015. Reflecting uncertainty in world markets, the price in 2015 reaches $16 per barrel in the Low Oil Price Case and nearly $34 per barrel in the High Oil Price Case. The key factor underlying the differences in the oil prices is the assumption concerning production in the Organization of Petroleum Exporting Countries (OPEC) and in the Former Soviet Union and Eastern Europe.

In addition to the five fully integrated cases, a series of 20 additional cases explore the impacts of changing key assumptions in individual sectors. In both the residential and commercial sectors, fixed technology cases assume that the average efficiencies for equipment sold through 2015 will be the same as the average efficiencies for equipment sold in 1995. Alternative high technology cases are examined in which the most energy-efficient technologies available in each forecast year are chosen, regardless of cost, to replace relatively less efficient capital stock. In the industrial and transportation sectors, there are similar fixed technology cases and high efficiency cases, which assume that efficiency gains in the future will be equivalent to those achieved since 1970.

In the coal production sector, additional analyses were based on assumptions of productivity improvements and labor wage rates up and down from those in the reference case. For electricity generation high and low technology cases assume that the advanced generating technologies reach their commercialization cost sooner or later then in the reference case. Additional cases explore the impacts of earlier and later nuclear plant retirements and higher electricity demand.

Two additional cases examine the impact of high or low technological progress in the oil and gas production sector. The high technology case includes more rapid efficiency improvements in the refining sector. The impact of the ethanol subsidy, scheduled to end in 2000, is examined in a seperate sensitivity case.

These side cases were designed to examine the impacts of varying key assumptions for individual 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, in the residential demand high technology side case, it is assumed that all equipment purchases from 1995 onward 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 October 1, 1995. These include the additional fuels taxes in the Omnibus Budget Reconciliation Act of 1993, the Clean Air Act Amendments of 1990, and the Energy Policy Act of 1992. Pending legislation and sections of existing legislation for which funds have not been appropriated are not reflected in these forecasts. One exception to the date is the repeal of the ban on exports of Alaskan crude oil, which was signed on November 28, 1995, but included in the analyses. Changes to oil and gas royalities in the Gulf of Mexico, which are part of the same legislation, are not included.

The projections include analysis of the provisions of the Climate Change Action Plan (CCAP), 44 actions to achieve carbon stabilization in the United States by 2000, relative to 1990. Thirteen of the actions are not related to the combustion of energy fuels and are not incorporated in the analysis. Since funding for many of the CCAP programs have been curtailed in budget negotiations, their full impact is not reflected in these projections.

Emissions

Total carbon emitted by the combustion of energy is a function of both the carbon content of each fuel and the use of that fuel. Fuel consumption is calculated by aggregating the fuel requirements of the four end-use demand sectors and the electricity conversion sector. Total fuel consumption by type is multiplied by an emissions coefficient to calculate the carbon emitted to the atmosphere.

It is assumed that combustion is 99 percent complete for non-gaseous fuels and 99.5 percent complete for gaseous fuels. In addition, a portion of certain fossil fuels is used for non-fuel processes, such as feedstocks for chemical production. In this case a significant proportion of the carbon is sequestered in the product and not released to the atmosphere. These fuels are subtracted from the total fuel demands in the emissions calculations. Table 1 displays the emission factors and sequestration rates used in the *AEO96*.

Table 1. Emission Factors

Fuel Type/Sector	Million Metric Tons Carbon per Quadrillion Btu	Proportion of Nonfuel Use (If Any) Sequestered[a]
Petroleum		
Motor Gasoline	19.43	-
Liquefied Petroleum Gas	17.02	0.80
Jet Fuel	19.34	-
Distillate Fuel	19.95	-
Residual Fuel	21.49	-
Asphalt and Road Oil	20.62	1.00
Lubricants	20.24	0.50
Petrochemical Feedstocks	19.37	0.80
Kerosene	19.72	-
Petroleum Coke	27.85	-
Petroleum Still Gas	17.51	
Other: Waxes and Miscellaneous	19.81	1.00
Coal		
Residential and Commercial	25.97	
Metallurgical	25.51	
Other Industrial	25.61	
Electrical Generation		
Bituminous Coal	25.37	
Subbituminous Coal	26.24	
Lignite	26.62	
Natural Gas		
Natural Gas	14.47	0.41

[a]The sequestered portion of nonfuel use does not emit carbon because it is permanently contained in the end product.

Source: Energy Information Administration, *Emissions of Greenhouse Gases in the United States, 1987-1994*, DOE/EIA-0573(87-94), (Washington, DC, October 1995); *Emissions factors by coal rank*: Science Applications International Corporation, "*An Analysis of the Relationship Between the Heat and Carbon Content of U.S. Coals*," Final Report prepared for the Energy Information Administration (1992).

Macroeconomic Activity Module

The Macroeconomic Activity Module 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.

Key Assumptions

The output of the Nation's economy, measured by GDP, is expected to increase by 2.0 percent between 1994 and 2015 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 2 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 *AEO96*. Total population is expected to grow by 1.0 percent between 1994 and 2015, showing slower rates 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 2. Growth in Gross Domestic Product, Labor Force, and Productivity
(Percent per Year)

Assumptions	1990-1995	1995-2000	2000-2005	2005-2010	2010-2015	1994-2015
GDP						
High Growth	2.3	3.0	2.6	2.2	2.0	2.5
Reference	2.3	2.4	2.2	1.7	1.5	2.0
Low Growth	2.2	1.8	1.8	1.2	1.0	1.5
Labor Force						
High Growth	1.3	1.8	1.5	1.1	0.7	1.3
Reference	1.3	1.5	1.3	0.9	0.5	1.1
Low Growth	1.2	1.1	1.0	0.7	0.2	0.8
Productivity						
High Growth	1.0	1.3	1.2	1.0	1.3	1.2
Reference	1.0	1.0	1.0	0.8	1.0	1.0
Low Growth	1.0	0.7	0.7	0.5	0.8	0.7

Source: Energy Information Administration, AEO 1996 National Energy Modeling System runs: aeo96b.d101995c; LMAC96.d101995f; and HMAC96.d101995d.

The productivity of labor is the second major determinate of 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 2.0 percent growth is an anticipated recovery in productivity growth. Productivity growth slowed in the 1970's, compared to the growth experienced post-World War II. There is no consensus about why productivity growth declined so much after 1973. However, between 1980 and 1990, business investment's share of GDP declined at the same time that both the Federal budget deficit and the trade deficit increased. Since 1991, the economic recovery has been led by strong gains in business investment as a result of lower interest rates. Productivity has shown recent strong gains as economic output has increased more rapidly than employment gains.

In the Reference Case, productivity growth remains relatively constant throughout the forecast period. 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 *AEO96* 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).[3] The DRI forecasts used in *AEO96* 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 *AEO96* Reference Case. With this change, the DRI projections are used as the starting point for the macroeconomic forecasts within the NEMS simulations for the *AEO96*. 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 2.5 percent between 1994 and 2015. 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 Growth Case, economic output is expected to increase by 1.5 percent over the forecast horizon.

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

[3]The underlying macroeconomic growth cases use DRI/McGraw-Hill's February 1995 Trend, Optimistic and Pessimistic Growth Cases. See DRI/McGraw-Hill, *Review of the U.S. Economy: Long-Range Focus,* Winter 1995 (Lexington, MA, 1995).

International Energy Module

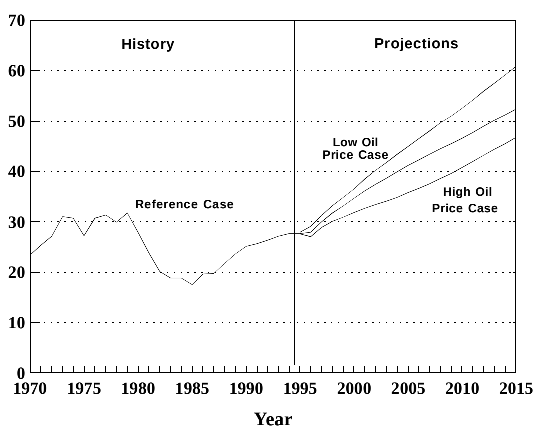
The International Energy Module determines changes in the world oil price and the supply prices of petroleum products for import to the United States in response to changes in U.S. import requirements. A market clearing method is used to determine the price at which worldwide demand for oil is equal 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.

Key Assumptions

The level of oil production by countries in the Organization of Petroleum Exporting Countries (OPEC) is a key factor influencing the world oil price projections incorporated into *AEO96*. Non-OPEC production, worldwide regional economic growth rates and the associated regional demand for oil, and the level of net oil exports from Eurasia (the former Soviet Union, China, and Eastern Europe) are additional factors affecting the world oil price.

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—in the neighborhood of 750 billion barrels, over 75 percent of the world's total, at the end of 1993.[4] For the *AEO96* 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.

Figure 2. OPEC Oil Production, 1970-2015
(Million Barrels per Day)

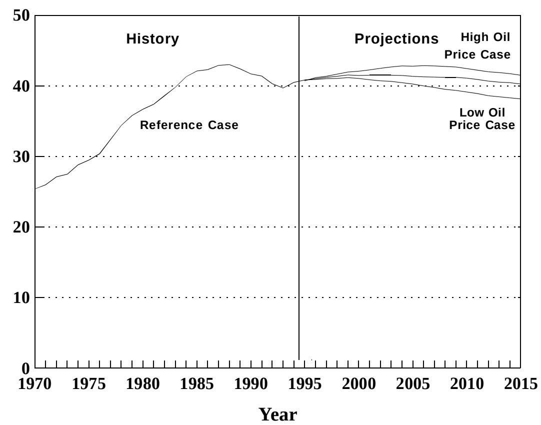


OPEC = Organization of Petroleum Exporting Countries.
Source: Energy Information Administration, AEO 1996 National Energy Modeling System runs: LWOP96.d101995b; AEO96b.d101995c; and HWOP96.d101995b.

[4]Energy Information Administration, *International Energy Outlook 1995*, DOE/EIA-0484(95) (Washington DC, June 1995).

Non-OPEC oil production is expected to follow a fairly flat path—with a slight rise through the year 2000 and a modest decline thereafter—as production declines in some parts of the world are offset by increases in other regions (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, 1970-2015
(Million Barrels per Day)



OPEC = Organization of Petroleum Exporting Countries.
Source: Energy Information Administration, AEO 1996 National Energy Modeling System runs: LWOP96.d101995b; AEO96b.d101995c; and HWOP96.d101995b.

The assumed growth rates for gross domestic product (GDP) for various regions in the world are shown in Table 3. 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 4 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 Eurasia (the former Soviet Union, China, and Eastern Europe) are projected to decline through 1995, with virtually all of the decline occurring in the former Soviet Union (FSU). Oil production in the FSU is assumed to decline through 1995 but to remain well above domestic FSU oil consumption. After 1995, oil production in the FSU recovers along with oil consumption, and the FSU remains a net exporter through 2015. In contrast, China is expected to become a net importer of oil before 1995 and remain so through 2015. Currently, Eastern Europe depends on imports for most of its oil and will continue to do so.

Table 3. Average Annual Regional Gross Domestic Product Growth Rates, 1995-2015
(Percent per Year)

Region	Gross Domestic Product
Organization for Economic Cooperation and Development	2.4
Organization of Petroleum Exporting Countries	4.6
Other Developing Countries	4.4
Eurasia	5.5
China	7.6
Former Soviet Union	4.4
Eastern Europe	3.1
Total World	3.5

Source: The WEFA Group, *World Economic Service and World Economic Service Historical Data* (June 1994) and *World Economic Outlook* (July 1995).

Table 4. Average Annual Regional Growth Rates for Oil Demand, 1993-2015
(Percent per Year)

Region	Low Price	Reference	High Price
Organization for Economic Cooperation and Development	1.7	1.1	0.7
Organization of Petroleum Exporting Countries	2.9	2.9	2.9
Other Developing Countries	4.3	3.9	3.5
Eurasia	2.2	2.2	2.2
China	4.1	3.6	3.1
Former Soviet Union	1.0	1.5	1.9
Eastern Europe	1.8	1.6	1.5
Total World	2.3	2.0	1.6

Source: Energy Information Administration, AEO 1996 National Energy Modeling System runs: LWOP96.d101995b; AEO96b.d101995c; and HWOP96.d101995b.

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 *AEO96* 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 *AEO96* 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 Demand Module and the Transportation Demand Module. 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 *AEO96* they are assumed to remain constant throughout the forecast period.

Residential Demand Module

The National Energy Modeling System (NEMS) Residential Demand Module estimates future residential sector energy requirements based on estimates of the number of households and the stock and efficiency of energy consuming equipment contained in these houses. In very general terms, the residential module begins with a base year housing stock, estimates of the types and numbers of different appliances contained in the stock and the energy consumption by appliance. The projection process includes adding new housing units to the stock, determining the equipment installed in new units, and retiring existing housing units, retiring and replacing appliances with current or projected appliances of like kind. The primary exogenous drivers for the module are housing starts by type (single-family, multifamily and mobile homes) and Census division and prices by fuel type and Census division. The module also requires projections of available equipment over the forecast horizon. Over time equipment efficiency tends to increase because of general engineering advances in the provision of energy services and also because of Federal efficiency standards. As energy prices change over the forecast horizon, the module includes potential changes to the type and efficiency of equipment purchased as well as changes in the usage patterns of equipment.

The end-use services for which equipment is tracked include space conditioning (heating and cooling), water heating, refrigeration, freezers, cooking, and clothes dryers. In addition to these major end-use services, the average unit energy consumption (UEC[5]) is tracked for secondary heating, lighting, and other electric and nonelectric appliances. The geographic coverage is the nine Census divisions. 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.

Key Assumptions

Housing Stock Submodule

The key driver in the residential sector is the number of occupied households. The number of households for the base year (1993) is derived from the Energy Information Administration's (EIA) *Residential Energy Consumption Survey* (RECS) (Table 5). The forecast for occupied households is based on the combination of the previous year's surviving stock and housing starts provided by the NEMS Macroeconomic Activity Module. The Housing Stock Submodule assumes a constant survival rate for each type of household unit; 0.997 for single-family units, 0.996 for multifamily units, and 0.970 for mobile home units.

Fuel consumption is dependent not only on the number of houses, but also on the type and geographic distribution of the houses. For example, distillate oil is frequently used as a heating fuel in New England, while natural gas dominates in the Midwest. Liquefied petroleum gas is a prevalent heating fuel among mobile homes.

Technology Choice Submodule

The key inputs in the Technology Choice Submodule are fuel prices and equipment characteristics (capital cost, efficiency, etc.) by Census division. Fuel prices are exogenous variables passed to the submodule from the various supply modules through the NEMS integration system. Equipment characteristics are exogenous variables which are modified to reflect Federal standards and anticipated changes in the market place. Table 6 lists capital cost and efficiency for selected residential appliances for the years 1995 and 2005.

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[5]Energy consumed by a technology or service measured in million Btu per household per year.

Table 5. 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).

Table 6. Capital Cost and Efficiency Ratings of Selected Equipment

Equipment Type	Relative Performance 1/	1995 Capital Cost 2/	1995 Efficiency 3/	2005 Capital Cost 2/	2005 Efficiency 3/
Electric Heat Pump	Minimum	$2,909	10.0	$3,117	13.0
	High	$4,986	16.0	$4,883	18.0
Natural Gas Furnace	Minimum	$1,351	0.78	$1,766	0.92
	High	$3,117	0.95	$2,182	0.96
Room Air Conditioner	Minimum	$623	8.7	$623	12.5
	High	$883	12.5	$883	13.0
Central Air Conditioner	Minimum	$2,182	10.0	$2,234	13.0
	High	$2,701	16.9	$3,168	18.0
Refrigerator (18 cubic ft)	Minimum	$519	683	$597	480
	High	$675	550	$779	400
Electric Water Heater	Minimum	$364	0.87	$364	0.88
	High	$1,299	1.80	$805	2.80

1_/ Minimum performance refers to the lowest efficiency equipment available. Best refers to the highest efficiency equipment available.

2_/ Capital costs are given in 1990 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 heater 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 module projects equipment choice for new construction based on a nested choice methodology. The first stage of the choice methodology determines the fuel and technology to be used. For new construction, home heating fuel and technology choice is determined based on life-cycle costs assuming a 20 percent discount rate. The choice of fuel for water heating and cooking is then linked to the space heating choice. For existing construction, equipment is usually replaced with equipment using the same fuel and technology. The exception is for the replacement of the main space heating system, where some fuel and technology switching is permitted. Fuel switching at the time of replacement is based on American Gas Association's *Residential Natural Gas Market Survey, 1992* and is assumed to be sensitive to changes in relative fuel prices. These data indicate a modest amount of switching from other space heating fuels (i.e., electricity, oil, liquified petroleum gas or wood) to natural gas heating, approximately 300,000 households per year (or roughly 0.3 percent of the housing stock). That is, if the price of a competing fuel rises (falls) relative to the natural gas price, then a greater (fewer) number of existing households will switch to natural gas in a given year.

