Chapter I

OVERVIEW

INTRODUCTION

More than a year has passed since publication of the first Project Independence Report. It has been a dynamic, controversial, and important period with respect to energy. Several events have occurred that will shape our future energy situation. This report is another look at America's ability to achieve energy independence, and the problems we face in attaining that goal.

A number of trends have become clearer that help us to forecast future energy demand and supply. Some of these make the situation appear worse, such as downward revisions in oil reserves; and some make it appear better, including upward revisions in Northern Alaskan rate of development.

In this reassessment of America's energy future, the implications of these trends have been taken into account in a set of revised forecasts. Major improvements in FEA's forecasting techniques have also been incorporated. Further, in order to sharpen the discussion of policy alternatives, the effects of alternative price regulation policies, environmental controls, and shifts in energy resource mix have been explicitly evaluated.

This chapter reviews the historical context of our present energy situation, evaluates the implications of the past year's events and then summarizes the major findings of this year's forecasts.

RECENT ENERGY TRENDS

Oil

Until the 1960's, the United States was essentially independent of foreign oil supplies. This nation produced and consumed more oil than any other country; its domestic supply was plentiful and proven reserves were growing. However, as production from older fields peaked and new exploration and development diminished because of the availability of less expensive imported oil, domestic petroleum production began to decline after 1970.

Declining supply, combined with a continued 4 percent annual growth rate in consumption, resulted in a dramatic rise in our reliance on imported oil. Import dependency has grown from 18 percent in 1960 to about 37 percent in 1975. Direct imports from OPEC now constitute about two-thirds of all imports, with Nigeria, Canada, Venezuela, Saudi Arabia, and Indonesia supplying most of our imported oil.

The rise in imports and the increase in the price of oil have placed severe burdens upon America's balance of payments for energy. In 1970, the United States paid about $3 billion for foreign oil; in 1975, our import bill was about $27 billion. Further, our vulnerability to an embargo continues to rise. Another supply cut-off could result in a large reduction in GNP and considerably greater unemployment.

As a consequence of the Arab oil embargo and OPEC price increases, both domestic crude oil and imported crude oil prices rose dramatically during the latter part of 1973 and the first quarter of 1974. Although price changes have been more gradual since then, they continued to increase. The higher prices affected all petroleum products, including motor gasoline, home heating oil, and residual fuel oil. The average retail price of gasoline has increased by about 50 percent since the onset of the embargo.

Higher crude oil prices have stimulated greater exploration activities. For the second successive year, oil wells drilled and drilling rigs in use increased; wells drilled have risen from 26,600 in 1973 to about 37,000 in 1975. The number of rotary rigs in operation in the United States increased from about 1200 in 1973 to over 1600 in 1975. However, despite the increased drilling activity, the leadtime from exploration to production is often several years; hence, the Nation's oil production continues to decline. In the two years since the Arab oil embargo, domestic production has dropped by nearly one million barrels per day (MMB/D) to a low of 8.2 MMB/D in December 1975 (see Figure I-1). In 1974, for the first time, the United States was surpassed as the world's largest oil producer -- by the Soviet Union. The completion of the Trans-Alaskan Pipeline in 1977, which will bring about two million barrels per day of North Slope oil to the "Lower 48" States, will only lift domestic production to levels reached in the early 1970's.

The higher oil prices experienced since the 1973 embargo have also had an important effect on petroleum consumption. Domestic oil demand fell by 4 percent in 1974 and an additional 2.5 percent in 1975 -- a startling reversal from the trend in recent years. Had pre-embargo trends continued, demand would have been about three million barrels per day higher than it was in 1975 (see Figure I-2). Although much of the decrease in demand is due to lower economic activity, significant reductions are a result of consumer response to higher prices. As evidence of the consumer reaction to higher prices, sales of sub-compact cars have increased considerably and the average fuel efficiency of new cars has increased from 15.6 miles per gallon (mpg.) in the 1975 model year to an estimated 17.6 mpg. in 1976.

The major legislative events affecting oil supply and demand were passage of the Energy Policy and Conservation Act (EPCA) and partial removal of the oil depletion allowance. The effects of these measures, as well as the impacts of the lower estimates of reserves published by the United States Geological Survey, are discussed later in this report.

Figure I-1

Domestic Production Of Crude Oil

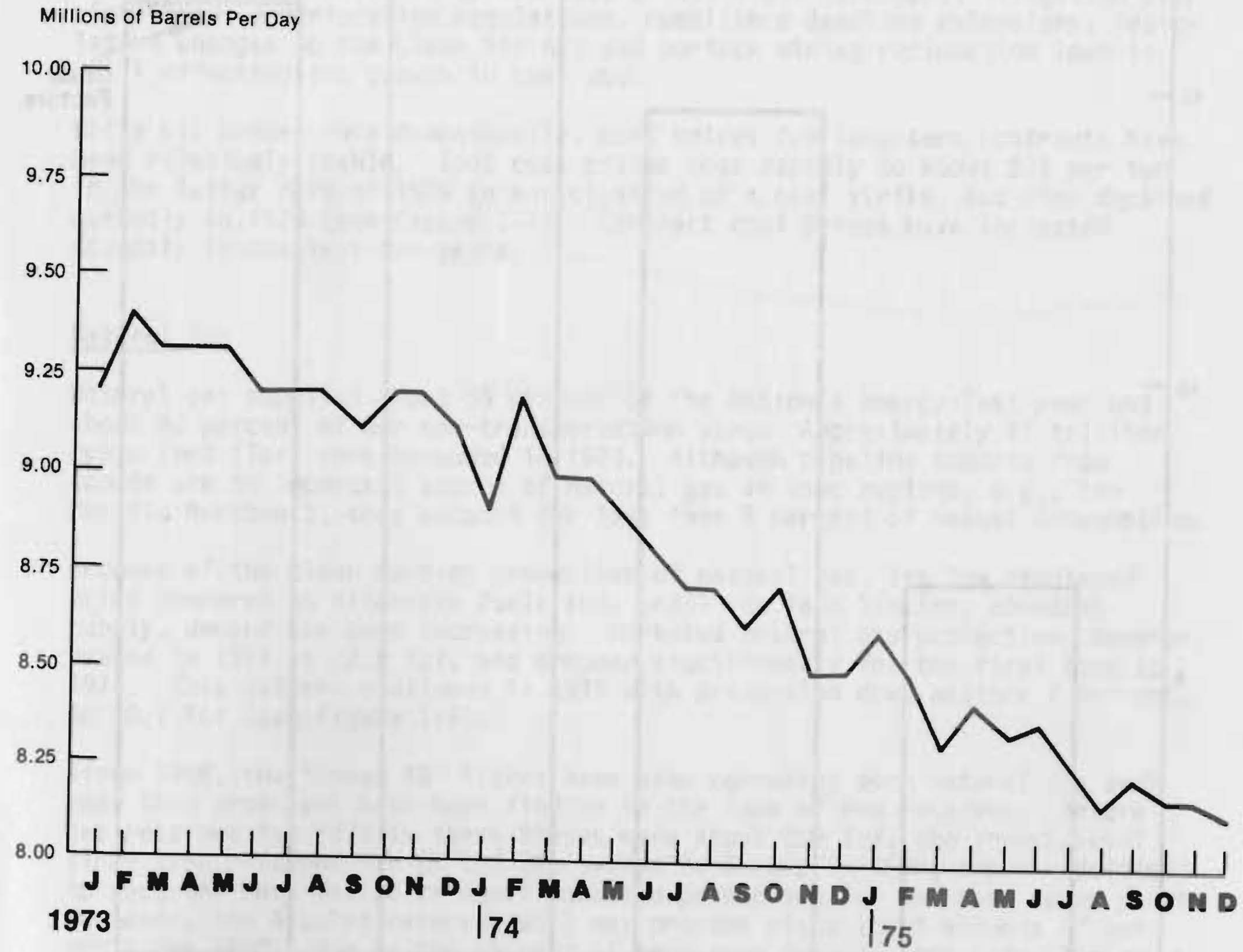
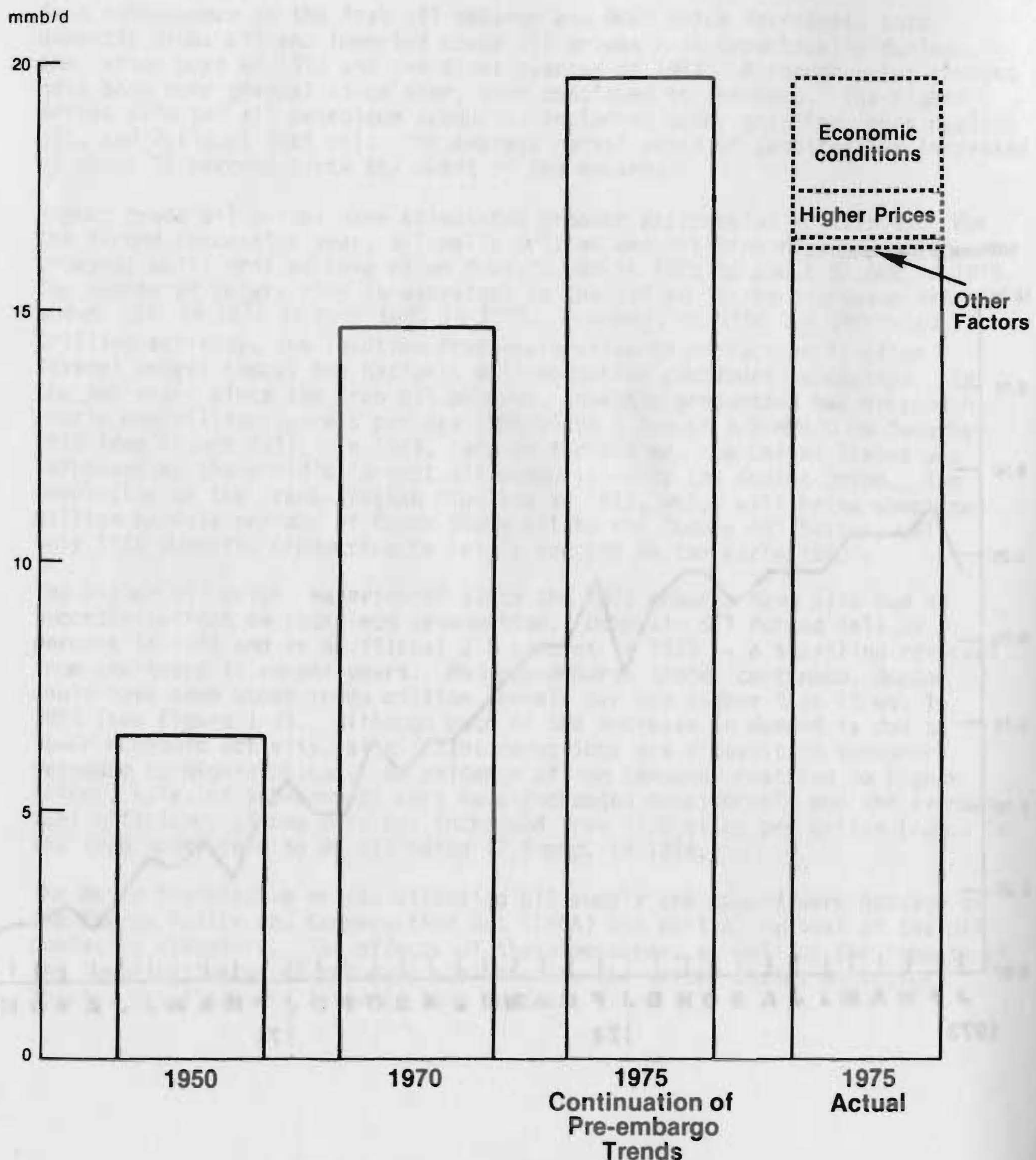


