DOE/EIA-0383(84)

ANNUAL ENERGY OUTLOOK 1984

With Projections to 1995

Energy Information Administration
Washington, D.C.

Published:
January 1985

MARK R.

This publication is available from the Superintendent of Documents, U.S. Government Printing Office (GPO). Ordering information and purchase of this and other Energy Information Administration (EIA) publications may be obtained from the GPO or the EIA's National Energy Information Center (NEIC). Questions on energy statistics should be directed to the NEIC. Addresses and telephone numbers appear below. An order form is enclosed for your convenience.

National Energy Information Center, EI-20
Energy Information Administration
Forrestal Building
Room 1F-048
Washington, D.C. 20585
(202) 252-8800

Superintendent of Documents
U.S. Government Printing Office
Washington, D.C. 20402
(202) 783-3238

Released for Printing January 18, 1985

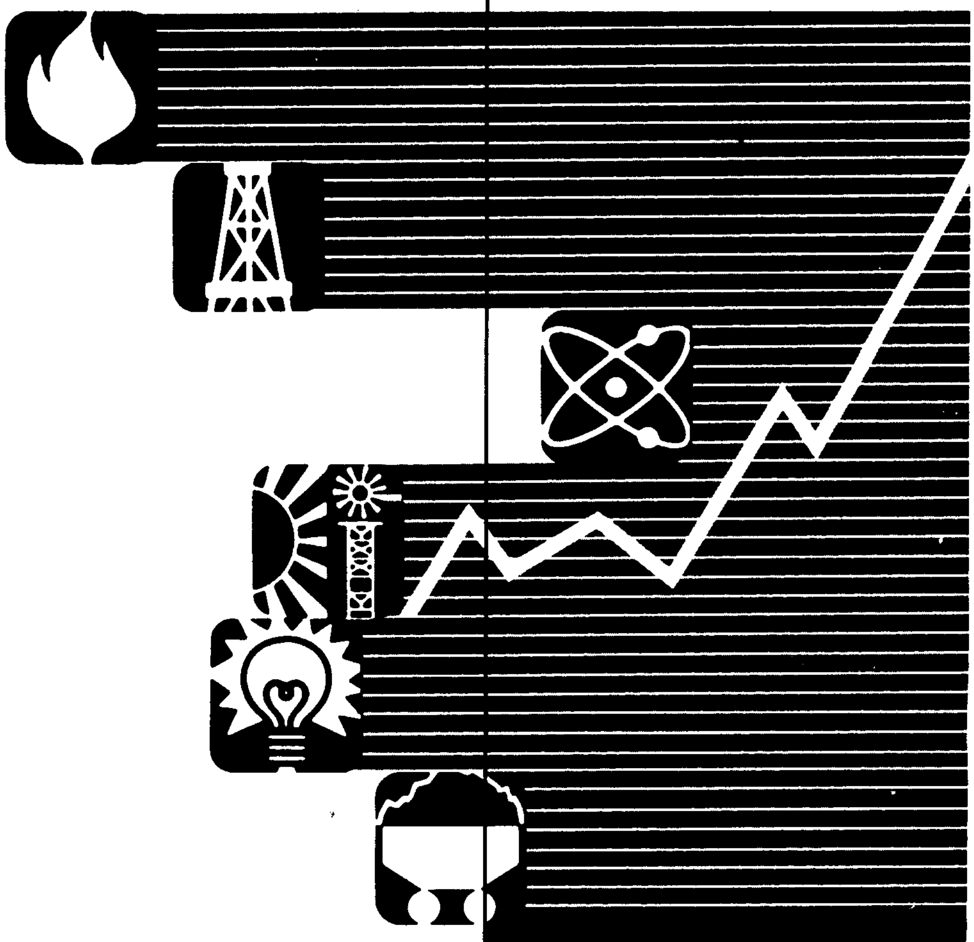
Energy Information Administration
Office of Energy Markets
and End Use
U.S. Department of Energy
Washington, DC 20585

ANNUAL ENERGY OUTLOOK 1984

With Projections to 1995

DOE/EIA-0383(84)
Distribution Category UC-98

Published:
January 1985



This report was prepared by the Energy Information Administration, the independent statistical and analytical agency within the Department of Energy. The information contained herein should not be construed as advocating or necessarily reflecting any policy position of the Department of Energy or any other organization.

Preface

The Annual Energy Outlook analyzes the issues and economic events that may affect the Nation's energy future. This report is published yearly by the Energy Information Administration (EIA) and provides projections through 1995 of the consumption, supply, and prices of energy, by fuel and end-use sector. Members of Congress, the Administration, and the public use this information. This report is the third edition of the Annual Energy Outlook. Previous projections were published in Volume 3 of the EIA Annual Report to Congress.

While this publication concentrates on intermediate energy forecasts, it also includes some discussion of the short-term outlook. More detailed analyses of projections for the short run are provided in EIA's quarterly Short-Term Energy Outlook, issued every January, April, July, and October. Each issue of that publication presents updated projections of energy production, consumption, and prices for five to six quarters.

This report was produced by the Energy Analysis and Forecasting Division in the Office of Energy Markets and End Use (EMEU), in cooperation with the other EIA offices. The International and Contingency Information Division of EMEU contributed the analysis on international energy markets. The discussion about energy and the economy was provided by the Economics and Statistics Division of EMEU. The analysis of petroleum and natural gas was provided by the Office of Oil and Gas. The coal, nuclear, and electric utility analyses were provided by the analysis and forecasting branches of the Coal, Nuclear, Electric, and Alternate Fuels Office.

Models maintained by EIA are used as tools for recording and exploring the implications of stated assumptions and analytical judgments. The value of a modeling framework lies in the speed and convenience of performing numerical calculations, and in the documentation and reproducibility of results. Resulting projections are, therefore, sophisticated opinions representing a set of potential outcomes based on the specified assumptions, and are selected to illustrate possible future trends in energy markets and the factors underlying those trends.

This year's projections were produced using the Intermediate Future Forecasting System (IFFS) together with the Gas Analysis Modeling System (GAMS). The supply and demand projections in this volume refer primarily to a base case scenario, which is based on middle economic growth and world oil price assumptions. Additional supply and demand sensitivity cases are discussed for all fuels, based on the effects of low and high economic growth rates and low and high world oil prices, in addition to other special cases. The detailed supply and disposition tables for the base and sensitivity cases are shown in Appendices A through E. Documentation of the models used to generate these projections and copies of the computer programs are available through the National Technical Information Service. Contact the Energy Information Adminstration, Office of Statistical Standards (202/252-2396) for details on obtaining this information.

Contents

Tables

Figures

Executive Summary

This year's Annual Energy Outlook contains a range of projections of energy supply, demand, and prices annually for 1985 through 1990 and for 1995. These projections are based on explicit assumptions about economic growth and world oil prices as well as implicit assumptions that are embodied in the representations of energy markets used to generate the projections. Both the structure of these energy models and the values assigned to specific variables represent assumptions about how energy supply, demand, and prices are expected to respond to changes in the market environment. To the extent possible, the representations of energy markets are based on analyses of historical data. However, even when historical patterns of response are well understood, developing projections of future events requires assumptions about whether past relationships can be expected to continue.

Models maintained by the Energy Information Administration are used as tools for recording and exploring the implications of such assumptions and analytical judgments. The value of a modeling framework lies in the speed and convenience of performing numerical calculations, and in the documentation and reproducibility of results. Resulting projections only represent a set of potential outcomes based on the specified assumptions and judgments contained therein, and are selected to illustrate possible future trends in energy markets and the factors underlying those trends. The most important message such projections convey is that other outcomes are likely if the underlying assumptions are changed.

The models used in this analysis employ two types of assumptions as the basis for making projections. The first type comprises exogenous assumptions about factors outside the scope of the energy models. These include assumptions about economic growth rates and world oil prices. The second type of assumption is used in selecting coefficients employed in the models to relate the exogenous assumptions to the energy projections. The coefficients include such factors as costs of drilling for oil and natural gas and rates of energy use per square foot in buildings. Where possible these coefficients are based on an analysis of historic behavior, but nevertheless represent the implicit assumption that historical behavior as represented in the model will continue into the future or will change at predictable rates. The effects of these two types of assumptions are examined in the text. Chapter 2 examines the effects of changing assumptions about economic growth rates and Chapter 3 examines the effects of changes in world oil prices. The remaining chapters examine the effects of changing assumptions about coefficients that are felt to be particularly uncertain.

Detailed discussions of the major factors that influence energy markets are presented in each chapter to examine the major uncertainties associated with energy supply, demand, and price projections between 1985 and 1995. Variations in the assumed rate of economic growth directly affect the demand for all fuels and energy sources; forecasts based on different assumed rates of economic growth thus provide a range of results for energy supply and demand. Different assumptions about world oil prices, which have a significant impact on oil supply, demand, and prices but a relatively smaller impact on the markets for other fuels, are also discussed in this report.

The major cases examined in this report are the high, middle, and low economic growth cases, which all assume the middle world oil price, and the low and high world oil price cases, which assume the middle economic growth rate (see Table ES1). The middle economic growth and middle world oil price assumptions form the base case. Although the five basic scenarios differ only in terms of assumptions about economic growth and world oil prices, many other factors are also uncertain and important to the future of energy markets. Quantitative examinations of the uncertainty around many of these other factors allow the reader to assess the effects of changing assumptions on the energy projections. Unless otherwise noted, all prices are stated in terms of 1984 dollars.

Table ES1. Scenarios Examined in 1984 Annual Energy Outlook

	Economic Growth Assumption (Average Annual GNP Growth Between 1985 and 1990)		
World Oil Price Assumption (1990 Price in 1984 dollars per barrel)	Low (2.1%)	Middle (3.1%)	High (3.9%)
Low ($25.00)		X	
Middle ($30.00)	X	X[a]	X
High ($40.00)		X	

X = The scenario considered.
[a]Denotes the base case scenario.

Forecasts become increasingly uncertain as they extend further into the future. Thus, results through 1990 are emphasized in this report. Possible trends after 1990 are interesting but very uncertain. The discussion of energy markets in 1995 concentrates on analysis of uncertainties and possible alternative outcomes.

Highlights

Between 1985 and 1990 the base case projections show no dramatic change in the U.S. energy situation. Alternative assumptions produce relatively small changes in results for 1990. Between 1990 and 1995, the base case projections for U.S. energy supply and demand still exhibit stability, but with some assumed increases in real world oil prices and increased dependence on petroleum imports. Under different assumptions about factors affecting oil supply and demand, the results for energy markets after 1990 vary widely. Under one set of assumptions, the 1990's would be characterized by continued stability, sustained domestic production and modest growth in demand. Under other assumptions, supplies of oil could tighten relative to demand, leading to increasing prices and increased dependence on petroleum imports by 1995. By 1990, net imports of crude oil and petroleum products to the United States are projected to be about one and one-half times the 1983 level, and by 1995 net imports in the base case are projected to be about twice the 1983 level, or about the same as the import level in 1978. These increases in imports are estimated to result equally from projected increases in oil consumption and projected declines in domestic production.

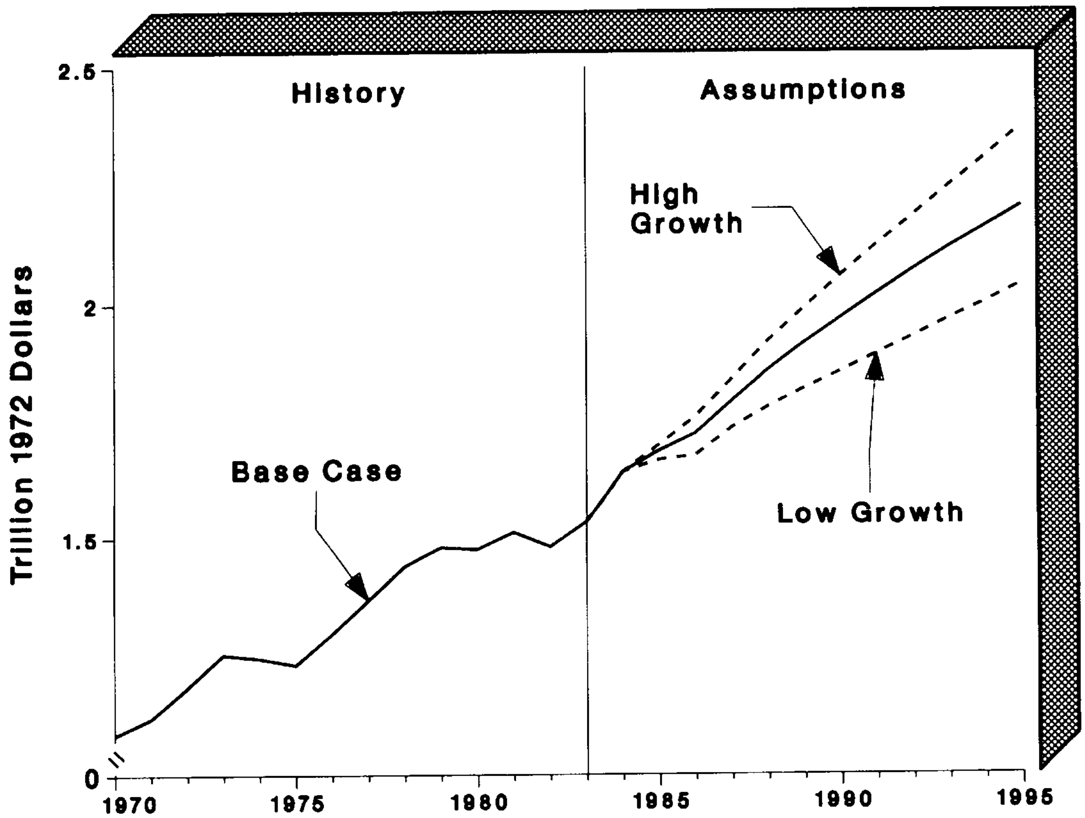
Energy demand in the base case is projected to rise at about two-thirds the rate of increase in the real gross national product (GNP) throughout the forecast period. Real crude oil prices are assumed to decline through 1985, remain about constant between 1986 and 1987, and return by 1990 to approximately the level prevailing in 1984. After 1990, real crude oil prices in the base case are assumed to increase again. Unlike crude oil price changes during recent years which were abrupt and large, the price changes assumed in the base case are relatively smooth and gradual. Recent declines in the oil price substantiate the view that the world petroleum market is becoming determined more by market conditions and less by OPEC strategies. Real natural gas prices are projected to remain about constant through 1986 and then increase gradually through 1990. After 1990 natural gas prices become quite uncertain, and depending on what is assumed about factors affecting supply and demand, the rise in natural gas prices could range from moderate to substantial. Real electricity prices are projected to decline slightly throughout the forecast period as a result of stable coal prices and relatively smaller capital cost additions to rate bases for power plant construction than experienced in the recent past.

Economic and International Assumptions

Economic growth is assumed to be fairly rapid in the near term, and then taper off significantly in the latter half of the forecast period. Between 1985 and 1990, real GNP in the base case is assumed to grow by 3.1 percent per year, but between 1990 and 1995 this rate is assumed to slow to an average of 2.3 percent per year (Figure ES1). These growth rates, derived from the economic forecasts from Data Resources, Incorporated, are assumed to be sustained by strong investment demand from the business sector, a resurgence of growth in manufacturing, and a stable housing market. Inflation is not expected to increase significantly, long-term interest rates gradually decline, and the dollar exchange rate adjusts downward gradually to forestall further deterioration in the real U.S. trade balance with the rest of the world. The effects of more modest and more vigorous levels of economic growth on energy markets are discussed in Chapter 2.

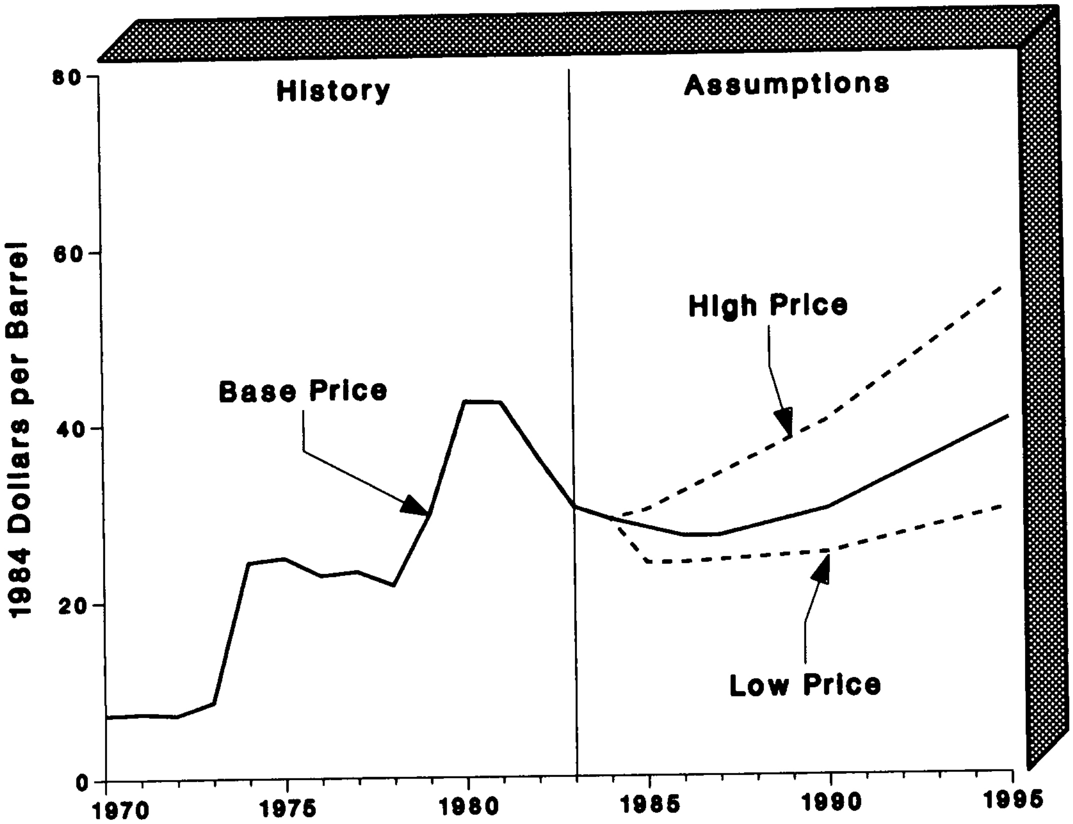
In real terms, oil prices to much of the world have risen since 1981, even though they have fallen to the United States, because of the increasing value of the U.S. dollar. Higher prices have been one cause of lower levels of petroleum consumption worldwide. The near-term decline in oil prices in the United States, however, is expected to contribute to increasing petroleum consumption and, thus, the need for petroleum imports. If this response is experienced worldwide, increasing pressure on oil production capacity is assumed to cause the real price of crude oil to return to $30 per barrel (1984 dollars) in 1990 and increase further to $40 per barrel (1984 dollars) in 1995 (Figure ES2). Despite increasing pressure on OPEC productive capacity after 1990, the crude oil price assumed in 1995 (when measured in real terms) is no greater than the 1980 price, and is about $12 per barrel lower in real terms than the level assumed for 1995 in last year's report. Alternative views of trends in conservation and oil supply lead to lower or higher assumed prices for the world price of crude oil, ranging from $25 per barrel to $40 per barrel in 1990 and $30 per barrel to $55 per barrel in 1995 (Figure ES2).

Figure ES1. Alternative Economic Growth Paths for Real GNP, 1970-1995



Source: • History: U.S. Department of Commerce, Bureau of Economic Analysis, Survey of Current Business (Washington, DC, July 1970-1984).
• Assumptions: Appendices A, B, C; Tables A19, B19, C19.

Figure ES2. World Oil Prices, 1970-1995



Note: All prices are the cost of crude oil to U.S. refiners.

Source: • History: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) and Monthly Energy Review, DOE/EIA-0035(84/06) (Washington, DC, 1984). • Assumptions: Table 12.

Energy Consumption

The outlook for U.S. energy consumption depends strongly on assumed growth rates in the economy, assumed levels of future world oil prices, and other factors such as energy conservation trends. Under a range of assumptions of lower and higher economic growth, aggregate energy demand could range from 81 quadrillion Btu to 86 quadrillion Btu in 1990 (Table ES3). Uncertainty about aggregate energy demand in 1995 is greater (Table ES4); low and high economic growth assumptions lead to a range of 86 and 95 quadrillion Btu in 1995. In general, it is estimated that for each 10-percent increase in real GNP by 1990, petroleum demand could increase by 8 percent, natural gas demand could increase by 6.9 percent, coal demand could increase by 7.5 percent, and electricity demand could increase by 8.0 percent. The overall increase in aggregate energy consumption as a result of a 10-percent increase in real GNP could be about 6.6 percent.

Future levels of petroleum demand are also affected by assumptions about the world oil price. Aggregate petroleum demand in 1990 could range from 15.8 million barrels per day to 17.2 million barrels per day, using the high and low assumptions for world oil prices. Petroleum demand in 1995 shows a wider range, from 16.4 to 19.3 million barrels per day. For each 10-percent increase in the real world oil price by 1990, aggregate petroleum demand is estimated to decrease by about 0.5 million barrels per day.

Using the base case assumptions for world oil prices and economic growth, U.S. energy consumption is projected to rise from an estimated 76 quadrillion Btu in 1985 to 84 quadrillion Btu in 1990 and to 90 quadrillion Btu in 1995 (Tables ES2, ES3, and ES4). Gross energy consumption in units of thousand Btu per 1972 dollar of GNP is projected to decrease uniformly from 45 in 1985 to 42 in 1990 and 41 in 1995, compared to 59 in 1973 (see Table 3, Chapter 2 for a comparison across all cases). This drop represents a projected decline in energy consumption per dollar of GNP between 1985 and 1990 of 1.0 percent per year, a slower rate than the 3.3-percent decline experienced from 1978 to 1983. For the 10-year period from 1985 to 1995, energy consumption per dollar of GNP is projected to decline at 0.9 percent per year in the base case. This slower projected decline is attributed to three factors: the drop in world oil prices that began in 1981, which is assumed to continue through 1987; the renewed strength in energy-intensive industries; and the strong trend toward electrification of end-use energy consumption which increases the energy intensity of the economy because of large energy losses involved in electricity generation. Different assumptions about conservation and growth of energy intensive industries could produce a decline in energy consumption per dollar of GNP between 1985 and 1995 closer to 2 percent per year.

Under the base case assumptions, most of the increase in total energy consumption is projected in the commercial and industrial sectors. Energy consumption growth in the residential and transportation sectors is projected to be modest. Between 1985 and 1990:

Table ES2. Energy Projections for the Economic and World Oil Price Scenarios, 1985

Fuel	Base Case[a]	Economic Growth Case Low	Economic Growth Case High	World Oil Price Case Low	World Oil Price Case High
Oil			(million barrels per day)		
Total Consumption	15.77	15.55	15.90	15.97	15.67
Motor Gasoline Consumption	6.67	6.56	6.72	6.74	6.61
Distillate Consumption	2.77	2.74	2.80	2.81	2.76
Residual Fuel Oil Consumption	1.35	1.38	1.40	1.40	1.39
Domestic Production	11.09	11.09	11.09	11.09	11.09
Net Imports (including SPR)	4.85	4.63	4.99	5.06	4.76
			(1984 dollars per barrel)		
World Oil Price	$28.00	$28.00	$28.00	$24.00	$30.00
Natural Gas			(trillion cubic feet)		
Total End-Use Consumption	18.22	18.22	18.22	18.22	18.22
Dry Gas Production	17.48	17.48	17.48	17.48	17.48
Net Imports	0.99	0.99	0.99	0.99	0.99
			(1984 dollars per thousand cubic feet)		
Average Wellhead Price	$ 2.67	$ 2.67	$ 2.67	$ 2.67	$ 2.67
Electricity			(billion kilowatthours)		
Generation	2,492	2,492	2,492	2,492	2,492
			(quadrillion Btu)		
Sales	7.92	7.92	7.92	7.92	7.92
			(1984 dollars per million Btu)		
Electricity Price (average)	$18.82	$18.82	$18.82	$18.72	$18.87
Coal			(million short tons)		
Production	899	899	899	899	899
Total End-Use Consumption	843	843	843	843	843
			(1984 dollars per short ton)		
Delivered Price to Electric Utilities	$38.54	$38.54	$38.54	$38.54	$38.55
			(quadrillion Btu)		
Total Energy Consumption	75.7	75.3	76.0	76.1	75.5
Economic Assumption			(compound rate)		
GNP Growth Between 1984-1985	2.7%	1.5%	3.5%	2.7%	2.7%
			(thousand Btu per 1972 dollars)		
Gross Energy Use per Dollar of GNP ...	44.9	45.2	44.7	45.1	44.8

[a] Assumes middle economic growth rate and middle world oil price.

Table ES3. Energy Projections for the Economic and World Oil Price Scenarios, 1990

Fuel	Base Case[a]	Economic Growth Case Low	Economic Growth Case High	World Oil Price Case Low	World Oil Price Case High
Oil					
			(million barrels per day)		
Total Consumption	16.74	16.12	17.34	17.24	15.83
Motor Gasoline Consumption	6.21	6.07	6.34	6.41	5.88
Distillate Consumption	3.19	3.06	3.30	3.28	3.01
Residual Fuel Oil Consumption	1.56	1.41	1.70	1.64	1.36
Domestic Production	10.34	10.27	10.41	9.89	10.96
Net Imports (including SPR)	6.59	6.03	7.16	7.56	5.04
			(1984 dollars per barrel)		
World Oil Price	$30.00	$30.00	$30.00	$25.00	$40.00
Natural Gas					
			(trillion cubic feet)		
Total End-Use Consumption	18.76	18.02	19.39	18.82	18.79
Dry Gas Production	17.32	16.65	17.81	17.27	17.46
Net Imports	1.57	1.57	1.57	1.51	1.57
			(1984 dollars per thousand cubic feet)		
Average Wellhead Price	$ 3.52	$ 3.32	$ 3.71	$ 3.53	$ 3.58
Electricity			(billion kilowatthours)		
Generation	2,927	2,808	3,033	2,943	2,897
			(quadrillion Btu)		
Sales	9.34	8.96	9.68	9.40	9.24
			(1984 dollars per million Btu)		
Electricity Price (average)	$18.62	$18.70	$18.63	$18.50	$18.86
Coal					
			(million short tons)		
Production	1,057	1,019	1,086	1,060	1,048
Total End-Use Consumption	958	922	986	961	950
			(1984 dollars per short ton)		
Delivered Price to Electric Utilities	$40.24	$39.79	$40.55	$40.27	$40.14
			(quadrillion Btu)		
Total Energy Consumption	83.5	80.6	86.0	84.6	81.5
Economic Assumption			(compound rate)		
GNP Growth Between 1985-1990	3.1%	2.1%	3.9%	3.3%	2.8%
			(thousand Btu per 1972 dollars)		
Gross Energy Use per dollar of GNP ...	42.4	43.5	41.8	42.7	42.0

[a]Assumes middle economic growth rate and middle world oil price.

Table ES4. Energy Projections for the Economic and World Oil Price Scenarios, 1995

Fuel	Base Case[a]	Economic Growth Case Low	Economic Growth Case High	World Oil Price Case Low	World Oil Price Case High
Oil			(million barrels per day)		
Total Consumption	18.00	16.80	20.04	19.25	16.36
Motor Gasoline Consumption	6.16	5.91	6.48	6.62	5.50
Distillate Consumption	3.66	3.40	3.97	3.87	3.42
Residual Fuel Oil Consumption	1.93	1.57	2.91	2.30	1.49
Domestic Production	9.40	9.31	9.53	7.61	11.18
Net Imports (including SPR)	8.65	7.52	10.62	11.74	5.21
			(1984 dollars per barrel)		
World Oil Price	$40.00	$40.00	$40.00	$30.00	$55.00
Natural Gas			(trillion cubic feet)		
Total End-Use Consumption	18.75	18.10	18.29	18.54	18.82
Dry Gas Production	16.39	16.04	16.27	16.05	16.78
Net Imports	2.11	2.11	2.03	1.97	2.11
			(1984 dollars per thousand cubic feet)		
Average Wellhead Price	$ 5.05	$ 4.42	$ 6.12	$ 5.01	$ 4.92
Electricity			(billion kilowatthours)		
Generation	3,401	3,221	3,606	3,459	3,318
			(quadrillion Btu)		
Sales	10.86	10.29	11.52	11.04	10.59
			(1984 dollars per million Btu)		
Electricity Price (average)	$18.30	$17.88	$19.05	$17.97	$18.44
Coal			(million short tons)		
Production	1,110	1,172	1,259	1,234	1,202
Total End-Use Consumption	1,110	1,060	1,148	1,122	1,091
			(1984 dollars per short ton)		
Delivered Price to Electric Utilities	$42.87	$42.32	$43.26	$43.00	$42.64
			(quadrillion Btu)		
Total Energy Consumption	90.1	85.8	94.9	92.8	86.4
Economic Assumption			(compound rate)		
GNP Growth Between 1990-1995	2.3%	1.9%	2.9%	2.4%	2.2%
			(thousand Btu per 1972 dollars)		
Gross Energy Use per Dollar of GNP	40.9	42.1	40.0	41.6	39.9

[a]Assumes middle economic growth rate and middle world oil price.

- Residential energy consumption growth is projected to be modest, due to the slow expected growth in the housing stock. Electricity consumption is projected to grow more rapidly than the demand for all fuels in the residential sector as a result of the sustained penetration of the electric heat pump in the heating market and growth of households in the South and West where electric air-conditioning use is a major factor.

- Energy demand in the commercial sector is projected to grow faster than any other sector except the industrial sector as a result of the assumed increase in commercial sector floor space of 2.6 percent per year between 1985 and 1990. As in the residential sector, electricity is projected to provide an increasing share of total energy use in this sector.

- Energy use in the industrial sector is projected to grow faster than any other sector. This growth is attributable to the relatively high, assumed growth in output in manufacturing between 1985 and 1990, including many energy-intensive industries.

- Transportation sector energy use is projected to remain about constant between 1985 and 1990. Gasoline consumption is expected to fall by about 1.5 percent per year because the improvement in the average miles per gallon of fuel used by the fleet is forecast to more than offset the increase in vehicle-miles traveled. Assumed rapid growth in the use of diesel fuel in the light truck fleet leads to a projected average annual growth of 3.6 percent in diesel fuel consumption over this period.

In addition to the level of economic activity and world oil prices, two other factors responsible for much of the uncertainty in the levels of energy consumption are:

- Conservation behavior--Continued energy savings could result in lower levels of energy consumption and production.

- Energy demand in the industrial sector--Energy demand could change as a result of structural changes.

Future trends in energy conservation are highly uncertain, and expert opinion varies widely on several issues, including: the length of time over which changes in energy consumption, as a result of energy price increases of the late 1970's, will continue to occur; and the degree to which behavioral changes may be reversed with lower energy prices. This uncertainty is heightened by the lack of reliable, recent data on industrial energy use. Because most forecasters failed to anticipate the extent to which energy consumption would fall in the early 1980's, a high conservation case illustrates potential market developments in the event that the base case underestimates the extent of conservation. The high conservation case assumes that the rapid trends in energy conservation during the 1970's will continue during the forecast period regardless of projected energy prices. This case results in a projection of total end-use energy consumption almost 10 percent below the base case level in 1995, with oil consumption, by assumption, decreased more than any other energy source (Table ES5).

Another key factor affecting energy demand is the mix of output in the U.S. industry. Much of the decline in the economy's energy consumption per dollar of GNP that occurred between 1973 and 1983 can be traced to the relatively slow growth of energy-intensive industries after 1974. (The aggregate relationship between energy consumption and GNP is discussed in Chapters 2 and 4). The base case assumes substantial growth of many of the energy-intensive industries, while the structural change case assumes a continuation of the downward trends of the late 1970's. In the base case the Chemical industry (SIC-28), which experienced a 2.6 percent a year growth rate between 1974 and 1983, is assumed to grow by 5.6 percent per year between 1985 and 1990 and by 4.3 percent per year between 1990 and 1995. The Stone, Clay, and Glass industry (SIC-32), which experienced a 0.8 percent per year increase in output between 1974 and 1983, is assumed to grow by 4.5 percent per year between 1985 and 1990 and 2.3 percent per year between 1990 and 1995. The Basic Metal industry (SIC-33), which experienced a 4.0 percent per year decrease in output between 1974 and 1983, is assumed to grow by 4.7 percent per year between 1985 and 1990 and by 1.5 percent per year between 1990 and 1995. These industries are the largest industrial consumers of energy in the United States. If the trends of the 1970's away from energy-intensive manufacturing do continue through 1995, industrial sector energy use is projected to be 3 percent lower in 1995 than the base case level.

Petroleum

Petroleum forecasts are heavily influenced by assumptions about both world oil prices and economic growth. Compared to last year's forecasts, real world oil prices in the base case are assumed to be $7 per barrel lower in 1990 and $12 per barrel lower in 1995, and the average annual rate of economic growth over the forecast period is slightly higher. This year's lower world oil price assumption resulted from the assumed increase in OPEC capacity and lower demand for OPEC oil relative to last year's assumptions. Higher assumed economic growth than in the base case could increase petroleum demand to 17.3 million barrels per day by 1990, and lower assumed economic growth could result in a petroleum demand of 16.1 million barrels per day, compared with a base case forecast for petroleum demand in 1990 of 16.7 million barrels per day. Because variations in the assumed level of economic growth have little impact on total petroleum supply, net petroleum imports in the high and low economic growth cases are projected to be 0.6 million barrels per day higher and lower, respectively, than the base case level of 6.6 million barrels per day in 1990.

Holding economic growth rates at the base case level but varying the assumed world oil price results in ranges of projections for domestic production and net imports that are considerably greater than in the high and low economic growth cases. Total domestic petroleum production, for example, is projected to vary by 1.0 million barrels per day in 1990 from the low to the high world oil price cases; whereas altering economic growth rates varies domestic production in 1990 by only 0.1 million barrels per day. The low and high world oil price cases imply a range in net petroleum imports in 1990 of between 7.6 million barrels per day in the low price case to 5.0 million barrels per day in the high price case.

Table ES5. Sensitivity of U.S. Energy Production and Imports to Production and Conservation Assumptions, 1995[a]

Assumptions	1990 Production Case Low	1990 Production Case Base	1990 Production Case High	1995 Production Case Low	1995 Production Case Base	1995 Production Case High
High and Low Supply						
Petroleum Production (million barrels per day)	7.2	8.3	8.9	5.3	7.5	10.6
Natural Gas Production (trillion cubic feet)	16.7	17.3	17.6	14.4	16.4	17.6
Net Petroleum Imports (million barrels per day)	7.7	6.6	6.0	10.9	8.7	5.6

Assumptions	1990 Conservation Case Base	1990 Conservation Case High	1995 Conservation Case Base	1995 Conservation Case High
High Conservation				
Petroleum Consumption (million barrels per day)	16.7	15.7[b]	18.0[b]	15.8[b]
Net Petroleum Imports (million barrels per day)	6.6	5.6[b]	8.7	6.5[b]
Natural Gas Consumption (trillion cubic feet)	18.8	18.2[b]	18.8	17.7[b]
Nonutility Coal Consumption (million short tons)	153	149	159	148
Electricity Consumption (billion kilowatthours)	2,738	2,670	3,182	2,978

[a]Values are estimated based upon independent sensitivity analyses referenced in Appendices F and G.

[b]Estimated and does not include effects of changes in electric utility petroleum consumption.

The base case projection for petroleum reflects a decrease in domestic production and increases in consumption and imports between 1985 and 1990. Petroleum consumption in the base case is projected to increase to 16.7 million barrels per day by 1990, with increases expected for most major petroleum products, especially for middle distillates and liquefied petroleum gases. Gasoline consumption is projected to decrease gradually between 1985 and 1990. Domestic production of crude oil (including natural gas liquids and processing gain) is projected to fall from

11.1 million barrels per day in 1985 to 10.3 million barrels per day in 1990, despite significant new contributions from the Arctic, the Outer Continental Shelf, and from enhanced oil recovery technologies. The combination of declining production and increasing consumption results in a projected increase in net imports in the base case from 4.9 million barrels per day in 1985 to 6.6 million barrels per day by 1990 (Tables ES2 and ES3). Throughout the forecast period, the domestic refining industry is projected to undergo substantial adjustment to changes in overall product demands and the changing quality of available crude oil feedstocks.

Between 1990 and 1995 the outlook for oil supply and demand becomes very uncertain. Under high and low world oil price assumptions, oil consumption in 1995 could range from 16.4 to 19.3 million barrels per day, and domestic production could range from 7.6 to 11.2 million barrels per day. Net oil imports could range from 5.2 to 11.7 million barrels per day in 1995. Lower domestic oil production in 1995, compared to 1990, could result from a substantial drop-off in Alaskan production, but that decline might be offset by a number of other developments. High and low world oil prices are not the only sources of this uncertainty. Even under base case oil price assumptions, higher or lower assumed costs for drilling and production could have a major impact on petroleum supply and imports.

Modifying variables directly related to the production process results in significant variations in projections of domestic crude oil production. Despite the stability of U.S. oil production over the last few years, future costs and supply levels cannot be forecast with precision. As proved reserves are depleted, new discoveries and reserve additions are needed. The level of additions is dependent on a number of factors, including geology and the quality of new discoveries, finding rates, the remaining amount of undiscovered resources, costs of drilling and equipment, and investment criteria.

To illustrate the degree of uncertainty in projecting U.S. oil supply, high and low supply cases were generated by shifting the finding rates, rates of equipment cost increases, and investment criteria from the base case levels. The world oil price was assumed to remain at the base case level across all these cases. In the high supply case, domestic oil production in 1995 is projected to be about 40 percent higher than the base case level. Conversely, the low supply case forecasts a level of domestic petroleum production of 5.3 million barrels per day in 1995, or 30 percent below the base case level (Table ES5).

These forecasts are based on the assumption that the world oil market will not experience large, abrupt price changes during the next 10 years. The assumption of a smooth, gradual rise in oil prices over the forecast period is based on the assumed return to relative calm in events affecting world oil markets, although the potential instability of oil markets cannot be ignored. The actual path of oil prices could be more erratic than the base case assumptions.

If there were a serious disruption to world oil supplies, the world oil price could rise significantly. How much prices might deviate from assumed trends would depend on the size of an interruption, its duration, and the response of oil consumption, production, and inventories in the United States and other countries. In the short run, a temporary increase in the price of oil would reduce oil consumption in the United States and, for a time, depress levels of economic activity. A permanent loss of economic well-being could occur because of the lost output during the initial years after the disruption and the lower level of investment and resulting capital stock during subsequent years. Over the longer term, such an incident would reinforce public uncertainty about the availability of energy supplies at stable prices and could give additional stimulus to conservation efforts and synthetic fuels development.

Other issues that are not examined but are nevertheless important to the petroleum industry include:

- Leasing--Land withdrawals and slower paced leasing by the Department of the Interior, moratoria on the leasing of certain Federal lands by the U.S. Congress, and lengthy court challenges to petroleum exploration and development could result in a reduction of the present expansion of crude oil production from Federal lands.

- Petroleum taxes--The 99th Congress is expected to consider legislation that would place a tax on petroleum production or consumption, initiatives that could represent a reduction in net return on petroleum investment and, thus, reduce future production potential.

- Environmental regulations--Additional environmental regulatory actions relating to both production processes and to standards for leaded gasoline could lead to higher prices and lower energy consumption.

Natural Gas

Little change is expected in natural gas markets between 1985 and 1990. Modest increases in the cost of finding new gas reserves cause small price increases in the base case with virtually constant gas production. The small projected increase (0.5 trillion cubic feet between 1985 and 1990) in gas demand is expected to be met through an assumed increase in natural gas imports from Canada. Higher and lower economic growth assumptions cause gas consumption in 1990 to range from 18.0 to 19.4 trillion cubic feet, around a base case level of 18.8 trillion cubic feet. Varying world oil price and economic assumptions has only a negligible effect on the projected price of natural gas in 1990.

By 1995, on the other hand, the outlook for natural gas prices is very sensitive to assumptions about economic growth. Increases in natural gas demand are expected to result in higher levels of cumulative extraction by 1995, with depletion of the relatively inexpensive reserves, and thus higher replacement costs of natural gas. Real natural gas wellhead prices in 1995 are projected to be about $4.40 per thousand cubic feet in the low economic growth case, and $6.10 per thousand cubic feet in the high economic growth case, compared to $5.10 per thousand cubic feet in the base case. Increasing the rate of economic growth leads to higher projected consumption of natural gas in the 1980's. As a result, low-cost gas reserves are depleted earlier, prices of natural gas are higher by 1995 than they would be under lower rates of economic growth, and natural gas consumption is lower. The price effects thus are projected to offset the income effects in determining natural gas demand under alternative economic growth cases.

The effect of oil prices on the natural gas market is even more complex. Higher world oil prices raise fuel oil prices and lead to slightly higher natural gas consumption in the electric utility and industrial sectors because, even in the low oil price case, natural gas remains less expensive than oil for most users capable of switching between the two fuels. However, higher oil prices also raise domestic oil production and, as a result, associated natural gas production. This expected increase in associated natural gas production (which is based on historical experience) is projected to keep pace with the increased demand for natural gas and, as a result, the wellhead price of natural gas is expected to remain about the same in the two cases. If, as is argued by some analysts, industrial natural gas demand rises due to fuel switching from petroleum to natural gas, then the additional demand response to higher world oil prices might increase natural gas prices more than shown in this analysis.

Natural gas prices in the base case are expected to remain stable through 1986 and then gradually increase through the remainder of the decade. Under base case assumptions, the average wellhead price of natural gas is projected to increase in real terms by about 6 percent per year between 1985 and 1990, while delivered prices to consumers are forecast to increase by only 4 percent per year. Higher rates of increase in prices are projected to occur between 1990 and 1995, when less expensive, more accessible natural gas reserves become increasingly scarce. The price of natural gas is projected to remain below a level competitive with oil prices until near the end of the forecast period, when some utilities are predicted to begin switching from natural gas to oil.

Consumption of natural gas in the base case is expected to increase modestly from 18.2 trillion cubic feet in 1985 to 18.8 trillion cubic feet in 1990 and then remain at that level through 1995. In contrast, domestic production is projected to be 17.5 trillion cubic feet in 1985, peak at 17.6 trillion cubic feet in 1988, and then decline to 16.4 trillion cubic feet in 1995. These trends accommodate a projected increase of natural gas imports over the forecast period to meet projected demand.

Greater reliance on the market in some aspects of natural gas production and transmission has resulted from a combination of partial decontrol of wellhead prices, recent decisions by the Federal Energy Regulatory Commission, and several court decisions. However, these factors have been accompanied by additional uncertainties about the future of natural gas markets, especially by 1995. Two important additional issues facing natural gas markets over the next 10 years are:

- Drilling costs--Higher or lower drilling cost and finding rates could affect the projections for natural gas supply, demand, and price.

- Imports--Different policies of the Canadian Government could have an impact on aggregate U.S. natural gas supplies and prices.

Significant variations in the projections of domestic natural gas production result from modifying assumptions about several factors, including geology, costs of finding and producing natural gas, and investment criteria. These uncertainties are greatest at the end of the forecast horizon. Assuming favorable supply conditions over the forecast period results in a projection of domestic natural gas production that is 7 percent higher than the base case estimate in 1995 and wellhead prices that are about 23 percent lower than the base case projection in 1995. The low supply case for 1995 results in domestic natural gas production estimates that are 12 percent lower and wellhead natural gas prices that are about 40 percent higher than the base case projections. This variation in prices differs markedly from that between the high and low oil supply cases where the oil price was assumed not to vary, because this price is set more by OPEC than by domestic market forces. Natural gas prices are more determined by internal supply and demand conditions, although Canadian imports also have an impact.

Higher or lower imports of natural gas from Canada could have a significant impact on natural gas markets in the United States, particularly for regions of the country that are close to Canadian sources. In the base case projections, imports of natural gas are assumed to increase steadily from about 0.9 trillion cubic feet in 1983 to 2.1 trillion cubic feet by 1995. If low imports of 1.3 trillion cubic feet are assumed for 1995, domestic wellhead prices are projected to be about 14 percent higher than the base case projections because marginal domestic reserves that are more expensive must be used to meet demand. In the high imports case, where natural gas imports are assumed to increase to 2.7 trillion cubic feet in 1995, wellhead natural gas prices are projected to be about 9 percent lower than the base case level, as imported natural gas replaces some of the more expensive domestic production.

Electric Power

Between 1985 and 1990, electricity generation in the base case is projected to increase by 3.3 percent per year, somewhat higher than the assumed growth of 3.1 percent per year for real GNP. Over the range of alternative economic growth cases, annual electricity generation growth between 1985 and 1990 could be as low as 2.4 percent or as high as 4.0 percent. Across the range of generation projections, ample reserve margins are projected to continue through 1990, without new capacity additions beyond those already under construction. By 1990, completion of construction projects now underway will allow the share of coal in electricity generation to remain at 55 percent. Nuclear power is projected to increase its share from 14 percent of total generation in 1984 to 20 percent in 1990.

Meeting projected growth in electricity demand after 1990 may require continued capacity expansion. Between 1985 and 1995, electricity generation in the base case is projected to increase by 3.2 percent per year, somewhat higher than the assumed growth of 2.7 percent per year for real GNP. Over the range of alternative economic growth cases, annual electricity growth between 1985 and 1995 could be as low as 2.6 percent or as high as 3.8 percent. In the base case, electricity demand growth is expected to be accompanied by the construction of 106 gigawatts of new generating capacity, resulting in almost 800 gigawatts of total capacity by 1995. This construction program represents a 15-percent increase in capacity. The combination of the projected growth in electricity demand and generating capacity is expected to result in an aggregate national reserve margin of 27 percent by 1995, about half its 1983 value. The reserve margin calculations used in this analysis are based on nameplate capacity and regional coincidental peak load data, rather than the lower net dependable capacity and higher noncoincidental peak load data used by some industry sources.

The base case results show an improved outlook for the financial condition of electric utilities; based on growth in sales and reduced construction programs, utilities are projected to have less need for external financing. Reducing construction programs is projected to result in the increased use of existing capacity and increased consumption of high-cost fuels (oil and natural gas) during the 1990's. However, coal and nuclear power are projected to remain the dominant sources for electricity generation throughout the forecast period. Average electricity prices are projected to decline slightly (by 0.2 percent per year) in real terms between 1985 and 1990. Declines in electricity prices may be slightly more rapid after 1990, as a result of the growth in the demand for electricity, the completion of utility construction programs, and relatively stable fuel prices. Despite the improved outlook, electric utilities continue to study the need for additional cancellations and delays of nuclear and coal-fired power plants, actions that may affect these projections.

The base case projections yield a ratio of electricity growth to real GNP growth of 1.2. If electricity and GNP are assumed to grow at the same rate, total generation is projected to be 2 percent lower than the base case level in 1990 and 4 percent lower than the base case level in 1995, reducing the need for new capacity as well as the use of oil and natural gas capacity. Compared to the base case, oil- and gas-fired generation would be 6 percent lower in 1990 and 15 percent lower in 1995.

Issues regarding the future adequacy of generating capacity, the reliability of power generation, and the financial strength of the electric utility industry include:

- Completion of existing construction projects--Rising costs, demand growth uncertainty, and public concerns regarding safety and environmental issues could affect current construction programs and the ability of the industry to provide sufficient capacity to meet demand reliably and economically.

- Inclusion of Construction Work in Progress (CWIP) in the rate base--The addition of CWIP in the rate base or other regulatory changes designed to affect utility financial conditions could change electricity prices and demand growth.

- Alternative sources of electricity--Alternative sources of power such as imports, cogeneration, and small power production not owned by domestic utilities could provide reliable, least-cost alternatives to generation from utility-owned, conventional central stations.

To examine the impacts of plant cancellations on the electric power industry, based on an evaluation of the construction stage and financing of each project, a case was examined that assumed that an additional 17 gigawatts of coal-fired and nuclear-powered capacity would be delayed or cancelled. In order to maintain a national aggregate reserve margin of at least 15 percent in all regions in this case, additional new capacity would be needed, ranging from 2 gigawatts if low economic growth is assumed to 8 gigawatts under high economic growth conditions in 1995.

Nationally, about 15 percent of Construction Work in Progress (CWIP) is allowed in the rate base. If 100 percent of CWIP were allowed to enter the rate base as the cost is incurred (rather than waiting until a plant is "used or useful," which generally has been the regulatory policy), electricity prices are projected to increase by 4 percent in 1986 over the base case level, resulting in a decline of 0.4 percent in electricity demand from the base level. By 1995, electricty demand is projected to be 0.2 percent below the base case level, with prices converging to base case levels by 1995.

For all nuclear units under construction at the beginning of 1983, the estimated average cost (in nominal dollars) at completion is assumed to be about $2,300 per kilowatt in the base case. To determine the impact of higher nuclear construction costs on electricity prices, the base case average cost was assumed to increase by about 10 percent, to about $2,500 per kilowatt of projected installed capacity. This increase coincides with a real escalation rate of 11 percent and is applied to the remaining portion of all nuclear units under construction at the beginning of 1983.

The impact of this assumed increase in nuclear construction costs depends on the projected completion date of each unit and the ratio of the book value of the nuclear additions to the book value of the assets of all the utilities. The biggest impacts of higher nuclear construction costs are projected to occur in the Northwest and New England regions, where average electricity prices are projected to be about 2 percent higher than in the base case in 1995. In all other regions and nationwide, prices are projected to be less than 1 percent higher than in the base case. For certain utility service areas (those with high-cost nuclear construction projects), the increase in electricity prices would be expected to be much greater.

Coal

Since the oil embargo of 1973, coal generally has been considered the energy resource of the future. Based on the trend toward electricity generation from coal, coal is projected to supply 26 percent of primary energy consumption by 1995. Recoverable U.S. coal reserves are estimated to be 245 billion short tons, which is equivalent to more than 76 times total U.S. energy consumption in 1983. The higher economic growth case shows coal production 3.1 percent higher than the base case level in 1995 (up by 38 million short tons), while production in the lower economic growth case is 4.0 percent lower than the base case level (down by 49 million short tons). This variation is considerably less than the variation in economic activity because much coal is used for baseload electric generation, which is relatively insensitive to economic conditions. The amount of available coal-fired generating capacity is the major determinant of coal use in electric generation, and different rates of economic growth cause only a slight variation in coal-fired generating capacity (2 gigawatts) over the 10-year forecast period due to lengthy plant construction leadtimes (typically 8 years for a coal plant).

In the base case, coal production is projected to increase by more than 17 percent between 1985 and 1990 and by more than one-third between 1985 and 1995. From about 900 million short tons in 1985, coal production is projected to increase to 1.1 billion short tons in 1990 and to over 1.2 billion short tons in 1995 (a rate of 3.1 percent per year over the 10-year period); this level of production is slightly higher than last year's EIA forecast. The average annual rate of growth in Western production (west of the Mississippi River) is projected to exceed the growth rate in Eastern production by 1.6 percentage points over the 10 year forecast period.

In the base case, coal consumption is projected to increase by 2.6 percent per year from 1985 to 1990, reaching about 960 million short tons in 1990. By 1995 coal consumption may reach 1.1 billion short tons. The electric utility sector is the largest consumer of coal (projected to be 84 percent of total coal use in 1990), followed by the industrial sector (9 percent). U.S. coal exports are projected to reach 91 million short tons by 1990 and 106 million short tons by 1995. This projected level of exports is much lower than was expected a few years ago because of a reduction in world coal trade and the growing competitive edge realized by foreign coal producers in the cost of mining and transporting coal.

Uncertainties regarding the development of future coal production are centered on the following:

- Environmental issues--Changing regulations and environmental costs could affect the level of coal consumption (issues discussed in the electricity section).

- Railroad deregulation--Deregulation could affect coal transportation rates, consumption, and production.

Although coal remains the least expensive fossil fuel on a Btu-equivalent basis, its delivered price (in real terms) to utilities increased by about 17 percent over the past 10 years. Almost all of this increase was due to increases in transportation fees as real minemouth prices decreased over this period. To capture the uncertainty in future coal transportation rates due to deregulation and the impact of the Staggers Rail Act of 1980, two alternative cases were considered: one in which the increase in rail rates by 1995 is about triple the 20-percent increase assumed in the base case, and the other in which rail rates are assumed to increase by only 6 percent in real terms. In the high rail rate case, western mines are projected to decrease their production by 8 million short tons in 1995, and eastern mines are projected to increase their production by 5 million short tons. The difference in eastern/western coal tonnage is attributable to the difference in Btu content of the coal located in these two areas.

Closing

The overall thrust of the base case forecast (which uses the middle assumptions for world oil prices and economic growth) is that little change is projected through 1990 in the U.S. energy situation. With declining oil prices assumed until late in the decade, gradual increases in oil consumption and somewhat smaller decreases in domestic oil production are projected to lead to oil imports in 1990 that are fifty percent higher than their current level. Natural gas demand is projected to increase slightly, accompanied by real price increases to ultimate consumers of about 4 percent per year between 1985 and 1990. Coal consumption is projected to continue to grow with stable prices. Significant projected increases in electricity demand can be met easily with current and planned capacity, with little change in the shares of various fuels used to generate electricity and a slight decline in electricity prices.

After 1990, the nature of the base case projections changes. By 1995, an increased reliance on energy imports is projected, and electric utilities are projected to make increasing use of oil-fired capacity. However, forecasts this far in the future are extremely uncertain. Different assumptions about world oil prices and economic growth imply very different trends in the 1990's, ranging from continuation of the situation projected through 1990 to even tighter supplies relative to demand. In addition to examining the implications of a range of assumptions about these factors, this report examines a number of other issues that create uncertainty about the energy outlook. This examination suggests that two sets of assumptions are primarily responsible for the trend projected through 1995:

- Assumed drilling costs and finding rates have a major effect on the supply of oil and natural gas.

- Demand growth rates embody conservation assumptions that strongly affect future demand levels.

With more optimistic assumptions about oil and natural gas supply or energy conservation, the dramatic increases forecasted for energy imports and the increased use of oil at electric utilities disappear. The results from the base cases and the sensitivity cases lead to a wide range of possible paths by 1995 for energy markets in the future. Events over the next decade will determine which of these paths energy supply and demand will take.

Beyond 1995, there are opportunities for the introduction of new technologies that could influence the outlook for energy supply and demand. Advances in the technology for oil and gas exploration and development under extreme conditions, for example, would permit additional expansion in frontier areas. Also, greater efficiency in delivered energy services such as heat and steam would enhance conservation gains. Although each of these advances requires a considerable lead time for efficient research, development, and market penetration, they have the potential to radically alter the supply demand balance beyond the horizon of these forecasts.

1. Introduction

This is the third Annual Energy Outlook and the ninth annual energy forecast published by the Energy Information Administration and its predecessor agencies. This report presents projections of energy supply, consumption, and prices through 1995 and examines both domestic and international energy markets.

Chapter 2 provides a comprehensive discussion of the base case energy forecast through 1995 and examines the sensitivity of the forecast to different assumed levels of economic growth. This range of energy forecasts underscores the uncertainty of these projections and provides the reader with an outlook of the possible direction of energy markets. Most of the base case discussion is concentrated in Chapter 2, leaving the following chapters to examine specific sensitivity cases, discuss important issues, and provide necessary background information.

Chapter 3 analyzes the international context in which domestic markets may be expected to operate through 1995 and examines the effect of higher and lower world oil price assumptions on the energy markets. The interaction between energy markets and the economy is described in Chapter 4. The forecasts of total energy consumption and end-use energy consumption by sector are provided in Chapter 5. Chapters 6, 7, and 8 explore forecasts and issues of energy supply, covering oil and natural gas, electric utilities and nuclear power, and coal. The results of sensitivity cases examining different aspects of the fuel-specific markets are also discussed in these chapters. Finally, Chapter 9 compares this forecast with other published energy forecasts as well as those from the Annual Energy Outlook, 1983. Seven appendices provide detailed results of different scenarios, a discussion of forecasting methodology and assumptions, and a description of the sensitivity cases.

The main purpose of this report is to outline the most likely energy situation in the midterm future between 1985 and 1995. Some discussion of short-term trends also is included. This report uses the results for 1984 and 1985 published in the October 1984 Short-Term Energy Outlook, which contains more detailed energy projections through 1985. All estimates, assumptions, and data were finalized using August and September 1984 values, which may have been revised slightly. For more recent estimates of data for 1983 and 1984, the reader is referred to the Monthly Energy Review or related source publications. All prices are expressed in 1984 dollars, unless otherwise noted.

The projections and data in this volume are documented in three major sources: 1) Appendices A through F in this report contain the five base case projections, 2) Appendix G describes the sensitivity cases and the location of the results, and 3) individual references identify sources for data not shown in the appendices. Projections for total energy, petroleum, natural gas, electricity, coal, and all energy prices are provided in Appendices A through E. In these appendices, Tables 1 through 3 show information on total energy supply and disposition. Tables 4 and 6 through 9 provide projections on energy consumption by sector. Tables 10 through 14 contain the electric power projections. Table 15 provides a supply and disposition balance for petroleum. Table 18 contains the coal supply and disposition balance, and Table 19 summarizes the major assumptions. Tables 5, 16, and 17 show the energy price projections.

The sources of data used for the projections are footnoted in each table. In general, limitations in the quality or coverage of the data are documented in publications or technical reports cited in the table footnotes. In cases where no reports are cited, the user is referred to the model documentation reports cited in Appendix F. Appendix G lists the names of the sensitivity cases and describes the process for obtaining the results of these analyses.

2. Base Case Outlook

This chapter presents the base case forecast for energy demand, supply, and prices through 1995 and discusses the effects of higher and lower levels of economic growth on energy markets. The energy outlook is necessarily influenced by recent changes in the world situation and domestic energy markets, and some of these changes are reflected in differences between this report and the Annual Energy Outlook, 1983.

The projected level of oil imports over the forecast period has been revised upward substantially from the base case forecast presented in the Annual Energy Outlook, 1983. This increase results from higher estimates of petroleum demand, based on the assumptions of lower world oil prices and higher economic growth rates, as well as from lower projected levels of domestic production. Another change is in the projection for the price of natural gas, which has been revised downward significantly from the forecast published last year. This revision is based on recent evidence that the price of natural gas, despite contract provisions, has adjusted to market conditions.

In past years, each chapter of this report included a discussion of the base case projection. An important change this year is the unified base case discussion in this chapter, which provides the reader with an overall picture of the projections. The base case discussion is presented in seven sections: world oil prices, the economy, energy consumption, and the markets for petroleum, natural gas, electricity and nuclear power, and coal. The first two sections discuss the base case assumptions for world oil prices and economic growth that are used for all base case projections. In previous years, higher and lower assumptions for the world oil prices were used to generate a range of energy projections around the base case levels. This year, the high and low cases are based on different assumptions about the future rate of economic growth, the major determinant of overall energy demand. The high and low projections discussed in this chapter thus represent a wide range of uncertainty in the energy projections. This approach was selected because, although certain parts of the economy and energy markets are very sensitive to changes in the world oil price, economic growth more directly affects all aspects of energy markets and thus results in a broader range of results for comparison. Cases examining the effects of higher and lower world oil price assumptions are discussed in the following chapters.

The energy consumption section begins with an overview of the base case projection of total U.S. energy demand and then discusses the projections by end-use sector. The last four sections present the outlook for fuel supplies and electric power, first reviewing the base case projection and then summarizing the sensitivity of these forecasts to higher and lower assumptions for economic growth. Because supporting details for the base case forecasts are covered in Chapters 3 through 8, the reader is often referred to the appropriate chapter.

This report focuses on the years 1985 through 1995, referred to as the forecast period. In most cases, the last year of complete data is 1983, with 1984 data being a combination of history and projections. To the extent that data are available for 1984, this information is reflected in the figures and tables. Readers interested in energy markets over the short term are referred to the

October 1984 Short-Term Energy Outlook,[1] which presents a more detailed picture of energy supply and demand through 1985. The 1985 forecasts in this Outlook were used as the beginning point for the longer term projections presented in this report, resulting in a consistent series of energy projections through 1995.

The analyses presented in this volume are based on a wide variety of assumptions that are combined to represent an assessment of future energy possibilities. The projections are not meant to be statements about what will happen in energy markets, but rather descriptions of a likely future based on data and experience at the time of the analysis. As with any attempt to foresee future events, these projections are surrounded by much uncertainty. In many cases, the results are particularly sensitive to the input assumptions (which are detailed in Appendix F). Chapter 2 discusses the possible range of results based on higher and lower rates of economic growth. Chapters 3 through 8 examine the effects of other possible developments, based on analyses of specific uncertainties in the individual energy markets. Areas of uncertainty include the future level of world oil prices, the level of energy conservation, the possibilities for fuel switching, and others. (The sensitivity cases examined in this report are listed in Appendix G.) Unless otherwise stated, all prices in this report are expressed in 1984 dollars. Although projections are presented for the years 1985 through 1995, the discussion of base case results concentrates on the year 1990. Any forecast becomes increasingly uncertain as its horizon is increased, and beyond 1990 the range of uncertainty about these projections encompasses a wide range of possibilities. The discussion of 1995 focuses on potential alternative outcomes and the factors underlying projected trends rather than on detailed analysis of base case results.

This year's Annual Energy Outlook contains a range of projections of energy supply, demand, and prices annually for 1985 through 1990 and for 1995. These projections are based on explicit assumptions about economic growth and world oil prices and other implicit assumptions that are embodied in the representations of energy markets used to generate the projections. Both the structure of these energy models and the values assigned to specific variables represent changes in the market environment. To the extend possible, the representations of energy markets are based on analyses of historical data. However, even when historical patterns of response are well understood, developing projections of future events requires assumptions about whether past relationships can be expected to continue.

Models maintained by the Energy Information Administration are used as tools for recording and exploring the implications of such assumptions and analytical judgments. The value of a modeling framework lies in the speed and convenience of performing numerical calculations, and in the documentation and reproducibility of results. Resulting projections only represent a set of potential outcomes based on the specified assumptions, and are selected to illustrate possible future trends in energy markets and the factors underlying those trends. The most important message such projections convey is that other outcomes are likely if underlying assumptions are changed.

---

[1]Energy Information Administration, Short-Term Energy Outlook, DOE/EIA-0202(84/4Q) (Washington, DC, 1984).

World Oil Prices

The nominal price of world oil fell from a high of $37 per barrel in 1981 to $29 per barrel by 1983. This decline is attributable to several factors: the energy conservation and efficiency efforts that followed the rise in oil prices in 1979, the low rate of economic growth prior to mid-1983, and the new supplies of oil from countries other than members of the Organization of Petroleum Exporting Countries (OPEC). The price of oil remained stable at about $29 per barrel through 1984, mainly because of surplus supply, although by the end of 1984 there were indications that downward pressure on prices might become severe. In constant 1984 dollars, the price of oil to the United States dropped from more than $42 per barrel in 1980 and 1981 to the current $29 per barrel. A similar reduction in prices did not occur in many other countries, however, because of the appreciation of the dollar relative to other major currencies. In France, for example, changes in the exchange rate effectively erased the $5-per-barrel price reduction by OPEC in early 1983 (see Chapter 3).

Based on preliminary data, total petroleum consumption in 1984 increased in the market economy countries[2] for the first time since 1979 and in the United States for the first time since 1978. However, abundant oil supplies are expected to keep downward pressure on oil prices for the next few years. World oil prices in nominal terms are assumed to remain at about $29 per barrel through 1986, but then to increase in the late 1980's and into the 1990's (Table 1). When adjusted for inflation, world oil prices are assumed to decline through 1986 and then increase through the remainder of the forecast period. The real price of world oil in 1990 is assumed to be about $30 per barrel (in 1984 dollars) and $40 per barrel in 1995--still a few dollars below the peak that real prices reached in 1980 and 1981. The increase in real world oil prices after 1986 is less than that assumed in the 1983 Annual Energy Outlook. By 1995, the assumed world oil price in this year's base case is about $12 per barrel (in 1984 dollars) lower than the level assumed last year.

Recent experience has increased expectations of future oil savings due to fuel substitution and conservation, particularly in Europe and Japan. Assumed economic growth rates for the developing countries have also been lowered since last year. In addition, the rate at which OPEC is assumed to increase oil production capacity in response to price increases has been increased from the rate assumed last year. Increasing capacities to 1980 levels would help countries with large oil reserves, such as Saudi Arabia, stabilize world oil markets and avoid the disruptive price shocks of the past. OPEC production is now assumed to increase to about 24 million barrels per day by 1990.

Three world oil price paths are discussed in Chapter 3. The assumptions used to develop these paths are consistent with those underlying the price forecasts presented in the October 1984 Short-Term Energy Outlook. Forecasts based on the higher and lower price paths illustrate the sensitivity of world oil markets to

---

[2]All countries other than the Centrally Planned Economies of Eastern Europe, the Soviet Union, China, Cuba, Kampuchea, North Korea, Laos, Mongolia, and Vietnam.

these assumptions. An important assumption underlying the base case price path is that no significant supply disruption will occur during the forecast period, especially in the Persian Gulf, where most of the world's excess oil production capacity is located.

Table 1. World Oil Prices: Base Case, 1973-1995
(1984 and Nominal Dollars per Barrel)

	History			Assumptions												
Price[a]	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
1984 Dollars	9	22	30	29	28	27	27	28	29	30	32	34	36	38	40
Nominal Dollars ...	4	15	29	29	29	29	31	34	37	41	46	52	59	66	74

[a]The cost of imported crude oil to U.S. refiners.

Source: • History: Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(84/06) and Annual Energy Review, 1983, DOE/EIA-0384(83) (Washington, DC, 1984). • Assumptions: Appendix A, Table A19.

The current surplus in world oil production capacity is estimated to be 8 million to 11 million barrels per day, with most of this surplus capacity located in OPEC countries. This concentration of surplus production capacity in OPEC is assumed to persist in the forecast period because only modest growth is forecast for non-OPEC production capacity. New sources of oil from areas such as Canada and offshore areas of the United States are not likely to do more than replace disappearing older sources. Production from OPEC thus is likely to meet much of the growth in petroleum demand. Continued efforts at fuel substitution should help maintain downward pressure on world oil prices for several more years, although incentives for switching from petroleum to natural gas in the United States have weakened since 1980 because of lower oil prices. As surplus production capacity for crude oil diminishes over the forecast period, the market is assumed to tighten, resulting in modest assumed increases in real prices before the end of the 1980's.

Economic Outlook

Strong economic growth is assumed to continue through 1995, although at slower rates in the later years, supported by strong investment demand from the business sector, sustained growth in manufacturing, and stability in the housing market. Between 1985 and 1995 the rate of inflation is assumed to average 5.9 percent, well below the average of 7.4 percent that was observed for 1973 through 1983. A gradual downward adjustment in the dollar exchange rate is expected to forestall deterioration in the real trade balance over the forecast period. Steady economic growth, a relatively low rate of inflation, and moderate world oil prices are assumed to result in higher levels of energy demand, particularly in the industrial sector of the economy.

The economic recovery that began at the end of 1982 contributed to growth in real gross national product (GNP) of 3.7 percent between 1982 and 1983, with growth in 1984 expected to be about 7.0 percent. Growth in real disposable income also was strong over this period. Investment activity has been an important factor in sustaining this expansion and has contributed to the strong growth in most manufacturing industries. Nevertheless, overall manufacturing capacity utilization was 82 percent in the second quarter of 1984, leaving an ample margin for continued noninflationary economic growth. (For a more detailed examination of economic growth and energy markets through 1985, see the October 1984 Short-Term Energy Outlook.[3])

The economic expansion is assumed to continue in the forecast period, but at a slower pace than during the recent economic recovery (Table 2). Growth in real GNP is assumed to average 3.1 percent per year from 1985 to 1990, although this rate is bracketed by assumed growth rates of 3.9 percent per year in the high case and 2.1 percent per year in the low case. The longer term outlook includes moderate levels of price inflation, reductions in nominal interest rates, and a gradually declining unemployment rate until 1989, with a slight increase through 1995. Average annual growth in productivity is assumed to be 1.9 percent between 1985 and 1990. The ability of the economy to achieve this growth depends on several supply-side factors including slower growth in the labor force, net additions to the capital stock, and developments in energy markets. The labor force is assumed to expand by approximately 1.5 percent per year between 1985 and 1990, compared with the 2.2-percent per year increase between 1973 and 1983. Thus, the labor force is assumed to have a limiting effect on the underlying growth potential of the economy relative to recent history. If future growth is to approach historical trends, both capital and energy must play an expanded role.

GNP and Its Components. Real GNP is assumed to grow at an annual rate of 3.1 percent between 1985 and 1990, and by 2.3 percent between 1990 and 1995. Examining the composition of the assumed growth in the base case (Figure 1), the key trends that are expected to have significant implications for energy consumption between 1985 and 1990 include:

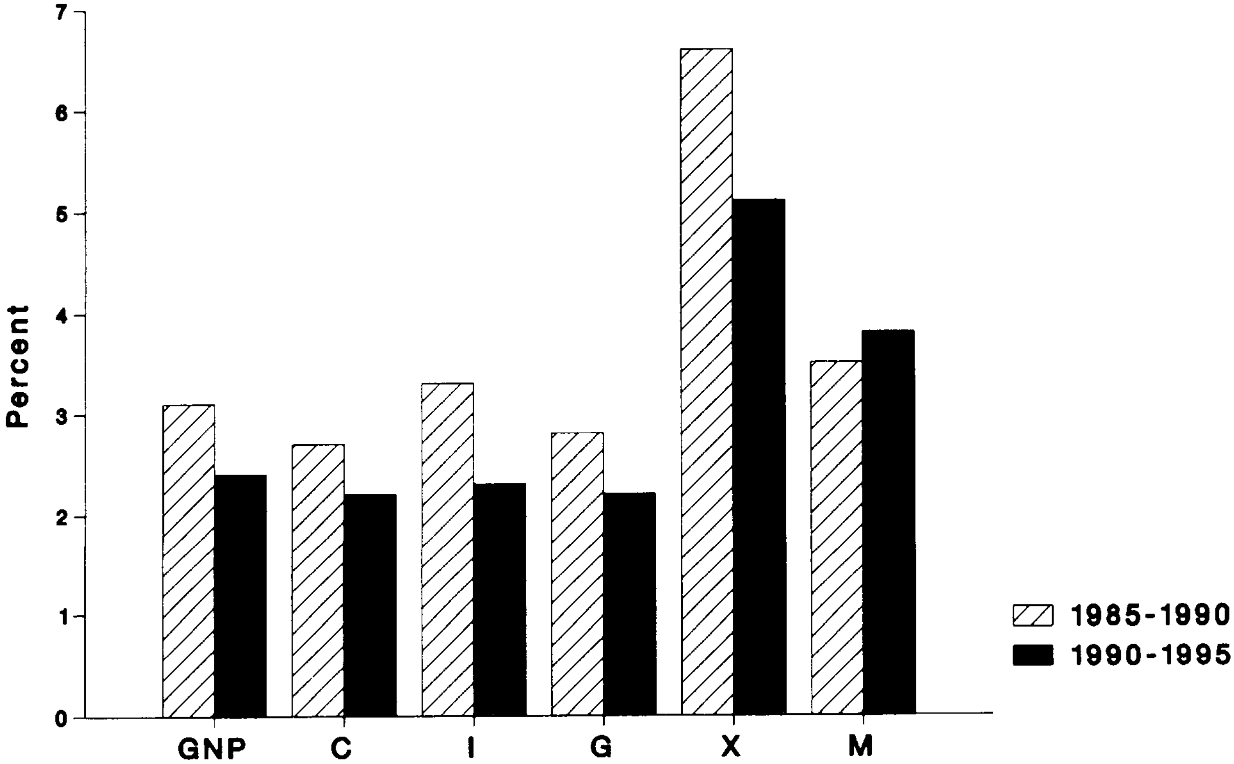
- Consumption expenditures--a 2.7-percent per year growth, led by a 4.0-percent per year increase in consumer durables. Consumption growth provided much of the early strength of the current recovery, but typically slows in the later stages, as other components of GNP regain strength.

- Nonresidential structures--a 3.7-percent per year growth, compared to the 0.5-percent per year growth for 1973 through 1983, and business demand for durable equipment--more robust

---

[3] This forecast is based on a modified version of the Data Resources, Inc., (DRI) U.S. economic forecast CONTROL092584, used to develop the economic assumptions for the Energy Information Administration, Short-Term Energy Outlook, DOE/EIA-0202 (84/4Q) (Washington, DC, 1984). The underlying DRI forecast is described in the October DRI Review of the U.S. Economy, October 1984 (Lexington, MA, 1984).

Figure 1. GNP and Its Components: Average Annual Rates of Growth, Selected Years



GNP - Real Gross National Product
C - Personal Consumption Expenditures
I - Gross Private Domestic Investment
G - Government Expenditures
X - Exports
M - Imports

Source: • History: U.S. Department of Commerce, Bureau of Economic Analysis, Survey of Current Business (Washington, DC, July 1984).
• Assumptions: Appendix A, Table A19; EIA, Office of Energy Markets and End Use, Memorandum to the Record, "Macroeconomic Forecasts for AEO84" (Washington, DC, December 7, 1984).

than business structures, with projected growth of 3.6 percent per year because the strength in investment expenditures, a typical recovery pattern, is boosted considerably by the favorable effect on corporate investment of the Economic Recovery Tax Act of 1981 (ERTA) which significantly increased the value of depreciation allowances that corporations could claim. As a result, the share of GNP devoted to business fixed investment is expected to continue its rising trend.

Table 2. Key Economic Indicators

Economic Indicator	History 1973	History 1978	History 1983	Average Annual Growth 1973-1983	Economic Growth Case	Assumptions 1985	Assumptions 1990	Assumptions 1995	Average Annual Growth 1985-1995
World Oil Price (1984 dollars per barrel)	9	22	30	12.8	High	30	40	55	6.2
					Middle	28	30	40	3.6
					Low	24	25	30	2.3
Real GNP (billion 1972 dollars)	1,254	1,439	1,535	2.0	High	1,700	2,057	2,372	3.4
					Middle	1,687	1,968	2,206	2.7
					Low	1,668	1,855	2,040	2.0
Gross Output in Manufacturing (billion 1972 dollars)	835	921	882	0.6	High	1,030	1,316	1,507	3.9
					Middle	993	1,230	1,383	3.4
					Low	941	1,122	1,245	2.8
Real Disposable Personal Income (billion 1972 dollars)	865	989	1,095	2.4	High	1,204	1,400	1,623	3.0
					Middle	1,202	1,360	1,511	2.3
					Low	1,188	1,330	1,453	2.0
Unemployment Rate (percent)	4.9	6.1	9.6	--	High	7.0	6.6	7.3	--
					Middle	7.3	6.9	7.2	--
					Low	7.7	7.9	7.5	--

-- = Not applicable.

Note: The rate of inflation is assumed to be 5.6 percent between 1985 and 1990 and 6.3 percent between 1990 and 1995 in the middle economic growth case. For the high economic growth case, inflation is assumed to be 5.0 percent per year from 1985 to 1990 and 5.1 percent per year from 1990 to 1995. The low economic growth case is based on an inflation rate of 7.1 percent per year from 1985 to 1990 and 8.4 percent per year from 1990 to 1995.

Source: • History: U.S. Department of Commerce, Bureau of Economic Analysis. • Assumptions: Energy Information Administration, Office of Energy Markets and End Use, Economics and Statistics Division (Washington, DC).

- Exports and imports--real annual growth of 6.6 percent and 3.5 percent, respectively. The decline in the trade deficit in real terms is due to the boost given efforts by a gradually declining dollar and the assumed recovery in the economies of U.S. trading partners. Measured in nominal dollars, however, the trade balance continues to be in deficit, due in part to the large oil import bill.

- Federal purchases of goods and services--a 3.1-percent per year growth, including a 4.1-percent per year growth in defense purchases. These growth rates reflect tax and expenditure policies designed to bring Federal expenditures to 23 percent of GNP by 1990 and bring about a gradual decline in the deficit through 1990.

- State and local purchases of goods and services--a 2.6-percent per year growth. This represents a reversal of the declines during 1981 through 1983 and reflects favorable developments for State and local finance as a result of declining unemployment rates and reductions in nominal interest rates.

High and Low Economic Growth Cases. The assumed rate of economic growth in the base case is surrounded by many uncertainties such as the level and importance of the Federal deficit, the future of interest rates, the type of incentives that might result from tax reform, and the implications of the U.S. exchange rate for trade developments. The high and low economic growth assumptions examine a reasonable range of uncertainty. Both alternative forecasts incorporate the base case assumption for oil prices and assume economic expansion, although at different rates, from 1985 through 1995[4] (Figure 2 and Table 2).

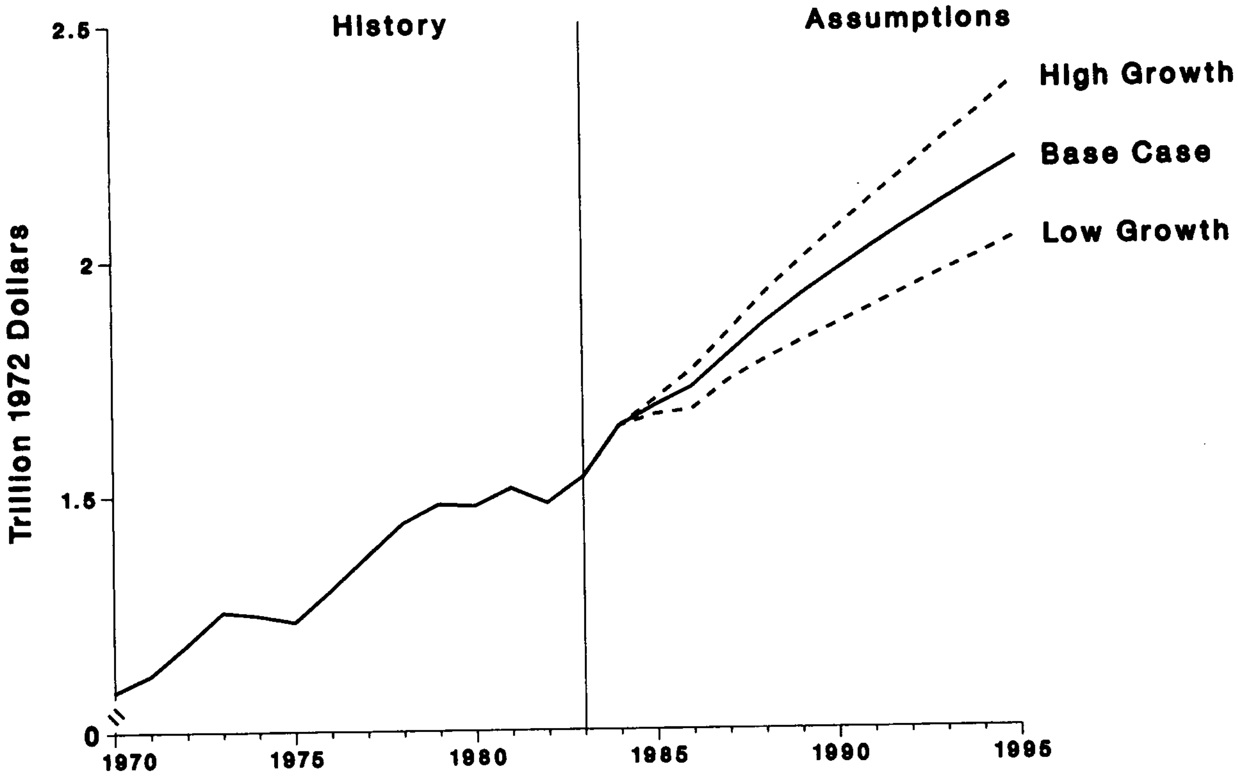
In the high economic growth case, increases in the labor force, capital stock, and technological change all are assumed to contribute more to economic growth than in the base case. Real GNP is thus assumed to grow by about 0.8 percentage points more per year between 1985 and 1990 than in the base case. The rate of inflation in the high growth case is assumed to remain at 5.0 percent per year (as opposed to 5.6 percent in the base case over the same period) because of less price pressure as a result of rapid growth in the supply of productive factors. Average annual growth in productivity is assumed to rise by 2.2 percent per year, up from 1.9 percent in the base case. Because of the reduced Federal deficit and lower interest rates, the U.S. exchange rate is assumed to decline faster than in the base case, thus contributing to greater demand for exports.

In the low economic growth case, real GNP growth between 1985 and 1990 is assumed to be about 1.0 percentage points lower than in the base case, and the labor force

---

[4]This report incorporates ranges for the likely variation in economic performance from 1985 through 1995, but all cases are driven by the same economic forecast in 1984. The exclusion of the year 1984 from the range of economic variables in this report is not meant to imply the absence of uncertainties in the short term.

Figure 2. Alternative Economic Growth Paths for Real GNP, 1970-1995



Source: • History: U.S. Department of Commerce, Bureau of Economic Analysis, Survey of Current Business (Washington, DC, July 1970-1984).
• Assumptions: Appendices A, B, C; Tables A19, B19, C19.

and the capital stock are assumed to expand less rapidly. Inflation is assumed to average 7.1 percent per year, because of slower expansion of productive factors. Productivity growth is assumed to increase by only 1.6 percent annually, and the U.S. exchange rate is assumed to remain strong relative to the base case, supported by relatively higher interest rates. More optimistic assumptions about domestic factor supply and competitiveness in world markets give rise to the high growth case (comparing to the base case), while the reverse is true for the low growth case. The higher labor force participation and productivity growth which lead to higher growth also lessen inflationary pressures and lead to slower increases in the general price level in the high growth case, in spite of the assumed deterioration in the value of the dollar. Conversely, pessimism regarding labor force participation and productivity growth in the low growth case lead to greater price pressure, in spite of an assumption that the high purchasing power of the dollar on world markets is maintained.

Energy Markets

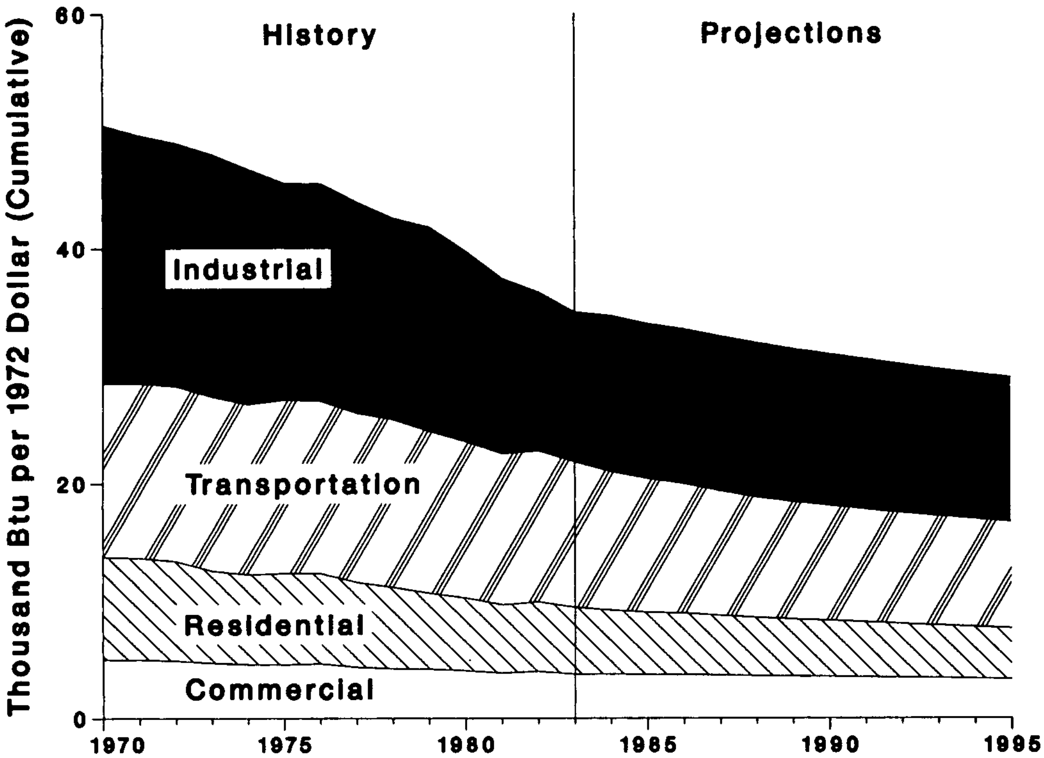
Total U.S. Energy Demand

Between 1985 and 1990, total U.S. energy consumption is projected to grow at an average annual rate of 2 percent, to 83.5 quadrillion Btu in the base case, although energy demand by 1990 could be as high as 86.0 quadrillion Btu in the high economic growth case or as low as 80.6 quadrillion Btu in the low economic growth case. Between 1990 and 1995, total U.S. energy consumption is projected to grow at an average annual rate of 1.5 percent, to 90.1 quadrillion Btu in the base case, although it could range from 94.9 quadrillion Btu to 85.8 quadrillion Btu depending on the assumptions about economic growth. In the base case, this level of energy demand represents an energy/GNP ratio of about 41 thousand Btu per 1972 dollar of GNP in 1995, about 9 percent lower than the level projected in 1985 (Table 3). Figure 3 illustrates these trends on a sectoral basis measured in terms of end-use energy consumption per GNP dollar.

Energy use grew at about the same rate as GNP in the decade prior to 1974 but slowed over the next ten years as a result of energy price increases. A return to more rapid growth in energy use is projected over the forecast period, because of the assumed return to strong economic growth and relatively low energy prices. Growing economies tend to be more energy-intensive than recessionary economies because much higher levels of investment are required for new structures and plastics, rubber, asphalt, glass, and cement. For example, in the first half of 1984 energy use grew at about the same rate as real GNP but between 1981 and 1982 (a recession year) energy use declined at about twice the rate of decline in real GNP.

The projected energy/GNP ratios shown in Table 3 would most likely be lower if energy prices grow more rapidly than assumed. Between 1973 and 1983, the energy/GNP ratio decreased on average by more than 2 percent per year, and between 1976 and 1983 the ratio decreased by 3 percent per year. In the base case projections, the energy/GNP ratio is projected to decrease by slightly more than 1 percent per year between 1985 and 1990 and by slightly less than 1 percent per year between 1990 and 1995. The lower rate of decline expected in the forecast period mainly results from the assumption that the increase in real energy prices will be modest

Figure 3. Energy Consumption per Constant Dollar of GNP by End-Use Sector, 1970-1995



Source: • History: Energy Information Administration, State Energy Data Report, 1960-1982, DOE/EIA-0214(82) and Monthly Energy Review, DOE/EIA-0035 (84/06) (Washington, DC, 1984). • Projections: Appendix A; Tables A4, A19.

in the projection period, compared to the increase experienced between 1973 and 1983. A high conservation case which examines the effect of even greater conservation is discussed in Chapter 5.

Table 3. Energy Consumption and Gross National Product, 1973-1995

	History				AARC[a] 1973-1983	Economic Growth Case	Projections			AARC[a] 1985-1995
	1973	1978	1983	1984			1985	1990	1995	
Total Energy Consumption						High	76.0	86.0	94.9	2.2
(quadrillion Btu)	74.2	78.0	70.7	74.8	-0.5	Middle	75.7	83.5	90.1	1.8
						Low	75.3	80.6	85.8	1.3
Gross National Product (billion						High	1,700	2,057	2,372	3.4
1972 dollars)	1,254	1,439	1,535	1,643	2.0	Middle	1,687	1,968	2,206	2.7
						Low	1,668	1,855	2,040	2.0
Total Energy/GNP						High	44.7	41.8	40.0	-1.1
Dollar (thousand	59.2	54.2	46.0	45.5	-2.5	Middle	44.9	42.4	40.9	-0.9
Btu per 1972 GNP dollar)						Low	45.2	43.5	42.1	-0.7

[a]Average annual rate of growth.

Source: • History: Energy Information Administration, State Energy Data Report 1960-1982, DOE/EIA-0214(82) (Washington, DC, 1984). • Projections: Appendices A, B, C; Tables A1, A19, B1, B19, C1, C19.

In both the short and long term, economic growth and energy prices are the most important factors affecting energy demand because energy is an essential input into the production process. In the short term, rapid economic growth and stable or falling real energy prices can be expected to produce sharp increases in energy demand, as are estimated for 1984. In the long term, however, slower economic growth and stable real prices are expected to result in lower growth in the demand for energy products. Energy conservation is also important in determining demand levels, and its role is discussed in more detail in Chapter 5.

Unlike energy demands in the residential and commercial sectors, which have relatively low responses to changes in income levels (because the turnover in equipment and building stock occurs slowly), the industrial and transportation sectors are quite sensitive to income variations (Table 4). In fact, almost all the variation in energy requirements over the different economic scenarios is projected to occur in the industrial and transportation sectors. In the transportation sector, changes in income translate directly into changes in demand for petroleum and imports of crude oil and petroleum products. Industrial energy consumption is more sensitive to changes in the assumed rate of economic growth than the other end-use sectors because of its stronger relationship between energy use and output (Chapter 5). Industrial energy consumption in the high economic

Table 4. Disposition of Total Energy by Sector and Fuel
(Quadrillion Btu)

	History				Economic Growth Case	Projections		
	1973	1978	1983	1984		1985	1990	1995
Disposition by End-Use Sector								
					High	8.9	9.4	9.6
Residential	9.89	9.99	8.72	8.95	Middle	9.0	9.4	9.6
					Low	9.0	9.4	9.5
					High	6.2	7.0	7.5
Commercial	5.88	6.04	5.74	6.16	Middle	6.2	6.9	7.3
					Low	6.2	6.9	7.2
					High	22.4	26.4	28.7
Industrial	25.84	24.60	19.52	21.78	Middle	22.2	25.4	27.0
					Low	22.0	24.0	25.3
					High	19.3	19.8	21.3
Transportation	18.58	20.57	19.02	19.35	Middle	19.2	19.2	20.1
					Low	18.9	18.7	19.1
Disposition by Fuel								
					High	31.5	34.4	40.1
Petroleum	34.8	38.0	30.1	31.5	Middle	31.3	33.2	35.7
					Low	30.8	31.9	33.2
					High	18.7	19.9	18.8
Natural Gas	22.5	20.0	17.5	18.5	Middle	18.7	19.3	19.3
					Low	18.7	18.5	18.6
					High	18.1	21.3	24.7
Coal	12.9	13.7	15.9	17.1	Middle	18.1	20.6	23.8
					Low	18.1	19.8	22.7
					High	4.1	6.3	7.1
Nuclear Power ..	0.9	3.0	3.2	3.7	Middle	4.1	6.3	7.1
					Low	4.1	6.3	7.1
Hydropower/					High	3.6	4.1	4.2
Other	3.1	3.2	4.0	4.0	Middle	3.6	4.1	4.2
					Low	3.6	4.1	4.2
					High	7.9	9.7	11.5
Electricity	5.8	6.9	7.3	7.7	Middle	7.9	9.3	10.9
					Low	7.9	9.0	10.3

Source: • History: Energy Information Administration, State Energy Data Report, 1960-1982, DOE/EIA-0214(82) (Washington, DC, 1984). • Projections: Appendices A, B, C; Tables A4, B4, C4.

growth case in 1990 is expected to be about 10 percent above the level in the low case, compared to a high/low differential of 7 percent for the aggregate of end-use energy consumption (Table 3).

Petroleum demand is projected to grow by an average of 1.2 percent per year between 1985 and 1990, reaching a level of 33.2 quadrillion Btu (16.7 million barrels per day) in 1990. Most of this projected growth is for transportation fuels and industrial feedstock uses. In the industrial sector, the assumed rapid growth of industries such as plastic materials and synthetic fibers that use liquefied petroleum gases and other petroleum feedstocks for manufacturing processes is expected to result in increased demand for those products.

Electricity use is projected to continue to increase, and to account for about 15 percent of end-use energy consumption by 1990, and 17 percent by 1995 compared with 14 percent in 1983 (Figure 4). This increased reliance on electricity is reinforced in the forecast period by a projected decline in real electricity prices, in contrast to significant increases in real prices expected for most other fuels. Even though electricity is the most expensive end-use energy source (per delivered Btu of energy), the projected growth in electricity use is mainly attributable to the narrowing differential between the price of electricity and the prices of other fuels, in addition to the relative efficiency of electricity in many applications. Over the range of low to high growth cases, changes in economic growth are expected to result in proportionately greater changes in electricity demand than in total energy consumption.

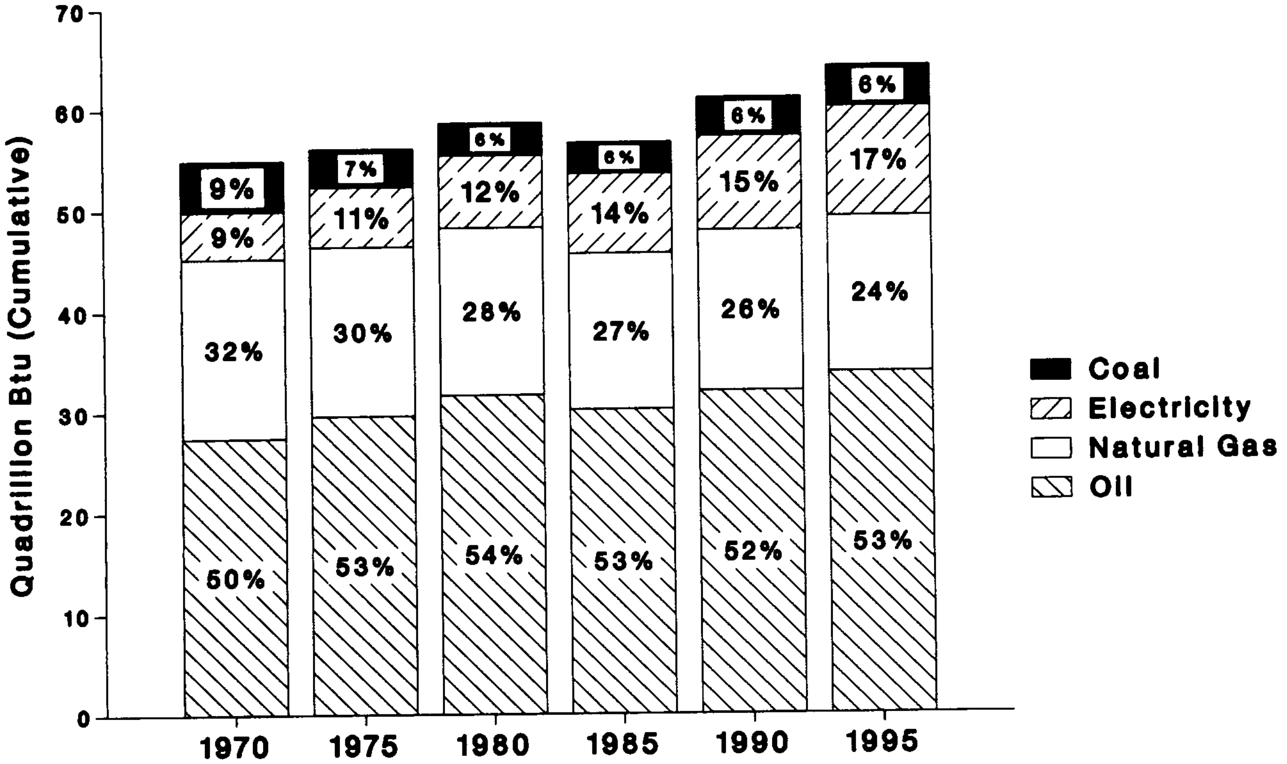
Total domestic energy production is projected to grow by 1.3 percent per year between 1985 and 1990, and by 0.4 percent per year between 1990 and 1995. This compares to an average annual rate of decline of 0.1 percent between 1973 and 1983 (Table 5). Domestic energy supply is less affected by changes in economic growth than energy demand because production decisions are more concerned with the costs of production factors and expected prices, which are affected only indirectly by alternative rates of economic growth. Imports grow to fill the gap between supply and demand.

Sectoral Trends

Residential Energy Demand. Energy consumption in the residential sector declined at an average annual rate of 1.3 percent from 1973 to 1983, despite a substantial increase in the number of households. This decline was largely in response to substantial increases in real energy prices, which encouraged improved efficiency of appliances and structures and lower thermostat settings. Wood consumption, which is not included in the residential sector's energy-use totals, also increased over this period. It is likely that part of the measured decrease in energy consumption per household was due to the substitution of wood for one of the more conventional fuels (Chapter 5).

Although residential energy use is expected to increase slowly between 1985 and 1990, energy use per household over that period is projected to decline at an average annual rate of about 0.7 percent. The projected reductions in energy use per household almost offset increases in energy use due to growth in the number of

Figure 4. End-Use Energy Consumption by Energy Source, Selected Years



Note: Percentage shares may not sum to 100 percent due to independent rounding.
Source: • History: Energy Information Administration, State Energy Data Report, 1960-1982, DOE/EIA-0214(82) (Washington, DC, 1984). • Projections: Appendix A, Table A4.

households. This decline in energy use per household is slower than the rate during recent years, reflecting the effect of the relatively stable energy prices projected through the late 1980's.

Table 5. Supply and Disposition Summary of Total Energy (Quadrillion Btu)

	History				Economic Growth	Projections		
	1973	1978	1983	1984	Case	1985	1990	1995
Supply								
					High	66.1	71.7	72.8
Production	62.0	61.0	61.1	65.6	Middle	66.1	70.5	71.9
					Low	66.1	68.9	70.4
					High	13.5	19.6	27.5
Imports	14.7	19.3	12.2	12.9	Middle	13.2	18.2	23.7
					Low	12.8	17.0	20.9
					High	79.2	90.1	99.3
Total Supply	76.2	80.0	74.4	78.3	Middle	79.0	87.6	94.6
					Low	78.5	84.7	90.3
Disposition								
					High	76.0	86.0	94.9
Consumption	74.2	78.0	70.7	74.8	Middle	75.7	83.5	90.1
					Low	75.3	80.6	85.8
Total					High	79.2	90.1	99.3
Disposition	76.2	80.0	74.4	78.3	Middle	79.0	87.6	94.6
					Low	78.5	84.7	90.3
					High	3.2	4.1	4.4
Exports	2.1	1.9	3.7	3.5	Middle	3.2	4.1	4.4
					Low	3.2	4.1	4.4

Source: • History: Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(84/06) (Washington, DC, 1984). • Projections: Appendices A, B, C; Tables A1, B1, C1.

In addition to the effects of energy prices on demand, part of the decline in energy use per household is attributable to the continuing population shift to warmer climates. Although only slightly more than one-half of the Nation's housing stock in 1982 was in the South and the West Census Regions, almost three-fourths of all new housing construction in 1982 was in those two regions. As would be expected, households in warmer climates consume less energy for heating uses and thus have lower total energy requirements.

Electricity is expected to account for nearly all of the projected increase in residential energy demand over the forecast period. The population shift toward warmer areas is expected to result in an increase in electricity use to provide nonheating services, such as air conditioning and refrigeration. Electricity's share of residential space heating also is projected to increase from about 6 percent in 1985 to about 7 percent by 1990. Residential electricity consumption is projected to increase at an average annual rate of about 1.8 percent from 1985 through 1990, and about 2.6 percent per year between 1990 and 1995. Over this period, the real price of residential electricity is projected to decline slightly.

Natural gas use in the residential sector is projected to remain stable through 1990 and then decrease slightly thereafter, due to a projected decline in heating uses relative to nonheating uses and an erosion of the natural gas price advantage. Although natural gas is projected to remain the lowest-priced major fuel through the forecast period (on a Btu basis), its price is projected to increase faster than the price of oil or electricity between 1990 and 1995, both in absolute and percentage terms. The narrowing differential between natural gas and electricity prices is likely to lead to increased use of new electrical equipment, even though residential gas prices are forecast to remain below alternative fuel prices. Residential oil (distillate plus kerosene), which is used almost exclusively for heating purposes, accounted for 13 percent of total residential energy use in 1983. The level of oil consumption in the residential sector is projected to remain at about 1.2 quadrillion Btu over the forecast period, implying a slight decline in this fuel's share.

Residential energy demand shows little variation from the low to the high economic growth cases in 1990 (Table 6). Higher (lower) levels of income are projected to lead to increases (decreases) in new housing starts as well as increases (decreases) in energy use per household. The residential sector is much less sensitive to changes in income than the industrial and transportation sectors because changes in housing size and quality influenced by income levels occur very slowly. Behavioral factors, such as thermostat settings, appear to vary only slightly in response to economic changes.

Commercial Energy Demand. The commercial sector consists of buildings used for offices, warehouses, public facilities, and other establishments that engage in commercial operations. Commercial building floorspace is used as an index to measure energy demand over these diverse types and sizes of buildings. Floorspace grew rapidly over the last decade and is projected to increase by about 2.6 percent per year from 1985 to 1990 and by 2.1 percent per year between 1990 and 1995, as a result of the projected growth in population and the general expansion of the economy. Under alternative economic growth assumptions, growth in commercial floorspace is projected to range from 2.4 percent to 2.9 percent per year between 1985 and 1990. In the base case, retail/ wholesale floorspace is projected to grow slightly faster (about 3.0 percent per year) than office floorspace (about 2.6 percent per year). Other building floorspace is forecast to grow by only 1.8 percent per year over that period.

From 1985 to 1990, commercial energy use in the base case is projected to increase at an average annual rate of 2.1 percent. However, energy use per square foot is projected to decrease by 0.4 percent per year over the same period, partially in response to higher energy prices. Improvements in energy efficiency are projected to result from the continuation of historical trends in new building construction, retrofit efficiency improvements, and lower thermostat settings.

Table 6. Energy Demand by End-Use Sector
(Quadrillion Btu)

End-Use Sector	History 1973	History 1978	History 1983	Economic Growth Case	Projections 1985	Projections 1990	Projections 1995
				High	8.9	9.4	9.6
Residential	9.9	10.0	8.7	Middle	9.0	9.4	9.6
				Low	9.0	9.4	9.5
				High	6.2	7.0	7.5
Commercial	5.9	6.0	5.7	Middle	6.2	6.9	7.3
				Low	6.2	6.9	7.2
				High	22.4	26.4	28.7
Industrial	25.8	24.6	19.5	Middle	22.2	25.4	27.0
				Low	22.0	24.0	25.3
				High	19.3	19.8	21.3
Transportation	18.6	20.6	19.0	Middle	19.2	19.2	20.1
				Low	18.9	18.7	19.1
End-Use Energy				High	56.8	62.6	67.0
Consumption[a] ...	60.2	61.2	53.0	Middle	56.6	60.9	63.9
				Low	56.1	59.0	61.1
Total Energy				High	76.0	86.0	94.9
Consumption	74.2	78.0	70.7	Middle	75.7	83.5	90.1
				Low	75.3	80.6	85.8

[a]Excludes losses incurred in the transmission and distribution of electricity.

Source: • History: Energy Information Administration, State Energy Data Report, Consumption Estimates, 1960-1982, DOE/EIA-0214(82) and Monthly Energy Review, DOE/EIA-0035(84) (Washington, DC, 1984). • Projections: Appendices A, B, C; Tables A4, B4, C4.

Real electricity prices are projected to remain relatively stable throughout the forecast period, and, as a result, electricity consumption in the commercial sector is projected to increase with floorspace growth. Electricity is forecast to meet about 41 percent of the commercial sector's energy requirements by 1990, and 44 percent in 1995, compared to 39 percent in 1985. This forecast takes into account regional variations in the growth of commercial floorspace and growth of floorspace by type of building. Historically, the commercial sector in the South and West Census regions has relied more heavily on electricity than the rest of the country. Over the forecast period, commercial floorspace in these regions is projected to grow about 50 percent faster than the average rate for the United States, thus strengthening the trend toward increased reliance on electricity.

Efficiency improvements are expected to continue to be sensitive to fuel prices. Natural gas prices to the commercial sector are projected to increase faster than prices of other fuels. The projected decline in natural gas consumption per square foot resulting from higher natural gas prices offsets the expected increase in natural gas consumption due to additional floorspace. The net effect is that natural gas use is projected to remain relatively steady and account for slightly less than 40 percent of this sector's energy needs in 1990 and 1995. Consumption of petroleum in the commercial sector is projected to increase slightly over the forecast period, although it's share of the sector's total energy consumption is expected to be only 18 percent in 1995.

In the high economic growth case, end-use energy consumption in the commercial sector in 1990 is forecast to be about 1 percent higher than in the low economic growth case (Table 6). In the high case, total commercial sector floorspace is forecast to be about 3 percent higher in 1990 than in the low case. The electricity share of end-use energy consumption in 1990 is also projected to be slightly higher in the high case than in the low case.

Industrial Energy Demand. The industrial sector is the largest end-use consumer of energy and is most sensitive to the assumptions about economic growth. This is also the sector with the least amount of detailed recent historical data. Since 1974, the decline in energy use per unit of industrial output has mirrored general improvements in productivity and changes in product mix. During the rapid energy price increases of the 1970's, energy use per unit of output in the manufacturing industries declined on average at about the same rate as the decline in labor, materials, and capital use per unit of output. Following several years of weak demand in this sector, annual growth in end-use energy consumption is projected to average 2.7 percent from 1985 to 1990 and 1.3 percent from 1990 to 1995, somewhat slower than the rate of overall economic growth. Energy use per unit of output is projected to continue to decline through 1995 because of energy price increases and the replacement of old equipment with new, more energy efficient equipment that will lower overall production costs. It is important to note that the analysis of manufacturing energy use is based on data through 1981 only and therefore has additional uncertainties due to lack of recent data.

The projections of industrial energy use are conditional on the assumption of rapid growth in highly cyclical industries (Chapter 4). Similar to trends in the other sectors, industrial consumption of energy is projected to shift toward increased reliance on electricity. Between 1985 and 1990, industrial electricity use is projected to increase by 4.8 percent per year, compared to 2.8 percent per year for total industrial energy consumption. Factors contributing to the projected increase in industrial reliance on electricity include projections for improved economic conditions (particularly in the industries such as primary metals that rely heavily on electricity) and for growth in electricity use for mining and irrigation.

Industrial use of petroleum is projected to increase by about 2.9 percent per year from 1985 to 1990 in response to overall economic growth and rapid expansion in the plastics industry. By 1990, petroleum is projected to account for 48 percent of the energy requirements in the industrial sector. Petroleum use is concentrated in portions of the industrial sector that cannot easily convert to natural gas, such as some petrochemical feedstocks and off-highway vehicles. Residual fuel oil, which competes with natural gas as a boiler fuel and in other applications, accounted for about 10 percent of industrial oil use in 1983.

Industrial use of natural gas is projected to remain stable through 1995: The upward effect of economic growth on natural gas consumption is expected to offset the downward effect of higher natural gas prices and conservation. Between 1985 and 1990, real natural gas prices are expected to increase at an average annual rate of 4.1 percent, compared to an average residual fuel oil price increase of 2.7 percent per year in the industrial sector. Industrial coal use is projected to reverse the downward trend experienced since 1970 and account for about 14 percent of the industrial sector's energy requirements in 1990, mainly because of coal's relatively lower costs. Investment in new plants and equipment, because of expected expansion in certain key industries such as stone, clay, and glass, is projected to raise the demand for coal.

Five industries--chemical and rubber; primary metals; paper; stone, clay, and glass; and food--consumed 80 percent of the manufacturing energy used for heat and power in 1981 (excluding petroleum refining use).[5] Output growth assumptions (from Data Resources, Inc.) in these industries are the major factors explaining projected changes in industrial energy consumption from 1985 to 1990:

- The chemical and rubber industry is assumed to grow by nearly 4.8 percent per year between 1985 and 1990, with only a 3.1-percent per year increase in energy use for heat and power. Petrochemical feedstocks are projected to grow by 3.8 percent per year over this period. This forecast assumes a slower growth in feedstocks output and a faster growth in input fuels than was experienced during the 1970's (Appendix F).

- Basic metal production (mostly steel and aluminum) is assumed to increase by about 4.5 percent per year from 1985 to 1990, due to increased demand by businesses for durable equipment. This rate compares with the 3.0-percent per year increase expected in total U.S. energy use.

- Energy use and output in the paper industry both are projected to increase by about 3.0 percent per year between 1985 and 1990. The energy-saving effects of recycling wood products are projected to offset the additional energy required in the finishing process to produce higher quality paper.

---

[5]Energy Information Administration, Energy Conservation Indicators, 1983, DOE/EIA-0441(83) (Washington, DC, 1984); Department of Commerce, Census Bureau, 1982 Census of Manufacturing, MC82-S-4 (Washington, DC, 1983).

- The stone, clay, and glass industry is assumed to grow by about 4.1 percent per year between 1985 and 1990 (consistent with patterns in new home construction and motor vehicle production). Energy use is projected to grow by only 1.8 percent per year over this period, with energy costs accounting for a decreasing share of total production costs because of greater reliance on coal and electricity.

- Real output in the food industry is assumed to increase by 2.0 percent per year, although energy use is projected to decrease between 1985 and 1990 as electricity displaces fossil fuels. The efficiency gains[6] from the increased use of electricity are expected to outweigh the potential increases in total energy costs in this industry.

Industrial energy consumption is more sensitive than the other end-use sectors to changes in the assumed rate of economic growth (Table 6). Industrial energy consumption in the high economic growth case is projected to be about 10 percent higher than in the low case in 1990, compared to a high/low difference of almost 10 percent for total end-use energy consumption in all sectors. The industrial fuel mix is also sensitive to economic growth assumptions. In the high economic growth case, industrial electricity and oil demand are 17 percent and 10 percent higher, respectively, in 1990 than in the low economic growth case.

Transportation Energy Demand. The transportation sector in 1983 used more than one-third of total end-use energy and about 60 percent of U.S. petroleum. In 1990 and 1995, the transportation sector is projected to account for 55 percent of total petroleum consumption. Total energy demand in this sector is expected to grow by less than about 0.1 percent per year between 1985 and 1990 and by 0.9 percent per year between 1990 and 1995, although this rate between 1985 and 1995 could vary from 0.1 percent per year in the low economic growth case to 1.0 percent per year in the high economic growth case.

The transportation sector relies heavily on petroleum and has much less fuel-choice flexibility than other sectors. The major change in this sector over the past 10 years has been the improvement in fuel efficiency. The energy efficiencies of automobiles, trucks, and aircraft are projected to continue to improve, but declines in the real prices of gasoline and diesel fuel are expected to slow the rates of improvement relative to the experience over the last several years. (The efficiency of new cars is estimated to have declined slightly between 1982 and 1983.) Recent data indicate that new-car sales are moving toward the ratio between large and small car shares that existed before the first oil embargo, although large cars are more fuel efficient now than in 1973. If the average fuel efficiency of the fleet increases at the projected average rate of almost 4 percent per year between 1985 and 1990 (compared to the 4.3-percent per year

---

[6]For example, microwave ovens often consume less energy than natural gas ovens (at the point of end use) because they produce less waste heat and permit more efficient cooking.

increase between 1979 and 1981), the automobile fleet in 1995 would be nearly 20 percent more fuel-efficient than in 1985.

Automobile and truck vehicle-miles traveled are projected to grow at average annual rates of 2.7 percent and 2.8 percent, respectively, from 1985 to 1990, based on the expectations of declining real motor fuel prices through the late 1980's and continued economic growth. Over the forecast period, highway fuel consumption is expected to remain nearly constant, as increases in vehicle-miles traveled counteract improved fuel efficiencies of the fleet. Motor gasoline consumption is projected to decrease slightly between 1985 and 1990, at an average annual rate of 1.6 percent. The projected increase in diesel fuel consumption, particularly in intermediate-weight trucks, compensates for the decline in motor gasoline consumption. By 1990 diesel fuel consumption is projected to be about 20 percent higher than the level in 1985.

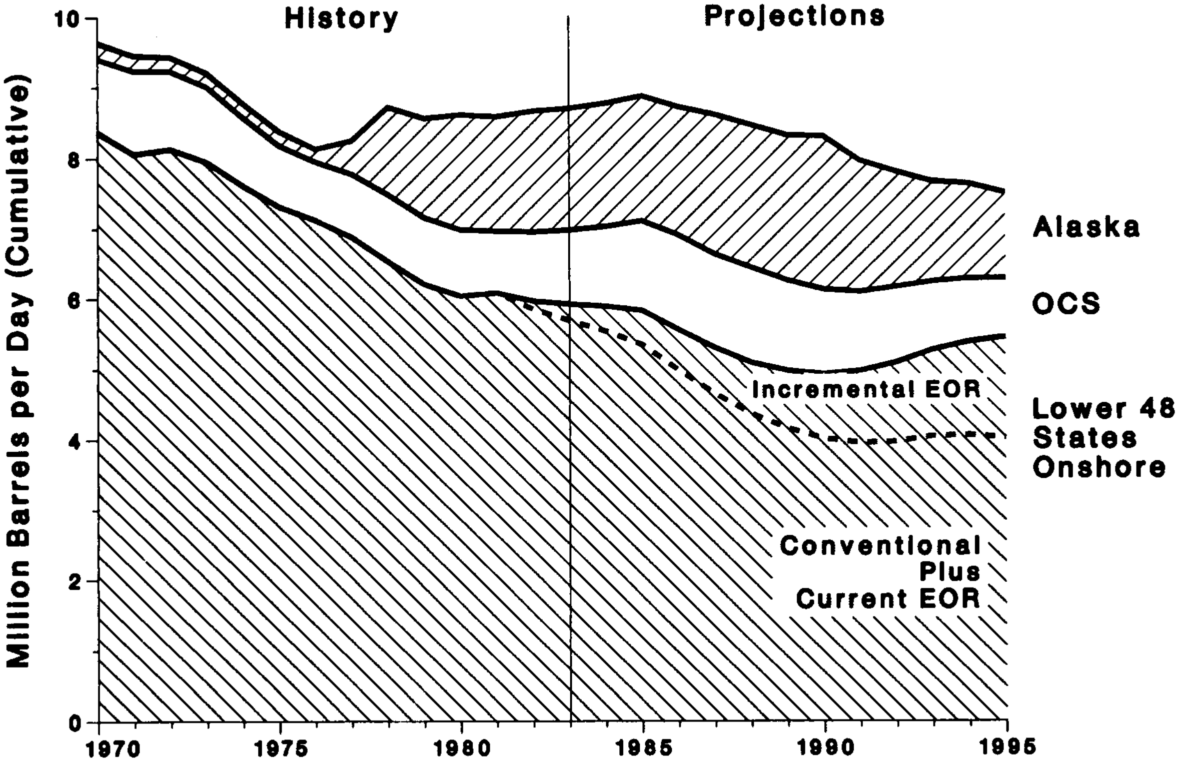
Energy use in the transportation sector varies considerably with the assumed rate of economic growth. In the high economic growth case, automobile and truck vehicle-miles traveled are expected to be 3.8 percent and 6.3 percent higher, respectively, than in the low growth case in 1990. Transportation fuel consumption is forecast to vary by similar percentages between the economic growth cases. These variations are consistent with historical data showing more driving during periods of high economic growth; combination truck travel is especially sensitive to changes in industrial output.

Petroleum Markets

Petroleum is expected to remain an important source of energy throughout the forecast period. End-use consumption of petroleum products is projected to increase by an average of 1.2 percent per year from 1985 to 1990, to 16.7 million barrels per day in the base case (ranging from 16.1 million barrels per day in the low economic growth case to 17.4 million barrels per day in the high economic growth case). Following a near-term increase, however, domestic crude oil production is projected to decline from 1985 through 1990. While the petroleum market is heavily influenced by changes in world oil prices, other factors related to the economics of exploration and development are also critical to the petroleum supply and demand projections. These factors are discussed in detail in Chapter 6.

Although a sizeable resource base of undiscovered crude oil remains, the incentives for drilling are projected to be dampened by the decline in the world oil price through 1986 and the relatively small increases expected by 1990. Increases in Alaskan oil production during this period are not expected to be sufficient to compensate for projected production declines in the Lower 48 States (Figure 5). Higher petroleum demand, concurrent with lower domestic production, is projected to result in a significant increase in net petroleum imports (crude oil plus refined products), from 4.8 million barrels per day in 1985 to 6.6 million barrels per day in 1990. The net imports level in 1990 is projected to range from 6.0 million barrels per day in the low economic growth case to 7.2 million barrels per day in the high economic growth case. This compares with a net import level of 8.6 million barrels per day in 1977, the peak year to date. The level of petroleum imports also is expected to vary widely depending on the assumptions about exploration and costs of production in the United States.

Figure 5. Oil Production by Source, 1970-1995



Source: • History: Total Production: Energy Information Administration (EIA), Annual Energy Review, 1983 (AER), DOE/EIA-0384(83) (Washington, DC, 1984), Table 35. Alaska: EIA, AER, 1983, Table 36, and Monthly Energy Review, DOE/EIA-0035(84/06). OCS: American Petroleum Institute, Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada (Washington, DC); EIA, U.S. Crude Oil and Natural Gas Reserves, DOE/EIA-0216(78), U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, DOE/EIA-0216(82), and Petroleum Supply Annual, 1983, DOE/EIA-0340 (83). EOR: National Petroleum Council, Enhanced Oil Recovery (Washington, DC, 1984). Lower 48 States: Derived. • Projections: Total Production: Appendix A, Table A15. Alaska: Appendix F. OCS: EIA, Outer Continental Shelf Oil and Gas Supply Model (OCSM). EOR: National Petroleum Council, Enchanced Oil Recovery (Washington, DC, 1984). Lower 48 States: EIA, Production of Onshore Lower-48 Oil and Gas (PROLOG) Model.

Domestic Crude Oil Supply. Although crude oil production is projected to decline gradually between 1985 and 1990 (Figure 5), the individual components of domestic supply are projected to follow different paths. Conventional onshore production in the Lower 48 States, the major component of oil supply, is projected to decline through this decade and then remain relatively stable after 1990. The base case assumptions for the world oil price through 1990 are not expected to provide sufficient incentive to add reserves at rates that would maintain production levels. While profitable prospects exist at current prices, the persistent slump in oil prices is expected to result in a general decline in the level of profitable projects. Without increases in real oil prices or significant technological advances in exploration and production, a decline in economically recoverable reserves is expected to continue.

Alaskan crude oil production is projected to increase to a peak level of 2.1 million barrels per day in 1990 and then decline through 1995. The increase in production through 1990 is expected from North Alaska: The Prudhoe Bay Sadlerochit formation is projected to continue producing 1.5 million barrels per day through 1990, and then experience severe production declines between 1990 and 1995 because of the advanced recovery techniques used to maintain production in the earlier years.

Other sources of supply include enhanced oil recovery (EOR) and offshore production. EOR is projected to increase over the forecast period.[7] Incremental volumes (those above the 1981 levels) amounted to about 300,000 barrels per day in 1984 and are expected to be about 0.9 million barrels per day by 1990. Outer Continental Shelf (OCS) production is expected to peak between 1986 and 1988 and then decline, mainly because of lower production in the Gulf of Mexico.

Petroleum Demand. The long-term outlook for combined domestic production of crude oil and natural gas liquids shows an average annual decline of 1.4 percent between 1985 and 1990. This decline in domestic production, in conjunction with the forecast growth in petroleum product demand, is expected to result in strong demand for petroleum imports. Total net imports of crude oil (including purchases for the Strategic Petroleum Reserve) and products are forecast to increase to nearly 6.6 million barrels per day by 1990. Net imports of crude oil are forecast to increase from 3.5 million barrels per day in 1985 to 5.1 million barrels per day by 1990, or almost half of the total crude oil expected to be processed by domestic refineries in that year.

Consumption increases are expected for all major petroleum products, except for motor gasoline. Growth across the energy-consuming sectors is expected to be uneven, however, resulting in relatively higher increases in the demands for some products--especially middle distillates and liquefied petroleum gases (LPG's). Domestic requirements for finished petroleum products can be met from three sources: domestic refining of domestic or foreign crude oil, refined product imports, and, in the short term, inventory drawdown.

---

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

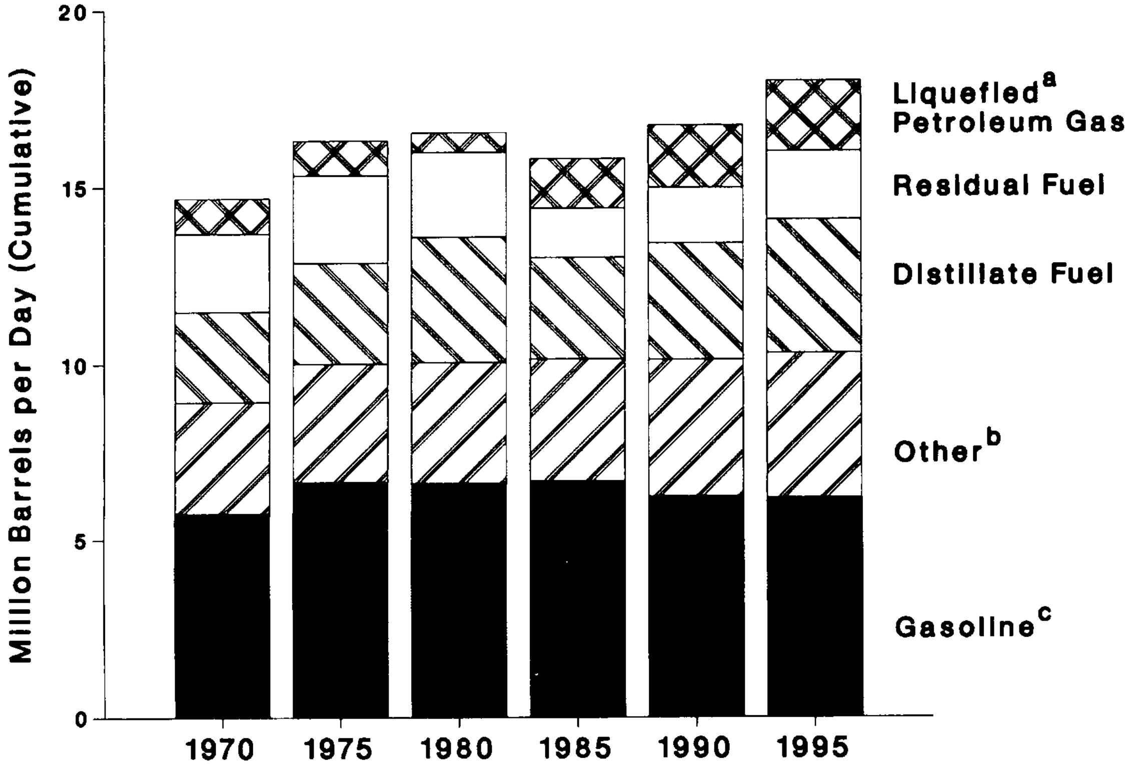
The domestic refining industry, the most important source of petroleum products, is undergoing adjustments to changes in product demand and the declining quality of available crude oils. With the recent recession and price-induced energy conservation, total refinery production dropped by almost 18 percent between 1978 and 1983. Refinery capacity (measured as operable crude oil distillation capacity) has declined since 1981. Because the projected level of refinery production in 1990 is much higher than the level in 1983, some combination of growth in refinery capacity, capacity utilization, and net refined product imports should be expected in the intervening years.

In response to the shifting mix of products demanded, the domestic refinery slate is projected to reflect an increasing emphasis on the production of middle distillates (Figure 6). Middle distillate output, as a percentage of total crude oil processed, is forecast to increase from 21 percent in 1985 to 22 percent in 1990. This increase is expected to be accompanied by a drop in the gasoline yield (net of natural gas liquid blending components) from 46 percent to 41 percent over the same period. The decline in gasoline yields, however, will be accompanied by the continued phaseout of leaded gasoline, which in turn will increase the average octane of unblended gasoline streams. At the same time, more of the distillate streams are forecast to be directed to diesel fuel because transportation uses of middle distillates in 1990 are projected to be about 2.5 times the amount consumed in the residential sector. The higher quality of both gasoline and diesel fuel is anticipated to add significantly to the refinery production costs of these products.

Total net imports of refined products, a second source of petroleum products, are forecast to increase by about 100,000 barrels per day between 1985 and 1990. By 1990, 38 percent of residual fuel oil demand and 27 percent of LPG demand are expected to be met by net imports. These imports are expected to moderate the shifts in refinery yields. Residual fuel oil production, which is projected to account for about 7 percent of crude oil processed in 1985, is forecast to remain near that level through 1995. Petroleum inventories, a short-term source of crude oil and refined products, are assumed to remain constant in terms of days of supply over the forecast period. Because of growing demand, this assumption results in an implied stock buildup equivalent to about 40,000 barrels per day by 1990 in the base case, an additional demand for crude oil and refined product that would have to be imported.

The low economic growth case results in an average consumption level for all petroleum products in 1990 that is 0.6 million barrels per day lower than the base case forecast. At the same time, net petroleum imports (crude oil and products) would be 0.6 million barrels per day lower. In the high economic growth case, net petroleum consumption in 1990 would be 0.6 million barrels per day higher than the base case level, and total petroleum imports would be 0.6 million barrels per day higher. The effect of varying economic growth assumptions is not the same for all fuels: Motor gasoline demand, for example, is more sensitive than residual fuel oil demand to changes in real income. The resulting shift toward gasoline production in the high growth case results in a lower residual fuel oil price relative to the gasoline price.

Figure 6. Petroleum Products Supplied, Selected Years



[a]Includes ethane, ethylene, propane, propylene, butanes, butylene, butane-propane mixtures, ethane-propane mixtures, and isobutane produced at refineries and natural gas processing plants.

[b]Includes aviation gasoline, jet fuels, kerosene, petrochemical feedstock (naphthas with less than 400 degrees Fahrenheit end points, other oils with over 400 degrees Fahrenheit end points, and refinery still gas consumed as feedstock), and all other products not shown explicitly.

[c]Includes motor gasoline only.

Source: • History: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) (Washington, DC, 1984). • Projections: Appendix A, Table A15.

Natural Gas Markets

Domestic production of dry natural gas in the forecast period is expected to peak in 1988 at 17.6 trillion cubic feet, then decline to 17.3 trillion cubic feet in 1990 (Figure 7). Natural gas consumption is expected to increase from 18.2 trillion cubic feet in 1985 to 18.8 trillion cubic feet in 1990 and then remain close to that level through 1995. The average wellhead price of natural gas (in 1984 dollars) is expected to be stable at about $2.70 per thousand cubic feet through 1986 following the partial deregulation mandated by the Natural Gas Policy Act (NGPA). Real wellhead prices are then expected to increase to an average of $3.50 per thousand cubic feet in 1990. The real price of natural gas in the residential sector was $6.37 per thousand cubic feet in 1983, almost 22 percent lower than the real heating oil price; in 1990, the price of natural gas is projected to be $7.20 per thousand cubic feet, or about 12 percent lower than the heating oil price. The increase in wellhead prices is primarily due to the depletion of relatively inexpensive reserves in the earlier years of the projection period. Residential prices are projected to increase more rapidly than wellhead prices because of the projected increase in average pipeline fuel costs and tariff adjustments to preserve switchable end-use markets (as discussed in Chapter 6). Additional uncertainties with respect to these projections are also discussed in Chapter 6.

Existing contract requirements (called take-or-pay commitments) have compelled many pipeline companies to purchase or pay for more natural gas than they can sell (Chapter 6). Companies not able to meet these contract requirements because of declining demand charged higher prices to consumers, an action that may have resulted in even lower demand. Since 1982, many pipeline companies have exercised market-out contract provisions that allowed them to lower the price of purchased gas.

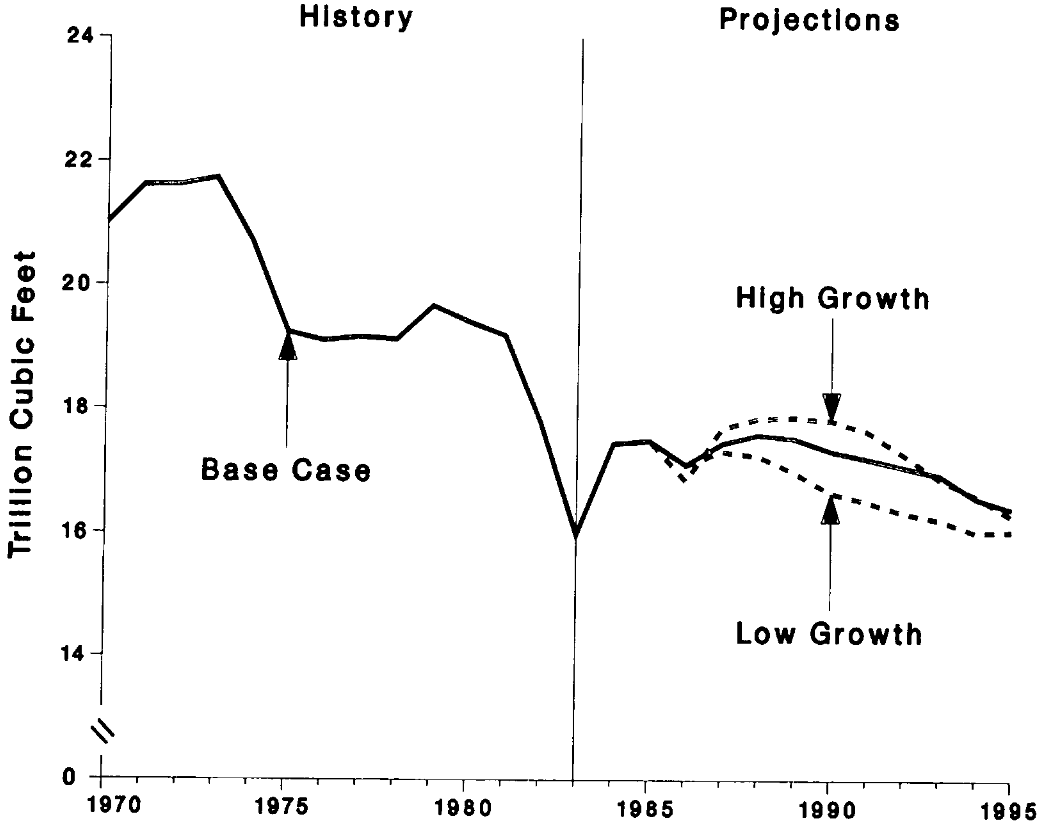
Some pipeline companies also have been successful in renegotiating contracts to lower take-or-pay requirements and to lower prices temporarily. In many cases, however, where pipeline companies and producers failed to reach an agreement, the pipeline companies purchased quantities of natural gas below contracted levels. As a result of these activities and the rapid drop in prices paid for gas in new contracts, the average wellhead price of natural gas remained essentially constant during 1983 and 1984. Consumption of natural gas in 1984 increased mainly because of the economic recovery, and also as the result of several programs implemented under the Natural Gas Act (NGA) and the NGPA to offer gas at lower rates and allow gas to flow more easily to certain users under direct sales or contract carriage arrangements.

After partial deregulation of wellhead prices in 1985 (see box), natural gas markets are expected to continue to evolve toward less regulation and greater reliance on market forces. The principal factors responsible for this change are as follows:

- New gas import policies by both the United States and Canadian governments

- A changing approach toward regulation at the Federal Energy Regulatory Commission and public utility commissions, allowing more flexibility in gas pricing and marketing

Figure 7. Marketed Natural Gas Production: Comparison of Economic Growth Scenarios, 1970-1995



Source: • History: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) (Washington, DC, 1984), Table 65.
• Projections: Appendices A, B, C; Tables A17, B17, C17.

- New institutions that lead to more competitive markets, such as spot markets and new pipeline carriage arrangements.

Under the new gas imports policy between the United States and Canada, imports are expected to have a growing effect on the domestic market in the forecast period. Both governments have moved toward a more market-based pricing strategy, which is projected to permit higher import levels at lower border prices. This change is expected to result in less costly natural gas imports to the United States and lower overall gas prices because of the increasingly competitive market.

Assumptions in this report about levels of natural gas imports were based on policies announced by the Canadian government in July of 1984. In November, 1984 (after the assumptions for this report were established), the Canadian government approved 6 long-term contracts under this policy allowing considerably more flexible pricing than was assumed in this report. As a result, natural gas imports from Canada are likely to exceed levels assumed in this report, and average import prices are likely to be lower in the near-term if the current Canadian policy remains in effect.

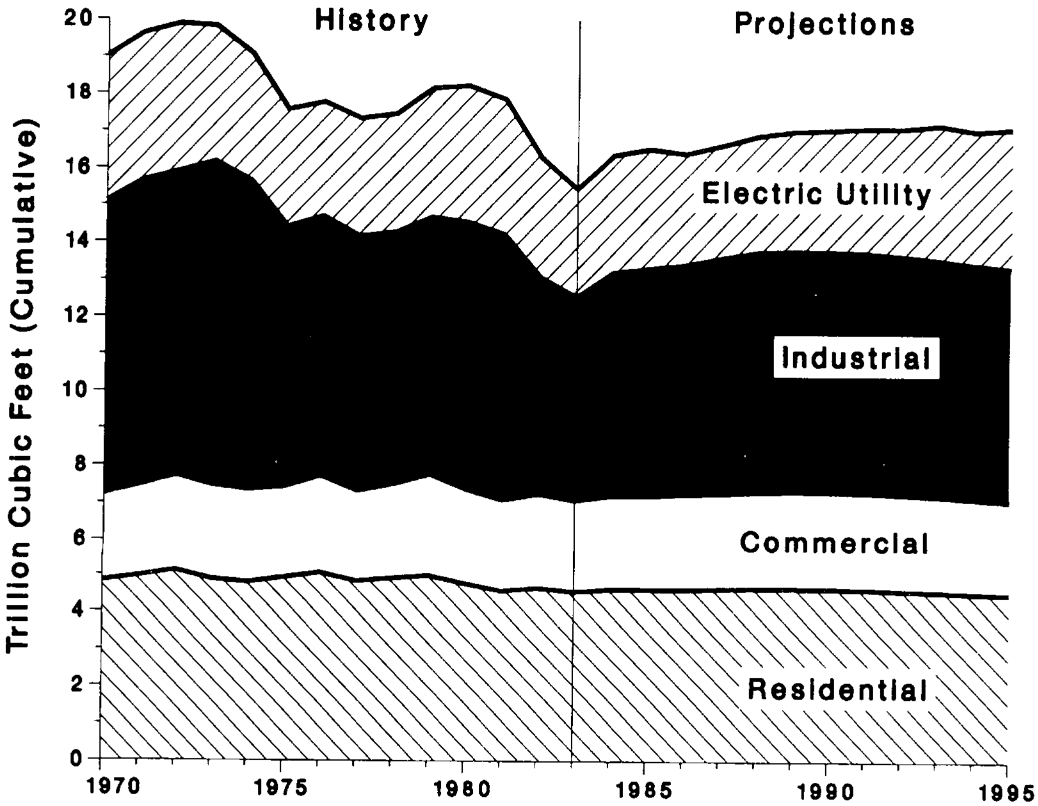
Several State regulatory commissions recently have allowed gas distributors to use flexible pricing, where distributors may lower gas prices to some customers in order to compete with fuel oil. When these competitive prices are below fully allocated gas costs, some commissions have allowed natural gas distributors to recoup losses by raising prices to residential customers and others unable to switch between fuels readily. The long-run response of these "captive" consumers (those without dual-fuel capabilities) to higher prices creates uncertainty regarding the extent to which flexible pricing can stabilize natural gas markets and sustain demand.

