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Assumptions for the Annual Energy Outlook 1991

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Assumptions for the *Annual Energy Outlook 1991*

April 1991

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Preface

This report serves as an auxiliary document to the Energy Information Administration (EIA) publication *Annual Energy Outlook 1991 (AEO)* (DOE/EIA-0383(91)), released in March 1991. The AEO forecasts were developed for four alternative cases and consist of energy supply, consumption, and price projections by major fuel and end-use sector, which are published at a national level of aggregation.

The purpose of this report is to present important quantitative assumptions, including world oil prices and macroeconomic growth, underlying the AEO forecasts. The report has been prepared in response to external requests, as well as analyst requirements for background information on the AEO and studies based on the AEO forecasts.

This report is a product of the Energy Information Administration, Office of Energy Markets and End Use, under the direction of W. Calvin Kilgore (202/586-1617). This report was prepared under the general supervision of John D. Pearson, Director, Energy Analysis and Forecasting Division (202/586-6160) and Edward J. Flynn, Chief, Demand Analysis and Forecasting Branch (202/586-5748). The report was a joint effort of all program offices of the EIA.

Information concerning specific topics is available as follows:

IFFS	Susan Shaw (202/586-4838)
DEMS	Michael Lehr (202/586-1470)
World Oil Price	A. David Sandoval (202/586-6581)
Macroeconomic Assumptions	Ronald Earley (202/586-1398)
Energy Consumption	
Residential	John Cymbalsky/Henry Clarius (202/586-5359)
Commercial	Eugene Reiser (202/586-5840)
Industrial	John A. Holte/Gerald Peabody (202/586-1458)
Transportation	Barry N. Cohen (202/586-5359)
Oil Markets (OMM)	Bruce Bawks (202/586-6579)
Gas Analysis Modeling System (GAMS)	Barbara Mariner-Volpe (202/586-5878)
Crude Oil Supply	Joe Benneche/Ted McAllister (202/586-4680)
Coal Supply and Pricing	Scott Sitzer (202/254-5300)
Renewables	Suraj Kanhouwa (202/254-5504)
Electricity	Jeff Jones (202/254-5348)
Nuclear	Mark Gielecki (202/254-5509)

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1. Introduction

This report is an auxiliary document to the *Annual Energy Outlook 1991* (*AEO*) (DOE/EIA-0383(91)). It presents a detailed discussion of the assumptions underlying the forecasts in the *AEO*. The energy modeling system is an economic equilibrium system, with component demand modules representing end-use energy consumption by major end-use sector. Another set of modules represents petroleum, natural gas, coal, and electricity supply patterns and pricing. A separate module generates annual forecasts of important macroeconomic and industrial output variables. Interactions among these components of energy markets generate projections of prices and quantities for which energy supply equals energy demand.

This equilibrium modeling system is referred to as IFFS/GAMS/DEMS. The Intermediate Future Forecasting System (IFFS) is the core of the system. It calls supply modules for oil markets, coal, and electricity, and links to the Gas Analysis Modeling System (GAMS), a natural gas supply model, and the Demand Evaluation Modeling System (DEMS), a set of energy demand models. The supply models in IFFS/GAMS determine supply and price for each fuel conditional upon consumption levels, while the demand models in DEMS determine consumption conditional upon end-use price. IFFS solves for market equilibrium for each fuel by balancing supply and demand to produce an energy balance in each forecast year.

Description of Four Scenarios

Four scenarios are discussed in this year's *AEO*. Taken as a group, they present a range of possible outcomes, which diverge over a 20-year projection into the future as cumulative market responses to different energy prices and the results of capital turnover become more apparent. The cases are based on reasonable upper and lower bounds on two key factors that affect energy trends—world oil price and the rate of economic growth—and characterize a reasonable range of uncertainty for domestic oil production and petroleum imports under current energy policy.

A Reference Case, which uses baseline assumptions about economic growth and a mid-level trajectory for future world oil prices, is discussed in connection with each consumption sector and every energy source; but it is not being put forth as the "most likely" scenario. The purpose of a reference forecast is to facilitate comparisons—both to the other cases in the *AEO* and to forecasts developed by other organizations.

The three other scenarios were constructed primarily to examine the combined effects of alternate assumptions about world oil prices, macroeconomic growth, and conservation. In every instance, changes in price and gross national product (GNP) are viewed as taking place smoothly, even though history suggests that intermediate ups and downs (which may make substantial differences to an unfolding picture) are just as likely in reaching a given endpoint with the same "average" results.

Many sections of the *AEO* refer to all four cases, and all four are detailed in Appendices to the *AEO*. However, some figures present only the bounding projections, and case details have been omitted from the text where variations from the Reference Case are slight.

Reference Case

The Reference Case used in the *AEO* combines the assumption of an annual economic growth rate that is commonly used as a baseline for analyzing long-term trends (2.1 percent) and a mid-level path for world oil price (reaching $34 in 1990 dollars by 2010). The macroeconomic assumption represents a mainstream projection—in which growth in the U.S. labor force slows, thereby constraining GNP. No new legislative initiatives are incorporated in this case.

Low Oil Price Case

This case starts with the same baseline economic growth as the Reference Case (2.1 percent per year), but combines this with an assumption that world oil prices will be no higher than $23 per barrel in 2010. Such relatively low prices could result from improved oil production capacity around the world or from new discoveries. Feedback within the model ultimately raises the growth rate slightly as a result of the generally low energy prices—to an equilibrium rate of 2.2 percent.

High Economic Growth Case

This case assumes the same world oil prices as the Low Oil Price Case ($23 in 2010), but combines them with high macroeconomic growth (2.8 percent). Such a combination produces the highest energy demand of any of the four cases in this year's *AEO*.

High Oil Price Case

This case combines the assumption of the Reference Case baseline growth rate (2.1 percent) with a high world oil price ($45 in 2010). In addition, this particular scenario examines the effects of increased energy conservation. Such a reaction might well be anticipated in the face of high world oil prices—which could result from less favorable developments in improving global capacity for petroleum production.

The oil price and economic growth assumptions are summarized in Table 1. Subsequent chapters will present other quantitative assumptions for specific demand and supply modules of the integrated forecasting model, that were used by EIA in developing the *AEO* scenario projections. Further details on the methodology, data, and assumptions are available from the contacts listed in the Preface.

Table 1. AEO Scenario Summary

Assumptions	Reference Case	Low Oil Price Case	High Economic Growth Case	High Oil Price Case
Oil Price in 2010 (1990 dollars)	$34	$23	$23	$45
Economic Growth Scenario	Baseline	Baseline	High	Baseline
Real GNP Growth Rate	2.1	2.2	2.8	2.1

Source: Energy Information Administration, Office of Energy Markets and End-Use.

2. World Oil Price and Macroeconomic Assumptions

World Oil Price

World oil markets are currently dominated by the uncertainty brought about by Iraq's invasion of Kuwait. Without this uncertainty, the current world oil surplus would likely result in oil prices at or below pre-invasion levels well into the mid-1990's. An eventual settlement to the Middle East crisis (bringing renewed access to the oil reserves of Iraq and Kuwait) is assumed in all scenarios. No effort was made to forecast the near-term price changes that might be caused by the crisis. Three price levels are given for 1991 ($19, $24, and $29 per barrel in constant 1990 dollars), due to the uncertainty as to economic growth, oil supply availability, and consumer behavior. Quick resolution of the Gulf crisis and restoration of resultant damage to the Kuwaiti oil fields would likely yield a price level near the lower end of this scale. Continued uncertainty regarding access to oil supplies yields a higher price. As political uncertainty subsides and market influences grow, oil consumption and OPEC's market share continue to rise, pushing prices higher through 2010 (Table 2). Projections of foreign oil production and consumption, and world oil prices were prepared using the Oil Market Simulation (OMS) Model.[1]

Scenarios

Low Oil Price

The world oil price, given baseline macroeconomic growth, is forecast to increase to only $23 in constant 1990 dollars by 2010, the result of increased production capacity and new discoveries. This expansion in the resource base is experienced mostly by OPEC countries, particularly Saudi Arabia. Development and extraction costs are assumed to remain well below the prevailing price level. Non-OPEC producers also increase output, to recoup revenues which would otherwise fall due to the lower crude oil price. The Soviet Union, in particular, is assumed to be successful in producing oil for export. On the demand side, oil consumption will grow to meet the needs of worldwide economic growth, but oil's share of total energy consumed should continue to diminish. Through the year 2010, the major consumers of oil will continue to be the industrialized nations, and much of the absolute growth in oil consumption will occur in the United States. The developing countries, however, will probably show the fastest rate of growth in oil consumption.

Mid-Level Assumption

The mid-level price path increases to $34 in constant 1990 dollars in 2010. The mid-level price assumption is combined with a baseline macroeconomic growth assumption to construct the Reference Case.

High Oil Price

The world oil price, given baseline macroeconomic growth, is forecast to increase to $45 in constant 1990 dollars by 2010, due to strengthening resolve of the OPEC countries to pursue an effective cartel strategy, for economic or political reasons. Non-OPEC producers are assumed to increase production by only a small amount because of the difficulty of raising output, even in the face of a favorable world oil price.

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[1]*Oil Market Simulation User's Manual*, DOE/EIA-M028(90).

Table 2. World Oil Prices, 1979-2010
(1990 Dollars per Barrel)

Year	Price Case: Low	Middle	High
1979		36.23	
1980		51.96	
1981		51.78	
1982		44.08	
1983		37.05	
1984		35.24	
1985		31.98	
1986		16.15	
1987		20.29	
1988		15.77	
1989		18.81	
1990	22.00	22.00	22.00
1991	19.00	24.00	29.00
1992	19.00	24.00	29.00
1993	19.00	24.00	29.00
1994	19.00	24.00	29.00
1995	19.00	24.00	29.00
1996	19.00	24.00	29.00
1997	19.00	24.00	29.00
1998	19.30	24.20	29.40
1999	19.70	24.90	30.30
2000	20.10	25.70	31.10
2001	20.40	26.60	32.60
2002	20.70	27.70	34.00
2003	21.10	28.80	35.40
2004	21.40	29.90	36.80
2005	21.70	31.00	38.20
2006	22.10	31.90	39.70
2007	22.40	32.70	41.10
2008	22.70	33.30	42.50
2009	23.10	33.80	43.90
2010	23.40	34.20	45.40

Note: Prices represent the U.S. refiner acquisition cost of imported crude oil.
Sources: **History**: Energy Information Administration (EIA), *Annual Energy Review 1989*, DOE/EIA-0384(89) (Washington, DC, 1990). **Projections**: EIA, Oil Market Simulation Model.

Macroeconomic Assumptions

Purpose

This section describes the general model structure, assumptions, and data used to produce the 1991 *AEO* macroeconomic forecasts and explains the choice of data and assumptions in the scenarios.

Methodology

The Mini-Macroeconomic Personal Computer Model (PCMAC) generates annual forecasts of important macroeconomic and industrial output variables used by the *AEO's* energy supply and demand models. This submodel produces forecasts of 39 macroeconomic variables and 11 industrial output variables. Among these variables are real gross national product (GNP82), the GNP price deflator, real disposable income, the interest rate on utility bonds, and the output of major industrial sectors, such as primary metals.

PCMAC is designed to mimic two larger and more complex models of the U.S. economy (the DRI Annual Model of the U.S. Economy and the DRI Input-Output Model). PCMAC utilizes data from controlled simulations of these two DRI models and constructs two sets of econometric models. The first set (the macroeconomic module), constructs the relationships between macroeconomic variables and energy prices. The second set (the industrial module), constructs the relationships between industrial output variables and macroeconomic variables.

The macroeconomic module receives forecasts of four energy prices (world oil price, industrial natural gas, industrial electricity, and steam coal to electric utilities) from the *AEO* integrating module. After consolidating these four energy prices into one aggregate energy price index (WPI05), the module inserts WPI05 into the 39 macro regression equations to calculate changes in the macro forecasts. The industrial module uses the calculated changes to the macro variables to estimate impacts on 11 industrial output variables. A more detailed explanation of the calculations performed by the macroeconomic and industrial output sections can be found in the PCMAC Model Documentation.

Scenarios

Long-term economic growth is fundamentally determined by the rate of expansion of the resource base of the economy (labor, capital, and energy) and changes in factor productivity. The path of U.S. economic growth is bounded by two considerations—first, the expectation that labor force growth will continue to decline, and, second, the great uncertainty about the path of productivity growth in the economy.

Because of changes in demographics, there is a consistently held view that the rate of growth in the labor force will decline steadily through 2010 and beyond. This factor imposes significant constraints on growth prospects for the economy. Average labor force growth rates are expected to equal about 1 percent over the forecast period, down from 2.1 percent from 1970 to 1989. To the extent the differences in labor force growth are evident, they generally reflect differing views on the potential for immigration, rather than changes in the extent of labor force participation.

Even with common labor force growth assumptions, projections of growth in potential GNP can differ because of differing views on the prospects for new capital formation and improvements in technology. To some degree, lower labor force growth is offset by improvement in labor force productivity, as capital is substituted for labor. Capital formation, capacity utilization, research and development, and energy market behavior will play critical roles in influencing the aggregate productivity of the economy. Those expecting higher rates of growth in potential GNP are generally more optimistic about capital formation and technology change. The baseline scenario for economic growth assumes an annual increase in labor productivity of 1.2 percent, while the high growth scenario assumes 1.9 percent. Projections of macroeconomic variables under these assumptions are given in Table 3.

Table 3. Macroeconomic Scenarios

Growth Rates (1989-2010)	Baseline Growth (percent)	High Growth (percent)
Real GNP	2.1	2.8
Disposable Income	1.7	2.3
GNP Deflator	4.1	4.0
Consumer Price Index	4.4	4.3
Unit Sales of Automobiles	0.6	1.5
Total Manufacturing Output	2.5	3.3
Total Industrial Output	2.3	3.0

Source: Energy Information Administration, Office of Energy Markets and End-Use, PC-AEO Forecasting Model for the *Annual Energy Outlook 1990*, DOE/EIA-M036(90), and Technical Notes.

In the Low Oil Price Case, feedback within the model raises the real GNP growth rate slightly as a result of generally low energy prices—to an equilibrium rate of 2.2 percent. Disposable income increases at an annual rate of 1.8 percent. High oil prices lead to inflation, so the GNP deflator growth rate and the CPI are slightly larger in the baseline growth scenario.

3. Demand Model Assumptions

Residential Sector

Purpose

This section describes the general model structure, assumptions, and data used to produce the *Annual Energy Outlook 1991* (AEO) residential energy demand forecasts and explains the choice of data and assumptions in the scenarios.

Methodology

The primary purpose and use of the residential model is to prepare long-term projections of residential energy consumption for the *AEO*.

The main inputs in the model are new and existing housing stock, equipment and shell efficiencies, and the regional price of energy by fuel type. A key driver in the model is the stock of housing in each of the four Census regions. The main output of the model is a projection of annual fuel consumption by year through the year 2010. The six fuels included in the model are: distillate, liquefied petroleum gases (LPG), natural gas, electricity, kerosene, and coal. (Renewable energy consumption is handled separately, and is discussed at the end of this section). Total energy projections are obtained by summing over fuels, where each fuel is measured in Btu of delivered energy. Fuel consumption projections are available by Census region, by type of service demand, and by type and vintage of residential structure. Fuel prices are provided exogenously to this model, which solves for unique consumption levels. Energy market equilibrium is obtained in the integrating framework. Projections are benchmarked to EIA's State Energy Data System (SEDS) for 1987 and 1988, and *Short-Term Energy Outlook* (*Outlook*) for 1989, 1990, and 1991.

The objective of the housing stock model is to project annually the total stock of housing by Census region, and to keep track of vintage and type of structure. Given the shell and equipment efficiencies of new and existing homes and the demand for new equipment, the model calculates an overall demand for each energy service. This demand is met by fuel-using technologies on the basis of their life-cycle costs. A logit analysis selects technologies and hence fuel shares for new and replacement equipment for each category of service demand.

Higher fuel prices increase the life-cycle costs of less-efficient fuel-using technologies relative to other technologies thereby affecting appliance choice for both new and replacement demand. Inter-fuel substitution occurs when new or replacement technologies are selected. Higher economic growth scenarios produce increases in new housing starts and thereby more energy demand.

The base year of the model is 1987, which is determined by the latest year of the EIA's Residential Energy Consumption Survey (RECS-87). This national survey of energy consumption in the residential sector provides much of the initial data for energy consumption and housing characteristics. Data for new construction is obtained from the Census publication *Characteristics of New Housing: 1988*. Additional engineering technology information comes from the DOE Office of Conservation and Renewable Energy and was developed by Lawrence Berkeley Laboratory.

The model has four basic parts—a model of the housing stock, a model of service demand, a model of service capacity, and a model of new technology choice for service capacity. A detailed description of the residential model and its submodels can be found in PC-AEO Forecasting Model for the *Annual Energy Outlook 1990*, DOE/EIA-M036(90), and Technical Notes. The following sections describe assumptions used in these submodels.

Housing Stock Model

Projections of aggregate new housing starts are obtained from the AEO's Macroeconomic Model, PCMAC. Regional housing stock estimates for each year are obtained by taking initial regional estimates as of 1987, adding new starts for all years after 1987, and subtracting estimated housing stock demolitions. Housing starts vary directly with macroeconomic growth.

Three housing types (h) are tracked: single-family (SF), multi-family (MF) and mobile home (MH).[2] In the current version of the model, new homes are allocated to these types with profiles that vary by Census region, but are constant over the forecast period. The following regional shares of housing by type of house are obtained from *Characteristics of New Housing: 1988*, Current Construction Reports C25-88-13, Bureau of the Census.

	Northeast	South	Midwest	West
Single Family	.69	.54	.58	.53
Multiple Family	.22	.28	.29	.40
Mobile Homes	.09	.18	.13	.07

Based upon Census sample estimates, approximately 0.6 percent of existing homes are demolished each year, with mobile homes having a higher retirement rate.[3]

Service Demand Model

The model views total energy demand as the sum of the energy demand for specific component services or end uses, e.g., Btu of heat per single family home. These services include: heating, air-conditioning, water heating, refrigeration, and all other appliances. The initial demand for cooling is estimated using RECS 1987 data. The demand for cooling is assumed to increase at a rate consistent with past increases as estimated from various RECS surveys up to a postulated limit. The postulated limit to demand is based on *Characteristics of New Housing: 1988*, where the percentage of households with any particular service has been constant across surveys. The exception is central air conditioning, which is continuing to gain popularity in new houses.

Service Capacity Model

Given a demand for a service such as heating, service capacity, in principle, is defined as the size of the unit that would deliver that heat. However, to calculate the heat output from a furnace per year in a given region requires a knowledge of the unit's size, efficiency, and average operating hours. Although the presence of a heating unit of a specific fuel is recorded, neither the efficiency, the operating hours or the unit size are available from the data.

To avoid the problem of lack of data, service capacity is defined as equal to service demand as measured in Btu of input fuel in a base year. Service capacity is thus relative to 1987.

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[2]The index set of housing types is expressed as {h} = {SF, MF, MH}.

[3]U.S. Department of Commerce, Bureau of the Census, *Current Housing Reports*, Series H-150-83, *General Housing Characteristics for the United States and Regions: 1983, Annual Housing Survey*, 1983, Part A.

New Technology Choice Model

Of the technology choices that will meet the demand for an energy service equally well, all other things being equal, the technology with the minimum life-cycle cost is preferred.

As existing equipment wears out, and as new homes are built, new equipment is purchased. Available equipment is characterized by the type of fuel it uses, its efficiency, and its capital cost. Average existing equipment efficiency is based on Lawrence Berkeley Laboratory research.[4] The efficiency of available equipment will vary across scenarios, with the High Oil Price Case reflecting significant efficiency improvements (Tables 4 and 5).

Fuel prices used in calculating life-cycle costs are the average retail prices in each Census region for a given year. They are assumed to be fixed for the lifetime of the equipment, reflecting the view of a "myopic" consumer who expects no price change. For example, if a consumer buys a refrigerator in 1994, he calculates life-cycle cost as if 1994 fuel prices will be in effect for the life of the refrigerator. A 20-percent real discount rate is applied to all forward costs (fuel and maintenance). This discount rate reflects the typical consumer's short payback period.[5]

Technology Penetration

Given the equilibrium technology choices from the life-cycle cost analysis, the remaining issue is how quickly these technologies penetrate the market place. We assume that in 1988, the first decision year, the choices of new technologies will not be substantially different from those in 1987 or earlier. Empirical evidence indicates that although a new technology may be economically optimal, consumers will be slow to adopt it. Therefore, ideal new technology shares are phased in via a market penetration lag of 0.2. The efficiency of the total stock of equipment thus adjusts slowly.

In the Reference Case, it is assumed that 80 percent of new and replacement equipment will be characterized by the average equipment currently in place. This reflects the average home-owner's propensity to replace with equipment of similar configuration and fuel characteristics. The remaining 20 percent will be shared by the various technologies chosen in the life-cycle calculations. These shares will vary across scenarios, depending on the path of fuel price increases and relative rates of efficiency improvement for each technology alternative.

Scenarios

Reference Case

Exogenous Variables and Parameters. The Reference Case uses input data which reflect current estimates of appliance and building efficiency, and current capital cost of energy-using equipment, in the context of baseline macroeconomic growth and mid-oil price assumptions. Average annual housing starts are 1.6 million per year from 1990 through 2010.

Improvements in shell efficiency are assumed to be minimal—a nominal 0.27-percent improvement per year in pre-1975 single and multi-family homes. This is based on an analysis of RECS-87 survey data. Post-1999 homes are assumed to have better shell efficiency, consistent with the likelihood of wider application of building standards and improved housing design and construction techniques. The least efficient equipment

[4]U.S. Department of Energy, Office of Policy, Planning and Analysis, *Energy Conservation Trends*, DOE/PE-0092, (U.S. Department of Energy: Washington, D.C.) 1989, p. 37.

[5]Harry Chernoff, "Individual Purchase Criteria for Energy-Related Durables: The Misuse of Life-Cycle Cost," Vol. 4, No. 4, *The Energy Journal*, 1983, pp.81-86.

alternatives provided by the model meet current Federal minimum appliance standards. The performance characteristics of alternative equipment choices are representative of advanced technology currently on the market (Tables 4 and 5). It is assumed that 80 percent of new and replacement equipment chosen will be characterized by the average equipment currently in place, in terms of cost and efficiency. This reflects the current tendency for homeowners to replace equipment of similar configuration and fuel use.

Rationale. The Reference Case data set reflects a continuation of past price and income behavior, with no change in attitudes toward energy conservation. Current Federal building and appliance standards remain in place, but are not assumed to become more stringent after 1992.

Low Oil Price Case

Exogenous Variables and Parameters. Low world oil prices and baseline macroeconomic growth are used to investigate the effect of price variations. The residential model's Reference Case assumptions regarding efficiency and consumer behavior are used in the Low Oil Price Case.

Rationale. The Low Oil Price Case input data set reflects a business-as-usual attitude toward energy conservation, in the context of low prices and baseline economic growth. As in the Reference and High Economic Growth cases, current Federal building and appliance standards remain in place, but are not assumed to become more stringent. This combination of assumptions serves to analyze the effect of price variations relative to the Reference Case.

High Economic Growth Case

Exogenous Variables and Parameters. High residential demand is assumed to be generated by low world oil prices and high macroeconomic growth. Average annual housing starts are 1.8 million.

The residential model's Reference Case assumptions regarding efficiency and consumer behavior are used in the High Economic Growth Case.

Rationale. The High Economic Growth input data set reflects a business-as-usual attitude toward energy conservation, in the context of low prices and high macroeconomic growth. Again, current Federal building and appliance standards remain in place, but are not assumed to become more stringent. This combination of assumptions establishes an upper bracket for consumption estimates.