Figure I-2
Petroleum Demand Forecast vs. Actual Demand



Coal

Coal production has remained essentially level during the past five years (see Figure I-3). Production in 1970 was 603 million tons; in 1974, it was still 603 million tons; and rose to about 640 million tons in 1975. Coal production could have been higher in 1974, but about 40 million tons of production were lost due to work stoppages in that year.

Over the past 20 years coal consumption has declined in the industrial and residential sectors, while the use of coal as a boiler fuel by utilities has increased. The regulated price for interstate natural gas, the removal of import controls on residual fuel oil and its cheap imported price until the embargo, and the continued development of nuclear power have limited the growth of coal use. In the late 1960's and early 1970's, State and local air pollution regulations discouraged the burning of coal in many situations. The uncertainty about environmental issues such as interim use of intermittent control systems, reliability and cost of stack gas scrubbers, litigation over significant deterioration regulations, compliance deadline extensions, legislative changes to the Clean Air Act and surface mining reclamation laws is still affecting the growth in coal use.

While oil prices rose dramatically, coal prices for long-term contracts have been relatively stable. Spot coal prices rose rapidly to about $32 per ton in the latter part of 1974 in anticipation of a coal strike, but then declined markedly in 1975 (see Figure I-4). Contract coal prices have increased steadily in the last two years.

Natural Gas

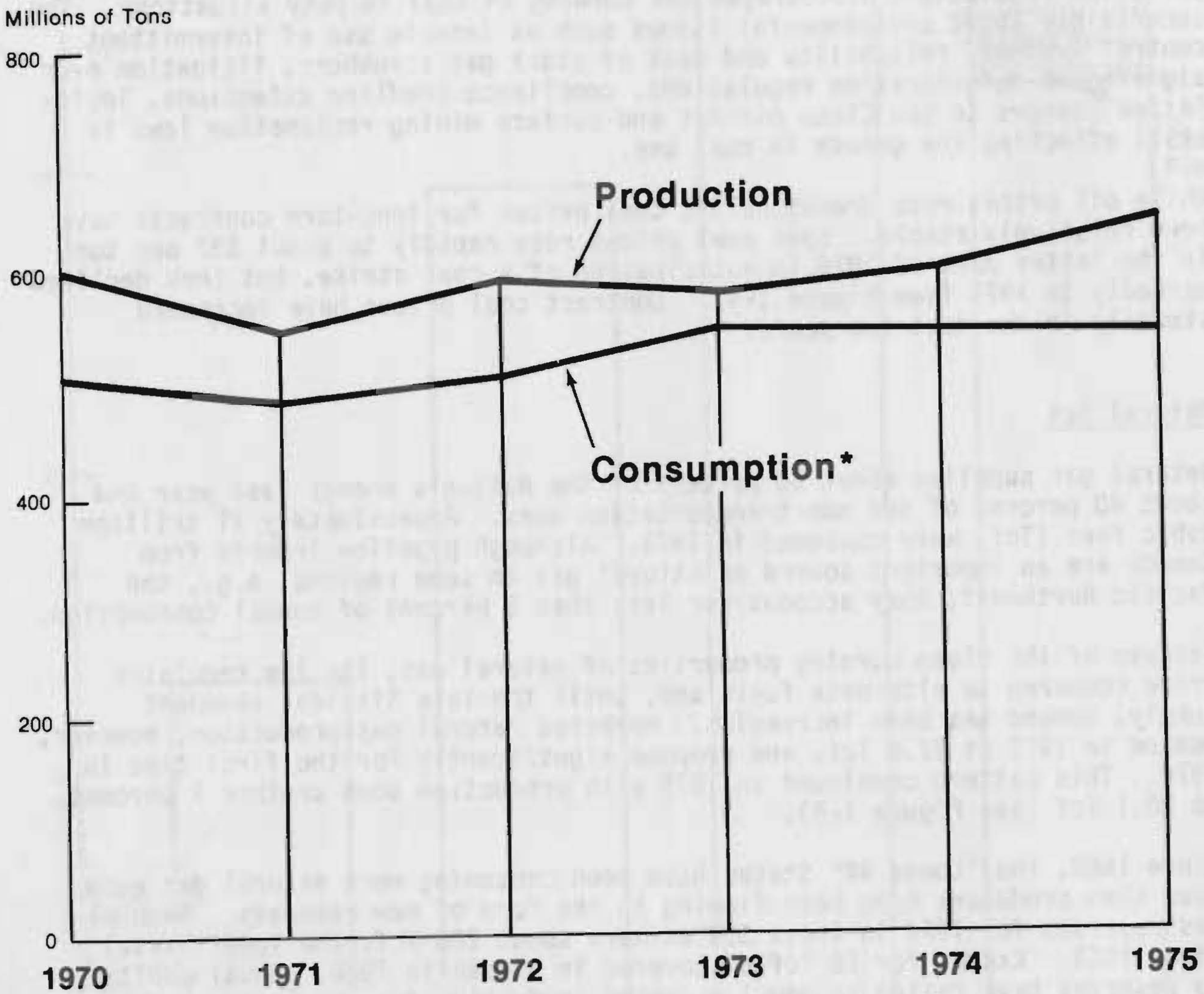
Natural gas supplied about 30 percent of the Nation's energy last year and about 40 percent of our non-transportation uses. Approximately 21 trillion cubic feet (Tcf) were consumed in 1974. Although pipeline imports from Canada are an important source of natural gas in some regions, e.g., the Pacific Northwest, they account for less than 5 percent of annual consumption.