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 usually three prototypes of varying efficiency available (low, medium and high efficiency). Efficiency choice is based on the installed capital cost (first cost) and operating cost. The parameters of this stage are calibrated to the most recently available shipment data for the major residential appliances collected by from various trade organizations (e.g., the Gas Appliance Manufacturing Association). Thus, the relative importance of first cost versus operating cost varies by service type. It is possible to calculate approximate discount rates from these coefficients, and for efficiency choice, discount rates in excess of 30 percent are common. The apparent use of such high discount rates by consumers has led to the notion of the "efficiency gap" -- that is, there are many investments that could be made to 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. The efficiency gap literature has been drawn on as the basis for efficiency standards and federal-sponsored voluntary programs under the Climate Change Action Plan. Once equipment efficiencies are determined, the installed efficiency for the entire segment of the residential equipment market is updated by weighing all of the individual equipment efficiencies by its respective market share of energy consumption.

Appliance Stock Submodule

The Appliance Stock Submodule computes the quantity and mix of equipment installed in new construction (based on the market shares mentioned above), tracks surviving equipment installed in previous years, and calculates the number of replacement units needed in the current year. A "saturation/penetration" approach is used to determine equipment purchases in a given year, therefore the number of appliance purchases is a function of the number of households. The number of newly constructed houses determines the number of appliances to be installed and the market shares (developed in the Technology Choice Submodule) determine the mix of the equipment. For existing structures (any house constructed prior to the current forecast year), the difference between the number of surviving houses and the number of surviving equipment determines the number of replacement equipment needed for a given year. For certain appliances, which have not yet achieved full penetration (central and room air conditioning, and clothes dryers), additional appliances beyond those needed for replacement or new construction are purchased.

The Appliance Stock Submodule works in conjunction with the Housing Stock Submodule to track the number of each type of equipment. Several assumptions are made in tracking the equipment stock. First, it is assumed that an appliance survives a minimum number of years after installation. Second, appliances do not survive beyond the maximum life expectancy. Between the minimum and maximum life expectancy, all appliances retire based on a linear decay function. 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 second-hand market for this equipment (Table 7).

Fuel Consumption Submodule

Energy consumption is calculated by multiplying the vintaged equipment stock by their respective UECs. The UECs include adjustments for the average efficiency of the stock, shell efficiency for heating and cooling, price elasticity and rebound effects on usage, the size of new construction relative to the existing stock, and weather. The various levels of aggregated consumption (consumption by fuel, by service, etc.) are derived from these detailed equipment-specific calculations.

Table 7. 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	18
Central Air Conditioners	8	16
Water Heaters	7	19
Cooking Stoves	16	21
Clothes Dryers	6	30
Refrigerators	13	25
Freezers	17	25

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

Equipment Efficiency

The average energy consumption of a particular appliance is based initially on estimates derived from RECS 1993. The efficiency of the appliance 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 geothermal heat pumps). In many cases, the average efficiency of shipments is available for a 20 to 30 year interval, which permits the calculation of current average efficiency when coupled with assumptions concerning equipment lifetimes.

As the stock efficiency changes over the simulation interval, 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. For example, if on average, electric heat pumps are now 10 percent more efficient than in 1993, then all else constant (weather, real energy prices, shell efficiency, etc.), then energy consumption per heat pump would now average 10 percent less. The Appliance Stock and Technology Choice Submodules determine the average efficiency of the stocks used in adjusting the initial UECs.

Adjusting for the Size of New Construction

Information derived from RECS 1993 indicates that new construction (post-1990) is approximately 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. This results in an increase in the average size of the housing stock of 1630 to 1710 square feet from 1993 through 2015.

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 residential module, proportionate adjustments are made to space heating and air conditioning UECs by Census division. These adjustments are based on 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. The residential module makes weather adjustments for the years 1993 through 1995. After 1995, 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. 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 -.15). Currently, the services affected by the short-term price effect and efficiency rebound are space heating, cooling and lighting.

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. 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 fuel prices. As fuel prices increase relative to their 1993 levels, it is assumed that the shell integrity of these homes improves. 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 tighter building codes become more widespread. 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.

Other Residential End Uses

Other end uses have grown at an average rate of over 6 percent a year over the last several years (between the RECS 1987 and 1993) surveys. These uses are substantially electric appliances and include personal computers, dishwashers and clothes dryers. They now account for 27 percent of total residential energy use and are projected to account for 39 percent by 2015, as these uses continue to penetrate the residential market.

Legislation and Other Federal Programs

Energy Policy Act of 1992

The Energy Policy Act of 1992 (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 0.88 for electric water heaters; and refrigerator standards that set consumption limits to 976 kilowatt-hours per year in 1990 and 691 kilowatt-hours per year in 1993.

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 level by the year 2000. The CCAP strategies which directly affect the residential sector are Actions 8 through 11. The Residential Demand Module for *AEO96* 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 DOE and 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.

Action Item 7 includes all future federal efficiency standards for residential equipment. *AEO96* assumes that the effects of federal efficiency standards will impact residential appliance efficiency over the simulation period as required by the current legislation. Future standards are generally not yet promulgated, but the legislation requires analysis and reconsideration of current standards in particular years. For 1998, additional standards will be required for room air conditioners, water heaters, and kitchen ranges and stoves. The efficiency levels assumed in the residential module are: 9.0 EER for room air conditioners, .87 EF for electric water heaters, .57 EF for gas water heaters, 562 Kwh per year for electric ranges, and 3.7 million Btu per year for gas ranges.

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 *AEO96*, 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. In total, the NEMS Residential Demand Module includes energy savings for these action items which are estimated to reduce carbon emissions by the year 2000 by 3.3 million metric tons.

Efficiency Standalone Cases

In addition to the *AEO96* reference case, two side cases were developed to examine the effect of equipment and building standards on residential energy use -- a 1995 efficiency case and a high technology case. These side cases were analyzed in standalone NEMS runs (not integrated with the supply modules) and thus do not include supply-responses to the altered residential consumption patterns of the two cases. Fuel shares of each technology remain fixed at the reference case level, only efficiencies change.

The 1995 technology case assumes that all future equipment purchases are made based only on equipment available in 1995. This case further assumes that build shell efficiency will increase more slowly than the reference case. In the reference case, the 2015 housing stock shell efficiency is 9 percent higher than in 1993 for heating (6 percent for cooling). In the 1995 technology case, heating shell efficiency is assumed to increase only 3 percent (cooling shell, 2 percent).

The high technology case assumes that all equipment purchases from 1995 forward are based on only the highest available efficiency in a particular simulation year. The high 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. In the high technology case, heating shell efficiency is assumed to increase by 17 percent (cooling shell, 12 percent).

Commercial Demand Module

The National Energy Modeling System (NEMS) Commercial Demand Module generates midterm forecasts of commercial sector energy demand. The definition of the commercial sector is, with only minor exceptions, consistent with EIA's State Energy Data System (SEDS).[6] 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.[7]

The commercial module forecasts consumption by fuel[8] 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[9] for eleven building categories[10] 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.[11] 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.[12]

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.

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[6]Some minor electricity transfers have been made out of the SEDS definition of the commercial sector and into transportation to account for public agencies providing transportation services. Also very small amounts of natural gas have been transferred out of the commercial sector to account for non-utility generation of electricity in the electric generator sector.

[7]See 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).

[8]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.

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

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

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

[12]The detailed documentation of 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(95), (Washington, DC, February 1995). See also the update DOE/EIA M066(96), forthcoming.

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 (MAM) floorspace projection.[13]

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.[14]

Table 8. 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	146	160	342	356	605	292	311	3,280
Middle Atlantic . . .	938	1,373	61	350	244	465	1,085	779	2,205	1,476	1,238	10,214
East North Central	1,280	1,530	110	289	270	405	1,182	839	1,873	1,916	1,047	10,741
West North Central	733	864	75	144	228	168	311	472	1,289	1,203	1,101	6,587
South Atlantic	1,375	1,158	114	183	310	520	1,144	892	1,635	2,119	1,149	10,600
East South Central	462	553	30	48	172	260	457	501	1,140	1,451	345	5,420
West South Central	1,781	917	106	178	122	255	559	618	1,486	1,398	1,161	8,582
Mountain	414	412	117	53	31	233	409	342	667	606	365	3,649
Pacific	1,046	1,076	96	155	263	416	1,112	974	1,579	1,044	1,264	9,024
United States	8,337	8,494	767	1,494	1,786	2,882	6,601	5,773	12,479	11,504	7,980	68,098

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 that are embodied in the Data Resources, Inc. (DRI) total floorspace forecast. New construction is calculated by applying DRI's assumed regional building retirement rates to the DRI building types, by Census division.[15] The DRI surviving floorspace from the previous year is subtracted from the DRI floorspace

[13]The floorspace from the Macroeconomic Activity Model is based on the Data Resources Incorporated (DRI) floorspace estimates which are approximately ten 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. Due to the higher floorspace estimates from CBECS, the additions implicit in the MAM forecast are derived from the forecast and added to the surviving CBECS stock.

[14]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.

[15]The DRI building retirement rates by Census Region are: Northeast - 1.30%, Midwest - 1.33%, South - 1.29%, and West - 1.30%.

forecast for the current year from MAM to yield new floorspace additions.[16] New additions are then mapped from the DRI definitions to the NEMS Commercial Demand Module's building types based on the CBECS building types shares.

Service Demand Submodule

Once the building stock is projected, the commercial 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.[17] 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.[18] 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 (described below).

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. In the *AEO96* reference case, shell improvements for new buildings are up to 30 percent more efficient than the 1992 stock of similar buildings. For existing buildings, efficiency is assumed to increase by 5 percent over the 1992 stock average unless new construction efficiency is less than 5 percent more efficient than the stock average for a particular building. The shell efficiency index affects the space heating and cooling service demand intensities directly, causing a decrease 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.[19] 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.

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

[17]"Other office equipment" includes communications equipment, security equipment, some appliances, tools, cash registers, elevators, water fountains, and clocks. A tenth category denoted other includes other non-office building-related equipment, Cogeneration use plus benchmarking adjustments which include energy consumed outside of buildings.

[18]Based on updated estimates using CBECS 1992 data and using a methodology similar to that described in *End-Use Energy Consumption Estimates for U.S. Commercial Buildings, 1989*, Belzer, D.B., Wrench, L.E., and Marsh, T.E., Pacific Northwest Laboratories, PNL-8946, Prepared for the U.S. DOE under Contract DE-AC06-76RLO-1830, (Richland, WA, November, 1993) a new report is forthcoming.

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

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:

1. **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.

2. **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.*

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

Under any of the three behavior rules, equipment that meets the service at the lowest annualized lifecycle cost is chosen. Table 9 illustrates the proportions of floorspace subject to the different behavior rules for space heating technology choices in large office buildings.

Table 9. 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. Office of Integrated Analysis and Forecasting.

Time Preferences

The time preferences of owners of commercial buildings are assumed to be distributed among six alternate time preference premiums. 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 *AEO96* assigns some floorspace a very high discount rate and simulates 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.

The discount rate distribution is the same for all end uses other than lighting as given in Table 10. For lighting, a block of commercial floorspace with high premiums has been "promoted" to a premium of 13.6 percent. This is to simulate additional retrofitting behavior resulting from the Environmental Protection Agency's Green Lights Program (see discussion of CCAP).

Table 10. Assumed Distribution of Time Preference Premiums for Two End Uses (Percent)

Space Heating		Lighting	
Proportion of Floorspace	Time Preference Premium	Proportion of Floorspace	Time Preference Premium
33.0	1000.0	33.0	1000.0
19.4	152.9	14.4	152.9
20.4	55.4	11.4	55.4
16.2	30.9	16.2	30.9
10.0	19.9	10.0	19.9
1.0	13.6	15.0	13.6
100.0		100.0	

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

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 11 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 1993, all else constant (weather, real energy prices, shell efficiency, etc.), then energy consumption per heat pump would now average 10 percent less. The Service Demand and Technology Choice Submodules together determine the average efficiency of the stocks used in adjusting the initial average energy consumptions.

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 UECs by Census division. These adjustments are based on 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 commercial module makes weather adjustments for the years 1993 through 1995. After 1995, 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. 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 -.15). Currently, the services affected by the short-term price effect and efficiency rebound are space heating, cooling 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 1993 by Census division, building type, and fuel. After 1993, 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.[20] 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

A key assumption incorporated in the technology selection process is that the equipment efficiency standards described in the Energy Policy Act of 1992 (EPACT) constrains minimum equipment efficiencies. The effects of standards is 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

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

boilers—minimum annual fuel utilization efficiency of 0.8, fluorescent lighting—minimum efficacy of 75 lumen per watt, incandescent lighting—minimum efficacy of 16.9, air conidtioners—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 Administration's 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 efficiency building shells and equipment for heating, cooling and other end uses. Action Item 2 targets the retrofitting of lighting equipment. Action Item 3 was unfunded and therefore not modeled. Future equipment standards are also considered part of CCAP. 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). The standards component of CCAP is modeled directly in the technology characterization database as described above. For Action Item 2, the distribution of discount rate premiums for lighting has been adjusted to include a lower premium based on the retrofitting agreements made by participants in the Environmental Protection Agency's Green Lights Program (and its planned expansion which is part of CCAP). For Action Items 1, 4 and 5, retrofits of equipment for space heating and air conditioning are incorporated in the distribution of premiums given in Table 10. Also, for these actions, the shell efficiency of existing buildings is assumed to increase at a uniform annual rate to a level that is 5 percent more efficient than 1992 by 2015. In total, the NEMS Commercial Demand Module include energy savings for these action items which are estimated to reduce carbon emissions by the commercial sector by 4.1 million metric tons for the year 2000.

Efficiency Standalone Cases

In addition to the *AEO96* reference case, two side cases were developed to examine the effect of equipment and building standards on commercial energy use—a 1995 efficiency case and a high technology case. These side cases were analyzed in stand-alone NEMS runs (not integrated with the supply modules) and thus do not include supply-responses to the altered commercial consumption patterns of the two cases.

The 1995 technology case assumes that all future equipment purchases are made based only on equipment available in 1995. This case further assumes that building shell efficiency will increase more slowly than in reference case. In the reference case, existing building shells are allowed to increase in efficiency by as much as 5 percent over 1992 levels. In the 1995 technology case, existing shell efficiency is assumed to be fixed at 1995 levels.

The high technology case assumes that all equipment purchases from 1995 forward are based on only the highest available efficiency in a particular simulation year. The high 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. In the high technology case, existing shell efficiency is assumed to increase to the levels of efficiency for new construction by 2015.

Fuel shares are allowed to change for an end use as the best technologies from each technology type compete to serve certain segments of the commercial floorspace market. For example, in the high technology case, the most efficient gas furnace technology competes with the most efficient electric heat pump technology. Existing building shells are assumed to become as efficient as current new construction by 2015 in the high technology case.

Table 11. Capital Cost and Efficiency Ratings of Selected Space Heating Equipment

Equipment Type	Vintage	Efficiency 1_/	Capital Cost (1990$ per Mbtu/hour)	Maintenance Cost (1990$ per Mbtu/hour)	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	$101.49	$3.79	12
Ground-Source Heat Pump	1992	10.2	$154.17	$3.47	13
	1993	11.6	$158.33	$3.47	13
	1995	13.0	$173.61	$3.47	13
	2000	11.6	$144.44	$3.47	13
	2005	14.0	$250.00	$3.47	13
	2010- low efficiency	13.0	$138.89	$3.47	13
	2010 - high efficiency	14.3	$222.22	$3.47	13
Electric Resistance	1992	1.0	$6.89	$0.45	25
Packaged Electric	1992	0.80	$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	$14.05	$0.14	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	$222.22	$6.25	13
	2005	1.02	$154.17	$4.86	13
	2005	1.45	$152.78	$4.17	15
	2010- low efficiency	1.02	$154.17	$4.86	13
	2010 - high efficiency	1.45	$152.78	$4.17	15
Distillate Oil Furnace	1992- low efficiency	0.72	$13.86	$0.23	15
	1992 - high efficiency	0.81	$14.95	$0.23	15
	1998	0.83	$16.06	$0.25	15
	2000	0.86	$16.26	$0.26	15
	2010	0.89	$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 furnaces and boilers are based on Annual Fuel Utilization Efficiency and natural gas heat pumps are rated on.

Source: Arthur D. Little, *EIA Technology Forecast Updates*, Reference Number 41615, June 1995.

Industrial Demand Module

The National Energy Modeling System (NEMS) Industrial Demand Module estimates energy consumption by energy source (fuels and feedstocks) for 25 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 12). 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 State Energy Data System (SEDS)[21] data, and the shares remain constant over time.