High Oil Price Case

Exogenous Variables and Parameters. Low residential demand is forecast in the context of high world oil prices, and baseline macroeconomic growth assumptions. Building and appliance efficiency improvements are phased in more rapidly over the forecast period. This is intended to assess the effect of a trend toward wider application of conservation standards. Efficiency improvements are limited to those which are cost effective.

Initially, the least efficient equipment that are evaluated by the equipment choice routine meets Federal minimum appliance standards. The most efficient units represent a mix of advanced technology currently on the market. Over the forecast period, equipment is assumed to become more efficient. Improvements in technology and corresponding cost estimates are based on information used in the National Energy Strategy (NES) service report.[6] NES projections are made over a 40-year period, from 1990 to 2030. Over this period, technology is assumed to improve, until all equipment choices are as efficient as the best the market currently

[6]Energy Information Administration, *Energy Consumption and Conservation Potential: Supporting Analysis for the National Energy Strategy*, SR/NES/90-02 (Washington, DC, 1990).

has to offer. The cost of equipment is also assumed to increase annually in the High Oil Price scenario, consistent with evidence that more efficient units have higher capital costs.

Equipment alternatives available in the High Oil Price Case are given in Tables 4 and 5. In the case of heat pumps, the Reference Case offers households the choice between three heat pumps, with heating efficiency levels of 2.14, 2.49, and 2.87. These efficiencies are constant throughout the forecast period. However, in the High Oil Price Case, each heat pump alternative gradually becomes more efficient (Figure 1), so that by 2010, households choose between efficiency levels of 2.49, 2.67, and 2.87. Efficiency improvements are assumed to proceed at the same rate as in the NES projections. Since the *AEO* forecast period is 20 years, from 1990 to 2010, efficiency improvements will reach half the limits seen in the NES projections.

Table 4. Residential Heating and Cooling Equipment Alternatives

Technology	Fuel/Service	Reference Case Efficiency[a] (Btu out/Btu in)	High Oil Price Efficiency Limit (2010)
Heat Pump 1	Electric Heating	2.14	2.49
Heat Pump 2	Electric Heating	2.49	2.67
Heat Pump 3	Electric Heating	2.87	2.87
Baseboard	Electric Heating	0.95	0.97
Gas Furnace 1	Gas Heating	0.69	0.87
Gas Furnace 2	Gas Heating	0.75	0.89
Gas Furnace 3	Gas Heating	0.81	0.94
Oil Furnace 1	Oil Heating	0.70	0.86
Oil Furnace 2	Oil Heating	0.90	0.92
Heat Pump 1	Electric Cooling	2.32	3.82
Heat pump 2	Electric Cooling	2.56	3.97
Heat pump 3	Electric Cooling	2.80	4.13
Air Conditioner 1	Electric Cooling	2.26	3.89
Air Conditioner 2	Electric Cooling	2.63	3.92
Air Conditioner 3	Electric Cooling	3.00	3.97

[a]Remains constant over forecast period, except in years appliance standards come into effect.

Sources: **Electric Heat Pump Heating Efficiency** Lortz, V., and Taylor, Z., (May 1989) *Recommendations for Energy Conservation Standards for New Residential Buildings*, Vol. 2 Automated Residential Energy Standard User's Guide, version 1.1, PNL, 6878, Richland, Washington, p. 46. **Cooling Efficiency** American Council for an Energy-Efficient Economy, (1989), *The Most Energy-Efficient Appliances.* Washington, D.C.: American Council for an Energy-Efficient Economy, pp. 17-19. **Electric Baseboard:** PNL, "Technical Support Document: Automated Residential Energy Standard ," PNL-6979, Vol. 2, May 1989. **Gas Furnace:** Wollstadt, R. "Can Energy Conservation Fully Replace Incremental Energy production in a Growing U.S. Economy?" Washington, D.C., American Petroleum Institute. **Oil Furnace:** DOE, "Technical Support Document: In Support of Interim Energy Conservation Standards...," DOE/CE-0223, Vol. 2., June 1988, p. 3.47. **Central Air Conditioner:** American Council for an Energy-Efficient Economy, (1989), *The Most Energy-Efficient Appliances.* Washington, D.C.: American Council for an Energy-Efficient Economy, pp. 17-19.

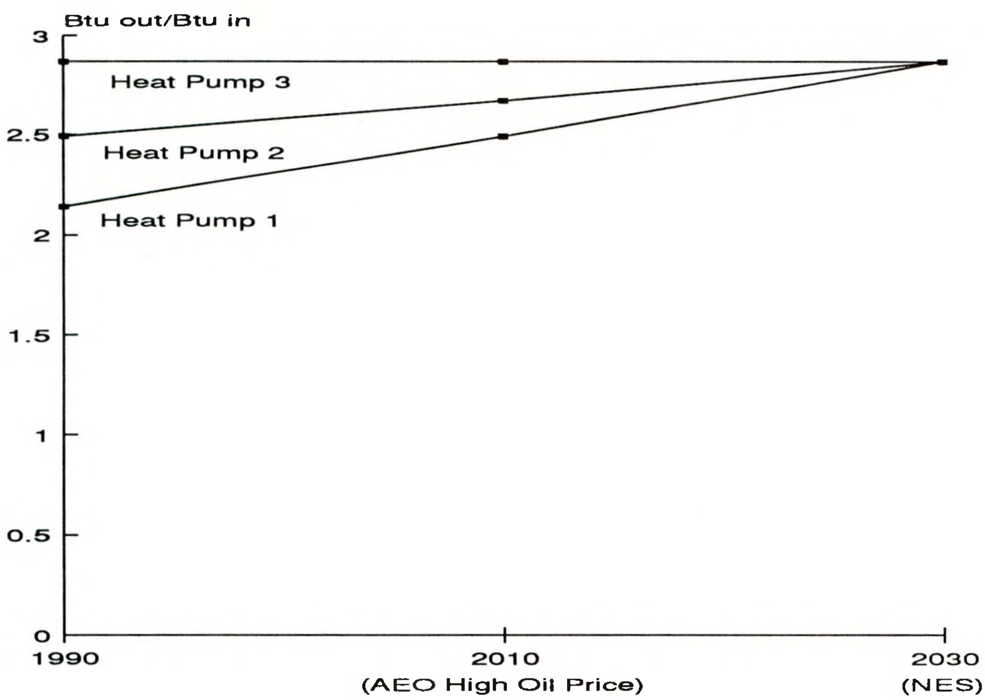
Table 5. Residential Water Heating, Refrigeration, and Other Appliance Alternatives

Technology	Fuel	Reference Case Efficiency[a] (Btu out/Btu in)	High Oil Price Efficiency Limit (2010)
Water Heating 1	Electric	0.75	2.12
Water Heating 2	Electric	0.93	2.15
Water Heating 3	Gas	0.45	0.65
Water Heating 4	Gas	0.56	0.66
Refrigerator 1	Electric	0.53	0.77
Refrigerator 2	Electric	0.65	0.83
Refrigerator 3	Electric	0.78	0.89
Refrigerator 4	Electric	0.87	0.94
Refrigerator 5	Electric	1.00	1.00
Appliances 1	Mix	1.00	1.39
Appliances 2	Mix	1.00	1.39

[a]Remains constant over forecast period, except in years appliance standards come into effect.

Sources: **Electric Water Heater:** American Council for an Energy-Efficient Economy, (1989), *The Most Energy-Efficient Appliances.* Washington, D.C.: American Council for an Energy-Efficient Economy, p. 13. **Gas Water Heater:** Carlsmith, Roger S., et al., (January 1990) "Energy Efficiency: How Far Can We Go?" Oak Ridge, Tennessee: Oak Ridge National Laboratory, p. 66. **Refrigerator:** Efficiency Index (Efficiency=1 for a Level 12 Refrigerator-Freezer) Cohen, S.,LBL,"Energy Efficiency Technologies for Residential and Commercial Buildings," 4-17-89, p.30. **Other Appliances:** Efficiency expressed as index. Aggregate based on information from DOE, "Technical Support Document: Energy Conservation Standards For Consumer Products: Dishwashers, Clothes Washers, and Clothes Dryers," DOE/CE-0267, July 1989.

Figure 1. New Heat Pump Efficiency



Source: Table 4, this report.

Improvements in building shells depend on building type. Existing buildings are assumed to be retrofitted periodically, with replacement windows or more insulation, for example. However, it is less expensive to build conservation features into homes from the start, so better shell integrity is assumed to be achievable in new homes. Shell improvements affect cooling loads less than heating loads, and this is also reflected in the High Oil Price Case. Compared to 1990, all new houses are assumed to have shell integrity nearly 50 percent better for heating and 30 percent better for cooling, by 2010. Old homes see more modest improvements.

To reflect energy conservation priorities under the High Oil Price Case, it is assumed that the more efficient technologies that are already commercially available will penetrate the market faster than under the Reference Case. The technology choices that are made via life-cycle cost evaluation penetrate the market with no lag, when equipment is scheduled for replacement.

Rationale. The High Oil Price Case is the only case in which the input parameters of the residential model are changed from the Reference set of inputs (Tables 4 and 5). In view of the relatively fast turnover of residential equipment stock (relative to capital turnover in other sectors), this sector is relatively responsive to changes in attitudes toward energy conservation and future conservation legislation. Federally mandated appliance standards are to be reviewed and possibly revised periodically, and this scenario can be used to investigate the effects of broader application of standards that are cost-effective at high energy prices.

The High Oil Price Case reflects accelerated market penetration of cost-effective technologies and conservation features. Cost-effectiveness is one of the criteria used by the Department of Energy in its mandated appliance efficiency standards. The reduced rate of energy consumption in the High Oil Price Case can be viewed as the consequence of both higher prices and increased penetration of cost-effective conservation measures.

Renewable Energy

Energy provided by renewables can be considered "dispersed" energy when produced and used directly by consumers. Dispersed renewable energy in the residential sector includes active and passive solar technology, biomass (wood), and geothermal energy captured by ground-source heat pumps. The residential model reports renewable consumption by sector and determines the degree to which the energy produced by renewables offsets energy demand for conventional fuels.

Projections of renewable energy consumption are estimated exogenous to the residential model. For active and passive solar technologies, a market penetration model is used to project the potential of these systems to displace primary energy from the present to the year 2010. The model provides projections in five-year increments for nine solar technologies.

The model is a spreadsheet that consists of four main steps:

- Determine the present and projected simple payback periods of active and passive solar technologies compared to conventionally-purchased energy

- Determine the present and projected potential shares of the energy markets that can be captured by active and passive solar technologies

- Determine the size of the present and projected energy markets for which active and passive solar technologies are suited

- Compute the present and projected energy contribution of active and passive solar technologies.

Present and projected active and passive solar system costs, the costs of electricity and natural gas, and the demand for energy are inputs to the model. The present and future simple payback periods are calculated for each active and passive renewable technology (for both electric and gas technology) by dividing the renewable energy unit prices by the appropriate efficiency-corrected conventional energy price.

The simple payback periods developed above are entered into a table of market penetration functions to determine the market share. The two market penetration functions, corresponding to commercial systems and residential systems, are imbedded in the spreadsheet. Appropriate adjustments are made for the share of the end-use energy that these technologies will provide in the future.

For ground water heat pumps, a market penetration model was developed to project the potential of these systems to displace the primary energy from the present to the year 2010. The model provides projections in five-year increments.

The model is a spreadsheet computer program that consists of four main steps:

- Determine the present and projected simple payback periods of ground water heat pump systems compared to the conventionally-purchased electricity

- Determine the present and projected potential shares of the energy market that can be captured by the ground water heat pump systems

- Determine the size of the present and projected energy markets for which the ground water heat pump systems are suited

- Compute the present and projected energy contribution of ground water heat pump systems.

Cost premiums (the difference between the cost of the ground water heat pump system and that of a competing technology), the annual savings in energy costs afforded by the ground water heat pump system and that of each competing technology, and the demand for energy are inputs to the model. The present and future simple payback periods are calculated by dividing the cost premium by the respective cost savings for each competing technology. The energy market for ground water heat pump systems is determined from regional historical and projected energy consumption data. In addition, the energy markets are separated into new construction and retrofit energy markets. Finally, the historical data are used to determine the present contribution of these technologies. Recent annual production rates of ground water heat pumps are used to project the energy contribution through the year 2000. After 2000, the market penetration model is used to predict the future energy contribution through 2010.

A stand-alone econometric model developed by Oak Ridge National Laboratory was used to develop estimates of wood consumption in the residential sector. Wood energy consumption, the dependent variable, was expressed in annual differences in quadrillion Btu. Data from 1961 through 1987 were used to estimate the residential equation, with the independent variables being annual differences in real electricity prices, real world oil prices, and real GNP.

The projected use of active and passive solar technologies, geothermal heat pumps and wood, exhibited only a minimal change in the last year of the forecast, when the inputs were revised to reflect the residential natural gas and electricity prices, the level of demand, and real world oil prices and GNP, for the other scenarios. The major factor, electricity price, does not change appreciably across scenarios. Therefore, the residential consumption of these renewable technologies is assumed not to vary across scenarios.

These projections, to the extent they exceed values for the year 1991, are used in the residential model to decrement the fossil fuel and electricity consumption projections.

Documentation for the dispersed renewable technologies is contained in *Market Penetration Models for Dispersed Renewable Technologies* and cited in Appendix A of this report.

Commercial Sector

Purpose

This section describes the general model structure, assumptions, and data used to produce the 1991 *AEO* commercial energy demand forecasts and explains the choice of data and assumptions in the scenarios.

Methodology

The commercial sector is extremely diverse, ranging from office buildings to restaurants. A special consideration relevant in projecting consumption trends and patterns in the commercial sector is the fraction of all inputs to the sector that energy represents. In no major sub-sector is it likely that energy costs at current levels are as significant as the cost of other factor inputs (such as labor or materials). To the extent that energy costs increase significantly faster than the cost of other factors, greater levels of relative price sensitivity and conservation can be expected.

In general, the solution methodology of the commercial model is parallel to that of the residential model. However, the commercial model is driven by employment forecasts generated by the macroeconomic model (PCMAC), whereas the residential model is driven by housing starts. A detailed discussion of the methodology can be found in PC-AEO Forecasting Model for the *Annual Energy Outlook 1990*, DOE/EIA-M036(90), and Technical Notes.

Floorspace Model

Floorspace growth is determined by the combined effect of floorspace construction and attrition of existing stock. Aggregate floorspace varies across macroeconomic cases because new construction is assumed to track the corresponding employment for each case. The resultant annual percentage growth of total stock of floorspace by region for the period (1989-2010) for the Reference Case is as follows:

- Northeast : 1.3 percent
- Midwest : 1.4 percent
- South : 2.1 percent
- West : 2.2 percent

- National : 1.8 percent

New Construction. Nonresidential Building Energy Consumption Survey estimates of total new construction for the period 1980-1986, divided by 7 to obtain a yearly average, was used as a proxy for the 1987 new construction pattern. The 1987 pattern was then extrapolated forward, year-by year, by region, at the same rate of growth as employment growth for the region.

Since new construction represents a different fraction of the total stock by region, total floorspace growth does not track total employment growth trends exactly. For example, total floorspace in the Midwest grows faster than in the Northeast, even though employment grows slightly faster in the Northeast.

The Reference Case annual growth rate of new employment over the forecast period varies by Census region as follows:

- Northeast : 1.0 percent
- Midwest : 0.8 percent
- South : 1.2 percent

- West : 1.4 percent
- National : 1.1 percent

The regional pattern was derived from the DRI/McGraw-Hill long-term regional employment forecast through 2010 contained in (TRENDLONG1090)

Existing Floorspace Attrition. The floorspace that existed in 1986 is assumed to undergo an attrition of about 0.5 percent per year in all regions. This attrition encompasses demolitions, casualty losses, and conversion to other uses, and is based on SRA Technologies Corporation's historical floorspace estimates. The relative magnitude of the service demand associated with pre-1987 buildings therefore declines gradually over the forecast period.

Service Demand Model

Like the residential model, the commercial model calculates the service demands required for each end use and then determines which fuels and what types of equipment will meet those service demands. The service demands are then adjusted for equipment efficiency in order to calculate actual consumption (in effect, the fuel purchases that are required to meet each service demand). Changes in floorspace and improvements in shell and equipment efficiency affect service demand over the forecast period. Six services are treated explicitly within the model: heating, cooling, water heating, cooking, lighting, and other.

New Technology Choice Model

Equipment choice considers life-cycle costs in deciding among alternative equipment types (fuels and efficiencies). The general methodology is identical to that used in the Residential Model. Life-cycle cost components are developed from the sources listed in Tables 6 and 7.

Technology Penetration. Like the residential model, the commercial model uses a logit-type formulation which uses existing market shares and observed new-product penetration rates to calibrate the rate of response to relative life-cycle costs. The market penetration is based on a lag of 0.2. This reflects consumer response to factors other than life-cycle costs in making equipment choices.

Scenarios

Reference Case

Exogenous Variables and Parameters. The Reference Case uses input data which reflect current estimates of appliance and building efficiency, and current capital cost of energy-using equipment, in the context of baseline macroeconomic growth and mid-world oil price assumptions. Employment grows at 1.1 percent per year (compounded) over the forecast period.

Shell efficiency improves 0.199 percent per year for heating and 0.56 percent per year for cooling in existing buildings and it improves 0.098 percent per year for heating and cooling in new buildings. This relatively slow rate of improvement reflects the slowdown in energy price increases (which lessens the incentive for conservation) and the levels of improvement already achieved in existing buildings (which serve to reduce the market size for specific technologies).

The least efficient equipment alternatives provided by the model meet current Federal minimum appliance standards for commercial equipment. The performance characteristics of alternative equipment choices are representative of advanced technology currently on the market (Tables 6 and 7).

Rationale. The Reference Case data set reflects a continuation of past price and income behavior, with no change in attitudes toward energy conservation. Current Federal building and appliance standards remain in place, but are not assumed to become more stringent.

Low Oil Price Case

Exogenous Variables and Parameters. Low world oil prices and baseline macroeconomic growth are used to investigate the effect of price variations. Employment grows at 1.1 percent per year (compounded) over the forecast period.

The commercial model's Reference Case assumptions regarding efficiency and technology penetration are used in the Low Oil Price Case.

Rationale. The Low Oil Price Case input data set reflects a business-as-usual attitude toward energy conservation, in the context of low prices and a mid level of national income. As in the Reference and High Economic Growth cases, current Federal building and equipment standards remain in place, but are not assumed to become more stringent. This combination of assumptions serves to analyze the effect of price variations relative to the Reference Case.

High Economic Growth Case

Exogenous Variables and Parameters. High commercial demand is assumed to be generated by low world oil prices and high macroeconomic growth. High economic growth is characterized by an annual compounded growth in employment of 1.3 percent over the forecast period.

The commercial model's Reference Case assumptions regarding efficiency and consumer behavior are used in the High Economic Growth Case.

Rationale. The High Economic Growth Case input data set reflects a business-as-usual attitude toward energy conservation, in the context of low prices and high income. Again, current Federal building and appliance standards remain in place, but are not assumed to become more stringent. This combination of assumptions establishes an upper bracket for consumption estimates.

High Oil Price Case

Exogenous Variables and Parameters. Low commercial demand is forecast in the context of high world oil prices, and baseline macroeconomic growth assumptions. Building and appliance efficiency improvements are phased in progressively over the forecast period. This is intended to assess the effect of a trend towards stronger conservation standards. Efficiency improvements are limited to those which are cost effective, and follow the same type of path seen in the residential model. Commercial equipment is assumed to have efficiency limits reflecting the less-widespread applicability of Federal standards for equipment configured for commercial applications, and considerations relating to proper sizing and maintenance (Tables 6 and 7).

Rationale. As in the residential sector, the High Oil Price Case is the only case in which the input parameters (cost and efficiency) of the commercial model are changed from the Reference set of inputs. Federally mandated equipment standards applicable to equipment that can be used in commercial applications are to be reviewed and possibly revised periodically, and this scenario can be used to investigate the effects of the more stringent standards which may be adopted.

Table 6. Commercial Heating and Cooling Equipment Alternatives

Technology	Fuel/Service	Reference Case Efficiency[a] (Btu out/Btu in)	High Oil Price Efficiency Limit (2010)
Heat Pump 1	Electric Heating	1.47	2.28
Heat Pump 2	Electric Heating	1.80	2.28
Heat Pump 3	Electric Heating	2.10	2.34
Gas Furnace 1	Gas Heating	0.72	0.86
Gas Furnace 2	Gas Heating	0.81	0.86
Gas Furnace 3	Gas Heating	0.92	0.92
Oil Furnace 1	Oil Heating	0.71	0.85
Oil Furnace 2	Oil Heating	0.80	0.85
Oil Furnace 3	Oil Heating	0.90	0.90
Heat Pump 1	Electric Cooling	2.20	2.39
Heat pump 2	Electric Cooling	2.30	2.44
Heat pump 3	Electric Cooling	2.60	2.60
Air Conditioner 1	Electric Cooling	3.10	3.99
Air Conditioner 2	Electric Cooling	3.20	4.04
Air Conditioner 3	Electric Cooling	3.70	4.31

[a]Remains constant over forecast period, except in years appliance standards come into effect.

Sources: **Electric Heat Pump Efficiency:** Mahoney, D. (July 1987), *Topical Report No. 1: Data Enhancements for Commercial Sector Analysis of the GRI Baseline Modeling System,* p. 4. **Gas and Oil Furnace Efficiency:** Holtberg, P., et al. (1987) *Baseline Projection Databook,* Washington, D.C: Gas Research Institute, p. 160. **Central Air Conditioner Efficiency:** Geller, H. (May 1989), "Commercial Building Equipment Efficiency: A State-of-the-Art Review," Washington, D.C: American Council for an Energy-Efficient Economy, p. 5.

Table 7. Commercial Water Heating Alternatives

Technology	Fuel	Reference Case Efficiency[a] (Btu out/Btu in)	High Oil Price Efficiency Limit (2010)
Water Heating 1	Electric	0.77	2.12
Water Heating 2	Electric	0.93	2.15
Water Heating 3	Gas	0.66	0.77
Water Heating 4	Gas	0.89	0.89

[a]Remains constant over forecast period, except in years appliance standards come into effect.

Sources: **Electric Water Heater:** American Council for an Energy-Efficient Economy, (1989), *The Most Energy-Efficient Appliances.* Washington, D.C.: American Council for an Energy-Efficient Economy, p. 13. **Gas Water Heater:** Carlsmith, Roger S., et al., (January 1990) "Energy Efficiency: How Far Can We Go?" Oak Ridge, Tennessee: Oak Ridge National Laboratory, p. 66.

Renewable Energy

In the commercial model, adjustments to service demand are made in the same way as in the residential model. The exogenous estimates of active and passive solar technologies and geothermal heat pumps were developed with the market penetration models described in the residential sector section. A stand-alone econometric model developed by Oak Ridge National Laboratory was used to develop estimates of wood consumption in the commercial sector. Documentation for the dispersed renewable technologies is contained in *Market Penetration Models for Dispersed Renewable Technologies* and cited in Appendix A of this report. To the extent that the solar and wood estimates are greater than 1991 levels, they will decrement heating service demand. Estimates of geothermal consumption will decrement cooling service demand.

Industrial Sector

Purpose

This section describes the general model structure, assumptions, and data used to produce the 1991 *AEO* industrial sector forecasts and explains the choice of data and assumptions in the scenarios.

The industrial model estimates each fuel or energy source in each industry as a separate entity, forecasting energy consumption for fuel (heat and power) and nonfuel (feedstock and miscellaneous) uses in the manufacturing, agriculture, mining, and construction industries. The consumption of energy for fuel and electrical uses is estimated from time-series data (The National Energy Accounts[7] from the Department of Commerce) over the period 1958 through 1985 (the manufacturing sector data in this time-series for 1985 is EIA's Manufacturing Energy Consumption Survey).[8] The estimation of nonfuel use of energy is from various sources, depending upon the availability of data.

