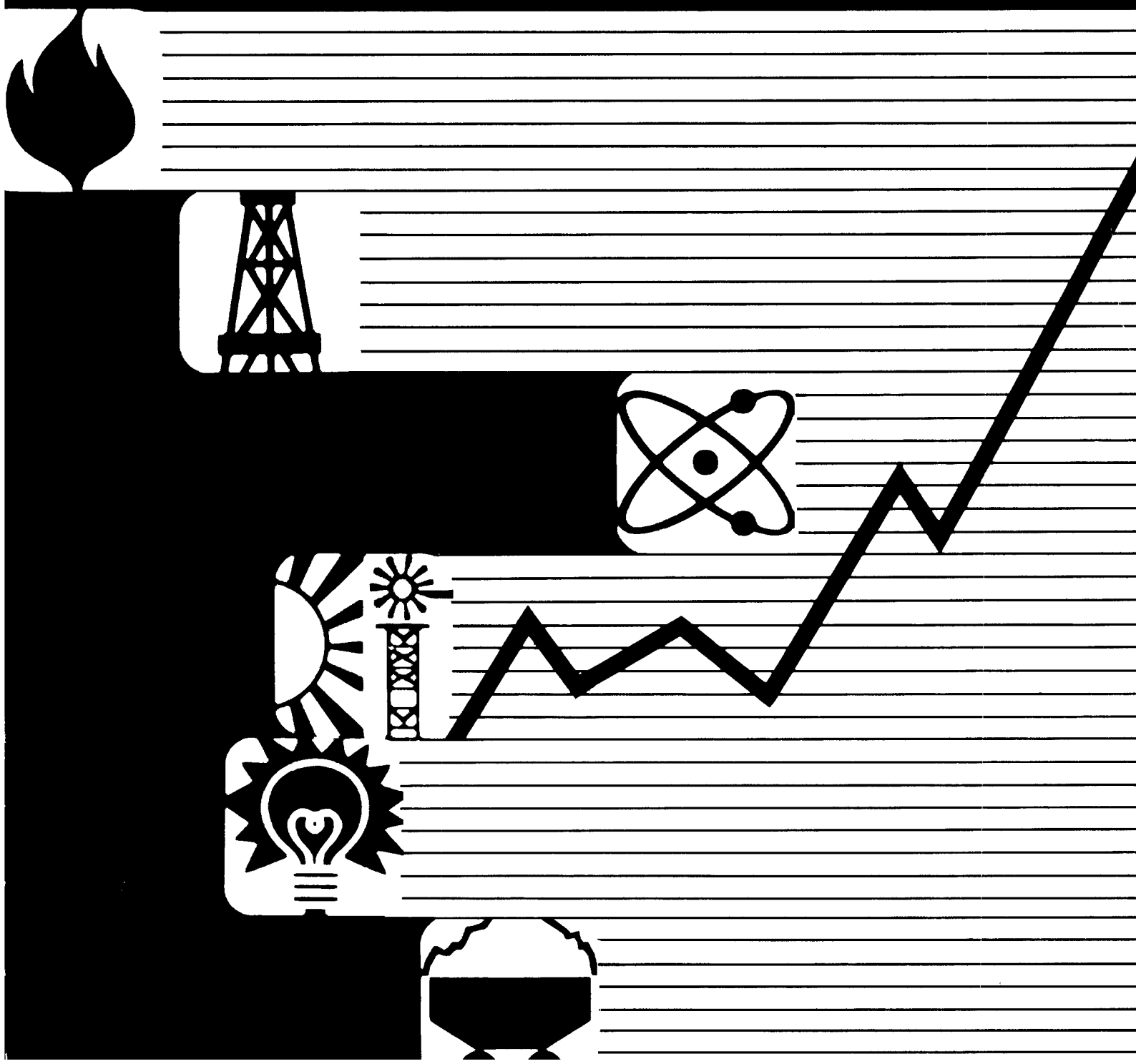
DOE/EIA-0383(85)

ANNUAL ENERGY OUTLOOK 1985

With Projections to 1995

Energy Information Administration
Washington, DC



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In the near future, a supplement to the *Annual Energy Outlook 1985* will be provided to all readers. This supplement, entitled *Comparison of Annual Energy Outlook 1985 Forecasts with Other Forecasts*, will compare the present projections with past projections from the Energy Information Administration, with the current National Energy Policy Plan projections from the Department of Energy, and with recent projections made by other forecasting groups such as Data Resources, Inc., Chase Econometric Associates, and Wharton Econometric Forecasting Associates.

You are invited to comment on the forecasts contained in this year's ***Annual Energy Outlook.*** Do you think the projected production, consumption, and import figures are too high, too low, or on target? If you have alternative views on any aspect of this forecast and care to express them, write to the Administrator of the Energy Information Administration.

Administrator's Foreword: Prophecy or Statistical Service?

No one can responsibly claim to know precisely what will happen in energy markets over the next 10 years. Any forecasts, including those in this report, are at best informed judgments about what is likely to occur. Because of the limitations to this inexact science, these forecasts are offered as information to interested users, providing a range of possible outcomes, rather than as a government plan for the next decade. The projections should be viewed more as a statistical service than as a prophecy of future events.

In large part, these forecasts are based on historical trends in energy production and consumption, modified to reflect current and expected future conditions. This process is aided by a modeling system that is used to forecast a consistent series of energy balances for the United States based on specified assumptions. The solution of these models in each case identifies a market clearing price (the point where supply equals demand) for each form of energy, and the corresponding levels of consumption and production for each form.

Both U.S. energy demand and the supply to meet it are affected directly by energy prices, especially the price of oil in world markets. To highlight this important link, the relationship between energy prices and movements in supply and demand is a major theme of this report. Energy markets also are strongly influenced by economic growth. Because world oil prices and national economic growth are critical but uncertain variables in the forecasting exercise, a range of results for energy supply, demand, and imports is produced using alternative assumptions about these variables (higher and lower than those used for the base case). Demographic changes and other economic developments are likely to influence energy supply and demand too; but these factors (such as the population growth rate and age distribution, turnover in the stocks of buildings and automobiles, and the size of domestic energy reserves) have been kept at the base-case values throughout the projection exercise.

The accuracy of forecasts usually depends on the validity of the underlying assumptions. Yet this forecasting system assumes no changes to current law and no new legislation, so the effects of such possible modifications are not considered. Furthermore, trends in energy prices or economic growth that are markedly different from those assumed here would probably result in a different energy supply and demand future than this report pictures. Finally, by definition, the effects of unpredictable world events (such as heightened unrest in the Middle East) cannot be reflected accurately in advance. Circumstances could change.

As always, long-term projections such as the one at hand follow relatively smooth trajectories when, in fact, the variables depicted may be subject to wide short-term swings of considerable magnitudes. As the deadline for this volume approaches, the world is once again in the throes of a violent downward swing in international crude oil prices. This simply indicates the presence of a very nervous market where prices are seemingly unable to stay at current levels, given the oil producing countries' intense efforts to retain, or to increase, their respective market shares. These short-term price swings notwithstanding, the fundamental message in this issue is that real prices of crude oil are likely to come down and stay low the next few years, but that they will recover and resume their upward trend by the end of this decade.

The longer term forecasting models used for previous editions of this annual outlook relied on relatively less current but detailed sectoral data. During the most recent period of falling energy prices, these models were not able to anticipate the continuing conservation efforts of consumers or the stability of domestic energy production. In an attempt to adjust for this failing, aggregate targets were established this time for key energy trends--based on historical trends, but also incorporating current information on apparent changes to them. These designated targets include the annual rates of change in the ratio of total energy consumption to GNP, petroleum demand growth, and several other major trends that are interrelated with energy supply and demand. An internally consistent extrapolation of these trends may provide the framework for a more reasonable picture of what energy markets could look like over the next 10 years.

The outlook for the future that emerges from this new approach is more conservative than previous forecasts from the Energy Information Administration. Energy consumption is expected to grow minimally, as the continuing effects from the high energy prices of the 1970's (which should further improve the efficiency of energy use) combine with several long-term trends, such as slower population growth and increases in the efficiency of the automobile fleet. Slower net growth in U.S. demand for energy translates into an expected rise in oil imports that is significantly less than estimated just a year ago.

These projections thus incorporate historical trends, some recently recognized changes, reasonable assumptions about key variables, and a good bit of professional judgment. By representing the most likely energy future based on such current knowledge, this report offers those who are interested in the U.S. energy market some potentially useful insights into many key factors affecting energy supply and demand. The way free market choices are made now (based not only on projections like these, but even more on a multitude of diverse individual preferences, perceptions, logic, and intuition) will be the final crucial determinant of the accuracy of these forecasts over the next 10 years.

Dr. H. A. Merklein
Administrator
Energy Information Administration

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Overview

Barring unforeseen changes, no dramatic modifications to the U.S. energy picture are anticipated between 1985[1] and 1990. Between 1990 and 1995, only moderate increases in oil and natural gas prices are projected, with higher levels of imports for those two commodities resulting mostly from declines in domestic production.

As stimulative and restraining factors offset each other, end-use energy demand is expected to rise at an average rate that could be well under 1 percent per year between now and 1995. Technological conservation should continue. However, total demand for primary energy is projected to increase a bit more rapidly than end-use demand. Greater use of electricity-- generated mainly from the coal and nuclear power that are more plentiful in this country--results in higher conversion losses. Overall, however, the size of the full "energy pie" is remarkably similar for 1975, for 1985, and as projected for 1995 (Figure ES1 on page 2).

Energy markets over the next 10 years are likely to be more stable than those of the 1970's. Following the wild fluctuations in energy prices, supply, and demand that occurred then, some basic long-term trends that began prior to this period are expected to reappear and continue through 1995. Energy consumption and energy efficiency normally both tended to rise; production from a depletable resource base usually tended to decline.

The most important new characteristic of the early 1980's that is expected to affect energy markets during the next decade is the continuation of world-wide excess production capacity in oil (Figure ES2 on page 3) which, in turn, affects all other forms of energy. This excess capacity has already exerted downward pressure on the prices of most major fuels, and, although this pressure is projected to lessen with time, it will probably be felt over most of the next 10 years. As a result, end-use price competition is expected to play a central role in determining primary supply prices, the energy-mix, and total consumer demand. The latter, of course, will depend as well on overall economic growth. Energy demand and gross national product (GNP) are still intertwined, although the numerical ratio between them has been changing.

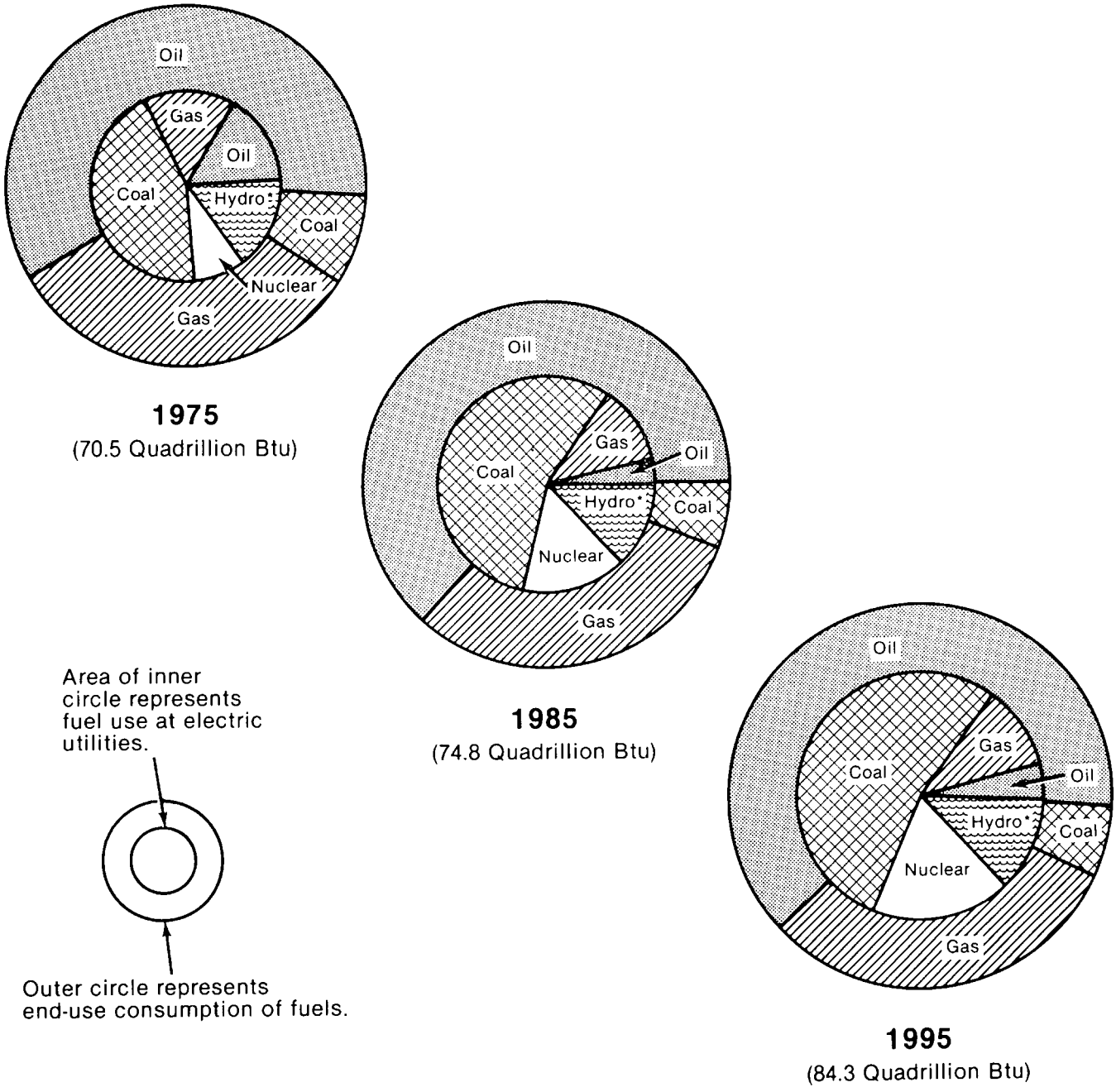
There seems to be adequate justification to assume a lower range of future oil prices in this year's *Annual Energy Outlook* (Figure ES3 on page 3) than was the case only 12 months ago. Even by 1995, world oil prices are now assumed in all three cases analyzed here to remain well below the peak of 1980 when expressed in constant dollars.

Lower prices for the major forms of energy are expected to lead to lower levels of domestic energy production, but (because of conservation trends) to only moderate increases over current demand. Total U.S. dependence on net energy imports of all kinds is projected to grow from 11 percent of total energy consumption in 1985 to 20 percent in 1995 in the base case (Figure ES4 on page 4). In fact, imports are expected to meet almost the entire increase in energy demand over this period, because total domestic energy production is projected to show little change. With the level of net energy imports being determined by the difference between domestic energy supply and domestic demand, it is easy to see why the pace of economic growth also drives the projections of total imports. In the "high oil imports" case (Table ES1 on page 4 and Table ES2 on page 5), total energy imports that are about 23 percent above the level forecast for 1995 in the base case would result from higher economic growth and lower oil prices than assumed in the base case (Table ES3 on page 5). In contrast, the lower economic growth and higher oil prices in the "low oil imports" case could be expected to result in total energy imports that are 17 percent lower than the base case level in 1995. These two alternative forecasts--either of which is quite possible--are presented in each section of this report to establish a range of energy futures. (A numerical summary of all three cases is presented in Appendix E).

[1]The latest year for which full and final data were available at the time this document was prepared was 1984. Thus, 1985 statistics throughout are themselves projections, made toward the end of calendar year 1985.

Figure ES1. Primary Versus End-Use Energy Consumption by Fuel Type: 1975, 1985, and 1995

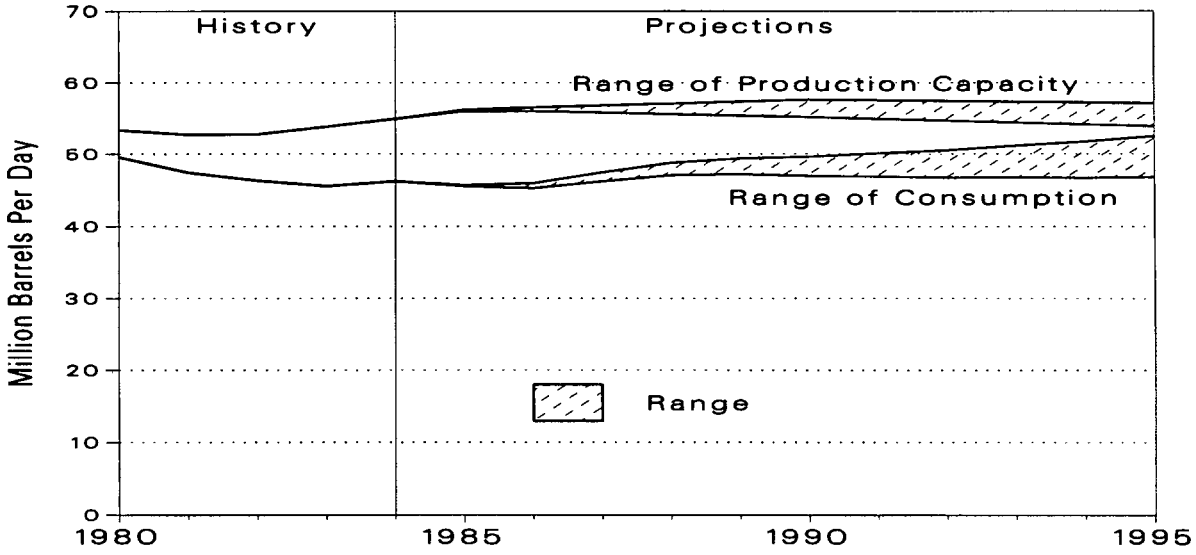
Although the demand for primary energy (the entire area of each circle) is projected to increase slowly, energy use at electric utilities (the area of the inner circle in each case) is forecast to grow more rapidly and thus account for an increasing share of total energy use.



* Share of other renewable sources is too small to represent at this scale.

Figure ES2. Range of World Petroleum Production Capacity and Consumption, 1980-1995

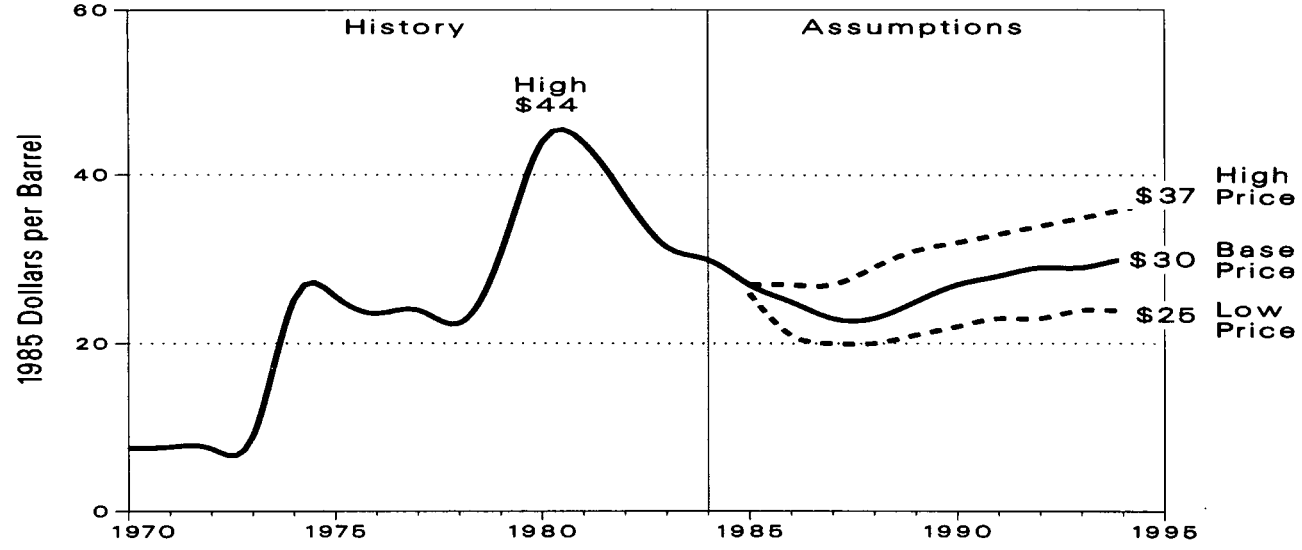
Current excess petroleum production capacity of 10-11 million barrels per day (mainly in OPEC) is projected to drop significantly by 1995.



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

Figure ES3. World Oil Prices in Constant 1985 Dollars, 1970-1995

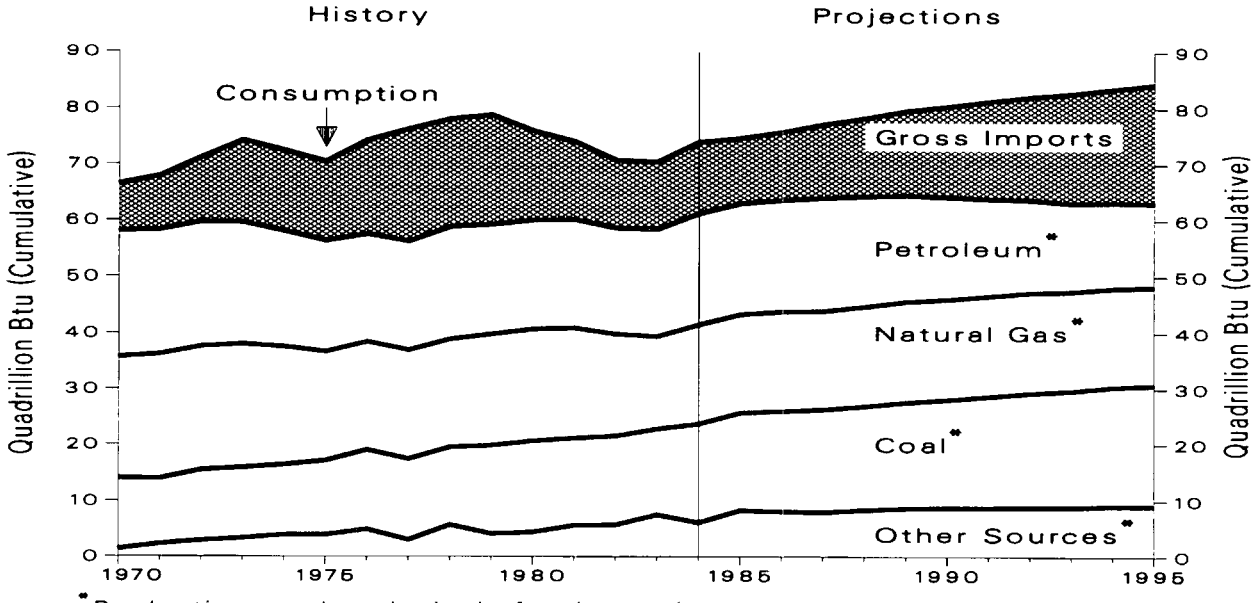
Real world oil prices are assumed to remain well below peak 1980 levels through 1995, given no major oil disruptions.



Source: Energy Information Administration, Annual Energy Review, 1984, DOE/EIA-0384(84), (1985).

Figure ES4. U.S. Energy Consumption, Gross Imports, and Production for Domestic Use by Fuel Type, 1970-1995

Gross imports are projected to account for an increasing share of total U.S. energy consumption.



*Production used exclusively for domestic consumption.

Source: Energy Information Administration, Annual Energy Review, 1984, DOE/EIA-0384(84), (1985).

Table ES1. Scenarios Examined in the *Annual Energy Outlook* 1985

World Oil Price Assumption (1995 Price in 1985 dollars per barrel)	Economic Growth Assumptions (Average Annual GNP Growth Between 1985 and 1995)		
	Low (2.4%)	Middle (2.8%)	High (3.2%)
Low ($25)	--	--	High Oil Imports Case
Middle ($30)	--	Base Case	--
High ($37)	Low Oil Imports Case	--	--

Table ES2. Assumptions for Economic Growth and World Oil Prices, 1974-1995

Variable	History 1974	History 1979	History 1984	Average Annual Growth 1974-1984 (Percent)	Oil Imports Case	Assumptions 1985	Assumptions 1990	Assumptions 1995	Average Annual Growth 1985-1995 (percent)
Real GNP (billion 1972 dollars)	1,246	1,479	1,639	2.8	High Imports	1,677	2,001	2,295	3.2
					Base Case	1,677	1,955	2,215	2.8
					Low Imports	1,677	1,922	2,134	2.4
Real GNP/Capita (1972 dollars per capita)	5,825	6,570	6,939	1.8	High Imports	7,034	8,030	8,858	2.3
					Base Case	7,034	7,845	8,549	2.0
					Low Imports	7,034	7,713	8,236	1.6
Gross Output in Manufacturing (billion 1972 dollars)	813	929	950	1.6	High Imports	960	1,163	1,325	3.3
					Base Case	960	1,127	1,272	2.9
					Low Imports	960	1,104	1,218	2.4
World Oil Price (1985 dollars per barrel)	25	31	30	1.8	High Imports	26	22	25	-0.4
					Base Case	27	27	30	1.1
					Low Imports	27	32	37	3.2

Source: Tables A11, B11, and C11.

Table ES3. Comparison of Energy Supply and Demand Projections, 1985, 1990, and 1995

(Quadrillion Btu per Year)

	1985	1990			1995		
		Low Oil Imports	Base Case	High Oil Imports	Low Oil Imports	Base Case	High Oil Imports
Domestic Energy Production							
Oil	21.3	20.5	19.6	18.7	18.1	16.3	14.1
Natural Gas	17.6	17.7	17.9	18.1	17.2	17.5	17.2
Coal	19.6	21.5	21.7	22.0	24.0	24.3	24.6
Nuclear Power	4.2	6.2	6.2	6.2	6.6	6.6	6.6
Hydroelectric/ Geothermal/Other	3.1	3.4	3.4	3.4	3.4	3.4	3.4
Total	65.8	69.3	68.8	68.3	69.3	68.3	66.0
Net Imports							
Oil	8.8	9.9	12.1	14.1	12.8	16.3	21.2
Natural Gas	1.0	1.9	1.9	1.9	2.5	2.5	2.5
Coal, Coke, and Electricity	-1.7	-1.7	-1.7	-1.7	-1.8	-1.8	-1.8
Total	8.1	10.1	12.3	14.3	13.5	17.0	21.9
Total Primary Supplya	74.8	78.7	80.4	81.9	81.8	84.3	86.8
End-Use Consumptionb							
Residential	8.9	9.5	9.7	9.8	9.8	10.0	10.2
Commercial	5.9	6.4	6.5	6.5	6.6	6.7	6.8
Industrial	21.3	22.2	22.7	23.2	22.1	22.7	23.5
Transportation	20.0	19.4	20.1	20.6	19.4	20.3	21.2
Total	56.0	57.4	59.0	60.2	57.8	59.8	61.7

aIncludes domestic production plus net imports, stock changes, and other adjustments.
bDoes not include fuel used by electric utilities for the generation and transmission of electricity. Lease and plant fuel is included under industrial consumption.
Note: Totals may not equal sum of components because of independent rounding.
Source: Tables A1, A2, B1, B2, C1, and C2.

At least two long-term trends may be assumed to slow the rate of growth in energy demand over the next 10 years:

- Expansion of the light manufacturing and service sectors will continue to replace traditional growth in energy-intensive heavy manufacturing.
- Slower population growth will affect end-use energy demand, particularly in the residential and transportation sectors.

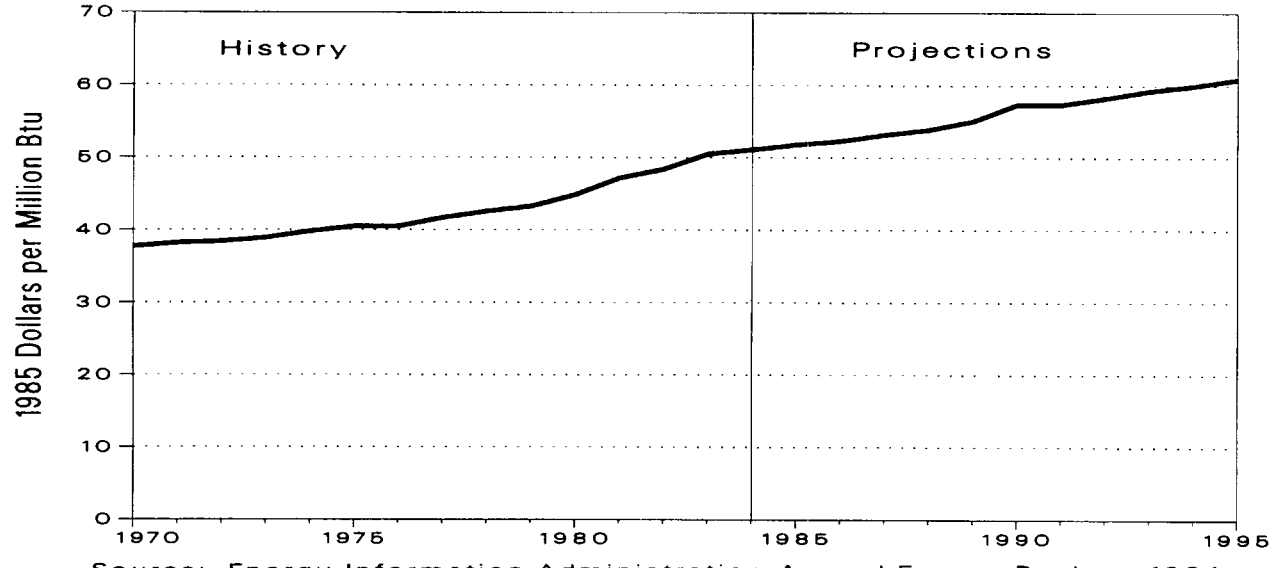
One long-term characteristic experienced in the natural gas industry is not expected to recur in the forecast period: With the expiration of regulations that existed in the 1970's and early 1980's, the gas market has become more competitive, a situation that is expected to remain over the next 10 years. Increased competition and the large increases projected in competitively priced imports (see Chapter 3) should result in only moderate changes in average natural gas prices over the next 10 years.

Although the rate of improvement in energy productivity (measured by real dollar of GNP per unit of energy use) is expected to moderate between 1985 and 1995, the conservation and efficiency improvements made as a result of the rapid energy price changes of the 1970's will remain in place--and penetrate markets even further--over the forecast period. These changes are expected to modify some preceding trends. For example:

- In the 50 years preceding the oil embargo in the 1970's, the ratio of real dollar of GNP per unit of energy consumption increased by about 0.9 percent per year. However, in the post-embargo decade, this ratio increased by about 2.5 percent annually. Between 1985 and 1995, GNP production per unit of energy use is projected to increase by about 1.6 percent per year--a rate that is lower than the recent experience, but more rapid than the pre-embargo trend. Figure ES5 shows the reciprocal of the traditional "energy intensity" ratio to emphasize the underlying reality that energy use is becoming more efficient.
- Mileage performance of the overall automobile fleet will continue to improve during the forecast period, reversing the trend that prevailed before the oil price increases of the 1970's. Vehicles from that earlier era will gradually be replaced almost completely, and the fleet average in miles per gallon is projected to increase from 18.0 miles per gallon in 1985 to 24.9 miles per gallon in 1995.

Figure ES5. Energy Productivity, 1970-1995

Gains in energy productivity (constant dollars of GNP per unit of primary energy consumption) are expected to continue through the forecast period at a somewhat slower pace than was experienced between 1975 and 1985.



Source: Energy Information Administration, Annual Energy Review, 1984, DOE/EIA-0385(84), (1985).

Assumptions

The Energy Information Administration's analysis is based on explicit assumptions regarding future trends in the economy and in world oil prices. (A detailed discussion of the major assumptions is presented in Appendix D.) Between 1985 and 1995, real GNP is assumed to grow by an average of 2.8 percent per year in the base case (Table ES2 on page 5). This rate is the same as the annual growth rate between 1974 and 1984, but slightly lower than the longer term growth rate of 3.2 percent experienced between 1964 and 1984. With population growth being projected to moderate, growth in GNP per capita in the forecast period would be slightly higher than that of the past 10 years. Growth of output in the major energy-intensive industries (such as primary metals) is not assumed to be as high as overall GNP growth or overall manufacturing output, because these industries have yet to recover fully from sharp drops in output (partly attributable to higher imports) during the past recession.

The other major assumption that had to be decided upon for this projection was the range in the path of future world oil prices. This assumption has an important direct influence on both the demand and supply of oil, as well as on the prices of substitute fuels such as natural gas. Real oil prices are assumed to decrease from $27 (in 1985 dollars) per barrel in 1985 to $23 per barrel in 1988 and then to increase gradually to $30 per barrel in 1995 in the base case. The latter would mean a price of $50 per barrel in 1995 dollars, but this would be well below the 1980 peak of $44 per barrel in constant 1985 dollar terms (Figure ES3 on page 3).

The current surplus capacity in world oil production is the major reason for assuming oil price declines during the early years of the 10-year forecast. Prices are assumed to increase during the later years as the world oil market tightens. Although the world oil prices used in this analysis represent assumptions, independent analysis shows them to be consistent with a world oil market in which supply and demand are equilibrated. Furthermore, these prices are consistent with past behavior of the Organization of Petroleum Exporting Countries (OPEC), which tends to increase prices when production approaches 80 percent of capacity. Details concerning these assumptions are provided in Appendix D.

Aggregate Energy Trends

Substantial growth in net energy imports is projected (see Table ES3 on page 5) for the next 10 years (from 11 percent of total energy consumption in 1985 to 20 percent for the base case in 1995). Domestic energy consumption is projected to rise at a slower rate than total GNP because of continued improvements in efficiency and the relatively weak performance assumed for heavy industry. Total domestic energy production is projected to grow slightly between 1985 and 1995. The marked decrease in domestic production of crude oil (down about 5 quadrillion Btu by 1995) is more than offset by projected increases in coal and nuclear power of about 5 quadrillion Btu and 2 quadrillion Btu, respectively. The decline of domestic crude oil production is projected because of relatively low wellhead prices and the continued depletion of U.S. oil fields.

Primary energy demand is projected to increase more rapidly than end-use demand because of the greater use of electricity, which involves large conversion losses. Between 1985 and 1995, about 60 percent of the increase in primary energy demand is attributable to losses associated with electric utility generation and distribution. While primary energy demand is projected to increase by 1.2 percent per year between 1985 and 1995, the end-use energy demand (which counts only delivered end-use electricity and not fuels used in its generation) increases by only about 0.6 percent per year.

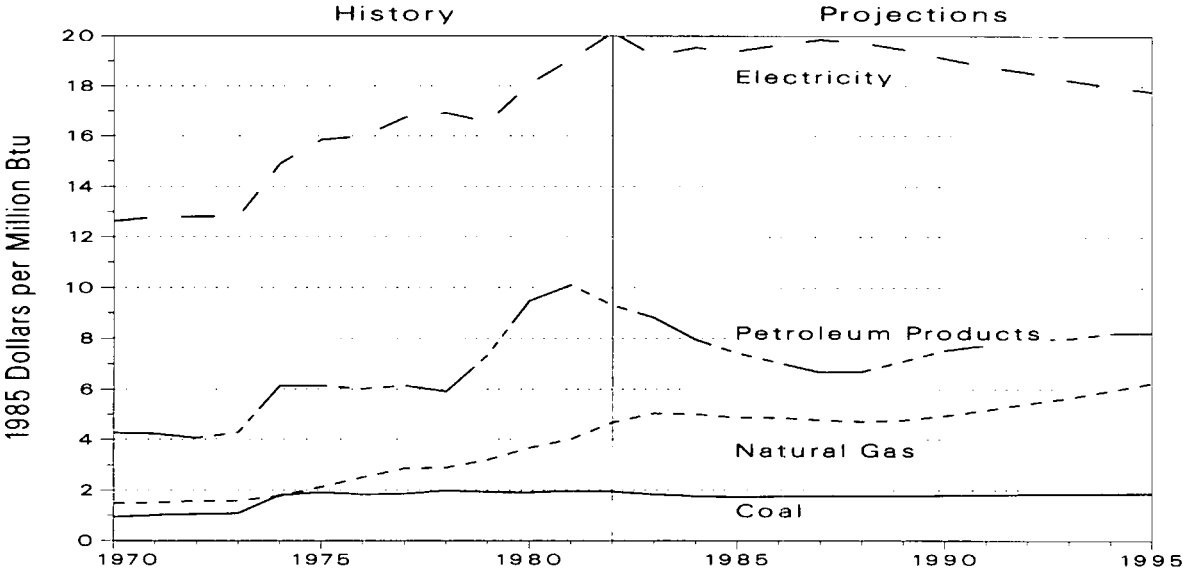
Energy Prices

Future end-use energy prices are expected to be determined more by competitive market forces and less by producer-country price-setting and government regulation, as compared with the experience during the last 10 years. As shown in the base case in Figure ES6 on page 8:

- Petroleum product prices are expected to follow the pattern of the assumed world oil price, dropping in real terms for several years before gradually increasing again. Their level in 1995 should be well below the peak prices experienced in 1980.
- End-use natural gas prices are forecast to remain about constant until 1990 before increasing in real terms through 1995. After 1990 natural gas prices are projected to increase faster than those of petroleum and refined oil products. This is because excess gas capacity is likely to dwindle and old gas supplies, currently subject to price controls ranging to $1.00 per MMBtu and less, are being depleted.

Figure ES6. End-Use Prices of Energy, 1970-1995

The real prices of petroleum products and natural gas are expected to rise gradually during the late 1980's and early 1990's, while coal prices are projected to remain stable through 1995. The price of electricity is projected to fall in real terms.



Source: Energy Information Administration, State Energy Price and Expenditure Report, 1970-1982, DOE/EIA-0376(82), (1985).

- End-use electricity prices are projected to increase slightly until 1987 (as new plants are added to the rate base) and then to decline gradually in real terms (by about 1 percent per year). This decline is attributable to a lower expected capital-cost component (Figure ES7 on page 9) in the later years of the forecast as the addition of new generation capability tapers off.
- Coal prices are assumed to increase slightly in real terms between 1985 and 1995.

Energy Demand

The largest single factor behind the projected increase in primary energy demand is the increase in electricity generation (Figure ES1 on page 2), which involves large losses prior to end use. For fossil fuel generation, the equivalent of about 3 British thermal units (Btu) of primary energy is consumed in generating and delivering 1 Btu of electricity. This ratio implies that consumption of primary energy will increase as electricity increases its market share.

Between 1974 and 1984, the share of electricity in end-use energy consumption grew from 10 percent to 14 percent. This increasing trend is expected to continue, with the share reaching 17 percent by 1995. As electricity generation increases to accommodate demand, the conversion losses (which are part of primary energy demand, but are not reflected in end-use energy demand) cause total energy demand to grow faster than end-use demand.

Oil is still projected to account for the largest share of total U.S. energy consumption, although the share represented by petroleum products is projected to continue its decline over the next 10 years. Increasing demand for oil is based on its unique value as a transportation fuel (where few substitute fuels are currently available) and on the fact that most of the easy substitution of alternate energy sources for petroleum products in sectors other than transportation has already taken place. The petroleum share of primary energy consumption is projected to fall from 41 percent in 1985 to 39 percent in 1995 as its growth is expected to be lower than that of other fuels.

As to the sectoral breakdown, both the industrial and transportation sectors (the two major end-use energy consumers) are projected to show almost no growth in total consumption between 1985 and 1995 (Chapter 2). The reasons for these projections are quite different for the two sectors. Relatively low growth in the industrial sector is projected primarily because of low growth anticipated in key energy-intensive industries and, to a lesser extent, the continuation of energy conservation trends. Between 1985 and 1995, outputs in the primary metals, chemicals, and the stone, clay, and glass industries are projected to grow significantly less rapidly than the 2.8-percent annual growth expected

for real GNP. These three industries account for a major share of end-use energy demand in the industrial sector. The factors contributing to lower growth include higher levels of imported steel and automobiles, the strong dollar, and the potential loss of part of the chemical market to foreign competitors. As for conservation, many energy-sparing innovations that are already recognized in industry require the installation of new equipment and/or major process changes. These are most likely to be adopted only as older facilities are retired or as new capacity is required. Thus, both existing and new energy conservation technology can be counted on to help restrain the industrial sector's consumption over the coming decade.

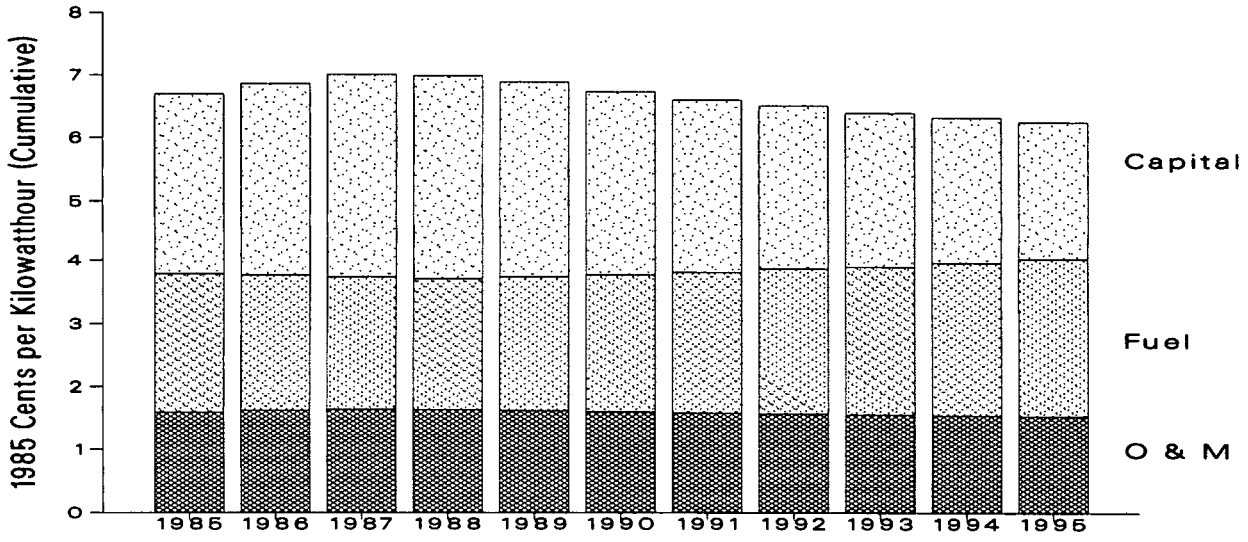
Energy use in the transportation sector is not projected to experience much growth either, but for a different set of reasons. Increases in the efficiency of the car fleet are projected to offset some increases in vehicle travel. In addition, however--because the population is aging--the rate of increase for total vehicle-miles traveled is projected to be slow relative to previous trends. The growth in energy demand that does take place in the transportation sector is likely to be in diesel fuel use by heavy and light trucks. Historically, growth in heavy truck travel has exceeded growth in GNP. The use of diesel fuel in light trucks also is expected to increase.

End-use energy demand between 1985 and 1995 is projected to grow most rapidly in the residential and commercial sectors. Even in these two sectors, however, growth is expected to be only 1.2 and 1.3 percent per year, respectively--low relative to earlier experience. These rates are consistent with historic trends after adjusting for the permanent improvement made to the stock of homes and businesses in response to the energy price increases of the 1970's.