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 with aggregate process flows. Each industry is modeled as three separate but interrelated components consisting of the Process / Assembly Component, the Buildings Component, and the Boiler / Steam / Cogeneration 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 broken down 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 was developed to trace energy flows from fuels to the industry's output. An important assumption in the development of this system is the use of 1988 baseline Unit Energy Consumption (UEC) estimates based on analysis of the Manufacturing Energy Consumption Survey 1988[22] and Standard and Poor's Major Industrial Plant Database.[23] 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 newand existing stock relative to the 1988 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.

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[21]Energy Information Administration, *State Energy Data Report 1993, DOE/EIA-0214(92)*, (Washington, D.C., May 1995).

[22]Energy Information Administration, *Manufacturing Energy Consumption Survey: Consumption of Energy 1988, DOE/EIA-0512(88)* (Washington, D.C., May 1991).

[23]Standard and Poor's, Inc., *Major Industrial Plant Database*, (New York, N.Y., 1989).

Table 12.Industry Categories

Energy-Intensive Manufacturing	Nonenergy-Intensive Manufacturing (continued)
Food and Kindred Products (SIC 20)	Leather and Leather Products (SIC 31)
Paper and Allied Products (SIC 26)	Other Stone, Clay, and Glass (SIC 325, 326, 327, 328, 329)
Bulk Chemicals (SIC 281, 282, 286, 287)	Other Primary Metals (SIC 33, excluding iron and steel and primary aluminum)
Glass and Glass Products (SIC 321, 322, 323)	Fabricated Metal Products (SIC 34)
Hydraulic Cement (SIC 324)	Industrial Machinery and Equipment(SIC 35)
Blast Furnaces and Basic Steel (SIC 331, 332)	Electronics, Except Computers (SIC 36)
Primary Aluminum (SIC 3334)	Transportation Equipment (SIC 37)
Nonenergy-Intensive Manufacturing	Instruments and Other Electric Equipment (SIC 38)
Tobacco Products (SIC 21)	Miscellaneous Manufacturing Industries (SIC 39)
Textile Mill Products (SIC 22)	**Nonmanufacturing Industries**
Apparel and Other Textile Products (SIC 23)	Agricultural Production - Crops (SIC 01)
Lumber and Wood Products (SIC 24)	Other Agriculture including Livestock (SIC 02, 07, 08, 09)
Furniture and Fixtures (SIC 25)	Coal Mining (SIC 12)
Printing and Publishing (SIC 27)	Oil and Gas Mining (SIC 13)
Other Chemicals (SIC 283, 284, 285, 289)	Metal and Other Nonmetallic Mining (SIC 10, 14)
Asphalt and Miscellaneous Products of Petroleum and Coal (SIC 295, 299)	Construction (SIC 15, 16, 17)
Rubber and Miscellaneous Plastics Products (SIC 30)	

SIC = Standard Industrial Classification.
Source: Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M064 (Washington, DC, January 1994).

Process/Assembly Component

The Process/Assembly 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 16). 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. In addition, byproducts produced in the Process/Assembly Component serve as fuels for the Boiler/Steam/Cogeneration 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 13). Energy consumption in the Building 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 Process/Assembly and Buildings Components are passed to the Boiler/Steam/Cogeneration Component, which applies a heat rate and a fuel share equation (Table 14) 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 heat rate is estimated from the Industrial Sector Technology Use Model,[24] and the boiler fuel shares are assumed to be those estimated using the 1991 MECS.[25]

Nonenergy-Intensive Industries

The UECs for the Process/Assembly Component of the nonenergy-intensive industries are econometrically estimated with autonomous and price-induced technical change. The autonomous trend is represented by cumulative output from existing technology. The short-term response to fuel price changes occurs by applying the estimated own- and cross-price elasticities[26] to the Process/Assembly UECs to reflect the

[24]Energy and Environmental Analysis, Inc., *Overview: The Industrial Sector Technology Use Model: ISTUM-2*, March 1986.

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

[26]The various elasticities are documented in Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System, DOE/EIA-M064*, (Washington, D.C., January 1994).

response. The cumulative output variable captures any autonomous trend over time within the industry that may affect the energy intensity of the production process.

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 15). 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 16). 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.

Legislation

The Energy Policy Act of 1992 (EPACT) and the Clean Air Act Amendments of 1990 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 CCAP target the industrial sector. The intent of these programs is to reduce greenhouse gas emissions by lowering industrial energy consumption. It was estimated that full implementation of these programs would reduce industrial electricity consumption by 40 billion kilowatthours and nonelectric consumption by 400 trillion Btu by 2000. The resulting carbon reduction is 11.3 million tons of carbon equivalent (MMtce). The energy savings were revised in proportion to the funding received. The energy savings for the Motor Challenge Program were further reduced because the assumed ratio of private to federal spending was 6 times higher for this program than was the average for all industrial sector programs. Consequently, electricity consumption is reduced by 10 billion kilowatthours, and nonelectric energy consumption is reduced by 80 trillion Btu. The nonelectric energy is assumed to be steam coal. In this case, carbon emissions are reduced by 3.2 MMtce.

High Efficiency and 1995 Technology Cases

Over the 1970-1990 period, industrial energy intensity fell by 1.9 percent annually. This was due to energy conservation and the changing composition of industrial output. The high efficiency case approximates the 1.9-percent annual decline from 1995 through 2015. This is twice the rate of decline anticipated in the Reference Case (0.9 percent). For this exercise, the composition of industrial output remained the same as in the Reference Case.

The 1995 technology case holds the energy efficiency of new plant and equipment constant over the forecast. New equipment and processes, however, typically are more energy efficient than those used in existing plants. As a result, the average energy intensity declines as old equipment is retired and new production capacity is added.

A standalone model run examined these side cases. Consequently, no potential fuel price or macroeconomic feedback effects are considered.

Table 13. Building Component Unit Energy Consumption (Trillion Btu/Thousand People Employed)

SIC	Industry	Building Use and Energy Source: Lighting: Electric UEC	HVAC: Electric UEC	HVAC: Natural Gas UEC	HVAC: Steam UEC
20	Food & Kindred Products	0.009	0.006	0.013	0.062
21	Tobacco Products	0.007	0.005	[a]	0.071
22	Textiles Mill Products	0.017	0.014	0.005	0.033
23	Apparel	0.001	0.002	0.005	0.009
24	Lumber	0.002	0.006	[a]	0.031
25	Furniture	0.001	0.002	0.002	0.030
26	Paper & Allied Products	0.054	0.008	0.002	0.096
27	Printing & Publishing	0.001	0.008	0.002	0.016
281, 282, 286, 287	Bulk Chemicals	0.037	0.018	0.002	0.118
283, 284, 285, 289	Other Chemicals	0.002	0.001	0.002	0.002
2911	Petroleum Refining	0.156	0.074	0.036	0.123
295, 299	Asphalt & Misc. Petroleum and Coal Products	0.002	0.001	0.001	0.001
30	Rubber	0.005	0.015	0.002	0.013
31	Leather	0.003	0.003	[a]	0.035
321, 322, 323	Glass and Glass Products	0.148	0.084	0.030	0.000
324	Hydraulic Cement	0.010	0.006	[a]	0.000
325, 326, 327, 328, 329	Other Stone, Clay and, Glass	0.005	0.003	0.002	0.000
331, 332, etc.	Blast Furnaces & Basic Steel	0.788	0.374	0.957	1.231
3334, 3341, etc.	Primary Aluminum	0.053	0.025	[a]	0.007
333-336, 339	Other Primary Metals	0.003	0.001	[a]	0.004
34	Fabricated Metals	0.006	0.005	0.012	0.030
35	Industrial Machinery	0.006	0.012	[a]	0.014
36	Electronic Equipment	0.006	0.017	0.001	0.011
37	Transportation Equipment	0.010	0.007	0.003	0.037
38	Instruments	0.004	0.014	0.001	0.027
39	Miscellaneous Manufacturing	0.003	0.003	0.007	0.011

[a] This value is less than 0.0005.
SIC = Standard Industrial Classification.
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 1994).

Table 14.Logit Function Parameters for Estimating Boiler Fuel Shares

Industry	Alpha	Natural Gas	Steam Coal	Oil
Food	-.75	.6367	.2886	.0666
Tobacco Products	-.50	.1579	.7895	.0526
Textile Mill Products	-.50	.6009	.2575	.1330
Apparel and Other Textile Products	-.50	.6635	.1896	.1469
Lumber and Other Wood Products.	-.50	.6842	.1053	.1579
Furniture and Fixtures . .	-1.25	.4286	.4286	.1429
Paper and Allied Products .	-.50	.4531	.3677	.1729
Printing and Publishing . .	-1.00	.9156	.0000	.0844
Bulk Chemicals	-.50	.7175	.2435	.0359
Petroleum Refining	-.50	.7651	.0940	.1275
Rubber	-.50	.4444	.1111	.4444
Leather	-.50	.8065	.1075	.0645
Glass and Glass Products .	-.50	.6364	.2500	.0909
Cement	-2.00	.7529	.1044	.1298
Other Stone, Clay, and Glass Products	-.50	.5123	.3499	.1325
Steel	-1.50	.3447	.5580	.0973
Aluminum	-.50	.6649	.1330	.2021
Other Primary Metals . . .	-.50	.9840	.0000	.0160
Fabricated Metals	-.50	.0000	.0000	1.000
Industrial Machinery . . .	-.50	.6257	.0898	.1998
Electronic Equipment . . .	-.50	.5676	.2162	.2162
Transportation Equipment .	-.50	.9009	.0000	.0000
Instruments	-.50	.6323	.3162	.0339
Miscellaneous Manufacturing. . . .	-.50			
	-.50	.8377	.0099	.1523

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

Table 15.Retirement Rates

Industry	Retirement Rate (percent)	Industry	Retirement Rate (percent)
Food and Kindred Products . . .	1.7	Blast Furnace and Basic Steel Products (Blast Furnace/Open Hearth)	50.0
Tobacco Products	4.3	Blast Furnace and Basic Steel Products (Blast Furnace/Basic Oxygen Furnace)	0.0
		Blast Furnace and Basic Steel Products (Electric Arc Furnace)	1.5
Textile Mill Products	4.6	Glass and Glass Products	1.3
		Hydraul: Cement	1.3
		Other Stone, Clay, and Glass	1.3
Apparel and Other Textile Products	1.9	Primary Aluminum	2.1
Lumber and Wood Products . .	0.7	Other Primary Metals	1.2
Furniture and Fixtures	1.0	Fabricated Metals	2.1
Paper and Allied Products	2.3	Industrial Machinery	2.7
Printing and Publishing	5.4	Electronic Equipment	4.5
Bulk Chemicals	1.9	Transportation Equipment	1.6
Other Chemicals	3.6	Instruments	1.5
Asphalt and Miscellaneous Coal Products	2.2	Miscellaneous Manufacturing	2.3

Source: Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-MO64 (Washington, DC, January 1994).

Table 16.Coefficients for Technology Possibility Curve

SIC Industry Process Unit	Old Facilities REI 1991 (Year 1)	Old Facilities REI[a] 2015 (Year 24)	Old Facilities Slope b	New Facilities REI 1991 (Year 1)	New Facilities REI[a] 2015 (Year 24)	New Facilities Slope b
26 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
32 Glass[b]						
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
32 Cement						
Dry Process	1.000	0.982	-0.00094	0.790	0.657	-0.00768
Wet Process[c]	1.000	0.954	-0.00247	NA	NA	NA
Finish Grinding	1.000	0.943	-0.00309	0.813	0.641	-0.00989
33 Steel						
Coke Oven	1.000	1.000	0	0.840	0.817	-0.00116
BF/OH[c]	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	1.000	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
33 Aluminum						
Alumina Refinery	1.000	0.965	-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

[a]Calculated from slope value b and exponential equation (see text).
[b]REIs and slope apply to virgin and recycled materials.
[c]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: Arthur D. Little Inc., *NEMS Industrial Model: Update on Selected Process Flows and Energy Use.* Unpublished report prepared for Energy Information Administration (Vienna, VA, April 28, 1994).

Transportation Demand Module

The National Energy Modeling System (NEMS) Transportation Demand Module estimates energy consumption across the 9 Census divisions and over 10 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 seven transport modes: light-duty vehicles (cars, light trucks, and vans), freight trucks, freight and passenger airplanes, freight rail, freight shipping, mass transit, and miscellaneous transport. 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 17) consist of the following: gross domestic product, 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-three percent.

Table 17. Macroeconomic Inputs to the Transportation Module
(Millions)

Macroeconomic Input	1990	1995	2000	2005	2010	2015
New Car Sales	9.5	8.9	9.1	9.4	9.7	10.0
New Light Truck Sales	4.4	5.5	6.3	7.1	7.5	7.9
Driving Age Population	192.7	202.1	212.8	223.8	235.4	245.8
Total Population	250.3	263.6	275.6	287.1	298.9	311.2

Source: Energy Information Administration, AEO96 Forecasting System run AEO96B.d101995c.

Light-Duty Vehicle Assumptions

The vehicle sales share module holds vehicle sales shares by import and domestic manufacturers constant within a vehicle size class benchmarked to 1994 National Highway Traffic and Safety Administration data.[27]

The fuel economy module utilizes 52 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 1993 levels.

[27]U.S. Department of Transportation, *National Highway Traffic and Safety Administration, Mid-Model Year Fuel Economy Reports from Automanufacturers*, 1995.

- 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 18) 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.[28,29,30] Automobile and light truck degradation factors are assumed to be the same over time. 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. The ratio of female to male VMT is assumed to asymptotically approach 80 percent by 2015. Total VMT is calibrated to Federal Highway Administration VMT data.[31],[32]

Table 18. Car and Light Truck Degradation Factors

1990	2000	2005	2010	2015
0.847	0.817	0.812	0.804	0.804

Source: Decision Analysis Corporation of Virginia, *Fuel Degradation Factor*, Final report, prepared for Energy Information Administration (Vienna, VA, August 3, 1992).

Commercial Fleet Assumptions

With the current focus of transportation legislation on commercial fleets and their composition, the Transportation Demand Module has been designed to divide commercial fleets into three types of fleets: business, government, and utility. Based on this classification, commercial fleet vehicles vary in survival rates and duration in the fleet, before being combined with the personal vehicle stock (Table 19).

Sales shares of fleet vehicles by fleet type remain constant over the forecast period. Automobile fleets are divided into the following shares: business (85.59 percent), government (7.09 percent), and utilities (7.27 percent). Both car (23.17 percent) and light truck (13.95 percent) fleet sales are assumed to be a constant fraction of total vehicle sales.[33]

Alternative-fuel shares of fleet sales by fleet type are initially set according to historical shares, then compared to a minimum constraint level of sales based on legislative initiatives, such as the Energy

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[28]Maples, John D., *The Light-Duty Vehicle MPG Gap: Its Size Today and Potential Impacts in the Future*, University of Tennessee Transportation Center, Knoxville, TN, May 28, 1993, Draft.

[29]Decision Analysis Corporation of Virginia, *Fuel Efficiency Degradation Factor*, Final report prepared for Energy Information Administration, (Vienna, VA, August 3, 1992).

[30]U.S. Department of Transportation, Federal Highway Administration, *New Perspectives in Commuting* (Washington, DC, July 1992).

[31]U.S. Department of Transportation, Federal Highway Administration, *Highway Statistics 1993*, FHWA-PL-94-023 (Washington, DC, 1993).

[32]Decision Analysis Corporation of Virginia, *NEMS Transportation Sector Model: Reestimation of VMT Model*, prepared for EIA (Vienna, Virginia, June 30, 1995).

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

Table 19. The Average Length of Time Vehicles Are Kept Before 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).

Policy Act and the Low Emission Vehicle Program.[34,35] Size class sales of alternative-fuel and conventional vehicles are held constant at historical levels (Table 20).[36] Individual sales shares of alternative-fuel fleet vehicles by technology type are assumed to remain at historical levels for utility and government fleets, but vary for business fleets in accordance with the technology shares applied in the personal vehicle stocks.

Table 20. 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).

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 vehicle new vehicle fuel economy and is subdivided into three size classes.

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

[35]California Air Resources Board, *Proposed Regulations for Low-Emission Vehicles and Clean Fuels, Staff Report*, August 13, 1990.

[36]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).

Alternative-Fuel Vehicle Technology Choice Assumptions

The alternative-fuel vehicle 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, liquefied petroleum gas (LPG), LPG bi-fuel, gas turbine gasoline, gas turbine CNG, fuel cell methanol, and fuel cell liquid hydrogen.

Listed in Table 21 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, all other attributes are exogenously set, based on offline analysis.[37,38,39,40,41,42]

Table 21. 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)	1990	8.20	12.70	12.90	10.95	58.20[a]	53.20[a]
	2015	13.45	13.87	14.07	14.39	22.24[a]	21.98[a]
Vehicle MPG Relative to Gasoline	1990	1.00	1.00	1.01	0.95	1.40	1.50
	2015	1.00	1.00	1.01	0.95	1.40	1.50
Vehicle Range (100 miles)	1990	3.09	2.60	2.20	2.25	2.50	1.20
	2015	3.09	3.09	2.82	2.89	3.09	1.54
Fuel Availability Relative to Gasoline	1990	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 . .	1990	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

[a]Electric vehicle battery replacement cost included.
CNG = Compressed natural gas.
MPG = Miles per gallon.