Methodology

The PC Industrial model used for this year's *AEO* is essentially the same model that was used for the *Annual Energy Outlook 1990*[9] *(AEO90)* and documented in *PC-AEO Forecasting Model for the Annual Energy Outlook 1990: Model Documentation*[10]. The only significant difference is that the current model is now coded in FORTRAN on the PC and runs as a module in the IFFS/DEMS System (Intermediate Future Forecasting System/Demand Evaluation Modeling System). IFFS is the mainframe equilibrium modeling system that has been run at EIA for a number of years, while DEMS is a new system that allows the demand models to be PC-based, and yet to run interactively with the mainframe models in IFFS.

There were several design objectives for the current model:

- The model uses currently available data and at the industry specific level as much as possible.

- The model is sensitive in expected directions and degrees to changes in energy prices and to changes in the level of industry output.

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[7]The National Energy Accounts database is documented in the U.S. Department of Commerce, Office of Business Analysis, *National Energy Accounts*, PB89-187918 (Washington, DC, February 1989).

[8]Energy Information Administration, *Manufacturing Energy Consumption Survey: Consumption of Energy 1985*, DOE/EIA-0512(85) (Washington, DC, November 1988).

[9]Energy Information Administration, *Annual Energy Outlook 1990*, DOE/EIA-0383(90) (Washington, DC, January 1990).

[10]The industrial model documentation is published in, Energy Information Administration, *PC-AEO Forecasting Model for the Annual Energy Outlook 1990: Model Documentation*, DOE/EIA-M036(90), (Washington, DC, March 1990).

- The model equations are directly explainable (understandable), the relationships are straightforward and intuitive and, if necessary, are of a form which is easy to "manage." (In other words, it includes the ability to make changes if something implausible is found, and/or to add a variety of additional exogenous impacts.)

General Description

The PC Industrial model is used to forecast annual industrial sector energy consumption through the year 2010. Most of the equations are econometrically based and are logically organized into sectors consisting of manufacturing heat and power, nonmanufacturing heat and power, and feedstocks (raw materials), and "other" fuels. The version of the PC Industrial model that now runs as part of the Demand Evaluation Modeling System (DEMS) in the Intermediate Future Forecasting System (IFFS) is coded in FORTRAN and runs on a PC. This version runs at a Census region level, using Census region inputs of prices and industrial output and producing forecasts of Census region consumption. The manufacturing sector of the PC Industrial model also includes a facility to implement offline efficiency trends and a module that provides for fuel switching between natural gas and oil. Projections for metallurgical coal take into account off-line projections of coking plant capacity, and steam coal consumption accounts for offline estimates of coal use for gasification and for liquefaction. In addition, the amounts of natural gas, residual oil, and coal used to generate nonutility electricity by the industrial sector are accounted for in the PC Industrial model. For this purpose, the model now receives forecasts of electricity generation and fuels consumed both for own use and for sales to the grid. These forecasts, which are passed interactively through the modeling system by a new nonutility electricity generation model, and natural gas lease and plant forecasts, are exogenous to the industrial model, but are endogenous to the IFFS modeling system. Finally, the PC Industrial model accounts for off-line forecasts of biomass (primarily wood) energy and other renewables.

The manufacturing sector model was estimated using least-squares techniques on time series data. The techniques involved using logarithmic transformations of the data. For some of the estimations, Cochrane-Orcutt transformation was used to correct for serial correlation of the errors. The time-series data that were used are from the updated (spring 1989) National Energy Accounts[11] from the Department of Commerce (drawing its sources primarily from the *Annual Survey of Manufactures*[12] *(ASM)* from 1958 to 1984 and the Manufacturing Energy Consumption Survey[13] (MECS) for 1985). The nonmanufacturing sector was estimated from the same data source and although the same estimation techniques were attempted, they were much less successful. Therefore, for much of this sector a more heuristic approach is used. The feedstock and "other" fuels were estimated using a variety of data sources and techniques. The other primary sources of data were the State Energy Data System[14] (SEDS) for consumption and the State Energy Price and Expenditure Data System[15] (SEPEDS) for prices.

All the equations in the industrial model are calibrated in their full level of detail to the available reconciled historical data bases in 1985. The primary source is the Manufacturing Energy Consumption Survey, along with the National Energy Accounts and the State Energy Data System (SEDS) (the overall totals are calibrated to the overall totals in SEDS). The industrial model is then benchmarked to overall historical data in 1986,

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[11]The National Energy Accounts database is documented in U.S. Department of Commerce, Office of Business Analysis, *National Energy Accounts*, PB89-187918 (Washington, DC, February 1989).

[12]U.S. Department of Commerce, Bureau of the Census, *Annual Survey of Manufactures, Fuels and Electric Energy Consumed*, (Washington, DC, Various Years).

[13]Energy Information Administration, *Manufacturing Energy Consumption Survey: Consumption of Energy, 1985*, DOE/EIA-0512(85) (Washington, DC, November 1988).

[14]Energy Information Administration, *State Energy Data Report, Consumption Estimates, 1960-1988*, DOE/EIA-0214(88) (Washington, DC, April 1990).

[15]Energy Information Administration, *State Energy Price and Expenditures Report 1988*, DOE/EIA-0376(88) (Washington, DC, October 1990).

1987, and 1988 from SEDS. Finally, the industrial model is benchmarked to the overall projections from the *Short Term Energy Outlook* for 1989, 1990 and 1991.

Miscellaneous Assumptions

Manufacturing sector energy consumption for feedstock (raw materials and miscellaneous nonfuel uses) is modeled separately from heat and power uses. Natural gas feedstocks, liquefied petroleum gas feedstocks, and petrochemical feedstocks are assumed to be related to the value of the final goods produced in the chemical industry and to natural gas prices, liquefied petroleum gas prices and residual oil prices (as a proxy), respectively. Asphalt and road oil is assumed to be related to the value of production in the construction industry and to residual oil prices (as a proxy). Small amounts of other nonfuel energy consumption are assumed to remain at their initial levels.

A review of the forecast of natural gas use for manufacturing heat and power as compared to the historical data revealed that there was a small efficiency trend which was not captured by the forecasting equations. The model can implement efficiency time trends which reflect these additional expectations of efficiency improvements above those captured in the specification of the estimated equations. This additional efficiency improvement was implemented for natural gas.

Scenarios

Exogenous Variables and Parameters. The industrial model scenarios are produced by running the industrial model using the high and low world oil price scenario exogenous price forecasts produced by the supply models and using the high and baseline macroeconomic scenario exogenous macroeconomic forecasts produced by the macroeconomic model. In addition, different exogenous forecasts of nonutility generation, natural gas lease and plant, renewables, and coal synthetics are used by the industrial model.

The growth rates of seven major fuel prices, and industrial output variables supplied by the macroeconomic model for the Reference, High Economic Growth, and High Oil Price cases are presented in Table 8. In the High Economic Growth and High Oil Price cases, consumption of distillate oil in the agricultural industry is assumed to have a price elasticity of 0.5 and an output elasticity of 0.75.

Table 8. Annual Growth Rates from 1989 through 2010 for Industrial Sector Prices and Output

	Reference	High Economic Growth	High Oil Price
Prices			
Distillate	2.00	1.42	3.24
Liquefied Petroleum Gas	3.43	2.79	4.67
Residual	3.53	2.17	5.01
Natural Gas	3.50	3.63	3.24
Metallurgical Coal	1.42	1.66	1.35
Steam Coal	1.50	1.70	1.40
Electricity	0.45	0.48	0.41
Output			
Manufacturing	2.53	3.31	2.40
Nonmanufacturing	1.49	2.15	1.44
GNP	2.15	2.80	2.06

Sources: Energy Information Administration, *Annual Energy Outlook 1991*, DOE/EIA/0383(91).

Rationale. Changes in assumptions corresponding to the different scenarios are limited to the price and output variables received from the macroeconomic model. This reflects the underlying economic assumption that firm managers seek to maximize profits, and base decisions about input levels (such as energy) on market signals. Capital is relatively fixed, so that technological change will not affect energy consumption to the degree it would in the residential sector, for example. Federal efficiency standards do not directly affect the industrial sector.

Renewable Energy

Renewable energy is used in industry for industrial processes, and for nonutility electricity generation. The pulp and paper industries, and to a lesser extent, the lumber industry, have historically used substantial amounts of biomass as energy sources. Municipal solid waste (MSW) is also a form of biomass used in the industrial sector to produce steam. Biomass forecasts are exogenous and added to energy consumption estimates for these industries. A stand-alone econometric model was used to develop estimates of wood consumption in the industrial sector. Documentation for the dispersed renewable technologies is contained in *Market Penetration Models for Dispersed Renewable Technologies* and cited in Appendix A of this report.

Wood fuel refers to all forms of wood-related materials: logs, pellets, chips, saw dust, planer shavings, bark, other wood scraps, and black liquor, the waste product of the pulping process.

Wood energy consumption, the dependent variable in the equation, was expressed in annual differences in quadrillion Btu. Data from 1956 through 1967 was used to estimate the industrial equation. The independent variables for the equation were annual differences in real GNP and lagged GNP.

The dispersed energy contribution from MSW is defined as the post-consumer solid waste generated at residences, commercial establishments, and institutions. Excluded from this stream are automobile bodies, demolition and construction debris, municipal waste water or drinking water sludge, ash from industrial boilers, and industrial solid waste.

Overall national totals on the use of MSW for energy were computed (in five-year increments) by estimating:

- Expected quantity of MSW based on population growth
- Future heating value
- Share of MSW being combusted versus recycled or landfilled.

Calculations of the portions of the overall totals used in the industrial sector were made by using available data from Government Advisory Associates (GAA). The GAA data base includes data on average operating throughput, design capacity, average Btu per pound of MSW, and type of energy produced. Plants producing only steam or electricity were tabulated separately to compute the dispersed and nondispersed energy. In plants producing both steam and electricity, the amount of MSW used for electricity generation was estimated by taking into account the GAA data on kilowatthour per ton of MSW processed and the power output rating of each plant. The amount of electricity sold to the grid versus that used in-house was calculated using the "gross" and "net" ratings provided in the data base.

The Btu for steam (dispersed energy) and electricity (nondispersed energy) by each plant was totaled across plants, and proportions were calculated on a regional basis. These proportions were applied to the national totals developed in the manner described above.

Unlike the residential model, the industrial model uses econometric estimates of fossil fuel and electricity demand, with stochastic specifications corresponding to each fuel and electricity. Since only fossil fuels and electricity are modeled, the output of the industrial model can be considered to be "all energy sources except renewables."

Renewables used in nonutility electricity generation are accounted for differently. Nonutility generation of electricity has two components. Some electricity is retained for the industry's own use, and some is sold to the power grid. Only electricity generated for own use is included in the industrial model (which accounts for purchased fuels and electricity only). The model assumes that all self-generated electricity for own-use before 1985 is already accounted for in the model equations. After 1985, half of the self-generated electricity over the 1985 level is assumed to be accounted for, and the other half is subtracted from forecasts of purchased energy. Fuels, including renewables, used for generating own electricity are assigned the same way.

The projected consumption of renewable energy in the industrial sector was assumed not to vary across scenarios.

Estimates of MSW used to provide energy are derived by taking into account the overall growth in population, levels of MSW generation per capita, the regional availability of landfills, and future trends in recycling. These variables tend not to change with variations in economic growth or conventional fuel prices.

The quantity of wood and wood waste consumed is a function of the amount of wood residues and by-products produced by the manufacturing process and, to a limited extent, the alternative uses of those residues or by-products. The amount of wood waste produced is related to production levels of the lumber and paper/pulp industries and, therefore, is somewhat responsive to change in economic growth, particularly in the high economic growth scenario. However, in view of the range of uncertainties associated with the projections of energy derived from wood (increases in the use of recycled paper is a prime example), the resulting marginal increases in wood usage in the high economic growth scenario were not presented. Other scenarios left the results essentially unchanged.

Transportation Sector

Purpose

This section describes the general model structure, assumptions, and data used to produce this year's *AEO* transportation energy demand forecasts and explains the choice of data and assumptions in the scenarios. A detailed description of the model methodology can be found in PC-AEO Forecasting Model for the *Annual Energy Outlook 1990*, DOE/EIA-M036(90), and Technical Notes.

The projections of energy consumption in the transportation sector are based upon the latest Residential Transportation Energy Consumption Survey (RTECS-88),[16] EIA's fuel consumption data,[17] and data from the Oak Ridge National Laboratory[18] on the composition of the transportation fleet and fuel efficiency. Consumption in this sector is almost completely in the form of oil. The oil consumption forecast is sensitive to the assumed level of macroeconomic activity as well as energy prices. Consumption of renewable energy in alternative-fuel vehicles depends on oil prices. Since the four *AEO* scenarios depend on three different oil price assumptions, alternative-fuel vehicles will be discussed under the corresponding scenario.

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[16]Energy Information Administration, *Household Vehicles Energy Consumption 1988*, DOE/EIA-0464(88) (Washington, DC, February 1990).

[17]Energy Information Administration, *Annual Energy Review 1988*,DOE/EIA-0384(88) (Washington, DC, 1989).

[18]Oak Ridge National Laboratory, *Transportation Energy Data Book*, Edition 10, ORNL-6565 (Oak Ridge, TN, September 1989).

Methodology

The PC Transportation Energy Demand Model (PC-TED) is designed to project transportation energy demand at the national and Census region level, by fuel and by year to 2010. PC-TED provides the transportation demand forecasts used in the *AEO* integrated spreadsheet modeling system. The model consists of four distinct segments: light-duty vehicle (cars and light trucks) highway travel, freight travel, aviation travel, and other transportation. These segments consist of data estimates and assumptions necessary to execute various specific forecasting equations of the model.

The model relies upon a variety of initial variables and estimated or assumed coefficients, parameters, and growth rates. The model also relies upon exogenous forecasts for several variables such as total population, driving age population, real disposable personal income, industrial output, gross national product, fuel consumption, and fuel prices. This information can be passed to the model when the transportation model is run as part of the larger system, or can be input independently when the model is run "standalone" as an independent transportation model. This information is used along with a series of structural equations to calculate forecasts such as light-duty vehicle travel motor gasoline consumption.

Light-Duty Vehicle Travel Consumption

Energy consumption in this sector is the product of two, more detailed, estimates—new car fuel efficiency and the level of light-duty vehicle travel. Changes in new car fuel efficiency depend on future gasoline prices, while the estimated level of travel is based on the level of per capita income as well as gasoline prices.

New car fuel efficiency estimates are based on the net savings consumers can realize if specific fuel efficiency improving technologies are introduced. Technologies that will save the consumer more in gasoline expenditures than they cost to purchase are assumed to be included in new car designs. Higher gasoline prices increase the forecast fuel efficiency because they increase gasoline expenditures without affecting the cost of available fuel efficiency-improving technologies. A 10-percent increase in gasoline prices above those assumed in the base case results in an initial short-term (1 year) effect of a 2-percent improvement in new car fuel efficiency (reflecting a customer-response to the existing mix of new cars available for purchase) and a longer-term effect of a 6-percent (asymptotic) improvement in fuel efficiency (reflecting a change in the mix of new cars available) if the price increase is sustained. Light-duty vehicle-miles traveled (VMT) are based on the assumed growth in disposable personal income and projected fuel prices, and average vehicle efficiency. Specifically, a 10-percent increase in per capita disposable personal income results in a 7.6-percent increase in vehicle miles traveled, while a 10-percent increase in the fuel cost of driving a mile results in only a 0.7-percent decline in vehicle miles traveled. Consumption by alternative-fuel vehicles is a function of sales levels, which vary across oil price scenarios.

Freight Travel Consumption

It is assumed that the average efficiency of freight trucks improves at a rate of 0.6 percent per year and that freight trucks increasingly are powered by diesel engines. The diesel share reaches 60 percent by 2010. Other freight vehicles are not assumed to show significant improvements in fuel efficiency.

Travel by freight vehicles is closely tied to the level of output in specific sectors of the economy, which varies across scenarios. These output levels are provided as exogenous inputs from PCMAC.

Aviation Travel Consumption

Forecasts of air travel are highly sensitive to assumed levels of economic growth. A 10-percent increase in forecast GNP results in a 19-percent increase in forecast jet travel. Jet fuel prices also affect the level of air travel through their effect on ticket prices. A 10-percent increase in ticket price results in about a 4-percent decline in forecast air travel. Aircraft fuel efficiency is assumed to improve at an annual rate of 1.2 percent between 1989 and 2010. This growth rate is based on an offline consideration of likely technology development within the aircraft industry.[19]

Alternative Fuels

In the near and mid-term, ethanol used as a blending component in gasoline (gasohol) for use in conventional internal combustion engine vehicles will dominate transportation reliance on renewable energy. Estimates of ethanol from biomass are based on the Interlaboratory White Paper, *The Potential of Renewable Energy.*[20] The report bases its forecasts mostly on expert judgment concerning the potential future trends in the costs and performance of biomass conversion technologies. The report does not consider payback periods, acceptance factors, and market penetration in a unified, quantitative manner. In addition, the report does not consider the issue of demand for land for crop growing versus the demand for land for urbanization.

Three alternative fuels (methanol, compressed natural gas, and electricity) are assumed to be used in new technology vehicles in the scenarios described below. These vehicles begin penetrating the new auto and light truck market in the mid-1990's largely in response to the Clean Air Act Amendments of 1990.

Currently, ethanol production is not competitive with conventional liquid fuels. Its production from biomass—principally corn—is heavily dependent on continuation of tax subsidies, availability of corn (as a function of dedication of arable land), and the existing conversion technology. In addition, the existing transportation infrastructure (i.e., the inability to use pipelines for distribution) inhibits its transformation from a localized/regional market into a national market. Without a major breakthrough in cost reductions and performance, the relative economics of ethanol production do not indicate any change due solely to variations in domestic economic growth and world oil price changes assumed in the *AEO.*

Scenarios

Reference Case

Baseline macroeconomic growth and mid-world oil prices are used in this scenario. In addition to the effects of these variables on consumption of conventional fuels, the world oil price variable is assumed to affect the number of alternative-fuel vehicles sold (Table 9).

Low Oil Price Case

Baseline macroeconomic growth and low world oil prices are used to generate the Low Oil Price Case. Low prices generate the lowest estimate of alternative-fuel vehicles.

High Economic Growth Case

High macroeconomic growth and low world oil prices are used to set an upper bound on transportation energy demand. The low world oil price generates the same number of alternative-fuel vehicles as in the previous case.

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[19]"Energy Efficiency Improvement Potential of Commercial Aircraft to 2010," ORNL-6622, Oak Ridge National Laboratory, June 1990.

[20]*The Potential of Renewable Energy*, Solar Energy Research Institute, SERI-TP-2603674 (Golden, CO, March 1990).

Table 9. Estimates of Alternative-Fuel Vehicle Sales, 2010 (Thousands)

	Oil Price Scenario		
	Low WOP ($23)	Mid WOP ($34)	High WOP ($45)
Light-Duty Vehicles	233.7	480.9	790.4
Medium-Duty Trucks	0	4.0	8.2
Heavy-Duty Trucks	0	3.4	6.9

Source: Table 10, this report.

High Oil Price Case

Baseline macroeconomic growth and high world oil prices generate the most conservative estimate of transportation energy demand. High oil prices create the strongest demand for alternative-fuel vehicles (Table 9).

Exogenous Variables and Parameters. All scenarios reflect the recent passage of the Clean Air Act Amendments of 1990, and therefore basic assumptions differ from those used in last year's *AEO*. These changes are described below.

Title II: Provisions Relating to Mobile Sources of the Clean Air Act Amendments of 1990 (CAA) contains three major provisions affecting the transportation model. Section 249 establishes a pilot test program in California, Section 246 implements a centrally fueled fleet provision, and Section 212 provides a schedule for the phased-in sales of alternative-fuel urban buses. In each case, these provisions affect the forecast of highway vehicle travel in terms of vehicle sales, vehicle stocks, and miles travelled by technology type and fuel type, and ultimately fuel consumption by fuel type.

These provisions are almost entirely emissions-based, leaving open the specifics regarding the vehicle technologies and the fuels that will be required to meet them. As a result, a great deal of uncertainty exists about the likely role to be played by any of the many combinations of fuel type and engine and emission control technologies that can reduce emissions. The assumptions outlined here attempt to address these uncertainties and estimate the likely effects the legislation will have on sales of alternative-fuel vehicles.

The CAA is assumed to affect sales of alternative-fuel light, medium, and heavy duty vehicles between 1994 (the first year of impact) and 2010. Estimates were made for low, medium, and high oil price scenarios, reflecting the importance of petroleum prices on these sales (Table 9). Estimates are independent of macroeconomic assumptions. These and other results, obtained either by running the Transportation model itself or by performing offline analysis (e.g., translating truck sales into vehicle-miles traveled (VMT) estimates) are discussed below.

The majority of sales of alternative-fuel vehicles are expected to be light-duty vehicles. However, in none of the weight classes, for any oil price scenario, do alternative-fuel vehicles represent greater than 5 percent of total vehicle sales. The substantially higher numbers for sales of light-duty, alternative-fuel vehicles than for medium- and heavy-duty vehicles are primarily due to the much greater level of overall sales of these vehicles. The resulting effects on fuel consumption are expected to be small.

Rationale. The shares of alternative-fuel vehicles used in the scenarios reflects the results of the analyses that follow.

Light-Duty Vehicles

Results. The number of light-duty, alternative-fuel vehicles is expected to rise from approximately 4,000 units in 1995 to nearly 500,000 by 2010 in the mid-oil price scenario. Penetration in the low and high oil price scenarios reaches approximately 230,000 and 790,000, respectively (Table 10). In percentage terms, the 2010 sales figures reach approximately 1.3 percent, 2.6 percent, and 4.3 percent of total sales in the low, mid, and high price scenarios, respectively. Based upon fuel-shares used in the National Energy Strategy (NES) High Conservation Case, the fuel shares of alternative-fuel vehicles sold in each year consist of 50 percent alcohol vehicles, 33 percent electric vehicles, and 17 percent compressed natural gas (CNG) units, although alcohol vehicles are assumed to shift from predominantly alcohol-gasoline flex-fueled vehicles in the early years to greater proportions of dedicated alcohol vehicles in the out-years of the forecast.

The stock of alternative-fuel vehicles as a percent of total vehicle stock will lag sales, due to the time necessary for the vehicle stock to turn over. In the light-duty vehicle class, the stock share of alternative-fuel vehicles reaches less than 2 percent in 2010 in the mid-oil price scenario. This translates into a comparable share of VMT, approximately 1.7 percent in 2010. In the low and high price cases, alternative-fuel vehicle VMT as a share of the total reach 0.9 percent and 2.6 percent, respectively.

These low vehicle numbers are likely to translate into correspondingly low levels of alternative fuel consumption in 2010. In the mid-oil price scenario, light-duty alternative-fuel vehicles are estimated to consume 135 trillion Btu (representing about 1 percent of total light-duty vehicle (LDV) fuel consumption). Of this figure, alcohol represents approximately 63 percent, CNG accounts for 25 percent, and electricity about 12 percent. In the low and high oil price cases, alternative fuel consumption is expected to represent about 0.5 percent and 1.5 percent of the total, respectively, with the fuel shares of alcohol, CNG and electricity the same as for the mid case.

Analysis and Assumptions. Table 11 consists of all the CAA program components that sum to the aggregate numbers in Table 10. The first component relates to the California pilot program (Section 249). However, California's own Low Emission Vehicle Program (LEVP), upon which much of the pilot program is based, surpasses the Pilot Program in stringency of emission standards and in mandating sales of clean fuel vehicles. Therefore, the LEVP numbers in Table 11 refer to the application of the California Air Resource Board (CARB) light-duty vehicle implementation standard. Note that the vehicle sales levels assumed in the CARB analysis (2.18 million vehicles in 2010) are not modified in this analysis.