Because of the clean burning properties of natural gas, its low regulated price compared to alternate fuels and, until the late Sixties, abundant supply, demand has been increasing. Marketed natural gas production, however, peaked in 1973 at 22.6 Tcf, and dropped significantly for the first time in 1974. This pattern continued in 1975 with production down another 7 percent, to 20.1 Tcf (see Figure I-5).

Since 1968, the "Lower 48" States have been consuming more natural gas each year than producers have been finding in the form of new reserves. Natural gas reserves for 1974 in these States were about 208 Tcf, the lowest level since 1952. Except for 26 Tcf discovered in Alaska in 1970, annual additions to reserves have failed to equal marketed production for the past seven years. Moreover, the Alaskan reserves will not provide significant amounts of gas until the 1980's due to the absence of necessary transportation facilities.

Figure I-3

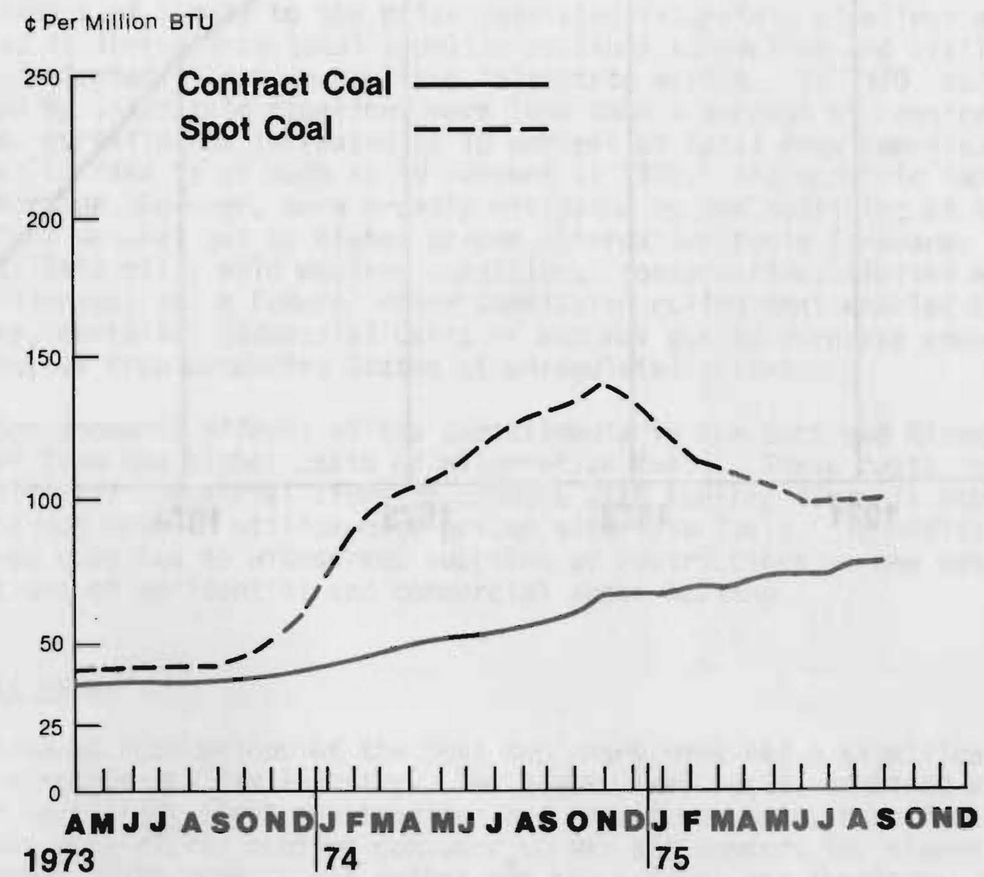
Annual U.S. Coal Production and Consumption



*Excluding Exports

Figure I-4

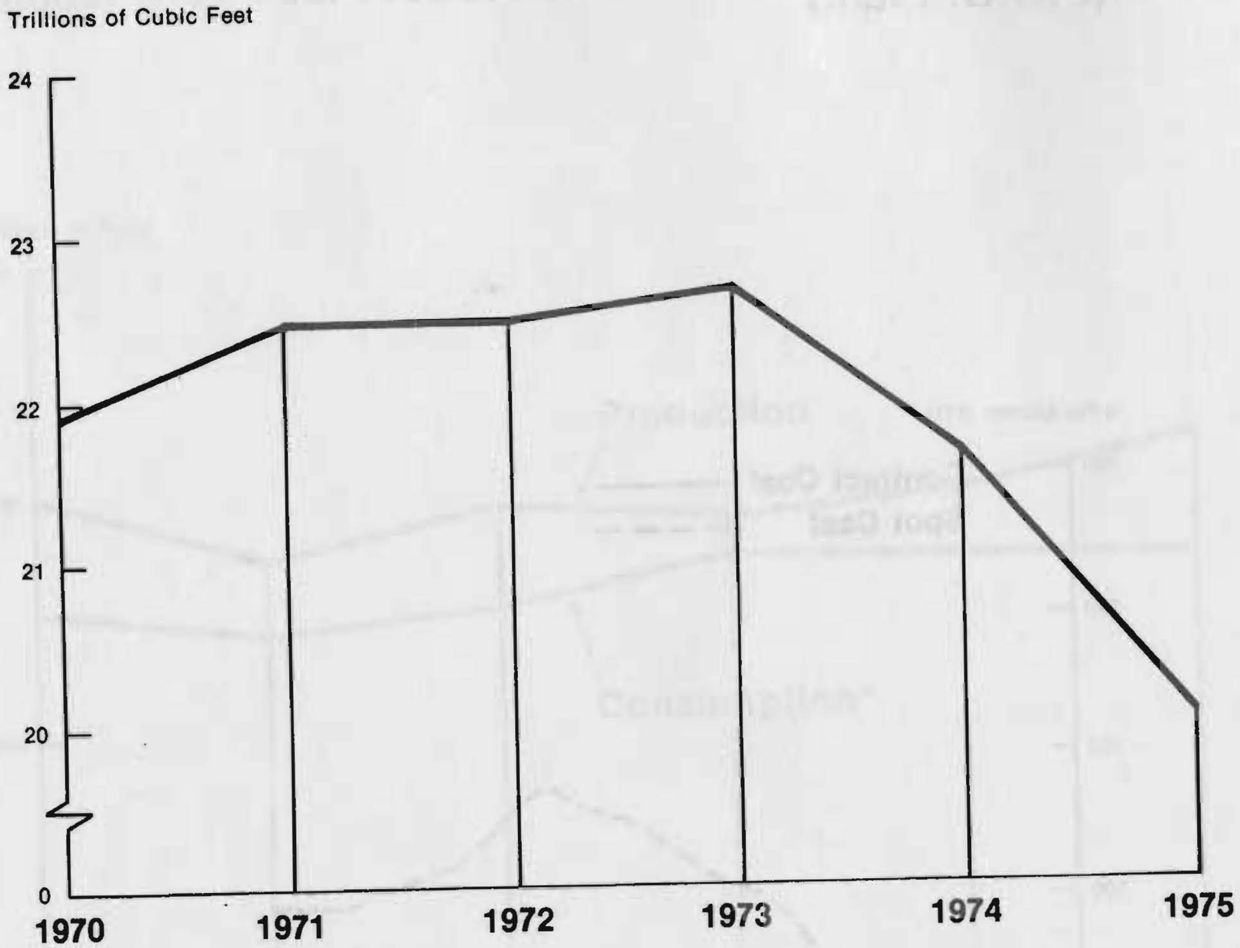
Average Coal Prices
(F.O.B. Plant)