Vehicle attributes vary by three size classes, and fuel availability varies by Census division. It is assumed that once the logit model estimates future sales shares, these shares are applicable to both cars and light trucks. Vehicle prices are assumed to represent mass production prices. All alternative-fuel vehicle (AFV) fuel efficiencies are calculated relative to conventional gasoline miles per gallon. It is assumed that fuel efficiency improvements to conventional vehicles will be transferred to

[37]Science Applications International Corporation, *Alternative-Fuel Vehicle Module Database*, draft report prepared for Energy Information Administration, (Washington, DC, September 15, 1992).
[38]Decision Analysis Corporation of Virginia, *"Alternative Fuel Model Database Updates,"* prepared for Energy Information Administration (Vienna, VA, November 15, 1994).
[39]EA Engineering, Science, and Technology, Inc., *AFV Differential Costs and Performance Attributes*, report prepared for Oak Ridge National Laboratory (Washington, DC, November 1993).
[40]Fulton, Lew, *AFV and EPACT: A Case Study in Technology Policy*, Dissertation Draft, June 1994.
[41]Department of Energy, Office of Transportation Technologies and Energy Efficiency and Renewable Energy, *Federal Alternative Fuel Program Light Duty Vehicle Operations: Second Annual Report to Congress for Fiscal Year 1992*, July 1993
[42]Department of Energy, Office of Transportation Technologies and Energy Efficiency and Renewable Energy, *Alternative-Fuel Vehicle Model, 1994.*

alternative-fuel vehicles.[43] Specific individual alternative-fuel technological improvements are handled separately by varying the fuel efficiency index 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 DOE Office of Energy Efficiency and Renewable Energy. 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.[45]

AFV sales are also a function of the number of makes and models within a vehicle size class.[46] Conventional vehicle offerings are held constant at 1994 levels.[47] Market-driven sales are assumed to begin in the year 2000, after the legislative AFV mandated have established necessary infrastructure for the private market.

Freight Truck Assumptions

The freight 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, remaining constant over time, and are estimated from historical freight data.[48,49] Freight truck load factors (ton-miles per truck) by SIC code are constants formulated from historical load factors.[50] Growth of VMT in the retail sector is assumed to be proportional to growth in total industrial output. Growth of VMT in the construction sector is assumed to be proportional to the growth in total disposable income. All freight trucks are subdivided into light, medium, and heavy-duty trucks. Freight truck fuel efficiency growth rates relative to fuel prices are tied to historical growth rates by size class.[50] VMT freight estimates by size class and technology are based on historical growth rates. Fuel consumption by freight trucks is regionalized according to the *State Energy Data Report 1993* distillate regional shares.[51]

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.[48],[52] Initial freight rail efficiencies are based on the freight model from Argonne National Laboratory.[53] The distribution of rail fuel consumption by fuel type remains constant and is based on historical data (Table 22).[50] Regional freight rail consumption estimates are distributed according to the *State Energy Data Report 1993*.[51]

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[43]Energy and Environmental Analysis, K.G. Duleep, initial coefficients for alternative-fuel vehicles relative to conventional vehicles were used from the Department of Energy, Office of Policy Analysis IDEAS Model.

[44]Bunch, David S., Mark Bradley, Thomas F. Golob, Ryuichi Kitamura, Gareth P. Occhiuzzo, *Demand for Clean-Fuel Personal Vehicles in California: A Discrete-Choice Stated Preference Survey*, paper presented at the Conference on Transportation and Global Climate Change: Long Run Options (Asilomar Conference Center, Pacific Grove, CA, August 26, 1991).

[45]EIA, *Alternatives to Traditional Fuels: An Overview*, DOE/EIA-0585/0 (Washington, D.C., June 1994).

[46]Train, Kenneth, *Qualitative Choice Analysis, Theory Econometrics and an Application to Automobile Demand*, MIT Press, Cambridge, Mass., 1986.

[47]U.S. Environmental Protection Agency, *1994 Gas Mileage Guide*, DOE/EE-0019/13, October 1993.

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

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

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

[51]Energy Information Administration, *State Energy Data Report 1993*, DOE/EIA-0214(93) (Washington, DC, May 1995).

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

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

Table 22. Distribution of Rail Fuel Consumption by Fuel Type, 1993
(Percent)

Rail Transit Type	Diesel Fuel	Electricity
Freight	100	0
Passenger		
Transit	0	56
Commuter	32	31
Intercity	68	13

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.[48] These freight adjustment coefficients are based on analysis of historical data[54] and remain constant throughout the forecast period. Domestic shipping efficiencies are based on the freight model by Argonne National Laboratory.[55] 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.[50] Regional domestic and international shipping consumption estimates are distributed according to the *State Energy Data Report 1993* 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 and other operating costs. Nonfuel operating costs are assumed to remain constant across the forecast horizon.[55] A demographic index based on the propensity to fly was introduced into the air travel demand equation.[56] The propensity to fly was made a function of the age and sex group distribution over the forecast period.[57,58] 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 50 percent by 2010.[59] Load factors, represented as the average number of passengers per airplane, are assumed to remain constant over the forecast period.

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

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

[55]U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Financial Statistics Quarterly and Monthly*, December 1994 and prior issues.

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

[57]Decision Analysis Corporation of Virginia, *Reestimation of NEMS Air Transportation Model*, unpublished prepared for the Energy Information Administration, (Vienna, VA, 1995).

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

[59]U.S. Department of Transportation, *U.S. International Air Travel Statistics*, Transportation Systems Center, Cambridge, MA, annual issues.

constant historical annual 1-percent rate.[60] 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 following constant within an aircraft type: airborne hours per aircraft per year, average flight speed, and the number of seats per aircraft (Table 23). 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.[61,62] Fuel efficiency of new aircraft acquisitions represents, at a minimum, a 5-percent improvement over the stock efficiency of surviving airplanes.[62] 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 24). Regional shares of all types of aircraft fuel are assumed to be constant and are consistent with the *State Energy Data Report 1993* estimate of regional jet fuel shares.

Table 23. Constant Available Seat-Miles Assumptions by Aircraft Type

Seat-Mile Variable	Narrow Body Aircraft	Wide Body Aircraft
Airborne Hours/Aircraft per Year	2,409	3,344
Average Flight Speed (MPH)	398	485
Number of Seats/Aircraft	125	296

MPH = Miles per hour.
Source: Federal Aviation Administration, *FAA Aviation Forecasts Fiscal Years 1993-2004*, FAA-APO 93-1 (February 1993), and previous editions.

Legislation

Energy Policy Act of 1992

Fleet alternative-fuel vehicle sales necessary to meet the Energy Policy Act of 1992 (EPACT) regulations come from the DOE Office of Policy (Table 25).[63] Total projected alternative-fuel vehicle sales are divided into fleets by government, business, and fuel providers. 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 both business and fuel provider fleet EPACT mandates do not take effect until the year 2000.

[60]U.S. Department of Transportation, Federal Aviation Administration, *FAA Aviation Forecasts Fiscal Years 1993-2004* (Washington, DC, February 1993).

[61,62]Oak Ridge National Laboratory, *Energy Efficiency Improvement of Potential Commercial Aircraft to 2010*, ORNL-6622 (Oak Ridge, TN, June 1990).

Oak Ridge National Laboratory, "Air Transport Energy Use Model," draft report (Oak Ridge, TN, April 1991).

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

Table 24. Future New Aircraft Technology Improvement List

Proposed Technology	Introduction Year	Jet Fuel Price Necessary For Cost-Effectiveness (1987 dollars per gallon)	Seat-Miles per Gallon Gain Over 1990 (percent)	
			Narrow Body	Wide Body
Engines				
Ultra-high Bypass	1995	0.69	10	10
Propfan	2000	1.36	23	0
Aerodynamics				
Hybrid Laminar Flow	2020	1.53	15	15
Advanced Aerodynamics	2000	1.70	18	18
Other				
Weight Reducing Materials	2000	-	15	15
Thermodynamics	2010	1.22	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.

Low Emission Vehicle Program

The Low Emission Vehicle Program, which began in California, has now been instituted in New York and Massachusetts. The following Zero Emission Vehicle (ZEV) and Ultra-Low Emission Vehicle (ULEV) sales numbers (Table 26) come from the California Air Resources Board.[64] In the Low Oil Price Case and the Reference Case, only the ZEV sales shares are used. With the High Oil Price Case, the ZEV and one-half of the ULEV sales shares are included. Only half of the ULEV sales were included, because there is uncertainty with respect to meeting the ULEV air standards with reformulated gasoline and a heated catalytic converter.

Table 25. EPACT Alternative-Fuel Vehicle Fleet Sale Estimates

Vehicle Type	Fleet Type	1995	2000	2005	2010	2015
Automobiles	Government	7,500	10,020	10,020	10,020	10,020
	Business	0	870	34,000	139,040	209,270
	Fuel Provider	0	2,280	88,860	98,530	136,020
Light Trucks	Government	7,500	10,020	10,020	10,020	10,020
	Business	0	100	9,160	22,490	30,190
	Fuel Provider	0	30	26,930	32,710	40,930

EPACT = Energy Policy Act of 1992.
Source: U.S. Department of Energy, Office of Policy, *Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector, Technical Report Fourteen: Market Potential and Analysis of Alternative-Fuel Use in Light-Duty Vehicles: A 2000/2010 Analysis* (Washington, DC, 1995).

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

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

Table 26. California Low Emission Vehicle Program Legislatively Mandated Alternative-Fuel Vehicle Sales
(Percentage)

Vehicle	1997	1998	1999	2000	2001	2002	2003
Ultra-Low Emission Vehicles	2	2	2	2	5	10	15
Zero Emission Vehicles	--	2	2	2	5	5	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 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 1.1 percent in 2000, representing a decline in consumption of approximately 164 trillion Btu. 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 40 trillion Btu. Total reductions of carbon emissions from CCAP reach 4.0 million metric tons per year by 2000.

High Efficiency and 1995 Technology Cases

Over the 1970-1990 period, transportation energy efficiency rose by 1.9 percent annually for light-duty vehicles, 1.5 percent for freight trucks, 1.6 percent for rail locomotives and marine vessels, and 2.1 percent for aircraft. In the high efficiency 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 16.5 percent lower (26.7 quadrillion Btu) than in the Reference Case by 2015.

The 1995 technology case assumes that new fuel efficiencies are held constant at 1995 levels over the forecast. As a result, the energy use in the transportation sector was 7.6 percent higher (32.5 quadrillion Btu) than in the Reference Case.

Both cases were run with only the transportation demand module rather than as a fully integrated NEMS run. Consequently, no potential macroeconomic feedback on travel demand was captured.

Electricity Market Module

The Electricity Market Module (EMM) of the National Energy Modeling System (NEMS) 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 eight capacity types are presented in the EMM (Table 27).

Table 27. Capacity Types Represented in the Electricity Market Module

Capacity Type
Existing Unscrubbed Coal, sulfur dioxide standard ≤ 1.20 pounds per million Btu
Existing Unscrubbed Coal, sulfur dioxide standard ≤ 2.50 pounds per million Btu
Existing Unscrubbed Coal, sulfur dioxide standard ≤ 3.34 pounds per million Btu
Existing Unscrubbed Coal, sulfur dioxide standard > 3.34 pounds per million Btu
Existing Scrubbed Coal to 2.5 pounds sulfur dioxide per million Btu
Existing Scrubbed Coal to 1.2 pounds sulfur dioxide per million Btu
Existing Scrubbed Coal to 0.6 pounds sulfur dioxide per million Btu
Existing Scrubbed Coal, 90 percent sulfur dioxide removal
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
Molton Carbonate Fuel Cell
Nuclear - Evolutionary Advanced Boiling Water Reactor
Advanced Nuclear - Mid-Size Advanced Pressurized Water 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 Fossil-Fueled 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 fossil-fueled technologies are summarized in Table 28. These characteristics are used, in combination with fuel price foresight from the NEMS Integrating Module, to compare resource options when new capacity is needed. Heatrates for fossil-fueled technologies decline linearly between 1995 and 2010. The assumptions for nuclear technologies are described later in this section, while the costs and supplies of renewable generating technologies are described in the Renewable Fuels Module section.

Table 28. Characteristics of New Fossil-Fueled Generating Technologies

Technology	Year Available	Overnight Costs (1987 dollars per kw)	1995 Heat Rate (Btu per kwh)	2010 Heat Rate (Btu per kwh)	Fixed O&M (1987 dollars per kw)	Variable O&M (1987 dollars per thousand kwh)
Pulverized Coal	2000	1190	9,961	8,142	40.5	1.9
Advanced Coal	2000	1008	8,730	7,582	39.4	1.0
Oil/Gas Steam	1990	752	9,477	9,477	5.3	5.2
Combined-Cycle	1999	344	7,900	6,842	22.8	0.4
Advanced Combined-Cycle . .	1999	332	7,300	5,687	21.0	0.4
Combustion Turbine	1990	275	11,900	10,663	9.4	0.1
Advanced Combustion Turbine	1990	600	9,000	7,935	26.7	0.5
Fuel Cell	2000	1071	6,450	5,687	17.9	0.3

O&M = Operation and maintenance.
Source: Office of Integrated Analysis and Forecasting, OIAF, Electric Power Research Institute, EPRI, Trade Journals and other engineering estimates.

The overnight costs listed for each technology in Table 28 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 29) to the cost of labor, factory equipment, and site material for each new generating technology.

Table 29. Regional Multipliers for New Construction

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**	**CNV**	**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*.

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 30). 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 30. 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

A large number of the fossil fuel-fired steam plants operating today are approaching the end of their normal lives, typically after 40 to 45 years. However, utilities have not reported plans to retire these units and appear to be planning to utilize these plants for the foreseeable future. Fossil fuel-fired steam plants with nameplate ratings greater than or equal to 100 megawatts and with no reported retirement dates are considered eligible for life extension at capital costs (Table 31) typically lower than those of new construction. Gas and oil-fired steam plants are eligible for life extension only in the New England and West South Central Census divisions and the states of New York, New Jersey, Florida and California where these plants account for more than 10 percent of total generation. Regions that do not rely heavily on oil or gas generation are assumed to use other resource options more economically attractive. After 25 years of service, life extended plants are refurbished over 5 years during planned outages. In the EMM it is assumed that most of the fossil fuel-fired steam plants reaching 25 years of age (200 gigawatts of coal-fired, and 68 gigawatts of oil- and gas-fired plants) will be maintained throughout the forecast period.

Units with nameplate capacities less than 100 megawatts are assumed to retire after 45 years of service. Approximately 84 gigawatts are retired from 1994 through 2015. These include 19 gigawatts of coal, 9 gigawatts of oil, 19 gigawatts of gas, and 37 gigawatts of nuclear retirements. No retirement of nonutility or cogenerator units is assumed.

Nonutility Generation and Supply

Nonutility generators (excluding cogenerators that are represented in the NEMS' refinery, oil and gas supply, and demand modules) compete with traditional electric utility supply options when new resources are needed. While the technology characteristics for nonutility units are assumed to be the same as those

Table 31. Capital Cost of Life Extension
(1987 Dollars per Kilowatt)

Fuel Type	Cost
Coal	216
Gas	112
Oil	145

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

for utilities, however, the financial structure of nonutilities is represented differently. The break-even cost for each project is calculated based on single project financing. Based on previous analysis, the financial structure of nonutilities is assumed to be 80 percent debt and 20 percent equity.[65] The cost of equity for nonutilities is assumed to be 1.5 percentage points higher than that for utilities, while the cost of debt to nonutilities is 0.75 percentage points higher.

The break-even costs of nonutility projects are compared with the levelized generation costs of utility projects in the capacity planning submodule and the most economical option is chosen. However, nonutility development is limited to reflect the debt obligation imposed on the purchasing utility. Debt rating agencies are including obligations to purchase power from nonutilities when calculating utilities' credit ratings. This inclusion of the off-balance sheet debt obligations has contributed to the downgrading of some utilities' debt. Currently, the adjusted national interest coverage ratio is approximately 2.96, and in the module it is allowed to fall to a low of 2.15 between 1995 and 2015.

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*

[65]Washington Consulting Group, *Establishing Constraints on Purchased Nonutility Generation*, prepared for the Energy Information Administration, Washington, DC, January 1993.

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 provisions of the Energy Policy Act of 1992 create a new class of electricity suppliers referred to as exempt wholesale generators. These exempt wholesale generators are included among nonutility producers and are assumed to have a highly leveraged capital structure compared to that of investor-owned regulated utilities.