Standards in grams per mile were established by CARB based on the emission of non-methane organic gas (NMOG) using 4 vehicle categories:

1) TLEV - Transitional Low-Emission Vehicles (.125 g/mi NMOG)

2) LEV - Low-Emission Vehicles (.075 g/mi)

3) ULEV - Ultra-Low-Emission Vehicles (.040 g/mi)

4) ZEV - Zero Emission Vehicles (0 g/mi).

Technical support and staff reports from CARB indicate that TLEV, LEV, and possibly ULEV emissions may be met largely by conventional vehicles using heated fuel systems in conjunction with modified catalytic converters and reformulated gasoline (modifications which may amount to as little as $120 in additional cost above conventional vehicles).[21] High case estimates assume that ZEV (electric vehicles, which have been mandated in absolute numbers) and ULEV vehicles will be exclusively alternatively-fuel based. Mid case estimates assume that all ZEV and half of ULEV autos will use alternative fuels, while low case estimates assume that only ZEV vehicles will run on alternative fuels.

Since the relative demand for different technologies to meet the emissions requirements is expected to be largely cost-based, it is assumed that higher oil prices will encourage greater sales of alternative-fuel vehicles to meet the standards. Thus the three cases described above are considered to correspond to the three world oil price cases depicted in *AEO* runs.

The second and third components of Table 11 are estimates from the centrally fueled fleet provision (Section 246) of the CAA, which applies to those areas that had a 1980 population of 250,000 or more, and either had a ozone nonattainment listing of serious, severe, or extreme during 1987, 1988, and 1989, or a carbon monoxide nonattainment level with a design value at or above 16.0 parts per million for 1988 and 1989. The former category includes 33 cities and the latter Denver and Los Angeles. Fleet calculations assume government and utilities constitute the definition of covered fleets, which requires that fleets be centrally fueled and contain 10 or more fleet vehicles. Estimates for passenger fleets are based on *AEO* Reference Case new auto sales, while light-duty truck (LDT) numbers are tied to *AEO* Reference Case LDV sales forecasts to incorporate the recent growth of LDT units. Both estimates include coefficients for those clean fuel vehicles (i.e., any vehicles which meet the clean fuel vehicle emission standards—not necessarily alternative-fuel) which are alternative-fuel. These coefficients were taken from the LEVP implementation schedule since the numbers were generated on cost efficiency, and achievable technology penetration levels.

Medium-Duty Vehicles

Results. The results of the medium-duty vehicle analysis are shown in Table 12. Medium-duty alternative-fuel vehicle sales begin in 1998 and increase to nearly 4,000 new vehicles in 2010 in the mid-oil price scenario, little over 1 percent of total medium-duty vehicle sales. In the high oil price scenario, sales reach just under 3 percent of the total, while in the low oil price scenario, sales are forecast to be zero in all years. In all scenarios and for all years, sales are assumed to consist of 60 percent CNG and 40 percent alcohol vehicles, consistent with the NES High Conservation Case.

These sales estimates result in forecasts of VMT similar, in percentage terms, to those for light duty vehicles. An offline analysis of the relationship between medium truck sales, stocks, and VMT results in a forecast of alternative-fuel vehicle VMT in the low, mid- and high oil price scenarios of approximately 0 percent, 1 percent and 2 percent, respectively. These VMT forecasts are expected to result in similar percentages for consumption of alternative fuels.

Analysis and Assumptions. The California Air Resource Board has also provided an implementation schedule for medium-duty vehicles in the LEVP program. These numbers were multiplied by DRI/McGraw-Hill medium-duty sales estimates to obtain a forecast for clean fuel vehicle sales. To simulate the percentage of clean fuel vehicles that will be alternative-fuel, the LEVP ULEV percentage numbers were used as coefficients for the upper estimate and 50 percent of ULEV shares generated the mid estimates, as with light-duty vehicles (Table 13).

The CAA medium-duty truck (MDT) centrally fueled fleet estimates (Table 13) are the second component to the total medium-duty estimates in Table 12. All estimates contained coefficients for the mandated CAA sales standard (1998: 30 percent, 1999: 50 percent, 2000: 70 percent of total fleet sales), population-weighted covered areas (37 percent—i.e., nonattainment areas), the centrally-fueled covered fleet (40 percent—approximated by

[21] California Air Resource Board, "Proposed Regulations for Low-Emission Vehicles and Clean Fuels," August 13, 1990. Note: The regulations have been passed into law.

government and utilities), and the percentage of clean fuel vehicles that are alternative-fuel (using ULEV LEVP implementation schedules).

Heavy-Duty Vehicles

Results. The results of the heavy-duty vehicle analysis are shown in Table 14. Heavy-duty vehicles enter the market in 1994, with sales rising to approximately 3500 by 2010 in the mid-oil price scenario. In the low oil price scenario, no sales are expected to occur, while in the high oil price scenario, sales of nearly 7,000 vehicles are expected. These figures represent approximately 0 percent, 1.7 percent, and 3.4 percent of total vehicle sales in the low, mid-, and high oil price scenarios, respectively. In all cases, heavy-duty alternative-fuel vehicles are forecast to be composed of 75 percent alcohol and 25 percent CNG vehicles.

Resulting alternative-fuel vehicle VMT estimates, in percentage terms, are expected to be slightly lower than the sales percentages, specifically 0 percent, 1.4 percent, and 2.8 percent in the low, mid, and high cases, respectively. As with medium-duty vehicles, fuel consumption percentages are expected to track closely the VMT forecasts.

Analysis and Assumptions. Clean Air Act centrally-fueled heavy-duty truck (HDT) fleet estimates were increased as a percentage of the *AEO* forecast of new LDV sales (from a recent mid-case run) then multiplied by the same type of coefficients as the CAA medium-duty truck section (Table 15).

Section 212 of the CAA does not mandate any implementation standards for urban buses, but does make provisions for the EPA to determine a phase-in of alternative fuel use requirements beginning 3 years after standards are proposed. Mr. Vincent DeMarco from the Department of Transportation Urban Transit Division provided an alternative fueled bus estimate of 2 percent of total sales for 1990 and 10 percent by the year 2010. New bus sales were forecast relative to *AEO* new car sales growth (Table 15).

Table 10. Summary Table of Light-Duty Alternative-Fuel Vehicle Sales

Vehicle Sales

High Oil Price			Mid-Oil Price			Low Oil Price		
Year	Num of Vehicles	Percent of Total	Year	Num of Vehicles	Percent of Total	Year	Num of Vehicles	Percent of Total
1994	4,281	0.03	1994	0	0.00	1994	0	0.00
1995	10,255	0.07	1995	4,395	0.03	1995	0	0.00
1996	23,055	0.15	1996	10,759	0.07	1996	7,685	0.05
1997	40,000	0.25	1997	20,000	0.13	1997	15,930	0.10
1998	72,855	0.45	1998	40,475	0.25	1998	32,380	0.20
1999	98,700	0.60	1999	61,206	0.37	1999	40,000	0.24
2000	151,920	0.90	2000	84,400	0.50	2000	67,520	0.40
2005	623,410	3.52	2005	416,007	2.35	2005	221,250	1.25
2010	790,367	4.30	2010	480,945	2.61	2010	233,726	1.27

Source: Table 11, this report.

Table 11. Light-Duty Alternative-Fuel Vehicle Estimates Based on the Clean Air Act of 1990

	California Clean Air Act Pilot Test Program and Low Emission Vehicle Program (LEVP) Estimates			Clean Air Act Passenger LDV Government and Utility Fleet Estimates (Covered Areas)			Clean Air Act Light-Duty Truck Government and Utility Fleet Estimates (Covered Areas)		
	High Oil Price	Mid-Oil Price	Low Oil Price	High Oil Price	Mid-Oil Price	Low Oil Price	High Oil Price	Mid-Oil Price	Low Oil Price
1993	0	0	0	0	0	0	0	0	0
1994	4,281	0	0	0	0	0	0	0	0
1995	10,255	4,395	0	0	0	0	0	0	0
1996	23,055	10,759	7,685	0	0	0	0	0	0
1997	40,000	20,000	15,930	0	0	0	0	0	0
1998	71,419	39,757	32,380	933	466	0	503	252	0
1999	96,287	60,000	40,000	1,561	780	0	852	426	0
2000	148,507	82,694	67,520	2,189	1,094	0	1,224	612	0
2001	218,000	163,500	109,000	5,583	2,792	0	3,139	1,569	0
2002	327,000	218,000	157,770	8,457	4,229	0	4,768	2,384	0
2003	545,000	381,500	211,200	14,107	7,053	0	7,978	3,989	0
2004	572,250	392,945	220,180	14,118	7,059	0	8,138	4,069	0
2005	600,863	404,733	221,250	14,247	7,123	0	8,301	4,150	0
2006	630,906	416,875	224,606	14,476	7,238	0	8,467	4,233	0
2007	662,451	429,382	226,852	14,417	7,208	0	8,636	4,318	0
2008	695,573	442,263	229,121	14,426	7,213	0	8,809	4,404	0
2009	730,352	455,531	231,412	14,353	7,176	0	8,985	4,492	0
2010	766,870	469,197	233,726	14,333	7,166	0	9,164	4,582	0

Source: Energy Information Administration, Office of Energy Markets and End Use.

Table 12. Summary Table of Medium-Duty Alternative-Fuel Vehicle Sales

Vehicle Sales

High Oil Price			Mid-Oil Price			Low Oil Price		
Year	Number of Vehicles	Percent of Total	Year	Number of Vehicles	Percent of Total	Year	Number of Vehicles	Percent of Total
1994	0	0.00	1994	0	0.00	1994	0	0.00
1995	0	0.00	1995	0	0.00	1995	0	0.00
1996	0	0.00	1996	0	0.00	1996	0	0.00
1997	0	0.00	1997	0	0.00	1997	0	0.00
1998	582	0.29	1998	291	0.15	1998	0	0.00
1999	708	0.35	1999	354	0.18	1999	0	0.00
2000	842	0.42	2000	421	0.21	2000	0	0.00
2005	7,258	2.90	2005	3,594	1.44	2005	0	0.00
2010	8,216	2.74	2010	3,968	1.32	2010	0	0.00

Source: Table 13, this report.

Table 13. Medium-Duty Alternative-Fuel Vehicle Sales Estimates Based on the Clean Air Act of 1990

	California Low Emission Vehicle Program Estimates			Clear Air Act Covered Fleet Estimates		
	High Oil Price	Mid-Oil Price	Low Oil Price	High Oil Price	Mid-Oil Price	Low Oil Price
1993	0	0	0	0	0	0
1994	0	0	0	0	0	0
1995	0	0	0	0	0	0
1996	0	0	0	0	0	0
1997	0	0	0	0	0	0
1998	400	200	0	182	91	0
1999	400	200	0	308	154	0
2000	400	200	0	442	221	0
2001	1,050	525	0	1,134	567	0
2002	2,200	1,100	0	2,296	1,148	0
2003	3,450	1,725	0	3,458	1,729	0
2004	3,554	1,760	0	3,527	1,764	0
2005	3,660	1,795	0	3,598	1,799	0
2006	3,770	1,831	0	3,670	1,835	0
2007	3,883	1,867	0	3,743	1,872	0
2008	3,999	1,905	0	3,818	1,909	0
2009	4,119	1,943	0	3,895	1,947	0
2010	4,243	1,981	0	3,973	1,986	0

Source: Energy Information Administration, Office of Energy Markets and End Use.

Table 14. Summary Table of Heavy-Duty Alternative-Fuel Vehicle Sales

Vehicle Sales

High Oil Price			Mid-Oil Price			Low Oil Price		
Year	Number of Vehicles	Percent of Total	Year	Number of Vehicles	Percent of Total	Year	Number of Vehicles	Percent of Total
1994	1,230	0.62	1994	615	0.31	1994	0	0.00
1995	1,382	0.69	1995	691	0.35	1995	0	0.00
1996	1,534	0.77	1996	767	0.38	1996	0	0.00
1997	1,686	0.84	1997	843	0.42	1997	0	0.00
1998	2,182	1.09	1998	1,091	0.55	1998	0	0.00
1999	2,339	1.17	1999	1,169	0.58	1999	0	0.00
2000	2,500	1.25	2000	1,250	0.62	2000	0	0.00
2005	5,821	2.91	2005	2,910	1.46	2005	0	0.00
2010	6,884	3.44	2010	3,442	1.72	2010	0	0.00

Source: Table 15, this report.

Table 15. Heavy-Duty Alternative-Fuel Vehicle Sales Estimates Based on the Clean Air Act of 1990

	Clear Air Act Covered Fleet Estimates			Clear Air Act Urban Bus Estimates		
	High Oil Price	Mid-Oil Price	Low Oil Price	High Oil Price	Mid-Oil Price	Low Oil Price
1993	0	0	0	0	0	0
1994	0	0	0	1,230	615	0
1995	0	0	0	1,382	691	0
1996	0	0	0	1,534	767	0
1997	0	0	0	1,686	843	0
1998	344	172	0	1,837	919	0
1999	350	175	0	1,989	995	0
2000	359	180	0	2,141	1,070	0
2001	920	460	0	2,293	1,146	0
2002	1,864	932	0	2,445	1,222	0
2003	2,807	1,404	0	2,596	1,298	0
2004	2,864	1,432	0	2,748	1,374	0
2005	2,921	1,460	0	2,900	1,450	0
2006	2,979	1,490	0	3,052	1,526	0
2007	3,039	1,519	0	3,203	1,602	0
2008	3,100	1,550	0	3,355	1,678	0
2009	3,162	1,581	0	3,507	1,754	0
2010	3,225	1,612	0	3,659	1,829	0

Source: Energy Information Administration, Office of Energy Markets and End Use.

4. Supply Model Assumptions

Crude Oil and Natural Gas Production Assumptions

Purpose

This section describes the model assumptions and data used to produce this year's *AEO* crude oil and natural gas production forecasts, and explains the choice of data and assumptions in the scenarios.

Methodology

Production forecasts for crude oil and natural gas were generated for this year's *AEO* by geographic region and recovery technique. The Production of Onshore Lower 48 Oil and Gas Model (PROLOG) was used to forecast production activities for both fuels in six onshore supply regions of the Lower 48 States. PROLOG encompasses production of crude oil and natural gas through conventional recovery techniques as well as production of natural gas through unconventional recovery techniques. Production forecasts were generated exogenously for crude oil produced in Alaska, from the offshore Lower 48 States, and through enhanced oil recovery techniques. These exogenous results are described later, in the Scenario section.

The primary activities in PROLOG are exploratory and developmental drilling. Natural gas is modeled by category, generally conforming to aggregations of categories defined by the Natural Gas Policy Act (NGPA) of 1978, as well as a category representing gas priced by way of a spot market. A linear program is used to select developmental drilling activities on the basis of their economic merit, subject to constraints on available rotary rigs and constraints based on historical drilling patterns. Forecast values include new discoveries from exploratory drilling, revisions from total drilling, as well as potential production from all flowing wells.

Oil and natural gas drilling activities are evaluated separately for each subclass of drilling. Exploratory and developmental drilling are treated separately within the model. Exploration yields new additions to the stock of known reserves and is modeled through a set of econometrically derived equations. Developmental drilling determines the rate of production from the stock of known reserves, and is modeled within the linear programming structure of the model.

Primary inputs to PROLOG are the world oil price and natural gas wellhead price. PROLOG projects exploratory oil and gas drilling levels for each region based on national wellhead prices. At each level, in terms of exploration, PROLOG calculates the associated reserve additions, production, and revenue. At the next stage of development, it generates a sequence of feasible oil and gas developmental drilling activities. Then, for each activity it determines the new production profile based on increased development. From this, it calculates the net present value of additional development. The linear programming framework of PROLOG solves for the allocation of developmental drilling and rig activity in order to find the optimal drilling levels that maximize the present value of profits stemming from the drilling projects.

PROLOG's intertemporal results--calculated revenues and production, updated drilling, reserves, and rig inventory--are used to determine the following year's rig availability, drilling capacity and the remaining resource base. PROLOG produces projections of oil and natural gas production annually through 2010. Each year's output is used as input to the Gas Analysis Modeling System, or PROLOG may be used in a stand-alone mode.

PROLOG is fully documented in *Model Methodology and Data Description of the Production of Onshore Lower 48 Oil and Gas Model*, DOE/EIA-MO34(91).

Scenarios

Reference Case

Resource Base. The resource base assumptions for PROLOG are presented below (Table 16). They are the same for all scenarios.

Table 16. Lower 48 Onshore Resources as of December 31, 1989

Type of Resource	Crude Oil (billion barrels)	Natural Gas (trillion cubic feet)
Proved Reserves	16.5	123.5
Inferred Reserves	18.5	139.1
Unconventional Resources	11.1	279.0
Undiscovered Recoverable Resources	18.2	186.1

Notes: The inferred reserves and undiscovered recoverable resources are based on the end-of-year 1988 features from the published reports. They were adjusted for 1989 revisions and reserve additions, respectively, from the 1989 EIA-23 report.

Sources: **Proved Reserves**: Energy Information Administration (EIA)-23 Report, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1989.* **Inferred Reserves, Unconventional Resources, and Undiscovered Recoverable Resources**: Energy Information Administration, Office of Oil and Gas, *The Domestic Oil and Gas Recoverable Resource Base: Supporting Analysis for the National Energy Strategy* and the 1989 EIA-23 Report.

Unconventional Gas Recovery. PROLOG projections of Lower 48 onshore unconventional gas production are based on combined estimates of 15 and 229 trillion cubic feet of undiscovered, economically recoverable resources as of the end of 1989 contained in Devonian shale and low permeability formations, respectively. The production of gas from coal seams is based on an estimate of 35 trillion cubic feet of economically recoverable resources. These assumptions are the same for all scenarios.

Alaskan Natural Gas. More than 40 trillion cubic feet of economically recoverable natural gas resources remain in Alaska. The estimates for gas available from the North Slope that will be transported to Lower 48 markets through the Alaskan Natural Gas Transportation System (ANGTS) are consistent with the capacity of this system. ANGTS is projected to come online in two phases, and it is assumed that production will be available to fully utilize the capacity in both phases, if constructed. Full capacity for the first phase is 840 billion cubic feet per year. Capacity increases to 1,260 billion cubic feet upon the completion of the second phase. Operation for each phase is assumed to begin at mid year, thus capacity is only available for half of the first year of operation, with full capacity available in each year thereafter. It is assumed that ANGTS will not begin operations until after 1995. Each phase of ANGTS is brought online in PROLOG when an average threshold wellhead price is reached for gas in the Lower 48 States. The price for phase one is $4.37, in 1990 dollars per thousand cubic feet. When this price is reached, ANGTS is brought online in the following year, with a total flow of 420 billion cubic feet, and reaches the full capacity of 840 billion cubic feet in subsequent years. If a higher threshold price of $5.00, in 1990 dollars per thousand cubic feet is reached, then phase two will begin the following year. The flow will increase by 210 billion cubic feet, to 1,050 billion cubic feet, and in each subsequent year the flow will be 1,260 billion cubic feet. This methodology is applied in all the scenarios.

Associated-Dissolved Natural Gas. Associated-dissolved natural gas production is computed in PROLOG as a co-product of Lower 48 crude oil production. End-of-year reserves of associated-dissolved gas in the Lower 48 States totalled 26.6 trillion cubic feet in the 1989 EIA-23 report. This reserves level, as well as the following regional co-product ratios, are used in all scenarios (Table 17).

Table 17. Associated-Dissolved Gas Co-Product Ratios

PROLOG Supply Region	Ratio (billion cubic feet per million barrels)
1	2.315
2	1.784
3	1.901
4	1.141
5	0.984
6	0.570

Source: *Model Methodology and Data Description of the Production of Onshore Lower 48 Oil and Gas Model*, DOE/EIA-M034(91).

Other, Exogenous Sources of Oil. Projections of crude oil production for Alaska, offshore, and enhanced oil recovery (EOR) are developed exogenously to complete the projections of total domestic oil production. The Alaskan projections were the result of a field-level analysis of known areas, incorporating assumptions of the likely maximum production and decline rates. Offshore production was estimated by using historical decline rates for existing production, combined with a procedure to estimate production from new reserves. Projections of EOR were derived by an interpolation (relative to EIA prices) of price-specific quantity forecasts from a National Petroleum Council study.[22] Further detail on the methodology used to develop the projections of oil production from these three sources is available in technical notes cited in the "Sources" for Table 18. The projections vary by world oil price assumption as shown below (Table 18).

Behind the exogenous projections are certain resource base assumptions measured as of the end-of-year, 1989, which do not vary across scenarios. Alaska projections are based on an estimate of approximately 5.7 billion barrels of accessible undiscovered recoverable oil and 6.7 billion barrels of proved reserves as of December 31, 1989. Underlying the offshore projections are an estimated 6.8 billion barrels of accessible undiscovered recoverable oil and 3.3 billion barrels of reserves at the end of 1989. Implicit in the EOR projections is an estimate of 11.1 billion barrels of oil producible by EOR techniques.

Scenarios

Low Oil Price Case

The methodology is the same as in the Reference Case. The only differences in data are in the exogenously determined forecasts for oil production from Alaska, the offshore, and through EOR techniques. These data are described with the Reference Case data.

[22]National Petroleum Council, *Enhanced Oil Recovery* (Washington, DC, June 1984).

Table 18. Exogenous Crude Oil Production Projections
(Thousand Barrels per Day)

Source/World Oil Price Path	1995	2000	2005	2010
Alaska				
High	1,352	971	952	1,175
Mid	1,321	902	670	782
Low	1,215	793	532	424
Offshore				
High	909	835	761	756
Mid	865	779	707	697
Low	814	715	633	610
EOR				
High	872	789	749	785
Mid	748	622	643	711
Low	614	473	386	393

Sources: Energy Information Administration, Office of Oil and Gas. **Alaska**: "Technical Notes for the *Annual Energy Outlook 1991*: Documentation for the Alaskan Oil Projection," (Washington, DC, February 1991. **Offshore**: "Technical Notes for the *Annual Energy Outlook 1991*: Documentation for the Outer Continental Shelf Oil and Condensate Projection," (Washington, DC, February 1991). **EOR**: "Technical Notes for the *Annual Energy Outlook 1991*: Documentation for Projections of Crude Oil by Enhanced Oil Recovery (EOR) Methods," (Washington, DC, February 1991).

High Oil Price Case

The methodology is the same as in the Reference Case. The only differences in data are in the exogenously determined forecasts for oil production from Alaska, the offshore, and through EOR techniques. These data are described with the Reference Case data.

High Economic Growth Case

The methodology is the same as in the Reference Case. The only differences in data are in the exogenously determined forecasts for oil production from Alaska, the offshore, and through EOR techniques. These data are described with the Reference Case data.

Natural Gas Markets

Purpose

This section describes the model, exogenous projection estimates, assumptions, and data used to produce the *AEO* forecasts of natural gas supply/demand balances, and explains the choice of data and assumptions in the scenarios.

Methodology

Natural gas supply, and wellhead and end-use prices for the *AEO* were determined using the Gas Analysis Modeling System (GAMS). GAMS is a computer based model used in analyzing the complex U.S. natural gas market, from the producer through pipeline companies and distributors, to the consumer. GAMS was developed to support preparation of regional projections of domestic natural gas supply/demand balances and the potential effects of alternative policies, regulations, and economic environments on these balances. GAMS encompasses natural gas production (using PROLOG as a submodel), as well as natural gas imports, pricing by pipeline companies and distributors, and transmission and distribution of natural gas. The model has been revised as laws and regulations concerning the natural gas market have evolved including incorporation of the Natural Gas Wellhead Decontrol Act of 1989.

The primary inputs needed for GAMS are the potential production forecast from PROLOG and demand projections in the form of demand curves from the Intermediate Future Forecasting System (IFFS), which are different for each forecast year.