From 1985 to 1990, old natural gas supplies are projected to decline from about 55 percent to about 30 percent of marketed production. New gas, most of which is assumed to be free of price regulations, is expected to increase from about 45 percent to about 70 percent of marketed production. During this period, the real wellhead price is forecast to increase at an average rate of about 6 percent annually, due to the depletion of less expensive old gas and the increasing price of oil in the late 1980's. From 1985 to 1990, domestic marketed production of dry natural gas is projected to decrease slightly to about 17.3 trillion cubic feet, and imports of natural gas are assumed to increase from their current levels of slightly less than 1.0 trillion cubic feet to 1.6 trillion cubic feet in 1990. Based on recent actions by the Canadian Nation Energy Board, the average price of imported gas over this period is projected to decline.

Overall consumption of natural gas is projected to remain relatively constant from 1985 to 1990 (Figure 8). In the residential and commercial sectors, the growth in the overall demand because of economic and demographic factors is expected to be counterbalanced to some extent by improvements in the efficiency of fuel use. Industrial consumption of natural gas (excluding refinery uses) is projected to increase by 6 percent from 1985 to 1990. Electric utility consumption is forecast to be relatively stable at about 3 trillion cubic feet through 1990.

From 1990 to 1995, the real world oil price is assumed to increase at an average rate of 6 percent per year, compared to the 8-percent per year increase projected

Figure 8. Natural Gas Delivered to Consumers by End-Use Sector, 1970-1995



Source: • History: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) (Washington, DC, 1984), Table 67.
• Projections: Appendix A, Table A17.

for the average real price of natural gas at the wellhead. The average delivered price of gas to the end-use sectors is projected to increase by 6 percent per year, driven largely by the increases in the cost of adding new natural gas reserves to replace cumulative production. Over this period, domestic production is forecast to decline by about 1 percent per year, while competitively priced imports are projected to increase from 1.6 trillion cubic feet in 1990 to 2.1 trillion cubic feet in 1995. Residential, commercial, and industrial consumption is projected to decline slightly, and electric utility consumption is expected to increase by about 3 percent per year. Demand for natural gas in the electric utility sector is the most sensitive to price changes because this sector has extensive capabilities for burning alternative fuels, mainly residual fuel oil. Thus, as the price of natural gas changes relative to the prices of substitute fuels, switching between these fuels is expected.

The relatively low, expected prices of natural gas, particularly in the early years of the forecast, are projected to be inadequate to stimulate enough drilling to find reserves to replace production volumes. From 1985 to 1990, annual additions to Lower 48 States' reserves are projected to average 11.7 trillion cubic feet. Production in the Lower 48 States during this period is expected to average 17.4 trillion cubic feet per year, resulting in a net drain of reserves through 1990. However, this trend experienced during the earlier part of the forecast period is expected to be reversed during the last 3 years of the forecast. By 1995, new discoveries for the Lower 48 States are projected to reach 15.9 trillion cubic feet, compared to an average 15.4 trillion cubic feet between 1985 and 1992. Higher projected levels of natural gas reserve additions reflect the combined impacts of higher prices, the accelerated leasing program undertaken over the past few years, and the potential for entirely new areas of supply. Higher prices, which are associated with rising prices for competing fuels (particularly oil) and with declining reserves, encourage exploration and production in areas previously considered to be too costly or too risky to develop. Natural gas production from the OCS in particular is expected to be a major contributor to the reserve base in the future.

In the alternative economic growth cases, differences in the levels of natural gas demand result in significantly different prices at the wellhead and to end-users. In the low economic growth case, the real average wellhead price in 1990 (in 1984 dollars) is projected to be about $3.30 per thousand cubic feet, or 6 percent lower than the base case level, with essentially the same level of production in that year. This difference in price reflects the cumulative effects of slower depletion of lower priced reserves, implying less need to move to higher-cost new sources. Electric utility consumption of natural gas in 1990 is projected to be 11 percent lower than the base case level as a result of lower demand, even though average prices are 5 percent lower than in the base case. Consumption in the residential and commercial sectors remains near the base case level regardless of economic growth assumptions, because it is determined more by the size and characteristics of the building stock than by the level of economic activity. Industrial consumption of natural gas in the low growth case is projected to be 5 percent below the base case level in 1990.

In the high economic growth case, the average wellhead price in 1990 is projected to be about $3.70 per thousand cubic feet, or 5 percent higher in real terms than in the base case with essentially the same domestic production level. Total supply in 1990 is projected to be about 3 percent higher than the base case level.

In the high economic growth case, industrial consumption of natural gas is projected to be 4 percent higher. In contrast, electric utility consumption is forecast to be about 11 percent higher than the base case level in 1990. In this case in 1995, total end-use natural gas consumption is projected to be lower than in the base case. This drop is attributable to a projected decrease in electric utility natural gas use which occurs because natural gas prices are projected to be above oil prices in this sector. This price situation causes switching from natural gas to oil, and the resulting decrease in electric utility consumption is sufficient to decrease total consumption.

Partial Wellhead Price Decontrol in 1985

On January 1, 1985, the price ceilings mandated by the Natural Gas Policy Act (NGPA) were removed from about half of the natural gas produced in the United States. For much of the gas in the interstate market this was the first time that the contract deregulation clauses were activated. In the intrastate market, much of the natural gas is now priced according to contract provisions active before the NGPA when Federal ceiling prices were not a part of intrastate market pricing (although several States currently have price ceilings on intrastate gas). An important question is what will happen to natural gas prices in the future as a result of deregulation.

In 1984, price ceilings from the NGPA constrained any upward price pressure that resulted from contract clauses; there also was significant downward pressure because production capacity exceeded demand. From 1978 to 1983, the average real wellhead price of natural gas doubled, continuing the upward trend that began in the mid-1970's. These price increases occurred despite stable or even declining consumption. The reasons for the increases are related to natural gas price regulations, to contractual relationships developed under those regulations, and to decisions to buy long-term supplies of gas at relatively high prices.

The average new-contract price of natural gas currently ranges from $2.90 to $3.35 per thousand cubic feet. However, some gas under existing contracts today is priced at more than $9 per thousand cubic feet. In response to the current excess supply of natural gas, pipelines have taken a number of actions to reduce the wellhead prices for gas under older, higher cost contracts. These actions include the exercise of market-out clauses, renegotiation of contracts, and abrogation of contracts. How rapidly and completely existing contracts can be altered to reflect new market conditions is a major problem in forecasting wellhead prices. The average wellhead price of natural gas has been essentially constant during 1983 and 1984, as a result of changes in purchase strategy, contract adjustments, and the drop in new gas prices.

The partial deregulation of natural gas that occurred on January 1, 1985, is expected to add upward pressure on wellhead prices because of contract terms that tie gas prices to the price of other fuels or to the prices of previously deregulated gas. Nevertheless, the downward pressure on natural gas prices resulting from current market conditions is expected to dominate the transition during 1985. Although there may be some isolated price adjustment problems, average wellhead prices are expected to remain stable (Chapter 6).

Electric Utilities

Demand for electricity is projected to increase by 3.4 percent per year between 1985 and 1990, compared to the projected growth rate in GNP of 3.1 percent per year over that period. For 1990 to 1995, electricity demand is projected to grow by 3.1 percent per year, with GNP growth slowing to 2.3 percent per year. Electricity demand could increase by as much as 4.1 percent per year between 1985 and 1990 if economic activity increases at 3.9 percent per year, as assumed in the high growth case. The lower range shows a 2.5-percent per year increase in electricity demand with a 2.1-percent annual growth in GNP between 1985 and 1990.

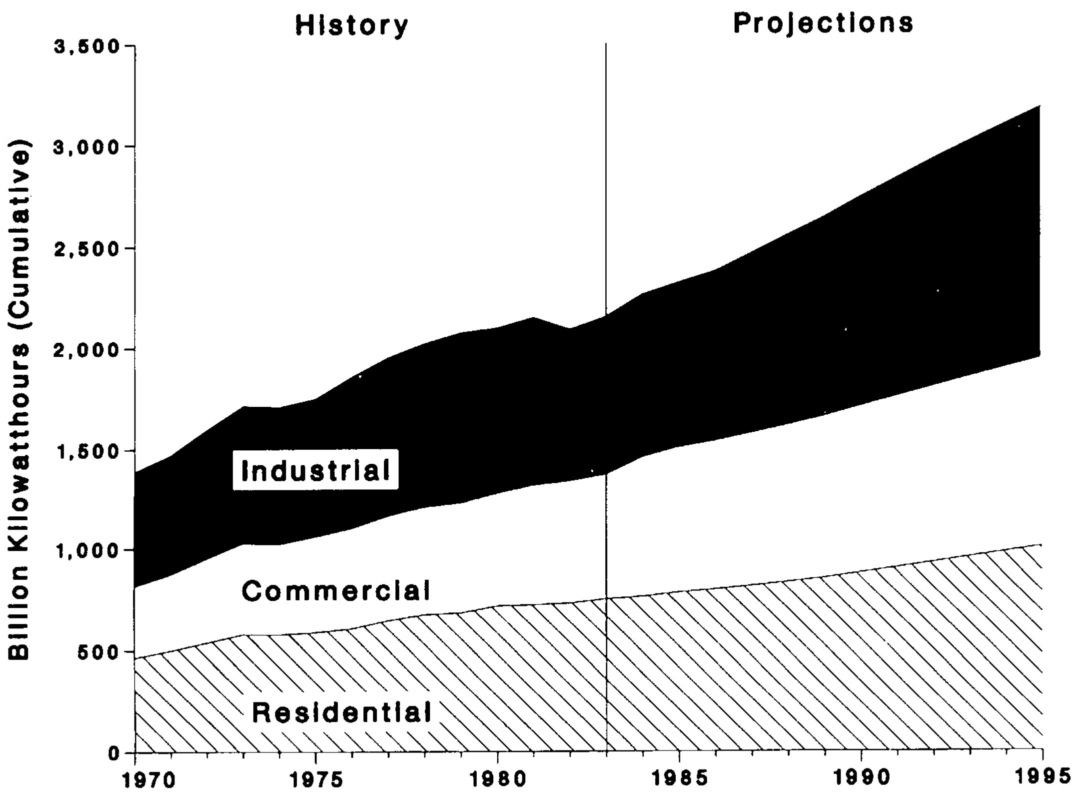
Since the early 1950's, the ratio between the rate of growth in electricity generation and the rate of growth in GNP has varied. From 1952 to 1982, this ratio averaged about 2. In recent years there has been a marked reduction in the rate of growth in electricity generation, but electricity demand still is expected to grow more rapidly than GNP over the forecast period because of consumer preference for electricity over other fuels, a trend reinforced by the projected decline in the relative price of electricity. The real price of electricity is forecast to decline through 1995 as a result of stable or declining fuel prices early in the forecast period and declining capital expansion programs for new power plants later in the forecast period (which compensate for higher fuel costs).

Supplies of electricity are projected to be adequate over the forecast period, although more than half of the regions could experience difficulties in meeting peak demand if increases in economic growth and electricity demand are higher than projected in the base case.[8] The fuel mix used to generate electricity also is expected to change as more coal-fired and nuclear-powered capacity becomes available. Industrial demand for electricity, which is expected to increase from about 35 percent of total end-use electricity in 1985 to 38 percent in 1990 (Figure 9), is projected to be grow more rapidly than residential and commercial demands.

<u>Electric Generating Capacity</u>. Following net new capacity additions of 17 gigawatts in 1984 and 23 gigawatts in 1985, a total of 60 gigawatts of net capacity is projected to be added from the end of 1985 through 1990 (Table 7). From 1990 to 1995, another 46 gigawatts of new capacity additions are projected. All expected nuclear units and the majority of new coal-fired facilities are already under construction. Significant nuclear capacity is projected to be added through 1988, with additions tapering off through 1995. Additional new capacity not currently planned or under construction is expected to be required to meet the projected level of electricity demand. However, the shortfall in generating capacity may be

[8] These projections assume normal hydroelectric conditions; under assumptions of adverse conditions such as a drought, supply adequacy would be decreased.

Figure 9. Electricity Consumption by End-Use Sector, 1970-1995



Note: Commercial inclues other end uses, such as transportation, railways, street lighting, and sales to Government.

Source: • History: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) and Monthly Energy Review, DOE/EIA-0035(84/06) (Washington, DC, 1984). • Projections: Appendix A, Table A11.

met by other means, such as conservation, imports, load management, or noncentral generating stations.

Net imports of electric power to the United States from Canada and Mexico are assumed to rise from 1.6 percent of U.S. generation in 1985 to 2.3 percent by 1990. This forecast assumes that electricity imports to the United States will continue to grow to supplement domestic production, with Canada being the major source of these imports. Net electricity imports (in fossil-fuel equivalents) are projected to grow from 0.4 quadrillion Btu in 1985 to 0.7 quadrillion Btu in 1990. In the post-1990 period, net imports are projected to remain nearly constant. These forecasts are predicated on the carrying capacity of existing and planned transmission lines and utility contracts, and they assume that both Mexico and Canada remain net exporters to the United States.

Table 7. Electric Utility Generating Capacity by Type, 1973-1995
(Gigawatts at End of Year)

Capacity Type	History 1973	1978	1983	Projections 1984	1985	1990	1995
Coal-Fired	184	234	286	296	304	329	360
Nuclear-Powered	21	53	[a]64	[a]69	81	110	117
Oil- and Gas-Fired							
Steam	135	161	157	157	157	157	157
Turbine	37	50	51	51	51	53	59
Combined Cycle	1	5	6	6	6	6	6
Other							
Hydroelectric, Conventional[b]	56	63	66	66	67	69	69
Hydroelectric, Pumped Storage	8	13	13	15	16	19	19
Other[c]	b	b	3	4	4	4	4
Total	442	579	646	663	686	746	792

[a]Nuclear capacity in 1983 and 1984 includes Three Mile Island 1, currently in extended shutdown, but assumed in this analysis to begin operation in 1985.

[b]Data for 1973 and 1978 for "Hydroelectric" include "Other."

[c]Includes geothermal power, wind, wood, and waste.

Note: Components and totals rounded independently. A gigawatt is 1,000 megawatts or 1 billion watts.

Note: Data for 1973 and 1978 include plants "out of service" or on inactive reserve; data for 1983 and projected figures exclude plants in these categories.

Source: • History: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83), for 1973 and 1978, and Energy Information Administration, Generating Unit Reference File (GURF) for 1983. • Projections: Appendix A, Table A12.

Other means of meeting projected electricity requirements, such as conservation, load management, and noncentral generation, are not explicitly represented in the projections. Technology-driven conservation or enhanced load management would reduce the quantity of electricity demanded without diminishing energy services delivered to end-users. Noncentral generation refers to facilities not owned and operated by regulated electric utilities. Such facilities, which include cogenerators and small power producers, are encouraged by the Public Utilities Regulatory Policies Act of 1978 (P.L. 95-617) to produce and sell electric power to improve overall energy production efficiency. Noncentral generating stations would increase the available supply of electric power.

Capacity growth rates are only affected slightly by changes in the assumed level of economic growth between 1985 and 1990, with capacity expected to grow by 1.7 percent per year in each of the economic growth cases. Differences in economic growth assumptions are expected to affect capacity additions in the 1990 to 1995 period, with a projected 1.5 percent per year increase in capacity in the high economic growth case and a 1.0 percent per year increase in the low economic growth case. Most of the difference in rate of capacity growth is attributable to changes in turbine capacity needed to meet peak demand growth.

Electricity demand is expected to be more responsive than capacity to changes in economic activity, growing by 2.5 percent per year in the low economic growth case to 4.1 percent per year in the high growth case between 1985 and 1990. Industrial electricity use is particularly responsive to the economic growth assumption, increasing by 3.2 percent per year and 5.8 percent per year in the low and high economic growth cases, respectively, over that period.

Because generating capacity is expected to grow less rapidly than electricity demand, reserve margins (the percent of capacity not in use at times of peak demand) are expected to decline to a national average of 39 percent by 1990.[9] Reserve margins are projected to remain well above 20 percent (a level generally considered adequate by industry analysts) in all regions except the West. By 1995, margins at the national level are still expected to average over 20 percent, but wide variations in conditions are expected among the individual regions. For example, even under the assumption of low economic growth, overall reserve margins in the West are projected to fall below 20 percent. In the base case, by 1995 reserve margins decline to between 15 and 19 percent in the West, Southwest, and Central regions; and in the high economic growth case, reserve margins of 14 percent to 18 percent are projected in over one-half the regions. Reserve margins of 15 percent are generally considered to be the minimum acceptable levels.

Reliability problems could occur in the 1990's, in light of the continued absence of new construction announcements and the projection that electricity demand will grow faster than the additions of new generating equipment. The timing and

---

[9]The measure of the reserve margin would be lower if net dependable capacity and regional noncoincidental peak load data rather than nameplate capacity and coincidental peak load data were used. In 1983, net dependable capacity was about 6 percent lower than nameplate capacity.

severity of these problems are dependent on actual electricity demand growth, capacity additions actually brought into service, contributions to electricity supply from noncentral station sources, and many other factors. In the high economic growth case, the expected reduction of reserve margins to levels considered minimally acceptable indicates that difficulties in providing reliable electricity service could occur.

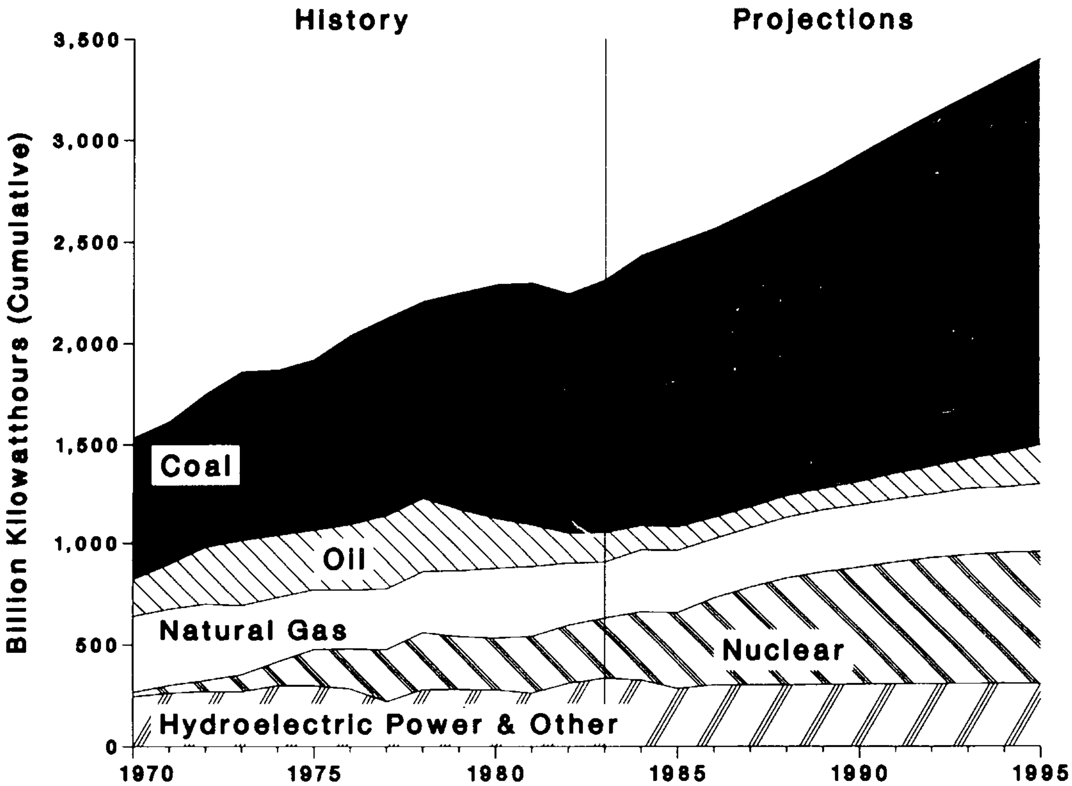
Electric Utility Fuel Use. Major changes in the fuels used to generate electricity have occurred since the 1973 oil embargo. Utilities instituted programs to use less expensive coal and nuclear fuels to decrease dependence on more expensive oil and natural gas (Figure 10). Over the forecast period, coal-fired and nuclear power plants are projected to be the principal sources of electricity generation, with their shares expected to continue to grow, although the average rate of growth is projected to fall below 1 percent. By 1990, electricity from coal is expected to constitute 55 percent of total generation, the same as its share in 1985, while nuclear-powered generation is projected to grow from 14 percent of total generation in 1985 to 20 percent in 1990. Electricity from oil and gas is expected to supply only 15 percent of total output in 1990. The shares of generation from hydroelectric power and other sources are projected to decline over the forecast period, given their much slower projected rates of capacity growth.

Changes in the assumed rate of economic growth are expected to affect relative fuel shares. Between the low and high economic growth cases, the combined oil and natural gas share of total generation is expected to range from 14 percent to 16 percent in 1990. The coal share is projected to remain essentially unchanged, despite an absolute increase in coal generation in the high economic growth case relative to the low case. Nuclear and hydroelectric generation are projected to remain constant over all cases; consequently, their shares of total generation are projected to decrease as electricity demand increases.

Cost of Electricity. The real price of electricity is expected to decline very slightly over the forecast period, at a rate of about 0.2 percent per year from 1985 to 1990 and 0.4 percent per year from 1990 to 1995 (Table 8). Because of this price decrease, electricity is expected to become increasingly competitive with other energy sources. Higher usage rates resulting from electricity demand growth and the slowing of new power plant construction are projected to reduce the capital cost per unit of electricity output, especially in the later years of the forecast. Higher total fuel costs at electric utilities, mainly resulting from increased consumption of oil and gas, are not expected to offset the projected declines in capital costs. The capital cost portion of the total electricity price is expected to fall from $25.5 per thousand kilowatthours in 1985 to $23.8 per thousand kilowatthours in 1990, and the fuel cost component is expected to rise from $23.2 per thousand kilowatthours to $24.4 per thousand kilowatthours over that period (Figure 11). Operating and maintenance costs are projected to remain at about $15 per thousand kilowatthours over the forecast period.

In the high economic growth case, electricity prices are expected to be stable through 1990, as higher fuel costs offset declines in capital and operating and maintenance (O&M) costs. Low economic growth assumptions initially result in a higher capital share and higher electricity prices than in the base case, but after 1990 yield lower total electricity price projections than in the base case because of anticipated lower fuel prices and less use of more expensive fuels.

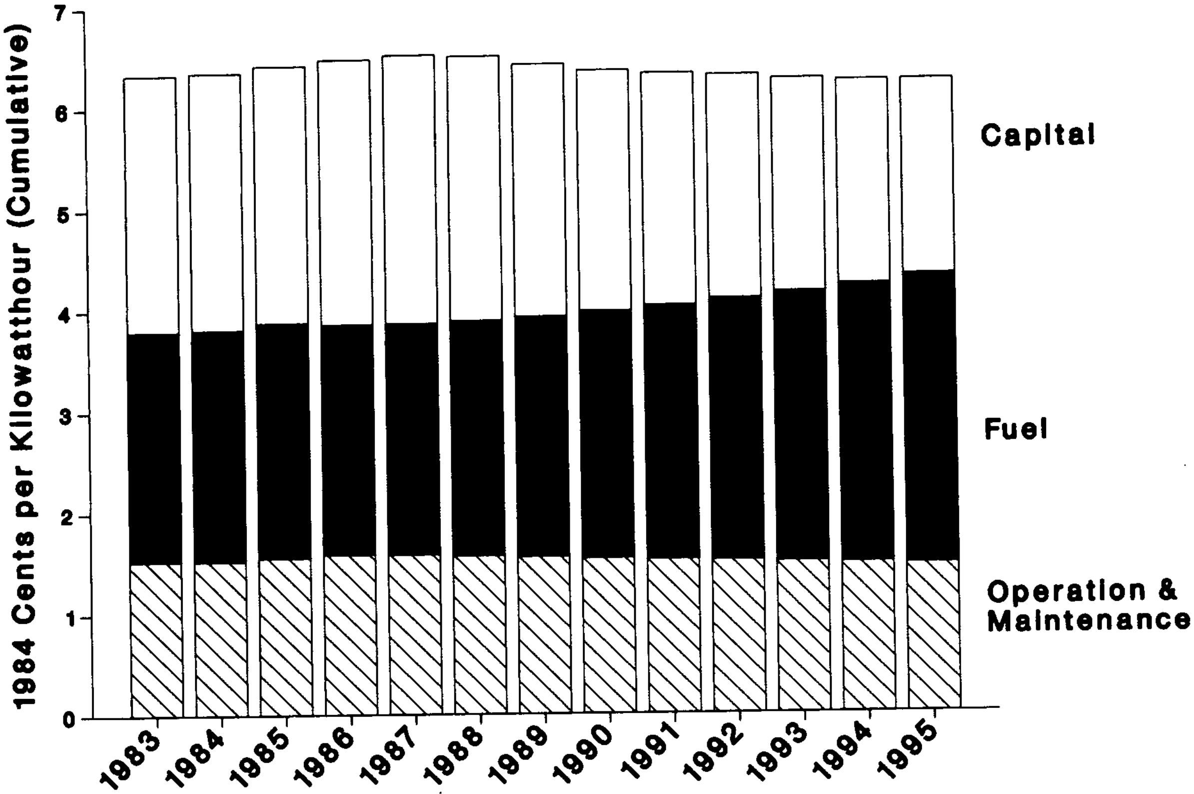
Figure 10. Sources of Electrical Supply, 1970-1995



Note: "Other" includes renewable resources such as geothermal, wood, waste, solar, and wind.

Source: • History: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) and Electric Power Monthly, DOE/EIA-0226 (84/06) (Washington, DC, 1984). • Projections: Appendix A, Table A12.

Figure 11. Projected Average Electricity Price Components, 1983-1995



Source: Appendix A, Table A14.

Financing Utility Construction. From 1985 through 1990, electric utilities are projected to require $161 billion (in nominal dollars) to install new capacity, an average of $26.9 billion per year. About $85 billion will be required for generating capacity; transmission, distribution, and other capital outlays are expected to account for the remainder. Additions to the rate base of the electric utility industry from 1985 through 1990 are expected to approach $217 billion. This figure includes capital expenditures incurred prior to 1985, but entering the rate base during the forecast period, as well as expenditures incurred for new capital projects. These total additions to the rate base are approximately equal to 60 percent of the estimated net value ($361 billion, in nominal terms) of all existing assets of the electric utility industry in 1983.[10]

Table 8. Components of Electricity Price, 1984-1995
(1984 Dollars per Thousand Kilowatthours)

Costs	1984	1985	1990	1995
Capital	25.5	25.5	23.8	19.3
Fuel	22.8	23.2	24.4	28.5
O&M[a]	15.2	15.5	15.3	14.7
Total	63.5	64.2	63.6	62.4

[a]Operating and maintenance costs.
Note: Totals may not add due to independent rounding.
Source: Appendix A, Table A14.

Increases in internal cash flow at electric utilities should help investor-owned utilities (IOU's) raise new capital. As the IOU's complete existing construction programs, internal cash generation as a percentage of construction expenditures is projected to increase from about 71 percent in 1985 to nearly 90 percent by 1990. This change indicates that borrowing as a share of new construction costs should decline over this period (Table 9). However, the ratio is expected to drop to 74 percent by 1995 because of increased capital expenditures for facilities expected to be completed after 1995. The earnings available to meet the industry's fixed interest obligations (such as interest payments on debt) are projected to improve from 2.3 times interest expenses in 1985 to 2.8 times in 1990, which could lower interest rates on borrowed funds.

The quality of earnings, which is a measure of the noncash portion of total earnings (represented by the ratio of the allowance for funds used during construction

[10]National Utility Financial Statement Model (NUFS) (Washington, DC, 1984) Run M1FGMB.D0314842, using base case assumptions.

(AFUDC) to total earnings available to common equity), is projected to improve from nearly 54 percent in 1985 to 22 percent in 1990. In addition, construction work in progress (CWIP) as a percentage of net electric utility plant (the investment in new assets compared to the total investment in existing assets) is projected to decline from about 22 percent in 1985 to 10 percent in 1990. However, individual utilities with large construction programs may continue to experience significant financial problems during the 1980's.

Table 9. Electric Utility Financial Ratios for Investor-Owned Utilities, 1983-1995 (Percent)

Financial Ratios	History		Projections		
	1983	1984	1985	1990	1995
Interest Coverage[a]	2.3	2.3	2.3	2.8	2.8
Internal Financing[b]	52.1	78.4	71.3	89.8	74.2
Ratio of AFUDC to Earnings[c]	63.7	60.5	53.5	22.0	21.8
Return on Equity	15.2	15.0	14.1	15.7	16.5
CWIP as a Percentage of Net Plant[d]	33.1	28.6	22.0	10.5	12.2

[a]Ratio of pretax earnings less allowance for funds used during construction (AFUDC) plus interest payments to interest payments (does not reflect interest expenses for nonelectric operations).

[b]Internal cash flow as a percentage of construction expenses.

[c]AFUDC = Allowance for funds used during construction--noncash earnings associated with future benefits of current construction activity.

[d]CWIP = Construction work in progress--the value of expenditures for plants that are incomplete and not yet in service.

Source: Energy Information Administration, Office of Energy Markets and End Use, Energy Analysis and Forecasting Division and Office of Coal, Nuclear, Electric, and Alternate Fuels, Electric Power Divsion, National Utility Financial Statement Model (NUFS) (Washington, DC, 1984) Run M1FGMB.D0314842, using base case assumptions.

For the electric power industry in general, the expected improvement of financial conditions should permit utilities to begin new construction programs needed to meet electricity demand growth in the late 1990's and beyond. Even if more construction than is projected is required to meet demand growth beyond 1995, the impact on electricity prices to consumers during the forecast period would be relatively small because the majority of the additional cost would not be reflected in prices until such plants are completed.[11] The magnitude and timing of new construction activities are dependent on demand growth and the perceived need for new investments by utility planners. Investment decisions for both refurbishing existing power plants to extend their life and improve their performance and for long leadtime projects (8 years for coal-fired plants and 10 to 15 years for nuclear plants) will be needed in the next several years, especially if demand levels projected in the high economic growth case are realized.

Coal

Coal production is projected to increase at an average annual rate of 3.3 percent between 1985 and 1990, to nearly 1.1 billion short tons (Figure 12). By 1995, coal production is projected to be over 1.2 billion short tons. This rapid increase is mainly attributable to the strong growth in electric utility demand for coal over the forecast period. Based on alternative assumptions about economic growth, coal production in 1990 could range from 1.0 billion short tons to 1.1 billion short tons, varying mainly because of the sensitivity of electricity demand to the level of economic activity. The coal industry is expected to produce all the coal demanded by domestic and foreign consumers through 1995 without substantial additional increases in real minemouth prices. Any shortages as a result of strikes or surges in demand are expected to be temporary, as there are ample coal reserves available for development.

Domestic Coal Consumption. Domestic coal consumption increased rapidly during the economic recovery of 1983 and 1984; however, a slowing in this rate of increase is expected in 1985 as a result of the lower projected rate of economic growth. Domestic coal consumption is projected to increase by 115 million short tons (about 2.6 percent per year) between 1985 and 1990 and by 152 million short tons (about 3.0 percent per year) from 1990 to 1995 (Table 10). The larger increase between 1990 and 1995 is primarily because a larger share of the growing level of electricity demand is expected to be met by coal-fired capacity as nuclear capacity additions decline.

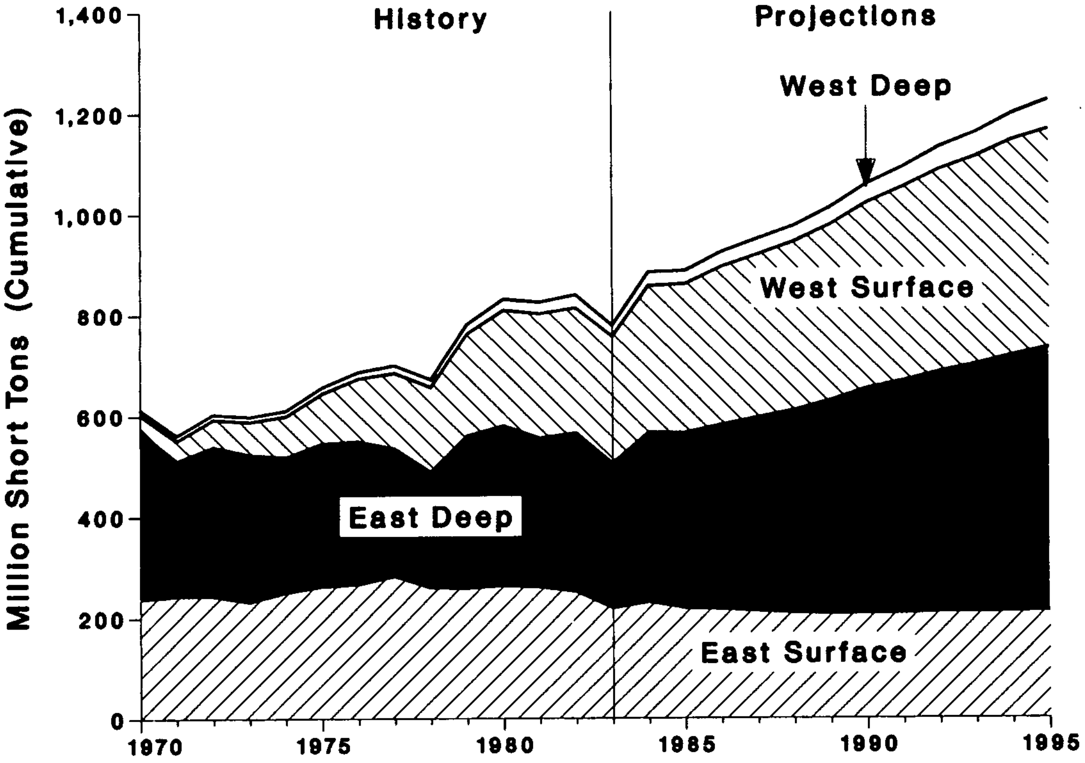
Coal consumption at electric utilities is projected to increase by 96 million short tons from 1985 to 1990 and by 146 million short tons from 1990 to 1995. Over half of the 14-percent increase in coal consumption by utilities from 1985 to 1990 reflects the projected 8-percent increase in coal-fired capacity, and increased utilization accounts for the remaining increase.

Consumption of industrial steam coal is projected to continue to represent a minor component of total coal demand. Nonetheless, this segment is projected to grow by 16 percent (12 million short tons) from 1985 to 1990. Besides the cement industry, which has largely converted its cement kilns to burn coal, other industries are expected to convert to coal, although more slowly because of the higher costs

---

[11] Under the assumptions used in the forecast, only 15 percent of construction work in progress enters the rate base and is incorporated in consumers' electricity prices prior to the completion of a generating plant.

Figure 12. Coal Production by Region and Type of Mining, 1970-1995



Source: • History: U.S. Department of the Interior, Bureau of Mines, Minerals Yearbooks, (Washington, DC, 1972-1977); Energy Information Administration, Bituminous Coal and Lignite in 1976, DOE/EIA-0118/1(76), Bituminous Coal and Lignite Production and Mine Operation, 1977-1978, DOE/EIA-0118 (77-78), and Coal Production, 1979-1983, DOE/EIA-0118(79-83) (Washington, DC). • Projections: Appendix A, Table A18.

associated with coal handling and combustion equipment compared with oil- and gas-fired equipment. However, the development of new sulfur-removal technologies, such as fluidized bed combustion, could lower the cost of meeting air quality standards with coal-fired boilers. (Several of these technologies are discussed in Chapter 8.)

Table 10. U.S. Coal Consumption by Sector, 1973-1995
(Million Short Tons)

	History			Projections			
Consuming Sector	1973	1978	1983	1984	1985	1990	1995
Electric Utility	389	481	625	666	709	805	951
Coke Plants	94	71	37	44	46	51	49
Other Industrial	68	63	66	76	77	89	98
Synthetics	--	--	--	--	5	6	6
Other[a]	11	10	8	8	8	7	7
Total Consumption	563	625	737	793	843	958	1,110

-- = Not applicable.
[a]Includes the residential and commercial sector.
Source: • History: Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(84/06) and Quarterly Coal Report, DOE/EIA-0121 (84/2Q) (Washington, DC, 1984). • Projections: Appendix A, Table A18.

Domestic metallurgical coal consumption is projected to increase moderately from 1985 to 1990, although a wide range of outcomes is possible. Two major uncertainties concerning the metallurgical coal projection are the share of domestic steel demand that will be met by imports and the share of domestic steel production that will be obtained by "minimills," which mainly use electric furnaces to make steel products from scrap. Increased imports of steel and steel products would reduce domestic steel production, and increased use of electric furnaces in steel production would reduce the consumption of pig iron and, hence, coke.

Use of coal to produce synthetic fuels for sale on the open market was negligible in 1983, but is expected to be about 6 million tons in 1990. The Great Plains Gasification Plant in North Dakota, which produces synthetic natural gas from lignite, is the only major plant included in the forecast. Coal use by industrial plants that consume the synthetic fuels they produce are included in the industrial sector's demand for coal.

Exports. U.S. coal exports are projected to increase to 91 million short tons by 1990 (Table 11). By 1995, coal exports are expected to be 106 million short tons, but still below the 1981 record level of 113 million short tons.[12] The world steam coal market is expected to grow considerably over the next decade, and the United States is expected to remain a major exporter of steam coal. The United States also is expected to remain the largest exporter of metallurgical coal, increasing its exports to Europe and South America. However, metallurgical coal exports to Asia are expected to decline because of competition from Australia and Canada.

Coal Production. Coal production is expected to increase at an average annual rate of 3.3 percent between 1985 and 1990, with most of this increase attributable to higher levels of domestic demand. Coal production by mines located east of the Mississippi River is projected to increase by close to 80 million short tons from 1985 to 1990. Mines west of the Mississippi River also are expected to increase production by about 80 million tons; the increase in production in the West represents an average annual increase of 4.4 percent, compared to a 2.6 percent growth for production from mines in the East (Figure 12).

Table 11. U.S. Coal Exports, 1973-1995
(Million Short Tons)

	History			Projections			
Coal Type	1973	1978	1983	1984	1985	1990	1995
Steam Coal	11	11	28	24	17	37	50
Metallurgical Coal ...	43	30	50	57	56	54	55
Total Exports	54	41	78	80	73	91	106

Note: Numbers may not add to total due to independent rounding.
Source: • History: Energy Information Administration, Annual Energy Review 1983, DOE/EIA-0384(83) (Washington, DC, 1984) for 1973, 1978 data; Weekly Coal Production, DOE/EIA-0218(84/08) (Washington, DC, 1983), Table 9, p. 9 for 1983 data. • Projections: Appendix A, Table A18.

Western coal production is projected to increase at a faster rate than eastern coal production primarily because of the rapid growth in the coal market west of the Mississippi River. Total electricity generation by plants located west of the Mississippi River is forecast to increase by 23 percent from 1985 to 1990, with an increase of only 14 percent forecast for eastern generation. The share of western electricity generated from coal is projected to increase slightly from 43 percent in 1985 to 44 percent in 1990. Coal's share of eastern electricity generation,

[12] Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384 (83) (Washington, DC, 1984).

however, is expected to decrease from 66 percent to 63 percent over the same period, due to the projected increase in nuclear capacity. Western coal production also benefits from a moderate increase in net shipments of coal from west to east across the Mississippi River.

The share of coal production from underground mines is projected to increase throughout the forecast period. Growth in production from eastern mines is expected to be primarily from underground mines; limited opportunities for expanded surface mine production are available in the Appalachian region, which is expected to be the source of over three-fourths of projected eastern production. Most of the growth in production from western mines is expected to be from surface mines, particularly from lignite mines (largely in Texas and North Dakota) and the very thick seams of subbituminous mines in the Powder River Basin of Wyoming. However, a lower growth rate is projected for the surface mines than for the western underground mines, which produce a higher quality bituminous coal.

Effect of Higher and Lower Economic Growth. In the high economic growth case, coal production in 1990 is projected to be 29 million short tons above the base case level. In the low growth case, production is expected to be 38 million short tons lower than the base case level. The coal markets supplied by western mines are projected to be less sensitive to the underlying rate of economic growth than the markets supplied by eastern mines. Electric utilities in the West are projected to operate their coal-fired units mainly for baseload generation, while eastern utilities are forecast to shift some units between base and intermediate load as demand changes. As a result, the projected share of total coal production from western mines in 1990 is projected to be 38.8 percent in the low economic growth case compared to 38.3 percent in the high growth case.

Total domestic coal consumption in the high economic growth case is projected to be about 2.9 percent higher than the base case level in 1990. In the low economic growth case, coal consumption is projected to be lower than the base case level by about 3.8 percent in 1990. The projected response of electric utilities' demand for coal to changes in the rate of economic growth is virtually equal to that of total coal consumption. Industrial steam coal consumption in the high and low economic growth cases is estimated to be 2.2 percent above and 3.4 percent below the base case level, respectively, in 1990.

U.S. coal exports are not directly affected by the level of U.S. economic growth. Demand for U.S. export coal is influenced by competition from other coal-exporting countries as well as from indigenous coal supplies in the importing countries, availability of coal substitutes, Government energy policies, the strength of the dollar in foreign exchange markets, and the rate of economic growth in the coal-importing countries. Therefore, the projected level of U.S. coal exports is assumed to be the same in all three growth cases.

3. International Energy Markets

This chapter considers how the base case world oil price path assumptions discussed in Chapter 2 might vary given different assumptions about developments in the international oil market. As past experience has shown, world oil prices and the factors that influence them are important determinants in the energy outlook for the United States. By examining a range of assumptions for the factors thought to determine world oil prices, including economic growth of the market economies,[1] development of world oil supplies, and behavior of energy consumers, three world oil path assumptions have been estimated for 1985 through 1995. In addition to these assumptions which characterize consumer and producer behavior, there are other factors which also determine future oil prices, such as the role of competing fuels and the international exchange rate.

The three price path assumptions help demonstrate the uncertainties in the oil market (Figure 13). For example, uncertainty prevailed in the world oil market in late 1984, as certain oil-exporting countries lowered the price for their oil while others agreed to lower production in order to stop a general price decline. Alternative assumptions for world oil prices in 1990 range from a low of $25 per barrel to a high of $40 per barrel. The corresponding range in 1995 is from $30 to $55 per barrel.

The analysis of these price path assumptions begins with an overview of the major market trends that are expected to influence price behavior between 1985 and 1990 and in 1995. Next, factors of uncertainty that could lead to a higher or lower world oil price path than the base case path are examined. A hypothetical supply disruption case is considered, to demonstrate how such an event might divert prices from the base case path to a greater extent than would normal market pressures. The oil price sensitivity analysis is followed by a discussion of the basic assumptions from which sensitivity tests are made. In turn, the sensitivity of world oil supplies and demands to the three world oil price paths is tested, and assumptions about oil consumption and production under the base case are presented. Oil consumption trends will be influenced by international developments in coal, natural gas, nuclear power, and other energy sources. Possible developments concerning these fuels under the base case assumptions are also reviewed.

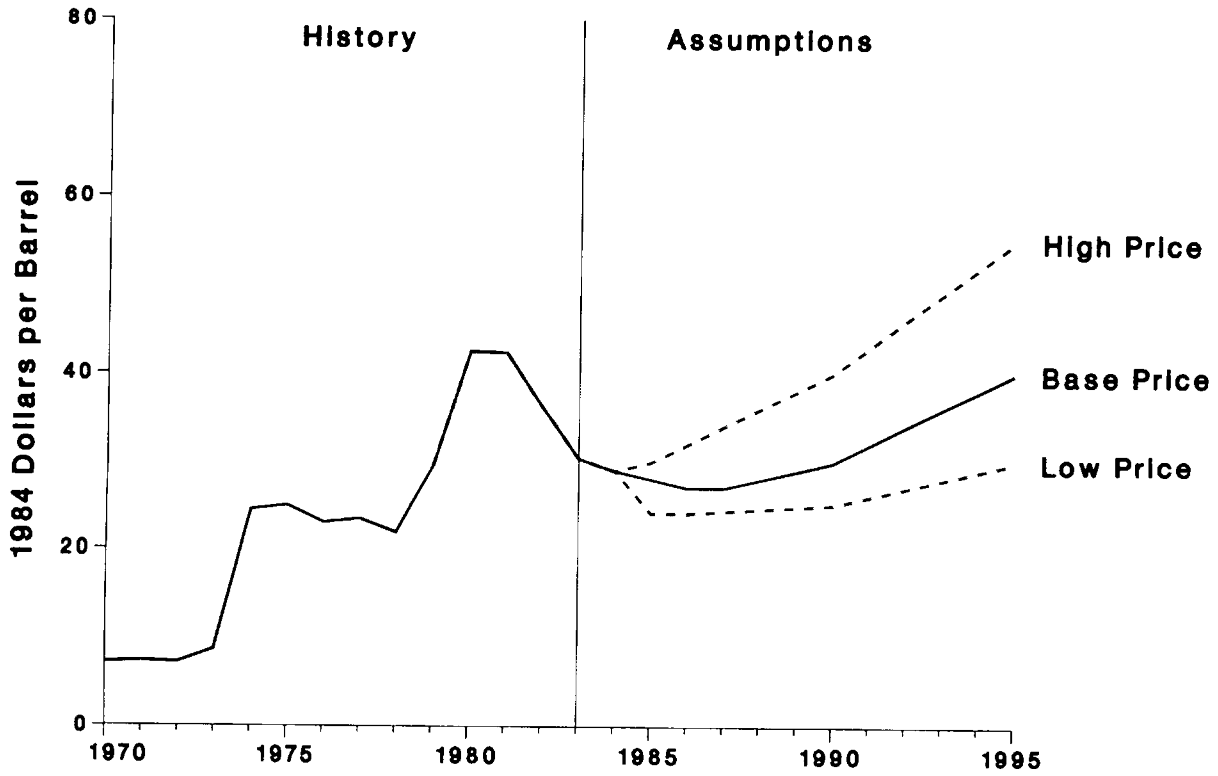
World Oil Price Sensitivity

World oil prices could decline to $24 per barrel (in 1984 dollars) in 1985 (as in the low price case) if demands resume the decline that was halted in 1984 or if production restraint by the Organization of Petroleum Exporting Countries (OPEC)

---

[1]The market economies include all countries other than the Centrally Planned Economies of Eastern Europe (including Yugoslavia), the Soviet Union, China, Cuba, Kampuchea, North Korea, Laos, Mongolia, and Vietnam.

Figure 13. World Oil Prices, 1970-1995



Note: All prices are the cost of crude oil to U.S. refiners.
Source: • History: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) and Monthly Energy Review, DOE/EIA-0035(84/06) (Washington, DC, 1984). • Assumptions: Table 12.

erodes.[2] Conversely, real prices could rise to $30 per barrel in 1985 (as in the high price case) if increased tension in the Persian Gulf raises general concern about the availability of oil supplies. The sensitivity of world oil prices to these and other possible events was considered in determining the three oil price path assumptions. Assumptions about key oil market factors were also modified to determine price path assumptions (Table 12). The rate of economic growth among market-economy countries appears to be a major determinant of future demands and, therefore, future prices, as well as efforts at energy conservation, fuel switching, and future oil supply trends.

Causes of Price Uncertainty

Economic Structure. The influence of certain international energy and economic trends on world oil prices in the past may not continue to the same extent in the future. An important trend acting to reduce oil demands and, therefore, oil prices has been the reduction in the amount of energy required to produce a given amount of output. Reductions in the ratio of energy consumption to gross domestic product (GDP) have occurred throughout the world and are due to increased energy conservation and to fundamental shifts in economic activities away from the more energy-intensive heavy manufacturing sectors and towards the less energy-intensive service and high technology sectors.

The decline in the energy/GDP ratio has accelerated since 1980. In the industrialized countries of the Organization for Economic Cooperation and Development (OECD)--excluding Greece, Portugal, and Turkey--energy per unit of output declined by about 1 percent per year between 1974 and 1979 and by more than 3.5 percent per year between 1980 and 1983.[3] The amount of oil consumption per unit of output declined at an even faster rate over this period, down by 2 percent per year between 1974 and 1979 and by more than 6 percent per year between 1980 and 1983.[4] The uncertainty of future changes in the energy/GDP ratio contributes to the uncertainty represented by the three oil price path assumptions (Table 12).

International Finance. World oil market and oil price trends have also been influenced by international financial markets. For example, the actual cost of world oil to the United States is not the same as that paid by other industrialized countries because of differences in currency exchange rates (Figure 14). The continued strength of the U.S. dollar has resulted from the strong economic performance since 1983 and the maintenance of relatively high real interest rates. A strong dollar has meant that other countries have not experienced the same decline in the real price of world oil as has the United States. Higher energy costs could mean lower rates of economic growth in other countries and different

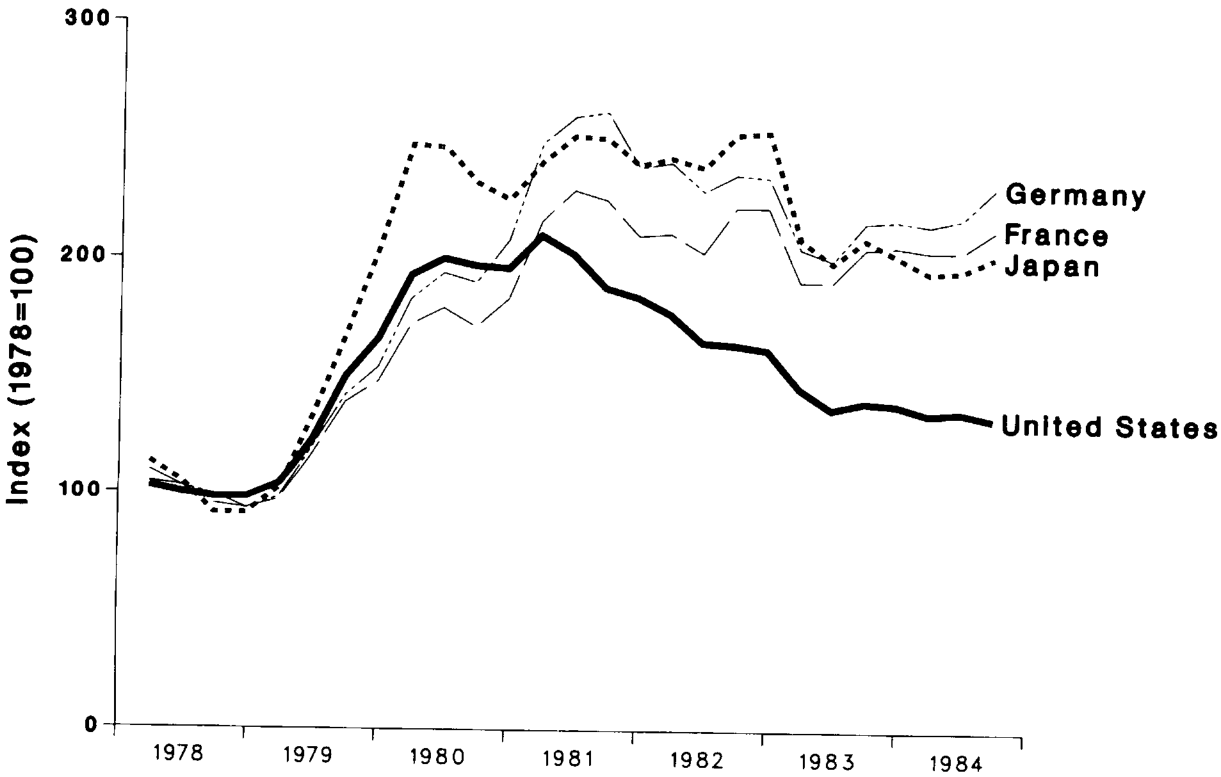
---

[2] The OPEC members are: Algeria, Ecuador, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

[3] The OECD members are Australia, Austria, Belgium, Canada, Denmark, Finland, France, West Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States.

[4] International Monetary Fund, World Economic Outlook, Occasional Paper No. 27 (Washington, DC, 1984).

Figure 14. Real World Oil Prices in Major Industrial Countries Based on National Currencies, 1978-1984



Note: The average refiner acquisition cost of imported crude oil in the United States is used as the world oil price for each country. The world oil price is converted to the national currency by using the appropriate exchange rate. This value is then converted to an index by dividing each quarterly value by the average value for 1978. Inflation rates for each country are used to determine real prices.

Source: Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(84/06) (Washington, DC, 1984); International Monetary Fund, International Financial Statistics (Washington, DC); Data Resources, Inc., U.S. Central, Europe, and Japan data bases.

sensitivities (price elasticities) to future changes in the world oil price (Table 13).

Table 12. World Oil Prices,[a] 1979-1990 and 1995: (1984 and Nominal Dollars per Barrel)

Year	Price Case Low	Price Case Middle	Price Case High
	(1984 dollars per Barrel)		
History			
1979		$29.60	
1980		42.42	
1981		42.29	
1982		36.11	
1983		30.39	
Assumptions			
1984	$28.69	29.01	$29.07
1985	24.00	28.00	30.00
1986	24.00	27.00	32.00
1987	24.00	27.00	34.00
1988	25.00	28.00	36.00
1989	25.00	29.00	38.00
1990	25.00	30.00	40.00
1995	30.00	40.00	55.00
	(Nominal dollars per Barrel)[b]		
History			
1979		$21.67	
1980		33.89	
1981		37.05	
1982		33.55	
1983		29.30	
Assumptions			
1984	$28.69	29.01	$29.07
1985	25.00	29.00	31.00
1986	26.00	29.00	35.00
1987	27.00	31.00	39.00
1988	30.00	34.00	44.00
1989	32.00	37.00	50.00
1990	34.00	41.00	56.00
1995	54.00	74.00	105.00

[a]The cost of imported crude oil to U.S. refiners.

[b]The inflation rates used to estimate nominal prices are given in Appendices A, D, E; Tables A19, D19, E19.

Source: • History: Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(84/06) (Washington, DC, 1984). • Assumptions: Appendices A, D, E; Tables A19, D19, E19.

Table 13. World Oil Price Assumption Sensitivity Analysis, 1995
(1984 Dollars per Barrel)

Scenario	1995 World Oil Price
Mid-Price Case	$40.00
	Difference from Base Case Price
Sensitivity Scenario[a]	
High Economic Growth	$6.46
Low Economic Growth	-3.85
Low Price Elasticity	4.26
High Price Elasticity	-2.52
Low Income Feedback Elasticity	0.32
High Income Feedback Elasticity	-0.31
Low OPEC Oil Production Capacity	5.23
High OPEC Oil Production Capacity	-4.44
Low Non-OPEC Oil Supply	11.73
High Non-OPEC Oil Supply	-7.68
	World Oil Price Range
Combined Uncertainty[b]	
Low Price Scenario	$30.00
High Price Scenario	$55.00

[a]Scenario prices are derived by varying each sensitivity factor separately while holding all other factors at mid-price case levels. High and Low ranges for the sensitivity factors are -0.7 and +0.7 percent per year for economic growth rates; -25 and +25 percent of estimated price and income-feedback elasticities; -10 to + 10 percent of mid-price case OPEC production capacity values by 1995; and -22 to +15 percent of mid-price case non-OPEC oil supply values by 1995. Mid-price case values are presented in Tables 14, 15, and 16 and in Oil Market Simulation Model Documentation Report, DOE/EIA-0412(83/06) (Washington, DC, 1983).

[b]High (low) prices are derived by taking the square root of the sum of the square of the individual high (low) differentials added to (subtracted from) the base case price. Final price assumptions were then rounded to the nearest $5.00.

Although oil consumption over the forecast period is expected to grow at a high rate in the developing countries, economic prospects in many of these countries are uncertain because of what has been called the "debt crisis." Latin American countries, in particular, have had difficulty in servicing international debts. Efforts to meet the financial emergency have included the imposition of severe austerity programs. Reduced economic activity in Latin America and in certain developing countries resulted in reduced oil imports which, in turn, helped contribute to the weak oil market.

Financial circumstances also add uncertainty to the future behavior of the oil-exporting developing countries. There is strong pressure among OPEC members to reduce production in order to maintain world oil prices at current levels. The ability to adhere to production quotas varies greatly among these countries, depending upon their domestic needs. The need to finance the war and to rebuild after the war ends adds to production pressures in Iran and Iraq. Large populations and low incomes per capita will add to higher production pressures in Indonesia and Nigeria. Indeed, prices have not fallen further since 1980, because countries with vast foreign holdings, such as Saudi Arabia, have been able to make large reductions in production.

Supply Uncertainty. The course of the Iran-Iraq war is a particularly unpredictable influence, because additional supplies will flow into the world market after the war ends. New and planned oil pipeline construction by Iraq will reduce this particular uncertainty over time, however. Non-OPEC producers will have a growing influence on world oil supplies and prices in the near term, and an uncertain influence over the longer term (Table 13). In the past, non-OPEC producers have added flexibility to the market by being more willing than OPEC to change prices in response to market pressures.

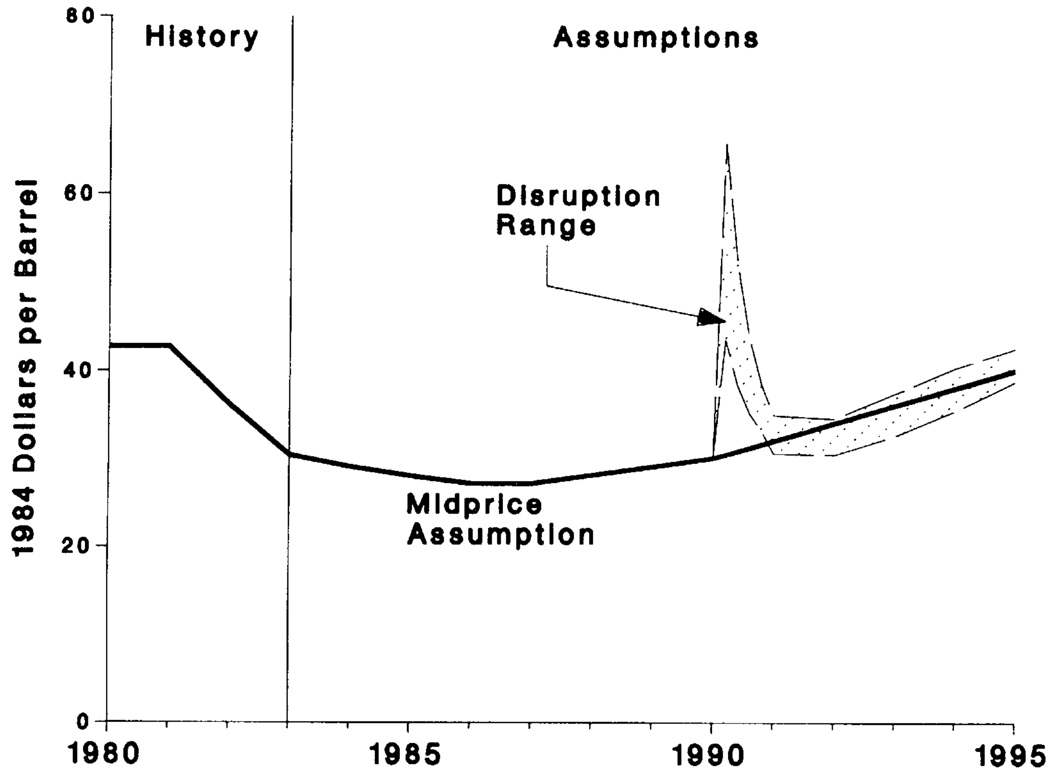
Other changes are occurring that add uncertainty to the oil market and to oil price trends. There is an increasing shift away from long-term contracts and a greater reliance on spot market purchases. Oil-exporting countries have assumed greater control of production, refining, and marketing operations from the major international oil companies. Speculation as to the impact on petroleum product markets of new OPEC export refineries and chemical plants, such as those being constructed at Yanbu and Jubail in Saudi Arabia, has been intense during the past year, particularly given the surplus refining capacity that exists in the OECD countries. Variability in world oil inventories intensified oil market imbalances in the past. The build-up of commercial and strategic stocks in the United States and other industrialized countries could help reduce market imbalances in the future.

The three oil price path assumptions were derived considering the uncertainties at work in international oil markets (Table 13). Not reflected in these assumptions are the additional impacts on world oil prices that could occur as the result of major oil supply disruptions. Past experience has shown that such disruptions can cause great fluctuations in world oil prices. Although the occurrence, size, or duration of a possible supply disruption cannot be predicted with any confidence, the oil-price impacts of a hypothetical disruption case are examined below.

Petroleum Supply Vulnerability

To illustrate possible extremes of the reaction of prices to a hypothetical disruption in oil supplies in 1990, a gross disruption of approximately 11 million barrels per day is assumed to occur at the beginning of the first quarter of 1990 (Figure 15). Only an extreme and highly unlikely combination of events would cause such a loss in supply. Smaller reductions in oil availability would cause prices to deviate by smaller amounts from base case levels. Moreover, there is a substantial range of uncertainty about the price impacts of the assumed reduction in world oil availability. The effects of a disruption depend on a number of factors, including the response of energy consumption to higher prices, the availability of replacement oil on the world market, and the behavior of suppliers concerning oil inventories.

Figure 15. Range of World Oil Prices with Hypothetical Disruption in Supply, 1980-1995



Note: This disruption price range is based on a hypothetical disruption that assumes that world oil availability is cut by 11 million barrels per day on January 1, 1990, for a period of 3 months.

Source: • History: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) and Monthly Energy Review, DOE/EIA-0035(84/06) (Washington, DC, 1984). • Assumptions: Table 12.

How high prices would rise as a result of a given loss in supply depends on many factors, including the market psychology and the resulting response of demand to price changes (the elasticity of demand). The more readily demand responds to price increases, the less will be the price increase required to clear the market at a lower level of supply availability. Price increases could also be mitigated by raising production up to capacity in non-disruption nations. However, oil inventory behavior is a significant factor in contributing to the size of the oil price increase.

An inventory build-up, caused by expectations of higher prices and uncertainty regarding the duration and magnitude of the disruption, could exacerbate price increases, while a worldwide drawdown of commercial inventories to levels that would not violate minimum operating levels could dampen the price rise. Drawing down the U.S. Strategic Petroleum Reserve and government controlled stocks in other free world nations also could result in a substantial reduction in oil prices during a disruption. In this hypothetical disruption, it is always assumed that the U.S. Strategic Petroleum Reserve and foreign government controlled stocks are drawn down.

Depending on what is assumed about the other factors, a gross supply disruption of about 11 million barrels per day could possibly increase prices by as little as $13 per barrel or by more than $35 per barrel (Figure 15). The aftermath of a disruption is also unpredictable. When oil supplies are restored (assumed in this example to occur in the second quarter of 1990), world oil prices could fall below base case levels. A cyclical pattern might then develop as a result of the continuing effect on oil demand in the post-disruption period of past high prices and reduced economic activity. The actual price levels described in this analysis are of much less interest than this erratic pattern of price movements. Although prices could rise or fall smoothly, as assumed in the base case, the experience of the 1970's suggests that a cyclical pattern of abrupt price increases and declines is also possible.

Base Case Assumptions

The current 8 to 11 million barrels per day of excess world oil production capacity is expected to help keep oil prices down through the mid-1980's. In the base case, nominal oil prices are assumed to remain constant at $29 per barrel through 1986. On the demand side, conservation and fuel-substitution efforts are assumed to help hold down oil consumption, particularly in the industrialized countries. Financial difficulties could slow oil consumption growth in many of the developing countries.[5] Real prices are assumed to rise in the late 1980's, as economic growth encourages increased oil consumption, while oil production capacity from non-OPEC sources remains relatively flat. Much of the growth in oil consumption is projected to occur in the United States, OPEC, and certain developing countries.

---

[5]Unless otherwise specified, the phrase "industrialized countries" is synonymous with "OECD countries," and the phrase "developing countries" is synonymous with "non-OECD countries."

The key remaining variable affecting future oil price paths is production capacity in OPEC countries. The total amount of proved and undiscovered reserves in the OPEC countries provides the group with wide discretion in choosing the levels of production capacity for 1990 and 1995. What levels will be chosen depends on the pricing strategy OPEC adopts and on the cohesiveness of the cartel. The range of capacity assumptions shown in Table 14 illustrates a range of possible choices that might be made. Without a much more definitive theory of OPEC decision making than now exists, there is little analytical basis for preferring one assumption over another. However, any production capacity in the ranges of Table 14 would lead to rising capacity utilization of OPEC oil production within the forecast period.

OPEC Pricing Behavior

In the past, OPEC's pricing responses have tended to vary depending upon the extent to which their production capacity was utilized (Figure 16). This relationship is assumed to hold in the future and is used in deriving the three oil price path assumptions. OPEC pricing behavior should continue to be the major influence in determining world oil prices in the future, because OPEC controls more than three-quarters of all proven oil reserves located in market economy countries. Almost two-thirds of the proven reserves in the market economy countries is concentrated in the Middle East alone. Mexico, another major oil exporter, accounts for about 5 percent of the total proven reserves in the market economies.

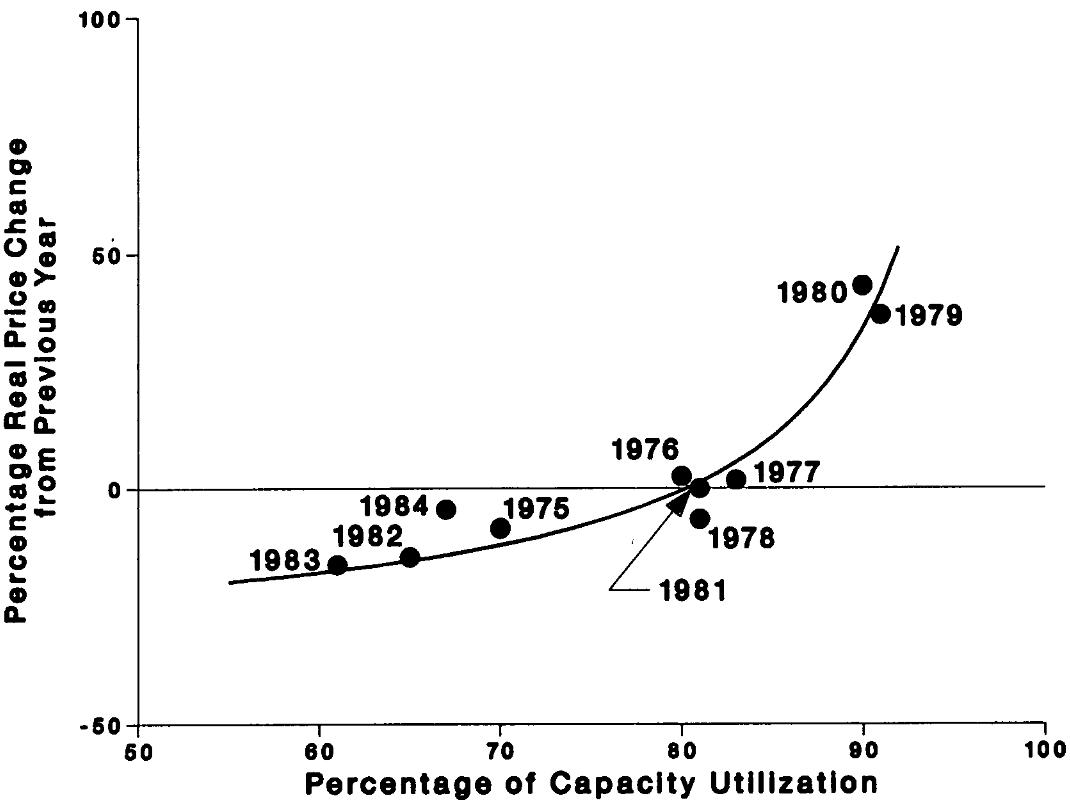
OPEC oil production, including crude oil and natural gas liquids, is assumed to remain at its 1984 level of about 19 million barrels per day through 1985 and then begin to rise in 1986. OPEC output is assumed to grow by over 4 million barrels per day between 1985 and 1990 as demands grow. Given increased use of its production capacity, OPEC is assumed in the base case to begin increasing prices in real terms by 1988 and to increase prices at an accelerated rate as demands continue to grow. In the low price case, capacity utilization does not begin to increase until 1987, and price increases begin after 1990. In the high price case, capacity utilization and prices both increase in 1985.

Economic Growth

Economic growth assumed for the market economies beyond 1985 is rather modest when compared to the growth rates of the 1960's, but it exceeds the growth anticipated between 1980 and 1985, a period which included a worldwide recession (Table 15). The growth rates reflect structural changes in economic activity that have occurred in the past. One such change has been the leveling off of growth in productivity per worker in the industrialized world. Contributing to this trend has been a shift from manufacturing activity to other, more labor-intensive activities, such as services.

Japan's rate of economic growth is assumed to moderate somewhat over the next 10 years, as its share of the export market begins to stabilize. Economic activity in the developing countries between 1985 and 1995 should be helped by increased economic activity assumed for the industrialized countries. Economic growth rates in the developing countries as a whole are applied to a relatively low economic base and are influenced by rapid developments in newly industrialized countries.

Figure 16. OPEC Pricing Behavior, 1975-1984



Note: Percentage of capacity utilization is derived by dividing OPEC crude oil production for a given year by OPEC maximum sustainable capacity for that year. Production capacity is defined as the maximum production rate that can be sustained for several months. The percentage of real price change from the previous year is derived using the average price of imported crude oil to U.S. refiners. The curve is fitted to historical data using least squares regression. The 1984 value was not used to fit the curve but is presented to demonstrate the applicability of this relationship.

Source: Energy Information Admistration, Monthly Energy Review, DOE/EIA-0035(84/06) (Washington, DC, 1984); Central Intelligence Agency, International Energy Statistical Review, selected issues (Washington, DC).

Economic growth in OPEC is assumed to be the highest of all country groups between 1985 and 1990, primarily because of inexpensive energy resources.

Table 14. Alternate Assumptions of OPEC Oil Production Capacities, 1984-1995 (Million Barrels per Day)

Country	1984	1990 Low	1990 High	1995 Low	1995 High
Crude Oil and Natural Gas Liquids					
Algeria	1.2	0.7	1.0	0.6	0.9
Ecuador	0.2	0.1	0.2	0.1	0.1
Gabon	0.2	0.1	0.2	0.1	0.1
Indonesia	1.7	1.3	1.5	1.2	1.4
Iran	3.2	2.5	3.5	2.5	3.5
Iraq	1.2	3.0	5.0	4.0	5.0
Kuwait	2.0[a]	1.5	1.5	1.5	1.5
Libya	2.1[a]	1.8	2.2	1.8	2.2
Neutral Zone	0.6	0.4	0.5	0.4	0.4
Nigeria	2.2	1.7	1.9	1.6	2.0
Qatar	0.6	0.5	0.7	0.4	0.6
Saudi Arabia	10.0[a]	10.0	11.0	10.0	11.0
United Arab Emirates	2.4[a]	2.0	2.2	2.0	2.2
Venezuela	2.4	2.0	2.2	1.8	2.2
Total	30.0[a]	27.6	33.6	28.0	33.1

[a]Because of extended periods of low production in these countries, the amount of production capacity that is considered to be operationally available in the near term has declined by about 2.8 million barrels per day. Available capacity is currently 1.3, 1.8, 8.9, 1.7, and 27.2 million barrels per day for Kuwait, Libya, Saudi Arabia, the United Arab Emirates, and total OPEC, respectively. In the base case, total oil production capacity is assumed to remain at 27.2 million barrels per day through 1990 and then rise to the middle of the capacity range by 1995.

Source: U.S. Department of Energy, Office of International Affairs and Energy Emergencies (Washington, DC).

Oil Demand and Supply Sensitivity

Oil consumption and production patterns in the market economies vary widely under the three world oil price path assumptions (Tables 16, 17, and 18). Under the high price case, oil consumption in the market economies is effectively constant to 1990 and rises by only 0.5 percent per year between 1990 and 1995. Under the low price case, total oil consumption rises by 13 percent by 1990, and by almost 24 percent between 1985 and 1995. Total oil consumption under the low price case is 6.4 million barrels per day greater than in the high price case by 1990 and 10 million barrels per day greater by 1995. The largest difference in oil consumption under the high and low oil price cases is in OECD Europe, a difference of 2.3 million barrels per day in 1990 and 3.4 million barrels per day in 1995. In contrast, the OPEC countries show no difference in oil consumption under the low and high price cases. Given their large reserves, OPEC members are assumed to be virtually immune to changes in the price of world oil. Consumption levels adjust similarly in all other regions because world oil price changes are assumed to be the same for all regions.

Table 15. Average Annual Compound Growth Rates of Real Gross Domestic Product,[a] 1980-1995
(Percent)

Region	1980-1985	1985-1990	1990-1995	1985-1995
United States	2.7	3.1	2.3	2.7
Canada	1.8	2.0	2.8	2.4
Japan	3.8	3.1	2.8	2.9
OECD Europe	1.1	1.8	2.4	2.1
Total OECD	2.1	2.6	2.4	2.5
OPEC	0.5	4.9	4.3	4.6
Other Countries...........	1.8	3.4	3.9	3.6
Developing Countries ...	1.5	3.8	4.0	3.9
Market Economies	2.0	2.8	2.8	2.8

[a]Aggregates are in 1975 U.S. dollars and at 1975 exchange rates.

Source: • History: Wharton Econometric Forecasting Associates, World Service Data Banks, May 1984 (Philadelphia, PA, 1984); United Nations, Department of International Economic and Social Affairs, Handbook of World Development Statistics, 1982 (New York, NY, October 1982). • Assumptions: Wharton Econometric Forecasting Associates, World Model (Philadelphia, PA).

Higher oil demands, given lower world oil prices, are met by higher production levels from OPEC. OPEC production is 7.5 million barrels per day higher by 1990 under the low price case than under the high price case. By 1995, the difference in OPEC production is 15.6 million barrels per day. OPEC actually increases its share of the oil market under the low price case by increasing its production capacity. Increased production from OPEC helps to lower world oil prices. Given the lower oil prices, other regions produce less oil under the low price case relative to the high price case. Production in the United States, for example, is 1.1 million barrels per day lower by 1990 and 3.6 million barrels per day lower by 1995 under the low price case than under the high price case. As with consumption, total production in the market economies is about 6 million barrels per day more by 1990 and 10 million barrels per day more by 1995 under the low price case than under the high price case. Oil consumption and production assumptions under the mid-price case are reviewed below.

Table 16. Market Economies Oil Consumption and Production:[a] Base Case, 1980-1995
(Million Barrels per Day)

Supply and Disposition	History				Projections							
	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Consumption												
United States[b]	17.5	16.5	15.7	15.5	16.2	16.1	16.1	16.3	16.6	16.8	17.0	18.3
Canada	1.9	1.8	1.6	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6
Japan	5.0	4.8	4.6	4.4	4.6	4.5	4.5	4.5	4.6	4.7	4.8	4.7
OECD Europe	13.5	12.5	12.1	11.8	11.9	11.9	11.8	11.8	12.0	12.3	12.6	12.4
OPEC	2.7	3.0	3.2	3.3	3.4	3.5	3.6	3.8	4.0	4.2	4.4	5.4
Other Countries	9.0	8.9	9.1	8.7	8.8	8.9	8.9	9.1	9.3	9.6	9.9	10.3
Total Consumption	49.6	47.4	46.3	45.2	46.3	46.3	46.4	47.0	48.0	49.1	50.3	52.7
Production												
United States	10.8	10.7	10.8	10.8	11.0	11.1	10.8	10.7	10.5	10.4	10.3	9.4
Canada	1.8	1.6	1.7	1.8	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8
OECD Europe	2.6	2.9	3.1	3.8	4.1	4.2	4.1	4.1	4.0	4.0	3.9	3.8
OPEC	27.7	23.6	19.9	18.6	19.1	19.1	19.5	20.2	21.3	22.5	23.5	26.0
Other Countries	6.3	6.9	7.6	7.9	8.5	8.6	8.9	9.1	9.4	9.7	10.0	11.4
Total Production	49.2	45.7	43.1	42.9	44.4	44.7	45.0	45.9	47.1	48.3	49.6	52.4
Net Exports from Centrally Planned Economies	1.2	1.5	1.7	1.9	1.9	1.8	1.7	1.5	1.3	1.1	1.0	0.5
Stock Withdrawals and Discrepancies	-0.8	0.2	1.5	0.4	-0.0	-0.2	-0.3	-0.4	-0.4	-0.3	-0.3	-0.2

[a] Includes crude oil, natural gas liquids, refinery gains, hydrogen, and other hydrocarbons.
[b] Includes Puerto Rico and the Virgin Islands.

Note: The market economies exclude the Centrally Planned Economies of Eastern Europe (including Yugoslavia), the Soviet Union, China, Cuba, Kampuchea, North Korea, Laos, Mongolia, and Vietnam. Numbers may not add to totals because of independent rounding.

Sources: • History: Energy Information Administration, Annual Energy Outlook, DOE/EIA-0383(83), Monthly Energy Review, DOE/EIA-0035(84/06), and International Energy Annual, DOE/EIA-0219 (Washington, DC); Organization for Economic Cooperation and Development/International Energy Agency, Quarterly Oil Statistics, Fourth Quarter 1983 (Paris, France, 1984); Petroleum Economics Limited, Quarterly Supply/Demand Outlook (London, England, 1984).

Table 17. Market Economies Oil Consumption and Production:[a] Low World Oil Price Case, 1980-1995
(Million Barrels per Day)

Supply and Disposition	History 1980	1981	1982	1983	Projections 1984	1985	1986	1987	1988	1989	1990	1995
Consumption												
United States[b]	17.5	16.5	15.7	15.5	16.1	16.3	16.3	16.6	16.9	17.2	17.6	19.6
Canada	1.9	1.8	1.6	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.7	1.8
Japan	5.0	4.8	4.6	4.4	4.6	4.5	4.5	4.6	4.8	4.9	5.1	5.3
OECD Europe	13.5	12.5	12.1	11.8	11.9	11.9	12.0	12.2	12.5	12.9	13.5	14.0
OPEC	2.7	3.0	3.2	3.3	3.4	3.5	3.6	3.8	4.0	4.2	4.4	5.4
Other Countries	9.0	8.9	9.1	8.7	8.8	8.9	9.2	9.4	9.7	10.1	10.5	11.3
Total Consumption	49.6	47.4	46.3	45.2	46.3	46.5	47.2	48.1	49.4	50.9	52.7	57.5
Production												
United States	10.8	10.7	10.8	10.8	11.0	11.1	10.7	10.5	10.4	10.1	9.9	7.6
Canada	1.8	1.6	1.7	1.8	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8
OECD Europe	2.6	2.9	3.1	3.8	4.1	4.2	4.1	4.1	4.0	4.0	3.9	3.5
OPEC	27.7	23.6	19.9	18.6	19.0	19.3	20.3	21.5	22.9	24.6	26.4	33.4
Other Countries	6.3	6.9	7.6	7.9	8.5	8.6	8.9	9.1	9.4	9.7	10.0	10.9
Total Production	49.2	45.7	43.1	42.9	44.4	44.9	45.8	47.0	48.5	50.1	52.1	57.1
Net Exports from Centrally Planned Economies	1.2	1.5	1.7	1.9	1.9	1.8	1.7	1.5	1.3	1.1	1.0	0.5
Stock Withdrawals and Discrepancies	-0.8	0.2	1.5	0.4	0.0	-0.2	-0.3	-0.4	-0.4	-0.4	-0.4	-0.2

[a] Includes crude oil, natural gas liquids, refinery gains, hydrogen, and other hydrocarbons.
[b] Includes Puerto Rico and the Virgin Islands.

Note: The market economies exclude the Centrally Planned Economies of Eastern Europe (including Yugoslavia), the Soviet Union, China, Cuba, Kampuchea, North Korea, Laos, Mongolia, and Vietnam. Numbers may not add to totals because of independent rounding.

Sources: • History: Energy Information Administration, Annual Energy Outlook, DOE/EIA-0383(83), Monthly Energy Review, DOE/EIA-0035(84/06), and International Energy Annual, DOE/EIA-0219 (Washington, DC); Organization for Economic Cooperation and Development/International Energy Agency, Quarterly Oil Statistics, Fourth Quarter 1983 (Paris, France, 1984); Petroleum Economics Limited, Quarterly Supply/Demand Outlook (London, England, 1984).

Table 18. Market Economies Oil Consumption and Production:[a] High World Oil Price Case, 1980-1995
(Million Barrels per Day)

Supply and Disposition	History				Projections							
	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Consumption												
United States[b]	17.5	16.5	15.7	15.5	16.1	16.0	15.7	15.8	15.9	16.0	16.1	16.7
Canada	1.9	1.8	1.6	1.5	1.5	1.5	1.5	1.4	1.4	1.4	1.4	1.3
Japan	5.0	4.8	4.6	4.4	4.6	4.5	4.4	4.3	4.3	4.3	4.4	4.1
OECD Europe	13.5	12.5	12.1	11.8	11.9	11.9	11.6	11.3	11.2	11.1	11.2	10.6
OPEC	2.7	3.0	3.2	3.3	3.4	3.5	3.6	3.8	4.0	4.2	4.4	5.4
Other Countries	9.0	8.9	9.1	8.7	8.8	8.9	8.6	8.5	8.6	8.7	8.9	9.3
Total Consumption	49.6	47.4	46.3	45.2	46.3	46.2	45.3	45.2	45.4	45.8	46.3	47.4
Production												
United States	10.8	10.7	10.8	10.8	11.0	11.1	10.9	10.8	10.8	10.8	11.0	11.2
Canada	1.8	1.6	1.7	1.8	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.9
OECD Europe	2.6	2.9	3.1	3.8	4.1	4.2	4.1	4.1	4.0	4.0	3.9	4.1
OPEC	27.7	23.6	19.9	18.6	19.0	19.0	18.3	18.2	18.4	18.7	18.9	17.8
Other Countries	6.3	6.9	7.6	7.9	8.5	8.6	8.9	9.1	9.4	9.7	10.0	11.9
Total Production	49.2	45.7	43.1	42.9	44.4	44.6	43.9	44.0	44.4	45.0	45.7	47.0
Net Exports from Centrally Planned Economies	1.2	1.5	1.7	1.9	1.9	1.8	1.7	1.5	1.3	1.1	1.0	0.5
Stock Withdrawals and Discrepancies	-0.8	0.2	1.5	0.4	0.0	-0.2	-0.3	-0.3	-0.3	-0.3	-0.3	-0.1

[a]Includes crude oil, natural gas liquids, refinery gains, hydrogen, and other hydrocarbons.
[b]Includes Puerto Rico and the Virgin Islands.

Note: The market economies exclude the Centrally Planned Economies of Eastern Europe (including Yugoslavia), the Soviet Union, China, Cuba, Kampuchea, North Korea, Laos, Mongolia, and Vietnam. Numbers may not add to totals because of independent rounding.

Sources: • History: Energy Information Administration, Annual Energy Outlook, DOE/EIA-0383(83), Monthly Energy Review, DOE/EIA-0035(84/06), and International Energy Annual, DOE/EIA-0219 (Washington, DC); Organization for Economic Cooperation and Development/International Energy Agency, Quarterly Oil Statistics, Fourth Quarter 1983 (Paris, France, 1984); Petroleum Economics Limited, Quarterly Supply/Demand Outlook (London, England, 1984).

Oil Consumption

Economic activity in the developing countries is assumed to grow over a percentage point per year more than that assumed for the OECD countries (Table 15). Thus, oil consumption is projected to grow faster in OPEC and certain developing countries (Figure 17). Among the developing countries, the fastest growth is likely to occur among the exporters of manufactured goods, such as Hong Kong, South Korea, Singapore, and Thailand. High-income oil exporting countries such as Saudi Arabia should also experience rapid growth. These countries have invested oil revenues into such energy-intensive industries as petrochemicals and into the public infrastructure needed for further economic expansion.

Oil consumption is also expected to grow in the low-income countries of the world, even though economic growth in many of these countries will continue to be dependent on external assistance. Oil is an important fuel in many low-income countries, particularly because of its concentrated use in agriculture. With insufficient capital to develop alternative fuels, oil should continue to be a basic energy source in the future. Additional growth in oil consumption could occur if populations continue the shift to urban centers.[6]

In the OECD countries, improved economic growth and relatively low world oil prices are assumed to encourage oil consumption through 1990. Increasing prices in the 1990's help to moderate oil consumption thereafter. By 1995, oil consumption in these countries is projected to be near the level reached in 1980, about 38 million barrels per day. The share of oil consumed by these OECD countries is projected to decrease from about 76 percent in 1980 to about 70 percent by 1995.

Several factors will help moderate oil consumption in the industrial countries. To reduce their dependence on oil imports, these countries have developed programs to encourage conservation and fuel switching, used taxes to discourage consumption of oil products, and increased the production of certain nonoil sources, particularly nuclear power. Expansion of service-related industries and growing efficiency in manufacturing should also limit consumption, particularly of residual fuel oil. On the other hand, expansion of the transportation sector will increase oil consumption, particularly gasoline.

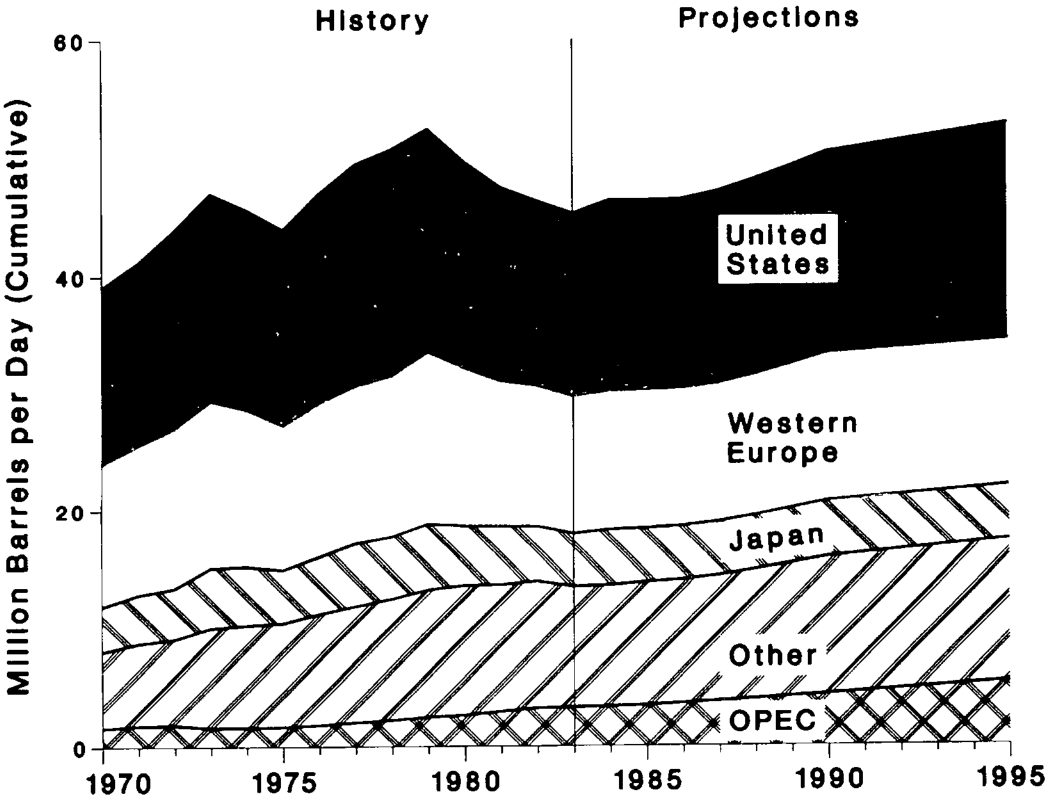
Oil Production

Regional production levels in the base case between 1985 and 1990 and in 1995 are expected to differ from those during the early 1980's (Figure 18). For example, while production in the United States, Canada, and Western Europe rose by almost 2 million barrels per day between 1980 and 1985, production in these regions is projected to decline by approximately 1.0 million barrels per day by 1990 and by 1 million barrels per day between 1990 and 1995. In contrast, OPEC production, which is demand limited, dropped by nearly 9 million barrels per day between 1980 and 1985, and is projected to increase by about 4.4 million barrels per day

---

[6]International Monetary Fund, World Economic Outlook, Occasional Paper No. 27 (Washington DC, 1984).

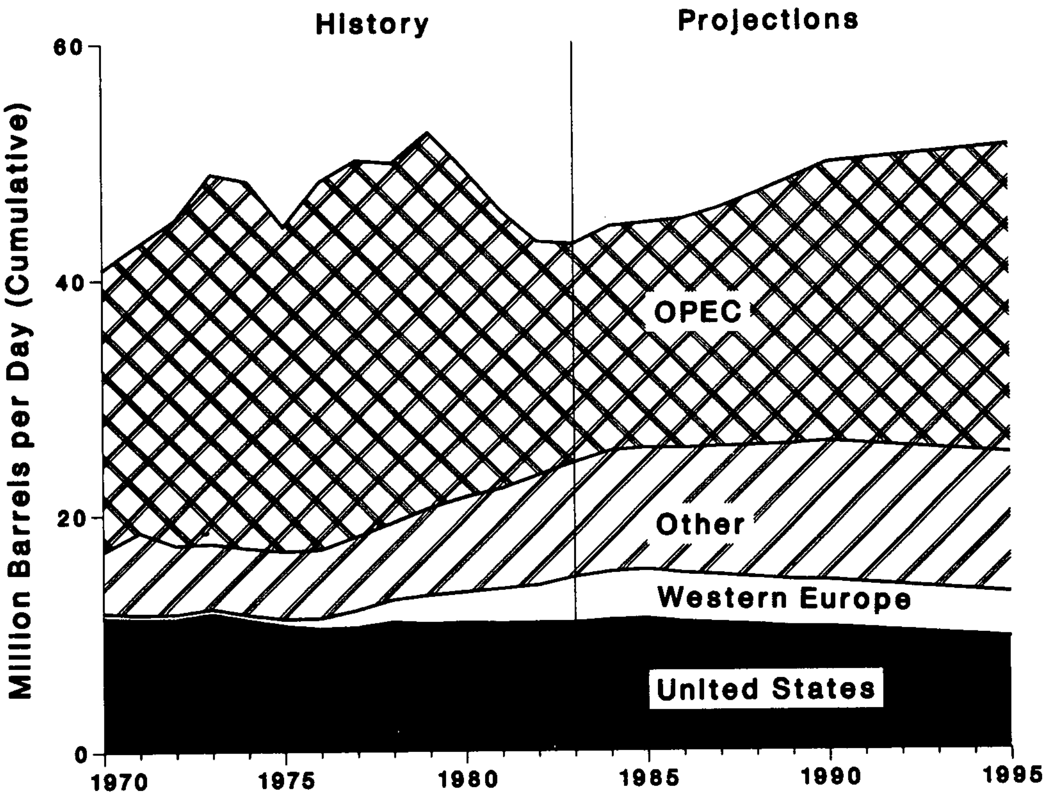
Figure 17. Market Economies Oil Consumption, 1970-1995



Note: Market economies include all countries other than the Centrally Planned Economies of Eastern Europe (including Yugoslavia), the Soviet Union, China, Cuba, Kampuchea, North Korea, Laos, Mongolia, and Vietnam.

Source: • History: Energy Information Administration, International Petroleum Annual, 1978, DOE/EIA-0042(78) and International Energy Annual, DOE/EIA-0219, selected issues (Washington, DC). • Projections: Table 16.

Figure 18. Market Economies Oil Production, 1970-1995



Note: Production includes natural gas liquids and synthetic liquids. Market economies include all countries other than the Centrally Planned Economies of Eastern Europe (including Yugoslavia), the Soviet Union, China, Cuba, Kampuchea, North Korea, Laos, Mongolia, and Vietnam.

Source: • History: Energy Information Administration, International Energy Annual, DOE/EIA-0219, selected issues (Washington, DC). • Projections: Table 16.

between 1985 and 1990 and by 2.5 million barrels per day between 1990 and 1995. Production from all other market-economy sources is expected to grow by 37 percent between 1980 and 1985 and by another third over the forecast period (Table 16). Other than OPEC and Mexico, most non-OPEC oil producers are currently producing close to capacity. Discovery of vast new oil reserves in other regions does not seem likely.

Additions to production among the OECD countries will come primarily from the North Sea and offshore areas of the United States and Canada and from more general use of enhanced recovery methods. Production in the United States and in Western Europe is expected to peak in 1985, however, and decline thereafter. Only the "other countries" group is projected to be producing more oil by 1990 and 1995 than in 1980. Mexico is the largest producer in this group and is the fourth largest producer of oil in the world today.

Consumption of Other Fuels

The sensitivity cases for world oil price assumptions and world oil balances were made in the context of oil's changing role in the energy market as a whole. In general, oil's share of total energy consumed in the market economies is projected to decline through 1990 and 1995 (Table 19). As with the oil market, there are many uncertainties concerning the future development and use of coal, natural gas, nuclear power, and other energy sources in the world. However, these additional uncertainties are not addressed in this analysis.

Total Energy

Total energy consumption in the market economies is projected to grow steadily over the projection period. As with oil consumption, the fastest rate of growth in total energy consumption is expected in the developing countries. Growth in total energy consumption will result from greater use of indigenous energy resources, relatively rapid rates of economic growth, and structural changes toward more energy-intensive economic activities. Countries and regions whose economies should perform particularly well in the future include Mexico, Brazil, South Africa, South Korea, Thailand, Hong Kong, and Singapore. Several of the major oil-exporting countries should also do well, using export energy earnings to diversify and expand their economies.

Economic growth and, consequently, total primary energy consumption in the industrialized countries are expected to grow at a slower rate than in the developing countries. Energy consumption is already at a much higher level in the industrial world, both in terms of total use and per-capita use. Conservation and efficiency efforts and the general shift of economic activity towards the less energy-intensive high technology and service sectors should also help reduce future growth of energy consumption. Among the industrial countries, the Pacific OECD region (Australia, New Zealand, and Japan) is projected to experience the fastest rate of growth.

Table 19. Market Economies Apparent Energy Consumption: Base Case, 1981-1995
(Quadrillion Btu)

Regions	History 1981	1982	Projections 1983	1984	1985	1986	1987	1988	1989	1990	1995
Total OECD	157	151	151	157	158	160	163	169	173	176	189
North America	84	80	80	84	85	87	88	91	92	94	102
OECD Europe	53	52	52	53	53	54	54	57	58	59	62
OECD Pacific	20	19	19	20	20	20	20	21	22	23	25
Developing Countries ...	39	40	41	42	43	45	46	48	50	52	62
Total Market Economies											
Consumption by Fuel Type											
Oil	97	95	93	95	95	95	97	99	101	103	108
Natural Gas	36	34	34	36	37	38	39	39	40	41	44
Coal	40	39	39	41	42	43	44	47	48	50	56
Nuclear	8	8	9	10	10	11	12	14	14	15	19
Other	15	16	16	17	16	17	18	18	19	19	23
Total	196	192	192	199	201	205	209	217	223	228	251

Note: Energy totals exclude fuel wood and all noncommercial fuel sources. The market economies exclude the Centrally Planned Economies of Eastern Europe (including Yugoslavia), the Soviet Union, China, Cuba, Kampuchea, North Korea, Laos, Mongolia, and Vietnam. Numbers may not add to totals because of independent rounding. Source: • History: Derived from Energy Information Administration, International Energy Annual, DOE/EIA-0219 (Washington, DC).

Coal

Coal is expected to increase its share of total energy consumed in the market economies because it is readily available in many parts of the world, including the United States, and because it serves as a relatively economic and secure substitute for oil in certain uses. Future expansion of coal consumption will depend largely upon rising demand for steam coal by electric utilities and industrial users. The use of metallurgical coal for steel production is not expected to expand significantly.

Falling world oil prices could reduce future growth in coal consumption in certain countries, however, if lower prices encourage postponement or cancellation of the construction of coal-fired electric generation plants. The development of nuclear energy could reduce coal consumption in certain countries. Transportation considerations and environmental concerns also could constrain future growth in coal consumption.

Natural Gas

Natural gas is projected to maintain its share of total energy consumed in the market economies. There should be no shortage of supplies to meet future requirements, although access to these supplies could be a limiting factor. Gas flow between countries requires substantial front-end investments to develop the required long-distance pipelines or liquefied natural gas (LNG) facilities. Such investments require the guarantee of sufficient gas reserves to sustain gas production over the long-term life of the project. Aside from the technical and financial factors influencing investment decisions, further considerations include the security of the supply source and the degree to which the project places significant dependence on a single external source of supply. Western Europe, for example, seeks to enhance natural gas security even as it begins to import natural gas supplies from the Soviet Union using the new Yamal pipeline. Japan, the major user of LNG, is also continuing to diversify its sources of natural gas supplies.

The major exporters of natural gas are the Soviet Union, the Netherlands, Norway, Canada, Indonesia (LNG), and Algeria (LNG). Despite large domestic resources, the United States expects to meet more of its future needs for natural gas from imports, primarily from Mexico and Canada.

As evidenced by the substantial investment by Saudia Arabia and other middle eastern countries in chemicals and other industry, natural gas does not need to be transported to effectively displace oil. Production of chemicals from these Middle Eastern plants could effectively replace chemical production in Europe and elsewhere which was based on petroleum feedstocks.

Nuclear Power

Nuclear power is projected to be the fastest growing source of energy over the next 11 years. Consumption of nuclear energy is projected to increase by 50 percent by 1990 and should nearly double between 1985 and 1995. Prospects for nuclear power vary considerably in different parts of the world, however. Nuclear power does not have the air quality problems associated with coal-fired electric generation, but waste management and plant safety continue to be major concerns. Many countries see nuclear power as an additional guarantee of energy stability and independence. France, in particular, is moving rapidly ahead with its nuclear program. The United States is currently the largest producer of nuclear power, followed by France, Japan, and the Soviet Union.

Other Fuels

Most of the growth in the consumption of hydroelectric and geothermal power should come from the developing countries. Brazil, in particular, has considerable potential for increased hydroelectric production. Canada and certain other countries in OECD Europe are also expected to tap these sources of power. The development of synthetic fuels, such as shale oil and liquified coal, will be hampered by rising estimates of production costs and declining estimates of conventional fuel costs. Solar energy could grow rapidly in certain industrialized countries, but its contribution to total energy consumption even by 1995 will still be small.

4. Energy and the Economy

Forecasts of the economy are subject to many uncertainties. To investigate the energy implications of these uncertainties, this report considers three alternative configurations of the economy: a base case, a high and a low economic growth case, and a high and a low oil price case. The assumptions for these cases were derived from private forecasts of likely developments in the economy through 1995; these forecasts were modified slightly for consistency with the energy projections.[1]

The first section of this chapter contrasts the assumed base case growth path with the alternative high and low economic growth paths. An analysis of the high and low world oil price sensitivity cases investigating the impact of alternative energy price trajectories on the economy follows. The last section examines explanations for recent structural changes in the U.S. economy and is closely linked to the later analysis of industrial energy consumption (Chapter 5).

High and Low Economic Growth Paths

The high and low economic growth paths are based on different sets of assumptions for key economic variables. These alternatives provide the basis for the high and low energy demand projections that are explored in detail in other chapters and summarized in Chapter 2. For the alternative growth cases, real world oil prices were assumed to follow the base case trajectory. All variations across the three growth cases are thus traceable to variation in the assumptions for nonenergy inputs to production, nonenergy factor prices, foreign trade developments, and other nonenergy determinants of growth.

Sources of Variations in Growth Projections

The principal underlying differences between the high and low growth cases and the base case may be attributed to the variation in nonenergy factors of production (Table 20) and some residual difference in productivity change. Basic nonenergy factors of production, in order of their importance to growth variations in 1995, are: labor force, capital stock, and research and development. Any variations in economic growth not attributable to these factors are accounted for as "residual productivity gain." In any given forecast year, variations in the labor force and capital stock generally account for approximately 80 to 90 percent of the difference between the level of real gross national product (GNP) in the high or low economic growth case and the level in the base case. All variations in these factors of production may be regarded as assumptions, giving rise to variations in other economic variables, such as differences in final demand levels, prices, interest rates, and industrial output levels.

Different assumptions about the influence of the public and trade sectors on economic growth potential also contribute to variations in growth rates. Federal

---

[1]See Appendix F and EIA, Office of Energy Markets and End Use (EMEU), Memorandum to the Record, "Macroeconomic Forecasts for AEO84" (Washington, DC, December 7, 1984).

deficits are assumed to be higher in the low growth case than in the base case, partly due to differences in fiscal policy. A higher public sector demand for funds is assumed to drive up interest rates and reduce funds available for private domestic investment. Lower business investment, in turn, limits long-term economic growth. In the high growth case, conversely, deficits are assumed to be lower, although principally due to differences from base case assumptions about fiscal policy in the near term only.

Table 20. GNP Components and Contributions to Growth, 1990 and 1995
(Percent Difference from Base Case)

	Economic Growth Case			
	High		Low	
	1990	1995	1990	1995
Difference in Real GNP From the Base Case, Attributable to Four Basic Factors of Production				
Labor Force	2.6	4.0	-2.6	-3.2
Capital Stock	1.8	2.8	-2.6	-3.2
Research and Development	0.1	0.2	-0.2	-0.2
Residual Productivity Gain	0.0	0.5	-0.3	-0.9
Real GNP	4.5	7.5	-5.7	-7.5
Differences From the Base Case for Components of Real GNP				
Consumption	2.4	6.6	-3.5	-6.4
Investment	12.1	15.5	-13.3	-14.9
Government	0.9	3.6	-2.1	-3.8
Exports	7.7	7.6	-9.4	-7.3
Imports	0.6	7.7	-1.0	-6.1
Real GNP	4.5	7.5	-5.7	-7.5

Source: Appendices A, B, C, Tables A19, B19, C19; EIA, Office of Energy Markets and End Use, Memorandum to the Record, "Macroeconomic Forecasts for AEO84" (Washington, DC, December 7, 1984).

Trade sector influences vary in several respects across the alternative growth cases, with regard to activity levels and rates of inflation. The high growth case assumes higher growth rates for real GNP in all industrial countries, while the low growth case assumes lower growth rates relative to the base case. Wholesale prices of major U.S. trading partners are assumed to increase more slowly in the high growth case, exhibiting price behavior similar to the lower inflation rates assumed for the United States in that case; alternatively, in the low growth case, wholesale prices in the United States and of its major trading partners are assumed to increase more rapidly. The exchange rate of the dollar is also assumed to vary, contributing to the range in the growth rates for the three cases. A falling value of the dollar contributes initially to greater export demand in the high growth case; in the low growth case, a value of the dollar higher than the base case level initially retards export demand.

While public sector and trade sector influences, research and development, and productivity all contribute directly or indirectly to explaining differences in the three growth cases, the most important determinants of economic growth are growth rates for labor and capital inputs. Due to the interplay of many factors, the assumed growth rate in investment in new business capital stock between 1985 and 1995 shows a variation from the high to low growth cases of 2.8 percentage points.[2] The cumulative effect from 1985 to 1995 is that additions to business capital stock are assumed to be 30 percent higher in the high growth case than in the low growth case in 1995.[3]

Even more important are the significant differences assumed in labor force growth between 1985 and 1995, due primarily to differences in labor force participation rates. The base, high growth, and low growth cases are based on assumed labor force participation rates broadly consistent with labor force projections published by the Bureau of Labor Statistics in November 1983.[4] The high growth case assumes that the female participation rate will continue to increase significantly, and that the male participation rate will slightly exceed base case levels. In the low growth case, increases in the female participation rate are assumed to moderate considerably relative to the base case, and the male participation rate is assumed to be slightly lower than in the base case. The labor force level for 1995 in the high growth case is assumed to exceed the base case projection by nearly 9 million persons, while the low growth case level is lower than the base case level by approximately 7 million persons.[5] These differences give rise to the large differences in GNP growth attributable to labor force variation.

Variations in the Structure of Final Demand

The three growth cases depict different paths for the future structure of final demand in the U.S. economy. An examination of the basic components of real GNP shows the broad differences between the three cases (Table 20). In the high growth case, the most dramatic difference from the base case in real aggregate demand growth between 1985 and 1995 is in total investment. This demand component is assumed to grow at an annual rate that is 0.9 percentage points higher than in the base case over this 10-year period, reaching a level almost 16 percent higher than the base case in 1995.[6] In the low growth case, investment demand is again the most significantly different of the components of real GNP, and is assumed to

---

[2] EIA, EMEU, Memorandum to the Record, "Macroeconomic Forecasts for AEO84" (Washington, DC, December 7, 1984).

[3] Ibid.

[4] See Appendix F and EIA, EMEU, Memorandum to the Record, "Macroeconomic Forecasts for AEO84" (Washington, DC, December 7, 1984).

[5] Data Resources, Inc., MODELNOTES on the OPTIM24YR0684 and PESSIM25YR0684 forecasts (Washington, DC, 1984).

[6] EIA, EMEU, Memorandum to the Record, "Macroeconomic Forecasts for AEO84" (Washington, DC, December 7, 1984).

grow at a rate that is 1.2 percentage points per year lower than in the base case.[7]

In terms of trade sector influences, the two cases reflect symmetric, but opposite, developments. In the high growth case, exports are assumed to expand more rapidly than in the base case through 1990, while imports increase at the same rate as in the base case. In the low growth case, exports expand less rapidly than in the base case through 1990, while imports again grow as in the base case. As a result, the assumed difference in 1990 between the high and low growth cases for net exports is an improvement over base case net exports of $18 billion (1972 dollars) in the high growth case and a decrement relative to the base case of $14 billion in the low growth case.[8]

A typical pattern in trade sector adjustments over time, however, is for any imbalance in real trade flows to bring about conditions that eventually lead to a reversal of that imbalance. This bias toward a central tendency also characterizes the differences in the three growth forecasts in the latter years. Relative to the base case, the high growth case assumes stronger growth in income, and this income growth gradually leads to a more rapid growth in imports between 1990 and 1995. Exports, on the other hand, are assumed to drop closer to base case levels between 1990 and 1995, in part because the dollar exchange rate is assumed to surpass base case levels by increasing amounts in each year after 1991. Conversely, in the low growth case, weaker income growth gradually pushes imports to levels increasingly below the middle growth case between 1990 and 1995. With exports again tending to base case levels in the later years, both this case and the high growth case project a real trade balance less divergent from the base case in 1995 than in 1990. By 1995, the assumed spread between high and low case net exports has been reduced to $6 billion (1972 dollars).

In comparing the high or low growth case to the base case, differences in the growth rates between 1985 and 1995 for real consumption expenditures or government demands for goods and services are not as great as differences in the growth of business investment or the net trade balance. In the high growth case, consumption is assumed to grow by 0.6 percentage points more than the base case in real terms between 1985 and 1995, while the growth rate in real government expenditures is assumed to be 0.4 percentage points higher.[9] In the low case, assumed rates of growth for real consumption expenditures and government purchases of goods and services are lower by 0.7 and 0.3 percentage points, respectively, over the same period.[10]

Differences in Industrial Structure

Because of the different compositions of aggregate final demand in the three alternative growth forecasts, significant differences are assumed for industrial

---

[7] Ibid.
[8] Ibid.
[9] Ibid.
[10] Ibid.

activity levels. Some industries show a smaller spread, relative to others, in the assumed 1995 levels of activity for the three cases, because demand for their outputs is relatively insensitive to changes in the growth rate of real GNP. An example is the food processing industry, where gross output[11] is assumed to vary by only 12 percent from the low to high economic growth cases.[12] A much wider range is assumed from the low to high economic growth cases in other industries: Steel output varies by approximately 31 percent from the low to high case in 1995, and transportation equipment production varies by approximately 24 percent.[13]

Regardless of the differences in the broad structure of aggregate demand across the growth forecasts, all three economic growth cases are dominated by two tendencies. First, overall growth in manufacturing is assumed to be strong from 1985 to 1995, given the growth in investment expenditures and consumer durables. This growth leads to substantial increases in domestic demand for energy from the industrial sector. Second, past and future energy price increases are expected to push the structure of manufacturing away from energy-intensive industries. This structural shift tends to dampen energy demand increases implied by rapid manufacturing growth.

In analyzing the second trend, it is useful to examine the top five energy consuming sectors (Standard Industrial Classification [SIC][14] sectoring basis) of the manufacturing sectors other than petroleum refining. Four of these sectors are assumed to show declines in their share of total manufacturing output in all three growth forecasts: basic metals (SIC 33); stone, clay and glass (SIC 32); paper and pulp products (SIC 26); and food processing (SIC 20). The share of manufacturing represented by the chemicals industry (SIC 28), however, is assumed to increase in all three forecasts. The dominant trend, nevertheless, is for a general movement away from energy-intensive industries in all three forecasts.[15] The issue of industrial structure and its influence on industrial energy demand is explored in more detail in the last major section of this chapter, as well as in Chapter 5.

The Energy/GNP Ratio for Alternative Economic Growth Trajectories

One measure of the relationship between energy and the economy is the ratio of energy consumption to aggregate economic activity. Figure 19 displays the

---

[11] Gross output represents the sum of an industry's sales to intermediate users plus all sales to final demand. For an explanation of the source of gross output estimates used in macroeconomic forecasts for this report, see the EIA, EMEU, Memorandum to the Record, "Macroeconomic Forecasts for AEO84."

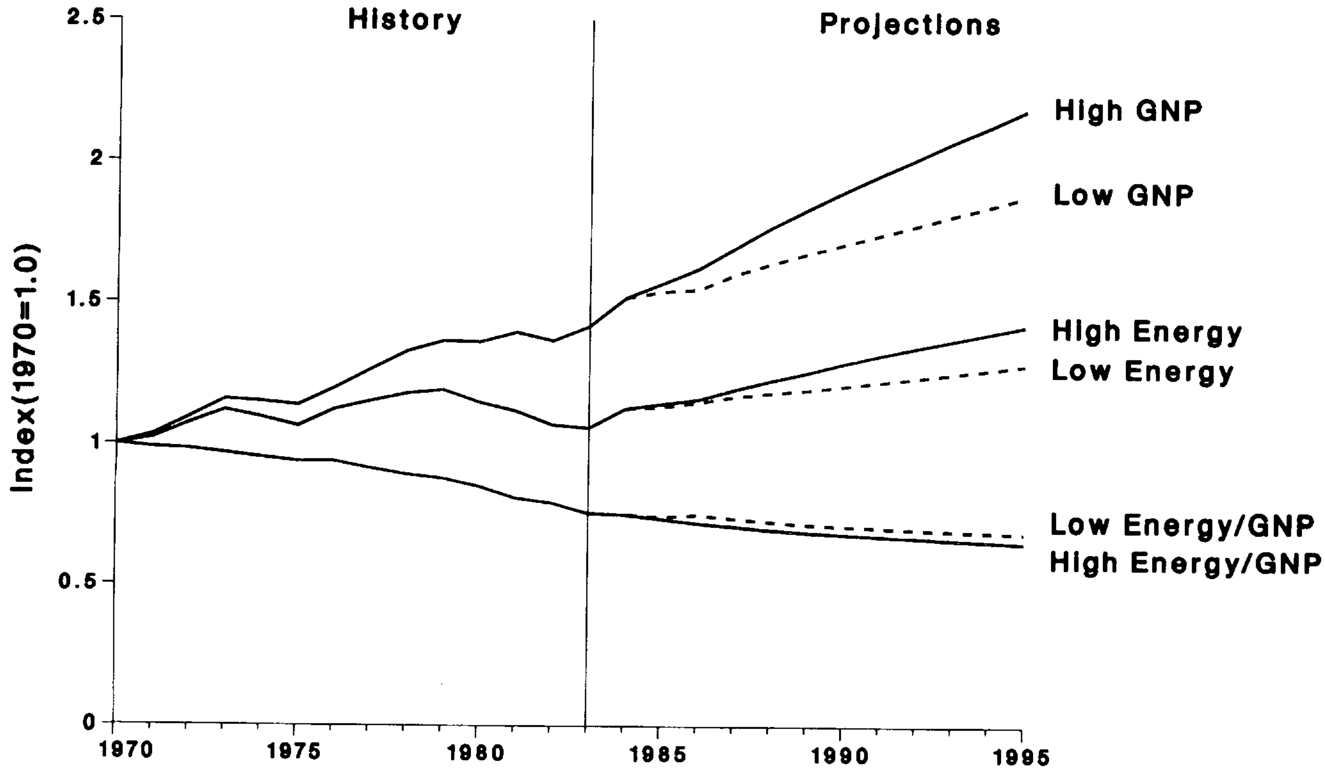
[12] EIA, EMEU, Memorandum to the Record, "Macroeconomic Forecasts for AEO84" (Washington, DC, December 7, 1984).

[13] Ibid.

[14] Refers to the Standard Industrial Classification of the Office of Management and Budget.

[15] EIA, EMEU, Memorandum to the Record, "Macroeconomic Forecasts for AEO84" (Washington, DC, December 7, 1984).

Figure 19. Indexes of Economic Activity and Energy Consumption: Economic Growth Scenarios, 1970-1995



Source: • History: Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(84/06) (Washington, DC, 1984); U.S. Department of Commerce, Bureau of Economic Analysis, Survey of Current Business (Washington, DC, July 1970-1984). • Projections: Appendices B, C; Tables B1, B19, C1, C19.

relationship between changes in economic activity, aggregate energy consumption, and the aggregate energy/GNP ratio. All series are indexed to their respective levels in 1970.

From 1973 to 1983, the aggregate energy/GNP ratio declined at an average rate of 2.5 percent per year. This decline was accompanied by a steep rise in world oil prices, which increased at an annual average rate of 13 percent per year, and relatively slow growth in the economy, with real GNP increasing at a compound annual rate of 2 percent. Following the oil price shock of 1973 to 1974, the ratio fell by 1.9 percent in 1974 and by 1.5 percent in 1975. This measure of the energy-to-output relationship began to level off from 1975 to 1976, declining further in 1977 and 1978. The largest declines came in response to the oil price shock of 1979 to 1980, as the aggregate energy/GNP ratio fell by 3.4 percent from 1979 to 1980 and by 5.0 percent from 1980 to 1981. This historical downward trend in the aggregate energy/GNP ratio primarily reflects shifts in demand away from the more energy-intensive industries, toward those that are less energy-intensive. Reductions in energy use per unit of output also have occurred as conservation and new technologies are adopted by industry in response to higher energy prices.

The energy projections presented in this report, coupled with assumptions about economic growth, suggest that from 1985 to 1995 the aggregate energy/GNP ratio will continue to decline in both the high and low growth cases. However, for the projection period, the energy/GNP ratio is forecast to decline at a rate somewhat less than experienced from 1973 to 1983. The high growth case reflects a more rapid projected decline in the energy/GNP ratio than the low growth case. From 1985 to 1990, the ratio in the high growth case is projected to decline at an average annual rate of 1.3 percent, as compared to a decline of 0.8 percent per year for the low growth case. The projected rates of decline taper off between 1990 and 1995 for both cases, to 0.9 percent per year (high growth) and 0.7 percent per year (low growth). The linkage between higher growth and a more rapidly declining energy/GNP ratio is not surprising. Higher growth leads to higher investment and thus faster replacement of depreciated capital stock. This faster replacement of older, inefficient capital leads to lower energy use per unit of output.

Economic Growth and Alternative Oil Price Trajectories

The world energy market affects the economy through the link between energy prices and general price inflation, through shifts in the real trade balance and the international distribution of income, and through long-term effects on productivity and investment. This section examines these relationships in more detail by focusing on the effects of higher energy prices. An analogous set of economic mechanisms applies to lower energy prices and their stimulative effects on the economy.

Inflation and the Process of Market Adjustment

An increase in the price of energy triggers product price increases. As manufacturers in this country experience increasing energy prices at the production level, it is likely that much of the increased cost of energy will be passed on to consumers. Increases in the actual and expected inflation rates experienced by consumers may lead them to demand greater wage increases which, if successful, further increase product prices. Inflation increases revenues at Federal, State, and local government levels, but inflation also causes increases in the cost of entitlement programs such as unemployment and retirement benefits. The ultimate effect of this cost-push cycle on the inflation rate is determined in large part by the monetary and fiscal policies that are pursued. Accommodation by monetary authorities to higher energy prices may lead to sustained increases in the levels of both inflation and interest rates (because nominal interest rates reflect actual and expected inflation). Similar consequences result if accommodating fiscal policies are pursued. Higher prices depress demand for both energy and nonenergy commodities.

This downward pressure on aggregate demand is accentuated by the redistribution of income that accompanies higher oil prices, transferring income away from U.S. consumers to energy producers, both foreign and domestic. Domestic producers may be expected to spend these revenues in the United States, so there is no loss of demand associated with this redistribution of income. However, about one-third of this income redistribution is to foreign producers. Therefore, a critical factor in determining the overall effect of higher energy prices is the share of revenues earned by foreign producers that is respent or reinvested in the United States and the speed of that recycling of funds. Before recycling occurs, higher expenditures for imports result in a dollar-for-dollar reduction in real GNP.

Energy prices affect aggregate demand and thereby the levels of economic activity and employment. Higher prices affect demand in the short run by lowering real household incomes, and as product demands fall in response, the demand for labor declines. However, as the price of one input (energy) rises, producers may substitute another, relatively cheaper, input (labor and capital) in industries where these factors can be substituted for energy. At the same time, other capital inputs that are complements to (used with) energy may face reductions in producers' demand. In the longer run, capital expenditure decisions initiated (or cancelled) as a result of energy price pressures will have important long-term effects on the level and composition of employment.

While the financial drain of an oil price shock could be significant and adverse, market adjustments can moderate these effects over time. Eventually, U.S. dollars will be returned to the economy as claims by oil-exporters for domestically produced real goods and services, or reinvested in U.S. capital markets, mitigating initial losses in output and employment. However, less of the potential aggregate domestic output of all goods and services will be available for domestic consumption when real exports to oil-producing countries increase, and the shift in real net wealth from the United States to foreigners persists for many years.

Total potential domestic output is also reduced when energy scarcity increases. The potential aggregate output of the economy depends on the availability and efficiency of capital, labor, energy, and raw materials. An increase in the relative price of energy sets in motion efforts to economize on energy use. Higher energy prices tend to make obsolete some capital (plant and equipment) designed when energy prices were lower. As this part of the capital stock is retired more quickly and priority is given to investment in energy-saving capital equipment, other planned investments must be postponed. Thus, the effort to "catch up" with higher energy prices may postpone or reduce productivity growth normally associated with new investment.

In addition to depressing productivity by altering typical investment decisions related to production costs, more rapid increases in real energy prices also slow economic growth and thus lead to generally less investment in most sectors. This further depresses the rate of productivity growth in the long run, because new capital stock is added more slowly. The problem for the business sector is that, in spite of a more rapid depreciation of capital which becomes obsolete due to faster energy price increases, the negative effect of real energy price increases on demand, at least in the short-term, is to limit profitability in many industries. Ultimately, as the economy adjusts to higher energy prices, some of the economic growth apparently "lost" in the initial reaction to the price increase may be recovered, but it is unlikely that all of the "lost" income will be recovered if the economic adjustments involved are substantial.

The Economy Under Alternative World Oil Price Trajectories

Two alternative cases are derived by considering the alternative world oil price paths discussed in Chapter 3. These oil price variations result in significant differences in economic growth and inflation (Table 21).[16] Focusing on 1995, the high world oil price is assumed to be $55 per barrel, and the low price is assumed to be $30 per barrel, in 1984 constant dollars. In terms of rates of growth between 1985 and 1995, real oil prices are assumed to grow at 7.0 percent per year in the high price case and only 0.7 percent per year in the low price case. This oil price swing causes a difference in the inflation rate of approximately 0.7 percentage points per year between the high and low price cases. The impacts on inflation, on the oil import bill, and on real resources available for economic growth result in variations of approximately 0.3 percentage points per year in the growth rates for real GNP and real disposable personal income. Manufacturing, which is more sensitive to energy prices than the economy as a whole, shows a variation in growth between the high and low world oil price cases of 0.7 percentage points per year, as measured by gross output in constant dollars. By 1995, the impact on manufacturing is 4.6-percent lower output (in constant dollars) in the high oil price case and 2.5-percent higher output in the low price case, relative to the base case. No monetary accommodation of the higher and lower assumed oil prices was incorporated into these economic projections.

At the two-digit SIC industry level, the alternative oil price trajectories affect growth rates of gross output in particular industries much differently than they affect the overall growth rate for manufacturing. Sensitivity to oil prices varies appreciably even among the most energy-intensive industries, and also depends upon whether the assumed oil price trajectory is higher or lower. Of the top five energy-consuming industries in manufacturing (excluding refining), three industries are assumed to vary by more than manufacturing overall as oil price trajectories change, and two industries are assumed to vary by less (Table 21).

---

[16]These alternative cases are derived by modifying the base case economic growth projections to reflect the influences of higher or lower assumed oil price projections.

Table 21. Key Economic Indicators for Alternative World Oil Price Trajectories, 1995 (Differences from Base Case)

Economic Indicator	World Oil Price Case: High — Absolute Difference	High — Percentage Difference	Low — Absolute Difference	Low — Percentage Difference
World Oil Price (1984 dollars per barrel)	15.0	37.5	-10.0	-25.0
Real GNP (billion 1972 dollars)	-38.0	-1.7	26.0	1.2
Inflation--GNP Deflator (average annual rate, 1985-1995)	0.4	--	-0.2	--
Real Disposable Personal Income (billion 1972 dollars)	-35.0	-2.3	19.0	1.3
Gross Output in Manufacturing (billion 1972 dollars)	-63.0	-4.6	35.0	2.5
Food Processing	-2.2	-1.2	1.2	0.7
Paper and Pulp	-2.0	-4.2	1.1	2.3
Chemicals	-5.6	-5.2	3.2	3.0
Stone, Clay, and Glass	-1.8	-6.5	1.0	3.6
Basic Metals	-7.5	-10.8	4.4	6.4

-- = Not applicable.
Source: Appendices A, B, C; Tables A1, A19, B1, B19, C1, C19.

These assumptions reflect the historical sensitivity of these industries to energy prices and economic activity. The net result of all effects on the output mix in the industrial sector, however, as well as price-induced factor substitution, is that industrial energy demand in the alternative oil price cases varies by less than is implied by variations in overall manufacturing output.

The Energy/GNP Ratio for Alternative World Oil Price Trajectories

The overall economic impacts associated with the three alternative oil price trajectories, as measured by real GNP differences, are not as great in relative terms as the impacts on energy consumption. Economic impacts of higher energy prices in these three cases are also less than experienced in the 1970's, partly due to the economic adjustments that have already occurred in response to higher energy prices, and partly due to the smoothness of all three oil price trajectories considered. In assuming smooth oil price trajectories, serious oil market disruptions are excluded from these cases.

All cases reflect the weakening of OPEC's ability to control world oil prices. The base case assumes that slackness in the oil market will continue through 1987 and will be reflected in a declining real price. After this period of slackness, a tighter market is assumed for the late 1980's, continuing through 1995. Real oil prices are assumed to rise between 1987 and 1995, but not at the rapid rates experienced in the past decade. Thus, the incentives to reduce oil consumption, and energy consumption in general, will be less than experienced from 1973 to 1983.

From 1985 to 1995, the real world oil price in the base case is assumed to increase 3.6 percent per year. In contrast, from 1973 to 1983, the real oil price to the United States rose by approximately 14 percent per year. As a result of the lower assumed increases in the real oil price relative to recent history, the projected decline in the energy/GNP ratio in the base case is also much less rapid than experienced between 1973 and 1983. The forecast rate of decline in the energy/GNP ratio for the base case is 0.9 percent per year, compared to 2.5 percent per year from 1973 to 1983 (Figure 20).

Over the forecast period, the higher world oil price case is associated with a lower projected energy/GNP ratio than that of the base case, because energy consumption is affected more than real GNP by the alternative oil price path. The converse of these results holds true for the low oil price case (Figure 20). Neither case is dramatically different from the base case; in the high price case, the projected energy/GNP ratio declines by 1.2 percent per year between 1985 and 1995,[17] while in the low price case the rate of decline is only 0.8 percent per year.

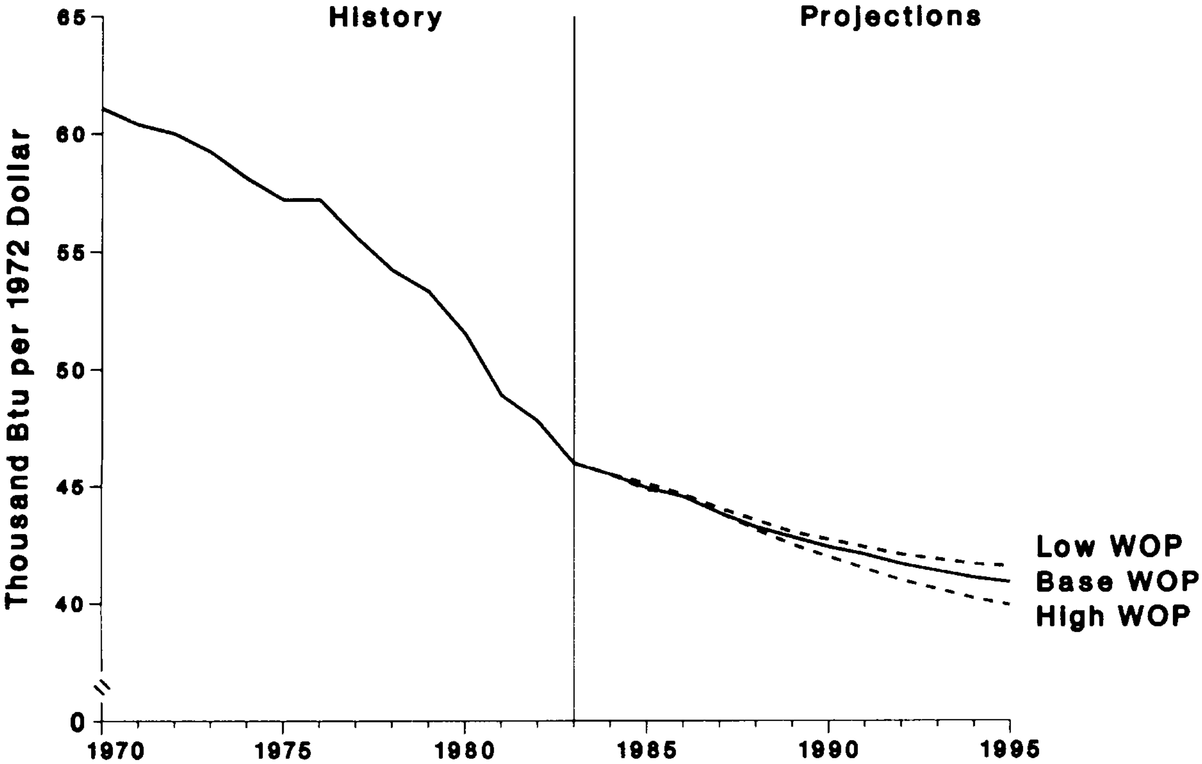
Structural Change in the U.S. Economy

Over the last 10 to 15 years, the U.S. economic outlook has undergone many changes, as the structure of both the domestic and international economy has been transformed by many forces. Of the significant forces shaping the general outlook for U.S. industries, those of most importance include the strength of the dollar, the outlook for continued high energy prices, and the expected slower growth and maturation of the labor force. Another force is the general tendency of developed countries to concentrate on high technology and service industries as newly developing industrial nations provide more of the world's basic industrial products. Interest rate and price movements, defense spending trends, labor-management relations, and many other economic and policy factors also affect industrial structure. This analysis does not attempt to explore all of the energy implications of changes in industrial structure. The analysis is limited to a characterization of recent history, the three growth cases, and some general points regarding any forecasts in this area.

---

[17] Sources for energy consumption, real GNP, and oil price projections are noted on Figure 20.

Figure 20. Gross Energy Use per Constant Dollar of GNP: Comparison of World Oil Price Scenarios, 1970-1995



WOP = World oil price.

Source: • History: Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(84/06) (Washington, DC, 1984); U.S. Department of Commerce, Bureau of Economic Analysis, Survey of Current Business (Washington, DC, July 1970-1984). • Projections: Appendices A, D, E; Tables A19, D19, E19.

Recent Developments in the Structure of Industry

This section examines the changing structure of the economy over three periods in recent history. Two broad trends stand out and have become even more pronounced over time, in comparing the 1960's, the 1970's, and the early 1980's through 1983 (Table 22).

Table 22. Growth Rates for Manufacturing Indexes for Selected Historical Periods (Percent)

Manufacturing Industry	1960-1970	1970-1980	1980-1983
Top Five Energy Consumers (excluding refining)			
Food (SIC 20)	3.3	3.2	1.5
Paper (SIC 26)	5.4	2.7	2.8
Chemicals (SIC 28)	7.9	5.6	1.2
Stone, Clay, & Glass (SIC 32)	3.0	3.4	-1.1
Basic Metals (SIC 33)	4.0	-0.4	-5.8
Total Manufacturing	5.0	3.3	0.3

Note: All figures are compound annual rates of change in the given index of industrial production (1967 = 1.0).
Source: Federal Reserve System, Data Release G.12.3. (Washington, DC, October 1984 and earlier releases).

First, the U.S. economy has become less concentrated in manufacturing, especially in traditional, capital-intensive industries such as basic metals. The share of manufacturing in total gross output of the economy fell from a peak of 40 percent in 1973 to nearly 35 percent in 1982.[18] This tendency was the result of many factors, including: (1) world trade conditions unfavorable to continued U.S. strength in traditionally important manufacturing industries, such as steel and automobile production, (2) the investment climate created by high inflation rates, interest rates, and energy prices, (3) the long-term trends toward services and high technology sectors, and (4) demographic factors affecting the growth, quality, and wage demands of the labor force.

Second, at the same time that manufacturing's share of the economy has fallen, there has also been a trend within manufacturing to shift away from the more energy-intensive industries. This shift has resulted partly from the two strong energy price shocks of 1973 to 1974 and 1978 to 1980. Much of the shift due to the energy price shocks may be a one-time restructuring, and may now be largely

[18] EIA, EMEU, Memorandum to the Record, "Macroeconomic Forecasts for AEO84" (Washington, DC, December 7, 1984).

completed. Factors other than rising energy prices, however, may continue to reduce energy-intensity in production. Some industries may run counter to the dominant trend, however; such energy-intensive industries as food-processing and chemicals have shown growth in output greater than manufacturing as a whole in recent years.

In Chapter 5, several explanations of past changes in the structure of the economy are examined, and energy forecasts resulting from each are compared. Similar forecasts for industrial energy demand are found to arise from the alternative theories considered. Broad similarities are also found in comparing the three growth cases with respect to industrial growth rates and the structure of manufacturing. While the different levels of economic growth imply different growth rates in industrial energy use, an equally significant trend away from energy intensity in manufacturing is present in all three growth cases, as measured by the change in the percentage of manufacturing output concentrated in the energy-intensive industries.

Industrial Structure and Energy Demand in the Three Growth Forecasts

In many respects, the base, high growth, and low growth forecasts exhibit strong similarities in the implications for industrial energy demand. All three cases implicitly assume strong growth in investment demand relative to the recent past, as well as significant expansion in the production of consumer durables. These factors, together with stability or moderate increases in the real prices of most fuels, lead to economic growth paths with the following characteristics in all three cases:

- Contrary to the general trend of the past 10 years, both manufacturing and a more broadly defined "industrial" sector (including agriculture, construction, and mining) are expected to increase their shares of total gross output over the forecast period. The relatively high growth rates in the manufacturing sector and the broader industrial sector are even more apparent when contrasted with growth in real GNP instead of total gross output.[19]

- Countering the positive effect on industrial energy demand due to the rising share of output devoted to industry is the trend toward a decline in the share of energy-intensive industries in total manufacturing.

This latter trend can be summarized by a weighted index of projected industrial output measured at the two-digit SIC level, where weights are derived from projected 1984 levels of energy consumption for two-digit industries (Figure 21). Due to the general shift in industrial structure away from heavily energy-using industries in all three growth forecasts, the energy-weighted index of industrial

---

[19] Real GNP measures only goods and services produced for final demand, while gross output includes intermediate products as well.

output increases in the three cases much less than total industrial output for agriculture, construction, mining, and manufacturing.

The energy-weighted index is a more relevant index of the influence of industrial growth on industrial energy demand than a simple constant dollar total of industrial output. This index grows at a rate much closer to that of GNP growth than does the constant dollar total of industrial output in all three growth cases. This similarity between real GNP growth and the energy-weighted industrial index growth is greatest in the low growth case, where real GNP and the weighted index grow at virtually the same rate from 1985 to 1995 (Figure 21).

Output of the top energy-consuming manufacturing industries as a share of total manufacturing output is virtually unchanged from the high to the low growth case, in spite of the sensitivity to growth rate variations of such energy-intensive sectors as basic metals; paper products; and stone, clay, and glass. The variations in these sectors are counterbalanced by the relative stability assumed in sectors such as food and chemicals, which are also heavy energy consumers.