Prices for electricity are assumed to be regulated at the State level. Prices for the residential, commercial, industrial, and transportation sectors are developed by classifying costs into four categories: fuel, fixed operation and maintenance, variable operation and maintenance, and capital. These costs are allocated to each of the four customer classes using the proportion of sales to the class and each class's contribution to system peak load requirements. These allocated costs are divided by the sales to each sector to obtain electricity prices to the sector.

Nuclear Power Plant Orders

It is assumed that one nuclear generating unit currently under construction will be operational by 2015: Watts Bar 1 in 1996. Watts Bar 2 and Bellefonte 1 and 2 are assumed not to be completed. These four units are owned by the Tennessee Valley Authority (TVA). In 1994, TVA announced it was canceling plans to complete both Bellefonte units and Watts Bar 2. The utility policy is shifting away from nuclear generation in favor of demand-side management, independent power producers and new technology.

The licensing status as of year end 1994 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. Operating plants to term assumes that there are no aging effects. This implies that the cost of operating nuclear power plants is cost-competitive with other technologies. On average, the reference forecast assumes no license renewal and no retirements prior to term. This assumption is based on an economic analysis of the operating lives of nuclear power plants in the United States.[66]

It is assumed that no newly ordered nuclear power plants will be operational through 2015 for the following reasons:

- Concerns about the disposal of radioactive waste
- Public concerns about safety
- Concern about economic and financial risks
- Uncertainty about power plant performance

With regard to the waste disposal issue, either a high-level waste repository, or, temporarily, a monitored retrievable storage facility is required; however, a permanent repository is not scheduled to be operational until at least 2010. According to the Nuclear Waste Policy Act of 1982, DOE is to take title to nuclear waste

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[66]James G. Hewlett, *The Operating Costs and Longevity of Nuclear Power Plants: Evidence from the USA*, *Energy Policy*, Volume 20, Number 7, July 1992.

beginning in 1998, but this provision will be adjudicated in the courts since a storage facility will not be available. In June 1994, two separate lawsuits were filed against DOE, one by a group of 14 utilities, the other by a group of 20 States and public utility commissions. They are asking the court to declare that the law requires DOE to accept spent fuel and high-level waste from utilities unconditionally, by the 1998 deadline, and that DOE must develop a program to enable it to meet this deadline without placing further financial burden on the utilities and the ratepayers. This issue is becoming critical, as many units are reaching the limits of their spent-fuel storage space. Furthermore, with a number of nuclear units scheduled for retirement beginning around 2005, the lack of a high-level waste repository becomes critical for decommissioning purposes as well. According to the Nuclear Waste Policy Amendments Act of 1987, construction of a monitored retrievable storage (MRS) facility cannot begin until the Nuclear Regulatory Commission issues a construction permit for the high-level waste repository. Given the history of schedule slippages in the waste repository program and the first-of-a-kind nature of the project, it is assumed that utilities, investors, and State regulatory commissions would not commit to a new order until an MRS was completed and available to receive waste. With the uncertainties surrounding nuclear waste funding and siting, as well as new nuclear construction costs and lead times; it will be difficult for a plant to get ordered and completed by 2015.

Public concerns about nuclear power plant operational safety and waste disposal must also be addressed. The safety concerns stem from the public's association of the technology with its weapons origin and the well-publicized accidents at operating plants, particularly at Three Mile Island and Chernobyl.

Utilities currently have an aversion to capital-intensive technologies with long lead times. With the increased competition in electricity generation markets, especially from short leadtime, low capital cost options, this aversion is likely to increase in the future. In addition, there are substantial uncertainties associated with the costs and risks of nuclear power. Research has shown that there is a 3.5- to 4.0-percentage point risk premium associated with the common stock of utilities with nuclear power plants.[67] More importantly, this risk premium is not construction and licensing issues, but rather to concerns about safety, operational factors, and decommissioning. There is growing investor concern about the escalation in decommissioning cost, early retirements, and the "stranded plant" problem.[68]

Additionally, even though vendors estimate competitive economics and 4- to 5-year construction lead times, these estimates are targets or best-case estimates. No nuclear plant to date has been built at initial estimated cost and/or schedule.[69] Also, major parts of new midsize plants will be prefabricated and constructed modularly. This new construction approach, while likely to decrease lead times in follow-on units, is less flexible than the conventional approach if design changes are required and, therefore, adds uncertainty when building a first-of-a-kind unit. Also, a new plant incorporates a large percentage of untested new technology, thereby greatly increasing the uncertainty associated with plant performance.

Given the history of ex post facto nuclear prudence reviews and cost disallowances, coupled with the high capital intensity of nuclear investments and historically long construction lead times, investments in nuclear technology would likely require some form of financial protection.

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

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[67]R. Fuller, G. Hinman, and T. Lowinger, *The Impact of Nuclear Power on the Systematic Risk and Market Value of Electric Utility Common Stock, The Energy Journal*, Volume 11, Issue 2.

[68]The stranded plant problem refers to capital-intensive plants that cannot recover all their capital costs because of the competitive pressure from lower cost plants.

[69]Energy Information Administration, *An Analysis of Nuclear Power Plant Construction Costs*, DOE/EIA-0485 (Washington, DC, March 1986).

technology options. Utilities have reported plans to increase their expenditures on demand-side management programs to more than 3.9 billion per year by 1998.[70]

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.[71] Coal prices are estimated using a regression analysis based on the coal and world oil price from the previous year. 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 $4.76 per thousand cubic feet (1987 dollars) and 950 trillion cubic feet, respectively. 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:

$$P_k = A * Q_k^{1.5} + B$$

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.

[70]Form EIA-861, *Annual Electric Utility Report*, 1993.

[71]Energy Information Administration, *NEMS Integrating Module Documentation Report*, DOE / EIA-M057(95) (Washington, DC, May 1995).

Technological Optimism and Learning Factors

Overnight cost are calculated for each new generating technology by applying the regional cost multipliers from Table 29 to the base overnight cost in Table 28. These costs are assumed to be nth-of-a-kind costs. For advanced technologies, technological optimism factors are applied to the first-of-a-kind unit and decrease linearly until a specified number of units are constructed. In addition, a cost reduction due to learning effects is applied for each doubling of a technology's capacity until a predetermined number of units has been reached. At this point, it is assumed that all learning has been realized and subsequent units are built at their nth-of-a-kind cost. Table 32 shows these assumptions for the reference and high and low technology cases.

Table 32. Technological Optimism and Learning Assumptions

Technology	Optimism Factor			Learning Factor		
	High Tech.	Reference	Low Tech.	High Tech.	Reference	Low Tech.
Advanced Coal	1.095	1.19	1.38	0.06	0.10	0.14
Advanced Combined Cycle	1.060	1.12	1.24	0.06	0.10	0.14
Advanced Turbines	1.060	1.12	1.24	0.06	0.10	0.14
Fuel Cell	1.120	1.24	1.48	0.06	0.10	0.14
Advanced Nuclear	1.260	1.52	2.04	0.06	0.10	0.14
Solar Thermal	1.095	1.19	1.38	0.06	0.10	0.14
Solar-PV	1.060	1.12	1.24	0.06	0.10	0.14
Wind	1.000	1.00	1.00	0.06	0.20	0.27
Biomass	1.095	1.19	1.38	0.06	0.10	0.14
Technology	**End Optimism (number of units)**			**End Learning (number of units)**		
	High Tech.	Reference	Low Tech.	High Tech	Reference	Low Tech.
Advanced Coal	2	4	6	20	40	60
Advanced Combined Cycle	2	4	6	20	40	60
Advanced Turbines	2	4	6	20	40	60
Fuel Cell	2	4	6	20	40	60
Advanced Nuclear	2	4	6	20	40	60
Solar Thermal	2	4	6	20	40	60
Solar PV	2	4	6	20	40	60
Wind	2	4	6	33	66	86
Biomass	2	4	6	20	40	60

Legislation

Clean Air Act Amendments of 1990

It is assumed that electricity producers comply with the Clean Air Act Amendments of 1990, 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 Clean Air Act Amendments of 1990 (CAAA90) by reducing emissions of NO_x by 2 million tons from 1980 levels. Similarly, 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).

Energy Policy Act of 1992

The provisions of the Energy Policy Act of 1992 (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 2010.

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.[72] 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, 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.

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

High Electricity Demand Case

The high electricity demand case assumes that the demand for electricity grows at the same rate as the economy in the Reference Case through 2000. After 2000, the ratio of electricity demand growth to economic growth is assumed to fall in a linear fashion from 1.00 in 2000 to 0.67 in 2015. The 0.67 ratio was chosen because it is approximately the ratio of electricity sales growth to economic growth over the 1993 to 2015 timeframe in the Reference Case. No attempt was made to determine the changes necessary in the end-use sectors needed to result in the stronger demand growth. The high electricity demand case is a partially integrated run, i.e., the Macroeconomic Activity, Petroleum Marketing, International Energy, and end-use demand modules use the Reference Case values and are not 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 Electricity Market Module in the high electricity demand case.

Low and High Technology Cases

The low and high technology cases assume different capital costs for advanced generating technologies than the reference case. In the low technology case, technological optimism and learning factors--which increase the nth-of-a-kind capital costs for new capacity--are doubled relative to the reference case and are applied to the first 6 units constructed (Table 32). After 6 units are constructed, the cost increase due to technological optimism is removed and a learning factor of 14 percent--where capital costs are reduced by 14 percent for each doubling of capacity--is applied to the next 48 units constructed. After a total of 60 units have been built, capital costs are assumed to remain constant at the nth-of-a-kind costs for all subsequent construction (Table 28). Conversely, the high technology case assumes a halving of the technological optimism factors relative to the reference case for the first 2 units and a learning factor of 6 percent applied to the next 18 units. After a total of 20 units have been built, capital costs are assumed to remain constant at the nth-of-a-kind costs for all subsequent construction.

The low and high technology 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 Electricity Market Module in the low and high technology cases.

Low and High Nuclear Cases

The low and high nuclear cases assume different retirement schedules. The low 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 current expiration date. These alternate scenarios model situations where either the majority of the plants retire early, or a substantial number of units renew their licenses. The cases do not attempt to pick which units will or will not perform well 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 using their license expiration dates. 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 are allowed to interact with the Electricity Market Module in the high and low nuclear cases.

Oil and Gas Supply Module

The Oil and Gas Supply Module (OGSM) constitutes a comprehensive framework with which to analyze oil and gas supply. 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.

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[73] consist of proved reserves,[74] inferred reserves,[75] and undiscovered economically recoverable resources.[76] OGSM employs regional estimates that are derived by EIA staff using analysis from the United States Geological Survey and the Minerals Management Service of the Department of the Interior, the National Petroleum Council, and the Office of Fossil Energy of the Department of Energy.[77] Published estimates were adjusted to remove intervening reserve additions resulting in estimates consistent with beginning-of-year 1990.

Expected recoverable resource estimates (Tables 33 and 34) reflect static technology and economic conditions. Within the 1990-2015 projection period of the model, the state of technology development and penetration proceeds, thus expanding the volume of economically recoverable resources. The initial

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[73] *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.

[74] *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.

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

[76] *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.

[77] 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); Richard F. Mast and others, United States Department of the Interior, U.S. Geological Survey and Minerals Management Service, *Estimates of Undiscovered Conventional Oil and Gas Resources in the United States—A Part of the Nation's Energy Endowment* (Washington, DC, 1989); 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); William L. Fisher and others, Oil Resources Panel convened by the U.S. Department of Energy, *An Assessment of the Oil Resource Base of the United States* (Washington, DC, October 1992).

recoverable resource estimates generally reflect the 1990 level of technological development and penetration. The 2015 estimates are based on the assumed rate of technological progress drawn from a review of the literature.

Table 33. Crude Oil Economically Recoverable Resources
(Billion Barrels)

Crude Oil Resource Category	1990 Level	Reference		Low Technology		High Technology	
		2015 Level	Technology Improvement Rate	2015 Level	Technology Improvement Rate	2015 Level	Technology Improvement Rate
Undiscovered	43.21	75.28	--	57.05	--	99.30	--
Onshore	33.53	55.01	2.0%	43.00	1.0%	70.20	3.0%
Offshore	9.68	20.27	3.0%	14.05	1.5%	29.09	4.5%
Inferred Reserves	63.46	66.56	--	64.74	--	69.14	--
EOR	11.83	11.83	--	11.83	--	11.83	--
Other Onshore	48.80	48.80	--	48.80	--	48.80	--
Offshore	2.83	5.93	3.0%	4.11	1.5%	8.51	4.5%
Total Lower 48 States Unproved	106.67	141.83	--	121.78	--	168.43	--
Alaska	10.53	22.05	3.0%	15.28	1.5%	31.65	4.5%
Total U.S. Unproved	117.20	163.88	--	137.06	--	200.08	--
Proved Reserves	26.25	26.25	--	26.25	--	26.25	--
Total Crude Oil	143.45	190.13	--	163.31	--	226.33	--

[a]The 1990 levels of conventional inferred onshore resources and inferred offshore gas 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 *AEO96* 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.

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 mid-year; thus only half 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 operations 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

Table 34. Natural Gas Economically Recoverable Resources
(Trillion Cubic Feet)

Natural Gas Resource Category	1990 Level	Reference		Low Technology		High Technology	
		2015 Level	Technology Improvement Rate	2015 Level	Technology Improvement Rate	2015 Level	Technology Improvement Rate
Nonassociated Gas							
Undiscovered	324.09	618.66	--	447.96	--	853.50	--
Onshore	201.99	363.01	--	270.79	--	486.54	--
Deep (>15,000 feet)	69.79	146.12	3.0%	101.26	1.5%	209.74	4.5%
Shallow (0-15,000 feet)	132.20	216.89	2.0%	169.54	1.0%	276.80	3.0%
Offshore	122.10	255.65	3.0%	177.16	1.5%	366.96	4.5%
Inferred Reserves	280.36	299.91	--	289.65	--	311.25	--
Onshore	231.55	244.63	--	237.7	--	252.43	--
Deep (>15,000 feet)	46.29	59.37	1.0%	52.44	0.5%	67.17	1.5%
Shallow (0-15,000 feet)	185.26	185.26	--	185.26	--	185.26	--
Offshore	48.80	55.28	0.5%	51.95	0.3%	58.83	0.8%
Unconventional Gas Recovery	278.41	582.94	--	403.96	--	836.76	--
Tight Gas	219.36	459.30	3.0%	318.28	1.5%	659.28	4.5%
Devonian	12.45	26.07	3.0%	18.07	1.5%	37.42	4.5%
Coalbed	46.60	97.57	3.0%	67.61	1.5%	140.05	4.5%
Associated-Dissolved Gas	124.30	124.30	--	124.30	--	124.30	--
Total Lower 48 States Unproved	1007.16	1625.80	--	1265.86	--	2125.81	--
Alaska	33.31	69.74	3.0%	48.33	1.5%	100.11	4.5%
Total U.S. Unproved	1040.47	1695.55	--	1314.20	--	2225.92	--
Proved Reserves	169.35	169.35	--	169.35	--	169.35	--
Total Natural Gas	1209.82	1864.90	--	1483.55	--	2395.27	--

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

is reached for gas delivered to the lower 48 States. The price for phase one is $3.71, in 1994 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 $4.96, in 1994 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 scenarios.

Supplemental Gas Supplies

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 1999, at 51.55 billion cubic feet per year. In all cases, it is assumed that in mid-year 2000 the Great Plains facility will stop producing natural gas. Other supplemental supplies are held at a constant level of 51.15 billion cubic feet per year throughout the forecast.

Natural Gas Imports and Exports

U.S. natural gas trade with Mexico and liquefied natural gas (LNG) imports and exports are determined exogenously to NEMS. Natural gas exports from the United States to Canada 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 below (Table 35).

Table 35. Natural Gas Imports and Exports
(Billion Cubic Feet per Year)

Year	Canada		Mexico	
	Imports[a]	Exports	Imports	Exports
2000	4,045	144	7	61
2005	4,098	204	7	37
2010	4,314	238	114	10
2015	4,630	250	356	10

[a]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: 1994 import and export volumes: Department of Energy, Office of Fuels Programs, Office of Fossil Energy, *Natural Gas Imports and Exports*, Fourth Quarter Report 1994, DOE/FE-0337 Projections: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Mexican import and export volumes for natural gas were drawn heavily from the analysis work supporting the recent National Petroleum Council study, *The Potential for Natural Gas in the United States* (Washington, DC, 1993).

Canadian production and exports to the United States are determined endogenously within the model. Assumed Canadian gas consumption levels (with an associated price) also affect the wellhead price by limiting the gas supply available for export to the United States. The consumption of gas in Canada was assumed to grow at 1.3 percent per year throughout the projection and in each scenario from its historical level of 2.79 trillion cubic feet in 1993 (taken from the *International Energy Annual*, DOE/EIA-0219(93)). Natural gas exports to Canada from the United States are expected to grow annually by 14 billion cubic feet from the 1993 level of approximately 50.0 billion cubic feet, reaching 250 billion cubic feet by 2015. 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 64.4 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 1994 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. In general, tankers were considered to be a constraining factor in the near term, but the necessary additional capacity is expected in time to support the projected flow volumes.