GAMS' forecasts are annual projections through 2010 at the national and federal region level of natural gas consumption and average price for four general categories of end-users: residential, commercial, industrial, and electric utility. Forecasts of natural gas imports, either through pipelines or in the form of liquefied natural gas, are determined exogenously.

GAMS is fully documented in *Model Documentation of the Gas Analysis Modeling System*, DOE/EIA-0450/91.

Scenarios

Reference Case

Natural Gas End-Use Prices. Natural gas prices to end users are estimated by adding State- and sector-specific markups to the national wellhead price for natural gas. These markups are held constant throughout the forecast and do not vary by scenario. The markups for residential, commercial, industrial, and electric utility end users, by State, are presented below (Table 19).

Table 19. Natural Gas End-Use Markups
(1990 Dollars per Million Btu)

State	Residential	Commercial	Industrial	Electric Utility
Alabama	4.98	3.77	1.40	0.75
Alaska	1.79	1.15	0.11	-0.26
Arizona	5.20	3.19	2.18	1.21
Arkansas	3.19	2.74	1.46	0.54
California	3.96	3.43	2.04	1.21
Colorado	3.02	2.41	1.56	0.81
Connecticut	6.70	4.29	2.65	0.87
Delaware	4.75	3.62	1.69	1.18
Florida	6.22	3.11	1.43	0.75
Georgia	4.77	3.89	2.05	0.75
Idaho	3.82	2.84	3.11	0.54
Illinois	3.20	2.77	2.04	0.34
Indiana	3.63	3.02	2.05	0.34
Iowa	3.17	2.33	1.17	0.61
Kansas	2.48	1.41	1.17	0.61
Kentucky	2.99	2.68	1.89	0.75
Louisiana	4.23	3.57	0.21	0.54
Maine	6.06	5.04	3.30	0.87
Maryland	4.69	3.65	3.19	1.18
Massachusetts	5.27	4.46	2.53	0.87
Michigan	3.80	3.40	2.76	0.34
Minnesota	3.02	2.38	1.07	0.34
Mississippi	4.17	3.46	0.94	0.75
Missouri	3.22	2.62	2.25	0.61
Montana	2.77	2.74	1.52	0.81
Nebraska	2.85	2.13	1.20	0.61
Nevada	4.03	2.87	2.56	1.21
New Hampshire	5.06	4.38	2.50	0.87
New Jersey	4.98	3.82	2.38	0.55
New Mexico	3.76	2.04	1.73	0.54
New York	5.40	3.92	3.02	0.55
North Carolina	5.00	3.54	2.04	0.75
North Dakota	3.56	2.90	1.76	0.81
Ohio	3.74	3.28	2.59	0.34
Oklahoma	2.97	2.47	0.21	0.54
Oregon	5.06	3.62	1.92	0.54
Pennsylvania	4.48	3.74	2.12	1.18
Rhode Island	5.38	4.40	3.57	0.87
South Carolina	5.21	4.09	1.99	0.75
South Dakota	3.31	2.51	1.47	0.81
Tennessee	3.14	2.81	1.61	0.75
Texas	3.83	2.59	0.48	0.54
Utah	3.51	2.82	1.55	0.81
Vermont	4.32	3.19	1.52	0.87
Virginia	4.57	3.11	2.01	1.18
Washington	3.92	3.00	1.27	0.54
West Virginia	4.22	3.76	1.44	1.18
Wisconsin	4.34	3.07	2.47	0.34
Wyoming	3.05	2.71	1.69	0.81

Sources: Federal Energy Regulatory Commission, Form 2, "Annual Report of Major Natural Gas Companies"; Energy Information Administration, Office of Oil and Gas, *Natural Gas Annual 1989*.

End-use prices for compressed natural gas (CNG) used in motor vehicles are calculated by Federal region in GAMS and passed to IFFS. These prices consist of the regional average industrial end-use price, plus a regional markup for motor gasoline taxes (calculated on a Btu equivalent basis). These markups remain constant over the forecast and do not vary by scenario (Table 20).

Table 20. CNG Markups
(1990 Dollars per Million Btu)

Federal Region	Markup
1	2.44
2	2.65
3	2.65
4	2.39
5	2.76
6	2.47
7	2.44
8	2.64
9	2.37
10	2.59

Sources: Energy Information Administration, Office of Oil and Gas, *Petroleum Marketing Monthly*, October 1990; and the Omnibus Budget Reconciliation Act of 1990.

Supplemental Gas Supplies. The forecast for supplemental gas supply is broken into three separate categories: synthetic gas from liquids, synthetic gas from coal, and other supplemental supplies. The quantity of other supplemental supplies is set at the 1989 level of 40 billion cubic feet throughout the forecast, for all scenarios. In recent history, levels of other supplemental supplies have been relatively stable.

Synthetic gas production from liquids is assumed to continue current trends, maintaining a minimum operating level of 14.8 billion cubic feet through 1992 (an estimate for when the current gas productive capacity will need to expand to meet normal production demand). After 1992, this base level of production is escalated, based on a nonlinear function of the natural gas to oil price ratio (natural gas wellhead price divided by domestic oil price in equivalent units). At 100 percent parity, the production level is assumed to be 255 billion cubic feet, which represents 75 percent utilization of the 1987 capacity of operating plants. At gas to crude oil price ratios above 100 percent parity, the production level is assumed to continue to grow, but at a slower rate relative to the ratio.[23]

The Great Plains Coal Gasification Plant that is currently in operation is assumed to continue to operate through the forecast period, producing 50 billion cubic feet per year. In the Reference Case, it is assumed that in mid-year 2005 the Great Plains facility will increase capacity by 50 percent by installing new and/or more gasifiers, resulting in synthetic gas production levels of 62.5 billion cubic feet in 2005, and 75 billion cubic feet through the remaining forecast years. In the High Oil Price Case, the same pattern of increased production of synthetic gas from coal is projected, but the first year of increased capacity is earlier, beginning in 2001. In the Low Oil Price Case and the High Economic Growth Case the amount of gas produced from coal is assumed to remain at current levels.

[23]Energy Information Administration, Model Documentation of the Gas Analysis Modeling System, DOE/EIA-0450(91) (Washington, DC, 1991), p. 14.

Natural Gas Imports and Exports. The levels of natural gas imports and exports are determined exogenously to GAMS. Net pipeline imports are projected to reach 2,321 billion cubic feet in 2010 in all scenarios except the High Oil Price Case which is slightly lower at 2,085 billion cubic feet. Canadian gas constitutes the bulk of these net imports, with Mexican imports projected to resume in 2000 in all cases. The level of pipeline exports is assumed to be 25 billion cubic feet per year throughout the forecast, all going to Canada. Liquefied natural gas (LNG) is another means of transferring gas across U.S. boundaries. LNG exports are assumed to be 50 billion cubic feet per year throughout the forecast. LNG imports were projected to reach 818 billion cubic feet by 2006 in the Reference Case. All export and import levels were based on the judgment of analysts in the Office of Oil and Gas, given current information about pipeline capacity and announced plans for facilities.

The apparent willingness of Canadian producers to supply natural gas at current price levels, in conjunction with the virtual complete utilization of the present pipeline capacity, indicate a market system that is constrained by available transportation. The effective demand, and hence the level of flow, for imports of Canadian gas was considered to be related primarily to the available pipeline capacity over time.

Numerous pipeline expansion projects are planned. The schedule for expansion was established in light of projections in the literature. The Canadian imports projection shows rapid growth, reaching 2,025 billion cubic feet per year by 1995 in all cases. This rate is sustained through 2008, and then drops to 1,846 billion cubic feet by 2010 in the Reference Case as well as in the Low Oil Price and High Economic Growth cases. In the High Oil Price Case, the 1995 level is maintained through 2006, then drops to 1,610 billion cubic feet by 2010. Resource depletion is not a major factor during this limited period given the substantial recoverable resource estimates for Canada (proved reserves in excess of 90 trillion cubic feet as of the end of 1986 as estimated by the Canadian National Energy Board in its September 1988 report, *Canadian Energy: Supply and Demand 1987-2005*).

Mexican import volumes were developed on the basis of analysts' judgment similar to the approach used in the case of Canada. The outlook for Mexican imports depends greatly on the specific assumptions regarding transportation capacity and development of the infrastructure. Natural gas resources in Mexico have not been developed to any great extent, however, Mexico has recently shown some interest in a more open trade policy and in economic growth led in general by export revenues. The estimated proved natural gas reserves in Mexico were approximately 73.4 trillion cubic feet as of the beginning of 1989.

Mexican imports are projected to resume in 2000 at 38 billion cubic feet per year, steadily increasing to 500 billion cubic feet per year in 2009 and 2010. The U.S. demand for natural gas is so large that competitively priced volumes at the projected levels would be marketable in the United States. Mexican import levels do not vary across the cases.

Projections of net pipeline imports (imports minus exports) are shown below (Table 21).

Table 21. Net Pipeline Imports of Natural Gas
(Billion Cubic Feet)

1991 AEO Scenario	1995	2000	2005	2010
High Oil Price	2,000	2,038	2,250	2,085
All Others	2,000	2,038	2,250	2,321

Sources: Technical Notes for the *Annual Energy Outlook 1991*: Documentation of Assumptions of Natural Gas Pipeline and Liquefied Natural Gas Imports (Washington, DC, March 1991).

A primary factor in the forecast of liquefied natural gas (LNG) imports is the current level of LNG terminal capacity. The United States has four existing LNG terminal facilities. The Lake Charles terminal in Louisiana reopened in December 1989, joining the Distrigas facility in Massachusetts as the only active LNG importation ports in the United States. Total design capacity of all four terminals measures just under 1.0 trillion cubic feet per year.

Announced plans for each import terminal serve as the primary determinant of the time for reopening these facilities. Once in operation, continued maintenance is expected to be sufficient to keep all plants operable at the maximum rates throughout the forecast horizon. It was assumed that capacity expansion does not occur at current sites or new locations. In general, tankers were considered to be a constraining factor in the near term, but additional tanker capacity is expected by the mid 1990's. Additional liquefaction capacity worldwide cannot be considered as committed to the United States without qualification. Nonetheless, based on announced plans for new capacity, along with a reasonable amount of additional construction over time, it is assumed that capacity will be adequate to make supplies available to the United States as projected.

Projections for total imports of LNG are shown in Table 22. The difference across scenarios primarily reflects the observed difference in natural gas prices. In addition, the gas price relative to the world oil price (which varies substantially across scenarios) was taken into account, although to much less of a degree. Exports of LNG from Alaska to Japan are assumed to remain at a constant level of 50 billion cubic feet throughout the forecast for each scenario.

Table 22. Gross Liquefied Natural Gas Imports
(Billion Cubic Feet)

1991 AEO Scenario	1995	2000	2005	2010
Reference, Low Oil Price	344	570	749	818
High Oil Price	282	498	641	641
High Economic Growth	378	669	818	818

Sources: Technical Notes for the *Annual Energy Outlook 1991*: Documentation of Assumptions of Natural Gas Pipeline and Liquefied Natural Gas Imports (Washington, DC, March 1991).

Scenarios

Low Oil Price Case

The methodology is the same as in the Reference Case. The difference in data is in projections for synthetic natural gas from coal, as described above.

High Oil Price Case

The methodology is the same as in the Reference Case. The differences in data are in projections for synthetic natural gas from coal and in the exogenously determined forecasts for Canadian pipeline imports and imports of liquefied natural gas. These data are described with the Reference Case data.

High Economic Growth Case

The methodology is the same as in the Reference Case. The only differences in data are in the exogenously determined forecasts for liquefied natural gas and for synthetic natural gas from coal. These data are described with the Reference Case data.

Petroleum Prices and Supply

Purpose

This section describes the general model structure, assumptions, and data used to produce the 1991 *AEO* petroleum prices and supply forecasts and explains the choice of assumptions in the scenarios.

Methodology

The Oil Market Module (OMM) computes the end-use prices of eight petroleum product categories for five different consumption sectors and ten different regions of the United States. The overall supply disposition balance is also calculated. The projections for petroleum prices and supply are primarily based on data in the latest *Petroleum Marketing Annual*[24] and *Petroleum Supply Annual.*[25]

The inputs to the OMM from other components of the 1991 *AEO* Forecasting System include:

- Quantities of refined product demanded
- The world oil price
- Domestic production of crude oil and natural gas and
- Production of related non-petroleum liquid streams.

Using some of these inputs, the OMM first computes refinery gate prices of the petroleum products along with an estimate of product imports. Additional mathematical relationships enable an estimate of other petroleum supply categories. Crude oil imports are calculated by subtracting product imports and estimates for domestic production, petroleum exports, natural gas liquids, stock changes and other liquids consumption from total petroleum demand.

Specific model computations along with the values and sources for the model parameters are identical to those described in the model documentation.[26] The assumptions that are particularly important in obtaining the results presented in the various 1991 *AEO* cases are provided below.

[24]Energy Information Administration, *Petroleum Marketing Annual 1989*, DOE/EIA-0487(89) (Washington, DC, December 1990).

[25]Energy Information Administration, *Petroleum Supply Annual 1989*, DOE/EIA-0340(89) (Washington, DC, May 1990).

[26]Decision Analysis Corporation of Virginia, *Model Documentation Report, the Oil Market Module* (Vienna, VA, September 1990) and Energy Information Administration, "Technical Notes for the Oil Market Model" (Washington, DC, February 1991).

Scenarios

Reference Case

End-use Markups. Federal Region end-use markups are added to the national refinery gate prices to include State and Federal taxes, distribution costs, and associated profits and losses (Table 23). These markups were derived by averaging the difference between retail prices and refiners' wholesale prices over the years 1984 to 1989. It is assumed that the historical values will continue through the forecast period.

Table 23. Petroleum Product End-Use Markups by Sector and Federal Region
(1990 Dollars per Million Btu)

Sector/Product	1	2	3	4	5	6	7	8	9	10
Residential Sector										
Distillate Fuel Oil	2.58	2.94	2.47	2.25	2.00	1.02	1.55	1.54	1.89	2.10
Liquefied Petroleum Gases	8.03	7.98	8.04	7.24	5.35	5.32	3.02	3.57	9.36	8.20
Other	5.05	5.65	4.69	4.39	4.63	3.44	3.73	3.13	8.70	6.04
Commercial Sector										
Gasoline	4.15	3.84	3.69	3.30	3.69	3.30	3.40	3.73	3.73	3.80
Distillate Fuel Oil	1.05	0.96	0.53	0.21	0.33	0.11	0.13	0.25	-0.04	0.28
Low Sulfur Residual Fuel Oil	0.16	0.47	0.29	-0.11	0.50	-0.83	-0.34	-0.05	0.92	1.60
Liquefied Petroleum Gases	8.61	8.75	6.24	5.68	5.18	2.27	4.26	3.17	6.06	6.18
Other	2.79	1.76	1.98	1.91	2.13	1.48	1.43	1.51	1.96	2.68
Utility Sector										
Distillate Fuel Oil	0.12	0.37	-0.01	0.18	0.29	0.12	0.20	0.33	0.57	0.14
High Sulfur Residual Fuel Oil	0.09	0.25	0.25	0.05	0.51	0.39	0.03	-0.30	0.12	-0.09
Low Sulfur Residual Fuel Oil	0.43	0.68	0.45	0.35	0.88	0.57	0.43	0.46	0.89	0.14
Other	-1.89	-1.89	-1.83	-1.84	-1.94	-1.91	-1.85	-1.91	-1.91	-1.91
Transportation Sector										
Gasoline	4.13	3.85	3.61	3.29	3.68	3.30	3.38	3.65	3.72	3.53
Distillate Fuel Oil	4.82	4.40	3.98	3.32	4.02	3.52	3.74	3.99	3.96	3.99
High Sulfur Residual Fuel Oil	0.33	0.01	0.26	0.16	0.01	-0.95	-0.32	0.07	0.43	0.45
Jet Fuel	0.38	0.07	0.09	0.05	0.16	-0.12	0.18	0.28	0.26	0.29
Liquefied Petroleum Gases	8.57	8.67	6.25	5.77	5.27	1.96	4.02	3.40	6.02	6.04
Other	13.23	13.25	13.02	13.28	13.11	13.22	13.11	13.26	13.27	13.52
Industrial Sector										
Gasoline	4.15	3.82	3.61	3.29	3.72	3.30	3.43	3.90	3.74	3.82
Distillate Fuel Oil	0.88	0.66	0.64	0.47	0.63	0.30	0.47	0.63	0.30	0.46
Low Sulfur Residual Fuel Oil	0.32	0.43	0.17	-0.13	-0.14	0.03	-0.53	-0.20	-0.18	0.17
Liquefied Petroleum Gases	8.55	8.53	6.03	5.35	4.93	1.05	3.80	3.42	6.03	6.02
Other	6.49	6.24	5.98	5.39	6.49	5.14	5.36	4.01	6.49	4.23

Sources: Energy Information Administration, EIA-14, "Refiners Monthly Cost Report," EIA-782A, "Refiners Gas Plant Operators' Monthly Petroleum Product Sales Report," EIA-782B, "Resellers/Retailers' Monthly Petroleum Product Sales Report", FPC-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," EIA-759, "Monthly Power Plant Report," *The 1988 State Energy Data System*, *The 1987 State Energy Price and Expenditures Data System*; American Gas Association, *Gas House Heating Survey: 1989*, Arlington, VA; EIA, *Petroleum Marketing Monthly*, October 1990; and the Omnibus Reconciliation Act of 1990.

The end-use markups include the additional 5.0-cent per gallon Federal tax on gasoline and diesel fuel resulting from the Budget Reconciliation Act of 1990. The end-use markups for Region 9 are adjusted for the

5.0-cent per gallon tax on transportation fuels that went into effect October 1990 in California and the annual increase in that tax for the next four years.

Environmental Markups. In addition to end-use markups, environmental markups are also added to refinery gate prices. These markups include cost increases resulting from several environmental regulations or laws that either became effective or were passed during 1989 and 1990 (Table 24). Incremental costs estimates are used only for regulations that specify dates and extent of coverage. As described below, the environmental markups include incremental costs resulting from the Resource Conservation and Recovery Act, the Clean Air Act, and the Clean Air Act Amendments of 1990.

Table 24. National Environmental Markups for Gasoline and Distillate Fuel Oil by Sector and Fuel Type
(1990 Dollars per Million Btu)

	Commercial	Transportation		Industrial
Year	Gasoline	Gasoline	Distillate Fuel Oil	Gasoline
1992	0.16	0.16	0.08	0.16
1993	0.17	0.17	0.38	0.17
1994	0.18	0.18	0.38	0.18
1995	0.33	0.33	0.38	0.33
1996	0.35	0.35	0.38	0.35
1997	0.38	0.38	0.38	0.38
1998	0.42	0.42	0.38	0.42
1999	0.45	0.45	0.38	0.45
2000	0.47	0.47	0.38	0.47
2001	0.51	0.51	0.38	0.51
2002	0.51	0.51	0.38	0.51
2003	0.54	0.54	0.38	0.54
2004	0.57	0.57	0.38	0.57
2005	0.66	0.66	0.38	0.66
2006	0.67	0.67	0.38	0.67
2007	0.68	0.68	0.38	0.68
2008	0.72	0.72	0.38	0.72
2009	0.74	0.74	0.38	0.74
2010	0.76	0.76	0.38	0.76

Sources: Markups derived from U.S. Environmental Protection Agency (EPA), Office of Underground Storage Tanks, "Regulatory Impact Analysis of Technical Standards for Underground Storage Tanks," Exhibit ES-1 (Washington, DC, August 24, 1988); EPA, final rule "Regulation of Fuels and Fuel Additives: Fuel Quality Regulations for Highway Diesel Fuel Sold in 1993 and Later Calendar Years," (Washington, DC, August 8, 1990), pp. 7, 19; *Federal Register*, Vol. 55, no. 112, June 11, 1990, p. 23663; American Petroleum Institute, *Costs of Congressionally Reformulated Gasoline*, Editorial and Special Issues Department, Public Affairs Group, May 4, 1990; 101st Congress, Second Session, *Congressional Record*, October 26, 1990, p. 12857; Congressional Budget Office, *Clean Fuels for Conventional Vehicles: Implications and Proposed Standards*, September 1990, p. 1.

The Resource Conservation and Recovery Act (RCRA) of 1984. Regulations issued by the Environmental Protection Agency (EPA) to halt the discharge of hazardous materials from the Nation's 700,000 underground storage facilities became effective generally between 1989 and 1990. Using EPA estimates,[27] the additional cost to store gasoline and distillate fuel oil resulting from this regulation was calculated to be approximately 1.0 cent per gallon and is included in the forecasts.

The Clean Air Act. Under the authority of the original Clean Air Act, EPA issued regulations concerning the volatility of gasoline. The second phase of the two phase program, announced June 11, 1990, will take effect May 1992. EPA's cost estimate of 1.1 cents per gallon[28] is included in the forecasts.

Also under the authority of the Clean Air Act, EPA issued regulations limiting the sulfur and aromatic content of on-highway diesel fuel oil, to take effect October 1993. EPA's cost estimate of 4.0 cents per gallon[29] is included in the forecasts.

The Clean Air Act Amendments of 1990. Congress' recent amendments to the CAA require that gasoline sold in nine U.S. cities beginning in 1995 must be "reformulated" gasoline and that beginning in 1992, for at least four months per year, gasoline sold in about 40 cities must be "oxygenated" gasoline. Reformulated gasoline must have an oxygen content of at least 2.0 weight percent and must comply with other specifications, such as the reduction of benzene and other aromatics. Oxygenated gasoline must contain more oxygen, at least 2.7 percent, but is not required to meet the rest of the specifications for reformulated gasoline.

Due to certain supply constraints, the initial use of the reformulated and oxygenated gasoline is assumed to be mostly restricted to the nonattainment cities. As more cities opt into the compliance program and refiners attempt to simplify distribution, construction of additional methyl-tertiary butyl ether (MTBE) plants and other downstream facilities is assumed to take place. By the year 2010, it is assumed that refiners will provide only reformulated and oxygenated gasolines. As more cities opt to require reformulated and oxygenated gasolines, the average markup increases to the full cost estimate, as shown by the increase in markups in Table 24.

Reformulated gasoline is estimated to cost an additional 8.0 cents per gallon while oxygenated gasoline is estimated to cost an additional 2.0 cents per gallon. This represents the middle of a range of prices projected by several groups such as the American Petroleum Institute, the Congressional Budget Office, and the EPA.[30]

Costs of other provisions of the new CAA amendments, mainly pertaining to toxic emissions from refineries and transportation facilities, have not been included. Regulations concerning the emission type and extent of control have yet to be issued by EPA. Refinery operations may be further influenced by future Federal and State regulations that are designed to bring nonattainment areas into attainment.

Domestic Refining Capacity. Because of changes in product specifications and processing requirements, net additions to atmospheric distilling capacity are expected to be small. Domestic refining capacity is assumed to be limited to 15.9 million barrels per day between 2000 and 2010. The underlying assumptions of this methodology are that facilities to transport higher product imports are available or will be constructed and that enough product is made in foreign refineries to meet U.S. specifications.

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[27]U.S. Environmental Protection Agency, Office of Underground Storage Tanks, "Regulatory Impact Analysis of Technical Standards for Underground Storage Tanks," Exhibit ES-1, August 24, 1988.

[28]*Federal Register*, Vol. 55, no. 112, June 11, 1990, p. 23663.

[29]U.S. Environmental Protection Agency, final rule, "Regulation of Fuels and Fuel Additives: Fuel Quality Regulations for Highway Diesel Fuel Sold in 1993 and Later Calendar Years" (Washington, DC, August 8, 1990), pp. 7, 19.

[30]American Petroleum Institute, *Costs of Congressionally Reformulated Gasoline*, Editorial and Special Issues Department, Public Affairs Group, May 4, 1990; Congressional Budget Office, *Clean Fuels for Conventional Vehicles: Implications and Proposed Standards*, September 1990, p. 1; 101st Congress, Second Session, *Congressional Record*, October 26, 1990, p. 12857.