Energy Sector Developments and Structural Change

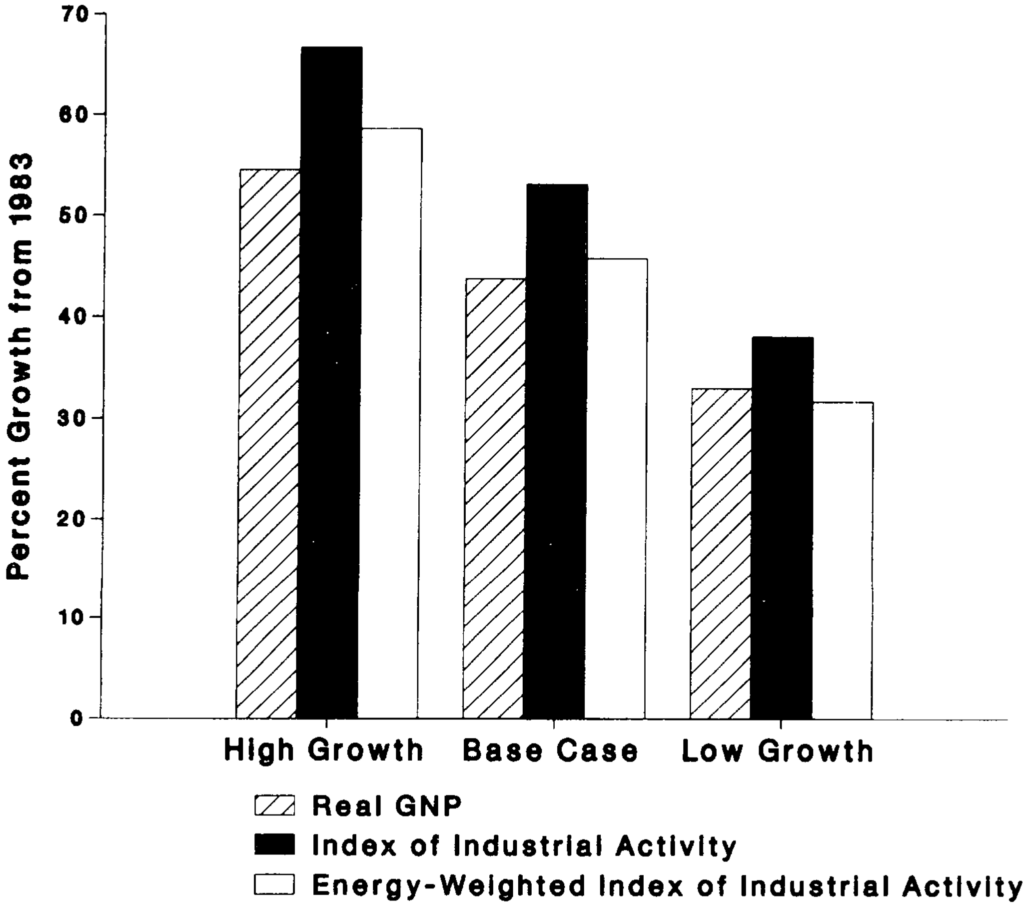
An earlier section discussed the effects of alternative world oil prices and the interaction between the energy sector and the overall productivity and investment levels of the economy. In Chapter 5, where a statistical analysis of the determinants of industrial structure is presented, energy prices are found to have an important role in explaining the path of output in various manufacturing industries in the recent past and the shares of real GNP accounted for by these industries. In evaluating the influence of energy on the economy, the following general points should be kept in mind:

- First, as more energy-efficient capital and methods are put into place in the United States and other countries, the possibilities for easy substitution of additional capital and other factors for energy are greatly reduced. As a result, relationships between energy scarcity and industrial growth observed in the past may display less flexibility in the future.

- Second, a major characteristic of all three growth cases is that the growth rate in the labor force must inevitably slow late in this decade, meaning that economic growth may slow unless such developments can be fully offset by the expansion of other productive factors. As production becomes more capital-intensive, the possibilities for substituting labor for energy may be significantly reduced. Again, the implication is that energy becomes more important in explaining growth potential and the structure of industry.

- Third, although the world economy can be expected to have increasing influence on the U.S. economy in the future, the United States also has a comparative advantage relative to most other industrialized (and agricultural exporting) countries, with respect to self-sufficiency in energy production. Thus, while some factors will tend to cause U.S. industry to be more sensitive to energy

Figure 21. Growth in Economic Activity: Comparison of Economic Growth Scenarios, 1983-1995



Source: • History: U.S. Department of Commerce, Bureau of Economic Analysis, Survey of Current Business (Washington, DC, July 1984). • Assumptions: Appendices A, B, C, Tables A19, B19, C19; EIA, Office of Energy Markets and End Use, Memorandum to the Record, "Macroeconomic Forecasts for AEO84" (Washington, DC, December 7, 1984).

developments in the future, such trends may be relatively less pronounced in this country than in many other competing economies. The end result may be that the U.S. economy will adjust more smoothly to energy market changes, and thus gain relative to other economies.

- Finally, each of the economic growth cases in this report is assumed to follow a trend path lacking in short-term cyclical movements or sudden shocks. Very different paths for the economy and for industrial structure are obtained if the probable recurrence of business cycles is considered. Differences from the trend paths are greater still if a large shock to the world economy is assumed to occur. The possible results of such a shock are discussed in Chapter 3, for the case of an upward surge in the world oil price.

5. Energy Consumption

The energy market disruptions of the 1970's provided a strong impetus for change in the way energy was used in the U.S. economy. The results of the sharp increases in oil prices and supply curtailments during the 1970's were striking. Between 1973 and 1983, the overall intensity of energy consumption (as measured by end-use[1] energy consumption per constant dollar of gross national product [GNP]) declined at an average rate of 3.2 percent per year, in sharp contrast to the nearly flat trend from 1963 to 1973.

A significant change is projected for the rate of decline in the economy's overall energy intensity between 1985 and 1995. From 1985 to 1995, the energy intensity of the economy is expected to decline by about 1.4 percent per year, less than one-half the rate of decline from 1973 to 1983 (Figure 3 in Chapter 2). This estimated reduction in the projected rate of energy conservation reflects the assumption of a relatively stable world oil market compared to that of the 1970's. Motor gasoline prices (adjusted for inflation), for example, are forecast to be lower in 1990 than they were in 1980.

Energy consumption projections in this report are determined by a variety of factors including economic growth, energy prices, and energy conservation trends. Considerable uncertainty is associated with estimating the behavior of these determining factors. It is also uncertain whether these determining factors will influence future energy consumption in the same way they did in the past.

Consumers react to economic growth by consuming more energy in the near term (for example, by driving more) and by purchasing energy-using equipment that affects energy consumption in the longer term. For example, between 1983 and 1984 it is estimated that total energy increased by about 6 percent in response to an estimated 7-percent increase in real GNP. New equipment tends to be more energy efficient and can change the mix of fuels consumed. In the industrial sector, the rate at which output from the energy-intensive industries, such as steel and basic chemicals, has grown relative to growth in GNP has been an important determinant of industrial energy use per dollar of GNP. Between 1974 and 1981, an estimated three-fifths of the drop in manufacturing energy used for heat and power resulted from the energy-intensive industries growing at a rate less than GNP.[2]

The sharp increases in energy prices in the 1970's had a substantial impact on total energy consumption. <u>The exact manner in which energy prices affect consumption, however, is not completely understood</u>. Some major questions concern whether consumers react to price levels or price changes, whether there is a threshold for price responses, whether price increases and decreases produce similar responses, and the length of the adjustment period to higher or lower prices. These

---

[1]End-use energy consumption measures energy delivered to final consumers. It does not include energy used to generate and transmit electricity, but it does include electricity delivered to consumers.

[2]Energy Information Adminstration, A Statistical Analysis of What Drives Industrial Energy Demand, DOE/EIA-0420/3 (Washington, DC, 1983), Appendix B; Electric Power Research Institute, "Industrial Electricity Demand: Prospects and Uncertainties, Proceedings of a Workshop on Industrial Structural Change (Palo Alto, CA, 1984).

questions are becoming increasingly significant as energy prices moderate or, in some cases, decline in the forecast period. In addition, there is substantial uncertainty regarding the future world oil price due to the volatile nature of the world oil market.

Much of the energy conservation behavior begun in the 1970's involved changes in technology or in energy-using equipment that improved energy efficiency and lowered fuel bills from what they otherwise would have been. Such changes included increasing residential insulation thickness and increasing the fuel efficiency of cars. The extent to which these changes have permanently affected consumers' behavior towards energy conservation is uncertain.

This chapter focuses on much of the uncertainty that underlies the base case forecasts of energy consumption. The uncertainty is illustrated by examining the effects on energy consumption resulting from alternative GNP and world oil price assumptions as well as alternative assumptions concerning the relative growth of energy-intensive industries and energy conservation trends. In each of these cases the forecast trends are contrasted to the historical energy-use trends. A general discussion of each sensitivity case is followed by detailed end-use sector results in the remainder of this chapter.

High and Low Economic Growth

Economic growth is one of the most important factors determining energy consumption. The net effect of higher economic growth is generally to increase energy consumption. In periods of high economic growth, consumers purchase more goods and services, including energy for use in equipment such as highway vehicles and consumer appliances. The overall increase in energy demand resulting from higher economic growth is dampened, however, as energy prices are bid up in response to the higher levels of energy consumption. At higher energy prices, the cost of energy-using services increases, and consumers reduce energy consumption. In addition, higher economic growth tends to accelerate improvements in the average efficiency of energy-using equipment because the average age of such equipment declines as more new equipment is purchased.

In the high economic growth case, real GNP in 1995 is assumed to be 7.5 percent higher than in the base case and, as a result, net end-use energy consumption is 4.8 percent higher in 1995. Similarly, real GNP in 1995 is 7.5 percent lower in the low economic growth case, resulting in a decrease of 4.5 percent in net end-use energy consumption. In the residential and commercial sectors, the sensitivity of energy consumption to changes in economic growth is less than in the transportation and industrial sectors. In general, this result is due to the slower turnover of residential buildings and commercial facilities.

Residential Sector

Higher assumed rates of economic growth between 1985 and 1995 result in an increased rate of new housing construction as is typical during rapid economic expansions. The total residential housing stock in 1995 is forecast to be about 2.7 percent higher in the high growth case than in the low growth case. Higher economic growth results also in a direct increase in energy consumption because of increased use of energy-using appliances such as air conditioners.

In comparing the high and low economic growth scenarios, however, energy consumption per household in 1995 actually is lower in the high growth case than in the low growth case (Appendix Tables B6, C6). This result occurs because residential sector energy prices in the high growth case are substantially higher than in the low growth case. The dampening effect on energy consumption, due to the higher prices, more than offsets the direct positive effect of higher income. Although energy consumption per household in 1995 is less in the high growth case, total residential energy consumption does exceed that in the low growth case by a small amount because of increases in the residential housing stock.

Commercial Sector

The commercial sector consists of buildings used for offices, warehouses, public facilities, and other establishments that engage in commercial operations. Commercial building floorspace is used as an index to measure energy demand over these diverse types and sizes of buildings. Higher assumed rates of economic growth lead to a higher forecast level of commercial floorspace and, therefore, increased total energy consumption (Appendix Tables A7, B7, C7).

In the high growth case, commercial sector energy consumption is forecast to be about 4.2 percent higher than in the low growth case in 1995. As in the residential sector, commercial energy use per square foot is lower in the high economic growth case than in the low case in 1995. This difference is due to the dampening effects of high prices in the high growth case, which outweigh the tendency to consume more energy as income increases.

Industrial Sector

Industrial energy use responds to the assumed rate of economic growth more than any other sector (Table 3 in Chapter 2). For example, in the first 8 months of 1984, industrial energy use was 12 percent higher than year earlier levels while residential and commercial consumption was only 4 percent higher than year earlier levels. Over this same period, real GNP was about 7 percent higher than year earlier levels. Energy use in the high and low economic growth cases differs by 10 percent in 1990 and 14 percent in 1995, which is close to the spread in real GNP and industrial output. Industrial electricity use varies across these cases even more than total industrial energy use because electricity is used heavily in industries such as the steel industry whose output is most affected by the rate of economic growth, particularly between 1985 and 1990. In the high economic growth case, industrial electricity demand is 21 percent higher than in the low case in 1995, and oil demand is 16 percent higher (Appendix Tables B4, C4). Metallurgical coal use is only 9 percent higher in 1995 in the high growth case than in the low growth case because the increase in steel production expected between 1983 and 1985 in the base case is not reflected in the high economic growth case. Had the 1983 through 1985 growth in steel production been considered, metallurgical coal consumption in the high growth case would have been about 30 percent higher than in the low growth case in 1995.

Transportation Sector

Total transportation sector energy use in 1995 is projected to be about 11 percent higher in the high growth case than in the low growth case. Differences in the amount of travel, rather than differences in fuel-use efficiencies, explain the impact of economic growth on transportation sector energy use. In the high growth case, automobile and truck vehicle-miles traveled are forecast to grow at average annual rates of 3.1 percent and 3.7 percent between 1985 and 1995, respectively, compared to rates of 2.4 percent and 2.6 percent in the low growth case. Even in the high growth case, the projected rates of growth in vehicle-miles traveled by automobiles and trucks are substantially below the rates of growth realized during periods of high economic growth in the past. These lower projected rates of growth in vehicle travel are based on projected slower growth in the driving-age population and an assumed lessening of the sensitivity of truck vehicle-miles traveled to growth in GNP. Total highway fuel consumption in the high growth case in 1995 is forecast to be about 10 percent higher than in the low growth case. Air travel has, historically, been very sensitive to the rate of economic growth. Airline activity (as measured by revenue passenger-miles) remained stagnant between 1973 and 1975, and again between 1979 and 1981, periods of economic recession. From 1975 to 1979, in contrast, airline activity increased at an average annual rate of more than 11 percent. In the base case, airline activity is projected to increase at an average annual rate of about 5.9 percent from 1985 to 1995 compared to a rate of 7.3 percent in the high economic growth case and 5.2 in the low economic growth case. In the high economic growth case, airline activity is about 25 percent above the low growth case, and jet fuel consumption is substantially higher (Appendix Tables A9, B9, C9).

High and Low World Oil Prices

Sharp increases in the price of oil products were a principal symptom of the "energy crisis" of the 1970's. Yet, it was not immediately accepted that these sharp increases in price would significantly affect energy consumption. Thus, some early analyses indicated that more than 100 quadrillion Btu of primary energy would be required to maintain a healthy U.S. economy by 1990.[3] Since then, such projections have been adjusted steadily downward as the overall intensity with which the economy uses energy has declined. Most energy analysts greatly underestimated the longer term conservation consequences of higher energy prices.

Rising energy prices have been an important factor dampening energy consumption. Energy prices are reflected in the prices of goods and services consumers purchase. Energy prices affect daily consumption decisions, as well as major equipment-choice decisions. If the cost of energy services (for example, traveling and heating) increases, consumers will ultimately purchase less of them. For example, as the cost of driving per mile increased after each of the two major gasoline price increases of the 1970's, consumers cut back on their travel. Similarly, the price of energy embodied in products that are relatively energy

---

[3] Energy: An Uncertain Future, Committee on Energy and Natural Resources, United States Senate, Publication No. 95-157 (Washington, DC, December 1978).

intensive, such as aluminum, would tend to increase in price more than other products, and demand for them should weaken.

Total end-use oil demand in the high world oil price case is about 13 percent below the low world oil price case result in 1995. The transportation sector, which consumed about two-thirds of end-use oil demand in 1983, is projected to account for most of the variation in oil consumption between the low and high world oil price cases (Table 23).

The estimates of future energy requirements are based on the experience gained in evaluating the effects of rising energy prices on energy consumption. Recently, however, the real price of petroleum products has declined. The rate at which energy consumption has increased in response to falling energy prices is significantly below the rate at which energy consumption decreased during periods of rising energy prices. This asymmetry remains an important area of uncertainty in the projections and may result in an upward bias in the energy consumption estimates.

Residential Sector

Energy use per household in 1983 was one-third less than its highest level in 1972. This substantial improvement in energy-use efficiency reflected consumers' responses to rapidly increasing energy prices. At higher energy prices, consumers' purchased more energy-efficient appliances and homes and adjusted their thermostats to reduce their heating and air-conditioning bills. In the base case, residential sector energy prices through 1986 are projected to be lower than the levels in 1983. Prices are projected to increase moderately after 1986. In sharp contrast to the substantial savings in energy use per household realized between 1973 and 1983, energy use per household is projected to remain relatively stable until the late 1980's and then to continue to decline as energy prices increase more rapidly (Table 24 and Appendix Tables A4, A5).

In the high world oil price case, the average residential energy price in 1995 is 3.3 percent higher than in the base case and, as a result, energy use per household is 3.3 percent below the base case result in 1995. In the high world oil price case, only the price of oil is assumed to be higher. Energy use per household in homes using oil for heating purposes in the high world oil price case is nearly 13 percent below the level used in the base case in 1995 (Table 24). In the low world oil price case in 1995, total energy use per household is 2.2 percent higher than in the base case, while energy use per household in oil-heated homes is more than 14 percent higher than in the base case.

Commercial Sector

Commercial building floorspace and energy prices are the two major factors influencing commercial energy consumption. Commercial floorspace is projected to increase by about 26 percent between 1985 and 1995 in the base case due to the projected growth in population and the general expansion of the economy. However, growth in energy consumption is dampened by this sector's continuing response to higher energy prices. Following trends similar to the residential sector, energy use per square foot of commercial floorspace is projected to decline only slightly until energy prices resume their increase in the late 1980's (Appendix Tables A5, A7).

Table 23. Effects of World Oil Price Assumptions on End-Use Energy Demand, 1990 and 1995
(Percentage Change from Base Case)

	1990		1995	
	Low Price	High Price	Low Price	High Price
World Oil Price	-16.7	33.3	-25.0	37.5
End-Use Energy Consumption				
Residential				
Oil	5.7	-12.6	12.9	-20.4
Total	1.2	-2.4	2.6	-3.5
Commercial				
Oil	4.8	-7.3	11.3	-14.3
Total	1.3	-2.2	3.3	-4.1
Industrial				
Oil	2.5	-3.8	4.1	-4.6
Total	1.1	-2.2	2.3	-3.5
Transportation				
Oil	2.8	-4.7	6.2	-7.7
Total	2.8	-4.5	5.6	-7.6
Total End-Use Consumption				
Oil	2.9	-4.9	5.7	-7.6
Total	1.7	-3.0	3.5	-4.8

Source: Appendices A, D, E; Tables A4, D4, E4.

In the high world oil price case, as expected, energy use per square foot decreases at a faster rate and by 1995 reaches a level 2.8 percent below the base case. In the low world oil price case, the opposite result is expected; by 1995, 2.5 percent more energy per square foot is consumed by commercial buildings than in the base case.

Industrial Sector

The world oil price has relatively little direct effect on industrial energy consumption. All fuels are consumed slightly less in the high world oil price case mainly because of reductions in industrial output. In the high world oil price case, oil use in 1995 is only 5.2 percent below the base case result. The impact is small because oil is used in applications where conservation and fuel switching is difficult. In 1981, only one-eighth of industrial oil use was for heat and power in manufacturing where substitution with natural gas is technically relatively easy.

Table 24. Effects of World Oil Price Assumptions on Residential Sector Energy Demand, 1990 and 1995
(Percentage Change from Base Case)

	1990		1995	
	Low Price	High Price	Low Price	High Price
World Oil Price	-16.7	33.3	-25.0	37.5
Residential Energy Consumption	1.2	-2.4	2.6	-3.5
Energy Use per Household	1.0	-3.1	2.2	-3.3
Energy Use per Household in Oil-Heated Homes	6.7	-9.4	14.5	-12.8

Source: Appendices A, D, E; Tables A6, D6, E6.

In the high world oil price case, the 1995 price of residual oil (the oil that competes with natural gas as a boiler fuel) is about 30 percent higher than it is in the base case, leading to a reduction in consumption of 17 percent. Distillate use falls slightly in the high world oil price case due mainly to increased conservation in agricultural uses. Other uses of oil, such as petrochemical feedstocks and distillate fuel for drill rigs, are projected to remain high. Such uses have been closely tied in the past to the level of economic activity, rather than the level of world oil prices.

Transportation Sector

The transportation sector relies almost entirely on petroleum products to meet its energy needs. Substitution of other fuels for oil is not expected to play a significant role through the forecast period. As a result, the transportation sector's projected total energy demand is more sensitive than any of the other sectors to the assumed price of oil products.

In the high price case, the transportation sector's energy consumption is about 13 percent lower than in the low price case in 1995. Motor gasoline consumption varies the most, while distillate oil demand varies only slightly (Appendix Tables

D4, E4). Highway fuel consumption (which accounted for about two-thirds of the transportation sector's energy requirements in 1983) depends on the level of automobile and truck vehicle-miles traveled as well as the average efficiency of the vehicles on the road. Vehicle travel historically has been related to the cost of driving per mile. Real motor gasoline prices increased sharply from 1973 to 1974, and again from 1978 to 1980. These sharp increases were not fully reflected in consumer expenditures, as consumers reacted to the higher prices (and the long lines at service stations) by traveling less.

In the forecast period, motor fuel prices are expected to continue to play an important role in determining the level of travel, particularly for automobiles. In the high price case automobile vehicle travel is 11 percent lower in 1995 than in the low price case (Table 25). Fuel prices make less of a difference to truck travel, which in the past has been more sensitive to the level of economic activity.

Table 25. Effects of World Oil Price Assumptions on Transportation Sector Energy Demand, 1990 and 1995
(Percentage Change from Base Case)

	1990		1995	
	Low Price	High Price	Low Price	High Price
World Oil Price	-16.7	33.3	-25.0	37.5
Total End-Use Demand	2.8	-4.5	5.6	-7.6
Motor Gasoline Demand	3.3	-5.4	7.5	-11.0
Distillate Demand	-0.3	0.0	-0.3	-1.5
Automobiles				
Vehicle-Miles Traveled	2.7	-4.0	5.1	-6.5
Miles Per Gallon	-0.9	1.4	-2.0	3.7
Trucks				
Vehicle-Miles Traveled	0.3	-0.9	1.0	-1.9
Miles Per Gallon	-0.7	1.5	-2.0	4.6

Source: Appendices A, D, E; Tables A9, D9, E9.

Historically, improvements in fuel efficiency have also been related to the cost of motor fuels. Prior to the first oil price shock of the 1970's, average automobile fuel efficiency had declined for many years. Higher fuel prices significantly changed the priorities of the new car buyers. Fuel efficiency, once a relatively unimportant characteristic compared to size and performance, became a primary concern for many buyers. Automobile manufacturers responded to the changing priorities, and new cars in 1983 were about three-fifths more fuel efficient than the average of the fleet. These improvements have been accomplished largely through producing smaller, less powerful cars. In 1983, new cars weighed 22 percent less, on average, than they did in 1973, while engine displacement was 37 percent lower.[4]

Motor fuel prices have declined recently. As a result, improvements in the average fuel efficiencies of new cars have slowed significantly. Between 1982 and 1983, new car fleet fuel economy declined slightly, the first decline since 1974.[5] Sales of large cars increased at more than twice the rate of the new car fleet from 1982 to 1983. The large car market share, however, remained considerably below the level reached before the sharp motor gasoline price increases of the 1970's. Even if new car fuel efficiencies do not continue to improve at the rate realized during the rapid price increases of the 1970's, considerable improvement will continue to occur in the average fleet efficiency as new cars replace older cars in the fleet.

Distillate fuel consumption varies only slightly with the assumed level of oil prices (Table 25). This result occurs because, as the price of oil is assumed to increase, the fuel efficiency advantage of diesel vehicles is expected to become more important to new car and truck buyers. In the high world oil price case, the diesel share of automobile vehicle-miles traveled in 1995 is estimated to be 8.5 percent, compared to a 3.8-percent estimated share in the low price case.

Structural Economic Change

Much of the decline in the economy's energy intensity that occurred between 1973 and 1983 can be traced to the slow relative growth of energy-intensive industries after 1974, including a decline in manufacturing as a whole relative to the GNP.[6] This section puts the base case into perspective by comparing it with the results of four alternative theories for projecting the output of all of the manufacturing industries. These alternative theories lead to different forecasts of growth in the energy-intensive industries.

Case 1. The time trend--This theory holds that the decline in energy-intensive industries was due solely to long-term trends, such as a shift from manufacturing to services, or a movement of manufacturing from advanced to developing nations. For example, the basic steel industry declined at an average rate of 3.3 percent per year from 1958 to

---

[4] U.S. Environmental Protection Agency, SAE Technical Paper Series #840499, "Passenger Car Fuel Economy Trends Through 1984" (Washington, DC, 1984).

[5] Oak Ridge National Laboratory, Energy Division, Transportation Energy Group, Motor Vehicle MPG and Market Share Report (Oak Ridge, TN, February 1984).

[6] Electric Power Research Institute, "Industrial Electricity Demand: Prospects and Uncertainties," Impact of Industrial Structural Change on Future Electric Demand, EA-3816 (Palo Alto, CA, 1984); Data Resources, Inc., "Interindustry Shifts and Their Impact on Energy Usage," DRI Energy Review (Lexington, MA, Spring 1984); "A Supply-Side View of Technical Change," U.S. Long-Term Review (Lexington MA, Fall 1984); Energy Information Administration, Energy Conservation Indicators 1983 Annual Report, DOE/EIA-0441(83) (Washington, DC, 1984).

1983, relative to the GNP. Case 1 simply extrapolates this trend to forecast the output of the various manufacturing industries.

Case 2. The trend theory, modified by the apparent effects of energy prices--Higher energy prices lead to higher costs in energy-intensive industries. These higher costs should increase the price of energy-intensive products and thereby reduce the demand for these products. In fact, the relative decline of steel output and industrial chemicals was greater in the years that followed energy price shocks. Case 2 extrapolates the historical correlation between energy prices and relative output in the manufacturing industries. For example, when the energy price effect is removed, the underlying trend in steel output is only a 1.8-percent decline per year relative to GNP.

Case 3. The trend theory, modified for the apparent effects of real GNP growth and real interest rates--The growth in GNP (not the level of GNP) determines the need for new investment throughout the economy. Interest rates also affect investment, automobile sales, and imports (because they affect the value of the dollar). Investment (such as construction and equipment), automobiles, and chemicals are the main markets for energy-intensive industries. This theory best represents historical trends for most industries.

Case 4. A combination of all of the above factors.

Heat and Power

Case 3 results in a projection of heat and power demand that is quite similar to the base case. This result should be expected because the base case projection is based on analysis (from Data Resources, Inc. [DRI]) that depends mainly on macroeconomic factors. Case 1 leads to lower energy demand, because it treats the performance of steel and basic chemical industries in recent years as part of a long-term trend rather than a cyclical effect. Case 2 leads to lower energy demand for the same reason. All four explanations lead to less electricity demand, because all four show slightly less output of primary metals than DRI projects in the base case (Table 26).

Raw Materials

All four explanations of the decline in energy-intensive industries relative to GNP lead to more petrochemical feedstock use than in the base case. The differences between the explanations are otherwise similar to their differences in projecting heat and power. The feedstock projection depends on the projection of output in Standard Industrial Classification (SIC) 282, plastic materials and synthetic fibers. In the base case projection it is assumed that the plastics industry has begun to mature, and the 1958 to 1983 trend is not extrapolated as far as

1995. The growth trend of chemicals after 1970 was in fact slower than the trend over the whole 1958 to 1983 period.

DRI has a lower forecast of basic steel production (SIC 331) than in Case 3, leading to less use of metallurgical coal. However, DRI projects more growth in primary metals. The base case methodology insures a consistent set of projections across all industries, while the separate study of historical trends by industry does not.

Table 26. Effects of Alternative Theories of Manufacturing Growth on Industrial Energy Demand, 1995 (Percentage Change from Base Case)

	Theory			
Industrial Demand	Time Trend	Energy Prices	Macroeconomic Factors	Combination
Heat and Power				
Distillate Oil	-2	-2	-1	-2
Residual Oil	-3	-6	2	-3
Liquefied Petroleum Gases	0	0	3	0
Natural Gas	-5	-7	19	-4
Coal	-5	-7	19	-4
Electricity	-9	-10	0	-6
Total	-5	-7	19	-4
Major Raw Materials				
LPG Feedstocks	12	14	32	32
Other Petrochemical Feedstock	13	14	31	31
Metallurgical Coal	-26	-24	17	-9
Industrial Total	-3	-4	5	1

Source: Energy Information Administration, Energy Markets and End-Use Division (Washington, DC).

Additional Uncertainties

The structural-economic-change cases considered here all assume the base case GNP growth and interest rates. Cases 3 and 4 are highly sensitive to both factors, and the results would be different if either changed. Only the industrial sector is considered in this sensitivity case. Different assumptions about structural change, however, would affect other end-use sectors as well. For a constant level of GNP, the industrial share cannot be smaller unless the commercial sector's share is that much larger. A shift from manufacturing to services would suggest an increase in commercial energy use in establishments providing such services as medical services, communications, and computer programming beyond the level projected in the base case. The commercial sector has also been the fastest-growing user of electricity in recent years. Therefore, the net effect of structural economic change on electricity use for all sectors is uncertain.

In addition to the explanations of the decline in the aggregate industrial energy intensity between 1958 and 1983, new factors may change the relative growth rates of different industries during the forecast period. For example, if foreign nations build steel and aluminum plants faster than they did in recent years, domestic production may be reduced. Foreign investment in metals and petrochemicals may likewise vary from the base case.

Increased Conservation

The high conservation case assumes that much of the accelerated energy conservation trends of the 1970's will continue during the forecast period regardless of forecast energy prices. In the base case, the rate of decline in the economy's energy intensity is expected to be substantially below that achieved after the energy price shocks of the 1970's. From 1985 to 1995, end-use energy consumption per dollar of GNP is forecast to decline at an average rate of 1.4 percent per year in the base case, compared to a 3.2-percent per year decline realized between 1973 and 1983. Much of the decline in the economy's energy intensity between 1973 and 1983 was the result of production losses in highly cyclical energy-intensive industries such as the steel industry.

Other factors that contributed to the economy's declining energy intensity from 1973 to 1983 included rapid increases in petroleum product prices and concerns over petroleum product supplies. The conservation behavior observed from 1978 to 1981 was explicitly assumed to be the result of increases in energy prices that occurred during that period. In the base case, energy prices are expected to behave quite differently than they did during the 1970's. Real world oil prices are projected to decline through 1986 and then increase only moderately through 1995, while supplies of oil and other energy products are expected to be ample and less vulnerable to political developments in the Middle East. The high conservation case considers the implications for end-use energy consumption if the assumed stability in oil and gas markets does not dampen energy conservation behavior. Energy consumption trends in the high conservation case were estimated by continuing the rate of energy price increase at half the rate experienced between 1978 and 1981. Thus, additional conservation savings should mirror the pattern previously observed in each sector.

Total end-use energy consumption in the high conservation case is nearly 10 percent below the base case results in 1995 (Table 27). Oil consumption is reduced more than any other energy source in the high conservation case. This result does not necessarily imply that there is more technical potential for conservation in the use of oil. Rather, it reflects the historical behavior of energy conservation after the oil price shocks of the 1970's.

In the high conservation case, the reduction in energy consumption is greatest in the industrial sector and least in the commercial sector. This pattern largely reflects the energy-using capital stock turnover rate in the different end-use sectors. Again, these results are not intended to indicate the maximum amount of conservation that could technically be achieved by 1995.

Residential Sector

Residential sector energy consumption in 1995 in the high conservation case is 7.4 percent below the base case result. Changes in the demands for specific fuels follow the general pattern in energy conservation realized during the 1970's. In 1995, fuel demands in the high conservation case are below the base case result as follows: electricity, 6.0 percent; fuel oil, 20.0 percent; and natural gas, 3.9 percent.

Table 27. End-Use Energy Consumption: High Conservation Case, 1990 and 1995 (Percentage Change from Base Case)

	1990	1995
Consumption by Energy Source		
Oil	-6.1	-12.5
Natural Gas	-3.3	-5.8
Coal	-2.7	-7.8
Electricity	-2.5	-6.4
Consumption by End-Use Sector		
Residential	-4.0	-7.4
Commercial	-2.7	-6.8
Industrial	-5.4	-10.7
Transportation	-4.7	-10.3
Total	-4.6	-9.6

Source: Energy Information Administration, Energy Markets and End-Use Division (Washington, DC).

The most common methods used to reduce energy use per household are changes to the thermal characteristics of residential structures such as adding insulation, adding storm windows, caulking, and a number of similar activities. These energy-saving measures can be utilized both in new and existing housing and were widely employed in the 1970's. The Residential Energy Consumption Survey[7] indicated that in just 2 years (1978 and 1979), about 18 percent of all existing households added caulking, about 6 percent added storm windows, and about 7 percent of single-family homes added roof or ceiling insulation.

Another method used to conserve energy is the use of more efficient appliances. Electric heat pumps were almost nonexistent in the early 1970's, but have

[7]Energy Information Administration, Residential Energy Consumption Survey, Consumption and Expenditures, DOE/EIA-0207/5 and DOE/EIA-0321/1 (81) (Washington, DC, 1981).

represented a 25-percent share of the market in new single-family homes since the late 1970's. Changes in the type of fuel or combinations of fuels used in the various appliances can also affect energy conservation. The share of electric heating systems installed in new single-family homes increased from about 30 percent in 1970 to 50 percent in 1980. A large part of the wood consumption increase in the 1970's (from about 400 trillion Btu in 1970 to 820 trillion Btu in 1980) was for use as a secondary fuel in combination with other fuels. Since wood is largely nonmarketed, its use reduces the consumption of marketed fuels (see box). Fuel price increases also led consumers to turn down thermostats in order to reduce energy bills.

Energy Supplies from Wood

The use of wood as an energy source declined from 1900 to the mid-1970's, as lower priced, more convenient alternative fuels became available. Today, wood is largely a nonmarketed fuel, so that reliable estimates of consumption are difficult to make. Total wood energy consumption is estimated to have been approximately 2.6 quadrillion Btu in 1983, or about 3.7 percent of total primary energy consumption.

In 1983, most wood consumption was in the residential and industrial sectors. In that year, wood energy accounted for about 10 percent of the end-use energy consumed by the residential sector. Almost all of the "wood" used in the industrial sector is recycled byproducts of wood consumed for other purposes in the paper and lumber industries.

With the exception of a small amount of wood consumed for fuel by electric utilities, wood is not included explicitly in the energy flows shown in this report. It does, however, displace other fuels that are covered in the end-use consumption estimates.

Average energy consumption per household decreased in the 1970's due to a variety of other factors that may not be closely related to changes in fuel prices. During the late 1970's, the size of new, single-family houses began to moderate, and in the last few years their size remained almost constant. In addition, the type of new housing constructed during the 1970's shifted slightly from single-family homes to multifamily homes. Between 1975 and 1981 the share of new single-family homes fell from 65 percent to 53 percent, while the share of multifamily homes rose from 20 percent to 29 percent. Multifamily homes are typically smaller, have more efficient structures, and use more efficient equipment for heating and cooling.

During the 1970's there was also a trend for housing to be built in the South and West where the population has been growing more rapidly. Between 1970 and 1981, the percentage of new houses constructed in the New England and North Central

Census regions fell from 36 percent to 26 percent, while those constructed in the South and West Census regions rose from 64 percent to 74 percent.

The base case projection includes many of these conservation activities but at a lesser rate than occurred in the late 1970's, as a result of expected relatively stable energy prices. The high conservation case projects residential sector energy demand through 1995, assuming that conservation continues at a higher rate than in the base case regardless of projected energy prices. In the high conservation case, total residential sector energy consumption is 7.4 percent below the base case level in 1995. Because much of the conservation activity in the residential sector occurred gradually over time, much of the savings from investments in the late 1970's and early 1980's are seen for many years after. The base case projection includes many of these lagged effects, and the high conservation case shows benefits that are not completely seen by the end of the forecast period.

In the high conservation case, housing construction is assumed to increase at the same rate as in the base case. Energy consumption declines as a result of a decrease in energy consumption per household. From 1970 through 1982, energy consumption per household fell at an average annual rate of 2.9 percent. In the base case forecast, energy consumption per household from 1985 to 1995 decreases at the average annual rate of 1.0 percent, while in the high conservation case it decreases at the rate of 1.7 percent. Residential energy consumption remained relatively steady from 1970 to 1979, but then fell sharply from 1979 to 1982. The base case projects total residential energy consumption in 1995 to return to near the 1970 level. However, the high conservation case forecasts consumption in 1995 to remain at about its 1982 level.

Commercial Sector

Commercial sector energy consumption is projected to increase at an average annual rate of 1.6 percent from 1985 to 1995 in the base case, as growth in commercial building floorspace outweighs energy efficiency improvements. Efficiency improvements are expected to continue to be sensitive to fuel prices. In the base case, the rate of decline in energy use per square foot of commercial floorspace slows significantly through the early years of the forecast as real energy prices decline.

In the high conservation case, the assumed rate of increase in commercial building construction is the same as the rate used in the base case. Energy conservation is the result of reduced energy requirements per square foot of building floorspace. From 1970 through 1982, energy consumption per square foot fell at an average annual rate of 2.1 percent. In the base case forecast, energy consumption per square foot from 1985 to 1995 decreases at the average annual rate of 0.7 percent; in the high conservation case, energy use per square foot decreases at the rate of 1.5 percent, more closely following the trends of the late 1970's. The consumption of each energy source in 1995 in the high conservation case decreased from the base case in a corresponding manner: electricity by 4.6 percent, natural gas by 5.5 percent, and fuel oil by 16.3 percent. Because oil prices in the base case are assumed to be much lower than those implied by the 1978 to 1981 trends, reductions in oil consumption in the high conservation case are greater than for other energy sources when the price paths of the late 1970's and early 1980's are implemented.

Industrial Sector

Total industrial energy consumption is projected to increase significantly in the base case as increases in output (particularly in the energy-intensive industries) more than offset improved energy efficiency. There remains, however, considerable uncertainty concerning how much industrial energy conservation can be expected in the future.

Before the energy price shocks of the 1970's, energy use per unit of output in some industries had decreased while that of others tended to increase. During the 1970's, the trend toward improved energy-use efficiency was accelerated in most industries as the price of energy increased dramatically, and possible energy supply shortfalls were a real concern. How strong the trend toward increased industrial energy-use efficiency will be in the face of stable energy prices and ample fuel supplies is uncertain. The base case assumes that the increased conservation efforts in manufacturing during the 1970's were a response to rapid energy price increases. After energy prices stabilize and industrial equipment has time to be replaced, a general slowdown in the rate of energy conservation should be expected because of lesser incentives (stable prices) to invest in energy saving equipment. The high conservation case assumes that the accelerated conservation trends of the 1970's will continue during the forecast period regardless of forecast energy prices. Total industrial energy use in the high conservation case is nearly 11 percent below the base case result in 1995 (Table 27). Most of this difference is explained by reduced energy consumption for agricultural uses. For the manufacturing sector, the base case is very close to a high conservation case.

Transportation Sector

Energy efficiency in the transportation sector generally showed a declining trend between the early 1960's and the early 1970's. In 1973, the average fuel efficiency of the automotive stock was about 8 percent below the level achieved in 1963. The energy price shocks of the 1970's as well as long gasoline lines changed this trend. From 1973 to 1978 and from 1978 to 1982, the average automotive fleet efficiency improved at average annual rates of 1.4 and 3.8 percent, respectively. In the high conservation case, energy prices are assumed to continue to increase above the levels projected in the base case. These higher energy prices make more efficient vehicles relatively more attractive.

In the high conservation case from 1985 to 1995, the automotive fleet efficiency is assumed to improve at about the same rate as occurred between 1978 and 1982, and more than one-fourth faster than in the base case. Automotive fuel consumption in 1995 in the high conservation case is about 16 percent below fuel consumption in the base case. This fuel savings reflects both the improved auto fuel efficiency and the reduced vehicle-miles traveled in the face of higher fuel prices. Because automobiles used about one-third of the economy's end-use oil consumption in 1983, the percentage reductions in energy use translate into large changes in total oil demand.

There remains considerable uncertainty concerning the rate at which the efficiency of the automotive fleet will improve in the future. New-car fleet fuel efficiency for 1983 declined slightly from the 1982 level as the large car share of auto sales moved toward the pre-oil embargo level. Nevertheless, the fuel efficiency of new, large cars remains considerably above the average fleet fuel efficiency.

6. Petroleum and Natural Gas

This chapter examines some factors that influence the supply and demand for crude oil, petroleum products, and natural gas. It is organized into three main sections: domestic crude oil and natural gas resources, petroleum markets, and natural gas markets. Within each section, the effects of different levels of world oil prices on choices made by producers and consumers are examined. Specific sensitivity analyses are discussed to explore several key issues.

The section on domestic crude oil and natural gas resources discusses several factors affecting the level of oil and gas production. Proved reserves (the stock from which domestic production is taken) of both oil and natural gas have declined from 1976 to 1983 as new discoveries have not kept pace with production despite record levels of drilling (see box). Projections of proved reserves are based on the historical trends in the amount of reserves found as a factor of the amount of drilling undertaken.

Crude oil and natural gas resources are taken from a finite resource base. The assumptions in this analysis are that resources are searched for and developed in a least-cost order. In the absence of significant technological developments, these assumptions imply that as more resources are produced, more expensive resources must be developed to satisfy future demand. Thus, high consumption in the early years of the forecast implies higher prices later in the forecast. Domestic supply depends on both current and anticipated prices; therefore, a range of forecasts based on alternative assumptions about price paths is discussed. Another sensitivity analysis examines the impact on oil and gas production and reserve additions resulting from different assumptions about exploration and development activities, specifically higher or lower drilling costs and drilling efficiency.

The petroleum markets section examines the expected sources of crude oil to the Nation's refineries (that is, imports versus domestic supply), the levels of domestic refining activity and refined product imports, the capabilities of the domestic refiners to process crude oil into the products demanded, and the supply of specific refined products projected over the forecast period. The effects of alternative world oil price paths are quantitatively assessed in the petroleum markets section.

The final section on natural gas markets discusses uncertainties in the sources and end-uses of natural gas, as the natural gas industry becomes less regulated and price is determined more by market factors. In the base case projection, natural gas distributors are assumed to have the flexibility to vary rates to different sectors to retain customers, particularly those who have the capability to switch to alternate fuels. In the event that Public Utility Commissions do not permit this type of pricing, one sensitivity evaluates the impact on natural gas demand and prices to other sectors.

Proved Reserves of Crude Oil and Natural Gas Decline in 1983, While Natural Gas Liquids Reserves Increase

As of December 31, 1983, U.S. proved reserves are estimated to have been 27.7 billion barrels of crude oil, 200.2 trillion cubic feet of dry natural gas (excluding gas in underground storage), and 7.9 billion barrels of natural gas liquids (including lease condensate). Although yearend crude oil and dry natural gas reserves showed relatively small declines from 1982 to 1983, large gains in natural gas liquid reserves were recorded in 1983.

Proved reserves of crude oil declined 0.4 percent, or 123 million barrels, during 1983, continuing the downward trend of 1982. Total discoveries declined for the 3rd consecutive year to 924 million barrels of oil; whereas, large net revisions (1.5 billion barrels) and net adjustments (462 million barrels) resulted in only a small net decrease in crude oil reserves. Proved reserves of natural gas liquids increased 680 million barrels or 9.4 percent over those recorded in 1982, continuing the upward trend that began in 1980. Positive net revisions and adjustments (915 million barrels) more than compensated for a decrease in total natural gas liquid discoveries. The net result is that total liquid hydrocarbon reserves (crude oil plus natural gas liquids) increased 1.6 percent during 1983 because of the large increase in natural gas liquids.

Proved reserves of dry natural gas declined 1.3 trillion cubic feet (0.6 percent) in 1983. Positive net revisions and adjustments of 3.1 trillion cubic feet were roughly equivalent to those of 1982. However, total discoveries of natural gas decreased by 21 percent to 11.4 trillion cubic feet, resulting in the overall recorded decline in 1983 yearend reserves.

These estimates are based on an analysis of data filed by 3,054 operators of oil and gas wells and by 1,011 operators of natural gas processing plants. These data are compiled in EIA's U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1983 Annual Report, DOE/EIA-0216(83) (Washington, DC, October 1984).

Natural gas imports have provided approximately 5 percent of total U.S. gas consumption since 1970. Uncertainty regarding the future level of imports to the United States has resulted from the recent cessation of natural gas exports by Mexico, the recent (and future) pricing adjustments made by the Canadians, and the current domestic surplus of productive capacity. Two alternative natural gas import cases examine the impact of higher or lower imports on domestic production and end-use prices. Finally, recent legislative and regulatory changes as well as recent events in natural gas markets are briefly discussed in terms of their potential significance to the market over the longer term.

Domestic Crude Oil and Natural Gas Resources

Domestic Supply Under Alternative World Oil Price Assumptions

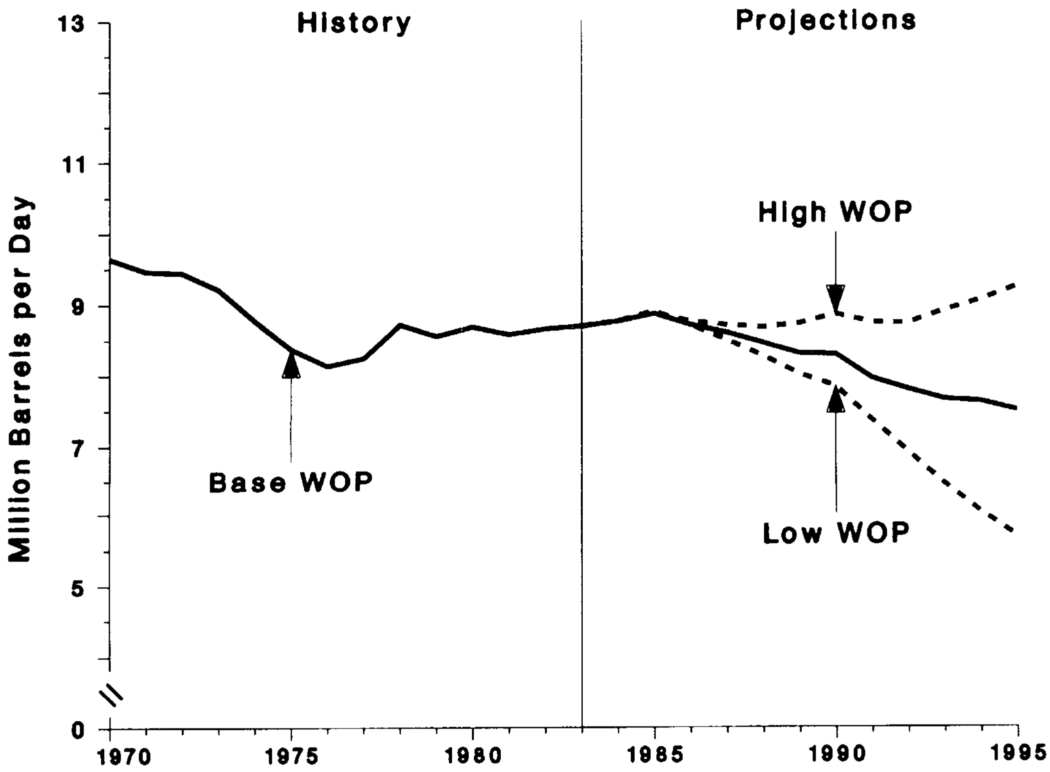
Over the range of world oil price assumptions analyzed, production of crude oil is projected to vary dramatically, while natural gas production is expected to react much less strongly. Total oil production in 1995 is about 1.8 million barrels per day higher or lower than the base case level in the high and low world oil price cases, respectively (Figure 22). Most of the deviation is expected to occur in the conventional onshore production from the Lower 48 States. In the high price case, more than 80 percent of the increase from the base level is projected for conventional onshore Lower 48 States production. The low price case results in an almost equal downward shift in total production, but only 67 percent of the decrease is associated with conventional onshore Lower 48 States production. This difference results because production potential from other areas (which have longer lead times) is somewhat limited in its ability to respond rapidly to higher oil prices. With lower oil prices, however, production from these other sources is projected to be lower.

The natural gas market is projected to react more subtly to changes in the world oil price. Natural gas prices are projected to be virtually identical in all three world oil price scenarios because of a combination of factors. More natural gas production is expected with higher world oil prices, because the higher oil prices stimulate demand for natural gas (the relatively cheaper fuel). However, higher oil prices also encourage oil supply activities that are expected to result in higher levels of associated natural gas being discovered and produced along with the oil. The projected increase in associated gas production almost exactly offsets the projected increase in natural gas extraction rates with higher oil prices, resulting in increased natural gas production with stable price levels.

The following discussion provides a more detailed description of the oil and natural gas projections, including the impacts of the alternate world oil price assumptions on the components of the forecasts. These impacts are of particular interest because the world oil price is a dominant factor in the U.S. markets for fossil fuels. When producers operate as price takers in a competitive environment, the domestic price of oil adjusts to the world oil price. This oil price determines the level of petroleum demand and influences the demand for other forms of energy, depending on the degree of substitutability in use. Also, given that about 20 percent of the natural gas production is a coproduct of oil production, the price of oil directly affects the supply of natural gas. The discussion focuses initially on the oil production forecasts, followed by the natural gas supply.

Crude Oil Production. The relatively stable oil prices assumed in the base case (compared to those used in last year's report) are expected to result in production declines throughout the forecast period. Beyond 1985, total crude oil production in the base case forecast is projected to decline at an average annual rate of 1.7 percent. The expected declines in conventional crude oil production (not including enhanced recovery) from the Lower 48 States continue the trend of recent years. Oil production from the OCS is projected to peak between 1986 and 1988 and then decline slowly, while Alaskan production is projected to fall

Figure 22. Oil Production: Comparison of World Oil Price Scenarios, 1970-1995



WOP = World oil price.

Source: • History: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) (Washington, DC, 1984), Table 36. • Projections: Appendices A, D, E; Tables A15, D15, E15.

rapidly after a peak in 1990. Increases in domestic production due to enhanced oil recovery are not projected to be sufficient to offset these declines.

Since 1980, oil production from the Lower 48 States has been stable despite significant changes in the factors affecting oil production. Since 1979, the industry has seen massive swings in oil prices and in drilling levels, as well as the imposition of the Windfall Profit Tax (WPT). (See box.) The WPT, which has been criticized as a major impediment limiting crude oil production, was enacted in 1980 to serve as a quid pro quo, allowing the phasing out of crude oil price controls. However, the price received at the wellhead, adjusted for the WPT, was higher than it had been and resulted in a greater number of wells drilled in each year since 1980 than had previously been recorded in the United States. Lower 48 States production stabilized at 7.0 million barrels per day during this period, arresting a downward trend that had persisted since 1970.

Crude oil production from the onshore Lower 48 States is projected to resume the general downward trend of the last 15 years. This trend is a consequence of depletion of the conventional resource base. The projected values are subject to uncertainty arising from possible discoveries of new, major hydrocarbon-bearing geologic areas or institutional changes resulting from new legislation, although the base case forecast does not incorporate any unexpected events.

Variations in world oil prices affect the oil projections significantly, just as they did from 1975 to 1980. Under the high world oil price case, U.S. crude oil production in 1995 is projected to be 23 percent higher than in the base case, while the lower oil prices lead to a drop of 24 percent. The high prices lead to higher drilling levels, more discoveries, and more intensive development of all reserves. The low price case has the opposite effect on the onshore conventional crude oil production.

Alaskan crude oil production is expected to increase over this decade, to a peak of 2.1 million barrels per day in 1990 (Figure 5 in Chapter 2). This peak figure is based on the assumption that the economics of utilizing the Trans-Alaska Pipeline System at this rate will be favorable. Virtually all of this production is expected from Northern Alaska. Production in the Cook Inlet area of South Alaska is expected to decline continually as no significant reserve additions are anticipated to arrest this trend. North Alaskan production, after peaking in 1990, is projected to decline dramatically thereafter, despite the startup of additional recovery projects after 1990. The Sadlerochit formation alone is projected to produce 1.5 million barrels per day from 1984 through 1990. This formation has currently been enhanced by a massive waterflooding project to maintain production levels and increase ultimate recovery. The waterflooding project is projected to maintain production through 1990 and then be followed by a precipitous dropoff in production rates. The large declines in production from Sadlerochit are only partially offset by the initiation of additional projects prior to 1995. While the new projects both onshore and in the Beaufort Sea are projected to be quite prolific, they are still insufficient to offset the massive production decline projected for the Sadlerochit operation. (See Appendix F for details of these projections.) The Arctic environmental conditions substantially increase both the lead times and the uncertainties associated with exploration and development in the Beaufort Sea.

The Crude Oil Windfall Profits Tax Act of 1980

The lifting of price controls on domestic oil production, announced on April 5, 1979, led to the passage of the Crude Oil Windfall Profits Tax Act of 1980. President Reagan accelerated the earlier schedule by his decision to decontrol oil prices immediately in January 1981. The Act was passed to increase the incentives for oil production by allowing producers to receive additional revenues, while taxing a portion of those incremental revenues. Recent data show the impact of the tax on production to have been somewhat limited.

Highlights from recent data include:

- Adjusted windfall profit tax (WPT) liability declined by 10 percent per quarter from the first quarter of 1981 to the third quarter of 1983. As the WPT base price grows, given declining oil prices, this trend should continue.

- The decline in petroleum consumption coupled with lower world oil prices resulted in net tax liabilities to the oil companies of $61 billion and, allowing for deductions, a net budget effect of $33.3 billion through 1983, considerably less than the $56.1 billion originally estimated.

- The U.S. General Accounting Office stated that considerable revenues are being requested for refunds based on prior over-withholding of funds. This would further lower the Federal receipts from the WPT.

The WPT for any project is computed as the difference between the wellhead price of the oil and an adjusted base price less an adjustment for State severance taxes. As the price of oil falls, the calculated WPT declines proportionately faster (Table 28). The WPT in the projections will be at a minimum in 1986 and 1987 when oil prices are projected to be at their lowest values. In fact, the computed WPT for oil produced from a property discovered after 1978, for heavy oil, or for incremental tertiary oil is less than $1 per barrel in 1986 through 1988, given the assumed world oil prices. Without legislative changes and with no oil price shocks, the WPT will be in existence through most of 1993.

Table 28. Summary of Windfall Profits Tax Revenues, 1980-1983

Year	Windfall Profits Tax (billion dollars) Tax Before Adjustments[a]	Tax After Adjustments[a]	Domestic Crude Oil Production[b] (billion barrels)	Average Tax (dollars per barrel)	Average Wellhead Price[b] (dollars per barrel)
1980[c]	11.0	9.9	3.1	3.16	21.59
1981	26.6	25.9	3.1	8.29	31.77
1982	18.3	16.8	3.2	5.31	28.52
1983[d]	12.1	11.2	3.2	3.53	26.19

[a]Units are in billion dollars, unadjusted for inflation. Department of the Treasury, Internal Revenue Service, SOI Bulletin (Washington, DC, Summer 1984).

[b]Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(84/06) (Washington, DC, 1984).

[c]Data for last 10 months of the year only.

[d]Projected tax payment for the year extrapolated from the first three quarters of the year.

High and low oil price assumptions change the economics of certain planned projects for new Alaskan supplies. The long lead times for new Alaskan production projects virtually prohibit currently unexpected projects from affecting the forecasts. Uncertainty affecting the Alaskan forecasts stems from two aspects: the production schedule and the realized levels of production within that schedule. Higher oil prices should accelerate the schedule on projects starting beyond 1987 and bring on one additional project not included in the base case. Lower world oil prices are assumed to cause delays on some projects and to eliminate the enhanced oil recovery (EOR) project at Prudhoe Bay, which would become uneconomic in this case.

Enhanced oil recovery in the Lower 48 States also is expected to contribute large amounts of crude oil production over the forecast period (see box). Enhanced oil recovery is defined as the incremental oil reserves that can be economically produced from a petroleum reservoir over that which can be economically recovered by conventional primary and secondary methods. The volumes shown in Figure 5 are incremental flows above the 1981 level. The EOR volumes according to the National Petroleum Council (NPC) are currently in excess of one-half million barrels per day and are expected to reach levels above 1 million barrels per day in the next decade.

The EOR production levels under the three world oil price cases are taken from the NPC report cited in the accompanying box. The low, base, and high EOR levels are assumed to match the NPC $20, $30, and $40 per barrel cases, respectively. The higher world oil prices are expected to lead to an increase in EOR production of

21 and 23 percent in 1990 and 1995, respectively. The equivalent fall in oil prices results in a dropoff in EOR production of 16 and 36 percent for the same years. The higher prices stimulate production but the incremental flow does not occur immediately. Both the expansion of existing projects and the initiation of additional projects are expected to occur over an extended period. The lower oil prices lead to fewer, new EOR projects, an impact which has a cumulative effect over the forecast horizon.

The OCS crude oil production off the Lower 48 States is projected to peak during 1986 through 1988 at 1.3 million barrels per day in the base case projections. Subsequent declines in offshore Lower 48 States' production are expected as production in the Gulf of Mexico decreases. It is assumed that Federal OCS leasing activities will not substantially constrain crude oil or natural gas production in the Gulf of Mexico during the forecast period. Pacific OCS oil production is projected to increase to more than 0.3 million barrels per day by 1990. Faster growth of Pacific supplies is not expected to occur, because of the relatively low world oil price, leasing constraints, and the long lead times required to implement production plans. The rise in offshore production in recent years is attributable to the unprecedented high levels of exploratory drilling early in this decade that resulted from the substantial increases in crude oil prices. The high level of discoveries is not projected to persist, because of lower world oil prices and a significant shift away from exploratory drilling towards developmental work.

Enhanced Oil Recovery

In June 1984, the National Petroleum Council (NPC) released a report titled Enhanced Oil Recovery,[1] quantifying the potential reserves that might be obtained from the Nation's known oil fields by using enhanced oil recovery (EOR) processes. The NPC, however, specified that the estimated supply is highly dependent on economic, technological, and political constraints. The base case assumes that the oil will receive a market price of $31 per barrel (in 1984 dollars) for the next 30 years and a 10-percent minimum rate of return. Under these conditions, it is estimated that about 14.5 billion barrels of additional crude oil could be recovered. Crude oil proved reserves at the end of December 1983 were estimated to be 27.7 billion barrels.

The NPC study indicated that 3.5 billion barrels of the 14.5 billion barrels of crude oil is attributable to EOR projects currently in operation. Of the total 14.5 billion barrels of oil that could be recovered, 17 percent is attributable to chemical flooding, 38 percent to miscible flooding, and 45 percent to thermal methods of recovery. Currently, thermal recovery provides nearly 90 percent of the Nation's daily EOR production. Under the base case, it is estimated that up to 1 million barrels of oil per day (or

---

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

more) might be produced from U.S. fields by EOR methods by as early as 1990, and a peak rate of about 1.2 million barrels per day might be reached by the year 2000.

All offshore production in the current projections flows from either the Pacific or Gulf of Mexico areas. At present, no Atlantic Ocean areas are being explored. The absence of any commercial discoveries to date, coupled with the time lag prior to the initiation of production from new discoveries, indicates that no significant flows of production from Atlantic areas are likely to arise in the forecast period. In light of the significant finds in the Hibernia area of Canadian waters, the North Atlantic may yield additional crude oil reserves in the long term. Offshore Alaskan production is expected to begin in 1992 (Seal Island) and increase its share of Alaskan production by 1995 (to about 15 percent). However, the long lead times required for production from these remote regions effectively prohibits additional production from occurring for at least 10 years.

Natural Gas Production. The outlook for natural gas production is affected by both the level of the world oil prices and economic growth. Petroleum products compete in the market place and about one-fifth of domestic gas is produced as a coproduct of oil; as a consequence, domestic natural gas markets are affected by world oil prices. The major components of domestic natural gas supply are: Lower 48 States onshore conventional production, unconventional gas recovery (UGR), and the OCS. UGR principally consists of production from tight (low permeability) sands but also includes methane from coal mines and geopressurized brines. A fourth potential source of natural gas supply, Northern Alaska, has been assumed not to begin production within the forecast horizon due to the absence of transportation facilities to bring the gas to markets in the Lower 48 States.

The natural gas prices over the forecast period are projected to be inadequate to add sufficient reserves to replace production volumes. Over the forecast period, yearly reserve additions in the base case are projected to average 15.6 trillion cubic feet in the Lower 48 States. However, low natural gas prices are projected to result in higher consumption and production but fewer reserve additions than would be the case with higher natural gas prices. Base case production in the Lower 48 States is expected to average 17.2 trillion cubic feet per year from 1985 to 1995. These conditions are expected to result in a net drain of reserves over time. In the final years of the forecast, cumulative depletion of the lower cost reserve base coupled with stable gas demand leads to higher prices for the new natural gas discoveries. The higher prices for new gas in turn stimulate drilling for new reserves towards the end of the forecast. By 1995, the average wellhead price for production is projected to be $5.05 per thousand cubic feet, but the new discoveries of 15.9 trillion cubic feet receive a new contract price of about $5.30 per thousand cubic feet.

The impact of changes in prices and reserve additions on the gas supply varies by supply source. Onshore conventional discoveries generally are projected to be stable, with the level of discoveries for any year fluctuating by less than 12 percent from the average over the forecast period. UGR reserve additions are projected to become a larger share of new supplies over time, although UGR production rates from a given reserves stock are only one-third to one-half those for conventional production. As UGR reserves become a larger share of the total, production rates from a given stock of reserves will become increasingly difficult to maintain, so the portion of reserves producible in any year will fall.

Natural gas from the OCS represents a significant part of total supply. Yearly reserve additions in the Gulf of Mexico are expected to average 3.2 trillion cubic feet per year over the forecast period. Outside of the Gulf of Mexico, only the Pacific OCS areas are expected to yield natural gas production over the forecast horizon. The U.S. Atlantic is not expected to produce commercial natural gas volumes of any significance through the forecast period.

Alaskan gas production in excess of consumption within Alaska is expected to continue to be converted into liquefied natural gas (LNG) and shipped to Japan. No West Coast facilities now exist or are assumed to be built that would allow for domestic consumption of this LNG. In the future, Alaska could serve as a major source of natural gas to the Nation. However, virtually all of Alaska's known gas reserves are in the remote areas in and around Prudhoe Bay. Transportation facilities for this gas are assumed not to be in place by 1995.

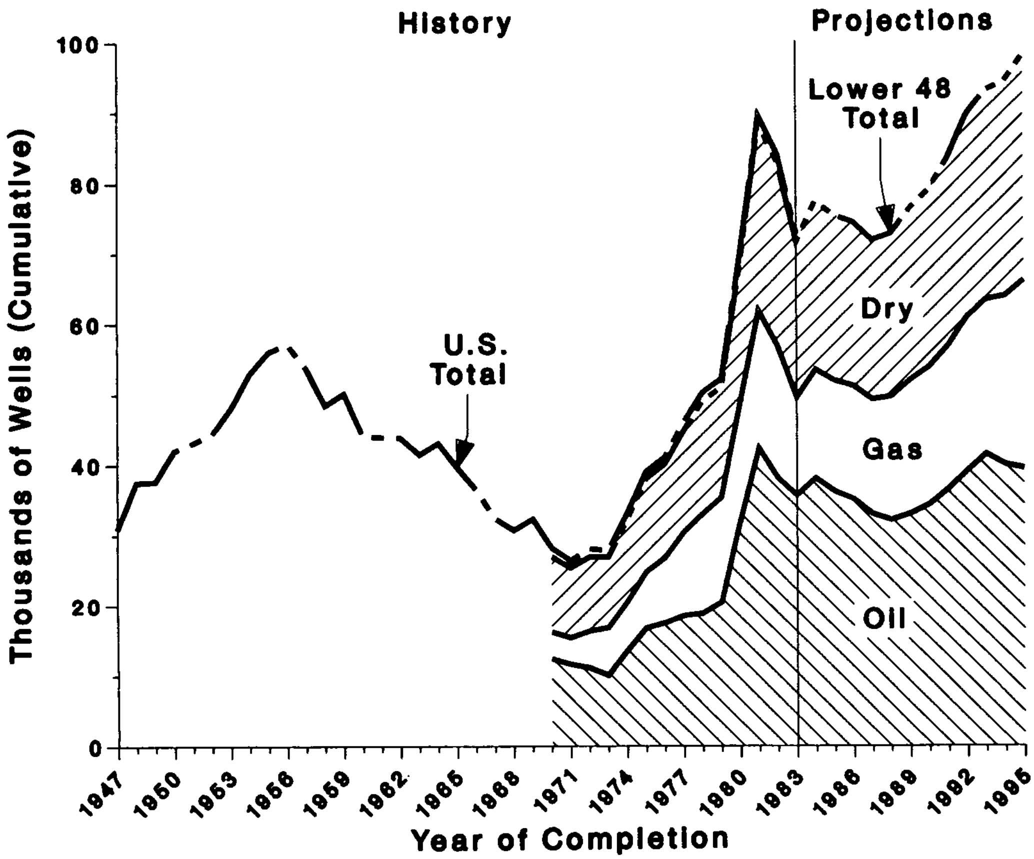
The impact of high and low world oil price assumptions on the natural gas markets is limited. The high oil prices stimulate demand for natural gas as a substitute fuel. However, higher oil prices have a depressing effect on the economy in general. The converse is true for lower oil prices. Natural gas production in 1995 is projected to be 2.4 percent above and 2.1 percent below the base case level in the high and low oil price cases, respectively. The reserve stock in 1995 for the high and low oil price cases is expected to differ from the base case by 4.8 and -1.0 percent, respectively. The additional reserves added in the high price case are due primarily to the natural gas reserves additions discovered in association with oil.

High and Low Domestic Supply Under Alternative Productivity and Costs

The sensitivity of the base case projection to alternate assumptions about factors affecting exploration and development activities of oil and gas was examined in the high and low supply cases. Proved reserves (the stock from which domestic production is taken) of crude oil declined from 1976 to 1983, because reserve additions did not keep pace with production, despite recent record levels of drilling. In 1983, proved reserves of crude oil declined by 0.4 percent, or 123 million barrels. The level of natural gas reserves has been stable over the last 5 years, varying by just over 1 percent during the period.

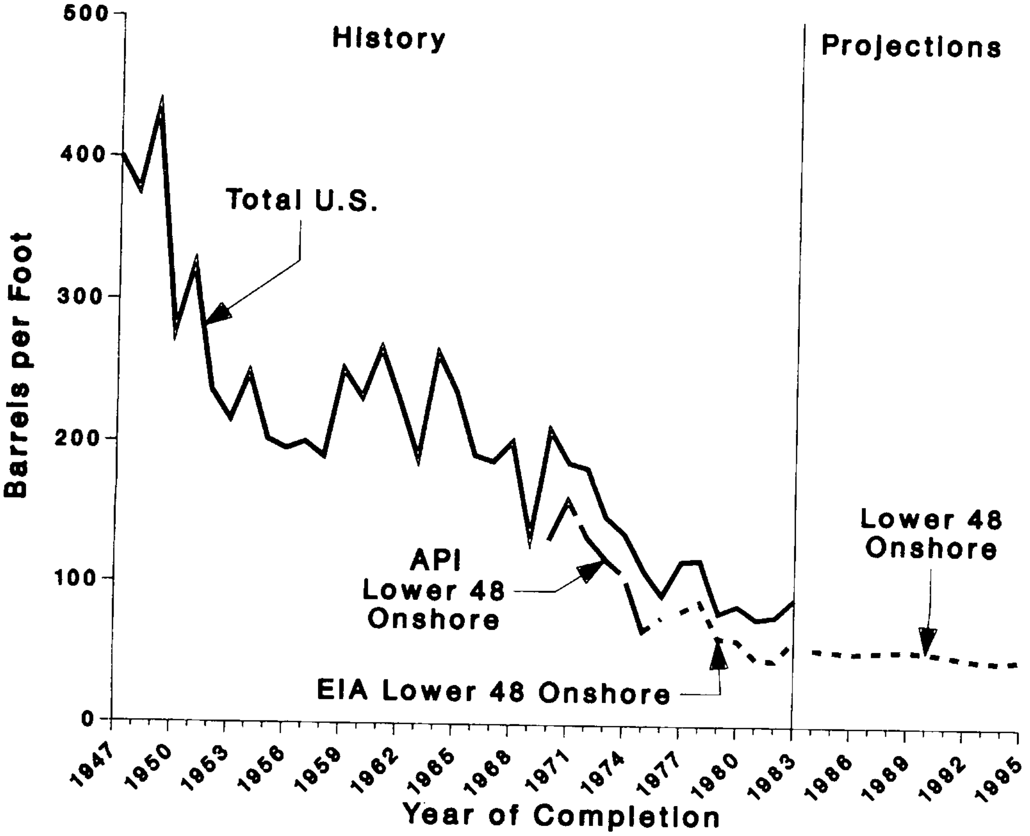
The oil supply projections are based on the underlying trends in the observed historical data. From 1973 through 1981, as the world oil price increased, drilling activity also increased (Figure 23). As the world oil price has fallen, so too has drilling. Wells drilled are assumed to continue to decline through 1987, followed by a resurgence by the end of the forecast period. This drilling pattern, coupled with the finding rate (Figure 24), results in a slump in reserve additions in the latter part of this decade, followed by an increase in the level of discoveries. Crude oil production is projected to fall by 1.7 percent per year over the projection period. The major portion of the falloff in production stems from the drop in Alaskan production. The Alaskan production rate is projected to fall by roughly 1 million barrels per day between 1990 and 1995. Alternate

Figure 23. Wells Drilled in the United States by Type, 1947-1995



Source: • History: U.S. Total, 1947-1969: American Petroleum Institute (API), Basic Petroleum Data Book (Washington, DC, May 1984), Vol. IV, No. 2, Section III, Table 2a. Lower 48 Total, 1970-1980: summarized by EIA from well and drilling statistics provided by API; 1981-1983: EIA estimates.
• Projections: Energy Information Administration, Office of Oil and Gas (Washington, DC).

Figure 24. Average New Discoveries for Total U.S. and Lower 48 States Onshore Exploratory Drilling, 1947-1995



Note: All historical data represent derived ratios of new discoveries to footage drilled.

Source: • History: Oil Exploratory Footage, 1947-1969: American Petroleum Institute (API), Basic Petroleum Data Book (Washington, DC, May 1984), Vol. IV, No. 2, Section III, Table 1; 1970-1980: summarized by EIA from well and drilling statistics provided by API; 1981-1983: EIA estimates. New Discoveries, 1947-1976: API, Basic Petroleum Data Book, Vol. IV, No. 2, Section II, Table 2a; 1977-1983: Energy Information Administration, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids, DOE/EIA-0216 (Washington, DC). • Projections: Energy Information Administration, Office of Oil and Gas (Washington, DC).

outcomes may occur, depending on the actual levels of discovery finding rates, well productivity, world oil prices, or factor costs.

Variations in drilling costs and the finding rates for oil and gas are expected to affect domestic reserve levels. Increases in production costs can be offset by technology advances such as changes in drilling and seismic technology. Such advances effectively lower overall costs of exploration and production by enhancing the productivity of the associated activity. The high and low supply sensitivity cases include shifts in both productivity of exploration and the costs of exploration and production. These cases evaluated the impact of changes in the oil and gas markets simultaneously, not as a partial analysis of each market separately.

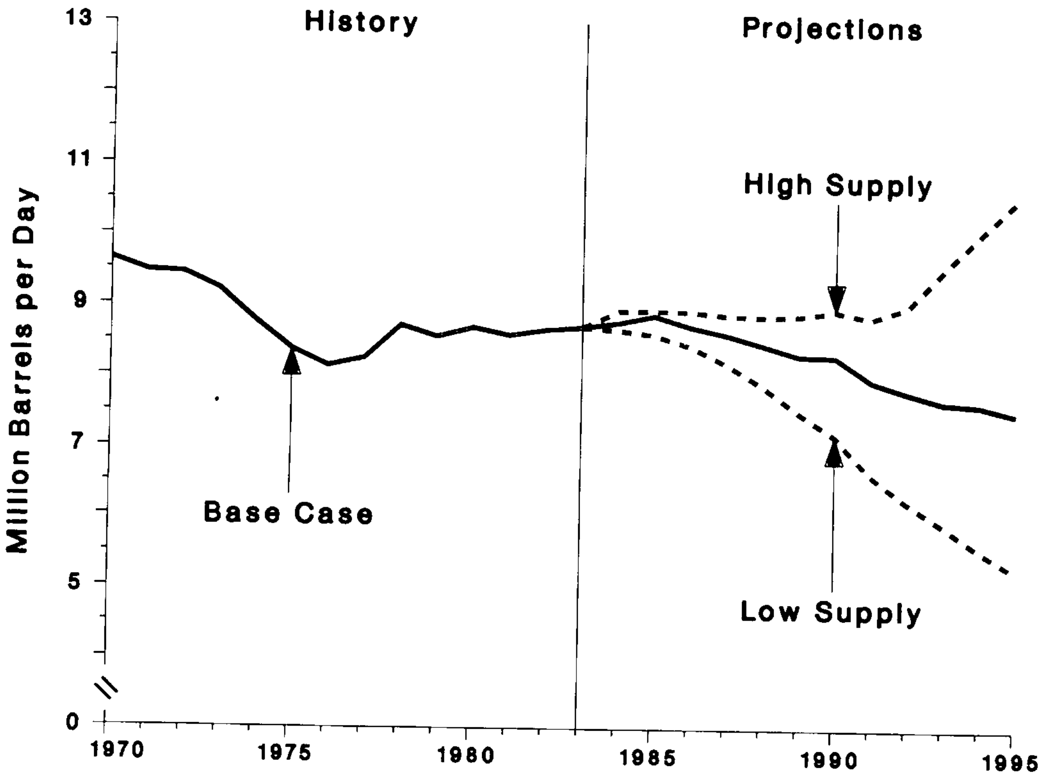
The level of reserves added in response to exploratory drilling is assumed to shift within the recent historical range of variation in finding rates, increasing by 10 percent for the high supply case and declining by 10 percent for the low supply case. Real factor costs in the base case are assumed to grow at an average rate of 3 percent per year between 1985 and 1995. The alternate assumptions are that factor costs will rise by 6 percent in the low supply case and not grow at all in the high supply case. The alternate assumptions were chosen as reasonable limits on the range of possible cost growth rates.

Modifications of the discount rates represent alternate attitudes towards investor perception of risk. Higher discount rates reflect higher levels of uncertainty and lower the present value of a given project. The base case assumes that developmental projects are discounted at 10 percent, and exploratory projects are discounted at 12 percent. The high supply case uses discount rates of 8 and 10 percent for developmental and exploratory projects, respectively; the low supply case uses discount rates of 15 and 20 percent. The level of oil production from EOR and the OCS was raised and lowered 10 percent for high and low supply, respectively. Likewise, the base level volumes of OCS and UGR gas reserve additions were shifted by 10 percent in each case.

Alaskan oil production was altered by the selection of particular projects to meet alternate schedules. Contrasted to the base case, the high supply projection assumes earlier starting dates for projects beginning beyond 1987. Conversely, the low supply case represents a pessimistic view that the severe conditions affecting the industry will delay all but the most firm projects. The high and low cases for Alaskan production are identical to the high and low world oil price cases.

Domestic oil production varies markedly between supply cases. By 1995, in the high supply case, oil production is projected to be about 40 percent higher than the base case level and 30 percent lower in the low supply case (Figure 25). All changes in the supply factors are complementary, so in low supply, for example, oil and natural gas are discovered at a slower rate and at higher costs. The combined effect of these changes on oil production also will lead to identical variation of oil imports. In analyzing the supply sensitivity, oil production is determined by the full impact of alternate cost and productivity assumptions given a fixed set of oil prices. The fixed oil price assumption is made because foreign sources provide the marginal source of domestic oil use and hence set the price of oil.

Figure 25. Oil Production: Comparison of Alternate Supply Scenarios, 1970-1995



Source: • History: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) (Washington, DC, 1984), Table 36.
• Projections: Appendix A, Table A15; Appendix G, High and Low Oil and Gas Supply cases.

The U.S. oil and natural gas markets are fundamentally different and, as a result, respond in different ways to changes in production-related assumptions. In the U.S. oil market, prices are determined exogenously (by OPEC) because marginal oil supplies are imported. In the U.S. natural gas market, the interaction of domestic supply and demand largely sets the price, so that variations in supply conditions can alter both prices and levels of demand. In the petroleum market, increases in oil production, due to more favorable supply assumptions, merely back out oil imports on a one-for-one basis (assuming fixed world oil prices).

More favorable natural gas supply assumptions imply a drop in the market price of natural gas and smaller increases in supply than would occur if natural gas prices were also set exogenously. Domestic natural gas supply can only increase to the extent that lower natural gas prices increase demand. The high natural gas supply case shows an increase in domestic natural gas production of 7 percent in 1995, compared with the base case, while the low supply case shows a decrease of 12 percent. This change is not as great as was observed for oil production. Between 1985 and 1995, almost one-third more natural gas is projected to be discovered in the high supply case compared to the low supply case. Relative to the base case, the 1995 natural gas wellhead price changes by -23 and 39 percent in the high and low supply cases, respectively. The relatively more stable volumes of gas production occur as a result of stable demand for natural gas. The level of economic activity serves as the primary determinant of natural gas demand for commercial and industrial users. The 1995 levels of consumption in these two sectors change by less than 4 percent from the base case to the sensitivity cases. The impact is strongest in the consumption by electric utilities as they switch to and from natural gas and residual fuel oil.

Petroleum Markets

The base case projections of petroleum supply presented in Chapter 2 were highlighted by four key trends:

- The combined outlook for sustained economic growth and only moderate increases in oil prices lead to an average 1.3 percent annual increase in total domestic petroleum consumption between 1985 and 1995, to 18.0 million barrels per day.

- Contributing to the change in total consumption are the increased road use of diesel fuel, the increased utility demand for residual fuel oil, and the increased petrochemical demand for liquefied petroleum gases which more than offset declining motor gasoline demand.

- Higher total domestic consumption and the outlook for an average 1.9-percent annual decline in total domestic production of crude oil and natural gas liquids result in a forecast annual increase in net petroleum imports (crude oil plus refined products) of 5.8 percent between 1985 and 1995, to 8.7 million barrels per day.

- Higher refining costs in this country, combined with new refining and petrochemical production capacity being built in the major oil and gas producing regions of the world, result in an outlook for increasing refined product imports--especially for residual fuel oil, liquefied petroleum gases, and petrochemical feedstocks.

This section summarizes the changes to the base case projections of refinery activity, net petroleum imports, and petroleum consumption as a result of sensitivity analyses conducted on world oil prices. Combining the assumptions of low oil prices and middle economic growth results in an average rate of consumption for all petroleum products in 1995 that is 1.3 million barrels per day higher than the base case forecast for that year. At the same time, domestic refinery production would be 0.9 million barrels per day higher, and net petroleum imports would be 3.1 million barrels per day higher. In the high oil price case, total petroleum consumption in 1995 would be 1.6 million barrels per day lower than in the base case, refinery production would be 1.3 million barrels per day lower, and net petroleum imports would be 3.4 million barrels per day lower.

Domestic Refining Activity

The domestic refining industry is undergoing long-term adjustments in response to changes in the total volume of product demanded, shifts in the desired product mix, and changes in the relative values and availabilities of the various grades of crude oils marketed. Uncertainties as to the direction and magnitude of adjustments in refinery capacity, processing flexibility, and inventory management form the basis for major uncertainties underlying the forecasts of refined product imports, prices, and demands.

Refinery Capacity

A major uncertainty in the petroleum supply forecasts concerns the shares of domestic demand that will be met from domestic refinery activity and imports. This allocation, in turn, reflects uncertainty concerning future trends in domestic refining capacity. This capacity is commonly measured as the aggregate throughput capacity of atmospheric distillation units (which separate the crude oil into its basic product fractions) at the Nation's petroleum refineries.

The analysis of refinery activity and costs presented in this report is not based on an explicit forecast of domestic refinery capacity. However, if refineries were assumed to operate on average over the forecast horizon at a relatively high, 90-percent utilization rate[2] (gross refinery inputs divided by operable distillation capacity), the base case projections of domestic refinery production would be consistent with an outlook for virtually no change in distillation capacity from January 1, 1984, through 1995. If domestic refinery capacity continues on the downward trend of the past 3 years or if the future refinery utilization rate is

---

[2]During the 1970's, refinery utilization averaged 91 percent. See Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) (Washington, DC, 1983), p. 95.

significantly less than 90 percent (for example, approximating the 1984 level of 76 percent), then total 1995 refinery production would be lower than the base case projection of 14.6 million barrels per day, and net refined product imports would have to be higher to satisfy projected demand levels. This same tradeoff between capacity and utilization rates on the one hand and net product imports on the other carries over to the high and low world oil price cases.

Refinery Flexibility

In addition to questions about the outlook for the total capacity of refineries, there is also significant uncertainty surrounding the flexibility of refiners to accommodate the projected shift in the composition and quality of petroleum products demanded. For example, motor gasoline's share of total domestic production (net of natural gas liquids blended into the gasoline) is projected in the base case to decrease from 46 percent in 1985 to 39 percent in 1995. Over the same period, the distillate fuel oil share of total production is projected to increase from 21 percent to 25 percent.

A basic shift in the downstream processing capabilities of domestic refineries represents one way the industry has responded in the past to changing relative demand levels. For example, in the aftermath of petroleum price decontrol in 1981 and the 1981-1983 economic recession, demands for distillate and residual fuel oils declined more sharply than that for gasoline. The subsequent decline in distillation capacity with the closure of smaller and older refineries was not accompanied by comparable declines in downstream capacity. As a result, the average complexity of domestic refineries has increased in the last 3 years, and refiners can now produce a wider range of products from a given stream of crude oil. Current investment trends indicate a continued increase in refinery capabilities to produce more light fuels and to process a wider range of crude oil qualities.

With respect to shifts in product quality, a major challenge facing domestic refiners during the late 1970's resulted from the need to produce higher octane gasoline blendstocks in response to the Environmental Protection Agency's (EPA) mandated restrictions on the use of octane-enhancing lead additives. Significant downstream investment in catalytic reforming capacity (which "reforms" low octane gasoline components into product streams with more volatile molecular structures) during this period was aided by the downturn in motor gasoline demand and slower growth in new car sales after 1979, so that the industry as a whole now controls sufficient octane producing capacity. The proposed acceleration of EPA's lead phasedown (to an average 0.1 grams of lead per gallon of leaded gasoline produced by January 1986) can probably be met without major problems for the industry, but uncertainties concerning the future level of unleaded gasoline demand as well as the cost and availability of other octane-enhancing additives translate directly into uncertainty for the cost and supply of gasoline that is not reflected in the forecasts presented here.

Uncertainties created by projected shifts in the composition and quality of the products demanded and the outlook for future downstream investments are complicated by further uncertainties surrounding the relative attractiveness of lower quality crude oil feedstocks. Of special concern to refiners since the oil embargo of 1973 has been the decreasing API gravity and increasing sulfur and mineral content of domestic crude oils coming to the market as well as the lower prices at which these lower quality oils are generally sold in the world markets. ("API gravity" is an index related to the specific gravity of crude oils developed by the American Petroleum Institute--a lower API number indicates a heavier oil.) Heavier crude oils generally contain a smaller percentage of the lighter hydrocarbon compounds that make up valuable lighter products such as gasoline. To meet an increasing relative demand for these light products while taking advantage of the cost advantage of processing heavy oils, refiners have invested in additional downstream processing to "crack" the heavy hydrocarbon molecules associated with heavy products into lighter product streams and to remove impurities.

Downstream investments by domestic refiners and lower refinery utilization rates have in turn increased the flexibility of these firms to pick and choose among crude oil types. The marketing position of countries producing the higher quality crude oils has accordingly been weakened, and, as a result, there has been a narrowing of quality-related price differentials across crude oils in recent years, with the heavier crude oils now commanding a price closer to that for light oils. However, these differentials are still in a state of flux, and there remains significant uncertainty as to whether further refinery investments to process lower API gravity, higher sulfur oils and upgrade heavier product fractions yielded in distillation will be profitable.

Refining Costs

Uncertainty concerning the direction of future refinery investments carries over to the outlook for refined product demand by virtue of the relationship between refinery flexibility and refinery production costs. Because products refined from crude oil are jointly produced, efforts to increase the production of one product may result in an increased output of other products that have higher than desired inventories. To maintain higher production and sales of a more profitable product, producers are generally willing to reduce the relative price of less profitable byproducts. Thus, along with forecast changes in the refinery product slate, changes in product demand can also result in changes in relative refining costs.

This relationship between product slate and relative costs is reflected in the refined product price projections presented in this report. The predominant effect of this relationship is to dampen the move towards higher relative demand levels for any one fuel by way of an accompanying relative cost and price increase. It is assumed that refiners will increase their overall profit margins over the decade from their present depressed levels and that increasing demand for a fuel such as distillate will permit refiners to recover higher margins on that fuel. For example, with the relative demand shift towards distillate fuel oil noted above, the forecast gross product margin for gasoline (the difference between the retail price for gasoline and the average refiners' cost of crude oil) increases by only $2.40 per barrel between 1985 and 1995 in the base case (in 1984 dollars), while the gross product margin for distillate fuel oil increases by $3.60 per barrel. Price spreads of this magnitude may stimulate additional investment in downstream processes such as petroleum cracking, which would enable refiners to increase the yield of distillates and lower the incremental cost of refining this product. Any mitigation of the forecast price change, in turn, would be reflected in the demand for distillates.

Inventory Management

Domestic petroleum demand can be met from combinations of three basic sources: current domestic production, current imports, or, in the short term, petroleum product inventory drawdowns. Optimal inventory levels and decisions to draw on or build stocks reflect the operating requirements of the industry, the need to accommodate periodic increases in consumption levels beyond production capabilities, and any hedging or speculative response to changing oil prices and supply uncertainty.

In the base case, small increases in crude oil and refined product stocks are projected to accompany increases in product demand. Projected total petroleum stocks (crude oil and product) are built up in the base case at an average rate of about 40,000 barrels per day between 1985 and 1995, reflecting the assumption of a constant days of supply in the projection period. With the higher demand in the low world oil price case, this buildup averages 60,000 barrels per day. In the high world oil price case, the stock buildup averages 20,000 barrels per day. Additional stock building, which would both drive and be driven by any rise in oil prices or market uncertainty, is not reflected in the petroleum product supply forecasts presented here.

Net Petroleum Imports

The major uncertainties underlying the forecasts of net petroleum imports relate to the world oil price and its effect on demand and to the capability of the domestic refineries to compete with foreign sources of refined product. The base case outlook is for an increase in net petroleum imports (including crude oil and refined product) from 4.8 million barrels per day in 1985 to 6.6 million barrels per day in 1990. Declining domestic oil production and a resumption of demand growth with recovery of the domestic economy are the principal factors behind this turnaround in net imports, which had declined from 1979 to 1982. In the low world oil price case, higher demand and lower domestic oil production result in a 2.5 million barrel per day increase in net imports between 1985 and 1990.

Domestic refinery output, based on the processing of both domestic and imported crude oil, is expected to be increasingly supplemented by imports of refined products. Basically, product imports will increase when the landed costs of foreign supplies are lower than domestic costs. Low-cost, seasonal operation of heavy-fuel producing refineries in the Caribbean has historically been an important source of winter supply for distillate and residual fuel oil to U.S. East Coast markets. Subsidies to small refineries in this country under the Entitlements Program had resulted in a shift away from these foreign sources, but with the end of price controls and the shutdown of these less efficient domestic refineries, the economics of product imports have improved.

Much of the current refinery investments is aimed at (1) producing gasoline and blending components of sufficient octane to compensate for the phasedown of lead additives, (2) producing higher yields of diesel fuel oil and liquefied petroleum gases, and (3) processing more of the low gravity, high-sulfur, high-minerals crude oils currently available in the world markets. These changes in refinery processes will alter both the relative yields and relative costs of the products refined domestically. In particular, there is an outlook for decreasing refinery yields of high-sulfur residual fuel oils, which will be valued increasingly as a feedstock for production of lighter products. As a result, domestic residual fuel oil demand is expected to be met increasingly by imports. (Effectively, some domestic residual fuel oil production capacity is forecast to be displaced by imports.) Increasing imports of lower cost liquefied petroleum gases are also expected. Finally, new refining and petrochemical production capacity currently being built in the major oil and gas producing regions of the world is expected to increase the penetration of lower cost refined product imports.

Refined product imports are projected in the base case to grow by about 10 percent between 1985 and 1990. The decade-long decline in net product imports' share of total net imports (at about 29 percent in 1985) is forecast to extend until around 1986 or 1987, when it will reach about 20 percent. By 1995, its share is expected to rebound to about 25 percent. The direction of future world oil prices introduces significant uncertainty to this outlook. While product imports increase with total product demand under lower price assumptions and decrease with higher prices, net product imports generally display less variation across price scenarios than do crude oil imports. Variations in crude oil imports reflect the effects of oil prices not only on product demand (as is the case with product imports), but also on domestic crude oil production. In the low world oil price case, refined product net imports make up 21 percent of the total net imports by 1995, and in the high world oil price case, 32 percent. Only net product import requirements are evaluated, and product export levels are assumed to average 0.6 million barrels per day throughout the forecast horizon in all scenarios.

In addition to questions concerning the future path of world oil prices, other uncertainties surrounding these petroleum import projections are derived from the specific mix and quality of products that will be demanded, the crude oil quality-related price differentials, and the ultimate investment levels in foreign refining capacity. These factors together will influence the mix of oils processed, the relative yields and costs of the products refined, and, hence, the relative economics of domestic production and imports.

Refined Product Supply

Petroleum products met 43 percent of the Nation's gross energy requirements in 1983 and are expected to remain the most important energy source throughout the forecast horizon. In the base case, the effects of relatively higher economic growth and slower growth in world oil prices are projected to offset the effects of conservation actions and competition from nonpetroleum fuels in sustaining a slow growth in total petroleum consumption through 1995. In the base case, total consumption is projected to increase from 15.8 million barrels per day in 1985 to 18.0 million barrels per day during 1995. In the low world oil price case, consumption grows by 3.3 million barrels per day to 19.3 million barrels per day in 1995 over this period, but in the high price case, increases by only 0.7 million barrels per day to 16.4 million barrels per day during 1995.

Uncertainties surrounding the projections of total petroleum product supplied presented in this report can best be described by considering important factors underlying the trends for each of four major refined product groupings: motor gasoline, distillate fuel oils, residual fuel oils, and the aggregate, "all other" category.

Motor Gasoline

Volumetrically, motor gasoline is the most important petroleum fuel consumed in this country, accounting for 44 percent of total petroleum product supplied in 1983. Federally mandated improvements in automobile fuel efficiency, combined with a slowed rate of increase in per capita vehicle-miles traveled, are projected to result in a small decline in gasoline consumption (see Chapter 5 for more detail in this area). For the immediate future, the current economic recovery and the renewed demand for new automobiles are expected to generate a short-term surge in average miles driven and consumption. In the base case, however, gasoline product supplied is projected to decrease from 6.7 million barrels per day in 1985 to 6.2 million barrels per day in 1995. In the low world oil price case, lower gasoline prices result in gasoline consumption declining by only 0.1 million barrels per day over the forecast horizon. In the high world oil price case, gasoline consumption decreases by 1.1 million barrels per day from 1985 to 1995.

Of significance for the Nation's petroleum refiners, the unleaded share of total gasoline product supplied (which averaged about 55 percent in 1983) is projected to continue to grow. This trend will require refineries to use higher octane blendstocks to compensate for reduced lead usage. Current Federal regulations granting preferential excise tax treatment to alcohol blends have stimulated the use of both ethyl and methyl alcohols as supplemental octane enhancers. The overall trend, however, is expected to be towards higher quality gasoline blend-stock production, even while gasoline production is declining. As discussed in the section on refinery flexibility, uncertainties surrounding those factors that condition refiners' ability to produce sufficient octane also introduce uncertainty to the gasoline price and supply forecasts presented here.

Distillate Fuel Oil

Middle distillates, which include diesel fuel and heating oil, accounted for about 18 percent of total petroleum products supplied in 1983. The residential and commercial sectors consumed distillates, primarily in the form of heating oil, at the average rate of 0.7 million barrels per day in 1983. Another 0.6 million barrels per day of distillates were consumed in the industrial and utility sectors in that year--some for space heating, but more importantly for steam generation, process heat, and mechanical drive. Distillates are also consumed in the transportation sector, by diesel powered trucks, autos, and trains. In 1983, the transportation sector consumed an average 1.3 million barrels per day of distillates.

Because of the slow turnover in energy-consuming equipment in the residential and commercial sectors, the fuel choice for space heating purposes is relatively limited, and near-term consumption patterns mainly reflect the effects of petroleum prices and economic growth. Over time, however, fuel switching, as opposed to overall energy conservation, is expected to have an increasing effect on heating oil demand. Total conservation, through building insulation and increased appliance and furnace efficiency, is not projected to make further significant inroads into demand. Although natural gas is forecast to claim part of the heating oil market, the current debate over the further deregulation of the natural gas industry introduces some uncertainty into this outlook (as discussed in the last section of this chapter).

In the base case, heating oil consumption (distillates supplied to the residential and commercial sectors) is projected to increase only slightly, by 60,000 barrels per day from 1985 to 1995. In the low world oil price case, heating oil consumption increases by 160,000 barrels per day over this period, and in the high world oil price case it declines by 90,000 barrels per day.

Increases in the use of diesel fuel in the automobile fleet have slowed considerably in recent years. Further penetration in heavy trucking, the most important use of diesel fuel, is not likely, but increased long-distance trucking with the forecast high economic growth and continued conversion to diesel of intermediate-weight (or short haul) trucks are forecast to result in a 50-percent increase in diesel fuel use by 1995. The resulting total increase in transportation uses of middle distillates will offset the expected low growth in heating oil consumption.

In the base case, diesel consumption (distillate supplied to the transportation sector) is projected to increase from 1.2 million barrels per day in 1985 to 1.9 million barrels per day in 1995. Diesel demand for transportation uses is more sensitive to the difference between diesel and gasoline prices than it is to the absolute price of diesel. Because this price spread is relatively constant across the world oil price cases, little variation in diesel demand is seen in these scenarios. In the three scenarios, demand for diesel is driven by the outlook for high economic growth, by the continued price advantage to consumers of diesel over gasoline (on a dollar-per-unit-of-energy basis), and by the fact that diesel engines are inherently more efficient than gasoline engines. Any increases in diesel fuel prices beyond those projected here due, for example, to increased taxes or increased refining, costs to meet the more stringent cetane requirements of diesel versus heating oil, would lower the forecast growth in diesel use. (Cetane ratings are an important index of diesel fuel performance.)

Residual Fuel Oil

Residual fuel oil is consumed principally by electric utilities to run steam turbines, by large industrial concerns for steam generation and process heat, and by tankers for transportation fuel. Total residual fuel oil use, including consumption in the transportation, industrial, and utility sectors as well as a small amount in the commercial sector, is projected in the base case to increase from 1.4 million barrels per day in 1985 to 1.9 million barrels per day in 1995. In the low world oil price case, residual fuel consumption increases by 0.9 million barrels per day over this period, and in the high world oil price case, increases by only 0.1 million barrels per day.

Electric utilities are the biggest users of residual fuel oil, consuming about 0.6 million barrels per day in 1983. Generally, residual fuel oil use in this sector is projected to remain constant through 1990 as increased demand for electricity is met largely from new coal-fired units and new nuclear-powered units currently being built (Chapter 7). Constraints on the addition of new coal and nuclear units are forecast to result in renewed growth in residual fuel oil consumption by utilities after 1990.

Industrial uses of residual fuel oil for process steam, process heat, and mechanical drive (including private electricity generation) are projected in the base case to increase at an average rate of 2.2 percent per year between 1985 and 1995, as industrial activity increases with the expanding economy. Further energy conservation in this sector restrains the increase in industrial fuel consumption. As many industrial fuel users develop their multifuel burning capabilities, however, residual fuel oil consumption in this sector is expected to become more sensitive to the increasing relative price of natural gas. Further increases in residual fuel oil consumption in the later years of the forecast horizon as a result of this fuel switching are possible.

Residual fuel oil consumed as a bunker fuel by tankers is projected in the base case to increase at an average 2.5 percent per year between 1985 and 1995. This projection reflects the expansion in bunkering demand with the forecast of sustained growth in economic activity worldwide.

All Other Refined Products

The "all other" products category consists mostly of jet fuels, liquefied petroleum gases, and petrochemical feedstocks. No major developments in kerosene-based jet fuel (kerojet) use are expected over the forecast horizon, as consumption closely follows air-miles traveled, which in turn follow the general level of economic activity. In the base case, kerojet use is projected to increase from 1.1 million barrels per day in 1985 to 1.4 million barrels per day in 1995. This 1995 estimate is approximately 0.1 million barrels per day higher in the low world oil price case and 0.1 million barrels per day lower in the high world oil price case.

An outlook for increased activity in the petrochemical industries drives an average 2.7-percent per year increase in the combined demand for liquefied petroleum gases (including propane, butane, and ethane) and petrochemical feedstocks. These industries are projected to shift more of their increased raw materials demand to products included in the liquefied petroleum gases (LPG) grouping. LPG consumption is projected in the base case to increase from 1.4 million barrels per day in 1985 to 2 million barrels per day in 1995. The increase over this period is estimated to be 0.9 million barrels per day in the low world oil price case and 0.5 million barrels per day in the high world oil price case.

Natural Gas Markets

The market for natural gas has been characterized by seemingly contradictory events between 1979 and 1983. The purchase price of gas rose steadily over the period because of contracts that tied the price of natural gas to increasing NGPA price ceilings. These price increases continued in the face of a significant surplus of gas production resulting from lower demand because of the recession and the higher prices to end-users. However, in contrast to the 1979-1983 period, wellhead price increases have ended over the past year. Also, with the strong economic recovery, demand and production have risen for the first half of 1984 compared to the same period in 1983.

Between 1985 and 1995, natural gas markets are expected to continue a trend of decreased regulation by Federal and State governments, resulting in greater reliance on market forces to determine prices. With decreased regulation, prices of natural gas at the wellhead and within the various end-use sectors will increasingly reflect the basic forces of supply and demand. Results in this report indicate that the price of natural gas through 1995 will be largely determined by two factors: (1) the cost of new reserve additions which in turn depend on the development of increasingly expensive resources and (2) the volumes and prices of imported natural gas, especially from Canada. The principal reasons why natural gas markets are assumed to respond increasingly to competitive forces are:

- The decontrol under the NGPA of all newly discovered natural gas

- The changing approach of Public Utility Commissions and distributors to natural gas marketing provisions which allow for flexible price schemes

- New gas imports policies of both the United States and Canadian governments which are expected to result in a significant expansion of Canadian gas imports to the United States

- A changing approach by FERC toward deregulation and more flexibility in marketing, such as new marketing programs and minimum bill rulemaking provisions

- New market institutions, including development of the spot-market, brokered transactions, and potential futures markets.

All projections in this volume are based on the decontrol schedule set forth in the NGPA. Quantitative estimates of the impact of varying assumptions regarding flexible natural gas pricing and natural gas imports are examined in the following sections. A discussion of the remaining items is also provided.

High and Low World Oil Prices

This section explores the implication of varying world oil price assumptions for natural gas consumption and prices. (Effects of world oil price variations on natural gas supply were discussed earlier in this chapter.) High or low world oil price assumptions lead to the striking result of almost no difference in natural gas prices among the cases. The assumed world oil price increases of 2.3, 3.6, and 6.2 percent annually (in real terms) from 1985 to 1995 across the low, middle, and high price scenarios, respectively, are projected to result in the price of natural gas to consumers increasing at an average annual rate of approximately 4 to 5 percent across all scenarios.

Some analyses of natural gas markets assume that the price of natural gas in an unregulated market would always be at the Btu-equivalent of oil at the burner-tip, or at some fixed percentage of Btu-equivalent of oil at the wellhead. This assumption (which is not used in this report) is based on some important connections between the price of oil and the price of natural gas. First, some industrial and utility consumers have the ability to burn either oil or natural gas. If the price of petroleum falls significantly below the price of natural gas, switching from consumption of natural gas to petroleum could be expected to occur, which would tend to lower the purchase price of natural gas. Second, to the extent that natural gas and oil exploration compete for the same drilling equipment and personnel, a fall in the price of petroleum relative to natural gas would divert resources from petroleum to natural gas exploration, thereby increasing the supply of natural gas and driving down the price. Third, some gas contracts explicitly tie the price of natural gas to the price of oil products.

Although there is some validity to each of these arguments, there are other factors at work in gas markets that prevent natural gas prices from mirroring oil prices exactly. Although many industrial and utility customers will switch between oil and natural gas whenever their delivered prices diverge, gas versus oil competition on the margin does not imply a fixed relation between the national average prices of oil and of natural gas. Because natural gas transportation costs to different regions differ widely, the delivered price of natural gas will necessarily vary around the country. Thus, no single wellhead price of gas could result in a delivered price of natural gas equivalent to oil product prices in all regions, and progressive decreases in oil prices would cause switching from natural gas to oil in discrete increments as the switching threshold is reached in different regions.

Moreover, switching potential is assumed to be limited. In these projections, costs of natural gas production are assumed to be sufficiently low, and that for the most part, natural gas market prices are set below levels that would cause gas to oil switching (see Table 29). Under midprice assumptions, natural gas wins by a wide margin in all markets where there is potential competition between oil and natural gas. In the low oil price case, only a small amount of dual-fired capacity, in limited geographic regions, faces prices that would cause switching out of gas. Since gas is already the fuel of choice in the base case, higher oil prices do not stimulate oil to gas switching. Thus, within the range of oil price variation assumed, oil price changes do not cause natural gas demand to change significantly. Lower oil price cases than those analyzed, or the assumption of greater fuel switching potential in the industrial sector, could cause natural gas prices to move more in step with oil. Finally, while natural gas and oil compete for drilling equipment and personnel, this does not mean that their wellhead prices must be equal or proportionate. Even if the price of oil rises more rapidly than the price of natural gas, some gas prospects will still be more attractive than oil prospects because of a higher probability of finding natural gas or lower production costs. It is more accurate to conclude that, although the rising oil prices would push up the price of natural gas to some extent, the price of natural gas may rise only enough to establish a new equilibrium at a price per million Btu below that of oil.

Other than in the electric utilities sector, alternative world oil prices are not projected to have a significant effect on either natural gas consumption levels or delivered prices. Under the range of assumed world oil prices, total consumption of natural gas is projected to vary by about 2 percent around the base case level. In this analysis, it is assumed that discounts are available to dual-fired users in the utility sector if they are necessary to prevent switching. With the exception of the electric utility sector, the impact of different world oil price assumptions on end-use natural gas prices is expected to be less than 3 percent across all scenarios in all years. If natural gas supply were not affected directly by changes in the world oil prices one would expect the effect of higher oil prices on natural gas demand to be an increase in natural gas prices. However, higher world oil prices also cause increased oil drilling activity and production which results in increased production of associated and dissolved natural gas that slightly exceeds the increases in natural gas demand by 1995. Thus pressure on natural gas prices that would arise from greater demand for natural gas is relieved, and wellhead prices remain almost unchanged.

Table 29. Fuel Prices to Electric Utilities, 1990 and 1995
(1984 Dollars per Million Btu)

	1990 World Oil Price Case			1995 World Oil Price Case		
Fuel	Low	Base	High	Low	Base	High
Natural Gas	4.26	4.35	4.56	5.46	5.89	6.02
Residual Fuel Oil	4.53	5.08	6.26	5.41	6.41	8.14

Source: Appendices A, D, E,; Tables A5, D5, E5.

In the high world oil price case, natural gas to the electric utility sector, which currently has the most extensive capability to switch to alternative fuels and possesses a 25-percent price per Btu competitive advantage, is projected to possess a 35-percent price per Btu competitive advantage over oil in 1995, and natural gas consumption is projected to be 6 percent greater than the base case level. In spite of a slight decrease in wellhead prices compared to the base case, the average price of natural gas to electric utilities is projected to be 2 percent higher than the base case level because fewer discounts are required under the assumption of flexible distributor pricing. Discounts are provided only to the extent necessary to maintain sales. With higher oil prices, less of a discount is required. Since discounts are provided only to the extent necessary to maintain sales, higher oil prices mean that less of a discount is required to prevent utilities from switching to oil. Natural gas prices to the remaining sectors are projected to show a slight decline in 1995. In the low world oil price case, natural gas distributors are assumed to offer discounts to electric utilities, but still cannot compete with the lower price of low-sulfur residual fuel oil particularly in California and, by 1995, electric utility consumption is projected to fall to about 93 percent of the base case level nationwide.

Flexible versus Fixed Tariffs

Many State regulatory commissions and FERC have recently allowed flexible pricing by natural gas pipeline companies and distributors, permitting distributors to lower prices to some customers in order to be competitive with fuel oil in an effort to maintain total load. In establishing special programs, FERC has attempted to ensure that those customers who have no alternative sources are no worse off than if the discount sale were not approved. When these competitive prices are below fully allocated costs, some Commissions have allowed distributors to recoup losses by raising prices to residential customers and others unable to switch fuels readily. The regulatory dilemma is whether to allow one class of customers to bear a portion of the cost of purchasing gas destined for another class or to limit the ability of distributors to spread their fixed costs over the largest possible volume of sales.

For this analysis, a flexible pricing option was assumed that represents characteristics of this special market mechanism. This flexible pricing option allows distributors to provide discounts to industrial and utility consumers with dual-fuel burning capabilities, and to recover some of these costs from the remaining customers. The flexible pricing option is assumed to be in effect throughout the forecast period in all cases except for the fixed tariff case discussed below. However, this option does not preclude switching from natural gas under all circumstances because no discount is provided that would take discounted prices below 95 percent of the distributor's average purchased gas costs.

The flexible tariff price option appears to have little effect on the price of natural gas. When the option of flexible pricing is removed, and the pre-1980's historical fixed tariff structure is assumed, only a slight loss of natural gas sales results. These small losses in sales occurred in both the base (flexible tariff) and fixed tariff cases because even without discounts the projected price for most electric utilities of alternative fuels, principally residual fuel oil, is higher than the delivered price of natural gas in California and the Southwest. As a result, these States which have the greatest potential to switch from burning natural gas to residual fuel oil continue to use natural gas.

Specifically, in the fixed tariff case, the total price and volume of natural gas supply (including wellhead production, imports, and supplemental sources) is projected to vary by less than 1 percent when compared with the base (flexible tariff) case. The impact on end-users is also expected to be slight; throughout the forecast period, levels of residential, commercial, and industrial consumption are projected to be constant, and utility consumption drops only slightly compared with the base (flexible tariff) case level. By 1995, total utility consumption is expected to be 4 percent lower than the base (flexible tariff) case, and prices of natural gas to utilities are about 2 percent higher nationwide. The impact of a fixed tariff could vary by region: For utilities in New York and New Jersey during the 1990 to 1995 period, a price increase of about 10 percent over the base (flexible tariff) case level is expected to result in natural gas prices that are greater than the residual fuel oil price, causing switching by utilities out of gas to residual fuel oil Utilities in the remaining States are projected to continue to burn natural gas at levels comparable to the base case.

The differential between supply prices and consumer prices for natural gas varies under the two cases. Because there is no reallocation of costs in the fixed tariff case, the residential and commercial price mark-ups are lower, and the industrial and utility sector mark-ups are higher than in the base (flexible tariff) case. By 1995, the national mark-ups from the wellhead price to the price to industrial and electric utility users are projected to be higher by 2 percent and 4 percent, respectively, compared with the base (flexible tariff) case. These differences may have been higher except that natural gas remains competitive with petroleum under the two cases.

Fuel Constraints on Utilities

This section discusses two cases which assume constraints on fuel consumption by utilities. The first case assumes that all on-line (dispatched) facilities which possess dual-fired capability burn gas throughout the forecast period. This case is referred to as the "gas preference" case. The second case assumes that these facilities burn oil and is called the "oil preference" case.

The results on electric utility natural gas consumption of the "gas preference" case and the base case are very similar, which confirms the competitive advantage held by natural gas over residual fuel oil in the base case. Wellhead production and prices of natural gas are projected to be essentially the same throughout the forecast period. Total consumption of natural gas through 1992 is projected to be the same as under the base case. In 1995, total consumption and prices are expected to be about 2 percent higher than the base case levels. This increase in the later years is due to an increase in utility consumption of 8 percent and in utility gas price of about 4 percent. Unanticipated utility demand for natural gas between 1993 and 1995 by gas pipelines and distributors is expected to be satisfied from supplemental sources including spot market purchases and additional imports. In 1995, natural gas from supplemental sources in the gas preference case accounts for 5 percent of total supply and is 31 percent above the base case level. Utilities in the New York and New Jersey area and California are projected to account for the increase in natural gas consumption; natural gas use at utilities in both areas is projected to increase by about 60 percent and 15 percent, respectively, compared with the base case volumes.

The "oil preference" case assumes that the dispatched facilities with oil and gas capability burn oil instead of natural gas. Such a restriction is projected to result in about a 60 percent drop in utility demand for natural gas compared to the base case level in 1995. The effect on the average supply price of natural gas across all sectors is expected to be moderate. In 1990, the price is 6 percent lower, however, by 1995 the price is 15 percent lower than in the base case. Lower supply prices are projected to stimulate nonutility demand.

The effects on petroleum consumption and prices of imposing fuel constraints on utilities are presented in Chapter 7. By 1995 residential, commercial, and industrial demand for natural gas is projected to be about 4 percent higher than in the base case responding to a 10-percent nonutility price reduction.

Natural Gas Imports

North American natural gas resources are plentiful (see box). From 1970 through 1982, imports of natural gas contributed approximately 5 percent of domestic consumption. This includes natural gas imports from Canada and Mexico and liquefied natural gas (LNG) from Algeria. Canada has always been the principal supplier of natural gas imports to the United States, supplying about 80 percent or more of U.S. imports since the 1970's.[3] Recently, a surplus of supply in U.S. markets has resulted in downward pressure on the Canadian price. In the face of a significant market loss, the Canadian government in 1983 lowered its border price and instituted additional price discounts through a Volume Related Incentive Pricing (VRIP) program for quantities above a base level (generally 50 percent of authorized volumes).

Natural Gas Resources of North America: 1983

North America has substantial natural gas resources. The reserves of the Lower 48 States, Alaska, Canada, and Mexico together total about 376 trillion cubic feet. The combined annual production of gas currently approximates 21 trillion cubic feet. Very large quantities of recoverable but undiscovered resources are thought to exist and total about 1,221 trillion cubic feet for the North American continent as a whole. Although these figures are large, the exploratory and developmental work necessary to bring these resources into production is significant and must be ongoing to maintain a sufficiency of supply for the future. This is especially true because most of these resources are in offshore waters, in deeper onshore areas or in the subarctic areas, all of which are more difficult and expensive to develop than conventional onshore resources.

EIA's yearend 1983 estimates of proved natural gas reserves for the Lower 48 United States stood at approximately 166 trillion cubic feet. Production in the Lower 48 States amounted to 16.0 trillion cubic feet, about 9.6 percent of its proved reserves.

The USGS mean estimate of undiscovered natural gas resources in the Lower-48 States stands at about 493 trillion cubic feet. An additional 172 trillion cubic feet of inferred reserves brings the total, in excess of presently proved reserves, to about 665 trillion cubic feet. About 21 percent of that (142 trillion cubic feet) is expected to lie in the outer continental shelf and slope areas.

At the end of 1983, Alaska's proved dry natural gas reserves stood at 34.3 trillion cubic feet, amounting to 17.1 percent of the Nation's total proved gas reserves. Alaska's marketed gas production in 1983 was only about 277 billion cubic feet. This was only 1.6 percent of total U.S. production. Most of Alaska's natural gas reserves are located in the North Slope area, and are awaiting the development of a transportation system.

As of 1980, the USGS' mean estimate of total Alaskan undiscovered recoverable gas reserves was about 107 trillion cubic feet. This figure includes

[3] Energy Information Administration, Natural Gas Monthly, May 1984, DOE/EIA-0130 (84/05) (Washington, DC, June 1984).

their estimates of inferred reserves for the region and thus represents estimated quantities in excess of presently proved reserves. This amount approximates one-half of the total U.S. proved reserves inventory. Nearly two-thirds of the total estimated undiscovered Alaskan gas resources is believed to occur offshore.

The National Energy Board of Canada estimates the reserves of Canada at 99 trillion cubic feet at yearend in 1982. Production in Canada in 1983 was approximately 2.3 trillion cubic feet, only 2.3 percent of its proved reserves. Estimates developed by the Geological Survey of Canada indicate that Canada has substantial undiscovered natural gas resources. Their average expectation for the whole of Canada is approximately 269 trillion cubic feet, or almost more than two and one-half times current marketable reserve levels. About 26 percent of this potential lies in the Western Canada Sedimentary Basin, 20 percent in the Beaufort Sea-MacKenzie Delta Area, 24 percent in the Arctic Island, and 25 percent in the Eastern Canada Offshore Area. The remainder is distributed more or less evenly between the Canadian West Coast and the eastern onshore areas.

Natural gas reserves in Mexico were estimated at 77 trillion cubic feet as of yearend 1983. This estimate was made by Petroleos Mexicanos (Pemex), the Mexican government's oil and gas exploration entity. Mexico's reserves amount to a little more than 20 percent of the North American total. Mexico's gross production of natural gas was about 1.6 trillion cubic feet in 1982, about 2 percent of reserves. Marketed production was about 1.1 trillion cubic feet.

The USGS estimates that about 180 trillion cubic feet of undiscovered recoverable natural gas remains to be found in Mexico. These undiscovered quantities are about two and one-half times current reserve levels. About one-third of this undiscovered potential lies in the northern portion of the country, with the remaining two-thirds attributable to the more prolific southeastern region.

In July 1984, when the Annual Energy Outlook assumptions were being set, the Canadian government announced a "New Natural Gas Export Policy to Allow Negotiated Price." The new policy stated that the negotiated arrangements must recover costs, be priced "not less than the wholesale price at the Toronto city gate under similar terms and conditions," "result in prices in the U.S. market area at least equal to the price of major competing energy sources," contain provisions to "permit adjustments to reflect changing market conditions," and "demonstrate reasonable assurance that volumes contracted will be taken." The communique also allowed Canadian exporters to participate in spot-market sales, but these sales must be "truly incremental," and not displace other Canadian gas sales. On the basis of this new policy, the Canadian government approved on November 1, 1984, amended licenses for 6 long-term agreements. The price of gas has been renegotiated to an expected price of between $3.31 and $3.41 per thousand cubic feet for these agreements, covering an estimated 0.7 trillion cubic feet in the contract year beginning November 1, 1984. (Previously, U.S. importers paid Canadian suppliers a border price of \$4.48 per thousand cubic feet or a VRIP price of \$3.46 per thousand cubic feet.[4]) This adjustment process was also accompanied by a new tariff arrangement with part of the costs in a demand charge which will raise the average cost if the expected volumes are not taken. Since these assumptions were made prior to the November 1, 1984 action by the Canadian government, it appears likely that Canadian export prices will be less than assumed and, as a result, the 1985 and 1986 average end-use prices could be lower than projected here, but by 1990 this influence should disappear.

Imports of natural gas from Mexico contributed 75 billion cubic feet in 1983. However, in November 1984, Mexico and its importers agreed to suspend imports to the United States, and, although they stated they would review the situation periodically, Mexican imports are not expected to increase significantly in the future for two reasons. First, the Mexican government plans to increase its domestic use of natural gas, leaving little for export, and second, geographic location forces Mexico to compete in the heart of the U.S. wellhead market, allowing for virtually no competitive locational advantage.

In 1982, with the startup of the Trunkline LNG project, authorized in 1974, Algerian LNG imports increased to 55 billion cubic feet. This amount jumped to 131 billion cubic feet in 1983, but the high cost of natural gas from this source made it increasingly noncompetitive. Imports from this project were suspended in December 1983 and are assumed to remain suspended for the forecast period.

With currently authorized licenses for cumulative export volumes to the United States of about 13 trillion cubic feet, Canada has the potential for significant contribution to the United States market. However, because of the current surplus of natural gas in the United States and the pricing policies of the Canadian National Energy Board (CNEB), the United States has not been importing the full amount authorized for export by Canada. In 1983, for example, Canadian gas exports to the United States amounted to about 40 percent of the volume authorized for export during the year. Unless additional significant unforeseen events transpire, U.S. pipeline companies are not expected to purchase all of the gas that Canada has available for export.

Contract renegotiations approved by the CNEB in November 1984 have new prices which compare favorably with the present price floor (approximately \$3.20 per thousand cubic feet at the Toronto city gate). However, these agreements still price Canadian gas above the prevailing average gas purchase costs of U.S. pipeline importers. The recent renegotiations provide for periodic adjustment in the price, and it is expected that the CNEB will allow price adjustments to maintain revenues. Consequently, the analyses assume that the price of Canadian exports will be competitive in the end-use market which they serve and that Canadian

---

[4] "New Canadian Export Pricing Policy Permits Negotiated Prices Subject to Floor Set at Toronto City Gate Price," Foster Natural Gas Report, No. 1475 (Washington, DC); "Canadian Government Approved Amended Licenses Covering Six Long-Term Export Contracts and Authorize One New Short-Term Export," Foster Natural Gas Report, No. 1490 (Washington, DC).

exports to the United States will increase steadily to a level of 2 trillion cubic feet or more by 1995. (The quantity assumptions are not constrained by actual costs of production.)

There are certain U.S. regional markets where Canadian imports can become extremely important. Because the geographic center of domestic gas production is in the south Texas/Louisiana area, the marginal costs of supplying markets in northern California, Oregon, Washington, New England, and other northern border States make these areas logical markets for Canadian imports under the new imports policies of both governments. To evaluate the sensitivity of the domestic market to varying levels of imports, two alternative cases are examined; the first, where imports are cumulatively 24 percent lower than the base case through 1995, and a second case where they are 35 percent higher than the base case. The assumption that new imports will be priced competitively with domestic supply is the same across all cases. With higher imports, the market price of natural gas in the United States is lowered, implying that to achieve higher levels of imports, Canada would have to accept lower prices. Lower import levels conversely imply higher prices in the U.S. market. No distinction is made in the source of imports.

Import Sensitivity Results. In the base case projections, imports of natural gas are expected to increase steadily throughout the forecast period to a level of 2.1 trillion cubic feet in 1995. Alternative import scenarios include a low import case where imports are assumed to move to a level of 1.3 trillion cubic feet in 1990 and remain at that level through 1995, and a high case, where imports are assumed to be 2.7 trillion cubic feet in 1995. The average import price in all cases is assumed to decline by 1988 to the $3.20 per thousand cubic feet Toronto city-gate floor price (currently in effect) as earlier contracts at higher prices account for lesser percentages of the total imports over time. New imports are assumed to be priced at competitive market prices.

Recent events suggest the import quantity and price assumptions for 1985 may be too high. With the cessation of imports from Mexico, natural gas imports to the United States are expected to be about 100 billion cubic feet lower than anticipated. Also, with the recent contract renegotiations for Canadian gas, the average price estimates may be 10 percent lower than assumed if enough gas is imported. These differences are not expected to significantly impact the domestic market throughout the forecast period because this change is within the high and low import range that generates little short-term change.

While the assumed level of imports in the high and low natural gas import cases differs significantly from the base case, the impact on end-use prices in 1990 is expected to be minimal, and consumption is nearly the same across the three cases due principally to the assumption of gradual increases in imports. However, by 1995 the cumulative effect of the alternative levels of imports is projected to have a major impact on end-use prices and consumption. These import levels are chosen to illustrate the uncertainty that Canadian natural gas export policies inject into the U.S. natural gas market. How aggressively Canada will pursue sales into the United States over the next decade cannot be predicted precisely, although recent events suggest that increasing imports at competitive prices are likely. The range of assumptions about import levels represents possible trends in Canadian policy.

In the low imports case, the import levels are assumed to increase more slowly than the base case, totaling 0.3 trillion cubic feet less than the base case level in 1990. A 1-percent increase in domestic production is expected to make up most of the difference. However, in order to meet the levels of consumption, in both the base and low imports cases, approximately 2 percent of total consumption is expected to come from supplemental sources of gas supply at market prices. This means either that additional imports or additional domestic supply must be available. By 1990, natural gas prices to consumers are expected to be approximately 1 percent higher across all sectors, but this small difference in price does not affect consumption , which is projected to be virtually identical to the base case levels. By 1995, the additional depletion of lower cost domestic supplies used to offset the lower imports is projected to result in a wellhead price that is 14 percent higher than the base case level, with production approximately 1 percent above the base case level. The price of natural gas imports is projected to be 19 percent higher than in the base case, resulting in a 9-percent increase in the price of gas to electric utilities and additional fuel switching in this sector, as the price of natural gas moves above the residual fuel oil price in some regions. Natural gas consumption is expected to be reduced by 12 percent in the electric utilities sector. Despite prices that are 8 to 11 percent above base levels, there is little difference in consumption in the other end-use sectors, because these sectors do not appear to be very sensitive to price changes of this magnitude.

In the high natural gas imports case, an import level that is 33 percent above (in cumulative terms) the base case for 1986 through 1990 is projected to result in a wellhead price in 1990 that is 3 percent lower than the base case. This decrease provides approximately a 2-percent decline in prices to consumers across all sectors. End-use consumption shows no significant change from the base case. Marketed production is down by 4 percent from the base case as the lower priced imports displace domestic production. By 1995, the cumulative effect of the higher imports from 1986 to 1995 is projected to result in substantial differences from the base case: Prices to end-use consumers are 7 percent lower than in the base case; end-use consumption is 2 percent higher than in the base case, principally as a result of a 9-percent increase in electric utility consumption (mostly in California); and marketed production is comparable to the base case, with wellhead prices 9 percent lower than in the base.

Recent Changes in Natural Gas Markets

Numerous changes have occurred in natural gas markets over the past 2 years. Significant problems surfaced over this period as contract provisions raised the price of natural gas above market clearing levels and resulted in lower demand. Pipeline companies with contractual requirements to either take or pay for specified quantities of gas were faced with large prepayments obligations as they were not able to accept specified quantities in view of the reduced demand. In response to the surplus of gas, alternative marketing programs have been approved by FERC. As large portions of the wellhead market are no longer under price regulations, more flexibility in the downstream markets has evolved as well.

The following sections review the potential impact of current contract provisions, the actions undertaken by FERC and the industry to maintain sales, and the marketing structures assumed over the forecast period. Assumptions in each of these areas condition the projections of the natural gas markets. In this report, it is assumed that, in general, natural gas markets will continue to become more competitive and more flexible, with contracts being renegotiated and additional development of flexible pricing schemes and spot market sales. Alternative assumptions about regulatory actions and the behavior of pipelines, producers, and distributors could lead to different projections of prices and markets for natural gas.

Producer/Pipeline Contracts.[5] There has been considerable change in wellhead contract provisions in recent years. The most important alteration has been the addition of market-out clauses (clauses that allow the purchaser to reduce the price of the gas if it is not marketable at that price), that have appeared in contracts with greater frequency over the past 3 years. If market-out provisions continue to be part of new contracts, contracts can be adjusted at regular intervals, prices can be made to reflect current market conditions, and other pricing provisions become relatively unimportant. From 1981 through 1984, the market experienced a natural gas surplus. The ability of purchasers to negotiate market-out provisions in new contracts when the market returns to a more balanced state is uncertain. Between 1985 and 1995, the average wellhead price of natural gas is expected to increase at an annual rate of 6.6 percent, but remain below the average new contract price (Figure 26).

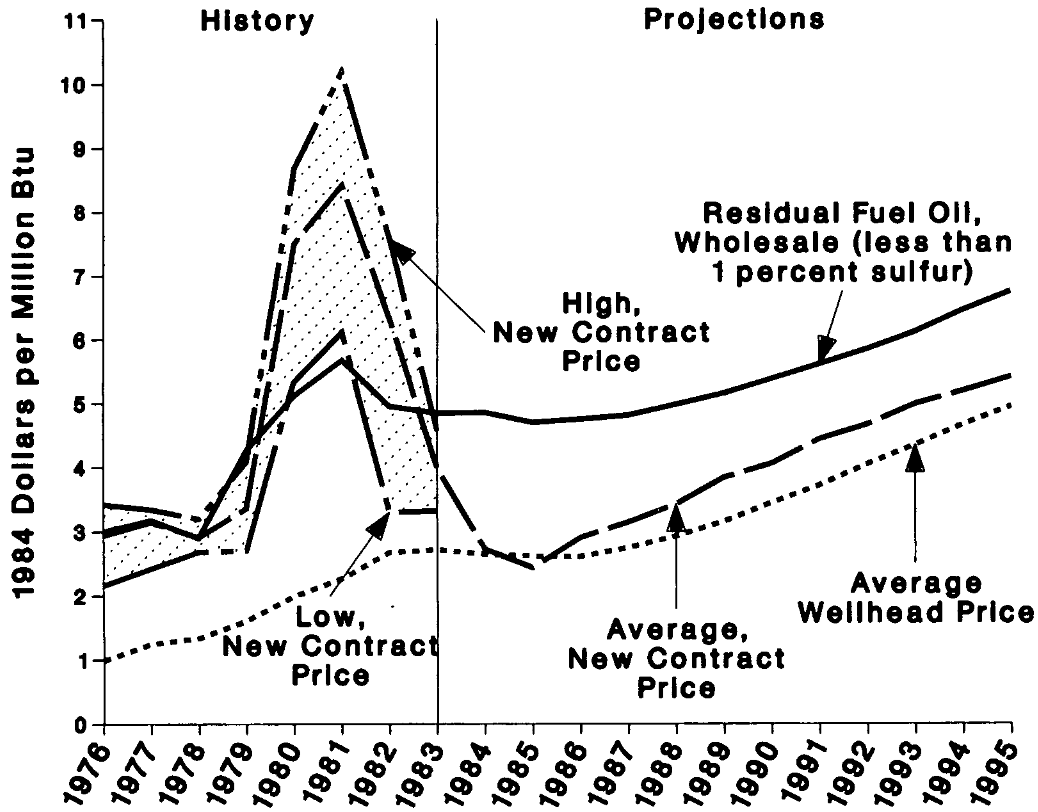
Of considerable concern are long-term contracts signed prior to 1983 covering recently deregulated natural gas. These contracts typically specify renegotiation or redetermination processes which tie the contract price to the highest prices being paid for gas within a large geographic area (for example, south Louisiana or several Texas Railroad Commission districts). These provisions are called most-favored-nation (MFN) clauses. A few contracts specify a parity price at the wellhead with No. 2 fuel oil (currently about $8 per thousand cubic feet). Most contracts signed before 1981 do not have a market-out provision. While oil-parity pricing provisions do not appear to cover a large quantity of gas, their real significance lies in providing a triggering mechanism for MFN clauses. Apart from legal action by Congress or the producing States, there are essentially two ways that above-market prices generated under these contracts may never actually be paid. Contracts could be renegotiated with a lump sum settlement as consideration for a lower price or a market-out provision, or purchasers simply may not honor contracts and force the producers to sue. In either case, the price cannot be used to trigger other MFN provisions, and price distortions in the market are avoided.

A second contractual issue which has had an important impact on pipeline companies over the past 2 years is provisions that require a pipeline to either take or pay for a specified quantity of gas. Because both take-or-pay and pricing provisions affect the cash flow to the producer, there are trade-offs between the two when contracts are negotiated. When price ceilings on natural gas were binding,

---

[5]For more detail see Energy Information Administration, Natural Gas Producer/Purchaser Contracts and Their Potential Impacts on the Natural Gas Market, DOE/EIA-0330 (Washington, DC); Structure and Trends in Natural Gas Wellhead Contracts, DOE/EIA-0419; and Competition and Other Current Issues in the Natural Gas Market, DOE/EIA-0489.

Figure 26. Comparison of Unregulated, New Natural Gas Contract Prices with Residual Fuel Oil and Average Wellhead Gas Prices, 1976-1995



Source: • History: Energy Information Administration, Competition and Other Current Issues in the Natural Gas Market, DOE/EIA-0489(84) (Washington, DC, 1984), Table A1 adjusted to annual levels. • Projections: Natural gas wellhead price: Appendix A, Table A17 converted to 1984 dollars per million Btu by a factor of 1.026. Average new contract price: EIA, Gas Analysis Modeling System. Residual fuel oil: EIA, Intermediate Future Forecasting System.

purchasers agreed to long-term contracts with high take-or-pay provisions. In response to the current excess supply of gas, pipelines have taken a number of steps to reduce the prices they pay for gas at the wellhead and their take-or-pay commitments. These steps include the exercise of market-outs clauses, renegotiation of contracts, and abrogation of contracts.

Approximately 30 market-out actions have been recorded from June 1982 to July 1984 (Figure 27). Some pipelines have lost reserves when the seller exercised the complementary option to find another buyer, but, in many cases, producers have agreed to lower prices. Some pipeline companies have been successful in renegotiating contracts to lower take-or-pay requirements and/or lower prices. However, the impact of any of these actions appears to be limited, because existing Section 102 gas contracts signed prior to 1983 have shown virtually no downward price adjustment through 1984. Finally, pipelines have abrogated contracts that are too inflexible under current market conditions. As a result, lawsuits have been filed against several interstate pipelines by many major and independent producers. These lawsuits and, more generally, the question of how rapidly and completely existing contracts can be altered to reflect new market realities, still represent a major problem in analyzing wellhead markets. The resolution of these suits may take considerable time, and it is uncertain who will bear these potential liabilities--the pipelines or their customers. The assumption in this analysis is that contracts will not operate as written and that the downward pressure caused by the surplus will act to hold down prices.

Innovative Marketing Programs. In the last few years, the natural gas interstate market has become more flexible by matching sellers and buyers through direct sales or contract carriage proposals. This matching has the effect of lowering prices to a wide range of consumers, as those served by pipelines with take-or-pay problems are relieved of some of that burden, while other consumers are permitted to obtain surplus gas at lower prices than would otherwise be available. Through the use of programs targeted to specific segments of the market such as off-system sales, blanket certificates, and special marketing programs, many new arrangements are now possible. New Special Marketing Programs (SMP's) allow producers facing cutbacks or shut-in production to sell gas at a discount to eligible consumers. These programs offer gas at lower rates and allow gas to flow more easily under new arrangements. More recently, necessary and sufficient conditions for participating in an SMP have been changed. In October 1984, FERC extended the SMP experiment for another year and eased the necessary conditions for gas to be sold into the program to include:

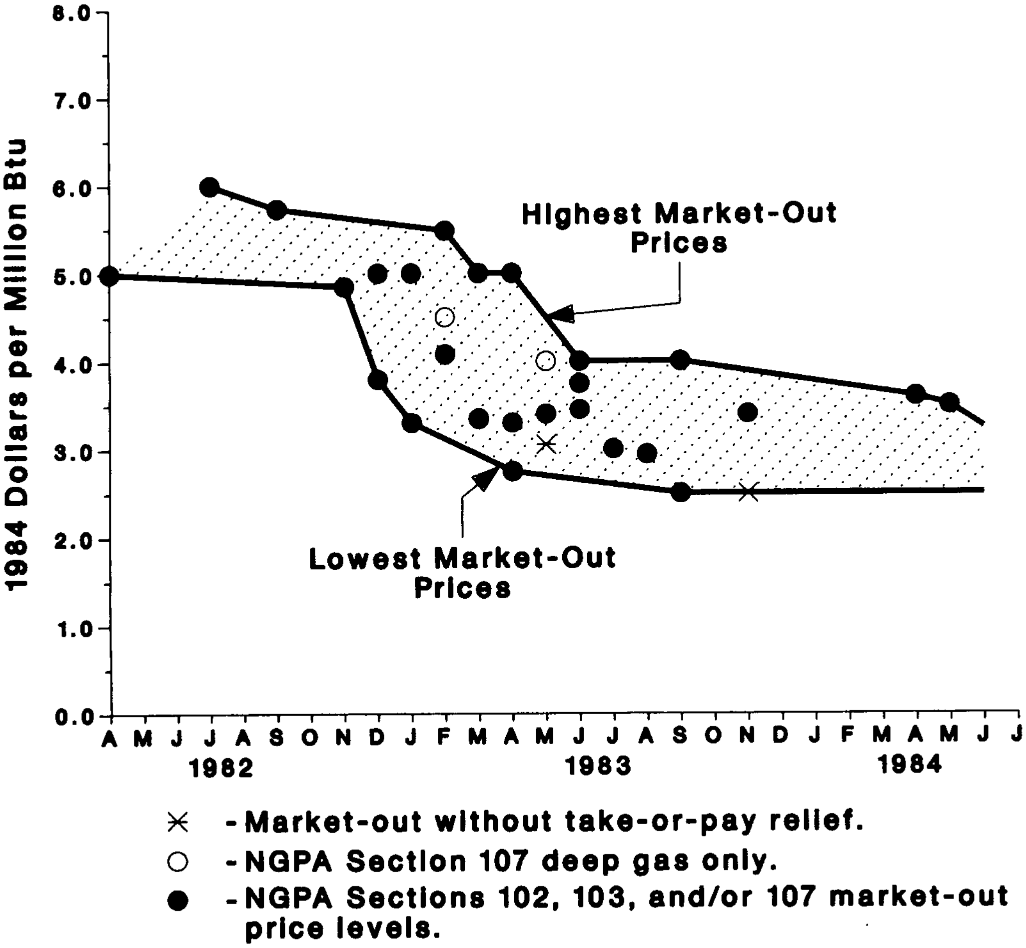
- Natural gas priced below the weighted-average cost of gas but above the Section 109 price

- Allowing more producers (that is, working-interest owners) to participate.

In this analysis, it is assumed that discounts are available to dual-fired users if they are necessary to prevent switching.

Spot-Market. Currently it is estimated that 0.5 to 1 trillion cubic feet of natural gas is sold on a spot basis each year, but very little is in documented

Figure 27. Market-Out Prices by Major Interstate Pipelines, 1982-1984



Source: Federal Energy Regulatory Commission, Purchased Gas Adjustment filings; American Gas Association, Gas Industry Actions by Field Purchasers to Reduce Gas Prices (Washington, DC, 1984).

transactions.[6] Although spot-markets have existed for many years, historically they have operated in a clandestine and ad hoc manner. Recently, a Wall Street investment firm, a law firm, and several interstate pipelines formed a group based in Houston called the Natural Gas Clearinghouse, but it has yet to demonstrate that it is an accepted market institution. In October 1984, Tenneco announced it would purchase gas delivered to two locations in Louisiana at a specified posted price. Although this event should be viewed as significant, it is too early to make a judgment on the long-term viability of a well functioning spot-market. In this analysis, it is assumed that an active spot-market develops and short-term supplies can be purchased on the spot-market (which includes imports). This assumption does not address the specific source (United States or Canada) of supply, consequently, additional spot market purchases could force domestic supply to a higher cost level on the long run supply curve by additional depletion of relatively inexpensive resource. In some cases, additional supplies purchased on the spot market are in excess of 4 trillion cubic feet over the 1985 to 1995 period.

Pipeline/Distributor Contracts. On May 25, 1984, FERC issued a rule prohibiting pipelines from using so-called "minimum bill" contract provisions to recover variable costs, such as purchased gas costs, that are not actually incurred. The rule disallows the recovery of any variable costs associated with natural gas not taken by a buyer in rate schedules or tariffs filed on or after July 31, 1984. Additionally, the rule requires that the purchased gas costs associated with any rate schedule or tariff must be stated separately. This rule has significant implications for pipeline customers who have access to more than one pipeline system, but, in a more general sense, suggests a willingness on the part of FERC to make the system more market-responsive.