Currently, only two LNG import terminals are in operation: the Distrigas facility in Everett, Massachusetts, and the Trunkline facility in Lake Charles, Louisiana. The announced plans for the other two existing import terminals, at Cove Point, Maryland, and at Elba Island, Georgia, were the primary determinants of the time for reopening these facilities. Once in operation, continued maintenance is expected to be sufficient to keep all plants operable at the stated rates throughout the projection.

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, DOE and EPA will create a program to raise the awareness among key coal companies and State agencies of the potential for cost-effective methane emissions reduction. As a result of the program, a total of 10 "gassy" (high methane content) coal mines that would, otherwise, not have been capturing their methane effluent are assumed to be doing so by 2000.

The cumulative number of mines effectively reached by CCAP Action Item 35 and the production from these mines are presented in Table 36. No further mines are assumed to be successfully targeted after 2000.

Table 36. Number and Production of Mines Reached by CCAP Action Item 35

Year	Cumulative Mines	Production (billion cubic feet)
1995	1	3.5
1996	3	8.7
1997	5	13.9
1998	7	17.4
1999	8	17.4
2000	10	19.1

The annual production increases resulting form 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*.[78]

High and Low Technology Cases

An additional analysis was performed to assess the sensitivity of the projections to the technology assumptions in both OGSM and the Petroleum Market Model. Two special technology cases were created by adjusting oil and gas technological progress rates for unproved resources and drilling costs upward

[78]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).

and downward by a given proportion—overall, approximately 50 percent. This change affects both the size of reserve additions per new well and the number of new well completions.

The analysis used the natural gas import levels and consumption requirements of the reference case for both of the technology side cases. The specific variations in economically recoverable resources used in the analysis are shown in Table 33 and Table 34.

Natural Gas Transmission and Distribution Module

The 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 is presented in *Model Documentation Report: Natural Gas Transmission and Distribution Model of the National Energy Modeling System*.

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.[79] 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 37).

Table 37. Electric Utility Natural Gas Demand Classification

Service Category	Plant Type
Core	Gas Steam Units Gas Combined-Cycle Units
Noncore	
Competitive With Distillate Fuel Oil	Gas Turbine Units Dual-Fired Turbine Units Coal Plants With Gas Start-up
Competitive With Residual Fuel Oil	Dual-Fired Steam Units

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

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

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 (the test for determining whether or not to build new capacity is done based on incremental rates, however). This is consistent with the recent Federal Energy Regulatory Commission (FERC) ruling to assume rolled-in pricing as the default for new construction. Core market transmission and distribution services remain subject to cost of service, rate of return regulation, with an adjustment that credits a portion of the revenue from interruptible and release capacity services to holders of firm capacity (to account for capacity release) should those revenues exceed costs. 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 above those included 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, core industrial, and core electric generator 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 1993 historical data (Table 38), 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 throughout the forecast.

End-use prices for industrial and electric generator noncore customers are established by adding a markup to the natural gas supply price for the noncore segment at the regional market hub. These markups are endogenously derived as the difference between estimated historical 1994 end-use prices[80] and the NGTDM regional noncore hub price, and held constant throughout the forecast.

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 39). The price to non-fleet vehicles is based on the industrial sector firm price plus an assumed $3.78 (1994 dollars per thousand cubic feet) dispensing charge plus Federal and State taxes. Federal taxes of $0.50 (1994 dollars) per thousand cubic feet are levied starting in 1994. It is assumed that the retailer will lower the dispensing charge by up to 20 percent if needed to be competitive with gasoline prices.

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 (1994 dollars per Mcf-mile per day) are assumed to be $1.60 for compression, $1.79 for looping, and $2.31 for new pipe. The average costs were regionalized by applying regional cost factors reflecting differences in terrain and labor costs.

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[80]Historical noncore industrial prices were based on data from the *Manufacturing Consumption of Energy 1991.*

Table 38. Base Year Average 1993 Annual Distributor Markup for Local Transportation Service
(1994 Dollars per Thousand Cubic Feet)

Region	Residential	Commercial	Core Industrial	Core Electric Generators
New England	4.59	2.50	-0.04	-1.54
Mid Atlantic	4.10	2.56	0.77	-0.83
East North Central	2.77	1.75	0.05	-1.58
West North Central	2.12	1.32	-0.42	-0.91
South Atlantic	3.63	2.26	-0.39	-0.68
East South Central	2.63	1.94	-0.42	-0.76
West South Central	2.69	1.13	-0.45	-0.66
Mountain	2.02	1.34	0.46	-0.54
Pacific	3.27	2.31	0.88	-0.19
Florida	6.74	3.08	-0.11	-0.52
Arizona/New Mexico	3.80	2.18	0.76	-0.07
California	3.42	3.22	1.14	0.14

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.

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 86 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

All interstate pipeline companies are assumed to have completed the switch from modified fixed variable to straight fixed variable rate design by January 1994 to comply with Federal Energy Regulatory Commission (FERC) Order 636 rate design changes. Approved transition costs are assumed to be consistent with FERC's revised cost estimate as published by the General Accounting Office in *Natural Gas: Costs, Benefits, and Concerns Related to FERC Order 636, Final Report*, November 1993 (Table 40). It is assumed that the gas supply realignment costs will be recovered over a 5-year period beginning in 1994.

Table 39. Vehicle Natural Gas (VNG) Pricing

Modified Census Divisions	Total Federal and State VNG Tax[a] (1994 dollars per thousand cubic feet)
New England	1.71
Middle Atlantic	0.93
East North Central	0.86
West North Central	1.47
South Atlantic (excludes Florida)	1.37
East South Central	1.28
West South Central	1.15
Mountain (excludes Arizona and New Mexico)	1.25
Pacific (excludes California)	1.66
Florida	1.33
Arizona and New Mexico	0.65
California	1.33

[a]Assuming a $0.50 (1994 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 the Clean Fuels Report, April 1993.

Furthermore, it is assumed that 90 percent of these costs will be assigned to core markets and 10 percent will be assigned to noncore markets as stipulated in Order 636. Purchased Gas Adjustment Account Balance (Account 191) costs are assumed to be collected over a 2-year period, also beginning in 1994. These costs will be paid only by core customers.

The *AEO96* methodology employed in solving for the natural gas supply and demand equilibrium assumes that core market prices are based on average cost of service rates minus a credit (to account for capacity release) that credits a share of the revenue from interruptible and release capacity services to holders of firm capacity should those revenues exceed costs. Noncore transmission services are competitively priced with the price floor equal to the variable cost of delivering natural gas (generally compressor station fuel plus a few cents).

Climate Change Action Plan

Provisions of the CCAP to increase the natural gas share of total energy use through Federal regulatory reform (Action 23) are assumed to have no impact on the transmission and distribution segment of the industry. Although regulatory changes that are recommended in this Action may be considered by the FERC in the near future, they go beyond the current FERC regulatory policy and thus are not considered in the reference case. 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 1996 through 2000, and by recovering the full 35 billion cubic feet from 2000 through the end of the forecast period.

Table 40. FERC Order 636 Transition Costs by Pipeline Company
(1992 Dollars)

Interstate Pipeline Company	Purchased Gas Adjustment Account Balance	Gas Supply Realignment	Total
Algonquin Gas Transmission Co.	0	0	0
ANR Pipeline Co.	0	229,862,348	229,862,348
Arkla, Inc.	97,814	29,344,130	29,441,943
Colorado Interstate Gas Co.	0	5,868,826	5,868,826
CNG Transmission Corp.	78,251,012	33,256,680	111,507,692
Columbia Gas Transmission Corp.	171,174,089	0	171,174,089
Columbia Gulf Transmission Corp.	0	0	0
East Tennessee Natural Gas Co.	0	0	0
El Paso Natural Gas Co.	0	0	0
Florida Gas Transmission Co.	0	52,819,433	52,819,433
Great Lakes Gas Transmission Co.	0	0	0
Kern River Gas Transmission Co.	0	0	0
K-N Energy, Inc.	0	244,534,413	244,534,413
Midwestern Gas Transmission Co.	0	0	0
Mississippi River Transmission Corp.	0	24,453,441	24,453,441
National Fuel Gas Supply Corp.	0	0	0
Natural Gas Pipeline Co. of America	0	537,975,709	537,975,709
Northern Border Pipeline Co.	0	0	0
Northern Natural Gas Co.	0	0	0
Northwest Pipeline Corp.	48,907	19,500	68,407
Pacific Gas Transmission Co.	0	0	0
Panhandle Eastern Pipeline Co.	19,562,753	48,906,883	68,469,636
Questar Pipeline Co.	0	0	0
Southern Natural Gas Co.	0	465,593,522	465,593,522
Tennessee Gas Pipeline Co.	120,897,814	432,336,842	553,234,656
TETCO	83,028,212	546,778,947	629,807,159
Texas Gas Transmission Corp.	0	171,174,089	171,174,089
Trailblazer Pipeline Co.	0	0	0
Transcontinental Gas PL Corp.	0	0	0
Transwestern Pipeline Co.	14,085,182	16,139,271	30,224,453
Trunkline Gas Co.	14,672,065	9,781,377	24,453,441
United Gas Pipeline Co.	6,749,150	20,540,891	27,290,040
Williams Natural Gas Co.	17,606,478	29,344,130	46,950,607
Williston Basin Interstate Gas Co.	0	19,562,753	19,562,753
Wyoming Interstate Natural Gas Co.	0	0	0
Other Pipeline Companies	5,022,597	225,402,041	230,424,637
Total Industry Costs	531,196,072	3,143,695,225	3,674,891,297

Source: Memorandum from Elizabeth Moler (FERC) to Chairman John Dingell, Response to Chairman Dingell's Questions Regarding Various Aspects of Order 636, March 16, 1993.

Petroleum Market Module

The 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 five 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.

Key Assumptions

Product Types and Specifications

The PMM models refinery production of the products shown in Table 41.

Table 41. Petroleum Product Categories

Product Category	Specific Products
Motor Gasoline	Traditional Unleaded, Oxygenated, Reformulated/High Oxygen
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 four different types of gasoline: traditional, oxygenated, reformulated, and reformulated/high-oxygen. The following specifications are included in PMM to differentiate between traditional and reformulated gasoline blends (Table 42): octane, oxygen content, Reid vapor pressure (Rvp), benzene content, aromatic content, sulfur content, and olefin content.

Beginning in 1995, traditional gasoline must comply with antidumping requirements aimed at preventing the quality of traditional gasoline from eroding as the reformulated gasoline program is implemented. The 1995-1997 specifications in PMM assume Simple Model compliance standards which restrict benzene, sulfur, and olefin specifications from exceeding 125 percent of the Environmental Protection Agency's (EPA) "1990 baseline."[81] Starting in 1998, traditional gasoline must meet the Complex Model compliance standards which cannot exceed average 1990 levels of toxic and nitrogen oxide emissions.[82] Traditional gasoline during the 1998-2015 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 oxygen content of 2.7 percent by weight. Some areas that require oxygenated gasoline will also require reformulated gasoline. In those overlapping areas, reformulated-high oxygen gasoline containing 2.7 percent oxygen will be required. Oxygenated gasoline is assumed to have specifications identical to traditional gasoline with the exception of a higher oxygen requirement. Similarly, the oxygen requirement is assumed to be the only difference between reformulated / high oxygen and reformulated gasoline blends.

Beginning in 1995, many areas of the country will require reformulated gasoline. Between 1995 and 1997 the Environmental Protection Agency (EPA) will certify reformulated gasoline according to either the "simple" or "complex" models. The PMM assumes that reformulated gasoline during this time period will meet the EPA's "simple model" definition, which allows no lead content, limits benzene content to 1.0 percent and aromatics content to 25 percent by volume, requires an oxygen content of 2.0 percent by weight, and caps nitrogen oxide emissions at a baseline level (Table 42). 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.

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 (PAD) District V refiners must meet the California specifications. Therefore, for 1993-1994, the specifications for oxygenated gasoline in PAD District V meet a 2.0-percent standard. Starting in 1996, the specifications for reformulated gasoline in PAD District 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 PAD district. 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, reformulated, and reformulated / high-oxygen gasolines by applying assumptions about the annual market shares for each type. The shares change over time based on assumptions about the market penetration of new fuels. Annual assumptions for each region account for the seasonal and city-by-city nature of the regulations. (See Table 43 for *AEO96* market share assumptions.) The market shares reflect the mandated use of reformulated blends in nonattainment areas as well as assumptions about opt-in and spillover demand from outside these areas. *AEO96* assumes a 5-percent spillover of oxygenated and reformulated gasoline into attainment areas.

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[81]*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)

[82]Ibid.

The oxygenated gasoline shares throughout the forecast assume wintertime participation of 39 carbon monoxide nonattainment areas. Year-round consumption of oxygenated gasoline in Minnesota is assumed beginning in 1997 in accordance with State legislation. *AEO96* also assumes that, starting in 1995, reformulated gasoline will be consumed in the nine required areas plus areas that had petitioned the EPA to opt in.[83] Areas that initially opted-in but opted-out as of June 1995 are not included in *AEO96*.

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 9 is assumed to meet Federal requirements.

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 1992* (DOE/EIA-0535(92) (Washington, DC, October 1993). 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. Fixed refinery costs include fixed operating costs,[84] a 4-percent return on assets, and environmental costs associated with controlling pollution at refineries[85] (Table 44). Assuming that refinery-related fixed costs are recovered in the prices of light products, fixed costs are allocated among the prices of liquefied petroleum gases, gasoline, distillate, kerosene, and jet fuel. These costs are based on average annual estimates and are assumed to remain constant over the forecast period.

The costs of distributing and marketing petroleum products are represented by adding fixed distribution costs to the marginal and refinery fixed costs of products. The distribution costs are applied at the Census division level (Table 45) and are assumed to be constant throughout the forecast and across scenarios. Distribution costs for each product, sector, and Census division represent average historical differences between end-use and wholesale prices. The 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 46 and 47). Recent tax trend analysis indicated that State taxes increase at the rate of inflation, while Federal taxes do not. In *AEO96*, therefore, State taxes are held constant in real terms throughout the forecast while Federal taxes are deflated as follows:

$$\text{Federal Tax}_{\text{product, year}} = \text{1993 Federal Tax}_{\text{product}} \;/\; \text{GDP Deflator}_{\text{year}}$$

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[83]Required areas: Baltimore, Chicago, Hartford, Houston, Los Angeles, Milwaukee, New York City, Philadelphia, and San Diego. Opt-ins Areas within: Texas, District of Columbia, New Jersey, Maryland, Delaware, New York, Connecticut, Virginia, New Hampshire, Massachusetts, Maine, and Rhode Island, Wisconsin, Kentucky.

[84]Fixed operating costs include payroll, maintenance, labor and materials, depreciation, and other expenses.

[85]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.

Table 42. Year Round Gasoline Specifications by PAD District

PAD District	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)
PAD District I-V							
1995-1997	10.2	--	--	39.0	1.9	423.0	13.54
1998-1999	9.5	--	--	28.62	1.6	338.4	10.83
2000-2015	9.3	--	--	28.62	1.6	338.4	10.83
Reformulated							
PAD District I-IV							
1995-1997	9.7	2.0	2.7	25.0	1.0	349.0	9.7
1998-1999	8.8	2.1	2.7	26.0	0.95	305.0	11.0
2000-2015	8.5	2.1	2.7	24.5	0.95	140.0	11.0
PAD District I-IV							
1995	8.7	1.8	2.2	25.0	1.0	349.0	9.7
1996-1997	8.7	1.8	2.2	25.0	1.0	40.0	6.0
1998-1999	8.2	1.8	2.2	25.0	1.0	40.0	6.0
2000-2015	7.9	1.8	2.2	25.0	1.0	40.0	6.0

Max = Maximum.
Min = Minimum.
PAD = Petroleum Administration for Defense.
PPM = Parts per million by weight.
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

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 48.

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 refining regions are the five PAD districts. Individual refineries are aggregated into one linear programming representation for each PAD district region. In order to interact with other NEMS modules with different regional representations, certain PMM inputs and outputs are converted from a PAD district to a non-PAD district regional structure and vice versa.