Crude Oil Exports. Crude oil exports, which typically consist of Alaskan crude oil refined in the Virgin Islands, are calculated as a function of the world oil price and Alaskan crude oil production.

Product Exports and Crude Oil Stock Withdrawals. Product exports and crude oil stock withdrawals are calculated as a function of domestic refinery production.

Product Stock Withdrawals. Product stock withdrawals are calculated as a function of domestic petroleum demand.

Natural Gas Liquids. Natural gas liquids, separated from natural gas at plants near production fields, are assumed to be related to natural gas production.

Methanol for MTBE Production. Methanol for MTBE production is calculated after assuming that MTBE production is the difference between the requirement for oxygenates less ethanol production, an input to the OMM from the renewables model. Both ethanol and methanol for MTBE production are included in the "Other Domestic Production" category.

Scenarios

Low Oil Price Case

The variables and parameters used in the Low Oil Price Case are identical to those used in the High Economic Growth Case.

High Oil Price Case

The variables and parameters used in the High Oil Price Case are identical to those used in the Reference Case.

High Economic Growth Case

The variables and parameters used in the High Economic Growth Case are identical to those used in the Reference Case with the following exception.

Markups for petroleum refining and distribution companies in the High Economic Growth Case are adjusted over time to capture charges for more petroleum tankers, new port facilities, and increased storage and domestic shipping costs. By 2010 in the High Economic Growth Case, the refiners' margin is assumed to be slightly less than the 1980 level, the highest refiners' margin in the recent past. For the distribution markup, the 2010 margin reflects the average (1985 to 1989) margin on gasoline, the largest margin of the petroleum products. The effect of this assumption results in a combined margin that averages 18 percent higher than the combined margins in the Reference and High Oil Price Cases.

5. Coal Supply Assumptions

Purpose

This chapter describes the models, assumptions, and data used to produce the 1991 *AEO* coal forecasts and explains the choice of data and assumptions used in the *AEO* scenarios.

Methodology

Coal Model Descriptions

Coal Supply and Transportation Model. The projections of coal supply and prices presented in the 1991 *AEO* were developed with the Coal Supply and Transportation Model (CSTM). The CSTM determines the sources and transportation routes of coal for a given set of coal demands. The transportation network of the CSTM links 32 supply regions with 48 demand regions (44 domestic and 4 foreign). Both rail and water movements are represented covering all major U.S. rail lines and barge and collier routes.

The projected levels of coal demand were provided by the Demand Evaluation Modeling System (DEMS) for the residential, commercial, and industrial sectors, and by the Electricity Market Module (EMM) for the electric utility sector. The CSTM used as input the output from other coal models, which are the National Coal Model (NCM), the Resource Allocation and Mine Costing Model (RAMC), and the International Coal Trade Model (ICTM).

National Coal Model. The projected shares of utility coal demand by demand region and coal type (coal rank and sulfur content) for the 1991 *AEO* were developed with the NCM. The NCM is a highly disaggregated coal supply and utility model that projects production and distribution of coal and electric utility fuel consumption. Utility fuel consumption forecasts of the NCM are based on specified levels of electricity consumption, existing and planned generating capacity, the economics of electricity generation, and nonutility demand for coal. Coal demands in each of 44 domestic demand regions are met via a transportation network from existing and new mines in 31 supply regions (32 RAMC supply regions less Louisiana). Flue gas desulfurization technology is internally represented, and both sulfur dioxide and other emissions are reported.

Resource Allocation and Mine Costing Model. Coal supply curves used for the 1991 *AEO* forecasts were developed with the RAMC and represent the quantity of coal which can be produced at given prices. The RAMC coal supply curves, classified by coal type, mining method, and coal supply region, are estimated by relating mine costs to various geologic and operating parameters of future mines. The distribution of coal reserves by coal type, mining method, and region is also represented. The RAMC coal supply curves are used as input to the CSTM and NCM.

International Coal Trade Model. U.S. coal exports projections presented in the 1991 *AEO* were developed using the ICTM. The ICTM is a static equilibrium model used to represent the international coal market. The model is used to assess the consequences of events and issues relating to world coal trade based on the various assumptions concerning world coal supply and demand.

The ICTM projects coal trade flows from 20 coal-exporting regions of the world to 9 demand regions for 3 types of coal: metallurgical, low-sulfur steam (less than 1.0 percent sulfur by weight), and high-sulfur steam. The model consists of supply, demand, trade, and transportation constraint components, the latter representing alternate routes of passage (Panama Canal, Suez Canal, direct ocean-going) and ship size (30,000 to 250,000 deadweight tons). The major coal-producing countries such as the United States, Australia, South Africa, Canada, and Poland are represented, as well as countries that could become major coal exporters such as Colombia, Venezuela, and China.

Statement of Exceptions from Model Documentation

Coal Supply and Transportation Model. All of the time series variables referenced in the CSTM documentation have been extended from 2000 to 2010.

National Coal Model. The NCM model logic and structure have been extended from 2000 to 2010.

Model Documentation and Archive Tapes

The CSTM was used to analyze coal markets in the *AEO* Forecasting System. The CSTM is documented in the following report: *Coal Supply and Transportation Model (CSTM) Description,* DOE/EIA-M022 (Washington, DC, June 1987).

Other coal models are:

Model	Inputs to the CSTM	Archive Tape	Documentation
National Coal Model	Shares of Utility Coal Demand by Region and Coal Type	NCM90 Available from Malek Mohtadi (254-5371)	DOE/EIA-0428(83) DOE/EIA-M027(88)
Resource Allocation and Mine Costing Model	Coal Supply Curves	RAMC90 Available from Malek Mohtadi (254-5371)	DOE/EIA-M021(87)
International Coal Trade Model	Exports of Steam and Metallurgical Coal	ICTM90 Available from Fred Mayes (254-5409)	DOE/EIA-M026(88)

Scenarios

Reference Case

Coal Supply and Transportation Model.

- The CSTM determines the least-cost supplies of coal by supply region for a given set of coal demands in each demand sector in each demand region by comparing alternative sources (minemouth prices) and transportation modes and routes (transportation costs). Annual increases in rail and barge rates over the forecast are based on rail- and barge- specific escalation factors.

- Available data on utility coal contracts (tonnage, duration, coal type, and origin and destination of shipments) are incorporated into the CSTM to represent coal shipments under contract. The coal contracts work as a constraint to the model. The contract data are from Federal Energy Regulatory Commission

(FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," supplemented with information on contract duration from the Coal Transportation Rate Data Base (CTRDB) maintained by the EIA.

National Coal Model. In the NCM, utility coal contracts (tonnage, duration, coal type, and origin and destination of shipments) are represented by forced shipments of coal from a supply region to a demand region, thus acting as a constraint to the model. As with the CSTM, the contract data used come from FERC Form 423 and the CTRDB.

Resource Allocation and Mine Costing Model.

- In the RAMC, some of the Demonstrated Reserve Base (DRB) of coal is considered inaccessible to mining. Inaccessible reserves fractions are established for each of the 32 supply regions used in the RAMC. The inaccessibility fractions for surface mines generally fall in the 10 to 25 percent range, while a 10 percent inaccessibility fraction prevails for underground reserves.

- Of the accessible coal reserves, the RAMC uses a recovery rate of 60 percent for underground mining, 80 percent for surface mining east of the Mississippi, and 90 percent for surface mining west of the Mississippi. These percentages are based on the current recovery rates reported by the operators of existing mines.

- In the RAMC, new underground and new large surface mines (greater than 200,000 tons per year) are assumed to have a mine life of 30 years, while new small surface mines (less than or equal to 200,000 tons per year) are assumed to have a mine life of 15 years.

- Assumptions about productivity affect mine costs. In general, it was assumed for this year's forecast that labor productivity will increase by 2 percent per year for underground mines and by 1 percent for surface mines.

- Coal cleaning in the RAMC is limited to the degree of cleaning required to return raw coal to its in-seam quality. Thus, the RAMC accounts for only low-intensity cleaning: coarse beneficiation of bituminous coal and breaking of subbituminous coal and lignite. Typical cleaning costs by region and coal type are assigned for the coarse beneficiation of bituminous coal, while no separate cleaning costs are assigned to subbituminous coal and lignite.

- Over the forecast horizon, capital and operating costs of the model mines in the RAMC are assumed to increase at the rate of general inflation.

- The RAMC 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 25 and 26.

International Coal Trade Model. World demand for imported coal is estimated at 5-year intervals from 1995 through 2010 on a country-by-country basis. Three types of coal are considered for trading: metallurgical coal, low-sulfur steam coal, and high-sulfur steam coal.

Ocean freight rates are estimated for all feasible pairs of importing and exporting regions. Separate rates are computed for steam and metallurgical coal, since many of the largest coal-importing handling facilities are for metallurgical coal only, especially in the Orient. Also, rates are computed separately for "direct" and canal rates.

Assumptions for the High Economic Growth, High Oil Price, and Low Oil Price Cases

Coal Supply and Transportation Model. In addition to domestic demand from the *AEO* 1991 Forecasting System, the inputs to the CSTM which vary across the *AEO* scenarios are the rail and barge transportation rate escalators and the U.S. coal exports from the ICTM. The transportation rate escalators used in the four *AEO* cases are shown in Table 27. The U.S. coal exports for the four *AEO* cases are shown in Tables 28 through 31.

National Coal Model. Inputs to the NCM which vary across the *AEO* scenarios are electricity demands from the Electricity Market Module (EMM), oil and gas prices also from the EMM, and transportation costs from the CSTM. Electricity demand inputs to the NCM for the four *AEO* cases are shown in Tables 32 through 35.

Resource Allocation and Mine Costing Model. No inputs to the RAMC vary across the *AEO* scenarios.

International Coal Trade Model.

- In the ICTM, U.S. coal exports are determined, in part, by the projected level of world coal import demand. For this year's AEO, world coal demand projections vary only with changes in assumptions about economic growth. Therefore, only the coal import demand in the High Economic Growth Case is different from that in the Reference Case. Table 36 shows world coal import demand for the Reference, High Oil Price, and Low Oil Price cases, and Table 37 shows the import demand for the High Economic Growth Case. All steam coal demand is assumed to be low-sulfur coal, except for approximately 40 percent of Canadian imports from the United States, which are assumed to be high sulfur.

- Ocean transportation rates in the ICTM vary with changes in world oil prices. Thus, ocean transportation rates are greater in the High Oil Price Case than in the Reference Case, and are lower in the High Economic Growth and Low Oil Price Cases. The ocean transportation rates for the four *AEO* cases are shown in Tables 38 through 41.

Table 25. Retirement of Existing Underground Mine Production Capacity in the Resource Allocation and Mine Costing Model, 1990-2010
(Fractions)

RAMC Supply Regions	1990	1995	2000	2005	2010
Pennsylvania	0.06	0.19	0.34	0.55	0.76
Ohio	0.02	0.05	0.14	0.37	0.60
Maryland	0.15	0.54	0.87	1.00	1.00
West Virginia, N.	0.02	0.13	0.32	0.49	0.66
West Virginia, S.	0.08	0.31	0.52	0.70	0.88
Virginia	0.13	0.39	0.59	0.81	0.96
Kentucky, E.	0.11	0.34	0.51	0.67	0.83
Tennessee	0.25	0.69	0.79	0.81	0.83
Alabama	0.09	0.26	0.46	0.81	1.00
Kentucky, W.	0.02	0.09	0.31	0.68	0.94
Illinois	0.00	0.05	0.24	0.52	0.80
Indiana	0.00	0.00	0.08	0.28	0.48
Iowa	0.40	1.00	1.00	1.00	1.00
Missouri	1.00	1.00	1.00	1.00	1.00
Kansas	1.00	1.00	1.00	1.00	1.00
Arkansas	1.00	1.00	1.00	1.00	1.00
Louisiana	1.00	1.00	1.00	1.00	1.00
Oklahoma	1.00	1.00	1.00	1.00	1.00
Texas	1.00	1.00	1.00	1.00	1.00
North Dakota	1.00	1.00	1.00	1.00	1.00
South Dakota	1.00	1.00	1.00	1.00	1.00
Montana, E.	1.00	1.00	1.00	1.00	1.00
Montana, W.	1.00	1.00	1.00	1.00	1.00
Wyoming, N.	1.00	1.00	1.00	1.00	1.00
Wyoming, S.	0.00	0.00	0.00	0.00	0.00
Colorado, N.	1.00	1.00	1.00	1.00	1.00
Colorado, S.	0.00	0.00	0.00	0.00	0.00
Utah	0.00	0.00	0.01	0.03	0.05
Arizona	1.00	1.00	1.00	1.00	1.00
New Mexico	0.00	0.00	0.00	0.00	0.00
Washington	1.00	1.00	1.00	1.00	1.00
Alaska	1.00	1.00	1.00	1.00	1.00

Source: Energy Information Administration, Coal Division, Coal Division Estimates.

Table 26. Retirement of Existing Surface Mine Production Capacity in the Resource Allocation and Mine Costing Model, 1990-2010
(Fractions)

RAMC Supply Regions	1990	1995	2000	2005	2010
Pennsylvania	0.21	0.59	0.81	1.00	1.00
Ohio	0.12	0.35	0.51	0.74	0.93
Maryland	0.32	0.89	1.00	1.00	1.00
West Virginia, N.	0.25	0.74	0.95	1.00	1.00
West Virginia, S.	0.24	0.64	0.82	1.00	1.00
Virginia	0.18	0.52	0.76	1.00	1.00
Kentucky, E.	0.20	0.53	0.76	1.00	1.00
Tennessee	0.40	1.00	1.00	1.00	1.00
Alabama	0.20	0.63	0.89	1.00	1.00
Kentucky, W.	0.30	0.84	0.95	0.96	0.97
Illinois	0.19	0.57	0.78	0.93	1.00
Indiana	0.21	0.57	0.73	0.92	1.00
Iowa	0.40	1.00	1.00	1.00	1.00
Missouri	0.00	0.00	0.26	0.78	1.00
Kansas	0.00	0.00	0.38	0.97	1.00
Arkansas	0.40	1.00	1.00	1.00	1.00
Louisiana	0.00	0.00	0.00	0.00	0.00
Oklahoma	0.23	0.64	0.85	1.00	1.00
Texas	0.00	0.00	0.00	0.00	0.00
North Dakota	0.04	0.10	0.15	0.28	0.41
South Dakota	1.00	1.00	1.00	1.00	1.00
Montana, E.	0.00	0.00	0.00	0.00	0.00
Montana, W.	0.00	0.00	0.00	0.00	0.00
Wyoming, N.	0.00	0.02	0.04	0.04	0.04
Wyoming, S.	0.03	0.12	0.18	0.21	0.24
Colorado, N.	0.03	0.29	0.61	0.61	0.61
Colorado, S.	0.14	0.41	0.49	0.49	0.49
Utah	1.00	1.00	1.00	1.00	1.00
Arizona	0.00	0.00	0.00	0.00	0.00
New Mexico	0.03	0.07	0.07	0.07	0.07
Washington	0.00	0.00	0.00	0.40	1.00
Alaska	0.00	0.00	0.00	0.00	0.00

Source: Energy Information Administration, Coal Division, Coal Division Estimates.

Table 27. Rail and Barge Transportation Rate Escalators by AEO Scenario, 1985-2010

Year	Rail Rates (1985=1.0000)				Barge Rates (1985=1.0000)			
	Reference	High Economic Growth	High Oil Price	Low Oil Price	Reference	High Economic Growth	High Oil Price	Low Oil Price
1985	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
1986	0.9550	0.9550	0.9550	0.9550	0.8280	0.8280	0.8280	0.8280
1987	0.9506	0.9506	0.9506	0.9506	0.8415	0.8415	0.8415	0.8415
1988	0.9958	0.9958	0.9958	0.9958	0.8081	0.8081	0.8081	0.8081
1989	0.9982	0.9982	0.9982	0.9982	0.8443	0.8443	0.8443	0.8443
1990	0.9674	0.9812	0.9721	0.9620	0.8871	0.8846	0.9035	0.8685
1991	0.9789	0.9834	0.9912	0.9640	0.9186	0.8830	0.9628	0.8669
1992	0.9808	0.9853	0.9930	0.9658	0.9179	0.8823	0.9621	0.8662
1993	0.9846	0.9894	0.9969	0.9696	0.9202	0.8846	0.9644	0.8683
1994	0.9890	0.9937	1.0014	0.9740	0.9232	0.8875	0.9676	0.8712
1995	0.9922	0.9974	1.0046	0.9771	0.9245	0.8890	0.9689	0.8724
1996	0.9960	1.0011	1.0084	0.9809	0.9263	0.8906	0.9709	0.8741
1997	0.9998	1.0049	1.0123	0.9846	0.9284	0.8921	0.9731	0.8761
1998	1.0048	1.0103	1.0177	0.9900	0.9334	0.8982	0.9796	0.8824
1999	1.0114	1.0165	1.0245	0.9959	0.9435	0.9060	0.9906	0.8902
2000	1.0179	1.0225	1.0307	1.0016	0.9539	0.9133	1.0002	0.8975
2001	1.0243	1.0281	1.0381	1.0067	0.9651	0.9196	1.0150	0.9035
2002	1.0301	1.0322	1.0440	1.0106	0.9761	0.9239	1.0271	0.9081
2003	1.0362	1.0369	1.0503	1.0153	0.9873	0.9239	1.0391	0.9139
2004	1.0424	1.0417	1.0567	1.0197	0.9982	0.9295	1.0510	0.9187
2005	1.0482	1.0464	1.0627	1.0240	1.0085	0.9392	1.0622	0.9231
2006	1.0540	1.0515	1.0692	1.0289	1.0176	0.9450	1.0743	0.9290
2007	1.0593	1.0563	1.0753	1.0333	1.0252	0.9496	1.0851	0.9333
2008	1.0635	1.0604	1.0807	1.0371	1.0304	0.9530	1.0947	0.9369
2009	1.0671	1.0643	1.0856	1.0408	1.0341	0.9570	1.1034	0.9409
2010	1.0709	1.0684	1.0910	1.0446	1.0375	0.9603	1.1131	0.9443

Source: Energy Information Administration, Coal Division, Coal Division Estimates.

Table 28. U.S. Coal Export Demand for the Reference Case, 1995-2010
(Million Short Tons)

CTSM Export Region/Coal Type	1995	2000	2005	2010
Northern Europe				
MET	20.54	15.70	16.70	24.35
STM	36.55	77.04	142.56	173.25
Southern Europe				
MET	11.31	0.01	0.01	1.05
STM	6.12	9.34	9.34	11.89
Orient and South America				
MET	15.11	10.88	6.30	12.71
STM	7.41	9.05	8.99	10.28
STM	2.02	2.01	1.73	1.73
Eastern Canada				
MET	4.68	3.87	3.79	3.44
STM	5.99	8.78	9.53	10.68
Total MET	51.64	30.45	26.79	41.55
Total STM	58.09	106.22	172.15	208.83
Grand Total	109.73	136.67	198.94	250.38

Note: Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration, Coal Division, International Coal Trade Model.

Table 29. U.S. Coal Export Demand for the High Economic Growth Case, 1995-2010
(Million Short Tons)

CTSM Export Region/Coal Type	1995	2000	2005	2010
Northern Europe				
MET	18.91	16.29	18.25	27.06
STM	44.38	89.21	167.96	197.40
Southern Europe				
MET	13.11	9.86	14.20	1.05
STM	6.31	9.34	9.34	13.09
Orient and South America				
MET	21.52	16.19	5.21	10.50
STM	7.82	9.84	11.67	11.21
STM	2.02	2.01	1.64	1.64
Eastern Canada				
MET	4.76	3.97	3.95	3.96
STM	5.57	9.25	11.87	12.83
Total MET	58.30	46.31	41.61	42.57
Total STM	66.10	119.65	202.48	236.17
Grand Total	124.40	165.96	244.09	278.74

Note: Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration, Coal Division, International Coal Trade Model.

Table 30. U.S. Coal Export Demand for the High Oil Price Case, 1995-2010
(Million Short Tons)

CTSM Export Region/Coal Type	1995	2000	2005	2010
Northern Europe				
MET	20.77	15.69	16.68	24.81
STM	39.09	77.33	142.96	173.89
Southern Europe				
MET	12.43	0.00	0.00	1.05
STM	6.08	9.34	9.34	10.69
Orient and South America				
MET	15.11	11.66	6.30	10.50
STM	7.41	9.05	8.88	10.28
STM	2.02	2.01	1.63	1.73
Eastern Canada				
MET	4.72	3.88	3.79	3.44
STM	5.99	8.78	9.53	11.68
Total MET	53.03	31.23	26.77	39.80
Total STM	60.59	106.51	172.34	208.27
Grand Total	113.62	137.74	199.11	248.07

Note: Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration, Coal Division, International Coal Trade Model.

Table 31. U.S. Coal Export Demand for the Low Oil Price Case, 1995-2010
(Million Short Tons)

CTSM Export Region/Coal Type	1995	2000	2005	2010
Northern Europe				
MET	20.54	15.70	16.70	24.35
STM	36.55	77.04	142.56	173.25
Southern Europe				
MET	11.31	0.01	0.01	1.05
STM	6.12	9.34	9.34	11.89
Orient and South America				
MET	15.11	10.88	6.30	12.71
STM	7.41	9.05	8.99	10.28
STM	2.02	2.01	1.73	1.73
Eastern Canada				
MET	4.68	3.87	3.79	3.44
STM	5.99	8.78	9.53	10.68
Total MET	51.64	30.45	26.79	41.55
Total STM	58.09	106.22	172.15	208.83
Grand Total	109.73	136.67	198.94	250.38

Note: Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration, Coal Division, International Coal Trade Model.

Table 32. Electricity Demand used by NCM by Federal Region for the Reference Case, 1990-2010

(Billion Kilowatthours)

Federal Region	1990	1995	2000	2005	2010
New England	88.6	88.5	92.2	93.4	103.0
NY/NJ	186.9	187.5	200.4	215.3	238.8
Mid-Atlantic	268.1	286.3	299.6	317.9	351.7
South Atlantic	570.2	620.4	683.0	732.0	798.3
Midwest	505.1	530.1	582.5	641.5	705.6
Southwest	351.6	384.4	425.1	468.3	511.4
Central	134.4	145.7	152.7	167.5	179.3
North Central	83.7	85.9	94.7	102.8	106.1
West	230.7	260.3	286.8	300.6	336.9
Northwest	145.1	159.4	171.8	183.9	198.8
Total	2,564.6	2,748.6	2,988.9	3,223.2	3,530.0

Note: Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration, AEO 1991 Forecasting System run IGMDCA.D0107913.

Table 33. Electricity Demand used by NCM by Federal Region for the High Economic Growth Case, 1990-2010

(Billion Kilowatthours)

Federal Region	1990	1995	2000	2005	2010
New England	88.6	91.1	96.9	100.8	113.1
NY/NJ	186.9	192.0	208.5	217.6	245.3
Mid-Atlantic	268.1	294.8	326.4	366.1	410.3
South Atlantic	570.2	636.5	712.7	779.7	867.8
Midwest	505.1	547.9	615.7	691.1	778.1
Southwest	351.6	395.9	434.5	489.5	541.8
Central	134.4	149.3	159.3	174.8	194.1
North Central	83.7	88.6	99.6	107.9	118.7
West	230.7	268.0	292.7	312.1	359.0
Northwest	145.1	164.5	177.5	195.1	213.7
Total	2,564.6	2,828.8	3,123.9	3,434.7	3,842.0

Note: Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration, AEO 1991 Forecasting System run IGLOCA.D1226901.