In its campaign to stimulate competition in the interstate market, FERC has taken a first evolutionary step toward more carriage by requiring the separation of purchased gas costs from other costs in tariffs. FERC can only encourage carriage by giving special incentives to carry natural gas or indirectly penalizing pipelines for not carrying gas. (The issue of mandatory carriage is being debated in Congress.) Without the carriage option, customers who cannot switch to another pipeline have few options, and FERC can offer only limited protection from the potential problems. Currently, interstate pipelines still face only limited competition in the sale of natural gas. A detailed discussion of minimum bill contract provisions can be found in A Study of Contracts Between Interstate Pipelines and Their Customers, July 1984, (DOE/EIA-0449). In this analysis, it is assumed that, over time, distributors will purchase higher shares of their needed supplies from the lower cost supplier.

[6]"Developments Show Gas Spot Market on Way to Being a Fixture, Says Analyst," Inside F.E.R.C. (New York, NY, September 3, 1984).

7. Electric Utilities and Nuclear Power

Chapter 2 presents the base case projections for electric utilities and nuclear power. This chapter provides electric utility and nuclear power projections under assumptions differing from the base case. These sensitivity projections offer an explanation of alternate outcomes and also provide additional information on the overall sensitivity of the projections.

First, this chapter examines the effects of changes in economic growth and capacity growth rate assumptions on electricity supply. It describes the effects on electricity supply of low and high economic growth, of reduced nuclear and coal-fired generating capacity additions, and of changes in the level of demand coupled with reduced capacity additions. The market implications of cogeneration, small power production, and lower electricity demand growth are also discussed. Second, the effects of changes in electric utility costs and financing assumptions on electricity markets are examined. These sensitivities describe the effects on electricity prices and utility financing of changed regulations for construction work in progress (CWIP), and of assumed increases in nuclear facilities' construction costs. This section also describes proposed revisions to the Price-Anderson Act that would allocate the costs of accidents at commercial nuclear facilities among utilities owning such facilities. Finally, the chapter discusses the effects on fuel use and electricity prices of switches in the fuels used in dual-fired capacity, and notes the probable effects on both the electric utilities and the coal industry of a major legislative proposal to reduce sulfur dioxide emissions by utilities.

Economic Uncertainty

In the 1960's, electricity demand growth was relatively stable and predictable, averaging about 7 percent per year, slightly less than twice the rate of growth in real gross national product (GNP). In the 1970's, rising fuel prices, conservation, and reduced growth in economic activity combined to slow the growth rate of electricity demand to an annual average of about 5 percent.[1] This decline in growth rates continued into the 1980's, including an absolute drop in electricity sales in 1982 and the first half of 1983. However, electricity demand began to increase again as a result of the economic recovery in the second half of 1983; the overall electricity demand growth rate for 1983 was about 3 percent. The demand growth has continued into 1984 resulting in an increase in electricity generation during the first 9 months of 6 percent compared to the same period in 1983.[2]

The decline in demand growth over the past decade, coupled with escalating construction costs, interest rates, and fuel prices, has contributed to the difficulties currently confronting the electric utility industry. The low demand growth exerted upward pressure on electricity prices because the rising fixed costs resulting from the completion of new plants with higher per-unit costs had

---

[1] Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) (Washington, DC, April 1984), p. 197.

[2] Energy Information Administration, Electric Power Monthly, DOE/EIA-0226(84/09) (Washington, DC, October 1984), p. 9.

to be distributed among smaller electricity sales. The low demand growth and completion of new plants also led to rising reserve margins, which resulted in postponements and cancellations of other new plants in various stages of construction and licensing. However, a benefit of lower demand growth has been lower utility consumption of expensive oil and natural gas, the marginal fuels for electricity generation. (See reserve margin discussion in Chapter 2.)

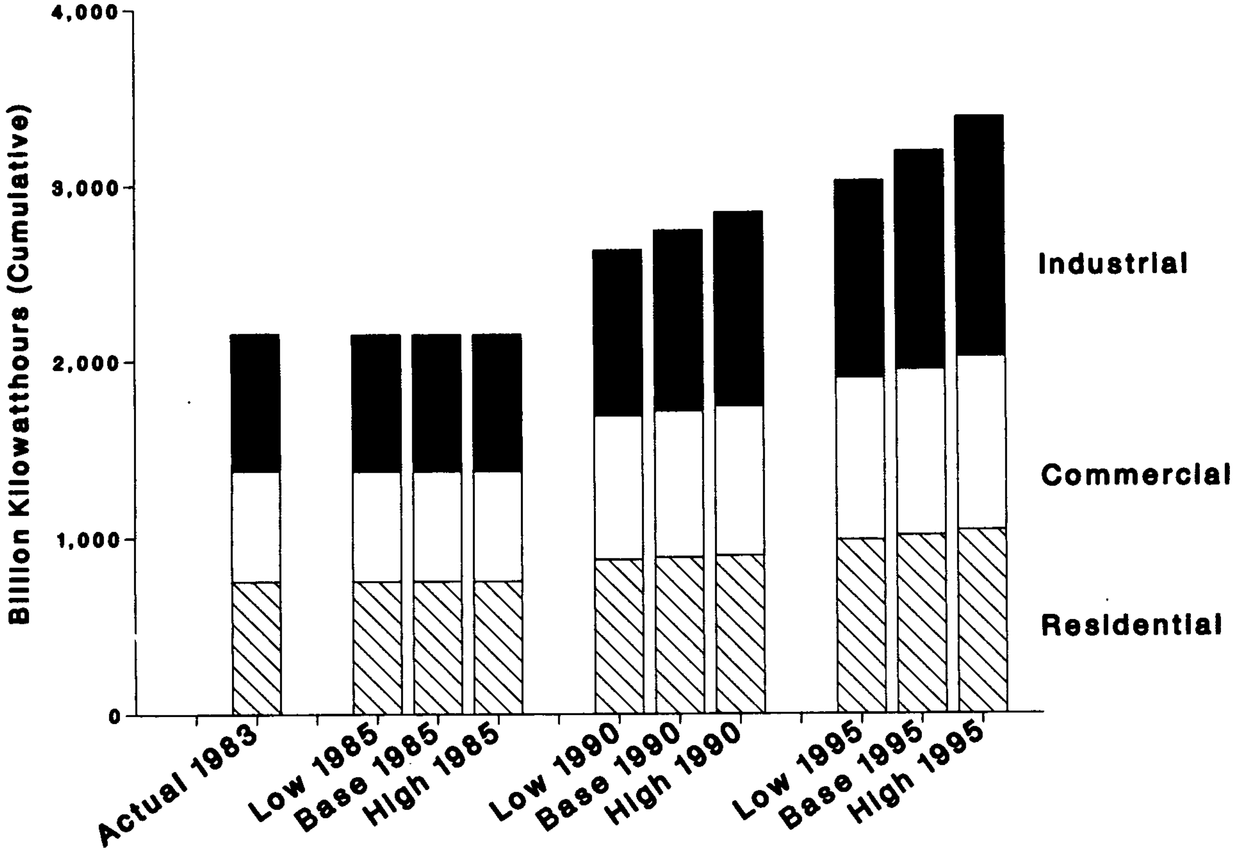
The rate of growth of electricity demand, a major source of uncertainty confronting the electric utility industry, will play a significant role in utility decisionmaking, as it influences electricity production, fuel consumption, capacity expansion, reliability, financing, and end-use electricity prices. The effects of various levels of economic activity on electricity demand are examined in the low, middle, and high economic growth cases (Appendix G). The average annual rates of electricity growth between 1985 and 1995 assumed under these cases are 2.7 percent, 3.2 percent, and 3.8 percent, respectively. The end-use consumption of electricity for each of these cases is dominated by growth in the industrial sector (Figure 28).

In all three economic growth scenarios, coal-fired and nuclear plants are projected to supply most of the electricity (Figure 29). Because of low operating costs, nuclear plants are expected to operate at their assumed maximum rates, and total nuclear production is projected to be unaffected by the differences among economic scenarios. As noted in Chapter 2, the share of total generation provided by nuclear power is projected to grow substantially in the base case, increasing from 13 percent of total generation in 1983 to over 19 percent in 1995 as new nuclear power facilities are completed. For the high economic growth case, no increase in the number of nuclear units is assumed. Between 1985 and 1995, there is little prospect for planning and construction of new nuclear units beyond those currently expected to be completed. There is some possibility, however, for new orders during the 1985 to 1995 time period for facilities that would come into operation after 1995. The nuclear share of total generation in 1995 ranges from 20 percent in the low economic growth case to 18 percent in the high economic growth case. Total coal-fired generation in 1995 is projected to increase by about 9 percent between the low and high cases, but the share of total generation supplied by coal-fired plants is projected to fall from 56 to 55 percent because total electricity generation in 1995 is expected to increase by about 12 percent between the low and high economic growth cases.

Because existing oil- and gas-fired plants have the highest operating costs, they are used to meet the electricity demand that cannot be satisfied by nuclear, coal-fired, or hydroelectric plants. Since the demand growth over the forecast horizon is projected to exceed the planned capacity additions, even in the low economic growth case, utility consumption of oil and natural gas is projected to increase both absolutely and relatively across all economic assumptions compared to 1983 levels. By 1995, the oil and gas share of total generation is expected to range from 14 percent in the low economic growth case to 19 percent in the high economic growth case.

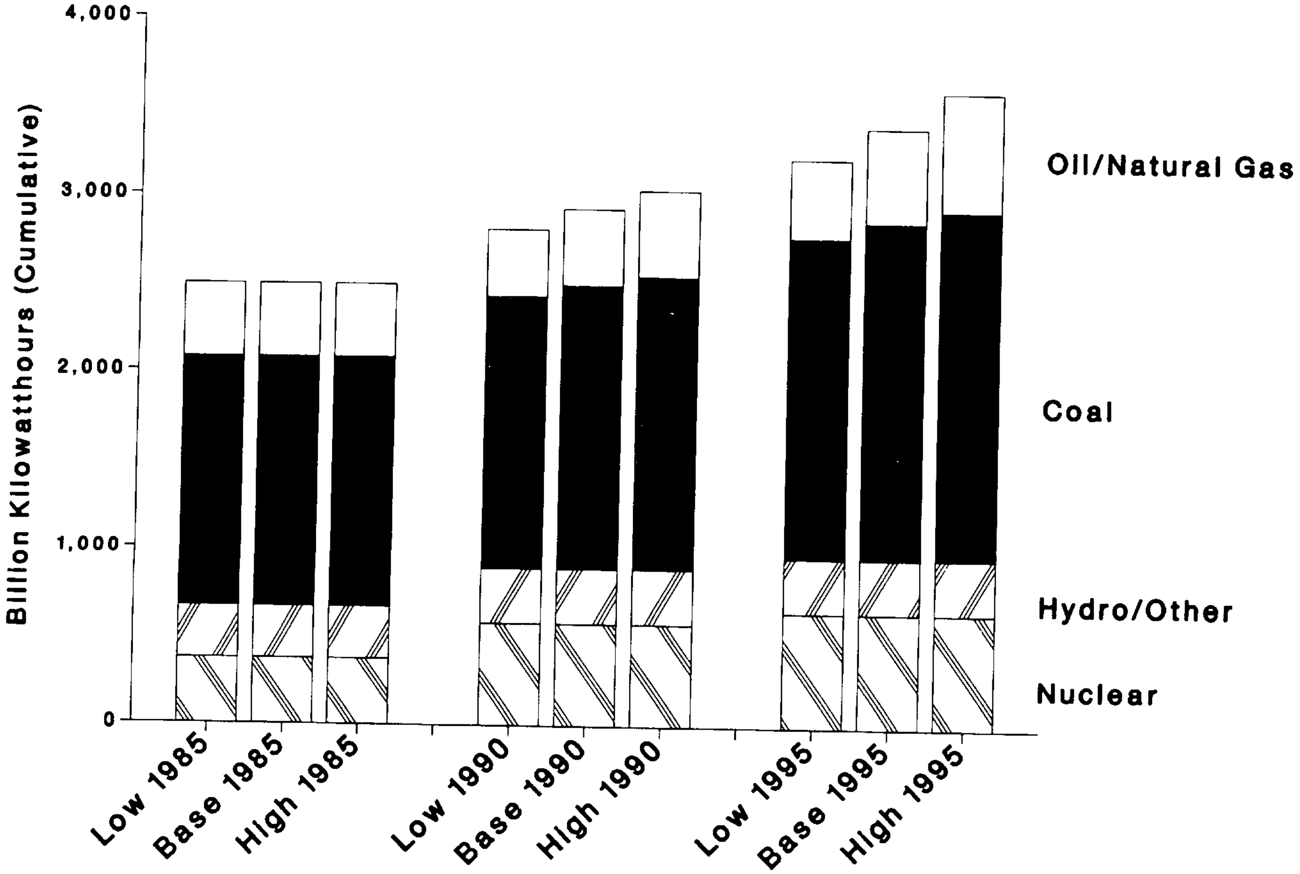
The price of electricity is projected to rise as demand increases, because of the increased use of expensive oil and natural gas. In 1995, electricity prices could be about 7 percent higher in the high economic growth case than in the low economic growth case (Table 30). Although capital expenditures are expected to increase with demand, the per-unit capital cost could decline because the higher

Figure 28. End-Use Electricity Consumption: Comparison of Economic Growth Scenarios, Selected Years



Source: • History: Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(84/06) (Washington, DC, 1984). • Projections: Appendices A, B, C; Tables A11, B11, C11.

Figure 29. Projected Sources of Electrical Supply: Comparison of Economic Growth Scenarios, Selected Years



Note: "Other" includes renewable resources such as geothermal, wood, waste, solar, and wind.
Source: Appendices A, B, C; Tables A12, B12, C12.

costs are spread over a larger base of sales. The operation and maintenance (O&M) cost could also decrease as demand increases because the share of electricity produced by oil- and gas-fired plants, which have relatively low O&M costs compared to coal-fired and nuclear plants, is expected to rise. However, the increase in fuel costs is expected to dominate the decline in capital and O&M costs.

Table 30. Projected Electricity Price and Cost Components: Comparison of Economic Growth Scenarios, 1995
(1984 Dollars per Thousand Kilowatthours)

	Economic Growth Case		
Component	Low	Base	High
Capital	19.6	19.3	19.1
Fuel	26.4	28.5	31.7
Operation and Maintenance	15.0	14.7	14.3
Total Electricity Price	61.0	62.4	65.0

Source: Appendices A, B, C; Tables A14, B14, C14.

Reserve margins, which indicate the electric utility industry's capability to provide reliable service, are projected to fall below current high levels during the forecast period in all three economic growth scenarios because increases in demand are expected to exceed the capacity additions. Typically, industry analysts consider reserve margins of 20 percent to be adequate and reserve margins below 15 percent to be inadequate. The national reserve margin in 1995 is projected to range from 22 percent in the high economic growth case to 33 percent in the low economic growth case, compared to a reserve margin of nearly 50 percent in 1983. However, the capacity additions currently planned or under construction are projected to be insufficient to maintain a reserve margin of at least 15 percent (the minimum level permitted in this analysis) in more than half the regions in the high economic growth case.

By 1995, the need for new generating capacity that is not already planned is projected to range from 3 gigawatts in the low economic growth case to 24 gigawatts in the high economic growth case. The need for these unplanned capacity additions could be partially reduced by conservation, greater electricity imports, or increased production from sources other than the domestic supplies included in these projections. (The projections in this report assume that the historic contribution of other sources of supply will continue in the future.) This evaluation is based on nameplate capacity ratings for existing power plants and normal water conditions for hydroelectric plants.

Lower Electricity Demand

An alternative projection approach (compared to the base case discussed in Chapter 2) is to assume that electricity demand grows no faster than the growth in the gross national product (GNP). In the base case, the ratio of electricity demand growth to GNP growth is projected to be 1.2 between 1985 and 1995. With the constant GNP-electricity growth assumption, coupled with the other base case assumptions, total electricity demand would be 4 percent lower than the base case level by 1995. In this case, consumption of the relatively more expensive fuels (petroleum products and natural gas) is projected to be 15 percent below the base case levels by 1995. The use of coal-fired generation is also projected to decline, reducing utility coal consumption by 3 percent nationally. Furthermore, lower demand growth would increase reserve margins by almost 4 percent and postpone the need for additional generating capacity, enabling the electric industry to delay nearly 3 gigawatts of capacity additions (Appendix G).

Cogeneration and Small Power Production

A significant portion of new electricity demand projected for the forecast period could be met by nonutility electric cogenerators and small power producers not explicitly considered in these projections. Cogeneration is the dual production of thermal and power energy from a single energy source. In most applications, cogeneration produces both electric power and steam or some other form of useful heat energy. Because cogeneration can increase energy utilization efficiency, there is general interest in encouraging its use. In 1978, Congress passed the Public Utility Regulatory Policies Act, P.L. 95-617 (PURPA), as part of the National Energy Act. One goal of PURPA is to increase the efficiency of electric utilities by increasing cogeneration and small power production.

Small power facilities are restricted in size to 80 megawatts or less and must use renewable or waste energy sources. The PURPA authorizes the Federal Energy Regulatory Commission (FERC) to establish rules to encourage electricity production from these sources and restricts electric utility ownership of such facilities. Under this authorization, FERC's rules require that electric utilities purchase the electricity offered for sale by qualifying cogenerators and small power producers at the utilities' avoided cost or some other mutually agreeable price. PURPA thus encourages noncentral generation by creating a market for power from these nonutility generating facilities.

Currently, no data system tracks the contribution of these nonutility generators to domestic electricity sources. However, the new Form EIA-714 will provide some of this information. Through June 1984, 1,073 filings of notification or applications for certification had been made with FERC by facilities seeking qualification under the provisions of PURPA.[3] These facilities (if they become operational) could represent as much as 15.2

---

[3] Federal Energy Regulatory Commission, "Quarterly Report on Qualifying Small Power Production and Cogeneration Facility Filings" (Washington, DC, July 1984).

gigawatts of electric generating capacity, or the equivalent of about 2 percent of total 1983 generating capacity. Approximately 11 gigawatts are classified as cogeneration and 4.2 as small power facilities. Since business prudence suggests that FERC certification be obtained prior to the actual installation of facilities, it is difficult to judge how much new nonutility generating capacity will become available or how much electricity will be produced.

Possibly as much as 5 to 20 percent of U.S. electricity consumption could be supplied by nonutility sources by the year 2000. However, the development of extensive noncentralized generation depends on many other factors, including the level of economic activity, relative attractiveness of investment in cogeneration and small power facilities, the mix of industrial activity, the prices of alternative energy sources, and the costs of additional means of generating electricity.

Reduced Generating Capacity Additions

In the base case, 106 gigawatts of net capacity are projected to be added between the end of 1985 and the end of 1995. These plants include 36 gigawatts of nuclear capacity and 57 gigawatts of coal-fired capacity, representing about 88 percent of the projected capacity additions during this period. The remaining capacity additions are gas- and oil-fired turbines, pumped storage, conventional hydroelectric, and other capacity.

Due to long licensing and construction periods for baseload generating capacity (typically about 8 years for a coal-fired plant and 10 to 15 years for a nuclear plant), utilities must plan construction projects far in advance of the actual need for new capacity. Based on the robust growth in electricity demand observed in the 1960's and early 1970's, utilities developed expansion plans for the late 1970's and early 1980's. When the demand projections for these years exceeded the actual demand growth and resulted in high reserve margins, many planned units were postponed or cancelled. The lower-than-expected profits resulting from the slow demand growth, escalating construction costs, high interest rates, and regulatory lag increased the financial pressure on many utilities and led to further delays and cancellations.

Unanticipated reductions in electricity demand growth or unexpected financial difficulties could result in the cancellation of some of the projected capacity additions included in the base case. The "reduced capacity additions" case examines the impact on electricity supply, assuming that some of the projected capacity additions will be cancelled. The assumed nuclear plant cancellations include those units that are currently less than 40-percent complete, or that are experiencing severe financial difficulties, or where construction work at the site has stopped. Under these assumptions, nuclear capacity would be 77 gigawatts in 1985, compared to 80 gigawatts in the base case: in 1990, capacity would be 104 gigawatts, compared to 110 gigawatts in the base case, and by 1995 the relevant comparison is 105 gigawatts rather than 117 gigawatts. Also, planned coal-fired units with boiler shipments that have been postponed indefinitely were assumed to be cancelled. The assumed nuclear and coal-fired cancellations through 1995 total

17 gigawatts and represent about 12 percent of the projected capacity additions in the base case.

The primary consequences of these capacity reductions could be lower reserve margins, higher utility oil and natural gas consumption, and higher electricity prices. The electricity that would have been produced by the cancelled nuclear and coal-fired plants could be produced instead by other new plants that were not projected to be built in the base case or by existing capacity that was projected to be unused in the base case. Oil- and gas-fired units are generally the marginal existing sources of electricity supply because they use the most expensive fuels. The incremental utility oil and natural gas demand is expected to be met by imports.

Assuming the same electricity demand growth specified in the base case, cancellation of 17 gigawatts of coal and nuclear capacity could decrease the national reserve margin to 25 percent in 1995, 2 percentage points lower than the base case level. In order to maintain a reserve margin of at least 15 percent in all regions, 14 gigawatts of capacity currently neither planned nor under construction by utilities will be needed, or 4 gigawatts more than in the base case (Appendix G).

Coal and nuclear generation projections are strongly influenced by assumptions about maximum capacity utilization, which place an upper limit on the percentage of time power plants are allowed to generate electricity. Capacity utilization for both coal-fired and nuclear plants is projected to increase significantly between 1983 and 1995 despite the aging of the capital stock (Table 31). The total system utilization rate is projected to grow from 41 percent in 1983 to 49 percent in 1995 in the base case. Many individual coal-fired and nuclear plants are currently operated at or above the level projected for 1995. High utilization rates are evident today in regions dependent on other more expensive fuels for electricity generation. For example, in New England the average utilization rate for coal-fired plants was 84 percent in 1983 while the average utilization rate for nuclear plants was 67 percent.[4]

Nuclear and coal-fired plants are projected to continue to produce most of the electricity in the United States. In the base case, nuclear and coal-fired generation is expected to supply about 75 percent of the total electricity in 1995, compared to 67 percent in 1983. By 1995, nuclear plants are projected to operate at their maximum utilization rates, but some regions could have coal plants that do not operate continuously because the demand is not expected to require full utilization of all coal capacity. In the reduced capacity additions case, the cancellations could decrease the available coal and nuclear capacity by

---

[4]Coal-fired and nuclear plant generation data for 1983 are shown in Energy Information Administration, Electric Power Annual, 1983, DOE/EIA-0348(83) (Washington, DC) p. 30 and p. 37, respectively. Coal-fired and nuclear plant capacity data are shown in Energy Information Administration, Inventory of Powerplants in the United States, 1983, DOE/EIA-0095(83) (Washington, DC), p. 14. Utilization rates are determined as follows:

Utilization Rate = 100 x [Annual Generation/(Capacity x Hours in the Year)].

about 3 percent in 1995. However, the accompanying decline in nuclear and coal-fired generation is projected to be only about 2 percent; the loss of this generating capability is projected to be partially offset by increases in the utilization of the remaining coal-fired plants and by the use of other new coal-fired plants projected to be built to replace some of the cancelled nuclear and coal-fired plants (Appendix G).

Table 31. Age of U.S. Steam Generating Capacity, 1983 and 1995

		Years in Service			
		40 Years or Less		More than 40 Years	
Plant Type	Mean Age (years)	Capacity (million kilowatts)	Percentage of Total	Capacity (million kilowatts)	Percentage of Total
Coal Steam					
1983	14.7	284	99.3	2	0.7
1995	21.6	333	92.5	27	7.5
Nuclear					
1983	8.9	64[a]	100.0	0	0
1995	14.5	117	100.0	0	0
All Other Steam[b]					
1983	18.9	153	97.5	4	2.5
1995	29.9	132	84.0	25	16.0
All Steam					
1983	15.3	502	98.8	6	1.2
1995	22.4	582	91.8	52	8.2

[a]Includes Three Mile Island 1.
[b]Includes oil, natural gas, oil/natural gas, waste, and all other steam sources.
Source: o 1983: Energy Information Administration, Generating Unit Reference File (GURF) (Washington, DC). o 1995: Energy Information Administration, Intermediate Future Forecasting System (IFFS) (Washington, DC).

In the reduced capacity additions case, the share of total generation in 1995 produced by oil- and gas-fired plants is expected to increase to replace generation not available from coal-fired and nuclear plants. Total oil and gas-fired generation could increase by about 10 percent. The projected increased utilization of oil- and gas-fired plants could increase the real price of electricity in 1995 by about 0.7 percent from the base case level. The relatively small increase in price is expected to occur because the capital and operation and maintenance (O&M) costs are projected to be lower than in the base case. The capital costs are expected to decline because of lower capital expenditures resulting from the scaled-back construction plans. The decrease in O&M costs could occur because oil- and gas-fired plants have lower O&M costs than coal-fired and nuclear units.

The sum of these cost reductions would be more than offset by the increase in fuel costs.

On a national level, the aggregate projections of electricity generation for the reduced capacity additions case are similar to the base case. However, the projected impacts have wide regional variations. Some regions could experience little or no difficulty meeting peak loads and may actually experience a slight decrease in electricity prices. These regions are generally characterized by high reserve margins and unused coal capacity, which could enable them to replace the cancelled capacity with existing coal-fired plants. The resulting increase in fuel costs could be relatively small compared to the decrease in capital costs. Conversely, there could be a great impact on those regions that are currently projected to have relatively low reserve margins and rely heavily on oil- and gas-fired plants. Further cancellations in these regions could raise electricity prices and reduce reserve margins considerably, requiring new coal-fired plants that are currently not scheduled to be built.

Reduced Capacity Additions Coupled with High and Low Demand

Because of the uncertainty in the growth rate of electricity demand and the importance of demand in capacity expansion decisions, a range of implications of reduced capacity additions can be observed by combining the electricity demand growth rates for both the low and high economic growth cases with the cancellation of nuclear and coal-fired plant additions. At levels of higher demand, lower capacity could have a proportionately greater effect on electricity supply, prices, and reliability. The ability of the electric utility industry to compensate for capacity reductions could decrease as demand increases because there would be less underutilized capacity available to produce additional electricity. Natural gas- and oil-fired plants would have to supply electricity at higher prices than would be charged for electricity produced by new coal-fired and nuclear plants.

In the low economic growth case with reduced capacity additions, coal-fired generation could increase slightly by 1995, as some regions have existing coal-fired plants that are not projected to operate at their maximum levels and could more than offset the loss of the cancelled coal-fired plants. The rest of the electricity that would have been produced by the cancelled plants in 1995 is expected to be supplied by existing oil- and gas-fired plants, resulting in an 11-percent increase (about 50 billion kilowatthours) in utility oil- and gas-fired generation compared to the low economic growth case without reduced capacity additions.

In the high economic growth case, the available coal-fired units are already projected to operate near their maximum rates, and the additional electricity that could be produced by these plants would only partially offset the electricity that could have been provided by the cancelled coal-fired plants. The rest of the cancelled coal-fired and nuclear plants could be replaced by existing oil- and gas-fired plants or new plants that are not currently scheduled to be built. If some new coal-fired plants are built, total 1995 coal-fired generation could increase slightly, and the increase in oil- and gas-fired generation could be about the same as in the low economic growth case. Otherwise, the increase in oil and gas use by utilities could be substantially higher.

The reduced capacity additions are projected to lower the national reserve margin in 1995 from 33 percent to 31 percent in the low economic growth case and from 22 percent to 21 percent in the high economic growth case. In both cases, the reserve margin in some regions could fall below 15 percent, given the reduced schedule of capacity additions. In the low economic growth case, about 2 gigawatts of the cancelled capacity would have to be replaced, either by unplanned capacity additions, conservation, cogeneration, electricity imports, or efficiency improvements in existing plants. In the high economic growth case, about 8 gigawatts of the cancelled capacity would have to be replaced.

The increase in electricity prices by 1995, due to the reduced capacity additions, is projected to range from 0.3 percent in the low economic growth case to 1.0 percent in the high economic growth case. In both cases, the capital and O&M cost components are projected to decrease because the cancelled nuclear and coal-fired plants have relatively high capital and O&M costs. However, the increase in fuel costs, particularly in the high case, is projected to be large enough to outweigh the decline in capital and O&M costs (Appendix G).

Construction Work in Progress

Alternative regulatory treatments of accounts for construction work in progress (CWIP) have been examined to determine the impacts of such alternative treatments on electricity prices and the expected changes in the financial condition of electric utilities. CWIP accounts contain the cost to a utility of new construction not yet in service. They include both the cost of new construction work in progress and the accumulated charges for monies (both external and internal) used to finance the construction. Under most current State regulations, the bulk of the cost of new construction of plants not yet in service cannot be placed in the rate base and charged to utility customers until the construction enters service, commonly called "used and useful."

Under one regulatory method, the carrying charges incurred during the construction period are capitalized on a utility's books for later recovery from ratepayers during the plant's operating life as part of depreciation expense. This method is often referred to as the AFUDC method after the term used for the carrying charges as they are recorded in the utility's books, that is, allowance for funds used during construction. The second method for recovery is to include CWIP in the rate base (referred to here as the CWIP in rate base method), thereby allowing current utility rates to reflect these carrying costs. Under the second method, ratepayers pay the carrying costs during the construction period whereas under the first method, rates exclude these costs until the plant is in operation.

Accumulating the financing cost until service begins, as done in the first method, increases the costs of new facilities by compounding the costs and causes two problems for utilities: first, the growth of unrecovered financial costs means that greater debts may be required, and second, costs of securing funds may increase because greater debt is associated with greater risk and, hence, higher costs for additional debt. When the plant does come into service and all of the costs are added to the rate base, there is the potential for "rate shock" (a large increase in electricity rates due to the addition in the rate base of a high-cost asset, such as a nuclear or coal-fired plant). To the extent that CWIP is included in the rate base as construction is underway, these problems are reduced and the financing requirements for a project could be less. From the consumer's perspective, including all of the CWIP account in the rate base would represent a "pay as you go" policy because the financing costs of the construction of new plants (from which consumers get no current benefits) would be included in current rates. The AFUDC method represents a "pay more later" policy because ratepayers do not pay financing costs in current rates but face even greater financing costs when the new plants do enter service. Consumers thus would benefit from lower rates under CWIP in rate base policy than with the AFUDC method when the plant comes into service.

Current regulatory rules for CWIP accounts vary among the individual States. Generally, States allow a small percentage of CWIP accounts to enter the rate base. Facilities built to reduce environmental problems receive special treatment; up to 100 percent of these expenditures are frequently permitted to enter the rate base. Wholesale sales of electricity (sales between utilities or across State boundaries), which account for about 11 percent of all electricity sales, are regulated by the Federal Energy Regulatory Commission (FERC). The FERC may permit up to 50 percent of financing costs in the rate base. The remaining 50 percent receives AFUDC treatment and thus accrues additional financing costs until the facility comes into operation.[5]

In order to capture current regulatory rules for CWIP, the base case assumes that an average (for all electricity sales) of 15 percent of the total CWIP account for all construction activities over all jurisdictions is permitted in the rate base. This percentage is based on the average over all jurisdictions (all States and the FERC), weighted by the share of sales. A variation in which 100-percent CWIP is allowed to enter the rate base was also analyzed. In this case, all accumulated expenditures in CWIP accounts (including AFUDC) are assumed to enter the rate base in 1986, and all subsequent CWIP expenditures in years after 1986 are permitted in the rate base in the year of the expenditure.

The inclusion of all outstanding CWIP in the rate base is examined to determine the maximum possible impact due to changes in current regulations. For some utilities, such a policy could cause significant increases in electricity rates in the year in which the policy is instituted. It is expected, however, that price increases in subsequent years (given current construction plans) would moderate because smaller increments of capital would enter the rate base compared to the base case. If CWIP is phased into utility ratebases over several years (instead of included all in the first year), projected national electricity price increases for the first year the policy is in effect would be less than those projected in this analysis. However, with a phased-in CWIP policy, price impacts associated with the change would be felt by consumers for a longer period of time.

An important consideration in regulatory treatment of CWIP is the impact on electricity prices and reductions in demand that might occur in response to higher prices. When a 100-percent CWIP policy is assumed, the national average price for electricity is projected to be 4 percent higher in 1986 than the base case

---

[5]Federal Energy Regulatory Commission, Environmental Assessment Related to FERC Rule Amendment Regarding Inclusion of CWIP in Rate Base (Washington, DC, March 1983), p. 4-3.

(Figure 30). The larger capital component of electricity prices is responsible for increased electricity prices (Table 32). This projected price increase results from including all CWIP in the rate base in 1986 and is an upper bound for potential regional price increases due to a change in the current treatment of CWIP. Implementation of a change in CWIP policy could be instituted gradually over a period of years or might include only expenditures made after a certain date. These policies could dampen the price increase projected in this analysis.

Table 32. Projected Changes in Electricity Cost Components: 100-Percent CWIP Case, 1986-1995
(Percent)

Cost Component	1986	1990	1995
Capital	9.7	2.1	0.6
Fuel	-0.3	-0.3	-0.3
Operation and Maintenance	0.6	0.3	0.1
Total Electric Cost	4.0	1.3	0.1

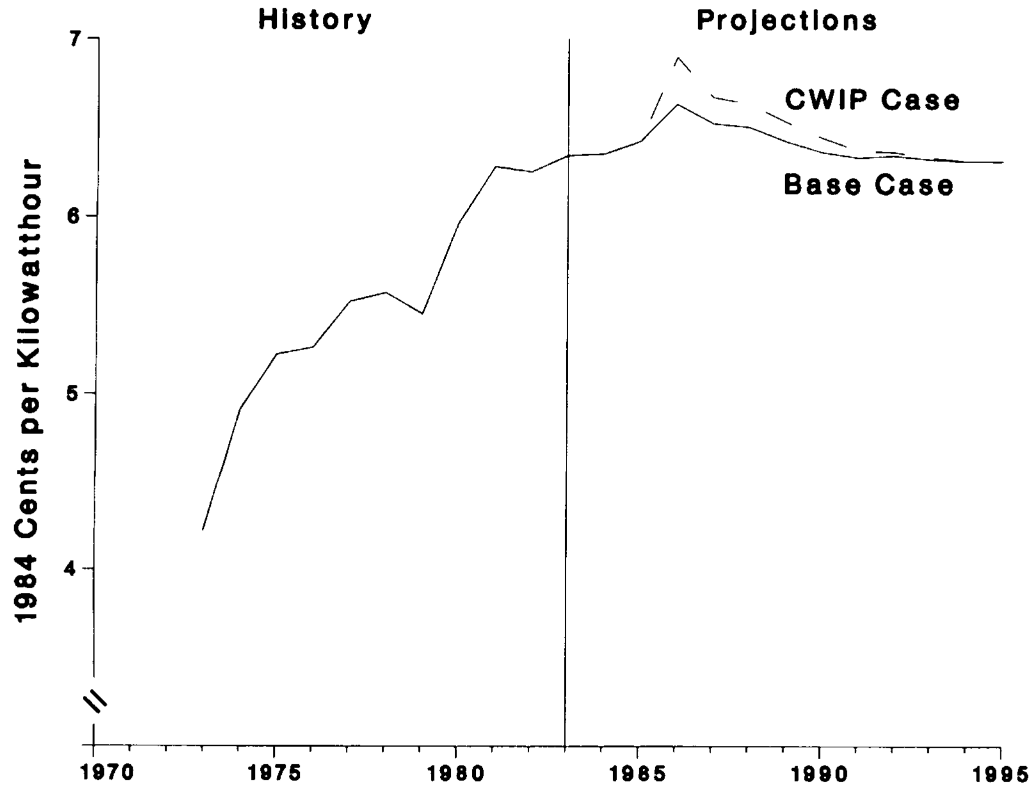
Note: Total Electric Cost is not the sum of its components because values of the components are different.
Source: Appendix G, 100-Percent CWIP case.

Price increases (compared to the base case) are projected to diminish over time, declining to near zero by 1995. Over the forecast period, increases in the capital component of electricity prices are expected to be responsible for electricity price increases. The higher price for electricity in 1986 is projected to cause electricity demand to drop by 0.4 percent in that year compared to the base case. As prices converge over time, the reductions in demand also diminish. By 1995, electricity demand is projected to be 0.2 percent lower in the 100-percent CWIP scenario than in the base case. In several regions, electricity prices are projected to be lower in the 1990's in the 100-percent CWIP scenario compared to the base case. In regions that are expected to require continued large construction programs, the prices are projected to be higher than the base case for a longer period of time.

In the base case under the current CWIP policy (15 percent of CWIP in rate base), national electricity prices are not projected to increase as new plants come into service. This result is due to the relatively small amount added to the existing rate bases for new construction projects in any given year. If all the current construction projects were completed in a given year and were to enter the rate bases, the increase in the electricity price at the national level in that year would be greater than that projected to occur in the 100-percent CWIP scenario.

This analysis of 100-percent CWIP in the rate base does not include projections beyond 1995 and, as a result, does not provide projections for possible reductions in electricity prices that could occur in subsequent years compared to the base

Figure 30. Electricity Prices: Comparison of Base and 100-Percent CWIP Cases, 1973-1995



Note: CWIP (construction work in progress) is included in the rate base in the 100-Percent CWIP case.

Source: • History: Energy Information Administration, State Energy Price and Expenditure Report, 1970-1981, DOE/EIA-0376(81) (Washington, DC, 1982). • Projections: Appendix A, Table A11; Appendix G, 100-Percent CWIP case.

case. Beyond 1995, electricity prices are expected to be lower in the 100-percent CWIP scenario than in the base case (given current construction plans), due to the absence of carrying charges for new construction in the 100-percent CWIP case. The CWIP accounts are expected to be almost $8 billion less by 1995 in the 100-percent CWIP case. These lower costs would be reflected in the rate base after 1995 and, in the absence of new construction programs, would result in lower rates compared to the base case.

The effects of a number of financial measures were examined under the alternative CWIP scenario. These measures include interest-coverage ratios, internal cash flows as a percentage of construction expenditures, allowance for funds used during construction (AFUDC) as a percent of earnings, and return on equity. The interest-coverage ratio provides an estimate of a utility's ability to meet its fixed obligations, such as interest payments on debt securities. Interest-coverage ratios in the range of 3 to 3.5 are considered desirable by financial analysts. If a utility's ratio were to decline below 2, the Securities and Exchange Commission would preclude it from issuing any new debt.

National average interest-coverage ratios (which are currently about 2.3) are projected to improve to about 3.1 for the forecast period in the 100-percent CWIP scenario. (In the base case, interest-coverage ratios are projected to be about 2.8 between 1983 and 1995.) The improvements in the 100-percent CWIP case are projected to occur because reduced requirements for funding construction projects (due to removal of carrying charges for plants under construction) result in additional funds being available from internal sources. Funds from internal sources become available because total outstanding debt is less and, as a result, costs of servicing debt are less. These improvements could result in utilities being able to borrow funds at lower interest rates than otherwise.

The availability of internally generated sources of funds is captured in the ratio of internal cash flow as a percentage of construction expenditures. This ratio, which indicates the extent to which construction must be financed from outside sources, is projected to improve significantly, increasing from 8 to 23 percentage points between 1986 and 1995 in the 100-percent CWIP scenario over the base case. The reduced need for external financing of construction activities is projected to improve the financial condition of utilities. The 100-percent CWIP policy is projected to improve the ability of utilities to fund capital expenditure programs without borrowing funds. As expected, the percentage of AFUDC (that is, the carrying charges on expenditures for new plants) to earnings drops to zero in the 100-percent CWIP case because all construction outlays are assumed to be in the rate base and earn an allowed rate of return.

High Nuclear Construction Cost Sensitivity

Estimates of nuclear power plant construction costs have been increasing over time. The electricity price projections in this report are based, in part, on utility estimates of nuclear construction costs at project completion as reported on Form EIA-254, "Quarterly Progress Report on Status of Reactor Construction." Based on these data, the base case estimated average cost at completion, in nominal dollars, for all nuclear units under construction at the beginning of 1983 is about $2,300 per kilowatt of projected installed capacity.[6]

To determine the impact of higher nuclear construction costs on electricity prices, the base case average cost was assumed to increase by about 10 percent, to about $2,500 per kilowatt of projected installed capacity. This increase coincides with a real escalation rate of 11 percent. This rate, estimated in two studies,[7] was applied annually to the estimated remaining portion of the "overnight cost" (real construction cost exclusive of financing costs) for each of the nuclear units currently under construction at the beginning of 1983 through their projected completion date.

The impact of this assumed increase in nuclear construction costs on electricity prices varies by region and over time. The magnitude of the impact depends on the estimated cost at completion of each unit, the projected completion date of each unit, and the ratio of the book value of the nuclear additions to the book value of the assets of all the utilities in a particular region. The biggest impacts of higher nuclear construction cost are projected to occur in the Northwest and New England regions, where average electricity prices are projected to be about 2 percent higher than the base case level in 1995. In all other regions and nationwide, prices are projected to be less than 1 percent higher than the base case level. For certain utility service areas within the regions, that is, those with high-cost nuclear construction projects, the increase in electricity prices would be expected to be much greater.

Limits to Liability in Case of a Nuclear Accident: The Price-Anderson Act

The Price-Anderson Act, which assigns liability in the event of commercial nuclear accidents, will expire in 1987. Therefore, Congress will once again determine the apportionment of potential commercial nuclear accident costs to the general public and to nuclear utilities. The Price-Anderson Act of 1957 was designed to assign liability and provide insurance in case of a commercial nuclear accident. First, the Act effectively established insurance pools to guarantee some compensation. Second, the Act limited the liability from a single accident to $560 million. At the time, only $60 million of private insurance was available; the remaining $500 million was to be provided by the Government.

---

[6] Energy Information Administration, Survey of Nuclear Power Plant Construction Costs, DOE/EIA-0439(84) (Washington, DC, November 1984).

[7] Charles Komanoff, Power Plant Cost Escalation (New York: Reinhold, 1981); Martin Zimmerman, "Learning Effects and the Commercialization of New Energy Technologies: The Case of Nuclear Power," Bell Journal of Economics (Autumn 1982).

The Act was modified in 1966 and 1975. The 1966 amendment provided for utility liability regardless of fault in case of extraordinary nuclear accidents. The 1975 amendment required all utilities with nuclear facilities to make a payment of $5 million per reactor in the event of a nuclear accident with damages in excess of $160 million, the amount of private insurance currently available. Since there are 84 reactors licensed to operate at present, this amendment effectively raised the liability limit to $580 million, and phased out the Government payments.

Modifications to the Act are being discussed. The Nuclear Regulatory Commission (NRC) in its 1983 report The Price-Anderson Act--The Third Decade has proposed that the $580-million liability limit be removed and that all utilities owning nuclear reactors as a group assume unlimited liability for all claims resulting from nuclear accidents beyond the $160-million private insurance. Claims above $160 million would be met by assessments not to exceed $10 million per year per reactor. There is also legislation pending (H.R. 3277) that would simply remove the limit to liability. As opposed to the NRC proposal, this legislation would make the affected utility liable for damages in excess of the current $580 million.

Fuel Switching in Dual-Fired Steam Plants

Because oil and natural gas are currently the most expensive utility fuels, electric utilities try to limit consumption of these fuels by using more coal, nuclear power, and hydropower. Consequently, changes in the relative prices of oil and gas have little effect on their combined use by utilities. However, the relative prices of oil and natural gas play a significant role in determining their individual generation shares. Currently, most utilities that are able to use natural gas have chosen to do so because oil is more expensive.

Many steam plants are equipped with multifuel boilers capable of burning either natural gas or oil. Although some of these dual-fired units can use the alternate fuel only on a short-term emergency basis, many can sustain long-term continuous firing with either fuel, and thus respond to changes in fuel prices and supplies by switching input fuels. This dual-fired capability is a strong incentive for suppliers to maintain price parity between competing fuels in order to protect market shares.

However, the ability of utilities to switch fuels may be limited in the short run by other considerations. Most oil and natural gas burned by utilities is purchased under contract; therefore, changing fuel consumption patterns may require waiting until existing obligations expire or incurring additional expenses to buy out or abrogate these contracts. Some contractual arrangements may also insulate utility fuel prices from short-run changes in market prices. In either case, the use of contracts tends to slow adjustments to changes in market conditions. Furthermore, utilities may prefer to keep options open by maintaining links with suppliers of both fuels. In the event of interruptions in the supply of one fuel, such as those caused by the 1973 oil embargo or by constraints on deliverability of natural gas during periods of cold weather peak heating demand, alternatives are available.

In 1983, about 100 gigawatts (16 percent of the total available generating capacity) were dual-fired oil and natural gas steam plants. About three-fourths of the Nation's dual-fired capacity is located in the Southwest and West. These regions are currently the largest utility gas consumers, accounting for almost 80 percent of the total electric utility gas consumption in 1983 (Appendix G).

To examine the range of fuel switching between oil and natural gas in dual-fired steam units, two alternative scenarios were defined--the first assuming maximum natural gas use (the natural gas preference case) and the second assuming maximum oil use (the oil preference case). The maximum shares for both gas- and oil-fired generation are based on historical consumption rates for the respective fuels.

In the base case, natural gas is generally expected to maintain its economic advantage over oil so limited potential is expected for switching from oil to natural gas in dual-fired plants. In a few regions, the price of oil could become competitive with the price of natural gas by the mid-1990's, and gas-fired generation in 1995 could be about 8 percent higher in the natural gas preference case than in the base case. The effect of higher natural gas consumption on the price of electricity would be almost negligible, because the increase in natural gas use would represent less than 1 percent of the total generation.

Because the respective fuel prices in the base case are usually expected to result in the use of natural gas instead of oil in dual-fired steam plants, circumstances requiring maximum oil use, such as limited natural gas supplies, could substantially change the projected oil and natural gas shares. Utility oil consumption in 1995 could be more than twice as high as the base case level, or about 1.8 million barrels per day, while natural gas use could decline by more than 60 percent. The increased use of the more expensive oil could raise electricity prices in 1995 by about 0.7 percent compared to the base case. The higher electricity price could result in a decrease in the electricity demand of about 0.8 percent.

Sulfur Dioxide Emissions Reductions

Sulfur dioxide (SO_2) emissions from coal-fired electric utilities are often cited as principal sources of acid rain, a major environmental concern. Proposed legislation to reduce utilities' SO_2 emissions could impose added costs on electric utilities in the future, raising overall electricity prices and inducing significant fuel switching among coal-fired electric utilities. EIA and other Federal and industry groups evaluated the electricity market effects of H.R. 3400 to reduce SO_2 emissions. This Act proposes the following: (1) a 10-million-ton reduction in SO_2 emissions from fossil-fueled electric utilities by 1993, (2) retrofitting the 50 largest SO_2 emitters with flue gas desulfurization equipment (FGD) and establishing State SO_2 emissions reduction plans, and (3) establishing a fee-supported trust fund paying 90 percent of FGD installation costs. The trust fund would be financed by a 1-mill-per-kilowatthour fee levied on all electricity generated (except that generated by nuclear plants) or imported into the 48 contiguous States.

The EIA analysis contained in a July 1984 service report, "Analysis of H.R. 3400: National Acid Deposition Control Act of 1983," found the following: coal-fired electric utilities are projected to retrofit about 68 gigawatts, or about 25 percent of existing (1984) coal-fired capacity, by 1995. Further, an additional 55 gigawatts of coal-fired capacity are projected to convert to low-sulfur coal. The total capital cost (in 1984 dollars) for FGD retrofitting, converting capacity to burn low-sulfur coal, and new capacity and transmission lines is estimated at $26 billion by 1995, including $22 billion provided by the trust fund. The trust fund is estimated to be sufficient to pay for 90 percent of FGD expenditures. Average electricity prices in 1995 are projected to increase by 2.0 mills per kilowatthour, about 3 percent, including the 1-mill-per-kilowatthour fee.

Coal markets would also be affected by the SO_2-emissions control legislation. Under HR 3400, electric utilities with retrofitted FGD equipment are projected to switch to less expensive high-sulfur coal, while utilities without FGD would meet emissions reduction requirements by converting to low-sulfur coal. As a result, consumption of medium-sulfur coal for electricity generation would be less than without the legislation. Under H.R. 3400, net regional coal production losses in 1995 would occur primarily in the Midwest (-9 million tons) and Northern and Southern Appalachia (-7 million tons) as medium-sulfur coal demand losses exceed high-sulfur coal demand increases, while the low-sulfur coal producing regions would experience the greatest net production increases. In 1995, coal production in the Western Northern Great Plains and in Central Appalachia under H.R. 3400 would be expected to increase about 26 million and 18 million tons, respectively.

These estimates of the impacts of H.R. 3400 depend on the interpretation of the legislation's requirements as well as many other assumptions. The EIA analysis assumed that the industry would be able to implement a least-cost approach in meeting the new requirements without addressing unforeseen uncertainties that could impact the industry. Other assumptions about factor costs, operating efficiencies, equipment longevity and dependability, and other matters would also affect the results.

Earlier legislative initiatives to address acid rain were proposed in the Congress, and future proposals are possible. These proposals may have impacts on electric utilities that differ from those estimated to occur under H.R. 3400. An analysis prepared by EIA of S. 3041 indicated different impacts on both electric utility expenditures and coal production patterns due to the form of that legislation. (See Energy Information Administration, Impacts of the Proposed Clean Air Act Amendments of 1982 on the Coal and Electric Utility Industries.) This report also provided comparisons with other studies including those prepared by the electric utility industry on S. 3041.

8. Coal

Many uncertainties surround the future levels of U.S. coal production, consumption, and exports. This chapter addresses some of those uncertainties that may have significant impacts on future projections of coal supply and demand. Such concerns are listed below:

- Economic growth and the impact of growth rates on demand and supply
- Coal transportation and the impact of rail rates
- Coal mine labor productivity and the impact of improvements on regional coal production
- U.S. coal exports and imports in the context of world coal trade.

Two additional uncertainties that could impact projections of coal supply and demand are environmental regulations and the future of nuclear power plants. These issues are discussed in Chapter 7.

High and Low Economic Growth

Future levels of coal consumption and production are analyzed under two scenarios, high and low economic growth, in addition to the base case. The high economic growth case assumes the real gross national product (GNP) is assumed to grow at an average annual rate of 3.4 percent and the low economic growth case at 2.0 percent, compared with a 2.7-percent rate in the base case, and a 2.5-percent annual rate from 1973 to 1983.

In the high economic growth case, coal consumption is projected to be 3.4 percent (38 million short tons) higher than the base case in 1995 (1.1 billion short tons), while in the low economic growth case, coal consumption is projected to be 4.5 percent (50 million short tons) lower (Table 33). As in the base case, coal consumption under both scenarios is projected to increase as fast as (or faster) than both GNP and total U.S. energy consumption, signifying coal's relative importance in the future U.S. energy mix.

As the primary user of coal, electric utilities account for most of the change in total coal consumption under all economic growth scenarios. In 1995, electric utility coal consumption under the high and low economic growth scenarios is projected to be about 3.3 percent above and 4.4 percent below the base case forecast of 951 million short tons, respectively.

Coal production in 1995 is projected to vary by 87 million short tons between the low and high economic growth cases (Table 33). The different assumptions about the rate of economic growth are expected to have little impact on patterns of coal distribution or types of coal mining.

Table 33. U.S. Coal Consumption and Production: Comparison of Economic Growth Scenarios, 1983-1995
(Million Short Tons)

	History	Projections						
		1985	1990			1995		
	1983	Base Case	Low Growth	Base Case	High Growth	Low Growth	Base Case	High Growth
Consumption by Sector								
Electric Utility	625	709	773	805	829	909	951	982
Other Industrial	66	77	86	89	91	91	98	102
Coke Plants	37	46	50	51	52	47	49	51
Synthetics	0	5	6	6	6	6	6	6
Other[a]	8	8	7	7	7	7	7	7
Total Consumption	737	843	922	958	986	1,060	1,110	1,148
Production by Region and Type of Mining								
East of Mississippi								
Surface	226	221	198	207	214	202	212	219
Underground	282	350	426	443	457	496	519	538
Total	507	571	624	650	670	698	731	758
West of Mississippi								
Surface	256	302	360	370	378	422	432	440
Underground	19	26	35	37	38	52	58	61
Total	275	328	395	407	416	473	490	501
U.S. Total								
Surface	482	523	558	577	591	624	644	659
Underground	300	376	461	480	494	548	577	599
Total Production	782	899	1,019	1,057	1,086	1,172	1,221	1,259

[a]Residential and commercial sectors.

Note: Numbers may not add to totals due to independent rounding.

Source: • History: Energy Information Administration, Quarterly Coal Report, DOE/EIA-0121(84/2Q) (Washington, DC, 1984). • Projections: Appendices A, B, C; Tables A18, B18, C18.

Coal Transportation

Transportation is an important factor in determining the types and sources of coal to be used. Different types of coal are concentrated in different regions of the country, and the Btu, sulfur, ash, and moisture content of different coals vary widely. Because a large amount of coal is required to fuel a power plant and because coal reserves and mining operations are generally distant from industrial sites and power plant locations, transportation costs are of utmost concern to coal users. For example, in 1983 the average minemouth price of coal was $25.98 a ton,[1] while the average price of coal delivered to electric utilities was $34.99 a ton.[2]

About 59 percent of the coal shipped to consumers in the United States in 1983 was transported by rail, 16 percent by water, and 14 percent by truck. Since the enactment of the Staggers Rail Act of 1980, which essentially deregulated railroad rates, the railroad industry has moved toward financial stability. However, the Act also makes the future of coal transportation rates uncertain. Under the current interpretation of the Act by the Interstate Commerce Commission (ICC), railroads are allowed to increase their rates up to 15 percent per year, in real terms, until they reach revenue adequacy.[3] At the same time, the Act also allows railroads to charge less than they are currently charging, without approval from the ICC, in order to compete more effectively with one another and with other modes of transportation.

Because these options are open to railroads, future rail rates are uncertain, and the regional levels and patterns of coal production projected for the base case are also uncertain. The impact on coal production of high and low rail transportation rates is analyzed to provide a range of forecasted regional coal production. This scenario analysis must be qualified in that it is performed under the assumption that the level of coal demand in thermal values obtained for the base case remains unchanged. Also, this analysis assumes the type of coal demanded and the contract purchases of coal represented in the base case are unchanged.

Between 1974 and 1984 rail rates increased by 26 percent in real terms. This increase was due to rising world oil prices, rail track rehabilitation, and the increase in the demand for coal-hauling services. In the base case, rail rates are estimated to increase by approximately 20 percent in real terms between 1985 and 1995. Increases in world oil prices and the cost of rehabilitating rail tracks are assumed to contribute about 62 percent of the real increase in total rail rates over this period. In the high and low railroad rate cases, unit train rates are estimated to increase in real terms by approximately 63 and 6 percent, respectively, between 1985 and 1995. In the high rail rate case, world oil prices and the cost of rehabilitating rail tracks are assumed to contribute 83 percent of the total rail rate increase in real terms; they are assumed to not affect rail rates at all in the low railroad rate case.

Low rail rates are expected to increase the demand for western subbituminous coal. This coal is less expensive to mine than eastern bituminous coal, although it has a lower Btu content. Ordinarily, high-Btu bituminous coal is more economical to

---

[1]Energy Information Administration, Coal Production--1983, DOE/EIA-0118(83) (Washington, DC, 1984).

[2]Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants, 1983, DOE/EIA-0191(83) (Washington, DC, 1984).

[3]Revenue adequacy refers to the ability of a railroad to earn enough profit to attract new capital and remain a viable entity. The ICC estimated that national average rail rate increases above the current rates (in real terms) of 29 percent by 1985, 71 percent by 1990, and 90 percent by 1995, would be sufficient to ensure revenue adequacy.

transport than is low-Btu subbituminous coal, because fewer tons are required for a given energy demand. However, when transportation rates are lower, it can become more economical for some eastern markets to use western subbituminous coal.

This analysis projects some regional shifts in coal production (Table 34). Under the low rail rate case, mines west of the Mississippi River will produce more coal than under the base case at the expense of mines east of the Mississippi River. Under the high rail rate case, the reverse is projected. The magnitude of the regional shifts under the low case, however, is negligible: an increase of 1.3 million short tons from western mines and a decrease of 0.5 million short tons from eastern mines are projected. In the high rail rate case, a decrease of 8.1 million short tons from western mines is projected to be accompanied by an increase of 5.0 million short tons from eastern mines. The analysis also shows a slight change in tonnage of total U.S. coal production. This is due to a trade-off between high-Btu eastern coal and low-Btu western coal for a given level of coal demand in thermal values. Another result of varying the rail rates is a projected shift between rail and water of about 3 percent of the total market in the low rail case and about 7 percent in the high rail case. Railroads are projected to increase their total ton-miles in the low rail rate case and decrease total ton-miles in the high rail rate case.

Table 34. Changes in Regional Coal Production from Base Case with Low and High Railroad Rates, 1995
(Million Short Tons)

Region	Low Rates	High Rates
Northern Appalachia	1.1	-1.5
Central Appalachia	2.8	-5.8
Southern Appalachia	-2.3	4.5
Midwest	-2.1	7.8
East of Mississippi River	-0.5	5.0
West Interior	-1.3	0.6
North Great Plains	4.9	-21.0
Rockies and Southwest	-2.0	9.9
Northwest and Alaska	-0.3	2.3
West of Mississippi River	1.3	-8.1
United States	0.8	-3.1

Note: Numbers may not add to totals due to independent rounding.
Source: Appendix G, High Coal Rail Rates case and Low Coal Rail Rates case.

Coal Mining Labor Productivity

Labor productivity in U.S. coal mining has varied significantly over the past 35 years. The average tonnage produced per miner-hour in all mines increased by 6.2

percent per year from 1949 to 1969, decreased by 3.4 percent per year from 1969 to 1978, and then increased by 4.5 percent per year from 1978 to 1982 (Table 35).

Table 35. Labor Productivity in Coal Mining, 1949-1983
(Average Short Tons per Miner per Hour)[a]

Year	Bituminous Coal and Lignite Mines[b] Underground	Surface	Average	Anthracite Mines Average	All Mines Average
1949	0.68	1.92	0.80	0.36	0.72
1969	1.95	4.50	2.49	0.93	2.41
1973	1.46	4.58	2.20	0.89	2.16
1978	1.04	3.03	1.79	0.81	1.77
1982	1.37	3.48	2.14	0.59	2.11
1983	1.62	3.87	2.52	1.01	2.50

[a]For the years 1949 through 1973 and for anthracite in 1978, an 8-hour miner work day is assumed.

[b]Includes subbituminous coal.

Source: • 1949-1973 and 1978 anthracite: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) (Washington, DC, 1984); • 1978: Energy Information Administration, Bituminous Coal and Lignite Production and Mine Operations--1978, DOE/EIA-0118(78) (Washington, DC, 1980); • 1982: Coal Production--1982, DOE/EIA-0118(82) (Washington, DC, 1983); • 1983: Coal Production--1983, DOE/EIA-0118(83) (Washington, DC, 1984).

From 1982 to 1983, the average productivity per miner-hour in all mines increased by about 18 percent, primarily because of curtailed production from smaller and less productive mines in response to depressed market conditions. The degree to which this current increase will be sustained as the coal market recovers is uncertain. This section discusses some of the possible reasons for these trends and the results of an analysis that assumes productivity in underground mines to rise faster than productivity in surface mines.

The increase in productivity from 1949 to 1969 was primarily due to the mechanization of the coal mining process and the increased production from surface mines. During this period, conventional underground mining and continuous mining largely displaced manual cutting and loading. In surface mining, the size of single units of equipment, such as trucks and drag lines, increased substantially. Since 1949, the increasing share of production from surface mines has contributed substantially to the overall increase in productivity. Average surface mine productivity has been two to three times that of underground mines since 1949. Most of this shift toward surface mining occurred in mines east of the Mississippi. The rapid growth of western surface mining began only in 1969. The decrease in productivity from 1969 to 1978 resulted from a series of exogenous factors that outweighed the effects of the continued shift toward surface mining in the East and the rapid growth of highly productive western surface mining. Two studies on coal mine labor productivity from 1950 through 1977 cited several factors that contributed to reduced labor productivity during the 1970's.[4]

The factors cited in the decline in underground mining productivity are:

- The Coal Mine Health and Safety Act of 1969 tended to reduce the actual mining time of each operating section and increase the number of personnel.

- Wage agreements with the United Mine Workers provided for job bidding and additional personnel.

- The surge in coal prices between 1973 and 1975 made productivity a matter of secondary concern.

- Inflated expectations for coal demand resulted in the opening of new mines, which are normally less productive than established mines.

- Strikes became more frequent.

The factors cited in the decline in surface mining productivity are:

- State regulations required extensive reclamation.

- Significant increases in coal prices made productivity improvements less important.

Since 1978, average labor productivity at U.S. bituminous coal and lignite mines, in short tons per miner-hour, has increased for both underground and surface mines (Table 36). Average productivity in underground bituminous coal and lignite mines increased 32 percent from 1978 to 1982 and another 18 percent from 1982 to 1983. The increase in underground mining productivity was significant in both the East and West, with all major underground mining states realizing an increase.

In contrast, surface bituminous coal and lignite mine productivity in the East improved 0.9 percent from 1978 to 1982 and 6.5 percent from 1982 to 1983, while western productivity increased 15 percent and 9.7 percent, respectively, for the same time periods. In the East and West, productivity improvements in some States were offset by declines in other States. For example, Wyoming's productivity increased 44 percent from 1978 to 1983, while that of Texas decreased 28 percent.[5]

---

[4] U.S. Department of Energy, Analysis of the Labor Productivity Decline in the U.S. Bituminous Coal Mining Industry, DOE/ET/10033-T1 (Washington, DC, 1981); Comptroller General of the United States, Report to the Congress, Low Productivity in American Coal Mining: Causes and Cures, EMD-81-17 (Washington, DC, 1981).

[5] For 1978 data, see Energy Information Administration, Bituminous Coal and Lignite Production and Mine Operation--1978, DOE/EIA-0118(78) (Washington, DC, 1980). For 1983 data, see Energy Information Administration, Coal Production--1983, DOE/EIA-0118(83) (Washington, DC, 1984).

Both Wyoming and Texas increased production by over 90 percent over this period. Wyoming's increase in production was primarily from the major reserves of the highly productive Powder River Basin. In contrast, Texas, which has a much smaller reserve base, appears to be expanding production under increasingly difficult conditions.

Table 36. Labor Productivity in Bituminous Coal and Lignite Mines by Region and Type of Mining, 1978-1983
(Average Short Tons per Miner-Hour)

Region/Type of Mining	1978	1982	1983
East of the Mississippi			
Underground	1.02	1.33	1.58
Surface	2.28	2.30	2.45
Total	1.44	1.64	1.88
West of The Mississippi			
Underground	1.09	1.88	2.28
Surface	6.08	7.00	7.68
Total	4.42	5.58	6.61
Total United States			
Underground	1.04	1.37	1.62
Surface	3.03	3.48	3.87
Total	1.79	2.14	2.52

Source: • 1978: Energy Information Administration, Bituminous Coal and Lignite Production and Mine Operations--1978, DOE/EIA-0118(78) (Washington, DC, 1980). • 1982: Coal Production--1982, DOE/EIA-0118(82) (Washington, DC, 1983). • 1983: Coal Production--1983, DOE/EIA-0118(83) (Washington, DC, 1984).

The gradual decrease in the average real minemouth price of coal from 1974 to 1982 and the sharp decrease in 1983 have probably forced marginal producers out of the market and reestablished productivity as a major consideration in mine management. The Federal Surface Mining Control and Reclamation Act of 1977 probably contributed to the slower increase in surface mine productivity since 1978, but other factors, such as increased overburden ratio, also might have been involved. Overall, the improvements in underground mine productivity since 1978 have been more widespread than the improvements in surface mine productivity, especially in the East, where more than 90 percent of underground coal is produced. To measure the potential impact of changes in labor productivity on coal production patterns and minemouth prices, underground mine productivity was assumed to increase 2.0 percent per year above the level of productivity assumed in the base case. This assumption reduces the price of underground-mined coal from that in the base case, because the minemouth price of coal is assumed to be determined by mining cost, which in turn is affected by productivity. The demand for coal (in Btu) in the high productivity case is the same as in the base case; therefore, only the sources of supply are allowed to change in response to changes in price.

The increased underground productivity shifts 83 million short tons (more than 10 percent) of projected base case eastern production in 1995 from surface to underground mines.[6] In the West, surface production is projected to be 28 million short tons lower than the base case and underground production is projected to be 21 million short tons higher. The variance between the increase and decrease is due to the shift from a low-Btu coal to a high-Btu coal, which requires less tonnage to meet the same Btu demand. The increase in productivity also reduces the projected U.S. average minemouth price of coal in the base case in 1995 by 5.0 percent.

Coal Exports and Imports

World coal trade increased significantly between 1979 and 1981, following the crude oil price increases of the Organization of Petroleum Exporting Countries (OPEC). During this period, world coal trade rose rapidly, reflecting increased steam coal demand in Western Europe and Asia. Since 1981, however, stable or declining oil prices and a worldwide economic recession have dampened the prospects for a rapid expansion of world coal trade. Although growth in steam coal consumption is still expected, that growth is likely to be slower than was previously envisioned.

World coal trade is projected to rise from the 1983 level of 284 million short tons to 428 million short tons in 1995--an increase of 51 percent, or an average annual increase of 3.5 percent (Table 37). During this period, world coal trade is projected to grow primarily in the steam coal market, in response to rising coal demand by electric utilities and industrial users in Western Europe and Asia.

World steam coal trade, which was 141 million short tons in 1983, is projected to almost double by 1995. The United States, Australia, South Africa, and Poland are expected to remain the major suppliers through 1995. World metallurgical coal trade, which was 143 million short tons in 1983, is projected to rise to 166 million short tons in 1995, as the steel industries in the major industrial countries recover from economic recession and the steel industries in developing countries (for example, Brazil and South Korea) continue to expand. The United States, historically, has been the largest supplier of metallurgical coal in the world market. Although the other major suppliers of metallurgical coal (Australia and Canada) have expanded their shares of the Asian market since the 1960's, the United States is, and is projected to remain, the largest exporter of metallurgical coal, increasing its exports to both Western Europe and the developing countries.

Coal Exports

Total U.S. coal exports are expected to recover from the depressed levels of 1983, reaching 91 million short tons in 1990 and 106 million short tons in 1995. The United States is expected to remain a major participant in the world coal market

---

[6] See Appendix G, High Labor Productivity in Underground Coal Mines case.

due to consumer concerns regarding supply reliability, supply diversification, balance of trade issues, and bilateral trade agreements. Although the strength of the U.S. dollar in foreign exchange markets hinders the competitiveness of U.S. coal exports, the value of the dollar in the long term is expected to return to a level that would not penalize U.S. exporters.

Table 37. World Coal Exports, 1983-1995
(Million Short Tons)

Exporters	History 1983	Projections 1990	Projections 1995
Steam Coal			
United States	28	37	50
Others	113[a]	170	211
Total	141[a]	207	262
Metallurgical Coal			
United States	50	54	55
Others	93[a]	100	111
Total	143[a]	155	166
Total Coal			
United States	78	91	106
Others	206[a]	270	322
Total	284[a]	362	428

[a]Preliminary.

Note: Numbers may not add to total due to independent rounding.

Source: • 1983 U.S. Exports: Energy Information Administration, Weekly Coal Production, DOE/EIA-0218(84/08) (Washington, DC, 1984), Table 9, p.9. • 1983 Non-United States and Total: SRI International, "International Coal Trade: Historical Trade Flows and Projected Coal-Import Demands" (Menlo Park, CA, 1984). • Projections: Energy Information Administration, International Coal Trade Model projections (Washington, DC).

The major uncertainty affecting the outlook for world coal trade is that of the world economic recovery and its effect on the relative energy prices. The rate of economic growth affects demand for steel and electricity (the major end products requiring coal) and therefore is the primary influence on the demand for coal in the coal-importing countries. A reduced differential between coal prices and oil prices could delay the development of coal markets by eliminating the incentive to substitute coal for oil. Conversely, an increased differential between coal prices and oil prices could lead to increased use of coal. A second uncertainty concerning the outlook for world coal trade is the environmental aspects of coal use and the costs of compliance with environmental standards. Whether environmental protection measures will be relaxed or tightened remains uncertain.

Projections of demand for coal imports are based on assumptions about the factors that influence each country's coal consumption (for example, degree of dependence on imported energy supplies, emphasis on diversity of fuels in electricity generation, and government policy regarding nuclear generation), as well as the level of indigenous coal production. These assumptions will be discussed in detail in a forthcoming EIA report entitled Annual Prospects for World Coal Trade, 1985.

Coal Imports

Imports represent a very small component of the U.S. coal supply. From 1974 through 1983, imports of coal averaged about 1.5 million short tons per year, and reached a peak of 3.0 million short tons in 1978 because of a U.S. miners' strike in that year. In 1982, U.S. coal imports declined to 0.7 million short tons, but rose in 1983 to 1.3 million short tons.[7]

Coal is imported largely to the Southeast Region of the United States--a region with expensive ($18 to $22 per short ton)[8] transportation links to the Appalachian coal-producing areas. The United States imports coal primarily from South Africa, Canada, and Poland. Coal imports from Colombia began in 1983 and may increase because of Colombia's relative proximity to the southeastern United States.

Emerging Clean-Coal Technologies

Emerging clean-coal technologies--in coal preparation, in stack gas scrubbing, and in combustion/utilization processes--could encourage the use of coal in environmentally sensitive markets in this country and abroad. Following is a summary of some of these technologies.

Coal Preparation

Coal-cleaning research is directed toward methods of achieving efficient, pollution-free combustion. To remove more than 75 percent of the impurities that degrade the environment when coal is burned, advanced techniques of cleaning coal are being tested, including fine grinding, froth flotation, oil agglomeration, and high gradient magnetic separation. Recently the Electric Power Research Institute (EPRI) and the Department of Energy (DOE) signed a 3-year agreement to test methods for reducing impurities from coal at the Pennsylvania Electric Co.'s Homer City plant. Also, the General Electric Co. and TRW, Inc. are testing processes that have proved successful in removing up to 90 percent of total impurities. These processes

---

[7] Energy Information Administration, Weekly Coal Production, DOE/EIA-0218(84/40) (Washington, DC, 1984), Table 15.

[8] "Some Southern Utilities Find it Cheaper to Import Coal," Coal Age (May 1984).

chemically release the impurities and form water-soluble substances that can be washed out of the coal. DOE recently selected TRW, Inc. to design and build a continuously fed microwave oven for scale-up operations.

Flue Gas Desulfurization (FGD)

FGD has become more significant over the past decade. Systems hardware has been simplified, corrosion-resistant alloys have been developed, and methods to convert scrubber sludge into commercial products have proven successful. Spray-dryer units (which permit easy handling of a dry-reaction product, decrease water consumption, eliminate reheating, and reduce corrosion) have been sold to plants of up to 600 megawatts where western low-sulfur coal is used. Test results have proven their potential to remove over 90 percent of sulfur dioxide (SO_2) in high-sulfur coal combustion. Current research focuses on scrubber techniques that remove 90 percent of both SO_2 and nitrogen oxide (NO_x) from stack gases. To bring improved FGD's online more quickly, a recent Government/ industry initiative[9] called for a more modest, retrofitable, and cheaper scrubber that removes only 50 percent of the undesirable emissions.

Fluidized Bed Combustion

Fluidized bed combustors (FBC's) are capable of removing 90 percent of SO_2 and holding NO_x to below standards. By suspending a burning mixture of coal and limestone on upward-blowing jets of air, FBC's increase heat transfer rates over conventional boilers, provide even temperatures that eliminate boiler damage, burn wet and low-quality coal efficiently, and avoid slagging of boiler surfaces with melted ash by operating at low temperatures. FBC's are commercially available and economically competitive for midsized industrial boiler applications.

A Tennessee Valley Authority (TVA)/EPRI 160-megawatt demonstration FBC is scheduled to begin operation in 1989. The Northern States Power Company is retrofitting its 85-megawatt Black Dog Unit in Burnsville, Minnesota, with an atmospheric FBC to reduce polluting emissions and increase its output to 125 megawatts. EPRI has identified about 200 utility units that could benefit from this type of retrofit. In addition, the American Electric Power Company--one of several U.S. firms testing pressurized FBC's--is planning a 70-megawatt demonstration unit at its Tidd power plant near Brilliant, Ohio.

Coal-Liquid Mixtures

Mixing coal with various liquids (for example, oil, water, methanol, and ethanol) offers the potential for expanding its use in oil and natural gas

---

[9]Hodel, Donald P., U.S. Department of Energy, Remarks before the Mining and Reclamation Council of America (Washington, DC, March 12, 1984).

markets. Ready-mixed coal-oil slurries, which contain pulverized coal in proportions of up to 50 percent by weight, are commercially available today for industrial burners and for testing in electric power plants. Coal-water mixtures--economically more attractive than coal-oil slurries--contain up to 70 percent of finely ground coal, and can be handled much like coal-oil mixtures. Developments in stabilization chemistry enable the coal particles to remain suspended or evenly mixed. Coal-water slurry testing in small burners has shown promising results, leading to scale-up studies of combustion characteristics in large-quantity, continuous operations.

Gasification/Combined Cycle

The Nation's first full-scale power plant based on coal gasification, the Cool Water Project (located in Daggett, California), went online in June 1984. The 100-megawatt gasification/combined cycle unit converts coal to pollution-free, hot synthesis gas, which fuels a combustion turbine, and also heats a steam turbine. Designed for efficiency and economy, the unit also produces usable sulfur instead of sludge. If the 5-year project demonstrates economic, environmental, and operational feasibility at a commercial scale, additional gasification/combined cycle plants may come online in the early 1990's.

Other advanced concepts include magnetohydrodynamics (MHD), phospheric acid and molten carbonate fuel cells, and fuel gas. In MHD research, DOE recently increased its cost-sharing programs with industry, which could lead to an integrated, coal-fired, MHD retrofit in 5 years. Synthetic fuels development has slowed in recent years because costs of alternative fuel resources in the near term have been lower than anticipated, costs of developing the technologies are relatively high, and raising the large capital sums required during a period of high interest rates has been difficult.

9. Forecast Comparisons

Forecasts of energy supply and demand may differ for many reasons. Much of the variation can be attributed to differences in underlying assumptions concerning future world oil prices, economic growth rates, demand elasticities, and other key determinants of supply and demand. Differences in analytical approaches and in the structures of the models used for forecasting also result in different sets of projections, although their implications are more difficult to detect and quantify. Additional deviations may arise from differences in definitions, in conversion factors, and in the timing of the analysis.

The projections presented in this Annual Energy Outlook reflect EIA's current understanding of world and domestic energy markets and changes that are likely to evolve in the future. These projections have been updated from those in the 1983 Annual Energy Outlook based on the continued downward trend in world oil prices, the strong economic recovery, and other changes that have occurred in the interim. This chapter presents a comparison of the 1984 EIA base case with the 1983 Annual Energy Outlook base case and other widely used energy forecasts. The alternative forecasts considered for this report include those published by the three principal, private economic forecasting groups: Data Resources, Inc.; Chase Econometric Associates, Inc.; and Wharton Econometric Forecasting Associates.[1] These forecasts were selected for comparison because they are broad enough in scope to cover the major energy supply and demand sectors, plus they are widely circulated and well documented. A limited number of projections developed by other public and private groups also are compared to the 1984 Annual Energy Outlook to provide additional perspective on market expectations. The sources for the other projections include the North American Electric Reliability Council, the National Coal Association, and several major oil companies. This chapter focuses on 1990 as a reference point, principally because several of the forecasts considered for comparison do not extend through to 1995.

Base Case Projections for International Energy Markets

Energy demand in the market economies is forecast to grow moderately through 1995.[2] In the 1984 Annual Energy Outlook, EIA projects a slight increase in total energy consumption, but a slight decline in both world oil demand and production relative to the forecast published in last year's report. The world oil price path is considerably lower in this year's Annual Energy Outlook, corresponding to a general downward trend in price expectations among the industry experts.

---

[1] Energy Review, Data Resources, Inc. (Lexington, MA, Autumn 1984); Energy Analysis Quarterly, Chase Econometric Associates, Inc. (Bala Cynwyd, PA, Third Quarter 1984); Wharton Long-Term Forecast, Wharton Econometric Forecasting Associates (Philadelphia, PA, September 1984).

[2] The market economies include all countries other than the Centrally Planned Economies of Eastern Europe, the Soviet Union, China, Cuba, Kampuchea, North Korea, Laos, Mongolia, and Vietnam.

Market Economy Demand and Supply Projections

This report's base case projects energy consumption in the market economies of 228 quadrillion Btu by 1990, about 1 percent more than the amount projected in the 1983 report (Table 38). Most of this increase is projected to occur in the United States and in the European members of the Organization for Economic Cooperation and Development (OECD), corresponding to upward revisions in assumed economic growth rates. For the United States, economic growth between 1985 and 1995 is assumed to average 2.7 percent per year in the 1984 Annual Energy Outlook, compared to 2.6 percent in the earlier report. For OECD Europe, annual increases in economic activity currently are assumed to average 2.1 percent per year, up from 1.7 percent per year projected in the 1983 Annual Energy Outlook.

Although the projection for total energy consumption is slightly higher in the 1984 Annual Energy Outlook relative to the 1983 edition, petroleum demand is projected to grow at essentially the same rate. The significant drop in the assumed world oil price for 1990 from 38 dollars (1984 dollars) in the 1983 Annual Energy Outlook to 30 dollars in the 1984 report is not expected to have much influence on total energy demand. The limited response in demand to lower prices is attributable to the fuel-switching and conservation measures that have been undertaken and that are ongoing in the industrialized countries. An additional factor constraining growth in oil demands in the 1984 report is the assumption of lower economic growth in the developing countries over the projection period. The combination of lower prices with slower economic growth results in no net change between the 1983 and 1984 Annual Energy Outlook projections for oil consumption by the other countries.

Oil production in the market economies through 1995 is projected to be slightly lower in this year's report than in the 1983 Annual Energy Outlook. Lower levels of production from the United States are expected to be partially offset by increased production from OPEC, particularly during the 1990 to 1995 period. OPEC is expected to provide any marginal increase in oil production because many non-OPEC countries already are producing at capacity and because new discoveries in these areas are expected to replace only a portion of the oil reserves that are produced.

The 1984 EIA base case projections and the projections from other organizations for energy supply and demand in the market economies are shown on Table 39. For purposes of comparison, certain projections were converted from their originally published units to million barrels per day of oil-equivalent. The EIA projection for total energy consumption is at the low end of the range in 1985, but falls within the range established by the other projections in 1990 and 1995. Projections of oil consumption and production are similar among the various studies, with the EIA estimates for 1990 falling in the middle of the range.

World Oil Price Assumptions

The 1984 Annual Energy Outlook assumes essentially no increase in real terms in the world crude oil price by 1990. This assumption has been lowered significantly from the 1983 report, despite the fact that oil consumption and production projections for the market economies as a whole have changed little between the 1983 and 1984 editions of the Annual Energy Outlook. Downward revisions in oil price expectations are based on recent events in the world oil market, as well as the general perception that countries with large oil reserves, such as Saudi Arabia, will pursue a course of action to maintain stable markets for their oil over the longer term. Furthermore, the 1984 Annual Energy Outlook oil price path is based on the assumption that the Organization of Petroleum Exporting Counties (OPEC) will expand production capacity at a more rapid rate than assumed for the 1983 Annual Energy Outlook.

Table 38. Comparison of 1983 and 1984 AEO Energy Projections for the Market Economies, 1990

Market Economies	AEO 1984	AEO 1983
	(quadrillion Btu)	
Energy Consumption		
United States	84	82
Japan	18	18
OECD Europe	59	58
Other Countries	67	67
Total	228	225
	(million barrels per day)	
Petroleum Consumption		
United States[a]	17.0	16.9
Japan	4.8	5.0
OECD Europe	12.6	13.1
Other Countries	15.9	15.8
Total	50.3	50.9
	(million barrels per day)	
Petroleum Production		
OPEC	23.5	23.5
United States	10.3	10.9
Other Non-OPEC	15.8	15.8
Total	49.6	50.2
Imports from CPE[b]	1.0	1.0
Total Available Supply	50.6	51.2

[a]Includes Puerto Rico and the Virgin Islands.
[b]CPE = Centrally Planned Economies.
Note: Columns may not add to totals because of independent rounding. Oil stock additions are projected at 0.3 million barrels per day in both reports.
Source: Energy Information Administration, Annual Energy Outlook, 1983, DOE/EIA-0383(83) (Washington, DC, 1984).

Table 39. Comparison of Energy Projections for the Market Economies, 1985, 1990, and 1995
(Million Barrels per Day of Oil-Equivalent)

Projection	Consumption		Production		CPE Net Oil Exports
	Energy	Oil	OPEC	Other	
1982 Actual	93	46	20	23	1.7
1985 Projections					
1984 AEO	98	46	19	26	1.8
IEA Paris (September 1984)	NA	46	19	25	1.0-1.7
DRI (Autumn 1984)	NA	47	20	24	2.0
Ashland (June 1984)	102	47	20-21	24-25	1.0-1.5
Chevron (June 1984)	100	47	22	25	NA
Conoco (April 1984)	98	46	19	26	1.0
1990 Projections					
1984 AEO	111	50	24	26	1.0
IEA Paris (July 1984) ...	NA	49	24	25	0.5
DRI (Autumn 1984)	NA	50	24	25	1.1
Ashland (June 1984)	115	51	23-26	23-26	1.0-1.5
Chevron (June 1984)	113	49	23	25	NA
Conoco (April 1984)	108	48	22	25	1.0
1995 Projections					
1984 AEO	122	53	26	26	0.5
IEA Paris (July 1984) ...	NA	53	29	26	0.0
DRI (Autumn 1984)	NA	53	29	25	0.3
Chevron (June 1984)	126	52	26	25	NA
Conoco (April 1984)	118	51	26	25	0.0

NA = Not available.

Note: The market economies exclude the Centrally Planned Economies of Eastern Europe, the Soviet Union, China, Cuba, Kampuchea, North Korea, Laos, Mongolia, and Vietnam. Oil consumption and production numbers may not balance because of rounding. Includes natural gas liquids.

Source: • International Energy Agency (IEA), 1985: Monthly Oil Report (Paris, France, 1984). • IEA, 1990 and 1995: Energy Policies and Programmes of IEA Countries, 1983 Review (Paris, France, 1984). • Chevron Co.: World Energy Outlook (San Francisco, CA, 1984). • Data Resources, Inc.: International Energy Bulletin (Lexington, MA, 1984). • Conoco: World Energy Outlook Through 2000 (Wilmington, DE, 1984). • Ashland: World Energy Outlook Through 1990 (Ashland, KY, 1984).

Different world oil price paths are associated with each of the different consumption and production forecasts presented in Table 39. While all of the projections are based on the assumption that the world crude oil price will rise by the end of the decade, differences arise with respect to whether prices are expected to decline in real terms in the interim, when price pressures will start to be felt, and how rapidly prices will increase.[3] The Chevron forecast assumes that crude oil prices will remain flat in real terms through the 1980's, then rise faster than inflation during the 1990's. Conoco suggests that further price declines may occur in the near term, with moderate real price increases possible during the second half of this decade. Ashland assumes that the price of Arab light remains close to 29 dollars per barrel until early 1987 and then increases gradually through 1990 at about 70 percent of the rate of inflation. DRI assumes the lowest crude oil prices of the projections presented in Table 39, corresponding to expectations of high levels of production in the OPEC countries.

Base Case Projections for Domestic Energy Supply and Demand

The general consensus among the energy projections shown in Table 40 is that there will be a substantial increase in the total amount of energy supplied to U.S. consumers, from 71 quadrillion Btu in 1983 to more than 80 quadrillion Btu in 1990. Out of this total, end-use energy consumption is projected to increase from 53 quadrillion Btu in 1983 to about 60 quadrillion Btu in 1990. The overall increase in end-use consumption over time reflects expectations of considerable growth in demand in the industrial and commercial sectors, with more modest growth in residential and transportation uses.

Domestic crude oil and natural gas production is expected to remain fairly constant through 1990, while coal and nuclear power will be responsible for the increase of close to 9 quadrillion Btu in total domestic output. As energy consumption is forecast to grow more rapidly than production, imports are projected to rise by several quadrillion Btu relative to 1983 levels.

Assumptions for Major Determinants

Differences in projections of energy supply and demand can be attributed to a considerable extent to differences in assumptions about world oil market developments, economic growth, and a wide range of other factors. Projections for the principal economic determinants of U.S. energy demand are presented in Table 41, along with midrange estimates for the world oil price.

Growth in economic activity, as measured by GNP, is expected to average close to 3.5 percent per year from 1983 to 1990. The 1984 Annual Energy Outlook and the DRI projections are based on essentially the same long-term economic projection, with minor differences attributable to world oil price assumptions and to the time periods during which the analyses were performed. The Wharton forecast falls on the low side of the range, primarily because of the expectation of a more dramatic slowdown in economic growth during the latter part of the decade than indicated by the Chase and DRI forecasts.

---

[3]Note that all of the forecasts were prepared before the series of OPEC price breaks, which began in October 1984.

Table 40. Comparison of Base Case Energy Supply and Demand Projections, 1990 (Quadrillion Btu per Year)

	AEO 1984	AEO 1983	DRI	Chase	Wharton[a]
Domestic Energy Supply					
Oil	19.7	20.8	20.1	19.2	19.1
Natural Gas	17.8	16.7	17.3	17.1	17.6
Coal	23.3	23.1	22.6	22.9	22.4
Hydroelectric/Geothermal/ Other	3.4	3.3	3.8	3.6	3.7
Nuclear Power	6.3	6.3	6.1	6.7	6.0
Total	70.5	70.3	69.9	69.5	68.8
Net Imports					
Oil	13.9	12.6	13.1	13.5	14.2
Natural Gas	1.9	1.3	2.2	1.8	0.9
Coal, Coke, and Electricity	-1.7	-2.4	-1.8	-1.9	-2.8
Total Available Supply[b]	83.5	81.7	82.5	83.0	80.8
End-Use Consumption[c]					
Residential	9.4	9.2	9.1	9.8	NA
Commercial	6.9	7.1	6.6	6.7	NA
Industrial	25.4	22.9	24.0	23.7	NA
Transportation	18.6	19.5	19.4	19.5	NA
Total	60.3	58.7	59.1	59.7	NA

NA = Not available.
[a]End-use consumption forecasts are not available.
[b]Total available supply is defined to include domestic production plus net imports, stock changes, and other adjustments.
[c]Does not include utility generation and transmission of electricity, refinery and pipeline fuels, and SPR additions. Lease and plant fuel is included under industrial consumption.
Source: Energy Information Administration, Annual Energy Outlook, 1983, DOE/EIA-0383(83) (Washington, DC, 1984); Data Resources, Inc., Energy Review (Lexington, MA, Autumn 1984); Chase Econometric Associates, Inc., Energy Analysis Quarterly (Bala Cynwyd, PA, Third Quarter 1984); Wharton Econometric Forecasting Associates, Wharton Long-Term Forecast (Philadelphia, PA, September 1984).

DRI, Chase, Wharton, and EIA all assume that the real world oil price will decline through 1986. Oil prices are expected to pick up again toward the end of the decade, and to continue to rise in real terms in the 1990's. The significant drop from the 1983 Annual Energy Outlook world price assumption to that in the 1984 report reflects expectations of greater OPEC production capacity, slower economic growth outside the United States, and lower energy requirements per unit of output than previously forecast. These expectations are supported by the most recently available data and by the fact that international oil markets have remained soft through 1984.

Demand Projections

The 1984 Annual Energy Outlook projects a decline in the energy/GNP ratio from 45.7 thousand Btu per 1972 dollar of GNP experienced during 1983 to 42.4 thousand Btu per dollar in 1990 (Table 42). This drop can be attributed in large part to expected improvements in efficiency as equipment is retrofitted or replaced over time. The other forecasts for the energy/GNP ratio fall in a close range around 42 thousand Btu per 1972 dollar of GNP (Figure 31). These forecasts all reflect the perception that the rapid declines in the energy/GNP ratio experienced during the 1970's are not likely to continue in the future. By 1995, the 1984 Annual Energy Outlook base case projection for the energy/GNP ratio is 40.9 thousand Btu per dollar, compared to 39.7 and 39.5 thousand Btu per dollar for DRI and Chase, respectively. EIA's slightly higher projected energy/GNP ratio reflects an assumed GNP level slightly lower than the others and an energy demand forecast close to 2 percent above the others. Higher expected rates of growth in industrial demand explain much of the difference between EIA's aggregate energy demand forecast and DRI's and Chase's.

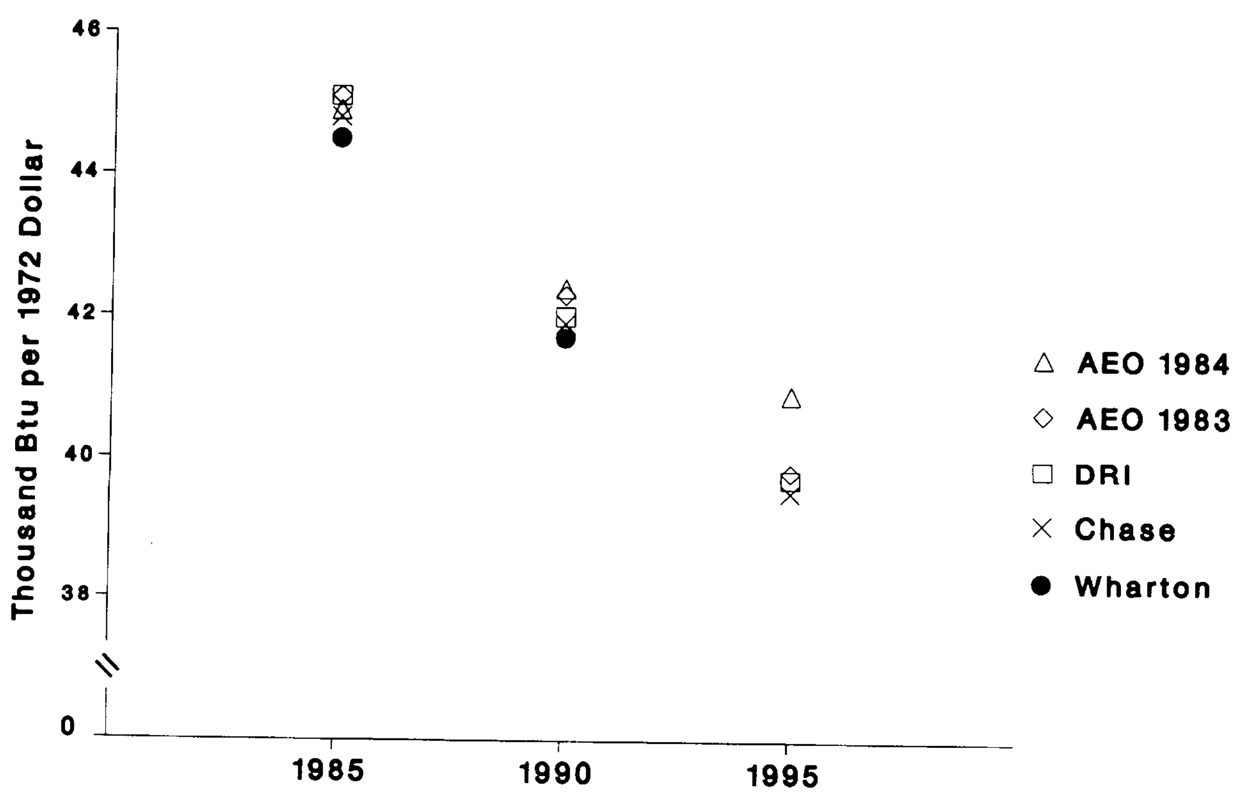
Forecasts of future energy requirements by the residential and commercial sectors generally indicate modest growth, with only electricity consumption showing any significant gains relative to 1983 levels. Projected average annual growth in electricity demand of close to 3 percent over the rest of the decade corresponds to expectations of essentially constant electricity prices, compared to more significant price increases forecast for natural gas.

For the industrial sector, the 1984 Annual Energy Outlook projects energy demand to rise by as much as 30 percent by 1990 from the 20 quadrillion Btu consumed in 1983. EIA's projection for total industrial demand is somewhat higher than DRI's or Chase's, with the difference essentially attributable to significant growth in demands for middle distillates and for liquefied petroleum gases projected in the 1984 Annual Energy Outlook.

In this report, transportation energy demand is projected to increase by less than 1 percent per year between 1983 and 1990. This increase is the net result of a 3.9-percent rise in miles traveled combined with an increase in passenger-car efficiency from 16.5 miles per gallon in 1983 to 22.1 miles per gallon in 1990. The projection in this report for average miles per gallon, which is based on the most recent new car sales data, is slightly lower than that used for the 1983 report. The EIA projection for transportation energy use is considerably lower than the others presented in Table 42.

Demand for electricity is projected to continue to grow in all end use sectors, particularly in the industrial sector. Residential and commercial electricity use is projected to grow less rapidly, by close to 3 percent per year. In order to meet this demand, electric utilities are forecast to consume between 30 quadrillion Btu and 32 quadrillion Btu of energy in 1990, with the 1984 Annual Energy Outlook projection falling in the middle of this range.

Figure 31. Forecast Comparison of the Energy/GNP Ratio, Selected Years



Source: Energy Information Administration, Annual Energy Outlook, 1983, DOE/EIA-0383(83) (Washington, DC, 1984); Data Resources, Inc., Energy Review (Lexington, MA, Autumn 1984); Chase Econometric Associates, Inc., Energy Analysis Quarterly (Bala Cynwyd, PA, Third Quarter 1984); Wharton Econometric Forecasting Associates, Wharton Long-Term Forecast (Philadelphia, PA, September 1984).

Table 41. Comparison of the Principal Determinants of U.S. Energy Demand, 1990

Determinant	AEO 1984	AEO 1983	DRI	Chase	Wharton
Real GNP (billion 1972 dollars)	1,968	1,934	1,966	1,979	1,939
Real Disposable Income (billion 1972 dollars)	1,360	1,347	1,361	1,387	1,358
GNP Price Deflator (Index, 1972=1.00)	3.04	3.13	3.06	3.12	3.00
New High-Grade Bond Rate (percent per year)	10.6	10.4	10.2	10.2	13.0
Total Industrial Production Index (1967=1.00)	2.09	1.99	2.07	1.98	1.95
Automobile Vehicle-Miles (trillion miles)	1.50	1.66	1.35	NA	1.28
Average Fleet Efficiency (automobile) (miles per gallon)	22.1	23.8	20.9	22.9	19.8
World Crude Oil Price (1984 dollars per barrel)	30.00	38.00	27.74	26.45	28.31

NA = Not available.

Source: Energy Information Administration, Annual Energy Outlook, 1983, DOE/EIA-0383(83) (Washington, DC, 1984); Data Resources, Inc., Energy Review (Lexington, MA, Autumn 1984); Chase Econometric Associates, Inc., Energy Analysis Quarterly (Bala Cynwyd, PA, Third Quarter 1984); Wharton Econometric Forecasting Associates, Wharton Long-Term Forecast (Philadelphia, PA, 1984).

Supply Projections

Total domestic energy production is projected to increase by 8 to 9 quadrillion Btu from 1983 to 1990, following a 5-year period of essentially no change. Crude oil and natural gas liquids production is forecast to decline by approximately 1 quadrillion Btu from the 1983 level of 20.6 quadrillion Btu, while natural gas production is projected to rise by about 1 quadrillion Btu by 1990. Rising wellhead prices for crude oil, and even more so for natural gas, help offset rising costs of production associated with depletion of the resource base. Coal production and nuclear power are expected to account for essentially all of the increase in total domestic energy output.

Table 42. Projections of U.S. Energy Demand by Sector, 1990
(Quadrillion Btu per Year)

Sector	AEO 1984	AEO 1983	DRI	Chase	Wharton
End-Use Consumption					
Residential					
Oil and LPG	1.6	1.6	1.4	1.6	1.6
Natural Gas	4.8	4.6	4.5	4.9	4.6
Coal	0.1	0.1	0.1	0.1	NA
Electricity	3.0	3.0	3.1	3.2	NA
Total	9.4	9.2	9.1	9.8	NA
Commercial					
Oil and LPG	1.2	1.3	1.0	1.0	NA
Natural Gas	2.8	2.9	2.9	2.9	NA
Coal	0.1	0.1	0.1	0.1	NA
Electricity	2.8	2.8	2.6	2.7	NA
Total	6.9	7.1	6.6	6.7	NA
Industrial					
Oil and LPG	10.5	9.3	9.7	9.1	NA
Natural Gas	7.7	6.6	7.1	7.4	NA
Coal	3.6	3.5	3.3	3.5	NA
Electricity	3.5	3.5	4.0	3.7	NA
Total	25.4	22.9	24.0	23.7	NA
Transportation[a]					
Oil and LPG	18.6	19.5	19.4	19.5	20.2
Electric Utility					
Oil	1.3	1.6	1.7	1.8	1.4
Natural Gas	3.4	3.3	3.7	2.8	2.6
Coal	16.9	16.5	16.8	16.8	16.8
Nuclear Power	6.3	6.3	6.1	6.7	6.0
Other[b]	4.0	3.7	4.0	4.1	3.7
Total	31.9	31.4	32.4	32.2	30.5
Total End-Use Consumption	60.3	58.7	59.1	59.7	NA
Primary Energy Consumption	83.5	81.7	82.5	83.0	80.8
Primary Energy/GNP Ratio (thousand Btu per 1972 dollar)	42.4	42.3	42.0	41.9	41.7

NA = Not available.
[a]Pipeline gas not included under transportation end-use demand.
[b]Includes hydroelectric, geothermal, and other (woodwastes, solar, wind).
Source: Energy Information Administration, Annual Energy Outlook, 1983, DOE/EIA-0383(83) (Washington, DC, 1984); Data Resources, Inc., Energy Review (Lexington, MA, Autumn 1984); Chase Econometric Associates, Inc., Energy Analysis Quarterly (Bala Cynwyd, PA, Third Quarter 1984); Wharton Econometric Forecasting Associates, Wharton Long-Term Forecast (Philadelphia, PA, 1984).

Total petroleum consumption in the 1984 Annual Energy Outlook base case is projected to increase to 16.7 million barrels per day in 1990, slightly higher than the comparable 1983 Annual Energy Outlook projection (Table 43). The main source for the difference is the outlook for lower world oil prices and higher economic growth in this year's report. The outlook for lower oil prices is also responsible for the lower forecast of domestic crude oil production. The combined effects of higher petroleum consumption and lower production drive the projection of higher petroleum imports in this year's report as well. This year's 1990 base case projection of domestic crude oil production is bracketed by estimates prepared by other organizations (the Wharton forecast is 0.28 million barrels per day lower and the DRI forecast is 0.34 million barrels per day higher). The base case projection of net petroleum imports, however, is on the high end of the range of alternative forecasts presented here (only the Wharton forecast exceeds the EIA figure, by 0.11 million barrels per day). The basis for the relatively high EIA estimate of net imports is the base case outlook for high growth in total petroleum consumption.

The 1984 Annual Energy Outlook base case projection of total petroleum consumption in 1990 is the highest estimate presented. This consumption projection is driven predominately by the outlook for "all other" petroleum products, while EIA's projections for motor gasoline, distillates, and residual fuel oil demands are generally lower than the alternative forecasts presented. Within the other fuels category, EIA's projection reflects the strongest growth in demand for liquefied petroleum gases (LPG's), primarily for petrochemical feedstock uses.

The range of forecasts for natural gas supply and demand, presented in Table 44, indicates general agreement that the total supply of natural gas available to meet market requirements through 1990 will increase in response to an increase in consumption and prices. DRI and Chase predict lower domestic production than the 1984 Annual Energy Outlook because of lower expectations for reserve additions in the Lower-48 States. All forecasts, however, indicate that supplemental sources of supplies, primarily imports from Canada, will contribute a greater share of future U.S. gas market requirements, compared to a total of 1.0 trillion cubic feet in 1983. Variations among the natural gas demand projections are caused mainly by differences in expectations for efficiency improvements by the energy-intensive industries and the extent to which industry and electric utilities will switch to alternate fuels.

The range established by the natural gas price projections reflects differences in world crude oil price assumptions and in expected market developments. There appears to be general agreement, however, that price adjustments are likely to develop between producers and pipeline purchasers as the gas market phases in the partial deregulation under the Natural Gas Policy Act (NGPA). Differences in end-use price forecasts reflect different assumptions for gas purchase costs from domestic sources of supply and imports. Expectations as to the extent to which natural gas will compete with alternate fuels in specific end-use markets also affect the end-use price projections.

Coal production is projected to rise to meet increasing demands from industry, electric utilities, and international markets. A comparison of coal supply and demand projections among EIA, DRI, Chase, and Wharton shows little difference in expectations (Table 45). In contrast, the National Coal Association (NCA) forecasts considerably less growth in coal markets. The NCA forecasts 681 million

Table 43. Projections of Domestic Petroleum Supply and Demand, 1990 (Million Barrels per Day)

	AEO 1984	AEO 1983	DRI	Chase	Wharton	Merrill Lynch	Texaco
Primary Supply							
Domestic Production							
Crude Oil	8.25	8.63	8.59	8.08	7.97	8.46	NA
Natural Gas Liquids	1.48	1.61	1.37	1.52	1.58	1.60	NA
Other Domestic	0.09	0.09	NA	0.12	NA	NA	NA
Processing Gain ...	0.53	0.52	0.57	0.54	NA	0.54	NA
Total	10.34	10.85	10.54	10.26	NA	NA	NA
Net Imports							
Crude Oil	5.06[a]	4.58[a]	4.22[a]	3.86	NA	NA	NA
Refined Product ...	1.54	1.37	1.95	2.53	NA	NA	NA
Total	6.59	5.95	6.17	6.39	6.70	5.87	NA
Primary Stock Changes							
Net Withdrawals ...	-0.05	-0.02	0	-0.05	NA	NA	NA
SPR Additions (-)	-0.14	-0.14	NA	NA	-0.15	NA	NA
Total Supply	16.74	16.63	16.71	16.59	NA	16.47	NA
Consumption							
Motor Gasoline	6.21	6.43	6.37	6.27	NA	7.03	5.80
Jet Fuel	1.32	1.28	1.33	1.21	NA	1.20	1.20
Distillate Fuel Oil	3.19	3.33	3.26	3.36	NA	3.03	3.50
Residual Fuel Oil ...	1.56	1.68	1.83	1.77	NA	1.39	2.00
All Other	4.46	3.91	3.92	3.99	NA	3.82	4.00
Total	16.74	16.63	16.71	16.59	NA	16.47	16.50

NA = Not available.

[a]Includes imports for the Strategic Petroleum Reserve.

Note: Additional estimates from these organizations and further forecast series by other organizations (including Chevron, Conoco, and Ashland) are publicly available, but not in the same format or for the same reference year used in this table.

Source: Energy Information Administration, Annual Energy Outlook, 1983, DOE/EIA-0383(83) (Washington, DC, 1984); Data Resources, Inc., Energy Review (Lexington, MA, Autumn 1984); Chase Econometric Associates, Inc., Energy Analysis Quarterly (Bala Cynwyd, PA, Third Quarter 1984); Wharton Econometric Forecasting Associates Wharton Long-Term Forecast (Philadelphia, PA, 1984); Merrill Lynch Economics, Inc., Long-Term Energy Outlook (New York, NY, 1984); Texaco, Free World Energy Summary (White Plains, NY, 1983).

short tons to be consumed in 1990 by the electric utility sector compared to 805 million short tons projected in the 1984 Annual Energy Outlook. The different projections for utility coal use reflect differences in electricity generation forecasts, with the NCA projecting an average annual rate of growth of 2.3 percent from 1985 to 1990 compared to the 1984 Annual Energy Outlook projections of 3.3 percent per year.

Table 44. Comparison of Natural Gas Demand, Supply, and Price Projections, 1990

	AEO 1984	DRI	Chase	GRI	Merrill/ Lynch	AGA[a]
End-Use Consumption			(trillion cubic feet)			
Residential	4.6	4.4	4.8	4.4	7.9	5.0
Commercial	2.7	0.8	2.9	2.9	NA[b]	3.0
Industrial[c]	7.5	0.9	7.2	7.5	8.0	7.9
Electric Utility	3.3	0.6	2.7	3.8	3.1	3.2
Total[d]	18.1	17.7	17.5	18.4	19.0	19.1
Supply			(trillion cubic feet)			
Domestic Production	17.3	16.4	16.7	17.7	18.9	19.3-21.0
Supplemental Supplies	1.9	2.5	1.7	1.3	1.1	3.5
Total	19.2	18.9	18.4	20.6	20.0	22.8-24.5
Natural Gas Prices			(1984 dollars per thousand cubic feet)			
Average Wellhead Price	3.52	3.01[e]	2.73	4.02[e]	2.83	NA
End-Use Prices						
Residential	7.22	6.52	5.54	6.51	7.34	NA
Commercial	6.60	5.77	5.27	6.20	NA	NA
Industrial	5.39	4.22	4.21	5.34	NA	NA
Electric Utility	4.50	NA	3.36	4.65	3.99	NA

NA = Not available.

[a]Supply based on the "National Policy of North American Self-Sufficiency" scenario. Demand projections taken from the "Base Case."

[b]Consumption by commercial sector includes residential sector consumption.

[c]Consumption by industrial sector includes lease and plant fuel.

[d]Natural gas used as pipleline compressor fuel excluded from end-use demands.

[e]Average acquisition price by producers from pipelines. In 1983, the average acquisition price was $3.04 per thousand cubic feet (1984 dollars) compared to $2.72 for the average wellhead price.

Sources: Data Resources, Inc., Energy Review (Lexington, MA, Autumn 1984); Chase Econometric Associates, Inc., Energy Analysis Quarterly (Bala Cynwyd, PA, Third Quarter 1984); American Gas Association (AGA), The Gas Energy Supply Outlook: 1983-2000 (1983 Update and The Gas Energy Demand Outlook: 1984-2000 (Arlington, VA, May 1984); Gas Research Institute (GRI), 1984 GRI Baseline Production of United States Energy Supply and Demand, 1983-2000 (Chicago, IL, 1984; Merrill Lynch Economics, Inc., Long-Term Energy Outlook (New York, NY, June 1984).

Rising electricity output is responsible for about two-thirds of the increase in coal production between 1983 and 1990 and all of the projected increase in nuclear power use. In the 1984 Annual Energy Outlook, generation is projected to increase by 3.4 percent per year from 1983 to 1990 (Table 46). The 1984 Annual Energy Outlook projection is similar to those published by DRI and Chase, whereas the North American Electric Reliability Council (NERC) and Wharton forecast much lower annual increases in electricity growth. The 1984 Annual Energy Outlook electric generation projection is somewhat lower than the 1983 Annual Energy Outlook projection, reflecting a downward revision in total demand for electricity and higher expectations for imports.

Table 45. Projections of Coal Supply and Demand, 1990
(Million Short Tons)

	AEO 1984	AEO 1983	DRI	Chase	Wharton	NCA
Domestic Consumption						
Electric Utilities	805	785	795	808	NA	681
Industrial						
Metallurgical	51	51	51	50	NA	50
Steam	89	85	89	90[a]	NA	96[a]
Residential/Commercial	7	7	9	NA	NA	NA
Synthetics	6	6	19	NA	NA	5
Total	958	934	963	949	NA	832
Net Exports	91	105	74	91	NA	109
Production						
East	650	648	NA	NA	622	596
West	407	397	NA	NA	409	345
Total	1,057	1,045	1,043	1,044	1,031	941

NA = Not available.
[a]Includes residential and commercial consumption.
Source: Energy Information Administration, Annual Energy Outlook, 1983, DOE/EIA-0383(83) (Washington, DC, 1984); Data Resources, Inc., Energy Review (Lexington, MA, Autumn 1984); Chase Econometric Associates, Inc., Energy Analysis Quarterly (Bala Cynwyd, PA, Third Quarter 1984); Wharton Econometric Forecasting Associates Wharton Long-Term Forecast (Philadelphia, PA, 1984); National Coal Association, Coal Markets in the Future (Washington, DC, 1984).

In terms of the relative contribution of the different energy sources to total electricity generation, EIA projects that coal-fired and nuclear generation together will account for nearly three-fourths of total generation in 1990, up from a combined share of approximately two-thirds of the total in 1983. The NERC forecast reflects a significant increase in the contribution from nuclear units over time, with the share of generation supplied by nuclear units nearly doubling by 1990. EIA and the others project a more modest increase in the nuclear share of net generation. In contrast to the growth in the projected shares for coal and nuclear power, the contribution from total natural gas and oil generation is projected to decline relative to its historical share. Hydroelectric power generation is projected to be about 300 billion kilowatthours in all projections except the NERC forecast, which is based on the assumption of lower than average water conditions. EIA does not explicitly consider geothermal and other major renewable sources separate from the hydroelectric total; for the non-hydroelectric renewables area, NERC and Wharton project the the most growth, while DRI and Chase also appear to be more optimistic than EIA. These differences are reflected in Table 46 as well as in the totals reported in Table 39.

More growth in demand than in total domestic energy production projected for the rest of the decade implies increased reliance on imports. Each projection included in this summary analysis indicates an increase in crude oil imports relative to the level in 1983. Natural gas imports also may rise, but there is less of a consensus among the alternative projections in this area.

Table 46. Projections of Electricity Generation by Fuel Type, 1990

	AEO 1984	AEO 1983	DRI	Chase	Wharton	NERC
	(billion kilowatts per year)					
Generation by Fuel Type						
Oil	121	155	158	177	130	102
Gas	312	303	338	251	237	211
Coal	1,610	1,594	1,601	1,607	1,461	1,468
Nuclear Power	574	581	555	613	546	662
Hydroelectric Power	309[a]	318[a]	319[a]	311	296	240[d]
Other[b]	c	c	21	21	29	49
Total Generation	2,927	2,952	2,991	2,977	2,700	2,731
	(compound rate)					
Average Annual Growth in Total Generation (1983-1990)	3.4%	3.6%	3.8%	3.7%	2.3%	2.4%

[a]Includes conventional hydroelectric generation plus energy loss for pumped storage generation.

[b]Renewable sources such as geothermal power, wood, waste, solar energy, and wind.

[c]Included in hydroelectricity.

[d]Includes energy loss for pumped storage hydroelectric generation.

Source: Energy Information Administration, Annual Energy Outlook, 1983, DOE/EIA-0383(83) (Washington, DC, 1984); Data Resources, Inc., Energy Review (Lexington, MA, Autumn 1984); Chase Econometric Associates, Inc., Energy Analysis Quarterly (Bala Cynwyd, PA, Third Quarter 1984); Wharton Econometric Forecasting Associates, Wharton Long-Term Forecast (Philadelphia, PA, 1984); North American Electric Reliability Council, Electric Power Supply and Demand 1984-1993 (Princeton, NJ, 1984).

Energy Price Projections

Expectations for future world oil prices heavily influence the projections for other energy prices (Table 47). With the drop in the assumed price for crude oil in 1990 from $38 to $30 (1984 dollars) per barrel from the previous Annual Energy Outlook, the 1984 report projects lower prices for petroleum products as well as for natural gas.

Even with the significant adjustment in prices from the 1983 to the 1984 Annual Energy Outlook, EIA's more recent world oil price projection for 1990 still exceeds those forecast by DRI, Chase, or Wharton by several dollars. Similarly, the EIA's projections for petroleum product prices and other energy prices are higher than the others. The 1984 Annual Energy Outlook projection for natural gas prices in 1990, in particular, stands out from the other forecasts, while there is less variation among the coal and electricity price forecasts.

Table 47. Energy Price Projections, 1990
(1984 Dollars)

Price	AEO 1984	AEO 1983	DRI	Chase	Wharton
World Crude Oil Price (dollars per barrel)	30.00	38.00	27.74	26.45	28.31
Motor Gasoline (average) (dollars per gallon)	1.29	1.47	1.19	1.16	NA
Distillate (residential heating) (dollars per gallon)	1.05	1.27	1.07	0.94	1.11
Residual (industrial) (dollars per barrel)	30.07	33.79	26.72	NA	NA
Natural Gas (wellhead) (dollars per thousand cubic feet)	3.52	3.75	3.01	2.78	2.95
Natural Gas (average end-use) (dollars per thousand cubic feet)	5.91	6.47	5.17[a]	4.74[a]	5.46
Coal (electric utilities) (dollars per short ton)	40.24	39.88	38.35	39.62	NA
Electricity (average end-use) (cents per kilowatthour)	6.4	6.6	6.2	6.2	6.5

NA = Not available.
[a]Volume-weighted average.
Source: Energy Information Administration, Annual Energy Outlook, 1983, DOE/EIA-0383(83) (Washington, DC, 1984); Data Resources, Inc., Energy Review (Lexington, MA, Autumn 1984); Chase Econometric Associates, Inc., Energy Analysis Quarterly (Bala Cynwyd, PA, Third Quarter 1984); Wharton Econometric Forecasting Associates, Wharton Long-Term Forecast (Philadelphia, PA, 1984).

Conclusion

The projections of domestic primary energy consumption examined for this chapter vary within a few quadrillion Btu of one another. The general agreement among the 1984 Annual Energy Outlook and the DRI, Chase, and Wharton projections can be attributed in part to the small range of variation among world oil price and economic growth assumptions. For 1990, expected world oil prices differ by less than $4 per barrel, while total variation among the GNP projections is only $40 billion (2.6 percent of the 1983 GNP level). Aggregation across sectors also contributes to the similarity in the totals, while masking some significant differences on a sector-by-sector basis. For example, the industrial end-use energy demand projections vary by almost 2 quadrillion Btu, while projections of total energy consumed by the industrial, residential, commercial and transportation sectors vary by only slightly more than 1 quadrillion Btu. An understanding of why projections differ at the disaggregate level is an important part of the analysis and forecasting process, but a discussion of the sources of these differences is beyond the scope of this chapter.

Corresponding to the similarity in end-use energy projections, DRI, Chase, Wharton, and EIA all project the energy/GNP ratio to be close to 42 thousand Btu per 1972 dollar in 1990. The 1984 Annual Energy Outlook projection for energy intensiveness is slightly higher than the others, but all of the forecasts indicate a dramatic slowdown in efficiency gains relative to the previous decade. The price and supply forecasts also reflect a general sense of agreement that energy markets essentially will remain stable through the rest of the decade.

Guide to Appendices A Through E

The following appendices contain detailed tables of U.S. energy supply and disposition for the combined economic growth and world oil price scenarios shown below:

World Oil Price Assumption (1990 Price in 1984 dollars per barrel)	Economic Growth Assumption (Average Annual GNP Growth Between 1985 and 1990) Low (2.1%)	Middle (3.1%)	High (3.9%)
Low ($25.00)		D	
Middle ($30.00)	B	A	C
High ($40.00)		E	

The letters shown above represent the appendix in which the tables for the particular scenario appear. Appendix A, which contains the middle economic growth and world oil price assumptions, is referred to as the base case. Economic growth refers to growth in the gross national product (GNP) asumming the middle world oil price. The tables in each appendix are designated by the corresponding appendix letter. Hence, the discussion below refers to the tables in all of these appendices.

Table A1 provides national summaries of energy supply and disposition by major fuel category. This table presents the basic energy balance summarizing the detail found in subsequent fuel- or sector-specific tables. Table A2 expands the supply detail given in Table A1 by also listing net storage withdrawals and available supplies of major fuels. Disposition totals found in Table A1 are also listed in Table A3, but by major end-use sector. Table A4 lists consumption totals for the same end-use sectors, but gives a greater breakdown for certain fuel categories. The corresponding prices for fuels in each sector are in Table A5. Tables A6 through A9 provide detailed energy projections for the residential, commercial, industrial, and transportation end-use sectors by subsector or subfuel category. Electric utility summaries are given in Tables A10 through A14 for prices, consumption, capacity, and generation. Petroleum supply, disposition, and prices are provided in Tables A15 and A16. Supply and disposition balances for natural gas and coal are given in Tables A17 and A18, respectively. Table A19 lists the national macroeconomic indicators. Prices shown in these appendix tables are expressed in 1984 dollars. International energy use and supply projection tables appear directly in Chapter 3.

Location of Key Solution Values

This reference guide for the tables in Appendices A through E indicates where to find specific topics, including supply, demand, and prices of primary fuels and products. A "P" in parentheses indicates that projections are in physical units, while an "S" denotes standard units (Btu). Note that the tables are referenced only by numbers, as the references apply to each appendix.

Domestic Supply:

- Total Energy Production
  - Domestic energy production by major fuels, total production: Table 1(S)
  - Net storage withdrawals by major fuels: Table 2(S)
  - Available supply by major fuels, total supply: Table 2(S)

- Oil
  - Total U.S. oil production: Tables 2(S), 15(P)
  - Crude oil: Tables 1(S), 15(P)
  - Refined petroleum products: Table 15(P)

- Natural Gas
  - Total U.S. production: Tables 1(S), 2(S), 17(P)
  - Available supply: Tables 1(S), 17(P)

- Electricity
  - Electric utility generation: Tables 10(S), 12(P)
  - Capacity/generation by plant/fuel type: Table 12(P)
  - Nuclear power: Tables 1(S), 12(P)

- Coal
  - Total U.S. production: Tables 1(S), 2(S), 18(P)
  - Available supply: Tables 2(S), 18(P)
  - Production by region: Table 18(P)

Domestic Consumption:

- Total Energy Consumption
  - By major fuels: Tables 1(S), 4(S)
  - By end-use sector: Tables 3(S), 4(S)
  - End-use sector detail: Tables 6(S), 7(S), 9(S,P)

- Oil
  - By end-use sector: Table 3(S)
  - Refined petroleum products: Tables 1(S), 4(S), 17(P)

- Natural Gas
  - Total U.S. Consumption: Table 1(S)
  - Consumption by end-use sector: Tables 3(S), 4(S), 17(P)

- Electricity
  - Total U.S. consumption: Tables 4(S), 10(S)
  - Consumption by end-use sector: Tables 4(S), 11(P)

- Coal
  - Total U.S. consumption: Tables 1(S), 18(P)
  - Consumption by end-use sector: Tables 3(S), 4(S), 18(P)

Imports (Exports):

- Total oil: Table 2(S)
- Crude oil: Tables 1(S), 15(P)
- Petroleum products: Tables 1(S), 15(P)
- Natural gas: Tables 1(S), 2(S), 17(P)
- Electricity: Tables 1(S), 2(S)
- Coal: Tables 1(S), 18(P)

Prices:

- To end-use sectors for major/minor fuels: Table 5(S)
- World oil price: Table 16(P)
- Petroleum products: Table 16(P)
- Natural gas: Table 17(P)
- Electricity: Tables 11(P), 14(P)
- Coal: Table 18(P)

Appendix A
Middle World Oil Price/Middle Economic Growth Case

Table A1. Yearly Supply and Disposition Summary of Total Energy
(Quadrillion Btu per Year)

Total Supply and Disposition	Middle World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Supply											
Production											
Crude Oil and Lease Condensate	19.5	18.4	18.4	18.5	18.8	18.4	18.2	17.9	17.7	17.6	16.0
Natural Gas Plant Liquids	2.6	2.2	2.2	2.3	2.3	2.2	2.2	2.1	2.1	2.1	1.8
Natural Gas[1]	22.2	19.5	16.4	17.9	18.0	17.6	17.9	18.1	18.0	17.8	16.8
Coal[2]	13.9	14.9	17.2	19.6	19.8	20.5	21.0	21.6	22.3	23.3	26.8
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Hydropower/Other[3]	2.9	3.0	3.6	3.6	3.1	3.3	3.3	3.3	3.3	3.4	3.4
Total Production	**62.0**	**61.0**	**61.1**	**65.6**	**66.1**	**66.7**	**68.0**	**68.8**	**69.6**	**70.5**	**71.9**
Imports											
Crude Oil[4]	6.9	13.5	7.1	7.4	7.7	9.2	9.7	10.2	10.8	11.1	14.2
Refined Petroleum Products[5]	6.6	4.4	3.6	4.1	3.9	3.3	3.7	4.1	4.3	4.5	5.8
Natural Gas[6]	1.1	1.0	1.1	1.0	1.2	1.4	1.3	1.5	1.7	1.9	2.9
Other Imports[7]	.2	.4	.4	.4	.5	.5	.5	.6	.6	.7	.8
Total Imports	**14.7**	**19.3**	**12.2**	**12.9**	**13.2**	**14.4**	**15.2**	**16.3**	**17.4**	**18.2**	**23.7**
Net Stock Withdrawals	**-.4**	**.3**	**1.1**	**-.7**	**.0**	**-.4**	**-.5**	**-.5**	**-.5**	**-.6**	**-.2**
Adjustments[8]	-.1	-.6	.0	.4	-.3	-.3	-.4	-.5	-.6	-.6	-.8
Total Supply[9]	**76.2**	**80.0**	**74.4**	**78.3**	**79.0**	**80.4**	**82.3**	**84.2**	**85.8**	**87.6**	**94.6**
Disposition											
Exports											
Oil	.5	.8	1.6	1.4	1.3	1.7	1.7	1.7	1.7	1.7	1.7
Natural Gas	.1	.1	.1	NA	NA	NA	NA	NA	NA	NA	NA
Coal	1.4	1.1	2.0	2.1	1.9	2.0	2.1	2.2	2.3	2.4	2.8
Other[10]	.1	.0	.1	NA	NA	NA	NA	NA	NA	NA	NA
Total Exports	**2.1**	**1.9**	**3.7**	**3.5**	**3.2**	**3.7**	**3.7**	**3.8**	**3.9**	**4.1**	**4.4**
Consumption											
Refined Petroleum Products[11]	34.8	38.0	30.1	31.5	31.3	31.3	31.7	32.2	32.7	33.2	35.7
Natural Gas	22.5	20.0	17.5	18.5	18.7	18.6	18.8	19.1	19.2	19.3	19.3
Coal[12]	12.9	13.7	15.9	17.1	18.1	18.4	18.8	19.3	19.9	20.6	23.8
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Hydro/Other/Electricity Imports[13]	3.1	3.2	4.0	4.0	3.6	3.8	3.9	3.9	4.0	4.1	4.2
Net Imports of Coke	.0	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total Consumption	**74.2**	**78.0**	**70.7**	**74.8**	**75.7**	**76.7**	**78.5**	**80.3**	**81.9**	**83.5**	**90.1**
Total Disposition	**76.2**	**80.0**	**74.4**	**78.3**	**79.0**	**80.4**	**82.3**	**84.2**	**85.8**	**87.6**	**94.6**

[1] Net dry marketed production after removal of nonhydrocarbon gases.
[2] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite, with anthracite included in bituminous.
[3] Hydropower/Other production includes hydropower, geothermal power, and wood waste.
[4] Includes imports of crude oil for the Strategic Petroleum Reserve.
[5] Includes imports of unfinished oils and natural gas plant liquids.
[6] Includes dry natural gas imports from Canada and Mexico, liquefied natural gas imports from Algeria, and supplemental gas.
[7] Includes electricity, coal, and coal coke imports.
[8] Balancing item that includes gains, losses, miscellaneous blending components, unaccounted for supply, coal used for synthetic fuel production, anthracite shipped overseas to U.S. Armed Forces and certain secondary stock withdrawals.
[9] Total supply is the sum of production, imports, net stock withdrawals, and adjustments.
[10] Includes electricity and coal coke exports.
[11] Includes natural gas plant liquids and crude oil consumed as a fuel.
[12] Excludes anthracite shipped overseas to U.S. Armed Forces and coal used for synthetic fuel production.
[13] Includes net electricity imports and renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[NA] = Not available.

NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical quantities are from the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984) pp. 5-29, Tables 1, 2, 3, and 13. Projected values are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = Middle World Oil Price Case, printed on December 28, 1984.
Historical quantities through 1983.

Table A2. Yearly Supply and Disposition of Total Energy, Supply Detail
(Quadrillion Btu per Year)

Total Supply	Middle World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
World Oil Price[1]	**8.62**	**21.63**	**30.39**	**29.00**	**28.00**	**27.00**	**27.00**	**28.00**	**29.00**	**30.00**	**40.00**
Domestic Production											
Oil[2]	22.1	20.7	20.6	20.8	21.1	20.6	20.4	20.0	19.8	19.7	17.8
Natural Gas[3]	22.2	19.5	16.4	17.9	18.0	17.6	17.9	18.1	18.0	17.8	16.8
Coal[4]	13.9	14.9	17.2	19.6	19.8	20.5	21.0	21.6	22.3	23.3	26.8
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Hydropower/Other[5]	2.9	3.0	-3.6	3.6	3.1	3.3	3.3	3.3	3.3	3.4	3.4
Total Domestic Production	**62.0**	**61.0**	**61.1**	**65.6**	**66.1**	**66.7**	**68.0**	**68.8**	**69.6**	**70.5**	**71.9**
Imports											
Oil[6]	13.5	17.8	10.7	11.5	11.6	12.5	13.4	14.3	15.0	15.6	20.0
Natural Gas[7]	1.1	1.0	1.1	1.0	1.2	1.4	1.3	1.5	1.7	1.9	2.9
Coal[8]	.0	.1	.0	.0	.0	NA	NA	NA	NA	NA	NA
Other Imports[9]	.2	.4	.4	.4	.4	.5	.5	.6	.6	.7	.8
Total Imports	**14.7**	**19.3**	**12.2**	**12.9**	**13.2**	**14.4**	**15.2**	**16.3**	**17.4**	**18.2**	**23.7**
Net Storage Withdrawals											
Oil	-.3	.5	.5	.1	.0	.0	-.1	-.1	-.1	-.1	-.1
Natural Gas	-.4	-.2	.5	.0	.0	.0	.0	.0	.0	.0	.0
Coal[10]	.3	.3	.6	-.4	.3	.0	-.1	-.1	-.1	-.2	-.1
SPR Fill Rate Additions (-)[11]	.0	-.3	-.5	-.4	-.3	-.3	-.3	-.3	-.3	-.3	.0
Net Stock Withdrawals	**-.4**	**.3**	**1.1**	**-.7**	**.0**	**-.4**	**-.5**	**-.5**	**-.5**	**-.6**	**-.2**
Available Supply[12]											
Oil	35.3	39.1	31.9	32.5	32.7	33.2	33.7	34.3	34.7	35.3	37.7
Natural Gas	22.8	20.3	18.0	19.0	19.2	19.0	19.3	19.6	19.7	19.7	19.8
Coal	14.2	15.2	17.8	19.2	20.1	20.4	21.0	21.5	22.2	23.1	26.7
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Other Supply[13]	3.1	3.4	4.0	4.0	3.6	3.8	3.9	3.9	4.0	4.1	4.2
SPR Fill Rate Additions (-)[11]	.0	-.3	-.5	-.4	-.3	-.3	-.3	-.3	-.3	-.3	.0
Total Supply (before adjustments)	**76.3**	**80.6**	**74.4**	**77.9**	**79.3**	**80.7**	**82.7**	**84.6**	**86.4**	**88.2**	**95.4**
Adjustments[14]	-.1	-.6	.0	.4	-.3	-.3	-.4	-.5	-.6	-.6	-.8
Total Supply[15]	**76.2**	**80.0**	**74.4**	**78.3**	**79.0**	**80.4**	**82.3**	**84.2**	**85.8**	**87.6**	**94.6**

[1] The cost of imported crude oil to U.S. refiners in 1984 dollars per barrel.
[2] Oil includes crude oil, lease condensate, and natural gas plant liquids.
[3] Net dry marketed production after removal of nonhydrocarbon gases.
[4] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite, with anthracite included in bituminous.
[5] Hydropower/Other production includes hydropower, geothermal power, and wood waste.
[6] Oil imports includes crude oil and refined petroleum products. Crude oil imports include imports for the Strategic Petroleum Reserve.
[7] Includes dry natural gas imports from Canada and Mexico, liquefied natural gas imports from Algeria, and supplemental gas.
[8] Includes small amounts of coal/coke imports.
[9] Consists of net electricity imports from Canada.
[10] From consumer stocks (utility, coke plant, and industrial) only.
[11] SPR is the Strategic Petroleum Reserve.
[12] Available supply is the sum of domestic production, imports, and net stock withdrawals.
[13] Includes net electricity imports from Canada, hydropower, geothermal power, wood, waste, solar power, and wind power.
[14] Balancing item that includes gains, losses, miscellaneous blending components, unaccounted for supply, coal used for synthetic fuel production, anthracite shipped overseas to U.S. Armed Forces and certain secondary stock withdrawals.
[15] Total supply is the sum of production, imports, net stock withdrawals, and adjustments.
[NA] = Not available.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Historical values are taken from Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984).

Input data file: Historical = MRG1126T, Projected = Middle World Oil Price Case, printed on December 28, 1984.

Historical prices through 1981 and quantities through 1983.

Table A3. Yearly Supply and Disposition of Total Energy, Disposition Detail

(Quadrillion Btu per Year)

Total Disposition	Middle World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Exports											
Oil[1]	0.5	0.8	1.6	1.4	1.3	1.7	1.7	1.7	1.7	1.7	1.7
Natural Gas	.1	.1	.1	NA	NA	NA	NA	NA	NA	NA	NA
Coal	1.4	1.1	2.0	2.1	1.9	2.0	2.1	2.2	2.3	2.4	2.8
Other[2]	.1	.0	.1	NA	NA	NA	NA	NA	NA	NA	NA
Total Exports	**2.1**	**1.9**	**3.7**	**3.5**	**3.2**	**3.7**	**3.7**	**3.8**	**3.9**	**4.1**	**4.4**
Consumption											
Residential and Commercial											
Oil[3]	4.4	4.1	2.3	2.6	2.5	2.6	2.7	2.7	2.8	2.8	2.8
Natural Gas	7.6	7.6	7.2	7.4	7.4	7.4	7.5	7.5	7.5	7.5	7.3
Coal	.3	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2
Total (excluding electricity)	**12.3**	**11.9**	**9.8**	**10.1**	**10.1**	**10.2**	**10.3**	**10.4**	**10.5**	**10.5**	**10.2**
Industrial											
Oil[4]	9.1	9.9	7.8	8.9	9.0	9.2	9.6	10.0	10.2	10.5	11.5
Natural Gas[5]	10.4	8.5	6.6	7.3	7.4	7.4	7.6	7.8	7.8	7.7	7.5
Coal[6]	4.0	3.2	2.5	2.9	2.9	3.2	3.3	3.4	3.5	3.6	3.8
Hydropower	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Net Imports of Coke	.0	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total (excluding electricity)	**23.5**	**21.8**	**16.9**	**19.0**	**19.4**	**19.8**	**20.6**	**21.2**	**21.5**	**21.8**	**22.8**
Transportation											
Oil[7]	17.8	20.0	18.4	18.7	18.6	18.3	18.3	18.4	18.5	18.6	19.4
Natural Gas[8]	.7	.5	.6	.6	.6	.6	.6	.6	.6	.6	.6
Coal	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total (excluding electricity)	**18.6**	**20.6**	**19.0**	**19.3**	**19.2**	**19.0**	**18.9**	**19.0**	**19.1**	**19.2**	**20.1**
Electric Utilities											
Oil	3.5	4.0	1.5	1.3	1.2	1.2	1.1	1.2	1.2	1.3	2.0
Natural Gas	3.7	3.3	3.0	3.3	3.3	3.1	3.1	3.3	3.3	3.4	3.9
Coal	8.7	10.3	13.2	14.0	14.9	15.0	15.3	15.6	16.2	16.9	19.9
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Hydropower/Other[9]	3.0	3.2	4.0	4.0	3.5	3.8	3.8	3.9	4.0	4.0	4.1
Total	**19.9**	**23.7**	**25.0**	**26.3**	**27.1**	**27.8**	**28.7**	**29.7**	**30.7**	**31.9**	**37.0**
Total Disposition	**76.2**	**80.0**	**74.4**	**78.3**	**79.0**	**80.4**	**82.3**	**84.2**	**85.8**	**87.6**	**94.6**

[1] Consists primarily of refined petroleum products.
[2] Includes electricity and coal coke exports.
[3] Residential and Commercial oil consists of motor gasoline, distillate fuel, kerosene, residual fuel, and liquefied petroleum gases.
[4] Industrial oil consists of distillate fuel, kerosene, residual fuel, liquefied petroleum gases, special naphthas, miscellaneous petroleum products, lubricants, waxes, unfractionated stream, plant condensate, natural gasoline, asphalt, road oil, petroleum coke, still gas, other oils greater than 400 degrees used for chemical feedstocks, motor gasoline, and naphthas less than 400 degrees used for feedstock purposes, including refinery fuel consumption.
[5] Industrial natural gas is composed of lease and plant fuel use, refinery fuel use, and other industrial uses.
[6] Industrial coal is composed of steam and metallurgical (coking) coal.
[7] Transportation oil consists of motor gasoline, aviation gasoline, jet fuel, distillate fuel, residual fuel, lubricants, and liquefied petroleum gases.
[8] Transportation natural gas represents natural gas used as a fuel by pipeline compressors.
[9] Includes net electricity imports from Canada, hydropower, geothermal power, wood, waste, solar power, and wind power.
[NA] = Not available.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Historical quantities are taken from Energy Information Administration, *State Energy Data Report, 1960 to 1982*, DOE/EIA 0214(82) (Washington, DC, 1984) and Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984). Projected quantities are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = MRG1126T, Projected = Middle World Oil Price Case, printed on December 28, 1984.
Historical quantities through 1983.