On an average annual basis, residential energy use grew by 2.5 percent and commercial sector use grew by 4.2 percent between 1964 and 1974. With higher energy prices in the 1974-1984 period, however, annual growth in energy demand in the residential and commercial sectors dropped to -0.5 percent and +0.4 percent, respectively. Between 1985 and 1995, the incentive to conserve energy stemming from rising energy prices is expected to fade, but the efficiency gains from most energy conservation measures (such as added insulation and more efficient heating and cooling systems) will remain in houses and commercial buildings.

Figure ES7. Components of the Average Electricity Cost, 1985-1995

Real electricity costs are projected to decline, mainly as a result of the smaller capital component.



Note: O & M = Operation and Maintenance. Capital includes debt, depreciation and taxes.

Now, more efficient heating and cooling equipment is standard design and routinely used for replacement. Furthermore, population growth has slowed, and the number of households, which grew by 2.3 percent per year between 1964 and 1974 and by 2.1 percent per year 1974 and 1984, is projected to grow by only 1.7 percent per year between 1985 and 1995. Energy use in the commercial sector is projected to grow at a slightly faster rate than energy use in the residential sector. The commercial increase is projected on the basis of an expanding service sector and the 2.3-percent-per-year growth expected for commercial floor-space between 1985 and 1995.

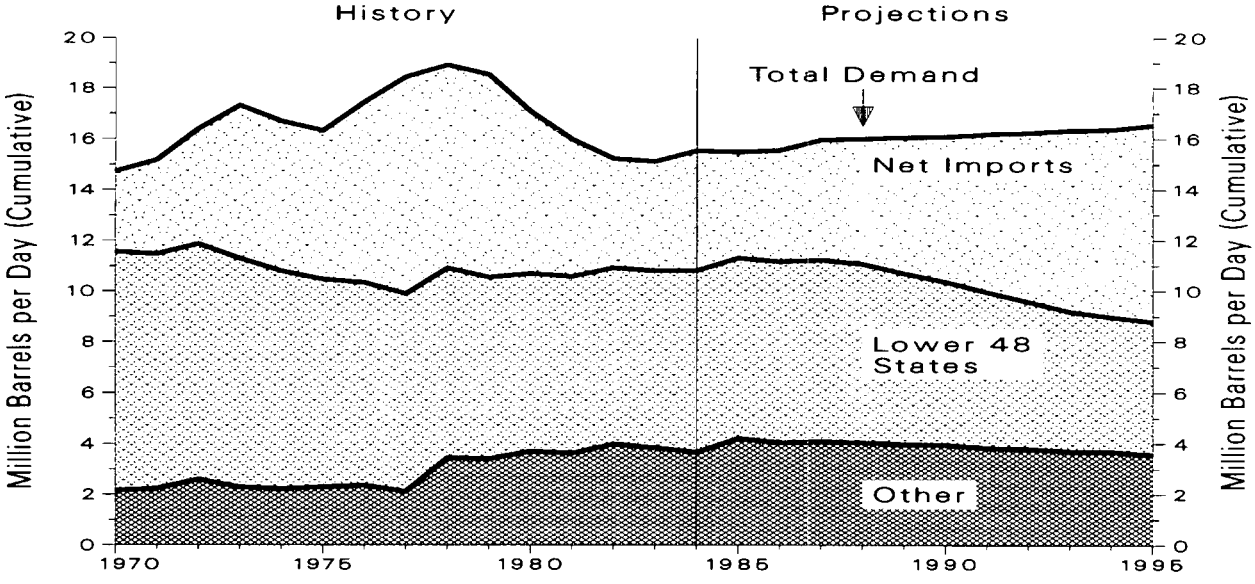
Energy Supply

Total domestic petroleum supply is projected to decrease during the forecast period as a whole, following a moderate increase in 1986 and 1987. A faster decline is expected during the last 5 years of the projection period (Figure ES8). Domestic oil production in 1985 (including natural gas liquids and refinery gain) is estimated to be 11.1 million barrels per day. This level is expected to drop to 10.4 million barrels per day in 1990 and 8.8 million barrels per day by 1995. This decrease is attributed to the relatively low world oil prices assumed, a distinct decline in Alaskan oil production after 1987, and the expected declines in the older domestic oil fields in the Lower 48 States. Lower oil prices provide less incentive for the exploration and development necessary to maintain production, and production from existing oil fields naturally declines unless new technology is developed and applied. The relatively constant oil production for the past several years can be attributed to increases in production from Alaska, the Outer Continental Shelf, and projects for enhanced oil recovery that were made possible mainly by higher oil prices.

Domestic natural gas production also is projected to increase slightly through this decade and then to decline through 1995--partly for the same reasons as those mentioned in connection with oil (a slower pace of exploration and development), and partly as a result of increased competition from Canadian imports. Growth in gas imports from Canada and modest growth in supplemental gas (propane, synthetics, and incremental supplies of spot market gas) are expected to more than offset the decline in domestic production. These changes will result in a modest increase in total supply of natural gas available to the United States over the next 10 years (Figure ES9 on page 11). The average wellhead price (in 1985 dollars) for domestic natural gas is expected to remain near $2.50 per thousand cubic feet through 1989, but then to increase to an average of about $4.00 per thousand cubic feet in 1995. This rise is anticipated because of the need to rely more heavily on higher-production-cost gas and the dissipation of current excess supply, the so-called gas bubble.

Figure ES8. Composition of Domestic Petroleum Supply, Total Demand, and Net Imports, 1970-1995

U.S. net oil imports are projected to increase because domestic production is projected to decline (especially in the Lower 48 States), widening the gap between production and a fairly stable demand.



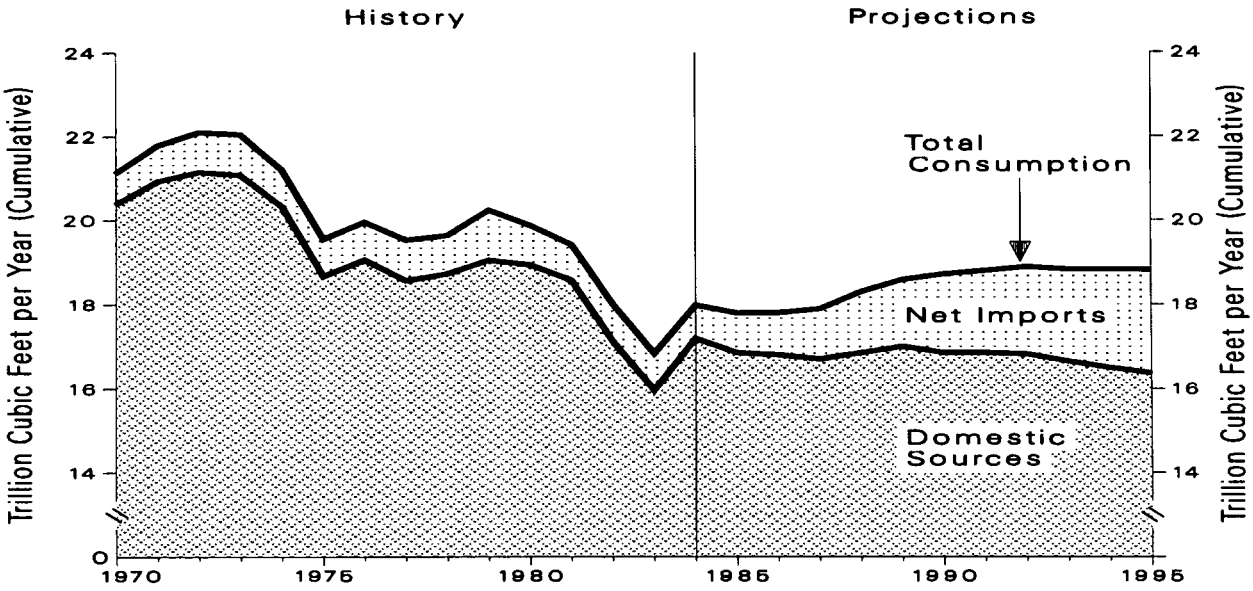
Note: Other supply includes Alaska, processing gain, net withdrawals, and natural gas plant liquids production.

Note: Lower 48 includes production from the Lower 48 States onshore and offshore, including enhanced oil recovery.

Source: Energy Information Administration, Annual Energy Review, 1984, DOE/EIA-0384(84), (1985).

Figure ES9. Natural Gas Production, Net Imports, and Consumption, 1970-1995

Imports from Canada are projected to offset declines in domestic production.



Note: Domestic sources includes dry gas, supplemental natural gas, stock changes, and unaccounted-for gas.

Source: Energy Information Administration, Annual Energy Review, 1984, DOE/EIA-0384(84), (1985).

Electricity generation capability is projected to grow over the next 10 years, but more slowly than electricity demand. Some combination of additions to existing capability (other than those currently planned), demand-management techniques, cogeneration projects, and other non-traditional sources of electricity generation could be needed if demand grows as projected. Most of the increased demand for electricity will be satisfied by new coal and nuclear plants currently under construction. The nuclear capacity additions that already exist or will be completed by 1995 will raise the nuclear share of generation from about 15 percent during 1985 to almost 19 percent in 1995.

Increases in domestic coal production are projected to offset some of the decreases in energy supplied by domestic oil and natural gas. Coal production is projected to rise from about 890 million tons in 1985 to about 1,120 million tons in 1995, with most of this additional output to be consumed at electric utilities. Industrial use of steam coal and exports of coal are both expected to increase moderately over the next 10 years, but metallurgical coal use in the United States is projected to decline. The modest gains attributable to increases in total steel output are expected to be more than offset by reductions in demand due to efficiency gains in the direct use of metallurgical coal and to increased use of electric arc furnaces.

Although renewable energy sources are not treated explicitly in this analysis, their use is included implicitly in EIA's projections by assuming that some of the historic decline in conventional energy use (which was the result of the increased use of renewable sources) will continue throughout the projection period. In any case, growth in the use of renewable energy sources (which will probably consist mainly of more wood use in the residential and industrial sectors and more electricity generated from wind and geothermal energy) is unlikely to be a major factor affecting conventional energy use over the next 10 years.

Cogeneration may meet a significant portion of new industrial electricity requirements because of special incentives that are assigned to it under the Public Utility Regulatory Policies Act (PURPA): Surplus electricity generated through cogeneration can be sold to local utilities at favorable rates (at the utilities' avoided cost). Cogeneration also produces process heat for industrial services. The potential for more cogeneration projects exists, but many uncertainties surround them, including the future treatment of these projects by public utility commissions and the possibility of modifications to PURPA. Increases in cogeneration would probably result in the use of more natural gas and in less need for central-station electricity generation (see Cogeneration Box in Chapter 2).

1. Energy Prices

Energy prices in real terms are projected to remain relatively stable between 1985 and 1995, edging upward slightly in the aggregate. This outlook is based on the premise that demand for energy will increase slowly, and that the current excess domestic production capacity in natural gas, coal, and electricity and the excess worldwide oil production capacity will gradually be reduced. The situation is in sharp contrast with the experience during the late 1970's and early 1980's, when energy prices--particularly oil prices--fluctuated dramatically.

The level of energy prices is important in determining the share of the total gross national product (GNP) that must be used to provide basic energy services. Although it is convenient to refer to energy prices in the aggregate, the prices people actually pay are associated with individual fuels, each having unique characteristics. Furthermore, because fuels are not all equally capable of satisfying specific demands, competition among energy sources is not based strictly on prices. For example, few other fuels at present can compete with petroleum products in providing transportation services. Likewise, electricity is virtually the only fuel used to provide lighting and to power stationary mechanical devices. Although natural gas and oil compete on a fairly even footing in some cases (such as in electricity generation and in large industrial boilers), the prices of these two energy sources are not tied together in any firm ratio. Nevertheless, while factors other than price are important, energy prices are the major determinant of energy demand.

During the late 1970's and early 1980's, as a result of OPEC actions, consumers faced rapidly escalating prices for all forms of energy. For a time, these prices seemed to be set independently of consumer responses. However, higher prices induced new energy production and significant conservation efforts which reversed these trends and significantly eroded the producers' influence on energy prices. This situation is expected to continue throughout most of the 10-year forecast period. Because of this increased competition among end-use energy prices, this chapter will begin with those prices and then continue with a review of the energy supply prices that underlie them.

End-Use Prices

End-use energy prices are critical in determining the level and type of energy demanded. Over the past decade, rapid increases in end-use prices led to a basic restructuring of energy markets. The large rise in the prices of oil, natural gas, and electricity encouraged conservation efforts in households and buildings, promoted efficiency improvements in vehicles and machinery, and encouraged significantly lower energy use per unit of output.

The era of rapidly rising energy prices began to change in 1981, with somewhat lower real prices for major fuels being followed by a period of relative price stability that is likely to continue. Over the next decade, for example, the average real price of all fuels to the residential sector (calculated as a consumption-weighted average of all residential energy prices) is projected to increase by only about 0.3 percent per year between 1985 and 1990, and by about 1.4 percent per year between 1990 and 1995. These rates are in sharp contrast with the 4.6-percent annual increase experienced between 1974 and 1984.

Between 1985 and 1990, the average prices of petroleum products (the largest single category of end-use energy) are projected to follow the pattern assumed for world oil prices. This means they will drop in real terms for the first few years but begin to increase as 1990 approaches. Likewise, the average real prices of natural gas, coal, and electricity to end users are expected to remain flat between 1985 and 1990. Increased volumes of competitively priced natural gas imports from Canada (and potential supplies from Mexico) are projected to limit domestic price increases for that fuel.

Between 1990 and 1995, the slow decline in excess world oil and U.S. natural gas production capacity is projected to allow moderate increases in real prices for these fuels. The average price of petroleum products to end users over this 5-year period is projected to increase by about 1.8 percent annually, compared with the 2.1-percent-per-year rise forecast for the world oil price. Individual petroleum products are all expected to follow similar price paths.

The real price of natural gas to end users between 1990 and 1995 is expected to rise by nearly 5 percent per year. This rate is higher than that projected between 1985 and 1990, but well below the rate of increase experienced between 1974 and 1984. The major reasons behind the expected increase are the dissipation of the current excess production capacity and production of more expensive reserves as the resource base is depleted. In 1995, average natural gas prices in the industrial sector are projected to be above prices for residual fuel oil, but still below the residual oil price in the electric utilities sector and the heating oil price in the residential sector.

Many forecasters expected a sharp increase (or "fly-up") in natural gas prices in 1985 when the price ceilings mandated by the Natural Gas Policy Act of 1978 were removed from about half of the natural gas produced in the United States. Such a fly-up never occurred, however, as the conservation resulting from earlier price increases, combined with low demand growing out of the recession of the early 1980's, resulted in the development of excess natural gas production capacity which served to moderate potential price increases. 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 gas-purchasing contracts, and abrogation of contracts. Average wellhead prices of natural gas are expected to continue declining in real terms over the next several years because of market conditions.

Electricity is the only major energy source whose real prices are expected to drop in the later years, between 1990 and 1995, declining by about 1.4 percent per year. By 1995, the average electricity price (expressed in constant dollars) is projected to be about the same as the 1980 price. The 1990-1995 decrease in real electricity prices is attributable to higher expected levels of capacity utilization (due to demand increases), additional use of coal and nuclear power, and the comparatively few additions of new generating capability to the rate base. Regional end-use prices for electricity are much more difficult to forecast, because the rates in effect in various service areas depend heavily on individual State public utility commissions whose adherence to cost-based pricing for electricity is not consistent.

In the residential sector, natural gas is projected to lose some of its current price advantage over home heating oil (distillate fuel oil), as the natural gas price increases faster--particularly between 1990 and 1995. Almost all of the projected increase in residential natural gas prices is the result of higher average wellhead prices, even though the wellhead price accounts for less than half (about 45 percent) of the final price total. (The remaining cost is attributable to transportation and distribution charges.) This percentage is projected to increase to about 50 percent by 1995 because of the combination of wellhead price increases and relatively stable transportation and distribution charges.

In the commercial sector, natural gas prices are projected to exceed distillate fuel prices by 1995. Commercial-sector prices of both distillate oil and natural gas are lower than their respective residential prices because of the larger average volumes consumed by commercial customers.

In the industrial sector, average natural gas prices are projected to remain above average residual fuel oil prices throughout the next 10 years. However, in certain key industrial markets (such as in the Gulf Coast area), natural gas may remain less expensive than oil to end users because the short-distance transportation fees for gas are relatively low. In addition, some natural gas utilities are trying to keep switchable industrial customers using natural gas by offering special discounts, a practice which is expected to continue.

Real electricity prices are projected to decline for customers in all sectors between 1985 and 1995--although, on a Btu-basis, this energy source is expected to remain far more expensive than oil, natural gas, or coal. The competitiveness of electricity with primary fuels is not as much on unit price as it is on convenience, its exclusive or greater suitability for certain tasks, and its potential for relatively high end-use efficiencies in comparison to competing energy forms.

Supply Prices

Oil

Low oil prices tend to discourage investment in oil exploration and oil field development. This situation, coupled with resource constraints, helps to explain the expected decline in oil and gas production over the next decade. The real price of world oil is assumed to fall through 1988 and then is projected to increase only moderately between 1989 and 1995. The assumed 1995 price of $30 per barrel (in 1985 dollars) is above the 1985 price but still well below the peak price of $44 per barrel in 1980. (All prices in this report are in 1985 dollars unless otherwise noted.)

While these oil price projections represent explicit assumptions, they are consistent with an overall supply and demand balance for world oil. The relatively low oil price in the early part of the forecast is assumed to restrain growth in non-OPEC oil production and specifically to cause U.S. production to decline. Moderate growth in the demand for oil should thus lead to increasing demand for OPEC oil production once again. As the excess production capacity in OPEC is slowly being reduced, small rises in world oil prices are expected. In the near term, there is great uncertainty concerning the level at which oil prices will settle, although some analysts expect large price declines as early as the spring of 1986. If excess OPEC production capacity shrinks later in the forecast period (as projected), increases in oil prices are more probable. Nevertheless, fluctuations in oil price are expected to be moderate compared with those of recent history.

Natural Gas

Beginning in 1985, the real wellhead price of natural gas is projected to fall slightly, to $2.39 per thousand cubic feet by 1988. This decline is much smaller than that expected for oil prices because of rigidities in the contract structure of natural gas sales. By 1990, the average price for gas at the wellhead is projected to rise to $2.68 per thousand cubic feet, followed by an increase of nearly 9 percent per year over the last 5 years of the forecast, to about $4.00 per thousand cubic feet in 1995.

The expected rise in the natural gas wellhead price between 1990 and 1995 is much steeper than the 2-percent real growth in world oil prices forecast over that period. This difference is explained by:

- Steady erosion of the excess production capacity that currently depresses natural gas prices
- Depletion of lower-cost, price-controlled gas reserves (which will thus represent a decreasing portion of overall supply) so that the average price of natural gas would rise if no other changes occurred in already decontrolled natural gas prices
- Increased reliance on offshore and unconventional sources, which have longer lead times before production can begin
- A relatively low rate of additions to gas reserves compared with the rate of gas production.

At present, natural gas fields in the United States are estimated to be capable of delivering annually about 2 to 3 trillion cubic feet of natural gas over and above what they are currently producing. This excess capacity is projected to diminish or perhaps disappear early in the next decade as additions to reserves of natural gas do not keep pace with production.

Some U.S. gas is still under price controls. In 1985, about 25 percent of all natural gas (about 4 trillion cubic feet) was sold under existing contracts in the interstate market for less than $1.50 per thousand cubic feet ("Section 104(b) gas"). As these contracts expire and the reserves supplying this lower cost "old" natural gas are depleted, the amount produced under price controls is projected to drop to about 3 trillion cubic feet in 1990 (17 percent of production) and less than 2 trillion cubic feet in 1995 (approximately 10 percent of domestic production). Absent any offsetting reduction in uncontrolled natural gas prices, the average price would tend to increase as the relatively inexpensive reserves are depleted.

Another factor in escalating natural gas prices is the depletion of known reserves (although this tends to be a function of drilling effort). The ratio of reserves to production in 1985 is estimated to be 9.3. The ratio is projected to be 8.5 by 1990, declining further to 7.8 by 1995. Over this 10-year period, the reserve stock is projected to decline by roughly 2 percent per year.

Coal

The real price of coal at the minemouth is expected to increase by less than 1 percent per year over the forecast period, in contrast with a decline in the real price of minemouth coal between 1974 and 1984. This reversal in the trend of coal prices at the mines reflects a partial recovery expected in the coal market, which is depressed at present due to relatively low growth in electricity demand and chronic excess production capability. Real end-use coal prices are projected to rise slightly faster after 1990, largely because of increases in rail transportation costs. Despite the turnaround expected for coal prices over the next 10 years, the increase will probably be held to a minimum by continued competition for markets among the numerous coal producers.

Value of Net Energy Imports

This report makes no explicit forecast of the value of net energy imports, but a value can be estimated using the expected levels of imports and the projected prices. The estimated real cost (in 1985 dollars) of net fossil energy imports is shown by this method to grow from $45.5 billion in 1985 to $53.0 billion in 1990 and to $88.4 billion in 1995 (Table 1). This prospective doubling of an important element of the U.S. trade deficit during the next 10 years is dominated by the value of net crude oil imports. This amount is expected to grow from $33.2 billion in 1985 to $70.8 billion in 1995. Slightly offsetting this increase is the projected increase in the value of net coal exports. The estimates of the value of refined petroleum products are based on quantity estimates which are the result of assumptions made for analytic convenience without detailed analysis of foreign competition.

Table 1. Estimated Value of Net Fossil Fuel Imports, 1974-1995
(Billion 1985 Dollars)

	History			Estimates		
Imported Fuel	1974	1979	1984	1985	1990	1995
Crude Oil	30.7	64.7	37.6	33.2	40.3	70.8
Refined Petroleum Products	20.5	12.6	13.9	13.7	12.0	13.1
Natural Gas	1.0	4.2	3.3	2.9	5.7	10.5
Coal and Coal Coke	-4.5	-4.4	-4.3	-4.3	-5.0	-6.0
Total	47.6	77.2	50.7	45.5	53.0	88.4

Source: Tables A3, A8, A9, and A10.

2. Energy Consumption

Total End-Use Energy Demand

Total end-use energy consumption is projected to increase at an average annual rate of 0.6 percent between 1985 and 1995, to 59.8 quadrillion Btu in the base case. This forecast is based on the expectation that real energy prices will remain roughly stable to 1990 and rise at a little less than 3 percent per year thereafter. Combined with the assumption of continued economic growth through 1995, this forecast represents a continuation of the very recent trend of slowly increasing energy consumption. In contrast, between 1979 and 1983, total end-use energy consumption declined by nearly 4 percent per year, while real energy prices rose rapidly and then declined.

Energy productivity (measured by increases in the real dollar value of GNP per unit of energy consumed) is forecast to continue despite relatively stable energy prices, although the rate of conservation improvements in the future is expected to be lower than recent experience. Between 1974 and 1984, the real dollar value of GNP per unit of energy consumed increased at an average rate of 2.5 percent per year. However, between 1983 and 1984, this rate was considerably lower (about 1.1 percent) as energy prices stabilized and output levels from energy-intensive industries increased. Gross national product (in constant dollars) per unit of energy consumed is projected to increase by about 1.6 percent per year over the next 10 years as a result of at least three forces: the further implementation of existing conservation technologies, the development of new conservation measures, and the assumed slow growth in energy-intensive industries.

Demand for energy between 1974 and 1984 grew slightly in the transportation and commercial sectors and declined in the residential and industrial sectors. In the forecast period, the demand for energy is projected to increase in all the consuming sectors, with the rates of increase in all but the transportation sector exceeding those experienced during the past 10 years (Table 2) and (Figure 1 on page 18). However, these increases are likely to be considerably lower than those experienced in the pre-embargo era of 1964 to 1974.

An examination of energy use by sector shows significantly different projections. As the major consumer of energy, the industrial sector is projected to experience a reversal of the earlier trend (a drop of about 1.6 percent per year between 1974 and 1984) to an increase of about 0.7 percent per year between 1985 and 1995. This recovery is attributable to the more moderate energy price changes expected in the next 10 years, in addition to the assumption that no recessions will occur during the forecast period to dampen output growth. Growth in transportation energy use is expected to continue the rising trend, but to increase at a rate of only 0.2 percent per year. This rate is lower than the 0.9-percent annual growth experienced between 1974 and 1984, reflecting the continued improvement expected in the average efficiency of vehicles and relatively slower growth in miles driven over the forecast period. Finally, the residential and commercial sectors, the two smaller energy users, are expected to see 1.2 and 1.3-percent-per-year increases, respectively, in energy demand between 1985 and 1995, based on increases in the number of houses and the amount of building floorspace. These increases are projected to be larger than those experienced during the past 10

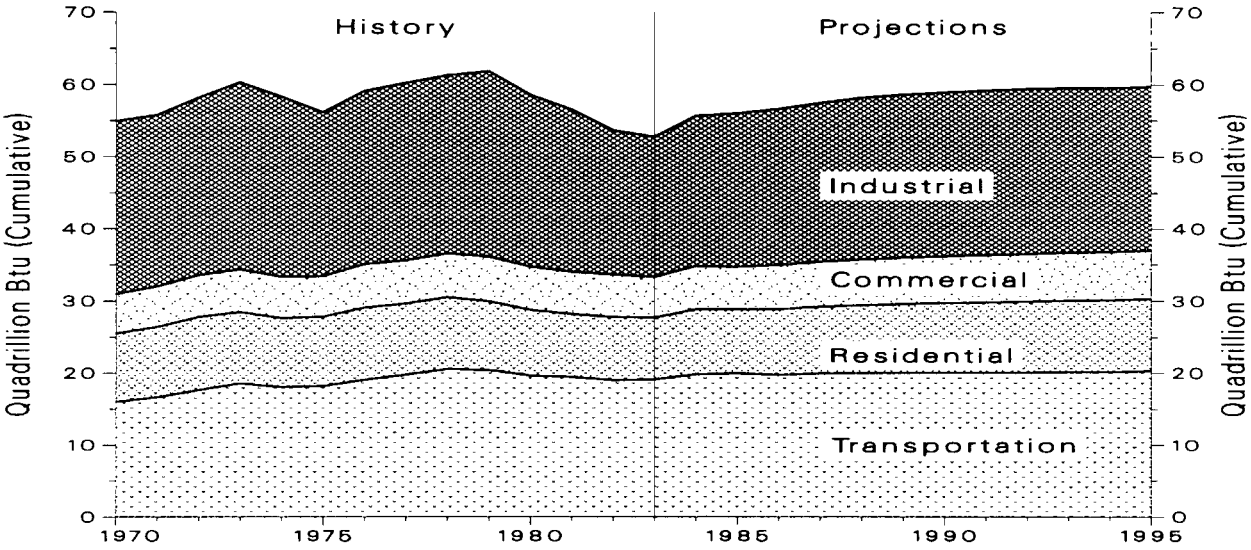
Table 2. Growth in Energy Consumption by Sector, 1964-1995
(Annual Average Percent)

Sector	1964-1974	1974-1984	1985-1995
Residential	2.5	-0.7	1.2
Commercial	4.2	0.4	1.3
Industrial	2.3	-1.6	0.7
Transportation	4.2	0.9	0.2
Total End-Use Energy	3.0	-0.6	0.6

Sources: • History: Energy Information Administration, State Energy Data Report, Consumption Estimates, 1960-1983, DOE/EIA-214(83) (1985). • Projections: Table A2.

Figure 1. Total End-Use Energy Consumption by Sector, 1970-1995

The industrial and transportation sectors are expected to remain the major consumers of energy over the next ten years.



Source: Energy Information Administration, State Energy Data Report, Consumption Estimates, 1960-1983, DOE/EIA-0214(83) (1985).

years mainly because of more moderate energy-price changes and because much of the inexpensive energy conservation has already occurred. Marginal improvements in the energy efficiency of the existing housing stock are likely to be smaller than in the past.

Comparing the projections for the types of energy consumed by end users, the most significant feature is the increased reliance on electricity forecast over the next 10 years, continuing the trend from the previous decade. Between 1974 and 1984, electricity consumption increased at an average annual rate of 2.9 percent, while end-use energy consumption decreased by 0.4 percent per year. This shift to electricity occurred despite a substantial increase in the price of electricity over that period (although the prices of competing fuels such as oil and natural gas actually increased faster, improving the relative position of electricity prices). With falling electricity prices and continued economic growth forecast over the next 10 years, the demand for electricity is projected to increase at an average rate of 2.7 percent per year, slightly below the rate of growth assumed for real GNP. The move toward electricity is evident in all sectors except transportation (which accounts for only a small fraction of total electricity demand), with fairly similar rates of growth expected between 1985 and 1995.

Total end-use oil demand, which declined between 1974 and 1984, is projected to increase by only 0.5 percent per year between 1985 and 1995, with most of the growth occurring in the industrial sector. This relatively low rate of increase forecast for oil demand reflects the relatively slow growth assumed for industries that use oil, the more efficient vehicles in the transportation sector, and the continued adjustment of all sectors to the oil price increases in the 1970's. Lower world oil prices in the future are not expected to lead to large increases in oil demand because natural gas prices are expected to remain competitive. Total end-use consumption of natural gas is projected to grow at an average annual rate of 0.6 percent between 1985 and 1995, in contrast to the drop of 1.6 percent per year experienced between 1974 and 1984. Following the average increase of 3.6 percent per year between 1974 and 1984, total end-use demand for coal is projected to grow by 2.1 percent per year between 1985 and 1995.

The projections contained in this analysis implicitly assume that trends in renewable energy use that existed over the past 10 years will continue into the future, thereby reducing the demand for conventional energy sources. If growth in the use of renewable energy sources exceeds past trends, the forecasts of conventional energy use in this report will be slightly too high.

Sectoral Trends

Residential Energy Demand

Residential energy consumption is forecast to increase at a rate of 1.2 percent per year between 1985 and 1995, to 10.0 quadrillion Btu. This rate of increase reflects the expectation of continued energy conservation over the next 10 years, with energy use per household forecast to decline slightly. The most rapid growth is expected for electricity demand, with only slight growth expected for natural gas use and virtually no growth projected in the demand for fuel oil. Fuel price increases are expected to be more moderate than those experienced over the last 10 years. However, the decline in energy use per household is not expected to be large enough to offset the modest price increase, implying that average residential energy bills in 1995 will be slightly higher than those in 1985.

These trends in the residential sector are consistent with the events of the previous decade, when residential energy consumption actually decreased at an average rate of 0.7 percent per year and energy use per household dropped by 2.7 percent per year. The decline in residential energy consumption experienced between 1974 and 1984 was largely in response to substantial increases in real energy prices, which encouraged improved efficiency of appliances and structures and adjustments in thermostat settings. An additional factor in the decline in energy use per household is the continuing population shift to warmer climates, where houses on average consume less energy for heating and cooling combined and thus have lower total energy requirements. The decline in energy use per household between 1985 and 1995 is expected to be slower than in recent years because relatively stable energy prices, combined with the effects of lower population growth rates, serve to moderate demand growth over the next 10 years.

Natural gas, used primarily for space and water heating in the residential sector, accounted for more than half of all residential energy use in 1984 (Table 3) and (Figure 2 on page 20), a share that is expected to drop slightly in the next 10 years. Residential demand for natural gas, which has remained relatively stable (with some peaks and valleys) over the past decade, is projected to increase slightly but remain near 5 quadrillion Btu over the forecast period. The projected decline in heating uses and the erosion of the natural gas price advantage with respect to the prices of oil and electricity are the primary causes of the lack of growth expected for residential natural gas demand.

Natural gas is projected to remain the lowest-priced major fuel (on a Btu basis) in the residential sector throughout the forecast period, but its price is projected to increase faster than the price of oil or electricity between 1985 and 1995 (Figure 3 on page 20). The narrowing differential between natural gas and electricity prices is likely to encourage installation of electric heat pumps, even though residential gas prices are forecast to remain below alternative fuel prices per million Btu. Natural gas use per household and the natural gas share of total residential energy are expected to decline slowly over the next 10 years.

The price trends discussed above are based on national average prices and hence do not reflect differences in specific regions. Although the price of oil is fairly uniform throughout the country, the prices of electricity and natural gas vary considerably by region. In 1982 (the latest historical data available), natural gas prices in the 10 Federal Regions ranged from $4.86 to $8.46 (real 1985 dollars) per million Btu, while electricity prices ranged from $10.27 to $33.98 (real 1985 dollars) per million Btu. Allowing for some possible changes in these patterns, regional differences in energy prices are projected to continue through 1995.

Electricity, which is used in the residential sector primarily for purposes other than heating, is expected to account for most of the projected increase in residential

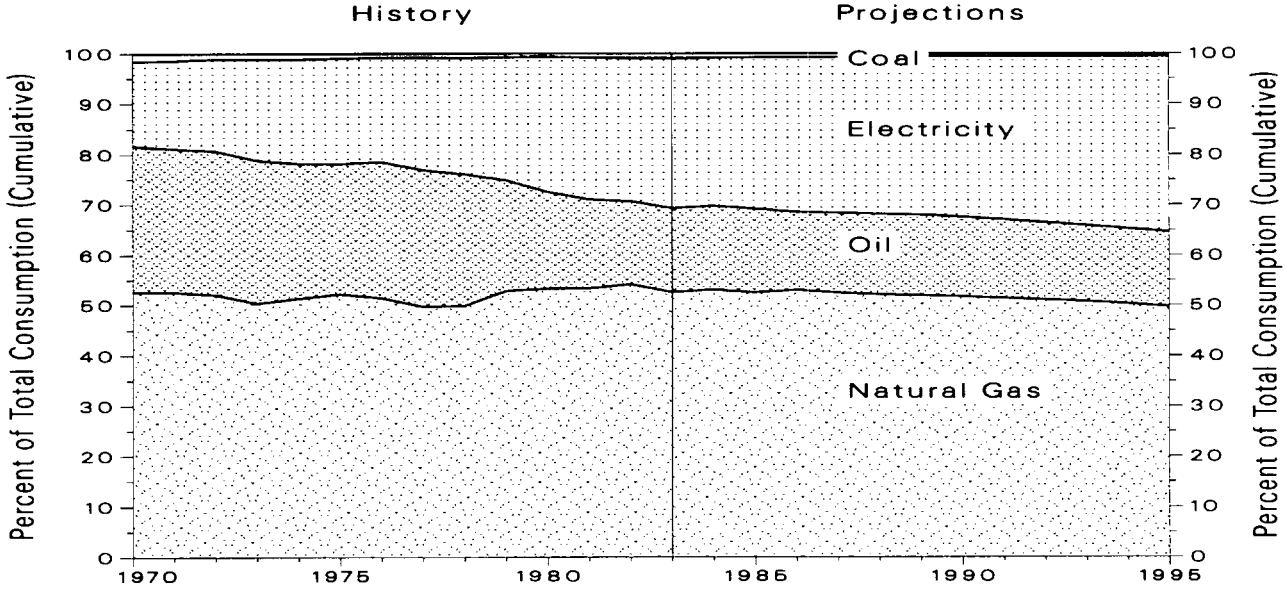
Table 3. Residential Energy Use by Fuel, 1974-1995
(Quadrillion Btu)

	History		Projections		
Fuel	1974	1984	1985	1990	1995
Natural Gas	4.90	4.70	4.65	5.01	4.99
Electricity	1.97	2.65	2.66	3.09	3.49
Distillate Fuel Oil	1.84	1.06	1.07	1.10	1.09
Liquefied Petroleum Gas	0.55	0.37	0.33	0.37	0.35
Kerosene	0.18	0.08	0.08	0.07	0.06
Steam Coal	0.11	0.08	0.07	0.06	0.06
Total	9.55	8.94	8.86	9.70	10.03

Source: Table A2.

Figure 2. Residential Energy Consumption by Source, 1970-1995

The share of electricity in residential energy consumption is projected to continue growing -- expanding from 30 percent to 35 percent between 1985 and 1995.

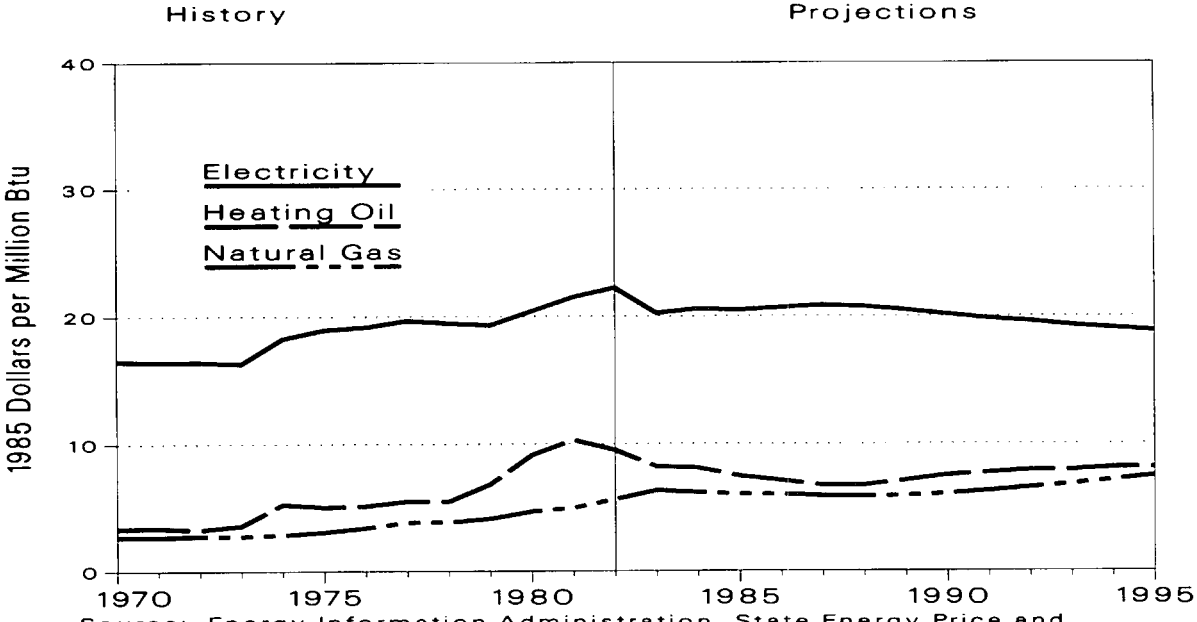


Note: Renewables, such as wood, solar, and wind, are not included.

Source: Energy Information Administration, State Energy Data Report, Consumption Estimates, 1960-1983, DOE/EIA-0214(83) (1985).

Figure 3. Residential Energy Prices, 1970-1995

The Btu unit-price advantage of natural gas and heating oil over electricity is projected to diminish.



Source: Energy Information Administration, State Energy Price and Expenditure Report, 1970-1982, DOE/EIA-0376(82), (1985).

energy demand. With the continued population shift toward warmer climates, implying a higher demand for air-conditioning, the share of electricity in residential energy use is expected to rise from 30 percent in 1985 to 35 percent in 1995 (Figure 2 on page 20). Electricity use in the residential sector is projected to increase by nearly 2.8 percent per year between 1985 and 1995, slightly less than the average annual increase of 3.0 percent experienced between 1974 and 1984. The real price of electricity to the residential sector, which increased between 1974 and 1984, is projected to decline over the next decade.

Fuel oil (distillate plus kerosene), the third major source of energy consumed in the residential sector, is used almost entirely for heating purposes and accounted for about 13 percent of total residential energy use in 1985. This fuel experienced a dramatic drop in demand of more than 5 percent per year between 1974 and 1984 as a result of the large price increases during that decade. However, in recent years residential fuel oil use has leveled off, and demand actually increased between 1983 and 1984 (although part of this rise may be attributable to the colder weather in 1984 in the Northeast). Residential fuel oil demand is projected to remain near the 1985 level through 1995, mainly because of the expected moderation in oil prices.

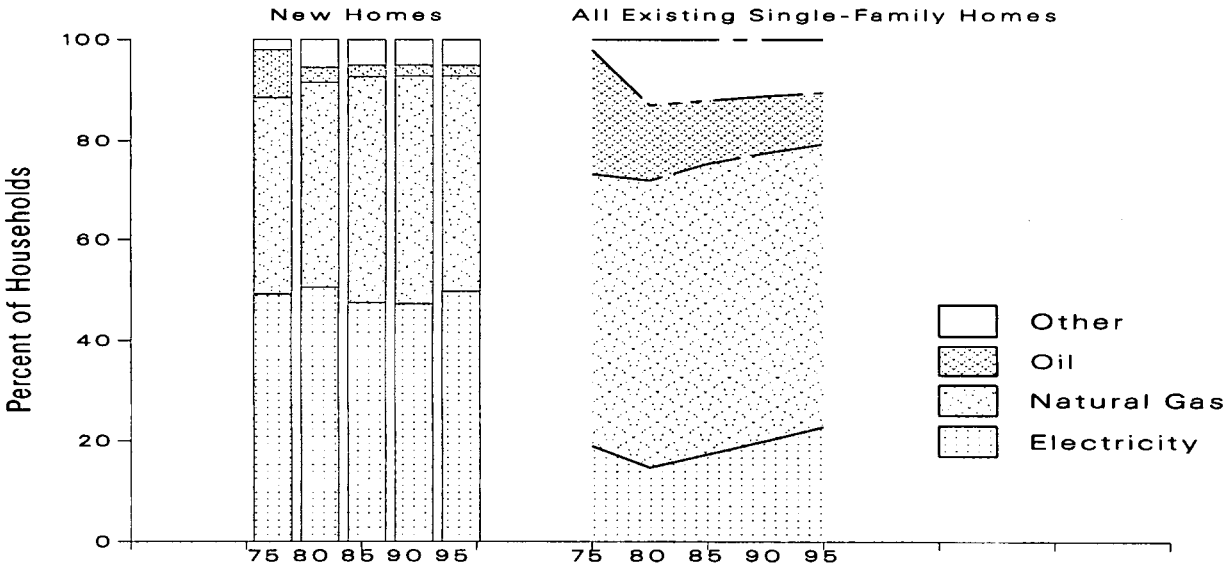
The fact that the total natural gas share of home heating is projected to change only slightly despite the electrification of new homes shows that change in the entire stock of houses occurs very gradually (Figure 4). Nearly 80 percent of the residential housing stock expected to exist in 1995 will have been built prior to 1985. The share of homes heated with oil, mostly in the Northeast, is expected to continue to decline over the next 10 years.

The two primary sources of renewable energy in the residential sector are wood and active solar (supplemented by very small amounts of geothermal, wind, and photovoltaics). Fuel wood consumption in the residential sector was estimated to be 925 trillion Btu in 1983, with a moderate increase recorded in each year since 1980. Wood consumption increased dramatically in the 1970's from a 30-year low point in 1973, mainly as a reaction to the high fuel prices in the 1970's and early 1980's. Fuel price increases are expected to moderate over the next decade, and, as a consequence, wood consumption is expected to remain level throughout the forecast period.

About 121,000 solar installations were added by the residential sector in the United States during 1981, according to an EIA survey that covered that year.

Figure 4. Residential Heating Fuel in New and Existing Single-Family Homes, 1975, 1980, 1985, 1990, and 1995

Electricity is projected to heat about half of new single-family homes through 1995, gradually displacing oil and narrowing the gap with natural gas in total housing stock of this type.



Sources: U.S. Department of Commerce, Characteristics of New Housing, (various years), and Annual Housing Survey, (various issues).

About 70 percent of these were for water heating, 16 percent were for pool heating, and the rest were for space heating or some combination. These solar units are estimated to have contributed incremental energy savings of 2 to 3 trillion Btu in 1981. Based on the number of shipments of active solar collectors from 1974 through 1984, it is estimated that the total amount of energy saving in 1984 through the use of active solar equipment was between 15 and 20 trillion Btu--less than 0.2 percent of residential energy consumption. If solar shipments continued at the rate experienced in 1984 (which may be optimistic, given the absence of solar tax credits), the energy savings due to solar in 1995 are estimated to range from 35 to 45 trillion Btu, a figure well within the error range of the projections presented here.