Table 43. 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									
1995	15	31	76	84	79	94	71	89	31
1996	15	31	76	84	79	94	71	89	17
1997 forward	15	31	76	74	79	94	71	89	17
Oxygenated Gasoline (2.7% oxygen)									
1995	0	0	0	16	1	1	1	11	23
1996	0	0	0	16	1	1	1	11	7
1997 forward	0	0	0	26	1	1	1	11	7
Reformulated Gasoline (2.0% oxygen)									
1995	78	37	24	0	18	5	28	0	46
1996 forward	78	37	24	0	18	5	28	0	76
Reformulated/High Oxygen (2.7% oxygen)									
1995 forward	7	32	0	0	2	0	0	0	0

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

Table 44. Summary of Fixed Costs by Petroleum Administration for Defense Districts
(1994 Dollars per Barrel)

Cost Category	PAD District I	PAD District II	PAD District III	PAD District IV	PAD District V
Fixed Operating Costs	3.36	2.16	2.56	2.10	3.22
Return on Assets at 4 Percent . . .	0.31	0.17	0.27	0.23	0.30
Environmental Costs	0.60	0.61	0.48	0.89	0.67
Total	**4.27**	**2.94**	**3.31**	**3.23**	**4.19**

PAD = Petroleum Administration for Defense.
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

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 PAD district 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 1995 is determined by adding to the existing capacities of units planned and under construction that are expected to begin operating during this time. Capacity

Table 45. Petroleum Product End-Use Markups by Sector and Census Division
(1994 Dollars per Gallon)

Sector/Product	Census Division 1	2	3	4	5	6	7	8	9
Residential Sector									
Distillate Fuel Oil	0.36	0.41	0.29	0.26	0.40	0.28	0.18	0.25	0.36
Gasoline	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Kerosene	0.51	0.56	0.45	0.38	0.50	0.32	0.43	0.63	0.82
Liquefied Petroleum Gases	0.84	0.88	0.55	0.35	0.75	0.64	0.56	0.54	0.85
Commercial Sector									
Distillate Fuel Oil	0.13	0.11	0.03	0.02	0.05	0.03	0.04	0.02	0.05
Gasoline	0.14	0.13	0.12	0.15	0.13	0.15	0.16	0.14	0.12
Kerosene	0.26	0.19	0.19	0.10	0.19	0.21	0.15	0.11	0.22
Liquefied Petroleum Gases	0.68	0.64	0.45	0.39	0.61	0.37	0.19	0.39	0.57
Low-Sulfur Residual Fuel Oil	0.01	0.05	0.04	0.02	0.04	0.03	-0.01	-0.02	0.09
Utility Sector									
Distillate Fuel Oil	-0.00	0.03	0.02	0.02	-0.00	0.07	0.03	0.04	0.07
High-Sulfur Residual Fuel Oil	-0.01	0.03	0.13	0.03	0.01	-0.03	0.06	0.01	0.06
Low-Sulfur Residual Fuel Oil	-0.00	0.02	0.18	0.06	0.01	0.19	0.10	0.10	0.19
Transportation Sector									
Distillate Fuel Oil	0.24	0.19	0.13	0.13	0.15	0.13	0.15	0.15	0.20
Ethanol	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Gasoline	0.14	0.12	0.12	0.15	0.12	0.15	0.16	0.14	0.11
High-Sulfur Residual Fuel Oil	-0.03	0.03	0.12	-0.01	-0.01	-0.07	0.06	0.15	0.10
Jet Fuel	-0.00	0.00	-0.02	-0.03	-0.06	0.01	0.00	-0.04	0.01
Liquefied Petroleum Gases	0.80	0.67	0.52	0.38	0.61	0.41	0.16	0.40	0.57
Methanol	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Industrial Sector									
Asphalt and Road Oil	0.19	0.14	0.23	0.27	0.15	0.15	0.21	0.33	0.27
Distillate Fuel Oil	0.11	0.09	0.09	0.08	0.09	0.08	0.08	0.07	0.10
Gasoline	0.14	0.12	0.12	0.16	0.12	0.15	0.16	0.15	0.12
Kerosene	0.26	0.18	0.19	0.09	0.17	0.20	0.14	0.12	0.19
Liquefied Petroleum Gases	0.71	0.63	0.51	0.32	0.58	0.32	0.06	0.32	0.57
Low-Sulfur Residual Fuel Oil	0.01	0.03	0.05	0.03	0.03	0.05	-0.02	0.01	0.07

Note: Use conversion factors listed in Table I1 of the *Annual Energy Outlook 1995* 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 1992*, DOE/EIA-0214(92) (Washington, DC, May 1994); EIA, *State Energy Price and Expenditures Report 1991*, DOE/EIA-0376(91) (Washington, DC, September 1993); and EIA, *Petroleum Marketing Monthly March 1994*, DOE/EIA-0380(94/03) (Washington, DC, March 1994).

Table 46. State-Level Taxes on Petroleum Transportation Fuels by Census Division
(1994 Dollars per Gallon)

Year/Product	Census Division 1	2	3	4	5	6	7	8	9
1994									
Gasoline[a]	0.24	0.19	0.21	0.18	0.16	0.18	0.19	0.20	0.22
Diesel	0.21	0.21	0.20	0.19	0.16	0.16	0.19	0.17	0.22
Liquefied Petroleum Gases	0.14	0.15	0.16	0.13	0.12	0.12	0.00	0.10	0.05
Methanol	0.19	0.15	0.18	0.18	0.14	0.18	0.19	0.19	0.08
Ethanol	0.19	0.18	0.18	0.17	0.15	0.18	0.19	0.19	0.09
Jet Fuel	0.03	0.03	0.01	0.03	0.04	0.02	0.00	0.03	0.02

[a]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 1995). *Clean Fuels Report* (Washington, D.C. February 1995).

Table 47. Federal Taxes
(1994 Dollars per Gallon)

Product	Tax
Gasoline	0.18
Diesel	0.24
Jet Fuel[a]	0.04
Liquefied Petroleum Gases	0.18
Methanol	0.11
Ethanol	0.12

[a]Tax begins in 1996.
Sources: Omnibus Budget Reconciliation Act of 1993 (H.R. 2264); and *Clean Fuels Report* (Washington, DC, February, 1995).

expansion plans are done every three years. For example, after the model has reached a solution for forecast year 1995, the PMM looks ahead and determines the optimal capacities given the demands and prices existing in the 1998 forecast year. The PMM then allows 50 percent of that capacity to be built in forecast year 1996, 26 percent in 1997, and 25 percent in 1998. At the end of 1998, the cycle begins anew, looking ahead to 2001.

Strategic Petroleum Reserve Fill Rate

AEO96 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.

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 as well as costs resulting from environmental legislation.

Table 48. 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	0 - 23

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

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, and takes effect in the PMM in 1994. Jet fuel has been granted a 2-year delay.

With a goal of reducing tailpipe emissions in areas failing to meet Federal air quality standards (nonattainment areas), Title II of the CAAA90 established regulations for gasoline formulation. Starting in November 1992, gasoline sold during the winter in 39 carbon monoxide nonattainment areas was required to be oxygenated.[86] Starting in 1995, gasoline sold in nine 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 a few metropolitan areas with both ozone and carbon monoxide problems, the requirements for oxygenated and reformulated gasoline will overlap. In other words, during the winter months a reformulated/high oxygen gasoline will be required.[87]

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.[88] 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 included only the lifting of the export ban. The portions of the legislation authorizing the sale of the Alaska Power Administration and exempting certain oil producers from paying royalties were not included. The PMM allowed for exports of Alaska North slope (ANS) crude oil up to 200 thousand barrels per day if the estimated target price was greater than the ANS value in PAD District V. The target prices were assumed to decline as ANS exports increased.

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

[87]The gasoline must meet the requirements of reformulated gasoline and must have an oxygen content of 2.7 percent by weight.

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

High and Low Technology Case

Two side cases were run to assess technology improvements. These test runs included the Oil and Gas Supply Module and the Natural Gas Transmission Distribution Module as well as the PMM. All other modules were turned off. In the high technology case, refinery processing units were assumed to become more efficient in their use of natural gas, electricity, and steam. The efficiency improvements reached 5 percent for steam in 2015, 12 percent for electricity, and 4 percent for natural gas. The low technology case assumed no change from the reference case.

Ethanol Subsidy Case

Another stand-alone analysis (only the PMM was used) was done by changing the assumption that the subsidy on ethanol would continue. Currently, the 18.4 cents per gallon Federal excise tax on motor gasoline is reduced to 13 cents per gallon for gasoline blends containing 10 percent ethanol, amounting to a subsidy of 54 cents per gallon of ethanol. The subsidy is prorated for blends of less than 10 percent but remains the equivalent of 54 cents per gallon of ethanol.

The legislation authorizing this reduction in excise tax is scheduled to expire in 2000. The ethanol subsidy has been renewed in the past and the reference case assumption in the PMM was that the subsidy would continue through the forecast period. However, the renewal of the subsidy has become more questionable as legislators look for ways to reduce government spending. Some attempts, as yet unsuccessful, have been made to repeal the current authorization.

This side case analysis looks at the impact of allowing the ethanol subsidy to expire starting in 2001. The 54 cents per gallon reduction in the price of ethanol for gasoline blending and ether production (e.g., ETBE) is completely eliminated from 2001 through the end of the forecast.

Coal Market Module

The Coal Market Module (CMM) provides forecasts of U.S. coal production, consumption, exports, distribution, and prices. The CMM comprises three submodules: the Coal Production Submodule, the Coal Distribution Submodule, and the Coal Export Submodule.

Key Assumptions

Coal Production Submodule

The Coal Production Submodule (CPS) generates a different set of supply curves for the CMM for each year of the forecast. Separate supply curves are developed for each of 16 supply regions, 16 coal types, and 2 mine types (surface or underground). The supply curves generated reflect the relationship between capacity utilization and minemouth prices in the short-run. In addition, annual adjustments to the CPS supply curves are made to reflect the effects of reserve depletion and changes in labor productivity and factor input costs (labor and diesel fuel).

To estimate annual production capacity for each supply curve, the CPS makes use of projections of coal demand from other NEMS modules and the Coal Export Submodule and coal distribution projections from the Coal Distribution Submodule. Projections of diesel fuel costs are obtained from the Petroleum Market Module.

The key assumptions underlying the CPS are:

- Estimates of recoverable coal reserves are based on the EIA Demonstrated Reserve Base (DRB) of in-ground coal resources of the United States, plus some additional resource estimates of coal contained within the inferred coal resource category, which have a higher degree of uncertainty than DRB estimates. Resource estimates are correlated with data on coal quality and geological characteristics from other sources to create a Coal Reserves Data Base. Estimates are developed on a regionally disaggregated basis. Recoverable DRB coal reserves in the United States are estimated at 265 billion short tons. Low-sulfur recoverable coal reserves in the DRB are estimated to total 100 billion short tons, with 87 percent concentrated in the West.
- Coal producers face lead-time constraints for bringing new production capacity on line to meet increased demand. In the CPS, it is assumed that coal producers add new mine capacity in response to projected changes in coal demand and that lowest-cost reserves will be mined first. The CPS uses projections of coal demand from the Electricity Market Module, End-Use Demand Modules and the Coal Export Submodule, and coal distribution projections from the Coal Distribution Submodule.
- Mining costs are assumed to vary with changes in capacity utilization of mines, labor productivity, and factor input costs. In the CPS, factor input costs are represented by projections of diesel fuel prices from the Petroleum Market Module and estimates of future coal mine labor costs. The incremental costs related to differences in geologic conditions of new mines versus existing mines is also considered in the CPS. In the forecast, new mines are opened to meet increased demand and to replace capacity lost when existing mines are retired.
- Between 1978 and 1994, 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.[89] Based on the expectation that further penetration

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

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 3.6 percent a year in the forecast, declining from an annual rate of 6.0 percent in 1994 to 1.6 percent over the 2010 to 2015 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.[90]

- Between 1984 and 1994, the average hourly wage for U.S. coal miners (in 1994 dollars) declined at an average rate of 1.5 percent per year, falling from $20.54 to $17.75.[91] In the reference case, the wage rate for U.S. coal miners, in real dollars, is assumed to remain constant over the forecast.

- The CPS accounts for the retirement of existing mines over the forecast by annually decrementing the segment of coal supply curves represented by existing mines. The decrements used for this year's forecast, by coal supply region, mining method, and year, are shown in Tables 49 and 50.

Table 49. Retirement of Existing Underground Mine Production Capacity[a] in the Coal Production Submodule, 2000-2015
(Fractions)

Coal Production Regions	2000	2005	2010	2015
Pennsylvania, Ohio, Maryland	0.11	0.23	0.40	0.66
West Virginia, North	0.21	0.36	0.51	0.72
West Virginia, South	0.47	0.70	0.79	0.90
Kentucky, East	0.62	0.85	0.92	0.93
Virginia, Tennessee	0.47	0.64	0.82	0.93
Alabama	0.03	0.13	0.31	0.40
Kentucky, West	0.30	0.44	0.64	0.74
Illinois, Indiana	0.10	0.35	0.58	0.68
Arkansas, Iowa, Kansas, Missouri, Oklahoma	0.08	0.27	1.00	1.00
Texas, Louisiana	--	--	--	--
North Dakota, South Dakota, Montana	--	--	--	--
Wyoming, East	--	--	--	--
Wyoming, West	0.07	0.07	0.26	1.00
Arizona, New Mexico, Colorado, Utah	0.17	0.27	0.34	0.46
Washington, Oregon, California	--	--	--	--
Alaska	--	--	--	--

[a]Represents existing production capacity in 1994.
-- = no existing underground production capacity in these regions.
Note: A value of 1.00 represents full (i.e., 100 percent) retirement of existing production capacity.
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Coal Distribution Submodule

The Coal Distribution Submodule (CDS) 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

[90]Stanley C. Suboleski, et. al., *Central Appalachia*: *Coal Mine Productivity and Expansion*, Electric Power Research Institute, EPRI IE-7117, September 1991.
[91]U.S. Department of Labor, Bureau of Labor Statistics.

demand region using a linear programming algorithm. Production and distribution are computed for 16 supply and 23 demand regions for 23 demand subsectors.

Table 50. Retirement of Existing Surface Mine Production Capacity[a] in the Coal Production Submodule, 2000-2015
(Fractions)

Supply Regions	2000	2005	2010	2015
Pennsylvania, Ohio, Maryland	0.52	0.67	0.81	0.83
West Virginia, North	0.66	0.73	1.00	1.00
West Virginia, South	0.54	0.84	0.98	0.98
Kentucky, East	0.65	0.86	0.94	0.97
Virginia, Tennessee	0.80	0.91	0.94	0.94
Alabama	0.41	0.47	0.66	0.84
Kentucky, West	0.66	0.80	0.98	0.98
Illinois, Indiana	0.51	0.69	0.82	0.92
Arkansas, Iowa, Kansas, Missouri, Oklahoma	0.39	0.44	0.47	0.47
Texas, Louisiana	0.00	0.00	0.01	0.01
North Dakota, South Dakota, Montana	0.06	0.09	0.18	0.24
Wyoming, East	0.01	0.07	0.23	0.48
Wyoming, West	0.01	0.09	0.20	0.37
Arizona, New Mexico, Colorado, Utah	0.14	0.15	0.24	0.40
Washington, Oregon, California	0.00	0.00	0.12	0.58
Alaska	0.00	0.00	0.00	0.30

[a]Represents existing production capacity in 1994.
Note: A value of 1.00 represents full (i.e., 100 percent) retirement of existing production capacity.
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

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 Electricity Market Module, and coal export demands are provided by the Coal Export Submodule. Coal supply curves are provided by the CPS.

The key assumptions underlying the CDS are:

- In the CDS, 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 assumed to change differently in the East and West, based on eastern and western rate escalation factors. Transportation rates are escalated over time in response to projected variations in Reference Case fuel costs (No. 2 diesel fuel), labor costs (railroad-related wage plus wage supplements), and other rail-industry-related operating costs (material and supplies, equipment rent, purchased services, depreciation, interest, and taxes). The transportation rate escalators used for all five *AEO96* scenarios are shown in Tables 51 and 52.

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

Coal Export Submodule

The Coal Export Submodule (CES) is a linear program which provides annual forecasts of U.S. steam and metallurgical coal exports, in the context of world coal trade, for input to the CMM. 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.

Table 51. Transportation Rate Escalators For Eastern Regions
(1994=1.0000)

Year	Reference Case	Low Economic Growth	High Economic Growth	Low Oil Price	High Oil Price
1994	1.0000	1.0000	1.0000	1.0000	1.0000
1995	1.0322	0.9580	0.9563	0.9348	0.9762
2000	0.9893	0.9829	0.9787	0.9574	1.0348
2005	0.9993	0.9993	1.0021	0.9554	1.0670
2010	1.0262	1.0182	1.0342	0.9620	1.0895
2015	1.0448	1.0271	1.0609	0.9627	1.1045

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

The CES 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). The CES includes five U.S. export regions and four U.S. import regions.

The key assumptions underlying the CES 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 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.

Table 52. Transportation Rate Escalators For Western Regions, 1994-2015
(1994=1.0000)

Year	Reference Case	Low Economic Growth	High Economic Growth	Low Oil Price	High Oil Price
1994	1.0000	1.0000	1.0000	1.0000	1.0000
1995	0.9781	0.9068	0.9051	0.8849	0.9239
2000	0.9269	0.9302	0.9262	0.9062	0.9791
2005	0.9456	0.9456	0.9483	0.9043	1.0093
2010	0.9709	0.9634	0.9786	0.9105	1.0306
2015	0.9885	0.9717	1.0037	0.9112	1.0447

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

Data inputs to the CES:

- In the CES, 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 *AEO96* forecast scenarios are shown in Tables 53 and 54.