Table A4. Consumption by Major Fuels and End-Use Sectors
(Quadrillion Btu per Year)

Sector and Fuel	Middle World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential											
Distillate Fuel	2.00	1.95	1.05	1.23	1.18	1.20	1.22	1.23	1.23	1.23	1.14
Kerosene	.23	.15	.09	.07	.06	.06	.06	.06	.06	.06	.06
Liquefied Petroleum Gas	.59	.52	.30	.25	.27	.28	.29	.30	.30	.30	.27
Natural Gas	4.98	4.98	4.65	4.72	4.72	4.72	4.74	4.75	4.76	4.75	4.59
Steam Coal	.11	.09	.08	.07	.07	.07	.07	.07	.06	.06	.06
Electricity	1.98	2.30	2.56	2.61	2.68	2.73	2.79	2.85	2.92	3.01	3.43
Total	**9.89**	**9.99**	**8.72**	**8.95**	**8.97**	**9.05**	**9.16**	**9.26**	**9.34**	**9.42**	**9.55**
Commercial											
Distillate Fuel	.64	.67	.44	.51	.51	.53	.56	.59	.61	.63	.68
Kerosene	.06	.05	.03	.06	.06	.06	.07	.07	.08	.08	.09
Motor Gasoline	.09	.11	.09	.09	.08	.08	.08	.08	.08	.08	.08
Residual Fuel	.67	.53	.30	.33	.33	.35	.37	.39	.41	.42	.46
Liquefied Petroleum Gas	.10	.09	.05	.03	.03	.03	.03	.03	.03	.03	.02
Natural Gas[1]	2.65	2.64	2.60	2.66	2.67	2.69	2.72	2.74	2.76	2.76	2.67
Steam Coal	.15	.13	.12	.11	.12	.12	.12	.12	.12	.11	.11
Electricity	1.52	1.81	2.12	2.36	2.45	2.51	2.58	2.65	2.73	2.81	3.20
Total	**5.88**	**6.04**	**5.74**	**6.16**	**6.24**	**6.37**	**6.52**	**6.66**	**6.80**	**6.93**	**7.30**
Industrial[2]											
Distillate Fuel	1.47	1.75	1.30	1.61	1.54	1.57	1.63	1.67	1.71	1.74	1.84
Kerosene	.16	.16	.14	.10	.09	.09	.09	.09	.09	.09	.08
Motor Gasoline	.26	.18	.14	.13	.14	.16	.18	.20	.22	.25	.38
Residual Fuel	1.86	1.72	.78	.98	.94	.96	1.01	1.04	1.06	1.09	1.17
Liquefied Petroleum Gas	1.24	1.26	1.61	1.52	1.56	1.60	1.75	1.87	1.95	2.02	2.35
Petrochemical Feedstocks[3]	.73	1.22	.85	1.38	1.48	1.47	1.56	1.63	1.64	1.65	1.62
Still Gas Used in Refineries	1.06	1.20	1.13	1.16	1.21	1.21	1.22	1.23	1.24	1.25	1.33
Other Raw Material Oil[4]	2.34	2.41	1.82	1.98	2.08	2.11	2.17	2.24	2.30	2.36	2.69
Natural Gas[5]	10.39	8.54	6.64	7.29	7.39	7.44	7.61	7.75	7.75	7.74	7.50
Steam Coal	1.43	1.46	1.50	1.72	1.75	1.91	1.99	2.08	2.15	2.23	2.46
Metallurgical Coal	2.54	1.79	.96	1.15	1.19	1.25	1.32	1.37	1.38	1.38	1.34
Net Coke Imports	-.01	.13	-.02	.00	.00	.00	.00	.00	.00	.00	.00
Electricity	2.34	2.76	2.65	2.74	2.78	2.86	3.02	3.19	3.34	3.51	4.22
Hydropower	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03
Total	**25.84**	**24.60**	**19.52**	**21.78**	**22.19**	**22.66**	**23.58**	**24.39**	**24.87**	**25.35**	**27.01**

See footnotes at end of table.

Table A4. Consumption by Major Fuels and End-Use Sectors (Continued)
(Quadrillion Btu per Year)

Sector and Fuel	Middle World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Transportation											
Aviation Gasoline	0.08	0.07	0.05	0.07	0.07	0.07	0.08	0.08	0.08	0.09	0.10
Distillate Fuel	2.22	2.68	2.84	2.67	2.63	2.70	2.79	2.89	3.01	3.14	3.98
Jet Fuel[6]	2.13	2.14	2.14	2.35	2.34	2.43	2.53	2.59	2.66	2.71	2.80
Motor Gasoline	12.45	13.93	12.47	12.67	12.57	12.18	11.93	11.76	11.65	11.58	11.36
Residual Fuel	.73	.99	.75	.74	.72	.73	.77	.79	.82	.84	.92
Liquefied Petroleum Gas	.04	.03	.03	.01	.01	.01	.01	.01	.01	.01	.01
Lubricants and Waxes	.16	.18	.16	.22	.22	.23	.23	.24	.24	.25	.27
Natural Gas[7]	.74	.54	.58	.61	.62	.61	.62	.63	.63	.63	.63
Other Transportation[8]	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01
Total	**18.58**	**20.57**	**19.02**	**19.35**	**19.18**	**18.97**	**18.96**	**19.00**	**19.10**	**19.24**	**20.08**
Electric Utilities											
Distillate Fuel	.27	.28	.10	.11	.05	.02	.01	.03	.03	.04	.15
Residual Fuel	3.24	3.71	1.45	1.20	1.12	1.14	1.11	1.15	1.16	1.24	1.88
Natural Gas	3.75	3.30	3.01	3.27	3.33	3.11	3.14	3.25	3.34	3.39	3.88
Steam Coal	8.66	10.25	13.23	14.05	14.94	15.01	15.32	15.65	16.16	16.86	19.89
Nuclear Power	.91	3.02	3.23	3.70	4.10	4.72	5.31	5.79	6.09	6.32	7.09
Hydropower/Other[9]	3.02	3.18	3.98	3.95	3.54	3.77	3.83	3.88	3.96	4.03	4.15
Total	**19.85**	**23.74**	**25.00**	**26.27**	**27.09**	**27.77**	**28.72**	**29.74**	**30.74**	**31.88**	**37.04**
Primary Energy Consumption											
Distillate Fuel	6.61	7.32	5.72	6.13	5.90	6.02	6.21	6.41	6.59	6.78	7.79
Kerosene	.45	.36	.26	.23	.21	.21	.22	.22	.23	.23	.22
Aviation Gasoline	.08	.07	.05	.07	.07	.07	.08	.08	.08	.09	.10
Motor Gasoline	12.80	14.21	12.70	12.88	12.79	12.42	12.19	12.04	11.95	11.91	11.82
Jet Fuel	2.13	2.14	2.14	2.35	2.34	2.43	2.53	2.59	2.66	2.71	2.80
Residual Fuel	6.49	6.95	3.27	3.25	3.12	3.19	3.26	3.37	3.44	3.59	4.43
Liquefied Petroleum Gas	1.98	1.89	1.99	1.81	1.86	1.91	2.07	2.20	2.28	2.36	2.66
Petrochemical Feedstocks	.73	1.22	.85	1.38	1.48	1.47	1.56	1.63	1.64	1.65	1.62
Still Gas	1.06	1.20	1.13	1.16	1.21	1.21	1.22	1.23	1.24	1.25	1.33
Lubricants and Waxes	.40	.41	.35	.45	.45	.46	.47	.48	.49	.50	.53
Other Petroleum	2.11	2.18	1.62	1.75	1.85	1.88	1.93	2.00	2.05	2.10	2.43
Natural Gas	22.50	20.00	17.47	18.54	18.73	18.57	18.83	19.13	19.24	19.28	19.27
Steam Coal	10.35	11.92	14.91	15.95	16.88	17.10	17.49	17.91	18.49	19.26	22.51
Metallurgical Coal	2.54	1.79	.96	1.15	1.19	1.25	1.32	1.37	1.38	1.38	1.34
Net Coke Imports	-.01	.13	-.02	.00	.00	.00	.00	.00	.00	.00	.00
Nuclear Power	.91	3.02	3.23	3.70	4.10	4.72	5.31	5.79	6.09	6.32	7.09
Hydropower/Other[9]	3.06	3.21	3.99	3.98	3.57	3.80	3.86	3.91	3.99	4.06	4.18
Total Consumption	**74.19**	**78.04**	**70.66**	**74.79**	**75.75**	**76.71**	**78.54**	**80.35**	**81.85**	**83.47**	**90.12**
Electricity Consumption (all sectors)	**5.84**	**6.89**	**7.34**	**7.72**	**7.92**	**8.11**	**8.40**	**8.70**	**9.00**	**9.34**	**10.86**

[1] Commercial natural gas includes deliveries to municipalities and public authorities for institutional heating, street lighting, etc.
[2] Industrial includes all fuels consumed for heat and power, including natural gas used as lease and plant fuel, industrial feedstock and raw material uses; also, all fuels consumed by refineries.
[3] Petrochemical feedstocks includes still gas used for feedstock purposes, naphthas less than 400 degrees, and other oils greater than 400 degrees.
[4] Consists of asphalt, special naphthas, lubricants, waxes, petroleum coke, road oil, and small amounts of Other Petroleum and Net Blending Oil as defined in Table A8.
[5] Includes lease and plant fuel consumption of natural gas.
[6] Jet fuel includes naphtha and kerosene types.
[7] Consists of natural gas used as pipeline compressor fuel.
[8] Other transportation includes steam coal and electricity.
[9] Includes renewable facilities such as hydropower, geothermal power, wood, waste, solar power, and wind power. Electric utility consumption includes net electicity imports.

NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical quantities are taken from Energy Information Administration, *State Energy Data Report, 1960 to 1982*, DOE/EIA-0214 (82) (Washington, DC, 1984) and Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984). Projected quantities are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = Middle World Oil Price Case, printed on December 21, 1984.
Historical quantities through 1983.

Table A5. Prices by Major Fuels and End-Use Sectors
(1984 Dollars per Million Btu)

Sector and Fuel	Middle World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential											
Distillate Fuel	3.46	5.28	7.94	7.70	7.47	7.33	7.34	7.56	7.78	8.02	10.05
Kerosene	3.96	6.01	8.29	8.04	7.81	7.65	7.67	7.89	8.12	8.37	10.49
Liquefied Petroleum Gas	7.66	7.08	9.02	7.76	7.53	7.37	7.38	7.61	7.85	8.10	10.27
All Petroleum Products	**4.38**	**5.68**	**8.19**	**7.72**	**7.50**	**7.35**	**7.36**	**7.58**	**7.81**	**8.05**	**10.11**
Natural Gas	2.66	3.72	6.20	6.00	5.94	5.94	6.11	6.31	6.66	7.03	9.07
Steam Coal[1]	2.47	3.81	2.05	2.10	2.12	2.15	2.17	2.19	2.22	2.26	2.40
Electricity	15.74	18.80	19.55	19.62	19.81	19.96	20.09	20.06	19.83	19.65	19.37
Average[2]	**5.76**	**7.71**	**10.41**	**10.24**	**10.31**	**10.38**	**10.55**	**10.73**	**10.95**	**11.21**	**12.89**
Commercial											
Distillate Fuel	2.90	4.72	6.57	6.33	6.11	5.95	5.97	6.18	6.40	6.63	8.65
Kerosene	2.04	4.68	6.62	6.36	6.13	5.98	5.99	6.22	6.45	6.70	8.81
Motor Gasoline	6.57	7.85	10.33	10.14	9.92	9.68	9.68	9.91	10.12	10.30	12.68
Residual Fuel	1.82	3.27	5.47	5.30	5.13	5.11	5.15	5.31	5.49	5.71	6.90
Liquefied Petroleum Gas	3.11	5.25	9.04	6.54	6.30	6.15	6.16	6.39	6.63	6.88	9.06
All Petroleum Products	**2.62**	**4.45**	**6.72**	**6.32**	**6.10**	**5.97**	**5.97**	**6.15**	**6.34**	**6.56**	**8.30**
Natural Gas[3]	1.95	3.27	5.59	5.55	5.48	5.46	5.59	5.77	6.08	6.43	8.34
Steam Coal[4]	.94	1.89	2.01	2.06	2.08	2.11	2.13	2.16	2.18	2.22	2.35
Electricity	15.08	19.48	19.75	19.80	20.04	20.24	20.41	20.42	20.17	19.99	19.75
Average[2]	**5.49**	**8.40**	**10.93**	**11.07**	**11.22**	**11.29**	**11.45**	**11.60**	**11.71**	**11.89**	**13.24**
Industrial											
Distillate Fuel	1.98	4.21	6.53	6.28	6.05	5.90	5.91	6.13	6.34	6.58	8.59
Kerosene	2.13	4.61	6.88	6.62	6.39	6.24	6.25	6.47	6.70	6.95	9.06
Motor Gasoline	6.62	7.82	10.38	10.19	9.96	9.72	9.72	9.95	10.16	10.33	12.69
Residual Fuel	1.69	3.16	4.53	4.35	4.18	4.16	4.21	4.38	4.55	4.78	5.97
Liquefied Petroleum Gas	2.99	5.17	7.85	6.69	6.46	6.30	6.31	6.53	6.77	7.02	9.17
Petrochemical Feedstocks[5]	1.98	4.21	6.16	5.90	5.65	5.47	5.48	5.71	5.93	6.18	8.28
Still Gas[6]	1.98	4.21	6.43	6.19	5.97	5.82	5.84	6.05	6.27	6.51	8.54
Other Petroleum[7]	1.98	4.21	5.16	5.15	4.87	4.78	4.79	4.88	4.96	5.05	5.68
All Petroleum Products	**2.19**	**4.22**	**6.30**	**5.87**	**5.64**	**5.52**	**5.55**	**5.74**	**5.94**	**6.15**	**7.85**
Natural Gas[8]	1.05	2.23	4.33	4.30	4.30	4.31	4.45	4.64	4.91	5.26	7.08
Steam Coal	.96	1.93	1.86	1.93	1.97	2.02	2.06	2.10	2.14	2.19	2.40
Metallurgical Coal	1.49	2.98	2.29	2.34	2.37	2.39	2.41	2.43	2.46	2.49	2.60
Net Coke Imports	1.93	4.55	4.08	4.16	4.21	4.25	4.28	4.32	4.36	4.41	4.60
Electricity	7.72	12.19	16.59	16.66	16.81	16.97	17.11	17.07	16.83	16.65	16.33
Average[2]	**2.06**	**4.15**	**6.44**	**6.16**	**6.09**	**6.06**	**6.16**	**6.34**	**6.52**	**6.75**	**8.18**

See footnotes at end of table.

Table A5. Prices by Major Fuels and End-Use Sectors (Continued)
(1984 Dollars per Million Btu)

Sector and Fuel	Middle World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Transportation[9]											
Aviation Gasoline	7.94	10.47	13.95	13.62	13.24	12.84	12.84	13.22	13.58	13.88	17.88
Distillate Fuel	3.48	5.04	9.58	9.34	9.12	8.97	8.98	9.19	9.42	9.65	11.68
Jet Fuel[10]	2.05	4.53	6.77	6.49	6.22	6.02	6.04	6.27	6.50	6.75	8.89
Motor Gasoline[11]	6.55	7.78	10.29	10.10	9.88	9.63	9.64	9.86	10.07	10.25	12.61
Residual Fuel[12]	1.35	2.25	3.60	3.43	3.27	3.26	3.30	3.46	3.64	3.87	5.07
Liquefied Petroleum Gas	2.87	4.78	8.38	9.98	9.75	9.59	9.60	9.83	10.07	10.32	12.49
Lubricants and Waxes[13]	12.48	14.88	24.54	24.13	23.75	23.49	23.51	23.88	24.26	24.66	28.13
All Petroleum Products	**5.47**	**6.86**	**9.63**	**9.45**	**9.23**	**8.99**	**8.97**	**9.17**	**9.37**	**9.56**	**11.77**
Natural Gas[14]	.45	1.33	2.64	2.62	2.60	2.58	2.72	2.91	3.14	3.42	4.91
Electricity	5.67	9.48	19.00	18.99	19.24	19.47	19.68	19.70	19.43	19.24	19.02
Average[2]	**5.27**	**6.72**	**9.43**	**9.24**	**9.03**	**8.79**	**8.77**	**8.96**	**9.17**	**9.36**	**11.56**
Electric Utilities											
Distillate Fuel[15]	1.87	3.70	7.79	7.12	6.66	5.36	5.60	6.55	7.09	7.12	8.70
Residual Fuel	1.65	3.17	4.69	4.53	4.38	4.44	4.50	4.67	4.85	5.08	6.41
All Petroleum Products	**1.67**	**3.20**	**4.89**	**4.75**	**4.48**	**4.45**	**4.51**	**4.72**	**4.91**	**5.15**	**6.58**
Natural Gas	.73	2.11	3.60	3.47	3.59	3.50	3.64	3.80	4.02	4.35	5.89
Steam Coal	.95	1.78	1.72	1.81	1.83	1.85	1.86	1.88	1.90	1.92	2.05
Fossil Fuel Average	**1.05**	**2.17**	**2.31**	**2.31**	**2.29**	**2.27**	**2.30**	**2.36**	**2.41**	**2.49**	**2.98**
Average Price to All Users											
Distillate Fuel	3.02	4.83	8.33	7.91	7.71	7.56	7.57	7.79	8.02	8.27	10.39
Kerosene	3.05	5.21	7.35	6.98	6.74	6.58	6.58	6.79	7.02	7.26	9.34
Aviation Gasoline	7.94	10.47	13.95	13.62	13.24	12.84	12.84	13.22	13.58	13.88	17.88
Motor Gasoline	6.55	7.78	10.30	10.10	9.88	9.64	9.64	9.86	10.07	10.25	12.61
Jet Fuel	2.05	4.53	6.77	6.49	6.22	6.02	6.04	6.27	6.50	6.75	8.89
Residual Fuel	1.65	3.04	4.48	4.31	4.14	4.16	4.20	4.37	4.55	4.78	6.06
Liquefied Petroleum Gas	2.99	5.17	7.85	6.69	6.46	6.30	6.31	6.53	6.77	7.02	9.17
Petrochemical Feedstocks	1.98	4.21	6.16	5.90	5.65	5.47	5.48	5.71	5.93	6.18	8.28
Lubricants and Waxes	12.48	14.88	24.54	24.13	23.75	23.49	23.51	23.88	24.26	24.66	28.13
Other Petroleum Products	1.98	4.21	5.63	5.37	5.15	5.01	5.02	5.21	5.42	5.65	7.51
All Petroleum Products	**4.02**	**5.62**	**8.30**	**7.98**	**7.75**	**7.54**	**7.51**	**7.68**	**7.86**	**8.04**	**9.92**
Natural Gas	1.42	2.68	4.82	4.70	4.69	4.69	4.83	5.00	5.29	5.63	7.41
Coal	1.07	1.97	1.77	1.86	1.88	1.91	1.92	1.95	1.96	1.99	2.12
Electricity	12.34	16.32	18.54	18.62	18.82	18.99	19.12	19.07	18.82	18.62	18.30
Average	**3.37**	**5.15**	**7.02**	**6.85**	**6.74**	**6.69**	**6.75**	**6.87**	**7.00**	**7.15**	**8.31**

[1] Projected residential coal prices are delivered to dealer prices and do not include dealer markup.
[2] Weighted average of end-use fuel prices consists of the prices shown above and the appropriate weights from Table 4.
[3] Commercial natural gas price is a weighted average of the commercial and other category.
[4] Historical price for commercial steam coal is the price of industrial steam coal at the State level. Projected prices do not include dealer markup, where applicable.
[5] Industrial distillate price is used in historical years (through 1978).
[6] The industrial distillate price is used. For 1983 forward, differences between the national prices of still gas and distillate fuel oil are due to differences in the regional composition of demand for these fuels.
[7] Industrial other price is a weighted average price for road oil, asphalt, lubricants, waxes, petroleum coke, special naphthas, and miscellaneous petroleum products.
[8] Industrial natural gas price is a weighted average of the lease and plant fuel price and the industrial price. In these reports, the natural gas price for industrial heat and power is used for the lease and plant fuel price, so both components of the average are the same.
[9] Transportation prices include the appropriate Federal excise tax and State road use taxes.
[10] Jet fuel price is for kerosene type jet fuel at retail.
[11] Gasoline price is an average for all types.
[12] Residual fuel price is for marine bunker.
[13] Historical price is the price of industrial lubricants.
[14] Transportation natural gas price is for pipeline fuel use only. The average wellhead price from Table 17 is used as a surrogate price.
[15] Historical price for electric utility distillate fuel oil is the price of electric utility kerosene.

NOTE: Metallurgical coal prices reflect a reduced level of projected demand. Projected coal prices are based on cost estimates and do not reflect market conditions.
NOTE: Electricity and natural gas prices are average prices, revenue divided by sales. Also, the electricity prices are averages for class A and B private electric utilities and public power authorities.
NOTE: Implicit Gross National Product Price Deflator, rebased to 1984 = 1.0, was used to convert from nominal to real dollars.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical prices are taken from Energy Information Administration, *State Energy Price and Expenditure Report*, (DOE/EIA-0376 (81) (Washington, DC, 1984), pp. 1-7. Projected prices are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = Middle World Oil Price Case, printed on December 21, 1984.
Historical prices through 1981.

Table A6. Residential Energy Use by End Use

(Quadrillion Btu per Year)

Fuel and End Use	Middle World Oil Price Case								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
Marketed Fuel Consumption[1]									
Fuel Use									
Space Heating	4.51	4.68	4.67	4.73	4.79	4.83	4.85	4.86	4.65
Water Heating	1.63	1.66	1.65	1.65	1.67	1.68	1.69	1.71	1.78
Air Conditioning	0.38	.39	.40	.40	.41	.42	.43	.44	.50
Other End Uses[2]	2.21	2.22	2.25	2.27	2.29	2.32	2.36	2.40	2.62
Total	**8.73**	**8.94**	**8.97**	**9.05**	**9.16**	**9.25**	**9.34**	**9.41**	**9.55**
Liquefied Petroleum Gas									
Space Heating	.21	.18	.19	.20	.21	.22	.22	.22	.19
Water Heating	.09	.07	.07	.07	.08	.08	.08	.08	.08
Total	**.30**	**.25**	**.27**	**.28**	**.29**	**.30**	**.30**	**.30**	**.27**
Fuel Oil[3]									
Space Heating	.93	1.06	1.02	1.04	1.06	1.07	1.07	1.07	.98
Water Heating	.21	.24	.22	.22	.22	.22	.22	.22	.22
Total	**1.14**	**1.30**	**1.24**	**1.26**	**1.28**	**1.29**	**1.29**	**1.29**	**1.20**
Natural Gas									
Space Heating	3.06	3.12	3.12	3.13	3.14	3.15	3.15	3.14	2.96
Water Heating	1.02	1.03	1.03	1.03	1.03	1.03	1.04	1.04	1.06
Air Conditioning	.01	.01	.01	.01	.01	.01	.01	.02	.02
Other End Uses[2]	.56	.56	.55	.55	.55	.55	.55	.55	.56
Total	**4.65**	**4.72**	**4.72**	**4.72**	**4.74**	**4.75**	**4.76**	**4.75**	**4.59**
Coal									
Space Heating	.08	.07	.07	.07	.07	.07	.06	.06	.06
Total	**.08**	**.07**	**.07**	**.07**	**.07**	**.07**	**.06**	**.06**	**.06**
Electricity									
Space Heating	.23	.25	.27	.29	.31	.32	.34	.36	.46
Water Heating	.31	.32	.33	.33	.34	.35	.36	.37	.42
Air Conditioning	.37	.37	.38	.39	.40	.41	.42	.43	.49
Other End Uses[2]	1.65	1.66	1.69	1.72	1.74	1.77	1.81	1.85	2.06
Total	**2.56**	**2.61**	**2.68**	**2.73**	**2.79**	**2.85**	**2.92**	**3.01**	**3.43**
Nonmarketed Fuel Consumption[1]									
Wood	**1.04**	**0.92**	**0.94**	**0.95**	**0.96**	**0.97**	**0.97**	**0.98**	**1.04**
Residential Activity									
Occupied Housing Stock (million units)	84.9	86.5	88.2	89.7	91.3	92.9	94.7	96.3	104.1
New Housing Construction[4] (million units)	1.5	2.0	2.1	1.9	2.1	2.1	2.2	2.1	1.9
Income Per Household (thousand 1984 dollars)	22.0	22.0	22.3	22.3	22.5	22.7	22.9	23.1	23.7
Energy Use Per Household (million Btu)	103	103	102	101	100	100	99	98	92
Fuel Expenditure Per Household (1984 dollars)	1,070	1,057	1,047	1,046	1,057	1,067	1,078	1,094	1,182

[1] Residential fuels are divided into marketed fuels (those with an associated price that are traded in economic markets) and nonmarketed fuels.
[2] Major other end uses include lighting, cooking, refrigeration, washing, and drying.
[3] Residential fuel oil category includes kerosene and distillate oil.
[4] New housing construction includes completions of single family, multifamily, and mobile housing units.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: The Residential model is documented in *Model Documentation: Household Model of Energy*, Energy Information Administration (DOE/EIA-0409) (Washington, DC, 1984). The major model data source is the public use tape of the Residential Energy Consumption Survey 1981, Energy Information Administration.
Input data file: Historical = MRG1126T, Projected = Middle World Oil Price Case, printed on December 21, 1984.
Historical quantities through 1983.

Table A7. Commercial Energy Use by Building Type
(Quadrillion Btu per Year)

Fuel and Building Type	Middle World Oil Price Case								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
Marketed Fuel Consumption									
Total Fuel Use	**5.75**	**6.15**	**6.24**	**6.37**	**6.52**	**6.66**	**6.80**	**6.93**	**7.30**
Liquefied Petroleum Gas	**.05**	**.03**	**.03**	**.03**	**.03**	**.03**	**.03**	**.03**	**.02**
Motor Gasoline	**.09**	**.09**	**.08**	**.08**	**.08**	**.08**	**.08**	**.08**	**.08**
Fuel Oil[1]									
Office[2]	.26	.31	.30	.32	.33	.35	.36	.37	.40
Retail/Wholesale	.17	.20	.19	.20	.21	.22	.23	.24	.25
Warehouse	.12	.15	.15	.17	.18	.19	.21	.22	.26
Other Buildings[3]	.22	.25	.25	.26	.27	.28	.29	.30	.32
Total	**.77**	**.90**	**.90**	**.95**	**1.00**	**1.05**	**1.09**	**1.13**	**1.23**
Natural Gas									
Office[2]	.74	.75	.75	.76	.77	.77	.78	.78	.75
Retail/Wholesale	.75	.77	.78	.79	.80	.81	.82	.83	.83
Warehouse	.35	.36	.36	.37	.37	.37	.37	.37	.36
Other Buildings[3]	.76	.78	.78	.78	.78	.78	.78	.78	.73
Total	**2.60**	**2.66**	**2.67**	**2.69**	**2.72**	**2.74**	**2.76**	**2.76**	**2.67**
Coal	**.12**	**.11**	**.12**	**.12**	**.12**	**.12**	**.12**	**.11**	**.11**
Electricity									
Office[2]	.81	.90	.93	.95	.98	1.01	1.04	1.07	1.22
Retail/Wholesale	.61	.68	.71	.73	.75	.78	.80	.83	.95
Warehouse	.29	.32	.33	.34	.35	.36	.37	.38	.44
Other Buildings[3]	.41	.46	.47	.48	.49	.50	.52	.53	.59
Total	**2.12**	**2.36**	**2.45**	**2.51**	**2.58**	**2.65**	**2.73**	**2.81**	**3.20**
Commercial Activity									
Building Floorspace Stock (billion square feet)	48.5	51.1	52.6	53.8	55.3	56.7	58.3	59.7	66.3
Office[2]	17.0	18.0	18.6	19.0	19.5	20.0	20.5	21.1	23.4
Retail/Wholesale	14.5	15.4	15.9	16.3	16.8	17.3	17.9	18.4	20.6
Warehouse	6.9	7.2	7.5	7.7	7.9	8.1	8.3	8.6	9.5
Other Buildings[3]	10.1	10.5	10.7	10.9	11.1	11.3	11.5	11.7	12.7
Energy Use Per Square Foot (thousand Btu)	118.6	120.4	118.6	118.4	118.0	117.4	116.7	116.0	110.2
Expenditures Per Square Foot (1984 dollars)	1.30	1.31	1.31	1.32	1.33	1.34	1.35	1.36	1.44

[1] The commercial fuel oil category includes kerosene, distillate fuel, and residual fuel.
[2] Office includes offices, educational buildings, laboratories, health clinics, and some public buildings.
[3] Other Buildings includes assembly buildings, hotels/motels, hospitals, parking garages, and jails.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: The Commercial model is documented in *Model Documentation: Commercial Sector Energy Model*, Energy Information Administration (DOE/EIA-0453), August 1984. The major model source is the public use tape of the Nonresidential Energy Consumption Survey 1980, Energy Information Administration.
Input data file: Historical = MRG1126T, Projected = Middle World Oil Price Case, printed on December 21, 1984.
Historical quantities through 1983.

Table A8. Industrial Energy Use
(Quadrillion Btu per Year)

Fuel and End Use	Middle World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Industrial Heat and Power											
Distillate Fuel	1.44	1.70	1.29	1.60	1.53	1.57	1.62	1.67	1.70	1.73	1.84
Residual Fuel	1.58	1.40	.65	.85	.82	.83	.88	.91	.94	.96	1.03
Liquefied Petroleum Gas	.13	.20	.57	.33	.33	.33	.34	.34	.35	.35	.35
Natural Gas[1]	8.50	7.08	5.56	6.08	6.22	6.26	6.42	6.55	6.54	6.53	6.26
Steam Coal[2]	1.43	1.46	1.50	1.72	1.75	1.91	1.99	2.08	2.15	2.23	2.46
Electricity[3]	2.34	2.76	2.65	2.63	2.67	2.75	2.91	3.07	3.22	3.39	4.09
Total	**15.43**	**14.61**	**12.21**	**13.21**	**13.32**	**13.65**	**14.16**	**14.62**	**14.90**	**15.19**	**16.03**
Refinery Fuel											
Distillate Fuel	.03	.05	.01	.01	.01	.01	.01	.01	.01	.01	.01
Residual Fuel	.28	.31	.13	.13	.12	.12	.13	.13	.13	.13	.14
Liquefied Petroleum Gas	.04	.06	.03	.03	.03	.03	.03	.03	.03	.03	.03
Still Gas	1.06	1.20	1.13	1.16	1.21	1.21	1.22	1.23	1.24	1.25	1.33
Petroleum Coke	.40	.39	.40	.42	.39	.39	.39	.40	.40	.41	.43
Other Petroleum	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Electricity	NA	NA	NA	.12	.11	.12	.12	.12	.12	.12	.13
Natural Gas	1.11	.82	.59	.66	.63	.63	.63	.64	.64	.65	.69
Total	**2.92**	**2.84**	**2.28**	**2.52**	**2.49**	**2.50**	**2.52**	**2.54**	**2.56**	**2.59**	**2.75**
Feedstocks, Raw Materials, and Other Fuel Uses											
Motor Gasoline	.26	.18	.14	.13	.14	.16	.18	.20	.22	.25	.38
Kerosene	.16	.16	.14	.10	.09	.09	.09	.09	.09	.09	.08
Petroleum Feedstocks[4]	.73	1.22	.85	1.38	1.48	1.47	1.56	1.63	1.64	1.65	1.62
Liquefied Petroleum Gas[5]	1.07	.99	1.01	1.17	1.21	1.25	1.38	1.50	1.57	1.65	1.97
Special Naphthas	.17	.20	.16	.21	.21	.22	.23	.25	.25	.26	.27
Lubricants and Waxes	.23	.23	.20	.23	.23	.23	.24	.25	.25	.25	.26
Petroleum Coke	.16	.16	.10	.13	.20	.23	.26	.29	.31	.35	.52
Asphalt and Road Oil	1.26	1.16	.90	1.01	1.11	1.14	1.17	1.20	1.22	1.23	1.25
Net Blending Oil[6]	.12	.27	.06	-.01	-.06	-.10	-.13	-.13	-.14	-.14	-.04
Metallurgical Coal[2]	2.54	1.79	.96	1.15	1.19	1.25	1.32	1.37	1.38	1.38	1.34
Natural Gas Raw Materials[7]	.78	.63	.49	.55	.55	.56	.56	.57	.57	.57	.55
Net Coke Imports	-.01	.13	-.02	.00	.00	.00	.00	.00	.00	.00	.00
Hydropower	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03
Total	**7.49**	**7.15**	**5.03**	**6.06**	**6.37**	**6.51**	**6.90**	**7.23**	**7.41**	**7.56**	**8.22**
Total Industrial Demand	**25.84**	**24.60**	**19.52**	**21.78**	**22.19**	**22.66**	**23.58**	**24.39**	**24.87**	**25.35**	**27.01**

[1] Includes lease and plant fuel.
[2] Includes refinery steam coal. The metallurgical coal estimates for 1983 and 1984 are not fully comparable, in part because of different Btu conversion factors.
[3] Includes refinery electricity before 1984.
[4] Petrochemical feedstocks includes naphthas less than 400 degrees, other oils greater than 400 degrees, and some still gas.
[5] The LPG price for Industrial Heat and Power is used for LPG feedstocks in weighted average price calculations.
[6] Net blending oil includes jet fuel, plant condensate, unfractionated stream, some still gas, miscellaneous, natural gasoline, unfinished oils, aviation blending components, and motor gasoline blending components, net of oil reclassified in blending.
[7] The natural gas price for Industrial Heat and Power is used for natural gas raw materials in weighted average price calculations.
NA = Not available.

NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: The Industrial model is documented in *Documentation of the PURHAPS Industrial Demand Model, Vol 1: Model Description, Overview, and Assumptions for the 1983 Annual Energy Outlook*, DOE/EIA-0420/1 (Washington, DC, 1984).
Input data file: Historical = MRG1126T, Projected = Middle World Oil Price Case, printed on December 21, 1984.
Historical quantities through 1983.

Table A9. Transportation Sector Energy Use By Mode

Fuel and Mode of Transportation	Middle World Oil Price Case								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
All Modes[1]									
Aviation Gasoline	0.05	0.07	0.07	0.07	0.08	0.08	0.08	0.09	0.10
Distillate Fuel	2.84	2.67	2.63	2.70	2.79	2.89	3.01	3.14	3.98
Jet Fuel	2.14	2.35	2.34	2.43	2.53	2.59	2.66	2.71	2.80
Motor Gasoline	12.47	12.67	12.57	12.18	11.93	11.76	11.65	11.58	11.36
Residual Fuel	.75	.74	.72	.73	.77	.79	.82	.84	.92
Liquefied Petroleum Gas	.03	.01	.01	.01	.01	.01	.01	.01	.01
Lubricants	.16	.22	.22	.23	.23	.24	.24	.25	.27
Natural Gas	.58	.61	.62	.61	.62	.63	.63	.63	.63
Electricity	.01	.01	.01	.01	.01	.01	.01	.01	.01
Total Consumption	**19.02**	**19.35**	**19.18**	**18.97**	**18.96**	**19.00**	**19.10**	**19.24**	**20.08**
Automobiles									
Vehicle-Miles Travelled[2]	1149.7	1,252.8	1,315.4	1,343.5	1,378.3	1,416.3	1,457.9	1,501.6	1,704.8
Fleet-Miles per Gallon	16.5	17.5	18.4	19.3	20.1	20.8	21.4	22.1	24.6
Total Fuel Use[3]	69.5	71.6	71.4	69.7	68.7	68.1	68.0	68.1	69.4
Trucks									
Vehicle-Miles Travelled[2]	449.1	484.6	498.5	509.1	522.0	537.0	553.6	571.8	682.4
Fleet-Miles per Gallon	10.5	11.1	11.6	12.0	12.4	12.8	13.2	13.6	15.2
Total Fuel Use[3]	42.6	43.8	43.1	42.4	42.0	41.8	41.9	42.1	44.8
Air									
Revenue Passenger-Miles[2]	300.1	354.3	370.0	401.2	437.2	468.6	500.9	530.2	654.6
Fuel Burned Per Seat-Mile[4]	.023	.022	.022	.021	.020	.019	.018	.017	.014
Total Jet Fuel[3]	16.0	17.6	17.5	18.2	18.9	19.4	19.9	20.3	21.0
Aviation Gasoline[3]	.4	.6	.6	.6	.6	.7	.7	.7	.8
Selected Fuel Expenditures[5]									
Motor Gasoline	128.4	128.0	124.1	117.3	115.0	115.9	117.3	118.7	143.3
Distillate Fuel	27.2	24.9	24.0	24.2	25.0	26.6	28.3	30.3	46.5

[1] Quadrillion Btu per year.
[2] Billion per year.
[3] Billion gallons per year.
[4] Gallons.
[5] Billion 1984 dollars per year.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Input data file: Historical = MRG1126T, Projected = Middle World Oil Price Case, printed on December 28, 1984.
Historical quantities through 1983.

Table A10. Electric Utility Fuel Consumption and Electricity Sales
(Quadrillion Btu per Year)

Fuel Consumption and Sales	Middle World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Fuel Inputs											
Oil											
Distillate	0.27	0.28	0.10	0.11	0.05	0.02	0.01	0.03	0.03	0.04	0.15
Residual LS[1]	NA	NA	NA	.69	.65	.70	.69	.72	.73	.79	1.25
Residual HS[1]	3.24	3.71	1.45	.51	.48	.44	.42	.42	.42	.45	.63
Natural Gas	3.75	3.30	3.01	3.27	3.33	3.11	3.14	3.25	3.34	3.39	3.88
Steam Coal	8.66	10.25	13.23	14.05	14.94	15.01	15.32	15.65	16.16	16.86	19.89
Nuclear Power	.91	3.02	3.23	3.70	4.10	4.72	5.31	5.79	6.09	6.32	7.09
Hydropower/Other[2]	2.87	2.97	3.61	3.55	3.11	3.29	3.30	3.30	3.32	3.33	3.36
Total Fuel Inputs	19.71	23.53	24.63	25.87	26.66	27.28	28.19	29.16	30.10	31.18	36.25
Net Imports	.15	.20	.37	.41	.43	.48	.53	.58	.64	.70	.78
Total Electricity Inputs	**19.85**	**23.74**	**25.00**	**26.27**	**27.09**	**27.77**	**28.72**	**29.74**	**30.74**	**31.88**	**37.04**
Disposition											
Total Electricity Inputs	19.85	23.74	25.00	26.27	27.09	27.77	28.72	29.74	30.74	31.88	37.04
Minus Conversion Losses[3]	13.50	16.21	17.12	17.99	18.58	19.03	19.70	20.41	21.11	21.89	25.43
Generation	6.35	7.53	7.88	8.28	8.50	8.73	9.03	9.33	9.64	9.99	11.61
Minus Transportation and Distribution Losses	.51	.64	.55	.57	.58	.62	.63	.63	.64	.64	.75
Electricity Sales	**5.84**	**6.89**	**7.34**	**7.72**	**7.92**	**8.11**	**8.40**	**8.70**	**9.00**	**9.34**	**10.86**
Electricity Sales by End-Use Sector											
Residential	1.98	2.30	2.56	2.61	2.68	2.73	2.79	2.85	2.92	3.01	3.43
Commercial/Other[4]	1.53	1.82	2.13	2.37	2.46	2.52	2.59	2.66	2.74	2.82	3.21
Industrial	2.34	2.76	2.65	2.74	2.78	2.86	3.02	3.19	3.34	3.51	4.22
Total Electricity Sales	**5.84**	**6.89**	**7.34**	**7.72**	**7.92**	**8.11**	**8.40**	**8.70**	**9.00**	**9.34**	**10.86**

[1] Prior to 1984, only the total of high-sulfur and low-sulfur residual oil is available, and is reported here as high-sulfur.
[2] Includes renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[3] Conversion losses includes net imports.
[4] Commercial/Other includes street lighting and the transportation sector.
[NA] = Not available.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Input data file: Historical = MRG1126T, Projected = Middle World Oil Price Case, printed on December 21, 1984. Historical quantities through 1983.

Table A11. Electric Utility Sectoral Prices and Demands
(Billion Kilowatthours per Year)
(1984 Dollars per Thousand Kilowatthours)

Prices and Demands	Middle World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Prices[1]											
Residential	53.70	64.16	66.69	66.96	67.58	68.12	68.56	68.44	67.66	67.06	66.09
Commercial[2]	51.28	66.28	67.39	67.53	68.35	69.04	69.64	69.66	68.81	68.19	67.38
Industrial	26.34	41.59	56.62	56.85	57.34	57.89	58.38	58.23	57.44	56.81	55.73
All Sectors	**42.11**	**55.67**	**63.26**	**63.54**	**64.22**	**64.79**	**65.23**	**65.07**	**64.22**	**63.55**	**62.44**
Demands											
Residential	579	674	751	764	784	800	817	836	857	882	1,005
Commercial[2]	448	534	624	695	721	738	759	780	802	827	941
Industrial	686	809	776	804	816	839	885	935	978	1,029	1,236
All Sectors	**1,713**	**2,018**	**2,151**	**2,262**	**2,321**	**2,376**	**2,461**	**2,551**	**2,637**	**2,738**	**3,182**

[1] Prices for 1983 to 1995 are from model simulations and represent average revenues per kilowatthour of demand for the total electric utility industry. Revenue requirements are projected from the financial information contained on the Federal Energy Regulatory Commission Form 1 and Form 1-M and on the Energy Information Administration Form 412.
[2] This category includes consumption for street and highway lighting, other public authorities, and railroads and railways.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Prices for 1973 and 1978 are from the Energy Information Administration, *State Energy Price and Expenditure Report*, DOE/EIA-0376(81) (Washington, DC, 1984), pp.1-7. Historical demands are from the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83), (Washington, DC, 1984).

Table A12. Electric Utility Capacity and Generation
(Generation in Billion Kilowatthours per Year)
(Capacity in Million Kilowatts)

Capacity and Generation	Middle World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Capacity[1]											
Coal Steam	184.0	233.9	285.9	296.0	303.8	309.6	314.2	317.3	323.7	328.5	360.4
Other Steam	135.0	161.4	157.2	157.2	157.2	157.2	157.2	157.2	157.2	157.2	157.2
Combined Cycle	1.3	4.9	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.8	5.8
Turbine	37.1	49.6	50.7	51.0	51.4	51.6	51.6	51.7	52.3	52.7	59.0
Nuclear Power	21.0	53.5	64.4	68.9	80.5	91.4	99.8	104.7	105.9	109.6	116.8
Hydropower/Other[2]	55.6	63.2	69.0	69.8	71.0	71.4	71.6	72.0	72.2	72.9	73.1
Pumped Storage Hydropower[3]	8.4	12.7	13.3	14.6	16.0	16.7	16.7	16.9	18.8	19.1	19.2
Total Capacity	442.4	579.2	**646.2**	**663.2**	**685.5**	**703.5**	**716.8**	**725.5**	**735.8**	**745.8**	**791.6**
Generation by Plant Type[4]											
Coal Steam	848	976	1,268	1,347	1,428	1,436	1,467	1,499	1,549	1,617	1,913
Other Steam	619	629	365	369	356	348	348	361	371	382	458
Combined Cycle	NA	13	32	33	32	28	28	28	28	30	32
Turbine	36	29	13	15	15	14	14	15	15	14	42
Nuclear Power	83	276	294	335	372	428	482	526	553	574	644
Hydropower/Other[2]	274	284	345	336	295	315	315	316	318	321	324
Pumped Storage Hydropower[3]	NA	NA	–6	–6	–6	–9	–9	–10	–10	–11	–12
Total Generation	**1,861**	**2,206**	**2,310**	**2,428**	**2,492**	**2,559**	**2,645**	**2,736**	**2,824**	**2,927**	**3,401**
Generation by Fuel Type											
Coal[5]	848	976	1,259	1,341	1,422	1,430	1,461	1,493	1,543	1,610	1,906
Natural Gas	341	305	274	299	301	285	288	298	307	312	349
Oil	314	365	144	124	109	111	108	112	113	121	190
Nuclear Power	83	276	294	335	372	428	482	526	553	574	644
All Hydropower/Other[6]	274	283	339	329	289	306	306	306	308	309	312
Total Generation	**1,861**	**2,206**	**2,310**	**2,428**	**2,492**	**2,559**	**2,645**	**2,736**	**2,824**	**2,927**	**3,401**

[1] Capacity for 1973 and 1978 include capacity out of service or in inactive reserve; 1983 and projected capacity exclude capacity out of service or in inactive reserve. Three Mile Island Unit 1 is included in the 1983 and 1984 capacity estimates but is not expected to restart opetation until 1985.

[2] This category includes other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

[3] See Glossary, Electricity Terminology for definition of pumped storage plant.

[4] Net generation data for 1973 excludes combined cycle generation. For 1973 and 1978 the hydropower/other category also contains pumped storage hydropower. The 1983 values are model estimates based on the best available data.

[5] Generation by coal and generation by coal steam plants are not identical because small amounts of oil and natural gas are used in coal steam plants for startup and flame stability.

[6] This category includes conventional and pumped storage hydropower and other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Generation data for 1973, 1978, and 1983 are from the Energy Information Administration, *Form EIA-759, "Monthly Power Plant Report."* Historical capacity data for 1973 and 1978 are based on the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984). Other capacity data are from the Intermediate Future Forecasting System.

Table A13. Electric Utility Capacity Additions
(Thousand Kilowatts)

Additions: Pipeline and New Starts	Middle World Oil Price Case												
	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Total Additions													
Nuclear Power[1]	3,064	4,480	12,369	10,939	8,391	4,884	1,235	3,702	3,690	2,464	1,065	0	0
Coal Steam	5,720	10,082	7,783	5,860	4,586	3,109	6,394	4,782	10,654	5,025	6,728	4,269	5,254
Other Steam[2]	61	3	0	0	0	0	0	100	0	0	0	0	0
Turbines[3]	202	275	385	197	40	130	561	343	330	264	531	2,707	2,497
Pumped Storage Hydropower[4]	260	1,264	1,400	700	0	200	1,923	285	0	0	0	150	0
Hydropower/Other[5]	1,034	874	1,163	383	242	407	200	706	75	74	26	0	6
Total New Capacity	**10,342**	**16,978**	**23,100**	**18,078**	**13,258**	**8,729**	**10,313**	**9,919**	**14,749**	**7,827**	**8,350**	**7,127**	**7,757**
Pipeline[6]													
Nuclear Power[1]	3,064	4,480	12,369	10,939	8,391	4,884	1,235	3,702	3,690	2,464	1,065	0	0
Coal Steam	5,720	10,082	7,783	5,860	4,586	3,109	6,394	4,782	10,654	5,025	5,718	2,764	3,347
Other Steam[2]	61	3	0	0	0	0	0	100	0	0	0	0	0
Turbines[3]	202	275	385	197	40	130	561	343	330	113	200	0	143
Pumped Storage Hydropower[4]	260	1,264	1,400	700	0	200	1,923	285	0	0	0	150	0
Hydropower/Other[5]	1,034	874	1,163	383	242	407	200	706	75	74	26	0	6
Total Pipeline	**10,342**	**16,978**	**23,100**	**18,078**	**13,258**	**8,729**	**10,313**	**9,919**	**14,749**	**7,676**	**7,009**	**2,914**	**3,496**
New Starts[7]													
Nuclear Power[1]	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal Steam	0	0	0	0	0	0	0	0	0	0	1,010	1,506	1,907
Other Steam[2]	0	0	0	0	0	0	0	0	0	0	0	0	0
Turbines[3]	0	0	0	0	0	0	0	0	0	151	331	2,707	2,354
Pumped Storage Hydropower[4]	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydropower/Other[5]	0	0	0	0	0	0	0	0	0	0	0	0	0
Total New Starts	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**151**	**1,341**	**4,213**	**4,261**

[1] Includes the scheduled return to service of the Three Mile Island 1 facility.
[2] Includes natural gas, oil, and dual fired oil/natural gas steam and combined cycle capacity.
[3] Includes all gas turbine and internal combustion capacity.
[4] See Glossary, Electricity Terminology for definition of pumped storage plant.
[5] Includes conventional hydroelectric and other renewable sources of power such as geothermal, wood, waste, solar, and wind.
[6] Includes all new capacity announced by the electric utility industry.
[7] Includes additional new capacity considered necessary to meet projected electricity demands.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: The Energy Information Administration Generating Unit Reference file (GURF); the Federal Energy Regulatory Commission, *Hydroelectric Power Resources of the United States - Developed and Undeveloped*, FERC-0070, January 1, 1980; Energy Information Administration, *U.S. Commercial Nuclear Power*, DOE/EIA-0315 (Washington, DC, March 1982); and the Energy Information Administration Form-254: "Quarterly Progress Report on Status of Reactor Construction."

Table A14. Summary of Components of Electricity Price
(1984 Dollars per Thousand Kilowatthours)

Price Components	Middle World Oil Price Case												
	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Capital Component[1]	25.44	25.52	25.53	26.30	26.67	26.27	25.06	23.84	22.97	22.13	21.10	20.14	19.28
Fuel Component[2]	22.65	22.81	23.18	22.69	22.77	23.16	23.66	24.38	25.06	25.82	26.59	27.46	28.51
O&M Component[3]	15.25	15.21	15.51	15.80	15.79	15.64	15.50	15.32	15.18	15.08	14.93	14.80	14.65
Total Price[4]	**63.34**	**63.54**	**64.22**	**64.79**	**65.23**	**65.07**	**64.22**	**63.55**	**63.22**	**63.03**	**62.61**	**62.39**	**62.44**

[1] The capital component represents the cost to the utility of capital assets needed to provide reliable service. It includes plant depreciation, taxes, and sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.
[2] The fuel component includes only the direct costs of fuel inputs used to generate electricity required to meet demand.
[3] The operation and maintenance (O&M) component includes all nonfuel costs necessary to operate and maintain generation, transmission, and distribution capacity used to deliver electricity to end-use sectors.
[4] All prices are from model simulations and represent average revenues per kilowatthour of demand for the total electric utility industry. Revenue requirements are projected from the financial information contained on the Federal Energy Regulatory Commission, Form FERC-1 and Form 1-M and on the Energy Information Administration, Form EIA-412.
NOTE: Total may not equal sum of components because of independent rounding.

Table A15. Petroleum Supply and Disposition Balance
(Million Barrels per Day)

Supply and Disposition	Middle World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Crude Oil[1]	9.21	8.71	8.69	8.76	8.86	8.70	8.59	8.45	8.28	8.25	7.19
Alaska North Slope	.00	1.09	1.65	1.67	1.70	1.76	1.92	1.97	2.02	2.14	1.20
Subarctic	9.21	7.62	7.04	7.08	7.15	6.95	6.67	6.47	6.26	6.11	5.98
Natural Gas Plant Liquids	1.74	1.57	1.56	1.61	1.64	1.55	1.54	1.51	1.49	1.48	1.29
Other Domestic[2]	.00	.00	.05	.05	.05	.05	.05	.05	.07	.09	.35
Processing Gain[3]	.45	.50	.49	.55	.54	.50	.51	.51	.52	.53	.57
Total Production	**11.40**	**10.78**	**10.79**	**10.97**	**11.09**	**10.80**	**10.69**	**10.52**	**10.36**	**10.34**	**9.40**
Imports (including SPR)											
Crude Oil[4]	3.24	6.36	3.33	3.48	3.62	4.33	4.56	4.81	5.07	5.23	6.69
Refined Products	3.01	2.01	1.72	1.95	1.85	1.57	1.75	1.93	2.03	2.15	2.74
Total Imports	6.26	8.36	5.05	5.43	5.47	5.89	6.31	6.74	7.10	7.38	9.44
Exports											
Crude Oil	.00	.16	.16	.18	.17	.17	.17	.17	.17	.17	.17
Refined Products	.23	.20	.58	.49	.45	.61	.61	.61	.61	.61	.61
Total Exports	.23	.36	.74	.67	.62	.78	.78	.78	.78	.78	.78
Net Imports (including SPR)	**6.02**	**8.00**	**4.31**	**4.76**	**4.85**	**5.11**	**5.53**	**5.95**	**6.31**	**6.59**	**8.65**
Primary Stock Changes											
Net Withdrawals[5]	-.14	.26	.25	.04	.00	-.01	-.06	-.06	-.05	-.05	-.05
SPR Fill Rate Additions (-)[6]	.00	-.16	-.23	-.18	-.14	-.14	-.14	-.14	-.14	-.14	.00
Total Primary Supply[7]	**17.29**	**18.87**	**15.11**	**15.59**	**15.79**	**15.76**	**16.01**	**16.27**	**16.49**	**16.74**	**18.00**
Refined Petroleum Products											
Motor Gasoline	6.67	7.41	6.62	6.72	6.67	6.47	6.36	6.28	6.23	6.21	6.16
Aviation Gasoline	.05	.04	.03	.04	.04	.04	.04	.04	.05	.05	.05
Jet Fuel[8]	1.06	1.06	1.05	1.15	1.14	1.19	1.23	1.27	1.30	1.32	1.37
Kerosene	.22	.18	.13	.11	.10	.10	.11	.11	.11	.11	.11
Distillate Fuel	3.09	3.43	2.69	2.88	2.77	2.83	2.92	3.01	3.10	3.19	3.66
Residual Fuel	2.82	3.02	1.42	1.42	1.35	1.39	1.42	1.47	1.50	1.56	1.93
Liquid Petroleum Gas	1.45	1.41	1.49	1.36	1.40	1.44	1.56	1.65	1.71	1.77	2.00
Petrochemical Feedstocks	.36	.59	.42	.68	.72	.72	.76	.79	.80	.81	.79
Other Petroleum Products[9]	1.59	1.70	1.37	1.50	1.57	1.58	1.62	1.65	1.69	1.72	1.92
Total Product Supplied	**17.31**	**18.85**	**15.23**	**15.86**	**15.77**	**15.76**	**16.01**	**16.27**	**16.48**	**16.74**	**18.00**

See footnotes at end of table.

1.4

Table A15. Petroleum Supply and Disposition Balance (Continued)
(Million Barrels per Day)

Supply and Disposition	Middle World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Refined Petroleum Products Supplied to End-Use Sectors											
Residential and Commercial	2.23	2.07	1.20	1.29	1.26	1.30	1.34	1.37	1.40	1.42	1.39
Industrial[10]	4.48	4.87	4.03	4.52	4.61	4.68	4.93	5.13	5.27	5.40	5.97
Transportation	9.05	10.14	9.33	9.48	9.39	9.27	9.25	9.26	9.30	9.36	9.75
Electric Utilities	1.54	1.75	.68	.58	.51	.51	.49	.51	.52	.56	.89
Total End-Use Consumption	**17.30**	**18.84**	**15.23**	**15.86**	**15.77**	**15.76**	**16.01**	**16.28**	**16.49**	**16.74**	**18.00**
Discrepancy[11]	-.01	.04	-.12	-.27	.02	.00	.00	.00	.00	.00	.00
Net Disposition[12]	**17.29**	**18.87**	**15.11**	**15.59**	**15.79**	**15.76**	**16.01**	**16.27**	**16.49**	**16.74**	**18.00**

[1] Includes lease condensate.
[2] Other Domestic prior to 1981 includes unfinished oils (net), hydrogen, and hydrocarbons not included elsewhere. After 1981, Other Domestic includes unfinished oils (net), motor gasoline blending components (net), aviation gasoline blending components (net), hydrogen, other hydrocarbons, alcohol, and synthetic crude production.
[3] Represents volumetric gain in refinery distillation and cracking processes.
[4] In 1977 and later years, crude oil imports include crude oil imported for the Strategic Petroleum Reserve.
[5] Net stock withdrawals for a given year, t, are defined as the change in yearend stock levels from period t-1 minus the yearend stock level from the year t. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.
[6] SPR is the Strategic Petroleum Reserve.
[7] Total primary supply is defined as total production plus net imports plus net stock withdrawals minus SPR additions.
[8] Jet fuel includes naphtha and kerosene type.
[9] Other petroleum products includes miscellaneous petroleum products, lubricants, waxes, unfractionated stream, plant condensate, natural gasoline, asphalt, road oil, still gas, special naphthas, and petroleum coke.
[10] Industrial refined products includes total industrial demand for petroleum as reported in Table 8.
[11] Discrepancy represents the difference between total supply and total products supplied.
[12] Net disposition is the sum of total products supplied and discrepancy.
NOTE: From 1981 onward, the product supplied data is on a new basis. From 1983 onward, the other product category is on a net basis, reclassified (petroleum products reprocessed into other categories) plus the other category of products supplied.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical data are from Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984) pp. 79-99, Tables 35, 36, 37, and 45. Projected values are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = Middle World Oil Price Case, printed on December 28, 1984.
Historical quantities through 1983.

Table A16. Petroleum Product Prices
(1984 Dollars per Barrel)

Sector and Fuel	Middle World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Crude Oil Prices											
World Oil Price[1]	**8.62**	**21.63**	**30.39**	**29.00**	**28.00**	**27.00**	**27.00**	**28.00**	**29.00**	**30.00**	**40.00**
Refiner Acquisition Cost[2]	**8.77**	**18.50**	**30.39**	**29.00**	**28.00**	**27.00**	**27.00**	**28.00**	**29.00**	**30.00**	**40.00**
Delivered Sector Product Prices											
Residential and Commercial											
Distillate Fuel	19.35	29.95	43.90	42.49	41.14	40.21	40.23	41.42	42.65	43.97	55.52
Kerosene	20.04	32.11	44.72	41.07	39.63	38.62	38.58	39.73	40.92	42.21	53.78
Motor Gasoline[3]	34.52	41.22	54.27	53.26	52.08	50.84	50.87	52.05	53.17	54.12	66.61
Residual Fuel	11.44	20.53	34.41	33.30	32.25	32.14	32.39	33.41	34.49	35.90	43.35
Liquefied Petroleum Gas[4]	26.12	24.96	32.87	27.76	27.02	26.46	26.53	27.38	28.25	29.18	37.07
Average[5]	**20.23**	**28.21**	**40.89**	**39.29**	**37.95**	**37.11**	**37.12**	**38.19**	**39.31**	**40.55**	**51.02**
Industrial											
Distillate Fuel	11.52	24.55	38.01	36.57	35.27	34.38	34.45	35.68	36.95	38.31	50.02
Kerosene	12.09	26.14	39.01	37.56	36.25	35.36	35.44	36.70	38.01	39.40	51.38
Motor Gasoline[3]	34.75	41.07	54.52	53.51	52.33	51.07	51.08	52.25	53.35	54.29	66.67
Residual Fuel	10.65	19.86	28.46	27.35	26.30	26.19	26.46	27.52	28.63	30.07	37.52
Liquefied Petroleum Gas	11.19	18.98	28.58	24.38	23.53	22.94	22.98	23.81	24.66	25.57	33.41
Petrochemical Feedstocks[6]	11.05	23.78	34.53	33.08	31.70	30.68	30.75	31.99	33.27	34.63	46.40
Asphalt & Road Oil	13.12	27.97	26.38	25.75	25.17	25.13	25.29	25.88	26.51	27.33	31.63
Petroleum Coke	11.91	25.39	7.67	7.61	7.58	7.58	7.61	7.70	7.78	7.89	8.47
Special Naphthas	10.38	22.12	34.27	32.99	31.83	31.04	31.11	32.23	33.39	34.63	45.24
Miscellaneous Petroleum Products	12.35	26.10	33.86	32.27	30.96	30.11	30.15	31.33	32.56	33.93	45.12
Average[5]	**12.25**	**23.19**	**30.27**	**28.56**	**27.40**	**26.78**	**26.85**	**27.77**	**28.71**	**29.75**	**37.96**
Transportation[7]											
Distillate Fuel	20.27	29.35	55.82	54.39	53.11	52.23	52.31	53.56	54.85	56.22	68.03
Aviation Gasoline	40.10	52.84	70.43	68.78	66.86	64.81	64.84	66.73	68.53	70.06	90.25
Motor Gasoline[3]	34.39	40.85	54.08	53.06	51.87	50.61	50.63	51.79	52.90	53.83	66.25
Jet Fuel[8]	11.48	25.41	37.94	36.37	34.90	33.74	33.86	35.14	36.46	37.87	49.85
Residual Fuel[9]	8.47	14.12	22.66	21.57	20.55	20.47	20.74	21.78	22.89	24.32	31.85
Liquefied Petroleum Gas	10.75	17.55	30.54	36.37	35.51	34.92	34.98	35.81	36.67	37.60	45.51
Lubricants[10]	75.70	90.23	148.87	146.32	144.03	142.47	142.61	144.82	147.12	149.57	170.59
Average[5]	**29.51**	**37.09**	**52.13**	**51.17**	**49.98**	**48.71**	**48.65**	**49.79**	**50.92**	**52.02**	**64.30**
Electric Utilities											
Distillate Fuel	10.92	21.53	45.38	41.46	38.81	31.21	32.60	38.16	41.29	41.49	50.70
Residual Fuel	10.37	19.91	29.51	28.49	27.52	27.90	28.29	29.38	30.50	31.95	40.31
Average[5]	**10.42**	**20.03**	**30.57**	**29.67**	**28.05**	**27.96**	**28.35**	**29.59**	**30.82**	**32.28**	**41.14**
Refined Petroleum Product Prices											
Distillate Fuel	17.57	28.12	48.50	46.10	44.92	44.04	44.12	45.39	46.74	48.18	60.52
Kerosene	17.27	29.55	41.70	39.55	38.21	37.30	37.32	38.52	39.79	41.15	52.95
Aviation Gasoline	40.10	52.84	70.43	68.78	66.86	64.81	64.84	66.73	68.53	70.06	90.25
Motor Gasoline[3]	34.40	40.85	54.08	53.06	51.88	50.62	50.64	51.80	52.91	53.84	66.26
Jet Fuel[8]	11.48	25.41	37.94	36.37	34.90	33.74	33.86	35.14	36.46	37.87	49.85
Residual Fuel	10.35	19.12	28.14	27.07	26.06	26.14	26.42	27.48	28.59	30.07	38.13
Liquefied Petroleum Gas	16.46	20.88	29.37	24.96	24.11	23.53	23.55	24.36	25.21	26.11	33.85
Lubricants (Transportation)[10]	75.70	90.23	148.87	146.32	144.03	142.47	142.61	144.82	147.12	149.57	170.59
Petrochemical Feedstocks[6]	11.05	23.78	34.53	33.08	31.70	30.68	30.75	31.99	33.27	34.63	46.40
Asphalt & Road Oil	13.12	27.97	26.38	25.75	25.17	25.13	25.29	25.88	26.51	27.33	31.63
Petroleum Coke	11.91	25.39	7.67	7.61	7.58	7.58	7.61	7.70	7.78	7.89	8.47
Special Naphthas	10.38	22.12	34.27	32.99	31.83	31.04	31.11	32.23	33.39	34.63	45.24
Miscellaneous Petroleum Products	12.35	26.10	33.86	32.27	30.96	30.11	30.15	31.33	32.56	33.93	45.12

[1] The cost of imported crude oil to U.S. refiners in 1984 dollars per barrel.
[2] Refiner acquisition cost is an average of imported and domestic refiner acquisition costs.
[3] Gasoline price is an average price for all types.
[4] Residential and commercial liquefied petroleum gas price includes only a residential price due to data limitations.
[5] Weighted average price; the weights are taken from the consumption categories from Table 4 and converted to physical units.
[6] Petrochemical feedstock price includes only the price of naphthas less than 400 degrees.
[7] Transportation prices include the appropriate State road use taxes and Federal excise tax.
[8] Jet fuel price is a retail price for kerosene type jet fuel.
[9] Residual fuel price in the transportation sector is for marine bunker.
[10] Lubricant price is an average for light stocks and multiweight motor oil.

NOTE: Implicit Gross National Product Price Deflator, rebased to 1984 = 1.0, was used to convert from nominal to real dollars.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical prices are taken from Energy Information Administration, *State Energy Price and Expenditure Report*, DOE/EIA-0376(81) (Washington, DC, 1984), pp. 1-7. Projected values are output from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = Middle World Oil Price Case, printed on December 21, 1984.
Historical quantities through 1983.

Table A17. Natural Gas Supply, Disposition, and Prices

(Trillion Cubic Feet per Year)

(1984 Dollars per Thousand Cubic Feet)

Supply, Disposition, and Prices	Middle World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Dry Gas Production[1]	21.73	19.12	15.97	17.43	17.48	17.10	17.44	17.58	17.52	17.32	16.39
Supplemental Natural Gas[2]	.00	.00	.14	.15	.15	.31	.14	.20	.22	.32	.74
Net Imports	.96	.91	.87	.86	.99	1.05	1.16	1.27	1.43	1.57	2.11
Net Storage Withdrawals[3]	-.42	-.15	.47	.03	.03	.00	.00	.00	.00	.00	.00
Total Supply[4]	**22.27**	**19.88**	**17.45**	**18.47**	**18.65**	**18.47**	**18.74**	**19.04**	**19.16**	**19.21**	**19.24**
Consumption by Sector[5]											
Residential	4.88	4.90	4.53	4.60	4.60	4.60	4.62	4.63	4.64	4.63	4.48
Commercial[6]	2.60	2.60	2.53	2.59	2.60	2.63	2.65	2.67	2.69	2.69	2.60
Industrial	8.69	6.76	5.47	6.01	6.11	6.18	6.33	6.46	6.46	6.46	6.28
Lease & Plant Fuel[7]	1.50	1.65	1.00	1.09	1.09	1.07	1.09	1.10	1.10	1.08	1.03
Transportation[8]	.73	.53	.56	.59	.60	.60	.60	.61	.62	.62	.62
Electric Utilities	3.66	3.19	2.91	3.16	3.22	3.00	3.04	3.14	3.23	3.28	3.75
Total End-Use Consumption	**22.05**	**19.63**	**17.00**	**18.04**	**18.22**	**18.07**	**18.33**	**18.61**	**18.73**	**18.76**	**18.75**
Unaccounted for[9]	.22	.25	.45	.43	.43	.39	.41	.43	.44	.45	.50
Average Wellhead Price	**.46**	**1.35**	**2.72**	**2.70**	**2.67**	**2.66**	**2.80**	**2.99**	**3.22**	**3.52**	**5.05**
Delivered Prices by Sectors											
Residential	2.71	3.78	6.37	6.16	6.09	6.10	6.26	6.47	6.83	7.22	9.30
Commercial[6]	1.99	3.33	5.73	5.69	5.63	5.60	5.74	5.91	6.24	6.60	8.56
Industrial	1.07	2.27	4.44	4.41	4.41	4.42	4.57	4.76	5.04	5.39	7.27
Electric Utilities	.75	2.18	3.73	3.59	3.72	3.62	3.77	3.94	4.16	4.50	6.10
Average to All Sectors[10]	**1.53**	**2.83**	**5.08**	**4.95**	**4.93**	**4.93**	**5.08**	**5.26**	**5.55**	**5.91**	**7.74**

[1] Net dry natural gas is defined as dry marketed production minus nonhydrocarbon gases removed.

[2] Prior to 1980 the amount of supplemental fuels included in the natural gas data cannot be determined. Supplemental natural gas includes synthetic natural gas (results from the manufacture, conversion, or the reforming of petroleum hydrocarbons), and propane air mixtures. After 1985 this quantity includes short-term spot market purchases that could include additional imports.

[3] Includes net stock withdrawals for dry natural gas from underground storage and liquefied natural gas. Net stock withdrawals are computed as the yearend stock levels from the current period subtracted from the yearend stock levels from the preceding period. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.

[4] Total supply is computed as dry gas production plus supplemental natural gas, net imports, and net stock withdrawals.

[5] Consumption values include small amounts of supplemental gas, which are not reported as production prior to 1980.

[6] Commercial category includes the other customer category.

[7] Lease and plant fuel natural gas represents natural gas used in the field gathering and processing plant machinery, usually totalled into the industrial sector for other consumption tables.

[8] Transportation natural gas is used to fuel the compressors in the pipeline pumping stations.

[9] Unaccounted for represents natural gas lost, the net result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure, and EIA's merger of different data reporting systems which vary in scope, format, definition, and respondent type.

[10] Weighted average price and the weights are the sectoral consumption values excluding lease and plant fuel and the transportation sector.

NOTE: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1984 equals 1.00. The natural gas prices in this table are average prices, total revenues divided by total sales for each customer class.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Historical data are taken from the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984) and Energy Information Administration, *Natural Gas Annual, 1982* DOE/EIA-0131(82) (Washington, DC, 1983).
Projected values are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = Middle World Oil Price Case, printed on December 21, 1984.
Historical quantities through 1983.

Table A18. ***Coal Supply, Disposition, and Prices***
(Million Short Tons per Year)
(1984 Dollars per Short Ton)

Supply, Disposition, and Price	Middle World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production[1]											
East of the Mississippi	522	487	507	583	571	580	594	608	626	650	731
West of the Mississippi	76	183	275	309	328	342	354	366	384	407	490
Total	**599**	**670**	**782**	**892**	**899**	**921**	**948**	**974**	**1,010**	**1,057**	**1,221**
Imports[2]	(*)	3	1	1	1	0	0	0	0	0	0
Exports[3]	54	41	78	80	73	74	77	81	86	91	106
Net Imports	**-53**	**-38**	**-77**	**-79**	**-72**	**-74**	**-77**	**-81**	**-86**	**-91**	**-106**
Net Storage Withdrawals[4]	**12**	**11**	**27**	**-20**	**15**	**-2**	**-4**	**-4**	**-6**	**-8**	**-6**
Total Supply[5]	**557**	**644**	**733**	**793**	**842**	**845**	**867**	**889**	**919**	**957**	**1,110**
Consumption by Sector											
Residential and Commercial	11	10	8	8	8	8	8	7	7	7	7
Industrial	68	63	66	76	77	77	80	83	86	89	98
Coking Plants[6]	94	71	37	44	46	46	49	50	51	51	49
Electric Utilities	389	481	625	666	709	712	725	742	769	805	951
Synthetic Fuels	0	0	0	0	5	5	5	6	6	6	6
Total End-Use Consumption	**563**	**625**	**737**	**793**	**843**	**848**	**866**	**889**	**919**	**958**	**1,110**
Discrepancy[7]	-6	18	-4	-2	-3	-4	(*)	(*)	(*)	(*)	(*)
Average Minemouth Price[8]	**18.14**	**32.48**	**26.95**	**30.02**	**29.89**	**30.34**	**30.51**	**30.69**	**30.83**	**30.95**	**31.88**
Delivered Prices by Sector											
Residential and Commercial[9]	45.53	69.97	45.87	47.00	47.44	51.59	52.26	52.81	53.41	54.15	57.58
Industrial	26.89	49.65	40.79	43.70	44.73	50.01	51.21	52.32	53.52	54.70	60.43
Coking Plants[6]	38.52	77.33	61.51	60.85	61.52	64.87	65.48	66.11	66.88	67.80	70.94
Electric Utilities[10]	19.03	35.26	36.30	38.13	38.54	38.93	39.35	39.66	39.84	40.24	42.87
Average to All End-Use Sectors[11]	**23.76**	**42.04**	**38.07**	**40.01**	**40.46**	**41.48**	**42.04**	**42.48**	**42.74**	**43.17**	**45.75**

[1] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite with anthracite included in bituminous.

[2] Coal imports are not projected beyond 1985.

[3] Excludes small quantities of anthracite shipped overseas to U.S. Armed Forces and coke exports.

[4] From stocks held by end-use sectors (secondary stocks held at industrial plants, coke plants, and electric utility plants). Net stock withdrawals are computed as the yearend stock levels from the current period subtracted from the yearend stock levels from the preceding period. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.

[5] Total supply is equivalent to production plus net imports plus net storage withdrawals.

[6] Coke plants consume metallurgical coal which is a mixture of anthracite and bituminous coal. Historically, coking plant coal price is a weighted average of anthracite and bituminous coal types. In the projections, anthracite is included in bituminous coal.

[7] Historically, discrepancy represents revisions in producers (primary) stock levels, losses, and unaccounted for. In the projected period, discrepancy represents errors due to conversion factors.

[8] In historical years, the average production price of coal produced at the mine. Projected prices are based on estimated cost and do not reflect market conditions.

[9] Historically, residential price is used for residential and commercial consumers. Projected residential and commercial prices do not include dealer markup.

[10] Historically, electric utility price includes anthracite, bituminous, and lignite coal purchased under long-term contracts and on the spot market. In the projections, anthracite is included in bituminous coal, with the bituminous coal price being used for anthracite coal price.

[11] Weighted average price and the weights are the sectoral consumption values.

(*) Greater than zero but less than .5.

NOTE: Metallurgical coal prices reflect a reduced level of projected demand. Other projected coal prices are based on cost estimates, and do not reflect market conditions.

NOTE: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1984 equals 1.00. Projected coal prices are based on cost estimates and do not reflect market conditions.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Historical prices from Energy Information Administration, *State Energy Price and Expenditure Report*, , (DOE/EIA-0376(81) (Washington, DC, 1984) pp. 1-7. Historical quantities are from the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984) pp. 161-169, Table 73, 74, and 75. Projected values are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = MRG1126T, Projected = Middle World Oil Price Case, printed on December 21, 1984.

Historical quantities through 1983.

2.0 2.5

Table A19. National Macroeconomic Indicators

Macroeconomic Indicators	Middle World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
World Oil Price[1]	**8.62**	**21.63**	**30.39**	**29.00**	**28.00**	**27.00**	**27.00**	**28.00**	**29.00**	**30.00**	**40.00**
NIPA Variables[2]											
Real GNP (billion 1972 dollars)	1,254	1,439	1,535	1,643	1,687	1,724	1,792	1,858	1,915	1,968	2,206
Real Disposable Income (billion 1972 dollars)	865	989	1,095	1,168	1,202	1,225	1,259	1,292	1,328	1,360	1,511
Real Disposable Income Per Capita (thousand 1972 dollars)	4.1	4.4	4.7	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.8
NIPA GNP Price Deflator (1972=1.00)	1.057	1.504	2.153	2.233	2.318	2.431	2.561	2.708	2.867	3.038	4.124
GNP Growth (1984 reference year)	NA	NA	NA	.0	2.7	4.9	9.1	13.1	16.5	19.8	34.3
Unemployment Rate, Civilian Workers (percent)	4.9	6.1	9.6	7.5	7.3	7.9	7.6	7.0	6.8	6.9	7.2
Population, Noninstitutional (million persons)	211.9	222.6	234.0	236.2	238.5	240.7	243.0	245.2	247.4	249.5	259.4
New, High Grade Bond Rate (percent per annum)	7.65	8.88	11.56	12.62	12.76	12.23	11.64	11.24	10.91	10.57	9.45
New Home Mortgage Yields (percent per annum)	8.08	9.69	13.35	13.56	13.90	13.32	12.51	11.96	11.73	11.52	10.40
Total Industrial Production Index (1967=1.00)	1.30	1.46	1.48	1.64	1.70	1.75	1.86	1.96	2.03	2.09	2.37
Total Manufacturing Output Index (1967=1.00)	1.30	1.47	1.48	1.66	1.72	1.77	1.89	2.00	2.08	2.15	2.46
Housing Starts (million units)	2.04	2.00	1.70	1.79	1.59	1.73	1.83	1.88	1.82	1.74	1.55
Energy Usage Indicators											
Gross Energy Use per Capita (million Btu per person)	350.1	350.6	301.8	316.6	317.7	318.7	323.2	327.7	330.9	334.5	347.4
Gross Energy Use per Dollar of GNP (thousand Btu per 1972 dollar)	59.2	54.2	46.0	45.5	44.9	44.5	43.8	43.2	42.8	42.4	40.9
Net Oil Imports (billion 1984 dollars)	15.0	56.5	47.0	52.7	48.9	49.9	53.7	59.8	65.5	70.7	122.1
Net Coal Imports (billion 1984 dollars)	-2.1	-2.9	-3.9	-4.2	-3.9	-4.0	-4.1	-4.4	-4.6	-5.0	-6.1

[1] The cost of imported crude oil to U.S. refiners in 1984 dollars per barrel.
[2] National Income and Product Accounts.
NOTE: Total may not equal sum of components because of independent rounding.

Appendix B
Middle World Oil Price/Low Economic Growth Case

Table B1. Yearly Supply and Disposition Summary of Total Energy
(Quadrillion Btu per Year)

Total Supply and Disposition	Low Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Supply											
Production											
Crude Oil and Lease Condensate	19.5	18.4	18.4	18.5	18.8	18.4	18.2	17.9	17.7	17.6	16.0
Natural Gas Plant Liquids	2.6	2.2	2.2	2.3	2.3	2.2	2.2	2.1	2.0	2.0	1.7
Natural Gas[1]	22.2	19.5	16.4	17.9	18.0	17.6	17.8	17.7	17.5	17.1	16.5
Coal[2]	13.9	14.9	17.2	19.6	19.8	20.6	20.9	21.1	21.7	22.5	25.7
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Hydropower/Other[3]	2.9	3.0	3.6	3.6	3.1	3.3	3.3	3.3	3.3	3.4	3.4
Total Production	**62.0**	**61.0**	**61.1**	**65.6**	**66.1**	**66.8**	**67.7**	**68.0**	**68.3**	**68.9**	**70.4**
Imports											
Crude Oil[4]	6.9	13.5	7.1	7.4	8.2	8.8	9.2	9.5	10.0	10.2	12.6
Refined Petroleum Products[5]	6.6	4.4	3.6	4.1	2.9	3.5	3.8	4.0	4.1	4.2	5.0
Natural Gas[6]	1.1	1.0	1.1	1.0	1.2	1.4	1.3	1.4	1.6	1.8	2.6
Other Imports[7]	.2	.4	.4	.4	.5	.5	.5	.6	.6	.7	.8
Total Imports	**14.7**	**19.3**	**12.2**	**12.9**	**12.8**	**14.2**	**14.9**	**15.5**	**16.3**	**17.0**	**20.9**
Net Stock Withdrawals	**-.4**	**.3**	**1.1**	**-.7**	**.0**	**-.4**	**-.5**	**-.4**	**-.4**	**-.5**	**-.2**
Adjustments[8]	-.1	-.6	.0	.4	-.3	-.5	-.6	-.6	-.6	-.7	-.8
Total Supply[9]	**76.2**	**80.0**	**74.4**	**78.3**	**78.5**	**80.0**	**81.6**	**82.6**	**83.5**	**84.7**	**90.3**
Disposition											
Exports											
Oil	.5	.8	1.6	1.4	1.3	1.7	1.7	1.7	1.7	1.7	1.7
Natural Gas	.1	.1	.1	NA	NA	NA	NA	NA	NA	NA	NA
Coal	1.4	1.1	2.0	2.1	1.9	2.0	2.1	2.2	2.3	2.4	2.8
Other[10]	.1	.0	.1	NA	NA	NA	NA	NA	NA	NA	NA
Total Exports	**2.1**	**1.9**	**3.7**	**3.5**	**3.2**	**3.7**	**3.7**	**3.8**	**3.9**	**4.1**	**4.4**
Consumption											
Refined Petroleum Products[11]	34.8	38.0	30.1	31.5	30.8	31.0	31.4	31.5	31.7	31.9	33.2
Natural Gas	22.5	20.0	17.5	18.5	18.7	18.5	18.7	18.7	18.6	18.5	18.6
Coal[12]	12.9	13.7	15.9	17.1	18.1	18.3	18.6	18.8	19.2	19.8	22.7
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Hydro/Other/Electricity Imports[13]	3.1	3.2	4.0	4.0	3.6	3.8	3.9	3.9	4.0	4.1	4.2
Net Imports of Coke	.0	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total Consumption	**74.2**	**78.0**	**70.7**	**74.8**	**75.3**	**76.4**	**77.8**	**78.7**	**79.6**	**80.6**	**85.8**
Total Disposition	**76.2**	**80.0**	**74.4**	**78.3**	**78.5**	**80.0**	**81.6**	**82.6**	**83.5**	**84.7**	**90.3**

[1] Net dry marketed production after removal of nonhydrocarbon gases.
[2] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite, with anthracite included in bituminous.
[3] Hydropower/Other production includes hydropower, geothermal power, and wood waste.
[4] Includes imports of crude oil for the Strategic Petroleum Reserve.
[5] Includes imports of unfinished oils and natural gas plant liquids.
[6] Includes dry natural gas imports from Canada and Mexico, liquefied natural gas imports from Algeria, and supplemental gas.
[7] Includes electricity, coal, and coal coke imports.
[8] Balancing item that includes gains, losses, miscellaneous blending components, unaccounted for supply, coal used for synthetic fuel production, anthracite shipped overseas to U.S. Armed Forces and certain secondary stock withdrawals.
[9] Total supply is the sum of production, imports, net stock withdrawals, and adjustments.
[10] Includes electricity and coal coke exports.
[11] Includes natural gas plant liquids and crude oil consumed as a fuel.
[12] Excludes anthracite shipped overseas to U.S. Armed Forces and coal used for synthetic fuel production.
[13] Includes net electricity imports and renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[NA] = Not available.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical quantities are from the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984) pp. 5-29, Tables 1, 2, 3, and 13. Projected values are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = Low Economic Growth Case, printed on December 28, 1984.
Historical quantities through 1983.

Table B2. Yearly Supply and Disposition of Total Energy, Supply Detail
(Quadrillion Btu per Year)

Total Supply	Low Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
World Oil Price[1]	**8.62**	**21.63**	**30.39**	**29.00**	**28.00**	**27.00**	**27.00**	**28.00**	**29.00**	**30.00**	**40.00**
Domestic Production											
Oil[2]	22.1	20.7	20.6	20.8	21.1	20.6	20.4	20.0	19.7	19.6	17.7
Natural Gas[3]	22.2	19.5	16.4	17.9	18.0	17.6	17.8	17.7	17.5	17.1	16.5
Coal[4]	13.9	14.9	17.2	19.6	19.8	20.6	20.9	21.1	21.7	22.5	25.7
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Hydropower/Other[5]	2.9	3.0	3.6	3.6	3.1	3.3	3.3	3.3	3.3	3.4	3.4
Total Domestic Production	**62.0**	**61.0**	**61.1**	**65.6**	**66.1**	**66.8**	**67.7**	**68.0**	**68.3**	**68.9**	**70.4**
Imports											
Oil[6]	13.5	17.8	10.7	11.5	11.1	12.3	13.0	13.6	14.1	14.4	17.6
Natural Gas[7]	1.1	1.0	1.1	1.0	1.2	1.4	1.3	1.4	1.6	1.8	2.6
Coal[8]	.0	.1	.0	.0	.0	NA	NA	NA	NA	NA	NA
Other Imports[9]	.2	.4	.4	.4	.4	.5	.5	.6	.6	.7	.8
Total Imports	**14.7**	**19.3**	**12.2**	**12.9**	**12.8**	**14.2**	**14.9**	**15.5**	**16.3**	**17.0**	**20.9**
Net Storage Withdrawals											
Oil	–.3	.5	.5	.1	.0	.0	–.1	.0	.0	–.1	–.1
Natural Gas	–.4	–.2	.5	.0	.0	.0	.0	.0	.0	.0	.0
Coal[10]	.3	.3	.6	–.4	.3	.0	–.1	.0	–.1	–.1	–.1
SPR Fill Rate Additions (-)[11]	.0	–.3	–.5	–.4	–.3	–.3	–.3	–.3	–.3	–.3	.0
Net Stock Withdrawals	**–.4**	**.3**	**1.1**	**–.7**	**.0**	**–.4**	**–.5**	**–.4**	**–.4**	**–.5**	**–.2**
Available Supply[12]											
Oil	35.3	39.1	31.9	32.5	32.3	33.0	33.4	33.6	33.8	34.0	35.2
Natural Gas	22.8	20.3	18.0	19.0	19.2	18.9	19.1	19.1	19.0	19.0	19.0
Coal	14.2	15.2	17.8	19.2	20.1	20.5	20.9	21.1	21.6	22.3	25.5
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Other Supply[13]	3.1	3.4	4.0	4.0	3.6	3.8	3.9	3.9	4.0	4.1	4.2
SPR Fill Rate Additions (-)[11]	.0	–.3	–.5	–.4	–.3	–.3	–.3	–.3	–.3	–.3	.0
Total Supply (before adjustments)	**76.3**	**80.6**	**74.4**	**77.9**	**78.9**	**80.6**	**82.1**	**83.1**	**84.1**	**85.4**	**91.1**
Adjustments[14]	–.1	–.6	.0	.4	–.3	–.5	–.6	–.6	–.6	–.7	–.8
Total Supply[15]	**76.2**	**80.0**	**74.4**	**78.3**	**78.5**	**80.0**	**81.6**	**82.6**	**83.5**	**84.7**	**90.3**

[1] The cost of imported crude oil to U.S. refiners in 1984 dollars per barrel.
[2] Oil includes crude oil, lease condensate, and natural gas plant liquids.
[3] Net dry marketed production after removal of nonhydrocarbon gases.
[4] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite, with anthracite included in bituminous.
[5] Hydropower/Other production includes hydropower, geothermal power, and wood waste.
[6] Oil imports includes crude oil and refined petroleum products. Crude oil imports include imports for the Strategic Petroleum Reserve.
[7] Includes dry natural gas imports from Canada and Mexico, liquefied natural gas imports from Algeria, and supplemental gas.
[8] Includes small amounts of coal/coke imports.
[9] Consists of net electricity imports from Canada.
[10] From consumer stocks (utility, coke plant, and industrial) only.
[11] SPR is the Strategic Petroleum Reserve.
[12] Available supply is the sum of domestic production, imports, and net stock withdrawals.
[13] Includes net electricity imports from Canada, hydropower, geothermal power, wood, waste, solar power, and wind power.
[14] Balancing item that includes gains, losses, miscellaneous blending components, unaccounted for supply, coal used for synthetic fuel production, anthracite shipped overseas to U.S. Armed Forces and certain secondary stock withdrawals.
[15] Total supply is the sum of production, imports, net stock withdrawals, and adjustments.
[NA] = Not available.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Historical values are taken from Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984).

Input data file: Historical = MRG1126T, Projected = Low Economic Growth Case, printed on December 28, 1984.
Historical prices through 1981 and quantities through 1983.

Table B3. Yearly Supply and Disposition of Total Energy, Disposition Detail
(Quadrillion Btu per Year)

Total Disposition	Low Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Exports											
Oil[1]	0.5	0.8	1.6	1.4	1.3	1.7	1.7	1.7	1.7	1.7	1.7
Natural Gas	.1	.1	.1	NA	NA	NA	NA	NA	NA	NA	NA
Coal	1.4	1.1	2.0	2.1	1.9	2.0	2.1	2.2	2.3	2.4	2.8
Other[2]	.1	.0	.1	NA	NA	NA	NA	NA	NA	NA	NA
Total Exports	**2.1**	**1.9**	**3.7**	**3.5**	**3.2**	**3.7**	**3.7**	**3.8**	**3.9**	**4.1**	**4.4**
Consumption											
Residential and Commercial											
Oil[3]	4.4	4.1	2.3	2.6	2.5	2.6	2.7	2.7	2.8	2.8	2.7
Natural Gas	7.6	7.6	7.2	7.4	7.4	7.5	7.5	7.5	7.5	7.5	7.3
Coal	.3	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2
Total (excluding electricity)	**12.3**	**11.9**	**9.8**	**10.1**	**10.1**	**10.3**	**10.4**	**10.4**	**10.5**	**10.5**	**10.3**
Industrial											
Oil[4]	9.1	9.9	7.8	8.9	8.9	9.2	9.6	9.7	9.8	9.9	10.7
Natural Gas[5]	10.4	8.5	6.6	7.3	7.4	7.4	7.5	7.5	7.4	7.3	7.1
Coal[6]	4.0	3.2	2.5	2.9	2.9	3.1	3.3	3.4	3.4	3.5	3.6
Hydropower	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Net Imports of Coke	.0	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total (excluding electricity)	**23.5**	**21.8**	**16.9**	**19.0**	**19.2**	**19.7**	**20.3**	**20.6**	**20.7**	**20.8**	**21.4**
Transportation											
Oil[7]	17.8	20.0	18.4	18.7	18.3	18.1	18.1	18.0	18.0	18.1	18.5
Natural Gas[8]	.7	.5	.6	.6	.6	.6	.6	.6	.6	.6	.6
Coal	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total (excluding electricity)	**18.6**	**20.6**	**19.0**	**19.3**	**18.9**	**18.7**	**18.7**	**18.6**	**18.6**	**18.7**	**19.1**
Electric Utilities											
Oil	3.5	4.0	1.5	1.3	1.2	1.2	1.1	1.1	1.0	1.1	1.3
Natural Gas	3.7	3.3	3.0	3.3	3.3	3.1	3.1	3.1	3.1	3.0	3.5
Coal	8.7	10.3	13.2	14.0	14.9	15.0	15.2	15.3	15.6	16.2	18.9
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Hydropower/Other[9]	3.0	3.2	4.0	4.0	3.5	3.8	3.8	3.9	4.0	4.0	4.2
Total	**19.9**	**23.7**	**25.0**	**26.3**	**27.1**	**27.7**	**28.5**	**29.1**	**29.7**	**30.6**	**35.1**
Total Disposition	**76.2**	**80.0**	**74.4**	**78.3**	**78.5**	**80.0**	**81.6**	**82.6**	**83.5**	**84.7**	**90.3**

[1] Consists primarily of refined petroleum products.
[2] Includes electricity and coal coke exports.
[3] Residential and Commercial oil consists of motor gasoline, distillate fuel, kerosene, residual fuel, and liquefied petroleum gases.
[4] Industrial oil consists of distillate fuel, kerosene, residual fuel, liquefied petroleum gases, special naphthas, miscellaneous petroleum products, lubricants, waxes, unfractionated stream, plant condensate, natural gasoline, asphalt, road oil, petroleum coke, still gas, other oils greater than 400 degrees used for chemical feedstocks, motor gasoline, and naphthas less than 400 degrees used for feedstock purposes, including refinery fuel consumption.
[5] Industrial natural gas is composed of lease and plant fuel use, refinery fuel use, and other industrial uses.
[6] Industrial coal is composed of steam and metallurgical (coking) coal.
[7] Transportation oil consists of motor gasoline, aviation gasoline, jet fuel, distillate fuel, residual fuel, lubricants, and liquefied petroleum gases.
[8] Transportation natural gas represents natural gas used as a fuel by pipeline compressors.
[9] Includes net electricity imports from Canada, hydropower, geothermal power, wood, waste, solar power, and wind power.
[NA] = Not available.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical quantities are taken from Energy Information Administration, *State Energy Data Report, 1960 to 1982*, DOE/EIA 0214(82) (Washington, DC, 1984) and Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984). Projected quantities are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = Low Economic Growth Case, printed on December 28, 1984.
Historical quantities through 1983.

Table B4. Consumption by Major Fuels and End-Use Sectors
(Quadrillion Btu per Year)

Sector and Fuel	Low Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential											
Distillate Fuel	2.00	1.95	1.05	1.23	1.17	1.19	1.21	1.22	1.22	1.21	1.10
Kerosene	.23	.15	.09	.07	.06	.06	.06	.06	.06	.06	.06
Liquefied Petroleum Gas	.59	.52	.30	.25	.28	.29	.30	.31	.31	.31	.28
Natural Gas	4.96	4.98	4.65	4.72	4.72	4.75	4.77	4.78	4.78	4.78	4.66
Steam Coal	.11	.09	.08	.07	.07	.07	.07	.07	.06	.06	.06
Electricity	1.98	2.30	2.56	2.60	2.70	2.75	2.79	2.84	2.89	2.96	3.34
Total	**9.89**	**9.99**	**8.72**	**8.94**	**9.00**	**9.12**	**9.20**	**9.27**	**9.33**	**9.39**	**9.50**
Commercial											
Distillate Fuel	.64	.67	.44	.51	.50	.53	.56	.58	.60	.62	.66
Kerosene	.06	.05	.03	.06	.06	.06	.07	.07	.07	.08	.09
Motor Gasoline	.09	.11	.09	.09	.08	.08	.08	.08	.08	.08	.08
Residual Fuel	.67	.53	.30	.33	.33	.35	.37	.39	.41	.42	.45
Liquefied Petroleum Gas	.10	.09	.05	.03	.03	.03	.03	.03	.03	.03	.03
Natural Gas[1]	2.65	2.64	2.60	2.66	2.67	2.72	2.74	2.75	2.76	2.76	2.68
Steam Coal	.15	.13	.12	.11	.12	.12	.12	.12	.12	.12	.11
Electricity	1.52	1.81	2.12	2.36	2.45	2.53	2.59	2.63	2.70	2.77	3.12
Total	**5.88**	**6.04**	**5.74**	**6.15**	**6.24**	**6.42**	**6.55**	**6.65**	**6.76**	**6.87**	**7.21**
Industrial[2]											
Distillate Fuel	1.47	1.75	1.30	1.61	1.49	1.52	1.57	1.58	1.60	1.62	1.69
Kerosene	.16	.16	.14	.10	.08	.08	.08	.08	.08	.08	.07
Motor Gasoline	.26	.18	.14	.13	.13	.15	.17	.19	.21	.24	.36
Residual Fuel	1.86	1.72	.78	.98	.92	.93	.97	.97	.98	.99	1.01
Liquefied Petroleum Gas	1.24	1.26	1.61	1.52	1.52	1.66	1.79	1.86	1.90	1.94	2.21
Petrochemical Feedstocks[3]	.73	1.22	.85	1.38	1.46	1.56	1.65	1.66	1.64	1.62	1.56
Still Gas Used in Refineries	1.06	1.20	1.13	1.16	1.21	1.21	1.22	1.22	1.23	1.24	1.28
Other Raw Material Oil[4]	2.34	2.41	1.82	1.98	2.04	2.05	2.11	2.16	2.19	2.23	2.53
Natural Gas[5]	10.39	8.54	6.64	7.29	7.39	7.36	7.48	7.48	7.39	7.34	7.11
Steam Coal	1.43	1.46	1.50	1.72	1.75	1.89	1.97	2.04	2.09	2.14	2.30
Metallurgical Coal	2.54	1.79	.96	1.15	1.19	1.25	1.30	1.33	1.36	1.36	1.28
Net Coke Imports	-.01	.13	-.02	.00	.00	.00	.00	.00	.00	.00	.00
Electricity	2.34	2.76	2.65	2.75	2.75	2.81	2.94	3.02	3.10	3.22	3.82
Hydropower	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03
Total	**25.84**	**24.60**	**19.52**	**21.79**	**21.98**	**22.50**	**23.27**	**23.63**	**23.79**	**24.04**	**25.25**

See footnotes at end of table.

Table B4. Consumption by Major Fuels and End-Use Sectors (Continued)
(Quadrillion Btu per Year)

Sector and Fuel	Low Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Transportation											
Aviation Gasoline	0.08	0.07	0.05	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.09
Distillate Fuel	2.22	2.68	2.84	2.67	2.61	2.66	2.74	2.83	2.93	3.03	3.73
Jet Fuel[6]	2.13	2.14	2.14	2.35	2.30	2.41	2.50	2.54	2.59	2.62	2.64
Motor Gasoline	12.45	13.93	12.47	12.67	12.37	12.01	11.76	11.57	11.42	11.32	10.90
Residual Fuel	.73	.99	.75	.74	.71	.71	.74	.76	.77	.78	.85
Liquefied Petroleum Gas	.04	.03	.03	.01	.01	.01	.01	.01	.01	.01	.01
Lubricants and Waxes	.16	.18	.16	.22	.22	.22	.23	.23	.24	.24	.26
Natural Gas[7]	.74	.54	.58	.61	.62	.61	.61	.61	.61	.61	.61
Other Transportation[8]	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01
Total	**18.58**	**20.57**	**19.02**	**19.35**	**18.91**	**18.72**	**18.68**	**18.63**	**18.65**	**18.70**	**19.09**
Electric Utilities											
Distillate Fuel	.27	.28	.10	.11	.05	.02	.01	.01	.01	.02	.04
Residual Fuel	3.24	3.71	1.45	1.20	1.12	1.14	1.08	1.04	1.00	1.04	1.28
Natural Gas	3.75	3.30	3.01	3.27	3.33	3.09	3.07	3.06	3.05	3.03	3.54
Steam Coal	8.66	10.25	13.23	14.05	14.94	14.99	15.19	15.27	15.60	16.16	18.95
Nuclear Power	.91	3.02	3.23	3.70	4.10	4.72	5.31	5.79	6.09	6.32	7.09
Hydropower/Other[9]	3.02	3.18	3.98	3.95	3.54	3.77	3.83	3.89	3.96	4.03	4.16
Total	**19.85**	**23.74**	**25.00**	**26.27**	**27.09**	**27.73**	**28.48**	**29.07**	**29.71**	**30.61**	**35.06**
Primary Energy Consumption											
Distillate Fuel	6.61	7.32	5.72	6.13	5.82	5.92	6.09	6.22	6.36	6.51	7.23
Kerosene	.45	.36	.26	.23	.20	.21	.21	.21	.22	.22	.21
Aviation Gasoline	.08	.07	.05	.07	.07	.07	.07	.08	.08	.08	.09
Motor Gasoline	12.80	14.21	12.70	12.89	12.58	12.24	12.01	11.83	11.71	11.63	11.33
Jet Fuel	2.13	2.14	2.14	2.35	2.30	2.41	2.50	2.54	2.59	2.62	2.64
Residual Fuel	6.49	6.95	3.27	3.25	3.09	3.14	3.16	3.16	3.16	3.24	3.59
Liquefied Petroleum Gas	1.98	1.89	1.99	1.81	1.83	1.98	2.13	2.21	2.24	2.29	2.53
Petrochemical Feedstocks	.73	1.22	.85	1.38	1.46	1.56	1.65	1.66	1.64	1.62	1.56
Still Gas	1.06	1.20	1.13	1.16	1.21	1.21	1.22	1.22	1.23	1.24	1.28
Lubricants and Waxes	.40	.41	.35	.45	.44	.44	.45	.46	.46	.47	.49
Other Petroleum	2.11	2.18	1.62	1.75	1.82	1.83	1.89	1.93	1.97	2.01	2.30
Natural Gas	22.50	20.00	17.47	18.54	18.73	18.53	18.66	18.68	18.60	18.52	18.60
Steam Coal	10.35	11.92	14.91	15.95	16.88	17.07	17.34	17.49	17.87	18.48	21.42
Metallurgical Coal	2.54	1.79	.96	1.15	1.19	1.25	1.30	1.33	1.36	1.36	1.28
Net Coke Imports	-.01	.13	-.02	.00	.00	.00	.00	.00	.00	.00	.00
Nuclear Power	.91	3.02	3.23	3.70	4.10	4.72	5.31	5.79	6.09	6.32	7.09
Hydropower/Other[9]	3.06	3.21	3.99	3.98	3.57	3.80	3.86	3.92	3.99	4.06	4.19
Total Consumption	**74.19**	**78.04**	**70.66**	**74.79**	**75.31**	**76.39**	**77.85**	**78.75**	**79.55**	**80.64**	**85.82**
Electricity Consumption (all sectors)	**5.84**	**6.89**	**7.34**	**7.72**	**7.92**	**8.10**	**8.33**	**8.51**	**8.69**	**8.96**	**10.29**

[1] Commercial natural gas includes deliveries to municipalities and public authorities for institutional heating, street lighting, etc.
[2] Industrial includes all fuels consumed for heat and power, including natural gas used as lease and plant fuel, industrial feedstock and raw material uses; also, all fuels consumed by refineries.
[3] Petrochemical feedstocks includes still gas used for feedstock purposes, naphthas less than 400 degrees, and other oils greater than 400 degrees.
[4] Consists of asphalt, special naphthas, lubricants, waxes, petroleum coke, road oil, and small amounts of Other Petroleum, and Net Blending Oil as defined in Table A8.
[5] Includes lease and plant fuel consumption of natural gas.
[6] Jet fuel includes naphtha and kerosene types.
[7] Consists of natural gas used as pipeline compressor fuel.
[8] Other transportation includes steam coal and electricity.
[9] Includes renewable facilities such as hydropower, geothermal power, wood, waste, solar power, and wind power. Electric utility consumption includes net electicity imports.

NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical quantities are taken from Energy Information Administration, *State Energy Data Report, 1960 to 1982*, DOE/EIA-0214 (82) (Washington, DC, 1984) and Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984). Projected quantities are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = Low Economic Growth Case, printed on December 21, 1984.
Historical quantities through 1983.

Table B5. Prices by Major Fuels and End-Use Sectors
(1984 Dollars per Million Btu)

Sector and Fuel	Low Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential											
Distillate Fuel	3.46	5.28	7.94	7.70	7.48	7.33	7.34	7.55	7.77	8.01	10.04
Kerosene	3.96	6.01	8.29	8.04	7.81	7.65	7.66	7.88	8.12	8.36	10.48
Liquefied Petroleum Gas	7.66	7.08	9.02	7.76	7.53	7.37	7.38	7.61	7.84	8.10	10.26
All Petroleum Products	**4.38**	**5.68**	**8.19**	**7.72**	**7.50**	**7.35**	**7.36**	**7.58**	**7.80**	**8.04**	**10.10**
Natural Gas	2.66	3.72	6.20	6.00	5.94	5.93	6.08	6.24	6.54	6.82	8.36
Steam Coal[1]	2.47	3.81	2.04	2.10	2.12	2.15	2.17	2.19	2.21	2.24	2.38
Electricity	15.74	18.80	19.55	19.63	19.79	19.95	20.09	20.06	19.87	19.69	18.91
Average[2]	**5.76**	**7.71**	**10.41**	**10.23**	**10.33**	**10.37**	**10.52**	**10.67**	**10.85**	**11.05**	**12.30**
Commercial											
Distillate Fuel	2.90	4.72	6.57	6.33	6.11	5.95	5.96	6.17	6.39	6.62	8.64
Kerosene	2.04	4.68	6.62	6.36	6.14	5.98	5.99	6.21	6.44	6.69	8.80
Motor Gasoline	6.57	7.85	10.33	10.14	9.87	9.64	9.64	9.85	10.05	10.22	12.49
Residual Fuel	1.82	3.27	5.47	5.30	5.14	5.12	5.16	5.32	5.49	5.72	6.92
Liquefied Petroleum Gas	3.11	5.25	9.04	6.54	6.31	6.15	6.16	6.39	6.62	6.87	9.04
All Petroleum Products	**2.62**	**4.45**	**6.72**	**6.32**	**6.10**	**5.96**	**5.96**	**6.14**	**6.34**	**6.55**	**8.28**
Natural Gas[3]	1.95	3.27	5.59	5.55	5.48	5.46	5.57	5.70	5.96	6.22	7.65
Steam Coal[4]	.94	1.89	2.01	2.06	2.08	2.11	2.13	2.15	2.17	2.20	2.33
Electricity	15.08	19.48	19.76	19.80	20.02	20.23	20.40	20.41	20.19	19.99	19.24
Average[2]	**5.49**	**8.40**	**10.93**	**11.07**	**11.23**	**11.29**	**11.44**	**11.55**	**11.64**	**11.76**	**12.70**
Industrial											
Distillate Fuel	1.98	4.21	6.53	6.28	6.06	5.90	5.91	6.12	6.34	6.57	8.57
Kerosene	2.13	4.61	6.88	6.62	6.40	6.24	6.25	6.47	6.70	6.94	9.05
Motor Gasoline	6.62	7.82	10.38	10.19	9.92	9.68	9.68	9.89	10.09	10.25	12.50
Residual Fuel	1.69	3.16	4.53	4.35	4.20	4.18	4.22	4.39	4.56	4.79	6.00
Liquefied Petroleum Gas	2.99	5.17	7.85	6.69	6.46	6.30	6.31	6.53	6.76	7.01	9.16
Petrochemical Feedstocks[5]	1.98	4.21	6.16	5.90	5.65	5.47	5.48	5.70	5.92	6.16	8.25
Still Gas[6]	1.98	4.21	6.43	6.19	5.97	5.82	5.84	6.05	6.27	6.50	8.53
Other Petroleum[7]	1.98	4.21	5.16	5.15	4.84	4.72	4.71	4.78	4.83	4.91	5.50
All Petroleum Products	**2.19**	**4.22**	**6.30**	**5.87**	**5.64**	**5.51**	**5.54**	**5.72**	**5.91**	**6.12**	**7.81**
Natural Gas[8]	1.05	2.23	4.33	4.30	4.30	4.30	4.44	4.58	4.81	5.07	6.44
Steam Coal	.96	1.93	1.86	1.93	1.98	2.02	2.06	2.09	2.13	2.17	2.37
Metallurgical Coal	1.49	2.98	2.29	2.34	2.37	2.40	2.41	2.43	2.45	2.48	2.58
Net Coke Imports	1.93	4.55	4.08	4.16	4.21	4.26	4.28	4.31	4.34	4.39	4.56
Electricity	7.72	12.19	16.59	16.66	16.80	16.95	17.10	17.05	16.85	16.67	15.85
Average[2]	**2.06**	**4.15**	**6.44**	**6.16**	**6.07**	**6.04**	**6.13**	**6.27**	**6.43**	**6.62**	**7.85**

See footnotes at end of table.

Table B5. Prices by Major Fuels and End-Use Sectors (Continued)
(1984 Dollars per Million Btu)

Sector and Fuel	Low Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Transportation[9]											
Aviation Gasoline	7.94	10.47	13.95	13.62	13.17	12.77	12.77	13.12	13.46	13.74	17.56
Distillate Fuel	3.48	5.04	9.58	9.34	9.12	8.97	8.98	9.19	9.41	9.64	11.67
Jet Fuel[10]	2.05	4.53	6.77	6.49	6.22	6.01	6.03	6.25	6.48	6.73	8.84
Motor Gasoline[11]	6.55	7.78	10.29	10.10	9.83	9.59	9.59	9.80	10.00	10.16	12.42
Residual Fuel[12]	1.35	2.25	3.60	3.43	3.28	3.26	3.30	3.47	3.65	3.88	5.09
Liquefied Petroleum Gas	2.87	4.78	8.38	9.98	9.75	9.59	9.60	9.82	10.06	10.31	12.48
Lubricants and Waxes[13]	12.48	14.88	24.54	24.13	23.75	23.49	23.51	23.87	24.25	24.65	28.10
All Petroleum Products	**5.47**	**6.86**	**9.63**	**9.45**	**9.20**	**8.96**	**8.94**	**9.13**	**9.33**	**9.51**	**11.67**
Natural Gas[14]	.45	1.33	2.64	2.62	2.60	2.58	2.71	2.84	3.03	3.23	4.30
Electricity	5.67	9.48	19.00	18.99	19.24	19.46	19.67	19.70	19.46	19.25	18.52
Average[2]	**5.27**	**6.72**	**9.43**	**9.24**	**8.99**	**8.76**	**8.74**	**8.93**	**9.13**	**9.32**	**11.43**
Electric Utilities											
Distillate Fuel[15]	1.87	3.70	7.79	7.12	6.67	5.35	5.57	5.79	6.31	7.26	9.16
Residual Fuel	1.65	3.17	4.69	4.53	4.39	4.44	4.50	4.67	4.85	5.08	6.33
All Petroleum Products	**1.67**	**3.20**	**4.89**	**4.75**	**4.49**	**4.46**	**4.52**	**4.68**	**4.87**	**5.13**	**6.42**
Natural Gas	.73	2.11	3.60	3.47	3.59	3.50	3.62	3.75	3.92	4.15	5.34
Steam Coal	.95	1.78	1.72	1.81	1.83	1.85	1.86	1.87	1.88	1.90	2.03
Fossil Fuel Average	**1.05**	**2.17**	**2.31**	**2.31**	**2.29**	**2.27**	**2.29**	**2.32**	**2.35**	**2.41**	**2.77**
Average Price to All Users											
Distillate Fuel	3.02	4.83	8.33	7.91	7.72	7.57	7.58	7.80	8.03	8.28	10.40
Kerosene	3.05	5.21	7.35	6.98	6.75	6.59	6.59	6.80	7.02	7.26	9.33
Aviation Gasoline	7.94	10.47	13.95	13.62	13.17	12.77	12.77	13.12	13.46	13.74	17.56
Motor Gasoline	6.55	7.78	10.30	10.10	9.83	9.59	9.59	9.80	10.00	10.17	12.42
Jet Fuel	2.05	4.53	6.77	6.49	6.22	6.01	6.03	6.25	6.48	6.73	8.84
Residual Fuel	1.65	3.04	4.48	4.31	4.16	4.17	4.21	4.37	4.55	4.78	6.02
Liquefied Petroleum Gas	2.99	5.17	7.85	6.69	6.46	6.30	6.31	6.53	6.76	7.01	9.16
Petrochemical Feedstocks	1.98	4.21	6.16	5.90	5.65	5.47	5.48	5.70	5.92	6.16	8.25
Lubricants and Waxes	12.48	14.88	24.54	24.13	23.75	23.49	23.51	23.87	24.25	24.65	28.10
Other Petroleum Products	1.98	4.21	5.63	5.37	5.16	5.01	5.02	5.22	5.42	5.65	7.52
All Petroleum Products	**4.02**	**5.62**	**8.30**	**7.98**	**7.74**	**7.52**	**7.49**	**7.67**	**7.86**	**8.04**	**9.92**
Natural Gas	1.42	2.68	4.82	4.70	4.69	4.69	4.82	4.96	5.21	5.47	6.81
Coal	1.07	1.97	1.77	1.86	1.88	1.91	1.92	1.94	1.95	1.97	2.10
Electricity	12.34	16.32	18.54	18.62	18.82	19.00	19.13	19.10	18.89	18.70	17.88
Average	**3.37**	**5.15**	**7.02**	**6.85**	**6.72**	**6.68**	**6.74**	**6.86**	**6.99**	**7.11**	**8.10**

[1] Projected residential coal prices are delivered to dealer prices and do not include dealer markup.
[2] Weighted average of end-use fuel prices consists of the prices shown above and the appropriate weights from Table 4.
[3] Commercial natural gas price is a weighted average of the commercial and other category.
[4] Historical price for commercial steam coal is the price of industrial steam coal at the State level. Projected prices do not include dealer markup, where applicable.
[5] Industrial distillate price is used in historical years (through 1978).
[6] The industrial distillate price is used. For 1983 forward, differences between the national prices of still gas and distillate fuel oil are due to differences in the regional composition of demand for these fuels.
[7] Industrial other price is a weighted average price for road oil, asphalt, lubricants, waxes, petroleum coke, special naphthas, and miscellaneous petroleum products.
[8] Industrial natural gas price is a weighted average of the lease and plant fuel price and the industrial price. In these reports, the natural gas price for industrial heat and power is used for the lease and plant fuel price, so both components of the average are the same.
[9] Transportation prices include the appropriate Federal excise tax and State road use taxes.
[10] Jet fuel price is for kerosene type jet fuel at retail.
[11] Gasoline price is an average for all types.
[12] Residual fuel price is for marine bunker.
[13] Historical price is the price of industrial lubricants.
[14] Transportation natural gas price is for pipeline fuel use only. The average wellhead price from Table 17 is used as a surrogate price.
[15] Historical price for electric utility distillate fuel oil is the price of electric utility kerosene.

NOTE: Metallurgical coal prices reflect a reduced level of projected demand. Projected coal prices are based on cost estimates and do not reflect market conditions.
NOTE: Electricity and natural gas prices are average prices, revenue divided by sales. Also, the electricity prices are averages for class A and B private electric utilities and public power authorities.
NOTE: Implicit Gross National Product Price Deflator, rebased to 1984 = 1.0, was used to convert from nominal to real dollars.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical prices are taken from Energy Information Administration, *State Energy Price and Expenditure Report*, (DOE/EIA-0376 (81) (Washington, DC, 1984), pp. 1-7. Projected prices are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = Low Economic Growth Case, printed on December 21, 1984.
Historical prices through 1981.

Table B6. Residential Energy Use by End Use
(Quadrillion Btu per Year)

Fuel and End Use	Low Economic Growth Case								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
Marketed Fuel Consumption[1]									
Fuel Use									
Space Heating	4.51	4.68	4.68	4.76	4.81	4.85	4.86	4.87	4.66
Water Heating	1.63	1.66	1.66	1.67	1.68	1.69	1.70	1.71	1.77
Air Conditioning	0.38	.39	.40	.41	.41	.42	.43	.44	.49
Other End Uses[2]	2.21	2.22	2.26	2.28	2.30	2.32	2.34	2.38	2.57
Total	**8.73**	**8.94**	**9.00**	**9.11**	**9.20**	**9.27**	**9.33**	**9.39**	**9.50**
Liquefied Petroleum Gas									
Space Heating	.21	.18	.20	.21	.22	.23	.23	.23	.19
Water Heating	.09	.07	.08	.08	.08	.08	.08	.08	.09
Total	**.30**	**.25**	**.28**	**.29**	**.30**	**.31**	**.31**	**.31**	**.28**
Fuel Oil[3]									
Space Heating	.93	1.06	1.01	1.03	1.05	1.06	1.06	1.05	.94
Water Heating	.21	.24	.22	.22	.22	.22	.22	.22	.22
Total	**1.14**	**1.30**	**1.23**	**1.25**	**1.27**	**1.28**	**1.28**	**1.27**	**1.16**
Natural Gas									
Space Heating	3.06	3.12	3.12	3.15	3.17	3.17	3.17	3.16	3.03
Water Heating	1.02	1.03	1.03	1.03	1.04	1.04	1.04	1.04	1.06
Air Conditioning	.01	.01	.01	.01	.01	.01	.01	.02	.02
Other End Uses[2]	.56	.56	.55	.55	.55	.55	.55	.55	.56
Total	**4.65**	**4.72**	**4.72**	**4.75**	**4.77**	**4.78**	**4.78**	**4.78**	**4.66**
Coal									
Space Heating	.08	.07	.07	.07	.07	.07	.06	.06	.06
Total	**.08**	**.07**	**.07**	**.07**	**.07**	**.07**	**.06**	**.06**	**.06**
Electricity									
Space Heating	.23	.25	.28	.29	.31	.32	.34	.35	.44
Water Heating	.31	.32	.33	.34	.34	.35	.35	.36	.41
Air Conditioning	.37	.37	.39	.39	.40	.41	.41	.42	.48
Other End Uses[2]	1.65	1.66	1.71	1.73	1.75	1.77	1.79	1.82	2.01
Total	**2.56**	**2.60**	**2.70**	**2.75**	**2.79**	**2.84**	**2.89**	**2.96**	**3.34**
Nonmarketed Fuel Consumption[1]									
Wood	**1.04**	**0.92**	**0.94**	**0.95**	**0.96**	**0.96**	**0.97**	**0.98**	**1.03**
Residential Activity									
Occupied Housing Stock (million units)	84.9	86.5	88.2	89.7	91.1	92.5	94.0	95.5	102.5
New Housing Construction[4] (million units)	1.5	2.0	2.1	1.9	1.8	1.9	1.9	1.9	1.8
Income Per Household (thousand 1984 dollars)	22.0	22.0	22.0	22.3	22.5	22.6	22.7	22.8	23.2
Energy Use Per Household (million Btu)	103	103	102	102	101	100	99	98	93
Fuel Expenditure Per Household (1984 dollars)	1,070	1,056	1,053	1,052	1,061	1,068	1,075	1,086	1,140

[1] Residential fuels are divided into marketed fuels (those with an associated price that are traded in economic markets) and nonmarketed fuels.
[2] Major other end uses include lighting, cooking, refrigeration, washing, and drying.
[3] Residential fuel oil category includes kerosene and distillate oil.
[4] New housing construction includes completions of single family, multifamily, and mobile housing units.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: The Residential model is documented in *Model Documentation: Household Model of Energy*, Energy Information Administration (DOE/EIA-0409) (Washington, DC, 1984). The major model data source is the public use tape of the Residential Energy Consumption Survey 1981, Energy Information Administration.
Input data file: Historical = MRG1126T, Projected = Low Economic Growth Case, printed on December 21, 1984.
Historical quantities through 1983.

Table B7. *Commercial Energy Use by Building Type*

(Quadrillion Btu per Year)

Fuel and Building Type	Low Economic Growth Case								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
Marketed Fuel Consumption									
Total Fuel Use	**5.75**	**6.15**	**6.24**	**6.41**	**6.55**	**6.64**	**6.76**	**6.86**	**7.21**
Liquefied Petroleum Gas	**.05**	**.03**	**.03**	**.03**	**.03**	**.03**	**.03**	**.03**	**.03**
Motor Gasoline	**.09**	**.09**	**.08**	**.08**	**.08**	**.08**	**.08**	**.08**	**.08**
Fuel Oil[1]									
Office[2]	.26	.31	.30	.32	.33	.35	.36	.37	.39
Retail/Wholesale	.17	.20	.19	.20	.21	.22	.23	.24	.24
Warehouse	.12	.15	.15	.17	.18	.19	.20	.21	.25
Other Buildings[3]	.22	.25	.24	.26	.27	.28	.29	.30	.31
Total	**.77**	**.90**	**.89**	**.94**	**.99**	**1.04**	**1.08**	**1.12**	**1.20**
Natural Gas									
Office[2]	.74	.75	.75	.76	.77	.77	.78	.78	.76
Retail/Wholesale	.75	.77	.78	.79	.81	.81	.82	.83	.83
Warehouse	.35	.36	.37	.37	.37	.37	.38	.38	.36
Other Buildings[3]	.76	.78	.78	.79	.79	.79	.79	.78	.73
Total	**2.60**	**2.66**	**2.67**	**2.72**	**2.74**	**2.75**	**2.76**	**2.76**	**2.68**
Coal	**.12**	**.11**	**.12**	**.12**	**.12**	**.12**	**.12**	**.12**	**.11**
Electricity									
Office[2]	.81	.90	.93	.96	.99	1.00	1.02	1.05	1.18
Retail/Wholesale	.61	.68	.71	.74	.75	.77	.79	.81	.92
Warehouse	.29	.32	.33	.34	.35	.36	.37	.38	.44
Other Buildings[3]	.41	.46	.47	.48	.49	.50	.51	.52	.58
Total	**2.12**	**2.36**	**2.45**	**2.53**	**2.59**	**2.63**	**2.70**	**2.77**	**3.12**
Commercial Activity									
Building Floorspace Stock (billion square feet)	48.5	51.1	52.3	53.8	55.2	56.3	57.7	58.9	64.7
Office[2]	17.0	18.0	18.4	19.0	19.4	19.8	20.3	20.7	22.8
Retail/Wholesale	14.5	15.4	15.8	16.3	16.8	17.2	17.7	18.1	20.1
Warehouse	6.9	7.2	7.4	7.7	7.9	8.1	8.3	8.5	9.4
Other Buildings[3]	10.1	10.5	10.6	10.9	11.1	11.2	11.4	11.6	12.4
Energy Use Per Square Foot (thousand Btu)	118.6	120.3	119.4	119.2	118.7	118.0	117.1	116.5	111.3
Expenditures Per Square Foot (1984 dollars)	1.30	1.31	1.32	1.32	1.34	1.34	1.34	1.35	1.39

[1] The commercial fuel oil category includes kerosene, distillate fuel, and residual fuel.
[2] Office includes offices, educational buildings, laboratories, health clinics, and some public buildings.
[3] Other Buildings includes assembly buildings, hotels/motels, hospitals, parking garages, and jails.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: The Commercial model is documented in *Model Documentation: Commercial Sector Energy Model*, Energy Information Administration (DOE/EIA-0453), August 1984. The major model source is the public use tape of the Nonresidential Energy Consumption Survey 1980, Energy Information Administration.

Input data file: Historical = MRG1126T, Projected = Low Economic Growth Case, printed on December 21, 1984.

Historical quantities through 1983.

Table B8. Industrial Energy Use
(Quadrillion Btu per Year)

Fuel and End Use	Low Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Industrial Heat and Power											
Distillate Fuel	1.44	1.70	1.29	1.60	1.49	1.51	1.56	1.58	1.59	1.61	1.69
Residual Fuel	1.58	1.40	.65	.85	.81	.81	.85	.86	.86	.87	.89
Liquefied Petroleum Gas	.13	.20	.57	.33	.34	.34	.34	.35	.34	.35	.34
Natural Gas[1]	8.50	7.08	5.56	6.08	6.22	6.18	6.28	6.28	6.19	6.14	5.89
Steam Coal[2]	1.43	1.46	1.50	1.72	1.75	1.89	1.97	2.04	2.09	2.14	2.30
Electricity[3]	2.34	2.76	2.65	2.63	2.64	2.70	2.82	2.91	2.98	3.11	3.70
Total	**15.43**	**14.61**	**12.21**	**13.21**	**13.25**	**13.43**	**13.83**	**14.00**	**14.06**	**14.21**	**14.81**
Refinery Fuel											
Distillate Fuel	.03	.05	.01	.01	.01	.01	.01	.01	.01	.01	.01
Residual Fuel	.28	.31	.13	.13	.12	.12	.12	.12	.12	.12	.12
Liquefied Petroleum Gas	.04	.06	.03	.03	.02	.02	.02	.02	.02	.02	.03
Still Gas	1.06	1.20	1.13	1.16	1.21	1.21	1.22	1.22	1.23	1.24	1.28
Petroleum Coke	.40	.39	.40	.42	.36	.37	.37	.37	.37	.37	.39
Other Petroleum	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Electricity	NA	NA	NA	.12	.11	.11	.11	.11	.11	.12	.12
Natural Gas	1.11	.82	.59	.66	.63	.63	.63	.63	.64	.64	.67
Total	**2.92**	**2.84**	**2.28**	**2.52**	**2.45**	**2.47**	**2.48**	**2.48**	**2.50**	**2.51**	**2.60**
Feedstocks, Raw Materials, and Other Fuel Uses											
Motor Gasoline	.26	.18	.14	.13	.13	.15	.17	.19	.21	.24	.36
Kerosene	.16	.16	.14	.10	.08	.08	.08	.08	.08	.08	.07
Petroleum Feedstocks[4]	.73	1.22	.85	1.38	1.46	1.56	1.65	1.66	1.64	1.62	1.56
Liquefied Petroleum Gas[5]	1.07	.99	1.01	1.17	1.16	1.30	1.42	1.49	1.53	1.57	1.85
Special Naphthas	.17	.20	.16	.21	.20	.21	.23	.23	.24	.24	.24
Lubricants and Waxes	.23	.23	.20	.23	.22	.22	.22	.23	.23	.23	.23
Petroleum Coke	.16	.16	.10	.13	.22	.25	.28	.31	.34	.37	.56
Asphalt and Road Oil	1.26	1.16	.90	1.01	1.10	1.10	1.14	1.15	1.16	1.16	1.15
Net Blending Oil[6]	.12	.27	.06	-.01	-.06	-.10	-.13	-.13	-.13	-.13	-.04
Metallurgical Coal[2]	2.54	1.79	.96	1.15	1.19	1.25	1.30	1.33	1.36	1.36	1.28
Natural Gas Raw Materials[7]	.78	.63	.49	.55	.54	.56	.56	.57	.57	.56	.55
Net Coke Imports	-.01	.13	-.02	.00	.00	.00	.00	.00	.00	.00	.00
Hydropower	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03
Total	**7.49**	**7.15**	**5.03**	**6.06**	**6.28**	**6.61**	**6.97**	**7.14**	**7.23**	**7.31**	**7.84**
Total Industrial Demand	**25.84**	**24.60**	**19.52**	**21.79**	**21.98**	**22.50**	**23.27**	**23.63**	**23.79**	**24.04**	**25.25**

[1] Includes lease and plant fuel.
[2] Includes refinery steam coal. The metallurgical coal estimates for 1983 and 1984 are not fully comparable, in part because of different Btu conversion factors.
[3] Includes refinery electricity before 1984.
[4] Petrochemical feedstocks includes naphthas less than 400 degrees, other oils greater than 400 degrees, and some still gas.
[5] The LPG price for Industrial Heat and Power is used for LPG feedstocks in weighted average price calculations.
[6] Net blending oil includes jet fuel, plant condensate, unfractionated stream, some still gas, miscellaneous, natural gasoline, unfinished oils, aviation blending components, and motor gasoline blending components, net of oil reclassified in blending.
[7] The natural gas price for Industrial Heat and Power is used for natural gas raw materials in weighted average price calculations.
NA = Not available.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: The Industrial model is documented in *Documentation of the PURHAPS Industrial Demand Model, Vol 1: Model Description, Overview, and Assumptions for the 1983 Annual Energy Outlook*, DOE/EIA-0420/1 (Washington, DC, 1984).
Input data file: Historical = MRG1126T, Projected = Low Economic Growth Case, printed on December 21, 1984.
Historical quantities through 1983.

Table B9. Transportation Sector Energy Use By Mode

Fuel and Mode of Transportation	Low Economic Growth Case								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
All Modes[1]									
Aviation Gasoline	0.05	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.09
Distillate Fuel	2.84	2.67	2.61	2.66	2.74	2.83	2.93	3.03	3.73
Jet Fuel	2.14	2.35	2.30	2.41	2.50	2.54	2.59	2.62	2.64
Motor Gasoline	12.47	12.67	12.37	12.01	11.76	11.57	11.42	11.32	10.90
Residual Fuel	.75	.74	.71	.71	.74	.76	.77	.78	.85
Liquefied Petroleum Gas	.03	.01	.01	.01	.01	.01	.01	.01	.01
Lubricants	.16	.22	.22	.22	.23	.23	.24	.24	.26
Natural Gas	.58	.61	.62	.61	.61	.61	.61	.61	.61
Electricity	.01	.01	.01	.01	.01	.01	.01	.01	.01
Total Consumption	**19.02**	**19.35**	**18.91**	**18.72**	**18.68**	**18.63**	**18.65**	**18.70**	**19.09**
Automobiles									
Vehicle-Miles Travelled[2]	1149.7	1,252.7	1,297.0	1,326.2	1,361.0	1,396.8	1,434.9	1,473.9	1,645.6
Fleet-Miles per Gallon	16.5	17.5	18.4	19.3	20.1	20.8	21.4	22.0	24.5
Total Fuel Use[3]	69.5	71.5	70.4	68.8	67.9	67.2	66.9	66.9	67.1
Trucks									
Vehicle-Miles Travelled[2]	449.1	484.5	492.9	501.7	512.5	524.7	537.9	552.0	636.1
Fleet-Miles per Gallon	10.5	11.1	11.6	12.0	12.4	12.8	13.2	13.6	15.2
Total Fuel Use[3]	42.6	43.8	42.6	41.8	41.2	40.8	40.7	40.6	41.7
Air									
Revenue Passenger-Miles[2]	300.1	354.3	363.4	398.4	431.5	456.4	483.9	506.9	601.9
Fuel Burned Per Seat-Mile[4]	.023	.022	.022	.021	.020	.019	.018	.017	.014
Total Jet Fuel[3]	16.0	17.6	17.2	18.1	18.7	19.0	19.4	19.6	19.8
Aviation Gasoline[3]	.4	.6	.6	.6	.6	.6	.6	.7	.7
Selected Fuel Expenditures[5]									
Motor Gasoline	128.4	128.0	121.6	115.2	112.8	113.4	114.2	115.1	135.3
Distillate Fuel	27.2	24.9	23.8	23.9	24.6	26.0	27.5	29.3	43.5

[1] Quadrillion Btu per year.
[2] Billion per year.
[3] Billion gallons per year.
[4] Gallons.
[5] Billion 1984 dollars per year.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Input data file: Historical = MRG1126T, Projected = Low Economic Growth Case, printed on December 28, 1984.
Historical quantities through 1983.

Table B10. Electric Utility Fuel Consumption and Electricity Sales
(Quadrillion Btu per Year)

Fuel Consumption and Sales	Low Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Fuel Inputs											
Oil											
Distillate	0.27	0.28	0.10	0.11	0.05	0.02	0.01	0.01	0.01	0.02	0.04
Residual LS[1]	NA	NA	NA	.69	.65	.70	.67	.65	.62	.66	.82
Residual HS[1]	3.24	3.71	1.45	.51	.48	.44	.41	.40	.38	.39	.46
Natural Gas	3.75	3.30	3.01	3.27	3.33	3.09	3.07	3.06	3.05	3.03	3.54
Steam Coal	8.66	10.25	13.23	14.05	14.94	14.99	15.19	15.27	15.60	16.16	18.95
Nuclear Power	.91	3.02	3.23	3.70	4.10	4.72	5.31	5.79	6.09	6.32	7.09
Hydropower/Other[2]	2.87	2.97	3.61	3.55	3.11	3.29	3.30	3.31	3.32	3.33	3.37
Total Fuel Inputs	19.71	23.53	24.63	25.87	26.66	27.25	27.95	28.49	29.07	29.91	34.27
Net Imports	.15	.20	.37	.41	.43	.48	.53	.58	.64	.70	.78
Total Electricity Inputs	**19.85**	**23.74**	**25.00**	**26.27**	**27.09**	**27.73**	**28.48**	**29.07**	**29.71**	**30.61**	**35.06**
Disposition											
Total Electricity Inputs	19.85	23.74	25.00	26.27	27.09	27.73	28.48	29.07	29.71	30.61	35.06
Minus Conversion Losses[3]	13.50	16.21	17.12	17.99	18.58	19.01	19.53	19.95	20.40	21.03	24.07
Generation	6.35	7.53	7.88	8.28	8.50	8.72	8.95	9.12	9.31	9.58	10.99
Minus Transportation and Distribution Losses	.51	.64	.55	.57	.58	.62	.62	.62	.62	.62	.70
Electricity Sales	**5.84**	**6.89**	**7.34**	**7.72**	**7.92**	**8.10**	**8.33**	**8.51**	**8.69**	**8.96**	**10.29**
Electricity Sales by End-Use Sector											
Residential	1.98	2.30	2.56	2.60	2.70	2.75	2.79	2.84	2.89	2.96	3.34
Commercial/Other[4]	1.53	1.82	2.13	2.37	2.47	2.54	2.60	2.65	2.71	2.78	3.13
Industrial	2.34	2.76	2.65	2.75	2.75	2.81	2.94	3.02	3.10	3.22	3.82
Total Electricity Sales	**5.84**	**6.89**	**7.34**	**7.72**	**7.92**	**8.10**	**8.33**	**8.51**	**8.69**	**8.96**	**10.29**

[1] Prior to 1984, only the total of high-sulfur and low-sulfur residual oil is available, and is reported here as high-sulfur.
[2] Includes renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[3] Conversion losses includes net imports.
[4] Commercial/Other includes street lighting and the transportation sector.
[NA] = Not available.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Input data file: Historical = MRG1126T, Projected = Low Economic Growth Case, printed on December 21, 1984. Historical quantities through 1983.

Table B11. Electric Utility Sectoral Prices and Demands
(Billion Kilowatthours per Year)
(1984 Dollars per Thousand Kilowatthours)

Prices and Demands	Low Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Prices[1]											
Residential	53.70	64.16	66.69	66.96	67.52	68.08	68.54	68.45	67.79	67.17	64.52
Commercial[2]	51.28	66.28	67.39	67.53	68.31	69.01	69.61	69.63	68.88	68.21	65.65
Industrial	26.34	41.59	56.62	56.85	57.32	57.84	58.34	58.19	57.50	56.86	54.09
All Sectors	**42.11**	**55.67**	**63.26**	**63.54**	**64.22**	**64.82**	**65.28**	**65.17**	**64.46**	**63.79**	**61.00**
Demands											
Residential	579	674	751	763	792	806	819	832	847	869	980
Commercial[2]	448	534	624	694	723	743	761	775	793	814	917
Industrial	686	809	776	805	807	825	860	885	908	944	1,118
All Sectors	**1,713**	**2,018**	**2,151**	**2,262**	**2,321**	**2,374**	**2,440**	**2,493**	**2,548**	**2,627**	**3,015**

[1] Prices for 1983 to 1995 are from model simulations and represent average revenues per kilowatthour of demand for the total electric utility industry. Revenue requirements are projected from the financial information contained on the Federal Energy Regulatory Commission Form 1 and Form 1-M and on the Energy Information Administration Form 412.
[2] This category includes consumption for street and highway lighting, other public authorities, and railroads and railways.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Prices for 1973 and 1978 are from the Energy Information Administration, *State Energy Price and Expenditure Report*, DOE/EIA-0376(81) (Washington, DC, 1984), pp.1-7. Historical demands are from the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83), (Washington, DC, 1984).

Table B12. Electric Utility Capacity and Generation
(Generation in Billion Kilowatthours per Year)
(Capacity in Million Kilowatts)

Capacity and Generation	Low Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Capacity[1]											
Coal Steam	184.0	233.9	285.9	296.0	303.8	309.6	314.2	317.3	323.7	328.5	358.9
Other Steam	135.0	161.4	157.2	157.2	157.2	157.2	157.2	157.2	157.2	157.2	157.2
Combined Cycle	1.3	4.9	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.8	5.8
Turbine	37.1	49.6	50.7	51.0	51.4	51.6	51.6	51.7	52.3	52.7	53.6
Nuclear Power	21.0	53.5	64.4	68.9	80.5	91.4	99.8	104.7	105.9	109.6	116.8
Hydropower/Other[2]	55.6	63.2	69.0	69.8	71.0	71.4	71.6	72.0	72.2	72.9	73.1
Pumped Storage Hydropower[3]	8.4	12.7	13.3	14.6	16.0	16.7	16.7	16.9	18.8	19.1	19.2
Total Capacity	442.4	579.2	**646.2**	**663.2**	**685.5**	**703.5**	**716.8**	**725.5**	**735.8**	**745.8**	**784.6**
Generation by Plant Type[4]											
Coal Steam	848	976	1,268	1,347	1,428	1,434	1,455	1,463	1,495	1,550	1,822
Other Steam	619	629	365	369	356	347	341	338	335	337	393
Combined Cycle	NA	13	32	33	32	28	28	28	28	29	30
Turbine	36	29	13	15	15	13	12	10	10	10	19
Nuclear Power	83	276	294	335	372	428	482	526	553	574	644
Hydropower/Other[2]	274	284	345	336	295	315	315	317	318	320	325
Pumped Storage Hydropower[3]	NA	NA	-6	-6	-6	-9	-9	-9	-10	-11	-12
Total Generation	**1,861**	**2,206**	**2,310**	**2,428**	**2,492**	**2,557**	**2,623**	**2,674**	**2,729**	**2,808**	**3,221**
Generation by Fuel Type											
Coal[5]	848	976	1,259	1,341	1,422	1,428	1,448	1,457	1,489	1,544	1,816
Natural Gas	341	305	274	299	301	284	282	282	282	280	323
Oil	314	365	144	124	109	111	105	101	97	101	125
Nuclear Power	83	276	294	335	372	428	482	526	553	574	644
All Hydropower/Other[6]	274	283	339	329	289	306	306	308	308	309	313
Total Generation	**1,861**	**2,206**	**2,310**	**2,428**	**2,492**	**2,557**	**2,623**	**2,674**	**2,729**	**2,808**	**3,221**

[1] Capacity for 1973 and 1978 include capacity out of service or in inactive reserve; 1983 and projected capacity exclude capacity out of service or in inactive reserve. Three Mile Island Unit 1 is included in the 1983 and 1984 capacity estimates but is not expected to restart opetation until 1985.

[2] This category includes other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

[3] See Glossary, Electricity Terminology for definition of pumped storage plant.

[4] Net generation data for 1973 excludes combined cycle generation. For 1973 and 1978 the hydropower/other category also contains pumped storage hydropower. The 1983 values are model estimates based on the best available data.