The high and low oil imports cases show the effect on residential energy demand of lower and higher world oil prices in combination with higher and lower assumed levels of disposable personal income. In the low imports case, world oil prices are higher and income is lower than in the high case. Most of the impact of the variations is on demand for petroleum products; and, because petroleum consumption is projected to be only about 15 percent of total residential energy consumption in 1995, the differential effects appear to be small. From the low to the high case, total residential energy consumption in 1995 ranges from 9.8 quadrillion Btu to 10.2 quadrillion Btu--a spread of only about 4 percent.

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. Between 1985 and 1995, commercial energy use is projected to increase at an average annual rate of 1.3 percent, to 6.7 quadrillion Btu (Table 4), with a concurrent decrease of about 1 percent per year in energy use per square foot of floorspace. Between 1974 and 1984, the average increase in commercial-sector energy use was 0.4 percent per year, which was accompanied by a rapid decrease of more than 2 percent per year in energy use per square foot of floorspace. Electricity growth accounts for the largest part of the projected growth in end-use energy demand in the commercial sector.

Electricity is projected to replace natural gas as the primary fuel used in the commercial sector during the next decade, accounting for about 45 percent of total commercial energy use by 1995 (compared with 39 percent in 1985) (Figure 5 on page 23). Commercial electricity use, which increased every year between 1974 and 1984 (at an average annual rate of 4.1 percent), is projected to continue increasing between 1985 and 1995 at an average annual rate of nearly 2.9 percent. Real electricity prices are projected to decline through the forecast period, and, as a result, electricity consumption in the commercial sector are expected to increase faster than commercial floorspace growth. (Trends in commercial fuel prices are similar to those shown in Figure 3 on page 20.)

As in the past, efficiency improvements in commercial buildings are assumed to remain sensitive to fuel price changes in the future. Natural gas prices to the commercial sector are projected to increase faster than the prices of other fuels, although the actual price level is expected to remain lower than that for most petroleum products until late in the forecast period. The decline in natural gas consumption per square foot of commercial floorspace in response to rising natural gas prices nearly offsets the expected increase in consumption due to floorspace growth. The net effect is that natural gas use in the commercial sector is expected to increase by less than 1 percent per year between 1985 and 1995.

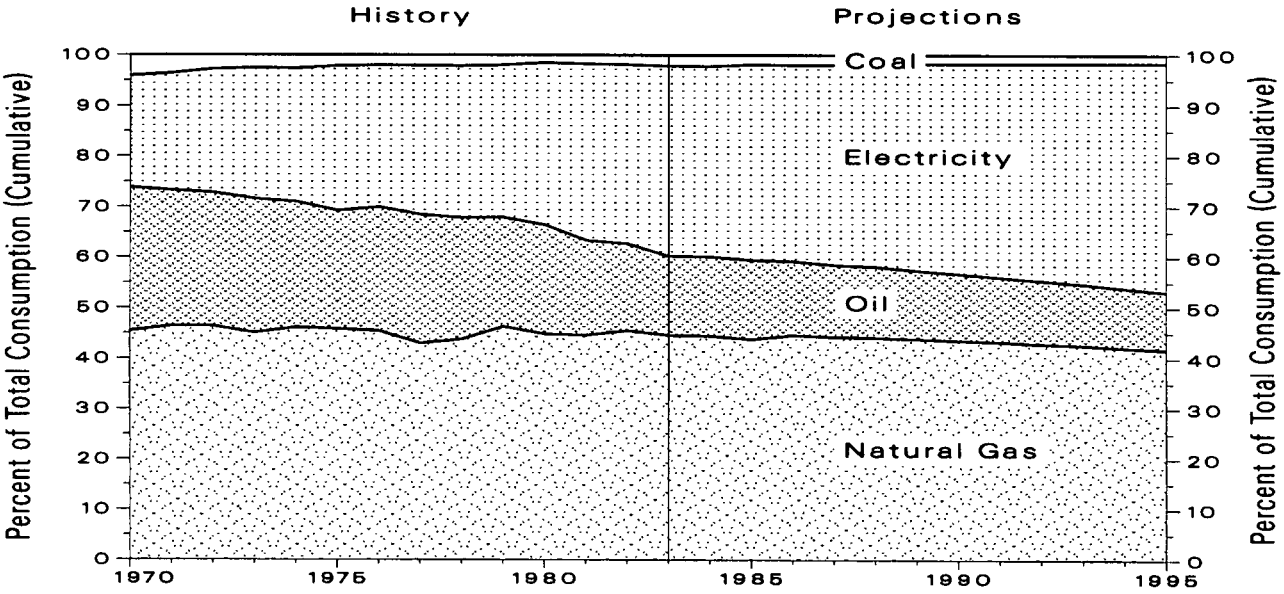
Table 4. Commercial Energy Use by Fuel, 1974-1995
(Quadrillion Btu)

	History		Projections		
Fuel	1974	1984	1985	1990	1995
Natural Gas	2.62	2.61	2.58	2.81	2.79
Electricity	1.50	2.24	2.28	2.68	3.02
Distillate Fuel Oil	0.60	0.45	0.45	0.45	0.46
Residual Fuel Oil	0.59	0.29	0.26	0.19	0.10
Steam Coal	0.15	0.13	0.11	0.11	0.11
Liquefied Petroleum Gas	0.10	0.06	0.07	0.06	0.06
Motor Gasoline	0.08	0.10	0.11	0.13	0.12
Kerosene	0.05	0.03	0.03	0.02	0.02
Total	5.69	5.92	5.89	6.46	6.69

Source: Table A2.

Figure 5. Commercial Energy Consumption by Source, 1970-1995

By 1995, electricity is projected to meet 45 percent of the energy requirements for the commercial sector.



Note: Renewables, such as wood, solar, and wind, are not included.

Source: Energy Information Administration, State Energy Data Report, Consumption Estimates, 1960-1983, DOE/EIA-0214(83) (1985).

Fuel oil consumption (including distillate, kerosene, and residual fuel oil) accounted for only 13 percent of total commercial energy use in 1985; it is projected to continue its decrease over the next 10 years, but at a much slower rate than the 4.7-percent-per-year decline experienced between 1974 and 1984. Most of the projected decline is attributable to a further sharp drop expected in the use of residual oil by the commercial sector.

As was the case in the residential sector, most of the difference in the higher and lower oil imports cases for commercial use projections lies in the demand for petroleum products. Again, however, because petroleum consumption is expected to be only a small percentage of commercial energy consumption in 1995 (about 11 percent in the base case), the impact is likely to be small. From the low to the high case, total commercial energy consumption ranges from 6.6 quadrillion Btu to 6.8 quadrillion Btu in 1995, a variation of about 3 percent.

Industrial Energy Demand

The industrial sector is the largest end-use consumer of energy and is the most sensitive to assumptions about economic growth. Growth in industrial energy consumption is projected to average 0.7 percent per year between 1985 and 1995, considerably lower than the rate of overall economic growth, but well above the 1.6-percent-per-year drop experienced between 1974 and 1984. Total industrial energy use is projected to be 22.7 quadrillion Btu in 1995, up slightly from 21.3 quadrillion Btu in 1985 (Table 5 on page 24). Energy use per unit of output is projected to continue to decline through 1995, largely because of the shift in the industrial mix away from energy-intensive industries, the increases in energy prices, and the replacement of old equipment with new, more energy-efficient equipment (Figure 6 on page 24).

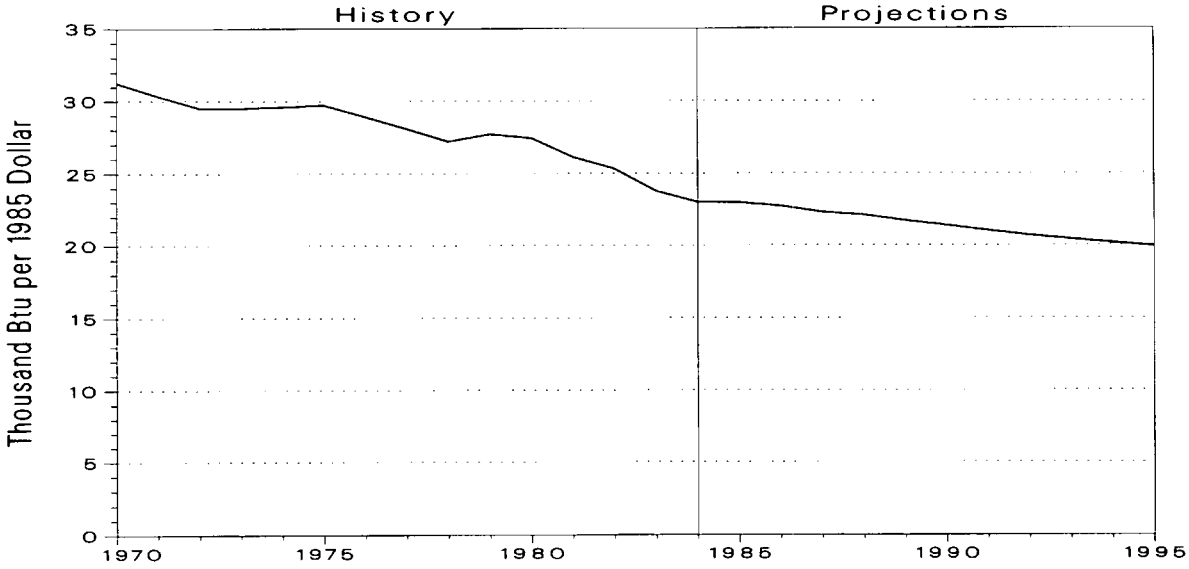
Table 5. Industrial Energy Use by Fuel, 1974-1995
(Quadrillion Btu)

Fuel	History		Projections		
	1974	1984	1985	1990	1995
Natural Gas	10.00	7.45	7.41	7.82	7.25
Metallurgical Coal	2.41	1.18	1.08	1.01	0.88
Electricity	2.34	2.87	2.95	3.27	3.80
Residual Fuel	1.73	0.78	0.70	0.64	0.43
Steam Coal	1.45	1.68	1.75	1.93	2.03
Distillate Fuel	1.35	1.36	1.37	1.62	1.73
Liquefied Petroleum Gas	1.23	1.60	1.67	1.80	1.90
Still Gas Used in Refineries	1.05	1.15	1.18	1.12	1.06
Petrochemical Feedstocks	0.74	0.82	0.81	0.78	0.69
Other Raw Material Oil	2.26	2.14	2.09	2.28	2.29
Motor Gasoline	0.24	0.11	0.12	0.30	0.48
Kerosene	0.13	0.13	0.14	0.17	0.19
Net Coke Imports	0.06	-0.01	-0.01	-0.01	-0.01
Industrial Hydropower	0.03	0.03	0.03	0.03	0.03
Total	25.00	21.30	21.30	22.74	22.73

Source: Table A2.

Figure 6. Industrial Energy Consumption per Unit Value of Output, 1970-1995

As equipment becomes more efficient and production shifts away from energy-intensive industries, industrial energy use per unit of output is projected to continue its long-term decline.



Sources: Energy Information Administration, Annual Energy Review, 1984, DOE/EIA-0384(84), (1985); and Energy Conservation Indicators 1984 Annual Report, DOE/EIA-0441(84) (1985).

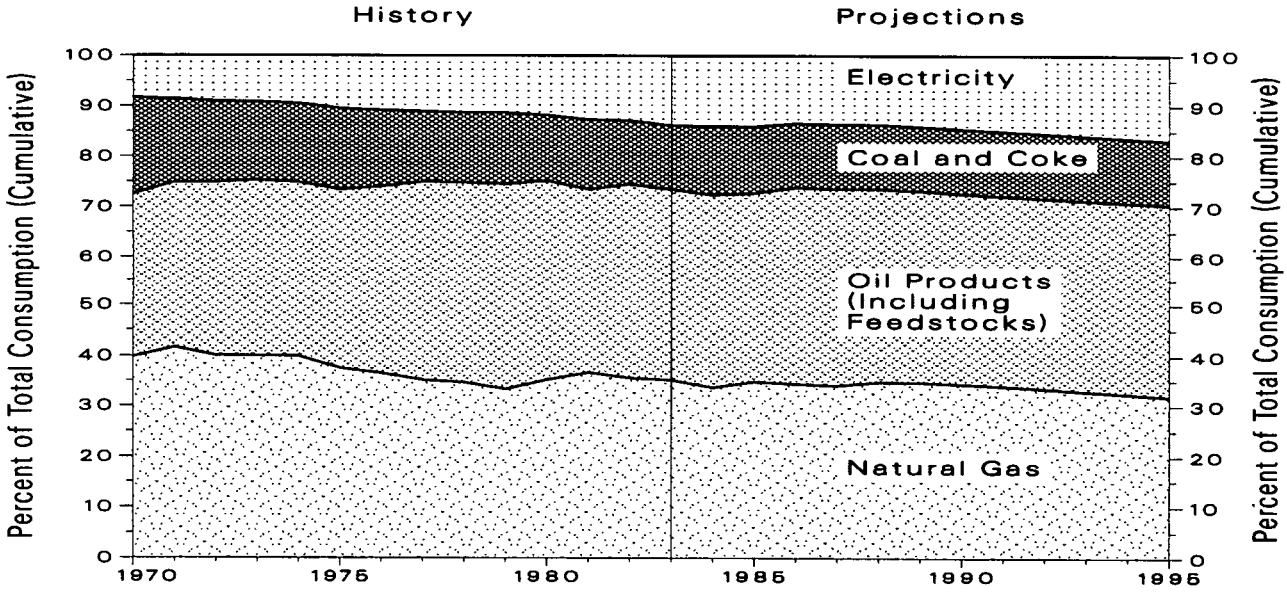
Similar to the trend in other sectors, industrial consumption of energy is projected to shift toward increased reliance on electricity over the forecast period. In 1995, industrial electricity use is expected to account for 17 percent of total industrial energy use (Figure 7), up from 14 percent in 1985. From 1974 to 1984, real electricity prices to the industrial sector grew at an average annual rate of 5.7 percent per year, while demand grew by only 2.1 percent per year; over the next 10 years, in contrast, declining real electricity prices (Figure 8 on page 27) are expected to result in industrial electricity demand growth averaging 2.6 percent per year.

Industrial use of petroleum is projected to increase slightly in absolute terms over the forecast period, in contrast with an actual decline experienced between 1974 and 1984. By 1995, petroleum is projected to account for nearly 39 percent of the energy requirements in the industrial sector, up slightly from 38 percent in 1985 (Figure 7). Petroleum use is concentrated in certain portions of the industrial sector (such as petrochemical feedstocks, agriculture, mining, and construction) that cannot easily convert to natural gas. Feedstock use is projected to decline slightly, based on an assumption of more rapid conservation and less rapid growth in the plastics industry than observed historically. The use of residual fuel oil in manufacturing, where it mainly competes with natural gas as a boiler fuel, accounted for less than 5 percent of industrial oil use in 1985; its share of total industrial energy use is expected to decline further by 1995, even though some switching into oil from natural gas is likely as natural gas prices exceed oil prices after 1990. Industrial distillate use is projected to increase over the forecast period as a result of increases in mining and construction activity. Industrial use of asphalt and lubricants is forecast to increase along with economic growth, in line with historical patterns. Finally, industrial gasoline use is projected to increase as a result of increased agricultural activity.

Industrial use of natural gas is projected to increase during the early years of the forecast period (when prices are stable), but then decline after 1989 (as prices increase more rapidly). The upward effect of economic growth on natural gas consumption is expected to be offset by the downward effect of higher natural gas prices and conservation in gas-using industries. Natural gas is forecast to account for nearly 32 percent of total industrial energy demand in 1995, down from 35 percent in 1985.

Figure 7. Industrial Energy Consumption by Source, 1970-1995

The use of electricity in the industrial sector is projected to increase its share over the forecast period, but oil remains an important industrial source of energy.



Note: Renewables, such as wood, solar, and wind, are not included.

Source: Energy Information Administration, State Energy Data Report, Consumption Estimates, 1960-1983, DOE/EIA-0214(83) (1986).

Industrial Cogeneration

Industrial cogeneration includes a wide variety of technologies, generally combining the generation of electricity with the use of heat in industrial processes. In recent years, provisions of the Public Utility Regulatory Policies Act (PURPA, P.L. 95-617) require electric utilities to purchase "qualified" electric power generated by alternative means at a price equal to the utility's "avoided cost." There has been a surge in applications to qualify such projects with the Federal Energy Regulatory Commission (FERC), with most of them using natural gas in the cogeneration, following the Supreme Court ruling in 1983 upholding PURPA. While more than 13 gigawatts of new cogeneration capacity have been filed with the FERC since 1980, more than half have been filed since the court decision. However, it is not known how much of the cogeneration capacity applied for has actually become operational to date.

The future role of cogeneration in energy consumption by the commercial and industrial sectors is difficult to assess in part because of the economic complexity of the process and in part because cogeneration processes are location- and application-specific. Many industries (such as primary metals, refining, chemicals, and paper) have traditionally made efficient use of their process-heat waste streams to produce electricity, supplementary heat, or useful steam. Thus, cogeneration may not represent a significant change in their behavior, but merely an enhancement to efficiency. One important aspect of cogeneration may be the new willingness of consumers to consider alternatives to centrally generated electricity. The availability of pre-packaged cogeneration systems that provide both steam heat and electricity may significantly change the fuel choices away from purchased electricity to natural gas or other alternatives.

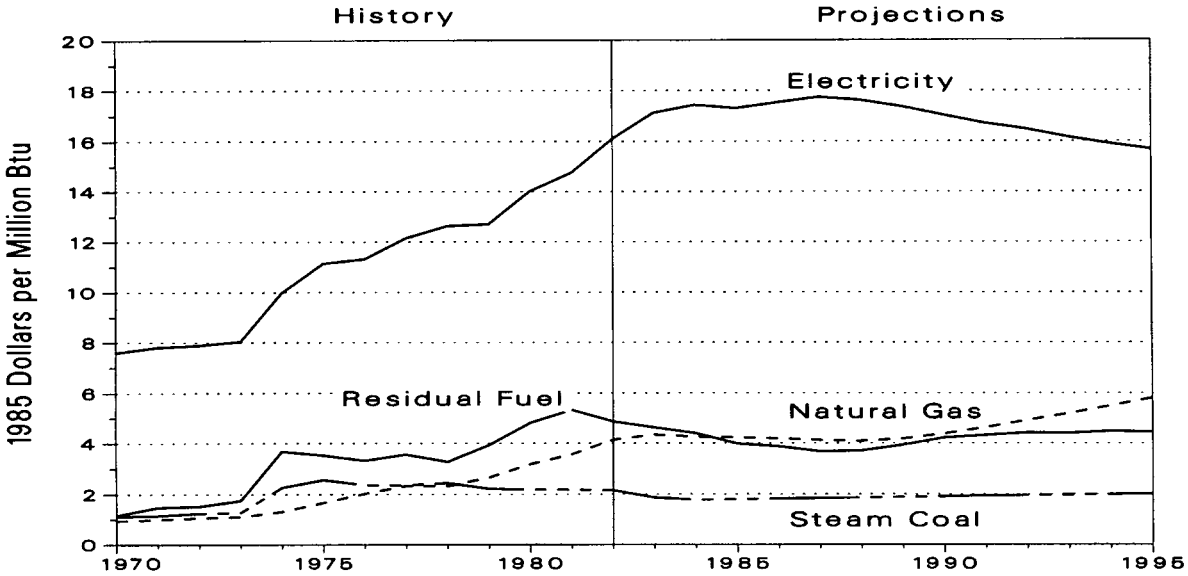
Many legal, institutional, and economic factors contribute to the uncertainty of growth projections in cogeneration. State public utility commissions differ in their interpretations of "full utility avoided costs" as specified by FERC. Changes in the basis on which utilities must purchase cogenerated electricity could have a detrimental effect on the economics of some projects.

If all of the projects filed with FERC come to fruition and growth in this technology continues, cogeneration of electricity (mainly from natural gas) will make a significant contribution to electricity supply in some regions. However, because little firm data exist on current use of cogeneration, projections through 1995 are very uncertain and no explicit forecast is being made here. An industry survey suggests that between 400 and 471 cogeneration plants existed in 1984, with a total generating capacity of between 12 and 15 gigawatts.[2]

[2]Sources: S. David Hu, *Cogeneration,* (Reston Publishing Company 1985); Frost and Sullivan Inc., *The Industrial/Commercial Cogeneration Systems and Services Market in the United States,* New York, March 1985.

Figure 8. Industrial Energy Prices, 1970-1995

Real industrial electricity prices are projected to decline by 12 percent between 1987 and 1995, in contrast to the sharp increases of the 1970's and early 1980's.



Source: Energy Information Administration, State Energy Price and Expenditure Report, 1970-1982, DOE/EIA-0376(82), (1985).

Mainly because of its continued price advantage, demand for industrial steam coal is projected to increase at an average annual rate of 1.5 percent between 1985 and 1995, reaching 2.0 quadrillion Btu in 1995. This forecast for industrial steam coal in 1995 is significantly lower than the one of 2.5 quadrillion Btu cited in last year's *Annual Energy Outlook*, because of the lower growth now projected for the heavy coal-using industries. Coal use is very sensitive to changes in the growth assumptions for these industries because coal is most attractive to large-scale plants with a growing demand for steam. Previous forecasts were much higher for two reasons: (1) the actual barriers to increased coal use (such as environmental factors) were not fully realized at that time, and (2) a more stringent interpretation regarding the prohibition of oil and natural gas use under the Powerplant and Industrial Fuel Use Act was assumed in the past.

U.S. use of metallurgical coal is projected to decline from 1.1 quadrillion Btu (40 million tons) in 1985 to about 0.9 quadrillion Btu (32 million tons) by 1995. This forecast is heavily dependent on the assumed rate of growth of the steel industry, on the competition from steel imports, and on the domestic adoption of electric-arc modes of steel production that do not use metallurgical coke. Corresponding views from the industry (American Iron and Steel Institute and others) suggest that the 66-percent share of steel currently produced by nonelectric means could fall to 55 percent by 1995. At the same time, technological improvements are assumed to reduce the average use of metallurgical coke in conventional steelmaking from approximately 0.53 tons of coke per ton of pig iron in 1985 to about 0.48 by 1995, approaching the level of the most efficient producers today. This EIA forecast assumes a continuation of the 2.6-percent-per-year decline in the quantity of metallurgical coal used per real dollar of steel production that was experienced between 1970 and 1982. This forecast also assumes growth in U.S. steel output will average only 0.3 percent per year between 1985 to 1995, reflecting the growth rate for all primary metals (Table 6 on page 28).

The percentage of renewable energy used in the industrial sector is assumed to remain stable throughout the forecast period. Wood byproducts, used primarily in the paper industry, account for almost all industrial use of renewable energy. Because wood byproducts are not purchased and little reliable data are available on current use, this category of energy use is not explicitly considered in developing the industrial energy projections. In this analysis, use of wood byproducts is represented as an improvement in energy efficiency.

Table 6. Trends in Output and End-Use Energy for Heat and Power in Selected Industries, 1974-1995

(Annual Percent Growth)

Industry	Energy Use Per Unit of Output		Output		Energy Use	
	1974-1981a	1985-1995	1974-1981a	1985-1995	1974-1981a	1985-1995
Chemicals, Plastics, and Rubber	-2.6	-2.0	1.1	2.3	-1.5	0.2
Primary Metals	0.1	0.0	-2.7	0.3	-2.6	0.3
Food	-2.6	-2.1	2.0	1.7	-0.6	-0.4
Stone, Clay, and Glass	-1.9	-0.9	-1.2	1.7	-3.1	0.8
Paper	-1.6	-0.3	0.8	1.4	-0.8	1.1

a1981 is used as a base year because this is the last year of Annual Survey of Manufactures data.
Source: Energy Information Administration, Office of Energy Markets and End Use.

According to the 1981 Annual Survey of Manufactures,[3] five industries--chemicals, plastics, and rubber; primary metals; paper; stone, clay, and glass; and food--consumed 80 percent of the energy used for heat and power in manufacturing during 1981 (excluding petroleum refining). Assumptions about growth in the output of these industries are a major factor in explaining the projected changes in industrial energy consumption over the forecast period. Major trends for these key industries are discussed below and summarized in Table 6.

- End-use energy consumed per unit of output in the chemicals, plastics, and rubber industry is assumed to decline by 2.0 percent per year between 1985 and 1995, compared with the 2.6-percent per year drop experienced between 1974 and 1981.[4] A 2.3-percent rise is projected for output, while energy use for heat and power in this industry is expected to grow by 0.2 percent per year over the next 10 years.

- End-use energy per unit of output in the primary metals industry is projected to remain constant, compared with a 0.1-percent annual increase experienced between 1974 and 1981.[5] With output projected to grow by 0.3 percent per year over the forecast period, energy use in this industry is expected to increase at that same rate. The share of electricity use in primary metals is projected to grow from 34 percent in 1985 to 46 percent in 1995, reflecting the greater use of electric furnaces and electric induction heaters and the historical trend towards alloys requiring more use of electricity in their preparation.

- End-use energy per unit of output in the paper industry is projected to decline by 0.3 percent between 1985 and 1995, compared with a 1.6-percent-per-year decline from 1974 to 1981. Output is projected to grow by 1.4 percent per year and energy use by 1.1 percent per year over the forecast period. Of the top five energy-intensive industries, the share of electricity has grown fastest in the paper industry, and this trend is expected to continue through 1995.

Industrial energy demand is sensitive to changes in the assumptions about economic growth and world oil prices. In the high oil imports case (high economic growth and low world oil prices), industrial energy demand is expected to be 23.5 quadrillion Btu in 1995, compared with 22.1 quadrillion Btu in the low oil imports case. As in the other sectors, oil consumption is expected to vary most over these cases: industrial oil use in 1995 for the high oil imports case is projected to be nearly 10 percent greater than in the low oil imports case.

[3]U.S. Department of Commerce, *1982 Census of Manufactures*, Fuels and Electric Energy Consumed (MC82-S-4, Part 1) (Washington, DC, 1983).

[4]Energy Information Administration, *Energy Conservation Indicators, 1983*, DOE/EIA-0441 (Washington, DC), 1984.

[5]This includes only heat and power energy, but excludes metallurgical coal.

Transportation Energy Demand

In 1995, total energy use in the transportation sector is projected in the base case to be 20.3 quadrillion Btu, about 2 percent above its 1985 level (Table 7). Improved fuel efficiencies of transportation vehicles nearly compensate for the growth in demand resulting from increases in personal and freight travel. The projected growth in total transportation energy use of only 0.2 percent per year between 1985 and 1995 compares with growth between 1974 and 1984, averaging 0.9 percent per year, most of which took place in the category of distillate fuel (diesel).

The transportation sector relies almost entirely on petroleum (Figure 9 on page 30) and has much less fuel-choice flexibility than other sectors. The major change over the past 10 years has been the improvement of vehicle 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 those experienced over the past few years. In particular, the average efficiency of new cars, which increased by 6.4 percent per year between 1974 and 1984 in response to higher prices for motor gasoline, is assumed to increase by about 1.7 percent per year between 1985 and 1995, reaching 32 miles per gallon in 1995 (Figure 10 on page 30).[6] This assumption is based on technical considerations and on vehicle sales trends. Motor gasoline prices are projected to decline through 1988 and then increase slightly through 1995. Although vehicles of much higher efficiency are now available, they did not constitute a significant portion of total car sales in 1985. This pattern is assumed to continue in the forecast period.

Over the forecast period, personal travel in automobiles and commercial light trucks (including vans) is forecast to increase at average annual rates of 2.2 and 6.2 percent, respectively. These patterns are consistent with historical periods of relatively stable energy prices. Fuel consumption for personal travel is expected to remain nearly constant between 1985 and 1995, as increases in vehicle-miles traveled counteract improvement in average fuel efficiency of the automobile fleet. In contrast, diesel fuel use in the transportation sector is forecast to increase over the next decade at a rate of nearly 1.9 percent per year. Although no substantial increase in the number of diesel-fueled cars is expected, the number of diesel-powered trucks is projected to continue to increase significantly: in 1995, diesel fuel is forecast to account for 65 percent of the fuel used by trucks carrying freight, compared with 56 percent in 1985.

Historically, truck vehicle-miles traveled have closely paralleled growth in the economy. Continuing this trend, vehicle-miles traveled by freight trucks are forecast to grow by about 2.4 percent per year between 1985 and 1995, or at about the same rate as the assumed increase in industrial output over that period (Figure 11 on page 31). Truck fuel consumption is projected to increase at only about one-third of this rate because of the effects of fuel efficiency improvements. Consumption of jet fuel is forecast to increase only slightly between 1985 and 1995, compared with a 1.9-percent annual rise during the previous decade. The new generation of efficient jets is assumed to offset increases in air traffic.

The transportation sector is more responsive than other end-use sectors to changes in the rate of economic growth and world oil prices. This sensitivity reflects the fact that most of the fuel used in this sector is petroleum, so oil price changes have a greater effect

Table 7. Transportation Energy Use by Fuel, 1974-1995
(Quadrillion Btu)

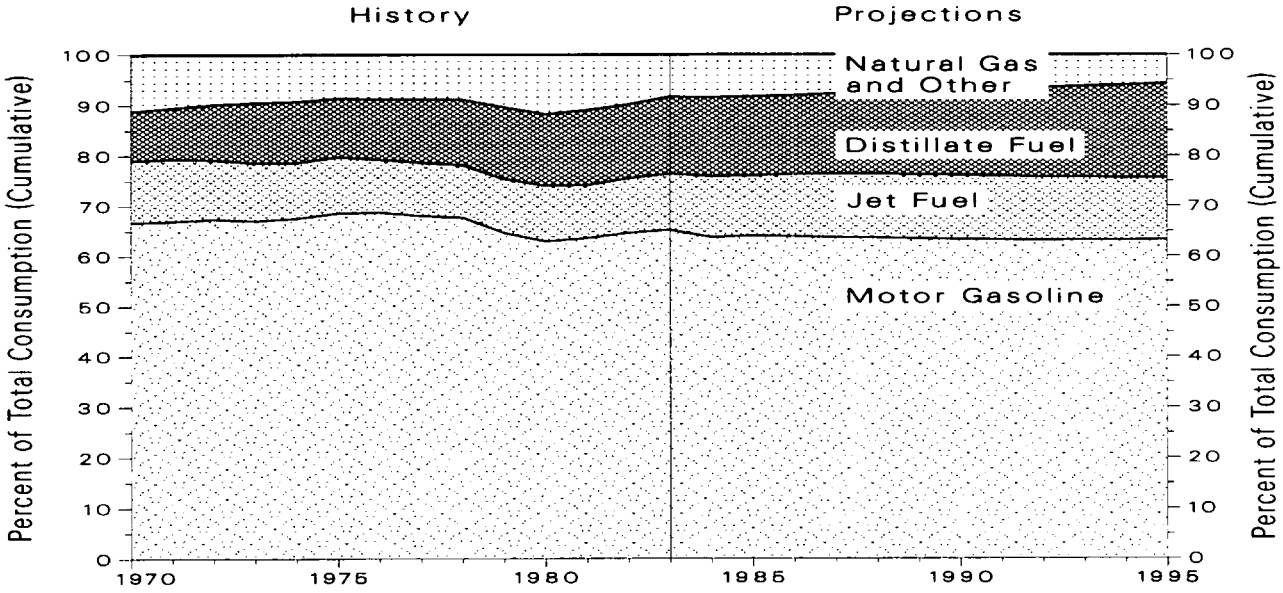
	History		Projections		
Fuel	1974	1984	1985	1990	1995
Motor Gasoline	12.22	12.65	12.82	12.70	12.85
Distillate Fuel	2.20	3.11	3.14	3.39	3.79
Jet Fuel	2.00	2.41	2.40	2.56	2.50
Residual Fuel	0.70	0.88	0.80	0.52	0.29
Natural Gas	0.68	0.54	0.55	0.55	0.53
Other (incl. electricity)	0.29	0.26	0.28	0.33	0.34
Total	18.09	19.86	19.99	20.05	20.30

Source: Table A2.

[6]Based on the Chase Automative Service and Technical projections from the Enviromental Protection Agency.

Figure 9. Transportation Energy Consumption by Source, 1970-1995

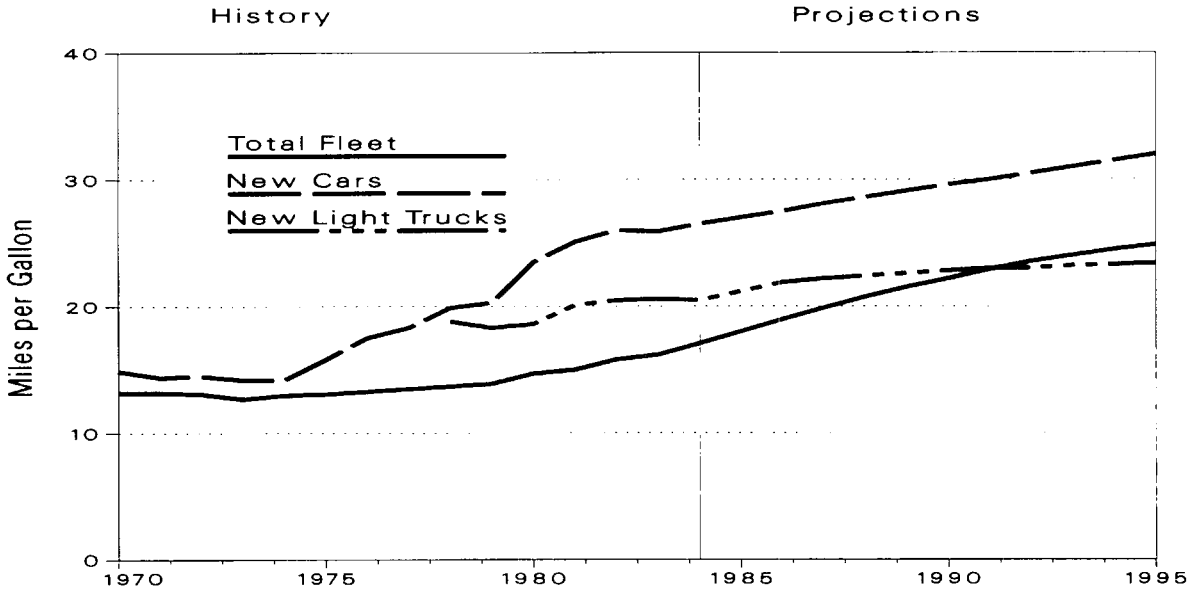
Distillate fuel oil is projected to increase its share of consumption in the transportation sector between 1985 and 1995 because of increased use of diesel-fueled trucks.



Source: Energy Information Administration, State Energy Data Report, Consumption Estimates, 1960-1983, DOE/EIA-0214(83) (1985).

Figure 10. Fuel Efficiency of Passenger Vehicles, 1970-1995

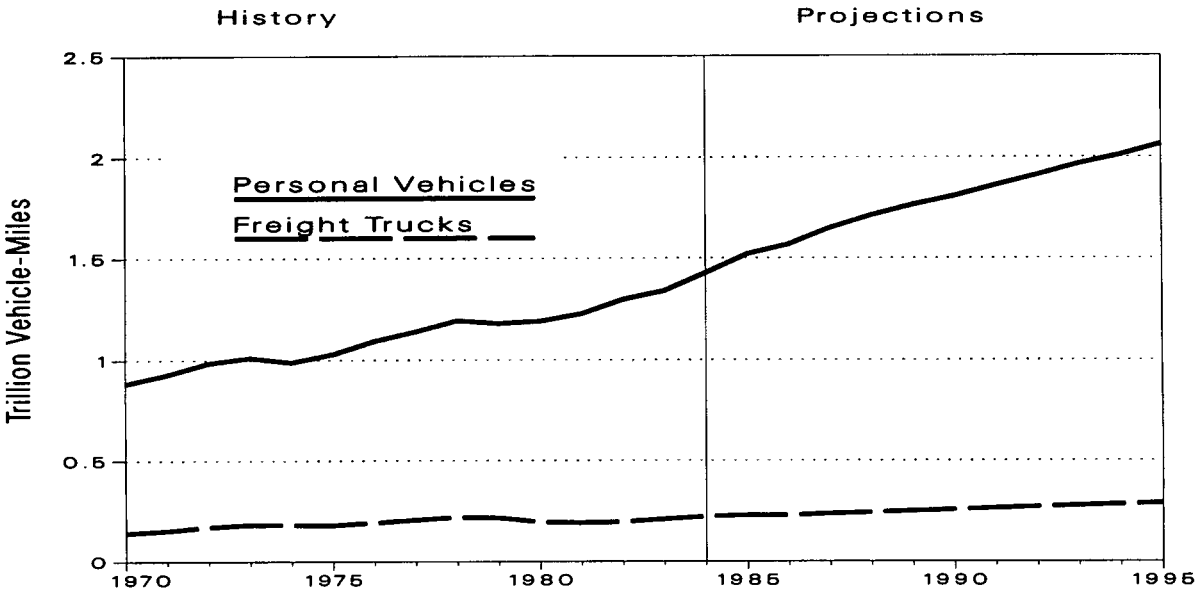
Growth in new car mpg is projected to be steady, but slower than in the late 1970's due to lower motor-fuel prices.



Sources: Federal Highway Administration, Highway Statistics, (various years), and U.S. Environmental Protection Agency, SAE Technical Paper Series #850550: 'Light Duty Automotive Fuel Economy Trends Through 1985', (1985).

Figure 11. Vehicle-Miles Traveled, 1970-1995

Growth in vehicle-miles traveled by freight trucks is expected to be limited by the slow growth assumed for some parts of the industrial sector.



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

on total demand. In the high oil imports case, the transportation sector is projected to use nearly 10 percent more energy than in the low oil imports case in 1995. The concomitant assumption of higher economic activity also tends to increase the demand for all modes of travel in the high imports case, but this result is dampened somewhat by the introduction of a higher percentage of new vehicles into the national fleet, thus raising average efficiencies.

Petroleum Product Trends

During the past 10 years, the U.S. petroleum market experienced rapid growth to a peak demand of 18.8 million barrels per day in 1978, followed by a severe contraction to a low of 15.2 million barrels per day in 1983. The demand trend for petroleum products turned upward again in 1984, reaching a total of more than 15.7 million barrels per day. Between 1985 and 1995, the petroleum market is projected to experience slow but steady growth, reaching more than 16.5 million barrels per day in 1995. The most significant changes in demand for individual products expected over this period are increases in distillate fuel oil and a concurrent drop in residual fuel oil. Smaller gains are projected for motor gasoline, liquefied petroleum gases (LPG), and jet fuel.

The domestic refining industry, the major source of petroleum products, is undergoing adjustments to changes in product demand and the declining quality of available crude oil. As a result of the recent recession and price-induced energy conservation, total U.S. refinery throughput dropped sharply, by about 16 percent between 1978 and 1985. Operable distillation capacity at refineries declined by about 8 percent over the same period. Domestic production of refined products is projected to increase very slowly, by about 0.7 percent per year between 1985 and 1995.

The slow growth in petroleum demand over the next 10 years is expected to create a stable market for the U.S. refining industry. Because the level of refinery production in 1995 is assumed to be slightly higher than the current level, a steady level of refinery capacity is expected over the next 10 years. The share of petroleum product imports (as a percent of the total petroleum product market) is assumed to decline slightly through the forecast period. This is strictly an assumption based on current trends made for analytic convenience without detailed analysis of foreign competition which might or might not change the share of product imports.

Total U.S. refinery production (including natural gas plant liquids) is projected to increase only slightly over the forecast period, from 14.2 million barrels per day in 1985 to 15.3 million barrels per day in 1995. The projected decline in domestic crude oil production in conjunction with the growth in petroleum product demand results in increased crude oil and product imports. Total net imports of crude oil--including purchases for the Strategic Petroleum Reserve (SPR)--and of petroleum products are projected to increase from 4.2 million barrels per day in 1985 to 5.7 million barrels per day in 1990 and 7.7 million barrels per day in 1995. SPR imports are assumed to be effectively zero after 1985. This is consistent with the budget proposal for 1986 and current Administration policy, but would change if future budget proposals changed.

The combination of higher world oil prices and lower economic growth assumed in the low oil imports case leads to a much lower projected increase in net imports between 1985 and 1995--a rise of 1.9 million barrels per day, as compared with an increase of 3.6 million barrels per day shown in the base case. In the low imports case, a slower rate of decline in domestic oil production is expected, attributable to the higher world oil prices assumed in this case. Domestic oil production reaches 9.6 million barrels per day by 1995 in the low imports case, as opposed to the 8.8 million barrel per day figure in the base case. In the low imports case, demand for petroleum products is lower than in the base case, almost unchanged between 1985 and 1995. Lower economic growth assumed in this case leads not only to lower direct demand for most petroleum products but also to lower demand for electricity, which means less petroleum use in electricity generation.

3. Energy Production

Despite the decline in energy prices over the past several years, domestic energy production (including petroleum production) has held reasonably steady because of the lagged response of exploration and field development to earlier rises in energy prices. This chapter discusses this factor and others that affect domestic energy supply. The discussion starts with oil because oil imports are greater than those of any other energy source. Following a discussion on natural gas, the chapter turns to the generation of electricity, because demand for electricity is the key determinant of U.S. coal supply and demand.

Petroleum Supply

Petroleum is expected to remain an important source of energy throughout the forecast period, accounting in the base case projection for 24 percent of total U.S. energy production in 1995. Table 8 summarizes the historical and projected sources of oil supply. Domestic crude oil production is expected to increase through 1987, continuing the upward trend in production experienced since 1976. Many development projects for oil and gas production that began before the recent decline in oil prices are just now reaching the operational stage. Furthermore, the severe decline in drilling during the early 1980's has been moderated by a recent drop in exploration and development costs.

Production of oil from the Lower 48 States has risen over the past several years in a delayed response to the near doubling of the real wellhead price of crude oil between 1979 and 1981. The dramatic increases in production from Alaska, in offshore production, and in enhanced oil recovery that began during the late 1970's have continued. Beginning in 1987, however, the effects of the recent fall in world oil prices will begin to be reflected, and total domestic oil production is projected to decline by about 3 percent per year

Table 8. Petroleum Supply, 1974-1995
(Million Barrels per Day)

Supply	History		Projections		
	1974	1984	1985	1990	1995
Domestic Production					
Crude Oil and Lease Condensate	8.77	8.88	8.92	8.05	6.53
Natural Gas Plant Liquids	1.69	1.63	1.63	1.74	1.69
Processing Gain and Other Liquids	0.52	0.60	0.56	0.58	0.60
Total Production	10.98	11.11	11.11	10.37	8.82
Imports (Including SPR)a					
Crude Oil	3.48	3.43	3.06	4.59	6.64
Refined Products	2.64	2.01	1.83	1.83	1.80
Total Imports	6.11	5.44	4.89	6.43	8.44
Total Exports	0.22	0.72	0.72	0.70	0.70
Net Imports (Including SPR)a	5.89	4.72	4.17	5.72	7.74
Total Primary Supplyb	16.69	15.54	15.49	16.08	16.53

aSPR is the Strategic Petroleum Reserve. SPR imports are assumed to be zero after 1985.
bTotal primary supply is defined as total production plus net imports plus net stock withdrawals minus SPR additions.
Source: Table A8.

through 1995. Most of this drop is projected to occur in the Lower 48 States, but Alaskan output also is expected to decline. These production forecasts are heavily influenced by assumptions about the future path of world oil prices, in the general context of exploration and development economics.