Source: FPC

Figure I-5

U.S. Natural Gas Annual Marketed Production



Low regulated prices have encouraged consumption and discouraged the search for new gas to supply the interstate market. Within the past five years, intrastate prices have been rising faster than the regulated prices for gas sold to interstate pipeline companies. As a consequence, the disparity in new contract prices between intrastate and interstate markets has widened considerably. Producers have been selling gas under new contracts at an average price of $1.00 to $1.50 per thousand cubic feet (Mcf) in the intrastate market compared to the regulated interstate ceiling price of 52 cents per Mcf. Since 1970, this price differential has led to the development and sale of most new natural gas within the state where it is produced. Over 90 percent of all reserve additions since 1970 have been dedicated to intrastate markets in contrast to a 60 percent figure for the five previous years (see Figure I-6).

Six States - Texas, Louisiana, Oklahoma, California, New Mexico, and Kansas - accounted for 93 percent of domestic production in 1974; Texas and Louisiana alone provided 73 percent. In 1974, approximately 50 percent of domestic consumption of natural gas was in these six States, largely because of industrial relocation in the 1960's and use of natural gas by chemical manufacturers and electric utilities in these States.

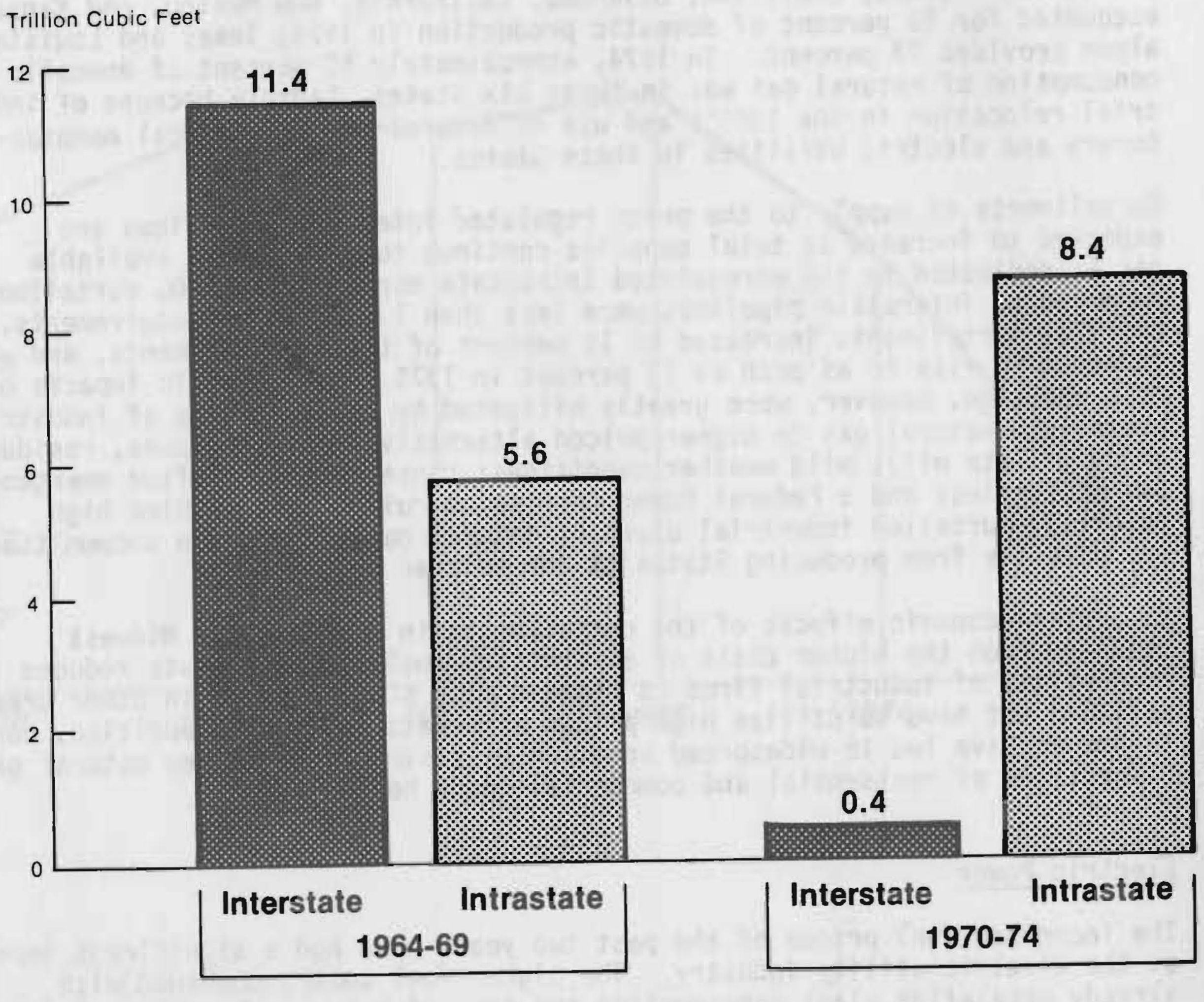
Curtailments of supply to the price regulated interstate pipelines are expected to increase as total supplies continue to decline and available gas is dedicated to the unregulated intrastate market. In 1970, curtailments reported by interstate pipelines were less than 1 percent of requirements. By 1974, curtailments increased to 10 percent of total requirements, and were forecast to rise to as much as 15 percent in 1975. The economic impacts of this shortage, however, were greatly mitigated by the switching of industrial users from natural gas to higher priced alternative fuels (propane, residual or distillate oil); mild weather conditions; conservation; limited emergency gas deliveries; and a Federal Power Commission ruling that enabled high priority, curtailed industrial users of natural gas to purchase uncommited gas directly from producing States at unregulated prices.

The major economic effects of the curtailments in the East and Midwest resulted from the higher costs of alternative fuels. These costs reduced the ability of industrial firms to compete with similar firms in other areas that did not have to utilize high-priced alternate fuels. In addition, curtailments have led to widespread adoption of restrictions on new natural gas connections of residential and commercial space heating.

Electric Power

The increased fuel prices of the past two years have had a significant impact on the electric utility industry. The higher fuel costs, combined with already escalating plant construction and operating costs, have forced higher rates for electricity causing consumer unrest and demands for changes in rate structures. With today's oil prices and the natural gas shortages, the economics of new plants has shifted to coal and nuclear power. Higher prices have also reduced demand and this, in turn, is likely to reduce future

Figure I-6
Average Annual Reserve Additions of Natural Gas



Source: American Gas Association, Federal Power Commission.

capacity needs. These effects, coupled with continuing debate over environmental, siting and safety issues, and financial problems in the utility industry, have introduced significant uncertainties into the outlook for electricity growth.

For many years, electric power demand grew at an annual rate of about 7 percent. Additions to generating capacity planned for the years through the early 1980's were based on this pre-embargo rate of demand growth. In 1974, however, the growth rate for electricity fell to zero and only increased by about 2 percent in 1975. This phenomenon is largely attributable to reduced consumption in response to higher prices and the economic slowdown.

Prices have risen most significantly in regions which rely heavily on residual oil for electric power. New England and the Mid-Atlantic, for instance, recorded price increases averaging more than 35 percent in 1974 and consumption declined significantly.