[5] Generation by coal and generation by coal steam plants are not identical because small amounts of oil and natural gas are used in coal steam plants for startup and flame stability.

[6] This category includes conventional and pumped storage hydropower and other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Generation data for 1973, 1978, and 1983 are from the Energy Information Administration, *Form EIA-759, "Monthly Power Plant Report."* Historical capacity data for 1973 and 1978 are based on the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984). Other capacity data are from the Intermediate Future Forecasting System.

Table B13. Electric Utility Capacity Additions
(Thousand Kilowatts)

Additions: Pipeline and New Starts	Low Economic Growth Case												
	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Total Additions													
Nuclear Power[1]	3,064	4,480	12,369	10,939	8,391	4,884	1,235	3,702	3,690	2,464	1,065	0	0
Coal Steam	5,720	10,082	7,783	5,860	4,586	3,109	6,394	4,782	10,654	5,025	6,421	3,466	4,795
Other Steam[2]	61	3	0	0	0	0	0	100	0	0	0	0	0
Turbines[3]	202	275	385	197	40	130	561	343	330	113	200	0	331
Pumped Storage Hydropower[4]	260	1,264	1,400	700	0	200	1,923	285	0	0	0	150	0
Hydropower/Other[5]	1,034	874	1,163	383	242	407	200	706	75	74	26	0	6
Total New Capacity	**10,342**	**16,978**	**23,100**	**18,078**	**13,258**	**8,729**	**10,313**	**9,919**	**14,749**	**7,676**	**7,712**	**3,616**	**5,132**
Pipeline[6]													
Nuclear Power[1]	3,064	4,480	12,369	10,939	8,391	4,884	1,235	3,702	3,690	2,464	1,065	0	0
Coal Steam	5,720	10,082	7,783	5,860	4,586	3,109	6,394	4,782	10,654	5,025	5,718	2,764	3,347
Other Steam[2]	61	3	0	0	0	0	0	100	0	0	0	0	0
Turbines[3]	202	275	385	197	40	130	561	343	330	113	200	0	143
Pumped Storage Hydropower[4]	260	1,264	1,400	700	0	200	1,923	285	0	0	0	150	0
Hydropower/Other[5]	1,034	874	1,163	383	242	407	200	706	75	74	26	0	6
Total Pipeline	**10,342**	**16,978**	**23,100**	**18,078**	**13,258**	**8,729**	**10,313**	**9,919**	**14,749**	**7,676**	**7,009**	**2,914**	**3,496**
New Starts[7]													
Nuclear Power[1]	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal Steam	0	0	0	0	0	0	0	0	0	0	703	703	1,448
Other Steam[2]	0	0	0	0	0	0	0	0	0	0	0	0	0
Turbines[3]	0	0	0	0	0	0	0	0	0	0	0	0	188
Pumped Storage Hydropower[4]	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydropower/Other[5]	0	0	0	0	0	0	0	0	0	0	0	0	0
Total New Starts	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**703**	**703**	**1,636**

[1] Includes the scheduled return to service of the Three Mile Island 1 facility.
[2] Includes natural gas, oil, and dual fired oil/natural gas steam and combined cycle capacity.
[3] Includes all gas turbine and internal combustion capacity.
[4] See Glossary, Electricity Terminology for definition of pumped storage plant.
[5] Includes conventional hydroelectric and other renewable sources of power such as geothermal, wood, waste, solar, and wind.
[6] Includes all new capacity announced by the electric utility industry.
[7] Includes additional new capacity considered necessary to meet projected electricity demands.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: The Energy Information Administration Generating Unit Reference file (GURF); the Federal Energy Regulatory Commission, *Hydroelectric Power Resources of the United States - Developed and Undeveloped*, FERC-0070, January 1, 1980; Energy Information Administration, *U.S. Commercial Nuclear Power*, DOE/EIA-0315 (Washington, DC, March 1982); and the Energy Information Administration Form-254: "Quarterly Progress Report on Status of Reactor Construction."

Table B14. Summary of Components of Electricity Price
(1984 Dollars per Thousand Kilowatthours)

Price Components	Low Economic Growth Case												
	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Capital Component[1]	25.44	25.52	25.53	26.31	26.76	26.58	25.63	24.57	23.78	22.93	21.81	20.65	19.58
Fuel Component[2]	22.65	22.81	23.18	22.70	22.66	22.76	23.05	23.55	23.99	24.46	25.03	25.60	26.39
O&M Component[3]	15.25	15.21	15.51	15.80	15.86	15.83	15.78	15.67	15.56	15.47	15.32	15.19	15.03
Total Price[4]	**63.34**	**63.54**	**64.22**	**64.82**	**65.28**	**65.17**	**64.46**	**63.79**	**63.33**	**62.87**	**62.16**	**61.44**	**61.00**

[1] The capital component represents the cost to the utility of capital assets needed to provide reliable service. It includes plant depreciation, taxes, and sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.
[2] The fuel component includes only the direct costs of fuel inputs used to generate electricity required to meet demand.
[3] The operation and maintenance (O&M) component includes all nonfuel costs necessary to operate and maintain generation, transmission, and distribution capacity used to deliver electricity to end-use sectors.
[4] All prices are from model simulations and represent average revenues per kilowatthour of demand for the total electric utility industry. Revenue requirements are projected from the financial information contained on the Federal Energy Regulatory Commission, Form FERC-1 and Form 1-M and on the Energy Information Administration, Form EIA-412.
NOTE: Total may not equal sum of components because of independent rounding.

Table B15. Petroleum Supply and Disposition Balance
(Million Barrels per Day)

Supply and Disposition	Low Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Crude Oil[1]	9.21	8.71	8.69	8.76	8.86	8.70	8.59	8.45	8.28	8.25	7.19
Alaska North Slope	.00	1.09	1.65	1.67	1.70	1.76	1.92	1.97	2.02	2.14	1.20
Subarctic	9.21	7.62	7.04	7.08	7.15	6.95	6.67	6.47	6.26	6.11	5.98
Natural Gas Plant Liquids	1.74	1.57	1.56	1.61	1.64	1.55	1.53	1.48	1.45	1.42	1.24
Other Domestic[2]	.00	.00	.05	.05	.05	.05	.05	.05	.07	.09	.35
Processing Gain[3]	.45	.50	.49	.55	.54	.49	.50	.50	.51	.51	.53
Total Production	**11.40**	**10.78**	**10.79**	**10.97**	**11.09**	**10.80**	**10.68**	**10.48**	**10.30**	**10.27**	**9.31**
Imports (including SPR)											
Crude Oil[4]	3.24	6.36	3.33	3.48	3.87	4.15	4.33	4.49	4.69	4.80	5.93
Refined Products	3.01	2.01	1.72	1.95	1.39	1.67	1.83	1.93	1.95	2.02	2.37
Total Imports	6.26	8.36	5.05	5.43	5.26	5.82	6.16	6.41	6.65	6.82	8.30
Exports											
Crude Oil	.00	.16	.16	.18	.17	.17	.17	.17	.17	.17	.17
Refined Products	.23	.20	.58	.49	.45	.61	.61	.61	.61	.61	.61
Total Exports	.23	.36	.74	.67	.62	.78	.78	.78	.78	.78	.78
Net Imports (including SPR)	**6.02**	**8.00**	**4.31**	**4.76**	**4.63**	**5.04**	**5.38**	**5.63**	**5.86**	**6.03**	**7.52**
Primary Stock Changes											
Net Withdrawals[5]	-.14	.26	.25	.04	.00	-.03	-.05	-.02	-.02	-.03	-.04
SPR Fill Rate Additions (-)[6]	.00	-.16	-.23	-.18	-.14	-.14	-.14	-.14	-.14	-.14	.00
Total Primary Supply[7]	**17.29**	**18.87**	**15.11**	**15.59**	**15.58**	**15.66**	**15.85**	**15.94**	**16.00**	**16.12**	**16.79**
Refined Petroleum Products											
Motor Gasoline	6.67	7.41	6.62	6.72	6.56	6.38	6.26	6.17	6.11	6.07	5.91
Aviation Gasoline	.05	.04	.03	.04	.04	.04	.04	.04	.04	.04	.05
Jet Fuel[8]	1.06	1.06	1.05	1.15	1.13	1.18	1.22	1.24	1.26	1.28	1.29
Kerosene	.22	.18	.13	.11	.10	.10	.10	.10	.10	.11	.10
Distillate Fuel	3.09	3.43	2.69	2.88	2.74	2.78	2.86	2.92	2.99	3.06	3.40
Residual Fuel	2.82	3.02	1.42	1.42	1.38	1.37	1.38	1.38	1.38	1.41	1.57
Liquid Petroleum Gas	1.45	1.41	1.49	1.36	1.38	1.49	1.60	1.66	1.69	1.72	1.90
Petrochemical Feedstocks	.36	.59	.42	.68	.71	.76	.81	.81	.80	.79	.76
Other Petroleum Products[9]	1.59	1.70	1.37	1.50	1.55	1.55	1.58	1.61	1.63	1.66	1.82
Total Product Supplied	**17.31**	**18.85**	**15.23**	**15.86**	**15.58**	**15.66**	**15.85**	**15.94**	**16.00**	**16.12**	**16.79**

See footnotes at end of table.

Table B15. Petroleum Supply and Disposition Balance (Continued)
(Million Barrels per Day)

Supply and Disposition	Low Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Refined Petroleum Products Supplied to End-Use Sectors											
Residential and Commercial	2.23	2.07	1.20	1.29	1.26	1.31	1.34	1.37	1.40	1.41	1.37
Industrial[10]	4.48	4.87	4.03	4.52	4.52	4.70	4.92	5.03	5.08	5.15	5.59
Transportation	9.05	10.14	9.33	9.48	9.25	9.15	9.12	9.08	9.09	9.11	9.26
Electric Utilities	1.54	1.75	.68	.57	.51	.51	.48	.46	.44	.46	.58
Total End-Use Consumption	**17.30**	**18.84**	**15.23**	**15.86**	**15.55**	**15.66**	**15.86**	**15.94**	**16.01**	**16.13**	**16.80**
Discrepancy[11]	-.01	.04	-.12	-.27	.03	.00	.00	.00	.00	.00	.00
Net Disposition[12]	**17.29**	**18.87**	**15.11**	**15.59**	**15.58**	**15.66**	**15.85**	**15.94**	**16.00**	**16.12**	**16.79**

[1] Includes lease condensate.
[2] Other Domestic prior to 1981 includes unfinished oils (net), hydrogen, and hydrocarbons not included elsewhere. After 1981, Other Domestic includes unfinished oils (net), motor gasoline blending components (net), aviation gasoline blending components (net), hydrogen, other hydrocarbons, alcohol, and synthetic crude production.
[3] Represents volumetric gain in refinery distillation and cracking processes.
[4] In 1977 and later years, crude oil imports include crude oil imported for the Strategic Petroleum Reserve.
[5] Net stock withdrawals for a given year, t, are defined as the change in yearend stock levels from period t-1 minus the yearend stock level from the year t. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.
[6] SPR is the Strategic Petroleum Reserve.
[7] Total primary supply is defined as total production plus net imports plus net stock withdrawals minus SPR additions.
[8] Jet fuel includes naphtha and kerosene type.
[9] Other petroleum products includes miscellaneous petroleum products, lubricants, waxes, unfractionated stream, plant condensate, natural gasoline, asphalt, road oil, still gas, special naphthas, and petroleum coke.
[10] Industrial refined products includes total industrial demand for petroleum as reported in Table 8.
[11] Discrepancy represents the difference between total supply and total products supplied.
[12] Net disposition is the sum of total products supplied and discrepancy.
NOTE: From 1981 onward, the product supplied data is on a new basis. From 1983 onward, the other product category is on a net basis, reclassified (petroleum products reprocessed into other categories) plus the other category of products supplied.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical data are from Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984) pp. 79-99, Tables 35, 36, 37, and 45. Projected values are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = Low Economic Growth Case, printed on December 28, 1984.
Historical quantities through 1983.

Table B16. Petroleum Product Prices
(1984 Dollars per Barrel)

Sector and Fuel	Low Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Crude Oil Prices											
World Oil Price[1]	**8.62**	**21.63**	**30.39**	**29.00**	**28.00**	**27.00**	**27.00**	**28.00**	**29.00**	**30.00**	**40.00**
Refiner Acquisition Cost[2]	**8.77**	**18.50**	**30.39**	**29.00**	**28.00**	**27.00**	**27.00**	**28.00**	**29.00**	**30.00**	**40.00**
Delivered Sector Product Prices											
Residential and Commercial											
Distillate Fuel	19.35	29.95	43.90	42.49	41.17	40.22	40.22	41.39	42.61	43.92	55.43
Kerosene	20.04	32.11	44.72	41.07	39.65	38.62	38.57	39.69	40.87	42.15	53.64
Motor Gasoline[3]	34.52	41.22	54.27	53.26	51.86	50.62	50.63	51.75	52.80	53.68	65.61
Residual Fuel	11.44	20.53	34.41	33.30	32.30	32.18	32.42	33.43	34.52	35.93	43.48
Liquefied Petroleum Gas[4]	26.12	24.96	32.87	27.76	27.03	26.46	26.52	27.36	28.22	29.15	37.02
Average[5]	**20.23**	**28.21**	**40.89**	**39.30**	**37.87**	**37.02**	**37.02**	**38.07**	**39.17**	**40.40**	**50.80**
Industrial											
Distillate Fuel	11.52	24.55	38.01	36.57	35.28	34.38	34.44	35.65	36.91	38.26	49.94
Kerosene	12.09	26.14	39.01	37.56	36.27	35.36	35.43	36.67	37.97	39.35	51.30
Motor Gasoline[3]	34.75	41.07	54.52	53.51	52.10	50.85	50.85	51.94	52.99	53.85	65.68
Residual Fuel	10.65	19.86	28.46	27.35	26.42	26.27	26.53	27.58	28.69	30.14	37.73
Liquefied Petroleum Gas	11.19	18.98	28.58	24.38	23.54	22.95	22.98	23.79	24.64	25.55	33.38
Petrochemical Feedstocks[6]	11.05	23.78	34.53	33.08	31.69	30.67	30.72	31.93	33.20	34.55	46.24
Asphalt & Road Oil	13.12	27.97	26.38	25.75	25.20	25.15	25.31	25.90	26.54	27.36	31.72
Petroleum Coke	11.91	25.39	7.67	7.61	7.59	7.60	7.63	7.71	7.80	7.91	8.50
Special Naphthas	10.38	22.12	34.27	32.99	31.85	31.05	31.10	32.20	33.35	34.59	45.18
Miscellaneous Petroleum Products	12.35	26.10	33.86	32.27	31.00	30.13	30.17	31.34	32.58	33.96	45.21
Average[5]	**12.25**	**23.19**	**30.27**	**28.56**	**27.39**	**26.73**	**26.79**	**27.67**	**28.60**	**29.62**	**37.74**
Transportation[7]											
Distillate Fuel	20.27	29.35	55.82	54.39	53.12	52.24	52.30	53.53	54.81	56.18	67.96
Aviation Gasoline	40.10	52.84	70.43	68.78	66.49	64.45	64.45	66.24	67.94	69.34	88.64
Motor Gasoline[3]	34.39	40.85	54.08	53.06	51.65	50.39	50.39	51.49	52.53	53.39	65.25
Jet Fuel[8]	11.48	25.41	37.94	36.37	34.87	33.70	33.81	35.05	36.35	37.73	49.57
Residual Fuel[9]	8.47	14.12	22.66	21.57	20.61	20.51	20.78	21.81	22.92	24.37	32.01
Liquefied Petroleum Gas	10.75	17.55	30.54	36.37	35.52	34.93	34.97	35.79	36.65	37.56	45.46
Lubricants[10]	75.70	90.23	148.87	146.32	144.06	142.48	142.59	144.77	147.05	149.49	170.46
Average[5]	**29.51**	**37.09**	**52.13**	**51.17**	**49.81**	**48.54**	**48.48**	**49.59**	**50.70**	**51.75**	**63.71**
Electric Utilities											
Distillate Fuel	10.92	21.53	45.38	41.46	36.82	31.19	32.44	33.74	36.75	42.31	53.36
Residual Fuel	10.37	19.91	29.51	28.49	27.58	27.93	28.32	29.35	30.49	31.97	39.79
Average[5]	**10.42**	**20.03**	**30.57**	**29.67**	**28.10**	**28.00**	**28.37**	**29.40**	**30.57**	**32.18**	**40.25**
Refined Petroleum Product Prices											
Distillate Fuel	17.57	28.12	48.50	46.09	44.99	44.09	44.16	45.44	46.78	48.23	60.59
Kerosene	17.27	29.55	41.70	39.55	38.25	37.35	37.36	38.56	39.82	41.16	52.89
Aviation Gasoline	40.10	52.84	70.43	68.78	66.49	64.45	64.45	66.24	67.94	69.34	88.64
Motor Gasoline[3]	34.40	40.85	54.08	53.06	51.65	50.40	50.40	51.50	52.54	53.40	65.27
Jet Fuel[8]	11.48	25.41	37.94	36.37	34.87	33.70	33.81	35.05	36.35	37.73	49.57
Residual Fuel	10.35	19.12	28.14	27.07	26.14	26.23	26.49	27.50	28.60	30.08	37.84
Liquefied Petroleum Gas	16.46	20.88	29.37	24.95	24.16	23.55	23.56	24.37	25.22	26.12	33.85
Lubricants (Transportation)[10]	75.70	90.23	148.87	146.32	144.06	142.48	142.59	144.77	147.05	149.49	170.46
Petrochemical Feedstocks[6]	11.05	23.78	34.53	33.08	31.69	30.67	30.72	31.93	33.20	34.55	46.24
Asphalt & Road Oil	13.12	27.97	26.38	25.75	25.20	25.15	25.31	25.90	26.54	27.36	31.72
Petroleum Coke	11.91	25.39	7.67	7.61	7.59	7.60	7.63	7.71	7.80	7.91	8.50
Special Naphthas	10.38	22.12	34.27	32.99	31.85	31.05	31.10	32.20	33.35	34.59	45.18
Miscellaneous Petroleum Products	12.35	26.10	33.86	32.27	31.00	30.13	30.17	31.34	32.58	33.96	45.21

[1] The cost of imported crude oil to U.S. refiners in 1984 dollars per barrel.
[2] Refiner acquisition cost is an average of imported and domestic refiner acquisition costs.
[3] Gasoline price is an average price for all types.
[4] Residential and commercial liquefied petroleum gas price includes only a residential price due to data limitations.
[5] Weighted average price; the weights are taken from the consumption categories from Table 4 and converted to physical units.
[6] Petrochemical feedstock price includes only the price of naphthas less than 400 degrees.
[7] Transportation prices include the appropriate State road use taxes and Federal excise tax.
[8] Jet fuel price is a retail price for kerosene type jet fuel.
[9] Residual fuel price in the transportation sector is for marine bunker.
[10] Lubricant price is an average for light stocks and multiweight motor oil.

NOTE: Implicit Gross National Product Price Deflator, rebased to 1984 = 1.0, was used to convert from nominal to real dollars.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical prices are taken from Energy Information Administration, *State Energy Price and Expenditure Report,* DOE/EIA-0376(81) (Washington, DC, 1984), pp. 1-7. Projected values are output from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = Low Economic Growth Case, printed on December 21, 1984.
Historical quantities through 1983.

Table B17. Natural Gas Supply, Disposition, and Prices

(Trillion Cubic Feet per Year)

(1984 Dollars per Thousand Cubic Feet)

Supply, Disposition, and Prices	Low Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Dry Gas Production[1]	21.73	19.12	15.97	17.43	17.48	17.09	17.31	17.24	16.98	16.65	16.04
Supplemental Natural Gas[2]	.00	.00	.14	.15	.15	.30	.10	.09	.12	.23	.40
Net Imports	.96	.91	.87	.86	.99	1.05	1.16	1.27	1.43	1.57	2.11
Net Storage Withdrawals[3]	-.42	-.15	.47	.03	.03	.00	.00	.00	.00	.00	.00
Total Supply[4]	**22.27**	**19.88**	**17.45**	**18.47**	**18.65**	**18.44**	**18.57**	**18.60**	**18.53**	**18.45**	**18.55**
Consumption by Sector[5]											
Residential	4.88	4.90	4.53	4.60	4.60	4.63	4.65	4.66	4.66	4.65	4.55
Commercial[6]	2.60	2.60	2.53	2.59	2.60	2.65	2.67	2.68	2.69	2.69	2.61
Industrial	8.69	6.76	5.47	6.01	6.11	6.11	6.20	6.21	6.14	6.11	5.92
Lease & Plant Fuel[7]	1.50	1.65	1.00	1.09	1.09	1.07	1.08	1.08	1.06	1.04	1.00
Transportation[8]	.73	.53	.56	.59	.60	.59	.60	.60	.60	.59	.60
Electric Utilities	3.66	3.19	2.91	3.16	3.22	2.99	2.96	2.96	2.95	2.93	3.42
Total End-Use Consumption	**22.05**	**19.63**	**17.00**	**18.04**	**18.22**	**18.04**	**18.16**	**18.18**	**18.10**	**18.02**	**18.10**
Unaccounted for[9]	.22	.25	.45	.43	.43	.40	.41	.42	.43	.43	.45
Average Wellhead Price	**.46**	**1.35**	**2.72**	**2.70**	**2.67**	**2.66**	**2.78**	**2.92**	**3.11**	**3.32**	**4.42**
Delivered Prices by Sectors											
Residential	2.71	3.78	6.37	6.16	6.09	6.09	6.24	6.41	6.71	6.99	8.58
Commercial[6]	1.99	3.33	5.73	5.69	5.63	5.60	5.72	5.85	6.12	6.38	7.85
Industrial	1.07	2.27	4.44	4.41	4.41	4.42	4.55	4.70	4.94	5.20	6.61
Electric Utilities	.75	2.18	3.73	3.59	3.72	3.62	3.75	3.88	4.05	4.29	5.53
Average to All Sectors[10]	**1.53**	**2.83**	**5.08**	**4.95**	**4.93**	**4.93**	**5.07**	**5.22**	**5.47**	**5.74**	**7.12**

[1] Net dry natural gas is defined as dry marketed production minus nonhydrocarbon gases removed.

[2] Prior to 1980 the amount of supplemental fuels included in the natural gas data cannot be determined. Supplemental natural gas includes synthetic natural gas (results from the manufacture, conversion, or the reforming of petroleum hydrocarbons), and propane air mixtures. After 1985 this quantity includes short-term spot market purchases that could include additional imports.

[3] Includes net stock withdrawals for dry natural gas from underground storage and liquefied natural gas. Net stock withdrawals are computed as the yearend stock levels from the current period subtracted from the yearend stock levels from the preceding period. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.

[4] Total supply is computed as dry gas production plus supplemental natural gas, net imports, and net stock withdrawals.

[5] Consumption values include small amounts of supplemental gas, which are not reported as production prior to 1980.

[6] Commercial category includes the other customer category.

[7] Lease and plant fuel natural gas represents natural gas used in the field gathering and processing plant machinery, usually totalled into the industrial sector for other consumption tables.

[8] Transportation natural gas is used to fuel the compressors in the pipeline pumping stations.

[9] Unaccounted for represents natural gas lost, the net result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure, and EIA's merger of different data reporting systems which vary in scope, format, definition, and respondent type.

[10] Weighted average price and the weights are the sectoral consumption values excluding lease and plant fuel and the transportation sector.

NOTE: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1984 equals 1.00. The natural gas prices in this table are average prices, total revenues divided by total sales for each customer class.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Historical data are taken from the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984) and Energy Information Administration, *Natural Gas Annual, 1982* DOE/EIA-0131(82) (Washington, DC, 1983). Projected values are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = MRG1126T, Projected = Low Economic Growth Case, printed on December 21, 1984.

Historical quantities through 1983.

Table B18. Coal Supply, Disposition, and Prices

(Million Short Tons per Year)

(1984 Dollars per Short Ton)

Supply, Disposition, and Price	Low Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production[1]											
East of the Mississippi	522	487	507	583	571	584	592	595	605	624	698
West of the Mississippi	76	183	275	309	328	341	351	358	374	395	473
Total	**599**	**670**	**782**	**892**	**899**	**924**	**943**	**953**	**980**	**1,019**	**1,172**
Imports[2]	(*)	3	1	1	1	0	0	0	0	0	0
Exports[3]	54	41	78	80	73	74	77	81	86	91	106
Net Imports	**-53**	**-38**	**-77**	**-79**	**-72**	**-74**	**-77**	**-81**	**-86**	**-91**	**-106**
Net Storage Withdrawals[4]	**12**	**11**	**27**	**-20**	**15**	**-7**	**-7**	**-4**	**-4**	**-6**	**-6**
Total Supply[5]	**557**	**644**	**733**	**793**	**842**	**843**	**859**	**868**	**890**	**921**	**1,060**
Consumption by Sector											
Residential and Commercial	11	10	8	8	8	8	8	8	7	7	7
Industrial	68	63	66	76	77	77	79	82	84	86	91
Coking Plants[6]	94	71	37	44	46	46	48	49	50	50	47
Electric Utilities	389	481	625	666	709	711	719	724	743	773	909
Synthetic Fuels	0	0	0	0	5	5	5	6	6	6	6
Total End-Use Consumption	**563**	**625**	**737**	**793**	**843**	**847**	**859**	**869**	**890**	**922**	**1,060**
Discrepancy[7]	-6	18	-4	-2	-3	-4	(*)	-1	-1	(*)	(*)
Average Minemouth Price[8]	**18.14**	**32.48**	**26.95**	**30.02**	**29.89**	**30.48**	**30.58**	**30.63**	**30.68**	**30.77**	**31.55**
Delivered Prices by Sector											
Residential and Commercial[9]	45.53	69.97	45.87	47.00	47.44	51.63	52.26	52.67	53.16	53.85	56.79
Industrial	26.89	49.65	40.79	43.70	44.76	50.01	51.11	52.12	53.20	54.32	59.62
Coking Plants[6]	38.52	77.33	61.51	60.87	61.52	65.06	65.52	65.93	66.54	67.34	70.37
Electric Utilities[10]	19.03	35.26	36.30	38.13	38.54	38.96	39.29	39.44	39.48	39.79	42.32
Average to All End-Use Sectors[11]	**23.76**	**42.04**	**38.07**	**40.01**	**40.46**	**41.50**	**41.98**	**42.26**	**42.42**	**42.76**	**45.16**

[1] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite with anthracite included in bituminous.
[2] Coal imports are not projected beyond 1985.
[3] Excludes small quantities of anthracite shipped overseas to U.S. Armed Forces and coke exports.
[4] From stocks held by end-use sectors (secondary stocks held at industrial plants, coke plants, and electric utility plants). Net stock withdrawals are computed as the yearend stock levels from the current period subtracted from the yearend stock levels from the preceding period. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.
[5] Total supply is equivalent to production plus net imports plus net storage withdrawals.
[6] Coke plants consume metallurgical coal which is a mixture of anthracite and bituminous coal. Historically, coking plant coal price is a weighted average of anthracite and bituminous coal types. In the projections, anthracite is included in bituminous coal.
[7] Historically, discrepancy represents revisions in producers (primary) stock levels, losses, and unaccounted for. In the projected period, discrepancy represents errors due to conversion factors.
[8] In historical years, the average production price of coal produced at the mine. Projected prices are based on estimated cost and do not reflect market conditions.
[9] Historically, residential price is used for residential and commercial consumers. Projected residential and commercial prices do not include dealer markup.
[10] Historically, electric utility price includes anthracite, bituminous, and lignite coal purchased under long-term contracts and on the spot market. In the projections, anthracite is included in bituminous coal, with the bituminous coal price being used for anthracite coal price.
[11] Weighted average price and the weights are the sectoral consumption values.
(*) Greater than zero but less than .5.

NOTE: Metallurgical coal prices reflect a reduced level of projected demand. Other projected coal prices are based on cost estimates, and do not reflect market conditions.

NOTE: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1984 equals 1.00. Projected coal prices are based on cost estimates and do not reflect market conditions.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Historical prices from Energy Information Administration, *State Energy Price and Expenditure Report*, , (DOE/EIA-0376(81) (Washington, DC, 1984) pp. 1-7. Historical quantities are from the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984) pp. 161-169, Table 73, 74, and 75. Projected values are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = MRG1126T, Projected = Low Economic Growth Case, printed on December 21, 1984.

Historical quantities through 1983.

Table B19. National Macroeconomic Indicators

Macroeconomic Indicators	Low Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
World Oil Price[1]	**8.62**	**21.63**	**30.39**	**29.00**	**28.00**	**27.00**	**27.00**	**28.00**	**29.00**	**30.00**	**40.00**
NIPA Variables[2]											
Real GNP (billion 1972 dollars)	1,254	1,439	1,535	1,643	1,668	1,677	1,736	1,780	1,819	1,855	2,040
Real Disposable Income (billion 1972 dollars)	865	989	1,095	1,168	1,188	1,224	1,255	1,277	1,307	1,330	1,453
Real Disposable Income Per Capita (thousand 1972 dollars)	4.1	4.4	4.7	4.9	5.0	5.1	5.2	5.2	5.3	5.3	5.6
NIPA GNP Price Deflator (1972=1.00)	1.057	1.504	2.153	2.233	2.316	2.473	2.635	2.828	3.036	3.268	4.893
GNP Growth (1984 reference year)	NA	NA	NA	.0	1.5	2.1	5.7	8.4	10.7	12.9	24.2
Unemployment Rate, Civilian Workers (percent)	4.9	6.1	9.6	7.5	7.7	8.9	8.5	8.0	7.9	7.9	7.5
Population, Noninstitutional (million persons)	211.9	222.6	234.0	236.2	238.5	240.7	243.0	245.2	247.4	249.5	259.4
New, High Grade Bond Rate (percent per annum)	7.65	8.88	11.56	12.62	12.13	13.65	12.37	11.89	11.63	11.40	11.82
New Home Mortgage Yields (percent per annum)	8.08	9.69	13.35	13.56	13.51	14.31	12.86	12.02	11.89	11.94	12.75
Total Industrial Production Index (1967=1.00)	1.30	1.46	1.48	1.64	1.66	1.67	1.77	1.82	1.86	1.91	2.14
Total Manufacturing Output Index (1967=1.00)	1.30	1.47	1.48	1.66	1.68	1.68	1.78	1.85	1.89	1.94	2.21
Housing Starts (million units)	2.04	2.00	1.70	1.79	1.61	1.50	1.56	1.59	1.61	1.56	1.38
Energy Usage Indicators											
Gross Energy Use per Capita (million Btu per person)	350.1	350.6	301.8	316.6	315.8	317.3	320.4	321.1	321.6	323.2	330.8
Gross Energy Use per Dollar of GNP (thousand Btu per 1972 dollar)	59.2	54.2	46.0	45.5	45.2	45.5	44.8	44.2	43.7	43.5	42.1
Net Oil Imports (billion 1984 dollars)	15.0	56.5	47.0	52.7	46.8	49.0	52.1	56.4	60.9	64.8	106.5
Net Coal Imports (billion 1984 dollars)	-2.1	-2.9	-3.9	-4.2	-3.9	-4.0	-4.1	-4.4	-4.6	-4.9	-6.1

[1] The cost of imported crude oil to U.S. refiners in 1984 dollars per barrel.
[2] National Income and Product Accounts.
NOTE: Total may not equal sum of components because of independent rounding.

Appendix C
Middle World Oil Price/High Economic Growth Case

Table C1. Yearly Supply and Disposition Summary of Total Energy
(Quadrillion Btu per Year)

Total Supply and Disposition	High Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Supply											
Production											
Crude Oil and Lease Condensate	19.5	18.4	18.4	18.5	18.8	18.4	18.2	17.9	17.7	17.6	16.0
Natural Gas Plant Liquids	2.6	2.2	2.2	2.3	2.3	2.2	2.1	2.2	2.1	2.1	1.9
Natural Gas[1]	22.2	19.5	16.4	17.9	18.0	17.3	18.2	18.3	18.4	18.3	16.7
Coal[2]	13.9	14.9	17.2	19.6	19.8	20.5	21.3	22.0	22.9	24.0	27.7
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Hydropower/Other[3]	2.9	3.0	3.6	3.6	3.1	3.3	3.3	3.3	3.3	3.4	3.4
Total Production	**62.0**	**61.0**	**61.1**	**65.6**	**66.1**	**66.5**	**68.5**	**69.6**	**70.6**	**71.7**	**72.8**
Imports											
Crude Oil[4]	6.9	13.5	7.1	7.4	9.0	9.6	10.2	10.8	11.5	12.1	16.3
Refined Petroleum Products[5]	6.6	4.4	3.6	4.1	2.9	3.3	3.8	4.2	4.5	4.8	7.8
Natural Gas[6]	1.1	1.0	1.1	1.0	1.2	1.7	1.3	1.6	1.8	2.1	2.6
Other Imports[7]	.2	.4	.4	.4	.5	.5	.5	.6	.6	.7	.8
Total Imports	**14.7**	**19.3**	**12.2**	**12.9**	**13.5**	**15.0**	**15.9**	**17.2**	**18.4**	**19.6**	**27.5**
Net Stock Withdrawals	**-.4**	**.3**	**1.1**	**-.7**	**.0**	**-.4**	**-.6**	**-.6**	**-.6**	**-.6**	**-.4**
Adjustments[8]	-.1	-.6	.0	.4	-.4	-.3	-.4	-.5	-.6	-.6	-.6
Total Supply[9]	**76.2**	**80.0**	**74.4**	**78.3**	**79.2**	**80.9**	**83.4**	**85.7**	**87.8**	**90.1**	**99.3**
Disposition											
Exports											
Oil	.5	.8	1.6	1.4	1.3	1.7	1.7	1.7	1.7	1.7	1.7
Natural Gas	.1	.1	.1	NA	NA	NA	NA	NA	NA	NA	NA
Coal	1.4	1.1	2.0	2.1	1.9	2.0	2.1	2.2	2.3	2.4	2.8
Other[10]	.1	.0	.1	NA	NA	NA	NA	NA	NA	NA	NA
Total Exports	**2.1**	**1.9**	**3.7**	**3.5**	**3.2**	**3.7**	**3.7**	**3.8**	**3.9**	**4.1**	**4.4**
Consumption											
Refined Petroleum Products[11]	34.8	38.0	30.1	31.5	31.5	31.6	32.3	33.0	33.6	34.4	40.1
Natural Gas	22.5	20.0	17.5	18.5	18.7	18.6	19.1	19.5	19.7	19.9	18.8
Coal[12]	12.9	13.7	15.9	17.1	18.1	18.5	19.1	19.7	20.4	21.3	24.7
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Hydro/Other/Electricity Imports[13]	3.1	3.2	4.0	4.0	3.6	3.8	3.9	3.9	4.0	4.1	4.2
Net Imports of Coke	.0	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total Consumption	**74.2**	**78.0**	**70.7**	**74.8**	**76.0**	**77.2**	**79.6**	**81.9**	**83.8**	**86.0**	**94.9**
Total Disposition	**76.2**	**80.0**	**74.4**	**78.3**	**79.2**	**80.9**	**83.4**	**85.7**	**87.8**	**90.1**	**99.3**

[1] Net dry marketed production after removal of nonhydrocarbon gases.
[2] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite, with anthracite included in bituminous.
[3] Hydropower/Other production includes hydropower, geothermal power, and wood waste.
[4] Includes imports of crude oil for the Strategic Petroleum Reserve.
[5] Includes imports of unfinished oils and natural gas plant liquids.
[6] Includes dry natural gas imports from Canada and Mexico, liquefied natural gas imports from Algeria, and supplemental gas.
[7] Includes electricity, coal, and coal coke imports.
[8] Balancing item that includes gains, losses, miscellaneous blending components, unaccounted for supply, coal used for synthetic fuel production, anthracite shipped overseas to U.S. Armed Forces and certain secondary stock withdrawals.
[9] Total supply is the sum of production, imports, net stock withdrawals, and adjustments.
[10] Includes electricity and coal coke exports.
[11] Includes natural gas plant liquids and crude oil consumed as a fuel.
[12] Excludes anthracite shipped overseas to U.S. Armed Forces and coal used for synthetic fuel production.
[13] Includes net electricity imports and renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[NA] = Not available.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical quantities are from the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984) pp. 5-29, Tables 1, 2, 3, and 13. Projected values are outputs from the Intermediate Future Forecasting System. Input data file: Historical = MRG1126T, Projected = High Economic Growth Case, printed on December 28, 1984. Historical quantities through 1983.

Table C2. Yearly Supply and Disposition of Total Energy, Supply Detail
(Quadrillion Btu per Year)

Total Supply	High Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
World Oil Price[1]	**8.62**	**21.63**	**30.39**	**29.00**	**28.00**	**27.00**	**27.00**	**28.00**	**29.00**	**30.00**	**40.00**
Domestic Production											
Oil[2]	22.1	20.7	20.6	20.8	21.1	20.6	20.3	20.1	19.8	19.8	17.9
Natural Gas[3]	22.2	19.5	16.4	17.9	18.0	17.3	18.2	18.3	18.4	18.3	16.7
Coal[4]	13.9	14.9	17.2	19.6	19.8	20.5	21.3	22.0	22.9	24.0	27.7
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Hydropower/Other[5]	2.9	3.0	3.6	3.6	3.1	3.3	3.3	3.3	3.3	3.4	3.4
Total Domestic Production	**62.0**	**61.0**	**61.1**	**65.6**	**66.1**	**66.5**	**68.5**	**69.6**	**70.6**	**71.7**	**72.8**
Imports											
Oil[6]	13.5	17.8	10.7	11.5	11.9	12.9	14.0	15.0	16.0	16.8	24.1
Natural Gas[7]	1.1	1.0	1.1	1.0	1.2	1.7	1.3	1.6	1.8	2.1	2.6
Coal[8]	.0	.1	.0	.0	.0	NA	NA	NA	NA	NA	NA
Other Imports[9]	.2	.4	.4	.4	.4	.5	.5	.6	.6	.7	.8
Total Imports	**14.7**	**19.3**	**12.2**	**12.9**	**13.5**	**15.0**	**15.9**	**17.2**	**18.4**	**19.6**	**27.5**
Net Storage Withdrawals											
Oil	-.3	.5	.5	.1	.0	.0	-.1	-.1	-.1	-.1	-.3
Natural Gas	-.4	-.2	.5	.0	.0	.0	.0	.0	.0	.0	.0
Coal[10]	.3	.3	.6	-.4	.3	-.1	-.1	-.1	-.2	-.2	-.1
SPR Fill Rate Additions (-)[11]	.0	-.3	-.5	-.4	-.3	-.3	-.3	-.3	-.3	-.3	.0
Net Stock Withdrawals	**-.4**	**.3**	**1.1**	**-.7**	**.0**	**-.4**	**-.6**	**-.6**	**-.6**	**-.6**	**-.4**
Available Supply[12]											
Oil	35.3	39.1	31.9	32.5	33.1	33.6	34.3	35.0	35.7	36.5	41.8
Natural Gas	22.8	20.3	18.0	19.0	19.2	19.0	19.5	19.9	20.1	20.4	19.3
Coal	14.2	15.2	17.8	19.2	20.1	20.5	21.2	21.9	22.8	23.8	27.6
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Other Supply[13]	3.1	3.4	4.0	4.0	3.6	3.8	3.9	3.9	4.0	4.1	4.2
SPR Fill Rate Additions (-)[11]	.0	-.3	-.5	-.4	-.3	-.3	-.3	-.3	-.3	-.3	.0
Total Supply (before adjustments)	**76.3**	**80.6**	**74.4**	**77.9**	**79.6**	**81.1**	**83.8**	**86.2**	**88.4**	**90.7**	**99.9**
Adjustments[14]	-.1	-.6	.0	.4	-.4	-.3	-.4	-.5	-.6	-.6	-.6
Total Supply[15]	**76.2**	**80.0**	**74.4**	**78.3**	**79.2**	**80.9**	**83.4**	**85.7**	**87.8**	**90.1**	**99.3**

[1] The cost of imported crude oil to U.S. refiners in 1984 dollars per barrel.
[2] Oil includes crude oil, lease condensate, and natural gas plant liquids.
[3] Net dry marketed production after removal of nonhydrocarbon gases.
[4] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite, with anthracite included in bituminous.
[5] Hydropower/Other production includes hydropower, geothermal power, and wood waste.
[6] Oil imports includes crude oil and refined petroleum products. Crude oil imports include imports for the Strategic Petroleum Reserve.
[7] Includes dry natural gas imports from Canada and Mexico, liquefied natural gas imports from Algeria, and supplemental gas.
[8] Includes small amounts of coal/coke imports.
[9] Consists of net electricity imports from Canada.
[10] From consumer stocks (utility, coke plant, and industrial) only.
[11] SPR is the Strategic Petroleum Reserve.
[12] Available supply is the sum of domestic production, imports, and net stock withdrawals.
[13] Includes net electricity imports from Canada, hydropower, geothermal power, wood, waste, solar power, and wind power.
[14] Balancing item that includes gains, losses, miscellaneous blending components, unaccounted for supply, coal used for synthetic fuel production, anthracite shipped overseas to U.S. Armed Forces and certain secondary stock withdrawals.
[15] Total supply is the sum of production, imports, net stock withdrawals, and adjustments.
[NA] = Not available.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Historical values are taken from Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984).

Input data file: Historical = MRG1126T, Projected = High Economic Growth Case, printed on December 28, 1984.

Historical prices through 1981 and quantities through 1983.

Table C3. Yearly Supply and Disposition of Total Energy, Disposition Detail
(Quadrillion Btu per Year)

Total Disposition	High Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Exports											
Oil[1]	0.5	0.8	1.6	1.4	1.3	1.7	1.7	1.7	1.7	1.7	1.7
Natural Gas	.1	.1	.1	NA	NA	NA	NA	NA	NA	NA	NA
Coal	1.4	1.1	2.0	2.1	1.9	2.0	2.1	2.2	2.3	2.4	2.8
Other[2]	.1	.0	.1	NA	NA	NA	NA	NA	NA	NA	NA
Total Exports	**2.1**	**1.9**	**3.7**	**3.5**	**3.2**	**3.7**	**3.7**	**3.8**	**3.9**	**4.1**	**4.4**
Consumption											
Residential and Commercial											
Oil[3]	4.4	4.1	2.3	2.6	2.5	2.6	2.7	2.7	2.8	2.9	2.9
Natural Gas	7.6	7.6	7.2	7.4	7.4	7.3	7.4	7.4	7.4	7.5	7.2
Coal	.3	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2
Total (excluding electricity)	**12.3**	**11.9**	**9.8**	**10.1**	**10.1**	**10.1**	**10.2**	**10.3**	**10.4**	**10.5**	**10.2**
Industrial											
Oil[4]	9.1	9.9	7.8	8.9	9.2	9.3	9.9	10.3	10.6	10.9	12.4
Natural Gas[5]	10.4	8.5	6.6	7.3	7.4	7.5	7.8	8.0	8.0	8.0	7.7
Coal[6]	4.0	3.2	2.5	2.9	2.9	3.2	3.4	3.5	3.6	3.7	4.0
Hydropower	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Net Imports of Coke	.0	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total (excluding electricity)	**23.5**	**21.8**	**16.9**	**19.0**	**19.5**	**20.1**	**21.1**	**21.8**	**22.2**	**22.7**	**24.0**
Transportation											
Oil[7]	17.8	20.0	18.4	18.7	18.7	18.5	18.6	18.7	18.9	19.1	20.6
Natural Gas[8]	.7	.5	.6	.6	.6	.6	.6	.6	.6	.7	.6
Coal	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total (excluding electricity)	**18.6**	**20.6**	**19.0**	**19.3**	**19.3**	**19.2**	**19.2**	**19.3**	**19.5**	**19.8**	**21.3**
Electric Utilities											
Oil	3.5	4.0	1.5	1.3	1.2	1.2	1.2	1.3	1.4	1.5	4.2
Natural Gas	3.7	3.3	3.0	3.3	3.3	3.1	3.3	3.4	3.6	3.8	3.3
Coal	8.7	10.3	13.2	14.0	14.9	15.1	15.5	16.0	16.6	17.4	20.6
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Hydropower/Other[9]	3.0	3.2	4.0	4.0	3.5	3.8	3.8	3.9	4.0	4.0	4.2
Total	**19.9**	**23.7**	**25.0**	**26.3**	**27.1**	**27.9**	**29.1**	**30.4**	**31.7**	**33.1**	**39.4**
Total Disposition	**76.2**	**80.0**	**74.4**	**78.3**	**79.2**	**80.9**	**83.4**	**85.7**	**87.8**	**90.1**	**99.3**

[1] Consists primarily of refined petroleum products.
[2] Includes electricity and coal coke exports.
[3] Residential and Commercial oil consists of motor gasoline, distillate fuel, kerosene, residual fuel, and liquefied petroleum gases.
[4] Industrial oil consists of distillate fuel, kerosene, residual fuel, liquefied petroleum gases, special naphthas, miscellaneous petroleum products, lubricants, waxes, unfractionated stream, plant condensate, natural gasoline, asphalt, road oil, petroleum coke, still gas, other oils greater than 400 degrees used for chemical feedstocks, motor gasoline, and naphthas less than 400 degrees used for feedstock purposes, including refinery fuel consumption.
[5] Industrial natural gas is composed of lease and plant fuel use, refinery fuel use, and other industrial uses.
[6] Industrial coal is composed of steam and metallurgical (coking) coal.
[7] Transportation oil consists of motor gasoline, aviation gasoline, jet fuel, distillate fuel, residual fuel, lubricants, and liquefied petroleum gases.
[8] Transportation natural gas represents natural gas used as a fuel by pipeline compressors.
[9] Includes net electricity imports from Canada, hydropower, geothermal power, wood, waste, solar power, and wind power.
[NA] = Not available.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical quantities are taken from Energy Information Administration, *State Energy Data Report, 1960 to 1982*, DOE/EIA 0214(82) (Washington, DC, 1984) and Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984). Projected quantities are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = High Economic Growth Case, printed on December 28, 1984.
Historical quantities through 1983.

Table C4. Consumption by Major Fuels and End-Use Sectors
(Quadrillion Btu per Year)

Sector and Fuel	High Economic Growth Case										
	1973	**1978**	**1983**	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**
Residential											
Distillate Fuel	2.00	1.95	1.05	1.23	1.18	1.20	1.22	1.23	1.24	1.24	1.18
Kerosene	.23	.15	.09	.07	.06	.06	.06	.06	.06	.06	.06
Liquefied Petroleum Gas	.59	.52	.30	.25	.26	.27	.28	.29	.30	.30	.27
Natural Gas	4.98	4.98	4.65	4.72	4.72	4.66	4.68	4.70	4.70	4.69	4.49
Steam Coal	.11	.09	.08	.07	.07	.07	.07	.06	.06	.06	.06
Electricity	1.98	2.30	2.56	2.61	2.65	2.71	2.78	2.86	2.95	3.04	3.52
Total	**9.89**	**9.99**	**8.72**	**8.95**	**8.94**	**8.97**	**9.10**	**9.21**	**9.31**	**9.40**	**9.57**
Commercial											
Distillate Fuel	.64	.67	.44	.51	.51	.53	.56	.59	.62	.65	.71
Kerosene	.06	.05	.03	.06	.06	.06	.07	.07	.08	.08	.09
Motor Gasoline	.09	.11	.09	.09	.08	.08	.08	.08	.08	.08	.08
Residual Fuel	.67	.53	.30	.33	.33	.35	.37	.39	.41	.43	.47
Liquefied Petroleum Gas	.10	.09	.05	.03	.03	.03	.03	.03	.02	.02	.02
Natural Gas[1]	2.65	2.64	2.60	2.66	2.67	2.66	2.69	2.72	2.75	2.76	2.68
Steam Coal	.15	.13	.12	.11	.12	.12	.12	.12	.11	.11	.11
Electricity	1.52	1.81	2.12	2.36	2.42	2.49	2.57	2.66	2.76	2.87	3.35
Total	**5.88**	**6.04**	**5.74**	**6.16**	**6.22**	**6.32**	**6.48**	**6.66**	**6.83**	**7.00**	**7.52**
Industrial[2]											
Distillate Fuel	1.47	1.75	1.30	1.61	1.58	1.62	1.70	1.75	1.79	1.84	2.01
Kerosene	.16	.16	.14	.10	.09	.09	.09	.10	.10	.10	.09
Motor Gasoline	.26	.18	.14	.13	.14	.16	.18	.20	.23	.26	.41
Residual Fuel	1.86	1.72	.78	.98	.96	.99	1.05	1.10	1.14	1.18	1.37
Liquefied Petroleum Gas	1.24	1.26	1.61	1.52	1.59	1.62	1.79	1.92	2.00	2.10	2.51
Petrochemical Feedstocks[3]	.73	1.22	.85	1.38	1.49	1.47	1.58	1.65	1.67	1.69	1.71
Still Gas Used in Refineries	1.06	1.20	1.13	1.16	1.21	1.21	1.23	1.24	1.26	1.28	1.41
Other Raw Material Oil[4]	2.34	2.41	1.82	1.98	2.11	2.16	2.24	2.33	2.39	2.46	2.86
Natural Gas[5]	10.39	8.54	6.64	7.29	7.39	7.52	7.82	7.99	7.99	8.02	7.67
Steam Coal	1.43	1.46	1.50	1.72	1.75	1.91	2.01	2.11	2.20	2.28	2.59
Metallurgical Coal	2.54	1.79	.96	1.15	1.19	1.30	1.36	1.39	1.41	1.42	1.39
Net Coke Imports	-.01	.13	-.02	.00	.00	.00	.00	.00	.00	.00	.00
Electricity	2.34	2.76	2.65	2.74	2.84	2.93	3.15	3.36	3.54	3.76	4.63
Hydropower	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03
Total	**25.84**	**24.60**	**19.52**	**21.77**	**22.38**	**23.03**	**24.23**	**25.16**	**25.77**	**26.41**	**28.66**

See footnotes at end of table.

Table C4. Consumption by Major Fuels and End-Use Sectors (Continued)

(Quadrillion Btu per Year)

Sector and Fuel	High Economic Growth Case										
	1973	**1978**	**1983**	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**
Transportation											
Aviation Gasoline	0.08	0.07	0.05	0.07	0.07	0.08	0.08	0.08	0.09	0.09	0.11
Distillate Fuel	2.22	2.68	2.84	2.67	2.64	2.72	2.82	2.94	3.07	3.21	4.20
Jet Fuel[6]	2.13	2.14	2.14	2.35	2.36	2.47	2.59	2.69	2.78	2.87	3.11
Motor Gasoline	12.45	13.93	12.47	12.67	12.65	12.30	12.07	11.92	11.84	11.83	11.95
Residual Fuel	.73	.99	.75	.74	.72	.74	.78	.81	.84	.87	.99
Liquefied Petroleum Gas	.04	.03	.03	.01	.01	.01	.01	.01	.01	.01	.01
Lubricants and Waxes	.16	.18	.16	.22	.23	.23	.23	.24	.25	.25	.28
Natural Gas[7]	.74	.54	.58	.61	.62	.61	.63	.64	.65	.66	.62
Other Transportation[8]	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01
Total	**18.58**	**20.57**	**19.02**	**19.35**	**19.30**	**19.17**	**19.21**	**19.34**	**19.53**	**19.79**	**21.27**
Electric Utilities											
Distillate Fuel	.27	.28	.10	.11	.05	.02	.02	.05	.06	.09	.34
Residual Fuel	3.24	3.71	1.45	1.20	1.12	1.16	1.16	1.24	1.30	1.43	3.86
Natural Gas	3.75	3.30	3.01	3.27	3.33	3.14	3.28	3.45	3.60	3.79	3.34
Steam Coal	8.66	10.25	13.23	14.05	14.94	15.07	15.54	16.01	16.65	17.40	20.58
Nuclear Power	.91	3.02	3.23	3.70	4.10	4.72	5.31	5.79	6.09	6.32	7.09
Hydropower/Other[9]	3.02	3.18	3.98	3.95	3.54	3.77	3.83	3.89	3.96	4.03	4.17
Total	**19.85**	**23.74**	**25.00**	**26.27**	**27.09**	**27.88**	**29.13**	**30.42**	**31.66**	**33.06**	**39.38**
Primary Energy Consumption											
Distillate Fuel	6.61	7.32	5.72	6.13	5.96	6.10	6.32	6.56	6.78	7.03	8.44
Kerosene	.45	.36	.26	.23	.21	.22	.23	.23	.24	.24	.24
Aviation Gasoline	.08	.07	.05	.07	.07	.08	.08	.08	.09	.09	.11
Motor Gasoline	12.80	14.21	12.70	12.88	12.88	12.55	12.33	12.21	12.15	12.16	12.43
Jet Fuel	2.13	2.14	2.14	2.35	2.36	2.47	2.59	2.69	2.78	2.87	3.11
Residual Fuel	6.49	6.95	3.27	3.25	3.13	3.24	3.36	3.54	3.69	3.90	6.69
Liquefied Petroleum Gas	1.98	1.89	1.99	1.81	1.88	1.92	2.10	2.24	2.33	2.43	2.81
Petrochemical Feedstocks	.73	1.22	.85	1.38	1.49	1.47	1.58	1.65	1.67	1.69	1.71
Still Gas	1.06	1.20	1.13	1.16	1.21	1.21	1.23	1.24	1.26	1.28	1.41
Lubricants and Waxes	.40	.41	.35	.45	.46	.47	.49	.51	.52	.53	.57
Other Petroleum	2.11	2.18	1.62	1.75	1.88	1.92	1.98	2.06	2.12	2.19	2.57
Natural Gas	22.50	20.00	17.47	18.54	18.73	18.59	19.10	19.49	19.69	19.93	18.80
Steam Coal	10.35	11.92	14.91	15.95	16.88	17.17	17.73	18.30	19.02	19.86	23.33
Metallurgical Coal	2.54	1.79	.96	1.15	1.19	1.30	1.36	1.39	1.41	1.42	1.39
Net Coke Imports	-.01	.13	-.02	.00	.00	.00	.00	.00	.00	.00	.00
Nuclear Power	.91	3.02	3.23	3.70	4.10	4.72	5.31	5.79	6.09	6.32	7.09
Hydropower/Other[9]	3.06	3.21	3.99	3.98	3.57	3.80	3.85	3.91	3.99	4.05	4.20
Total Consumption	**74.19**	**78.04**	**70.66**	**74.79**	**76.00**	**77.22**	**79.64**	**81.88**	**83.83**	**85.98**	**94.88**
Electricity Consumption (all sectors)	**5.84**	**6.89**	**7.34**	**7.72**	**7.92**	**8.14**	**8.52**	**8.90**	**9.27**	**9.68**	**11.52**

[1] Commercial natural gas includes deliveries to municipalities and public authorities for institutional heating, street lighting, etc.
[2] Industrial includes all fuels consumed for heat and power, including natural gas used as lease and plant fuel, industrial feedstock and raw material uses; also, all fuels consumed by refineries.
[3] Petrochemical feedstocks includes still gas used for feedstock purposes, naphthas less than 400 degrees, and other oils greater than 400 degrees.
[4] Consists of asphalt, special naphthas, lubricants, waxes, petroleum coke, road oil, and small amounts of Other Petroleum and Net Blending Oil as defined in Table A8.
[5] Includes lease and plant fuel consumption of natural gas.
[6] Jet fuel includes naphtha and kerosene types.
[7] Consists of natural gas used as pipeline compressor fuel.
[8] Other transportation includes steam coal and electricity.
[9] Includes renewable facilities such as hydropower, geothermal power, wood, waste, solar power, and wind power. Electric utility consumption includes net electicity imports.

NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical quantities are taken from Energy Information Administration, *State Energy Data Report, 1960 to 1982*, DOE/EIA-0214 (82) (Washington, DC, 1984) and Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984). Projected quantities are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = High Economic Growth Case, printed on December 21, 1984.
Historical quantities through 1983.

Table C5. Prices by Major Fuels and End-Use Sectors
(1984 Dollars per Million Btu)

Sector and Fuel	High Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential											
Distillate Fuel	3.46	5.28	7.94	7.70	7.47	7.33	7.34	7.56	7.79	8.03	10.07
Kerosene	3.96	6.01	8.29	8.04	7.80	7.65	7.67	7.90	8.13	8.38	10.50
Liquefied Petroleum Gas	7.66	7.08	9.02	7.76	7.53	7.37	7.39	7.62	7.86	8.11	10.29
All Petroleum Products	**4.38**	**5.68**	**8.19**	**7.72**	**7.50**	**7.35**	**7.36**	**7.59**	**7.81**	**8.06**	**10.13**
Natural Gas	2.66	3.72	6.20	6.00	5.94	5.97	6.15	6.39	6.81	7.26	10.29
Steam Coal[1]	2.47	3.81	2.05	2.10	2.12	2.15	2.17	2.20	2.23	2.27	2.42
Electricity	15.74	18.80	19.55	19.62	19.83	19.98	20.09	20.04	19.81	19.69	20.14
Average[2]	**5.76**	**7.71**	**10.41**	**10.24**	**10.28**	**10.41**	**10.59**	**10.81**	**11.07**	**11.39**	**13.84**
Commercial											
Distillate Fuel	2.90	4.72	6.57	6.33	6.10	5.95	5.97	6.19	6.41	6.65	8.67
Kerosene	2.04	4.68	6.62	6.36	6.13	5.98	5.99	6.22	6.46	6.71	8.83
Motor Gasoline	6.57	7.85	10.33	10.14	9.95	9.71	9.72	9.96	10.19	10.39	12.91
Residual Fuel	1.82	3.27	5.47	5.30	5.12	5.11	5.15	5.31	5.48	5.71	6.87
Liquefied Petroleum Gas	3.11	5.25	9.04	6.54	6.30	6.15	6.16	6.40	6.64	6.89	9.07
All Petroleum Products	**2.62**	**4.45**	**6.72**	**6.32**	**6.10**	**5.97**	**5.98**	**6.16**	**6.35**	**6.57**	**8.31**
Natural Gas[3]	1.95	3.27	5.59	5.55	5.49	5.48	5.62	5.84	6.23	6.64	9.54
Steam Coal[4]	.94	1.89	2.01	2.06	2.08	2.11	2.14	2.16	2.19	2.23	2.37
Electricity	15.08	19.48	19.76	19.79	20.06	20.26	20.42	20.41	20.17	20.04	20.55
Average[2]	**5.49**	**8.40**	**10.93**	**11.07**	**11.20**	**11.32**	**11.49**	**11.66**	**11.82**	**12.05**	**14.13**
Industrial											
Distillate Fuel	1.98	4.21	6.53	6.28	6.05	5.90	5.92	6.13	6.35	6.59	8.61
Kerosene	2.13	4.61	6.88	6.62	6.39	6.24	6.25	6.48	6.71	6.96	9.08
Motor Gasoline	6.62	7.82	10.38	10.19	9.99	9.75	9.76	10.00	10.22	10.42	12.92
Residual Fuel	1.69	3.16	4.53	4.35	4.17	4.16	4.20	4.37	4.55	4.77	5.93
Liquefied Petroleum Gas	2.99	5.17	7.85	6.69	6.45	6.29	6.31	6.54	6.78	7.03	9.19
Petrochemical Feedstocks[5]	1.98	4.21	6.16	5.90	5.65	5.47	5.49	5.72	5.95	6.20	8.31
Still Gas[6]	1.98	4.21	6.43	6.19	5.97	5.82	5.84	6.06	6.28	6.52	8.56
Other Petroleum[7]	1.98	4.21	5.16	5.15	4.90	4.85	4.88	4.98	5.06	5.15	5.80
All Petroleum Products	**2.19**	**4.22**	**6.30**	**5.87**	**5.65**	**5.53**	**5.57**	**5.76**	**5.96**	**6.18**	**7.88**
Natural Gas[8]	1.05	2.23	4.33	4.30	4.30	4.32	4.47	4.70	5.04	5.45	8.21
Steam Coal	.96	1.93	1.86	1.93	1.97	2.02	2.06	2.11	2.15	2.20	2.42
Metallurgical Coal	1.49	2.98	2.29	2.34	2.37	2.39	2.42	2.44	2.47	2.50	2.62
Net Coke Imports	1.93	4.55	4.08	4.16	4.20	4.25	4.29	4.33	4.38	4.43	4.63
Electricity	7.72	12.19	16.59	16.66	16.82	16.98	17.11	17.05	16.82	16.69	17.12
Average[2]	**2.06**	**4.15**	**6.44**	**6.16**	**6.11**	**6.08**	**6.21**	**6.41**	**6.62**	**6.88**	**8.70**

See footnotes at end of table.

Table C5. Prices by Major Fuels and End-Use Sectors (Continued)
(1984 Dollars per Million Btu)

Sector and Fuel	High Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Transportation[9]											
Aviation Gasoline	7.94	10.47	13.95	13.62	13.30	12.89	12.91	13.31	13.68	14.02	18.27
Distillate Fuel	3.48	5.04	9.58	9.34	9.12	8.97	8.98	9.20	9.42	9.66	11.69
Jet Fuel[10]	2.05	4.53	6.77	6.49	6.23	6.02	6.05	6.28	6.52	6.78	8.95
Motor Gasoline[11]	6.55	7.78	10.29	10.10	9.91	9.67	9.68	9.91	10.13	10.33	12.84
Residual Fuel[12]	1.35	2.25	3.60	3.43	3.26	3.25	3.30	3.46	3.64	3.86	5.03
Liquefied Petroleum Gas	2.87	4.78	8.38	9.98	9.74	9.59	9.60	9.84	10.08	10.33	12.51
Lubricants and Waxes[13]	12.48	14.88	24.54	24.13	23.74	23.49	23.52	23.89	24.27	24.68	28.15
All Petroleum Products	**5.47**	**6.86**	**9.63**	**9.45**	**9.26**	**9.01**	**8.99**	**9.19**	**9.40**	**9.60**	**11.89**
Natural Gas[14]	.45	1.33	2.64	2.63	2.60	2.60	2.75	2.98	3.26	3.61	5.96
Electricity	5.67	9.48	19.00	18.99	19.27	19.49	19.68	19.69	19.43	19.29	19.82
Average[2]	**5.27**	**6.72**	**9.43**	**9.24**	**9.05**	**8.81**	**8.79**	**8.99**	**9.20**	**9.40**	**11.72**
Electric Utilities											
Distillate Fuel[15]	1.87	3.70	7.79	7.11	6.66	5.36	5.60	6.55	7.22	6.89	8.77
Residual Fuel	1.65	3.17	4.69	4.53	4.37	4.43	4.50	4.67	4.86	5.08	6.51
All Petroleum Products	**1.67**	**3.20**	**4.89**	**4.75**	**4.47**	**4.45**	**4.52**	**4.74**	**4.95**	**5.18**	**6.70**
Natural Gas	.73	2.11	3.60	3.47	3.59	3.51	3.67	3.87	4.15	4.53	6.74
Steam Coal	.95	1.78	1.72	1.81	1.83	1.85	1.87	1.89	1.91	1.93	2.06
Fossil Fuel Average	**1.05**	**2.17**	**2.31**	**2.31**	**2.29**	**2.28**	**2.32**	**2.39**	**2.47**	**2.58**	**3.31**
Average Price to All Users											
Distillate Fuel	3.02	4.83	8.33	7.91	7.70	7.55	7.56	7.78	8.02	8.26	10.36
Kerosene	3.05	5.21	7.35	6.98	6.73	6.57	6.57	6.79	7.02	7.26	9.35
Aviation Gasoline	7.94	10.47	13.95	13.62	13.30	12.89	12.91	13.31	13.68	14.02	18.27
Motor Gasoline	6.55	7.78	10.30	10.10	9.91	9.67	9.68	9.91	10.14	10.33	12.85
Jet Fuel	2.05	4.53	6.77	6.49	6.23	6.02	6.05	6.28	6.52	6.78	8.95
Residual Fuel	1.65	3.04	4.48	4.31	4.14	4.15	4.20	4.37	4.55	4.78	6.20
Liquefied Petroleum Gas	2.99	5.17	7.85	6.69	6.45	6.29	6.31	6.54	6.78	7.03	9.19
Petrochemical Feedstocks	1.98	4.21	6.16	5.90	5.65	5.47	5.49	5.72	5.95	6.20	8.31
Lubricants and Waxes	12.48	14.88	24.54	24.13	23.74	23.49	23.52	23.89	24.27	24.68	28.15
Other Petroleum Products	1.98	4.21	5.63	5.37	5.15	5.01	5.01	5.21	5.42	5.64	7.49
All Petroleum Products	**4.02**	**5.62**	**8.30**	**7.98**	**7.76**	**7.55**	**7.51**	**7.68**	**7.86**	**8.05**	**9.82**
Natural Gas	1.42	2.68	4.82	4.70	4.69	4.70	4.84	5.05	5.40	5.79	8.55
Coal	1.07	1.97	1.77	1.86	1.88	1.91	1.93	1.95	1.97	2.00	2.13
Electricity	12.34	16.32	18.54	18.62	18.82	18.98	19.09	19.02	18.77	18.63	19.05
Average	**3.37**	**5.15**	**7.02**	**6.85**	**6.74**	**6.70**	**6.75**	**6.89**	**7.03**	**7.20**	**8.69**

[1] Projected residential coal prices are delivered to dealer prices and do not include dealer markup.
[2] Weighted average of end-use fuel prices consists of the prices shown above and the appropriate weights from Table 4.
[3] Commercial natural gas price is a weighted average of the commercial and other category.
[4] Historical price for commercial steam coal is the price of industrial steam coal at the State level. Projected prices do not include dealer markup, where applicable.
[5] Industrial distillate price is used in historical years (through 1978).
[6] The industrial distillate price is used. For 1983 forward, differences between the national prices of still gas and distillate fuel oil are due to differences in the regional composition of demand for these fuels.
[7] Industrial other price is a weighted average price for road oil, asphalt, lubricants, waxes, petroleum coke, special naphthas, and miscellaneous petroleum products.
[8] Industrial natural gas price is a weighted average of the lease and plant fuel price and the industrial price. In these reports, the natural gas price for industrial heat and power is used for the lease and plant fuel price, so both components of the average are the same.
[9] Transportation prices include the appropriate Federal excise tax and State road use taxes.
[10] Jet fuel price is for kerosene type jet fuel at retail.
[11] Gasoline price is an average for all types.
[12] Residual fuel price is for marine bunker.
[13] Historical price is the price of industrial lubricants.
[14] Transportation natural gas price is for pipeline fuel use only. The average wellhead price from Table 17 is used as a surrogate price.
[15] Historical price for electric utility distillate fuel oil is the price of electric utility kerosene.

NOTE: Metallurgical coal prices reflect a reduced level of projected demand. Projected coal prices are based on cost estimates and do not reflect market conditions.
NOTE: Electricity and natural gas prices are average prices, revenue divided by sales. Also, the electricity prices are averages for class A and B private electric utilities and public power authorities.
NOTE: Implicit Gross National Product Price Deflator, rebased to 1984 = 1.0, was used to convert from nominal to real dollars.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical prices are taken from Energy Information Administration, *State Energy Price and Expenditure Report*, (DOE/EIA-0376 (81) (Washington, DC, 1984), pp. 1-7. Projected prices are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = High Economic Growth Case, printed on December 21, 1984.
Historical prices through 1981.

Table C6. Residential Energy Use by End Use
(Quadrillion Btu per Year)

Fuel and End Use	High Economic Growth Case								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
Marketed Fuel Consumption[1]									
Fuel Use									
Space Heating	4.51	4.68	4.67	4.68	4.75	4.79	4.82	4.83	4.61
Water Heating	1.63	1.66	1.64	1.64	1.65	1.67	1.69	1.70	1.78
Air Conditioning	0.38	.39	.39	.40	.41	.42	.44	.45	.51
Other End Uses[2]	2.21	2.22	2.23	2.25	2.28	2.32	2.37	2.42	2.67
Total	**8.73**	**8.95**	**8.93**	**8.97**	**9.10**	**9.21**	**9.31**	**9.40**	**9.57**
Liquefied Petroleum Gas									
Space Heating	.21	.18	.19	.20	.21	.21	.22	.22	.19
Water Heating	.09	.07	.07	.07	.07	.08	.08	.08	.08
Total	**.30**	**.25**	**.26**	**.27**	**.28**	**.29**	**.30**	**.30**	**.27**
Fuel Oil[3]									
Space Heating	.93	1.06	1.02	1.04	1.06	1.07	1.08	1.08	1.01
Water Heating	.21	.24	.22	.22	.22	.22	.22	.22	.22
Total	**1.14**	**1.30**	**1.24**	**1.26**	**1.28**	**1.29**	**1.30**	**1.30**	**1.23**
Natural Gas									
Space Heating	3.06	3.12	3.12	3.09	3.11	3.12	3.11	3.10	2.87
Water Heating	1.02	1.03	1.03	1.01	1.02	1.02	1.03	1.03	1.05
Air Conditioning	.01	.01	.01	.01	.01	.01	.01	.02	.02
Other End Uses[2]	.56	.56	.55	.54	.54	.54	.54	.55	.56
Total	**4.65**	**4.72**	**4.72**	**4.66**	**4.68**	**4.70**	**4.70**	**4.69**	**4.49**
Coal									
Space Heating	.08	.07	.07	.07	.07	.06	.06	.06	.06
Total	**.08**	**.07**	**.07**	**.07**	**.07**	**.06**	**.06**	**.06**	**.06**
Electricity									
Space Heating	.23	.25	.27	.29	.31	.33	.35	.37	.49
Water Heating	.31	.32	.32	.33	.34	.35	.36	.37	.43
Air Conditioning	.37	.37	.38	.39	.40	.41	.42	.43	.49
Other End Uses[2]	1.65	1.66	1.67	1.70	1.74	1.78	1.82	1.87	2.11
Total	**2.56**	**2.61**	**2.65**	**2.71**	**2.78**	**2.86**	**2.95**	**3.04**	**3.52**
Nonmarketed Fuel Consumption[1]									
Wood	**1.04**	**0.92**	**0.94**	**0.95**	**0.96**	**0.97**	**0.98**	**0.99**	**1.06**
Residential Activity									
Occupied Housing Stock (million units)	84.9	86.5	88.2	89.7	91.5	93.4	95.2	97.0	105.3
New Housing Construction[4] (million units)	1.5	2.0	2.1	2.0	2.3	2.3	2.3	2.2	2.1
Income Per Household (thousand 1984 dollars)	22.0	22.0	22.3	22.4	22.6	22.9	23.2	23.6	25.2
Energy Use Per Household (million Btu)	103	103	101	100	99	99	98	97	91
Fuel Expenditure Per Household (1984 dollars)	1,070	1,057	1,040	1,039	1,051	1,065	1,082	1,103	1,257

[1] Residential fuels are divided into marketed fuels (those with an associated price that are traded in economic markets) and nonmarketed fuels.
[2] Major other end uses include lighting, cooking, refrigeration, washing, and drying.
[3] Residential fuel oil category includes kerosene and distillate oil.
[4] New housing construction includes completions of single family, multifamily, and mobile housing units.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: The Residential model is documented in *Model Documentation: Household Model of Energy*, Energy Information Administration (DOE/EIA-0409) (Washington, DC, 1984). The major model data source is the public use tape of the Residential Energy Consumption Survey 1981, Energy Information Administration.
Input data file: Historical = MRG1126T, Projected = High Economic Growth Case, printed on December 21, 1984.
Historical quantities through 1983.

Table C7. Commercial Energy Use by Building Type
(Quadrillion Btu per Year)

Fuel and Building Type	High Economic Growth Case								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
Marketed Fuel Consumption									
Total Fuel Use	**5.75**	**6.16**	**6.21**	**6.32**	**6.48**	**6.65**	**6.83**	**7.00**	**7.51**
Liquefied Petroleum Gas	**.05**	**.03**	**.03**	**.03**	**.03**	**.03**	**.02**	**.02**	**.02**
Motor Gasoline	**.09**	**.09**	**.08**	**.08**	**.08**	**.08**	**.08**	**.08**	**.08**
Fuel Oil[1]									
Office[2]	.26	.31	.30	.32	.33	.35	.37	.38	.42
Retail/Wholesale	.17	.20	.19	.20	.21	.22	.23	.24	.25
Warehouse	.12	.15	.15	.17	.18	.19	.21	.22	.27
Other Buildings[3]	.22	.25	.25	.26	.27	.28	.30	.31	.33
Total	**.77**	**.91**	**.90**	**.94**	**1.00**	**1.05**	**1.10**	**1.15**	**1.27**
Natural Gas									
Office[2]	.74	.75	.75	.75	.76	.76	.77	.78	.76
Retail/Wholesale	.75	.77	.78	.78	.79	.81	.82	.83	.84
Warehouse	.35	.36	.36	.36	.37	.37	.37	.37	.35
Other Buildings[3]	.76	.78	.78	.77	.77	.78	.78	.78	.72
Total	**2.60**	**2.66**	**2.67**	**2.66**	**2.69**	**2.72**	**2.75**	**2.76**	**2.68**
Coal	**.12**	**.11**	**.12**	**.12**	**.12**	**.12**	**.11**	**.11**	**.11**
Electricity									
Office[2]	.81	.90	.93	.95	.98	1.02	1.06	1.10	1.30
Retail/Wholesale	.61	.68	.70	.72	.75	.78	.81	.84	.99
Warehouse	.29	.32	.33	.34	.35	.36	.37	.39	.45
Other Buildings[3]	.41	.46	.47	.48	.49	.51	.52	.54	.62
Total	**2.12**	**2.36**	**2.42**	**2.49**	**2.57**	**2.66**	**2.76**	**2.87**	**3.35**
Commercial Activity									
Building Floorspace Stock (billion square feet)	48.5	51.1	52.7	53.9	55.4	57.1	58.9	60.8	69.2
Office[2]	17.0	18.0	18.6	19.0	19.5	20.2	20.8	21.5	24.7
Retail/Wholesale	14.5	15.4	15.9	16.4	16.9	17.5	18.1	18.7	21.6
Warehouse	6.9	7.2	7.5	7.7	7.9	8.1	8.4	8.6	9.8
Other Buildings[3]	10.1	10.5	10.7	10.9	11.1	11.4	11.6	11.9	13.2
Energy Use Per Square Foot (thousand Btu)	118.6	120.4	118.0	117.3	117.0	116.5	115.9	115.2	108.6
Expenditures Per Square Foot (1984 dollars)	1.30	1.31	1.30	1.31	1.32	1.34	1.35	1.37	1.51

[1] The commercial fuel oil category includes kerosene, distillate fuel, and residual fuel.
[2] Office includes offices, educational buildings, laboratories, health clinics, and some public buildings.
[3] Other Buildings includes assembly buildings, hotels/motels, hospitals, parking garages, and jails.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: The Commercial model is documented in *Model Documentation: Commercial Sector Energy Model*, Energy Information Administration (DOE/EIA-0453), August 1984. The major model source is the public use tape of the Nonresidential Energy Consumption Survey 1980, Energy Information Administration.
Input data file: Historical = MRG1126T, Projected = High Economic Growth Case, printed on December 21, 1984.
Historical quantities through 1983.

Table C8. Industrial Energy Use
(Quadrillion Btu per Year)

Fuel and End Use	High Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Industrial Heat and Power											
Distillate Fuel	1.44	1.70	1.29	1.60	1.58	1.62	1.69	1.75	1.79	1.83	2.00
Residual Fuel	1.58	1.40	.65	.85	.83	.86	.92	.96	1.00	1.04	1.20
Liquefied Petroleum Gas	.13	.20	.57	.33	.33	.33	.34	.35	.35	.36	.37
Natural Gas[1]	8.50	7.08	5.56	6.09	6.22	6.34	6.62	6.78	6.78	6.80	6.42
Steam Coal[2]	1.43	1.46	1.50	1.72	1.75	1.91	2.01	2.11	2.20	2.28	2.59
Electricity[3]	2.34	2.76	2.65	2.62	2.72	2.82	3.03	3.24	3.42	3.63	4.50
Total	**15.43**	**14.61**	**12.21**	**13.20**	**13.43**	**13.88**	**14.62**	**15.18**	**15.53**	**15.94**	**17.08**
Refinery Fuel											
Distillate Fuel	.03	.05	.01	.01	.01	.01	.01	.01	.01	.01	.01
Residual Fuel	.28	.31	.13	.13	.13	.13	.13	.13	.14	.14	.17
Liquefied Petroleum Gas	.04	.06	.03	.03	.03	.03	.03	.03	.03	.03	.03
Still Gas	1.06	1.20	1.13	1.16	1.21	1.21	1.23	1.24	1.26	1.28	1.41
Petroleum Coke	.40	.39	.40	.42	.41	.41	.42	.42	.43	.43	.48
Other Petroleum	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Electricity	NA	NA	NA	.12	.12	.12	.12	.12	.12	.12	.14
Natural Gas	1.11	.82	.59	.66	.63	.63	.63	.64	.65	.66	.71
Total	**2.92**	**2.84**	**2.28**	**2.52**	**2.52**	**2.53**	**2.56**	**2.59**	**2.63**	**2.67**	**2.94**
Feedstocks, Raw Materials, and Other Fuel Uses											
Motor Gasoline	.26	.18	.14	.13	.14	.16	.18	.20	.23	.26	.41
Kerosene	.16	.16	.14	.10	.09	.09	.09	.10	.10	.10	.09
Petroleum Feedstocks[4]	.73	1.22	.85	1.38	1.49	1.47	1.58	1.65	1.67	1.69	1.71
Liquefied Petroleum Gas[5]	1.07	.99	1.01	1.16	1.23	1.26	1.42	1.54	1.62	1.71	2.11
Special Naphthas	.17	.20	.16	.21	.22	.23	.25	.26	.27	.28	.29
Lubricants and Waxes	.23	.23	.20	.23	.23	.24	.26	.27	.27	.28	.29
Petroleum Coke	.16	.16	.10	.13	.19	.22	.24	.27	.30	.33	.49
Asphalt and Road Oil	1.26	1.16	.90	1.01	1.12	1.16	1.21	1.24	1.27	1.29	1.35
Net Blending Oil[6]	.12	.27	.06	-.01	-.06	-.10	-.13	-.14	-.14	-.14	-.04
Metallurgical Coal[2]	2.54	1.79	.96	1.15	1.19	1.30	1.36	1.39	1.41	1.42	1.39
Natural Gas Raw Materials[7]	.78	.63	.49	.54	.55	.55	.56	.57	.57	.57	.54
Net Coke Imports	-.01	.13	-.02	.00	.00	.00	.00	.00	.00	.00	.00
Hydropower	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03
Total	**7.49**	**7.15**	**5.03**	**6.05**	**6.43**	**6.62**	**7.05**	**7.38**	**7.60**	**7.79**	**8.65**
Total Industrial Demand	**25.84**	**24.60**	**19.52**	**21.77**	**22.38**	**23.03**	**24.23**	**25.16**	**25.77**	**26.41**	**28.66**

[1] Includes lease and plant fuel.
[2] Includes refinery steam coal. The metallurgical coal estimates for 1983 and 1984 are not fully comparable, in part because of different Btu conversion factors.
[3] Includes refinery electricity before 1984.
[4] Petrochemical feedstocks includes naphthas less than 400 degrees, other oils greater than 400 degrees, and some still gas.
[5] The LPG price for Industrial Heat and Power is used for LPG feedstocks in weighted average price calculations.
[6] Net blending oil includes jet fuel, plant condensate, unfractionated stream, some still gas, miscellaneous, natural gasoline, unfinished oils, aviation blending components, and motor gasoline blending components, net of oil reclassified in blending.
[7] The natural gas price for Industrial Heat and Power is used for natural gas raw materials in weighted average price calculations.
[NA] = Not available.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: The Industrial model is documented in *Documentation of the PURHAPS Industrial Demand Model, Vol 1: Model Description, Overview, and Assumptions for the 1983 Annual Energy Outlook*, DOE/EIA-0420/1 (Washington, DC, 1984).
Input data file: Historical = MRG1126T, Projected = High Economic Growth Case, printed on December 21, 1984.
Historical quantities through 1983.

Table C9. Transportation Sector Energy Use By Mode

Fuel and Mode of Transportation	High Economic Growth Case								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
All Modes[1]									
Aviation Gasoline	0.05	0.07	0.07	0.08	0.08	0.08	0.09	0.09	0.11
Distillate Fuel	2.84	2.67	2.64	2.72	2.82	2.94	3.07	3.21	4.20
Jet Fuel	2.14	2.35	2.36	2.47	2.59	2.69	2.78	2.87	3.11
Motor Gasoline	12.47	12.67	12.65	12.30	12.07	11.92	11.84	11.83	11.95
Residual Fuel	.75	.74	.72	.74	.78	.81	.84	.87	.99
Liquefied Petroleum Gas	.03	.01	.01	.01	.01	.01	.01	.01	.01
Lubricants	.16	.22	.23	.23	.23	.24	.25	.25	.28
Natural Gas	.58	.61	.62	.61	.63	.64	.65	.66	.62
Electricity	.01	.01	.01	.01	.01	.01	.01	.01	.01
Total Consumption	**19.02**	**19.35**	**19.30**	**19.17**	**19.21**	**19.34**	**19.53**	**19.79**	**21.27**
Automobiles									
Vehicle-Miles Travelled[2]	1149.7	1,252.8	1,326.9	1,355.5	1,391.2	1,432.2	1,478.4	1,529.5	1,793.5
Fleet-Miles per Gallon	16.5	17.5	18.4	19.3	20.1	20.8	21.5	22.1	24.6
Total Fuel Use[3]	69.5	71.6	72.0	70.3	69.3	68.9	68.9	69.3	72.9
Trucks									
Vehicle-Miles Travelled[2]	449.1	484.6	502.9	514.8	529.4	546.6	566.0	587.3	722.1
Fleet-Miles per Gallon	10.5	11.1	11.6	12.0	12.4	12.8	13.2	13.6	15.3
Total Fuel Use[3]	42.6	43.8	43.5	42.9	42.6	42.6	42.8	43.2	47.3
Air									
Revenue Passenger-Miles[2]	300.1	354.3	374.1	409.2	450.1	490.4	531.5	572.2	753.0
Fuel Burned Per Seat-Mile[4]	.023	.022	.022	.021	.020	.019	.018	.017	.014
Total Jet Fuel[3]	16.0	17.6	17.7	18.5	19.4	20.1	20.8	21.5	23.3
Aviation Gasoline[3]	.4	.6	.6	.6	.7	.7	.7	.8	.9
Selected Fuel Expenditures[5]									
Motor Gasoline	128.4	128.0	125.3	118.9	116.8	118.1	120.0	122.2	153.4
Distillate Fuel	27.2	24.9	24.1	24.4	25.3	27.0	28.9	31.0	49.1

[1] Quadrillion Btu per year.
[2] Billion per year.
[3] Billion gallons per year.
[4] Gallons.
[5] Billion 1984 dollars per year.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Input data file: Historical = MRG1126T, Projected = High Economic Growth Case, printed on December 28, 1984.
Historical quantities through 1983.

Table C10. Electric Utility Fuel Consumption and Electricity Sales
(Quadrillion Btu per Year)

Fuel Consumption and Sales	High Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Fuel Inputs											
Oil											
Distillate	0.27	0.28	0.10	0.11	0.05	0.02	0.02	0.05	0.06	0.09	0.34
Residual LS[1]	NA	NA	NA	.69	.65	.72	.73	.79	.84	.92	2.79
Residual HS[1]	3.24	3.71	1.45	.51	.48	.44	.43	.45	.46	.51	1.07
Natural Gas	3.75	3.30	3.01	3.27	3.33	3.14	3.28	3.45	3.60	3.79	3.34
Steam Coal	8.66	10.25	13.23	14.05	14.94	15.07	15.54	16.01	16.65	17.40	20.58
Nuclear Power	.91	3.02	3.23	3.70	4.10	4.72	5.31	5.79	6.09	6.32	7.09
Hydropower/Other[2]	2.87	2.97	3.61	3.55	3.11	3.29	3.30	3.31	3.32	3.33	3.39
Total Fuel Inputs	19.71	23.53	24.63	25.87	26.66	27.40	28.60	29.84	31.01	32.36	38.60
Net Imports	.15	.20	.37	.41	.43	.48	.53	.58	.64	.70	.78
Total Electricity Inputs	**19.85**	**23.74**	**25.00**	**26.27**	**27.09**	**27.88**	**29.13**	**30.42**	**31.66**	**33.06**	**39.38**
Disposition											
Total Electricity Inputs	19.85	23.74	25.00	26.27	27.09	27.88	29.13	30.42	31.66	33.06	39.38
Minus Conversion Losses[3]	13.50	16.21	17.12	17.99	18.58	19.11	19.98	20.87	21.73	22.71	27.08
Generation	6.35	7.53	7.88	8.28	8.50	8.77	9.15	9.54	9.92	10.35	12.30
Minus Transportation and Distribution Losses	.51	.64	.55	.57	.58	.63	.63	.65	.65	.67	.79
Electricity Sales	**5.84**	**6.89**	**7.34**	**7.72**	**7.92**	**8.14**	**8.52**	**8.90**	**9.27**	**9.68**	**11.52**
Electricity Sales by End-Use Sector											
Residential	1.98	2.30	2.56	2.61	2.65	2.71	2.78	2.86	2.95	3.04	3.52
Commercial/Other[4]	1.53	1.82	2.13	2.37	2.44	2.50	2.58	2.67	2.77	2.88	3.36
Industrial	2.34	2.76	2.65	2.74	2.84	2.93	3.15	3.36	3.54	3.76	4.63
Total Electricity Sales	**5.84**	**6.89**	**7.34**	**7.72**	**7.92**	**8.14**	**8.52**	**8.90**	**9.27**	**9.68**	**11.52**

[1] Prior to 1984, only the total of high-sulfur and low-sulfur residual oil is available, and is reported here as high-sulfur.
[2] Includes renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[3] Conversion losses includes net imports.
[4] Commercial/Other includes street lighting and the transportation sector.
NA = Not available.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Input data file: Historical = MRG1126T, Projected = High Economic Growth Case, printed on December 21, 1984. Historical quantities through 1983.

Table C11. Electric Utility Sectoral Prices and Demands
(Billion Kilowatthours per Year)
(1984 Dollars per Thousand Kilowatthours)

Prices and Demands	High Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Prices[1]											
Residential	53.70	64.16	66.69	66.95	67.65	68.17	68.55	68.36	67.59	67.17	68.70
Commercial[2]	51.28	66.28	67.39	67.52	68.43	69.11	69.66	69.63	68.81	68.38	70.12
Industrial	26.34	41.59	56.62	56.84	57.39	57.94	58.38	58.18	57.40	56.94	58.42
All Sectors	**42.11**	**55.67**	**63.26**	**63.54**	**64.21**	**64.77**	**65.13**	**64.90**	**64.06**	**63.56**	**64.98**
Demands											
Residential	579	674	751	764	776	794	816	839	865	892	1,033
Commercial[2]	448	534	624	695	714	733	757	784	813	845	986
Industrial	686	809	776	803	832	860	924	985	1,039	1,101	1,357
All Sectors	**1,713**	**2,018**	**2,151**	**2,262**	**2,321**	**2,387**	**2,497**	**2,608**	**2,717**	**2,838**	**3,376**

[1] Prices for 1983 to 1995 are from model simulations and represent average revenues per kilowatthour of demand for the total electric utility industry. Revenue requirements are projected from the financial information contained on the Federal Energy Regulatory Commission Form 1 and Form 1-M and on the Energy Information Administration Form 412.
[2] This category includes consumption for street and highway lighting, other public authorities, and railroads and railways.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Prices for 1973 and 1978 are from the Energy Information Administration, *State Energy Price and Expenditure Report*, DOE/EIA-0376(81) (Washington, DC, 1984), pp.1-7. Historical demands are from the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83), (Washington, DC, 1984).

Table C12. Electric Utility Capacity and Generation

(Generation in Billion Kilowatthours per Year)

(Capacity in Million Kilowatts)

Capacity and Generation	High Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Capacity[1]											
Coal Steam	184.0	233.9	285.9	296.0	303.8	309.6	314.2	317.3	323.7	328.5	361.1
Other Steam	135.0	161.4	157.2	157.2	157.2	157.2	157.2	157.2	157.2	157.2	157.2
Combined Cycle	1.3	4.9	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.8	5.8
Turbine	37.1	49.6	50.7	51.0	51.4	51.6	51.6	51.7	52.3	52.7	72.2
Nuclear Power	21.0	53.5	64.4	68.9	80.5	91.4	99.8	104.7	105.9	109.6	116.8
Hydropower/Other[2]	55.6	63.2	69.0	69.8	71.0	71.4	71.6	72.0	72.2	72.9	73.1
Pumped Storage Hydropower[3]	8.4	12.7	13.3	14.6	16.0	16.7	16.7	16.9	18.8	19.1	19.2
Total Capacity	**442.4**	**579.2**	**646.2**	**663.2**	**685.5**	**703.5**	**716.8**	**725.5**	**735.8**	**745.8**	**805.4**
Generation by Plant Type[4]											
Coal Steam	848	976	1,268	1,347	1,428	1,442	1,488	1,534	1,596	1,669	1,980
Other Steam	619	629	365	369	356	352	361	382	401	422	543
Combined Cycle	NA	13	32	33	32	28	28	29	30	33	32
Turbine	36	29	13	15	15	14	17	20	20	27	94
Nuclear Power	83	276	294	335	372	428	482	526	553	574	644
Hydropower/Other[2]	274	284	345	336	295	315	315	317	318	321	325
Pumped Storage Hydropower[3]	NA	NA	-6	-6	-6	-9	-9	-10	-10	-11	-10
Total Generation	**1,861**	**2,206**	**2,310**	**2,428**	**2,492**	**2,570**	**2,682**	**2,797**	**2,908**	**3,033**	**3,606**
Generation by Fuel Type											
Coal[5]	848	976	1,259	1,341	1,422	1,436	1,482	1,527	1,589	1,662	1,972
Natural Gas	341	305	274	299	301	288	300	315	330	345	286
Oil	314	365	144	124	109	113	113	122	129	143	391
Nuclear Power	83	276	294	335	372	428	482	526	553	574	644
All Hydropower/Other[6]	274	283	339	329	289	306	306	307	308	309	315
Total Generation	**1,861**	**2,206**	**2,310**	**2,428**	**2,492**	**2,570**	**2,682**	**2,797**	**2,908**	**3,033**	**3,606**

[1] Capacity for 1973 and 1978 include capacity out of service or in inactive reserve; 1983 and projected capacity exclude capacity out of service or in inactive reserve. Three Mile Island Unit 1 is included in the 1983 and 1984 capacity estimates but is not expected to restart opetation until 1985.

[2] This category includes other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

[3] See Glossary, Electricity Terminology for definition of pumped storage plant.

[4] Net generation data for 1973 excludes combined cycle generation. For 1973 and 1978 the hydropower/other category also contains pumped storage hydropower. The 1983 values are model estimates based on the best available data.

[5] Generation by coal and generation by coal steam plants are not identical because small amounts of oil and natural gas are used in coal steam plants for startup and flame stability.

[6] This category includes conventional and pumped storage hydropower and other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Generation data for 1973, 1978, and 1983 are from the Energy Information Administration, *Form EIA-759, "Monthly Power Plant Report."* Historical capacity data for 1973 and 1978 are based on the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984). Other capacity data are from the Intermediate Future Forecasting System.

Table C13. Electric Utility Capacity Additions
(Thousand Kilowatts)

Additions: Pipeline and New Starts	High Economic Growth Case												
	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Total Additions													
Nuclear Power[1]	3,064	4,480	12,369	10,939	8,391	4,884	1,235	3,702	3,690	2,464	1,065	0	0
Coal Steam	5,720	10,082	7,783	5,860	4,586	3,109	6,394	4,782	10,654	5,025	7,023	4,310	5,559
Other Steam[2]	61	3	0	0	0	0	0	100	0	0	0	0	0
Turbines[3]	202	275	385	197	40	130	561	343	1,103	3,016	2,585	3,683	9,155
Pumped Storage Hydropower[4]	260	1,264	1,400	700	0	200	1,923	285	0	0	0	150	0
Hydropower/Other[5]	1,034	874	1,163	383	242	407	200	706	75	74	26	0	6
Total New Capacity	**10,342**	**16,978**	**23,100**	**18,078**	**13,258**	**8,729**	**10,313**	**9,919**	**15,522**	**10,579**	**10,699**	**8,143**	**14,720**
Pipeline[6]													
Nuclear Power[1]	3,064	4,480	12,369	10,939	8,391	4,884	1,235	3,702	3,690	2,464	1,065	0	0
Coal Steam	5,720	10,082	7,783	5,860	4,586	3,109	6,394	4,782	10,654	5,025	5,718	2,764	3,347
Other Steam[2]	61	3	0	0	0	0	0	100	0	0	0	0	0
Turbines[3]	202	275	385	197	40	130	561	343	330	113	200	0	143
Pumped Storage Hydropower[4]	260	1,264	1,400	700	0	200	1,923	285	0	0	0	150	0
Hydropower/Other[5]	1,034	874	1,163	383	242	407	200	706	75	74	26	0	6
Total Pipeline	**10,342**	**16,978**	**23,100**	**18,078**	**13,258**	**8,729**	**10,313**	**9,919**	**14,749**	**7,676**	**7,009**	**2,914**	**3,496**
New Starts[7]													
Nuclear Power[1]	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal Steam	0	0	0	0	0	0	0	0	0	0	1,305	1,547	2,213
Other Steam[2]	0	0	0	0	0	0	0	0	0	0	0	0	0
Turbines[3]	0	0	0	0	0	0	0	0	773	2,903	2,385	3,683	9,012
Pumped Storage Hydropower[4]	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydropower/Other[5]	0	0	0	0	0	0	0	0	0	0	0	0	0
Total New Starts	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**773**	**2,903**	**3,690**	**5,229**	**11,224**

[1] Includes the scheduled return to service of the Three Mile Island 1 facility.
[2] Includes natural gas, oil, and dual fired oil/natural gas steam and combined cycle capacity.
[3] Includes all gas turbine and internal combustion capacity.
[4] See Glossary, Electricity Terminology for definition of pumped storage plant.
[5] Includes conventional hydroelectric and other renewable sources of power such as geothermal, wood, waste, solar, and wind.
[6] Includes all new capacity announced by the electric utility industry.
[7] Includes additional new capacity considered necessary to meet projected electricity demands.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: The Energy Information Administration Generating Unit Reference file (GURF); the Federal Energy Regulatory Commission, *Hydroelectric Power Resources of the United States - Developed and Undeveloped*, FERC-0070, January 1, 1980; Energy Information Administration, *U.S. Commercial Nuclear Power*, DOE/EIA-0315 (Washington, DC, March 1982); and the Energy Information Administration Form-254: "Quarterly Progress Report on Status of Reactor Construction."

Table C14. Summary of Components of Electricity Price
(1984 Dollars per Thousand Kilowatthours)

Price Components	High Economic Growth Case												
	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Capital Component[1]	25.44	25.52	25.53	26.26	26.48	25.90	24.56	23.26	22.37	21.59	20.69	19.82	19.06
Fuel Component[2]	22.65	22.81	23.17	22.76	22.98	23.54	24.25	25.25	26.40	27.66	28.95	30.08	31.65
O&M Component[3]	15.25	15.21	15.51	15.76	15.67	15.45	15.26	15.05	14.88	14.75	14.57	14.43	14.27
Total Price[4]	**63.34**	**63.54**	**64.21**	**64.77**	**65.13**	**64.90**	**64.06**	**63.56**	**63.65**	**64.00**	**64.21**	**64.33**	**64.98**

[1] The capital component represents the cost to the utility of capital assets needed to provide reliable service. It includes plant depreciation, taxes, and sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.
[2] The fuel component includes only the direct costs of fuel inputs used to generate electricity required to meet demand.
[3] The operation and maintenance (O&M) component includes all nonfuel costs necessary to operate and maintain generation, transmission, and distribution capacity used to deliver electricity to end-use sectors.
[4] All prices are from model simulations and represent average revenues per kilowatthour of demand for the total electric utility industry. Revenue requirements are projected from the financial information contained on the Federal Energy Regulatory Commission, Form FERC-1 and Form 1-M and on the Energy Information Administration, Form EIA-412.
NOTE: Total may not equal sum of components because of independent rounding.

Table C15. Petroleum Supply and Disposition Balance
(Million Barrels per Day)

Supply and Disposition	High Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Crude Oil[1]	9.21	8.71	8.69	8.76	8.86	8.70	8.59	8.45	8.28	8.25	7.19
Alaska North Slope	.00	1.09	1.65	1.67	1.70	1.76	1.92	1.97	2.02	2.14	1.20
Subarctic	9.21	7.62	7.04	7.08	7.15	6.95	6.67	6.47	6.26	6.11	5.98
Natural Gas Plant Liquids	1.74	1.57	1.56	1.61	1.64	1.55	1.52	1.54	1.52	1.52	1.36
Other Domestic[2]	.00	.00	.05	.05	.05	.05	.05	.05	.07	.09	.35
Processing Gain[3]	.45	.50	.49	.55	.54	.50	.51	.53	.54	.55	.63
Total Production	**11.40**	**10.78**	**10.79**	**10.97**	**11.09**	**10.81**	**10.68**	**10.56**	**10.41**	**10.41**	**9.53**
Imports (Including SPR)											
Crude Oil[4]	3.24	6.36	3.33	3.48	4.22	4.49	4.79	5.09	5.42	5.67	7.67
Refined Products	3.01	2.01	1.72	1.95	1.39	1.57	1.82	2.00	2.12	2.27	3.73
Total Imports	6.26	8.36	5.05	5.43	5.61	6.07	6.60	7.09	7.54	7.94	11.40
Exports											
Crude Oil	.00	.16	.16	.18	.17	.17	.17	.17	.17	.17	.17
Refined Products	.23	.20	.58	.49	.45	.61	.61	.61	.61	.61	.61
Total Exports	.23	.36	.74	.67	.62	.78	.78	.78	.78	.78	.78
Net Imports (Including SPR)	**6.02**	**8.00**	**4.31**	**4.76**	**4.99**	**5.28**	**5.82**	**6.31**	**6.76**	**7.16**	**10.62**
Primary Stock Changes											
Net Withdrawals[5]	-.14	.26	.25	.04	.00	-.01	-.08	-.08	-.06	-.08	-.12
SPR Fill Rate Additions (-)[6]	.00	-.16	-.23	-.18	-.14	-.14	-.14	-.14	-.14	-.14	.00
Total Primary Supply[7]	**17.29**	**18.87**	**15.11**	**15.59**	**15.93**	**15.94**	**16.28**	**16.64**	**16.96**	**17.34**	**20.03**
Refined Petroleum Products											
Motor Gasoline	6.67	7.41	6.62	6.72	6.72	6.54	6.43	6.36	6.34	6.34	6.48
Aviation Gasoline	.05	.04	.03	.04	.04	.04	.04	.05	.05	.05	.06
Jet Fuel[8]	1.06	1.06	1.05	1.15	1.15	1.21	1.26	1.31	1.36	1.40	1.52
Kerosene	.22	.18	.13	.11	.10	.10	.11	.11	.11	.12	.11
Distillate Fuel	3.09	3.43	2.69	2.88	2.80	2.87	2.97	3.08	3.18	3.30	3.97
Residual Fuel	2.82	3.02	1.42	1.42	1.40	1.41	1.46	1.54	1.61	1.70	2.91
Liquid Petroleum Gas	1.45	1.41	1.49	1.36	1.41	1.45	1.58	1.68	1.75	1.82	2.11
Petrochemical Feedstocks	.36	.59	.42	.68	.73	.72	.77	.81	.82	.83	.84
Other Petroleum Products[9]	1.59	1.70	1.37	1.50	1.58	1.61	1.65	1.70	1.74	1.78	2.03
Total Product Supplied	**17.31**	**18.85**	**15.23**	**15.86**	**15.93**	**15.94**	**16.28**	**16.64**	**16.96**	**17.34**	**20.03**

See footnotes at end of table.

Table C15. Petroleum Supply and Disposition Balance (Continued)
(Million Barrels per Day)

Supply and Disposition	High Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Refined Petroleum Products Supplied to End-Use Sectors											
Residential and Commercial	2.23	2.07	1.20	1.29	1.25	1.29	1.34	1.37	1.40	1.43	1.43
Industrial[10]	4.48	4.87	4.03	4.52	4.68	4.76	5.06	5.29	5.46	5.63	6.42
Transportation	9.05	10.14	9.33	9.48	9.45	9.37	9.38	9.42	9.51	9.63	10.35
Electric Utilities	1.54	1.75	.68	.57	.51	.52	.51	.56	.59	.66	1.84
Total End-Use Consumption	**17.30**	**18.84**	**15.23**	**15.86**	**15.90**	**15.94**	**16.29**	**16.65**	**16.96**	**17.35**	**20.04**
Discrepancy[11]	-.01	.04	-.12	-.27	.03	.00	.00	.00	.00	.00	.00
Net Disposition[12]	**17.29**	**18.87**	**15.11**	**15.59**	**15.93**	**15.94**	**16.28**	**16.64**	**16.96**	**17.34**	**20.03**

[1] Includes lease condensate.
[2] Other Domestic prior to 1981 includes unfinished oils (net), hydrogen, and hydrocarbons not included elsewhere. After 1981, Other Domestic includes unfinished oils (net), motor gasoline blending components (net), aviation gasoline blending components (net), hydrogen, other hydrocarbons, alcohol, and synthetic crude production.
[3] Represents volumetric gain in refinery distillation and cracking processes.
[4] In 1977 and later years, crude oil imports include crude oil imported for the Strategic Petroleum Reserve.
[5] Net stock withdrawals for a given year, t, are defined as the change in yearend stock levels from period t-1 minus the yearend stock level from the year t. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.
[6] SPR is the Strategic Petroleum Reserve.
[7] Total primary supply is defined as total production plus net imports plus net stock withdrawals minus SPR additions.
[8] Jet fuel includes naphtha and kerosene type.
[9] Other petroleum products includes miscellaneous petroleum products, lubricants, waxes, unfractionated stream, plant condensate, natural gasoline, asphalt, road oil, still gas, special naphthas, and petroleum coke.
[10] Industrial refined products includes total industrial demand for petroleum as reported in Table 8.
[11] Discrepancy represents the difference between total supply and total products supplied.
[12] Net disposition is the sum of total products supplied and discrepancy.
NOTE: From 1981 onward, the product supplied data is on a new basis. From 1983 onward, the other product category is on a net basis, reclassified (petroleum products reprocessed into other categories) plus the other category of products supplied.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical data are from Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984) pp. 79-99, Tables 35, 36, 37, and 45. Projected values are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = High Economic Growth Case, printed on December 28, 1984.
Historical quantities through 1983.

Table C16. Petroleum Product Prices
(1984 Dollars per Barrel)

Sector and Fuel	High Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Crude Oil Prices											
World Oil Price[1]	**8.62**	**21.63**	**30.39**	**29.00**	**28.00**	**27.00**	**27.00**	**28.00**	**29.00**	**30.00**	**40.00**
Refiner Acquisition Cost[2]	**8.77**	**18.50**	**30.39**	**29.00**	**28.00**	**27.00**	**27.00**	**28.00**	**29.00**	**30.00**	**40.00**
Delivered Sector Product Prices											
Residential and Commercial											
Distillate Fuel	19.35	29.95	43.90	42.49	41.13	40.21	40.25	41.45	42.68	44.01	55.59
Kerosene	20.04	32.11	44.72	41.07	39.62	38.62	38.60	39.76	40.97	42.28	53.88
Motor Gasoline[3]	34.52	41.22	54.27	53.26	52.24	51.01	51.08	52.32	53.51	54.55	67.82
Residual Fuel	11.44	20.53	34.41	33.30	32.21	32.11	32.37	33.40	34.48	35.89	43.20
Liquefied Petroleum Gas[4]	26.12	24.96	32.87	27.76	27.01	26.46	26.54	27.40	28.28	29.22	37.13
Average[5]	**20.23**	**28.21**	**40.89**	**39.28**	**38.00**	**37.17**	**37.19**	**38.28**	**39.41**	**40.66**	**51.21**
Industrial											
Distillate Fuel	11.52	24.55	38.01	36.57	35.26	34.38	34.47	35.72	37.01	38.38	50.13
Kerosene	12.09	26.14	39.01	37.56	36.24	35.36	35.46	36.74	38.06	39.47	51.47
Motor Gasoline[3]	34.75	41.07	54.52	53.51	52.49	51.24	51.30	52.52	53.69	54.72	67.89
Residual Fuel	10.65	19.86	28.46	27.35	26.23	26.13	26.42	27.47	28.58	30.00	37.25
Liquefied Petroleum Gas	11.19	18.98	28.58	24.39	23.51	22.93	22.99	23.83	24.69	25.61	33.47
Petrochemical Feedstocks[6]	11.05	23.78	34.53	33.08	31.70	30.69	30.78	32.05	33.34	34.73	46.60
Asphalt & Road Oil	13.12	27.97	26.38	25.75	25.15	25.11	25.27	25.87	26.49	27.31	31.51
Petroleum Coke	11.91	25.39	7.67	7.61	7.56	7.57	7.60	7.68	7.77	7.88	8.43
Special Naphthas	10.38	22.12	34.27	32.99	31.83	31.04	31.13	32.27	33.43	34.69	45.33
Miscellaneous Petroleum Products	12.35	26.10	33.86	32.27	30.94	30.08	30.14	31.32	32.55	33.92	44.99
Average[5]	**12.25**	**23.19**	**30.27**	**28.56**	**27.41**	**26.81**	**26.91**	**27.85**	**28.80**	**29.86**	**38.16**
Transportation[7]											
Distillate Fuel	20.27	29.35	55.82	54.40	53.09	52.23	52.33	53.59	54.89	56.29	68.12
Aviation Gasoline	40.10	52.84	70.43	68.78	67.12	65.08	65.18	67.17	69.08	70.76	92.23
Motor Gasoline[3]	34.39	40.85	54.08	53.06	52.03	50.78	50.84	52.06	53.23	54.26	67.46
Jet Fuel[8]	11.48	25.41	37.94	36.37	34.92	33.77	33.92	35.23	36.58	38.02	50.21
Residual Fuel[9]	8.47	14.12	22.66	21.57	20.52	20.44	20.72	21.76	22.86	24.28	31.65
Liquefied Petroleum Gas	10.75	17.55	30.54	36.37	35.50	34.92	34.99	35.83	36.70	37.64	45.57
Lubricants[10]	75.70	90.23	148.87	146.32	144.01	142.47	142.64	144.89	147.20	149.68	170.75
Average[5]	**29.51**	**37.09**	**52.13**	**51.17**	**50.10**	**48.82**	**48.77**	**49.93**	**51.10**	**52.24**	**64.97**
Electric Utilities											
Distillate Fuel	10.92	21.53	45.38	41.43	38.79	31.20	32.62	38.17	42.03	40.14	51.08
Residual Fuel	10.37	19.91	29.51	28.49	27.49	27.86	28.28	29.37	30.53	31.94	40.95
Average[5]	**10.42**	**20.03**	**30.57**	**29.67**	**28.02**	**27.93**	**28.36**	**29.70**	**31.04**	**32.45**	**41.84**
Refined Petroleum Product Prices											
Distillate Fuel	17.57	28.12	48.50	46.10	44.85	43.99	44.06	45.33	46.70	48.11	60.34
Kerosene	17.27	29.55	41.70	39.55	38.19	37.25	37.28	38.50	39.78	41.16	53.00
Aviation Gasoline	40.10	52.84	70.43	68.78	67.12	65.08	65.18	67.17	69.08	70.76	92.23
Motor Gasoline[3]	34.40	40.85	54.08	53.06	52.04	50.79	50.85	52.07	53.24	54.27	67.48
Jet Fuel[8]	11.48	25.41	37.94	36.37	34.92	33.77	33.92	35.23	36.58	38.02	50.21
Residual Fuel	10.35	19.12	28.14	27.07	26.01	26.09	26.39	27.47	28.61	30.08	38.98
Liquefied Petroleum Gas	16.46	20.88	29.37	24.96	24.08	23.51	23.54	24.36	25.21	26.12	33.87
Lubricants (Transportation)[10]	75.70	90.23	148.87	146.32	144.01	142.47	142.64	144.89	147.20	149.68	170.75
Petrochemical Feedstocks[6]	11.05	23.78	34.53	33.08	31.70	30.69	30.78	32.05	33.34	34.73	46.60
Asphalt & Road Oil	13.12	27.97	26.38	25.75	25.15	25.11	25.27	25.87	26.49	27.31	31.51
Petroleum Coke	11.91	25.39	7.67	7.61	7.56	7.57	7.60	7.68	7.77	7.88	8.43
Special Naphthas	10.38	22.12	34.27	32.99	31.83	31.04	31.13	32.27	33.43	34.69	45.33
Miscellaneous Petroleum Products	12.35	26.10	33.86	32.27	30.94	30.08	30.14	31.32	32.55	33.92	44.99

[1] The cost of imported crude oil to U.S. refiners in 1984 dollars per barrel.
[2] Refiner acquisition cost is an average of imported and domestic refiner acquisition costs.
[3] Gasoline price is an average price for all types.
[4] Residential and commercial liquefied petroleum gas price includes only a residential price due to data limitations.
[5] Weighted average price; the weights are taken from the consumption categories from Table 4 and converted to physical units.
[6] Petrochemical feedstock price includes only the price of naphthas less than 400 degrees.
[7] Transportation prices include the appropriate State road use taxes and Federal excise tax.
[8] Jet fuel price is a retail price for kerosene type jet fuel.
[9] Residual fuel price in the transportation sector is for marine bunker.
[10] Lubricant price is an average for light stocks and multiweight motor oil.

NOTE: Implicit Gross National Product Price Deflator, rebased to 1984 = 1.0, was used to convert from nominal to real dollars.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical prices are taken from Energy Information Administration, *State Energy Price and Expenditure Report,* DOE/EIA-0376(81) (Washington, DC, 1984), pp. 1-7. Projected values are output from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = High Economic Growth Case, printed on December 21, 1984.
Historical quantities through 1983.

Table C17. Natural Gas Supply, Disposition, and Prices
(Trillion Cubic Feet per Year)
(1984 Dollars per Thousand Cubic Feet)

Supply, Disposition, and Prices	High Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Dry Gas Production[1]	21.73	19.12	15.97	17.43	17.48	16.84	17.69	17.84	17.86	17.81	16.27
Supplemental Natural Gas[2]	.00	.00	.14	.15	.15	.61	.16	.30	.32	.48	.52
Net Imports	.96	.91	.87	.86	.99	1.05	1.16	1.27	1.43	1.57	2.03
Net Storage Withdrawals[3]	-.42	-.15	.47	.03	.03	.00	.00	.00	.00	.00	.00
Total Supply[4]	**22.27**	**19.88**	**17.45**	**18.47**	**18.65**	**18.50**	**19.01**	**19.41**	**19.61**	**19.86**	**18.82**
Consumption by Sector[5]											
Residential	4.88	4.90	4.53	4.60	4.60	4.54	4.56	4.58	4.58	4.57	4.37
Commercial[6]	2.60	2.60	2.53	2.59	2.60	2.59	2.62	2.65	2.68	2.69	2.61
Industrial	8.69	6.76	5.47	6.01	6.11	6.28	6.52	6.67	6.67	6.70	6.46
Lease & Plant Fuel[7]	1.50	1.65	1.00	1.09	1.09	1.05	1.11	1.12	1.12	1.12	1.02
Transportation[8]	.73	.53	.56	.59	.60	.60	.61	.62	.63	.64	.60
Electric Utilities	3.66	3.19	2.91	3.16	3.22	3.03	3.17	3.33	3.48	3.66	3.23
Total End-Use Consumption	**22.05**	**19.63**	**17.00**	**18.04**	**18.22**	**18.09**	**18.59**	**18.97**	**19.16**	**19.39**	**18.29**
Unaccounted for[9]	.22	.25	.45	.43	.43	.40	.42	.44	.45	.47	.53
Average Wellhead Price	**.46**	**1.35**	**2.72**	**2.70**	**2.67**	**2.67**	**2.82**	**3.06**	**3.35**	**3.71**	**6.12**
Delivered Prices by Sectors											
Residential	2.71	3.78	6.37	6.16	6.09	6.13	6.31	6.56	6.99	7.44	10.56
Commercial[6]	1.99	3.33	5.73	5.69	5.63	5.62	5.77	5.99	6.39	6.81	9.79
Industrial	1.07	2.27	4.44	4.41	4.41	4.43	4.59	4.82	5.17	5.59	8.42
Electric Utilities	.75	2.18	3.73	3.59	3.71	3.63	3.79	4.01	4.29	4.69	6.97
Average to All Sectors[10]	**1.53**	**2.83**	**5.08**	**4.95**	**4.94**	**4.94**	**5.09**	**5.31**	**5.66**	**6.07**	**8.91**

[1] Net dry natural gas is defined as dry marketed production minus nonhydrocarbon gases removed.

[2] Prior to 1980 the amount of supplemental fuels included in the natural gas data cannot be determined. Supplemental natural gas includes synthetic natural gas (results from the manufacture, conversion, or the reforming of petroleum hydrocarbons), and propane air mixtures. After 1985 this quantity includes short-term spot market purchases that could include additional imports.

[3] Includes net stock withdrawals for dry natural gas from underground storage and liquefied natural gas. Net stock withdrawals are computed as the yearend stock levels from the current period subtracted from the yearend stock levels from the preceding period. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.

[4] Total supply is computed as dry gas production plus supplemental natural gas, net imports, and net stock withdrawals.

[5] Consumption values include small amounts of supplemental gas, which are not reported as production prior to 1980.

[6] Commercial category includes the other customer category.

[7] Lease and plant fuel natural gas represents natural gas used in the field gathering and processing plant machinery, usually totalled into the industrial sector for other consumption tables.

[8] Transportation natural gas is used to fuel the compressors in the pipeline pumping stations.

[9] Unaccounted for represents natural gas lost, the net result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure, and EIA's merger of different data reporting systems which vary in scope, format, definition, and respondent type.

[10] Weighted average price and the weights are the sectoral consumption values excluding lease and plant fuel and the transportation sector.

NOTE: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1984 equals 1.00. The natural gas prices in this table are average prices, total revenues divided by total sales for each customer class.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Historical data are taken from the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984) and Energy Information Administration, *Natural Gas Annual, 1982* DOE/EIA-0131(82) (Washington, DC, 1983). Projected values are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = MRG1126T, Projected = High Economic Growth Case, printed on December 21, 1984.

Historical quantities through 1983.

Table C18. *Coal Supply, Disposition, and Prices*

(Million Short Tons per Year)

(1984 Dollars per Short Ton)

Supply, Disposition, and Price	High Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production[1]											
East of the Mississippi	522	487	507	583	571	582	603	622	645	670	758
West of the Mississippi	76	183	275	309	328	343	358	372	392	416	501
Total	**599**	**670**	**782**	**892**	**899**	**924**	**961**	**994**	**1,037**	**1,086**	**1,259**
Imports[2]	(*)	3	1	1	1	0	0	0	0	0	0
Exports[3]	54	41	78	80	73	74	77	81	86	91	106
Net Imports	**-53**	**-38**	**-77**	**-79**	**-72**	**-74**	**-77**	**-81**	**-86**	**-91**	**-106**
Net Storage Withdrawals[4]	**12**	**11**	**27**	**-20**	**15**	**(*)**	**-5**	**-6**	**-7**	**-9**	**-5**
Total Supply[5]	**557**	**644**	**733**	**793**	**842**	**850**	**879**	**907**	**944**	**986**	**1,148**
Consumption by Sector											
Residential and Commercial	11	10	8	8	8	8	8	7	7	7	7
Industrial	68	63	66	76	77	77	81	85	88	91	102
Coking Plants[6]	94	71	37	44	46	48	50	51	52	52	51
Electric Utilities	389	481	625	666	709	715	735	758	791	829	982
Synthetic Fuels	0	0	0	0	5	5	5	6	6	6	6
Total End-Use Consumption	**563**	**625**	**737**	**793**	**843**	**853**	**878**	**907**	**944**	**986**	**1,148**
Discrepancy[7]	-6	18	-4	-2	-3	-4	(*)	(*)	(*)	(*)	(*)
Average Minemouth Price[8]	**18.14**	**32.48**	**26.95**	**30.02**	**29.89**	**30.33**	**30.57**	**30.77**	**30.95**	**31.11**	**32.13**
Delivered Prices by Sector											
Residential and Commercial[9]	45.53	69.97	45.87	47.00	47.46	51.61	52.36	52.97	53.65	54.42	57.97
Industrial	26.89	49.65	40.79	43.70	44.72	50.06	51.31	52.48	53.74	55.02	61.05
Coking Plants[6]	38.52	77.33	61.51	60.88	61.52	64.88	65.63	66.29	67.17	68.13	71.47
Electric Utilities[10]	19.03	35.26	36.30	38.13	38.54	38.96	39.49	39.87	40.12	40.55	43.26
Average to All End-Use Sectors[11]	**23.76**	**42.04**	**38.07**	**40.01**	**40.45**	**41.55**	**42.19**	**42.66**	**43.00**	**43.46**	**46.20**

[1] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite with anthracite included in bituminous.

[2] Coal imports are not projected beyond 1985.

[3] Excludes small quantities of anthracite shipped overseas to U.S. Armed Forces and coke exports.

[4] From stocks held by end-use sectors (secondary stocks held at industrial plants, coke plants, and electric utility plants). Net stock withdrawals are computed as the yearend stock levels from the current period subtracted from the yearend stock levels from the preceding period. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.

[5] Total supply is equivalent to production plus net imports plus net storage withdrawals.

[6] Coke plants consume metallurgical coal which is a mixture of anthracite and bituminous coal. Historically, coking plant coal price is a weighted average of anthracite and bituminous coal types. In the projections, anthracite is included in bituminous coal.

[7] Historically, discrepancy represents revisions in producers (primary) stock levels, losses, and unaccounted for. In the projected period, discrepancy represents errors due to conversion factors.

[8] In historical years, the average production price of coal produced at the mine. Projected prices are based on estimated cost and do not reflect market conditions.

[9] Historically, residential price is used for residential and commercial consumers. Projected residential and commercial prices do not include dealer markup.

[10] Historically, electric utility price includes anthracite, bituminous, and lignite coal purchased under long-term contracts and on the spot market. In the projections, anthracite is included in bituminous coal, with the bituminous coal price being used for anthracite coal price.

[11] Weighted average price and the weights are the sectoral consumption values.

(*) Greater than zero but less than .5.

NOTE: Metallurgical coal prices reflect a reduced level of projected demand. Other projected coal prices are based on cost estimates, and do not reflect market conditions.

NOTE: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1984 equals 1.00. Projected coal prices are based on cost estimates and do not reflect market conditions.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Historical prices from Energy Information Administration, *State Energy Price and Expenditure Report*, , (DOE/EIA-0376(81) (Washington, DC, 1984) pp. 1-7. Historical quantities are from the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984) pp. 161-169, Table 73, 74, and 75. Projected values are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = MRG1126T, Projected = High Economic Growth Case, printed on December 21, 1984.

Historical quantities through 1983.

Table C19. National Macroeconomic Indicators

Macroeconomic Indicators	High Economic Growth Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
World Oil Price[1]	**8.62**	**21.63**	**30.39**	**29.00**	**28.00**	**27.00**	**27.00**	**28.00**	**29.00**	**30.00**	**40.00**
NIPA Variables[2]											
Real GNP (billion 1972 dollars)	1,254	1,439	1,535	1,643	1,700	1,759	1,839	1,919	1,989	2,057	2,372
Real Disposable Income (billion 1972 dollars)	865	989	1,095	1,168	1,204	1,228	1,264	1,307	1,353	1,400	1,623
Real Disposable Income Per Capita (thousand 1972 dollars)	4.1	4.4	4.7	4.9	5.0	5.1	5.2	5.3	5.5	5.6	6.3
NIPA GNP Price Deflator (1972=1.00)	1.057	1.504	2.153	2.233	2.313	2.402	2.525	2.663	2.804	2.950	3.776
GNP Growth (1984 reference year)	NA	NA	NA	.0	3.5	7.1	12.0	16.8	21.1	25.2	44.4
Unemployment Rate, Civilian Workers (percent)	4.9	6.1	9.6	7.5	7.0	7.2	6.9	6.6	6.6	6.6	7.3
Population, Noninstitutional (million persons)	211.9	222.6	234.0	236.2	238.5	240.7	243.0	245.2	247.4	249.5	259.4
New, High Grade Bond Rate (percent per annum)	7.65	8.88	11.56	12.62	11.95	10.27	9.04	8.49	8.18	8.14	7.54
New Home Mortgage Yields (percent per annum)	8.08	9.69	13.35	13.56	13.45	11.54	10.19	9.50	9.26	9.18	8.47
Total Industrial Production Index (1967=1.00)	1.30	1.46	1.48	1.64	1.72	1.83	1.97	2.10	2.18	2.25	2.59
Total Manufacturing Output Index (1967=1.00)	1.30	1.47	1.48	1.66	1.74	1.86	2.01	2.15	2.24	2.32	2.68
Housing Starts (million units)	2.04	2.00	1.70	1.79	1.69	1.98	1.98	1.99	1.94	1.87	1.72
Energy Usage Indicators											
Gross Energy Use per Capita (million Btu per person)	350.1	350.6	301.8	316.6	318.7	320.8	327.8	333.9	338.8	344.6	365.7
Gross Energy Use per Dollar of GNP (thousand Btu per 1972 dollar)	59.2	54.2	46.0	45.5	44.7	43.9	43.3	42.7	42.1	41.8	40.0
Net Oil Imports (billion 1984 dollars)	15.0	56.5	47.0	52.7	50.5	51.6	56.5	63.3	70.1	76.8	148.4
Net Coal Imports (billion 1984 dollars)	-2.1	-2.9	-3.9	-4.2	-3.9	-4.0	-4.1	-4.4	-4.7	-5.0	-6.2

[1] The cost of imported crude oil to U.S. refiners in 1984 dollars per barrel.
[2] National Income and Product Accounts.
NOTE: Total may not equal sum of components because of independent rounding.

Appendix D
Low World Oil Price/Middle Economic Growth Case

Table D1. Yearly Supply and Disposition Summary of Total Energy
(Quadrillion Btu per Year)

Total Supply and Disposition	Low World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Supply											
Production											
Crude Oil and Lease Condensate	19.5	18.4	18.4	18.5	18.8	18.3	18.0	17.5	17.1	16.7	12.1
Natural Gas Plant Liquids	2.6	2.2	2.2	2.3	2.3	2.1	2.0	2.1	2.1	2.1	1.8
Natural Gas[1]	22.2	19.5	16.4	17.9	18.0	17.2	18.1	18.2	17.9	17.8	16.5
Coal[2]	13.9	14.9	17.2	19.6	19.8	20.5	21.0	21.6	22.4	23.4	27.1
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Hydropower/Other[3]	2.9	3.0	3.6	3.6	3.1	3.3	3.3	3.3	3.3	3.4	3.4
Total Production	**62.0**	**61.0**	**61.1**	**65.6**	**66.1**	**66.1**	**67.8**	**68.6**	**69.0**	**69.6**	**68.0**
Imports											
Crude Oil[4]	6.9	13.5	7.1	7.4	9.1	9.8	10.5	11.2	12.1	13.0	20.0
Refined Petroleum Products[5]	6.6	4.4	3.6	4.1	2.9	3.4	3.9	4.1	4.2	4.7	6.5
Natural Gas[6]	1.1	1.0	1.1	1.0	1.2	1.8	1.3	1.5	1.9	2.0	3.1
Other Imports[7]	.2	.4	.4	.4	.5	.5	.5	.6	.6	.7	.8
Total Imports	**14.7**	**19.3**	**12.2**	**12.9**	**13.7**	**15.5**	**16.2**	**17.4**	**18.9**	**20.4**	**30.4**
Net Stock Withdrawals	**-.4**	**.3**	**1.1**	**-.7**	**.0**	**-.4**	**-.5**	**-.5**	**-.5**	**-.6**	**-.3**
Adjustments[8]	-.1	-.6	.0	.4	-.4	-.4	-.5	-.5	-.7	-.7	-.9
Total Supply[9]	**76.2**	**80.0**	**74.4**	**78.3**	**79.4**	**80.9**	**82.9**	**84.9**	**86.7**	**88.7**	**97.2**
Disposition											
Exports											
Oil	.5	.8	1.6	1.4	1.3	1.7	1.7	1.7	1.7	1.7	1.7
Natural Gas	.1	.1	.1	NA	NA	NA	NA	NA	NA	NA	NA
Coal	1.4	1.1	2.0	2.1	1.9	2.0	2.1	2.2	2.3	2.4	2.8
Other[10]	.1	.0	.1	NA	NA	NA	NA	NA	NA	NA	NA
Total Exports	**2.1**	**1.9**	**3.7**	**3.5**	**3.2**	**3.7**	**3.7**	**3.8**	**3.9**	**4.1**	**4.4**
Consumption											
Refined Petroleum Products[11]	34.8	38.0	30.1	31.5	31.7	31.8	32.3	32.9	33.3	34.2	38.3
Natural Gas	22.5	20.0	17.5	18.5	18.7	18.6	18.9	19.2	19.4	19.3	19.1
Coal[12]	12.9	13.7	15.9	17.1	18.1	18.4	18.8	19.3	19.9	20.7	24.1
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Hydro/Other/Electricity Imports[13]	3.1	3.2	4.0	4.0	3.6	3.8	3.9	3.9	4.0	4.1	4.2
Net Imports of Coke	.0	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total Consumption	**74.2**	**78.0**	**70.7**	**74.8**	**76.1**	**77.2**	**79.2**	**81.1**	**82.8**	**84.6**	**92.8**
Total Disposition	**76.2**	**80.0**	**74.4**	**78.3**	**79.4**	**80.9**	**82.9**	**84.9**	**86.7**	**88.7**	**97.2**

[1] Net dry marketed production after removal of nonhydrocarbon gases.
[2] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite, with anthracite included in bituminous.
[3] Hydropower/Other production includes hydropower, geothermal power, and wood waste.
[4] Includes imports of crude oil for the Strategic Petroleum Reserve.
[5] Includes imports of unfinished oils and natural gas plant liquids.
[6] Includes dry natural gas imports from Canada and Mexico, liquefied natural gas imports from Algeria, and supplemental gas.
[7] Includes electricity, coal, and coal coke imports.
[8] Balancing item that includes gains, losses, miscellaneous blending components, unaccounted for supply, coal used for synthetic fuel production, anthracite shipped overseas to U.S. Armed Forces and certain secondary stock withdrawals.
[9] Total supply is the sum of production, imports, net stock withdrawals, and adjustments.
[10] Includes electricity and coal coke exports.
[11] Includes natural gas plant liquids and crude oil consumed as a fuel.
[12] Excludes anthracite shipped overseas to U.S. Armed Forces and coal used for synthetic fuel production.
[13] Includes net electricity imports and renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[NA] = Not available.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical quantities are from the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984) pp. 5-29, Tables 1, 2, 3, and 13. Projected values are outputs from the Intermediate Future Forecasting System. Input data file: Historical = MRG1126T, Projected = Low World Oil Price Case, printed on December 28, 1984.
Historical quantities through 1983.

Table D2. Yearly Supply and Disposition of Total Energy, Supply Detail
(Quadrillion Btu per Year)

Total Supply	Low World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
World Oil Price[1]	**8.62**	**21.63**	**30.39**	**29.00**	**24.00**	**24.00**	**24.00**	**25.00**	**25.00**	**25.00**	**30.00**
Domestic Production											
Oil[2]	22.1	20.7	20.6	20.8	21.1	20.4	20.0	19.6	19.2	18.8	13.9
Natural Gas[3]	22.2	19.5	16.4	17.9	18.0	17.2	18.1	18.2	17.9	17.8	16.5
Coal[4]	13.9	14.9	17.2	19.6	19.8	20.5	21.0	21.6	22.4	23.4	27.1
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Hydropower/Other[5]	2.9	3.0	3.6	3.6	3.1	3.3	3.3	3.3	3.3	3.4	3.4
Total Domestic Production	**62.0**	**61.0**	**61.1**	**65.6**	**66.1**	**66.1**	**67.8**	**68.6**	**69.0**	**69.6**	**68.0**
Imports											
Oil[6]	13.5	17.8	10.7	11.5	12.0	13.2	14.4	15.3	16.4	17.7	26.5
Natural Gas[7]	1.1	1.0	1.1	1.0	1.2	1.8	1.3	1.5	1.9	2.0	3.1
Coal[8]	.0	.1	.0	.0	.0	NA	NA	NA	NA	NA	NA
Other Imports[9]	.2	.4	.4	.4	.4	.5	.5	.6	.6	.7	.8
Total Imports	**14.7**	**19.3**	**12.2**	**12.9**	**13.7**	**15.5**	**16.2**	**17.4**	**18.9**	**20.4**	**30.4**
Net Storage Withdrawals											
Oil	-.3	.5	.5	.1	.0	.0	-.1	-.1	-.1	-.1	-.1
Natural Gas	-.4	-.2	.5	.0	.0	.0	.0	.0	.0	.0	.0
Coal[10]	.3	.3	.6	-.4	.3	.0	-.1	-.1	-.1	-.2	-.1
SPR Fill Rate Additions (-)[11]	.0	-.3	-.5	-.4	-.3	-.3	-.3	-.3	-.3	-.3	.0
Net Stock Withdrawals	**-.4**	**.3**	**1.1**	**-.7**	**.0**	**-.4**	**-.5**	**-.5**	**-.5**	**-.6**	**-.3**
Available Supply[12]											
Oil	35.3	39.1	31.9	32.5	33.2	33.7	34.4	34.9	35.4	36.3	40.3
Natural Gas	22.8	20.3	18.0	19.0	19.2	19.0	19.3	19.7	19.9	19.8	19.6
Coal	14.2	15.2	17.8	19.2	20.1	20.4	21.0	21.6	22.3	23.2	27.0
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Other Supply[13]	3.1	3.4	4.0	4.0	3.6	3.8	3.9	3.9	4.0	4.1	4.2
SPR Fill Rate Additions (-)[11]	.0	-.3	-.5	-.4	-.3	-.3	-.3	-.3	-.3	-.3	.0
Total Supply (before adjustments)	**76.3**	**80.6**	**74.4**	**77.9**	**79.8**	**81.3**	**83.4**	**85.4**	**87.4**	**89.4**	**98.1**
Adjustments[14]	-.1	-.6	.0	.4	-.4	-.4	-.5	-.5	-.7	-.7	-.9
Total Supply[15]	**76.2**	**80.0**	**74.4**	**78.3**	**79.4**	**80.9**	**82.9**	**84.9**	**86.7**	**88.7**	**97.2**

[1] The cost of imported crude oil to U.S. refiners in 1984 dollars per barrel.
[2] Oil includes crude oil, lease condensate, and natural gas plant liquids.
[3] Net dry marketed production after removal of nonhydrocarbon gases.
[4] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite, with anthracite included in bituminous.
[5] Hydropower/Other production includes hydropower, geothermal power, and wood waste.
[6] Oil imports includes crude oil and refined petroleum products. Crude oil imports include imports for the Strategic Petroleum Reserve.
[7] Includes dry natural gas imports from Canada and Mexico, liquefied natural gas imports from Algeria, and supplemental gas.
[8] Includes small amounts of coal/coke imports.
[9] Consists of net electricity imports from Canada.
[10] From consumer stocks (utility, coke plant, and industrial) only.
[11] SPR is the Strategic Petroleum Reserve.
[12] Available supply is the sum of domestic production, imports, and net stock withdrawals.
[13] Includes net electricity imports from Canada, hydropower, geothermal power, wood, waste, solar power, and wind power.
[14] Balancing item that includes gains, losses, miscellaneous blending components, unaccounted for supply, coal used for synthetic fuel production, anthracite shipped overseas to U.S. Armed Forces and certain secondary stock withdrawals.
[15] Total supply is the sum of production, imports, net stock withdrawals, and adjustments.
[NA] = Not available.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical values are taken from Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984).
Input data file: Historical = MRG1126T, Projected = Low World Oil Price Case, printed on December 28, 1984.
Historical prices through 1981 and quantities through 1983.