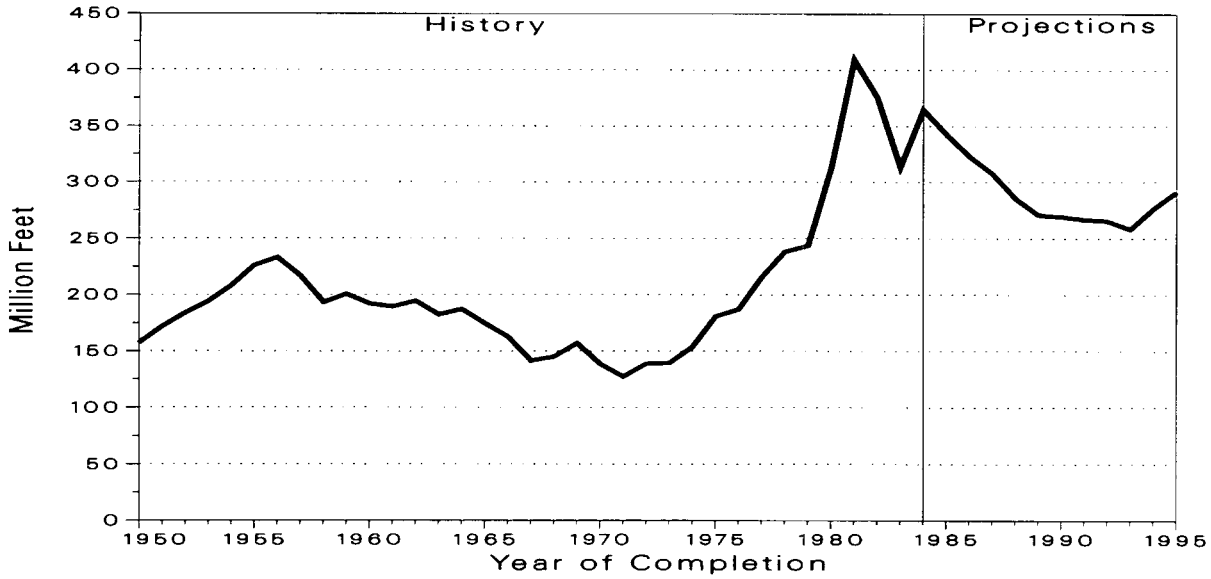
The overall lower level of domestic production, combined with slightly higher petroleum demand (as discussed in Chapter 2), is expected to raise net petroleum imports (counting both crude oil and refined products) from 4.2 million barrels per day in 1985 to 7.7 million barrels per day in 1995. This base case projection compares with an actual net import level of 8.6 million barrels per day in 1977, the peak year to date.

Although a sizeable resource base of undiscovered crude oil remains in the United States, the incentives for exploratory drilling will be dampened by the projected decline in the real world oil prices through 1987 and by the relatively small increase in prices expected between 1988 and 1995. Historically, changes in drilling have followed changes in wellhead prices closely (although 1984 appears to be an exception). Based on this relationship, decreased drilling during the early 1980's was directly attributable to the turnaround in oil prices in 1981. The increase in drilling during 1984 resulted from lower drilling costs in that year (relative to peak levels in 1981). Drilling activity is projected to decline over the next few years and then increase gradually during the final years of the 10-year forecast period in response to higher oil and natural gas wellhead prices projected in those years (Figure 12).

Onshore production in the Lower 48 States is projected to remain the major component of domestic oil supply (due in part to enhanced oil recovery), but it is still expected to decline in absolute terms through the forecast period (Figure 13 on page 35). The world oil prices assumed in the base case are not expected to provide sufficient incentive to encourage enough additional conventional oil exploration and development to offset production declines from existing fields. Alaskan crude oil production, which accounted for about 16 percent of total U.S. petroleum liquids production in 1985, is forecast to peak in 1987 at 1.85 million barrels per day, and then dip to about 1.30 million barrels per day by 1995 (still about 15 percent of total U.S. petroleum liquids production at that time). During the latter part of the forecast period, production from the Prudhoe reservoir is expected to fall by more than 12 percent annually because of the effects of secondary recovery methods which were used there to boost both production in the earlier years and ultimate crude oil recovery. Alaskan production from areas other than the North Slope or Cook Inlet is not expected by 1995.

Figure 12. Footage Drilled in the United States, 1950-1995

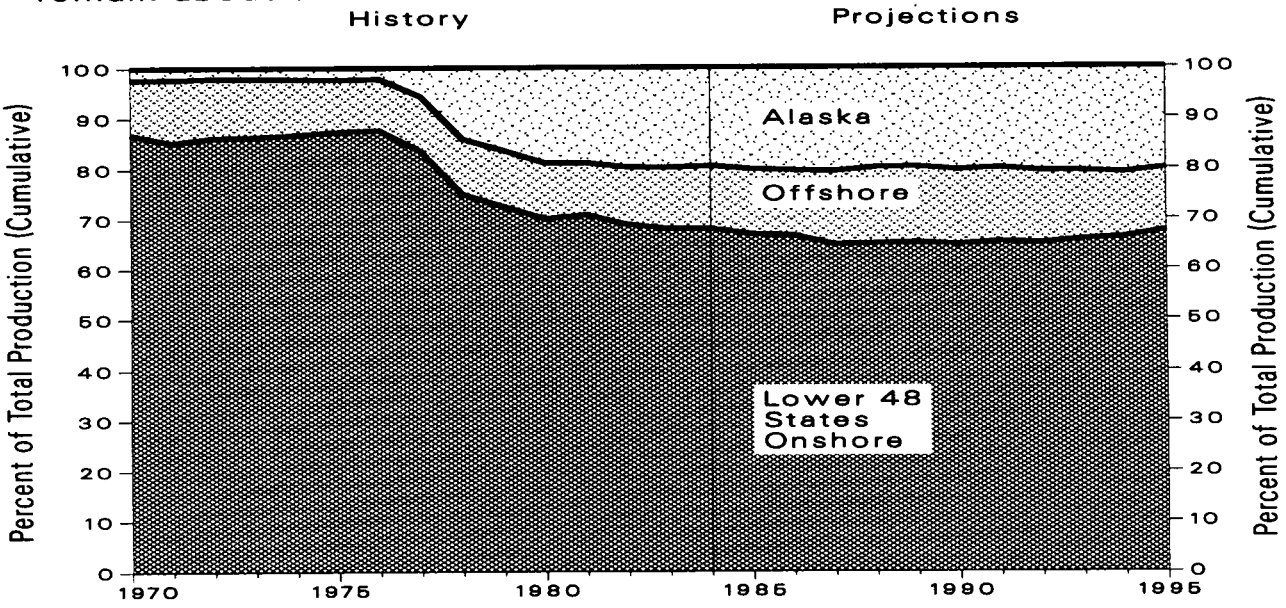
Total drilling activity is expected to fall and then rise in the latter part of the forecast period, generally following the projected path for oil prices.



Sources: o 1950-1969: American Petroleum Institute, Basic Petroleum Data Book, (1984); o 1970-1984: Energy Information Administration, Office of Oil and Gas.

Figure 13. Oil Production Shares by Source, 1970-1995

Although declines in crude oil production are anticipated from each of the domestic producing areas, their relative shares remain about the same.



Source: Energy Information Administration, Annual Energy Review, 1984, DOE/EIA-0384(84), (1985), and U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, DOE/EIA-0216; and American Petroleum Institute, "Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada"(1985).

Coincidentally, offshore oil production from the Lower 48 States is also expected to peak in 1987 and then to decline through the remainder of the forecast period. Output from the Gulf of Mexico is likely to follow this general trend, but offshore production along the Pacific Coast is expected to rise into the 1990's, stabilizing after about 1992. New discoveries in the Pacific are not expected to make significant contributions to domestic oil supply by 1995, because there is usually a lead time of up to 10 years before new offshore discoveries result in actual production.

Barring unforeseen discoveries or technological developments, the continued production of conventional resources will further deplete the domestic oil resource base if the price projections in the base case prove accurate. Proved reserves of oil (defined as the stock of known producible resources from which domestic production is taken) have declined since 1976 (although they did increase in 1984) because the record levels of drilling in the 1980's have not yielded enough new discoveries to keep pace with production. Although profitable prospects exist at current prices, the persistent slump in oil prices is expected to reduce the number of profitable projects generally. However, the contribution from unconventional oil production is expected to grow over the next decade. This increase is based on the expected application of established technology on a broader scale, as well as on the expectation of some fresh advances in extraction technology.

In the cases using alternative world oil prices and alternative rates of economic growth, projections of crude oil production show significant variation. In the low oil imports case (with higher world oil prices and slower economic growth), total domestic oil production in 1995 is projected to be about 0.8 million barrels per day higher than the base case level, while the high oil imports case projects production to be more than 1 million barrels per day lower than the base case--mainly in response to the lower oil prices. Most of the rise in production from the base case to the low imports case is expected in conventional onshore production from the Lower 48 States. A smaller production response in either the higher or lower oil imports cases is anticipated in Alaska and offshore, where longer lead times prevent a quick reaction changing oil prices.

Natural Gas Supply

The total annual U.S. supply of natural gas is expected to increase through the rest of the 1980's, but then remain relatively constant at somewhat more than 19 trillion cubic feet through 1995 (Table 9). The sources of supply are expected to shift during the next 10 years, with Canadian imports increasing from 4 percent of total supply in 1984 to nearly 13 percent in 1995. Canadian gas is assumed to remain competitively priced, resulting in downward pressure on U.S. wellhead prices, which, in turn, is expected to lead to a decline in marketed production of domestically produced natural gas after 1990. The average wellhead price of natural gas is expected to remain stable through 1990 and then increase through 1995. The current gas surplus (with excess deliverability estimated at about 2 to 3 trillion cubic feet in 1985) is expected to disappear over the course of the forecast period.

Natural gas markets are expected to continue the trend toward less Federal and State regulation and greater reliance on market forces to determine prices. The price of natural gas through 1995 will be determined largely by three factors: (1) the cost of new reserve additions, which implies the development of increasingly expensive resources; (2) the volumes and prices of imported natural gas, especially from Canada; and (3) the demand for natural gas by end users. Although gas is being produced from increasingly expensive sources over time, average production costs are expected to stay low enough to permit natural gas to be competitive with oil for most end uses.

Between 1979 and 1984, residential natural gas prices climbed in real terms at an average annual rate of about 9 percent. The reluctance of some end users to accept these price increases brought on the current natural gas surplus. The outlook for the next 10 years shows increased stability in both supply and demand as the natural gas market responds to competitive forces. Evidence of this changing situation includes:

- Lessening of effective controls on natural gas prices under the Natural Gas Policy Act, as the supply of price-controlled "old gas" dwindles. By 1990, approximately 80 percent of gas production is expected to be deregulated natural gas. This share is projected to increase to 90 percent by 1995.

Table 9. Natural Gas Supply, Disposition, and Prices, 1974-1995

Supply, Disposition, and Prices	History		Projections		
	1974	1984	1985	1990	1995
	(Trillion Cubic Feet per Year)				
Production					
Dry Gas Production	20.71	17.39	16.95	17.33	16.50
Supplemental Natural Gasa	0.00	0.11	0.15	0.01	0.44
Net Imports	0.88	0.79	0.94	1.86	2.44
Net Storage Withdrawals	-0.06	-0.21	0.00	0.00	0.00
Total Supply	21.53	18.08	18.04	19.20	19.38
Unaccounted forb	0.31	0.10	0.25	0.49	0.57
	(1985 Dollars per Thousand Cubic Feet)				
Average Wellhead Price	0.60	2.76	2.60	2.68	4.03
Delivered Prices by Sectors					
Residential	2.93	6.37	6.25	6.26	7.71
Commercial	2.16	5.78	5.69	5.64	7.01
Industrial	1.34	4.39	4.36	4.51	5.99
Electric Utilities	1.02	4.31	3.99	3.97	5.11
Average to All Sectors	1.79	5.14	5.01	5.09	6.44

aSupplemental natural gas includes synthetic and propane mixtures and in the forecast includes additional spot market transactions.
bUnaccounted for gas represents accounting discrepancies between producers and consumers.
Source: Table A9 (which contains additional footnotes).

- The changing approaches of public utility commissions and the Federal Energy Regulatory Commission, which tend to allow more flexibility in gas pricing and marketing.
- New policies toward U.S. imports of natural gas (in both the United States and Canada), which are expected to result in a significant expansion of Canadian gas deliveries to this country over the forecast horizon.
- New market institutions, including the development of spot markets and futures markets in gas, which will lead to a more competitive environment.

Canada has moved toward a more market-based pricing strategy for gas, which is projected to permit higher import levels at lower U.S. border prices and to make the domestic market more competitive. The price of Canadian natural gas was reduced sharply to remain competitive in the U.S. market, following a period during which U.S. gas imports declined rapidly after Canada (and Mexico) sought parity between gas and distillate fuel oil prices. Imports of natural gas from Canada are projected to increase at an average annual rate of about 10 percent between 1985 and 1995, to more than 2.4 trillion cubic feet.

Mexican gas imports to the United States ceased on November 1, 1984, by mutual agreement between PEMEX (Mexico's national oil company) and the U.S. pipeline importers. At that time, PEMEX explained that prevailing market conditions--including increased pressure to reduce natural gas prices--made it more efficient to use Mexico's resources of natural gas domestically and to export the residual fuel it replaced. There are no current indications that Mexico will resume deliveries of gas to the U.S. market, given the overall depressed demand for gas in the United States, the availability of gas from Canada at competitive prices, and the overall economic benefit Mexico derives from using natural gas in its domestic market. For these reasons, imports of natural gas from Mexico are assumed to be insignificant over the forecast period, although the resumption of Mexican gas exports becomes a distinct possibility as gas prices gradually rise in the United States while oil prices fall. If U.S. imports from Mexico did begin again, they would have the same effect Canadian supplies have had, namely to restrain U.S. natural gas prices.

The relatively lower prices projected for natural gas in the United States (particularly in the earlier years of the forecast period) reduce the incentives for drilling. Less drilling, in turn, results in reserve discoveries that are insufficient to replace the amount of gas being removed from fields each year. As a result, total U.S. gas reserves are expected to be 30 trillion cubic feet lower in 1995 compared with the 1985 level.

The domestic price of natural gas changes little in either the high or the low oil imports cases, mainly because of counterbalancing factors. These factors are: (1) changes in the demand for natural gas in response to assumptions about the rate of economic growth; (2) changes in the supply of natural gas, because alternative assumptions for oil prices lead to more or less oil production and similar changes in associated gas production; and (3) changes in the fuel mix used (particularly at electric utilities) as the changing price of oil encourages switching between oil and gas. In the low oil imports case, the higher assumed oil price results in increased demand for natural gas (through the substitution effect) and an increased supply of natural gas through more associated production of natural gas. However, the lower economic growth assumption tends to offset some of the demand increase. The net effect is that supply and demand equilibrate near the original point, resulting in very little change in the price of natural gas. In the high oil imports case, the reverse is true but the end result is the same. The net effect of all the different assumptions thus is that natural gas prices vary only slightly in the three cases examined here.

Electric Utilities and Nuclear Supply

Demand for electricity is projected to increase by 2.7 percent per year between 1985 and 1995, close to the rate projected for GNP growth over that period. Although the growth rate in electricity output has slowed considerably since the 1970's, electricity demand still is expected to grow more rapidly than the demand for other energy sources over the forecast period. A technological preference for electricity in most sectors is projected to be reinforced by a decline in the real price of electricity through 1995.

Generating Capability

Largely because of a current excess in electricity production capacity, total generating capability[7] (net of retirements) is projected to increase less rapidly than electricity demand between 1985 and 1995--growing at an average annual rate of about 1.2 percent over that

[7]Capability values published here differ in three respects from the nameplate capacity values published in previous editions of EIA's *Annual Energy Outlook*. First, published capability values describe "net summer capability", the load-carrying ability of a generator under adverse conditions (usually in the summer) for a specified time period; these values are generally about 5 to 7 percent below the nameplate capacity values published in the past. The net summer capability value also includes a small amount of inactive capacity that was formerly excluded. Furthermore, capability values projected here are net of expected retirements, which are expected to total about 15 gigawatts between 1985 and 1995. AEO projections published in earlier years did not reflect these retirements.

period. Total net dependable generating capability in the United States, estimated to be 642 gigawatts in 1985, is projected to increase to 685 gigawatts in 1990 and 727 gigawatts in 1995 (Table 10). Most of this increase is expected to be in new coal capability, with net additions of 39 gigawatts forecast between 1985 and 1995. Significant nuclear capability is projected to be added through 1989, with additions tapering off thereafter through 1995: Net nuclear additions over the next decade are anticipated to total 32 gigawatts, with total nuclear capability equaling 15 percent of total generation capability in 1995. All of the expected nuclear units and the majority of the new coal-fired facilities are already under construction.

Additional new generating capability not currently planned or under construction may be required to meet the level of electricity demand projected nationwide for 1995. Some of this potential shortfall in generating capability may be met by other means, such as conservation, electricity imports, increased bulk transfers of power, load management, cogeneration, or decentralized generation. Projections of the amount of additional capability needed through 1995 range from 13 gigawatts to 25 gigawatts, depending on the level of electricity demand resulting from different assumptions about economic growth and world oil prices. This range of additional generation requirements is based only on the cases contained in this report. Different values assumed for peak demand, reserve margins, or retirement rates could expand this range considerably.

Utility Fuel Use and Imports

Utility fuel use is constrained by fuel economics as well as by the availability of generating capability. Although the vast majority of the oil- and gas-fired capability that was in use during the 1970's still exists, the fuel costs of utilities are lower when coal and nuclear power can be used instead of oil or gas. Because this fuel-cost relationship is not expected to change appreciably, and because the size of the present generating base is so great, the percentage shares of electricity generated by the various fuels are projected to change only slightly over the next 10 years (Figure 14 on page 39 and Table A5). The share of nuclear generation is projected to grow from nearly 16 percent of total generation in 1985 to about 19 percent in 1995, with nuclear output increasing in absolute terms from about 383 billion kilowatthours to about 606 billion kilowatthours. Despite new coal capacity additions, the percentage share of coal generation is forecast to drop from 57 percent in 1985 to 56 percent in 1995 (although the actual contribution from coal over this period is projected to rise from about 1,400 billion kilowatthours to nearly 1,800 billion kilowatthours), because total generation grows more rapidly than coal capability.

Generation from coal and nuclear energy is used (and probably will continue to be used) chiefly to meet baseload electricity demand. Because existing and planned capacity of this type appears to be inadequate to provide all of the additional generation that will be

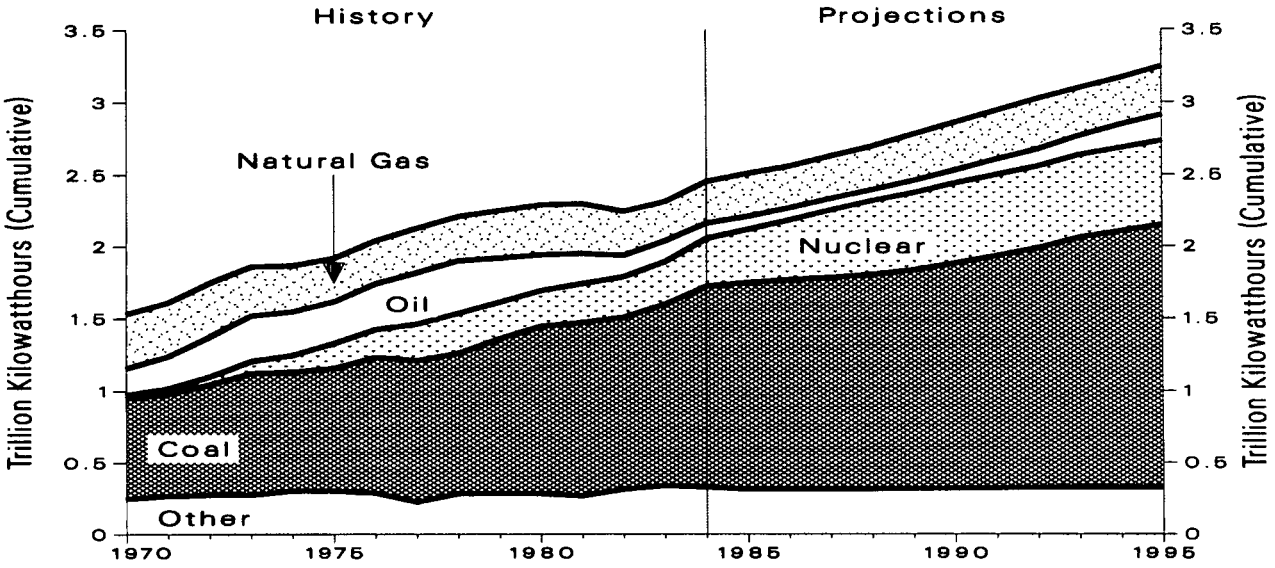
Table 10. Electric Utility Net Generating Capability by Type, 1974-1995
(Gigawatts at End of Year)

	History		Projections		
Capability Type	1974	1984	1985	1990	1995
Coal-Fired	176	275	280	295	319
Nuclear Power	32	70	79	105	111
Oil- and Gas-Fired					
Steam	137	152	145	141	135
Turbine	37	44	43	45	61
Combined Cycle	2	5	5	5	5
Other					
Hydroelectric and Othera	57	72	74	76	77
Hydroelectric, Pumped Storage	9	14	16	18	19
Total	449	631	642	685	727

aIncludes geothermal power, wind, wood, central station solar, and waste.
Note: Components and totals rounded independently. A gigawatt is 1,000 megawatts or 1 billion watts.
Source and additional notes: Table A5.

Figure 14. Sources of Electricity Supply, 1970-1995

Coal and nuclear power are expected to provide most of the increase in electricity generation requirements.



Note: Other consists of hydropower and renewables.

Source: Energy Information Administration, Annual Energy Review, 1984, DOE/EIA-0384(84), (1985).

needed to meet electricity demand growth by 1995, natural gas- and oil-fired generation is also projected to grow during the next decade, particularly after 1990. Generation from the two latter sources combined is projected to increase from 392 billion kilowatthours in 1985 to 501 billion kilowatthours by 1995. All of this increase is expected to occur after 1990, with fairly similar increments in generation projected from gas and oil. However, growth in generation from these sources could be moderated if utilities announce and complete new coal-using facilities between now and 1995. The level of central-station electricity generation by hydroelectric dams and other sources is expected to change only slightly over the forecast period (except for years of unexpected drought or heavy precipitation). "Other sources" include geothermal, wood, waste, wind, photovoltaic, and solar-thermal energy sources connected to electric utility distribution systems. All these sources accounted for less than 1 percent of total central-station generation in 1985, and their combined output is not expected to grow significantly in absolute terms over the next 10 years.

The choice in the use of oil versus and natural gas as the marginal sources of primary fuel inputs to electricity generating systems in this country is highly dependent on the relative prices of natural gas and low-sulfur fuel oil to utilities in certain regions. If crude oil prices should rise significantly, as assumed in the low imports case, utility fuel oil would become relatively more expensive than natural gas, and its share of total generation would fall. Conversely, very low oil prices could conceivably make fuel oil relatively more attractive to some utilities.

Net imports of electricity to the United States have grown steadily over the past 10 years, from about 13 billion kilowatthours (0.1 quadrillion Btu) in 1974 to 39 billion kilowatthours (0.4 quadrillion Btu) in 1984 (about 2 percent of total electricity supply in the latter year). Most of this electricity is purchased from Canada, although a small amount comes from Mexico. This electricity trade is an important source of electricity for certain regions of the country where relatively higher cost oil and gas generation is displaced by relatively cheaper imports. Electricity imports could reach 80 billion kilowatthours (0.8 quadrillion Btu) by 1995 (remaining at about 2 percent of total supply) if all current international trade agreements are maintained and those under consideration become firm.

Cost of Electricity

Reversing the trend of the past 10 years, the average real price of electricity for the nation as a whole is

projected to decline at an average rate of about 0.9 percent per year between 1985 and 1995. The major reason is that, as utility construction programs are completed, the capital-cost portion of the total electricity price is expected to fall after about 1988. Beyond that date, the depreciation of the rate base should more than compensate for the cost of anticipated additions due to new construction (Table 11), because most construction projects now in progress will be completed by 1990, and further additions to capacity for the years after 1990 are likely to be less capital intensive. With less rapid growth in capital stock, the increase in demand over the forecast period substantially reduces the fixed cost per unit. This contributes to the decline in unit capital and operation and maintenance costs and contributes to lower electricity prices. Furthermore, lower interest rates are expected to reduce the cost of electricity, particularly during the second half of the forecast period (Figure ES7 on page 9).

The cost basis of electricity has three major components: capital cost, fuel cost, and the costs of operation and maintenance. The amounts allowed for each of these factors are regulated by State Public Utility Commissions, which also assign a target for the return on investment in approving rate schedules.

The capital-cost component is determined principally by the amount and cost of generating equipment used to produce electricity. This component has received much attention recently because of the very large amounts it has contributed in the case of nuclear generating capability (plants already completed and those expected in the future) being added to the rate base. At the national level, the capital-cost component overall is projected to remain relatively stable through 1988 and then begin to decline as depreciation of the existing rate base exceeds the effects of continuing new capacity additions to the rate base. By 1995, the flow of new additions to the capital stock of utilities is projected to decline. Included in the pre-1995 capacity calculation is an allowance for post-1995 incremental growth in electricity demand. However, only a small portion of the cost of post-1995 capacity additions is included in the 1995 electricity price because the limitations on inclusion of funds used during construction in the rate base.

Fuel cost, the second basic component of electricity cost, is projected to be stable through 1990, but then to increase through 1995 as a result of higher use of relatively expensive oil and natural gas as fuels for electricity generation. Because the operation and maintenance costs of oil- and gas-fired units are lower than those for units using coal, however, this component of electricity cost is expected to decline between 1990 and 1995.

Changes among the three cost components are not expected to offset one another precisely for the nation as a whole, so average real electricity prices will decline over the next 10 years. At the level of individual utilities, however, local differences are to be expected. Some utilities are or will be adding new plants whose individual total cost is of the same magnitude as all of their existing assets. Such sudden expansion of the rate base will raise utility rates sharply at the local level in these areas, although the actual rate changes depend on how State utility commissions treat costs and whether or not an effort is made to gradually phase in the inevitable increases.

Financial conditions for the electric power industry in general are projected to improve between 1985 and 1995. Financial pressures on investor-owned utilities are expected to ease up as capital construction programs are completed. Even if, as seems likely, more construction than currently planned is required to meet demand growth beyond 1995, the impact on average U.S. electricity prices to consumers during the forecast period should be relatively small--because the majority of such additional costs would not be reflected in prices until those new plants are completed and have entered service.

Table 11. Projected Components of Electricity Price, 1985-1995
(1985 Cents per Kilowatthour)

Costs	1985	1990	1995
Capital	2.81	2.75	2.09
Fuel	2.18	2.13	2.41
O&Ma	1.63	1.64	1.57
Total	6.62	6.52	6.07

aOperation and maintenance costs.
Note: Totals may not add due to independent rounding.
Source: Table A7.

Coal Supply

Coal production is projected to increase at an average annual rate of 2.3 percent between 1985 and 1995. This will raise production to about 1.1 billion short tons by 1995, or nearly twice the level of production in 1974, the period of the oil embargo. Anticipated growth in coal demand over the next decade is attributable mainly to the projected growth for coal use by electric utilities. Real minemouth coal prices, which declined at an average annual rate of 1.8 percent between 1974 and 1984, are expected to increase moderately during the forecast period as overcapacity is reduced.

Production

U.S. coal production has generally been demand-limited, and most of the projected increase in production is expected to be in response to rising domestic demand. In this analysis, domestic coal consumption is projected to increase by 73 million short tons (about 1.7 percent per year) between 1985 and 1990, and by about 117 million short tons (about 2.5 percent per year) between 1990 and 1995 (Table 12). The faster increase between 1990 and 1995 is foreseen primarily because the rate of growth in new nuclear capability begins to decline in the nineties and coal-fired generation once again assumes a relatively larger share of increasing electricity demand. By 1995, coal is expected to supply 26 percent of total primary energy demand, up from 24 percent in 1985.

As the primary users of coal, electric utilities account for most of the growth in coal demand foreseen now. With coal-fired generating capability expected to increase by about 39 gigawatts between 1985 and 1995, coal consumption at electric utilities is projected to grow at an average annual rate of 2.4 percent over that period, reaching 882 million short tons in 1995 (Table 12).In comparison, coal use by electric utilities increased by 5.4 percent per year between 1974 and 1984, a decade during which coal-fired generating capability increased by 99 gigawatts.

Consumption of industrial steam coal is projected to remain a minor component of total U.S. coal demand, increasing at an average annual rate of 1.2 percent between 1985 and 1995. Furthermore, domestic consumption of metallurgical coal is expected to decrease slightly over the forecast period, although a wide range of outcomes is possible. The rapid decrease in metallurgical coal use between 1974 and 1984 (a drop of nearly 7 percent per year) is expected to slow substantially in the next decade as domestic steel production stabilizes. 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 from "minimills," which use electric furnaces to produce steel products from scrap.

Significant quantities of coal are not projected to be used for the production of commercially produced synthetic fuels if, as assumed, the Great Plains Gasification Plant in North Dakota is closed. In the event that operations continue, lignite production and consumption each year would be about 5 million tons more than projected between 1985 and 1995.

Coal production from mines east of the Mississippi River is expected to increase at an average annual rate of 1.6 percent between 1985 and 1995, compared to projected growth of 3.6 percent per year for production from western mines. These forecasts represent modifications of the trends experienced between 1974 and 1984 for these two regions, when the respective annual growth rates were 1.3 percent and 12.8 percent.

Table 12. Consumption by Sector, 1974-1995
(Million Short Tons)

	History		Projections		
Consuming Sector	1974	1984	1985	1990	1995
Residential and Commercial	11	9	8	7	7
Industrial	65	74	77	83	87
Coking Plants	90	44	40	37	32
Electric Utilities	392	664	693	764	882
Total Consumption	558	791	818	891	1,008

Source: 1974: Energy Information Administration, Annual Energy Review, 1984, DOE/EIA-0384(84) (Washington, DC, 1985); 1984: Energy Information Administration, Quarterly Coal Report, DOE/EIA-0125(85/2Q) (Washington, DC, October 1985). See Table A10 for additional notes.

Transportation costs essentially divide the United States into two coal markets, east and west of the Mississippi. Eastern production is expected to follow the growth of eastern coal markets, because western coal is not expected to significantly increase its penetration of eastern markets. However, more rapid growth in utility use of coal is expected in the west over the forecast period. For the most part, differences in the fuels expected to be used to generate electricity are dominated by the regional roles of new nuclear capacity and by the substitution of coal for gas. Total electricity generation in the east is projected to increase by 2.4 percent per year between 1985 and 1995, with the share generated by coal falling from 67.3 percent to 61.3 percent over that period. This drop in coal use is expected because more than three-fourths of the nuclear additions scheduled over the next 10 years are located east of the Mississippi River. In contrast, electricity generation in the west is projected to grow by 2.8 percent per year between 1985 and 1995, with the share of coal increasing from 42.9 percent to 47.4 percent of total generation. Part of this increasing coal share is due to shifting from natural gas to coal for new baseload generation in some major western markets such as Texas.

For the Nation as a whole, the share of coal produced from underground mines is projected to increase throughout the forecast period, from 41 percent in 1985 to more than 44 percent in 1995. Between 1974 and 1984, the share of underground production had declined from 46 percent to 41 percent. Growth in production from eastern mines is expected to be primarily from underground mines because limited opportunities for expanded surface mine production are available in the Appalachian region, the expected source of more than three-fourths of projected eastern production. However, nearly all of the growth in production from western mines is expected to be from surface mines, particularly from mines with very thick seams of subbituminous coal in the Powder River Basin of Montana and Wyoming.

Exports

The world market for steam coal is expected to grow considerably over the next 10 years, and the United States is expected to remain a major coal exporter. (Australia, which became the largest coal exporter in 1984, is expected to maintain that position through the forecast period.) The United States is projected to remain the largest metallurgical coal exporter in the world, with sales increasing moderately over the next 10 years, reaching 63 million short tons in 1995.

Total U.S. exports of all types of coal are projected to increase to 104 million short tons by 1995, still below the 1981 record level of 113 million short tons (Table 13). This increase represents an average growth of about 2 percent per year between 1985 and 1995, compared with the 2.9-percent average annual growth experienced over the past decade. The United States is projected to increase its coal exports to southern Europe, North Africa, the Middle East, and the Pacific Rim.

U.S. coal imports represent a very small portion of total U.S. coal consumption, amounting to only a bit more than a million tons annually in recent years. In 1985, however, imports began to increase as a result of stepped-up shipments from Colombia and Canada. The outlook for U.S. coal imports will be discussed in detail in a forthcoming EIA analysis report, mandated by the Energy Policy and Conservation Amendments Act of 1985.

Table 13. U.S. Coal Exports, 1974-1995
(Million Short Tons)

	History		Projections		
	1974	1984	1985	1990	1995
Coal Type					
Steam	9	25	26	31	41
Metallurgical	52	57	59	58	63
Total Exports	61	81	85	89	104

Source: • History: Energy Information Administration, Weekly Coal Production, DOE/EIA-0218(85/41) (Washington, DC, 1985). • Projections: Energy Information Administration, International Coal Trade Model projections.

Because coal production responds to electricity demand, production is projected to be slightly higher in the high oil import case (low oil price, high economic growth) than in the base case, and correspondingly lower in the low oil import case (which makes contrary assumptions). In both instances, economic growth is the prevailing influence. Although there is some potential for substitution between coal and oil in the industrial market, the change in economic growth and its impact on coal demand (including utility use) more than offsets the incentives to switch back and forth between coal and oil in response to changes in the oil price.

Appendix A

Base Case Forecasts

Appendix A

Base Case Forecasts

Table A1. Yearly Supply and Disposition Summary of Total Energy
(Quadrillion Btu per Year)

Total Supply and Disposition	Base Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Crude Oil and Lease Condensate	18.6	18.1	18.4	18.8	18.9	19.0	19.1	18.6	17.8	17.1	13.9
Natural Gas Plant Liquids	2.5	2.3	2.2	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.4
Natural Gas[1]	21.2	20.1	16.7	18.0	17.6	17.8	17.6	17.8	18.0	17.9	17.5
Coal[2]	14.1	17.5	17.3	19.8	19.6	20.1	20.6	20.8	21.2	21.7	24.3
Nuclear Power	1.3	2.8	3.2	3.6	4.2	4.6	5.2	5.6	5.9	6.2	6.6
Hydropower/Other[3]	3.2	3.0	3.6	3.6	3.1	3.4	3.3	3.3	3.4	3.4	3.4
Total Production	**60.8**	**63.8**	**61.3**	**66.2**	**65.8**	**67.2**	**68.3**	**68.7**	**68.9**	**68.8**	**68.3**
Imports											
Crude Oil[4]	7.4	13.8	7.1	7.3	6.5	6.2	7.3	7.9	8.9	9.8	14.1
Petroleum Products[5]	5.7	4.1	3.6	4.2	3.8	4.4	4.1	4.0	3.9	3.8	3.7
Natural Gas[6]	1.0	1.3	.9	.8	1.0	1.0	1.2	1.5	1.6	1.9	2.5
Other Imports[7]	.3	.4	.4	.5	.5	.5	.6	.6	.7	.7	.9
Total Imports	**14.4**	**19.6**	**12.0**	**12.8**	**11.7**	**12.2**	**13.2**	**14.0**	**15.1**	**16.2**	**21.2**
Exports											
Coal	1.6	1.8	2.0	2.2	2.2	2.2	2.3	2.3	2.3	2.4	2.7
Crude Oil and Petroleum Products	.5	1.0	1.6	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Other[8]	.1	.1	.1	.1	NA	NA	NA	NA	NA	NA	NA
Total Exports	**2.2**	**2.9**	**3.7**	**3.8**	**3.8**	**3.7**	**3.8**	**3.8**	**3.8**	**3.9**	**4.3**
Net Stock Withdrawals	**-.3**	**-1.4**	**1.1**	**-1.4**	**.9**	**.1**	**-.2**	**-.1**	**-.1**	**-.2**	**-.2**
Adjustments[9]	-.2	-.2	-.2	.6	.1	.0	-.3	-.4	-.5	-.6	-.7
Consumption											
Petroleum Products[10]	33.5	37.1	30.1	31.1	31.0	31.0	31.5	31.5	31.6	31.6	32.5
Natural Gas	21.7	20.7	17.4	18.5	18.3	18.4	18.4	18.9	19.2	19.3	19.4
Coal	12.7	15.0	15.9	17.2	17.7	17.9	18.3	18.5	18.8	19.3	21.5
Nuclear Power	1.3	2.8	3.2	3.6	4.2	4.6	5.2	5.6	5.9	6.2	6.6
Hydroelectric Power/Other[11]	3.4	3.2	4.0	4.0	3.6	3.8	3.8	3.9	4.0	4.1	4.3
Net Coke Imports	.1	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total Consumption	**72.5**	**78.9**	**70.5**	**74.4**	**74.8**	**75.8**	**77.1**	**78.4**	**79.5**	**80.4**	**84.3**

[1] Net dry marketed production after removal of nonhydrocarbon gases, plus supplemental natural gas.
[2] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite, with anthracite included in bituminous.
[3] 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, and liquefied natural gas imports from Algeria. In the forecast period (1985-1995), gas imports are net imports.
[7] Includes electricity, coal, and coal coke imports.
[8] Includes natural gas, electricity, and coal coke exports. Gas exports are not included in the forecast period (1985-1995).
[9] Balancing item that includes stock changes, 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.
[10] Includes natural gas plant liquids and crude oil consumed as a fuel.
[11] Includes industrial generation of hydroelectric power, net electricity imports, and electricity produced from geothermal, wood, waste, wind, photovoltaic, solar thermal sources connected to electric utility distribution systems.
[NA] = Not available.
Note: Totals may not equal sum of components because of independent rounding.
Sources: Historical quantities are from the Energy Information Administration, *Annual Energy Review, 1984*, DOE/EIA-0384(84) (Washington, DC, 1985), pp. 5-15, Tables 1, 2, 3, and 6. Historical quantities are through 1984. Projected values are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = D1230851, Projected = IFGMMM.D1118851. Table printed on February 3, 1986.

Table A2. Consumption by Major Fuels and End-Use Sectors
(Quadrillion Btu per Year)

Sector and Fuel	Base Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential											
Distillate Fuel	1.84	1.63	1.00	1.06	1.07	1.01	1.05	1.08	1.09	1.10	1.09
Kerosene	.18	.13	.09	.08	.08	.07	.07	.07	.07	.07	.06
Liquefied Petroleum Gas	.55	.35	.35	.37	.33	.34	.36	.37	.38	.37	.35
Natural Gas	4.90	5.05	4.52	4.70	4.65	4.83	4.87	4.92	4.97	5.01	4.99
Steam Coal	.11	.07	.08	.08	.07	.07	.07	.07	.06	.06	.06
Electricity	1.97	2.33	2.56	2.65	2.66	2.80	2.87	2.94	3.01	3.09	3.49
Total	**9.55**	**9.57**	**8.59**	**8.94**	**8.86**	**9.12**	**9.28**	**9.44**	**9.58**	**9.70**	**10.03**
Commercial											
Distillate Fuel	.60	.58	.42	.45	.45	.42	.43	.44	.44	.45	.46
Kerosene	.05	.08	.03	.03	.03	.02	.02	.02	.02	.02	.02
Motor Gasoline	.08	.10	.10	.10	.11	.14	.13	.13	.13	.13	.12
Residual Fuel	.59	.51	.27	.29	.26	.24	.23	.22	.20	.19	.10
Liquefied Petroleum Gas	.10	.06	.06	.06	.07	.07	.07	.07	.07	.06	.06
Natural Gas[1]	2.62	2.84	2.51	2.61	2.58	2.72	2.75	2.77	2.80	2.81	2.79
Steam Coal	.15	.12	.12	.13	.11	.12	.12	.11	.11	.11	.11
Electricity	1.50	1.85	2.12	2.24	2.28	2.37	2.46	2.52	2.61	2.68	3.02
Total	**5.69**	**6.14**	**5.63**	**5.92**	**5.89**	**6.09**	**6.20**	**6.29**	**6.40**	**6.46**	**6.69**
Industrial[2]											
Distillate Fuel	1.35	1.76	1.29	1.36	1.37	1.54	1.59	1.60	1.61	1.62	1.73
Kerosene	.13	.18	.15	.13	.14	.15	.15	.16	.16	.17	.19
Motor Gasoline	.24	.16	.11	.11	.12	.20	.22	.25	.27	.30	.48
Residual Fuel	1.73	1.66	.73	.78	.70	.79	.78	.74	.69	.64	.43
Liquefied Petroleum Gas	1.23	1.71	1.54	1.60	1.67	1.70	1.75	1.77	1.78	1.80	1.90
Petrochemical Feedstocks[3]	.74	1.38	.85	.82	.81	.84	.84	.82	.80	.78	.69
Still Gas Used in Refineries	1.05	1.23	1.13	1.15	1.18	1.18	1.17	1.15	1.14	1.12	1.06
Other Raw Material Oil[4]	2.26	2.51	1.80	2.14	2.09	2.18	2.21	2.24	2.26	2.28	2.29
Natural Gas[5]	10.00	8.55	6.83	7.45	7.41	7.46	7.50	7.82	7.85	7.82	7.25
Steam Coal	1.45	1.52	1.50	1.68	1.75	1.70	1.77	1.83	1.88	1.93	2.03
Metallurgical Coal	2.41	2.06	.99	1.18	1.08	1.07	1.08	1.06	1.03	1.01	.88
Net Coke Imports	.06	.06	-.02	-.01	-.01	-.01	-.01	-.01	-.01	-.01	-.01
Electricity	2.34	2.87	2.65	2.87	2.95	2.87	2.95	3.03	3.14	3.27	3.80
Hydropower	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03
Total	**25.00**	**25.68**	**19.57**	**21.30**	**21.30**	**21.69**	**22.03**	**22.48**	**22.63**	**22.74**	**22.73**
Transportation											
Aviation Gasoline	.08	.07	.05	.04	.06	.06	.06	.06	.06	.07	.07
Distillate Fuel	2.20	2.91	2.92	3.11	3.14	3.09	3.18	3.24	3.32	3.39	3.79
Jet Fuel[6]	2.00	2.19	2.14	2.41	2.40	2.45	2.52	2.55	2.56	2.56	2.50
Motor Gasoline	12.22	13.22	12.48	12.65	12.82	12.63	12.73	12.72	12.71	12.70	12.85
Residual Fuel	.70	1.23	.82	.88	.80	.73	.68	.62	.57	.52	.29
Liquefied Petroleum Gas	.04	.01	.04	.04	.04	.04	.04	.04	.04	.04	.04
Lubricants and Waxes	.16	.19	.16	.17	.19	.20	.20	.20	.21	.21	.21
Natural Gas[7]	.68	.61	.51	.54	.55	.55	.55	.55	.56	.55	.53
Other Transportation[8]	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01
Total	**18.09**	**20.44**	**19.12**	**19.86**	**19.99**	**19.75**	**19.97**	**20.00**	**20.03**	**20.05**	**20.30**
Electric Utilities											
Distillate Fuel	.31	.18	.10	.09	.06	.04	.02	.02	.04	.06	.16
Residual Fuel	3.06	3.11	1.44	1.20	1.02	.92	.96	.94	.99	1.00	1.57
Natural Gas	3.52	3.61	3.00	3.22	3.15	2.79	2.77	2.80	2.97	3.10	3.84
Steam Coal	8.53	11.26	13.21	14.09	14.67	14.98	15.22	15.40	15.69	16.16	18.41
Nuclear Power	1.27	2.78	3.20	3.57	4.18	4.62	5.16	5.64	5.95	6.16	6.64
Hydropower/Other[9]	3.33	3.20	3.97	3.94	3.54	3.82	3.81	3.88	3.98	4.05	4.26
Total	**20.02**	**24.13**	**24.93**	**26.12**	**26.62**	**27.17**	**27.95**	**28.68**	**29.61**	**30.53**	**34.88**
Primary Energy Consumption											
Distillate Fuel	6.30	7.06	5.72	6.07	6.10	6.10	6.26	6.38	6.50	6.60	7.24
Kerosene	.36	.39	.26	.24	.25	.24	.25	.26	.26	.26	.28
Aviation Gasoline	.08	.07	.05	.04	.06	.06	.06	.06	.06	.07	.07
Motor Gasoline	12.53	13.49	12.70	12.87	13.04	12.96	13.09	13.10	13.11	13.13	13.44
Jet Fuel	2.00	2.19	2.14	2.41	2.40	2.45	2.52	2.55	2.56	2.56	2.50
Residual Fuel	6.07	6.49	3.26	3.16	2.79	2.68	2.64	2.51	2.45	2.35	2.39
Liquefied Petroleum Gas	1.91	2.14	1.99	2.07	2.10	2.14	2.21	2.24	2.26	2.28	2.35
Petrochemical Feedstocks	.74	1.38	.85	.82	.81	.84	.84	.82	.80	.78	.69
Still Gas	1.05	1.23	1.13	1.15	1.18	1.18	1.17	1.15	1.14	1.12	1.06
Lubricants and Waxes	.38	.43	.36	.38	.47	.50	.53	.54	.56	.56	.58
Other Petroleum	2.04	2.27	1.60	1.93	1.81	1.87	1.88	1.89	1.91	1.92	1.92
Natural Gas	21.73	20.66	17.35	18.53	18.34	18.35	18.44	18.87	19.15	19.29	19.39
Steam Coal	10.25	12.97	14.91	15.99	16.60	16.86	17.17	17.41	17.74	18.26	20.60
Metallurgical Coal	2.41	2.06	.99	1.18	1.08	1.07	1.08	1.06	1.03	1.01	.88
Net Coke Imports	.06	.06	-.02	-.01	-.01	-.01	-.01	-.01	-.01	-.01	-.01
Nuclear Power	1.27	2.78	3.20	3.57	4.18	4.62	5.16	5.64	5.95	6.16	6.64
Hydropower/Other[9]	3.36	3.23	4.00	3.98	3.57	3.85	3.84	3.91	4.01	4.08	4.29
Total Consumption	**72.55**	**78.90**	**70.49**	**74.37**	**74.77**	**75.77**	**77.14**	**78.39**	**79.48**	**80.43**	**84.30**
Electricity Consumption (all sectors)	**5.82**	**7.07**	**7.34**	**7.77**	**7.91**	**8.05**	**8.28**	**8.50**	**8.77**	**9.04**	**10.33**

See footnotes at end of Appendix C.