The financial situation of electric utilities has been dramatically affected by higher fuel costs, which necessitated large rate increases and hardened resistance to further rate adjustments. At the same time, lower capacity utilization, lengthening times of licensing and construction, and high inflation associated with new plant construction required even greater rate increases if utilities were to finance new plants. When these were not forthcoming, their ability to raise new debt or equity was impaired, and the cash shortage caused cancellation or deferral of many new plants. While the situation has improved somewhat in the past year, financial problems are still evident.

The fuels used to generate electricity have shifted in recent years, with the nuclear share of electricity production growing sharply from 4.5 percent in 1973 to about 8.6 percent estimated for 1975 (see Figure I-7). Although nuclear power has the lowest variable operating costs and is insensitive to oil price fluctuations, nuclear plants require the largest capital investment and the longest construction leadtime of any type of electric generating plant. Consequently, they have been the most heavily affected by recent plant deferrals and cancellations. Since June 1974, orders for over 100,000 megawatts of planned nuclear capacity have been cancelled or postponed. These cancellations and deferrals amount to almost 70 percent of planned additions. Nevertheless, with the drop in electricity growth and the additions of new plants, reserve capacity is now 34 percent, compared with a traditional level of 20 percent.

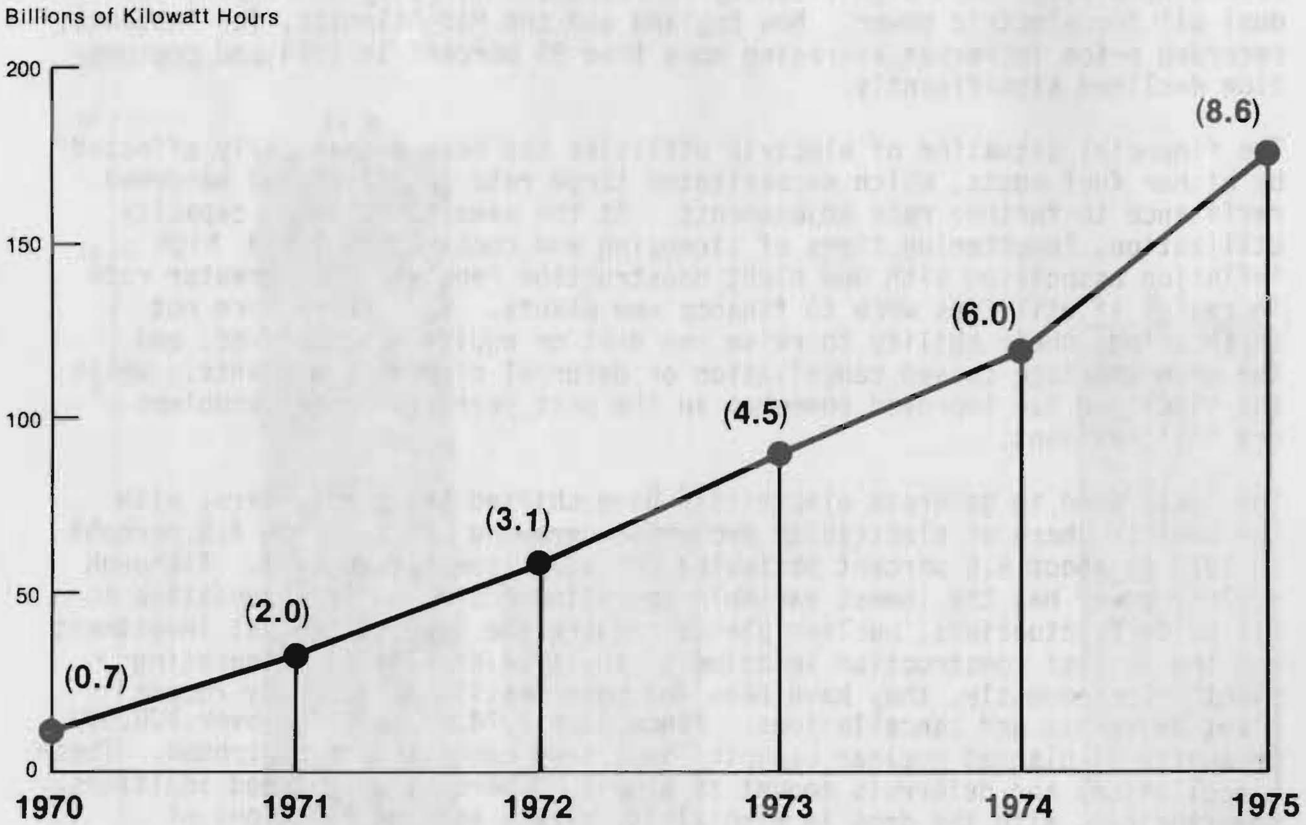
International Energy Perspective

The shock wave felt throughout America and the rest of the oil importing countries at the onset of the Arab embargo has subsided. Consumer nations have reacted sharply to the higher world oil prices. The International Energy Agency (IEA) was established under the aegis of the Organization for Economic Cooperation and Development. Supply security has been a primary concern, but considerable attention has also been given to the issue

Figure I-7

Nuclear Power Generation by Year

(Percentage of Total Electric Power Generation)



of higher oil prices and longer-term energy matters. The IEA has developed an emergency program which calls for a coordinated response in the event of a future oil embargo. IEA members have also developed plans for long-term cooperation on conservation, research, resource development, and access to supply.

As higher prices and conservation reduced world oil demand, OPEC has been forced to reduce production to prevent prices from falling. Excess OPEC productive capacity has increased greatly since the embargo and now amounts to an estimated 10-12 million barrels per day, or one-third of total OPEC capacity. OPEC production, which had increased steadily for nine years, declined from 31.2 million barrels per day in 1973, to about 27 million barrels per day in 1975. The major cutbacks were absorbed by Saudi Arabia, Libya and Kuwait. Nevertheless in 1975, OPEC's members approved a 10 percent increase in the price of Saudi Arabian marker crude oil, from $10.51 per barrel to $11.56.

FORECASTING OUR ENERGY FUTURE

The Analytical Base

Against this background of energy developments, a number of changes were made in this year's analysis. The FEA forecasting model -- the Project Independence Evaluation System (PIES) -- was improved to reflect current energy data and new strategies were evaluated.

The PIES system is a model of the technologies, leadtimes, costs and geographical locations which affect energy commodities from the point of discovery, through production, transportation, conversion to more useful forms, and ultimately consumption by all sectors of the economy (see Appendix A for a description of the PIES integrating model). Consumption (final demand) for a particular fuel depends on prices for that fuel, the prices of substitute fuels, the general level of economic activity, and the ability of consumers and capital stocks to adjust to these factors (see Appendix B for a description of economic assumptions). For each year of analysis, FEA forecasts the demand for refined petroleum products, natural gas, electricity, and coal. These fuel demands are made for each Census region and for each end-use consuming sector -- residential and commercial, industrial, and transportation. These demand forecasts are based on estimated prices and vary as prices change (Appendix C discusses the demand model in more detail).

Energy supply is estimated separately for oil, natural gas, and coal. For each fuel, many different regions are separately evaluated to assess the differences between OCS and Alaskan oil or Appalachian and Western coal. For each region and fuel, reserve estimates are combined with the technologies and costs of finding and producing these fuels to estimate the cost of increasing supply (see Appendix D for a discussion of the supply models). Major improvements have been made in the oil and gas models to estimate drilling patterns, link finding rates and enhanced recovery directly to revised reserve estimates, and account for changes in the depletion allowance. The coal supply estimates distinguish between various sulfur and Btu contents.

The PIES then attempts to match these energy demands as a function of fuel, sector, and price with the available supply in the regions which can supply these needs at the lowest price to find a balance or equilibrium. If supply is not available to satisfy the specific demands in an area, the prices are allowed to vary until supply and demand are brought into balance.

Alternative Scenarios

While there are an infinite number of possible energy policy strategies for the United States, last year's report examined four alternatives -- business as usual, accelerated supply, accelerated conservation, and a combination of accelerated supply and conservation. These four broad scenarios were chosen because they depicted a range of feasible actions that could be expected to lead to very different energy outcomes by 1985.