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 88 percent of domestic coal demand in 1994, incorporates the provisions of the Clean Air Act Amendments of 1990. It is assumed that electricity producers will be granted the full flexibility to meet the specified reductions in sulfur dioxide emissions.

Climate Change Action Plan

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

Labor Productivity Cases

In the reference case, labor productivity is assumed to increase at an average rate of 3.6 percent a year through 2015. Two alternative cases were modeled in the NEMS Coal Market Module, assuming labor productivity growth of 5.1 percent a year (high productivity case) and 2.2 percent a year (low productivity case). In the two alternative cases that were run to examine the impacts of different labor productivity assumptions, the annual growth rates were increased and decreased by 50 percent in each year after 1995. For example, a 4-percent productivity rate specific to a given year, mine type, and region in the reference case was set to 6 percent in the high productivity case and to 2 percent in the low productivity case. Both cases were run using only the Coal Market Module, rather than as a fully integrated NEMS run. Consequently, no demand feedback on coal markets was captured. In an integrated run, the demand response would tend to moderate the magnitude of the equilibrium price response.

Table 53. World Steam Coal Import Demand by Import Region, 2000-2015
(Million Metric Tons of Coal Equivalent)

Import Regions[a]	2000	2005	2010	2015
The Americas	21.3	25.4	31.7	43.9
United States	7.8	8.2	8.2	8.2
Canada	5.5	5.3	5.0	5.5
Mexico	2.8	4.7	8.2	14.8
South America	5.2	7.2	10.3	15.4
Europe	104.9	131.2	158.5	181.2
Scandinavia	15.0	15.6	17.1	15.1
U.K./Ireland	12.4	17.6	25.3	26.3
Germany	15.5	20.6	30.1	40.9
Other NW Europe	23.0	25.5	26.3	28.0
Iberia	14.3	16.9	18.0	20.7
Italy	9.5	9.8	10.6	11.5
Med/E Europe	15.2	25.2	31.1	38.7
Asia	152.5	192.6	232.4	264.7
Japan	65.5	73.9	85.2	92.0
East Asia	52.5	62.0	69.5	80.3
China/Hong Kong	15.3	23.8	30.3	34.8
ASEAN	9.3	16.7	25.2	30.6
Indian Sub	9.9	16.2	22.2	27.0
Total	278.7	349.2	422.6	489.8

[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.

Labor Cost Cases

In the reference case, labor costs, in constant 1994 dollars, are assumed to remain constant through 2015. Two alternative cases were modeled in the NEMS Coal Market Module, assuming labor cost growth of 0.5 percent a year (high labor cost case) and -0.5 percent a year (low labor cost case), in each year after 1995. Both cases were run using only the Coal Market Module, rather than an fully integrated NEMS run. Consequently, no demand feedback on coal markets was captured.

Table 54. World Metallurgical Coal Import Demand by Import Region, 2000-2015
(Million Metric Tons of Coal Equivalent)

Import Regions[a]	2000	2005	2010	2015
The Americas	18.6	19.2	20.2	21.9
United States	1.2	1.2	1.2	1.2
Canada	4.2	4.5	5.0	6.0
Mexico	0.8	1.0	1.2	1.4
South America	12.4	12.5	12.8	13.3
Europe	50.7	52.1	54.5	57.6
Scandinavia	2.0	1.8	1.7	1.7
U.K./Ireland	7.4	7.1	6.7	6.0
Germany	4.9	6.0	7.5	10.0
Other NW Europe	16.1	16.0	15.3	14.7
Iberia	4.0	3.5	3.4	3.4
Italy	7.7	7.5	7.3	7.0
Med/E Europe	8.6	10.2	12.6	14.8
Asia	85.2	85.5	86.1	87.0
Japan	52.7	51.1	50.5	49.5
East Asia	20.2	20.8	21.2	21.7
China/Hong Kong	2.2	2.7	3.2	3.3
ASEAN	0.0	0.0	0.0	0.0
Indian Sub	10.1	10.9	11.2	12.5
Total	154.5	156.8	160.8	166.5

[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.

Renewable Fuels Module

The Renewable Fuels Module (RFM) consists of six distinct submodules that represent the major renewable energy technologies. A seventh major renewable energy technology, conventional hydroelectric power, is described here along with other renewables. However, hydroelectric is now included in the Electricity Market Module (EMM); it is no longer part of the RFM. Some, such as ethanol 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. A common feature that extends across all renewable energy forms is that consumption of an energy form today does not lessen the supply of that form in the future. The technologies cover the gamut of commercial market penetration, from hydroelectric power, which was the original source of electricity generation and is a mature and possibly declining source, to new power systems using wind, solar, biomass, and geothermal energy, which in some cases require technological innovation to become cost effective or have inherent characteristics, such as intermittency, which make their penetration into the electricity grid dependent upon new methods for utility system planning or upon low-cost energy storage.

Because of the high degree of diversity of the energy forms within the RFM, the submodules of the RFM have interaction only with modules and submodules outside of the RFM rather than links with other RFM submodules. These interactions occur through common elements of the model with the Electricity Market Module (EMM) and the Petroleum Market Module (PMM) for ethanol. Because of the high level of integration with these other National Energy Modeling System (NEMS) modules, the final outputs (levels of consumption and market penetration over time) for renewable energy forms are largely dependent upon assumptions in those other modules. The RFM includes the investment tax and energy production credits called for in the Energy Policy Act of 1992 for the appropriate energy types.

For *AEO96*, 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 each technology, the RFM provides the EMM the overnight capital cost that corresponds to the limit (end) of assumed learning effects, usually defined to occur at 40 units. In addition, unit size is provided to the EMM for renewable technologies, so that the level of market penetration can be determined. As a rule of thumb, a doubling of market penetration produces a 10-percent decline in capital costs (the exception to this rule is wind) For an in-depth discussion of the learning curves, see the EMM section and the background section of th model summmary for the Geothermal Electric Submodule.

Key Assumptions

Nonelectric Renewable Energy Uses

In addition to projections for renewable energy used in electricity generation, the *AEO96* 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 geothermal water use (e.g., district heating and greenhouses), are not included in the projections because their expected penetration is limited to small markets.

Electric Power Generation

The RFM specifically and NEMS in general consider only grid-connected electricity generation. Off-grid sources, such as some types of photovoltaic, Stirling engine solar, and wind generation, are not included in the energy balances for the *AEO96*. The renewable submodules that interact with the EMM are the hydroelectric, solar, wind, geothermal, wood, and MSW submodules. Most provide specific data that characterize that resource in a representative 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. The values are presented in Table 55.

Table 55. Renewable Resources for Grid-Connected Electric Power Generation: Cost and Performance Values for 2010, California[a]

(1987 dollars)

Parameter	Conventional Hydro-electric	Geothermal[b]	Biomass	MSW[c]	Solar Thermal[d]	Wind	PV
Current Capital Cost ($ per kilowatt)[e]	2,176	2,337	1,962	5,456	1,660	792	2,657
Variable Operating Cost (mills per kilowatthour)	3.2	0.0	15.1[f]	-1.0[f,g]	0.0	0.0	0.0
Fixed Operating Cost ($ per kilowatt)	10.2	64.6	67.9	12.8	19.8	20.9	5.1
Average Capacity Factor (Percent)	28	80	80	80	40	40	30
Date Commercial Availability, new technologies (Year)	NA	NA	2000	NA	1997	NA	1997
Construction Lead Time (Years)	3	4	4	1	3	3	3
Unit Size (Megawatts)	NA	[h]	100	NA	200	50	50
Maximum units with learning effects, "n"	NA	[h]	40	NA	40	66	40

[a]Region 13 includes most of California. Although most renewable energy technologies (except solar thermal and geothermal) are assumed to compete in all regions, region 13 values are shown because it remains the most likely region for most new capacity.

[b]Since 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 the indicated year and region.

[c]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.

[d]Solar thermal only operates in Electricity Market Module regions 2, 5, and 10-13 because of its requirement for significant direct, normal insulation.

[e]Overnight capital cost plus project contingencies, then adjusted for regional costs.

[f]Value represents the sum of variable operating and maintenance and fuel costs.

[g]Negative value represents tipping fees for MSW disposal.

[h]Geothermal learning costs involve capital components for well, field, and two plant types, as well as operation and maintenance components. Details are provided in the model documentation (see footnote 95).

[i]The number of units installed of a new technology after which cost no longer declines because of learning.

Sources: Most values are derived by the Energy Information Administration, Office of Integrated Analysis and Forecasting. **Hydroelectric**: Forms EIA-860 and EIA-867. **Solar Thermal**: California Energy Commission Memorandum, "Technology Characterization for ER94, August 6, 1993. **Photovoltaic**: Technical Assessment Guide-Electric Power Research Institute (EPRI-TAG 1993). **Wind**: EPRI. **Geothermal**: EPRI-TAG, 1993. **MSW**: EPRI-TAG 1993. **Biomass**: Derived by EIA from EPRI-TAG 1993.

Conventional Hydroelectric Power Submodule

Background

The Hydroelectric Power Submodule (now located in the EMM rather than the RFM) 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 is not a renewable energy use. Hydroelectric power is not competed against any other electricity generation technologies for capacity expansion, and all the hydropower generated (from power marketing administrations, etc.) is assumed to be consumed. The submodule provides for conventional hydropower, the available capacity, capacity factors, costs (capital and fixed and variable operating and maintenance) to the EMM by region. 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.

Solar Electric Submodule

Background

The Solar Electric Submodule currently includes two solar technologies: central receiver (power tower) solar thermal (ST) and fixed-flat plate thin-film copper-indium-diselenide (CIS) photovoltaic technologies. PV is assumed available in all 13 EMM regions, while ST is available only in the six primarily Southwestern regions where direct normal solar insolation is sufficient. Most 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 (identified as "n" in Table 55) are determined by EIA.

Assumptions

- Additional reductions in capital costs obtained by experience (learning effects) are assumed to cease for PV after the 40th unit (the general modeling assumption).

- 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).

- Because solar technologies are more expensive than other utility grid-connected technologies, early penetration will be driven by broad economic decisions such as the desire to become familiar with a new technology and environmental considerations.

- Solar resources are well in excess of conceivable demand for new capacity; therefore, energy supplies are considered elastic within regions. Accordingly, there is no reason to track installed solar resources in NEMS. However, other issues such as proximity to transmission lines and land use and environmental restrictions could limit solar from major penetration within the forecast horizon. 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 in the forecast term.

- NEMS models the 10-percent investment tax credit for solar electric power generation by tax-paying entities. However, it does not include the 1.5-cent-per-kilowatthour subsidy to solar energy production for State and nonprofit electric cooperatives, since it does not keep track of these distinctions within the model.

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 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 Laboratories study and a subsequent update.[92] The technological performance, cost, and other wind data used in NEMS are derived from the Electric Power Research Institute's Technology Assessment Guide.[93]

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. The fossil-fuel heat rate equivalents for wind are provided to the report writer for energy consumption calculation purposes only. These form the basis on which the EMM decides how much power generation capacity is available from wind energy.

Assumptions

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

- Availability of wind power is based on the Pacific Northwest Laboratories' 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.

- 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) costs for new wind units must be less than the variable operating and fuel costs for existing 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

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[92]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*" Richard, WA: Pacific Northwest Laboratory, August 1991) and 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* October 19-23, 1992, Seattle.

[93]In collaboration with EPRI, capital cost declining as a function of time were converted to costs declining as a function of market penetration for use in the learning functions detailed elsewhere in this report.

to a national average of over 35 percent. However, as better wind resources are depleted, capacity factors go down.

- Because of increased market activity in windpower and the introduction of improved technologies, the capital cost for wind energy at the time learning is assumed to be fully achieved is $690 in 1987 dollars (excluding contingencies). This so-called “nth-of-a-kind” cost represents a 20-percent decrease in capital costs for a doubling of capacity. This corresponds to 3,300 megawatts (MW) of capacity or 66 wind farms with a capacity of 50 megawatts each.

- For *AEO96*, Wind resources are mapped in relation to appropriate transmission capacity for a 10 mile corridor on either side of the transmission lines. Transmission cost factors are added to the resources further from the transmission lines.

Geothermal-Electric Power Submodule

Background

In developing geothermal capacity growth projections, hydrothermal resources are considered, but hot dry rock is not included in the analysis. This is because the technology probably will be at best 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.[94] 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. A value for avoided cost is obtained from the Electricity Capacity Planning Submodule to truncate the curves to exclude the higher cost resources. Technology cost learning which emulates what is done in the EMM is incorporated in the GES.[95]

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. These (six) wells are assumed to be retired after 35 years.

- Capital and operating costs vary by sites and years; values shown in Table 55 are indicative of those used by EMM for geothermal build and dispatch decisions.

[94]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).

[95]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)

Biomass Electric Power Submodule

Background

In the electricity sector, capital and operating costs, fuel costs, and capacity factors, as shown in Table 55, are provided to the EMM to allow biomass-fueled units to compete with other fuels. Fuel costs are developed on a regional basis and combined with variable operating costs. Because of the uncertainty surrounding this technology, unplanned builds were restricted to 200 MW per NERC region per year. If the bound is reached, there is a waiting period of 3 years before capacity can be built in that region. This is meant to emulate the conservative nature of the electricity generation industry—especially in light of reduced fuel costs. The specific build patterns are presented in Table 56.

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 55 are based, is an advanced gasifier-combined cycle plant. Co-firing with coal is a distinct possibility, but it would not add capacity.

- The submodule deals with noncaptive wood consumption only. Consumption by the wood products and paper industries is modeled in the industrial demand model.

- Fuel costs are contained in a set of cost-supply schedules which are a composite of mill residues, logging residues, whole tree chips, other wood and energy crops.[96] One cost-supply schedule is stable from 1990 through 2009. Yearly schedule represents anticipated resources from 2010 to 2015, the only period covering energy crops.

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.[97]

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 and population are used as the drivers in an econometric equation that establishes the supply of MSW.

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[96] Decision Analysis Corporation of Virginia, "*Data Documentation for the Biomass Cost-Suppply Schedule*", Vienna VA, July 1995.

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

- The values are extrapolated from historical Environmental Protection Agency (EPA) values for MSW and factored upward by 1.42 to reflect a broader definition of materials known to be combusted. The factor 1.42 is derived from information in the Biocycle State Survey.[98]

- 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 higher (i.e. Biocycle-based) value for generation of MSW, 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 Government Advisory Associates database of MSW plants.

- Capacities are computed from total energy by applying an assumed heat rate of 16,284 Btu per kilowatthour and a combustion capacity factor of 0.88 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. The resulting electricity generation is added to the generation from MSW combusion.

Biofuels (Ethanol) Supply Submodule

Background

The Biofuels (Ethanol) Supply Submodule provides supply functions on an annual basis through 2015 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.[99]

• 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 PMM.

• Interregional transportation costs are not calculated within the Biofuels Supply submodule.

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[98] *The State of Grabage in America,* Biocycle, April 1995, p. 58.

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

Legislation

The RFM includes the investment tax and energy production credits called for in the Energy Policy Act of 1992 (EPACT) for the appropriate energy types. EPACT provides a renewable electricity production credit of 1.5 cents per kilowatthour 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 reported generating capacity plans and capacity projected through use of the RFM, the *AEO96* also includes 1, 798 megawatts additional new generating capacity (net summer capability) powered by renewable resources. Some of the capacity represents commitments not yet reported to EIA, some represents mandated new capacity required by Minnesota law (mandates in New York and California have been overturned), and the remainder represents minimum EIA "floor" estimates of new capacity assumed to be built for unmodeled solar technologies, niche market needs not covered by the RFM, or for testing, as follows:

Table 56. Supplemental Capacity Plans (Megawatts, Net Summer Capability)

Rationale	Geothermal	Solar Thermal	Solar Photovoltaic	Wind	Biomass	Total
Commitments	157	41[a]		313	0	511
Mandates	0	0	0	400	125	525
Unmodeled	0	475	287	0	0	762
Total	157	516[a]	287[a]	713	125	1,798

[a]Commitments have not determined solar technology type.
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.

In the *AEO96* all supplemental capacity plans are included among planned capacity additions along with plans reported on the EIA-860 and EIA-867.

Climate Change Action Plan

Action Item 26, "Form Renewable Energy Market Mobilization Collaborative with Technology Demonstration," of the Climate Change Action Plan (CCAP),[100] is designed to spur field validation of selected renewable energy technologies by supporting specified electric utility tests. The demonstrations,

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

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 *AEO96* of Action Item 26 are incorporated in EIA's projections for renewable technologies in two ways. First, the supplemental capacity additions include additions that will be cost-shared by DOE and industry; second, for wind-powered technologies, CCAP results in capital cost declines that are more rapid than for other technologies. 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.