Sources: Historical quantities are taken from the Energy Information Administration, *State Energy Data Report, 1960 to 1983*, DOE/EIA-0214(83) (Washington, DC, 1985) and the Energy Information Administration, *Annual Energy Review, 1984*, DOE/EIA-0384(84) (Washington, DC, 1985). Historical quantities are through 1984. Projected quantities are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = D1230851, Projected = IFGMMM.D1118851. Table printed on January 31, 1986.

Table A3. Prices by Major Fuels and End-Use Sectors
(1985 Dollars per Million Btu)

Sector and Fuel	Base Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential	**6.84**	**8.52**	**11.57**	**10.75**	**10.61**	**10.67**	**10.63**	**10.60**	**10.65**	**10.76**	**11.51**
Primary Energy	3.87	5.05	6.90	6.60	6.36	6.23	6.06	6.03	6.15	6.37	7.59
Petroleum Products	5.78	7.32	8.88	8.15	7.50	7.13	6.73	6.74	7.12	7.54	8.16
Distillate Fuel	5.25	6.84	8.32	8.12	7.48	7.12	6.74	6.74	7.12	7.53	8.14
Kerosene	5.90	7.95	10.02	8.48	7.81	7.43	7.03	7.04	7.43	7.86	8.50
Liquefied Petroleum Gas	7.52	9.27	10.17	8.16	7.47	7.08	6.67	6.67	7.08	7.51	8.15
Natural Gas	2.86	4.12	6.33	6.19	6.06	6.03	5.91	5.86	5.91	6.07	7.48
Steam Coal[1]	4.35	3.50	3.18	1.96	1.97	1.99	2.01	2.02	2.03	2.05	2.13
Electricity	18.26	19.31	22.57	20.59	20.50	20.69	20.87	20.75	20.48	20.14	18.85
Commercial	**6.94**	**8.84**	**12.03**	**11.50**	**11.45**	**11.48**	**11.59**	**11.61**	**11.66**	**11.73**	**12.34**
Primary Energy	2.93	4.41	5.92	5.72	5.52	5.43	5.27	5.23	5.34	5.54	6.68
Petroleum Products	4.56	5.91	6.69	6.52	5.98	5.78	5.44	5.45	5.82	6.21	6.89
Distillate Fuel	4.59	6.39	7.27	6.59	5.95	5.59	5.21	5.21	5.59	5.99	6.59
Kerosene	4.36	6.81	7.42	6.71	6.04	5.67	5.27	5.27	5.66	6.09	6.71
Motor Gasoline[2]	8.72	10.05	9.19	9.23	8.52	8.06	7.63	7.63	8.09	8.52	9.29
Residual Fuel	3.86	4.39	4.60	5.36	4.97	4.83	4.64	4.67	4.91	5.21	5.55
Liquefied Petroleum Gas	5.24	5.66	7.31	6.82	6.14	5.75	5.34	5.34	5.75	6.18	6.82
Natural Gas[3]	2.11	3.80	5.85	5.62	5.52	5.47	5.35	5.29	5.33	5.47	6.80
Steam Coal[4]	1.74	1.78	1.86	1.93	1.94	1.95	1.97	1.98	2.00	2.02	2.09
Electricity	18.15	19.11	22.16	21.00	20.82	20.99	21.23	21.12	20.82	20.46	19.21
Industrial	**3.54**	**5.09**	**6.61**	**6.77**	**6.57**	**6.44**	**6.35**	**6.35**	**6.53**	**6.76**	**7.54**
Primary Energy	2.72	3.90	4.91	4.73	4.54	4.46	4.31	4.31	4.51	4.76	5.65
Petroleum Products	4.34	5.41	6.67	6.39	5.99	5.71	5.41	5.46	5.84	6.24	6.93
Distillate Fuel	4.11	5.53	6.68	6.48	5.84	5.48	5.09	5.10	5.47	5.88	6.48
Kerosene	4.38	6.87	7.49	6.92	6.25	5.87	5.47	5.48	5.87	6.30	6.93
Motor Gasoline[2]	8.67	10.01	9.33	9.30	8.62	8.17	7.74	7.74	8.20	8.62	9.40
Residual Fuel	3.68	3.93	4.71	4.58	4.20	4.06	3.87	3.90	4.13	4.43	4.77
Liquefied Petroleum Gas	5.06	5.70	7.16	6.94	6.26	5.87	5.45	5.46	5.86	6.30	6.94
Petrochemical Feedstocks[5]	4.11	5.53	NA	6.35	5.66	5.26	4.86	4.86	5.26	5.68	6.29
Other Petroleum[6]	4.11	5.53	NA	6.29	6.43	6.32	6.19	6.27	6.56	6.84	7.33
Natural Gas[7]	1.31	2.66	4.31	4.29	4.23	4.18	4.11	4.09	4.18	4.38	5.81
Steam Coal	2.27	2.22	1.90	1.78	1.80	1.82	1.84	1.86	1.89	1.91	2.02
Metallurgical Coal	2.74	2.68	2.32	2.18	2.25	2.27	2.28	2.29	2.30	2.32	2.38
Net Coke Imports	NA	NA	NA	4.33	4.44	4.47	4.49	4.51	4.53	4.56	4.66
Electricity	9.98	12.70	15.72	17.43	17.29	17.51	17.72	17.61	17.35	17.02	15.67
Transportation	**7.49**	**8.79**	**8.63**	**8.75**	**8.12**	**7.72**	**7.31**	**7.33**	**7.78**	**8.21**	**9.00**
Primary Energy	7.48	8.79	8.62	8.75	8.12	7.71	7.31	7.32	7.77	8.20	8.99
Petroleum Products	7.48	8.79	8.62	8.75	8.12	7.71	7.31	7.32	7.77	8.20	8.99
Aviation Gasoline	10.55	13.40	17.87	12.14	10.99	10.22	9.49	9.50	10.27	11.00	12.30
Distillate Fuel[8]	5.25	7.08	7.84	8.91	8.28	7.91	7.53	7.53	7.91	8.32	8.92
Jet Fuel[9]	3.36	5.89	7.00	6.54	5.85	5.42	5.03	5.04	5.44	5.88	6.52
Motor Gasoline[2]	8.69	10.00	9.18	9.25	8.57	8.12	7.69	7.69	8.15	8.58	9.35
Residual Fuel[10]	2.84	3.37	5.12	3.87	3.47	3.34	3.15	3.18	3.42	3.72	4.07
Liquefied Petroleum Gas	5.03	5.74	7.33	9.56	8.87	8.49	8.07	8.08	8.48	8.92	9.56
Lubricants and Waxes[11]	17.03	17.83	17.63	23.59	22.49	21.87	21.22	21.22	21.87	22.57	23.59
Electricity	12.97	14.37	17.70	20.24	20.04	20.21	20.47	20.35	20.03	19.65	18.49
Total Energy	**5.79**	**7.37**	**8.87**	**8.73**	**8.39**	**8.22**	**8.05**	**8.05**	**8.29**	**8.56**	**9.34**
Primary Energy -- Four Sectors	4.67	6.06	6.94	6.83	6.45	6.18	5.92	5.90	6.19	6.51	7.45
Electricity	14.90	16.56	20.03	19.54	19.40	19.65	19.86	19.74	19.47	19.11	17.79
Electric Utilities											
Fossil Fuel Average	**1.85**	**2.35**	**2.52**	**2.35**	**2.22**	**2.16**	**2.14**	**2.13**	**2.17**	**2.23**	**2.58**
Petroleum Products	3.80	4.34	6.50	4.78	4.61	4.45	4.25	4.26	4.51	4.85	5.30
Distillate Fuel[12]	4.34	6.25	4.95	6.41	5.79	5.42	5.11	5.14	5.40	5.76	6.32
Residual Fuel	3.75	4.23	6.60	4.66	4.54	4.40	4.23	4.25	4.48	4.80	5.19
Natural Gas	.99	2.47	3.72	4.17	3.87	3.80	3.72	3.62	3.67	3.85	4.96
Steam Coal	1.43	1.73	1.78	1.71	1.68	1.70	1.72	1.72	1.73	1.75	1.83
Average Price to All Users											
Petroleum Products	6.14	7.35	7.98	7.96	7.43	7.05	6.68	6.70	7.11	7.53	8.22
Distillate Fuel[8]	4.91	6.56	7.73	8.02	7.39	6.99	6.61	6.62	7.00	7.41	8.01
Kerosene	5.14	7.23	8.32	7.41	6.75	6.29	5.89	5.88	6.27	6.69	7.25
Aviation Gasoline	10.55	13.40	17.87	12.14	10.99	10.22	9.49	9.50	10.27	11.00	12.30
Motor Gasoline[2]	8.69	10.00	9.18	9.25	8.57	8.12	7.69	7.69	8.15	8.58	9.35
Jet Fuel	3.36	5.89	7.00	6.54	5.85	5.42	5.03	5.04	5.44	5.88	6.52
Residual Fuel	3.63	4.00	4.91	4.48	4.19	4.05	3.88	3.92	4.17	4.50	5.00
Liquefied Petroleum Gas	5.79	6.31	7.71	7.21	6.49	6.10	5.69	5.70	6.11	6.54	7.16
Petrochemical Feedstocks	4.11	5.53	NA	6.35	5.66	5.26	4.86	4.86	5.26	5.68	6.29
Lubricants and Waxes	17.03	17.83	17.63	23.59	22.49	21.87	21.22	21.22	21.87	22.57	23.59
Other Petroleum Products	4.11	5.53	NA	5.77	5.11	5.31	4.52	4.52	4.98	5.17	5.74
Natural Gas	1.76	3.20	5.04	5.00	4.87	4.86	4.77	4.71	4.76	4.94	6.25
Coal	1.80	1.92	1.84	1.76	1.73	1.75	1.76	1.77	1.78	1.80	1.87
Electricity	14.90	16.56	20.03	19.54	19.40	19.65	19.86	19.74	19.47	19.11	17.79

See footnotes at end of Appendix C.

Sources: Historical prices through 1982 are from the Energy Information Administration, *State Energy Price and Expenditure Report*, DOE/EIA-0376(82) (Washington, DC, 1985), pp. 4-21. Prices for 1983 are preliminary. Prices for 1984 are estimated. All other prices are forecasts from the Intermediate Future Forecasting System. Input data file: Historical = D1230851, Projected = IFGMMM.D1118851. Table printed on January 31, 1986.

Table A4. Electric Utility Fuel Consumption and Electricity Sales
(Quadrillion Btu per Year)

Fuel Consumption and Sales	Base Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Fuel Inputs											
Oil											
Distillate	0.31	0.18	0.10	0.09	0.06	0.04	0.02	0.02	0.04	0.06	0.16
Residual	3.06	3.11	1.44	1.20	1.02	.92	.96	.94	.99	1.00	1.57
Natural Gas	3.52	3.61	3.00	3.22	3.15	2.79	2.77	2.80	2.97	3.10	3.84
Steam Coal	8.53	11.26	13.21	14.09	14.67	14.98	15.22	15.40	15.69	16.16	18.41
Nuclear Power	1.27	2.78	3.20	3.57	4.18	4.62	5.16	5.64	5.95	6.16	6.64
Hydropower/Other[1]	3.20	2.99	3.60	3.53	3.11	3.34	3.28	3.30	3.33	3.36	3.42
Total Fuel Inputs	19.89	23.92	24.56	25.70	26.19	26.69	27.42	28.10	28.97	29.84	34.03
Net Imports	.13	.21	.37	.41	.43	.48	.53	.58	.64	.70	.84
Total Electricity Inputs	**20.02**	**24.13**	**24.93**	**26.12**	**26.62**	**27.17**	**27.95**	**28.68**	**29.61**	**30.53**	**34.88**
Disposition											
Total Electricity Inputs	20.02	24.13	24.93	26.12	26.62	27.17	27.95	28.68	29.61	30.53	34.88
Minus Conversion Losses[2]	13.65	16.46	17.05	17.87	18.24	18.63	19.03	19.55	20.20	20.85	23.87
Generation	6.37	7.67	7.88	8.24	8.38	8.54	8.92	9.13	9.41	9.68	11.00
Minus Transportation and Distribution Losses	.55	.60	.54	.47	.48	.49	.64	.63	.63	.64	.68
Electricity Sales	**5.82**	**7.07**	**7.34**	**7.77**	**7.91**	**8.05**	**8.28**	**8.50**	**8.77**	**9.04**	**10.33**
Electricity Sales by End-Use Sector											
Residential	1.97	2.33	2.56	2.65	2.66	2.80	2.87	2.94	3.01	3.09	3.49
Commercial/Other[3]	1.51	1.86	2.13	2.25	2.29	2.38	2.47	2.54	2.63	2.69	3.04
Industrial	2.34	2.87	2.65	2.87	2.95	2.87	2.95	3.03	3.14	3.27	3.80
Total Electricity Sales	**5.82**	**7.07**	**7.34**	**7.77**	**7.91**	**8.05**	**8.28**	**8.50**	**8.77**	**9.04**	**10.33**

[1] Includes renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[2] Conversion losses includes net imports.
[3] Includes street lighting and sales to the transportation end-use sector.
Note: Totals may not equal sum of components because of independent rounding.
Sources: Historical values are obtained or derived from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(85/08), (Washington, DC, 1985), pp. 29 and 77.
Input data file: Historical = D1230851, Projected = IFGMMM.D1118851. Table printed on January 31, 1986.

Table A5. Electric Utility Summer Capability and Generation

(Capability in Million Kilowatts)

(Generation in Billion Kilowatthours per Year)

Summer Capability and Generation	Base Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Capability[1]											
Coal Steam	175.7	225.9	266.1	274.8	280.3	285.8	288.5	292.1	293.7	294.6	318.8
Other Fossil Steam	136.9	154.4	153.8	152.1	145.3	144.5	143.9	142.8	142.1	141.1	135.4
Combined Cycle	2.3	4.8	4.8	4.9	4.5	4.5	4.5	4.5	4.5	4.7	4.8
Turbine/Diesel	36.5	43.6	43.7	43.7	43.2	43.2	43.3	43.6	43.6	44.9	61.1
Nuclear Power[2]	31.6	49.6	63.0	69.7	78.6	91.5	100.3	103.8	105.1	105.1	110.6
Hydropower/Other[3] [4]	56.5	65.9	70.0	71.6	73.6	74.0	74.2	75.1	75.6	76.4	77.1
Pumped Storage Hydropower[4]	9.1	12.9	13.8	14.3	16.4	16.4	16.4	16.6	17.7	18.0	19.0
Total Capability	**448.6**	**557.1**	**615.2**	**631.1**	**641.9**	**660.0**	**671.3**	**678.5**	**682.3**	**684.8**	**726.7**
Generation by Plant Type											
Coal Steam	828	1,075	1,259	1,342	1,417	1,431	1,483	1,501	1,529	1,575	1,796
Other Fossil Steam	580	595	397	393	334	314	319	319	337	345	422
Combined Cycle	5	15	12	15	22	21	22	22	23	24	28
Turbine/Diesel	36	23	10	10	17	5	3	3	6	9	45
Nuclear Power	114	255	294	328	383	424	471	514	543	562	606
Hydropower/Other[3]	304	284	339	330	292	318	325	327	330	333	340
Pumped Storage Hydropower	NA	NA	NA	NA	-8	-10	-10	-10	-11	-11	-12
Total Generation	**1,867**	**2,247**	**2,310**	**2,416**	**2,457**	**2,503**	**2,614**	**2,676**	**2,757**	**2,838**	**3,225**
Generation by Fuel Type											
Coal[5]	828	1,075	1,259	1,342	1,399	1,425	1,478	1,495	1,523	1,569	1,790
Natural Gas	320	329	274	297	293	258	256	258	273	285	340
Oil	301	304	144	120	99	88	94	92	98	101	161
Nuclear Power	114	255	294	328	383	424	471	514	543	562	606
All Hydropower/Other[6]	304	284	339	330	284	308	315	317	320	322	328
Total Generation	**1,867**	**2,247**	**2,310**	**2,416**	**2,457**	**2,503**	**2,614**	**2,676**	**2,757**	**2,838**	**3,225**

[1] Net summer capability is the load carrying ability of a generator under summer (adverse) conditions for a specified time period. Historical values include capability out-of-service; projections exclude this capability.

[2] Nuclear capability is as of the date the unit first delivers power to the grid; all other capability is as of the date the unit begins commercial service.

[3] Includes other renewable sources such as geothermal power, wood, waste, solar energy, and wind; historical pumped storage data for generation are not collected separately and are included among hydropower/other totals.

[4] All pumped storage and conventional hydropower values, both historical and projected, are nameplate capacity, which are approximately 15 to 25 percent lower than net summer capability for hydroelectric units.

[5] Historical values (1974-1984) understate coal steam generation and overstate other steam generation because they attribute small amounts of oil and natural gas used for startup and flame stability in coal steam plants to other steam plant generation.

[6] Includes conventional and pumped storage hydropower and other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

NA = Not available.

Note: Previous editions of the *Annual Energy Outlook* published nameplate capacity rather than net summer capability and did not consider projected retirements. Net summer capability values are generally from 5 to 7 percent below nameplate capacity values; retirements are expected to total about 15 gigawatts between 1985 and 1995.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Generation data for 1974-1984 are from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035 (85/08), Washington, DC, 1985), p. 76, and the Energy Information Administration, Form EIA-759, "Monthly Power Plant Report." Capability values are estimates based on the Energy Information Administration Generating Unit Reference File (GURF), 1983; the Federal Energy Regulatory Commission, *Hydroelectric Power Resources of the United States - Developed and Undeveloped*, FERC-0070 (January 1980); the Energy Information Administration, *U.S. Commercial Nuclear Power*, DOE/EIA-0315 (Washington, DC, March 1982); and Form EIA-254, "Quarterly Progress Report on Status of Reactor Construction." Historical quantities are through 1984.

Input data file: Historical = D1230851, Projected = IFGMMM.D1118851. Table printed on February 5, 1986.

Table A6. Electric Utility Summer Capability Additions
(Thousand Kilowatts)

Additions	Base Case										
	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Total Additions											
Nuclear Power[1]	8,958	12,906	8,826	3,487	1,239	0	0	2,244	0	1,242	2,025
Coal Steam	5,937	5,562	2,753	3,588	1,824	1,422	7,439	3,400	6,342	3,475	4,148
Other Steam[2]	0	0	0	0	0	208	108	0	0	0	0
Turbines[3]	151	131	176	289	80	1,450	1,865	862	3,390	5,105	5,974
Pumped Storage Hydropower	2,100	0	0	200	1,075	285	848	0	0	150	0
Hydropower/Other[4]	1,398	327	278	862	543	803	282	325	4	93	0
Total New Capability	**18,544**	**18,926**	**12,033**	**8,425**	**4,761**	**4,167**	**10,541**	**6,830**	**9,737**	**10,065**	**12,147**
Announced/Planned Construction[5]											
Nuclear Power[1]	8,958	12,906	8,826	3,487	1,239	0	0	2,244	0	1,242	2,025
Coal Steam	5,937	5,562	2,753	3,588	1,824	1,422	7,439	3,400	6,342	3,475	4,148
Other Steam[2]	0	0	0	0	0	208	108	0	0	0	0
Turbines[3]	151	131	176	289	80	800	65	262	90	55	124
Pumped Storage Hydropower	2,100	0	0	200	1,075	285	848	0	0	150	0
Hydropower/Other[4]	1,398	327	278	862	543	803	282	325	4	93	0
Total Announced/Planned	**18,544**	**18,926**	**12,033**	**8,425**	**4,761**	**3,517**	**8,741**	**6,230**	**6,437**	**5,015**	**6,297**
Additional Needed Capability[6]											
Nuclear Power[1]	0	0	0	0	0	0	0	0	0	0	0
Coal Steam	0	0	0	0	0	0	0	0	0	0	0
Other Steam[2]	0	0	0	0	0	0	0	0	0	0	0
Turbines[3]	0	0	0	0	0	650	1,800	600	3,300	5,050	5,850
Pumped Storage Hydropower	0	0	0	0	0	0	0	0	0	0	0
Hydropower/Other[4]	0	0	0	0	0	0	0	0	0	0	0
Total Additional Needed	**0**	**0**	**0**	**0**	**0**	**650**	**1,800**	**600**	**3,300**	**5,050**	**5,850**

[1] Includes the scheduled return to service of the Three Mile Island 1 facility. Nuclear capability is as of the date the unit first delivers power to the grid; all other capability is as of the date the unit begins commercial service.
[2] Includes natural gas, oil, and dual-fired oil/natural gas steam and combined cycle capability.
[3] Includes all gas turbine and internal combustion capability.
[4] Includes conventional hydroelectric and other renewable sources of power such as geothermal, wood, waste, solar, and wind.
[5] Includes all new capability announced by the electric utility industry.
[6] Includes additional new capability considered necessary by the Energy Information Administration to meet electricity demands.
Note: Totals may not equal sum of components because of independent rounding.
Sources: Historical values: The Energy Information Administration Generating Unit Reference File (GURF).
Input data file: Projected = IFGMMM.D1118851. Table printed on January 31, 1986.

Table A7. Electric Utility Sectoral Demands, Prices, and Price Components

(Billion Kilowatthours per Year)

(1985 Dollars per Thousand Kilowatthours)

Demands, Prices and Price Components	Base Case														
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Demands															
Residential	578	683	751	778	780	820	840	860	882	905	928	952	976	1,000	1,022
Commercial[1]	443	546	624	660	673	699	723	744	770	789	809	830	849	868	891
Industrial	685	842	776	841	864	842	864	887	919	957	993	1,026	1,054	1,081	1,113
All Sectors	**1,706**	**2,071**	**2,151**	**2,278**	**2,317**	**2,360**	**2,427**	**2,491**	**2,570**	**2,651**	**2,730**	**2,808**	**2,879**	**2,949**	**3,026**
Prices[2]															
Residential	62.30	65.89	77.01	70.26	69.95	70.59	71.22	70.79	69.87	68.72	67.61	66.83	65.78	65.02	64.31
Commercial[1]	61.79	65.12	75.61	71.63	71.02	71.60	72.42	72.04	71.04	69.80	68.69	67.91	66.88	66.17	65.52
Industrial	34.04	43.32	53.64	59.48	59.04	59.80	60.53	60.11	59.24	58.12	57.01	56.24	55.16	54.29	53.54
All Sectors	**51.05**	**56.70**	**68.34**	**66.68**	**66.19**	**67.04**	**67.77**	**67.36**	**66.42**	**65.21**	**64.07**	**63.28**	**62.22**	**61.42**	**60.70**
Price Components															
Capital Component[3]	NA	NA	NA	NA	28.07	29.18	30.24	30.16	29.04	27.48	26.01	24.75	23.46	22.19	20.89
Fuel Component[4]	NA	NA	NA	NA	21.79	21.15	20.74	20.44	20.77	21.31	21.83	22.45	22.81	23.42	24.12
O&M Component[5]	NA	NA	NA	NA	16.33	16.71	16.79	16.76	16.60	16.41	16.23	16.08	15.95	15.82	15.70
Total Price[6]	**51.05**	**56.70**	**68.34**	**66.68**	**66.19**	**67.04**	**67.77**	**67.36**	**66.42**	**65.21**	**64.07**	**63.28**	**62.22**	**61.42**	**60.70**

[1] Includes consumption for street and highway lighting, other public authorities, and railroads and railways.

[2] Prices for 1985 to 1995 are estimated 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, Form FERC-1-M, and on the Energy Information Administration Form EIA-412.

[3] 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.

[4] The fuel component includes only the direct costs of fuel inputs used to generate electricity required to meet demand.

[5] 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.

[6] 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, Form FERC-1-M, and on the Energy Information Administration Form EIA-412.

NA = Not available.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Prices for 1974 and 1979 are from the Energy Information Administration, *State Energy Price and Expenditure Report*, DOE/EIA-0376(82) (Washington, DC, 1985), pp. 6-7. Prices for 1983 are based on preliminary data. Historical demands are from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(85/07), (Washington, DC, 1985), p. 77. Electricity prices representing both public and private utilities for 1984 are estimates. Projected prices are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = D1230851, Projected = IFGMMM.D1118851. Table printed on February 5, 1986.

Table A8. Petroleum Supply and Disposition Balance
(Million Barrels per Day)

Supply and Disposition	Base Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Crude Oil[1]	8.77	8.55	8.69	8.88	8.92	8.96	9.01	8.78	8.38	8.05	6.53
Alaska	.19	1.40	1.71	1.72	1.80	1.83	1.85	1.74	1.65	1.63	1.30
Lower 48	8.58	7.15	6.97	7.16	7.12	7.14	7.16	7.04	6.73	6.41	5.23
Natural Gas Plant Liquids	1.69	1.58	1.56	1.63	1.63	1.63	1.72	1.74	1.75	1.74	1.69
Other Domestic[2]	.04	.04	.05	.05	.05	.05	.05	.05	.05	.05	.05
Processing Gain[3]	.48	.53	.49	.55	.51	.52	.53	.53	.53	.53	.55
Total Production	**10.98**	**10.71**	**10.79**	**11.11**	**11.11**	**11.16**	**11.31**	**11.10**	**10.71**	**10.37**	**8.82**
Imports (including SPR)											
Crude Oil[4]	3.48	6.52	3.33	3.43	3.06	2.93	3.45	3.71	4.18	4.59	6.64
Refined Products	2.64	1.94	1.72	2.01	1.83	2.13	1.98	1.92	1.89	1.83	1.80
Total Imports	6.11	8.46	5.05	5.44	4.89	5.06	5.43	5.63	6.07	6.43	8.44
Exports											
Crude Oil	.00	.23	.16	.18	.19	.15	.17	.17	.17	.17	.17
Refined Products	.22	.24	.58	.54	.53	.53	.53	.53	.53	.53	.53
Total Exports	.22	.47	.74	.72	.72	.68	.70	.70	.70	.70	.70
Net Imports (including SPR)	**5.89**	**7.99**	**4.31**	**4.72**	**4.17**	**4.38**	**4.73**	**4.93**	**5.36**	**5.72**	**7.74**
Primary Stock Changes											
Net Withdrawals[5]	-.18	-.09	.25	-.08	.32	.02	-.06	-.02	-.02	-.01	-.03
SPR Fill Rate Additions (-)[6]	.00	-.07	-.23	-.20	-.12	.00	.00	.00	.00	.00	.00
Total Primary Supply[7]	**16.69**	**18.54**	**15.12**	**15.54**	**15.49**	**15.56**	**15.97**	**16.01**	**16.06**	**16.08**	**16.53**
Refined Petroleum Products											
Motor Gasoline	6.54	7.03	6.62	6.69	6.80	6.76	6.83	6.83	6.84	6.85	7.01
Aviation Gasoline	.04	.04	.03	.02	.03	.03	.03	.03	.04	.04	.04
Jet Fuel[8]	.99	1.08	1.05	1.18	1.17	1.20	1.23	1.24	1.25	1.25	1.22
Kerosene	.18	.19	.13	.12	.12	.11	.12	.12	.12	.12	.14
Distillate Fuel	2.95	3.31	2.69	2.84	2.86	2.87	2.94	3.00	3.05	3.10	3.40
Residual Fuel	2.64	2.83	1.42	1.36	1.21	1.17	1.15	1.10	1.07	1.02	1.04
Liquid Petroleum Gas	1.41	1.59	1.51	1.57	1.58	1.61	1.66	1.68	1.70	1.71	1.76
Petrochemical Feedstocks	.36	.67	.41	.40	.39	.41	.41	.40	.39	.38	.34
Other Petroleum Products[9]	1.55	1.78	1.40	1.57	1.54	1.58	1.60	1.60	1.61	1.60	1.58
Total Product Supplied	**16.65**	**18.51**	**15.26**	**15.75**	**15.72**	**15.74**	**15.97**	**16.01**	**16.06**	**16.08**	**16.53**
Refined Petroleum Products Supplied to Sectors											
Residential and Commercial	2.04	1.73	1.21	1.27	1.24	1.20	1.23	1.25	1.26	1.25	1.19
Industrial[10]	4.30	5.33	3.94	4.18	4.21	4.41	4.49	4.50	4.50	4.51	4.58
Transportation	8.84	10.00	9.41	9.72	9.82	9.70	9.81	9.83	9.84	9.85	10.00
Electric Utilities	1.48	1.44	.67	.56	.47	.42	.43	.42	.45	.46	.76
Total Consumption	**16.65**	**18.49**	**15.23**	**15.73**	**15.74**	**15.74**	**15.97**	**16.00**	**16.06**	**16.08**	**16.53**
Discrepancy[11]	.04	.05	-.11	-.19	-.25	-.18	.01	.01	.01	.01	.01
Net Disposition[12]	**16.69**	**18.54**	**15.12**	**15.54**	**15.49**	**15.56**	**15.97**	**16.01**	**16.06**	**16.08**	**16.53**

[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 end-of-year stock levels from period t-1 minus the end-of-year 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] Includes naphtha and kerosene type.
[9] Includes miscellaneous petroleum products, lubricants, waxes, unfractionated stream, plant condensate, natural gasoline, asphalt, road oil, still gas, special naphthas, and petroleum coke.
[10] Includes total industrial demand for petroleum.
[11] Represents the difference between total primary supply and total consumption.
[12] Net disposition is the sum of total consumption and discrepancy.

Note: From 1983 onward, the product supplied data and stock data are on a new basis. The other product category is on a net basis, reclassified (petroleum products reprocessed into other categories) plus the other category of products supplied.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Historical data are from the Energy Information Administration, *Annual Energy Review, 1984*, DOE/EIA-0384(84) (Washington, DC, 1985), pp. 89-109, Tables 39, 40, 41, and 49. Historical quantities are through 1984. Projected values are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = D1230851, Projected = IFGMMM.D1118851. Table printed on January 31, 1986.

Table A9. Natural Gas Supply, Disposition, and Prices

(Trillion Cubic Feet per Year)

(1985 Dollars per Thousand Cubic Feet)

Supply, Disposition, and Prices	Base Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Dry Gas Production[1]	20.71	19.66	16.03	17.39	16.95	17.08	17.11	17.29	17.40	17.33	16.50
Supplemental Natural Gas[2]	NA	NA	.13	.11	.15	.15	.00	.00	.06	.01	.44
Net Imports	.88	1.20	.87	.79	.94	1.00	1.19	1.45	1.58	1.86	2.44
Net Storage Withdrawals[3]	-.06	-.29	.44	-.21	.00	-.02	.00	.00	.00	.00	.00
Total Supply[4]	**21.53**	**20.57**	**17.47**	**18.08**	**18.04**	**18.21**	**18.31**	**18.75**	**19.05**	**19.20**	**19.38**
Consumption by Sector[5]											
Residential	4.79	4.97	4.38	4.57	4.51	4.69	4.73	4.78	4.82	4.86	4.84
Commercial[6]	2.56	2.79	2.43	2.54	2.50	2.64	2.67	2.69	2.72	2.73	2.70
Industrial	8.29	6.90	5.64	6.16	6.32	6.36	6.41	6.71	6.73	6.70	6.15
Lease & Plant Fuel[7]	1.48	1.50	.98	1.08	.87	.87	.87	.88	.89	.89	.88
Transportation[8]	.67	.60	.49	.53	.53	.53	.53	.54	.54	.54	.51
Electric Utilities	3.44	3.49	2.91	3.11	3.06	2.71	2.69	2.72	2.88	3.01	3.73
Total Consumption	**21.22**	**20.24**	**16.83**	**17.98**	**17.79**	**17.80**	**17.89**	**18.30**	**18.58**	**18.71**	**18.81**
Unaccounted for[9]	.31	.34	.63	.10	.25	.41	.42	.44	.47	.49	.57
Average Wellhead Price	**.60**	**1.67**	**2.78**	**2.76**	**2.60**	**2.52**	**2.46**	**2.39**	**2.48**	**2.68**	**4.03**
Delivered Prices by Sectors											
Residential	2.93	4.20	6.53	6.37	6.25	6.22	6.09	6.04	6.09	6.26	7.71
Commercial[6]	2.16	3.87	6.03	5.78	5.69	5.64	5.52	5.45	5.49	5.64	7.01
Industrial	1.34	2.71	4.48	4.39	4.36	4.32	4.25	4.22	4.31	4.51	5.99
Electric Utilities	1.02	2.55	3.83	4.31	3.99	3.91	3.83	3.73	3.78	3.97	5.11
Average to All Sectors[10]	**1.79**	**3.27**	**5.19**	**5.14**	**5.01**	**5.01**	**4.91**	**4.85**	**4.91**	**5.09**	**6.44**

[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 end-of-year stock levels from the current period subtracted from the end-of-year 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 sector 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. Weights used are the sectoral consumption values excluding lease and plant fuel and the transportation sector.

NA = Not available.

Note: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1985 equals 1.00. The natural gas prices in this table are average prices, total revenues divided by total sales for each customer class.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Historical data are taken from the Energy Information Administration, *Annual Energy Review, 1984*, DOE/EIA-0384(84) (Washington, DC, 1985) and the Energy Information Administration, *Natural Gas Annual, 1983*, Vol. 1 DOE/EIA-0131(83)/1 (Washington, DC, 1985). Historical quantities are through 1984. Projected values are based on preliminary estimates of 1983 and 1984 prices, and on outputs from the Intermediate Future Forecasting System.

Input data file: Historical = D1230851, Projected = IFGMMM.D1118851. Table printed on February 5, 1986.

Table A10. Coal Supply, Disposition, and Prices

(Million Short Tons per Year)

(1985 Dollars per Short Ton)

Supply, Disposition, and Price	Base Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production[1]											
East of the Mississippi	518	560	507	588	570	582	590	594	600	613	667
West of the Mississippi	92	221	275	308	316	327	339	347	358	372	449
Total	**610**	**781**	**782**	**896**	**886**	**909**	**930**	**940**	**958**	**985**	**1,116**
Imports[2]	2	2	1	1	2	2	2	2	2	2	2
Exports[3]	61	66	78	81	85	85	85	86	87	89	104
Net Imports	**-59**	**-64**	**-77**	**-80**	**-83**	**-83**	**-83**	**-84**	**-85**	**-87**	**-102**
Net Storage Withdrawals[4]	**8**	**-36**	**27**	**-29**	**25**	**5**	**-5**	**-4**	**-5**	**-7**	**-6**
Total Supply[5]	**559**	**681**	**732**	**787**	**828**	**831**	**841**	**853**	**867**	**891**	**1,008**
Consumption by Sector											
Residential and Commercial	11	8	8	9	8	8	7	7	7	7	7
Industrial	65	68	66	74	77	75	76	78	81	83	87
Coking Plants[6]	90	77	37	44	40	40	40	39	38	37	32
Electric Utilities	392	527	625	664	693	711	719	728	742	764	882
Total Consumption	**558**	**681**	**737**	**791**	**818**	**833**	**842**	**853**	**867**	**891**	**1,008**
Discrepancy[7]	1	0	-5	-4	10	-3	(*)	(*)	(*)	(*)	(*)
Average Minemouth Price[8]	**31.82**	**33.66**	**27.95**	**26.55**	**26.63**	**26.88**	**28.13**	**28.17**	**28.25**	**28.42**	**28.93**
Delivered Prices by Sector											
Residential and Commercial[9]	63.82	55.44	43.38	44.45	44.44	44.78	48.69	48.87	49.07	49.33	51.05
Industrial	50.70	49.78	42.27	40.73	40.96	41.41	42.98	43.46	43.98	44.55	47.16
Coking Plants[6]	73.32	71.80	63.78	58.62	60.24	60.71	62.07	62.42	62.86	63.31	65.09
Electric Utilities[10]	31.11	37.05	37.62	36.39	35.65	35.86	36.33	36.44	36.64	36.92	38.24
Average to All Sectors[11]	**40.84**	**42.48**	**39.41**	**38.12**	**37.45**	**37.63**	**38.25**	**38.38**	**38.57**	**38.82**	**39.96**

[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, but are held constant at 2 million short tons per year.

[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 end-of-year stock levels from the current period subtracted from the end-of-year 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, plus losses and unaccounted for coal. 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 (1985-1995) are estimated and do not reflect market conditions.

[9] Projected residential and commercial prices (1983-1995) 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: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1985 equals 1.00. Projected coal prices are based on cost estimates and do not reflect market conditions.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Historical prices through 1982 from the Energy Information Administration, *State Energy Price and Expenditure Report*, DOE/EIA-0376(82) (Washington, DC, 1985), pp. 4-21. Historical quantities through 1982 are from the Energy Information Administration, *Annual Energy Review, 1984*, DOE/EIA-0384(84) (Washington, DC, 1985), pp. 145-153, Tables 65, 66, and 67. Historical 1983 and 1984 quantities and prices (excluding residential and commercial) are from the Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0125(85/2Q) (Washington, DC, October, 1985). Historical quantities are through 1984. Projected values are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = D1230851, Projected = IFGMMM.D1118851. Table printed on January 31, 1986.

Table A11. National Macroeconomic Indicators

Macroeconomic Indicators	Base Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
World Oil Price[1]	25.18	30.70	31.50	29.93	27.00	25.00	23.00	23.00	25.00	27.00	30.00
Economic Variables											
Real GNP (billion 1972 dollars)	1,246	1,479	1,535	1,639	1,677	1,713	1,775	1,828	1,894	1,955	2,215
Real Disposable Income (billion 1972 dollars)	858	1,016	1,096	1,169	1,199	1,225	1,263	1,300	1,345	1,383	1,560
Real Disposable Income per Capita (thousand 1972 dollars)	4.0	4.5	4.7	4.9	5.0	5.1	5.2	5.3	5.4	5.5	6.0
NIPA GNP Price Deflator (1972:1.00)	1.151	1.634	2.153	2.234	2.315	2.395	2.499	2.622	2.749	2.894	3.831
GNP Growth (percent per annum)	0.0	2.8	3.7	6.8	2.3	2.2	3.6	3.0	3.6	3.2	2.4
Unemployment Rate, Civilian Workers (percent)	5.6	5.9	9.6	7.5	7.4	7.6	7.6	7.4	7.2	7.0	7.1
Population, Noninstitutional (million persons)	213.9	225.1	234.0	236.2	238.4	240.5	242.7	244.9	247.0	249.2	259.1
New, High Grade Bond Rate (percent per annum)	8.96	9.86	11.56	12.28	11.07	9.96	10.06	10.31	10.13	9.95	9.85
Home Mortgage Rate (percent per annum)	9.21	11.13	13.35	13.55	12.50	11.42	11.41	11.74	11.52	11.23	10.95
Gross Output - Manufacturing (billion 1972 dollars)	813	929	860	950	960	976	1,019	1,053	1,091	1,127	1,272
Housing Starts (million units)	1.33	1.72	1.70	1.77	1.83	1.91	1.90	1.80	1.81	1.80	1.50
Energy Usage Indicators											
Gross Energy Use per Capita (million Btu per person)	339.2	350.5	301.24	314.9	313.7	315.0	317.8	320.1	321.7	322.7	325.4
Gross Energy Use per Dollar of GNP (thousand Btu per 1972 dollar)	58.2	53.3	45.9	45.4	44.6	44.2	43.5	42.9	42.0	41.1	38.1

[1] The cost of imported crude oil to U.S. refiners in 1985 dollars per barrel.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Historical data are derived from the following sources: Data Resources, Inc., USMODEL database, (September, 1985), the Bureau of Labor Statistics, for the industrial gross output in constant dollars (1984), and the Energy Information Administration, *Annual Energy Review, 1984*, DOE/EIA-0384(84) (Washington, DC, 1985). Historical quantities are through 1984. Projected values are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = D1230851, Projected = IFGMMM.D1118851. Table printed on January 31, 1986.