The scenarios discussed in this report still evaluate the impacts of accelerated development and conservation, but the scope of analysis has been expanded to include different government price controls and regional growth restrictions, expectations about geologic and resource potential, and the effects of a greater use of electricity. These energy scenarios do not represent FEA or Administration policy recommendations. They are neither comprehensive, nor mutually exclusive. Each is intended to illustrate a major trend or impact of a possible policy direction and to show the implications of some of the more extreme energy policies being considered. The intent is to provide a spectrum of alternatives that can be used to evaluate specific proposals. The scenarios are described in more detail in Appendix E.

ENERGY THROUGH 1985: THE FEA FORECAST

International Oil Price

Any analysis of the domestic energy outlook must begin with a perspective on future world oil prices. The world oil price will greatly influence domestic energy demand and the economic feasibility of producing various high cost sources of domestic supply. The events of the past two years have indicated an ability by the oil producing cartel to maintain the high prices of oil established during the embargo, even in the face of substantial declines in world oil demand due to the high prices and reduced rates of world economic growth. It seems clear that little can be done between now and 1980 to alter the supply and demand relationships between OPEC and consuming nations enough to weaken the cartel's exclusive control over prices. Thus, there is no significant likelihood of a considerably lower price for OPEC oil in this period.

Nevertheless, there are political factors which are likely to be as important in determining the viability of the cartel as economics. The dynamic relationships among producers and consumers will be crucial during this period. Further, the major consumer nations have each initiated programs to cope with higher energy prices and excessive dependence on foreign oil. Although consumer nations have not yet implemented all these programs to apply downward pressure on cartel prices, pressure can be brought by aggressive resource development and conservation actions to stabilize prices.

Recognizing the uncertain nature of world oil price dynamics, FEA continues to forecast at various world oil prices. It is almost certain that the era of $3-4 per barrel oil is over, and thus our analysis considers a range which brackets current prices ($8-16). Most of the analytical emphasis, however, is placed on a continuation of current prices (about $13 per barrel c.i.f. United States, in 1975 dollars). The $8 and $13 prices are almost equivalent to the $7 and $11 prices (in 1973 dollars) used in last year's report, accounting for inflation.

Energy Consumption

The analysis of our energy future begins with a discussion of one set of forecasts of what can reasonably be expected to happen if present government policies and market forces are allowed to operate. In most respects, the Reference Scenario in this analysis is similar to last year's Base Case and is designed to illustrate the major technical and data changes between 1974 and the present. Numerous assumptions are needed to make this forecast; the impacts of changing these assumptions are described later in the chapter.

If current prices continue, energy demand should increase from 72.9 quadrillion Btu (quads) in 1974 to 98.9 quads in 1985 (see Table I-1). This is a growth rate of 2.8 percent, compared with the recent historical rate of 3.6 percent. Appendix F contains the complete computer output of this $13 Reference Scenario and a description of how to read it.

The greatest growth will occur in electric generation, which will continue to grow at about twice the rate of total energy consumption (or about 5.4 percent annually), although more slowly than in the past. In the Electric Sector, however, the forecast of additions to nuclear capacity has been reduced considerably from last year's levels, as will be discussed later in this chapter.

The rate at which energy demand will grow and distribution of demand by end-use sector is highly sensitive to the price of imported oil. For example, in the Reference Scenario, at $13 prices, demand grows at 2.8 percent annually; if world prices drop to $8 per barrel, the growth rate would be increased to 3.2 percent (see Appendix G for a summary of the results for all scenarios and prices analyzed by FEA).

Table I-1

ENERGY DEMAND BY SECTOR, 1985
(Reference Scenario at $13 Imported Oil)
(Quadrillion Btu)

	Coal	Petroleum	Natural Gas	Nuclear	Other	Total Gross Inputs	Utility Electric Distributed
Household/Commercial	0.1	8.2	6.4	--	--	14.8	6.4
Industrial	4.8	8.2	14.0	--	--	27.1	3.9
Transportation	--	22.4	0.8	--	--	23.2	
Electrical Generation	15.4	2.7	3.1	8.7	3.9	33.7	(10.3)
Other	0.3	--	(0.2)	--	--	0.1	--
Total	20.6	41.5	24.1	8.7	3.9	98.9	--

There are major changes in the growth rate to be experienced in each end-use sector. The most pronounced change is in the Household/Commercial Sector which is expected to experience a considerable reduction in growth (1.7 percent at $13 oil prices, as compared to 3.8 percent in recent history). This lower growth rate is in response to higher prices and slower projected population growth in the coming decade. Since about 30 percent of industrial use of oil is insensitive to price (feedstock), industrial energy use will grow at about the historic rate in spite of higher prices. Whereas total energy use for transportation grew historically at 3.1 percent, it is expected to grow at about only 2.1 percent through 1985 if today's high oil prices continue (see Table I-2). The figures in Table I-2 assume net electricity

Table I-2

ENERGY GROWTH RATES BY SECTOR, REFERENCE SCENARIO
(Percent/Year)

	1952-1972	1974-1985 at $8/bbl.	1974-1985 at $13/bbl.
Household/Commercial	3.8	2.4	1.7
Industrial	2.6	2.9	2.6
Transportation	3.4	2.9	2.1
Electrical Generation	7.3	5.2	5.4
Total	3.6	3.2	2.8

distributed among sectors, but not inputs of electricity. Since about two-thirds of the energy used to generate electricity is lost before end-use, the growth rate would be higher in some sectors (particular Household if gross electricity inputs were accounted for in the Table.

Petroleum Consumption

Petroleum demand is naturally most sensitive to oil prices. This is particularly evident in the Electric Sector, where petroleum and coal are readily substitutable in new facilities based on their relative economics. For example, at $8 oil prices, in 1985, 8.3 quads (about 3.8 MMB/D) of petroleum are used to generate electricity; whereas only 2.7 quads of petroleum are forecast for this sector at $13 prices. As a result, coal replaces oil in electric generation at higher import prices, and coal use in utilities increases by over 137 million tons if oil prices shift from 8 to 13 dollars per barrel. This shift occurs because electricity from a new baseload coal plant is cheaper than from an oil-fired plant if oil is above $9.00 per barrel. Further, when oil is above $10.50 per barrel, it is economic to build a new coal plant for baseload and to shift an existing oil-fired plant to intermediate load.

Overall, the 1985 forecast use of petroleum is 20.7 MMB/D at $13 prices, but would be 4.9 MMB/D higher at $8 prices (see Table I-3).

Table I-3

PETROLEUM CONSUMPTION ACROSS PRICES
REFERENCE SCENARIO
(MMB/D)

	1974 Usage	1985 Demand at $8/bbl (growth rate)	1985 Demand at $13/bbl. (growth rate)
Household/Commercial	3.4	4.8 (4.6)	4.0 (2.8)
Industrial	3.1	4.6 (3.8)	4.2 (3.1)
Transportation	8.7	12.4 (3.3)	11.5 (2.1)
Electrical Generation	1.5	3.8 (8.3)	1.2(-2.3)
Total	16.6	25.6 (4.0)	20.7 (2.0)

Even at $13 per barrel import prices in 1985, there is still a considerable amount of petroleum being utilized in the Industrial and Electric Generation Sectors. The electric use is mainly in currently existing powerplants used solely for intermediate or peak loads. These facilities are still attractive, despite the higher operating costs, because they are run relatively infrequently, and because the cost of construction has already been incurred.

The industrial demand for petroleum tends to be relatively insensitive to price since about 30 percent of the use is as a raw material, where alternative fuels cannot be physically substituted. The Transportation Sector accounts for more than half of petroleum demand. Higher gasoline prices, along with recent enactment of mandatory auto fuel efficiency legislation, should bring about the purchase of more efficient automobiles.

Petroleum demand is also greatly affected by the policy scenario chosen. Demand could range from about 18.7 MMB/D in 1985 if stringent conservation measures are taken (thermal efficiency standards, expanded industrial program and other actions in the Conservation Scenario) to 23.2 MMB/D in the $13 Supply Pessimism Scenario in which oil prices are regulated below import prices, thereby encouraging greater use. The increased demand in the regulation case occurs in the Electric Generation Sector, where demand for oil rises from about 750,000 barrels per day to over 3.1 million barrels per day by 1985.