Table 34. Electricity Demand used by NCM by Federal Region for the High Oil Price Case, 1990-2010
(Billion Kilowatthours)

Federal Region	1990	1995	2000	2005	2010
New England	88.6	86.2	87.9	86.5	92.2
NY/NJ	186.9	183.1	192.7	210.1	226.9
Mid-Atlantic	268.1	278.5	302.2	323.9	348.1
South Atlantic	570.2	601.4	653.4	706.4	754.1
Midwest	505.1	516.5	566.8	621.5	670.0
Southwest	351.6	372.4	406.8	441.5	472.5
Central	134.4	141.9	153.2	163.4	173.1
North Central	83.7	83.6	90.9	95.6	95.6
West	230.7	252.5	272.6	289.3	315.6
Northwest	145.1	155.4	165.1	173.7	183.2
Total	2,564.6	2,671.4	2,891.8	3,111.9	3,331.4

Note: Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration, AEO 1991 Forecasting System run IGHICA.D0101911.

Table 35. Electricity Demand used by NCM by Federal Region for the Low Oil Price Case, 1990-2010
(Billion Kilowatthours)

Federal Region	1990	1995	2000	2005	2010
New England	88.6	88.5	92.2	93.4	103.0
NY/NJ	186.9	187.5	200.4	215.3	238.8
Mid-Atlantic	268.1	286.3	299.6	317.9	351.7
South Atlantic	570.2	620.4	683.0	732.0	798.3
Midwest	505.1	530.1	582.5	641.5	705.6
Southwest	351.6	384.4	425.1	468.3	511.4
Central	134.4	145.7	152.7	167.5	179.3
North Central	83.7	85.9	94.7	102.8	106.1
West	230.7	260.3	286.8	300.6	336.9
Northwest	145.1	159.4	171.8	183.9	198.8
Total	2,564.6	2,748.6	2,988.6	3,223.2	3,530.0

Note: Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration, AEO 1991 Forecasting System run IGMDCA.D0107913.

Table 36. World Coal Import Demand by ICTM Region and Coal Type for the Reference, High Oil Price, and Low Oil Price Cases, 1995-2010
(Million Short Tons)

	1995	2000	2005	2010
		Steam Coal		
The Americas				
Canada	5.5	8.8	10.3	11.7
U.S. West Coast	0.8	1.2	1.2	1.2
U.S. East Coast	0.6	0.8	1.1	1.5
U.S. South	3.5	4.7	6.6	9.1
Latin America	2.4	4.2	7.7	12.7
Europe				
Northern Europe	101.3	132.6	177.9	217.4
Southern Europe	55.1	70.5	86.6	98.3
Eastern Europe	16.9	20.8	26.3	27.4
Asia	119.3	152.3	183.0	210.9
Total	305.4	396.1	500.8	590.3
		Metallurgical Coal		
The Americas				
Canada	4.6	3.9	3.7	3.4
U.S. West Coast	0.3	0.3	0.3	0.3
U.S. East Coast	0	0	0	0
U.S. South	0	0	0	0
Latin America	13.8	16.0	19.0	20.9
Europe				
Northern Europe	32.3	30.0	28.9	36.8
Southern Europe	23.0	23.8	24.1	26.2
Eastern Europe	23.0	23.0	23.0	23.0
Asia	95.0	89.0	84.2	82.5
Total	192.1	185.9	183.3	193.3

Note: Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration, Coal Division, Coal Division Estimates.

Table 37. World Coal Import Demand by ICTM Region and Coal Type for the High Economic Growth Case, 1995-2010
(Million Short Tons)

	1995	2000	2005	2010
		Steam Coal		
The Americas				
Canada	5.7	9.3	11.0	12.8
U.S. West Coast	0.8	1.2	1.2	1.2
U.S. East Coast	0.6	0.8	1.1	1.5
U.S. South	3.5	4.7	6.6	9.1
Latin America	2.5	4.4	8.3	13.8
Europe				
Northern Europe	104.2	139.1	190.4	237.3
Southern Europe	57.7	76.3	96.7	113.4
Eastern Europe	17.5	22.1	28.7	30.6
Asia	124.8	164.7	204.3	243.2
Total	317.2	422.5	548.3	663.1
		Metallurgical Coal		
The Americas				
Canada	4.8	4.0	4.0	3.7
U.S. West Coast	0.3	0.3	0.3	0.3
U.S. East Coast	0	0	0	0
U.S. South	0	0	0	0
Latin America	14.2	16.8	20.3	22.9
Europe				
Northern Europe	33.2	31.5	30.9	40.2
Southern Europe	24.1	25.7	27.0	30.3
Eastern Europe	23.9	24.5	25.1	25.7
Asia	99.4	96.1	94.0	95.1
Total	199.8	198.9	201.6	218.1

Note: Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration, Coal Division, Coal Division Estimates.

Table 38. Ocean Transportation Rates[a] for the Reference Case, 1995-2010
(1990 Dollars)

Route	1995	2000	2005	2010
U.S. East - Rotterdam	9.04	9.13	9.43	9.60
Australia - Rotterdam[b]	14.84	15.14	16.13	16.74
Colombia - Rotterdam	10.40	10.51	10.87	11.10
South Africa - Rotterdam	11.75	11.92	12.49	13.89
Australia - Japan[c]	12.39	12.49	12.85	13.07
South Africa - Japan	13.97	14.15	14.99	15.18

[a]Rates are for direct shipments of steam coal.
[b]Shipments are from Queensland, Australia.
[c]Shipments are from New South Wales, Australia.
Source: Energy Information Administration, Coal Division, International Coal Trade Model.

Table 39. Ocean Transportation Rates[a] for the High Economic Growth Case, 1995-2010
(1990 Dollars)

Route	1995	2000	2005	2010
U.S. East - Rotterdam	8.75	8.77	8.84	8.94
Australia - Rotterdam[b]	13.89	13.97	14.20	14.49
Colombia - Rotterdam	10.05	10.08	10.15	10.26
South Africa - Rotterdam	11.19	11.24	11.36	11.52
Australia - Japan[c]	12.06	12.08	12.15	12.26
South Africa - Japan	13.35	13.40	13.54	13.72

[a]Rates are for direct shipments of steam coal.
[b]Shipments are from Queensland, Australia.
[c]Shipments are from New South Wales, Australia.
Source: Energy Information Administration, Coal Division, International Coal Trade Model.

Table 40. Ocean Transportation Rates[a] for the High Oil Price Case, 1995-2010
(1990 Dollars)

Route	1995	2000	2005	2010
U.S. East - Rotterdam	9.33	9.45	9.88	10.30
Australia - Rotterdam[b]	15.80	16.25	17.62	19.04
Colombia - Rotterdam	10.76	10.92	11.43	11.94
South Africa - Rotterdam	12.31	12.58	13.39	14.20
Australia - Japan[c]	12.74	12.90	13.40	13.90
South Africa - Japan	14.59	14.88	15.75	16.66

[a]Rates are for direct shipments of steam coal.
[b]Shipments are from Queensland, Australia.
[c]Shipments are from New South Wales, Australia.
Source: Energy Information Administration, Coal Division, International Coal Trade Model.

Table 41. Ocean Transportation Rates[a] for the Low Oil Price Case, 1995-2010
(1990 Dollars)

Route	1995	2000	2005	2010
U.S. East - Rotterdam	8.75	8.77	8.84	8.94
Australia - Rotterdam[b]	13.89	13.97	14.20	14.49
Colombia - Rotterdam	10.05	10.08	10.15	10.26
South Africa - Rotterdam	11.19	11.24	11.36	11.52
Australia - Japan[c]	12.06	12.08	12.15	12.26
South Africa - Japan	13.35	13.40	13.54	13.72

[a]Rates are for direct shipments of steam coal.
[b]Shipments are from Queensland, Australia.
[c]Shipments are from New South Wales, Australia.
Source: Energy Information Administration, Coal Division, International Coal Trade Model.

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6. Electric Power Supply Assumptions

Purpose

This chapter documents inputs to the Electricity Market Module (EMM), the National Utility Financial Statement (NUFS) Model, and the Nonutility Generation Supply (NUGS) Model used to produce electricity forecasts for this year's *AEO*.

Model Description

The EMM forecasts electricity supply and prices and determines the amount of fuel consumed to produce electricity for the 10 Federal Regions through 2010. The EMM is part of an iterative process in which the supply and demand modules of the *AEO* Forecasting System are solved sequentially until prices and quantities for all fuel types converge to an equilibrium. The EMM consists of four major components: the planning component, the operations component, the pricing component, and the demand component.

The planning component performs maintenance scheduling, determines capacity-expansion profiles, and computes fixed capital accounts for generating capacity, transmission, and distribution equipment.

Using fuel prices and demands for electricity from other components of the *AEO* Forecasting System, the operations component allocates the available generating capacity to meet demand. Plant types are ranked in ascending order of their fuel and variable operation and maintenance (O&M) costs and dispatched based on this merit order so that the most economical plants are utilized the most, subject to meeting the constraints imposed by the Clean Air Act Amendments of 1990. Exceptions to this process are the nuclear, hydro, and renewable generating capacities. Dispatching occurs on a seasonal basis to account for variations in such factors as plant availability and demand for electricity. Based on seasonal dispatching decisions, annual generation and fuel requirements are determined. Fuel and O&M expenses are then determined and passed to the pricing component. Fuel consumption is passed to the other supply modules of the *AEO* Forecasting System.

The NUFS Model represents the pricing component of the EMM. The NUFS combines the cost information from the planning and operations components to estimate the average prices of electricity. Other output from the model include forecasts of income statements, balance sheets, sources and uses of funds, revenue requirements, electricity prices, and financial ratios.

The demand component allocates revenue requirements from the pricing component to customer classes to derive end-use sectoral prices. These sectoral prices are passed to the integrating module of the *AEO* Forecasting System, which tests for convergence of all demands and prices.

The Nonutility Generation Supply (NUGS) Model forecasts the electricity produced by industrial and other cogenerators, independent power producers (IPPs), and small power producers (SPPs). It provides projections for capacity, generation, fuel use and costs. The SPP projections for nonutility units using renewable sources are provided exogenously to the NUGS.

The NUGS model first determines the potential supply of electricity from cogenerators (using a database of industrial steam users) and IPPs (using the capital, fuel and O&M costs in the EMM). The units are then prioritized based on a simulation of the Public Utility Regulatory Policies Act (PURPA)[31] bidding process. The NUGS model intercepts the utility capacity expansion choices from the EMM, which are then competed against potential nonutility sources on a unit level by comparing the utility's avoided cost to the nonutility's breakeven price. After the selection process has completed, the sectoral (utility, industrial, and commercial) fuel demands are adjusted and the EMM generation dispatch continues. In addition, electricity demand is adjusted to capture the impacts of self generation from cogenerators and purchased power costs are adjusted in the revenue requirements.

The EMM was previously documented in *Model Documentation: Electricity Market Module*, DOE/EIA-MO01 (Washington, DC, December 1984). The model has been updated and modified since the original documentation was published. The updated EMM is documented in *Electricity Market Module: Overview of Model Methodology and Data Documentation*, March 1989, and *Electricity Market Module: Model Methodology and Data Documentation of the Planning Component*, June 1989, prepared by the Decision Analysis Corporation of Virginia for the Department of Energy (DOE) under Contract Number DE-AC01-87EI-19801, Task 65.

The NUFS is documented in *Documentation of the National Utility Financial Statement (NUFS) Model*, March 1989, prepared by the Decision Analysis Corporation of Virginia for the DOE under Contract Number DE-AC01-87EI-19801, Task 65.

Documentation of the NUGS is provided in *Nonutility Generation Supply Model, Final Documentation*, October 23, 1990, prepared by the Orkand Corporation for the DOE under Contract Number DE-AC01-84-EI19658, Task 90550.

Statement of Exceptions from Model Documentation

For electric utilities, compliance strategies for meeting the provisions of the Clean Air Act (CAA) Amendments of 1990 were determined by the National Coal Model (NCM) and provided as inputs to the Electricity Market Module (EMM). These data include the distribution of coal consumed (by sulfur and Btu content), the distribution of residual fuel oil consumed (by sulfur content), and the amount and cost of pollution control equipment retrofitted on existing units. Inputs from the NCM were also used to represent the regional impacts due to the provision of the CAA Amendments that allows utilities to buy and sell sulfur dioxide emission allowances.

The methodology used to derive sectoral prices was modified in the NUFS. The current methodology attempts to mimic the approaches employed by regulators. That is, the costs of service incurred by the electric utility are allocated to the various customer classes to reflect the costs of rendering the service. This new approach was documented in *Design Considerations for the Implementation of Cost Allocation Techniques to Establish Sectoral Prices Within the EIA Modeling Framework*, November 1988, prepared by the Orkand Corporation for the DOE/EIA.

List of Models

1. AEO Models: EMM, NUFS, and NUGS are the models used to analyze electricity markets in the *AEO* Forecasting System.

2. Inputs from Other Models: The following models provided the listed exogenous forecasts:

[31]PURPA designated certain small power production and cogeneration facilities as qualifying facilities eligible for various benefits.

Model	Inputs to EMM	Archive Tape	Documented
National Coal Model	- Coal Distribution by Sulfur Type - Scrubber Retrofits	NCM90 Available from Malek Mohtadi 254-5371	DOE/EIA-0428(83) DOE/EIA-M027(88)
International Nuclear Model	- Average Annual Regional Nuclear Capacity Factors	INM90 Available from Bill Liggett 254-5508	International Nuclear Model Documentation Volumes 1-3
Levelized Nuclear Fuel Cost Code	- Nuclear Fuel Costs and Reactor Operating Characteristics	PC diskette Available from Diane Jackson 254-5536	MDR/ES/81

Scenarios

Reference Case

The Reference Case assumes no changes to existing laws and regulations. In the electric power sector, the status quo in the legislative and regulatory framework imposed by this assumption affects only the nuclear projections.

Load Characteristics. Seasonal load curves are used to make capacity-dispatch decisions. These load profiles for the 10 Federal Regions were estimated by using hourly load data from 1973 to 1982. Research completed in 1984 found no evidence of changing shapes at the Federal Region level of aggregation (see Trends in Electric Utility Load Duration Curves, Energy Information Administration (EIA)/19635-1). While it is possible that individual utilities have altered the shapes of their load curves using demand-side management programs, these effects are not seen at the Federal Region level.

Capacity Factors for Coal-Fired Plants. In the forecast period, coal-fired plants that have operated with utilization rates above 68 percent in the past are assumed to maintain these rates. The potential maximum utilization rates for all other existing coal-fired plants are assumed to grow to 68 percent by 1995 and to remain constant thereafter. Many units are expected to undergo refurbishment and life extension, which would allow them to achieve the maximum utilization rates of 68 percent.

Capacity Factors for Nuclear Plants. For nuclear units, there are separate capacity factor assumptions for the first fuel cycle and the remaining or equilibrium cycles. The first cycle extends for eight quarters and has an average capacity factor of 60 percent. The average equilibrium cycle capacity factor values are disaggregated by Federal Region. These values result in a U.S. aggregate trend from the current level of about 66 percent in 1990 to 69 percent in 2010. EIA assumes that utilities will continue the recent emphasis on performance. Because of the uncertainty of new orders for nuclear capacity, the incentive to keep plants operating well continues.

Capacity Factors for Renewable Plants. The capacity factors for renewable technologies shown in Table 42 are based on historical performance. For geothermal, wind, and solar thermal technologies, the capacity factors are assumed to improve over time with technological advancement from ongoing research and development.

Table 42. Average Annual Capacity Factors for Renewable Technologies
(Percent)

Technology	1995	2000	2005	2010
Hydroelectric	46	46	46	46
Geothermal	73	79	84	84
Municipal Solid Waste	75	77	78	78
Wood	64	64	64	64
Wind	20	27	28	28
Solar Thermal	24	31	32	32

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Plant Efficiencies. A plant's efficiency is the ratio of energy produced to energy consumed. Efficiencies for existing fossil fuel plants are assumed to be the average of the actual figures from 1982 through 1987. In 1987, the average efficiency of existing coal- and oil-steam plants was 33 percent and the efficiency of gas-steam plants was 32 percent. Assumptions for new generating units in the forecast period are shown in Table 43. The efficiency rate for hydroelectric and other renewable resources is based on energy displaced rather than energy consumed.

Table 43. Efficiency Rates for New Generating Units
(Percent)

Plant Type	Efficiency
Noncoal Fossil-Fired Steam	35
Coal-Fired Steam with Flue Gas Desulfurization	
Bituminous (Low- and Medium-Sulfur)	36
Bituminous (High-Sulfur)	34
Subbituminous (Low-Sulfur)	35
Subbituminous (Medium-Sulfur)	34
Lignite (Low-Sulfur)	33
Lignite (Medium-Sulfur)	34
Combined Cycle	41
Combustion Turbine	25
Nuclear Power	31
Hydroelectric Power and Other Renewable Resources	33
Advanced Coal[a]	43
Advanced Combined Cycle[a]	47

[a]Advanced Coal and Advanced Combined Cycle will be commercially available in 2006. Advanced coal is mainly Integrated Gasification Combined Cycle.

Sources: **Coal-Fired:** Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, estimated from PEI Associates, Inc., "Regionalized Capital, Operating and Maintenance Cost Estimates for Emission Control Equipment Required for New Fossil Steam Power Plants" (November 1985). **Nuclear and Hydroelectric:** Energy Information Administration, *Monthly Energy Review* (June 1988). **Other:** Electric Power Research Institute, *1986 Technical Assessment Guide.*

Renewable Capacity. The renewable capacity is determined exogenously from the EMM and NUGS models. The capacities are provided by technology type, region, ownership category (utility and nonutility), and whether they are announced or projected additions. The announced additions for utility-owned capacity were obtained from Form EIA-860. The announced additions for nonutility-owned capacity were obtained from the North American Electric Reliability Council report *1989 Electricity Supply & Demand for 1989-1998*. The projected capacities for municipal solid waste and wood were obtained from Oak Ridge National Laboratory from work done for the National Energy Strategy. The projected capacity additions, in addition to the announced plans, were based on the National Energy Strategy Fossil 2 Reference Case of July 1990. EIA assumed that the ownership shares of the projected capacity to be the same as the ownership shares of the announced capacity additions. Table 44 shows the projected renewable capacity by technology type and ownership.

Table 44. Projections of Utility and Nonutility Electric Capability for Renewable Technologies (Gigawatts)

	1990		1995		2000		2005		2010	
	Utility	Nonutility	Utility	Nonutility	Utility	Nonutility	Utility	Nonutility	Utility	Nonutility
Hydropower (Conventional)	73.5	2.1	74.6	3.3	74.8	3.5	74.8	3.5	74.8	3.8
Geothermal	1.6	1.0	1.9	1.4	3.1	3.2	4.4	5.2	4.8	5.8
Municipal Solid Waste	0.4	1.7	0.6	3.2	0.6	5.6	0.6	8.2	0.6	10.3
Biofuels-Wood	0.3	5.2	0.3	5.9	0.4	6.7	0.4	7.5	0.5	8.4
Solar Thermal	0.0	0.4	0.0	0.4	0.0	0.4	0.0	0.8	0.1	1.6
Photovoltaic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	2.0	0.0	2.5	0.0	3.4	0.0	4.3	0.0	5.2
Total	75.8	12.5	77.3	16.8	78.8	22.8	80.2	29.5	80.8	34.8

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

The renewable capacity is assumed not to vary across scenarios. The major source of renewable energy for electricity generation is hydroelectric power.

Additions to hydroelectric generating capability have been small during the decade of the 1980's and are not likely to increase significantly in the foreseeable future. Constraints to hydropower's future development stem from the prevailing overlapping regulatory processes, conflicting license and permitting requirements, and disagreements over environmental issues and mitigation requirements. Given this regulatory environment, hydropower projections are assumed not to change due to the changes in economic growth and world oil prices assumed in this report.

The expansion of the remaining renewable resources (geothermal, wind, and solar thermal) are influenced mostly by location of the resource, technological limitations, and tax treatments of various projects. Changes due to economic growth and world oil prices occur only as a second order effect if the cost of producing electricity from conventional energy sources escalated significantly.

Life Extension for Fossil Steam Plants. The following describes the assumptions made to capture the cost and performance impacts of life extension.

- Fossil steam plants with nameplate capacities greater than or equal to 100 megawatts and with no reported retirement dates are considered eligible for life extension. Only plants of 100 megawatts or larger were considered eligible for life extension because economies of scale favor the refurbishment of large generating units.
- Gas- and oil-fired steam plants are only eligible for life extension in the New England, New York/New Jersey, Southwest, and West Federal Regions and in Florida, where these plants account for more than 10 percent of total generation. EIA believed that regions that did not rely heavily on gas or oil generation would find other resource options more economically attractive.
- Two categories of life extension are established. Super-critical units and units currently operated at a capacity factor greater than 35 percent would be fully life-extended while the remaining units would be partially life-extended. Fully life-extended units are assumed to perform as new units. Partially life-

extended units will not be able to perform as new units and their maximum capacity factor will be limited to 40 percent since many of the units currently being used in the cycling mode could not be economically operated as baseload units and utilities are expected to spend less money refurbishing them.

- After 25 years of service, life-extended plants are to be refurbished over 5 years during planned outages.
- The life-extended plants are assumed not to comply with the Revised New Source Performance Standards (RNSPS) because higher costs would occur if RNSPS environmental standards had to be met.

Table 45 shows the capital costs per kilowatt of life extension and Table 46 shows the amount of capacity that results from these assumptions.

Table 45. Capital Costs of Life Extension
(1990 Dollars per Kilowatt)

Fuel Type	Partially Life-Extended	Fully Life-Extended
Coal	94.9	244.1
Gas	49.7	126.6
Oil	66.7	163.9

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

Table 46. Fossil Steam Plant Life Extension, 1991-2010
(Gigawatts)

Status	Capacity
Fully Life-Extended	284.5
Partially Life-Extended	61.5
Total	346.0

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Plant Retirements for Fossil-Fueled Plants. Between 1991 and 2010 retirements from fossil-fueled (coal steam, gas steam, gas/oil steam, gas combined cycle, oil combined cycle, gas turbine, oil turbine, and gas/oil turbine) plants are expected to total 42.6 gigawatts; 10.9 gigawatts have been reported by utilities and EIA assumes that an additional 31.7 gigawatts will be retired over the forecast period (Table 47). Because utilities are only required to report planned retirements for the next 10 years, many planned retirements after 1999 may be as yet unreported. EIA assumes that fossil steam plants with no scheduled retirement date will be retired after 45 years of age if their nameplate capacity is under 100 megawatts. Small fossil-fuel plants were retired after 45 years of service because historical evidence shows that similar plants which have been retired have averaged between 38 and 42 years of age at retirement. Most plants which have already retired were built in the 1940's. Plants built in the 1950's and 1960's are expected to operate slightly longer.

Table 47. Fossil-Fueled Plant Retirements
(Gigawatts)

Plant Type	1991-1995	1996-2000	2001-2005	2006-2010	Total
Steam					
Coal	5.5	5.0	3.1	2.6	16.2
Gas	0.8	0.9	0.9	0.3	2.9
Oil	2.8	1.8	1.2	0.6	6.4
Gas/Oil	3.5	4.6	4.2	2.8	15.1
Combined Cycle	0	0	0	0	0
Turbine	0.3	0.4	1.3	0	2.0
Total	12.9	12.7	10.7	6.3	42.6

Note: The data shown here include those announced retirements reported by utilities and additional retirements expected by Energy Information Administration. Retirements scheduled in December are treated as retiring on January 1 of the following year.
Source: The announced retirements are reported from Form EIA-860, "Annual Electric Generator Report."

Capacity Additions and Retirements for Nuclear Plants. Nuclear capacity does not compete with other generating technologies in the *AEO* modeling system, but rather, operable dates for units under construction or expected to be constructed are individually established and the capacity cumulated over the projection period. Unit operable schedules have been adjusted from utility estimates based on information concerning construction progress and licensing status. The retirement dates are based on an assumed 40-year operating life. This assumption leads to the retirement of 11 units, totaling 5.5 net gigawatts, for the period beginning 1991 through 2010. Four units for which construction has stopped (Grand Gulf 2, Perry 2, Shoreham, and WNP 1) are assumed to not begin operating during the forecast period.