Appendix B

High Oil Import Case Forecasts

Appendix B

High Oil Import Case Forecasts

Table B1. Yearly Supply and Disposition Summary of Total Energy
(Quadrillion Btu per Year)

Total Supply and Disposition	High Oil Import Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Crude Oil and Lease Condensate	18.6	18.1	18.4	18.8	18.9	18.7	18.7	18.1	17.2	16.1	11.7
Natural Gas Plant Liquids	2.5	2.3	2.2	2.4	2.4	2.4	2.5	2.6	2.6	2.6	2.4
Natural Gas[1]	21.2	20.1	16.7	18.0	17.6	17.9	17.9	18.2	18.2	18.1	17.2
Coal[2]	14.1	17.5	17.3	19.8	19.6	20.3	20.8	21.0	21.4	22.0	24.6
Nuclear Power	1.3	2.8	3.2	3.6	4.2	4.6	5.2	5.6	5.9	6.2	6.6
Hydropower/Other[3]	3.2	3.0	3.6	3.6	3.1	3.4	3.3	3.3	3.4	3.4	3.4
Total Production	**60.8**	**63.8**	**61.3**	**66.2**	**65.8**	**67.3**	**68.4**	**68.8**	**68.7**	**68.3**	**66.0**
Imports											
Crude Oil[4]	7.4	13.8	7.1	7.3	6.5	6.2	8.5	9.2	10.5	11.9	18.2
Petroleum Products[5]	5.7	4.1	3.6	4.2	3.8	4.4	4.0	3.9	3.8	3.7	4.5
Natural Gas[6]	1.0	1.3	.9	.8	1.0	1.0	1.2	1.5	1.6	1.9	2.5
Other Imports[7]	.3	.4	.4	.5	.5	.5	.6	.6	.7	.7	.9
Total Imports	**14.4**	**19.6**	**12.0**	**12.8**	**11.7**	**12.2**	**14.4**	**15.2**	**16.6**	**18.3**	**26.1**
Exports											
Coal	1.6	1.8	2.0	2.2	2.2	2.2	2.3	2.3	2.3	2.4	2.7
Crude Oil and Petroleum Products	.5	1.0	1.6	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Other[8]	.1	.1	.1	.1	NA	NA	NA	NA	NA	NA	NA
Total Exports	**2.2**	**2.9**	**3.7**	**3.8**	**3.8**	**3.7**	**3.8**	**3.8**	**3.8**	**3.9**	**4.3**
Net Stock Withdrawals	**-.3**	**-1.4**	**1.1**	**-1.4**	**.9**	**.1**	**-.2**	**-.1**	**-.2**	**-.2**	**-.2**
Adjustments[9]	-.2	-.2	-.2	.6	.2	.9	-.4	-.4	-.6	-.6	-.8
Consumption											
Petroleum Products[10]	33.5	37.1	30.1	31.1	31.1	31.7	32.2	32.2	32.4	32.7	35.1
Natural Gas	21.7	20.7	17.4	18.5	18.3	18.4	18.7	19.2	19.4	19.5	19.0
Coal	12.7	15.0	15.9	17.2	17.7	18.1	18.5	18.7	19.0	19.5	21.8
Nuclear Power	1.3	2.8	3.2	3.6	4.2	4.6	5.2	5.6	5.9	6.2	6.6
Hydroelectric Power/Other[11]	3.4	3.2	4.0	4.0	3.6	3.9	3.8	3.9	4.0	4.1	4.3
Net Coke Imports	.1	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total Consumption	**72.5**	**78.9**	**70.5**	**74.4**	**74.8**	**76.7**	**78.4**	**79.6**	**80.7**	**81.9**	**86.8**

[1] Net dry marketed production after removal of nonhydrocarbon gases, plus supplemental natural gas.
[2] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite, with anthracite included in bituminous.
[3] 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, and liquefied natural gas imports from Algeria. In the forecast period (1985-1995), gas imports are net imports.
[7] Includes electricity, coal, and coal coke imports.
[8] Includes natural gas, electricity, and coal coke exports. Gas exports are not included in the forecast period (1985-1995).
[9] Balancing item that includes stock changes, 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.
[10] Includes natural gas plant liquids and crude oil consumed as a fuel.
[11] Includes industrial generation of hydroelectric power, net electricity imports, and electricity produced from geothermal, wood, waste, wind, photovoltaic, solar thermal sources connected to electric utility distribution systems.
NA = Not available.
Note: Totals may not equal sum of components because of independent rounding.
Sources: Historical quantities are from the Energy Information Administration, *Annual Energy Review, 1984*, DOE/EIA-0384(84) (Washington, DC, 1985), pp. 5-15, Tables 1, 2, 3, and 6. Historical quantities are through 1984. Projected values are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = D1230851, Projected = IFGMLH.D1118851. Table printed on February 3, 1986.

Table B2. Consumption by Major Fuels and End-Use Sectors
(Quadrillion Btu per Year)

Sector and Fuel	High Oil Import Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential											
Distillate Fuel	1.84	1.63	1.00	1.06	1.07	1.03	1.08	1.12	1.15	1.16	1.20
Kerosene	.18	.13	.09	.08	.08	.07	.07	.07	.07	.07	.07
Liquefied Petroleum Gas	.55	.35	.35	.37	.33	.34	.36	.37	.38	.38	.37
Natural Gas	4.90	5.05	4.52	4.70	4.65	4.84	4.89	4.96	5.01	5.05	5.00
Steam Coal	.11	.07	.08	.08	.07	.07	.07	.07	.06	.06	.06
Electricity	1.97	2.33	2.56	2.65	2.66	2.80	2.87	2.95	3.02	3.11	3.55
Total	**9.55**	**9.57**	**8.59**	**8.94**	**8.87**	**9.15**	**9.34**	**9.53**	**9.70**	**9.84**	**10.24**
Commercial											
Distillate Fuel	.60	.58	.42	.45	.45	.42	.43	.45	.46	.46	.49
Kerosene	.05	.08	.03	.03	.03	.02	.02	.02	.02	.03	.03
Motor Gasoline	.08	.10	.10	.10	.11	.14	.13	.13	.13	.13	.12
Residual Fuel	.59	.51	.27	.29	.26	.24	.21	.19	.17	.16	.11
Liquefied Petroleum Gas	.10	.06	.06	.06	.07	.07	.07	.07	.07	.06	.06
Natural Gas[1]	2.62	2.84	2.51	2.61	2.58	2.74	2.77	2.79	2.82	2.84	2.81
Steam Coal	.15	.12	.12	.13	.11	.12	.12	.11	.11	.11	.11
Electricity	1.50	1.85	2.12	2.24	2.28	2.39	2.48	2.55	2.63	2.70	3.07
Total	**5.69**	**6.14**	**5.63**	**5.92**	**5.89**	**6.14**	**6.24**	**6.31**	**6.41**	**6.49**	**6.80**
Industrial[2]											
Distillate Fuel	1.35	1.76	1.29	1.36	1.39	1.63	1.67	1.68	1.70	1.72	1.84
Kerosene	.13	.18	.15	.13	.14	.16	.16	.17	.18	.18	.21
Motor Gasoline	.24	.16	.11	.11	.12	.20	.23	.26	.29	.32	.51
Residual Fuel	1.73	1.66	.73	.78	.71	.84	.75	.68	.62	.58	.46
Liquefied Petroleum Gas	1.23	1.71	1.54	1.60	1.68	1.74	1.79	1.81	1.82	1.85	1.96
Petrochemical Feedstocks[3]	.74	1.38	.85	.82	.81	.85	.85	.83	.81	.80	.71
Still Gas Used in Refineries	1.05	1.23	1.13	1.15	1.18	1.18	1.17	1.16	1.15	1.14	1.09
Other Raw Material Oil[4]	2.26	2.51	1.80	2.14	2.09	2.19	2.26	2.28	2.31	2.34	2.39
Natural Gas[5]	10.00	8.55	6.83	7.45	7.39	7.47	7.64	8.00	7.95	7.91	7.33
Steam Coal	1.45	1.52	1.50	1.68	1.75	1.71	1.78	1.85	1.91	1.96	2.10
Metallurgical Coal	2.41	2.06	.99	1.18	1.08	1.10	1.13	1.10	1.07	1.04	.92
Net Coke Imports	.06	.06	-.02	-.01	-.01	-.01	-.01	-.01	-.01	-.01	-.01
Electricity	2.34	2.87	2.65	2.87	2.95	2.90	3.00	3.08	3.20	3.34	3.92
Hydropower	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03
Total	**25.00**	**25.68**	**19.57**	**21.30**	**21.30**	**21.97**	**22.46**	**22.92**	**23.04**	**23.20**	**23.47**
Transportation											
Aviation Gasoline	.08	.07	.05	.04	.06	.06	.06	.06	.07	.07	.07
Distillate Fuel	2.20	2.91	2.92	3.11	3.14	3.12	3.24	3.31	3.38	3.46	3.91
Jet Fuel[6]	2.00	2.19	2.14	2.41	2.41	2.53	2.64	2.68	2.71	2.75	2.73
Motor Gasoline	12.22	13.22	12.48	12.65	12.87	12.98	13.10	13.08	13.10	13.14	13.42
Residual Fuel	.70	1.23	.82	.88	.80	.73	.61	.52	.46	.41	.27
Liquefied Petroleum Gas	.04	.01	.04	.04	.04	.04	.04	.04	.04	.04	.04
Lubricants and Waxes	.16	.19	.16	.17	.19	.20	.20	.21	.21	.21	.22
Natural Gas[7]	.68	.61	.51	.54	.55	.55	.55	.56	.56	.56	.51
Other Transportation[8]	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01
Total	**18.09**	**20.44**	**19.12**	**19.86**	**20.06**	**20.23**	**20.46**	**20.48**	**20.55**	**20.64**	**21.20**
Electric Utilities											
Distillate Fuel	.31	.18	.10	.09	.07	.05	.04	.03	.05	.06	.31
Residual Fuel	3.06	3.11	1.44	1.20	1.01	.92	1.01	1.00	1.08	1.15	2.47
Natural Gas	3.52	3.61	3.00	3.22	3.15	2.82	2.86	2.89	3.03	3.19	3.38
Steam Coal	8.53	11.26	13.21	14.09	14.67	15.12	15.36	15.54	15.83	16.33	18.61
Nuclear Power	1.27	2.78	3.20	3.57	4.18	4.62	5.16	5.64	5.95	6.16	6.64
Hydropower/Other[9]	3.33	3.20	3.97	3.94	3.54	3.84	3.81	3.88	3.98	4.05	4.26
Total	**20.02**	**24.13**	**24.93**	**26.12**	**26.62**	**27.37**	**28.23**	**28.97**	**29.92**	**30.94**	**35.67**
Primary Energy Consumption											
Distillate Fuel	6.30	7.06	5.72	6.07	6.13	6.25	6.46	6.58	6.74	6.88	7.75
Kerosene	.36	.39	.26	.24	.25	.25	.26	.27	.27	.28	.31
Aviation Gasoline	.08	.07	.05	.04	.06	.06	.06	.06	.07	.07	.07
Motor Gasoline	12.53	13.49	12.70	12.87	13.10	13.32	13.46	13.47	13.52	13.58	14.05
Jet Fuel	2.00	2.19	2.14	2.41	2.41	2.53	2.64	2.68	2.71	2.75	2.73
Residual Fuel	6.07	6.49	3.26	3.16	2.78	2.73	2.59	2.39	2.33	2.29	3.32
Liquefied Petroleum Gas	1.91	2.14	1.99	2.07	2.11	2.18	2.26	2.28	2.31	2.34	2.44
Petrochemical Feedstocks	.74	1.38	.85	.82	.81	.85	.85	.83	.81	.80	.71
Still Gas	1.05	1.23	1.13	1.15	1.18	1.18	1.17	1.16	1.15	1.14	1.09
Lubricants and Waxes	.38	.43	.36	.38	.47	.52	.55	.57	.58	.59	.62
Other Petroleum	2.04	2.27	1.60	1.93	1.80	1.87	1.91	1.92	1.94	1.96	1.99
Natural Gas	21.73	20.66	17.35	18.53	18.32	18.42	18.71	19.20	19.37	19.54	19.03
Steam Coal	10.25	12.97	14.91	15.99	16.60	17.01	17.32	17.57	17.92	18.47	20.87
Metallurgical Coal	2.41	2.06	.99	1.18	1.08	1.10	1.13	1.10	1.07	1.04	.92
Net Coke Imports	.06	.06	-.02	-.01	-.01	-.01	-.01	-.01	-.01	-.01	-.01
Nuclear Power	1.27	2.78	3.20	3.57	4.18	4.62	5.16	5.64	5.95	6.16	6.64
Hydropower/Other[9]	3.36	3.23	4.00	3.98	3.57	3.87	3.84	3.91	4.01	4.08	4.29
Total Consumption	**72.55**	**78.90**	**70.49**	**74.37**	**74.84**	**76.75**	**78.37**	**79.62**	**80.74**	**81.95**	**86.82**
Electricity Consumption (all sectors)	**5.82**	**7.07**	**7.34**	**7.77**	**7.90**	**8.10**	**8.37**	**8.59**	**8.86**	**9.17**	**10.55**

See footnotes at end of Appendix C.

Sources: Historical quantities are taken from the Energy Information Administration, *State Energy Data Report, 1960 to 1983*, DOE/EIA-0214(83) (Washington, DC, 1985) and the Energy Information Administration, *Annual Energy Review, 1984*, DOE/EIA-0384(84) (Washington, DC, 1985). Historical quantities are through 1984. Projected quantities are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = D1230851, Projected = IFGMLH.D1118851. Table printed on January 31, 1986.

Table B3. Prices by Major Fuels and End-Use Sectors
(1985 Dollars per Million Btu)

Sector and Fuel	High Oil Import Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential	**6.84**	**8.52**	**11.57**	**10.75**	**10.58**	**10.53**	**10.46**	**10.40**	**10.46**	**10.56**	**11.44**
Primary Energy	3.87	5.05	6.90	6.60	6.32	6.05	5.85	5.79	5.94	6.16	7.48
Petroleum Products	5.78	7.32	8.88	8.15	7.31	6.38	6.18	6.18	6.38	6.61	7.23
Distillate Fuel	5.25	6.84	8.32	8.12	7.30	6.38	6.19	6.19	6.39	6.61	7.24
Kerosene	5.90	7.95	10.02	8.48	7.62	6.66	6.46	6.47	6.67	6.91	7.55
Liquefied Petroleum Gas	7.52	9.27	10.17	8.16	7.28	6.30	6.08	6.09	6.30	6.53	7.17
Natural Gas	2.86	4.12	6.33	6.19	6.06	6.00	5.80	5.72	5.85	6.06	7.62
Steam Coal[1]	4.35	3.50	3.18	1.96	1.97	1.99	2.01	2.02	2.04	2.05	2.14
Electricity	18.26	19.31	22.57	20.59	20.53	20.70	20.85	20.69	20.44	20.11	18.92
Commercial	**6.94**	**8.84**	**12.03**	**11.50**	**11.44**	**11.39**	**11.49**	**11.48**	**11.56**	**11.62**	**12.32**
Primary Energy	2.93	4.41	5.92	5.72	5.48	5.25	5.08	5.01	5.15	5.35	6.60
Petroleum Products	4.56	5.91	6.69	6.52	5.82	5.11	4.95	4.96	5.16	5.37	5.99
Distillate Fuel	4.59	6.39	7.27	6.59	5.77	4.85	4.66	4.66	4.86	5.08	5.68
Kerosene	4.36	6.81	7.42	6.71	5.85	4.90	4.69	4.70	4.90	5.13	5.77
Motor Gasoline[2]	8.72	10.05	9.19	9.23	8.30	7.17	6.97	6.98	7.21	7.43	8.26
Residual Fuel	3.86	4.39	4.60	5.36	4.87	4.44	4.35	4.38	4.51	4.70	5.07
Liquefied Petroleum Gas	5.24	5.66	7.31	6.82	5.94	4.96	4.75	4.76	4.97	5.20	5.85
Natural Gas[3]	2.11	3.80	5.85	5.62	5.52	5.44	5.25	5.15	5.28	5.48	6.95
Steam Coal[4]	1.74	1.78	1.86	1.93	1.94	1.96	1.97	1.99	2.00	2.02	2.10
Electricity	18.15	19.11	22.16	21.00	20.84	20.99	21.20	21.05	20.77	20.42	19.27
Industrial	**3.54**	**5.09**	**6.61**	**6.77**	**6.52**	**6.18**	**6.13**	**6.11**	**6.28**	**6.47**	**7.30**
Primary Energy	2.72	3.90	4.91	4.73	4.48	4.17	4.06	4.05	4.22	4.42	5.33
Petroleum Products	4.34	5.41	6.67	6.39	5.83	5.06	4.96	5.00	5.22	5.45	6.13
Distillate Fuel	4.11	5.53	6.68	6.48	5.66	4.74	4.55	4.55	4.75	4.97	5.57
Kerosene	4.38	6.87	7.49	6.92	6.06	5.11	4.90	4.91	5.11	5.34	5.98
Motor Gasoline[2]	8.67	10.01	9.33	9.30	8.39	7.29	7.09	7.09	7.32	7.54	8.36
Residual Fuel	3.68	3.93	4.71	4.58	4.10	3.67	3.57	3.60	3.74	3.92	4.29
Liquefied Petroleum Gas	5.06	5.70	7.16	6.94	6.06	5.08	4.87	4.87	5.08	5.32	5.97
Petrochemical Feedstocks[5]	4.11	5.53	NA	6.35	5.47	4.50	4.29	4.29	4.50	4.72	5.35
Other Petroleum[6]	4.11	5.53	NA	6.29	6.32	5.91	5.94	6.00	6.17	6.34	6.86
Natural Gas[7]	1.31	2.66	4.31	4.29	4.22	4.15	3.99	3.92	4.12	4.37	5.92
Steam Coal	2.27	2.22	1.90	1.78	1.80	1.82	1.85	1.87	1.89	1.92	2.03
Metallurgical Coal	2.74	2.68	2.32	2.18	2.25	2.27	2.28	2.30	2.31	2.32	2.39
Net Coke Imports	NA	NA	NA	4.33	4.44	4.47	4.50	4.52	4.54	4.57	4.67
Electricity	9.98	12.70	15.72	17.43	17.32	17.52	17.70	17.56	17.32	17.00	15.77
Transportation	**7.49**	**8.79**	**8.63**	**8.75**	**7.92**	**6.89**	**6.71**	**6.73**	**6.96**	**7.19**	**7.99**
Primary Energy	7.48	8.79	8.62	8.75	7.91	6.88	6.70	6.72	6.96	7.19	7.98
Petroleum Products	7.48	8.79	8.62	8.75	7.91	6.88	6.70	6.72	6.96	7.19	7.98
Aviation Gasoline	10.55	13.40	17.87	12.14	10.61	8.73	8.39	8.40	8.80	9.16	10.55
Distillate Fuel[8]	5.25	7.08	7.84	8.91	8.09	7.18	6.98	6.99	7.18	7.40	8.01
Jet Fuel[9]	3.36	5.89	7.00	6.54	5.65	4.65	4.46	4.47	4.68	4.92	5.58
Motor Gasoline[2]	8.69	10.00	9.18	9.25	8.35	7.24	7.04	7.04	7.28	7.49	8.31
Residual Fuel[10]	2.84	3.37	5.12	3.87	3.38	2.95	2.86	2.88	3.02	3.21	3.58
Liquefied Petroleum Gas	5.03	5.74	7.33	9.56	8.68	7.70	7.49	7.49	7.70	7.94	8.59
Lubricants and Waxes[11]	17.03	17.83	17.63	23.59	22.18	20.61	20.28	20.29	20.62	21.00	22.04
Electricity	12.97	14.37	17.70	20.24	20.06	20.20	20.42	20.27	19.97	19.60	18.52
Total Energy	**5.79**	**7.37**	**8.87**	**8.73**	**8.29**	**7.78**	**7.70**	**7.68**	**7.86**	**8.04**	**8.87**
Primary Energy -- Four Sectors	4.67	6.06	6.94	6.83	6.32	5.69	5.53	5.51	5.70	5.92	6.89
Electricity	14.90	16.56	20.03	19.54	19.43	19.65	19.83	19.68	19.42	19.07	17.86
Electric Utilities											
Fossil Fuel Average	**1.85**	**2.35**	**2.52**	**2.35**	**2.21**	**2.13**	**2.11**	**2.10**	**2.15**	**2.22**	**2.59**
Petroleum Products	3.80	4.34	6.50	4.78	4.52	4.05	3.95	3.97	4.11	4.31	4.95
Distillate Fuel[12]	4.34	6.25	4.95	6.41	5.59	4.68	4.49	4.50	4.63	4.83	5.40
Residual Fuel	3.75	4.23	6.60	4.66	4.45	4.02	3.93	3.96	4.08	4.29	4.90
Natural Gas	.99	2.47	3.72	4.17	3.86	3.75	3.57	3.47	3.62	3.82	4.77
Steam Coal	1.43	1.73	1.78	1.71	1.68	1.70	1.72	1.72	1.73	1.75	1.84
Average Price to All Users											
Petroleum Products	6.14	7.35	7.98	7.96	7.24	6.28	6.12	6.15	6.37	6.59	7.23
Distillate Fuel[8]	4.91	6.56	7.73	8.02	7.20	6.24	6.05	6.06	6.26	6.48	7.06
Kerosene	5.14	7.23	8.32	7.41	6.55	5.52	5.31	5.30	5.50	5.72	6.30
Aviation Gasoline	10.55	13.40	17.87	12.14	10.61	8.73	8.39	8.40	8.80	9.16	10.55
Motor Gasoline[2]	8.69	10.00	9.18	9.25	8.35	7.24	7.04	7.04	7.28	7.49	8.31
Jet Fuel	3.36	5.89	7.00	6.54	5.65	4.65	4.46	4.47	4.68	4.92	5.58
Residual Fuel	3.63	4.00	4.91	4.48	4.09	3.66	3.61	3.66	3.82	4.04	4.72
Liquefied Petroleum Gas	5.79	6.31	7.71	7.21	6.29	5.31	5.10	5.11	5.33	5.56	6.20
Petrochemical Feedstocks	4.11	5.53	NA	6.35	5.47	4.50	4.29	4.29	4.50	4.72	5.35
Lubricants and Waxes	17.03	17.83	17.63	23.59	22.18	20.61	20.28	20.29	20.62	21.00	22.04
Other Petroleum Products	4.11	5.53	NA	5.77	4.91	4.19	4.00	4.00	4.18	4.40	4.82
Natural Gas	1.76	3.20	5.04	5.00	4.86	4.82	4.64	4.54	4.70	4.92	6.34
Coal	1.80	1.92	1.84	1.76	1.73	1.75	1.77	1.77	1.79	1.80	1.88
Electricity	14.90	16.56	20.03	19.54	19.43	19.65	19.83	19.68	19.42	19.07	17.86

See footnotes at end of Appendix C.

Sources: Historical prices through 1982 are from the Energy Information Administration, *State Energy Price and Expenditure Report*, DOE/EIA-0376(82) (Washington, DC, 1985), pp. 4-21. Prices for 1983 are preliminary. Prices for 1984 are estimated. All other prices are forecasts from the Intermediate Future Forecasting System. Input data file: Historical = D1230851, Projected = IFGMLH.D1118851. Table printed on January 31, 1986.

Table B4. Electric Utility Fuel Consumption and Electricity Sales
(Quadrillion Btu per Year)

Fuel Consumption and Sales	High Oil Import Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Fuel Inputs											
Oil											
Distillate	0.31	0.18	0.10	0.09	0.07	0.05	0.04	0.03	0.05	0.06	0.31
Residual	3.06	3.11	1.44	1.20	1.01	.92	1.01	1.00	1.08	1.15	2.47
Natural Gas	3.52	3.61	3.00	3.22	3.15	2.82	2.86	2.89	3.03	3.19	3.38
Steam Coal	8.53	11.26	13.21	14.09	14.67	15.12	15.36	15.54	15.83	16.33	18.61
Nuclear Power	1.27	2.78	3.20	3.57	4.18	4.62	5.16	5.64	5.95	6.16	6.64
Hydropower/Other[1]	3.20	2.99	3.60	3.53	3.11	3.36	3.28	3.30	3.33	3.36	3.42
Total Fuel Inputs	19.89	23.92	24.56	25.70	26.19	26.89	27.71	28.39	29.28	30.24	34.83
Net Imports	.13	.21	.37	.41	.43	.48	.53	.58	.64	.70	.84
Total Electricity Inputs	**20.02**	**24.13**	**24.93**	**26.12**	**26.62**	**27.37**	**28.23**	**28.97**	**29.92**	**30.94**	**35.67**
Disposition											
Total Electricity Inputs	20.02	24.13	24.93	26.12	26.62	27.37	28.23	28.97	29.92	30.94	35.67
Minus Conversion Losses[2]	13.65	16.46	17.05	17.87	18.24	18.77	19.22	19.75	20.41	21.13	24.42
Generation	6.37	7.67	7.88	8.24	8.38	8.60	9.01	9.22	9.51	9.81	11.25
Minus Transportation and Distribution Losses	.55	.60	.54	.47	.48	.49	.64	.64	.64	.65	.69
Electricity Sales	**5.82**	**7.07**	**7.34**	**7.77**	**7.90**	**8.10**	**8.37**	**8.59**	**8.86**	**9.17**	**10.55**
Electricity Sales by End-Use Sector											
Residential	1.97	2.33	2.56	2.65	2.66	2.80	2.87	2.95	3.02	3.11	3.55
Commercial/Other[3]	1.51	1.86	2.13	2.25	2.29	2.41	2.50	2.56	2.64	2.71	3.08
Industrial	2.34	2.87	2.65	2.87	2.95	2.90	3.00	3.08	3.20	3.34	3.92
Total Electricity Sales	**5.82**	**7.07**	**7.34**	**7.77**	**7.90**	**8.10**	**8.37**	**8.59**	**8.86**	**9.17**	**10.55**

[1] Includes renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[2] Conversion losses includes net imports.
[3] Includes street lighting and sales to the transportation end-use sector.
Note: Totals may not equal sum of components because of independent rounding.
Sources: Historical values are obtained or derived from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(85/08), (Washington, DC, 1985), pp. 29 and 77.
Input data file: Historical = D1230851, Projected = IFGMLH.D1118851. Table printed on January 31, 1986.

Table B5. Electric Utility Summer Capability and Generation

(Capability in Million Kilowatts)

(Generation in Billion Kilowatthours per Year)

Summer Capability and Generation	High Oil Import Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Capability[1]											
Coal Steam	175.7	225.9	266.1	274.8	280.3	285.8	288.5	292.1	293.7	294.6	318.8
Other Fossil Steam	136.9	154.4	153.8	152.1	145.3	144.5	143.9	142.8	142.1	141.1	135.4
Combined Cycle	2.3	4.8	4.8	4.9	4.5	4.5	4.5	4.5	4.5	4.7	4.8
Turbine/Diesel	36.5	43.6	43.7	43.7	43.2	43.2	43.3	43.6	43.8	45.7	69.2
Nuclear Power[2]	31.6	49.6	63.0	69.7	78.6	91.5	100.3	103.8	105.1	105.1	110.6
Hydropower/Other[3] [4]	56.5	65.9	70.0	71.6	73.6	74.0	74.2	75.1	75.6	76.4	77.1
Pumped Storage Hydropower[4]	9.1	12.9	13.8	14.3	16.4	16.4	16.4	16.6	17.7	18.0	19.0
Total Capability	**448.6**	**557.1**	**615.2**	**631.1**	**641.9**	**660.0**	**671.3**	**678.5**	**682.6**	**685.6**	**734.8**
Generation by Plant Type											
Coal Steam	828	1,075	1,259	1,342	1,417	1,440	1,497	1,514	1,543	1,591	1,816
Other Fossil Steam	580	595	397	393	334	320	331	331	350	364	455
Combined Cycle	5	15	12	15	22	21	22	23	23	25	26
Turbine/Diesel	36	23	10	10	17	6	4	4	7	12	66
Nuclear Power	114	255	294	328	383	424	471	514	543	562	606
Hydropower/Other[3]	304	284	339	330	292	318	325	327	330	333	340
Pumped Storage Hydropower	NA	NA	NA	NA	-8	-10	-10	-10	-11	-11	-12
Total Generation	**1,867**	**2,247**	**2,310**	**2,416**	**2,457**	**2,519**	**2,640**	**2,703**	**2,786**	**2,876**	**3,296**
Generation by Fuel Type											
Coal[5]	828	1,075	1,259	1,342	1,399	1,439	1,491	1,508	1,537	1,585	1,809
Natural Gas	320	329	274	297	293	261	263	266	278	291	294
Oil	301	304	144	120	99	89	100	98	108	115	259
Nuclear Power	114	255	294	328	383	424	471	514	543	562	606
All Hydropower/Other[6]	304	284	339	330	284	308	315	317	320	322	328
Total Generation	**1,867**	**2,247**	**2,310**	**2,416**	**2,457**	**2,520**	**2,640**	**2,703**	**2,786**	**2,876**	**3,296**

[1] Net summer capability is the load carrying ability of a generator under summer (adverse) conditions for a specified time period. Historical values include capability out-of-service; projections exclude this capability.

[2] Nuclear capability is as of the date the unit first delivers power to the grid; all other capability is as of the date the unit begins commercial service.

[3] Includes other renewable sources such as geothermal power, wood, waste, solar energy, and wind; historical pumped storage data for generation are not collected separately and are included among hydropower/other totals.

[4] All pumped storage and conventional hydropower values, both historical and projected, are nameplate capacity, which are approximately 15 to 25 percent lower than net summer capability for hydroelectric units.

[5] Historical values (1974-1984) understate coal steam generation and overstate other steam generation because they attribute small amounts of oil and natural gas used for startup and flame stability in coal steam plants to other steam plant generation.

[6] Includes conventional and pumped storage hydropower and other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

NA = Not available.

Note: Previous editions of the *Annual Energy Outlook* published nameplate capacity rather than net summer capability and did not consider projected retirements. Net summer capability values are generally from 5 to 7 percent below nameplate capacity values; retirements are expected to total about 15 gigawatts between 1985 and 1995.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Generation data for 1974-1984 are from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035 (85/08), Washington, DC, 1985), p. 76, and the Energy Information Administration, Form EIA-759, "Monthly Power Plant Report." Capability values are estimates based on the Energy Information Administration Generating Unit Reference File (GURF), 1983; the Federal Energy Regulatory Commission, *Hydroelectric Power Resources of the United States - Developed and Undeveloped*, FERC-0070 (January 1980); the Energy Information Administration, *U.S. Commercial Nuclear Power*, DOE/EIA-0315 (Washington, DC, March 1982); and Form EIA-254, "Quarterly Progress Report on Status of Reactor Construction." Historical quantities are through 1984.

Input data file: Historical = D1230851, Projected = IFGMLH.D1118851. Table printed on February 5, 1986.

Table B6. Electric Utility Summer Capability Additions
(Thousand Kilowatts)

Additions	High Oil Import Case										
	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Total Additions											
Nuclear Power[1]	8,958	12,906	8,826	3,487	1,239	0	0	2,244	0	1,242	2,025
Coal Steam	5,937	5,562	2,753	3,588	1,824	1,422	7,439	3,400	6,342	3,475	4,148
Other Steam[2]	0	0	0	0	0	208	108	0	0	0	0
Turbines[3]	151	131	176	289	330	2,000	2,415	1,862	5,190	6,505	8,525
Pumped Storage Hydropower	2,100	0	0	200	1,075	285	848	0	0	150	0
Hydropower/Other[4]	1,398	327	278	862	543	803	282	325	4	93	0
Total New Capability	**18,544**	**18,926**	**12,033**	**8,425**	**5,011**	**4,718**	**11,091**	**7,830**	**11,537**	**11,465**	**14,698**
Announced/Planned Construction[5]											
Nuclear Power[1]	8,958	12,906	8,826	3,487	1,239	0	0	2,244	0	1,242	2,025
Coal Steam	5,937	5,562	2,753	3,588	1,824	1,422	7,439	3,400	6,342	3,475	4,148
Other Steam[2]	0	0	0	0	0	208	108	0	0	0	0
Turbines[3]	151	131	176	289	80	800	65	262	90	55	124
Pumped Storage Hydropower	2,100	0	0	200	1,075	285	848	0	0	150	0
Hydropower/Other[4]	1,398	327	278	862	543	803	282	325	4	93	0
Total Announced/Planned	**18,544**	**18,926**	**12,033**	**8,425**	**4,761**	**3,517**	**8,741**	**6,230**	**6,437**	**5,015**	**6,297**
Additional Needed Capability[6]											
Nuclear Power[1]	0	0	0	0	0	0	0	0	0	0	0
Coal Steam	0	0	0	0	0	0	0	0	0	0	0
Other Steam[2]	0	0	0	0	0	0	0	0	0	0	0
Turbines[3]	0	0	0	0	250	1,200	2,350	1,600	5,100	6,450	8,400
Pumped Storage Hydropower	0	0	0	0	0	0	0	0	0	0	0
Hydropower/Other[4]	0	0	0	0	0	0	0	0	0	0	0
Total Additional Needed	**0**	**0**	**0**	**0**	**250**	**1,200**	**2,350**	**1,600**	**5,100**	**6,450**	**8,400**

[1] Includes the scheduled return to service of the Three Mile Island 1 facility. Nuclear capability is as of the date the unit first delivers power to the grid; all other capability is as of the date the unit begins commercial service.
[2] Includes natural gas, oil, and dual-fired oil/natural gas steam and combined cycle capability.
[3] Includes all gas turbine and internal combustion capability.
[4] Includes conventional hydroelectric and other renewable sources of power such as geothermal, wood, waste, solar, and wind.
[5] Includes all new capability announced by the electric utility industry.
[6] Includes additional new capability considered necessary by the Energy Information Administration to meet electricity demands.
Note: Totals may not equal sum of components because of independent rounding.
Sources: Historical values: The Energy Information Administration Generating Unit Reference File (GURF).
Input data file: Projected = IFGMLH.D1118851. Table printed on January 31, 1986.

Table B7. Electric Utility Sectoral Demands, Prices, and Price Components

(Billion Kilowatthours per Year)

(1985 Dollars per Thousand Kilowatthours)

Demands, Prices and Price Components	High Oil Import Case														
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Demands															
Residential	578	683	751	778	780	820	842	864	886	911	937	963	989	1,015	1,040
Commercial[1]	443	546	624	660	673	705	732	750	774	796	817	840	860	881	904
Industrial	685	842	776	841	864	850	879	903	938	980	1,019	1,055	1,084	1,115	1,150
All Sectors	**1,706**	**2,071**	**2,151**	**2,278**	**2,316**	**2,375**	**2,453**	**2,517**	**2,598**	**2,686**	**2,773**	**2,858**	**2,933**	**3,011**	**3,093**
Prices[2]															
Residential	62.30	65.89	77.01	70.26	70.05	70.61	71.14	70.60	69.73	68.60	67.55	66.80	66.07	65.22	64.56
Commercial[1]	61.79	65.12	75.61	71.63	71.10	71.60	72.33	71.83	70.87	69.65	68.61	67.84	67.16	66.33	65.74
Industrial	34.04	43.32	53.64	59.48	59.15	59.84	60.45	59.94	59.14	58.05	57.00	56.27	55.51	54.58	53.90
All Sectors	**51.05**	**56.70**	**68.34**	**66.68**	**66.29**	**67.05**	**67.66**	**67.14**	**66.25**	**65.06**	**63.98**	**63.22**	**62.48**	**61.60**	**60.94**
Price Components															
Capital Component[3]	NA	NA	NA	NA	28.08	29.25	30.19	30.03	28.90	27.34	25.86	24.63	23.42	22.23	20.99
Fuel Component[4]	NA	NA	NA	NA	21.71	20.99	20.61	20.29	20.69	21.28	21.89	22.51	23.12	23.58	24.28
O&M Component[5]	NA	NA	NA	NA	16.50	16.82	16.86	16.83	16.66	16.45	16.24	16.07	15.94	15.80	15.67
Total Price[6]	**51.05**	**56.70**	**68.34**	**66.68**	**66.29**	**67.05**	**67.66**	**67.14**	**66.25**	**65.06**	**63.98**	**63.22**	**62.48**	**61.60**	**60.94**

[1] Includes consumption for street and highway lighting, other public authorities, and railroads and railways.

[2] Prices for 1985 to 1995 are estimated 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, Form FERC-1-M, and on the Energy Information Administration Form EIA-412.

[3] 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.

[4] The fuel component includes only the direct costs of fuel inputs used to generate electricity required to meet demand.

[5] 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.

[6] 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, Form FERC-1-M, and on the Energy Information Administration Form EIA-412.

NA = Not available.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Prices for 1974 and 1979 are from the Energy Information Administration, *State Energy Price and Expenditure Report*, DOE/EIA-0376(82) (Washington, DC, 1985), pp. 6-7. Prices for 1983 are based on preliminary data. Historical demands are from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(85/07), (Washington, DC, 1985), p. 77. Electricity prices representing both public and private utilities for 1984 are estimates. Projected prices are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = D1230851, Projected = IFGMLH.D1118851. Table printed on February 5, 1986.

Table B8. Petroleum Supply and Disposition Balance
(Million Barrels per Day)

Supply and Disposition	High Oil Import Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Crude Oil[1]	8.77	8.55	8.69	8.88	8.92	8.84	8.81	8.56	8.07	7.58	5.46
Alaska	.19	1.40	1.71	1.72	1.80	1.83	1.84	1.74	1.65	1.52	1.24
Lower 48	8.58	7.15	6.97	7.16	7.12	7.02	6.97	6.82	6.42	6.06	4.22
Natural Gas Plant Liquids	1.69	1.58	1.56	1.63	1.63	1.63	1.75	1.77	1.78	1.76	1.67
Other Domestic[2]	.04	.04	.05	.05	.05	.05	.05	.05	.05	.05	.05
Processing Gain[3]	.48	.53	.49	.55	.51	.52	.54	.54	.54	.55	.59
Total Production	**10.98**	**10.71**	**10.79**	**11.11**	**11.11**	**11.04**	**11.16**	**10.92**	**10.44**	**9.94**	**7.77**
Imports (including SPR)											
Crude Oil[4]	3.48	6.52	3.33	3.43	3.06	2.93	4.02	4.31	4.94	5.59	8.56
Refined Products	2.64	1.94	1.72	2.01	1.83	2.13	1.96	1.87	1.84	1.81	2.19
Total Imports	6.11	8.46	5.05	5.44	4.89	5.06	5.97	6.17	6.78	7.40	10.74
Exports											
Crude Oil	.00	.23	.16	.18	.19	.15	.17	.17	.17	.17	.17
Refined Products	.22	.24	.58	.54	.53	.53	.53	.53	.53	.53	.53
Total Exports	.22	.47	.74	.72	.72	.68	.70	.70	.70	.70	.70
Net Imports (including SPR)	**5.89**	**7.99**	**4.31**	**4.72**	**4.17**	**4.38**	**5.27**	**5.47**	**6.08**	**6.70**	**10.04**
Primary Stock Changes											
Net Withdrawals[5]	-.18	-.09	.25	-.08	.32	.02	-.07	-.01	-.03	-.03	-.04
SPR Fill Rate Additions (-)[6]	.00	-.07	-.23	-.20	-.12	.00	.00	.00	.00	.00	.00
Total Primary Supply[7]	**16.69**	**18.54**	**15.12**	**15.54**	**15.49**	**15.44**	**16.36**	**16.37**	**16.49**	**16.61**	**17.77**
Refined Petroleum Products											
Motor Gasoline	6.54	7.03	6.62	6.69	6.83	6.95	7.02	7.03	7.05	7.08	7.33
Aviation Gasoline	.04	.04	.03	.02	.03	.03	.03	.04	.04	.04	.04
Jet Fuel[8]	.99	1.08	1.05	1.18	1.18	1.24	1.29	1.31	1.33	1.34	1.33
Kerosene	.18	.19	.13	.12	.12	.12	.12	.13	.13	.13	.15
Distillate Fuel	2.95	3.31	2.69	2.84	2.88	2.94	3.03	3.09	3.16	3.23	3.64
Residual Fuel	2.64	2.83	1.42	1.36	1.21	1.19	1.13	1.04	1.02	1.00	1.45
Liquid Petroleum Gas	1.41	1.59	1.51	1.57	1.59	1.64	1.70	1.72	1.74	1.76	1.84
Petrochemical Feedstocks	.36	.67	.41	.40	.39	.41	.41	.40	.40	.39	.35
Other Petroleum Products[9]	1.55	1.78	1.40	1.57	1.54	1.59	1.62	1.62	1.63	1.64	1.65
Total Product Supplied	**16.65**	**18.51**	**15.26**	**15.75**	**15.77**	**16.11**	**16.36**	**16.37**	**16.49**	**16.61**	**17.77**
Refined Petroleum Products Supplied to Sectors											
Residential and Commercial	2.04	1.73	1.21	1.27	1.24	1.22	1.24	1.27	1.28	1.29	1.28
Industrial[10]	4.30	5.33	3.94	4.18	4.22	4.51	4.59	4.58	4.60	4.63	4.80
Transportation	8.84	10.00	9.41	9.72	9.86	9.94	10.06	10.07	10.11	10.16	10.46
Electric Utilities	1.48	1.44	.67	.56	.47	.42	.46	.45	.49	.53	1.22
Total Consumption	**16.65**	**18.49**	**15.23**	**15.73**	**15.79**	**16.10**	**16.35**	**16.37**	**16.48**	**16.61**	**17.76**
Discrepancy[11]	.04	.05	-.11	-.19	-.30	-.66	.01	.01	.01	.01	.00
Net Disposition[12]	**16.69**	**18.54**	**15.12**	**15.54**	**15.49**	**15.44**	**16.36**	**16.37**	**16.49**	**16.61**	**17.77**

[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 end-of-year stock levels from period t-1 minus the end-of-year 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] Includes naphtha and kerosene type.

[9] Includes miscellaneous petroleum products, lubricants, waxes, unfractionated stream, plant condensate, natural gasoline, asphalt, road oil, still gas, special naphthas, and petroleum coke.

[10] Includes total industrial demand for petroleum.

[11] Represents the difference between total primary supply and total consumption.

[12] Net disposition is the sum of total consumption and discrepancy.

Note: From 1983 onward, the product supplied data and stock data are on a new basis. The other product category is on a net basis, reclassified (petroleum products reprocessed into other categories) plus the other category of products supplied.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Historical data are from the Energy Information Administration, *Annual Energy Review, 1984*, DOE/EIA-0384(84) (Washington, DC, 1985), pp. 89-109, Tables 39, 40, 41, and 49. Historical quantities are through 1984. Projected values are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = D1230851, Projected = IFGMLH.D1118851. Table printed on January 31, 1986.

Table B9. Natural Gas Supply, Disposition, and Prices

(Trillion Cubic Feet per Year)

(1985 Dollars per Thousand Cubic Feet)

Supply, Disposition, and Prices	High Oil Import Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Dry Gas Production[1]	20.71	19.66	16.03	17.39	16.95	17.19	17.36	17.56	17.56	17.51	16.08
Supplemental Natural Gas[2]	NA	NA	.13	.11	.15	.15	.02	.04	.13	.02	.61
Net Imports	.88	1.20	.87	.79	.94	1.00	1.20	1.48	1.58	1.90	2.44
Net Storage Withdrawals[3]	-.06	-.29	.44	-.21	.00	-.02	.00	.00	.00	.00	.00
Total Supply[4]	**21.53**	**20.57**	**17.47**	**18.08**	**18.04**	**18.32**	**18.58**	**19.09**	**19.27**	**19.43**	**19.13**
Consumption by Sector[5]											
Residential	4.79	4.97	4.38	4.57	4.51	4.69	4.74	4.81	4.86	4.90	4.85
Commercial[6]	2.56	2.79	2.43	2.54	2.50	2.66	2.69	2.71	2.74	2.75	2.73
Industrial	8.29	6.90	5.64	6.16	6.30	6.38	6.53	6.87	6.82	6.78	6.24
Lease & Plant Fuel[7]	1.48	1.50	.98	1.08	.87	.87	.88	.89	.89	.89	.87
Transportation[8]	.67	.60	.49	.53	.53	.54	.54	.54	.54	.54	.50
Electric Utilities	3.44	3.49	2.91	3.11	3.06	2.73	2.77	2.81	2.94	3.09	3.28
Total Consumption	**21.22**	**20.24**	**16.83**	**17.98**	**17.77**	**17.87**	**18.15**	**18.63**	**18.79**	**18.95**	**18.46**
Unaccounted for[9]	.31	.34	.63	.10	.27	.45	.43	.46	.47	.48	.66
Average Wellhead Price	**.60**	**1.67**	**2.78**	**2.76**	**2.60**	**2.50**	**2.33**	**2.24**	**2.44**	**2.68**	**4.12**
Delivered Prices by Sectors											
Residential	2.93	4.20	6.53	6.37	6.25	6.19	5.98	5.90	6.03	6.25	7.85
Commercial[6]	2.16	3.87	6.03	5.78	5.69	5.61	5.41	5.31	5.44	5.65	7.17
Industrial	1.34	2.71	4.48	4.39	4.35	4.28	4.12	4.05	4.24	4.50	6.10
Electric Utilities	1.02	2.55	3.83	4.31	3.98	3.86	3.67	3.57	3.72	3.94	4.91
Average to All Sectors[10]	**1.79**	**3.27**	**5.19**	**5.14**	**5.01**	**4.97**	**4.78**	**4.69**	**4.85**	**5.07**	**6.54**

[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 end-of-year stock levels from the current period subtracted from the end-of-year 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 sector 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. Weights used are the sectoral consumption values excluding lease and plant fuel and the transportation sector.