The recent enactment of the Energy Policy and Conservation Act in December, 1975, is expected to reduce petroleum demand by about 2.5 MMB/D. This reduction is due primarily to automobile fuel efficiency standards, appliance labeling, and state conservation programs contained in the Act.

Electricity Consumption

Electricity has been growing about twice as fast as the total of all energy sources in the last twenty years and will continue to do so, although at a slower overall rate. In the Reference Scenario, FEA estimates that electricity will grow at a rate of 5.4 percent from 1974-1985, if present world oil prices continue.

The demand for electricity is one of the large uncertainties in our energy future and affects coal, nuclear, oil, and gas consumption. If electricity grows more slowly or quickly than expected, coal demand could be affected dramatically. Electricity tends to displace direct use of oil and natural gas in households and industry, and since nuclear growth through 1985 is constrained by long leadtimes for new plants, the next cheapest source of electric power -- coal -- becomes the economic fuel for swing capacity. For each 1 percent change in the electricity growth rate from 1974-1985, coal consumption changes by 150 million tons in 1985, provided that coal plants can be completed in time.

An area of key concern with electricity forecasts is the impact of forecasting errors. The capital intensity of electric power generation and the leadtimes for new construction can make errors in this sector particularly expensive, both in financial terms and in the effects on import dependence. If actual consumption grows more slowly than forecast, utilities may have overbuilt and find themselves with idle capacity. This idle capacity is expensive for consumers, since the carrying and overhead costs must be paid whether or not the equipment is used. For example, if demand growth is actually 1 percent

below forecast, utilities could have almost $50 billion of excess capacity in 1985, and the added cost of carrying extra capacity could be $7.2 billion annually, requiring an 8 percent increase in electric utility revenues.

Equally important, if not more critical, are the costs if consumption will be higher than forecast. In such a situation there are two possibilities. First, utilities recognizing possible shortages may build oil or gas fired plants to meet the extra demand. These plants can be built relatively quickly (3-5 years), are less capital intensive than coal or nuclear plants, but involve higher fuel costs, will raise consumer bills, and utilize fuels that will have to be imported, contrary to a goal of reduced vulnerability. For example, if demand growth is 1 percent faster than expected and oil and gas plants must be used to meet the extra needs, imports could rise by over one million barrels per day in 1985. Moreover, it is possible that gas turbine manufacturing capacity could be limited as manufacturers close existing facilities because of poor initial market conditions.

A second possibility, which may occur if demand surges in a 2-3 year period, is low reserve margins that could imperil supply reliability. Reserve margins should remain adequate in most areas through the 1970's, since many additions to capacity have continued despite low demand growth. However, adequacy is less certain for the 1980's.

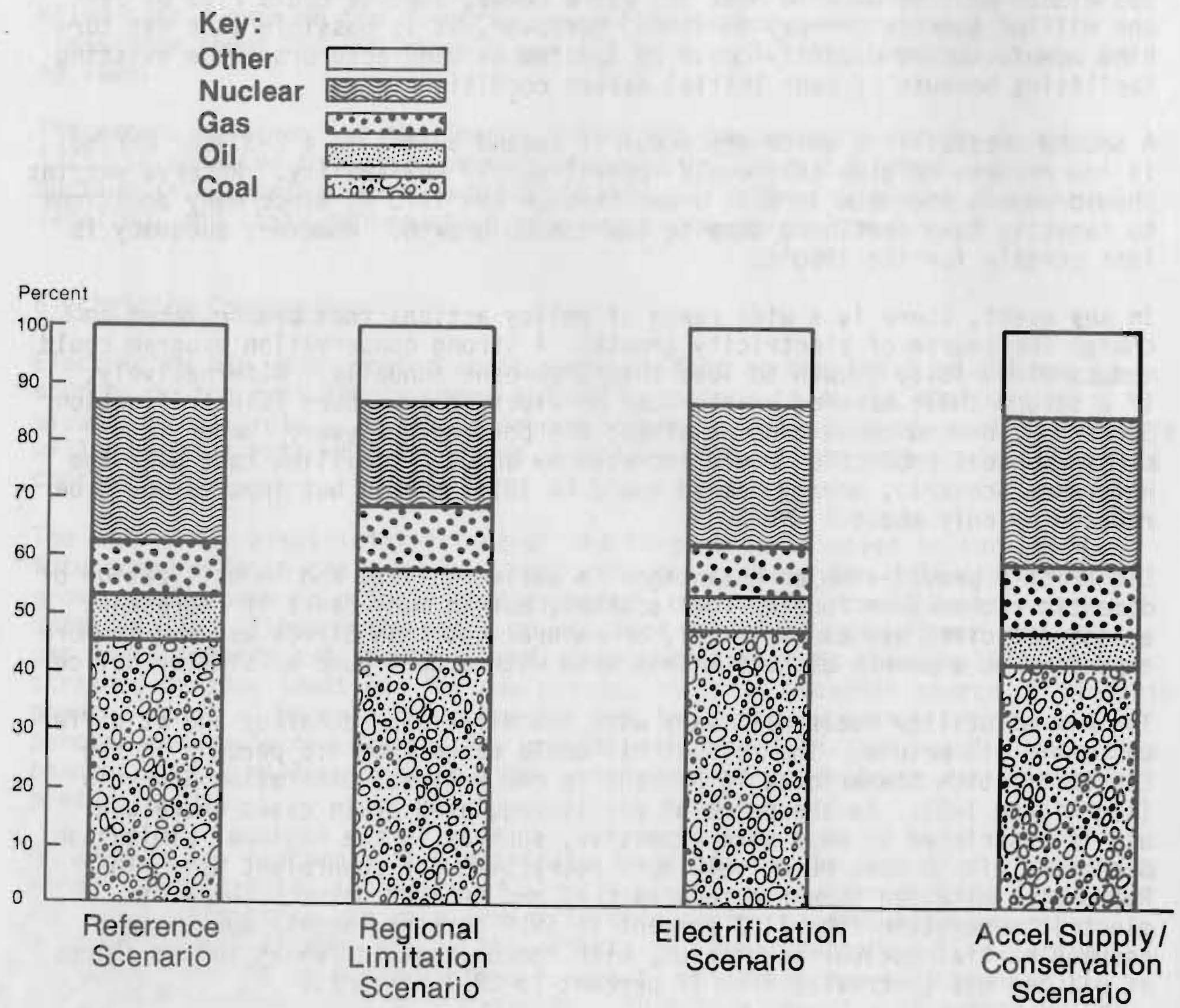
In any event, there is a wide range of policy actions that can be taken to change the course of electricity growth. A strong conservation program could reduce electricity growth to less than 5 percent annually. Alternatively, if a strong shift towards greater use of electricity occurs (Electrification Scenario), demand could grow at almost 6.5 percent per year. Under this scenario, coal production would increase by about 220 million tons over the Reference Scenario, energy demand would be 101.5 quads, but imports would be reduced by only about 1 MMB/D.

Electricity provides major advantages in deliverability and in utilization of domestic rather than foreign fuel sources, but in many cases it represents a less efficient use of coal, oil, or natural gas than direct use and is more expensive as a source of heat unless used with a heat pump or similar device.

The mix of utility fuels will vary with the different scenarios and at different world oil prices. The role of oil could range from 4.5 percent in the Electrification Scenario to 16 percent in the Regional Limitation Scenario (see Figure I-8). As the price of oil is regulated or in cases where coal use is restricted or made more expensive, such as in the Regional Limitation Scenario, oil becomes relatively more attractive for powerplant use. The Regional Limitation Scenario reduces coal and nuclear power's share of electric generation from 71.3 percent to 59.6 percent largely due to an assumed partial nuclear moratorium, with concomitant increases in the shares of oil and gas (increases from 17 percent to 28.1 percent).

Figure I-8

1985 Utility Fuel Mix
($13 Imported Oil)



Coal Consumption

The bulk of the 72 percent increase forecast for coal consumption in the 1974-1985 period will occur in the Electric Utility Sector (see Table I-4).