Table D3. Yearly Supply and Disposition of Total Energy, Disposition Detail
(Quadrillion Btu per Year)

Total Disposition	Low World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Exports											
Oil[1]	0.5	0.8	1.6	1.4	1.3	1.7	1.7	1.7	1.7	1.7	1.7
Natural Gas	.1	.1	.1	NA	NA	NA	NA	NA	NA	NA	NA
Coal	1.4	1.1	2.0	2.1	1.9	2.0	2.1	2.2	2.3	2.4	2.8
Other[2]	.1	.0	.1	NA	NA	NA	NA	NA	NA	NA	NA
Total Exports	**2.1**	**1.9**	**3.7**	**3.5**	**3.2**	**3.7**	**3.7**	**3.8**	**3.9**	**4.1**	**4.4**
Consumption											
Residential and Commercial											
Oil[3]	4.4	4.1	2.3	2.6	2.5	2.6	2.7	2.8	2.9	3.0	3.1
Natural Gas	7.6	7.6	7.2	7.4	7.4	7.5	7.5	7.5	7.6	7.6	7.3
Coal	.3	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2
Total (excluding electricity)	**12.3**	**11.9**	**9.8**	**10.1**	**10.1**	**10.3**	**10.4**	**10.5**	**10.6**	**10.7**	**10.6**
Industrial											
Oil[4]	9.1	9.9	7.8	8.9	9.2	9.3	9.8	10.1	10.4	10.7	11.9
Natural Gas[5]	10.4	8.5	6.6	7.3	7.4	7.4	7.6	7.8	7.7	7.7	7.5
Coal[6]	4.0	3.2	2.5	2.9	2.9	3.2	3.3	3.5	3.5	3.6	3.9
Hydropower	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Net Imports of Coke	.0	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total (excluding electricity)	**23.5**	**21.8**	**16.9**	**19.0**	**19.6**	**19.9**	**20.7**	**21.4**	**21.7**	**22.1**	**23.3**
Transportation											
Oil[7]	17.8	20.0	18.4	18.7	18.8	18.6	18.7	18.7	18.9	19.1	20.6
Natural Gas[8]	.7	.5	.6	.6	.6	.6	.6	.6	.6	.6	.6
Coal	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total (excluding electricity)	**18.6**	**20.6**	**19.0**	**19.3**	**19.4**	**19.2**	**19.3**	**19.4**	**19.5**	**19.8**	**21.2**
Electric Utilities											
Oil	3.5	4.0	1.5	1.3	1.2	1.2	1.1	1.2	1.1	1.4	2.7
Natural Gas	3.7	3.3	3.0	3.3	3.3	3.1	3.2	3.3	3.5	3.4	3.6
Coal	8.7	10.3	13.2	14.0	14.9	15.0	15.3	15.7	16.2	16.9	20.1
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Hydropower/Other[9]	3.0	3.2	4.0	4.0	3.5	3.8	3.8	3.9	4.0	4.0	4.2
Total	**19.9**	**23.7**	**25.0**	**26.3**	**27.1**	**27.8**	**28.8**	**29.8**	**30.9**	**32.1**	**37.7**
Total Disposition	**76.2**	**80.0**	**74.4**	**78.3**	**79.4**	**80.9**	**82.9**	**84.9**	**86.7**	**88.7**	**97.2**

[1] Consists primarily of refined petroleum products.
[2] Includes electricity and coal coke exports.
[3] Residential and Commercial oil consists of motor gasoline, distillate fuel, kerosene, residual fuel, and liquefied petroleum gases.
[4] Industrial oil consists of distillate fuel, kerosene, residual fuel, liquefied petroleum gases, special naphthas, miscellaneous petroleum products, lubricants, waxes, unfractionated stream, plant condensate, natural gasoline, asphalt, road oil, petroleum coke, still gas, other oils greater than 400 degrees used for chemical feedstocks, motor gasoline, and naphthas less than 400 degrees used for feedstock purposes, including refinery fuel consumption.
[5] Industrial natural gas is composed of lease and plant fuel use, refinery fuel use, and other industrial uses.
[6] Industrial coal is composed of steam and metallurgical (coking) coal.
[7] Transportation oil consists of motor gasoline, aviation gasoline, jet fuel, distillate fuel, residual fuel, lubricants, and liquefied petroleum gases.
[8] Transportation natural gas represents natural gas used as a fuel by pipeline compressors.
[9] Includes net electricity imports from Canada, hydropower, geothermal power, wood, waste, solar power, and wind power.
[NA] = Not available.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical quantities are taken from Energy Information Administration, *State Energy Data Report, 1960 to 1982*, DOE/EIA 0214(82) (Washington, DC, 1984) and Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984). Projected quantities are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = Low World Oil Price Case, printed on December 28, 1984.
Historical quantities through 1983.

Table D4. Consumption by Major Fuels and End-Use Sectors
(Quadrillion Btu per Year)

Sector and Fuel	Low World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential											
Distillate Fuel	2.00	1.95	1.05	1.23	1.19	1.23	1.25	1.27	1.29	1.30	1.28
Kerosene	.23	.15	.09	.07	.06	.06	.07	.07	.07	.07	.07
Liquefied Petroleum Gas	.59	.52	.30	.25	.27	.28	.29	.30	.31	.31	.31
Natural Gas	4.98	4.98	4.65	4.72	4.72	4.74	4.76	4.78	4.78	4.77	4.62
Steam Coal	.11	.09	.08	.07	.07	.07	.07	.07	.06	.06	.06
Electricity	1.98	2.30	2.56	2.61	2.68	2.73	2.79	2.86	2.93	3.02	3.46
Total	**9.89**	**9.99**	**8.72**	**8.95**	**8.99**	**9.11**	**9.23**	**9.34**	**9.44**	**9.53**	**9.80**
Commercial											
Distillate Fuel	.64	.67	.44	.51	.51	.54	.57	.60	.64	.67	.77
Kerosene	.06	.05	.03	.06	.06	.06	.07	.07	.08	.08	.10
Motor Gasoline	.09	.11	.09	.09	.08	.08	.08	.08	.08	.08	.08
Residual Fuel	.67	.53	.30	.33	.33	.35	.37	.39	.42	.44	.51
Liquefied Petroleum Gas	.10	.09	.05	.03	.03	.03	.03	.03	.03	.03	.02
Natural Gas[1]	2.65	2.64	2.60	2.66	2.67	2.71	2.74	2.76	2.78	2.79	2.71
Steam Coal	.15	.13	.12	.11	.12	.12	.12	.12	.11	.11	.11
Electricity	1.52	1.81	2.12	2.36	2.45	2.51	2.58	2.66	2.74	2.82	3.24
Total	**5.88**	**6.04**	**5.74**	**6.16**	**6.24**	**6.40**	**6.56**	**6.71**	**6.87**	**7.02**	**7.54**
Industrial[2]											
Distillate Fuel	1.47	1.75	1.30	1.61	1.61	1.63	1.68	1.73	1.78	1.83	1.99
Kerosene	.16	.16	.14	.10	.09	.09	.09	.09	.09	.09	.08
Motor Gasoline	.26	.18	.14	.13	.14	.16	.18	.20	.22	.25	.40
Residual Fuel	1.86	1.72	.78	.98	.98	.98	1.04	1.07	1.12	1.17	1.33
Liquefied Petroleum Gas	1.24	1.26	1.61	1.52	1.58	1.62	1.77	1.89	1.97	2.05	2.39
Petrochemical Feedstocks[3]	.73	1.22	.85	1.38	1.50	1.49	1.58	1.65	1.66	1.67	1.64
Still Gas Used in Refineries	1.06	1.20	1.13	1.16	1.21	1.22	1.23	1.24	1.25	1.27	1.39
Other Raw Material Oil[4]	2.34	2.41	1.82	1.98	2.09	2.13	2.19	2.27	2.32	2.38	2.71
Natural Gas[5]	10.39	8.54	6.64	7.29	7.39	7.43	7.63	7.77	7.74	7.72	7.47
Steam Coal	1.43	1.46	1.50	1.72	1.75	1.91	1.99	2.08	2.16	2.24	2.52
Metallurgical Coal	2.54	1.79	.96	1.15	1.19	1.25	1.32	1.37	1.38	1.38	1.34
Net Coke Imports	-.01	.13	-.02	.00	.00	.00	.00	.00	.00	.00	.00
Electricity	2.34	2.76	2.65	2.74	2.78	2.86	3.03	3.21	3.36	3.55	4.33
Hydropower	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03
Total	**25.84**	**24.60**	**19.52**	**21.78**	**22.35**	**22.79**	**23.76**	**24.58**	**25.09**	**25.63**	**27.62**

See footnotes at end of table.

Table D4. Consumption by Major Fuels and End-Use Sectors (Continued)
(Quadrillion Btu per Year)

Sector and Fuel	Low World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Transportation											
Aviation Gasoline	0.08	0.07	0.05	0.07	0.08	0.08	0.09	0.09	0.09	0.10	0.11
Distillate Fuel	2.22	2.68	2.84	2.67	2.63	2.69	2.78	2.89	3.00	3.13	3.97
Jet Fuel[6]	2.13	2.14	2.14	2.35	2.37	2.48	2.59	2.66	2.74	2.81	3.01
Motor Gasoline	12.45	13.93	12.47	12.67	12.71	12.39	12.17	12.03	11.96	11.96	12.21
Residual Fuel	.73	.99	.75	.74	.71	.73	.76	.79	.81	.84	.94
Liquefied Petroleum Gas	.04	.03	.03	.01	.01	.01	.01	.01	.01	.01	.01
Lubricants and Waxes	.16	.18	.16	.22	.26	.26	.26	.27	.28	.28	.32
Natural Gas[7]	.74	.54	.58	.61	.62	.61	.62	.63	.64	.64	.63
Other Transportation[8]	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01
Total	**18.58**	**20.57**	**19.02**	**19.35**	**19.38**	**19.26**	**19.29**	**19.37**	**19.54**	**19.77**	**21.20**
Electric Utilities											
Distillate Fuel	.27	.28	.10	.11	.05	.03	.02	.03	.04	.05	.22
Residual Fuel	3.24	3.71	1.45	1.20	1.12	1.15	1.12	1.16	1.09	1.31	2.47
Natural Gas	3.75	3.30	3.01	3.27	3.33	3.11	3.17	3.27	3.48	3.42	3.62
Steam Coal	8.66	10.25	13.23	14.05	14.94	15.01	15.33	15.69	16.22	16.93	20.11
Nuclear Power	.91	3.02	3.23	3.70	4.10	4.72	5.31	5.79	6.09	6.32	7.09
Hydropower/Other[9]	3.02	3.18	3.98	3.95	3.54	3.77	3.83	3.88	3.96	4.03	4.15
Total	**19.85**	**23.74**	**25.00**	**26.27**	**27.09**	**27.78**	**28.77**	**29.83**	**30.87**	**32.06**	**37.66**
Primary Energy Consumption											
Distillate Fuel	6.61	7.32	5.72	6.13	5.99	6.11	6.31	6.53	6.75	6.98	8.22
Kerosene	.45	.36	.26	.23	.21	.21	.22	.23	.23	.24	.25
Aviation Gasoline	.08	.07	.05	.07	.08	.08	.09	.09	.09	.10	.11
Motor Gasoline	12.80	14.21	12.70	12.88	12.93	12.62	12.43	12.31	12.26	12.29	12.69
Jet Fuel	2.13	2.14	2.14	2.35	2.37	2.48	2.59	2.66	2.74	2.81	3.01
Residual Fuel	6.49	6.95	3.27	3.25	3.14	3.21	3.28	3.42	3.44	3.75	5.24
Liquefied Petroleum Gas	1.98	1.89	1.99	1.81	1.89	1.94	2.09	2.22	2.31	2.40	2.73
Petrochemical Feedstocks	.73	1.22	.85	1.38	1.50	1.49	1.58	1.65	1.66	1.67	1.64
Still Gas	1.06	1.20	1.13	1.16	1.21	1.22	1.23	1.24	1.25	1.27	1.39
Lubricants and Waxes	.40	.41	.35	.45	.51	.52	.53	.55	.56	.57	.61
Other Petroleum	2.11	2.18	1.62	1.75	1.83	1.88	1.92	1.99	2.04	2.09	2.41
Natural Gas	22.50	20.00	17.47	18.54	18.73	18.60	18.93	19.21	19.42	19.34	19.05
Steam Coal	10.35	11.92	14.91	15.95	16.88	17.10	17.51	17.95	18.56	19.35	22.79
Metallurgical Coal	2.54	1.79	.96	1.15	1.19	1.25	1.32	1.37	1.38	1.38	1.34
Net Coke Imports	-.01	.13	-.02	.00	.00	.00	.00	.00	.00	.00	.00
Nuclear Power	.91	3.02	3.23	3.70	4.10	4.72	5.31	5.79	6.09	6.32	7.09
Hydropower/Other[9]	3.06	3.21	3.99	3.98	3.57	3.80	3.86	3.91	3.99	4.06	4.18
Total Consumption	**74.19**	**78.04**	**70.66**	**74.79**	**76.14**	**77.23**	**79.21**	**81.10**	**82.77**	**84.61**	**92.77**
Electricity Consumption (all sectors)	**5.84**	**6.89**	**7.34**	**7.72**	**7.92**	**8.11**	**8.41**	**8.73**	**9.04**	**9.40**	**11.04**

[1] Commercial natural gas includes deliveries to municipalities and public authorities for institutional heating, street lighting, etc.
[2] Industrial includes all fuels consumed for heat and power, including natural gas used as lease and plant fuel, industrial feedstock and raw material uses; also, all fuels consumed by refineries.
[3] Petrochemical feedstocks includes still gas used for feedstock purposes, naphthas less than 400 degrees, and other oils greater than 400 degrees.
[4] Consists of asphalt, special naphthas, lubricants, waxes, petroleum coke, road oil, and small amounts of Other Petroleum and Net Blending Oil as defined in Table A8.
[5] Includes lease and plant fuel consumption of natural gas.
[6] Jet fuel includes naphtha and kerosene types.
[7] Consists of natural gas used as pipeline compressor fuel.
[8] Other transportation includes steam coal and electricity.
[9] Includes renewable facilities such as hydropower, geothermal power, wood, waste, solar power, and wind power. Electric utility consumption includes net electicity imports.

NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical quantities are taken from Energy Information Administration, *State Energy Data Report, 1960 to 1982*, DOE/EIA-0214 (82) (Washington, DC, 1984) and Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984). Projected quantities are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = Low World Oil Price Case, printed on December 21, 1984.
Historical quantities through 1983.

Table D5. Prices by Major Fuels and End-Use Sectors
(1984 Dollars per Million Btu)

Sector and Fuel	Low World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential											
Distillate Fuel	3.46	5.28	7.94	7.70	6.73	6.76	6.77	6.99	7.02	7.06	8.10
Kerosene	3.96	6.01	8.29	8.04	7.03	7.06	7.07	7.30	7.33	7.37	8.46
Liquefied Petroleum Gas	7.66	7.08	9.02	7.76	6.73	6.76	6.78	7.00	7.03	7.08	8.19
All Petroleum Products	**4.38**	**5.68**	**8.19**	**7.72**	**6.74**	**6.77**	**6.79**	**7.00**	**7.03**	**7.08**	**8.13**
Natural Gas	2.66	3.72	6.20	6.00	5.94	5.91	6.08	6.31	6.67	7.04	9.02
Steam Coal[1]	2.47	3.81	2.05	2.10	2.12	2.15	2.17	2.19	2.22	2.26	2.41
Electricity	15.74	18.80	19.55	19.62	19.71	19.89	20.02	20.00	19.75	19.53	19.06
Average[2]	**5.76**	**7.71**	**10.41**	**10.24**	**10.15**	**10.22**	**10.39**	**10.59**	**10.76**	**10.97**	**12.38**
Commercial											
Distillate Fuel	2.90	4.72	6.57	6.33	5.36	5.39	5.40	5.61	5.64	5.68	6.71
Kerosene	2.04	4.68	6.62	6.36	5.36	5.39	5.40	5.62	5.65	5.70	6.78
Motor Gasoline	6.57	7.85	10.33	10.14	9.01	9.01	9.03	9.26	9.25	9.22	10.57
Residual Fuel	1.82	3.27	5.47	5.30	4.74	4.81	4.84	4.99	5.05	5.15	5.75
Liquefied Petroleum Gas	3.11	5.25	9.04	6.54	5.51	5.54	5.55	5.78	5.81	5.86	6.97
All Petroleum Products	**2.62**	**4.45**	**6.72**	**6.32**	**5.46**	**5.48**	**5.48**	**5.66**	**5.68**	**5.72**	**6.59**
Natural Gas[3]	1.95	3.27	5.59	5.55	5.48	5.43	5.57	5.77	6.09	6.44	8.30
Steam Coal[4]	.94	1.89	2.01	2.06	2.08	2.11	2.13	2.16	2.18	2.22	2.36
Electricity	15.08	19.48	19.76	19.79	19.91	20.14	20.32	20.34	20.07	19.84	19.36
Average[2]	**5.49**	**8.40**	**10.93**	**11.07**	**11.08**	**11.14**	**11.30**	**11.45**	**11.52**	**11.63**	**12.63**
Industrial											
Distillate Fuel	1.98	4.21	6.53	6.28	5.31	5.34	5.35	5.56	5.58	5.62	6.64
Kerosene	2.13	4.61	6.88	6.62	5.62	5.65	5.66	5.88	5.91	5.95	7.03
Motor Gasoline	6.62	7.82	10.38	10.19	9.06	9.06	9.07	9.30	9.29	9.26	10.58
Residual Fuel	1.69	3.16	4.53	4.35	3.78	3.85	3.89	4.05	4.11	4.21	4.80
Liquefied Petroleum Gas	2.99	5.17	7.85	6.69	5.66	5.69	5.70	5.93	5.96	6.00	7.09
Petrochemical Feedstocks[5]	1.98	4.21	6.16	5.90	4.88	4.89	4.90	5.11	5.14	5.18	6.26
Still Gas[6]	1.98	4.21	6.43	6.19	5.23	5.26	5.27	5.48	5.51	5.56	6.60
Other Petroleum[7]	1.98	4.21	5.16	5.15	4.73	4.71	4.73	4.83	4.82	4.82	4.97
All Petroleum Products	**2.19**	**4.22**	**6.30**	**5.87**	**5.05**	**5.08**	**5.11**	**5.30**	**5.33**	**5.37**	**6.22**
Natural Gas[8]	1.05	2.23	4.33	4.30	4.28	4.27	4.42	4.63	4.92	5.25	7.02
Steam Coal	.96	1.93	1.86	1.93	1.98	2.02	2.06	2.10	2.14	2.19	2.40
Metallurgical Coal	1.49	2.98	2.29	2.34	2.37	2.39	2.41	2.43	2.46	2.49	2.60
Net Coke Imports	1.93	4.55	4.08	4.16	4.21	4.25	4.28	4.32	4.36	4.41	4.60
Electricity	7.72	12.19	16.59	16.66	16.72	16.90	17.05	17.01	16.76	16.54	16.06
Average[2]	**2.06**	**4.15**	**6.44**	**6.16**	**5.83**	**5.86**	**5.96**	**6.15**	**6.27**	**6.42**	**7.45**

See footnotes at end of table.

Table D5. Prices by Major Fuels and End-Use Sectors (Continued)
(1984 Dollars per Million Btu)

Sector and Fuel	Low World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Transportation[9]											
Aviation Gasoline	7.94	10.47	13.95	13.62	11.71	11.71	11.73	12.12	12.11	12.05	14.31
Distillate Fuel	3.48	5.04	9.58	9.34	8.37	8.40	8.41	8.63	8.65	8.70	9.73
Jet Fuel[10]	2.05	4.53	6.77	6.49	5.44	5.43	5.45	5.68	5.71	5.76	6.88
Motor Gasoline[11]	6.55	7.78	10.29	10.10	8.97	8.97	8.98	9.21	9.20	9.17	10.50
Residual Fuel[12]	1.35	2.25	3.60	3.43	2.88	2.95	2.99	3.14	3.21	3.31	3.92
Liquefied Petroleum Gas	2.87	4.78	8.38	9.98	8.95	8.98	8.99	9.22	9.25	9.30	10.41
Lubricants and Waxes[13]	12.48	14.88	24.54	24.13	22.48	22.53	22.54	22.90	22.96	23.03	24.80
All Petroleum Products	**5.47**	**6.86**	**9.63**	**9.45**	**8.41**	**8.38**	**8.37**	**8.58**	**8.57**	**8.55**	**9.76**
Natural Gas[14]	.45	1.33	2.64	2.63	2.59	2.55	2.70	2.92	3.15	3.43	4.88
Electricity	5.67	9.48	19.00	18.99	19.11	19.36	19.58	19.61	19.32	19.07	18.59
Average[2]	**5.27**	**6.72**	**9.43**	**9.24**	**8.23**	**8.20**	**8.19**	**8.40**	**8.39**	**8.39**	**9.62**
Electric Utilities											
Distillate Fuel[15]	1.87	3.70	7.79	7.11	5.92	4.84	5.04	5.98	6.20	6.01	6.70
Residual Fuel	1.65	3.17	4.69	4.53	3.99	4.13	4.19	4.35	4.45	4.53	5.41
All Petroleum Products	**1.67**	**3.20**	**4.89**	**4.75**	**4.07**	**4.15**	**4.20**	**4.40**	**4.50**	**4.58**	**5.51**
Natural Gas	.73	2.11	3.60	3.47	3.53	3.42	3.58	3.78	3.98	4.26	5.46
Steam Coal	.95	1.78	1.72	1.81	1.83	1.85	1.86	1.88	1.90	1.92	2.05
Fossil Fuel Average	**1.05**	**2.17**	**2.31**	**2.31**	**2.26**	**2.24**	**2.28**	**2.34**	**2.39**	**2.46**	**2.87**
Average Price to All Users											
Distillate Fuel	3.02	4.83	8.33	7.91	6.95	6.98	6.99	7.20	7.23	7.28	8.37
Kerosene	3.05	5.21	7.35	6.98	5.97	5.99	6.00	6.21	6.23	6.27	7.31
Aviation Gasoline	7.94	10.47	13.95	13.62	11.71	11.71	11.73	12.12	12.11	12.05	14.31
Motor Gasoline	6.55	7.78	10.30	10.10	8.97	8.97	8.98	9.21	9.20	9.17	10.50
Jet Fuel	2.05	4.53	6.77	6.49	5.44	5.43	5.45	5.68	5.71	5.76	6.88
Residual Fuel	1.65	3.04	4.48	4.31	3.75	3.85	3.89	4.05	4.12	4.23	5.02
Liquefied Petroleum Gas	2.99	5.17	7.85	6.69	5.66	5.69	5.70	5.93	5.96	6.00	7.09
Petrochemical Feedstocks	1.98	4.21	6.16	5.90	4.88	4.89	4.90	5.11	5.14	5.18	6.26
Lubricants and Waxes	12.48	14.88	24.54	24.13	22.48	22.53	22.54	22.90	22.96	23.03	24.80
Other Petroleum Products	1.98	4.21	5.63	5.37	4.47	4.49	4.50	4.69	4.72	4.76	5.68
All Petroleum Products	**4.02**	**5.62**	**8.30**	**7.98**	**7.01**	**7.00**	**6.97**	**7.14**	**7.14**	**7.13**	**8.08**
Natural Gas	1.42	2.68	4.82	4.70	4.67	4.65	4.79	5.00	5.28	5.62	7.31
Coal	1.07	1.97	1.77	1.86	1.88	1.91	1.93	1.95	1.96	1.99	2.12
Electricity	12.34	16.32	18.54	18.62	18.72	18.91	19.04	19.00	18.73	18.50	17.97
Average	**3.37**	**5.15**	**7.02**	**6.85**	**6.42**	**6.46**	**6.51**	**6.65**	**6.71**	**6.77**	**7.55**

[1] Projected residential coal prices are delivered to dealer prices and do not include dealer markup.
[2] Weighted average of end-use fuel prices consists of the prices shown above and the appropriate weights from Table 4.
[3] Commercial natural gas price is a weighted average of the commercial and other category.
[4] Historical price for commercial steam coal is the price of industrial steam coal at the State level. Projected prices do not include dealer markup, where applicable.
[5] Industrial distillate price is used in historical years (through 1978).
[6] The industrial distillate price is used. For 1983 forward, differences between the national prices of still gas and distillate fuel oil are due to differences in the regional composition of demand for these fuels.
[7] Industrial other price is a weighted average price for road oil, asphalt, lubricants, waxes, petroleum coke, special naphthas, and miscellaneous petroleum products.
[8] Industrial natural gas price is a weighted average of the lease and plant fuel price and the industrial price. In these reports, the natural gas price for industrial heat and power is used for the lease and plant fuel price, so both components of the average are the same.
[9] Transportation prices include the appropriate Federal excise tax and State road use taxes.
[10] Jet fuel price is for kerosene type jet fuel at retail.
[11] Gasoline price is an average for all types.
[12] Residual fuel price is for marine bunker.
[13] Historical price is the price of industrial lubricants.
[14] Transportation natural gas price is for pipeline fuel use only. The average wellhead price from Table 17 is used as a surrogate price.
[15] Historical price for electric utility distillate fuel oil is the price of electric utility kerosene.

NOTE: Metallurgical coal prices reflect a reduced level of projected demand. Projected coal prices are based on cost estimates and do not reflect market conditions.
NOTE: Electricity and natural gas prices are average prices, revenue divided by sales. Also, the electricity prices are averages for class A and B private electric utilities and public power authorities.
NOTE: Implicit Gross National Product Price Deflator, rebased to 1984 = 1.0, was used to convert from nominal to real dollars.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical prices are taken from Energy Information Administration, *State Energy Price and Expenditure Report*, (DOE/EIA-0376 (81) (Washington, DC, 1984), pp. 1-7. Projected prices are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = Low World Oil Price Case, printed on December 21, 1984.
Historical prices through 1981.

Table D6. Residential Energy Use by End Use
(Quadrillion Btu per Year)

Fuel and End Use	Low World Oil Price Case								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
Marketed Fuel Consumption[1]									
Fuel Use									
Space Heating	4.51	4.68	4.69	4.77	4.85	4.90	4.93	4.96	4.85
Water Heating	1.63	1.66	1.65	1.66	1.67	1.69	1.70	1.72	1.80
Air Conditioning	0.38	.39	.40	.41	.41	.42	.43	.45	.51
Other End Uses[2]	2.21	2.22	2.25	2.27	2.30	2.33	2.36	2.41	2.64
Total	**8.73**	**8.94**	**8.99**	**9.11**	**9.23**	**9.34**	**9.43**	**9.53**	**9.80**
Liquefied Petroleum Gas									
Space Heating	.21	.18	.20	.21	.21	.22	.23	.23	.22
Water Heating	.09	.07	.07	.08	.08	.08	.08	.08	.09
Total	**.30**	**.25**	**.27**	**.28**	**.29**	**.30**	**.31**	**.31**	**.31**
Fuel Oil[3]									
Space Heating	.93	1.06	1.03	1.07	1.10	1.12	1.13	1.14	1.12
Water Heating	.21	.24	.22	.22	.22	.22	.22	.22	.22
Total	**1.14**	**1.30**	**1.25**	**1.29**	**1.32**	**1.34**	**1.35**	**1.36**	**1.35**
Natural Gas									
Space Heating	3.06	3.12	3.12	3.14	3.16	3.17	3.17	3.16	2.98
Water Heating	1.02	1.03	1.03	1.03	1.03	1.04	1.04	1.05	1.06
Air Conditioning	.01	.01	.01	.01	.01	.01	.02	.02	.02
Other End Uses[2]	.56	.56	.55	.55	.55	.55	.55	.55	.56
Total	**4.65**	**4.72**	**4.72**	**4.74**	**4.76**	**4.78**	**4.78**	**4.77**	**4.62**
Coal									
Space Heating	.08	.07	.07	.07	.07	.07	.06	.06	.06
Total	**.08**	**.07**	**.07**	**.07**	**.07**	**.07**	**.06**	**.06**	**.06**
Electricity									
Space Heating	.23	.25	.27	.29	.31	.32	.34	.36	.47
Water Heating	.31	.32	.33	.33	.34	.35	.36	.37	.42
Air Conditioning	.37	.37	.38	.39	.40	.41	.42	.43	.49
Other End Uses[2]	1.65	1.66	1.69	1.72	1.74	1.77	1.81	1.85	2.08
Total	**2.56**	**2.61**	**2.68**	**2.73**	**2.79**	**2.86**	**2.93**	**3.02**	**3.46**
Nonmarketed Fuel Consumption[1]									
Wood	**1.04**	**0.92**	**0.94**	**0.95**	**0.95**	**0.96**	**0.96**	**0.97**	**1.01**
Residential Activity									
Occupied Housing Stock (million units)	84.9	86.5	88.2	89.7	91.3	93.0	94.7	96.4	104.3
New Housing Construction[4] (million units)	1.5	2.0	2.1	1.9	2.1	2.1	2.2	2.1	2.0
Income Per Household (thousand 1984 dollars)	22.0	22.0	22.3	22.3	22.6	22.8	23.0	23.2	24.0
Energy Use Per Household (million Btu)	103	103	102	102	101	100	100	99	94
Fuel Expenditure Per Household (1984 dollars)	1,070	1,057	1,033	1,037	1,048	1,062	1,070	1,081	1,162

[1] Residential fuels are divided into marketed fuels (those with an associated price that are traded in economic markets) and nonmarketed fuels.
[2] Major other end uses include lighting, cooking, refrigeration, washing, and drying.
[3] Residential fuel oil category includes kerosene and distillate oil.
[4] New housing construction includes completions of single family, multifamily, and mobile housing units.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: The Residential model is documented in *Model Documentation: Household Model of Energy*, Energy Information Administration (DOE/EIA-0409) (Washington, DC, 1984). The major model data source is the public use tape of the Residential Energy Consumption Survey 1981, Energy Information Administration.
Input data file: Historical = MRG1126T, Projected = Low World Oil Price Case, printed on December 21, 1984.
Historical quantities through 1983.

Table D7. Commercial Energy Use by Building Type
(Quadrillion Btu per Year)

Fuel and Building Type	Low World Oil Price Case								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
Marketed Fuel Consumption									
Total Fuel Use	**5.75**	**6.15**	**6.24**	**6.40**	**6.56**	**6.71**	**6.87**	**7.01**	**7.54**
Liquefied Petroleum Gas	**.05**	**.03**	**.03**	**.03**	**.03**	**.03**	**.03**	**.03**	**.02**
Motor Gasoline	**.09**	**.09**	**.08**	**.08**	**.08**	**.08**	**.08**	**.08**	**.08**
Fuel Oil[1]									
Office[2]	.26	.31	.30	.32	.34	.36	.37	.39	.45
Retail/Wholesale	.17	.20	.19	.21	.22	.23	.24	.25	.28
Warehouse	.12	.15	.15	.17	.18	.20	.21	.22	.28
Other Buildings[3]	.22	.25	.25	.26	.28	.29	.30	.32	.37
Total	**.77**	**.91**	**.90**	**.95**	**1.01**	**1.07**	**1.13**	**1.18**	**1.38**
Natural Gas									
Office[2]	.74	.75	.75	.76	.77	.78	.78	.78	.76
Retail/Wholesale	.75	.77	.78	.79	.81	.82	.83	.84	.85
Warehouse	.35	.36	.36	.37	.37	.38	.38	.38	.36
Other Buildings[3]	.76	.78	.78	.78	.79	.79	.79	.79	.74
Total	**2.60**	**2.66**	**2.67**	**2.71**	**2.74**	**2.76**	**2.78**	**2.79**	**2.71**
Coal	**.12**	**.11**	**.12**	**.12**	**.12**	**.12**	**.11**	**.11**	**.11**
Electricity									
Office[2]	.81	.90	.93	.96	.98	1.01	1.04	1.08	1.24
Retail/Wholesale	.61	.68	.71	.73	.75	.78	.80	.83	.96
Warehouse	.29	.32	.33	.34	.35	.36	.37	.39	.44
Other Buildings[3]	.41	.46	.47	.48	.49	.50	.52	.53	.60
Total	**2.12**	**2.36**	**2.45**	**2.51**	**2.58**	**2.66**	**2.74**	**2.82**	**3.24**
Commercial Activity									
Building Floorspace Stock									
(billion square feet)	48.5	51.1	52.6	53.8	55.3	56.8	58.4	59.9	66.8
Office[2]	17.0	18.0	18.6	19.0	19.5	20.0	20.6	21.1	23.7
Retail/Wholesale	14.5	15.4	15.9	16.3	16.8	17.3	17.9	18.4	20.8
Warehouse	6.9	7.2	7.5	7.7	7.9	8.1	8.3	8.6	9.6
Other Buildings[3]	10.1	10.5	10.7	10.9	11.1	11.3	11.5	11.7	12.8
Energy Use Per Square Foot									
(thousand Btu)	118.6	120.4	118.6	118.9	118.6	118.2	117.6	117.2	112.9
Expenditures Per Square Foot									
(1984 dollars)	1.30	1.31	1.29	1.30	1.32	1.33	1.33	1.34	1.41

[1] The commercial fuel oil category includes kerosene, distillate fuel, and residual fuel.
[2] Office includes offices, educational buildings, laboratories, health clinics, and some public buildings.
[3] Other Buildings includes assembly buildings, hotels/motels, hospitals, parking garages, and jails.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: The Commercial model is documented in *Model Documentation: Commercial Sector Energy Model*, Energy Information Administration (DOE/EIA-0453), August 1984. The major model source is the public use tape of the Nonresidential Energy Consumption Survey 1980, Energy Information Administration.
Input data file: Historical = MRG1126T, Projected = Low World Oil Price Case, printed on December 21, 1984.
Historical quantities through 1983.

Table D8. Industrial Energy Use
(Quadrillion Btu per Year)

Fuel and End Use	Low World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Industrial Heat and Power											
Distillate Fuel	1.44	1.70	1.29	1.60	1.60	1.62	1.68	1.72	1.77	1.82	1.98
Residual Fuel	1.58	1.40	.65	.85	.85	.85	.90	.94	.98	1.02	1.16
Liquefied Petroleum Gas	.13	.20	.57	.33	.35	.34	.35	.36	.36	.37	.38
Natural Gas[1]	8.50	7.08	5.56	6.08	6.21	6.23	6.43	6.55	6.52	6.49	6.20
Steam Coal[2]	1.43	1.46	1.50	1.72	1.75	1.91	1.99	2.08	2.16	2.24	2.52
Electricity[3]	2.34	2.76	2.65	2.63	2.66	2.75	2.91	3.09	3.24	3.42	4.20
Total	**15.43**	**14.61**	**12.21**	**13.21**	**13.43**	**13.70**	**14.26**	**14.74**	**15.04**	**15.37**	**16.44**
Refinery Fuel											
Distillate Fuel	.03	.05	.01	.01	.01	.01	.01	.01	.01	.01	.01
Residual Fuel	.28	.31	.13	.13	.13	.13	.13	.13	.14	.14	.17
Liquefied Petroleum Gas	.04	.06	.03	.03	.03	.03	.03	.03	.03	.03	.03
Still Gas	1.06	1.20	1.13	1.16	1.21	1.22	1.23	1.24	1.25	1.27	1.39
Petroleum Coke	.40	.39	.40	.42	.42	.42	.42	.43	.43	.44	.48
Other Petroleum	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Electricity	NA	NA	NA	.12	.12	.12	.12	.12	.12	.12	.13
Natural Gas	1.11	.82	.59	.66	.63	.63	.64	.64	.65	.66	.71
Total	**2.92**	**2.84**	**2.28**	**2.52**	**2.53**	**2.55**	**2.57**	**2.59**	**2.63**	**2.67**	**2.93**
Feedstocks, Raw Materials, and Other Fuel Uses											
Motor Gasoline	.26	.18	.14	.13	.14	.16	.18	.20	.22	.25	.40
Kerosene	.16	.16	.14	.10	.09	.09	.09	.09	.09	.09	.08
Petroleum Feedstocks[4]	.73	1.22	.85	1.38	1.50	1.49	1.58	1.65	1.66	1.67	1.64
Liquefied Petroleum Gas[5]	1.07	.99	1.01	1.17	1.21	1.25	1.39	1.50	1.58	1.65	1.98
Special Naphthas	.17	.20	.16	.21	.24	.26	.28	.29	.30	.31	.34
Lubricants and Waxes	.23	.23	.20	.23	.26	.26	.27	.28	.28	.29	.30
Petroleum Coke	.16	.16	.10	.13	.18	.20	.23	.25	.28	.32	.51
Asphalt and Road Oil	1.26	1.16	.90	1.01	1.13	1.17	1.21	1.24	1.26	1.28	1.35
Net Blending Oil[6]	.12	.27	.06	-.01	-.13	-.18	-.21	-.22	-.24	-.26	-.26
Metallurgical Coal[2]	2.54	1.79	.96	1.15	1.19	1.25	1.32	1.37	1.38	1.38	1.34
Natural Gas Raw Materials[7]	.78	.63	.49	.55	.55	.56	.57	.57	.57	.57	.56
Net Coke Imports	-.01	.13	-.02	.00	.00	.00	.00	.00	.00	.00	.00
Hydropower	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03
Total	**7.49**	**7.15**	**5.03**	**6.06**	**6.39**	**6.54**	**6.93**	**7.25**	**7.43**	**7.59**	**8.26**
Total Industrial Demand	**25.84**	**24.60**	**19.52**	**21.78**	**22.35**	**22.79**	**23.76**	**24.58**	**25.09**	**25.63**	**27.62**

[1] Includes lease and plant fuel.
[2] Includes refinery steam coal. The metallurgical coal estimates for 1983 and 1984 are not fully comparable, in part because of different Btu conversion factors.
[3] Includes refinery electricity before 1984.
[4] Petrochemical feedstocks includes naphthas less than 400 degrees, other oils greater than 400 degrees, and some still gas.
[5] The LPG price for Industrial Heat and Power is used for LPG feedstocks in weighted average price calculations.
[6] Net blending oil includes jet fuel, plant condensate, unfractionated stream, some still gas, miscellaneous, natural gasoline, unfinished oils, aviation blending components, and motor gasoline blending components, net of oil reclassified in blending.
[7] The natural gas price for Industrial Heat and Power is used for natural gas raw materials in weighted average price calculations.
[NA] = Not available.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: The Industrial model is documented in *Documentation of the PURHAPS Industrial Demand Model, Vol 1: Model Description, Overview, and Assumptions for the 1983 Annual Energy Outlook*, DOE/EIA-0420/1 (Washington, DC, 1984).
Input data file: Historical = MRG1126T, Projected = Low World Oil Price Case, printed on December 21, 1984.
Historical quantities through 1983.

Table D9. Transportation Sector Energy Use By Mode

Fuel and Mode of Transportation	Low World Oil Price Case								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
All Modes[1]									
Aviation Gasoline	0.05	0.07	0.08	0.08	0.09	0.09	0.09	0.10	0.11
Distillate Fuel	2.84	2.67	2.63	2.69	2.78	2.89	3.00	3.13	3.97
Jet Fuel	2.14	2.35	2.37	2.48	2.59	2.66	2.74	2.81	3.01
Motor Gasoline	12.47	12.67	12.71	12.39	12.17	12.03	11.96	11.96	12.21
Residual Fuel	.75	.74	.71	.73	.76	.79	.81	.84	.94
Liquefied Petroleum Gas	.03	.01	.01	.01	.01	.01	.01	.01	.01
Lubricants	.16	.22	.26	.26	.26	.27	.28	.28	.32
Natural Gas	.58	.61	.62	.61	.62	.63	.64	.64	.63
Electricity	.01	.01	.01	.01	.01	.01	.01	.01	.01
Total Consumption	**19.02**	**19.35**	**19.38**	**19.26**	**19.29**	**19.37**	**19.54**	**19.77**	**21.20**
Automobiles									
Vehicle-Miles Travelled[2]	1149.7	1,252.8	1,336.9	1,367.7	1,405.2	1,445.7	1,491.7	1,541.8	1,791.9
Fleet-Miles per Gallon	16.5	17.5	18.4	19.2	20.0	20.7	21.3	21.9	24.1
Total Fuel Use[3]	69.5	71.6	72.7	71.2	70.3	69.9	70.0	70.5	74.5
Trucks									
Vehicle-Miles Travelled[2]	449.1	484.6	498.3	509.3	522.5	537.8	554.9	573.7	689.4
Fleet-Miles per Gallon	10.5	11.1	11.5	12.0	12.4	12.8	13.1	13.5	14.9
Total Fuel Use[3]	42.6	43.8	43.2	42.6	42.2	42.1	42.3	42.7	46.4
Air									
Revenue Passenger-Miles[2]	300.1	354.3	377.4	412.5	451.5	485.2	522.4	558.0	722.6
Fuel Burned Per Seat-Mile[4]	.023	.022	.022	.021	.020	.019	.018	.017	.014
Total Jet Fuel[3]	16.0	17.6	17.7	18.5	19.4	19.9	20.5	21.0	22.5
Aviation Gasoline[3]	.4	.6	.7	.7	.7	.8	.8	.8	.9
Selected Fuel Expenditures[5]									
Motor Gasoline	128.4	128.0	114.0	111.1	109.3	110.8	110.0	109.6	128.3
Distillate Fuel	27.2	24.9	22.0	22.6	23.4	24.9	26.0	27.2	38.6

[1] Quadrillion Btu per year.
[2] Billion per year.
[3] Billion gallons per year.
[4] Gallons.
[5] Billion 1984 dollars per year.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Input data file: Historical = MRG1126T, Projected = Low World Oil Price Case, printed on December 28, 1984.
Historical quantities through 1983.

Table D10. Electric Utility Fuel Consumption and Electricity Sales
(Quadrillion Btu per Year)

Fuel Consumption and Sales	Low World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Fuel Inputs											
Oil											
Distillate	0.27	0.28	0.10	0.11	0.05	0.03	0.02	0.03	0.04	0.05	0.22
Residual LS[1]	NA	NA	NA	.69	.65	.71	.70	.74	.72	.85	1.76
Residual HS[1]	3.24	3.71	1.45	.51	.48	.44	.42	.43	.37	.46	.71
Natural Gas	3.75	3.30	3.01	3.27	3.33	3.11	3.17	3.27	3.48	3.42	3.62
Steam Coal	8.66	10.25	13.23	14.05	14.94	15.01	15.33	15.69	16.22	16.93	20.11
Nuclear Power	.91	3.02	3.23	3.70	4.10	4.72	5.31	5.79	6.09	6.32	7.09
Hydropower/Other[2]	2.87	2.97	3.61	3.55	3.11	3.29	3.30	3.30	3.32	3.33	3.37
Total Fuel Inputs	19.71	23.53	24.63	25.87	26.66	27.30	28.24	29.25	30.23	31.36	36.87
Net Imports	.15	.20	.37	.41	.43	.48	.53	.58	.64	.70	.78
Total Electricity Inputs	**19.85**	**23.74**	**25.00**	**26.27**	**27.09**	**27.78**	**28.77**	**29.83**	**30.87**	**32.06**	**37.66**
Disposition											
Total Electricity Inputs	19.85	23.74	25.00	26.27	27.09	27.78	28.77	29.83	30.87	32.06	37.66
Minus Conversion Losses[3]	13.50	16.21	17.12	17.99	18.58	19.04	19.73	20.47	21.20	22.02	25.86
Generation	6.35	7.53	7.88	8.28	8.50	8.74	9.04	9.36	9.67	10.04	11.80
Minus Transportation and Distribution Losses	.51	.64	.55	.57	.58	.62	.63	.63	.64	.65	.76
Electricity Sales	**5.84**	**6.89**	**7.34**	**7.72**	**7.92**	**8.11**	**8.41**	**8.73**	**9.04**	**9.40**	**11.04**
Electricity Sales by End-Use Sector											
Residential	1.98	2.30	2.56	2.61	2.68	2.73	2.79	2.86	2.93	3.02	3.46
Commercial/Other[4]	1.53	1.82	2.13	2.37	2.46	2.52	2.59	2.67	2.75	2.83	3.25
Industrial	2.34	2.76	2.65	2.74	2.78	2.86	3.03	3.21	3.36	3.55	4.33
Total Electricity Sales	**5.84**	**6.89**	**7.34**	**7.72**	**7.92**	**8.11**	**8.41**	**8.73**	**9.04**	**9.40**	**11.04**

[1] Prior to 1984, only the total of high-sulfur and low-sulfur residual oil is available, and is reported here as high-sulfur.
[2] Includes renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[3] Conversion losses includes net imports.
[4] Commercial/Other includes street lighting and the transportation sector.
[NA] = Not available.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Input data file: Historical = MRG1126T, Projected = Low World Oil Price Case, printed on December 21, 1984. Historical quantities through 1983.

Table D11. Electric Utility Sectoral Prices and Demands
(Billion Kilowatthours per Year)
(1984 Dollars per Thousand Kilowatthours)

Prices and Demands	Low World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Prices[1]											
Residential	53.70	64.16	66.69	66.96	67.25	67.86	68.32	68.23	67.37	66.65	65.02
Commercial[2]	51.28	66.28	67.39	67.53	67.94	68.71	69.34	69.38	68.45	67.67	66.05
Industrial	26.34	41.59	56.62	56.85	57.05	57.67	58.17	58.04	57.19	56.45	54.80
All Sectors	**42.11**	**55.67**	**63.26**	**63.54**	**63.88**	**64.52**	**64.98**	**64.84**	**63.91**	**63.11**	**61.31**
Demands											
Residential	579	674	751	764	785	800	818	837	858	884	1,015
Commercial[2]	448	534	624	695	721	738	760	782	805	830	952
Industrial	686	809	776	804	815	840	888	940	985	1,039	1,270
All Sectors	**1,713**	**2,018**	**2,151**	**2,262**	**2,321**	**2,378**	**2,466**	**2,558**	**2,648**	**2,754**	**3,237**

[1] Prices for 1983 to 1995 are from model simulations and represent average revenues per kilowatthour of demand for the total electric utility industry. Revenue requirements are projected from the financial information contained on the Federal Energy Regulatory Commission Form 1 and Form 1-M and on the Energy Information Administration Form 412.
[2] This category includes consumption for street and highway lighting, other public authorities, and railroads and railways.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Prices for 1973 and 1978 are from the Energy Information Administration, *State Energy Price and Expenditure Report*, DOE/EIA-0376(81) (Washington, DC, 1984), pp.1-7. Historical demands are from the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83), (Washington, DC, 1984).

Table D12. Electric Utility Capacity and Generation

(Generation in Billion Kilowatthours per Year)

(Capacity in Million Kilowatts)

Capacity and Generation	Low World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Capacity[1]											
Coal Steam	164.0	233.9	285.9	296.0	303.8	309.6	314.2	317.3	323.7	328.5	360.7
Other Steam	135.0	161.4	157.2	157.2	157.2	157.2	157.2	157.2	157.2	157.2	157.2
Combined Cycle	1.3	4.9	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.8	5.8
Turbine	37.1	49.6	50.7	51.0	51.4	51.6	51.6	51.7	52.3	52.7	60.5
Nuclear Power	21.0	53.5	64.4	68.9	80.5	91.4	99.8	104.7	105.9	109.6	116.8
Hydropower/Other[2]	55.6	63.2	69.0	69.8	71.0	71.4	71.6	72.0	72.2	72.9	73.1
Pumped Storage Hydropower[3]	8.4	12.7	13.3	14.6	16.0	16.7	16.7	16.9	18.8	19.1	19.2
Total Capacity	442.4	579.2	**646.2**	**663.2**	**685.5**	**703.5**	**716.8**	**725.5**	**735.8**	**745.8**	**793.4**
Generation by Plant Type[4]											
Coal Steam	848	976	1,268	1,347	1,428	1,436	1,469	1,503	1,555	1,624	1,934
Other Steam	619	629	365	369	356	349	350	364	376	389	485
Combined Cycle	NA	13	32	33	32	28	28	28	29	31	31
Turbine	36	29	13	15	15	14	14	16	15	16	53
Nuclear Power	83	276	294	335	372	428	482	526	553	574	644
Hydropower/Other[2]	274	284	345	336	295	315	315	316	318	321	324
Pumped Storage Hydropower[3]	NA	NA	-6	-6	-6	-9	-9	-10	-10	-11	-12
Total Generation	**1,861**	**2,206**	**2,310**	**2,428**	**2,492**	**2,561**	**2,650**	**2,744**	**2,835**	**2,943**	**3,459**
Generation by Fuel Type											
Coal[5]	848	976	1,259	1,341	1,422	1,430	1,462	1,497	1,548	1,617	1,927
Natural Gas	341	305	274	299	301	285	291	300	319	314	324
Oil	314	365	144	124	109	112	109	114	107	129	252
Nuclear Power	83	276	294	335	372	428	482	526	553	574	644
All Hydropower/Other[6]	274	283	339	329	289	306	306	306	308	309	313
Total Generation	**1,861**	**2,206**	**2,310**	**2,428**	**2,492**	**2,561**	**2,650**	**2,744**	**2,835**	**2,943**	**3,459**

[1] Capacity for 1973 and 1978 include capacity out of service or in inactive reserve; 1983 and projected capacity exclude capacity out of service or in inactive reserve. Three Mile Island Unit 1 is included in the 1983 and 1984 capacity estimates but is not expected to restart opetation until 1985.

[2] This category includes other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

[3] See Glossary, Electricity Terminology for definition of pumped storage plant.

[4] Net generation data for 1973 excludes combined cycle generation. For 1973 and 1978 the hydropower/other category also contains pumped storage hydropower. The 1983 values are model estimates based on the best available data.

[5] Generation by coal and generation by coal steam plants are not identical because small amounts of oil and natural gas are used in coal steam plants for startup and flame stability.

[6] This category includes conventional and pumped storage hydropower and other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Generation data for 1973, 1978, and 1983 are from the Energy Information Administration, *Form EIA-759, "Monthly Power Plant Report."* Historical capacity data for 1973 and 1978 are based on the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984). Other capacity data are from the Intermediate Future Forecasting System.

Table D13. Electric Utility Capacity Additions
(Thousand Kilowatts)

Additions: Pipeline and New Starts	Low World Oil Price Case												
	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Total Additions													
Nuclear Power[1]	3,064	4,480	12,369	10,939	8,391	4,884	1,235	3,702	3,690	2,464	1,065	0	0
Coal Steam	5,720	10,082	7,783	5,860	4,586	3,109	6,394	4,782	10,654	5,025	7,023	4,269	5,254
Other Steam[2]	61	3	0	0	0	0	0	100	0	0	0	0	0
Turbines[3]	202	275	385	197	40	130	561	343	330	599	1,222	2,928	2,742
Pumped Storage Hydropower[4]	260	1,264	1,400	700	0	200	1,923	285	0	0	0	150	0
Hydropower/Other[5]	1,034	874	1,163	383	242	407	200	706	75	74	26	0	6
Total New Capacity	**10,342**	**16,978**	**23,100**	**18,078**	**13,258**	**8,729**	**10,313**	**9,919**	**14,749**	**8,162**	**9,336**	**7,347**	**8,002**
Pipeline[6]													
Nuclear Power[1]	3,064	4,480	12,369	10,939	8,391	4,884	1,235	3,702	3,690	2,464	1,065	0	0
Coal Steam	5,720	10,082	7,783	5,860	4,586	3,109	6,394	4,782	10,654	5,025	5,718	2,764	3,347
Other Steam[2]	61	3	0	0	0	0	0	100	0	0	0	0	0
Turbines[3]	202	275	385	197	40	130	561	343	330	113	200	0	143
Pumped Storage Hydropower[4]	260	1,264	1,400	700	0	200	1,923	285	0	0	0	150	0
Hydropower/Other[5]	1,034	874	1,163	383	242	407	200	706	75	74	26	0	6
Total Pipeline	**10,342**	**16,978**	**23,100**	**18,078**	**13,258**	**8,729**	**10,313**	**9,919**	**14,749**	**7,676**	**7,009**	**2,914**	**3,496**
New Starts[7]													
Nuclear Power[1]	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal Steam	0	0	0	0	0	0	0	0	0	0	1,305	1,506	1,907
Other Steam[2]	0	0	0	0	0	0	0	0	0	0	0	0	0
Turbines[3]	0	0	0	0	0	0	0	0	0	486	1,022	2,928	2,599
Pumped Storage Hydropower[4]	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydropower/Other[5]	0	0	0	0	0	0	0	0	0	0	0	0	0
Total New Starts	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**486**	**2,327**	**4,433**	**4,506**

[1] Includes the scheduled return to service of the Three Mile Island 1 facility.
[2] Includes natural gas, oil, and dual fired oil/natural gas steam and combined cycle capacity.
[3] Includes all gas turbine and internal combustion capacity.
[4] See Glossary, Electricity Terminology for definition of pumped storage plant.
[5] Includes conventional hydroelectric and other renewable sources of power such as geothermal, wood, waste, solar, and wind.
[6] Includes all new capacity announced by the electric utility industry.
[7] Includes additional new capacity considered necessary to meet projected electricity demands.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: The Energy Information Administration Generating Unit Reference file (GURF); the Federal Energy Regulatory Commission, *Hydroelectric Power Resources of the United States - Developed and Undeveloped*, FERC-0070, January 1, 1980; Energy Information Administration, *U.S. Commercial Nuclear Power*, DOE/EIA-0315 (Washington, DC, March 1982); and the Energy Information Administration Form-254: "Quarterly Progress Report on Status of Reactor Construction."

Table D14. Summary of Components of Electricity Price
(1984 Dollars per Thousand Kilowatthours)

Price Components	Low World Oil Price Case												
	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Capital Component[1]	25.44	25.52	25.50	26.27	26.61	26.20	24.96	23.71	22.82	21.95	20.93	19.96	19.07
Fuel Component[2]	22.65	22.81	22.87	22.46	22.59	23.02	23.49	24.12	24.79	25.51	26.17	26.86	27.70
O&M Component[3]	15.25	15.21	15.51	15.79	15.77	15.61	15.46	15.28	15.13	15.01	14.85	14.70	14.54
Total Price[4]	**63.34**	**63.54**	**63.88**	**64.52**	**64.98**	**64.84**	**63.91**	**63.11**	**62.73**	**62.47**	**61.94**	**61.52**	**61.31**

[1] The capital component represents the cost to the utility of capital assets needed to provide reliable service. It includes plant depreciation, taxes, and sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.
[2] The fuel component includes only the direct costs of fuel inputs used to generate electricity required to meet demand.
[3] The operation and maintenance (O&M) component includes all nonfuel costs necessary to operate and maintain generation, transmission, and distribution capacity used to deliver electricity to end-use sectors.
[4] All prices are from model simulations and represent average revenues per kilowatthour of demand for the total electric utility industry. Revenue requirements are projected from the financial information contained on the Federal Energy Regulatory Commission, Form FERC-1 and Form 1-M and on the Energy Information Administration, Form EIA-412.
NOTE: Total may not equal sum of components because of independent rounding.

Table D15. Petroleum Supply and Disposition Balance
(Million Barrels per Day)

Supply and Disposition	Low World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Crude Oil[1]	9.21	8.71	8.69	8.76	8.86	8.65	8.49	8.26	7.99	7.80	5.37
Alaska North Slope	.00	1.09	1.65	1.67	1.70	1.76	1.92	1.92	1.92	1.97	1.00
Subarctic	9.21	7.62	7.04	7.08	7.15	6.89	6.57	6.34	6.06	5.82	4.37
Natural Gas Plant Liquids	1.74	1.57	1.56	1.61	1.64	1.48	1.44	1.51	1.50	1.46	1.28
Other Domestic[2]	.00	.00	.05	.05	.05	.05	.05	.05	.07	.09	.36
Processing Gain[3]	.45	.50	.49	.55	.54	.51	.51	.52	.53	.54	.61
Total Production	**11.40**	**10.78**	**10.79**	**10.97**	**11.09**	**10.69**	**10.50**	**10.35**	**10.09**	**9.89**	**7.61**
Imports (including SPR)											
Crude Oil[4]	3.24	6.36	3.33	3.48	4.29	4.62	4.94	5.29	5.71	6.12	9.41
Refined Products	3.01	2.01	1.72	1.95	1.40	1.63	1.84	1.95	2.02	2.23	3.11
Total Imports	6.26	8.36	5.05	5.43	5.68	6.25	6.78	7.24	7.73	8.34	12.52
Exports											
Crude Oil	.00	.16	.16	.18	.17	.17	.17	.17	.17	.17	.17
Refined Products	.23	.20	.58	.49	.45	.61	.61	.61	.61	.61	.61
Total Exports	.23	.36	.74	.67	.62	.78	.78	.78	.78	.78	.78
Net Imports (including SPR)	**6.02**	**8.00**	**4.31**	**4.76**	**5.06**	**5.46**	**6.00**	**6.45**	**6.94**	**7.56**	**11.74**
Primary Stock Changes											
Net Withdrawals[5]	-.14	.26	.25	.04	.00	-.01	-.06	-.07	-.06	-.07	-.07
SPR Fill Rate Additions (-)[6]	.00	-.16	-.23	-.18	-.14	-.14	-.14	-.14	-.14	-.14	.00
Total Primary Supply[7]	**17.29**	**18.87**	**15.11**	**15.59**	**16.00**	**16.01**	**16.29**	**16.59**	**16.83**	**17.24**	**19.27**
Refined Petroleum Products											
Motor Gasoline	6.67	7.41	6.62	6.72	6.74	6.58	6.48	6.42	6.39	6.41	6.62
Aviation Gasoline	.05	.04	.03	.04	.04	.05	.05	.05	.05	.05	.06
Jet Fuel[8]	1.06	1.06	1.05	1.15	1.16	1.21	1.26	1.30	1.34	1.37	1.47
Kerosene	.22	.18	.13	.11	.10	.10	.11	.11	.11	.12	.12
Distillate Fuel	3.09	3.43	2.69	2.88	2.81	2.87	2.97	3.07	3.17	3.28	3.87
Residual Fuel	2.82	3.02	1.42	1.42	1.40	1.40	1.43	1.49	1.50	1.64	2.30
Liquid Petroleum Gas	1.45	1.41	1.49	1.36	1.42	1.46	1.57	1.67	1.74	1.80	2.05
Petrochemical Feedstocks	.36	.59	.42	.68	.73	.73	.77	.81	.81	.82	.80
Other Petroleum Products[9]	1.59	1.70	1.37	1.50	1.59	1.61	1.64	1.68	1.72	1.76	1.98
Total Product Supplied	**17.31**	**18.85**	**15.23**	**15.86**	**16.00**	**16.01**	**16.29**	**16.59**	**16.83**	**17.24**	**19.27**

See footnotes at end of table.

Table D15. Petroleum Supply and Disposition Balance (Continued)
(Million Barrels per Day)

Supply and Disposition	Low World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Refined Petroleum Products Supplied to End-Use Sectors											
Residential and Commercial	2.23	2.07	1.20	1.29	1.27	1.32	1.37	1.41	1.45	1.48	1.56
Industrial[10]	4.48	4.87	4.03	4.52	4.69	4.76	5.01	5.21	5.37	5.53	6.19
Transportation	9.05	10.14	9.33	9.48	9.49	9.42	9.42	9.45	9.52	9.63	10.32
Electric Utilities	1.54	1.75	.68	.57	.51	.51	.50	.52	.49	.59	1.18
Total End-Use Consumption	**17.30**	**18.84**	**15.23**	**15.86**	**15.97**	**16.01**	**16.30**	**16.59**	**16.84**	**17.24**	**19.25**
Discrepancy[11]	-.01	.04	-.12	-.27	.03	.00	-.01	.00	.00	-.01	.02
Net Disposition[12]	**17.29**	**18.87**	**15.11**	**15.59**	**16.00**	**16.01**	**16.29**	**16.59**	**16.83**	**17.24**	**19.27**

[1] Includes lease condensate.

[2] Other Domestic prior to 1981 includes unfinished oils (net), hydrogen, and hydrocarbons not included elsewhere. After 1981, Other Domestic includes unfinished oils (net), motor gasoline blending components (net), aviation gasoline blending components (net), hydrogen, other hydrocarbons, alcohol, and synthetic crude production.

[3] Represents volumetric gain in refinery distillation and cracking processes.

[4] In 1977 and later years, crude oil imports include crude oil imported for the Strategic Petroleum Reserve.

[5] Net stock withdrawals for a given year, t, are defined as the change in yearend stock levels from period t-1 minus the yearend stock level from the year t. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.

[6] SPR is the Strategic Petroleum Reserve.

[7] Total primary supply is defined as total production plus net imports plus net stock withdrawals minus SPR additions.

[8] Jet fuel includes naphtha and kerosene type.

[9] Other petroleum products includes miscellaneous petroleum products, lubricants, waxes, unfractionated stream, plant condensate, natural gasoline, asphalt, road oil, still gas, special naphthas, and petroleum coke.

[10] Industrial refined products includes total industrial demand for petroleum as reported in Table 8.

[11] Discrepancy represents the difference between total supply and total products supplied.

[12] Net disposition is the sum of total products supplied and discrepancy.

NOTE: From 1981 onward, the product supplied data is on a new basis. From 1983 onward, the other product category is on a net basis, reclassified (petroleum products reprocessed into other categories) plus the other category of products supplied.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Historical data are from Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984) pp. 79-99, Tables 35, 36, 37, and 45. Projected values are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = MRG1126T, Projected = Low World Oil Price Case, printed on December 28, 1984.

Historical quantities through 1983.

Table D16. Petroleum Product Prices
(1984 Dollars per Barrel)

Sector and Fuel	Low World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Crude Oil Prices											
World Oil Price[1]	**8.62**	**21.63**	**30.39**	**29.00**	**24.00**	**24.00**	**24.00**	**25.00**	**25.00**	**25.00**	**30.00**
Refiner Acquisition Cost[2]	**8.77**	**18.50**	**30.39**	**29.00**	**24.00**	**24.00**	**24.00**	**25.00**	**25.00**	**25.00**	**30.00**
Delivered Sector Product Prices											
Residential and Commercial											
Distillate Fuel	19.35	29.95	43.90	42.49	36.82	36.94	36.94	38.11	38.22	38.40	44.15
Kerosene	20.04	32.11	44.72	41.07	35.24	35.30	35.25	36.37	36.43	36.56	42.24
Motor Gasoline[3]	34.52	41.22	54.27	53.26	47.33	47.35	47.42	48.64	48.61	48.45	55.52
Residual Fuel	11.44	20.53	34.41	33.30	29.79	30.22	30.43	31.40	31.78	32.41	36.18
Liquefied Petroleum Gas[4]	26.12	24.96	32.87	27.76	24.12	24.26	24.32	25.16	25.28	25.45	29.51
Average[5]	**20.23**	**28.21**	**40.89**	**39.29**	**34.07**	**34.19**	**34.20**	**35.26**	**35.38**	**35.59**	**40.84**
Industrial											
Distillate Fuel	11.52	24.55	38.01	36.57	30.94	31.10	31.15	32.37	32.53	32.75	38.70
Kerosene	12.09	26.14	39.01	37.56	31.85	32.02	32.09	33.33	33.51	33.75	39.86
Motor Gasoline[3]	34.75	41.07	54.52	53.51	47.57	47.58	47.64	48.84	48.79	48.62	55.59
Residual Fuel	10.65	19.86	28.46	27.35	23.76	24.19	24.43	25.44	25.83	26.48	30.20
Liquefied Petroleum Gas	11.19	18.98	28.58	24.38	20.63	20.74	20.78	21.59	21.70	21.85	25.84
Petrochemical Feedstocks[6]	11.05	23.78	34.53	33.08	27.33	27.39	27.45	28.67	28.83	29.06	35.09
Asphalt & Road Oil	13.12	27.97	26.38	25.75	23.77	24.03	24.17	24.73	24.96	25.34	27.53
Petroleum Coke	11.91	25.39	7.67	7.61	7.39	7.43	7.46	7.53	7.57	7.63	7.94
Special Naphthas	10.38	22.12	34.27	32.99	27.93	28.08	28.14	29.25	29.40	29.61	35.03
Miscellaneous Petroleum Products	12.35	26.10	33.86	32.27	26.86	26.99	27.02	28.17	28.34	28.61	34.16
Average[5]	**12.25**	**23.19**	**30.27**	**28.56**	**24.32**	**24.46**	**24.52**	**25.43**	**25.58**	**25.80**	**29.93**
Transportation[7]											
Distillate Fuel	20.27	29.35	55.82	54.39	48.77	48.95	49.01	50.24	50.41	50.65	56.69
Aviation Gasoline	40.10	52.84	70.43	68.78	59.12	59.14	59.23	61.20	61.11	60.84	72.23
Motor Gasoline[3]	34.39	40.85	54.08	53.06	47.12	47.12	47.18	48.39	48.33	48.16	55.16
Jet Fuel[8]	11.48	25.41	37.94	36.37	30.49	30.44	30.56	31.83	32.03	32.29	38.58
Residual Fuel[9]	8.47	14.12	22.66	21.57	18.10	18.55	18.78	19.76	20.17	20.82	24.67
Liquefied Petroleum Gas	10.75	17.55	30.54	36.37	32.60	32.72	32.77	33.59	33.70	33.86	37.91
Lubricants[10]	75.70	90.23	148.87	146.32	136.31	136.62	136.73	138.92	139.23	139.65	150.39
Average[5]	**29.51**	**37.09**	**52.13**	**51.17**	**45.49**	**45.43**	**45.40**	**46.57**	**46.56**	**46.52**	**53.28**
Electric Utilities											
Distillate Fuel	10.92	21.53	45.38	41.43	34.47	28.20	29.38	34.81	36.10	35.01	39.03
Residual Fuel	10.37	19.91	29.51	28.49	25.07	25.97	26.33	27.36	27.95	28.50	34.01
Average[5]	**10.42**	**20.03**	**30.57**	**29.67**	**25.51**	**26.02**	**26.39**	**27.58**	**28.24**	**28.74**	**34.45**
Refined Petroleum Product Prices											
Distillate Fuel	17.57	28.12	48.50	46.10	40.46	40.64	40.70	41.94	42.14	42.40	48.75
Kerosene	17.27	29.55	41.70	39.55	33.83	33.99	34.00	35.19	35.32	35.53	41.47
Aviation Gasoline	40.10	52.84	70.43	68.78	59.12	59.14	59.23	61.20	61.11	60.84	72.23
Motor Gasoline[3]	34.40	40.85	54.08	53.06	47.12	47.13	47.19	48.40	48.34	48.17	55.18
Jet Fuel[8]	11.48	25.41	37.94	36.37	30.49	30.44	30.56	31.83	32.03	32.29	38.58
Residual Fuel	10.35	19.12	28.14	27.07	23.58	24.20	24.45	25.47	25.89	26.62	31.59
Liquefied Petroleum Gas	16.46	20.88	29.37	24.96	21.22	21.34	21.35	22.15	22.25	22.39	26.31
Lubricants (Transportation)[10]	75.70	90.23	148.87	146.32	136.31	136.62	136.73	138.92	139.23	139.65	150.39
Petrochemical Feedstocks[6]	11.05	23.78	34.53	33.08	27.33	27.39	27.45	28.67	28.83	29.06	35.09
Asphalt & Road Oil	13.12	27.97	26.38	25.75	23.77	24.03	24.17	24.73	24.96	25.34	27.53
Petroleum Coke	11.91	25.39	7.67	7.61	7.39	7.43	7.46	7.53	7.57	7.63	7.94
Special Naphthas	10.38	22.12	34.27	32.99	27.93	28.08	28.14	29.25	29.40	29.61	35.03
Miscellaneous Petroleum Products	12.35	26.10	33.86	32.27	26.86	26.99	27.02	28.17	28.34	28.61	34.16

[1] The cost of imported crude oil to U.S. refiners in 1984 dollars per barrel.
[2] Refiner acquisition cost is an average of imported and domestic refiner acquisition costs.
[3] Gasoline price is an average price for all types.
[4] Residential and commercial liquefied petroleum gas price includes only a residential price due to data limitations.
[5] Weighted average price; the weights are taken from the consumption categories from Table 4 and converted to physical units.
[6] Petrochemical feedstock price includes only the price of naphthas less than 400 degrees.
[7] Transportation prices include the appropriate State road use taxes and Federal excise tax.
[8] Jet fuel price is a retail price for kerosene type jet fuel.
[9] Residual fuel price in the transportation sector is for marine bunker.
[10] Lubricant price is an average for light stocks and multiweight motor oil.

NOTE: Implicit Gross National Product Price Deflator, rebased to 1984 = 1.0, was used to convert from nominal to real dollars.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical prices are taken from Energy Information Administration, *State Energy Price and Expenditure Report,* DOE/EIA-0376(81) (Washington, DC, 1984), pp. 1-7. Projected values are output from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = Low World Oil Price Case, printed on December 22, 1984.
Historical quantities through 1983.

Table D17. Natural Gas Supply, Disposition, and Prices
(Trillion Cubic Feet per Year)
(1984 Dollars per Thousand Cubic Feet)

Supply, Disposition, and Prices	Low World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Dry Gas Production[1]	21.73	19.12	15.97	17.43	17.48	16.77	17.59	17.69	17.46	17.27	16.05
Supplemental Natural Gas[2]	.00	.00	.14	.15	.15	.69	.20	.33	.48	.49	1.02
Net Imports	.96	.91	.87	.86	.99	1.05	1.04	1.11	1.41	1.51	1.97
Net Storage Withdrawals[3]	-.42	-.15	.47	.03	.03	.00	.00	.00	.00	.00	.00
Total Supply[4]	**22.27**	**19.88**	**17.45**	**18.47**	**18.65**	**18.51**	**18.83**	**19.13**	**19.35**	**19.28**	**19.04**
Consumption by Sector[5]											
Residential	4.88	4.90	4.53	4.60	4.60	4.62	4.64	4.66	4.66	4.65	4.51
Commercial[6]	2.60	2.60	2.53	2.59	2.60	2.64	2.67	2.69	2.71	2.72	2.64
Industrial	8.69	6.76	5.47	6.01	6.11	6.19	6.34	6.46	6.45	6.44	6.28
Lease & Plant Fuel[7]	1.50	1.65	1.00	1.09	1.09	1.05	1.10	1.11	1.09	1.08	1.01
Transportation[8]	.73	.53	.56	.59	.60	.60	.61	.62	.62	.62	.61
Electric Utilities	3.66	3.19	2.91	3.16	3.22	3.00	3.06	3.16	3.36	3.30	3.50
Total End-Use Consumption	**22.05**	**19.63**	**17.00**	**18.04**	**18.22**	**18.10**	**18.42**	**18.70**	**18.90**	**18.82**	**18.54**
Unaccounted for[9]	.22	.25	.45	.43	.43	.41	.41	.43	.45	.45	.50
Average Wellhead Price	**.46**	**1.35**	**2.72**	**2.70**	**2.67**	**2.63**	**2.78**	**3.00**	**3.24**	**3.53**	**5.01**
Delivered Prices by Sectors											
Residential	2.71	3.78	6.37	6.16	6.09	6.06	6.24	6.48	6.84	7.22	9.25
Commercial[6]	1.99	3.33	5.73	5.69	5.62	5.57	5.71	5.92	6.25	6.61	8.51
Industrial	1.07	2.27	4.44	4.41	4.39	4.38	4.53	4.75	5.04	5.38	7.20
Electric Utilities	.75	2.18	3.73	3.59	3.65	3.54	3.71	3.91	4.12	4.41	5.65
Average to All Sectors[10]	**1.53**	**2.83**	**5.08**	**4.95**	**4.91**	**4.89**	**5.04**	**5.25**	**5.54**	**5.89**	**7.63**

[1] Net dry natural gas is defined as dry marketed production minus nonhydrocarbon gases removed.

[2] Prior to 1980 the amount of supplemental fuels included in the natural gas data cannot be determined. Supplemental natural gas includes synthetic natural gas (results from the manufacture, conversion, or the reforming of petroleum hydrocarbons), and propane air mixtures. After 1985 this quantity includes short-term spot market purchases that could include additional imports.

[3] Includes net stock withdrawals for dry natural gas from underground storage and liquefied natural gas. Net stock withdrawals are computed as the yearend stock levels from the current period subtracted from the yearend stock levels from the preceding period. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.

[4] Total supply is computed as dry gas production plus supplemental natural gas, net imports, and net stock withdrawals.

[5] Consumption values include small amounts of supplemental gas, which are not reported as production prior to 1980.

[6] Commercial category includes the other customer category.

[7] Lease and plant fuel natural gas represents natural gas used in the field gathering and processing plant machinery, usually totalled into the industrial sector for other consumption tables.

[8] Transportation natural gas is used to fuel the compressors in the pipeline pumping stations.

[9] Unaccounted for represents natural gas lost, the net result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure, and EIA's merger of different data reporting systems which vary in scope, format, definition, and respondent type.

[10] Weighted average price and the weights are the sectoral consumption values excluding lease and plant fuel and the transportation sector.

NOTE: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1984 equals 1.00. The natural gas prices in this table are average prices, total revenues divided by total sales for each customer class.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Historical data are taken from the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984) and Energy Information Administration, *Natural Gas Annual, 1982* DOE/EIA-0131(82) (Washington, DC, 1983). Projected values are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = MRG1126T, Projected = Low World Oil Price Case, printed on December 22, 1984.
Historical quantities through 1983.

Table D18. Coal Supply, Disposition, and Prices
(Million Short Tons per Year)
(1984 Dollars per Short Ton)

Supply, Disposition, and Price	Low World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production[1]											
East of the Mississippi	522	487	507	583	571	580	594	609	628	652	740
West of the Mississippi	76	183	275	309	328	342	354	367	385	408	494
Total	**599**	**670**	**782**	**892**	**899**	**921**	**948**	**976**	**1,013**	**1,060**	**1,234**
Imports[2]	(*)	3	1	1	1	0	0	0	0	0	0
Exports[3]	54	41	78	80	73	74	77	81	86	91	106
Net Imports	**-53**	**-38**	**-77**	**-79**	**-72**	**-74**	**-77**	**-81**	**-86**	**-91**	**-106**
Net Storage Withdrawals[4]	**12**	**11**	**27**	**-20**	**15**	**-2**	**-4**	**-4**	**-6**	**-8**	**-6**
Total Supply[5]	**557**	**644**	**733**	**793**	**842**	**845**	**867**	**891**	**922**	**960**	**1,122**
Consumption by Sector											
Residential and Commercial	11	10	8	8	8	8	8	7	7	7	7
Industrial	68	63	66	76	77	77	80	84	86	89	100
Coking Plants[6]	94	71	37	44	46	46	49	50	51	51	49
Electric Utilities	389	481	625	666	709	713	726	744	771	808	961
Synthetic Fuels	0	0	0	0	5	5	5	6	6	6	6
Total End-Use Consumption	**563**	**625**	**737**	**793**	**843**	**848**	**867**	**891**	**922**	**961**	**1,122**
Discrepancy[7]	-6	18	-4	-2	-3	-4	(*)	(*)	(*)	-1	(*)
Average Minemouth Price[8]	**18.14**	**32.48**	**26.95**	**30.02**	**29.89**	**30.34**	**30.51**	**30.69**	**30.84**	**30.97**	**31.97**
Delivered Prices by Sector											
Residential and Commercial[9]	45.53	69.97	45.87	47.01	47.45	51.59	52.26	52.82	53.44	54.20	57.61
Industrial	26.89	49.65	40.79	43.69	44.73	50.01	51.22	52.35	53.56	54.77	60.61
Coking Plants[6]	38.52	77.33	61.51	60.88	61.53	64.88	65.49	66.12	66.91	67.82	71.09
Electric Utilities[10]	19.03	35.26	36.30	38.12	38.54	38.93	39.36	39.68	39.87	40.27	43.00
Average to All End-Use Sectors[11]	**23.76**	**42.04**	**38.07**	**40.01**	**40.46**	**41.48**	**42.05**	**42.49**	**42.77**	**43.20**	**45.89**

[1] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite with anthracite included in bituminous.
[2] Coal imports are not projected beyond 1985.
[3] Excludes small quantities of anthracite shipped overseas to U.S. Armed Forces and coke exports.
[4] From stocks held by end-use sectors (secondary stocks held at industrial plants, coke plants, and electric utility plants). Net stock withdrawals are computed as the yearend stock levels from the current period subtracted from the yearend stock levels from the preceding period. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.
[5] Total supply is equivalent to production plus net imports plus net storage withdrawals.
[6] Coke plants consume metallurgical coal which is a mixture of anthracite and bituminous coal. Historically, coking plant coal price is a weighted average of anthracite and bituminous coal types. In the projections, anthracite is included in bituminous coal.
[7] Historically, discrepancy represents revisions in producers (primary) stock levels, losses, and unaccounted for. In the projected period, discrepancy represents errors due to conversion factors.
[8] In historical years, the average production price of coal produced at the mine. Projected prices are based on estimated cost and do not reflect market conditions.
[9] Historically, residential price is used for residential and commercial consumers. Projected residential and commercial prices do not include dealer markup.
[10] Historically, electric utility price includes anthracite, bituminous, and lignite coal purchased under long-term contracts and on the spot market. In the projections, anthracite is included in bituminous coal, with the bituminous coal price being used for anthracite coal price.
[11] Weighted average price and the weights are the sectoral consumption values.
(*) Greater than zero but less than .5.

NOTE: Metallurgical coal prices reflect a reduced level of projected demand. Other projected coal prices are based on cost estimates, and do not reflect market conditions.

NOTE: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1984 equals 1.00. Projected coal prices are based on cost estimates and do not reflect market conditions.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Historical prices from Energy Information Administration, *State Energy Price and Expenditure Report*, , (DOE/EIA-0376(81) (Washington, DC, 1984) pp. 1-7. Historical quantities are from the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984) pp. 161-169, Table 73, 74, and 75. Projected values are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = MRG1126T, Projected = Low World Oil Price Case, printed on December 22, 1984.

Historical quantities through 1983.

Table D19. National Macroeconomic Indicators

Macroeconomic Indicators	Low World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
World Oil Price[1]	**8.62**	**21.63**	**30.39**	**29.00**	**24.00**	**24.00**	**24.00**	**25.00**	**25.00**	**25.00**	**30.00**
NIPA Variables[2]											
Real GNP (billion 1972 dollars)	1,254	1,439	1,535	1,643	1,687	1,731	1,800	1,866	1,925	1,982	2,232
Real Disposable Income (billion 1972 dollars)	865	989	1,095	1,168	1,202	1,225	1,261	1,295	1,332	1,366	1,530
Real Disposable Income Per Capita (thousand 1972 dollars)	4.1	4.4	4.7	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.9
NIPA GNP Price Deflator (1972=1.00)	1.057	1.504	2.153	2.233	2.318	2.426	2.551	2.694	2.847	3.010	4.036
GNP Growth (1984 reference year)	NA	NA	NA	.0	2.7	5.4	9.6	13.6	17.2	20.6	35.9
Unemployment Rate, Civilian Workers (percent)	4.9	6.1	9.6	7.5	7.3	7.9	7.5	7.0	6.8	6.8	7.0
Population, Noninstitutional (million persons)	211.9	222.6	234.0	236.2	238.5	240.7	243.0	245.2	247.4	249.5	259.4
New, High Grade Bond Rate (percent per annum)	7.65	8.88	11.56	12.62	12.76	12.21	11.64	11.27	10.94	10.62	9.61
New Home Mortgage Yields (percent per annum)	8.08	9.69	13.35	13.56	13.90	13.31	12.48	11.95	11.74	11.54	10.51
Total Industrial Production Index (1967=1.00)	1.30	1.46	1.48	1.64	1.70	1.75	1.87	1.97	2.04	2.11	2.43
Total Manufacturing Output Index (1967=1.00)	1.30	1.47	1.48	1.66	1.72	1.77	1.90	2.01	2.09	2.17	2.52
Housing Starts (million units)	2.04	2.00	1.70	1.79	1.59	1.74	1.84	1.89	1.84	1.76	1.62
Energy Usage Indicators											
Gross Energy Use per Capita (million Btu per person)	350.1	350.6	301.8	316.6	319.3	320.8	326.0	330.8	334.6	339.1	357.6
Gross Energy Use per Dollar of GNP (thousand Btu per 1972 dollar)	59.2	54.2	46.0	45.5	45.1	44.6	44.0	43.5	43.0	42.7	41.6
Net Oil Imports (billion 1984 dollars)	15.0	56.5	47.0	52.7	44.0	47.6	52.0	58.1	62.6	68.1	125.8
Net Coal Imports (billion 1984 dollars)	-2.1	-2.9	-3.9	-4.2	-3.9	-4.0	-4.1	-4.4	-4.6	-5.0	-6.1

[1] The cost of imported crude oil to U.S. refiners in 1984 dollars per barrel.
[2] National Income and Product Accounts.
NOTE: Total may not equal sum of components because of independent rounding.

Appendix E
High World Oil Price/Middle Economic Growth Case

Table E1. Yearly Supply and Disposition Summary of Total Energy
(Quadrillion Btu per Year)

Total Supply and Disposition	High World Oil Price Case										
	1973	**1978**	**1983**	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**
Supply											
Production											
Crude Oil and Lease Condensate	19.5	18.4	18.4	18.5	18.8	18.5	18.4	18.4	18.6	18.8	19.7
Natural Gas Plant Liquids	2.6	2.2	2.2	2.3	2.3	2.2	2.2	2.2	2.2	2.2	1.9
Natural Gas[1]	22.2	19.5	16.4	17.9	18.0	18.0	18.1	18.2	18.1	17.9	17.2
Coal[2]	13.9	14.9	17.2	19.6	19.8	20.5	21.0	21.5	22.2	23.1	26.4
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Hydropower/Other[3]	2.9	3.0	3.6	3.6	3.1	3.3	3.3	3.3	3.3	3.4	3.4
Total Production	**62.0**	**61.0**	**61.1**	**65.6**	**66.1**	**67.3**	**68.4**	**69.4**	**70.5**	**71.8**	**75.7**
Imports											
Crude Oil[4]	6.9	13.5	7.1	7.4	8.5	8.6	8.7	8.7	8.6	8.4	7.9
Refined Petroleum Products[5]	6.6	4.4	3.6	4.1	2.9	3.1	3.3	3.6	3.8	4.0	4.8
Natural Gas[6]	1.1	1.0	1.1	1.0	1.2	1.2	1.3	1.5	1.6	1.8	2.6
Other Imports[7]	.2	.4	.4	.4	.5	.5	.5	.6	.6	.7	.8
Total Imports	**14.7**	**19.3**	**12.2**	**12.9**	**13.0**	**13.3**	**13.9**	**14.4**	**14.6**	**14.8**	**16.0**
Net Stock Withdrawals	**-.4**	**.3**	**1.1**	**-.7**	**.0**	**-.3**	**-.4**	**-.4**	**-.5**	**-.5**	**-.2**
Adjustments[8]	-.1	-.6	.0	.4	-.3	-.3	-.4	-.4	-.5	-.5	-.7
Total Supply[9]	**76.2**	**80.0**	**74.4**	**78.3**	**78.8**	**79.9**	**81.4**	**82.9**	**84.2**	**85.6**	**90.8**
Disposition											
Exports											
Oil	.5	.8	1.6	1.4	1.3	1.7	1.7	1.7	1.7	1.7	1.7
Natural Gas	.1	.1	.1	NA	NA	NA	NA	NA	NA	NA	NA
Coal	1.4	1.1	2.0	2.1	1.9	2.0	2.1	2.2	2.3	2.4	2.8
Other[10]	.1	.0	.1	NA	NA	NA	NA	NA	NA	NA	NA
Total Exports	**2.1**	**1.9**	**3.7**	**3.5**	**3.2**	**3.7**	**3.7**	**3.8**	**3.9**	**4.1**	**4.4**
Consumption											
Refined Petroleum Products[11]	34.8	38.0	30.1	31.5	31.1	30.6	30.7	30.9	31.1	31.3	32.4
Natural Gas	22.5	20.0	17.5	18.5	18.7	18.8	19.0	19.3	19.3	19.3	19.4
Coal[12]	12.9	13.7	15.9	17.1	18.1	18.4	18.8	19.2	19.8	20.5	23.4
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Hydro/Other/Electricity Imports[13]	3.1	3.2	4.0	4.0	3.6	3.8	3.9	3.9	4.0	4.1	4.2
Net Imports of Coke	.0	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total Consumption	**74.2**	**78.0**	**70.7**	**74.8**	**75.5**	**76.3**	**77.7**	**79.1**	**80.2**	**81.5**	**86.4**
Total Disposition	**76.2**	**80.0**	**74.4**	**78.3**	**78.8**	**79.9**	**81.4**	**82.9**	**84.2**	**85.6**	**90.8**

[1] Net dry marketed production after removal of nonhydrocarbon gases.
[2] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite, with anthracite included in bituminous.
[3] Hydropower/Other production includes hydropower, geothermal power, and wood waste.
[4] Includes imports of crude oil for the Strategic Petroleum Reserve.
[5] Includes imports of unfinished oils and natural gas plant liquids.
[6] Includes dry natural gas imports from Canada and Mexico, liquefied natural gas imports from Algeria, and supplemental gas.
[7] Includes electricity, coal, and coal coke imports.
[8] Balancing item that includes gains, losses, miscellaneous blending components, unaccounted for supply, coal used for synthetic fuel production, anthracite shipped overseas to U.S. Armed Forces and certain secondary stock withdrawals.
[9] Total supply is the sum of production, imports, net stock withdrawals, and adjustments.
[10] Includes electricity and coal coke exports.
[11] Includes natural gas plant liquids and crude oil consumed as a fuel.
[12] Excludes anthracite shipped overseas to U.S. Armed Forces and coal used for synthetic fuel production.
[13] Includes net electricity imports and renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[NA] = Not available.

NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical quantities are from the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984) pp. 5-29, Tables 1, 2, 3, and 13. Projected values are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = High World Oil Price Case, printed on December 28, 1984.
Historical quantities through 1983.

Table E2. Yearly Supply and Disposition of Total Energy, Supply Detail

(Quadrillion Btu per Year)

Total Supply	High World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
World Oil Price[1]	**8.62**	**21.63**	**30.39**	**29.00**	**30.00**	**32.00**	**34.00**	**36.00**	**38.00**	**40.00**	**55.00**
Domestic Production											
Oil[2]	22.1	20.7	20.6	20.8	21.1	20.7	20.6	20.6	20.8	21.0	21.6
Natural Gas[3]	22.2	19.5	16.4	17.9	18.0	18.0	18.1	18.2	18.1	17.9	17.2
Coal[4]	13.9	14.9	17.2	19.6	19.8	20.5	21.0	21.5	22.2	23.1	26.4
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Hydropower/Other[5]	2.9	3.0	3.6	3.6	3.1	3.3	3.3	3.3	3.3	3.4	3.4
Total Domestic Production	**62.0**	**61.0**	**61.1**	**65.6**	**66.1**	**67.3**	**68.4**	**69.4**	**70.5**	**71.8**	**75.7**
Imports											
Oil[6]	13.5	17.8	10.7	11.5	11.4	11.7	12.0	12.3	12.3	12.3	12.7
Natural Gas[7]	1.1	1.0	1.1	1.0	1.2	1.2	1.3	1.5	1.6	1.8	2.6
Coal[8]	.0	.1	.0	.0	.0	NA	NA	NA	NA	NA	NA
Other Imports[9]	.2	.4	.4	.4	.4	.5	.5	.6	.6	.7	.8
Total Imports	**14.7**	**19.3**	**12.2**	**12.9**	**13.0**	**13.3**	**13.9**	**14.4**	**14.6**	**14.8**	**16.0**
Net Storage Withdrawals											
Oil	-.3	.5	.5	.1	.0	.1	-.1	-.1	.0	-.1	-.1
Natural Gas	-.4	-.2	.5	.0	.0	.0	.0	.0	.0	.0	.0
Coal[10]	.3	.3	.6	-.4	.3	.0	-.1	-.1	-.1	-.2	-.1
SPR Fill Rate Additions (-)[11]	.0	-.3	-.5	-.4	-.3	-.3	-.3	-.3	-.3	-.3	.0
Net Stock Withdrawals	**-.4**	**.3**	**1.1**	**-.7**	**.0**	**-.3**	**-.4**	**-.4**	**-.5**	**-.5**	**-.2**
Available Supply[12]											
Oil	35.3	39.1	31.9	32.5	32.6	32.6	32.7	32.9	33.1	33.3	34.2
Natural Gas	22.8	20.3	18.0	19.0	19.2	19.2	19.4	19.7	19.8	19.8	19.8
Coal	14.2	15.2	17.8	19.2	20.1	20.4	20.9	21.4	22.1	23.0	26.2
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Other Supply[13]	3.1	3.4	4.0	4.0	3.6	3.8	3.9	3.9	4.0	4.1	4.2
SPR Fill Rate Additions (-)[11]	.0	-.3	-.5	-.4	-.3	-.3	-.3	-.3	-.3	-.3	.0
Total Supply (before adjustments)	**76.3**	**80.6**	**74.4**	**77.9**	**79.1**	**80.3**	**81.8**	**83.4**	**84.7**	**86.1**	**91.5**
Adjustments[14]	-.1	-.6	.0	.4	-.3	-.3	-.4	-.4	-.5	-.5	-.7
Total Supply[15]	**76.2**	**80.0**	**74.4**	**78.3**	**78.8**	**79.9**	**81.4**	**82.9**	**84.2**	**85.6**	**90.8**

[1] The cost of imported crude oil to U.S. refiners in 1984 dollars per barrel.
[2] Oil includes crude oil, lease condensate, and natural gas plant liquids.
[3] Net dry marketed production after removal of nonhydrocarbon gases.
[4] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite, with anthracite included in bituminous.
[5] Hydropower/Other production includes hydropower, geothermal power, and wood waste.
[6] Oil imports includes crude oil and refined petroleum products. Crude oil imports include imports for the Strategic Petroleum Reserve.
[7] Includes dry natural gas imports from Canada and Mexico, liquefied natural gas imports from Algeria, and supplemental gas.
[8] Includes small amounts of coal/coke imports.
[9] Consists of net electricity imports from Canada.
[10] From consumer stocks (utility, coke plant, and industrial) only.
[11] SPR is the Strategic Petroleum Reserve.
[12] Available supply is the sum of domestic production, imports, and net stock withdrawals.
[13] Includes net electricity imports from Canada, hydropower, geothermal power, wood, waste, solar power, and wind power.
[14] Balancing item that includes gains, losses, miscellaneous blending components, unaccounted for supply, coal used for synthetic fuel production, anthracite shipped overseas to U.S. Armed Forces and certain secondary stock withdrawals.
[15] Total supply is the sum of production, imports, net stock withdrawals, and adjustments.
[NA] = Not available.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Historical values are taken from Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984).

Input data file: Historical = MRG1126T, Projected = High World Oil Price Case, printed on December 28, 1984.

Historical prices through 1981 and quantities through 1983.

Table E3. Yearly Supply and Disposition of Total Energy, Disposition Detail

(Quadrillion Btu per Year)

Total Disposition	High World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Exports											
Oil[1]	0.5	0.8	1.6	1.4	1.3	1.7	1.7	1.7	1.7	1.7	1.7
Natural Gas	.1	.1	.1	NA	NA	NA	NA	NA	NA	NA	NA
Coal	1.4	1.1	2.0	2.1	1.9	2.0	2.1	2.2	2.3	2.4	2.8
Other[2]	.1	.0	.1	NA	NA	NA	NA	NA	NA	NA	NA
Total Exports	**2.1**	**1.9**	**3.7**	**3.5**	**3.2**	**3.7**	**3.7**	**3.8**	**3.9**	**4.1**	**4.4**
Consumption											
Residential and Commercial											
Oil[3]	4.4	4.1	2.3	2.6	2.5	2.5	2.6	2.6	2.6	2.5	2.3
Natural Gas	7.6	7.6	7.2	7.4	7.4	7.4	7.4	7.5	7.5	7.5	7.2
Coal	.3	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2
Total (excluding electricity)	**12.3**	**11.9**	**9.8**	**10.1**	**10.1**	**10.1**	**10.2**	**10.2**	**10.2**	**10.2**	**9.7**
Industrial											
Oil[4]	9.1	9.9	7.8	8.9	9.0	9.0	9.3	9.7	9.9	10.1	10.9
Natural Gas[5]	10.4	8.5	6.6	7.3	7.4	7.5	7.6	7.7	7.7	7.7	7.4
Coal[6]	4.0	3.2	2.5	2.9	2.9	3.2	3.3	3.4	3.5	3.6	3.7
Hydropower	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Net Imports of Coke	.0	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total (excluding electricity)	**23.5**	**21.8**	**16.9**	**19.0**	**19.3**	**19.7**	**20.3**	**20.9**	**21.1**	**21.3**	**22.0**
Transportation											
Oil[7]	17.8	20.0	18.4	18.7	18.4	18.1	17.9	17.8	17.7	17.7	17.9
Natural Gas[8]	.7	.5	.6	.6	.6	.6	.6	.6	.6	.6	.6
Coal	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total (excluding electricity)	**18.6**	**20.6**	**19.0**	**19.3**	**19.0**	**18.7**	**18.5**	**18.4**	**18.4**	**18.4**	**18.5**
Electric Utilities											
Oil	3.5	4.0	1.5	1.3	1.2	1.0	.9	.9	.9	1.0	1.3
Natural Gas	3.7	3.3	3.0	3.3	3.3	3.3	3.3	3.4	3.5	3.5	4.1
Coal	8.7	10.3	13.2	14.0	14.9	15.0	15.3	15.6	16.1	16.7	19.5
Nuclear Power	.9	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3	7.1
Hydropower/Other[9]	3.0	3.2	4.0	4.0	3.5	3.8	3.8	3.9	4.0	4.0	4.1
Total	**19.9**	**23.7**	**25.0**	**26.3**	**27.1**	**27.8**	**28.7**	**29.6**	**30.5**	**31.6**	**36.1**
Total Disposition	**76.2**	**80.0**	**74.4**	**78.3**	**78.8**	**79.9**	**81.4**	**82.9**	**84.2**	**85.6**	**90.8**

[1] Consists primarily of refined petroleum products.
[2] Includes electricity and coal coke exports.
[3] Residential and Commercial oil consists of motor gasoline, distillate fuel, kerosene, residual fuel, and liquefied petroleum gases.
[4] Industrial oil consists of distillate fuel, kerosene, residual fuel, liquefied petroleum gases, special naphthas, miscellaneous petroleum products, lubricants, waxes, unfractionated stream, plant condensate, natural gasoline, asphalt, road oil, petroleum coke, still gas, other oils greater than 400 degrees used for chemical feedstocks, motor gasoline, and naphthas less than 400 degrees used for feedstock purposes, including refinery fuel consumption.
[5] Industrial natural gas is composed of lease and plant fuel use, refinery fuel use, and other industrial uses.
[6] Industrial coal is composed of steam and metallurgical (coking) coal.
[7] Transportation oil consists of motor gasoline, aviation gasoline, jet fuel, distillate fuel, residual fuel, lubricants, and liquefied petroleum gases.
[8] Transportation natural gas represents natural gas used as a fuel by pipeline compressors.
[9] Includes net electricity imports from Canada, hydropower, geothermal power, wood, waste, solar power, and wind power.
[NA] = Not available.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical quantities are taken from Energy Information Administration, *State Energy Data Report, 1960 to 1982*, DOE/EIA 0214(82) (Washington, DC, 1984) and Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984). Projected quantities are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = High World Oil Price Case, printed on December 28, 1984.
Historical quantities through 1983.

Table E4. Consumption by Major Fuels and End-Use Sectors
(Quadrillion Btu per Year)

Sector and Fuel	High World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential											
Distillate Fuel	2.00	1.95	1.05	1.23	1.17	1.17	1.16	1.13	1.11	1.08	0.91
Kerosene	.23	.15	.09	.07	.06	.06	.06	.06	.06	.06	.05
Liquefied Petroleum Gas	.59	.52	.30	.25	.26	.27	.27	.26	.26	.25	.21
Natural Gas	4.98	4.98	4.65	4.72	4.72	4.71	4.73	4.74	4.75	4.74	4.61
Steam Coal	.11	.09	.08	.07	.07	.07	.07	.07	.06	.06	.06
Electricity	1.98	2.30	2.56	2.61	2.68	2.73	2.78	2.85	2.91	2.99	3.39
Total	**9.89**	**9.99**	**8.72**	**8.95**	**8.96**	**9.00**	**9.06**	**9.11**	**9.15**	**9.19**	**9.22**
Commercial											
Distillate Fuel	.64	.67	.44	.51	.51	.52	.54	.56	.57	.58	.57
Kerosene	.06	.05	.03	.06	.06	.06	.06	.07	.07	.07	.08
Motor Gasoline	.09	.11	.09	.09	.08	.08	.08	.08	.08	.08	.08
Residual Fuel	.67	.53	.30	.33	.34	.35	.36	.37	.38	.39	.39
Liquefied Petroleum Gas	.10	.09	.05	.03	.03	.03	.03	.03	.03	.03	.02
Natural Gas[1]	2.65	2.64	2.60	2.66	2.67	2.68	2.71	2.72	2.73	2.73	2.62
Steam Coal	.15	.13	.12	.11	.12	.12	.12	.12	.12	.11	.11
Electricity	1.52	1.81	2.12	2.36	2.45	2.50	2.57	2.64	2.71	2.79	3.14
Total	**5.88**	**6.04**	**5.74**	**6.16**	**6.24**	**6.35**	**6.47**	**6.58**	**6.68**	**6.78**	**7.00**
Industrial[2]											
Distillate Fuel	1.47	1.75	1.30	1.61	1.51	1.50	1.52	1.55	1.57	1.59	1.69
Kerosene	.16	.16	.14	.10	.09	.08	.09	.09	.09	.08	.07
Motor Gasoline	.26	.18	.14	.13	.14	.15	.17	.19	.21	.24	.37
Residual Fuel	1.86	1.72	.78	.98	.92	.91	.92	.94	.95	.96	.97
Liquefied Petroleum Gas	1.24	1.26	1.61	1.52	1.55	1.59	1.73	1.85	1.92	2.00	2.33
Petrochemical Feedstocks[3]	.73	1.22	.85	1.38	1.47	1.46	1.55	1.62	1.63	1.64	1.61
Still Gas Used in Refineries	1.06	1.20	1.13	1.16	1.21	1.20	1.19	1.19	1.19	1.20	1.23
Other Raw Material Oil[4]	2.34	2.41	1.82	1.98	2.08	2.11	2.17	2.23	2.29	2.34	2.66
Natural Gas[5]	10.39	8.54	6.64	7.29	7.39	7.50	7.64	7.75	7.71	7.69	7.36
Steam Coal	1.43	1.46	1.50	1.72	1.75	1.90	1.98	2.06	2.13	2.19	2.35
Metallurgical Coal	2.54	1.79	.96	1.15	1.19	1.25	1.32	1.37	1.38	1.38	1.34
Net Coke Imports	-.01	.13	-.02	.00	.00	.00	.00	.00	.00	.00	.00
Electricity	2.34	2.76	2.65	2.74	2.79	2.86	3.01	3.17	3.30	3.45	4.06
Hydropower	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03
Total	**25.84**	**24.60**	**19.52**	**21.78**	**22.12**	**22.54**	**23.33**	**24.03**	**24.41**	**24.80**	**26.07**

See footnotes at end of table.

Table E4. Consumption by Major Fuels and End-Use Sectors (Continued)
(Quadrillion Btu per Year)

Sector and Fuel	High World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Transportation											
Aviation Gasoline	0.08	0.07	0.05	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.09
Distillate Fuel	2.22	2.68	2.84	2.67	2.63	2.70	2.78	2.89	3.01	3.14	4.04
Jet Fuel[6]	2.13	2.14	2.14	2.35	2.32	2.37	2.42	2.45	2.48	2.50	2.53
Motor Gasoline	12.45	13.93	12.47	12.67	12.46	12.02	11.67	11.38	11.15	10.96	10.11
Residual Fuel	.73	.99	.75	.74	.72	.73	.75	.77	.79	.81	.89
Liquefied Petroleum Gas	.04	.03	.03	.01	.01	.01	.01	.01	.01	.01	.01
Lubricants and Waxes	.16	.18	.16	.22	.21	.21	.22	.22	.22	.23	.25
Natural Gas[7]	.74	.54	.58	.61	.62	.62	.63	.63	.64	.64	.64
Other Transportation[8]	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01
Total	**18.58**	**20.57**	**19.02**	**19.35**	**19.05**	**18.73**	**18.55**	**18.43**	**18.38**	**18.37**	**18.55**
Electric Utilities											
Distillate Fuel	.27	.28	.10	.11	.05	.02	.01	.01	.02	.02	.07
Residual Fuel	3.24	3.71	1.45	1.20	1.13	.97	.91	.93	.91	.97	1.18
Natural Gas	3.75	3.30	3.01	3.27	3.33	3.28	3.32	3.42	3.49	3.52	4.11
Steam Coal	8.66	10.25	13.23	14.05	14.94	15.01	15.30	15.59	16.06	16.72	19.54
Nuclear Power	.91	3.02	3.23	3.70	4.10	4.72	5.31	5.79	6.09	6.32	7.09
Hydropower/Other[9]	3.02	3.18	3.98	3.95	3.54	3.77	3.83	3.88	3.96	4.03	4.15
Total	**19.85**	**23.74**	**25.00**	**26.27**	**27.09**	**27.77**	**28.67**	**29.62**	**30.53**	**31.57**	**36.15**
Primary Energy Consumption											
Distillate Fuel	6.61	7.32	5.72	6.13	5.87	5.91	6.01	6.14	6.28	6.41	7.27
Kerosene	.45	.36	.26	.23	.21	.21	.21	.21	.21	.21	.20
Aviation Gasoline	.08	.07	.05	.07	.07	.07	.07	.08	.08	.08	.09
Motor Gasoline	12.80	14.21	12.70	12.88	12.68	12.25	11.92	11.65	11.44	11.28	10.55
Jet Fuel	2.13	2.14	2.14	2.35	2.32	2.37	2.42	2.45	2.48	2.50	2.53
Residual Fuel	6.49	6.95	3.27	3.25	3.11	2.95	2.95	3.01	3.04	3.13	3.43
Liquefied Petroleum Gas	1.98	1.89	1.99	1.81	1.85	1.89	2.03	2.14	2.21	2.28	2.56
Petrochemical Feedstocks	.73	1.22	.85	1.38	1.47	1.46	1.55	1.62	1.63	1.64	1.61
Still Gas	1.06	1.20	1.13	1.16	1.21	1.20	1.19	1.19	1.19	1.20	1.23
Lubricants and Waxes	.40	.41	.35	.45	.43	.43	.44	.45	.46	.47	.49
Other Petroleum	2.11	2.18	1.62	1.75	1.86	1.89	1.94	2.00	2.05	2.10	2.42
Natural Gas	22.50	20.00	17.47	18.54	18.73	18.78	19.02	19.26	19.31	19.31	19.35
Steam Coal	10.35	11.92	14.91	15.95	16.88	17.10	17.46	17.84	18.37	19.09	22.06
Metallurgical Coal	2.54	1.79	.96	1.15	1.19	1.25	1.32	1.37	1.38	1.38	1.34
Net Coke Imports	-.01	.13	-.02	.00	.00	.00	.00	.00	.00	.00	.00
Nuclear Power	.91	3.02	3.23	3.70	4.10	4.72	5.31	5.79	6.09	6.32	7.09
Hydropower/Other[9]	3.06	3.21	3.99	3.98	3.57	3.80	3.86	3.91	3.99	4.06	4.18
Total Consumption	**74.19**	**78.04**	**70.66**	**74.79**	**75.54**	**76.28**	**77.71**	**79.11**	**80.24**	**81.47**	**86.40**
Electricity Consumption (all sectors)	**5.84**	**6.89**	**7.34**	**7.72**	**7.92**	**8.10**	**8.38**	**8.66**	**8.93**	**9.24**	**10.59**

[1] Commercial natural gas includes deliveries to municipalities and public authorities for institutional heating, street lighting, etc.
[2] Industrial includes all fuels consumed for heat and power, including natural gas used as lease and plant fuel, industrial feedstock and raw material uses; also, all fuels consumed by refineries.
[3] Petrochemical feedstocks includes still gas used for feedstock purposes, naphthas less than 400 degrees, and other oils greater than 400 degrees.
[4] Consists of asphalt, special naphthas, lubricants, waxes, petroleum coke, road oil, and small amounts of Other Petroleum and Net Blending Oil as defined in Table A8.
[5] Includes lease and plant fuel consumption of natural gas.
[6] Jet fuel includes naphtha and kerosene types.
[7] Consists of natural gas used as pipeline compressor fuel.
[8] Other transportation includes steam coal and electricity.
[9] Includes renewable facilities such as hydropower, geothermal power, wood, waste, solar power, and wind power. Electric utility consumption includes net electicity imports.

NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical quantities are taken from Energy Information Administration, *State Energy Data Report, 1960 to 1982*, DOE/EIA-0214 (82) (Washington, DC, 1984) and Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984). Projected quantities are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = High World Oil Price Case, printed on December 21, 1984.
Historical quantities through 1983.

Table E5. Prices by Major Fuels and End-Use Sectors
(1984 Dollars per Million Btu)

Sector and Fuel	High World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential											
Distillate Fuel	3.46	5.28	7.94	7.70	7.85	8.26	8.66	9.07	9.50	9.95	13.04
Kerosene	3.96	6.01	8.29	8.04	8.19	8.63	9.04	9.47	9.91	10.38	13.60
Liquefied Petroleum Gas	7.66	7.08	9.02	7.76	7.93	8.37	8.79	9.23	9.69	10.17	13.47
All Petroleum Products	**4.38**	**5.68**	**8.19**	**7.72**	**7.88**	**8.30**	**8.70**	**9.12**	**9.55**	**10.00**	**13.14**
Natural Gas	2.66	3.72	6.20	6.00	5.94	5.98	6.16	6.38	6.74	7.09	8.94
Steam Coal[1]	2.47	3.81	2.05	2.10	2.12	2.15	2.17	2.19	2.22	2.25	2.39
Electricity	15.74	18.80	19.55	19.62	19.86	20.08	20.24	20.23	20.04	19.88	19.50
Average[2]	**5.76**	**7.71**	**10.41**	**10.24**	**10.39**	**10.61**	**10.87**	**11.12**	**11.38**	**11.66**	**13.31**
Commercial											
Distillate Fuel	2.90	4.72	6.57	6.33	6.48	6.89	7.28	7.69	8.11	8.56	11.63
Kerosene	2.04	4.68	6.62	6.36	6.52	6.95	7.36	7.80	8.24	8.70	11.93
Motor Gasoline	6.57	7.85	10.33	10.14	10.37	10.81	11.25	11.67	12.07	12.42	15.63
Residual Fuel	1.82	3.27	5.47	5.30	5.32	5.61	5.87	6.15	6.46	6.83	8.68
Liquefied Petroleum Gas	3.11	5.25	9.04	6.54	6.70	7.15	7.57	8.01	8.47	8.94	12.25
All Petroleum Products	**2.62**	**4.45**	**6.72**	**6.32**	**6.42**	**6.78**	**7.11**	**7.47**	**7.84**	**8.25**	**10.92**
Natural Gas[3]	1.95	3.27	5.59	5.55	5.49	5.49	5.64	5.83	6.16	6.48	8.20
Steam Coal[4]	.94	1.89	2.01	2.06	2.08	2.11	2.13	2.15	2.18	2.21	2.35
Electricity	15.08	19.48	19.75	19.79	20.10	20.38	20.60	20.63	20.42	20.26	19.94
Average[2]	**5.49**	**8.40**	**10.93**	**11.07**	**11.30**	**11.51**	**11.77**	**11.98**	**12.16**	**12.37**	**13.81**
Industrial											
Distillate Fuel	1.98	4.21	6.53	6.28	6.43	6.84	7.23	7.64	8.06	8.50	11.57
Kerosene	2.13	4.61	6.88	6.62	6.78	7.21	7.62	8.05	8.49	8.96	12.17
Motor Gasoline	6.62	7.82	10.38	10.19	10.41	10.86	11.29	11.71	12.10	12.45	15.64
Residual Fuel	1.69	3.16	4.53	4.35	4.38	4.68	4.94	5.23	5.54	5.92	7.78
Liquefied Petroleum Gas	2.99	5.17	7.85	6.69	6.86	7.29	7.71	8.15	8.60	9.08	12.36
Petrochemical Feedstocks[5]	1.98	4.21	6.16	5.90	6.04	6.45	6.85	7.28	7.71	8.17	11.34
Still Gas[6]	1.98	4.21	6.43	6.19	6.34	6.76	7.15	7.56	7.99	8.44	11.53
Other Petroleum[7]	1.98	4.21	5.16	5.15	4.96	5.14	5.36	5.57	5.76	5.97	7.26
All Petroleum Products	**2.19**	**4.22**	**6.30**	**5.87**	**5.94**	**6.30**	**6.66**	**7.04**	**7.42**	**7.82**	**10.45**
Natural Gas[8]	1.05	2.23	4.33	4.30	4.31	4.36	4.53	4.73	5.03	5.35	7.00
Steam Coal	.96	1.93	1.86	1.93	1.98	2.02	2.06	2.10	2.14	2.18	2.38
Metallurgical Coal	1.49	2.98	2.29	2.34	2.37	2.39	2.41	2.43	2.46	2.49	2.59
Net Coke Imports	1.93	4.55	4.08	4.16	4.21	4.25	4.28	4.32	4.36	4.41	4.58
Electricity	7.72	12.19	16.59	16.66	16.85	17.07	17.24	17.22	17.02	16.85	16.40
Average[2]	**2.06**	**4.15**	**6.44**	**6.16**	**6.22**	**6.40**	**6.65**	**6.90**	**7.17**	**7.46**	**9.23**

See footnotes at end of table.

Table E5. Prices by Major Fuels and End-Use Sectors (Continued)

(1984 Dollars per Million Btu)

Sector and Fuel	High World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Transportation[9]											
Aviation Gasoline	7.94	10.47	13.95	13.62	14.01	14.76	15.50	16.20	16.87	17.45	22.86
Distillate Fuel	3.48	5.04	9.58	9.34	9.49	9.90	10.29	10.71	11.13	11.58	14.66
Jet Fuel[10]	2.05	4.53	6.77	6.49	6.62	6.99	7.41	7.84	8.28	8.74	11.91
Motor Gasoline[11]	6.55	7.78	10.29	10.10	10.33	10.77	11.21	11.62	12.01	12.36	15.56
Residual Fuel[12]	1.35	2.25	3.60	3.43	3.46	3.76	4.01	4.30	4.61	4.99	6.85
Liquefied Petroleum Gas	2.87	4.78	8.38	9.98	10.15	10.59	11.01	11.45	11.91	12.38	15.69
Lubricants and Waxes[13]	12.48	14.88	24.54	24.13	24.38	25.09	25.76	26.47	27.19	27.95	33.23
All Petroleum Products	**5.47**	**6.86**	**9.63**	**9.45**	**9.65**	**10.05**	**10.44**	**10.83**	**11.22**	**11.60**	**14.69**
Natural Gas[14]	.45	1.33	2.64	2.62	2.60	2.63	2.78	2.98	3.21	3.48	4.78
Electricity	5.67	9.48	19.00	18.99	19.31	19.62	19.88	19.93	19.71	19.54	19.26
Average[2]	**5.27**	**6.72**	**9.43**	**9.24**	**9.42**	**9.81**	**10.19**	**10.57**	**10.95**	**11.32**	**14.35**
Electric Utilities											
Distillate Fuel[15]	1.87	3.70	7.79	7.12	6.99	6.30	6.84	8.08	9.19	9.69	11.95
Residual Fuel	1.65	3.17	4.69	4.53	4.58	4.99	5.27	5.57	5.88	6.26	8.14
All Petroleum Products	**1.67**	**3.20**	**4.89**	**4.75**	**4.68**	**5.02**	**5.29**	**5.60**	**5.96**	**6.34**	**8.37**
Natural Gas	.73	2.11	3.60	3.47	3.63	3.63	3.80	3.99	4.23	4.56	6.02
Steam Coal	.95	1.78	1.72	1.81	1.83	1.85	1.86	1.88	1.89	1.92	2.04
Fossil Fuel Average	**1.05**	**2.17**	**2.31**	**2.31**	**2.31**	**2.31**	**2.35**	**2.42**	**2.48**	**2.56**	**3.02**
Average Price to All Users											
Distillate Fuel	3.02	4.83	8.33	7.91	8.09	8.52	8.93	9.35	9.79	10.26	13.48
Kerosene	3.05	5.21	7.35	6.98	7.13	7.55	7.94	8.36	8.79	9.25	12.42
Aviation Gasoline	7.94	10.47	13.95	13.62	14.01	14.76	15.50	16.20	16.87	17.45	22.86
Motor Gasoline	6.55	7.78	10.30	10.10	10.33	10.77	11.21	11.62	12.02	12.36	15.56
Jet Fuel	2.05	4.53	6.77	6.49	6.62	6.99	7.41	7.84	8.28	8.74	11.91
Residual Fuel	1.65	3.04	4.48	4.31	4.34	4.66	4.92	5.21	5.52	5.90	7.77
Liquefied Petroleum Gas	2.99	5.17	7.85	6.69	6.86	7.29	7.71	8.15	8.60	9.08	12.36
Petrochemical Feedstocks	1.98	4.21	6.16	5.90	6.04	6.45	6.85	7.28	7.71	8.17	11.34
Lubricants and Waxes	12.48	14.88	24.54	24.13	24.38	25.09	25.76	26.47	27.19	27.95	33.23
Other Petroleum Products	1.98	4.21	5.63	5.37	5.50	5.88	6.24	6.62	7.03	7.46	10.36
All Petroleum Products	**4.02**	**5.62**	**8.30**	**7.98**	**8.12**	**8.51**	**8.85**	**9.20**	**9.56**	**9.93**	**12.71**
Natural Gas	1.42	2.68	4.82	4.70	4.70	4.73	4.90	5.09	5.40	5.72	7.34
Coal	1.07	1.97	1.77	1.86	1.88	1.91	1.92	1.94	1.96	1.99	2.11
Electricity	12.34	16.32	18.54	18.62	18.87	19.11	19.27	19.25	19.04	18.86	18.44
Average	**3.37**	**5.15**	**7.02**	**6.85**	**6.89**	**7.09**	**7.30**	**7.49**	**7.69**	**7.90**	**9.29**

[1] Projected residential coal prices are delivered to dealer prices and do not include dealer markup.

[2] Weighted average of end-use fuel prices consists of the prices shown above and the appropriate weights from Table 4.

[3] Commercial natural gas price is a weighted average of the commercial and other category.

[4] Historical price for commercial steam coal is the price of industrial steam coal at the State level. Projected prices do not include dealer markup, where applicable.

[5] Industrial distillate price is used in historical years (through 1978).

[6] The industrial distillate price is used. For 1983 forward, differences between the national prices of still gas and distillate fuel oil are due to differences in the regional composition of demand for these fuels.

[7] Industrial other price is a weighted average price for road oil, asphalt, lubricants, waxes, petroleum coke, special naphthas, and miscellaneous petroleum products.

[8] Industrial natural gas price is a weighted average of the lease and plant fuel price and the industrial price. In these reports, the natural gas price for industrial heat and power is used for the lease and plant fuel price, so both components of the average are the same.

[9] Transportation prices include the appropriate Federal excise tax and State road use taxes.

[10] Jet fuel price is for kerosene type jet fuel at retail.

[11] Gasoline price is an average for all types.

[12] Residual fuel price is for marine bunker.

[13] Historical price is the price of industrial lubricants.

[14] Transportation natural gas price is for pipeline fuel use only. The average wellhead price from Table 17 is used as a surrogate price.

[15] Historical price for electric utility distillate fuel oil is the price of electric utility kerosene.

NOTE: Metallurgical coal prices reflect a reduced level of projected demand. Projected coal prices are based on cost estimates and do not reflect market conditions.

NOTE: Electricity and natural gas prices are average prices, revenue divided by sales. Also, the electricity prices are averages for class A and B private electric utilities and public power authorities.

NOTE: Implicit Gross National Product Price Deflator, rebased to 1984 = 1.0, was used to convert from nominal to real dollars.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Historical prices are taken from Energy Information Administration, *State Energy Price and Expenditure Report*, (DOE/EIA-0376 (81) (Washington, DC, 1984), pp. 1-7. Projected prices are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = MRG1126T, Projected = High World Oil Price Case, printed on December 21, 1984.

Historical prices through 1981.

Table E6. Residential Energy Use by End Use
(Quadrillion Btu per Year)

Fuel and End Use	High World Oil Price Case								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
Marketed Fuel Consumption[1]									
Fuel Use									
Space Heating	4.51	4.68	4.66	4.68	4.70	4.70	4.69	4.66	4.36
Water Heating	1.63	1.66	1.65	1.65	1.66	1.67	1.69	1.70	1.76
Air Conditioning	0.38	.39	.40	.40	.41	.42	.43	.44	.50
Other End Uses[2]	2.21	2.22	2.25	2.26	2.29	2.32	2.35	2.39	2.59
Total	**8.73**	**8.94**	**8.96**	**8.99**	**9.06**	**9.11**	**9.15**	**9.19**	**9.21**
Liquefied Petroleum Gas									
Space Heating	.21	.18	.19	.19	.19	.19	.18	.17	.13
Water Heating	.09	.07	.07	.07	.08	.08	.08	.08	.08
Total	**.30**	**.25**	**.26**	**.27**	**.27**	**.26**	**.26**	**.25**	**.21**
Fuel Oil[3]									
Space Heating	.93	1.06	1.01	1.01	.99	.97	.95	.92	.73
Water Heating	.21	.24	.22	.22	.22	.22	.22	.22	.22
Total	**1.14**	**1.30**	**1.23**	**1.23**	**1.21**	**1.19**	**1.17**	**1.14**	**.95**
Natural Gas									
Space Heating	3.06	3.12	3.12	3.12	3.14	3.15	3.15	3.14	2.99
Water Heating	1.02	1.03	1.03	1.02	1.03	1.03	1.03	1.04	1.05
Air Conditioning	.01	.01	.01	.01	.01	.01	.01	.02	.02
Other End Uses[2]	.56	.56	.55	.55	.55	.55	.55	.55	.56
Total	**4.65**	**4.72**	**4.72**	**4.71**	**4.73**	**4.74**	**4.75**	**4.74**	**4.61**
Coal									
Space Heating	.08	.07	.07	.07	.07	.07	.06	.06	.06
Total	**.08**	**.07**	**.07**	**.07**	**.07**	**.07**	**.06**	**.06**	**.06**
Electricity									
Space Heating	.23	.25	.27	.29	.31	.32	.34	.36	.45
Water Heating	.31	.32	.33	.33	.34	.35	.36	.37	.41
Air Conditioning	.37	.37	.38	.39	.40	.41	.42	.43	.48
Other End Uses[2]	1.65	1.66	1.69	1.71	1.74	1.77	1.80	1.84	2.03
Total	**2.56**	**2.61**	**2.68**	**2.73**	**2.78**	**2.85**	**2.91**	**2.99**	**3.39**
Nonmarketed Fuel Consumption[1]									
Wood	**1.04**	**0.92**	**0.94**	**0.95**	**0.96**	**0.98**	**0.99**	**1.01**	**1.09**
Residential Activity									
Occupied Housing Stock (million units)	84.9	86.5	88.2	89.7	91.2	92.9	94.6	96.2	103.6
New Housing Construction[4] (million units)	1.5	2.0	2.1	1.9	2.0	2.1	2.1	2.1	1.8
Income Per Household (thousand 1984 dollars)	22.0	22.0	22.3	22.3	22.5	22.6	22.8	22.9	23.3
Energy Use Per Household (million Btu)	103	103	102	100	99	98	97	95	89
Fuel Expenditure Per Household (1984 dollars)	1,070	1,057	1,054	1,063	1,077	1,088	1,098	1,111	1,183

[1] Residential fuels are divided into marketed fuels (those with an associated price that are traded in economic markets) and nonmarketed fuels.
[2] Major other end uses include lighting, cooking, refrigeration, washing, and drying.
[3] Residential fuel oil category includes kerosene and distillate oil.
[4] New housing construction includes completions of single family, multifamily, and mobile housing units.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: The Residential model is documented in *Model Documentation: Household Model of Energy*, Energy Information Administration (DOE/EIA-0409) (Washington, DC, 1984). The major model data source is the public use tape of the Residential Energy Consumption Survey 1981, Energy Information Administration.
Input data file: Historical = MRG1126T, Projected = High World Oil Price Case, printed on December 21, 1984.
Historical quantities through 1983.

Table E7. Commercial Energy Use by Building Type
(Quadrillion Btu per Year)

Fuel and Building Type	High World Oil Price Case								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
Marketed Fuel Consumption									
Total Fuel Use	**5.75**	**6.15**	**6.24**	**6.34**	**6.47**	**6.58**	**6.68**	**6.78**	**7.00**
Liquefied Petroleum Gas	**.05**	**.03**	**.03**	**.03**	**.03**	**.03**	**.03**	**.03**	**.02**
Motor Gasoline	**.09**	**.09**	**.08**	**.08**	**.08**	**.08**	**.08**	**.08**	**.08**
Fuel Oil[1]									
Office[2]	.26	.31	.30	.31	.33	.33	.34	.35	.35
Retail/Wholesale	.17	.20	.19	.20	.21	.21	.21	.21	.20
Warehouse	.12	.15	.15	.16	.17	.18	.19	.20	.22
Other Buildings[3]	.22	.25	.25	.25	.26	.27	.27	.27	.26
Total	**.77**	**.91**	**.90**	**.93**	**.97**	**1.00**	**1.02**	**1.04**	**1.03**
Natural Gas									
Office[2]	.74	.75	.75	.76	.76	.77	.77	.77	.74
Retail/Wholesale	.75	.77	.78	.79	.80	.81	.82	.82	.82
Warehouse	.35	.36	.36	.37	.37	.37	.37	.37	.35
Other Buildings[3]	.76	.78	.78	.78	.78	.78	.78	.77	.71
Total	**2.60**	**2.66**	**2.67**	**2.68**	**2.71**	**2.72**	**2.73**	**2.73**	**2.62**
Coal	**.12**	**.11**	**.12**	**.12**	**.12**	**.12**	**.12**	**.11**	**.11**
Electricity									
Office[2]	.81	.90	.93	.95	.98	1.00	1.03	1.06	1.19
Retail/Wholesale	.61	.68	.71	.73	.75	.77	.79	.82	.93
Warehouse	.29	.32	.33	.34	.35	.36	.37	.38	.44
Other Buildings[3]	.41	.46	.47	.48	.49	.50	.51	.52	.58
Total	**2.12**	**2.36**	**2.45**	**2.50**	**2.57**	**2.64**	**2.71**	**2.79**	**3.14**
Commercial Activity									
Building Floorspace Stock (billion square feet)	48.5	51.1	52.6	53.7	55.2	56.5	58.0	59.3	65.3
Office[2]	17.0	18.0	18.6	18.9	19.4	19.9	20.4	20.9	23.0
Retail/Wholesale	14.5	15.4	15.9	16.3	16.8	17.3	17.8	18.2	20.3
Warehouse	6.9	7.2	7.5	7.7	7.9	8.1	8.3	8.5	9.5
Other Buildings[3]	10.1	10.5	10.7	10.9	11.1	11.3	11.5	11.7	12.5
Energy Use Per Square Foot (thousand Btu)	118.6	120.4	118.6	118.0	117.3	116.4	115.3	114.2	107.1
Expenditures Per Square Foot (1984 dollars)	1.30	1.31	1.32	1.33	1.35	1.37	1.37	1.39	1.45

[1] The commercial fuel oil category includes kerosene, distillate fuel, and residual fuel.
[2] Office includes offices, educational buildings, laboratories, health clinics, and some public buildings.
[3] Other Buildings includes assembly buildings, hotels/motels, hospitals, parking garages, and jails.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: The Commercial model is documented in *Model Documentation: Commercial Sector Energy Model*, Energy Information Administration (DOE/EIA-0453), August 1984. The major model source is the public use tape of the Nonresidential Energy Consumption Survey 1980, Energy Information Administration.
Input data file: Historical = MRG1126T, Projected = High World Oil Price Case, printed on December 21, 1984.
Historical quantities through 1983.

Table E8. Industrial Energy Use
(Quadrillion Btu per Year)

Fuel and End Use	High World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Industrial Heat and Power											
Distillate Fuel	1.44	1.70	1.29	1.60	1.50	1.49	1.51	1.54	1.57	1.59	1.68
Residual Fuel	1.58	1.40	.65	.85	.80	.79	.81	.83	.84	.85	.86
Liquefied Petroleum Gas	.13	.20	.57	.33	.32	.32	.32	.33	.33	.33	.33
Natural Gas[1]	8.50	7.08	5.56	6.08	6.22	6.32	6.45	6.56	6.53	6.50	6.18
Steam Coal[2]	1.43	1.46	1.50	1.72	1.75	1.90	1.98	2.06	2.13	2.19	2.35
Electricity[3]	2.34	2.76	2.65	2.63	2.67	2.75	2.90	3.05	3.19	3.34	3.94
Total	**15.43**	**14.61**	**12.21**	**13.21**	**13.27**	**13.57**	**13.98**	**14.38**	**14.58**	**14.80**	**15.35**
Refinery Fuel											
Distillate Fuel	.03	.05	.01	.01	.01	.01	.01	.01	.01	.01	.01
Residual Fuel	.28	.31	.13	.13	.12	.12	.11	.11	.11	.11	.11
Liquefied Petroleum Gas	.04	.06	.03	.03	.02	.02	.02	.02	.02	.02	.03
Still Gas	1.06	1.20	1.13	1.16	1.21	1.20	1.19	1.19	1.19	1.20	1.23
Petroleum Coke	.40	.39	.40	.42	.38	.38	.37	.37	.37	.38	.38
Other Petroleum	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Electricity	NA	NA	NA	.12	.11	.11	.11	.11	.11	.11	.12
Natural Gas	1.11	.82	.59	.66	.63	.63	.63	.63	.63	.63	.65
Total	**2.92**	**2.84**	**2.28**	**2.52**	**2.48**	**2.46**	**2.45**	**2.45**	**2.45**	**2.45**	**2.51**
Feedstocks, Raw Materials, and Other Fuel Uses											
Motor Gasoline	.26	.18	.14	.13	.14	.15	.17	.19	.21	.24	.37
Kerosene	.16	.16	.14	.10	.09	.08	.09	.09	.09	.08	.07
Petroleum Feedstocks[4]	.73	1.22	.85	1.38	1.47	1.46	1.55	1.62	1.63	1.64	1.61
Liquefied Petroleum Gas[5]	1.07	.99	1.01	1.17	1.21	1.25	1.38	1.50	1.57	1.64	1.97
Special Naphthas	.17	.20	.16	.21	.20	.20	.21	.21	.21	.21	.20
Lubricants and Waxes	.23	.23	.20	.23	.22	.22	.23	.23	.24	.24	.24
Petroleum Coke	.16	.16	.10	.13	.21	.23	.25	.27	.29	.32	.47
Asphalt and Road Oil	1.26	1.16	.90	1.01	1.11	1.11	1.12	1.13	1.14	1.14	1.13
Net Blending Oil[6]	.12	.27	.06	-.01	-.03	-.02	-.01	.01	.03	.05	.23
Metallurgical Coal[2]	2.54	1.79	.96	1.15	1.19	1.25	1.32	1.37	1.38	1.38	1.34
Natural Gas Raw Materials[7]	.78	.63	.49	.55	.55	.55	.56	.56	.56	.56	.54
Net Coke Imports	-.01	.13	-.02	.00	.00	.00	.00	.00	.00	.00	.00
Hydropower	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03
Total	**7.49**	**7.15**	**5.03**	**6.06**	**6.37**	**6.50**	**6.90**	**7.21**	**7.39**	**7.54**	**8.20**
Total Industrial Demand	**25.84**	**24.60**	**19.52**	**21.78**	**22.12**	**22.54**	**23.33**	**24.03**	**24.41**	**24.80**	**26.07**

[1] Includes lease and plant fuel.
[2] Includes refinery steam coal. The metallurgical coal estimates for 1983 and 1984 are not fully comparable, in part because of different Btu conversion factors.
[3] Includes refinery electricity before 1984.
[4] Petrochemical feedstocks includes naphthas less than 400 degrees, other oils greater than 400 degrees, and some still gas.
[5] The LPG price for Industrial Heat and Power is used for LPG feedstocks in weighted average price calculations.
[6] Net blending oil includes jet fuel, plant condensate, unfractionated stream, some still gas, miscellaneous, natural gasoline, unfinished oils, aviation blending components, and motor gasoline blending components, net of oil reclassified in blending.
[7] The natural gas price for Industrial Heat and Power is used for natural gas raw materials in weighted average price calculations.
[NA] = Not available.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: The Industrial model is documented in *Documentation of the PURHAPS Industrial Demand Model, Vol 1: Model Description, Overview, and Assumptions for the 1983 Annual Energy Outlook*, DOE/EIA-0420/1 (Washington, DC, 1984).
Input data file: Historical = MRG1126T, Projected = High World Oil Price Case, printed on December 21, 1984.
Historical quantities through 1983.

Table E9. Transportation Sector Energy Use By Mode

Fuel and Mode of Transportation	High World Oil Price Case								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
All Modes[1]									
Aviation Gasoline	0.05	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.09
Distillate Fuel	2.84	2.67	2.63	2.70	2.78	2.89	3.01	3.14	4.04
Jet Fuel	2.14	2.35	2.32	2.37	2.42	2.45	2.48	2.50	2.53
Motor Gasoline	12.47	12.67	12.46	12.02	11.67	11.38	11.15	10.96	10.11
Residual Fuel	.75	.74	.72	.73	.75	.77	.79	.81	.89
Liquefied Petroleum Gas	.03	.01	.01	.01	.01	.01	.01	.01	.01
Lubricants	.16	.22	.21	.21	.22	.22	.22	.23	.25
Natural Gas	.58	.61	.62	.62	.63	.63	.64	.64	.64
Electricity	.01	.01	.01	.01	.01	.01	.01	.01	.01
Total Consumption	**19.02**	**19.35**	**19.05**	**18.73**	**18.55**	**18.43**	**18.38**	**18.37**	**18.55**
Automobiles									
Vehicle-Miles Travelled[2]	1149.7	1,252.8	1,306.5	1,327.0	1,351.5	1,378.9	1,409.6	1,442.2	1,594.3
Fleet-Miles per Gallon	16.5	17.5	18.4	19.3	20.2	21.0	21.7	22.4	25.5
Total Fuel Use[3]	69.5	71.6	70.8	68.6	67.0	65.7	64.9	64.3	62.4
Trucks									
Vehicle-Miles Travelled[2]	449.1	484.6	498.9	508.8	520.7	534.6	550.0	566.9	669.7
Fleet-Miles per Gallon	10.5	11.1	11.6	12.1	12.5	13.0	13.4	13.8	15.9
Total Fuel Use[3]	42.6	43.8	43.1	42.2	41.6	41.2	41.0	40.9	42.1
Air									
Revenue Passenger-Miles[2]	300.1	354.3	366.8	387.8	411.9	433.0	455.9	476.6	565.0
Fuel Burned Per Seat-Mile[4]	.023	.022	.022	.021	.020	.019	.018	.017	.014
Total Jet Fuel[3]	16.0	17.6	17.4	17.7	18.1	18.3	18.6	18.7	18.9
Aviation Gasoline[3]	.4	.6	.6	.6	.6	.6	.6	.7	.7
Selected Fuel Expenditures[5]									
Motor Gasoline	128.4	128.0	128.7	129.4	130.7	132.2	133.9	135.5	157.3
Distillate Fuel	27.2	24.9	25.0	26.7	28.7	30.9	33.5	36.3	59.2

[1] Quadrillion Btu per year.
[2] Billion per year.
[3] Billion gallons per year.
[4] Gallons.
[5] Billion 1984 dollars per year.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Input data file: Historical = MRG1126T, Projected = High World Oil Price Case, printed on December 28, 1984.
Historical quantities through 1983.

Table E10. Electric Utility Fuel Consumption and Electricity Sales
(Quadrillion Btu per Year)

Fuel Consumption and Sales	High World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Fuel Inputs											
Oil											
Distillate	0.27	0.28	0.10	0.11	0.05	0.02	0.01	0.01	0.02	0.02	0.07
Residual LS[1]	NA	NA	NA	.69	.65	.66	.63	.64	.64	.68	.82
Residual HS[1]	3.24	3.71	1.45	.51	.48	.31	.28	.28	.27	.29	.35
Natural Gas	3.75	3.30	3.01	3.27	3.33	3.28	3.32	3.42	3.49	3.52	4.11
Steam Coal	8.66	10.25	13.23	14.05	14.94	15.01	15.30	15.59	16.06	16.72	19.54
Nuclear Power	.91	3.02	3.23	3.70	4.10	4.72	5.31	5.79	6.09	6.32	7.09
Hydropower/Other[2]	2.87	2.97	3.61	3.55	3.11	3.29	3.30	3.30	3.32	3.33	3.36
Total Fuel Inputs	19.71	23.53	24.63	25.87	26.66	27.29	28.14	29.04	29.89	30.88	35.37
Net Imports	.15	.20	.37	.41	.43	.48	.53	.58	.64	.70	.78
Total Electricity Inputs	**19.85**	**23.74**	**25.00**	**26.27**	**27.09**	**27.77**	**28.67**	**29.62**	**30.53**	**31.57**	**36.15**
Disposition											
Total Electricity Inputs	19.85	23.74	25.00	26.27	27.09	27.77	28.67	29.62	30.53	31.57	36.15
Minus Conversion Losses[3]	13.50	16.21	17.12	17.99	18.58	19.04	19.67	20.33	20.97	21.69	24.83
Generation	6.35	7.53	7.88	8.28	8.50	8.73	9.00	9.29	9.56	9.88	11.32
Minus Transportation and Distribution Losses	.51	.64	.55	.57	.58	.62	.63	.63	.63	.64	.73
Electricity Sales	**5.84**	**6.89**	**7.34**	**7.72**	**7.92**	**8.10**	**8.38**	**8.66**	**8.93**	**9.24**	**10.59**
Electricity Sales by End-Use Sector											
Residential	1.98	2.30	2.56	2.61	2.68	2.73	2.78	2.85	2.91	2.99	3.39
Commercial/Other[4]	1.53	1.82	2.13	2.37	2.46	2.51	2.58	2.65	2.72	2.80	3.15
Industrial	2.34	2.76	2.65	2.74	2.79	2.86	3.01	3.17	3.30	3.45	4.06
Total Electricity Sales	**5.84**	**6.89**	**7.34**	**7.72**	**7.92**	**8.10**	**8.38**	**8.66**	**8.93**	**9.24**	**10.59**

[1] Prior to 1984, only the total of high-sulfur and low-sulfur residual oil is available, and is reported here as high-sulfur.
[2] Includes renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[3] Conversion losses includes net imports.
[4] Commercial/Other includes street lighting and the transportation sector.
[NA] = Not available.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Input data file: Historical = MRG1126T, Projected = High World Oil Price Case, printed on December 21, 1984. Historical quantities through 1983.

Table E11. Electric Utility Sectoral Prices and Demands
(Billion Kilowatthours per Year)
(1984 Dollars per Thousand Kilowatthours)

Prices and Demands	High World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Prices[1]											
Residential	53.70	64.16	66.69	66.96	67.75	68.50	69.06	69.03	68.36	67.82	66.52
Commercial[2]	51.28	66.28	67.39	67.53	68.58	69.53	70.27	70.39	69.67	69.13	68.04
Industrial	26.34	41.59	56.62	56.85	57.49	58.23	58.82	58.75	58.07	57.48	55.96
All Sectors	**42.11**	**55.67**	**63.26**	**63.54**	**64.40**	**65.19**	**65.75**	**65.69**	**64.96**	**64.36**	**62.93**
Demands											
Residential	579	674	751	764	784	799	816	834	854	878	992
Commercial[2]	448	534	624	695	721	736	757	776	797	820	923
Industrial	686	809	776	804	817	840	883	928	967	1,012	1,190
All Sectors	**1,713**	**2,018**	**2,151**	**2,262**	**2,321**	**2,375**	**2,455**	**2,538**	**2,618**	**2,710**	**3,105**

[1] Prices for 1983 to 1995 are from model simulations and represent average revenues per kilowatthour of demand for the total electric utility industry. Revenue requirements are projected from the financial information contained on the Federal Energy Regulatory Commission Form 1 and Form 1-M and on the Energy Information Administration Form 412.
[2] This category includes consumption for street and highway lighting, other public authorities, and railroads and railways.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Prices for 1973 and 1978 are from the Energy Information Administration, *State Energy Price and Expenditure Report*, DOE/EIA-0376(81) (Washington, DC, 1984), pp.1-7. Historical demands are from the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83), (Washington, DC, 1984).