NA = Not available.

Note: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1985 equals 1.00. The natural gas prices in this table are average prices, total revenues divided by total sales for each customer class.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Historical data are taken from the Energy Information Administration, *Annual Energy Review, 1984*, DOE/EIA-0384(84) (Washington, DC, 1985) and the Energy Information Administration, *Natural Gas Annual, 1983*, Vol. 1 DOE/EIA-0131(83)/1 (Washington, DC, 1985). Historical quantities are through 1984. Projected values are based on preliminary estimates of 1983 and 1984 prices, and on outputs from the Intermediate Future Forecasting System.

Input data file: Historical = D1230851, Projected = IFGMLH.D1118851. Table printed on February 5, 1986.

Table B10. Coal Supply, Disposition, and Prices

(Million Short Tons per Year)

(1985 Dollars per Short Ton)

Supply, Disposition, and Price	High Oil Import Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production[1]											
East of the Mississippi	518	560	507	588	570	588	597	600	607	621	677
West of the Mississippi	92	221	275	308	316	329	342	349	360	375	452
Total	**610**	**781**	**782**	**896**	**886**	**917**	**939**	**949**	**967**	**996**	**1,129**
Imports[2]	2	2	1	1	2	2	2	2	2	2	2
Exports[3]	61	66	78	81	85	85	85	86	87	89	104
Net Imports	**-59**	**-64**	**-77**	**-80**	**-83**	**-83**	**-83**	**-84**	**-85**	**-87**	**-102**
Net Storage Withdrawals[4]	**8**	**-36**	**27**	**-29**	**25**	**5**	**-5**	**-4**	**-5**	**-7**	**-6**
Total Supply[5]	**559**	**681**	**732**	**787**	**828**	**839**	**850**	**861**	**877**	**902**	**1,021**
Consumption by Sector											
Residential and Commercial	11	8	8	9	8	7	7	7	7	7	7
Industrial	65	68	66	74	77	75	77	80	82	84	90
Coking Plants[6]	90	77	37	44	40	41	41	41	39	38	34
Electric Utilities	392	527	625	664	693	718	725	734	748	772	891
Total Consumption	**558**	**681**	**737**	**791**	**818**	**842**	**850**	**861**	**877**	**902**	**1,021**
Discrepancy[7]	1	0	-5	-4	10	-3	(*)	(*)	(*)	(*)	(*)
Average Minemouth Price[8]	**31.82**	**33.66**	**27.95**	**26.55**	**26.63**	**26.92**	**28.20**	**28.24**	**28.32**	**28.49**	**29.02**
Delivered Prices by Sector											
Residential and Commercial[9]	63.82	55.44	43.40	44.45	44.45	44.84	48.70	48.89	49.09	49.40	51.15
Industrial	50.70	49.78	42.27	40.73	40.97	41.47	43.05	43.55	44.09	44.68	47.36
Coking Plants[6]	73.32	71.80	63.78	58.62	60.24	60.81	62.19	62.55	63.01	63.42	65.25
Electric Utilities[10]	31.11	37.05	37.62	36.39	35.65	35.89	36.38	36.50	36.71	37.00	38.34
Average to All Sectors[11]	**40.84**	**42.48**	**39.41**	**38.12**	**37.45**	**37.69**	**38.35**	**38.48**	**38.68**	**38.93**	**40.10**

[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, but are held constant at 2 million short tons per year.

[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 end-of-year stock levels from the current period subtracted from the end-of-year 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, plus losses and unaccounted for coal. 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 (1985-1995) are estimated and do not reflect market conditions.

[9] Projected residential and commercial prices (1983-1995) 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: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1985 equals 1.00. Projected coal prices are based on cost estimates and do not reflect market conditions.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Historical prices through 1982 from the Energy Information Administration, *State Energy Price and Expenditure Report*, DOE/EIA-0376(82) (Washington, DC, 1985), pp. 4-21. Historical quantities through 1982 are from the Energy Information Administration, *Annual Energy Review, 1984*, DOE/EIA-0384(84) (Washington, DC, 1985), pp. 145-153, Tables 65, 66, and 67. Historical 1983 and 1984 quantities and prices (excluding residential and commercial) are from the Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0125(85/2Q) (Washington, DC, October, 1985). Historical quantities are through 1984. Projected values are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = D1230851, Projected = IFGMLH.D1118851. Table printed on January 31, 1986.

Table B11. National Macroeconomic Indicators

Macroeconomic Indicators	High Oil Import Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
World Oil Price[1]	**25.18**	**30.70**	**31.50**	**29.93**	**26.00**	**21.00**	**20.00**	**20.00**	**21.00**	**22.00**	**25.00**
Economic Variables											
Real GNP (billion 1972 dollars)	1,246	1,479	1,535	1,639	1,677	1,730	1,807	1,864	1,933	2,001	2,295
Real Disposable Income (billion 1972 dollars)	858	1,016	1,096	1,169	1,199	1,234	1,279	1,317	1,360	1,401	1,596
Real Disposable Income per Capita (thousand 1972 dollars)	4.0	4.5	4.7	4.9	5.0	5.1	5.3	5.4	5.5	5.6	6.2
NIPA GNP Price Deflator (1972:1.00)	1.151	1.634	2.153	2.234	2.315	2.381	2.471	2.581	2.687	2.806	3.574
GNP Growth (percent per annum)	0.0	2.8	3.7	6.8	2.3	3.2	4.5	3.2	3.7	3.5	2.6
Unemployment Rate, Civilian Workers (percent)	5.6	5.9	9.6	7.5	7.4	7.4	7.1	6.9	6.8	6.7	6.9
Population, Noninstitutional (million persons)	213.9	225.1	234.0	236.2	238.4	240.5	242.7	244.9	247.0	249.2	259.1
New, High Grade Bond Rate (percent per annum)	8.96	9.86	11.56	12.28	11.07	9.58	9.53	9.39	8.83	8.61	8.58
Home Mortgage Rate (percent per annum)	9.21	11.13	13.35	13.55	12.50	11.06	10.89	10.85	10.20	9.86	9.65
Gross Output - Manufacturing (billion 1972 dollars)	813	929	860	950	960	993	1,049	1,085	1,124	1,163	1,325
Housing Starts (million units)	1.33	1.72	1.70	1.77	1.83	1.97	1.98	1.90	1.94	1.94	1.63
Energy Usage Indicators											
Gross Energy Use per Capita (million Btu per person)	339.2	350.5	301.24	314.9	314.0	319.1	322.9	325.2	326.8	328.8	335.1
Gross Energy Use per Dollar of GNP (thousand Btu per 1972 dollar)	58.2	53.3	45.9	45.4	44.6	44.4	43.4	42.7	41.8	41.0	37.8

[1] The cost of imported crude oil to U.S. refiners in 1985 dollars per barrel.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Historical data are derived from the following sources: Data Resources, Inc., USMODEL database, (September, 1985), the Bureau of Labor Statistics, for the industrial gross output in constant dollars (1984), and the Energy Information Administration, *Annual Energy Review, 1984*, DOE/EIA-0384(84) (Washington, DC, 1985). Historical quantities are through 1984. Projected values are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = D1230851, Projected = IFGMLH.D1118851. Table printed on January 31, 1986.

Appendix C

Low Oil Import Case Forecasts

Appendix C

Low Oil Import Case Forecasts

Table C1. Yearly Supply and Disposition Summary of Total Energy
(Quadrillion Btu per Year)

Total Supply and Disposition	Low Oil Import Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Crude Oil and Lease Condensate	18.6	18.1	18.4	18.8	18.9	19.2	19.4	19.1	18.6	18.0	15.7
Natural Gas Plant Liquids	2.5	2.3	2.2	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.4
Natural Gas[1]	21.2	20.1	16.7	18.0	17.6	17.6	17.6	17.8	17.9	17.7	17.2
Coal[2]	14.1	17.5	17.3	19.8	19.6	19.8	20.4	20.6	21.0	21.5	24.0
Nuclear Power	1.3	2.8	3.2	3.6	4.2	4.6	5.2	5.6	5.9	6.2	6.6
Hydropower/Other[3]	3.2	3.0	3.6	3.6	3.1	3.4	3.3	3.3	3.4	3.4	3.4
Total Production	**60.8**	**63.8**	**61.3**	**66.2**	**65.8**	**67.0**	**68.4**	**68.9**	**69.4**	**69.3**	**69.3**
Imports											
Crude Oil[4]	7.4	13.8	7.1	7.3	6.5	6.2	6.1	6.3	7.0	8.0	10.8
Petroleum Products[5]	5.7	4.1	3.6	4.2	3.8	4.4	3.7	3.5	3.5	3.4	3.5
Natural Gas[6]	1.0	1.3	.9	.8	1.0	1.0	1.2	1.5	1.6	1.9	2.5
Other Imports[7]	.3	.4	.4	.5	.5	.5	.6	.6	.7	.7	.9
Total Imports	**14.4**	**19.6**	**12.0**	**12.8**	**11.7**	**12.2**	**11.6**	**11.9**	**12.8**	**14.0**	**17.7**
Exports											
Coal	1.6	1.8	2.0	2.2	2.2	2.2	2.3	2.3	2.3	2.4	2.7
Crude Oil and Petroleum Products	.5	1.0	1.6	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Other[8]	.1	.1	.1	.1	NA	NA	NA	NA	NA	NA	NA
Total Exports	**2.2**	**2.9**	**3.7**	**3.8**	**3.8**	**3.7**	**3.8**	**3.8**	**3.8**	**3.9**	**4.3**
Net Stock Withdrawals	**-.3**	**-1.4**	**1.1**	**-1.4**	**.9**	**.1**	**-.2**	**-.1**	**-.1**	**-.2**	**-.1**
Adjustments[9]	-.2	-.2	-.2	.6	.1	-.8	-.3	-.4	-.5	-.6	-.8
Consumption											
Petroleum Products[10]	33.5	37.1	30.1	31.1	31.0	30.4	30.2	30.0	30.1	30.2	30.7
Natural Gas	21.7	20.7	17.4	18.5	18.3	18.2	18.4	18.8	19.1	19.2	19.1
Coal	12.7	15.0	15.9	17.2	17.7	17.6	18.1	18.3	18.6	19.1	21.1
Nuclear Power	1.3	2.8	3.2	3.6	4.2	4.6	5.2	5.6	5.9	6.2	6.6
Hydroelectric Power/Other[11]	3.4	3.2	4.0	4.0	3.6	3.9	3.8	3.9	4.0	4.1	4.3
Net Coke Imports	.1	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total Consumption	**72.5**	**78.9**	**70.5**	**74.4**	**74.8**	**74.8**	**75.7**	**76.6**	**77.7**	**78.7**	**81.8**

[1] Net dry marketed production after removal of nonhydrocarbon gases, plus supplemental natural gas.
[2] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite, with anthracite included in bituminous.
[3] 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, and liquefied natural gas imports from Algeria. In the forecast period (1985-1995), gas imports are net imports.
[7] Includes electricity, coal, and coal coke imports.
[8] Includes natural gas, electricity, and coal coke exports. Gas exports are not included in the forecast period (1985-1995).
[9] Balancing item that includes stock changes, 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.
[10] Includes natural gas plant liquids and crude oil consumed as a fuel.
[11] Includes industrial generation of hydroelectric power, net electricity imports, and electricity produced from geothermal, wood, waste, wind, photovoltaic, solar thermal sources connected to electric utility distribution systems.
[NA] = Not available.
Note: Totals may not equal sum of components because of independent rounding.
Sources: Historical quantities are from the Energy Information Administration, *Annual Energy Review, 1984*, DOE/EIA-0384(84) (Washington, DC, 1985), pp. 5-15, Tables 1, 2, 3, and 6. Historical quantities are through 1984. Projected values are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = D1230851, Projected = IFGMHL.D1118851. Table printed on February 3, 1986.

Table C2. Consumption by Major Fuels and End-Use Sectors
(Quadrillion Btu per Year)

Sector and Fuel	Low Oil Import Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential											
Distillate Fuel	1.84	1.63	1.00	1.06	1.07	1.00	1.02	1.03	1.03	1.03	1.00
Kerosene	.18	.13	.09	.08	.08	.07	.07	.07	.06	.06	.06
Liquefied Petroleum Gas	.55	.35	.35	.37	.33	.34	.35	.35	.35	.34	.31
Natural Gas	4.90	5.05	4.52	4.70	4.65	4.83	4.86	4.89	4.93	4.95	4.95
Steam Coal	.11	.07	.08	.08	.07	.07	.07	.07	.06	.06	.06
Electricity	1.97	2.33	2.56	2.65	2.66	2.79	2.85	2.91	2.98	3.06	3.45
Total	**9.55**	**9.57**	**8.59**	**8.94**	**8.86**	**9.10**	**9.21**	**9.32**	**9.41**	**9.51**	**9.81**
Commercial											
Distillate Fuel	.60	.58	.42	.45	.45	.42	.42	.43	.43	.43	.43
Kerosene	.05	.08	.03	.03	.03	.02	.02	.02	.02	.02	.02
Motor Gasoline	.08	.10	.10	.10	.11	.14	.13	.13	.13	.13	.12
Residual Fuel	.59	.51	.27	.29	.26	.24	.21	.18	.16	.15	.10
Liquefied Petroleum Gas	.10	.06	.06	.06	.07	.07	.07	.07	.07	.06	.06
Natural Gas[1]	2.62	2.84	2.51	2.61	2.58	2.70	2.73	2.74	2.78	2.79	2.76
Steam Coal	.15	.12	.12	.13	.11	.12	.12	.11	.11	.11	.11
Electricity	1.50	1.85	2.12	2.24	2.28	2.34	2.43	2.49	2.59	2.66	2.98
Total	**5.69**	**6.14**	**5.63**	**5.92**	**5.89**	**6.04**	**6.13**	**6.18**	**6.29**	**6.36**	**6.58**
Industrial[2]											
Distillate Fuel	1.35	1.76	1.29	1.36	1.37	1.49	1.51	1.51	1.53	1.55	1.63
Kerosene	.13	.18	.15	.13	.14	.15	.14	.15	.15	.15	.17
Motor Gasoline	.24	.16	.11	.11	.12	.19	.21	.24	.26	.29	.44
Residual Fuel	1.73	1.66	.73	.78	.70	.77	.69	.61	.55	.51	.38
Liquefied Petroleum Gas	1.23	1.71	1.54	1.60	1.67	1.65	1.70	1.72	1.74	1.76	1.83
Petrochemical Feedstocks[3]	.74	1.38	.85	.82	.81	.82	.82	.80	.79	.77	.67
Still Gas Used in Refineries	1.05	1.23	1.13	1.15	1.18	1.18	1.16	1.13	1.12	1.11	1.02
Other Raw Material Oil[4]	2.26	2.51	1.80	2.14	2.09	2.15	2.17	2.19	2.21	2.22	2.20
Natural Gas[5]	10.00	8.55	6.83	7.45	7.41	7.39	7.41	7.73	7.75	7.71	7.23
Steam Coal	1.45	1.52	1.50	1.68	1.75	1.68	1.74	1.80	1.85	1.89	1.95
Metallurgical Coal	2.41	2.06	.99	1.18	1.08	1.02	1.05	1.03	1.01	.98	.84
Net Coke Imports	.06	.06	-.02	-.01	-.01	-.01	-.01	-.01	-.01	-.01	-.01
Electricity	2.34	2.87	2.65	2.87	2.95	2.82	2.91	3.00	3.10	3.22	3.67
Hydropower	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03
Total	**25.00**	**25.68**	**19.57**	**21.30**	**21.30**	**21.32**	**21.54**	**21.93**	**22.06**	**22.18**	**22.06**
Transportation											
Aviation Gasoline	.08	.07	.05	.04	.06	.06	.06	.06	.06	.07	.07
Distillate Fuel	2.20	2.91	2.92	3.11	3.14	3.03	3.12	3.19	3.26	3.33	3.67
Jet Fuel[6]	2.00	2.19	2.14	2.41	2.40	2.37	2.41	2.41	2.40	2.40	2.28
Motor Gasoline	12.22	13.22	12.48	12.65	12.82	12.39	12.33	12.21	12.25	12.31	12.28
Residual Fuel	.70	1.23	.82	.88	.80	.73	.62	.55	.49	.44	.30
Liquefied Petroleum Gas	.04	.01	.04	.04	.04	.03	.04	.04	.04	.04	.04
Lubricants and Waxes	.16	.19	.16	.17	.19	.19	.20	.20	.20	.20	.21
Natural Gas[7]	.68	.61	.51	.54	.55	.55	.55	.55	.56	.55	.52
Other Transportation[8]	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01
Total	**18.09**	**20.44**	**19.12**	**19.86**	**19.99**	**19.36**	**19.33**	**19.21**	**19.26**	**19.35**	**19.38**
Electric Utilities											
Distillate Fuel	.31	.18	.10	.09	.07	.04	.01	.02	.03	.06	.05
Residual Fuel	3.06	3.11	1.44	1.20	1.01	.91	.73	.70	.76	.78	1.36
Natural Gas	3.52	3.61	3.00	3.22	3.15	2.75	2.88	2.91	3.07	3.17	3.61
Steam Coal	8.53	11.26	13.21	14.09	14.67	14.77	15.09	15.27	15.56	16.02	18.19
Nuclear Power	1.27	2.78	3.20	3.57	4.18	4.62	5.16	5.64	5.95	6.16	6.64
Hydropower/Other[9]	3.33	3.20	3.97	3.94	3.54	3.84	3.81	3.88	3.98	4.05	4.26
Total	**20.02**	**24.13**	**24.93**	**26.12**	**26.62**	**26.93**	**27.69**	**28.41**	**29.34**	**30.24**	**34.12**
Primary Energy Consumption											
Distillate Fuel	6.30	7.06	5.72	6.07	6.11	5.98	6.09	6.17	6.28	6.40	6.79
Kerosene	.36	.39	.26	.24	.25	.24	.23	.24	.24	.24	.25
Aviation Gasoline	.08	.07	.05	.04	.06	.06	.06	.06	.06	.07	.07
Motor Gasoline	12.53	13.49	12.70	12.87	13.04	12.72	12.67	12.58	12.64	12.73	12.84
Jet Fuel	2.00	2.19	2.14	2.41	2.40	2.37	2.41	2.41	2.40	2.40	2.28
Residual Fuel	6.07	6.49	3.26	3.16	2.78	2.64	2.25	2.04	1.96	1.88	2.15
Liquefied Petroleum Gas	1.91	2.14	1.99	2.07	2.10	2.09	2.15	2.17	2.19	2.20	2.24
Petrochemical Feedstocks	.74	1.38	.85	.82	.81	.82	.82	.80	.79	.77	.67
Still Gas	1.05	1.23	1.13	1.15	1.18	1.18	1.16	1.13	1.12	1.11	1.02
Lubricants and Waxes	.38	.43	.36	.38	.47	.49	.51	.52	.52	.53	.54
Other Petroleum	2.04	2.27	1.60	1.93	1.81	1.85	1.86	1.87	1.88	1.90	1.87
Natural Gas	21.73	20.66	17.35	18.53	18.34	18.22	18.42	18.82	19.09	19.17	19.07
Steam Coal	10.25	12.97	14.91	15.99	16.60	16.63	17.01	17.25	17.58	18.09	20.30
Metallurgical Coal	2.41	2.06	.99	1.18	1.08	1.02	1.05	1.03	1.01	.98	.84
Net Coke Imports	.06	.06	-.02	-.01	-.01	-.01	-.01	-.01	-.01	-.01	-.01
Nuclear Power	1.27	2.78	3.20	3.57	4.18	4.62	5.16	5.64	5.95	6.16	6.64
Hydropower/Other[9]	3.36	3.23	4.00	3.98	3.57	3.87	3.84	3.91	4.01	4.08	4.29
Total Consumption	**72.55**	**78.90**	**70.49**	**74.37**	**74.76**	**74.77**	**75.70**	**76.63**	**77.68**	**78.68**	**81.85**
Electricity Consumption (all sectors)	**5.82**	**7.07**	**7.34**	**7.77**	**7.90**	**7.97**	**8.20**	**8.42**	**8.68**	**8.95**	**10.11**

See footnotes at end of Appendix C.

Sources: Historical quantities are taken from the Energy Information Administration, *State Energy Data Report, 1960 to 1983*, DOE/EIA-0214(83) (Washington, DC, 1985) and the Energy Information Administration, *Annual Energy Review, 1984*, DOE/EIA-0384(84) (Washington, DC, 1985). Historical quantities are through 1984. Projected quantities are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = D1230851, Projected = IFGMHL.D1118851. Table printed on January 31, 1986.

Table C3. Prices by Major Fuels and End-Use Sectors
(1985 Dollars per Million Btu)

Sector and Fuel	Low Oil Import Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential	**6.84**	**8.52**	**11.57**	**10.75**	**10.62**	**10.75**	**10.83**	**10.91**	**10.99**	**11.05**	**11.59**
Primary Energy	3.87	5.05	6.90	6.60	6.36	6.31	6.26	6.37	6.52	6.67	7.71
Petroleum Products	5.78	7.32	8.88	8.15	7.50	7.50	7.49	7.87	8.25	8.47	9.48
Distillate Fuel	5.25	6.84	8.32	8.12	7.48	7.49	7.47	7.85	8.22	8.45	9.44
Kerosene	5.90	7.95	10.02	8.48	7.81	7.82	7.80	8.19	8.58	8.82	9.85
Liquefied Petroleum Gas	7.52	9.27	10.17	8.16	7.47	7.48	7.46	7.86	8.26	8.49	9.54
Natural Gas	2.86	4.12	6.33	6.19	6.06	6.02	5.95	5.98	6.07	6.20	7.28
Steam Coal[1]	4.35	3.50	3.18	1.96	1.97	1.99	2.00	2.02	2.03	2.05	2.13
Electricity	18.26	19.31	22.57	20.59	20.55	20.76	21.02	20.90	20.65	20.30	18.75
Commercial	**6.94**	**8.84**	**12.03**	**11.50**	**11.47**	**11.53**	**11.77**	**11.89**	**11.99**	**12.02**	**12.36**
Primary Energy	2.93	4.41	5.92	5.72	5.52	5.50	5.46	5.55	5.69	5.82	6.78
Petroleum Products	4.56	5.91	6.69	6.52	5.98	6.11	6.14	6.52	6.90	7.14	8.17
Distillate Fuel	4.59	6.39	7.27	6.59	5.95	5.96	5.94	6.31	6.69	6.91	7.89
Kerosene	4.36	6.81	7.42	6.71	6.04	6.05	6.03	6.42	6.81	7.05	8.07
Motor Gasoline[2]	8.72	10.05	9.19	9.23	8.52	8.47	8.48	8.93	9.38	9.58	10.77
Residual Fuel	3.86	4.39	4.60	5.36	4.97	5.03	5.03	5.26	5.50	5.71	6.28
Liquefied Petroleum Gas	5.24	5.66	7.31	6.82	6.14	6.15	6.13	6.53	6.93	7.17	8.22
Natural Gas[3]	2.11	3.80	5.85	5.62	5.52	5.46	5.40	5.41	5.48	5.60	6.59
Steam Coal[4]	1.74	1.78	1.86	1.93	1.94	1.95	1.97	1.98	2.00	2.01	2.09
Electricity	18.15	19.11	22.16	21.00	20.86	21.06	21.39	21.28	21.02	20.64	19.11
Industrial	**3.54**	**5.09**	**6.61**	**6.77**	**6.58**	**6.57**	**6.65**	**6.79**	**6.99**	**7.14**	**7.89**
Primary Energy	2.72	3.90	4.91	4.73	4.54	4.60	4.61	4.78	4.98	5.15	6.10
Petroleum Products	4.34	5.41	6.67	6.39	5.99	6.03	6.07	6.45	6.82	7.06	8.11
Distillate Fuel	4.11	5.53	6.68	6.48	5.84	5.85	5.83	6.20	6.57	6.80	7.78
Kerosene	4.38	6.87	7.49	6.92	6.25	6.26	6.24	6.63	7.02	7.26	8.28
Motor Gasoline[2]	8.67	10.01	9.33	9.30	8.62	8.58	8.59	9.04	9.49	9.69	10.87
Residual Fuel	3.68	3.93	4.71	4.58	4.20	4.26	4.26	4.49	4.73	4.94	5.50
Liquefied Petroleum Gas	5.06	5.70	7.16	6.94	6.26	6.26	6.24	6.64	7.04	7.28	8.33
Petrochemical Feedstocks[5]	4.11	5.53	NA	6.35	5.66	5.64	5.63	6.01	6.40	6.63	7.64
Other Petroleum[6]	4.11	5.53	NA	6.29	6.43	6.53	6.60	6.88	7.13	7.31	8.08
Natural Gas[7]	1.31	2.66	4.31	4.29	4.23	4.19	4.18	4.24	4.36	4.52	5.65
Steam Coal	2.27	2.22	1.90	1.78	1.80	1.81	1.84	1.86	1.88	1.91	2.01
Metallurgical Coal	2.74	2.68	2.32	2.18	2.25	2.26	2.28	2.29	2.30	2.32	2.38
Net Coke Imports	NA	NA	NA	4.33	4.44	4.46	4.49	4.50	4.53	4.55	4.65
Electricity	9.98	12.70	15.72	17.43	17.34	17.59	17.86	17.75	17.51	17.17	15.55
Transportation	**7.49**	**8.79**	**8.63**	**8.75**	**8.12**	**8.12**	**8.14**	**8.58**	**9.03**	**9.25**	**10.44**
Primary Energy	7.48	8.79	8.62	8.75	8.12	8.11	8.13	8.58	9.02	9.25	10.43
Petroleum Products	7.48	8.79	8.62	8.75	8.12	8.11	8.13	8.58	9.02	9.25	10.43
Aviation Gasoline	10.55	13.40	17.87	12.14	10.99	10.92	10.94	11.70	12.46	12.79	14.80
Distillate Fuel[8]	5.25	7.08	7.84	8.91	8.28	8.28	8.27	8.64	9.01	9.24	10.22
Jet Fuel[9]	3.36	5.89	7.00	6.54	5.85	5.80	5.79	6.19	6.59	6.83	7.86
Motor Gasoline[2]	8.69	10.00	9.18	9.25	8.57	8.53	8.54	8.99	9.44	9.64	10.82
Residual Fuel[10]	2.84	3.37	5.12	3.87	3.47	3.53	3.54	3.77	4.01	4.22	4.79
Liquefied Petroleum Gas	5.03	5.74	7.33	9.56	8.87	8.88	8.86	9.26	9.66	9.90	10.96
Lubricants and Waxes[11]	17.03	17.83	17.63	23.59	22.49	22.51	22.48	23.11	23.75	24.14	25.82
Electricity	12.97	14.37	17.70	20.24	20.08	20.30	20.64	20.53	20.24	19.84	18.42
Total Energy	**5.79**	**7.37**	**8.87**	**8.73**	**8.40**	**8.44**	**8.52**	**8.75**	**9.01**	**9.15**	**9.99**
Primary Energy -- Four Sectors	4.67	6.06	6.94	6.83	6.45	6.42	6.41	6.66	6.96	7.15	8.24
Electricity	14.90	16.56	20.03	19.54	19.45	19.73	20.02	19.90	19.64	19.28	17.70
Electric Utilities											
Fossil Fuel Average	**1.85**	**2.35**	**2.52**	**2.35**	**2.22**	**2.16**	**2.15**	**2.15**	**2.21**	**2.26**	**2.57**
Petroleum Products	3.80	4.34	6.50	4.78	4.62	4.65	4.68	4.90	5.16	5.42	5.98
Distillate Fuel[12]	4.34	6.25	4.95	6.41	5.78	5.80	5.92	6.27	6.53	6.68	7.74
Residual Fuel	3.75	4.23	6.60	4.66	4.54	4.60	4.66	4.87	5.11	5.33	5.91
Natural Gas	.99	2.47	3.72	4.17	3.87	3.80	3.80	3.76	3.87	4.01	5.00
Steam Coal	1.43	1.73	1.78	1.71	1.68	1.70	1.71	1.72	1.73	1.74	1.83
Average Price to All Users											
Petroleum Products	6.14	7.35	7.98	7.96	7.43	7.42	7.47	7.89	8.30	8.52	9.57
Distillate Fuel[8]	4.91	6.56	7.73	8.02	7.39	7.36	7.36	7.74	8.12	8.34	9.35
Kerosene	5.14	7.23	8.32	7.41	6.75	6.68	6.67	7.05	7.43	7.65	8.62
Aviation Gasoline	10.55	13.40	17.87	12.14	10.99	10.92	10.94	11.70	12.46	12.79	14.80
Motor Gasoline[2]	8.69	10.00	9.18	9.25	8.57	8.53	8.55	8.99	9.44	9.64	10.82
Jet Fuel	3.36	5.89	7.00	6.54	5.85	5.80	5.79	6.19	6.59	6.83	7.86
Residual Fuel	3.63	4.00	4.91	4.48	4.19	4.24	4.26	4.50	4.76	5.00	5.70
Liquefied Petroleum Gas	5.79	6.31	7.71	7.21	6.49	6.50	6.48	6.88	7.28	7.51	8.55
Petrochemical Feedstocks	4.11	5.53	NA	6.35	5.66	5.64	5.63	6.01	6.40	6.63	7.64
Lubricants and Waxes	17.03	17.83	17.63	23.59	22.49	22.51	22.48	23.11	23.75	24.14	25.82
Other Petroleum Products	4.11	5.53	NA	5.77	5.11	5.11	5.08	5.47	5.83	6.05	6.97
Natural Gas	1.76	3.20	5.04	5.00	4.87	4.86	4.82	4.84	4.93	5.07	6.12
Coal	1.80	1.92	1.84	1.76	1.73	1.75	1.76	1.77	1.78	1.79	1.87
Electricity	14.90	16.56	20.03	19.54	19.45	19.73	20.02	19.90	19.64	19.28	17.70

See footnotes at end of Appendix C.

Sources: Historical prices through 1982 are from the Energy Information Administration, *State Energy Price and Expenditure Report*, DOE/EIA-0376(82) (Washington, DC, 1985), pp. 4-21. Prices for 1983 are preliminary. Prices for 1984 are estimated. All other prices are forecasts from the Intermediate Future Forecasting System. Input data file: Historical = D1230851, Projected = IFGMHL.D1118851. Table printed on January 31, 1986.

Table C4. Electric Utility Fuel Consumption and Electricity Sales
(Quadrillion Btu per Year)

Fuel Consumption and Sales	Low Oil Import Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Fuel Inputs											
Oil											
Distillate	0.31	0.18	0.10	0.09	0.07	0.04	0.01	0.02	0.03	0.06	0.05
Residual	3.06	3.11	1.44	1.20	1.01	.91	.73	.70	.76	.78	1.36
Natural Gas	3.52	3.61	3.00	3.22	3.15	2.75	2.88	2.91	3.07	3.17	3.61
Steam Coal	8.53	11.26	13.21	14.09	14.67	14.77	15.09	15.27	15.56	16.02	18.19
Nuclear Power	1.27	2.78	3.20	3.57	4.18	4.62	5.16	5.64	5.95	6.16	6.64
Hydropower/Other[1]	3.20	2.99	3.60	3.53	3.11	3.36	3.28	3.30	3.33	3.36	3.42
Total Fuel Inputs	19.89	23.92	24.56	25.70	26.19	26.45	27.16	27.83	28.69	29.54	33.28
Net Imports	.13	.21	.37	.41	.43	.48	.53	.58	.64	.70	.84
Total Electricity Inputs	**20.02**	**24.13**	**24.93**	**26.12**	**26.62**	**26.93**	**27.69**	**28.41**	**29.34**	**30.24**	**34.12**
Disposition											
Total Electricity Inputs	20.02	24.13	24.93	26.12	26.62	26.93	27.69	28.41	29.34	30.24	34.12
Minus Conversion Losses[2]	13.65	16.46	17.05	17.87	18.24	18.47	18.86	19.37	20.02	20.66	23.34
Generation	6.37	7.67	7.88	8.24	8.38	8.46	8.83	9.04	9.31	9.58	10.78
Minus Transportation and Distribution Losses	.55	.60	.54	.47	.48	.48	.63	.63	.63	.63	.66
Electricity Sales	**5.82**	**7.07**	**7.34**	**7.77**	**7.90**	**7.97**	**8.20**	**8.42**	**8.68**	**8.95**	**10.11**
Electricity Sales by End-Use Sector											
Residential	1.97	2.33	2.56	2.65	2.66	2.79	2.85	2.91	2.98	3.06	3.45
Commercial/Other[3]	1.51	1.86	2.13	2.25	2.29	2.35	2.44	2.50	2.60	2.67	2.99
Industrial	2.34	2.87	2.65	2.87	2.95	2.82	2.91	3.00	3.10	3.22	3.67
Total Electricity Sales	**5.82**	**7.07**	**7.34**	**7.77**	**7.90**	**7.97**	**8.20**	**8.42**	**8.68**	**8.95**	**10.11**

[1] Includes renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[2] Conversion losses includes net imports.
[3] Includes street lighting and sales to the transportation end-use sector.
Note: Totals may not equal sum of components because of independent rounding.
Sources: Historical values are obtained or derived from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(85/08), (Washington, DC, 1985), pp. 29 and 77.
Input data file: Historical = D1230851, Projected = IFGMHL.D1118851. Table printed on January 31, 1986.

Table C5. Electric Utility Summer Capability and Generation

(Capability in Million Kilowatts)

(Generation in Billion Kilowatthours per Year)

Summer Capability and Generation	Low Oil Import Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Capability[1]											
Coal Steam	175.7	225.9	266.1	274.8	280.3	285.8	288.5	292.1	293.7	294.6	318.8
Other Fossil Steam	136.9	154.4	153.8	152.1	145.3	144.5	143.9	142.8	142.1	141.1	135.4
Combined Cycle	2.3	4.8	4.8	4.9	4.5	4.5	4.5	4.5	4.5	4.7	4.8
Turbine/Diesel	36.5	43.6	43.7	43.7	43.2	43.2	43.3	43.6	43.6	44.3	56.5
Nuclear Power[2]	31.6	49.6	63.0	69.7	78.6	91.5	100.3	103.8	105.1	105.1	110.6
Hydropower/Other[3] [4]	56.5	65.9	70.0	71.6	73.6	74.0	74.2	75.1	75.6	76.4	77.1
Pumped Storage Hydropower[4]	9.1	12.9	13.8	14.3	16.4	16.4	16.4	16.6	17.7	18.0	19.0
Total Capability	**448.6**	**557.1**	**615.2**	**631.1**	**641.9**	**660.0**	**671.3**	**678.5**	**682.3**	**684.1**	**722.2**
Generation by Plant Type											
Coal Steam	828	1,075	1,259	1,342	1,417	1,416	1,470	1,489	1,517	1,562	1,775
Other Fossil Steam	580	595	397	393	334	306	307	306	324	331	393
Combined Cycle	5	15	12	15	22	21	22	22	22	24	27
Turbine/Diesel	36	23	10	10	17	4	2	2	5	7	31
Nuclear Power	114	255	294	328	383	424	471	514	542	562	606
Hydropower/Other[3]	304	284	339	330	292	318	325	327	330	333	340
Pumped Storage Hydropower	NA	NA	NA	NA	-8	-10	-10	-10	-11	-11	-12
Total Generation	**1,867**	**2,247**	**2,310**	**2,416**	**2,457**	**2,479**	**2,588**	**2,650**	**2,730**	**2,809**	**3,159**
Generation by Fuel Type											
Coal[5]	828	1,075	1,259	1,342	1,399	1,406	1,465	1,483	1,511	1,556	1,769
Natural Gas	320	329	274	297	293	255	265	267	282	290	322
Oil	301	304	144	120	99	87	72	69	75	79	134
Nuclear Power	114	255	294	328	383	424	471	514	542	562	606
All Hydropower/Other[6]	304	284	339	330	284	308	315	317	320	322	328
Total Generation	**1,867**	**2,247**	**2,310**	**2,416**	**2,457**	**2,478**	**2,588**	**2,650**	**2,730**	**2,809**	**3,159**

[1] Net summer capability is the load-carrying ability of a generator under summer (adverse) conditions for a specified time period. Historical values include capability out-of-service; projections exclude this capability.

[2] Nuclear capability is as of the date the unit first delivers power to the grid; all other capability is as of the date the unit begins commercial service.

[3] Includes other renewable sources such as geothermal power, wood, waste, solar energy, and wind; historical pumped storage data for generation are not collected separately and are included among hydropower/other totals.

[4] All pumped storage and conventional hydropower values, both historical and projected, are nameplate capacity, which are approximately 15 to 25 percent lower than net summer capability for hydroelectric units.

[5] Historical values (1974-1984) understate coal steam generation and overstate other steam generation because they attribute small amounts of oil and natural gas used for startup and flame stability in coal steam plants to other steam plant generation.

[6] Includes conventional and pumped storage hydropower and other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

NA = Not available.

Note: Previous editions of the *Annual Energy Outlook* published nameplate capacity rather than net summer capability and did not consider projected retirements. Net summer capability values are generally from 5 to 7 percent below nameplate capacity values; retirements are expected to total about 15 gigawatts between 1985 and 1995.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Generation data for 1974-1984 are from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035 (85/08), Washington, DC, 1985), p. 76, and the Energy Information Administration, Form EIA-759, "Monthly Power Plant Report." Capability values are estimates based on the Energy Information Administration Generating Unit Reference File (GURF), 1983; the Federal Energy Regulatory Commission, *Hydroelectric Power Resources of the United States - Developed and Undeveloped*, FERC-0070 (January 1980); the Energy Information Administration, *U.S. Commercial Nuclear Power*, DOE/EIA-0315 (Washington, DC, March 1982); and Form EIA-254, "Quarterly Progress Report on Status of Reactor Construction." Historical quantities are through 1984.

Input data file: Historical = D1230851, Projected = IFGMHL.D1118851. Table printed on February 5, 1986.

Table C6. Electric Utility Summer Capability Additions
(Thousand Kilowatts)

Additions	Low Oil Import Case										
	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Total Additions											
Nuclear Power[1]	8,958	12,906	8,826	3,487	1,239	0	0	2,244	0	1,242	2,025
Coal Steam	5,937	5,562	2,753	3,588	1,824	1,422	7,439	3,400	6,342	3,475	4,148
Other Steam[2]	0	0	0	0	0	208	108	0	0	0	0
Turbines[3]	151	131	176	289	80	800	1,515	812	1,540	4,255	5,174
Pumped Storage Hydropower	2,100	0	0	200	1,075	285	848	0	0	150	0
Hydropower/Other[4]	1,398	327	278	862	543	803	282	325	4	93	0
Total New Capability	**18,544**	**18,926**	**12,033**	**8,425**	**4,761**	**3,517**	**10,191**	**6,780**	**7,887**	**9,215**	**11,347**
Announced/Planned Construction[5]											
Nuclear Power[1]	8,958	12,906	8,826	3,487	1,239	0	0	2,244	0	1,242	2,025
Coal Steam	5,937	5,562	2,753	3,588	1,824	1,422	7,439	3,400	6,342	3,475	4,148
Other Steam[2]	0	0	0	0	0	208	108	0	0	0	0
Turbines[3]	151	131	176	289	80	800	65	262	90	55	124
Pumped Storage Hydropower	2,100	0	0	200	1,075	285	848	0	0	150	0
Hydropower/Other[4]	1,398	327	278	862	543	803	282	325	4	93	0
Total Announced/Planned	**18,544**	**18,926**	**12,033**	**8,425**	**4,761**	**3,517**	**8,741**	**6,230**	**6,437**	**5,015**	**6,297**
Additional Needed Capability[6]											
Nuclear Power[1]	0	0	0	0	0	0	0	0	0	0	0
Coal Steam	0	0	0	0	0	0	0	0	0	0	0
Other Steam[2]	0	0	0	0	0	0	0	0	0	0	0
Turbines[3]	0	0	0	0	0	0	1,450	550	1,450	4,200	5,050
Pumped Storage Hydropower	0	0	0	0	0	0	0	0	0	0	0
Hydropower/Other[4]	0	0	0	0	0	0	0	0	0	0	0
Total Additional Needed	**0**	**0**	**0**	**0**	**0**	**0**	**1,450**	**550**	**1,450**	**4,200**	**5,050**

[1] Includes the scheduled return to service of the Three Mile Island 1 facility. Nuclear capability is as of the date the unit first delivers power to the grid; all other capability is as of the date the unit begins commercial service.
[2] Includes natural gas, oil, and dual-fired oil/natural gas steam and combined cycle capability.
[3] Includes all gas turbine and internal combustion capability.
[4] Includes conventional hydroelectric and other renewable sources of power such as geothermal, wood, waste, solar, and wind.
[5] Includes all new capability announced by the electric utility industry.
[6] Includes additional new capability considered necessary by the Energy Information Administration to meet electricity demands.
Note: Totals may not equal sum of components because of independent rounding.
Sources: Historical values: The Energy Information Administration Generating Unit Reference File (GURF).
Input data file: Projected IFGMHL.D1118851. Table printed on January 31, 1986.

Table C7. Electric Utility Sectoral Demands, Prices, and Price Components

(Billion Kilowatthours per Year)

(1985 Dollars per Thousand Kilowatthours)

Demands, Prices and Price Components	Low Oil Import Case														
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Demands															
Residential	578	683	751	778	780	819	835	854	874	896	919	942	966	989	1,011
Commercial[1]	443	546	624	660	673	690	715	734	762	784	804	821	838	856	877
Industrial	685	842	776	841	864	828	852	878	909	943	973	1,002	1,025	1,048	1,075
All Sectors	**1,706**	**2,071**	**2,151**	**2,278**	**2,317**	**2,337**	**2,402**	**2,466**	**2,545**	**2,623**	**2,696**	**2,766**	**2,829**	**2,893**	**2,964**
Prices[2]															
Residential	62.30	65.89	77.01	70.26	70.11	70.84	71.73	71.32	70.46	69.26	67.92	66.97	65.84	64.83	63.96
Commercial[1]	61.79	65.12	75.61	71.63	71.17	71.84	72.96	72.61	71.69	70.40	69.05	68.08	66.98	65.99	65.18
Industrial	34.04	43.32	53.64	59.48	59.20	60.07	61.00	60.59	59.79	58.63	57.29	56.33	55.17	54.04	53.13
All Sectors	**51.05**	**56.70**	**68.34**	**66.68**	**66.35**	**67.32**	**68.29**	**67.88**	**67.02**	**65.78**	**64.42**	**63.45**	**62.31**	**61.26**	**60.39**
Price Components															
Capital Component[3]	NA	NA	NA	NA	28.09	29.23	30.41	30.24	29.15	27.64	26.02	24.68	23.29	21.88	20.50
Fuel Component[4]	NA	NA	NA	NA	21.76	21.12	20.83	20.63	21.03	21.48	21.92	22.43	22.80	23.28	23.91
O&M Component[5]	NA	NA	NA	NA	16.50	16.96	17.05	17.01	16.84	16.65	16.48	16.34	16.23	16.10	15.98
Total Price[6]	**51.05**	**56.70**	**68.34**	**66.68**	**66.35**	**67.32**	**68.29**	**67.88**	**67.02**	**65.78**	**64.42**	**63.45**	**62.31**	**61.26**	**60.39**

[1] Includes consumption for street and highway lighting, other public authorities, and railroads and railways.