Forty years is the period for which nuclear operating licenses are issued. For early licenses, this period was defined to begin at issuance of the construction permits, and after about 1982, the period was defined to begin at issuance of the operating (low power) license. The NRC has issued a ruling which permits utilities to apply for redefinition of the earlier licenses to match the later license, and approval of this change is almost automatic. EIA has assumed that all unit licenses will be redefined as described for the Reference Case. Other cases assume 50 percent or 70 percent of the units will apply for and receive an additional 20-year extension of their operating license.

Fuel Price Expectations for Life-Cycle Costing. Capacity-expansion projections are based on a life-cycle cost analysis over a 30 year period. Therefore, an evaluation of alternative capacity-expansion profiles through 2010 requires assumptions about fuel prices through 2040. Prices for natural gas and coal are especially important, because these two fuels are expected to represent the primary energy sources for new generation through 2010.

The life-cycle costing methodology requires price expectations for residual oil, distillate oil, natural gas, and coal. Prices for residual fuel oil and distillate fuel in each scenario are assumed to grow at the same rate as the world oil price. Regional natural gas price projections prior to 2010 are assumed to equal the Reference Case prices. After 2010, the regional delivered prices of natural gas to electric utilities are assumed to be a constant multiple of the Reference Case world oil price plus a regional markup. These regional markups vary by the 10 Federal Regions but remain constant throughout the forecast horizon. Between 2000 and 2040 the delivered prices of natural gas in the 10 Federal Regions are assumed to grow at average annual rates ranging from 0.5 percent to 1.0 percent.

Coal Prices obtained from the Coal Supply and Transportation Model (CSTM) are expected to increase due to increased coal production from new mines, and higher fuel costs for transporting coal. The delivered prices of coal are assumed to be the sum of minemouth costs and transportation markups. Between 2000 and 2040 the delivered prices of coal to electric utilities in the Mid-Atlantic, South Atlantic, and Midwest Regions, regions which use substantial amount of coal for electricity generation, are expected to grow at rates ranging from 0.7 percent to 1.0 percent per year.

Capital Costs for Fossil, Nuclear, and Hydroelectric Plants. The capital costs vary by the 10 Federal Regions but stay constant throughout the forecast period. Table 48 shows the capital costs for new generating units built in the Midwest Region, which is considered representative of the national average. These costs represent "overnight" costs, that is, they do not include interest charges. Interest charges are added based on construction profiles, costs of capital, and regulatory policies in the States that make up a particular region. Costs for coal-fired steam plants and combined cycle are obtained from the *Final Report Regionalized Capital, Operating and Maintenance Cost Estimates for Emission Control Equipment Required for New Fossil Steam Power Plants*, April 1984, prepared by the J.A. Reyes Associates, Inc. for the DOE/EIA under Contract Number DE-AC01-81EI11816. Costs for other fossil-fired units and hydroelectric units are derived using the Electric Power Research Institute (EPRI), *Technical Assessment Guide 1986*. The costs for nuclear units currently under construction are taken from utility estimates as reported on Form EIA-254. The cost for a new nuclear plant (Table 48), was developed by Oak Ridge National Laboratory based on estimates by the Department of

Energy, EPRI, and Westinghouse Corporation. The costs are for a single-unit, second generation nuclear plant such as the Westinghouse AP-600 design, with a pre-approved site and pre-approved standardized design.[32]

Table 48. Estimated Overnight Construction Costs for New Generating Units, Midwest Region
(1990 Dollars per Kilowatt)

Type of Generating Capacity	Cost
Oil-Fired Steam	896
Gas-Fired Steam	788
Coal-Fired Steam with Flue Gas Desulfurization	
Bituminous (Low-Sulfur)	1,371
Bituminous (Medium-Sulfur)	1,400
Bituminous (High-Sulfur)	1,446
Subbituminous (Low-Sulfur)	1,414
Subbituminous (Medium-Sulfur)	1,459
Lignite (Low-Sulfur)[a]	1,436
Lignite (Medium-Sulfur)[a]	1,371
Combined Cycle	564
Combustion Turbine (Gas)	327
Combustion Turbine (Distillate)	327
Conventional Hydroelectric	1,020
Pumped Storage Hydroelectric	1,156
Advanced Coal[b]	1,353
Advanced Combined Cycle[b]	559
Nuclear	1,480

[a]Costs for low- and medium-sulfur lignite-fired plants are from Federal Regions 8 and 6, respectively, since Region 5 does not use lignite.
[b]Advanced Coal and Advanced Combined Cycle will be commercially available in 2006. Advanced Coal is mainly Integrated Gasification Combined Cycle.
Sources: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Costs for coal-fired steam units with FGD and combined cycle units are obtained from the *Final Report Regionalized Capital, Operating and Maintenance Cost Estimates for Emission Control Equipment Required for New Fossil Steam Power Plants*, April 1984, prepared by the J.A. Reyes Associates, Inc. for DOE/EIA under Contract Number DE-AC01-81EI11816. Costs for other fossil-fired units and hydroelectric units are estimated from the Electric Power Research Institute, *Technical Assessment Guide 1986*. The nuclear cost is for a single-unit, second generation plant such as the Westinghouse AP-600 design and was developed by the Oak Ridge National Laboratory based on estimates by the Department of Energy, Electric Power Research Institute, and Westinghouse Electric Corporation.

Renewable Technology Cost Assumptions. The cost of renewable sources of electricity is included in the model only to measure contributions to electricity costs, not for economic competition with other technologies. Projections of incremental renewable sources are exogenous to the EMM. Their cost is accounted for in electricity pricing as an operating expense. The annual expense is determined as the amount of renewable generation times a rate equal to the average cost of nonutility generation sold to the grid. The nonutility renewable energy price is assumed to be 33 mills per kilowatthour (1990 dollars).

Non-Fuel O&M Costs for Fossil, Nuclear, and Hydroelectric Plants. Operation costs are expenditures associated with routine functions such as physically operating the facility, security, and purchasing nonfuel

[32]Second generation reactors refer to mid-sized units that incorporate evolutionary changes to current designs and include passively safe design features.

materials. Maintenance costs are costs for preserving the operating efficiency or physical condition of utility plants, such as labor and parts. O&M costs do not vary by the Federal Regions, but remain constant throughout the forecast period. Table 49 presents the O&M costs of new generating units built in the United States. Costs for coal-fired units are obtained from the *Final Report Regionalized Capital, Operating and Maintenance Cost Estimates for Emission Control Equipment Required for New Fossil Steam Power Plants,* April 1984, prepared by the J.A. Reyes Associates, Inc. for the DOE/EIA under Contract Number DE-AC01-81EI11816. Costs for other fossil-fired units and hydroelectric units were derived using the EPRI's *Technical Assessment Guide 1986*. The nuclear O&M costs are based on historical trends from the Federal Energy Regulatory Commission (FERC) Form 1 and the Form EIA-412. The nuclear costs vary by Federal Regions; the costs reported in the table are for Federal Region 5, the Midwest. Nuclear O&M costs are assumed to escalate in real terms by 1.5 percent per year.

Table 49. O&M Costs for Fossil, Nuclear, and Hydroelectric Plants
(1990 Dollars)

Plant Type	Fixed Cost (Dollars per Kilowatt)	Variable Cost (Mills per Kilowatthour)
Coal Steam Without Flue Gas Desulfurization		
Bituminous	16.4	1.7
Subbituminous	16.2	1.1
Lignite	13.1	1.1
Coal Steam With Flue Gas Desulfurization		
Bituminous	29.0	6.7
Subbituminous	28.6	4.2
Lignite	24.0	4.1
Oil-Fired Steam	5.9	5.8
Gas-Fired Steam	5.0	4.8
Combined Cycle	8.0	2.1
Combustion Turbine	0.5	4.8
Poundage Hydroelectric	6.1	1.9
Pumped Storage	5.1	5.1
Advanced Coal[a]	37.0	2.9
Advanced Combined Cycle[a]	8.0	2.1
Nuclear	104.9	0.7

[a]Advanced Coal and Advanced Combined Cycle will be commercially available in 2006. Advanced Coal is mainly Integrated Gasification Combined Cycle.

Sources: Coal steam units are obtained from the *Final Report Regionalized Capital, Operating and Maintenance Cost Estimates for Emission Control Equipment Required for New Fossil Steam Power Plants*, April 1984, prepared by the J.A. Reyes Associates for the DOE/EIA under Contract Number DE-AC01-81EI11816. Other fossil-fired units and hydroelectric units are estimated from the Electric Power Research Institute, *Technical Assessment Guide 1986*. Costs for coal steam plants without FGD were determined using FGD costs from Stearns-Rogers Engineering Corporation, *Economic Evaluation of FGD Systems*, Volume 1, "Throwaway FGD Processes, High- and Low-Sulfur Coal" (Palo Alto, California, December 1983). The nuclear costs are based on historical trends from FERC Form 1 and Form EIA-412.

Post-Operational Capital Costs for Fossil and Hydroelectric Plants. The post-operational capital expenditures are incurred when an existing plant is undergoing life-extension, refurbishment or major repairs. The data were derived from the FERC Form 1 and Form EIA-412 for 1980 through 1987. EIA assumes that the annual post-operational capital costs for coal-fired steam plants in the 10 Federal Regions ranging from \$3.30 per kilowatt to \$19.20 per kilowatt (in 1990 dollars). The post-operational capital costs of hydroelectric plants are assumed to be ranging from \$5.60 per kilowatt to \$22.00 per kilowatt (in 1990 dollars).

Post-Operational Capital Costs for Nuclear Plants. The annual post-operational capital costs for nuclear plants are projected to be \$41 per kilowatt (in 1990 dollars) for the life of each plant throughout the forecast period. The estimate assumes a 1,100 megawatt unit. These costs represent expenditures for major repairs that are recovered through a utility's rate base and are assumed to be depreciated over 15 years. Straight line depreciation is used.

Nuclear Decommissioning Costs. The estimated decommissioning cost for pressurized water reactors is \$264 per kilowatt (in 1990 dollars) and for boiling water reactors is \$245 per kilowatt (in 1990 dollars). The estimates are obtained from the Government Accounting Office, *NRC Cost Estimates Appear Low*, GAO/RCED-88-184.

Nuclear Fuel Costs. The average core-resident fuel costs in 1990 mills per kilowatthour are presented in Table 50.

Table 50. Nuclear Fuel Costs

Year	Mills per kilowatthour
1990	6.7
1995	4.9
2000	5.0
2005	5.1
2010	5.0

Source: Levelized Nuclear Fuel Cost Code, Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Cost of Financing. The nominal cost of capital and the capital structure of investor-owned electric utilities are specified by Federal Region. In 1990, the nominal weighted average cost of debt is estimated to have been 11.1 percent; of preferred equity to have been 9.5 percent; and of common equity, 14.7 percent. Based upon the macroeconomic assumptions discussed above, in 2010 the nominal cost of embedded debt is assumed to be 9.9 percent; of preferred equity to be 9.5 percent; and of common equity, 12.0 percent. The estimated average capital structure for all investor-owned electric utilities was 49.7 percent debt, 8.7 percent preferred, and 41.6 percent common equity in 1990. The cost of financing for publicly-owned electric utilities is assumed to be 7.5 percent in 2010.

Environmental Standards. Utilities are assumed to meet Federal and State laws that control air quality. The Federal air-quality regulations are the New Source Performance Standards (NSPS), the Revised New Source Performance Standards (RNSPS), and the Prevention of Significant Deterioration (PSD) rules and the CAA Amendments of 1990. State air-quality regulations include requirements for construction and operating permits and pollution control statutes that enforce State Implementation Plans (SIP).

NSPS and RNSPS impose emission standards on generating units based on when construction began. These standards limit the emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter from power plants. Pre-NSPS units (those on which construction began before August 18, 1971) are subject only to SIP, which are generally less stringent than NSPS. NSPS units (those on which construction began after August 17, 1971, but before September 19, 1978) must not emit more than 1.2 pounds of SO_2 per million Btu of heat input. RNSPS units (those on which construction began after September 18, 1978) must also meet this limit. In addition, RNSPS requires SO_2 emissions from all new or modified (post-1978) units to be reduced according to the sulfur content of the coal that they burn. Emissions from burning all coals must be reduced by at least 90 percent unless 90-percent removal reduces emissions to less than 0.6 pounds per million Btu. If emissions fall below that level, reductions between 70 and 90 percent are permitted, depending on the sulfur content of the coal. RNSPS for NO_x are complex and, as with NSPS, set limits varying from 0.2 to 0.8 pounds per million Btu, depending on the type of fuel burned and combustion device used. RNSPS for NO_X differ from NSPS in the number of categories of combustion into which they are divided. Individual coal-fired units are classified according to their applicable air quality regulations. Generating units that are subject to the SIP are included among the standards shown in Table 51, based on the emission rates allowed for SO_2.

Table 51. Coal Sulfur Categories Corresponding to State Implementation Plan (SIP) Emission Standards

SIP Emission Standard (pounds SO_2 per million Btu)	Coal Sulfur Category (pounds sulfur per million Btu)
0.68-0.80	0.00-0.40
0.81-1.20	0.41-0.60
1.21-1.66	0.61-0.83
1.67-3.34	0.84-1.67
3.35-5.00	1.68-2.50
Over 5.00	Over 2.50

Source: Energy Information Administration, *Model Description and Formulation, National Coal Model,* DOE/EIA-0428, (Washington, DC, September 1983).

Title IV of the Clean Air Act Amendments (CAA) of 1990, Acid Deposition Control, will have a profound effect upon electricity generation. The industry must now minimize the cost of producing electricity, given sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emission limits. To help incorporate this effect into the forecasts, the NCM was used. The NCM is a linear programming model. By minimizing the cost of producing electricity while meeting specific operational and environmental constraints,[33] it determines supply, demand, and prices in the coal industry and generation, fuel consumption, and capacity expansion in the electric utility industry.

Under the CAA, generating units are allocated permits, or allowances, to emit a specified amount of SO_2 in a given year. Most, but not all, generating units are affected units (i.e., subject to the requirements of the CAA). Therefore, EIA assumes that unaffected generating units will continue to emit at historical levels. When emissions for unaffected units are combined with an estimate of allowances for affected units, an emission limit is established. This limit ranges from approximately 14 million tons of SO_2 in 1995 decreasing to almost 9 million tons in 2010. No allowances are distributed for NO_x emissions. Instead, the intent of the

[33]For a detailed description of the NCM, see Energy Information Administration, *National Coal Model: Executive Summary,* DOE/EIA-0325 (Washington, DC, April 1982).

CAA is that a two million ton reduction in NO_x emissions be achieved by 2000. To do this, EIA assumes that all units will be retrofitted with low NO_x burners at a cost of approximately 4 dollars per kilowatt.[34]

Estimates of allowance banking and the costs of retrofitting units with flue gas desulfurization equipment (scrubbers) are also input into the NCM. EIA assumes that slightly more than 1 million tons of allowances will be banked (saved for later use) between 1995 and 1999.[35] The use of the banked allowances is assumed to be distributed evenly over the period 2000 through 2009. The regional cost of retrofitting units with scrubbers ranges from $190 to $418 (1990 dollars) per kilowatt, with the national average at $264 (1990 dollars) per kilowatt.[36] Almost 143 gigawatts of existing capacity can be retrofitted with scrubbers.[37]

Using these inputs, the NCM determines the amount of capacity that will be retrofitted with scrubbers, the amount of low sulfur coal and oil that will be consumed (Table 52), and the amount of emission trading that will occur. The fuel shares by sulfur content are then input into the EMM. In addition, the revenues and costs of trading allowances (Table 53) and the scrubber and low NO_x burner retrofit costs are input to the NUFS model, which determines electricity prices.

Table 52. Fuel Consumption Shares for Clean Air Act

	1995	2000	2005	2010
Coal Consumption Shares (Percent)				
Low Sulfur	44.1	53.1	55.4	50.5
Mid Sulfur	37.3	33.0	30.1	29.6
High Sulfur	18.6	13.8	14.5	20.0
Oil Consumption Shares (Percent)				
Low Sulfur	72.4	74.7	74.1	100.0
High Sulfur	27.6	25.3	25.9	0.0
Capacity Retrofitted with Scrubbers (Gigawatts)	10.7	13.6	13.7	15.1

Source: Office of Coal, Nuclear, Electric, and Alternate Fuels, National Coal Model, Reference Case--run CAA91.D1219903.

The same methodology was used to incorporate the Clean Air Act into the High Economic Growth and High World Oil Price Cases. The fuel consumption shares, scrubber retrofits, and allowance costs will change because of the variations in economic growth and world oil price, however.

Methodology for Projecting U.S. International Electricity Trade. The majority of U.S. electricity imports are from Canada; these imports vary with economic and hydroelectric conditions, and, in the longer run, are increasing as Canada adds generating capacity for export.

The methodology used to project U.S. international electricity trade is based on projections by those utilities that import or export electricity. The projections include estimates of surplus (interruptible) energy sales and assume normal water conditions and firm power sales based on the continuation of agreements currently in

[34]PEI Associates, Inc., *Development of CERs for Fossil Fuel-Fired Electric Utilities for SO_2 and NO_x Controls*, (Washington, DC, March 1987).

[35]November 16, 1990 facsimile transmission from E.H. Pechan and Associates.

[36]PEI Associates, Inc., *Development of CERs for Fossil Fuel-Fired Electric Utilities for Installation of Limestone Flue Gas Desulfurization, Lime Spray Dryers, and Low Sulfur Coal Combustion*, (Arlington, TX, October 1988).

[37]PEI Associates, Inc., *Development of CERs for Fossil Fuel-Fired Electric Utilities for Installation of Limestone Flue Gas Desulfurization, Lime Spray Dryers, and Low Sulfur Coal Combustion*, (Arlington, TX, October 1988).

Table 53. Costs from Trading Allowances
(Million 1990 Dollars)

	1995	2000	2005	2010
New England	0	46	40	-27
New York/ New Jersey	0	35	74	-23
Mid Atlantic	0	552	458	519
South Atlantic	0	-12	15	-37
Midwest	0	-73	-77	119
Southwest	0	-231	-237	-263
Central	0	-134	-40	-19
North Central	0	-104	-146	-168
West	0	-80	-77	-94
Northwest	0	1	-9	-9
United States	0	0	0	0

Note: A negative cost indicates that the region is a net seller of allowances.
Source: Office of Coal, Nuclear, Electric, and Alternate Fuels, National Coal Model, Reference Case--run CAA91.D1219903.

place or proposed by utilities. The information on future trade ranges from specific amounts under contract to projections of trends. In the post-2000 period, proposed agreements were incorporated in the forecast based upon the progress of current negotiations. The individual utility projections were aggregated to Federal regions; they were discussed with both Canadian and U.S. utilities and the Department of Energy's Office of Fuels Programs.

High Oil Price Case

Nuclear Plant Life Extension. The nuclear capacity projection for the High Oil Price Case does not change from the Reference Case through 2000. However, in the High Oil Price case, EIA assumes that the Nuclear Regulatory Commission (NRC) finalizes a ruling that establishes procedures by which utilities may apply for a renewal of a nuclear unit's original or revised 40-year license term for up to 20 years. On this basis, EIA assumes that after 2000, 50 percent of all existing units will be life-extended for 20 years from the original retirement dates assumed in the Reference Case. The decision on plant life extension for any individual unit is determined by ranking all units based on a set of weighted selection criteria.[38] Based on these criteria, the units for which the operating license would have expired during the projection period, but are assumed to be life-extended are: Haddam Neck, Ginna, Dresden 2, Point Beach 1 and Millstone 1. However, 6 units totaling 2.6 net gigawatts are retired in the period from 1991 through 2010.

High Economic Growth Case

Nuclear Plant Life Extension and New Nuclear Orders. In this case, it is assumed that the NRC issues a final rule on license renewal and the following barriers to a resumption of nuclear orders are removed: 1) public concerns about operational safety; 2) public concerns about the disposal of nuclear waste; 3) uncertainty in licensing and regulatory processes; and 4) uncertainty about performance, economics, and financial risk. Based on these assumptions, in each year from 2006 through 2010, two new 600 megawatts second generation reactors begin operation. The same ranking approach for life extension was used in this case as for the High Oil Price Case. However, it was assumed that 70 percent of all existing units are life-extended for 20 years. For the period covered by the projection, the units life-extended are, coincidentally, the same as those in the High Oil Price Case. Consequently, the retired capacity is the same as that in the High Oil price Case.

[38]Decision Analysis Corporation of Virginia, Nuclear Plant Life Extension, Contract No. DE-AC01-87EI19801, Vienna, Virginia, September 28, 1990.

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Appendix

Summary of Model Documentation

Model	Documentation
Intermediate Future Forecasting System (IFFS)	*Model Documentation of the Integrating Module of the Intermediate Future Forecasting System,* DOE/EIA-M023(91) (forthcoming).
Demand Evaluation Modeling System (DEMS)	*DEMS Integrating Module,* vol.1, *System Documentation,* vol. 2, *Program Source Code,* vol. 3, *Bridging Ratios* (forthcoming).
Oil Market Simulation Model (OMS)	*Oil Market Simulation User's Manual* DOE/EIA-M028(90).
Macroeconomic Model (PCMAC)	PC-AEO Forecasting Model for the *Annual Energy Outlook 1990,* DOE/EIA-M036(90), and Technical Notes.
Residential Energy End-Use Model	PC-AEO Forecasting Model for the *Annual Energy Outlook 1990,* DOE/EIA-M036(90), and Technical Notes.
Building Energy End-Use Model	PC-AEO Forecasting Model for the *Annual Energy Outlook 1990,* DOE/EIA-M036(90), and Technical Notes.
Industrial Energy Demand Model	PC-AEO Forecasting Model for the *Annual Energy Outlook 1990,* DOE/EIA-M036(90), and Technical Notes.
Transportation Energy Demand Model	PC-AEO Forecasting Model for the *Annual Energy Outlook 1990,* DOE/EIA-M036(90), and Technical Notes.
Oil Market Model (OMM)	*Model Documentation Report, The Oil Market Module,* September 1990.
Gas Analysis Modeling System (GAMS)	*Model Documentation of the Gas Analysis Modeling System,* DOE/EIA-0450(91).
Crude Oil Supply (PROLOG)	*Model Methodology and Data Description of the Production of Onshore Lower 48 Oil and Gas Model,* DOE/EIA-M034(91).
Coal Supply and Transportation Model (CSTM)	*Coal Supply and Transportation Model (CSTM) Description,* DOE/EIA-M022 (June 1987).
Resource Allocation and Mine Costing Model (RAMC)	*Documentation of Resource Allocation and Mine Costing (RAMC) Model, Methodology Description,* DOE/EIA-M021(87).

International Coal Trade Model (ICTM)	*International Coal Trade Model Version 2 (ICTM-2) User's Guide*, DOE/EIA-M026(88).
National Coal Model (NCM)	*National Coal Model Description and Formulation*, DOE/EIA-0428(83) and *National Coal Model Versions 6 and 7 User's Manual*, DOE/EIA-M027(88).
Electricity Market Module (EMM)	*Electricity Market Module: Overview of Model Methodology and Data Documentation*, March 1989, *Electricity Market Module: Model Methodology and Data Documentation of the Planning Component*, June 1989, and *Model Documentation: Electricity Market Module*, December 1984.
National Utility Financial Statement (NUFS) Model	*Documentation of the National Utility Financial Statement (NUFS) Model*, March 1989.
Nonutility Generation Supply (NUGS) Model	*Nonutility Generation Supply Model, Final Documentation*, October 1990.
Market Penetration Model for Dispersed Renewable Technologies	*Market Penetration Model for Dispersed Renewable Technologies*, August 1990.

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