Table E12. Electric Utility Capacity and Generation
(Generation in Billion Kilowatthours per Year)
(Capacity in Million Kilowatts)

Capacity and Generation	High World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Capacity[1]											
Coal Steam	184.0	233.9	285.9	296.0	303.8	309.6	314.2	317.3	323.7	328.5	359.5
Other Steam	135.0	161.4	157.2	157.2	157.2	157.2	157.2	157.2	157.2	157.2	157.2
Combined Cycle	1.3	4.9	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.8	5.8
Turbine	37.1	49.6	50.7	51.0	51.4	51.6	51.6	51.7	52.3	52.7	56.7
Nuclear Power	21.0	53.5	64.4	68.9	80.5	91.4	99.8	104.7	105.9	109.6	116.8
Hydropower/Other[2]	55.6	63.2	69.0	69.8	71.0	71.4	71.6	72.0	72.2	72.9	73.1
Pumped Storage Hydropower[3]	8.4	12.7	13.3	14.6	16.0	16.7	16.7	16.9	18.8	19.1	19.2
Total Capacity	**442.4**	**579.2**	**646.2**	**663.2**	**685.5**	**703.5**	**716.8**	**725.5**	**735.8**	**745.8**	**788.4**
Generation by Plant Type[4]											
Coal Steam	848	976	1,268	1,347	1,428	1,436	1,465	1,494	1,540	1,603	1,880
Other Steam	619	629	365	369	356	346	345	354	361	368	421
Combined Cycle	NA	13	32	33	32	28	28	28	28	29	32
Turbine	36	29	13	15	15	13	13	14	13	13	29
Nuclear Power	83	276	294	335	372	428	482	526	553	574	644
Hydropower/Other[2]	274	284	345	336	295	315	315	316	318	321	324
Pumped Storage Hydropower[3]	NA	NA	−6	−6	−6	−9	−9	−10	−10	−11	−12
Total Generation	**1,861**	**2,206**	**2,310**	**2,428**	**2,492**	**2,558**	**2,639**	**2,722**	**2,803**	**2,897**	**3,318**
Generation by Fuel Type											
Coal[5]	848	976	1,259	1,341	1,422	1,430	1,459	1,488	1,534	1,597	1,873
Natural Gas	341	305	274	299	301	300	305	313	320	323	373
Oil	314	365	144	124	109	94	87	89	89	93	117
Nuclear Power	83	276	294	335	372	428	482	526	553	574	644
All Hydropower/Other[6]	274	283	339	329	289	306	306	306	308	309	312
Total Generation	**1,861**	**2,206**	**2,310**	**2,428**	**2,492**	**2,558**	**2,639**	**2,722**	**2,803**	**2,897**	**3,318**

[1] Capacity for 1973 and 1978 include capacity out of service or in inactive reserve; 1983 and projected capacity exclude capacity out of service or in inactive reserve. Three Mile Island Unit 1 is included in the 1983 and 1984 capacity estimates but is not expected to restart opetation until 1985.

[2] This category includes other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

[3] See Glossary, Electricity Terminology for definition of pumped storage plant.

[4] Net generation data for 1973 excludes combined cycle generation. For 1973 and 1978 the hydropower/other category also contains pumped storage hydropower. The 1983 values are model estimates based on the best available data.

[5] Generation by coal and generation by coal steam plants are not identical because small amounts of oil and natural gas are used in coal steam plants for startup and flame stability.

[6] This category includes conventional and pumped storage hydropower and other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Generation data for 1973, 1978, and 1983 are from the Energy Information Administration, *Form EIA-759, "Monthly Power Plant Report."* Historical capacity data for 1973 and 1978 are based on the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984). Other capacity data are from the Intermediate Future Forecasting System.

Table E13. Electric Utility Capacity Additions
(Thousand Kilowatts)

Additions: Pipeline and New Starts	High World Oil Price Case												
	1983	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**
Total Additions													
Nuclear Power[1]	3,064	4,480	12,369	10,939	8,391	4,884	1,235	3,702	3,690	2,464	1,065	0	0
Coal Steam	5,720	10,082	7,783	5,860	4,586	3,109	6,394	4,782	10,654	5,025	6,421	3,665	5,254
Other Steam[2]	61	3	0	0	0	0	0	100	0	0	0	0	0
Turbines[3]	202	275	385	197	40	130	561	343	330	113	200	1,390	2,057
Pumped Storage Hydropower[4]	260	1,264	1,400	700	0	200	1,923	285	0	0	0	150	0
Hydropower/Other[5]	1,034	874	1,163	383	242	407	200	706	75	74	26	0	6
Total New Capacity	**10,342**	**16,978**	**23,100**	**18,078**	**13,258**	**8,729**	**10,313**	**9,919**	**14,749**	**7,676**	**7,712**	**5,205**	**7,317**
Pipeline[6]													
Nuclear Power[1]	3,064	4,480	12,369	10,939	8,391	4,884	1,235	3,702	3,690	2,464	1,065	0	0
Coal Steam	5,720	10,082	7,783	5,860	4,586	3,109	6,394	4,782	10,654	5,025	5,718	2,764	3,347
Other Steam[2]	61	3	0	0	0	0	0	100	0	0	0	0	0
Turbines[3]	202	275	385	197	40	130	561	343	330	113	200	0	143
Pumped Storage Hydropower[4]	260	1,264	1,400	700	0	200	1,923	285	0	0	0	150	0
Hydropower/Other[5]	1,034	874	1,163	383	242	407	200	706	75	74	26	0	6
Total Pipeline	**10,342**	**16,978**	**23,100**	**18,078**	**13,258**	**8,729**	**10,313**	**9,919**	**14,749**	**7,676**	**7,009**	**2,914**	**3,496**
New Starts[7]													
Nuclear Power[1]	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal Steam	0	0	0	0	0	0	0	0	0	0	703	901	1,907
Other Steam[2]	0	0	0	0	0	0	0	0	0	0	0	0	0
Turbines[3]	0	0	0	0	0	0	0	0	0	0	0	1,390	1,914
Pumped Storage Hydropower[4]	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydropower/Other[5]	0	0	0	0	0	0	0	0	0	0	0	0	0
Total New Starts	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**703**	**2,291**	**3,821**

[1] Includes the scheduled return to service of the Three Mile Island 1 facility.
[2] Includes natural gas, oil, and dual fired oil/natural gas steam and combined cycle capacity.
[3] Includes all gas turbine and internal combustion capacity.
[4] See Glossary, Electricity Terminology for definition of pumped storage plant.
[5] Includes conventional hydroelectric and other renewable sources of power such as geothermal, wood, waste, solar, and wind.
[6] Includes all new capacity announced by the electric utility industry.
[7] Includes additional new capacity considered necessary to meet projected electricity demands.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: The Energy Information Administration Generating Unit Reference file (GURF); the Federal Energy Regulatory Commission, *Hydroelectric Power Resources of the United States - Developed and Undeveloped*, FERC-0070, January 1, 1980; Energy Information Administration, *U.S. Commercial Nuclear Power*, DOE/EIA-0315 (Washington, DC, March 1982); and the Energy Information Administration Form-254: "Quarterly Progress Report on Status of Reactor Construction."

Table E14. Summary of Components of Electricity Price
(1984 Dollars per Thousand Kilowatthours)

Price Components	High World Oil Price Case												
	1983	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**
Capital Component[1]	25.44	25.52	25.54	26.34	26.74	26.40	25.24	24.07	23.25	22.43	21.39	20.36	19.48
Fuel Component[2]	22.65	22.81	23.34	23.05	23.21	23.61	24.16	24.88	25.53	26.19	26.89	27.66	28.64
O&M Component[3]	15.25	15.21	15.51	15.80	15.81	15.68	15.55	15.40	15.28	15.20	15.06	14.94	14.81
Total Price[4]	**63.34**	**63.54**	**64.40**	**65.19**	**65.75**	**65.69**	**64.96**	**64.36**	**64.06**	**63.81**	**63.34**	**62.97**	**62.93**

[1] The capital component represents the cost to the utility of capital assets needed to provide reliable service. It includes plant depreciation, taxes, and sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.
[2] The fuel component includes only the direct costs of fuel inputs used to generate electricity required to meet demand.
[3] The operation and maintenance (O&M) component includes all nonfuel costs necessary to operate and maintain generation, transmission, and distribution capacity used to deliver electricity to end-use sectors.
[4] All prices are from model simulations and represent average revenues per kilowatthour of demand for the total electric utility industry. Revenue requirements are projected from the financial information contained on the Federal Energy Regulatory Commission, Form FERC-1 and Form 1-M and on the Energy Information Administration, Form EIA-412.
NOTE: Total may not equal sum of components because of independent rounding.

Table E15. Petroleum Supply and Disposition Balance
(Million Barrels per Day)

Supply and Disposition	High World Oil Price Case										
	1973	**1978**	**1983**	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**
Production											
Crude Oil[1]	9.21	8.71	8.69	8.76	8.86	8.76	8.70	8.67	8.70	8.81	8.94
Alaska North Slope	.00	1.09	1.65	1.67	1.70	1.76	1.92	1.97	2.07	2.16	1.26
Subarctic	9.21	7.62	7.04	7.08	7.15	7.00	6.78	6.70	6.63	6.65	7.68
Natural Gas Plant Liquids	1.74	1.57	1.56	1.61	1.64	1.55	1.58	1.58	1.57	1.56	1.37
Other Domestic[2]	.00	.00	.05	.05	.05	.05	.05	.05	.07	.09	.35
Processing Gain[3]	.45	.50	.49	.55	.54	.49	.49	.49	.50	.50	.52
Total Production	**11.40**	**10.78**	**10.79**	**10.97**	**11.09**	**10.85**	**10.82**	**10.80**	**10.84**	**10.96**	**11.18**
Imports (including SPR)											
Crude Oil[4]	3.24	6.36	3.33	3.48	3.99	4.05	4.08	4.09	4.04	3.94	3.71
Refined Products	3.01	2.01	1.72	1.95	1.39	1.46	1.59	1.72	1.79	1.89	2.28
Total Imports	6.26	8.36	5.05	5.43	5.38	5.51	5.67	5.81	5.83	5.82	6.00
Exports											
Crude Oil	.00	.16	.16	.18	.17	.17	.17	.17	.17	.17	.17
Refined Products	.23	.20	.58	.49	.45	.61	.61	.61	.61	.61	.61
Total Exports	.23	.36	.74	.67	.62	.78	.78	.78	.78	.78	.78
Net Imports (including SPR)	**6.02**	**8.00**	**4.31**	**4.76**	**4.76**	**4.72**	**4.88**	**5.03**	**5.05**	**5.04**	**5.21**
Primary Stock Changes											
Net Withdrawals[5]	–.14	.26	.25	.04	.00	.03	–.03	–.04	–.02	–.03	–.03
SPR Fill Rate Additions (-)[6]	.00	–.16	–.23	–.18	–.14	–.14	–.14	–.14	–.14	–.14	.00
Total Primary Supply[7]	**17.29**	**18.87**	**15.11**	**15.59**	**15.70**	**15.45**	**15.53**	**15.64**	**15.72**	**15.83**	**16.36**
Refined Petroleum Products											
Motor Gasoline	6.67	7.41	6.62	6.72	6.61	6.39	6.21	6.07	5.97	5.88	5.50
Aviation Gasoline	.05	.04	.03	.04	.04	.04	.04	.04	.04	.04	.05
Jet Fuel[8]	1.06	1.06	1.05	1.15	1.13	1.16	1.18	1.20	1.21	1.22	1.23
Kerosene	.22	.18	.13	.11	.10	.10	.10	.10	.10	.10	.09
Distillate Fuel	3.09	3.43	2.69	2.88	2.76	2.78	2.82	2.89	2.95	3.01	3.42
Residual Fuel	2.82	3.02	1.42	1.42	1.39	1.29	1.28	1.31	1.33	1.36	1.49
Liquid Petroleum Gas	1.45	1.41	1.49	1.36	1.39	1.42	1.52	1.61	1.67	1.72	1.93
Petrochemical Feedstocks	.36	.59	.42	.68	.72	.71	.76	.79	.80	.80	.79
Other Petroleum Products[9]	1.59	1.70	1.37	1.50	1.56	1.57	1.60	1.63	1.65	1.68	1.85
Total Product Supplied	**17.31**	**18.85**	**15.23**	**15.86**	**15.70**	**15.45**	**15.53**	**15.64**	**15.72**	**15.83**	**16.36**

See footnotes at end of table.

Table E15. Petroleum Supply and Disposition Balance (Continued)
(Million Barrels per Day)

Supply and Disposition	High World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Refined Petroleum Products Supplied to End-Use Sectors											
Residential and Commercial	2.23	2.07	1.20	1.29	1.25	1.27	1.28	1.28	1.28	1.26	1.14
Industrial[10]	4.48	4.87	4.03	4.52	4.58	4.60	4.81	4.99	5.10	5.21	5.72
Transportation	9.05	10.14	9.33	9.48	9.32	9.15	9.04	8.97	8.93	8.92	8.96
Electric Utilities	1.54	1.75	.68	.58	.51	.43	.40	.41	.41	.43	.55
Total End-Use Consumption	**17.30**	**18.84**	**15.23**	**15.86**	**15.67**	**15.45**	**15.53**	**15.64**	**15.72**	**15.83**	**16.36**
Discrepancy[11]	-.01	.04	-.12	-.27	.03	.00	.00	.00	.00	.00	.00
Net Disposition[12]	**17.29**	**18.87**	**15.11**	**15.59**	**15.70**	**15.45**	**15.53**	**15.64**	**15.72**	**15.83**	**16.36**

[1] Includes lease condensate.
[2] Other Domestic prior to 1981 includes unfinished oils (net), hydrogen, and hydrocarbons not included elsewhere. After 1981, Other Domestic includes unfinished oils (net), motor gasoline blending components (net), aviation gasoline blending components (net), hydrogen, other hydrocarbons, alcohol, and synthetic crude production.
[3] Represents volumetric gain in refinery distillation and cracking processes.
[4] In 1977 and later years, crude oil imports include crude oil imported for the Strategic Petroleum Reserve.
[5] Net stock withdrawals for a given year, t, are defined as the change in yearend stock levels from period t-1 minus the yearend stock level from the year t. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.
[6] SPR is the Strategic Petroleum Reserve.
[7] Total primary supply is defined as total production plus net imports plus net stock withdrawals minus SPR additions.
[8] Jet fuel includes naphtha and kerosene type.
[9] Other petroleum products includes miscellaneous petroleum products, lubricants, waxes, unfractionated stream, plant condensate, natural gasoline, asphalt, road oil, still gas, special naphthas, and petroleum coke.
[10] Industrial refined products includes total industrial demand for petroleum as reported in Table 8.
[11] Discrepancy represents the difference between total supply and total products supplied.
[12] Net disposition is the sum of total products supplied and discrepancy.
NOTE: From 1981 onward, the product supplied data is on a new basis. From 1983 onward, the other product category is on a net basis, reclassified (petroleum products reprocessed into other categories) plus the other category of products supplied.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical data are from Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984) pp. 79-99, Tables 35, 36, 37, and 45. Projected values are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = High World Oil Price Case, printed on December 28, 1984.
Historical quantities through 1983.

Table E16. Petroleum Product Prices
(1984 Dollars per Barrel)

Sector and Fuel	High World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Crude Oil Prices											
World Oil Price[1]	**8.62**	**21.63**	**30.39**	**29.00**	**30.00**	**32.00**	**34.00**	**36.00**	**38.00**	**40.00**	**55.00**
Refiner Acquisition Cost[2]	**8.77**	**18.50**	**30.39**	**29.00**	**30.00**	**32.00**	**34.00**	**36.00**	**38.00**	**40.00**	**55.00**
Delivered Sector Product Prices											
Residential and Commercial											
Distillate Fuel	19.35	29.95	43.90	42.49	43.31	45.65	47.86	50.20	52.60	55.13	72.82
Kerosene	20.04	32.11	44.72	41.07	41.83	44.13	46.31	48.63	51.00	53.50	71.27
Motor Gasoline[3]	34.52	41.22	54.27	53.26	54.46	56.79	59.11	61.29	63.38	65.23	82.08
Residual Fuel	11.44	20.53	34.41	33.30	33.48	35.29	36.88	38.67	40.58	42.92	54.55
Liquefied Petroleum Gas[4]	26.12	24.96	32.87	27.76	28.47	30.09	31.63	33.24	34.90	36.63	48.61
Average[5]	**20.23**	**28.21**	**40.89**	**39.29**	**39.90**	**42.02**	**44.02**	**46.14**	**48.33**	**50.67**	**66.63**
Industrial											
Distillate Fuel	11.52	24.55	38.01	36.57	37.44	39.83	42.10	44.48	46.94	49.51	67.38
Kerosene	12.09	26.14	39.01	37.56	38.46	40.90	43.22	45.65	48.16	50.79	69.02
Motor Gasoline[3]	34.75	41.07	54.52	53.51	54.71	57.02	59.32	61.49	63.56	65.39	82.14
Residual Fuel	10.65	19.86	28.46	27.35	27.56	29.41	31.06	32.90	34.85	37.23	48.91
Liquefied Petroleum Gas	11.19	18.98	28.58	24.38	24.97	26.57	28.09	29.69	31.34	33.06	45.02
Petrochemical Feedstocks[6]	11.05	23.78	34.53	33.08	33.88	36.14	38.42	40.80	43.25	45.81	63.60
Asphalt & Road Oil	13.12	27.97	26.38	25.75	25.87	26.92	27.84	28.88	29.99	31.34	38.03
Petroleum Coke	11.91	25.39	7.67	7.61	7.67	7.81	7.93	8.07	8.22	8.39	9.26
Special Naphthas	10.38	22.12	34.27	32.99	33.79	35.95	38.01	40.17	42.40	44.73	60.89
Miscellaneous Petroleum Products	12.35	26.10	33.86	32.27	33.03	35.31	37.48	39.80	42.22	44.82	62.27
Average[5]	**12.25**	**23.19**	**30.27**	**28.56**	**28.93**	**30.67**	**32.35**	**34.13**	**35.95**	**37.89**	**50.65**
Transportation[7]											
Distillate Fuel	20.27	29.35	55.82	54.39	55.28	57.69	59.97	62.37	64.84	67.43	85.40
Aviation Gasoline	40.10	52.84	70.43	68.78	70.72	74.49	78.23	81.76	85.14	88.11	115.42
Motor Gasoline[3]	34.39	40.85	54.08	53.06	54.25	56.57	58.86	61.03	63.11	64.94	81.72
Jet Fuel[8]	11.48	25.41	37.94	36.37	37.11	39.23	41.55	43.95	46.43	49.01	66.80
Residual Fuel[9]	8.47	14.12	22.66	21.58	21.78	23.62	25.23	27.05	28.98	31.35	43.08
Liquefied Petroleum Gas	10.75	17.55	30.54	36.37	36.96	38.58	40.11	41.71	43.37	45.11	57.14
Lubricants[10]	75.70	90.23	148.87	146.32	147.89	152.18	156.24	160.52	164.92	169.53	201.52
Average[5]	**29.51**	**37.09**	**52.13**	**51.17**	**52.22**	**54.46**	**56.67**	**58.87**	**61.05**	**63.14**	**80.44**
Electric Utilities											
Distillate Fuel	10.92	21.53	45.38	41.46	40.70	36.70	39.85	47.07	53.55	56.44	69.60
Residual Fuel	10.37	19.91	29.51	28.49	28.77	31.37	33.16	35.00	36.97	39.36	51.18
Average[5]	**10.42**	**20.03**	**30.57**	**29.67**	**29.31**	**31.49**	**33.22**	**35.19**	**37.41**	**39.79**	**52.36**
Refined Petroleum Product Prices											
Distillate Fuel	17.57	28.12	48.50	46.10	47.15	49.64	52.00	54.47	57.04	59.76	78.50
Kerosene	17.27	29.55	41.70	39.55	40.41	42.81	45.04	47.41	49.86	52.43	70.43
Aviation Gasoline	40.10	52.84	70.43	68.78	70.72	74.49	78.23	81.76	85.14	88.11	115.42
Motor Gasoline[3]	34.40	40.85	54.08	53.06	54.26	56.58	58.87	61.04	63.12	64.95	81.74
Jet Fuel[8]	11.48	25.41	37.94	36.37	37.11	39.23	41.55	43.95	46.43	49.01	66.80
Residual Fuel	10.35	19.12	28.14	27.07	27.30	29.33	30.94	32.76	34.68	37.08	48.83
Liquefied Petroleum Gas	16.46	20.88	29.37	24.96	25.56	27.15	28.63	30.20	31.82	33.53	45.37
Lubricants (Transportation)[10]	75.70	90.23	148.87	146.32	147.89	152.18	156.24	160.52	164.92	169.53	201.52
Petrochemical Feedstocks[6]	11.05	23.78	34.53	33.08	33.88	36.14	38.42	40.80	43.25	45.81	63.60
Asphalt & Road Oil	13.12	27.97	26.38	25.75	25.87	26.92	27.84	28.88	29.99	31.34	38.03
Petroleum Coke	11.91	25.39	7.67	7.61	7.67	7.81	7.93	8.07	8.22	8.39	9.26
Special Naphthas	10.38	22.12	34.27	32.99	33.79	35.95	38.01	40.17	42.40	44.73	60.89
Miscellaneous Petroleum Products	12.35	26.10	33.86	32.27	33.03	35.31	37.48	39.80	42.22	44.82	62.27

[1] The cost of imported crude oil to U.S. refiners in 1984 dollars per barrel.
[2] Refiner acquisition cost is an average of imported and domestic refiner acquisition costs.
[3] Gasoline price is an average price for all types.
[4] Residential and commercial liquefied petroleum gas price includes only a residential price due to data limitations.
[5] Weighted average price; the weights are taken from the consumption categories from Table 4 and converted to physical units.
[6] Petrochemical feedstock price includes only the price of naphthas less than 400 degrees.
[7] Transportation prices include the appropriate State road use taxes and Federal excise tax.
[8] Jet fuel price is a retail price for kerosene type jet fuel.
[9] Residual fuel price in the transportation sector is for marine bunker.
[10] Lubricant price is an average for light stocks and multiweight motor oil.

NOTE: Implicit Gross National Product Price Deflator, rebased to 1984 = 1.0, was used to convert from nominal to real dollars.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical prices are taken from Energy Information Administration, *State Energy Price and Expenditure Report,* DOE/EIA-0376(81) (Washington, DC, 1984), pp. 1-7. Projected values are output from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = High World Oil Price Case, printed on December 21, 1984.
Historical quantities through 1983.

Table E17. Natural Gas Supply, Disposition, and Prices
(Trillion Cubic Feet per Year)
(1984 Dollars per Thousand Cubic Feet)

Supply, Disposition, and Prices	High World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Dry Gas Production[1]	21.73	19.12	15.97	17.43	17.48	17.55	17.62	17.71	17.62	17.46	16.78
Supplemental Natural Gas[2]	.00	.00	.14	.15	.15	.08	.15	.20	.18	.20	.41
Net Imports	.96	.91	.87	.86	.99	1.05	1.16	1.27	1.43	1.57	2.11
Net Storage Withdrawals[3]	-.42	-.15	.47	.03	.03	.00	.00	.00	.00	.00	.00
Total Supply[4]	**22.27**	**19.88**	**17.45**	**18.47**	**18.65**	**18.68**	**18.93**	**19.17**	**19.23**	**19.23**	**19.30**
Consumption by Sector[5]											
Residential	4.88	4.90	4.53	4.60	4.60	4.59	4.61	4.62	4.63	4.62	4.50
Commercial[6]	2.60	2.60	2.53	2.59	2.60	2.62	2.64	2.65	2.66	2.66	2.56
Industrial	8.69	6.76	5.47	6.01	6.11	6.21	6.34	6.44	6.41	6.40	6.13
Lease & Plant Fuel[7]	1.50	1.65	1.00	1.09	1.09	1.10	1.10	1.11	1.10	1.09	1.05
Transportation[8]	.73	.53	.56	.59	.60	.60	.61	.62	.62	.62	.62
Electric Utilities	3.66	3.19	2.91	3.16	3.22	3.17	3.21	3.30	3.37	3.40	3.97
Total End-Use Consumption	**22.05**	**19.63**	**17.00**	**18.04**	**18.22**	**18.28**	**18.51**	**18.74**	**18.80**	**18.79**	**18.82**
Unaccounted for[9]	.22	.25	.45	.43	.43	.40	.41	.43	.44	.44	.48
Average Wellhead Price	**.46**	**1.35**	**2.72**	**2.70**	**2.67**	**2.70**	**2.86**	**3.06**	**3.30**	**3.58**	**4.92**
Delivered Prices by Sectors											
Residential	2.71	3.78	6.37	6.16	6.09	6.14	6.32	6.55	6.92	7.27	9.17
Commercial[6]	1.99	3.33	5.73	5.69	5.63	5.64	5.79	5.99	6.33	6.65	8.41
Industrial	1.07	2.27	4.44	4.41	4.42	4.48	4.65	4.85	5.16	5.49	7.18
Electric Utilities	.75	2.18	3.73	3.59	3.76	3.75	3.94	4.13	4.38	4.72	6.24
Average to All Sectors[10]	**1.53**	**2.83**	**5.08**	**4.95**	**4.95**	**4.98**	**5.15**	**5.35**	**5.66**	**6.00**	**7.67**

[1] Net dry natural gas is defined as dry marketed production minus nonhydrocarbon gases removed.
[2] Prior to 1980 the amount of supplemental fuels included in the natural gas data cannot be determined. Supplemental natural gas includes synthetic natural gas (results from the manufacture, conversion, or the reforming of petroleum hydrocarbons), and propane air mixtures. After 1985 this quantity includes short-term spot market purchases that could include additional imports.
[3] Includes net stock withdrawals for dry natural gas from underground storage and liquefied natural gas. Net stock withdrawals are computed as the yearend stock levels from the current period subtracted from the yearend stock levels from the preceding period. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.
[4] Total supply is computed as dry gas production plus supplemental natural gas, net imports, and net stock withdrawals.
[5] Consumption values include small amounts of supplemental gas, which are not reported as production prior to 1980.
[6] Commercial category includes the other customer category.
[7] Lease and plant fuel natural gas represents natural gas used in the field gathering and processing plant machinery, usually totalled into the industrial sector for other consumption tables.
[8] Transportation natural gas is used to fuel the compressors in the pipeline pumping stations.
[9] Unaccounted for represents natural gas lost, the net result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure, and EIA's merger of different data reporting systems which vary in scope, format, definition, and respondent type.
[10] Weighted average price and the weights are the sectoral consumption values excluding lease and plant fuel and the transportation sector.

NOTE: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1984 equals 1.00. The natural gas prices in this table are average prices, total revenues divided by total sales for each customer class.

NOTE: Total may not equal sum of components because of independent rounding.

SOURCE: Historical data are taken from the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984) and Energy Information Administration, *Natural Gas Annual, 1982* DOE/EIA-0131(82) (Washington, DC, 1983). Projected values are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = MRG1126T, Projected = High World Oil Price Case, printed on December 21, 1984.

Historical quantities through 1983.

Table E18. Coal Supply, Disposition, and Prices

(Million Short Tons per Year)
(1984 Dollars per Short Ton)

Supply, Disposition, and Price	High World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production[1]											
East of the Mississippi	522	487	507	583	571	580	593	606	622	644	719
West of the Mississippi	76	183	275	309	328	342	353	365	382	404	483
Total	**599**	**670**	**782**	**892**	**899**	**921**	**946**	**970**	**1,004**	**1,048**	**1,202**
Imports[2]	(*)	3	1	1	1	0	0	0	0	0	0
Exports[3]	54	41	78	80	73	74	77	81	86	91	106
Net Imports	**-53**	**-38**	**-77**	**-79**	**-72**	**-74**	**-77**	**-81**	**-86**	**-91**	**-106**
Net Storage Withdrawals[4]	**12**	**11**	**27**	**-20**	**15**	**-2**	**-4**	**-4**	**-5**	**-7**	**-6**
Total Supply[5]	**557**	**644**	**733**	**793**	**842**	**845**	**865**	**886**	**913**	**949**	**1,091**
Consumption by Sector											
Residential and Commercial	11	10	8	8	8	8	8	7	7	7	7
Industrial	68	63	66	76	77	77	80	83	85	88	94
Coking Plants[6]	94	71	37	44	46	46	49	50	51	51	49
Electric Utilities	389	481	625	666	709	713	724	739	764	798	936
Synthetic Fuels	0	0	0	0	5	5	5	6	6	6	6
Total End-Use Consumption	**563**	**625**	**737**	**793**	**843**	**848**	**865**	**886**	**914**	**950**	**1,091**
Discrepancy[7]	-6	18	-4	-2	-3	-3	(*)	(*)	-1	-1	(*)
Average Minemouth Price[8]	**18.14**	**32.48**	**26.95**	**30.02**	**29.89**	**30.34**	**30.50**	**30.67**	**30.81**	**30.92**	**31.73**
Delivered Prices by Sector											
Residential and Commercial[9]	45.53	69.97	45.87	47.00	47.46	51.59	52.25	52.77	53.35	54.10	57.36
Industrial	26.89	49.65	40.79	43.70	44.75	50.01	51.17	52.25	53.43	54.56	59.88
Coking Plants[6]	38.52	77.33	61.51	60.87	61.52	64.87	65.47	66.09	66.80	67.69	70.75
Electric Utilities[10]	19.03	35.26	36.30	38.12	38.55	38.94	39.34	39.62	39.78	40.14	42.64
Average to All End-Use Sectors[11]	**23.76**	**42.04**	**38.07**	**40.01**	**40.46**	**41.48**	**42.03**	**42.44**	**42.69**	**43.07**	**45.48**

[1] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite with anthracite included in bituminous.
[2] Coal imports are not projected beyond 1985.
[3] Excludes small quantities of anthracite shipped overseas to U.S. Armed Forces and coke exports.
[4] From stocks held by end-use sectors (secondary stocks held at industrial plants, coke plants, and electric utility plants). Net stock withdrawals are computed as the yearend stock levels from the current period subtracted from the yearend stock levels from the preceding period. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.
[5] Total supply is equivalent to production plus net imports plus net storage withdrawals.
[6] Coke plants consume metallurgical coal which is a mixture of anthracite and bituminous coal. Historically, coking plant coal price is a weighted average of anthracite and bituminous coal types. In the projections, anthracite is included in bituminous coal.
[7] Historically, discrepancy represents revisions in producers (primary) stock levels, losses, and unaccounted for. In the projected period, discrepancy represents errors due to conversion factors.
[8] In historical years, the average production price of coal produced at the mine. Projected prices are based on estimated cost and do not reflect market conditions.
[9] Historically, residential price is used for residential and commercial consumers. Projected residential and commercial prices do not include dealer markup.
[10] Historically, electric utility price includes anthracite, bituminous, and lignite coal purchased under long-term contracts and on the spot market. In the projections, anthracite is included in bituminous coal, with the bituminous coal price being used for anthracite coal price.
[11] Weighted average price and the weights are the sectoral consumption values.
(*) Greater than zero but less than .5.

NOTE: Metallurgical coal prices reflect a reduced level of projected demand. Other projected coal prices are based on cost estimates, and do not reflect market conditions.
NOTE: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1984 equals 1.00. Projected coal prices are based on cost estimates and do not reflect market conditions.
NOTE: Total may not equal sum of components because of independent rounding.
SOURCE: Historical prices from Energy Information Administration, *State Energy Price and Expenditure Report*, , (DOE/EIA-0376(81) (Washington, DC, 1984) pp. 1-7. Historical quantities are from the Energy Information Administration, *Annual Energy Review, 1983* DOE/EIA-0384(83) (Washington, DC, 1984) pp. 161-169, Table 73, 74, and 75. Projected values are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = MRG1126T, Projected = High World Oil Price Case, printed on December 21, 1984.
Historical quantities through 1983.

Table E19. National Macroeconomic Indicators

Macroeconomic Indicators	High World Oil Price Case										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
World Oil Price[1]	**8.62**	**21.63**	**30.39**	**29.00**	**30.00**	**32.00**	**34.00**	**36.00**	**38.00**	**40.00**	**55.00**
NIPA Variables[2]											
Real GNP (billion 1972 dollars)	1,254	1,439	1,535	1,643	1,687	1,712	1,774	1,836	1,890	1,941	2,168
Real Disposable Income (billion 1972 dollars)	865	989	1,095	1,168	1,202	1,223	1,255	1,285	1,318	1,347	1,476
Real Disposable Income Per Capita (thousand 1972 dollars)	4.1	4.4	4.7	4.9	5.0	5.1	5.2	5.2	5.3	5.4	5.7
NIPA GNP Price Deflator (1972=1.00)	1.057	1.504	2.153	2.233	2.318	2.440	2.583	2.743	2.916	3.101	4.270
GNP Growth (1984 reference year)	NA	NA	NA	.0	2.7	4.2	8.0	11.8	15.0	18.1	32.0
Unemployment Rate, Civilian Workers (percent)	4.9	6.1	9.6	7.5	7.3	7.9	7.7	7.2	7.0	7.1	7.6
Population, Noninstitutional (million persons)	211.9	222.6	234.0	236.2	238.5	240.7	243.0	245.2	247.4	249.5	259.4
New, High Grade Bond Rate (percent per annum)	7.65	8.88	11.56	12.62	12.76	12.26	11.65	11.21	10.83	10.45	9.15
New Home Mortgage Yields (percent per annum)	8.08	9.69	13.35	13.56	13.90	13.35	12.58	12.00	11.73	11.49	10.16
Total Industrial Production Index (1967=1.00)	1.30	1.46	1.48	1.64	1.70	1.75	1.85	1.94	2.00	2.05	2.28
Total Manufacturing Output Index (1967=1.00)	1.30	1.47	1.48	1.66	1.72	1.76	1.88	1.97	2.04	2.10	2.35
Housing Starts (million units)	2.04	2.00	1.70	1.79	1.59	1.73	1.81	1.84	1.77	1.68	1.43
Energy Usage Indicators											
Gross Energy Use per Capita (million Btu per person)	350.1	350.6	301.8	316.6	316.8	316.9	319.8	322.6	324.3	326.5	333.0
Gross Energy Use per Dollar of GNP (thousand Btu per 1972 dollar)	59.2	54.2	46.0	45.5	44.8	44.6	43.8	43.1	42.5	42.0	39.9
Net Oil Imports (billion 1984 dollars)	15.0	56.5	47.0	52.7	51.4	54.7	59.7	64.6	68.2	71.5	99.3
Net Coal Imports (billion 1984 dollars)	-2.1	-2.9	-3.9	-4.2	-3.9	-4.0	-4.1	-4.4	-4.6	-5.0	-6.1

[1] The cost of imported crude oil to U.S. refiners in 1984 dollars per barrel.
[2] National Income and Product Accounts.
NOTE: Total may not equal sum of components because of independent rounding.

Appendix F
Forecasting Methodology and Assumptions

APPENDIX F
Forecasting Methodology and Assumptions

The Basic Models

The forecasts presented in this Annual Energy Outlook result from the interaction among model representations of the key energy supply, conversion, and consuming sectors. The forecasts represent solutions to the integrating framework of the Intermediate Future Forecasting System (IFFS),[1] which provides an internally consistent set of prices and quantities for which energy supplies equal consumption on an annual basis. The assumptions underlying the representations reflect recently published values for historical data, empirically estimated relationships observed over recent history, and plausible paths for future behavior.

Natural gas supply in the IFFS is represented by the Gas Analysis Modeling System (GAMS).[2] Although the GAMS itself is an independent representation of the gas markets, it is used as the IFFS natural gas supply module in the context of the linked IFFS/GAMS.[3]

The IFFS accommodates for the major economic factors affecting energy supply and demand, including interfuel competition and Government policies and regulations. Although the IFFS includes some representation of new technologies, it emphasizes the major fuels. The IFFS consists of a central integrating procedure, together with individual modules for electric utilities, oil refining, natural gas supply, coal supply, and energy demand by end-use sector. Interactions between the energy sector and the overall economy are represented in the end-use demands sector.[4] The current operation of the model is depicted in Figure F1.

A major external input to the IFFS analyses of energy is the projected world price of crude oil. Future crude oil prices are estimated using the Oil Market Simulation (OMS) Model[5] to account for production capacity, economic growth, and demand in the market economies. The baseline assumptions about the behavior of the domestic economy are based on values for gross national product and other macroeconomic variables forecast by Data Resources, Inc.[6]

Individual Modules

Each module simulates either the consumption activities of end-users or the operating and investment activities of firms supplying major energy forms. On the

---

[1] Energy Information Administration, Intermediate Future Forecasting System: Executive Summary, DOE/EIA-0430 (Washington, DC, 1983).

[2] Energy Information Administration, Model Documentation of the Gas Analysis Modeling System, DOE/EIA-0450, Volumes 1-3 (Washington, DC, 1984).

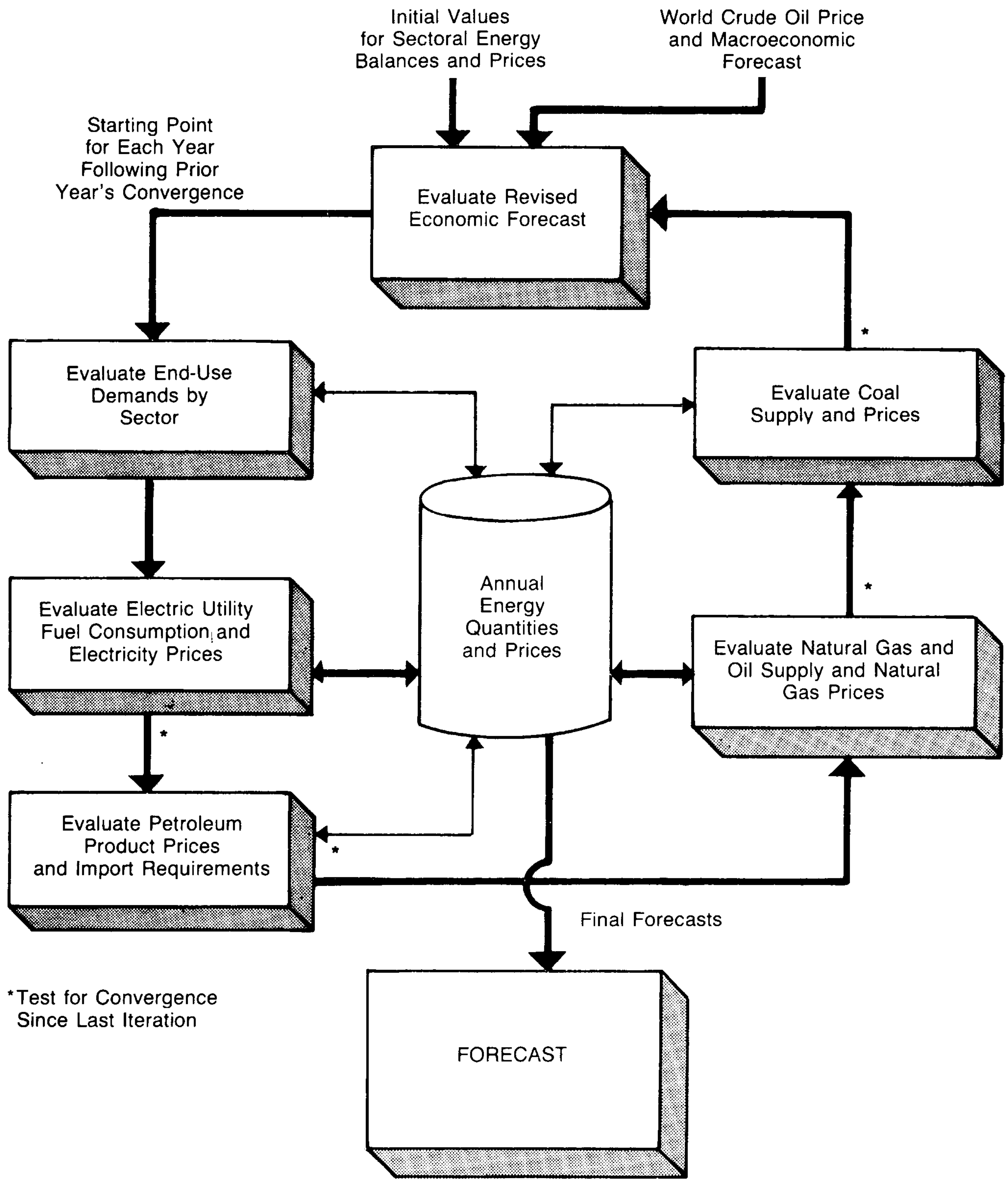
[3] Energy Information Administration, Linkage Methodology of the Intermediate Future Forecasting System/Gas Analysis Modeling System Interface for the Annual Energy Outlook, 1983, DOE/EIA-0456 (Washington, DC, 1984).

[4] Energy Information Administration, Office of Energy Markets and End Use, Model Documentation of the Mini-Macroeconomic Model: MINMAC, in clearance as of December 1984 (Washington, DC).

[5] Energy Information Administration, Oil Market Simulation Model Documentation Report, DOE/EIA-0412(83/06) (Washington, DC, 1983).

[6] Data Resources, Inc., U.S. Long-Term Review, Fall and Summer 1984 issues (Lexington, MA).

Figure F1. IFFS/GAMS Calculation Flow



demand side, separate modules are used to represent the residential, commercial, industrial, and transportation sectors. The supply modules include electric utilities, oil refining, natural gas, and coal. Although the results presented in the Annual Energy Outlook are for the United States as a whole, the IFFS contains regional disaggregation that varies by module as necessary to adequately represent regional diversification. Regionalized activities are integrated through a transportation network where appropriate, primarily in the coal and natural gas supply module.

The individual supply modules have essentially the same basic structure for representing operating and investment decisions. Operating decisions use only current period prices. Investment projections are made based on past and projected future prices. The calculations are made under the assumption that energy producers are cost-minimizers. This is consistent with market conditions in which no single coal, oil, or natural gas firm represents a market force that is significant enough to affect prices measurably. Electric utilities are treated as regulated regional monopolies that attempt to minimize cost.

Consuming Sectors

The residential and commercial modules compute consumption of major energy forms taking account of the stock of structures, available fuel choices, and energy utilization by end use.[7] The modules are disaggregated by end uses (including space heating, water heating, and air conditioning) and several fuel/technology types. Structures are analyzed on the basis of groupings by major regions and year of construction.

Industrial demands for direct heat, process steam from boilers, and power, including machine drive, are forecast for each of 17 categories of manufacturing activity. These demands are sensitive to manufacturing output, capital availability, and labor, material, and energy prices.[8] Heat and power consumption outside of manufacturing and petroleum feedstocks use at the national level are projected by econometric equations that differ from sector to sector. In most cases, the projection is dominated by historical trends in the ratio of fuel use to economic activity.

The demand for transportation sector services is disaggregated into the following categories: passenger cars, single-unit and combination trucks, piston aircraft, commercial jets, marine bunker fuel use, jet fuel use, and liquefied petroleum gas use.[9] Highway motor gasoline and distillate fuel use are calculated as the

---

[7]Energy Information Administration, Model Documentation: The Household Model of Energy, DOE/EIA-0409 and Model Documentation: The Commercial Sector Energy Model, DOE/EIA-0453 (Washington, DC, 1984).

[8]Energy Information Administration, Documentation of the PURHAPS Industrial Demand Model, Volume I: Model Description, Overview, and Assumptions for the 1983 Annual Energy Outlook, DOE/EIA-0420/1 (Washington, DC, 1984).

[9]Energy Information Administration, Model Documentation: The Transportation Sector Energy Model, DOE/EIA-0454 (Washington, DC, 1984).

product of estimated average fleet efficiency in gallons per mile and vehicle-miles traveled, both of which are responsive to projected prices and economic activity. Estimates of fuel use in the remaining transportation subsectors (rail, marine, LPG, and off-highway diesel use) are based on historical trends, economic activity, and fuel prices.

Energy Conversion Sectors

The Electric Market Module[10] estimates capacity expansion and simulates regulatory behavior in pricing electricity as a function of operating and capital costs. The electric utility industry uses a variety of plant types and fuel inputs: coal-, gas-, or oil-fired steam; gas or oil combined cycle; gas or oil turbines; and nuclear and hydroelectric energy. The utilization of generating capacity is forecast to depend on relative generation costs, reliability, and demand; while capacity expansion is a function of total annualized system cost. Under the current regulatory structure, the supply price is based on the average cost of generation, composed of fuel and operation and maintenance costs. Capital cost includes a capital charge on the undepreciated portion of existing plants and a capital charge for construction work in progress, where allowed.

The petroleum sector contains a representation of refineries and refined product demand.[11] The costs of refined products depend on the world price of oil, the costs of refining the product mix, and transportation and distribution costs. The quantity of imported crude oil is calculated as the difference between the total crude oil input to refineries (determined by the refinery module) and domestic crude production.

Oil, Natural Gas, and Coal Production

The domestic oil and gas supply projections are based on estimates of certain categories of production and EIA analysis systems external to IFFS: the Outer Continental Shelf Oil and Gas Supply Model (OCSM)[12] and the Production of Lower-48 Oil and Gas (PROLOG) Model.[13] These models produce estimates of reserve additions of oil and gas and of the production of oil from both existing and new reserves.

---

[10] Energy Information Administration, Model Documentation: Electricity Market Module, DOE/EIA-M001 (Washington, DC, 1984).

[11] A documentation report is in preparation. Discussion of the refining sector of IFFS is found in John Conti, "Introduction to the Oil Subsystem" and Neil J. Cleary, "Refinery Subsystem: A Critique," in Saul I. Gass, Frederic H. Murphy, and Susan H. Shaw, Editors, Intermediate Futures Forecasting System, U.S. Department of Commerce, National Bureau of Standards, NBS SP 670 (Washington, DC, December 1983).

[12] Energy Information Administration, Outer Continental Shelf (OCS) Oil and Gas Supply Model, Volume 1: Model Summary and Methodology Description, DOE/EIA-0372 (Washington, DC, 1982).

[13] Energy Information Administration, Production of Onshore Lower-48 Oil and Gas--Model Methodology and Data Description, DOE/EIA-0345 (Washington, DC, 1982).

Natural gas liquids production is computed as a function of marketed natural gas production.

The gas supply representation, the GAMS, takes into account the major factors that influence the natural gas market including the Natural Gas Policy Act of 1978, current contract provisions, and the possibility of fuel switching. The GAMS contains detailed representations of four groups that interact in the natural gas market: producers, pipeline companies, distributors, and consumers. The GAMS recognizes separate long-term and short-term markets for natural gas.

The coal module is derived from the Coal Supply and Transportation Model (CSTM).[14] The supply component is derived from the Resource Allocation and Mine Costing (RAMC) Model,[15] which uses the quantity of available reserves and the cost of mining (through the use of nine representative mine models) to calculate the amount of coal available at a given price for both underground- and surface-mined coal. The CSTM uses this information to specify the potential levels of coal produced in each region over a range of price levels. To meet each end-use demand, the CSTM determines the least-cost combination of coal supply source and transportation route, taking into account the heat content for different types of coal and emissions control requirements.

Consistency of Data with Other EIA Publications

The consumption levels for the years 1980 through 1985 in this report have been calibrated to be consistent with the most recent information available in other EIA publications. The demand models are calibrated to actual "State Energy Data System" (SEDS) consumption data for 1980, 1981, and 1982, available by fuel, sector, and region, reported in the EIA State Energy Data Report, 1960-1982. The models are also calibrated to the annual data published in the EIA Annual Energy Review, 1983 and to the projections published in the EIA October 1984 Short-Term Energy Outlook (STEO) for 1984 and 1985. Additional fuel detail supporting the aggregate numbers published in the STEO is used in the IFFS/STEO calibration procedure. Full sectoral and regional detail are not available from the STEO publication or supporting analyses; therefore, the IFFS projections of consumption by sectors and regions for 1984 and 1985 are used to share out the totals provided by the STEO.

---

[14] Energy Information Administration, Coal Supply and Transportation Model: Model Description and Data Documentation, DOE/EIA-0401 and Coal Supply and Transportation Model: Executive Summary, DOE/EIA-1401 (Washington, DC, 1983).

[15] Energy Information Administration, Documentation of the Resource Allocation and Mine Costing (RAMC) Model, DOE/NBB-0020 (Washington, DC, 1982).

Detailed Assumptions

Macroeconomic Assumptions

The original base case and the high and low economic growth forecasts were based upon modifications of forecasts of Data Resources, Inc., generated in June 1984, called TRENDLONG0684 (for the base case), OPTIM25YR0684 (for the high growth case), and PESSIM25YR0684 (for the low growth case). EIA modifications controlled real world oil prices to follow the path of TRENDLONG0684 in the modified high and low growth forecasts. (TRENDLONG0684 was not modified when used to generate the base case forecasts in EIA's modeling system.)

These original forecasts were subsequently updated in September 1984 by EIA, by adopting DRI's TRENDLONG0984 forecast of September 1984 as the new base case source forecast, and modifying EIA model inputs for the high and low growth cases to reflect this update. The percentage changes in DRI's TRENDLONG0984 forecast, for each variable needed, from the June to September forecasts, were also imposed on the high and low growth cases of June in this update.

As a result of this updating procedure, no actual DRI forecasts can be cited as sources for high and low growth case inputs. This procedure did, however, have the virtue of giving a wider spread than adopting DRI's full set of alternative long-term forecasts for September as inputs. For further details, see the Memorandum to the Record, EIA, Office of Energy Markets and End Use, "Macroeconomic Forecasts for AEO84," December 7, 1984.

Residential and Commercial Sector Assumptions

Residential electricity, natural gas, fuel oil (distillate and kerosene), and liquefied petroleum gas (LPG) consumption are calculated using a structural equation system. This system consist of sets of equations to forecast housing stocks, fuel shares, and average utilization. New housing is assumed to be allocated to Census Regions and housing types according to the average ratios in the "Annual Housing Survey" (AHS). Retirement rates for the housing stock are derived from "Energy Capital in the U.S. Economy."

The elasticities of fuel shares with respect to fuel costs for space heating in new structures are assumed to equal one. This provides a one-to-one response between the changes in the relative costs of fuels and the changes in the logit form for fuel shares. Air conditioning fuel shares in new structures are based on trends in the late 1970's. Forecast fuel shares in new structures for water heating and other uses are assumed to equal forecast fuel shares in the previous year. For existing structures, fuel shares for space heating are forecast to change based on relative prices, investment costs, and other factors which would affect the decision to convert from fuel oil to natural gas. Initial data for new fuel shares are from "Characteristics of New Housing" (CNH), and initial data for existing fuel shares are based on a combination of the "Residential Energy Consumption Survey (1981)" (RECS)[16] and the 1981 AHS.

Long-term utilization (energy use per household) for each of the major fuels is estimated from RECS data. The short-term (one year) utilization elasticity is assumed to be 20 percent of the estimated long-term elasticity for each of the end uses. The elasticities for fuel oil utilization and natural gas utilization are assumed to be the same. The electric heat pump use portion of total electric space heat is assumed to equal that which is reported in the 1982 CNH. The coefficient of performance (ratio of energy delivered to electric energy used) for heat pumps is assumed to be 1.4 in the base year. Residential wood consumption forecasts are based on a logit equation with an upper limit on use assumed to be no more than 50 percent above the highest wood use in the last 10 years as detailed in EIA's "Estimates of U.S. Wood Energy Consumption from 1949 to 1971."

Commercial electricity, natural gas, and fuel oil use are projected using a structural system which forecasts commercial floorspace, fuel shares, and average utilization. The commercial floorspace stock is based on data from the "Nonresidential Buildings Energy Consumption Survey" (NBECS) for 1979. The retirement rate for existing floorspace is assumed to be 0.6 percent annually. Fuel choices in newly constructed floorspace are assumed to equal an average of those in the 1974 through 1980 vintage structures and those in vintages before 1974 from the NBECS. Fuel choices in existing floorspace are assumed not to change during the forecast period. Long-term utilization for each of the major fuels is estimated from NBECS data. The short-term utilization elasticity is assumed to be about 3.5 percent of the estimated long-term elasticity for electricity and natural gas, and about 8 percent of that for fuel oil. Coal, LPG's, and motor gasoline consumption estimates are based on growth rates from recent SEDS data.

Industrial Sector Assumptions[17]

Industrial sector energy use is projected by three components of IFFS corresponding to the three groupings in Table A8: heat and power, oil refineries, and raw materials plus minor fuels (except gasoline). (Oil refineries are discussed elsewhere in this appendix.) Natural gas lease and plant fuel, projected in the gas sector, are also included with heat and power in Appendix Table A8.

---

[16] Energy Information Administration, Technical Documentation, Residential Energy Consumption Survey: Housing Characteristics, 1980, and Consumption and Expenditures April 1980 through March 1981--Public Use Tape (Washington, DC, 1983).

[17] Energy Information Administration, A Statistical Analysis of What Drives Industrial Demand: Volume III of the PURHAPS Model Documentation, DOE/EIA-0420/3 (Washington, DC, December 1983), Documentation of the PURHAPS Industrial Demand Model, Volume I: Model Description, Overview, and Assumptions for the 1983 Annual Energy Outlook, DOE/EIA-0420/1 (Washington, DC, 1984), and Documentation of the Industrial Minor Fuels and Raw Materials Model (MFUEL), DOE/EIA-0490 (Washington, DC).

Heat and Power. Heat and power consumed in manufacturing is based on the same 17-sector, State-level model used and documented in the 1983 Annual Energy Outlook. However, two changes have been made: The equations to predict total U.S. energy use by industry were fitted to the revised production data from the Bureau of Labor Statistics (for 1958 through 1981), which show less production growth and slightly less conservation than did the preliminary data. The trend towards less energy intensity in the chemical industry is assumed to be 2 percent per year (in addition to the effects of prices), rather than 4 percent in order to reflect recent data suggesting maturation of the industry and to counterbalance an assumption about feedstocks.

Projections of heat and power in agriculture and mining are now based on time-series data. Distillate oil and gasoline used on farms compete on the basis of price; total demand for these fuels has a price elasticity of 0.37. Demand for all fuels reflects trends in the ratio of fuel use to production. In the five mining sectors, preliminary data from the 1982 Census of Mineral Industries are compared with 1972 Census data and a variety of current production measures to estimate these trends. Energy use per unit of output has exhibited an upward trend throughout mining and agriculture from 1972 to 1982 due, in part, to mineral depletion; however, it has remained constant for stone, gravel, and sand extraction and for LPG use on farms. Fuel shares are projected for each of the different sectors based on historical experience.

Raw Materials. The Industrial Minor Fuels (MFUEL) and Raw Materials Model[18] has been updated to reflect complete 1982 data. LPG feedstocks now compete with other petroleum feedstocks on the basis of price. When the price of LPG is 1 percent below the parity price, the ratio of LPG to other feedstocks use rises by 0.38 percent, even when LPG was cheaper in the previous year.

Total feedstocks demand depends on the production of the plastic materials and synthetic fibers industry (SIC 282). From 1963 to 1982, feedstocks use grew faster than SIC 282 output. In the projections, a decline in feedstock use per unit of output of 0.7 percent per year is assumed in order to reflect new developments in plastics. Previously, low-cost bulk plastics production grew rapidly, resulting in high feedstock use per unit of value. In the future, Data Resources, Inc., projects a rapid growth in SIC 282 based on higher value, higher quality specialty products that require more processing. This is expected to reduce oil use by about 1 quadrillion Btu by 1995, relative to that which would be projected based solely on historical trends in the feedstock input to output ratio.

Metallurgical coal use is projected on the basis of an independent analysis by EIA's Office of Coal, Nuclear, Electric, and Alternative Fuels. This projection calls for the ratio of metallurgical coal use to total iron and steel production (SIC 331) to decline at half the rate observed in recent years.

---

[18] Energy Information Administration, Documentation of the Industrial Minor Fuels and Raw Materials Model, DOE/EIA-0490 (Washington, DC, 1984).

Transportation Sector Assumptions[19]

Highway fuel consumption calculations are based on analyses of Federal Highway Administration data on vehicle-miles traveled and average fleet efficiency. For passenger cars, single-unit trucks, and combination trucks, total vehicle-miles traveled for both gasoline- and diesel-powered vehicles are forecast on the basis of economic growth as well as the cost per mile of travel and past trends. Fuel efficiency estimates for each vehicle type are based on forecasts of fuel prices as well as past trends in efficiency.

Total jet fuel consumption is the sum of commercial, general aviation, and military jet fuel consumption. These figures are based on Federal Aviation Administration and EIA forecasts. In estimating commercial jet fuel use, it is assumed that airline activity is represented by revenue passenger-miles for all domestic flights plus one-half of revenue passenger-miles for international flights. It is assumed that commercial cargo jet fuel use is 3.2 percent of commercial passenger jet fuel use. The load factor of 63 percent for commercial jets is assumed to be constant over the projection period.

Transportation electricity consumption is held fixed during the forecast period at its 1981 level of 11 trillion Btu.

Electric Utility Assumptions

Capacity Factors. The utilization rates for existing nuclear and fossil-fired steam plants are based on actual data through 1982. In the projection period, plants experiencing historical utilization rates above 65 percent are assumed to maintain current rates as maximum potential. The potential utilization rates for all other existing coal-fired plants are assumed to grow to 65 percent in 1986 and to remain constant. Table F1 provides the equilibrium cycle capacity factors for nuclear plants. New nuclear plants are assumed to operate at a 44-percent capacity factor during the first fuel cycle (typically the first 2 years of operation) and at the equilibrium cycle capacity factor, thereafter.

Nuclear Fuel. It is assumed that adequate supplies of uranium will exist throughout the forecast period and that the cost in constant dollars will remain unchanged.

Plant Efficiencies. In each forecast year, the plant efficiencies for existing plants are assumed to be the average of the actual 1980 through 1982 figures. The efficiencies for new plants are given in Table F2. Estimates for coal-fired plants were derived from EIA's "Regionalized Capital and Operation and Maintenance Cost Estimates for Emission Control Equipment for New Coal-Fired Power Plants," May 1982. Note that environmental regulations require that any new coal plant that does not have a flue gas desulfurization (FGD) system must use low-sulfur coal. Nuclear and hydroelectric efficiencies are obtained from EIA's December

---

[19]Energy Information Administration, Model Documentation: Transportation Sector Energy Demand Model, DOE/EIA-0454 (Washington, DC, 1984).

1983 Monthly Energy Review. All other efficiencies were taken from DOE's Data Notebook Generating Technology Assessment, R-035-DOE-80, January 1980.

Table F1. Equilibrium Cycle Capacity Factors for Nuclear Plants (Percent)

DOE Region	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
1-7, 9	59	60	60	61	61	61	62	62	62	63	63	63	63
8	25	27	29	31	33	34	36	38	40	42	44	46	48
10	45	46	47	48	49	50	51	52	53	54	55	56	57

Environmental Standards. Existing coal-fired plants are assumed to burn the same coal types as they did in 1982, which implies that the plants will meet or exceed the State Implementation Plan (SIP) standards. Coal-fired plants currently under construction which were licensed before September 1978 must satisfy the New Source Performance Standards (NSPS). If the license for a new coal-fired plant was obtained after September 1978, the plant must satisfy the Revised New Source Performance Standards (RNSPS).

Table F2. Efficiencies for New Electric Power Plants (Percent)

Plant Type	Efficiency Rate
Noncoal Fossil-Fired Steam	35
Coal-Fired without FGD	
Bituminous--Low Sulfur	37
Subbituminous--Low Sulfur	36
Lignite--Low Sulfur	35
Coal-Fired with FGD	
Bituminous--All Fuel Levels	35
Subbituminous--Low Sulfur	34
Subbituminous--Medium Sulfur	33
Lignite--Low Sulfur	33
Lignite--Medium Sulfur	34
Combined Cycle	36
Turbines	24
Nuclear Power	31
Hydroelectric Power	33

Plant Capacities. The levels of existing capacity and capacity currently under construction are obtained from EIA's Generating Unit Reference File (GURF)[20] except for nuclear and existing hydroelectric plants. Hydroelectric plants are from the Federal Energy Regulatory Commission (FERC), Hydroelectric Power Resources of the United States--Developed and Undeveloped, FERC-0070, January 1, 1980. Existing nuclear capacities are obtained from the Nuclear Regulatory Commission (NRC), Licensed Operating Reactors, Vol. 8, No. 6, NUREG-0020, June 1984. Projected nuclear capacity additions are from the NRC's Regulatory Licensing, Vol. 12, No. 12, NUREG-0580, January 1984, and modified by a reactor-by-reactor analysis of commercial operation dates.

New Plant Construction. It is assumed that construction and licensing, which is specified on a plant-by-plant basis, typically take 10 or 15 years for nuclear plants, 8 years for fossil-fired steam plants, 4 years for combined-cycle plants, 2 years for turbines, and 5 years for hydroelectric plants. No new construction, except for plants currently planned or under construction, is assumed for gas-fired steam plants and turbines or for nuclear and hydroelectric capacity.

Capital Costs. Capital costs vary significantly according to the location of the new plant. Table F3 contains the capital costs of new plants built in Federal Region 5, which is considered representative of the national average. The estimates for capital costs for new plants in 1983 dollars per kilowatt are based on plants constructed "overnight" and do not include any allowance for funds used during construction (AFUDC). Estimates for coal-fired steam plants were taken from Oak Ridge National Laboratory's Conceptual Capital Cost Model (CONCEP).[21] Nuclear capital costs were obtained from EIA's Quarterly Progress Report on the Status of Reactor Construction. The nuclear cost is the capacity-weighted average of all units currently under construction in Federal Region 5. All other figures were based on data taken from DOE's Data Notebook Generating Technology Assessment, R-035-DOE-80, January 1980. Note that the costs for low- and medium-sulfur lignite-fired plants are from Federal Regions 8 and 6, respectively, since Region 5 does not use lignite.

Construction Profiles. The annual expenditures (as a percentage of the total construction costs) for new nuclear and coal plants, which account for almost all of the capacity additions during the forecast period, are shown in Table F4. The capital expenditure profiles are extracted from the CONCEP Model. The nuclear profiles vary by unit based on differences in lead times for construction.

Cost of Finance. The assumed nominal costs of finance for debt, preferred equity, and common equity range from 12.3, 12.3, and 15.4 percent, respectively, in 1983 to 10.3, 10.3, and 13.5 percent, respectively, in 1995.[22] The assumed financial

---

[20]Energy Information Administration, Generating Unit Reference File (GURF), computerized data base maintained by the Office of Coal, Nuclear, Electric, and Alternate Fuels (Washington, DC).

[21]Oak Ridge National Laboratory, Technology Division, CONCEP-5 User's Manual, ORNL-5470 (Oak Ridge, TN).

[22]ICF Incorporated, National Utility Financial Statement Model (NUFS) Volume 1: Model Overview and Description, ORNL/Sub/82-18806/1.

structure of electric utilities in terms of debt, preferred equity, and common equity ranges from 52.5, 12.0, and 35.5 percent, respectively, in 1983 to 53.0, 12.0, and 35.0 percent, respectively, in 1995.

Table F3. Capital Costs by Type of Generating Capacity, Federal Region 5 (1983 Dollars per Kilowatt)

Generating Capacity	Cost
Oil/Gas Steam	731
Coal-fired Steam without FGD	
Bituminous--Low Sulfur	838
Subbituminous--Low Sulfur	865
Lignite--Low Sulfur	919
Coal-fired Steam with FGD	
Bituminous--Low Sulfur	929
Bituminous--Medium Sulfur	943
Bituminous--High Sulfur	1,001
Subbituminous--Low Sulfur	958
Subbituminous--Medium Sulfur	970
Lignite--Low Sulfur	1,017
Lignite--Medium Sulfur	980
Combined Cycle--Gas	469
Turbines--Gas	219
Turbines--Distillate	236
Nuclear Power	1,581
Hydroelectric Power	1,357

Interregional and International Electricity Trade

Transfers of electricity among utilities are adjusted for transmission losses by using an assumed loss factor of 9 percent. Assumptions with respect to net imports of electricity from Canada and Mexico are based on forecasts for 1990 by the Economic Regulatory Administration (Table F5). Interregional transfers of domestically produced power are determined exogenously to reflect the need to balance domestic production and sales to ultimate consumers. Changes in interregional transfers are projected to reflect scheduled plans.

Oil and Natural Gas Resource and Production Assumptions

World Oil Price. Table 1 (Chapter 2) gives the historical and projected average landed prices of imported crude as estimated using EIA's OMS Model. The domestic crude oil and refiner acquisition costs of crude are assumed to equal the world oil price.

Oil and Natural Gas Resource Levels. The levels of new reserve discoveries are determined as the incremental return to cumulative drilling. The exponential declines in production from producing fields were estimated from historical data. Alternative functions, using parameters based on the United States Geological

Survey (USGS) estimates of undiscovered recoverable resources,[23] were employed when the recent finding rates did not decline (as occurred in the Western Overthrust Belt) or the historical trend led to unuseable results.

Table F4. Annual Shares of Plant Construction Expenditures, Region 5 (Percent)

	Years Before Commercial Operation													
Plant Type	15	14	13	12	11	10	9	8	7	6	5	4	3	2
Nuclear														
10-Year Lead Time ..	--	--	--	--	--	0.2	2.5	9.7	20.2	26.9	23.5	12.8	3.7	0.4
12-Year Lead Time ..	--	--	--	0.1	1.2	5.0	11.6	18.9	22.7	20.3	13.1	5.6	1.4	0.1
14-Year Lead Time ..	--	0.0	0.7	2.8	6.9	12.3	17.3	19.6	17.7	12.7	6.8	2.6	0.6	0.1
15-Year Lead Time ..	0.0	0.5	2.1	5.4	9.9	14.6	17.8	17.9	14.8	9.8	5.0	1.8	0.4	0.0
Coal	--	--	--	--	--	--	--	0.4	2.3	9.7	29.1	27.5	19.1	12.0

-- = Not applicable.

Leasing, Regulations, and Environmental Policies. The leasing of Federal property for the exploration and development of energy resources will not be a constraint on domestic energy production through 1995. In addition, current environmental regulations are assumed to remain in force throughout the forecast period. State-level regulations, including well-spacing, prorationing, allowable production rates, and unitization, are assumed to continue in their current form.

Crude Oil Windfall Profit Tax Act. This law includes a definition for each category of oil, a base price, and a tax rate to be applied. The rate is applied to the difference between the base price and the market price, less a deduction for severance tax liabilities on the windfall profit tax portion of the price. The windfall profit attributed to any barrel of crude oil is limited to 90 percent of the net income attributed to that barrel. The treatment given to each of the crude oil categories is as follows:

[23] U.S. Geological Survey, "Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States," Circular 860 (Washington, DC, 1981)

- Old oil: The development of old oil is estimated using the windfall profit tax (WPT) parameters appropriate to major producers.
  - Rate: 70 percent
  - Base: $12.81 adjusted for inflation since June 1979 ($17.50 per barrel in 1984 dollars)

- New oil: The exploration for and development of newly discovered oil incorporates the following WPT parameters.
  - Rate: 30 percent in 1981, declining to 15 percent in 1985 and thereafter
  - Base: $16.55 per barrel plus inflation since second quarter of 1979, plus 2 percent real increase per year ($25.00 per barrel in 1984 dollars)

- Alaskan oil: The WPT imposed on current production from Cook Inlet and the Sadlerochit formation of the Prudhoe Bay field is the same as that for old oil. All other Alaskan oil discovered after 1979 is exempt from the WPT.

Table F5. Assumptions on Net Interregional Transfers of Electricity, 1990
(Trillion Btu)

	Source										
Destination	Canada/ Mexico	1	2	3	4	5	6	7	8	9	10
1	42.1	--	15.4	--	--	--	--	--	--	--	--
2	122.2	--	--	79.8	--	--	--	--	--	--	--
3	--	--	--	--	--	--	--	--	--	--	--
4	--	--	--	--	--	--	8.1	3.4	--	--	--
5	14.7	--	--	62.0	14.7	--	--	--	29.0	--	--
6	--	--	--	--	--	--	--	3.8	--	--	--
7	--	--	--	--	--	0.3	--	--	6.6	--	--
8	9.2	--	--	--	--	--	--	--	--	--	--
9	31.2	--	--	--	--	--	27.3	--	--	--	81.1
10	7.8	--	--	--	--	5.8	--	--	158.2	--	--

-- = Not applicable.

Investment Decisions and Discount Rates. Investment decisions are based on the return adjusted for the windfall profit tax on new oil and the assumption of constant expected future prices. Revenue values in the discounted cash flow (DCF) computation include revenues from coproducts. The discount rates used in the DCF calculations in the PROLOG Model are generally 10 percent for developmental drilling projects and 12 percent for exploratory drilling projects. From 1982 to 1984, the discount rates are 15 and 20 percent for developmental and exploratory drilling projects, respectively. The higher rates reflect the influence of greater uncertainty in those years surrounding the world oil price and the regulatory environment in the natural gas market.

Exploration and Production Costs. Geological and geophysical costs, lease equipment costs, and operating costs all are estimated from the EIA Annual Survey of Oil and Gas. These cost components, as well as drilling costs, are assumed to increase by 3 percent annually in real terms over the forecast period. Marginal lease acquisition costs are assumed to be zero.

Alaska. Due to the repeated postponement of the expected start date for Prudhoe Bay gas production and the high degree of uncertainty surrounding several key issues, particularly financing of the pipeline, Alaska is not assumed to supply gas in the forecast period.

Projections of Alaskan oil production are based on a detailed review of the industry announcements rather than an explicit model run. Table F6 shows production under the base case scenario. The Prudhoe Bay base case flow matches Case I from the report, "Three-Dimensional Model, Waterflood Performance Study, Sadlerochit Formation, Prudhoe Bay field, Alaska," prepared for the Alaska Oil and Gas Conservation Commission by H. K. Van Pollen and Associates, Inc., April 1983. Other volumes reflect announced flow rates or figures recommended by the Department of Revenue, State of Alaska; final determination of the published forecasts is the sole responsibility of EIA staff. It is assumed that flows in excess of 2 million barrels per day are technologically and economically feasible through the Trans-Alaska Pipeline System. All announced plans were incorporated into the high world oil price case (not shown). Lower prices have the effect of delaying or outright eliminating selected projects, rather than reducing flows from included projects.

Assumptions for the Low, Base, and High Petroleum Supply Cases

The high and low supply assumptions for the Lower 48 States onshore production essentially provide best and worst cases for the supply of oil and natural gas (Table F7). For the Lower 48 onshore supplies, the PROLOG Model was executed with changes to costs growth, discount rates, and shifts in the yield to exploration--the finding rate. For other supply areas, a direct percentage adjustment was applied to the oil production and gas reserve additions from the outer continental shelf (OCS), enhanced oil recovery (EOR), and unconventional gas recovery (UGR). Due to the few large projects anticipated for Alaska, a judgmental approach was used to retain or exclude selected projects. The high and low supply cases conform to the high and low world oil price scenarios presented above.

Petroleum Market, Import, and Refining Assumptions

Road-Use Taxes. Gasoline and on-highway diesel prices reflect State and Federal taxes. For diesel fuel oil, the Federal tax increased from 9 cents to 15 cents per gallon on August 1, 1984.

Table F6. Alaskan Oil Production Middle World Oil Prices
(Thousand Barrels per Day)

Year	North Alaska: Prudhoe Bay Area: Sadlerochit Base	Sadlerochit EOR	Kuparuk	Lisburne Formation	West Sak	Milne Point	Duck Island	Seal Island	Other Beaufort	Total	South Alaska
1981 ...	1,522	--	3	--	--	--	--	--	--	1,525	88
1982 ...	1,532	--	89	--	--	--	--	--	--	1,621	80
1983 ...	1,537	--	109	--	--	--	--	--	--	1,646	71
1984 ...	1,535	--	115	--	--	--	--	--	--	1,650	62
1985 ...	1,535	--	170	--	--	--	--	--	--	1,705	52
1986 ...	1,545	--	210	--	--	10	--	--	--	1,765	47
1987 ...	1,545	--	250	100	--	30	--	--	--	1,925	42
1988 ...	1,545	--	250	100	50	30	--	--	--	1,975	36
1989 ...	1,545	--	250	100	93	30	--	--	--	2,018	32
1990 ...	1,545	25	250	100	137	30	52	--	--	2,139	28
1991 ...	1,250	25	197	100	180	30	58	--	--	1,840	24
1992 ...	1,011	25	155	100	180	30	63	52	--	1,616	20
1993 ...	818	25	122	100	180	30	69	58	--	1,402	16
1994 ...	662	25	97	100	180	30	75	63	100	1,332	12
1995 ...	536	25	76	100	180	30	81	75	100	1,203	8

-- = Not applicable.

Imports. Refined product imports are generally assumed to constitute the same regional proportion of demand as in 1983, as described in the EIA 1983 Petroleum Supply Annual. However, the refinery yield of residual fuel is constrained to not exceed 7.1 percent and the combined yield of LPG and petrochemical feedstocks is not allowed to exceed 6 percent (the yields reported in the EIA 1983 Petroleum Supply Annual). Increases in demand which would require higher yields for these products are supplied by imports.

Petroleum Product Prices. Retail prices represent the summation of the refiner's price and a total markup. Separate refining costs, wholesale markups, and retail markups are not modeled explicitly.

Refinery prices depend on the refiner acquisition cost of oil (RAQ), production levels of individual products, and capacity utilization. Prices are normalized so that the average refiner price (in 1984 dollars per barrel) does not drop below a level determined by the following equation:

$$(1 + 0.1 * M) * RAQ + 2.77 * M$$

The variable M is the ratio of throughput in the projection year to throughput in 1983.

Table F7. Petroleum Supply Assumptions
(Percent)

Assumptions	Supply Case Low	Base	High
Costs			
(annual rate of growth)	6	3	0
Discount Rate			
Exploration	20	12	10
Development	15	10	8
Finding Rates			
Lower-48 Onshore and OCS (percentage change from base)	-10	0	10
Enhanced Oil Recovery			
(percentage change from base)	-10	0	10
Unconventional Gas Recovery			
(percentage change from base)	-10	0	10

In 1983, refinery prices for each product are subtracted from retail prices, thus generating total markups. Regional- and sector-specific markups are estimated. Once generated, the markups are fixed in real terms throughout the forecast period.

Capacity Utilization. Regional production of petroleum products is adjusted so that the capacity utilization rate is the same across Regions 1 through 7 and between Regions 9 and 10. Total refinery fuel use is directly proportional to refinery throughput and consists of still gas, petroleum coke, natural gas, and residual fuel oil. Refinery fuel use of natural gas and residual fuel oil are sensitive to the prices of these fuels.

Natural Gas Market Assumptions

Wellhead Price Regulation. The forecasts included in this volume are based on the assumption that the wellhead price ceilings on certain types of natural gas imposed by the Natural Gas Policy Act of 1978 (NGPA) will be removed according to the schedule contained in the Act.

Wellhead Prices and Purchases. Wellhead prices for gas in 1981, 1982, and 1983 that was in production in 1980 were obtained from the Form EIA-758 ("Natural Gas Producer/Pipeline Contract Report") and Purchased Gas Adjustment data. It is assumed that contracts with "market-out" clauses (which allow a purchaser to refuse to purchase gas that cannot be marketed) are reset to the market price each year. It is assumed that all contracts signed after 1980 have market-out clauses, and that downward pressure on prices due to the current surplus inhibits price increases under pre-1981 contracts. The current gas price forecasts are based on the results of negotiations that are known to have already taken place.

Prices for some pipeline system NGPA categories were adjusted based on market-out actions detailed in "Gas Industry Actions by Field Purchasers to Reduce Gas Costs" and published by the American Gas Association. These adjustments were assumed to remain in effect until January 1, 1985.

Wellhead Contract Provisions. Data from the EIA Natural Gas Pipeline/Producer Contracts: A Preliminary Analysis (DOE/EIA-0312) and the Form EIA-758 were used to provide the distribution of contract escalation clauses for existing contracts or contracts in effect prior to 1981.

Contracts in effect in 1980 for gas for which the price is currently controlled are divided between those with clauses specifying a fixed escalation so the price is known in advance, referred to as "definite only" pricing, and those with clauses specifying highest allowed regulated rates, based on data from Form EIA-758. Prices for the "definite only" category came from Form EIA-758. Gas priced under a highest allowed regulated rate receives the NGPA ceiling price until deregulation.

New contracts (post-1980) for gas under price ceilings are categorized as having a highest allowed regulated rate clause and receive the NGPA ceiling price until decontrol. All new contracts for gas not under price ceilings receive the market clearing price.

When gas under existing contracts is decontrolled, most clauses with the highest allowed regulated rates provide for alternative pricing clauses upon deregulation. Information on deregulation pricing is taken from Form EIA-758, and contracts are divided into five categories: oil parity clauses without market-out provisions, most-favored-nation clauses without market-out provisions, all other deregulation clauses (including oil parity and most-favored-nation with market-out provisions), highest allowed regulated rate with no deregulation clauses, and "definite only" pricing.

Upon decontrol, gas covered under contracts with oil parity clauses with no market-out clause is assumed to receive a price equivalent to 110 percent of the price of distillate fuel oil. Gas sold subject to most-favored-nation clauses with no market-out provisions is adjusted over each year to the price of oil-parity contracts with a 1-year lag. However, because of the downward pressure on prices as a result of the current surplus of natural gas, price increases under these contracts are limited. All other deregulated gas receives, by assumption, the new contract price in the first year, with the price adjusted each year as contractually specified adjustments take place to reflect the new contract price each year.

Under a market-out clause, which is assumed to be included in all contracts signed in or after 1981, a pipeline can refuse to take delivery of gas it cannot market, but the producer has the right to seek alternate buyers. It is assumed that gas covered by market-out clauses would be priced at the market price for new gas supplies.

All wellhead prices are calibrated to national level totals in EIA's Natural Gas Monthly and Purchased Gas Adjustment filings.

Take-or-Pay. Take-or-pay requirements for any new (post-1980) contract are assumed to be 75 percent of the well deliverability. For contracts in effect in 1980, pipeline take-or-pay percentages are assigned to each category of gas using the Form EIA-758 data. The take-or-pay percentages applied to reserve categories for the period from 1982 through 1984 have been adjusted according to actions reported in "Gas Industry Actions" mentioned above. These adjustments were assumed to remain in effect until January 1, 1985.

Distributor Pricing. Some public utility commissions are permitting a lesser share of the distribution costs of gas to be passed to industrial and electric utility customers who would otherwise switch to oil (see EIA, Competition and Other Current Natural Gas Issues in the Natural Gas Market, DOE/EIA-0489). A number of entities, including pipelines, are actively engaged in the intense marketing of gas, such as facilitating the sale of gas directly from producers to customers and special discount programs.

Flexible pricing by distributors is assumed for industrial and electric utility gas users that can switch to oil. If the usual calculated tariff to these users results in the price being higher than the regional residual fuel oil price, these consumers are assumed to receive gas prices at parity with the price of residual fuel. However, prices to these customers are not reduced below the distributor's average purchased gas costs minus 50 percent of the average charge for transmission (35 cents per million Btu). When prices to these customers are reduced, half of the revenue loss by large distributors is passed to gas users that do not have the option of quickly switching to oil.

Lower 48 Reserves and Production by NGPA Section. Analysis of the supply outlook requires detailed data on prices, reserves, and production for each NGPA category and for each pipeline system. These data are not available from a single source; consequently, several data sources were used either directly or to allocate the information to the level of detail required.

Reserves, production, and price data were developed for 17 domestic pipeline systems. Reserves and production data were obtained from two sources, Forms FERC-15 and EIA-23. The Form FERC-15 data include reserves and production information reported by interstate pipeline companies for different geographic areas. The Form EIA-23 survey, a sample of oil and gas operators stratified by size, contains data on total reserves and production for each State.

To allocate reserves and production by NGPA category, two additional data systems were used. The Purchase Gas Adjustment data provide projected wellhead purchase volumes by NGPA Category for 20 interstate pipeline companies. These were used to allocate reserves and production for those 20 companies, using the ratio of purchases by NGPA section to total purchases. The remaining interstate companies and intrastate area reserves were apportioned in a similar manner, using Form FERC-121 data system which includes data on production by region, company, interstate or intrastate market, and NGPA category and subcategory. These data were then benchmarked to historical reserves and production levels for the period 1980 through 1983.

Natural Gas Imports. In July 1984, the Canadian Government announced a new policy where "exporters of Canadian gas will be free to negotiate prices with their customers." This statement along with the U.S. policy on gas imports leads to the assumption that the price of imported gas will reflect current market conditions. Currently, the Canadian Government has authorized about 13 trillion cubic feet of its reserves for export to the United States but could easily authorize more. Three gas import scenarios have been specified (Table F8).

Table F8. Natural Gas Import Assumptions
(Trillion Cubic Feet)

Year	Low Case	Base Case	High Case
1984	0.9	0.9	0.9
1985	1.0	1.0	1.0
1986	1.0	1.1	1.3
1987	1.0	1.2	1.5
1988	1.1	1.3	1.7
1989	1.2	1.4	1.9
1990	1.3	1.6	2.3
1991	1.3	1.7	2.4
1992	1.3	1.8	2.5
1993	1.3	1.9	2.6
1994	1.3	2.0	2.6
1995	1.3	2.1	2.7

Coal Assumptions

Exports. Export projections are derived from EIA's International Coal Trade Model (ICTM).[24] It is assumed that U.S. rail transportation rates for export coal will remain deregulated. No U.S. ports are assumed to be deepened. However, topping-off operations are permitted in loading large colliers at U.S. ports.

Emission Standards. Utilities are assumed to meet regional standards based on 1982 air pollution control regulations. Utilities that do not have scrubbers are required to meet one of the following standards in terms of the maximum sulfur content of the coal used:

[24] Energy Information Administration, Description of the International Coal Trade Model, DOE/EI/11815-1 (Washington, DC, 1982).

Emission Standard ($lbs. SO_2/MBtu$)	Coal Sulfur Categories (lbs. sulfur/MBtu)
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
NSPS	0.41 - 0.60

For plants meeting Revised New Source Performance Standards (NSPS), the choice of which coal sulfur category to burn is based on the delivered costs of the different coals less an adjustment factor. This adjustment factor is a regional credit for use of a lower sulfur coal than required to meet the standard. The credit reflects the reduction in plant operating costs resulting from scrubbing lower sulfur coal. However, the utility is charged the delivered cost of the coal chosen.

Utility Coal Use. Plants that have a contract for coal shipments in 1983 are assumed to burn that coal in 1983. In the forecast years, the contract shipment is decremented based on depletion of individual mine reserves. The size of the decrement is based on the estimated life remaining for mines existing in 1980 (for both surface and deep mines) in each region. Plants that do not have a contract for coal shipments select the most economical coal type that satisfies the environmental standards they are required to meet.

Industrial Coal Use. Industrial boilers existing as of 1974 are considered to be "old" and are assumed to reduce coal consumption by 3 percent per year. These industries are allowed to burn high-sulfur coal. Those boilers which came on line after 1974 are characterized as "new" and are allowed to use only low-sulfur coal.

Metallurgical Coal Use. Metallurgical coal demand is assumed to be met by a blend of 86 percent premium-grade coking coal and 14 percent marginal-grade coking coal. This quality distribution was estimated for 1975 oven-coke plant consumption by Eugene T. Sheridan, in the U.S. Bureau of Mines Special Publication, "Supply and Demand for United States Coking Coals and Metallurgical Coke," 1976, p. 10.

Transportation Rates. Domestic rail rates, which are functions of fuel costs, right-of-way rehabilitation costs and volume, are assumed to increase from 1985 to 1995 by 20 percent. Over this period, fuel costs are projected to increase by 4.3 percent, and the other costs are assumed to increase by a total of 15 percent. Barge and collier rates are functions of fuel costs; barge rates are also functions of volume. Both barge and collier rates are assumed to increase from 1985 to 1995 by 15 percent due to fuel cost increases. Barge rates also increase by about 1 percent due to volume.

Model List and Contacts

Intermediate Future Forecasting System (IFFS): Office of Energy Markets and End Use

Oil/Gas:	Susan Shaw	(202) 252-1468
Coal:	Reginald Sanders	(202) 252-1466
Electricity:	Reginald Sanders	(202) 252-1466
Macroeconomics:	William Curtis	(202) 252-1455
Residential:	John Holte	(202) 252-1471
Commercial	John Holte	(202) 252-1471
Industrial	Paul Werbos	(202) 252-1197
Transportation:	Barry Cohen	(202) 252-5359
Refineries:	Michael Lehr	(202) 252-1470

Oil Market Simulation (OMS) Model: Office of Energy Markets and End Use
Erik Kriel (202) 252-6572

Outer Continental Shelf Oil and Gas Supply Model (OCSM): Office of Oil and Gas
William Trapmann (202) 252-6408

Gas Analysis Modeling Systems (GAMS): Office of Oil and Gas
Barbara Mariner-Volpe (202) 252-4749

Production of Onshore Lower-48 Oil and Gas (PROLOG) Model: Office of Oil and Gas
William Trapmann (202) 252-6408

Resource Allocation and Mine Costing (RAMC) Model: Office of Coal, Nuclear, Electric, and Alternate Fuels
Robert Crockett (202) 252-4266

Coal Supply and Transportation Model (CSTM): Office of Coal, Nuclear, Electric, and Alternate Fuels
Jarvis Seely (202) 252-6853

International Coal Trade Model (ICTM): Office of Coal, Nuclear, Electric, and Alternate Fuels
Ercan Tukenmez (202) 252-5253

Conceptual Capital Cost Model (CONCEP): Office of Coal, Nuclear, Electric, and Alternate Fuels
Arthur Fuldner (202) 252-9852

National Utility Financial Statement (NUFS) Model: Office of Coal, Nuclear, Electric, and Alternate Fuels
Gerald Price (202) 252-9854

Appendix G Sensitivity Case Listing

APPENDIX G
Sensitivity Case Listing

Sensitivity Name	Description
Petroleum Supply Vulnerability	World oil availability is assumed to decrease throughout the first quarter of 1990 by about 11 million barrels per day. A range of world oil price impacts is determined by varying assumptions about the response of energy consumption to higher prices, the availability of replacement oil in the world oil market, and the use of oil inventories.
Oil Demand and Supply Sensitivity	The low, base, and high world oil price assumptions are used to test the sensitivity of oil consumption and production to world oil prices in the market economies. Oil consumption in the market economies is about 10 million barrels per day higher by 1995 under the low price case than under the high price case. OPEC provides the output needed to meet the higher oil demands generated by lower world oil prices.
Structural Economic Change	The structural economic change sensitivity case compares the base case with the results of four alternative theories for projecting the output of manufacturing industries. These theories include a time trend, a time trend modified by the apparent effects of energy prices, a time trend modified by the apparent effects of growth in real gross national product and real interest rates, and a combination of all of these theories.
High Conservation	The high conservation sensitivity case assumes that much of the accelerated energy conservation trends of the 1970's will continue during the forecast period. The high conservation case considers the implications for end-use energy consumption if the lower world oil price forecast and other price forecasts of the base case do not dampen energy conservation behavior.

Sensitivity Name	Description
High Domestic Oil and Gas Supply	This case adjusts factors affecting exploration and development activities to assume higher productivity from exploration activity as well as lower costs of exploration and production.
Low Domestic Oil and Gas Supply	This case adjusts factors affecting exploration and development activities to assume lower productivity from exploration activity as well as higher costs of exploration and production.
High Natural Gas Imports	Natural gas imports are assumed to increase gradually from current levels to 2.7 trillion cubic feet in 1995.
Low Natural Gas Imports	Natural gas imports are assumed to increase to 1.3 trillion cubic feet in 1995.
Fixed Tariff	Natural gas distributors are assumed to apply the historical tariff structure, which does not permit them to reallocate costs among different customer classes to discourage industrial and electric utility customers from switching to alternate fuels.
Low Electricity Demand	The low electricity demand case constrains electricity demand to grow at the same rate as gross national product; as opposed to the base case, which allows the interaction of energy prices and economic activity to determine electricity demand, and results in electricity demand growing at a higher rate than growth in gross national product.
Reduced Capacity Additions	The reduced capacity additions case assumes the postponement or cancellation of 17 gigawatts of planned coal and nuclear generating capacity. This reduces projected capacity additions in the base case by 12 percent.
Low Growth, Reduced Capacity Additions	The low growth, reduced capacity additions case assumes both low economic growth and the postponement or cancellation of 17 gigawatts of planned coal and nuclear generating capacity.

Sensitivity Name	Description
High Growth, Reduced Capacity Additions	The high growth, reduced capacity additions case assumes case both high economic growth and the postponement or cancellation of 17 gigawatts of planned coal and nuclear generating capacity.
100-Percent CWIP	The 100-percent CWIP case provides utility projections assuming 100-percent CWIP (construction work in progress) in the rate base.
Fuel Switching	The fuel-switching cases examine alternate limits on the use of oil and natural gas in dual-fired electric generating capacity. The first case assumes maximum use of natural gas and the second case assumes maximum oil use. Each case is based upon maximum historical utilization rates.
High Nuclear Cost	The high nuclear cost case assumes a 10-percent average construction cost increase for new nuclear plants over costs assumed in the base case, comprising a real cost escalation rate over the base case of about 11 percent.
High Coal Rail Rates	Rail rates in constant dollars are assumed to increase by 63 percent between 1985 and 1995.
Low Coal Rail Rates	Rail rates in constant dollars are assumed to increase by 6 percent between 1985 and 1995.
High Labor Productivity in Underground Coal Mines	Labor productivity in underground coal mines is assumed to increase at an annual rate of 2 percent above base case levels from 1984 through 1995, resulting in a 24-percent increase between 1984 and 1995.

Tapes of the above sensitivity cases are available from EIA's National Energy Information Center at the following address:

National Energy Information Center, EI-20
Energy Information Administration
Forrestal Building, Room 1F-048
Washington, DC 20585
(202)252-8800

Glossary

GLOSSARY

Sectoral Definitions

Residential Sector: Energy consumed by private household establishments primarily for space heating, water heating, air conditioning, cooking, and clothes drying. This sector's consumption does not include consumption by individual households that are located in master metered apartment buildings.

Commercial Sector: Energy consumed by nonmanufacturing business establishments: motels, restaurants, wholesale businesses, retail stores, laundries, and other service enterprises; health, social, and educational institutions; and energy consumed by Federal, State, and local government. This sector includes consumption by individual households that are located in master metered apartment buildings. The consumption of motor gasoline by vehicles operated by commercial sector establishments are now included in the transportation sector.

Industrial Sector: Energy consumed by manufacturing, construction, mining, agriculture, fishing, and forestry establishments. Natural gas (consumed as a lease and plant fuel), motor gasoline, jet fuel, industrial hydroelectric power, and refinery fuel (except for electricity and coal) are excluded from this sector. Lubricants consumed by the industrial sector include lubricants used by transportation equipment.

Transportation Sector: Energy consumed to move people and commodities in both private and public sectors, such as military, railroad, vessel bunkering, and marine uses. Natural gas used as a pipeline fuel and lubricants are excluded from this sector.

Electric Utility Sector: Energy consumed by private and publicly owned establishments which generate electricity primarily for resale.

Coal Terminology

Anthracite: A hard, jet black coal with a high luster used for generating electricity and space heating. Its ignition temperature is approximately 925 to 970 degrees Fahrenheit. Anthracite is mined almost exclusively in northeastern Pennsylvania.

Bituminous Coal: The most common type of coal; also known as soft coal. It is dense and black, often with well-defined bands of bright and dull material, and is used for generating electricity, making coke, and space heating. The ignition temperature is 700 to almost 900 degrees Fahrenheit. Bituminous coal is mined chiefly in the Appalachian and Interior coal fields.

Blast Furnace: A furnace in which solid fuel (coke) is used as a fuel and as a reducing agent and limestone is used as a flux to smelt iron ore.

Btu (British Thermal Units): A standard unit for measuring the quantity of heat energy equal to the quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit.

Coal Carbonized: Coal that is decomposed into solid (coke and breeze), liquid, and gaseous products by heating it in a coke oven with little nor no air supply.

Coal Producing Districts: A classification of coal fields defined in the Bituminous Coal Act of 1937. The districts were originally established to aid in formulating minimum prices of bituminous and subbituminous coal and lignite. Much statistical information was compiled in terms of these districts; therefore, their use for statistical purposes has continued since the abandonment of that legislation in 1943.

Coal Producing Regions: A geographic classification of coal producing States. The States in the Appalachian region are Alabama, Georgia, eastern Kentucky, Maryland, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. States in the Interior region are Arkansas, Illinois, Indiana, Iowa, Kansas, western Kentucky, Louisiana, Missouri, Oklahoma, and Texas. States in the Western region are Alaska, Arizona, Colorado, Montana, New Mexico, North Dakota, Utah, Washington, and Wyoming.

Coal Rank/Group: A classification of coal based on fixed carbon, volatile matter, and heating value. It is an indication of the progressive alteration, or coalification, from lignite to anthracite.

Coke: The strong porous residue consisting of carbon and mineral ash. It is formed when the volatile constituents of bituminous coal are driven off by being heated in a limited air supply or in the absence of air. It is most often used as a fuel source and as a reducing agent in a blast furnace.

Coke Plants: Plants where coal is carbonized in slot or beehive ovens for the manufacture of coke.

C.I.F. Cost: Cost including insurance and freight costs. The delivered cost of coal.

F.A.S. Value: The free alongside ship value of a commodity at the port of exportation. It generally includes the purchase price plus all charges incurred in placing the commodity alongside the carrier at the port of exportation in the country of exportation.

F.O.B. Mine Price: The free on board mine price. The price for coal measured in dollars per short ton at the mining operation site and, therefore, does not include freight/shipping and insurance costs.

Lignite: A brownish black coal having a high moisture content and used mainly to generate electricity. It has an ignition temperature of approximately 600 degrees Fahrenheit. It is mined in North Dakota, Montana, and Texas, and is expected to be mined in Louisiana during the forecast period.

Magnetohydrodynamics: A system in which coal is burned at extremely high temperatures and the gases channeled through an intense magnetic field to generate electricity.

Metallurgical Coal: Coal that meets the requirements for making coke. It must be low in ash and sulfur and form a coke that is strong enough to withstand handling.

Overburden: Any material, consolidated or unconsolidated, that overlies a coal deposit.

Overburden Ratio: The amount of overburden that is removed during surface mining to excavate a given quantity of coal.

Short Ton: A unit of weight equal to 2,000 pounds.

Steam Coal: Coal that is best suited for generating steam to produce electricity or for other purposes.

Stocks: The supply of coal or coke at the mine, plant, or utility at the end of a specific period of time.

Subbituminous Coal: A type of coal having a dull black color. It is used for generating electricity and space heating and is mined in the western coal fields.

Natural Gas Terminology

Allowables: The maximum rate of production from a well or group of wells that is allowed by a particular State or governing body. The rate is set by rules which vary among the various States or governing bodies.

Associated-Dissolved Gas: Natural gas occurring in reservoirs with crude oil either as free gas (associated) or as gas in solution with the crude oil (dissolved).

Categories of Gas: Natural gas as defined by the Natural Gas Policy Act (NGPA), designated by the section of the Act in which they are defined, as follows:

- Section 102--New Natural Gas--Gas from new (post July 27, 1976) reservoirs on old offshore leases, gas from new (post April 20, 1977) offshore gas leases, and new (post April 20, 1977) onshore wells at least 2.5 miles from the nearest old well or 1,000 feet deeper than any well within 2.5 miles.

- Section 103--Gas from wells where the surface drilling began after February 19, 1977, but which do not qualify for Section 102 because the wells are within 2.5 miles of old wells and are not 1,000 feet deeper than any other well within 2.5 miles.

- Section 104--Gas Dedicated to Interstate Commerce before the NGPA enactment (November 9, 1978), including flowing gas and gas from certain designated locations.

- Section 105--Gas under Existing Intrastate Contracts not dedicated to interstate commerce on November 11, 1978--Gas sold under such contracts in place at the date of enactment.

- Section 106--Sales of Gas Made under "Rollover" Contracts--Section 104 and 105 gas under contracts that are renegotiated upon expiration.

- Section 107--High Cost Natural Gas--Gas from wells drilled after February 19, 1977, that are 15,000 feet or deeper--gas from coal seams, Devonian shale, tight sands, or geopressurized brine.

- Section 108--Stripper Well Natural Gas--Nonassociated natural gas produced at low flow rates.

- Section 109--Production from wells not covered above, largely Prudhoe Bay Alaskan gas.

Ceiling Price: The maximum price a producer is allowed to collect under the NGPA for a first sale of gas.

High-Cost Gas: Terminology used for Section 107 sources of gas, most of which is either deregulated or benefits from relatively high ceiling prices.

Incremental Pricing: Those provisions of the NGPA written to pass the cost of higher priced gas to large industrial consumers. Industrial customers are required to pay the increased cost until their cost reaches a level computed from the equivalent price of fuel oil. Because of the high number of exemptions granted, the incremental pricing provisions have had little impact on consumer prices.

Interstate Gas: Natural gas that is dedicated to interstate commerce.

Intrastate Gas: Natural gas that is produced and consumed within one State's boundaries and transported by nonjurisdictional pipelines. As such, the gas was not subject to any Federal regulation until the enactment of the NGPA.

Loss and Unaccounted-For Gas: Actual natural gas losses, such as those due to leaks or the merging of new pipelines, customers coming on or leaving the system, or meter breakdowns resulting in estimated billing.

Natural Gas Policy Act of 1978 (NGPA): Legislation providing: a broad range of price controls on domestically produced gas, with price regulations extended to gas that had not been regulated earlier; a schedule of price increases leading to decontrol of most gas at specified future dates; and a mechanism for shifting most of the burden for the higher cost, new gas supplies on industrial consumers who could potentially convert to coal.

New Gas: Terminology generally used to describe Sections 102 and 103 gas or, less frequently, Sections 102, 103, 107, 108, and 109 gas.

Nonassociated Gas: Free natural gas not in contact with crude oil in the reservoir.

Off-System Sales: Natural gas sales made by pipelines to new customers in order to dispose of surplus gas that the pipelines' traditional markets cannot take.

Old Gas: Terminology used to encompass several of the NGPA categories, generally Sections 104, 105, and 106 gas. This loosely defines old wells and reservoirs existing at the time of the NGPA enactment.

Pipegate: The point of a gas purchase between a producer and a first purchaser. The quantity purchased is usually less than wellhead production, primarily due to the removal of lease and plant fuel. The price is usually higher than the wellhead price, due to gathering and processing charges.

Pipeline: The company that receives the gas from the producer and transports it for delivery to another pipeline, a local distribution company, or to end-use consumers. The pipeline company generally purchases the gas from the producer after field handling of the gas or directly at the wellhead and resells it to a local distribution company. Whether or not the pipeline operates across State boundaries determines its classification as interstate or intrastate.

Producer: That company or entity that drills, maintains, and operates the gas or gas/oil well. The producer may also perform the gathering and initial field handling and processing of the gas.

Proved Reserves: Geological deposits of gas known to exist and to be economically recoverable using current technology.

Purchased Gas Adjustment (PGA) Filings: Filings submitted by major interstate pipeline companies to the Federal Energy Regulatory Commission. These submissions allow the companies to recover the difference between their anticipated actual purchase costs for natural gas and the costs reflected in their current rate structure.

Take-or-Pay Provision: A provision typically found in contracts between producers and pipeline purchasers that requires the purchaser to take or pay for, even if not taken, a certain quantity of gas. Some percentages are based on minimum daily quantities, annual quantities, or minimum contract quantities. Take-or-pay quantities may change over time under initial provisions of the contract or may be changed in an amendment to the contract.

Unconventional Gas: Natural gas resources characterized by the geologic environment, including tight gas reservoirs, Devonian shale, coal seams, and geopressurized brine.

Wellhead: The point at which natural gas is transferred from the well to a pipeline or other nonwell facility. This term is used in referring to the "wellhead price," which is the price producers of natural gas receive excluding reimbursement for severance taxes and other production related costs.

Petroleum Terminology

Alcohol: The family name of a group of organic chemical compounds composed of carbon, hydrogen, and oxygen. The series of molecules vary in chain length and are composed of a hydrocarbon plus a hydroxyl group, CH-(CH)n-OH. Alcohol includes ethanol and methanol.

Asphalt: A dark brown/black material, containing bitumens as the predominant constituents, obtained either naturally or by petroleum procession. It is the residue from the distillation of an asphaltic crude oil or the insoluble portion from an extraction process that utilizes propane or other suitable solvents. The definition includes crude asphalt as well as the following finished products: cements, fluxes, the asphalt content of emulsion (exclusive of water), and petroleum distillates blended with asphalt to make cutback asphalts. The conversion factor is 5.5 42-gallon barrels per short ton.

Aviation Gasoline (Finished): All special grades of gasoline for use in aviation reciprocating engines, as given in ASTM Specification D910 and Military Specification MIL-G-5572. Aviation gasoline includes all refinery products within the gasoline range that are to be marketed straight or in blends as aviation gasoline without further refinery processing.

Barrel: A volumetric unit of measure of crude oil and petroleum products equivalent to 42 U.S. gallons. This measure is used in most statistical reports. Factors for converting petroleum coke, asphalt, wax, and still gas to barrels are given in the definitions for these products.

Barrels per Calendar Day: The number of barrels per stream day of input to crude oil processing units that can be processed by a refinery in an average 24-hour period after making allowances for the following limitations: downstream limitations, environmental constraints, types and grades of input, planned and unplanned downtime, and types and grades of products.

Barrels per Stream Day: The amount a unit can process running at full capacity under optimal crude and product slate conditions.

Catalytic Cracking: Basically the same as thermal cracking since heat is used, but differs in its use of a catalyst to direct the cracking reaction to produce more of the higher octane hydrocarbons; provides a motor spirit of 10 to 15 octane numbers higher than that of the thermally cracked product and is more effective in producing isoparaffins and aromatics, all of which are of high antiknock qualities or value. Modern cracking units are one of two types: the "fluid process," which uses a finely powdered catalyst that is moved and circulated through the system by a "fluidized-solid" technique, and the "moving bed process," in which pellet catalysts are circulated by elevators or the gas-lift method.

Catalytic Hydrocracking: A refining process for converting middle-boiling or residual material to high-octane gasoline, reformer charge stock, jet fuel, and/or high grade fuel oil. Hydrocracking is an efficient, relatively low-temperature process using hydrogen and a catalyst.

Catalytic Hydrofining: A process for improving the quality of petroleum products (especially gasoline) by treating them with hydrogen in the presence of a catalyst at a temperature below that at which decomposition occurs.

Catalytic Hydrotreating: A process of treating petroleum fractions and unfinished oils in the presence of catalysts and substantial quantities of hydrogen to upgrade their quality.

Catalytic Reforming: The use of controlled heat and pressure with catalysts to effect the rearrangement of certain hydrocarbon molecules without altering their composition appreciably; the conversion of low-octane gasoline fractions into higher octane stocks suitable for blending into finished gasoline; also the conversion of naphthas to obtain a more volatile product of higher octane number.

Crude Distillation: The processing of separating crude oil components by heating and subsequent condensing of the fractions by cooling.

Crude Oil: A naturally occurring mixture of liquid hydrocarbons that remains liquid at atmospheric pressure after passing through surface separating facilities. Lease condensate is included. Drips are also included, but topped crude (residual) oil and other unfinished oils are excluded. Liquids produced at natural gas processing plants and mixed with crude oil are likewise excluded where identifiable.

Crude Oil Type: Crude oil is classified as follows:

- Sweet--Under 0.5 weight percent sulfur.
- Medium Sulfur--Between 0.5 and 1.0 weight percent sulfur.
- Light Medium--15 percent or less at 1,050 degrees Farenheit + residuum assay.
- Heavy Medium--Greater than 15 percent at 1,050 degrees Fahrenheit + residuum assay.
- High Sulfur--In excess of 1.0 weight percent sulfur.
- Light High--15 percent or less at 1,050 degrees Farenheit + residuum assay.
- Heavy High--Greater than 15 percent at 1,050 degrees Farenheit + residuum assay.
- Domestic Production--Crude oil produced in the United States or from its Outer Continental Shelf as defined in 43 U.S.C. 1331. Synthetic hydrocarbons such as shale oil and tar sand oil are included.
- Foreign Production--Crude oil produced outside the United States. Imported Athabasca hydrocarbons are reported as crude oil.

Distillate Fuel Oil: A general classification for one of the petroleum fractions which, when produced in conventional distillation operations, has a boiling range of 400 degrees Farenheit at the 10-percent point to 640 degrees Farenheit at the 90-percent point. It is used primarily for space heating, on- and off-highway diesel engine fuel (including railroad engine fuel and fuel for agricultural machinery), and electric power generation. Included are products known as No. 1 and No. 2 heating oils, diesel fuels, and No. 4 fuel oil.

Feedstocks: Crude oil or other hydrocarbons that are the basic materials for a refining or manufacturing process.

Field Production: Represents crude oil production on leases, natural gas liquids production at natural gas processing plants, and new supplies of other hydrocarbons and alcohol.

Hydrogen: A colorless, highly flammable gaseous element. It is the lightest of all gases and the most abundant element in the universe, and it is used in the production of synthetic ammonia and methanol, in the refining of petroleum, and in the hydrogenation of organic materials.

Kerosene: A petroleum distillate that boils at a temperature between 300 and 550 degrees Farenheit, that has a flash point higher than 100 degrees Farenheit by ASTM Method D56, that has a gravity range from 40 degrees to 46 degrees API, and that has a burning point in the range of 150 to 175 degrees Farenheit. It is a clean-burning product suitable for use as an illuminant when burned in wick lamps. Includes grades of kerosene called range oil having properties similar to No. 1 fuel oil, but with a gravity of about 43 degrees API and a maximum end point of 625 degrees Farenheit. Kerosene is used in space heaters, cook stoves, and water heaters.

Kerosene-Type Jet Fuel: A quality kerosene product with an average gravity of about 41 degrees API, a 10-percent distillation temperature of 400 degrees Farenheit, and an end point of 572 degrees Farenheit. It is covered by ASTM Specification D1655 and Military Specification MIL-T-5624L (Grades JP-5 and JP-8). It is used primarily for commercial turbojet and turboprop aircraft engines.

Lease Condensate: A natural gas liquid recovered from gas-well gas (associated and nonassociated) in lease separators or natural gas field facilities. Lease condensate consists primarily of pentanes and heavier hydrocarbons.

Lubricants: A substance used to reduce friction between bearing surfaces. Petroleum lubricants may be produced either from distillates or residuals. Other substances may be added to impart or improve certain required properties. Lubricants include all grades of lubricating oils from spindle oil to cylinder oil and those used in greases. The three categories reported are as follows:

- Bright Stock--A refined, high viscosity lubricating oil base stock that is usually made from a residuum by a treatment such as deasphalting, acid treatment, or solvent extraction.

- Neutral--A distillate lubricating oil base stock with a viscosity that is usually not above 550 Saybolt Seconds Universal (SSU) at 100 degrees Farenheit. It is prepared by a treatment such as hydrofining, acid treatment, or solvent extraction.

- Other--A lubricating oil base stock used in finished lubricating oils and greases, including black, coastal, and red oils.

Miscellaneous Products: Includes all finished products not classified elsewhere. Miscellaneous products include petroleum, absorption oils, ram-jet fuel, petroleum rocket fuels, synthetic natural gas feedstocks, and naphthas.

Motor Gasoline (Finished): A complex mixture of relatively volatile hydrocarbons, with or without small quantities of additives for use in spark-ignition engines. Specifications for motor gasoline, as given in ASTM Specification D439 or Federal Specification VV-G-1690B, include a boiling range of 122 to 158 degrees Farenheit at the 10-percent point to 365 to 374 degrees Farenheit at the 90-percent point and a Reid vapor pressure range from 9 to 15 psi. Motor gasoline includes finished leaded gasoline, finished unleaded gasoline, and gasohol. Blendstock is excluded until blending has been completed. Alcohol that is to be used in the blending of gasohol is also excluded. The categories of motor gasoline are defined as follows:

- Leaded Gasoline--Contains more than 0.05 grams of lead per gallon or more than 0.005 grams of phosphorus per gallon. The actual lead content of any given gallon, however, may vary as a function of the size of the producer and company according to specific Environmental Protection Agency waiver provisions. Premium and regular grades are included, depending on the octane rating.

- Unleaded Gasoline--Contains up to 0.05 grams of lead per gallon and 0.005 grams of phosphorus per gallon. Premium and regular grades are included, depending on the octane rating.

- Gasohol--A blend of alcohol and finished motor gasoline that is about 90 percent finished motor gasoline and 10 percent alcohol (ethanol or methanol).

Naphtha: A colorless, flammable liquid obtained from crude petroleum and used as a solvent and cleaning fluid and as a raw material for gasoline.

Naphtha-Type Jet Fuel: A fuel in the heavy naphtha boiling range with an average gravity of about 53 percent API and 20 to 90 percent distillation temperatures of 290 to 470 degrees Farenheit, meeting Military Specification MIL-T-5624L (Grade JP-4). JP-4 is used for turbojet and turboprop aircraft engines, primarily by the military. This category excludes ram-jet and petroleum rocket fuels, which are included in the miscellaneous products category.

Natural Gas Plant Liquids: Natural gas liquids recovered from natural gas in gas processing plants and in some situations, from natural gas field facilities. Natural gas liquids extracted by fractionators are also included. These liquids are defined according to the published specifications of the Gas Processors Association and the American Society for Testing and Materials, and are classified as follows: ethane, propane, ethane-propane mix, isobutane, butane, butane-propane mix, isopentane, natural gasoline, plant condensate, unfractionated stream, and other products from natural gas processing plants (products meeting the standards of finished petroleum products produced at natural gas processing plants, such as finished motor gasoline, finished aviation gasoline, special naphthas, kerosene, distillate, fuel oil, and miscellaneous products).

Operable Capacity: Represents the capability of crude oil distillation units to process crude oil at a petroleum refinery. Operable capacity is the sum of operating and idle capacity, which are defined as follows:

- Operating Capacity--Throughput capacity of crude oil distillation units that are in operation.

- Idle Capacity--Throughput capacity of crude oil distillation units that are not in operation but are capable of being placed in operation within 90 days.

Permanently Shutdown: A classification for petroleum refineries that represents refineries that have ceased operation and/or are incapable of being placed in operation within 90 days.

Petroleum Products: Petroleum products obtained from the processing of crude oil (including lease condensate), natural gas, and other hydrocarbon compounds. Petroleum products include unfinished oils, natural gasoline, isopentane, plant condensate, unfractionated stream, ethane, liquefied petroleum gases, aviation gasoline, motor gasoline, naphtha-type jet fuel, kerosene-type jet fuel, kerosene, distillate fuel oil, residual fuel oil, naphtha less than 400 degrees Farenheit end-point, special naphthas, lubricants, waxes, petroleum coke, asphalt, road oil, still gas, and miscellaneous products.

Petroleum Refinery: An installation that manufactures finished petroleum products from crude oil, unfinished oils, natural gas plant liquids, other hydrocarbons, and alcohol.

Primary Stocks: Stocks of crude oil or petroleum products held in storage by refineries, natural gas processing plants, pipelines, tankfarms, and bulk terminals. Crude oil that is in transit from Alaska or that is stored on Federal leases is included. Bulk terminals are facilities that can store at least 50,000 barrels of petroleum products or that can receive petroleum products by tanker, barge, or pipeline. Primary stocks exclude stocks of foreign origin that are meant for domestic consumption but have not cleared the U.S. Customs Service.

Residual Fuel Oil: Topped crude of refinery operations. Residual fuel oil includes No. 5 and No. 6 fuel oils as defined in ASTM, Specification D396 and Federal Specification VV-F-815C, Navy Special fuel oil as defined in Military Specification MIL-F859E (including Amendment 2), Bunker C fuel oil (a heavy oil used by ships and industry for heating large-scale installations--referred to as No. 6 fuel oil), and acid sludge used for refinery fuels. Residual fuel oil is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes.

Road Oil: Any heavy petroleum oil, including residual asphaltic oils, used as a dust palliative and surface treatment of roads and highways. It is generally produced in six grades: from 0, the most liquid, to 5, the most viscous.

Special Naphthas: All finished products within the gasoline range that are used as paint thinners, cleaners, and solvents. These products are refined to a specified flash point and have a boiling range of 90 to 220 degrees Farenheit.

Electricity Terminology

Allowance for Funds Used During Construction (AFUDC): Allowances included are net cost of borrowed funds and a reasonable rate on other funds used for this purpose by the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts in the cost of construction (when applicable).

Baseload Capacity: The generating equipment normally operated to serve loads on a round-the-clock basis.

Baseload Plant: A plant, usually housing high-efficiency, steam-electric units, which is normally operated to take all or part of the minimum load of a system, and which consequently produces electricity at an essentially constant rate.

Boiler: A device for generating steam for power, processing, or heating purposes; or hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes found in the boiler shell. This fluid is delivered to an end-use at a desired pressure, temperature, and quality.

Capability: The maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress.

Capacity: The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated.

Capital (Financial): The line items on the right side of a balance sheet, which include debt, preferred stock, and common equity. A net increase in assets must be financed by an increase in one or more forms of capital.

Construction Costs: All direct and indirect costs incurred in acquiring and constructing electric utility plant and equipment and proportionate shares of common utility plant. These costs include the cost of land and improvements, nuclear fuel and spare parts, allowance for funds used during construction, and general overheads capitalized, less the cost of acquiring plant and equipment previously operated in utility service.

Construction Expenditures: The gross expenditures for construction costs, including the cost of replacing worn-out plants, electric construction costs, and land held for future use.

Construction Work In Progress (CWIP): The total balance shown on a utility's balance sheet for construction work not yet completed but in progress. This balance line item may or may not be included in the rate base.

Cost: The amount (or value) of goods and services paid to acquire resources such as plant, equipment, fuel, and labor services. Fixed costs in the electric utility industry are associated with resources that cannot be changed during a given time span (such as plant and equipment) and are independent of the level of generation. Variable costs are associated with resources that can vary during a given time period (such as fuel and labor services) and are directly related to the level of generation.

Cost of Capital: The rate of return a firm must offer to obtain additional funds. This is expressed as the weighted average cost of debt, preferred stock, and common stockholders' equity that comprises the firm's money capital or finance. The cost of capital varies with the leverage ratio, the effective income tax rate, conditions in the bond and stock markets, growth rate of the firm, the firm's dividend strategy, stability of net income, the amount of new capital required, and other factors dealing with business and financial risks.

Demand: The rate at which electric energy is delivered to or by a system, part of a system, or piece of equipment at a given instant, or averaged over any designated period of time.

Dependable Capacity: The load-carrying ability of a station or system under adverse conditions for a specified time period.

Earnings Quality (of the electric power industry): The relative ratio of cash earnings to reported earnings. The relative ratio is the sum of internal cash generation plus dividends on common stock, dividends on cooperative memberships, or funds remitted to the general fund for public entities--excluding, however, such non-cash credits as the allowance for funds used during construction ("interest capitalized")--to the reported earnings on common stock (for investor-owned companies), earnings on memberships (for cooperatives), or funds reserved for plant expansion plus those remitted to the general fund (for public entities).

Electric Operating Expenses: Operation expenses, maintenance expenses, depreciation expenses, amortization, taxes other than income taxes, Federal income taxes, other income taxes, provisions for deferred income taxes, provisions for deferred income (credit, investment tax credit adjustment), and net gains and losses from the disposition of electric utility plants.

Electric Power Industry: The public, private, and cooperative electric utility systems of the United States taken as a whole. This includes all electric systems serving the public: regulated investor-owned electric utility companies; Federal power projects; State, municipal and other government-owned systems, including public electric utility districts; electric cooperatives, including generation and transmission entities ("G and T's"); jointly owned electric utility facilities, and electric utility facilities owned by a lessor and leased to an electric utility firm. Excluded from this list are the special-purpose electric facilities or systems that do not offer service to the public.

Electric Plant: A station containing prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or fission energy into electric energy.

Electric Rate Schedule: A statement of the electric rate and the terms and conditions governing its application, including attendant contract terms and conditions that have been accepted by a regulatory body with appropriate oversight authority.

Energy Source: The primary source that provides the power that is converted to electricity through chemical, mechanical, or other means. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

Financial Needs: The electric power industry's requirement for money and credit that is used for construction expenditures, capital fund needs; these include, by definition, all relatively permanent increases in working capital needs, and overall financing requirements for both new money and refundings.

Fixed Charge Coverage: The ratio of earnings available to pay so-called fixed charges to such fixed charges. Fixed charges include interest on funded debt (including leases) plus the related amortization of debt discount, premium, and expense. Earnings available for fixed charges may be computed before or after deducting income taxes. Occasionally credits for the "allowance for funds used during construction" are excluded from the earnings figures. The precise procedures followed in calculating fixed charge or interest coverages vary widely.

Fossil Fuel Plant: A plant using coal, oil, or gas as its source of energy.

Gas-Turbine Plant: A plant in which the prime mover is a gas turbine. A gas turbine consists typically of an axial-flow air compressor (one or more combustion chambers where liquid or gaseous fuel is burned and the hot gases are passed to the turbine), where hot gases expand to drive the generator and run the compressor.

Generation: The act or process of producing electric energy from other forms of energy; also, the amount of electricity produced.

Generator: A machine that converts mechanical energy into electric energy.

Geothermal Energy: Energy from the internal heat of the earth: residual heat, friction heat, or heat resulting from radioactive decay. The heat is found in rocks and fluids at various depths and can be extracted by drilling and/or pumping.

Geothermal Plant: A plant in which the prime mover is a steam turbine. The turbine is driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted by drilling and/or pumping.

Gigawatt (GW): One billion watts.

Gigawatthour (GWh): One billion watthours.

Gross Generation: The total amount of electric energy produced by a generating station or stations, measured at the generator terminals.

Hydroelectric Plant: A plant in which the turbine generators are driven by falling water.

Hydropower: The harnessing of flowing water to produce mechanical or electric energy.

Installed Nameplate Capacity: The full-load continuous rating of a generator, prime mover, or other electric equipment under specified conditions as designated by the manufacturer. It is usually indicated on a nameplate attached physically to the equipment. Installed station capacity does not include auxiliary or house units.

Interest Coverage Ratio: The number of times that fixed interest charges were earned indicates the margin of safety of interest on fixed debt. The times-interest-earned ratio is calculated using earnings before and after income taxes, and the credits of interest charged to construction have been treated as other incomes. The interest charges include interest on long-term debt, interest on debt of associated companies, and other interest expense.

Internal Cash Flow: Composed of funds available for common stockholders after adjustments for common stock equivalents, depreciation and depletion, amortization, deferred income taxes (net), investment tax credit (net), and other internal sources (net), less common dividends and AFUDC (total). The funds available for common stock holders less common stock equivalents is income before extraordinary items and discontinued operations less preferred and preference dividend requirements plus savings due to common stock equivalents. Amortization is the gradual extinguishment of an amount by the systematic write-off of assets over the period that they produce an economic benefit. Deferred income taxes (net) is the net amount that results from accelerated amortization and/or liberalized depreciation in income tax returns less the provision for deferred income taxes. The investment tax credit (net) is the current year's investment tax credit less the current year's amortization of accumulated investment tax credit. Other internal sources includes extraordinary items and discontinued operations, minority interest, and undistributed earnings of unconsolidated subsidiaries.

Internal Combustion Plant: A plant in which the prime mover is an internal combustion engine. An internal combustion engine has one or more cylinders in which the process of combustion take place, converting energy released from the rapid burning of a fuel-air mixture into mechanical energy. Diesel and natural gas engines are the principal types used in electric plants. The plant is usually operated during periods of high demand for electricity.

Kilowatt (kW): One thousand watts.

Kilowatthour (kWh): One thousand watthours.

Load: The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the customers.

Megawatt (MW): One million watts.

Megawatthour (MWh): One million watthours.

Net Capability: The net capability of a generating station is the amount of power that could be produced as demonstrated by test or as determined by actual operating experience less power generated and used for station uses. Net capability may vary with the character of the load, time of year (due to circulating water temperatures in thermal stations or availability of water in hydroelectric power stations), and other characteristic causes.

Net Generation: Gross generation less plant use, measured at the high voltage terminals of the station's step-up transformer. The energy required for pumping at pumped-storage plants is regarded as plant use and must be deducted from the gross generation.

Nuclear Fuel: Fissionable materials that have been enriched to such a composition that when placed in a nuclear reactor will support a self-sustaining fission chain reaction, producing heat in a controlled manner for process use.

Nuclear Power Plant: A plant in which the prime mover is a steam turbine. The steam used to drive the turbine is produced by a heat transfer from the reactor vessel during the period when the nuclear fuel is undergoing fission.

Nuclear Reactor: A device in which a fission chain reaction can be initiated, maintained, and controlled. Its essential component is a core with fissionable fuel.

Operating and Maintenance Expenses: Operating expenses are associated with the operation of a utility, such as payroll, provisions for depreciation and amortization, taxes other than income taxes, income taxes, provisions for deferred income taxes, income taxes deferred in prior years (credit and investment tax credit adjustments). Maintenance expenses are that portion of expenses consisting of labor, materials, and other direct and indirect expenses incurred for preserving the operating efficiency or physical condition of utility plants which are used for power production, transmission, and distribution of energy.

Operating Reserve Margin: The amount of unused available capability of an electric power system at peak load.

Other Generation: Electricity originating from these sources: biomass, fuel cells, geothermal, solar, waste, wind, and wood.

Outage: The period during which a generating unit, transmission line, or other facility is out of service.

Peaking Capacity: The capacity of generating equipment normally operated during the hours of highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on a round-the-clock basis.

Peak Load: The maximum load during a specified period of time.

Peak Load Plant: A plant normally run during periods of peak demand and usually housing old, low-efficiency steam units, turbines (gas, oil, diesels), or pumped-storage hydroelectric equipment.

Plant: A station where prime movers, electric generators, and auxiliary equipment are located for converting mechanical, chemical, and/or nuclear energy into electric energy. A station may contain more than one type of prime mover.

Prime Mover: The engine, turbine, water wheel, or similar machine that drives an electric generator.

Pumped-Storage Hydroelectric Plant: A plant that usually generates electric energy during peak-load periods by using water previously pumped into an elevated storage reservoir during off-peak periods when excess generating capacity is available to do so. When additional generating capacity is needed, the water can be released from the reservoir through a conduit to turbine generators located in a power plant at a lower level.

Rate of Return: The ratio of financing costs to the rate base. The return earned by a utility is calculated as a percentage of its rate base.

Ratemaking Authority: Authority to fix, modify, approve, or disapprove rates determined by a utility commission.

Required Rate of Return: The minimum rate of return necessary to induce investors to buy or hold a given security. It equals the risk-free rate of interest, usually represented by the current yield on U.S. Treasury securities, plus a risk premium.

Reserve Generating Capacity: The capacity of generating units available to meet peak or abnormally high demands for power and to generate power during scheduled or unscheduled outages.

Reserve Margin: The percent of unused capacity at the time of peak load. The measure of reserve margin developed in these projections is different than estimates prepared by the North American Electric Reliability Council (NERC). The reserve margin calculations developed in this report are based on nameplate capacity, rather than the lower net dependable capacity used by NERC. In addition, the Energy Information Administration (EIA) national reserve margin estimate is developed using regional coincidental peak load data, rather than the higher non-coincidental peak load data used by NERC. The EIA analysis assumes that all plants are available at the time of peak load. These differences, individually and cumulatively, result in higher EIA reserve margin estimates than NERC estimates.

Retained Earnings: The accumulated net income of the utility, less distribution to stockholders and transfers to other capital accounts.

Revenue Requirement: The sum of the estimated operation and maintenance expenses, taxes, depreciation, and a reasonable return on an appropriate rate base needed to cover the cost of capital invested in the utility company.

Reversible Turbine: A hydraulic turbine, normally installed in a pumped storage plant, which can be used alternatively as a pump or as an engine, turbine, water wheel, or other apparatus that drives an electric generator.

Standby Facility: A facility that is in support to a utility system and is generally running under no-load. It is available to replace or supplement a facility normally in service.

Steam-Electric Plant (Conventional): A plant in which the prime mover is a steam turbine. The steam used to drive the turbine is produced in a boiler where fossil fuels are burned.

Stocks (Fuel): A supply of fuel accumulated for future use. This includes coal and fuel oil stocks in coal cars, tanks, or barges at the plant site or at separate storage sites.

System (Electric): Physically connected generation, transmission, and distribution facilities operated as an integrated unit under one central management or operating supervision.

Transmission: The movement or transfer of electric energy in bulk over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers or to other electric power systems.

Turbine: A machine for generating rotary mechanical power from the energy in a stream of fluid (such as water, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction, or a mixture of the two. Most electricity is generated by the impulse principle in which the fluid strikes rotor blades producing mechanical power via the turning rotor.

Watt: The electrical unit of power. The rate of energy transfer equivalent to one ampere flowing under a pressure of one volt at unity power factor.

Wholesale Sales: Energy supplied to other electric utilities, cooperatives, municipalities, and Federal and State electric agencies for resale to ultimate consumers.

Conversion Factors

Most of the tables in the Annual Energy Outlook report values in British Thermal Units (Btu). The table below is provided for the users of this publication who may wish to convert a value reported in Btu into its physical units. The conversion factors listed correspond to the estimated Btu content of the various fuels at the time of consumption in 1984. Unless otherwise noted, the conversion factors were obtained directly from the Annual Energy Review, 1983. When aggregated fuel categories are reported, the included fuels are listed with their conversion factors. The conversion factors for the aggregate fuels appear in parenthesis in the table below. In most cases, these conversion factors were applied to the projected values as well.

Sector/Energy Category	Conversion Factor	Unit
Residential		
Distillate	5.825	Million Btu/barrel
Kerosene	5.670	Million Btu/barrel
LPG[a]	3.643	Million Btu/barrel
Steam Coal[b]	[c](22.650)	Million Btu/short ton
Bituminous & Lignite	22.300	Million Btu/short ton
Anthracite	25.200	Million Btu/short ton
Natural Gas	1,026	Btu/cubic foot
Electricity	3,412	Btu/kilowatthour
Commercial		
Distillate	5.825	Million Btu/barrel
Residual Fuel	6.287	Million Btu/barrel
Motor Gasoline	5.253	Million Btu/barrel
Kerosene	5.670	Million Btu/barrel
LPG[a]	3.643	Million Btu/barrel
Steam Coal[b]	[c](22.650)	Million Btu/short ton
Bituminous	22.300	Million Btu/short ton
Anthracite	25.200	Million Btu/short ton
Natural Gas	1,026	Btu/cubic foot
Electricity	3,412	Btu/kilowatthour
Industrial		
Distillate	5.825	Million Btu/barrel
Residual Fuel	6.287	Million Btu/barrel
Motor Gasoline	5.253	Million Btu/barrel
Kerosene	5.670	Million Btu/barrel
LPG[a]	3.643	Million Btu/barrel
Asphalt & Road Oil	6.636	Million Btu/barrel
Petroleum Coke	6.024	Million Btu/barrel
Special Naphthas	5.248	Million Btu/barrel
Lubricants and Waxes	6.065	Million Btu/barrel
Petrochemical Feedstocks	[d](5.606)	Million Btu/barrel
Naphtha	5.248	Million Btu/barrel
Still Gas	6.000	Million Btu/barrel

Sector/Energy Category	Conversion Factor	Unit
Steam Coal[b]	22.650	Million Btu/short ton
Coking Coal[b]	26.000	Million Btu/short ton
Coke Imports	26.000	Million Btu/short ton
Natural Gas	1,026	Btu/cubic foot
Hydropower	10,470	Btu/kilowatthour
Electricity	3,412	Btu/kilowatthour
Transportation		
Distillate	5.825	Million Btu/barrel
Residual Fuel Oil	6.287	Million Btu/barrel
Motor Gasoline	5.253	Million Btu/barrel
Aviation Gasoline	5.048	Million Btu/barrel
LPG[a]	3.643	Million Btu/barrel
Lubricants	6.065	Million Btu/barrel
Jet Fuel	[d](5.608)	Million Btu/barrel
Naphtha	5.355	Million Btu/barrel
Kerosene	5.670	Million Btu/barrel
Natural Gas	1,026	Btu/cubic foot
Electricity	3,412	Btu/kilowatthour

[a]Data from Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(83/12[4]) (Washington, DC, 1984).

[b]In the projected period, coal conversion factors are based on model results: Metallurgical Coal (27.2), Residential/Commercial Coal (24.2), Utility Coal (from 21.2 in 1985 to 20.9 in 1995), Industrial Coal (from 23.9 in 1985 to 25.2 in 1995).

[c]Implied residential/commercial sector conversion factor based on 1983 Annual Energy Review data in physical and Btu units.

[d]Quantity weights from Energy Information Administration, Petroleum Supply Annual, 1981, DOE/EIA-0340(81) (Washington, DC, 1982).

☆ U.S. GOVERNMENT PRINTING OFFICE: 1985-461-195:10139

DOE F 1340.2
(2-80)

Energy Information Administration

GPO SINGLE ISSUE AND ANNUAL ORDER FORM

B

(For use in ordering EIA Publications only – Read Ordering Information Section before completing form.)

SEND ORDER FORM TO: Superintendent of Documents, U.S. Government Printing Office, Washington, D.C., 20402

Enclosed is $ ____________ ☐ Check

☐ Money order, or charge to my Deposit Account No.

☐☐☐☐☐☐☐ – ☐

Order No. ____________

VISA

MasterCard

Credit Card Orders Only

Total charges $ ____________ Fill in the boxes below

Credit Card No. ☐☐☐☐☐☐☐☐☐☐☐☐☐☐☐☐☐

Expiration Date Month/Year ☐☐☐☐ ☐ VISA ☐ Master Card

PLEASE PRINT OR TYPE **NAME AND ADDRESS**

NAME – FIRST, LAST

COMPANY NAME OR ADDITIONAL ADDRESS LINE

STREET ADDRESS

CITY STATE ZIP CODE

(OR COUNTRY)

PLEASE PRINT OR TYPE THE GPO STOCK NO. OF SINGLE ISSUES OR ANNUALS YOU WISH TO RECEIVE:

____

____

____

____

____

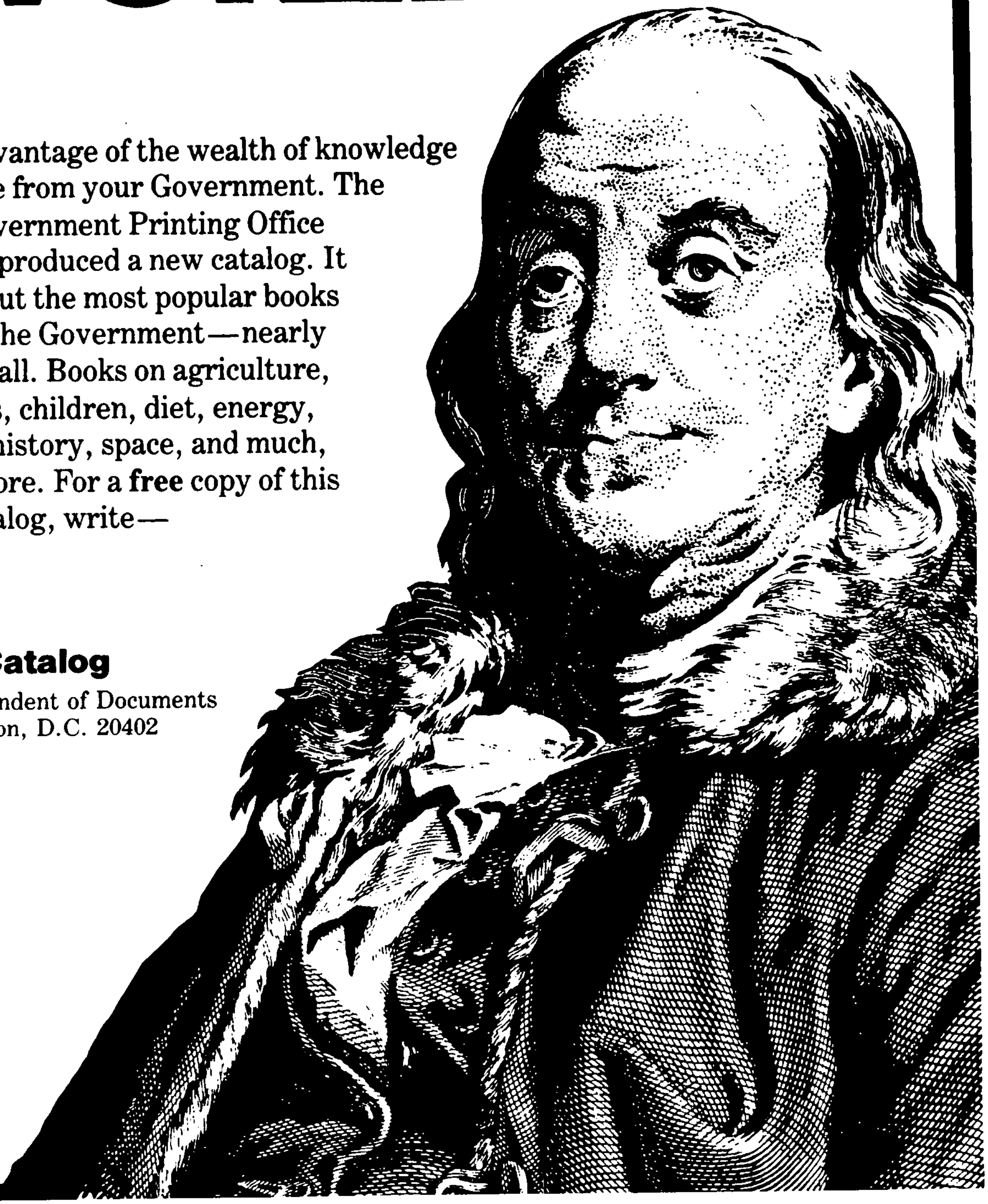
____

____

____

FOR OFFICE USE ONLY

QUANTITY	CHARGES
.... ENCLOSED	
.... TO BE MAILED	
.... SUBSCRIPTIONS	
POSTAGE	
FOREIGN HANDLING	
MMOB	
OPNR	
.... UPNS	
.... DISCOUNT	
.... REFUND	



Energy Information Administration
Forrestal Building
Washington, D.C. 20585

FIRST—CLASS MAIL
POSTAGE & FEES PAID
U.S. DEPT. OF ENERGY
PERMIT NO. G 20

FIRST CLASS MAIL

OFFICIAL BUSINESS
PENALTY FOR PRIVATE USE, $300