[2] Prices for 1985 to 1995 are estimated 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, Form FERC-1-M, and on the Energy Information Administration Form EIA-412.

[3] 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.

[4] The fuel component includes only the direct costs of fuel inputs used to generate electricity required to meet demand.

[5] 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.

[6] 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, Form FERC-1-M, and on the Energy Information Administration Form EIA-412.

NA = Not available.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Prices for 1974 and 1979 are from the Energy Information Administration, *State Energy Price and Expenditure Report*, DOE/EIA-0376(82) (Washington, DC, 1985), pp. 6-7. Prices for 1983 are based on preliminary data. Historical demands are from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(85/07), (Washington, DC, 1985), p. 77. Electricity prices representing both public and private utilities for 1984 are estimates. Projected prices are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = D1230851, Projected = IFGMHL.D1118851. Table printed on February 5, 1986.

Table C8. Petroleum Supply and Disposition Balance
(Million Barrels per Day)

Supply and Disposition	Low Oil Import Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Crude Oil[1]	8.77	8.55	8.69	8.88	8.92	9.07	9.16	9.01	8.75	8.44	7.36
Alaska	.19	1.40	1.71	1.72	1.80	1.89	1.90	1.78	1.74	1.66	1.32
Lower 48	8.58	7.15	6.97	7.16	7.12	7.18	7.26	7.23	7.01	6.78	6.05
Natural Gas Plant Liquids	1.69	1.58	1.56	1.63	1.63	1.63	1.72	1.74	1.75	1.74	1.64
Other Domestic[2]	.04	.04	.05	.05	.05	.05	.05	.05	.05	.05	.05
Processing Gain[3]	.48	.53	.49	.55	.51	.52	.51	.50	.51	.51	.52
Total Production	**10.98**	**10.71**	**10.79**	**11.11**	**11.11**	**11.27**	**11.44**	**11.30**	**11.06**	**10.73**	**9.57**
Imports (including SPR)											
Crude Oil[4]	3.48	6.52	3.33	3.43	3.06	2.93	2.85	2.96	3.31	3.76	5.09
Refined Products	2.64	1.94	1.72	2.01	1.83	2.13	1.81	1.71	1.68	1.62	1.69
Total Imports	6.11	8.46	5.05	5.44	4.89	5.06	4.65	4.67	4.99	5.38	6.78
Exports											
Crude Oil	.00	.23	.16	.18	.19	.15	.17	.17	.17	.17	.17
Refined Products	.22	.24	.58	.54	.53	.53	.53	.53	.53	.53	.53
Total Exports	.22	.47	.74	.72	.72	.68	.70	.70	.70	.70	.70
Net Imports (including SPR)	**5.89**	**7.99**	**4.31**	**4.72**	**4.17**	**4.38**	**3.95**	**3.97**	**4.28**	**4.68**	**6.07**
Primary Stock Changes											
Net Withdrawals[5]	-.18	-.09	.25	-.08	.32	.02	-.02	.01	-.01	-.02	-.01
SPR Fill Rate Additions (-)[6]	.00	-.07	-.23	-.20	-.12	.00	.00	.00	.00	.00	.00
Total Primary Supply[7]	**16.69**	**18.54**	**15.12**	**15.54**	**15.49**	**15.66**	**15.37**	**15.27**	**15.33**	**15.39**	**15.64**
Refined Petroleum Products											
Motor Gasoline	6.54	7.03	6.62	6.69	6.80	6.63	6.61	6.56	6.59	6.64	6.70
Aviation Gasoline	.04	.04	.03	.02	.03	.03	.03	.03	.03	.04	.04
Jet Fuel[8]	.99	1.08	1.05	1.18	1.17	1.16	1.18	1.18	1.17	1.17	1.11
Kerosene	.18	.19	.13	.12	.12	.11	.11	.11	.11	.12	.12
Distillate Fuel	2.95	3.31	2.69	2.84	2.87	2.81	2.86	2.90	2.95	3.01	3.19
Residual Fuel	2.64	2.83	1.42	1.36	1.21	1.15	.98	.89	.86	.82	.94
Liquid Petroleum Gas	1.41	1.59	1.51	1.57	1.58	1.57	1.62	1.63	1.65	1.66	1.68
Petrochemical Feedstocks	.36	.67	.41	.40	.39	.40	.40	.39	.38	.38	.33
Other Petroleum Products[9]	1.55	1.78	1.40	1.57	1.54	1.57	1.57	1.57	1.57	1.57	1.53
Total Product Supplied	**16.65**	**18.51**	**15.26**	**15.75**	**15.72**	**15.44**	**15.37**	**15.27**	**15.32**	**15.39**	**15.64**
Refined Petroleum Products Supplied to Sectors											
Residential and Commercial	2.04	1.73	1.21	1.27	1.24	1.19	1.20	1.19	1.18	1.17	1.10
Industrial[10]	4.30	5.33	3.94	4.18	4.21	4.31	4.34	4.32	4.32	4.34	4.37
Transportation	8.84	10.00	9.41	9.72	9.82	9.50	9.50	9.43	9.46	9.50	9.54
Electric Utilities	1.48	1.44	.67	.56	.47	.41	.33	.31	.34	.37	.62
Total Consumption	**16.65**	**18.49**	**15.23**	**15.73**	**15.74**	**15.43**	**15.36**	**15.26**	**15.30**	**15.39**	**15.63**
Discrepancy[11]	.04	.05	-.11	-.19	-.25	.24	.01	.01	.02	.01	.01
Net Disposition[12]	**16.69**	**18.54**	**15.12**	**15.54**	**15.49**	**15.66**	**15.37**	**15.27**	**15.33**	**15.39**	**15.64**

[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 end-of-year stock levels from period t-1 minus the end-of-year 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] Includes naphtha and kerosene type.
[9] Includes miscellaneous petroleum products, lubricants, waxes, unfractionated stream, plant condensate, natural gasoline, asphalt, road oil, still gas, special naphthas, and petroleum coke.
[10] Includes total industrial demand for petroleum.
[11] Represents the difference between total primary supply and total consumption.
[12] Net disposition is the sum of total consumption and discrepancy.

Note: From 1983 onward, the product supplied data and stock data are on a new basis. The other product category is on a net basis, reclassified (petroleum products reprocessed into other categories) plus the other category of products supplied.
Note: Totals may not equal sum of components because of independent rounding.
Sources: Historical data are from the Energy Information Administration, *Annual Energy Review, 1984*, DOE/EIA-0384(84) (Washington, DC, 1985), pp. 89-109, Tables 39, 40, 41, and 49. Historical quantities are through 1984. Projected values are outputs from the Intermediate Future Forecasting System.
Input data file: Historical = D1230851, Projected = IFGMHL.D1118851. Table printed on January 31, 1986.

Table C9. Natural Gas Supply, Disposition, and Prices

(Trillion Cubic Feet per Year)

(1985 Dollars per Thousand Cubic Feet)

Supply, Disposition, and Prices	Low Oil Import Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Dry Gas Production[1]	20.71	19.66	16.03	17.39	16.95	16.92	17.08	17.24	17.40	17.21	16.40
Supplemental Natural Gas[2]	NA	NA	.13	.11	.15	.15	.00	.00	.00	.00	.28
Net Imports	.88	1.20	.87	.79	.94	1.00	1.21	1.44	1.58	1.87	2.44
Net Storage Withdrawals[3]	-.06	-.29	.44	-.21	.00	-.02	.00	.00	.00	.00	.00
Total Supply[4]	**21.53**	**20.57**	**17.47**	**18.08**	**18.04**	**18.05**	**18.29**	**18.67**	**18.98**	**19.08**	**19.11**
Consumption by Sector[5]											
Residential	4.79	4.97	4.38	4.57	4.51	4.68	4.71	4.75	4.78	4.80	4.80
Commercial[6]	2.56	2.79	2.43	2.54	2.50	2.62	2.64	2.66	2.70	2.71	2.67
Industrial	8.29	6.90	5.64	6.16	6.32	6.29	6.33	6.62	6.63	6.60	6.08
Lease & Plant Fuel[7]	1.48	1.50	.98	1.08	.87	.87	.86	.87	.89	.88	.93
Transportation[8]	.67	.60	.49	.53	.53	.53	.53	.53	.54	.53	.51
Electric Utilities	3.44	3.49	2.91	3.11	3.06	2.67	2.79	2.82	2.99	3.07	3.51
Total Consumption	**21.22**	**20.24**	**16.83**	**17.98**	**17.79**	**17.67**	**17.87**	**18.25**	**18.52**	**18.59**	**18.50**
Unaccounted for[9]	.31	.34	.63	.10	.25	.38	.42	.42	.47	.48	.61
Average Wellhead Price	**.60**	**1.67**	**2.78**	**2.76**	**2.60**	**2.52**	**2.51**	**2.52**	**2.66**	**2.80**	**3.82**
Delivered Prices by Sectors											
Residential	2.93	4.20	6.53	6.37	6.25	6.21	6.14	6.17	6.26	6.40	7.50
Commercial[6]	2.16	3.87	6.03	5.78	5.69	5.63	5.56	5.57	5.65	5.77	6.79
Industrial	1.34	2.71	4.48	4.39	4.36	4.32	4.31	4.37	4.50	4.66	5.81
Electric Utilities	1.02	2.55	3.83	4.31	3.98	3.91	3.92	3.88	3.98	4.13	5.15
Average to All Sectors[10]	**1.79**	**3.27**	**5.19**	**5.14**	**5.01**	**5.01**	**4.97**	**4.98**	**5.08**	**5.23**	**6.31**

[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 end-of-year stock levels from the current period subtracted from the end-of-year 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 sector 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. Weights used are the sectoral consumption values excluding lease and plant fuel and the transportation sector.

NA = Not available.

Note: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1985 equals 1.00. The natural gas prices in this table are average prices, total revenues divided by total sales for each customer class.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Historical data are taken from the Energy Information Administration, *Annual Energy Review, 1984*, DOE/EIA-0384(84) (Washington, DC, 1985) and the Energy Information Administration, *Natural Gas Annual, 1983*, Vol. 1 DOE/EIA-0131(83)/1 (Washington, DC, 1985). Historical quantities are through 1984. Projected values are based on preliminary estimates of 1983 and 1984 prices, and on outputs from the Intermediate Future Forecasting System.

Input data file: Historical = D1230851, Projected = IFGMHL.D1118851. Table printed on February 5, 1986.

Table C10. Coal Supply, Disposition, and Prices

(Million Short Tons per Year)

(1985 Dollars per Short Ton)

Supply, Disposition, and Price	Low Oil Import Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production[1]											
East of the Mississippi	518	560	507	588	570	573	585	588	594	607	656
West of the Mississippi	92	221	275	308	316	324	338	345	355	370	444
Total	**610**	**781**	**782**	**896**	**886**	**897**	**922**	**932**	**949**	**976**	**1,101**
Imports[2]	2	2	1	1	2	2	2	2	2	2	2
Exports[3]	61	66	78	81	85	85	85	86	87	89	104
Net Imports	**-59**	**-64**	**-77**	**-80**	**-83**	**-83**	**-83**	**-84**	**-85**	**-87**	**-102**
Net Storage Withdrawals[4]	**8**	**-36**	**27**	**-29**	**25**	**5**	**-6**	**-4**	**-5**	**-7**	**-6**
Total Supply[5]	**559**	**681**	**732**	**787**	**828**	**819**	**833**	**844**	**859**	**882**	**993**
Consumption by Sector											
Residential and Commercial	11	8	8	9	8	8	7	7	7	7	7
Industrial	65	68	66	74	77	74	75	77	79	81	84
Coking Plants[6]	90	77	37	44	40	38	39	38	37	36	31
Electric Utilities	392	527	625	664	693	701	713	722	736	758	872
Total Consumption	**558**	**681**	**737**	**791**	**818**	**821**	**833**	**844**	**859**	**882**	**993**
Discrepancy[7]	1	0	-5	-4	10	-2	-1	(*)	(*)	(*)	(*)
Average Minemouth Price[8]	**31.82**	**33.66**	**27.95**	**26.55**	**26.63**	**26.85**	**28.08**	**28.11**	**28.19**	**28.35**	**28.83**
Delivered Prices by Sector											
Residential and Commercial[9]	63.82	55.44	43.40	44.44	44.45	44.68	48.67	48.85	49.05	49.26	50.96
Industrial	50.70	49.78	42.27	40.73	40.97	41.30	42.89	43.35	43.86	44.43	46.85
Coking Plants[6]	73.32	71.80	63.78	58.62	60.24	60.52	61.94	62.31	62.77	63.20	64.94
Electric Utilities[10]	31.11	37.05	37.62	36.39	35.65	35.81	36.28	36.38	36.56	36.85	38.11
Average to All Sectors[11]	**40.84**	**42.48**	**39.41**	**38.12**	**37.45**	**37.54**	**38.17**	**38.29**	**38.47**	**38.72**	**39.77**

[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, but are held constant at 2 million short tons per year.

[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 end-of-year stock levels from the current period subtracted from the end-of-year 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, plus losses and unaccounted for coal. 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 (1985-1995) are estimated and do not reflect market conditions.

[9] Projected residential and commercial prices (1983-1995) 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: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1985 equals 1.00. Projected coal prices are based on cost estimates and do not reflect market conditions.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Historical prices through 1982 from the Energy Information Administration, *State Energy Price and Expenditure Report*, DOE/EIA-0376(82) (Washington, DC, 1985), pp. 4-21. Historical quantities through 1982 are from the Energy Information Administration, *Annual Energy Review, 1984*, DOE/EIA-0384(84) (Washington, DC, 1985), pp. 145-153, Tables 65, 66, and 67. Historical 1983 and 1984 quantities and prices (excluding residential and commercial) are from the Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0125(85/2Q) (Washington, DC, October, 1985). Historical quantities are through 1984. Projected values are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = D1230851, Projected = IFGMHL.D1118851. Table printed on January 31, 1986.

Table C11. National Macroeconomic Indicators

Macroeconomic Indicators	Low Oil Import Case										
	1974	1979	1983	1984	1985	1986	1987	1988	1989	1990	1995
World Oil Price[1]	**25.18**	**30.70**	**31.50**	**29.93**	**27.00**	**27.00**	**27.00**	**29.00**	**31.00**	**32.00**	**37.00**
Economic Variables											
Real GNP (billion 1972 dollars)	1,246	1,479	1,535	1,639	1,677	1,681	1,747	1,802	1,864	1,922	2,134
Real Disposable Income (billion 1972 dollars)	858	1,016	1,096	1,169	1,199	1,212	1,246	1,279	1,326	1,369	1,530
Real Disposable Income per Capita (thousand 1972 dollars)	4.0	4.5	4.7	4.9	5.0	5.0	5.1	5.2	5.4	5.5	5.9
NIPA GNP Price Deflator (1972:1.00)	1.151	1.634	2.153	2.234	2.315	2.410	2.521	2.656	2.793	2.954	4.221
GNP Growth (percent per annum)	0.0	2.8	3.7	6.8	2.3	0.2	3.9	3.1	3.4	3.1	2.1
Unemployment Rate, Civilian Workers (percent)	5.6	5.9	9.6	7.5	7.4	8.2	8.1	7.6	7.3	7.1	7.2
Population, Noninstitutional (million persons)	213.9	225.1	234.0	236.2	238.4	240.5	242.7	244.9	247.0	249.2	259.1
New, High Grade Bond Rate (percent per annum)	8.96	9.86	11.56	12.28	11.07	10.56	10.19	10.47	10.79	11.21	12.23
Home Mortgage Rate (percent per annum)	9.21	11.13	13.35	13.55	12.50	12.04	11.60	11.85	12.13	12.44	13.36
Gross Output - Manufacturing (billion 1972 dollars)	813	929	860	950	960	948	996	1,033	1,071	1,104	1,218
Housing Starts (million units)	1.33	1.72	1.70	1.77	1.83	1.69	1.82	1.74	1.74	1.73	1.40
Energy Usage Indicators											
Gross Energy Use per Capita (million Btu per person)	339.2	350.5	301.24	314.9	313.7	310.9	311.9	313.0	314.5	315.7	315.9
Gross Energy Use per Dollar of GNP (thousand Btu per 1972 dollar)	58.2	53.3	45.9	45.4	44.6	44.5	43.3	42.5	41.7	40.9	38.4

[1] The cost of imported crude oil to U.S. refiners in 1985 dollars per barrel.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Historical data are derived from the following sources: Data Resources, Inc., USMODEL database, (September, 1985), the Bureau of Labor Statistics, for the industrial gross output in constant dollars (1984), and the Energy Information Administration, *Annual Energy Review, 1984*, DOE/EIA-0384(84) (Washington, DC, 1985). Historical quantities are through 1984. Projected values are outputs from the Intermediate Future Forecasting System.

Input data file: Historical = D1230851, Projected = IFGMHL.D1118851. Table printed on January 31, 1986.

Supplementary Footnotes for Appendix Tables

Footnotes for Tables A2, B2, and C2

1. Includes deliveries to municipalities and other public authorities for institutional heating, street lighting, etc.
2. Includes all fuels consumed for heat and power, including natural gas used as lease and plant fuel and for industrial feedstock and raw material uses; also, all fuels consumed by refineries.
3. 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.
5. Includes lease and plant fuel consumption of natural gas.
6. Includes naphtha and kerosene types.
7. Consists of natural gas used as pipeline compressor fuel.
8. 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. Totals may not equal sum of components because of independent rounding.

Footnotes for Tables A3, B3, and C3

1. Projected residential coal prices are delivered-to-dealer prices and do not include dealer markup.
2. Projected motor gasoline prices are averages for all grades. Federal and State taxes are included, but county and local taxes are not included.
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 1979).
6. Industrial other price is a weighted average price for road oil, asphalt, lubricants, waxes, petroleum coke, special naphthas, and miscellaneous petroleum products.
7. Industrial natural gas price in this table excludes uses for refinery fuel and for lease and plant fuel.
8. The projected price of transportation distillate includes Federal and State taxes on diesel fuel, but does not include county and local taxes.
9. Jet fuel price is for kerosene type jet fuel at retail.
10. Residual fuel price is for marine bunker fuel.
11. Historical price is the price of industrial lubricants.
12. Historical price for electric utility distillate fuel oil is the price of electric utility kerosene.

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 1985 = 1.0, was used to convert from nominal to real dollars.

Note. Totals may not equal sum of components because of independent rounding.

Note. Weighted average of end-use fuel prices derived from the prices shown in each sector and the corresponding sectoral consumption, following the conventions of the *State Energy Price and Expenditure Report.*

Appendix D

Assumptions

Appendix D

Assumptions

Macroeconomic Assumptions

Base Case

In the base case, the real Gross National Product (GNP) is assumed to grow by 2.8 percent per year between 1985 and 1995 (Table D1).[8] This growth rate is very similar to the longer term growth rate in real GNP of 3.2 percent per year experienced between 1964 and 1984 and the average annual growth of 2.8 percent per year experienced over the last 10 years (1974-1984). Growth in GNP is assumed to be stronger during the first half of the forecast period, averaging 3.1 percent per year from 1985 to 1990, and decreasing to 2.5 percent per year between 1990 and 1995.

The longer term outlook includes moderate levels of price inflation, reductions in nominal interest rates, and an unemployment rate ranging from 6.8 percent to 7.6 percent over the 10-year period. The rate of economic growth depends on several supply-side factors including 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 1.3 percent per year between 1985 and 1995, compared with the historical rate of 2.1 percent per year between 1974 and 1984. Thus, the labor force is assumed to have a limiting effect on the underlying growth potential of the economy relative to recent history.

Table D1. Key Economic Indicators, 1974-1995

Economic Indicator	History 1974	History 1979	History 1984	Average Annual Growth 1974-1984	Oil Imports Cases	Assumptions 1985	Assumptions 1990	Assumptions 1995	Average Annual Growth 1985-1995
Real GNP (billion 1972 dollars)	1,246	1,479	1,639	2.8	High Imports	1,677	2,001	2,295	3.2
					Base Case	1,677	1,955	2,215	2.8
					Low Imports	1,677	1,922	2,134	2.4
Gross Output in Manufacturing (billion 1972 dollars)	813	929	950	1.6	High Imports	960	1,163	1,325	3.3
					Base Case	960	1,127	1,272	2.9
					Low Imports	960	1,104	1,218	2.4
Real Disposable Personal Income (billion 1972 dollars)	858	1,016	1,169	3.1	High Imports	1,199	1,401	1,596	2.9
					Base Case	1,199	1,383	1,560	2.7
					Low Imports	1,199	1,369	1,530	2.5
Unemployment Rate (percent)	5.6	5.9	7.5	--	High Imports	7.4	6.7	6.9	--
					Base Case	7.4	7.0	7.1	--
					Low Imports	7.4	7.1	7.2	--

-- = Not applicable.

Note: The rate of inflation is assumed to be 4.6 percent between 1985 and 1990 and 5.8 percent between 1990 and 1995 in the base case. For the high oil imports case, inflation is assumed to be 3.9 percent per year from 1985 to 1990 and 5.0 percent per year from 1990 and 1995. The low oil imports case is based on an inflation rate of 5.0 percent per year from 1985 to 1990 and 7.4 percent per year from 1990 to 1995.

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

[8]This forecast is based on a modified version of the Data Resources, Inc., (DRI) U.S. economic forecast TREND25YR0985. The underlying DRI forecast is described in the fall DRI U.S. *Long-Term Review* (Lexington, MA, Fall 1985).

GNP and Its Components

Examining the composition of the assumed growth in the base case, the key trends that are expected to have significant implications for energy consumption between 1985 and 1995 include:

- Consumption expenditures--a 2.6-percent-per-year growth over the 10- year period. As true of the overall economy, growth between 1990 and 1995 is assumed to be slower than in the first 5 years. The share of consumption in GNP is assumed to decline from 65.8 percent in 1985 to 64.7 percent in 1990 and 64.4 percent in 1995, reversing the steady upward trend in that share during the previous 10 years.
- Nonresidential structures and equipment--a 3.7-percent-per-year growth, compared to the 4.2-percent per year growth experienced between 1974 and 1984. As a result, the share of GNP devoted to business fixed investment is expected to continue its rising trend, from 13.0 percent in 1985 to 13.6 percent in 1990 and 14.1 percent in 1995. This strong growth in business investment is expected to offset some of the adverse effects of the slow growth in the labor force over the next decade.
- The trade deficit, measured in real terms, is assumed to moderate as growth in exports (6.1 percent per year from 1985 to 1995) exceeds the growth in imports (3.8 percent per year.) The decline in the trade deficit in real terms is attributable to the boost given by a gradually declining dollar and the assumed recovery in the economies of U.S. trading partners.
- Federal purchases of goods and services--a 2.2-percent-per-year growth, led by a 2.8-percent per year growth in defense expenditures. These growth rates reflect tax and expenditures policies that maintain the Federal deficit in the range of $165 billion to $200 billion over the next 10 years (the Gramm/Rudman bill had not been passed when these assumptions where made).
- State and local purchases of good and services--a 2.7-percent-per- year-growth. This represents a reversal of the decline during 1981 through 1983 and reflects favorable developments for State and local finances as a result of declining unemployment rates and reductions in nominal interest rates.

Although aggregate measures of GNP are critical in the determination of overall energy use, assumptions regarding growth of manufacturing and key energy-intensive industries within the manufacturing sector also are very important. Table D2 on page 91 and Figure D1 on page 91 present the assumptions concerning trends in the five largest energy-using industries: primary metals; chemicals; stone, clay, glass; food; and paper. In 1982 these industries accounted for 72 percent of total manufacturing energy use. Key assumptions include:

- Manufacturing output is assumed to grow by 2.9 percent per year between 1985 and 1995, a rate slightly higher than the overall rate of growth expected for real GNP. Manufacturing output is assumed to grow at 3.3 percent per year from 1985 to 1990, slightly above the overall GNP growth rate of 3.1 percent for that period. From 1990 to 1995, growth in manufacturing output is assumed to be 2.5 percent per year, equalling the GNP growth rate for the second 5-year period of the forecast.
- Output from three of the five energy-intensive industries (primary metals, chemicals and rubber, and stone, clay and glass) is assumed to grow over the next 10 years at rates higher than those experi- enced between 1974 and 1984. Output from the other two major energy-using industries (paper and food) is assumed to grow at rates slightly below those experienced over the last 10 years.
- Nevertheless, each of these energy-intensive industries will experience growth lower than is assumed for overall manufacturing and for the overall economy. Relatively lower growth rates for these industries serve to dampen growth in energy demand.

High and Low Economic Growth Assumptions

The assumed rate of economic growth in the base case depends on many uncertain factors, 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 assume economic expansion, although at different rates between 1985 and 1995 (Figure D1 on page 91 and Table D1 on page 89).

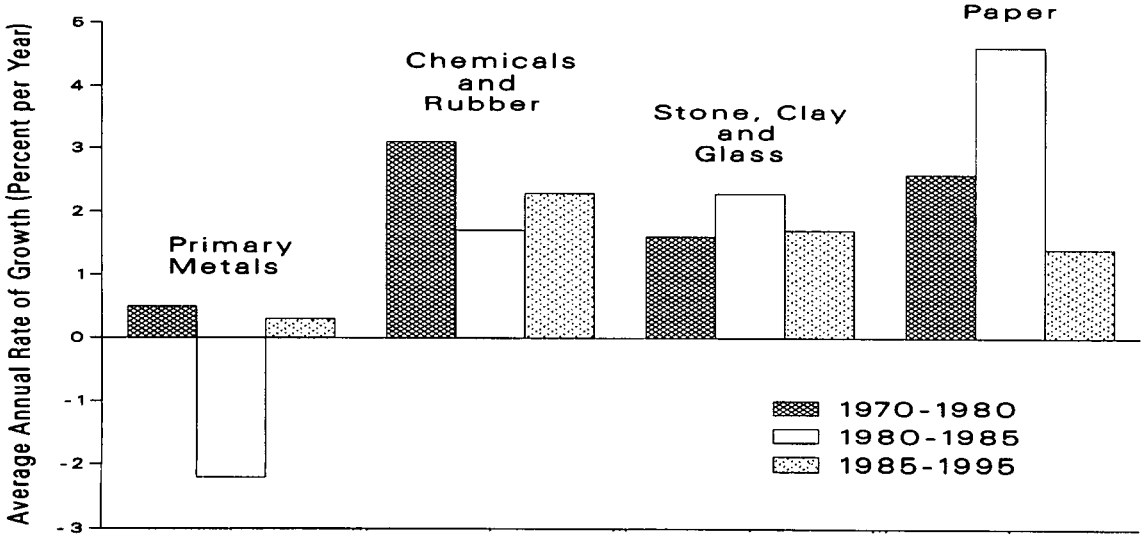
In the high oil imports case, increases in the labor force, capital stock, and technological change all are assumed to contribute more to economic growth than in the base case. Real GNP in this case is assumed to grow by about 3.2 percent per year between 1985 and 1995. The rate of inflation in the high case is assumed to average 4.4 percent per year (as opposed to 5.2 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 and lower assumed world oil prices. 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.

Table D2. Indicators of Manufacturing Output, 1974-1995

Economic Indicator	History 1974	History 1979	History 1984	Average Annual Growth 1974-1984	Oil Imports Case	Assumptions 1985	Assumptions 1990	Assumptions 1995	Average Annual Growth 1985-1995
Gross Output in Manufacturing (billion 1972 dollars)	813	929	950	1.6	High Imports	960	1,163	1,325	3.3
					Base Case	960	1,127	1,272	2.9
					Low Imports	960	1,104	1,218	2.4
Primary Metals Output (billion 1972 dollars)	72	67	52	-3.2	High Imports	53	57	57	0.7
					Base Case	53	55	55	0.4
					Low Imports	53	53	52	-0.2
Chemical & Rubber Output (billion 1972 dollars)	84	95	101	1.9	High Imports	96	113	127	2.8
					Base Case	96	109	121	2.3
					Low Imports	96	105	113	1.6
Stone, Clay, and Glass Output (billion 1972 dollars)	22	23	22	0.0	High Imports	24	27	29	1.9
					Base Case	24	26	28	1.6
					Low Imports	24	26	27	1.2
Paper Output (billion 1972 dollars)	31	34	37	1.8	High Imports	41	45	48	1.6
					Base Case	41	45	48	1.6
					Low Imports	41	45	47	1.4
Food Output (billion 1972 dollars)	119	129	142	1.8	High Imports	142	158	171	1.9
					Base Case	142	156	168	1.7
					Low Imports	142	155	165	1.5

Figure D1. Assumed Growth in Gross Output for Key Energy-Consuming Industries, 1970-1980, 1980-1985, and 1985-1995

The paper industry is projected to experience the greatest change in gross output over the forecast period from the 1980-1985 rate.



Source: Bureau of Labor Statistics, 'Time Series Data for the Input-Output Industries', (June 1985).

In the low oil imports case, real GNP growth between 1985 and 1995 is assumed to be about 2.4 percent per year, and the labor force and the capital stock are assumed to expand less rapidly than in the base case. Inflation is assumed to average 6.2 percent per year over that period because of slower expansion of productive factors and a higher assumed world oil price. Less optimistic assumptions than in the base case about domestic supply of factors of production and competitiveness in world markets are used in the low case while the reverse is true for the high case.

World Oil Prices

Base Case

The level and rate of change of world oil prices is affected by many factors, the most important being the supply and demand of oil from the Organization of Petroleum Exporting Countries (OPEC). The demand for OPEC oil is determined by the consumption patterns of the market economy countries and the supply of non-OPEC oil. The supply of OPEC oil during the last few years has been determined largely by OPEC production quotas and market forces. These production quotas have tended to stabilize price decreases, although the possibility of a price collapse currently is much greater than has been the case for many years.

The nominal price of world oil fell from a high of $37 per barrel in 1981 to $27 per barrel by the end of 1985. This decline is attributable to several factors: the energy conservation and efficiency efforts that followed the rise in oil prices in 1979, the lower rate of economic growth prior to mid-1983, and the new supplies of oil from countries other than the members of OPEC. In constant 1985 dollars, the price of oil to the United States dropped from about $44 per barrel in 1980 and 1981 to $27 per barrel in 1985. A similar reduction in the oil price did not occur in many other countries, however, because of the appreciation of the dollar relative to the 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.

In the base case, world oil prices in nominal terms are assumed to decline from about $27 per barrel in 1985 to about $25 per barrel in 1987, but then to increase in the late 1980's and into the 1990's to $50 per barrel by 1995. In constant 1985 dollars, prices are expected to rise from $23 per barrel in 1988 to $30 per barrel by 1995, still about $14 per barrel below the peak reached in 1980 (Table D3 on page 93). The current surplus capacity in world oil production of about 10 million to 11 million barrels per day is the major reason for assuming declining prices through 1988. However, much of this surplus capacity is located in the Persian Gulf region. Growth in oil production outside of OPEC is assumed to approach 27 million barrels per day in 1986, remain at about that level through 1990, and then decline steadily thereafter, particularly in Alaska and the North Sea. These declines are thought to be largely a lagged response to the relatively low world oil prices during the mid-1980's and natural production declines in existing fields. Oil exports from the Soviet Union also are assumed to decline over the projection period.

In contrast to declines in non-OPEC production, oil demands in the market economies, spurred by economic growth and relatively low oil prices, are assumed to grow by about 4 million barrels per day over the next decade, reaching about 50 million barrels per day by 1995. More than half of this demand growth is assumed to occur in the developing countries, including OPEC. Although oil consumption in the market economies is assumed to grow in absolute terms through 1995, its share of total commercial energy consumption is expected to decline from about 45 percent in 1985 to about 40 percent by 1995. Almost half of the drop in oil's share is assumed to be taken by natural gas and about a third by nuclear energy. Given growing oil demands and declining oil production elsewhere, OPEC oil production (including natural gas liquids) is assumed to grow from about 17 million barrels per day in 1985 to about 24 milion barrels per day by 1995. Oil prices are assumed to increase during the later years of the forecast horizon as the world oil market tightens.

Assumptions for High and Low Cases

Assumptions about future trends in oil consumption and supply were varied to obtain the high and low world oil price assumptions. As in the base case, prices in the high and low oil imports cases begin rising in real terms near the end of the 1980's. High and low world oil demand cases were determined by varying assumptions about economic growth, ratios of energy use to gross domestic product, non-oil fuel intensity, and the responsiveness of oil demand to price changes in the industrialized countries and other developing countries taken as a group. High and low world oil supply cases were determined by varying assumptions about oil production capacity in OPEC and production/reserve ratios in non-OPEC regions. By 1990 world oil prices in the two alternative scenarios are assumed to be as low as $22 per barrel or as high as $32 per barrel (1985 dollars). By 1995 this range widens to between $25 per barrel and $37 per barrel.

Table D3. World Oil Prices, 1979-1990 and 1995[a]

(1985 and Nominal Dollars per Barrel)

Year	Price Case		
	Low	Middle	High
	(1985 dollars per barrel)		
History			
1979		$30.70	
1980		43.98	
1981		43.85	
1982		37.45	
1983		31.50	
1984		29.93	
Assumptions			
1985	$26	27	$27
1986	21	25	27
1987	20	23	27
1988	20	23	29
1989	21	25	31
1990	22	27	32
1995	25	30	37
	(nominal dollars per barrel)		
History			
1979		$21.67	
1980		33.89	
1981		37.05	
1982		33.55	
1983		29.30	
1984		28.88	
Assumptions			
1985	$26	27	$27
1986	22	26	28
1987	22	25	29
1988	23	26	33
1989	25	30	37
1990	28	34	40
1995	41	50	61

aThe cost of imported crude oil to U.S. refiners.

Note: The deflators used to calculate the low and high price trajectories were those used in the base case.

Source: o History: Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(85/06) (Washington, DC, 1985). o Assumptions: Appendix A; Table A11.

The high and low assumptions for economic growth and world oil price assumptions were combined to represent high and low oil import cases. These two alternative cases produced a range of import levels. The high economic growth assumptions were combined with the low world price assumption to yield the high oil imports case. Conversely, the low economic growth assumption was combined with the high world oil price assumption to yield the low oil imports case. This method was chosen to represent the variation in imports that has been observed in the past.

Appendix E

Forecast Summary

Appendix E

Forecast Summary

Table E1. Summary of Energy Projections, 1985

Fuel	Base Case
Oil	(million barrels per day)
Total Consumption	15.7
Motor Gasoline	6.8
Distillate	2.9
Residual Fuel Oil	1.2
Domestic Production	11.1
Net Imports (including SPR)	4.2
	(1985 dollars per barrel)
World Oil Price	27.00
Natural Gas	(trillion cubic feet)
Total End-Use Consumption	17.8
Dry Gas Productiona	17.0
Net Imports	0.9
	(1985 dollars per thousand cubic feet)
Average Wellhead Price	2.60
Electricity	
	(billion kilowatthours)
Generation	2,457
	(billion kilowatthours)
Sales	2,317
	(1985 dollars per thousand kilowatthours)
Electricity Price (average)	66.19
Coal	
	(million short tons)
Production	886
Total End-Use Consumption	818
	(1985 dollars per short ton)
Delivered Price to Electric Utilities	35.65
	(quadrillion Btu)
Total Energy Consumption	74.8
	(percent)
GNP Growth, 1984-1985	2.3
	(thousand Btu per 1972 dollar)
Gross Energy Use per Dollar of GNP	44.6

aExcludes supplemental natural gas production.

Table E2. Summary of Energy Projections, 1990

Fuel	Case		
	Base Casea	Low Oil Importsb	High Oil Importsc
Oil			
	(million barrels per day)		
Total Consumption	16.1	15.4	16.6
Motor Gasoline	6.9	6.6	7.1
Distillate	3.1	3.0	3.2
Residual Fuel Oil	1.0	0.8	1.0
Domestic Production	10.4	10.7	9.9
Net Imports (including SPR)	5.7	4.7	6.7
	(1985 dollars per barrel)		
World Oil Price	27.00	32.00	22.00
Natural			
	(trillion cubic feet)		
Total End-Use Consumption	18.7	18.6	19.0
Dry Gas Production	17.3	17.2	17.5
Net Imports	1.9	1.9	1.9
	(1985 dollars per thousand cubic feet)		
Average Wellhead Price	2.68	2.80	2.68
Electricity	(billion kilowatthours)		
Generation	2,838	2,809	2,876
	(billion kilowatthours)		
Sales	2,651	2,623	2,686
	(1985 dollars per thousand kilowatthours)		
Electricity Price (average)	65.21	65.78	65.06
Coal			
	(million short tons)		
Production	985	976	996
Total End-Use Consumption	891	882	902
	(1985 dollars per short ton)		
Delivered Price to Electric Utilities	36.92	36.85	37.00
	(quadrillion Btu)		
Total Energy Consumption	80.4	78.7	81.9
	(annual compound rate)		
GNP Growth, 1985-1990	3.1	2.8	3.6
	(thousand Btu per 1972 dollars)		
Gross Energy Use per Dollar of GNP	41.1	40.9	40.9

aAssumes middle economic growth rate and middle world oil price.
bAssumes lower economic growth and higher world oil price than in the base case.
cAssumes higher economic growth and lower world oil price than in the base case.

Table E3. Summary of Energy Projections, 1995

Fuel	Base Casea	Case: Low Oil Importsb	Case: High Oil Importsc
Oil			
		(million barrels per day)	
Total Consumption	16.5	15.6	17.8
Motor Gasoline	7.0	6.7	7.3
Distillate	3.4	3.2	3.6
Residual Fuel Oil	1.0	0.9	1.5
Domestic Production	8.8	9.6	7.8
Net Imports (including SPR)	7.7	6.1	10.0
		(1985 dollars per barrel)	
World Oil Price	30.00	37.00	25.00
Natural Gas			
		(trillion cubic feet)	
Total End-Use Consumption	18.8	18.5	18.5
Dry Gas Production	16.5	16.4	16.1
Net Imports	2.4	2.4	2.4
		(1985 dollars per thousand cubic feet)	
Average Wellhead Price	4.03	3.82	4.12
Electricity			
		(billion kilowatthours)	
Generation	3,225	3,159	3,296
		(billion kilowatthours)	
Sales	3,026	2,964	3,093
		(1985 dollars per thousand kilowatthours)	
Electricity Price (average)	60.70	60.39	60.94
Coal			
		(million short tons)	
Production	1,116	1,101	1,129
Total End-Use Consumption	1,008	993	1,021
		(1985 dollars per short ton)	
Delivered Price to Electric Utilities	38.24	38.11	38.34
		(quadrillion Btu)	
Total Energy Consumption	84.3	81.8	86.8
		(annual compound rate)	
GNP Growth, 1990-1995	2.5	2.1	2.8
		(thousand Btu per 1972 dollar)	
Gross Energy Use per Dollar of GNP	38.3	38.4	37.8

aAssumes middle economic growth rate and middle world oil price.
bAssumes lower economic growth and higher world oil price than in the base case.
cAssumes higher economic growth and lower world oil price than in the base case.

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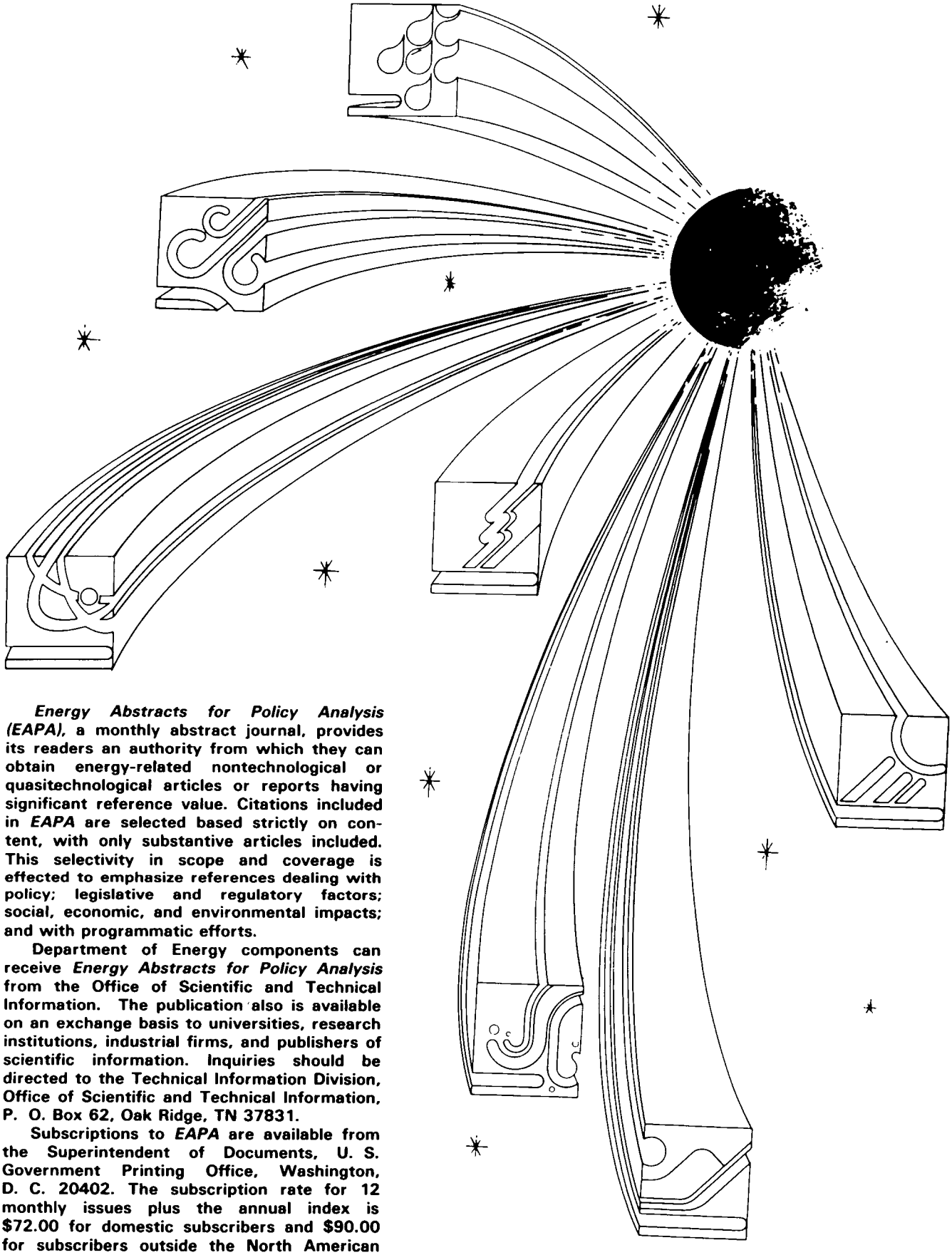

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