Table I-4

1985 COAL CONSUMPTION AT $13 OIL PRICES, REFERENCE SCENARIO
(Million Tons)

	1974*	1985	Growth Rate (Percent/Year)
Electric Utilities	390	715	5.7
Household/Commercial	11	5	-6.9
Industrial	94	151	4.4
Metallurgical	63	73	1.3
Synthetics	0	16	
Exports	60	80	2.4
Total	618	1040	4.8

* Coal consumption in 1974 was greater than production due to changes in inventory.

The greatest increases in electric generation from coal are expected to be in the East, Midwest, and Southwest. This indicates that the trend towards oil burning plants in the East will be reversed and that natural gas baseload plants in the Southwest will be phased out. The actual coal consumption in the Electric Sector will depend upon environmental standards, availability of coal transportation, surface mining regulations, and other factors discussed later in this chapter.

Other sectors are anticipated to have little growth potential for coal. Opportunities for coal consumption by the Industrial Sector are limited by the cost of complying with air pollution control requirements and the diseconomies of scale for handling coal in small quantities. In addition, synthetic fuels from coal are not yet competitive at $13 per barrel prices and are not expected to develop substantially until the late 1980's.

Natural Gas Consumption

Natural gas usage is projected to increase slightly through the next ten years, assuming deregulation of new natural gas prices. Natural gas usage under the Reference Scenario would be 23.4 Tcf in 1985 (this assumes marketed domestic production of 22.3 Tcf in 1985, with the balance being met by LNG imports and Canadian pipeline imports), as compared to about 21 Tcf in 1974. If present regulations continue and the maximum feasible level of gas imports is allowed, consumption would be about 20.9 Tcf in 1985, and could be even lower if LNG is not available. Natural gas use is constrained by the limited availability of inexpensive supply. Much of the more readily accessible domestic source is already dwindling before liquefied natural gas (LNG) imports, synthetic fuels, and Alaskan gas can have much impact.

There is also considerable uncertainty with respect to the distribution of natural gas among consuming sectors. FEA forecasts that gas consumption in industry will grow and that residential use will be reduced. This has been the national trend in the past few years, but in some regions the pattern of growth has been different. The sectoral distribution of gas use is an area of major uncertainty requiring further analysis.

Residential consumption declined in 1972-1975 mainly because gas deliveries to the interstate market, particularly in the Mid-Atlantic and Midwest, have been declining; weather has been considerably warmer than usual in the last two winters; and new residential natural gas connections have been restricted in many areas. On the other hand, the intrastate market, where most of the industrial demand is located, continues to be strong. With industrial users of natural gas in the interstate market generally having the lowest priority during curtailments, many industries are voluntarily switching from natural gas to electricity, coal, or in some cases, oil to assure supply reliability.

The FEA Reference Scenario forecast of natural gas use is made under the assumption of deregulation and market clearing prices. The higher natural gas prices would reduce demand, as natural gas prices increase more than those of other fuels. There is a large uncertainty concerning the relative proportion of natural gas, heating oil, and electricity use in the Household/Commericial Sector. Distribution costs for gas to this sector are higher than for oil, and could make gas more expensive to consumers. Electricity prices are expected to remain relatively constant (in real terms) in the Household/Commercial Sector, whereas natural gas prices under deregulation would increase significantly, and thus electricity could penetrate further in this sector. Industrial users, however, may retain the flexibility to use gas if its relative price is lower than other fuels.

The ultimate choices made by consumers depend greatly on their perception as to gas availability in the future. The distribution of a commodity such as natural gas is a major policy question. If natural gas prices continue to be regulated, curtailments of service will persist and most industrial use may have to be severely limited. The FEA analysis, with its uncertainty in this sector, indicates that in a higher price environment, the Household/Commercial Sector may move away from natural gas more than the Industrial Sector.

Effects of Conservation

It is clear that energy demand can vary substantially depending upon policy actions taken to change consumption patterns. In particular, the actions assumed in the Conservation Scenario can reduce demand by the equivalent of about 2.9 million barrels per day (6 quads) and imports by about 2 million barrels per day (see Table I-5).

Table I-5

IMPACT OF ENERGY CONSERVATION ACTIONS

	1985 Energy Savings (MMB/D)	1985 Oil Import Reductions (MMB/D)
Transportation Sector:		
Auto Efficiency Standards	1.0	1.0
National Van Pool Program	0.1	0.1
Improved Airline Load Factors	0.1	0.1
Household/Commercial Sector:		
Thermal Efficiency Standards for New Buildings	0.3	0.3
Appliance Standards for Labeling	0.2	0.1
Insulation Tax Credit	0.1	0.1
Elimination of Gas Pilot Lights	0.2	0.2
Industrial Sector and Others:		
Industrial Energy Conservation Program	0.6	0.3
Increased Dispersed Solar Equipment	0.1	--
Solid Waste Energy Combustion	0.2	--
Total	2.9	2.2

The measures in this Scenario are not all proposed by the President or intended to represent the only possible conservation program. They are, however, an indicator of the level of energy savings which an aggressive program can achieve. The conservation measures described in Table I-5 include several measures which have already been enacted in the EPCA. The EPCA includes the automobile fuel efficiency standard of 20 miles per gallon (mpg.) in the 1980 model year and 27.5 mpg. in 1985 (with possible changes if auto emission standards place too heavy a burden on fuel efficiency), which is the single most significant conservation measure. It can save about one million barrels per day by 1985. The Act also includes appliance labeling and efficiency improvement goals, voluntary industrial conservation, and a Federal/State conservation program. The EPCA could reduce 1985 demand by the equivalent of about 2.5 MMB/D.

The national thermal efficiency standards for all new residential and commercial buildings and insulation tax credit have been proposed by the President and have passed the House of Representatives. The van pool program involves encouragement of an increasingly attractive commuting concept in which vans are purchased either by a firm or by a group of commuters; a monthly fee is paid by the riders to cover operating costs and the depreciation of the vans. Experience to date has shown that transportation costs to and from work are reduced, and in addition, some individuals no longer require second cars.

The industrial conservation program delineated in Table I-5 involves an expanded system of energy accounting and technical assistance whose scope and coverage of firms goes well beyond the program for industry established by the EPCA, establishing extensive reporting requirements. Similarily, the elimination of gas pilot lights in new appliances and equipment, mandatory retrofit of existing residential pilot light systems by 1980, and changes in airline load factors do not represent policy recommendations, but are only included for analytical purposes.

Although the conservation actions described above would reduce demand by about 3 MMB/D, adoption of load management practices in the Electric Utility Sector could tend to increase demand. Load management techniques are actions which lead to shifts in electricity demand from peak hours of use to times when existing capacity is not fully utilized. The use of time-of-day meters (i.e. peak load pricing), ripple control systems, storage devices, and other innovations will shift the utilization and efficiency of the total capacity. Since a utility must have sufficient reserve capacity to meet expected peak demand, significant reductions in maximum demand through deferral or increased efficiency of on-peak loads can lessen requirements for expensive new capacity, improve generation efficiency and fuel mix, and eventually lower electricity costs. However, lower electricity costs not only benefit customers, but result in a small increase in the demand for electricity.

The Conservation Scenario reduces overall consumption by over 6 quads, with the greatest growth rate reductions in the Transportation Sector, as a result of the automobile fuel efficiency standards (see Table I-6). While these actions cut the growth in all Sectors, in no case is the growth rate zero. In the non-industrial sectors, however, the growth rates are already substantially below their historic rates. The Industrial Sector, although sensitive to higher prices, cannot reduce consumption much further without curbing economic activity.

Table I-6

EFFECTS OF CONSERVATION ACTIONS
AT $13 IMPORTED OIL PRICES
(Quadrillion Btu)

	Reference Scenario Growth Rate 1974-1985 (percent/year)	Conservation Scenario Growth Rate 1974-1985 (percent/year)
Household/Commericial	1.7	0.8
Industrial	2.6	2.2
Transportation	2.1	1.1
Electrical Generation	5.4	4.3
Total	2.8	2.2

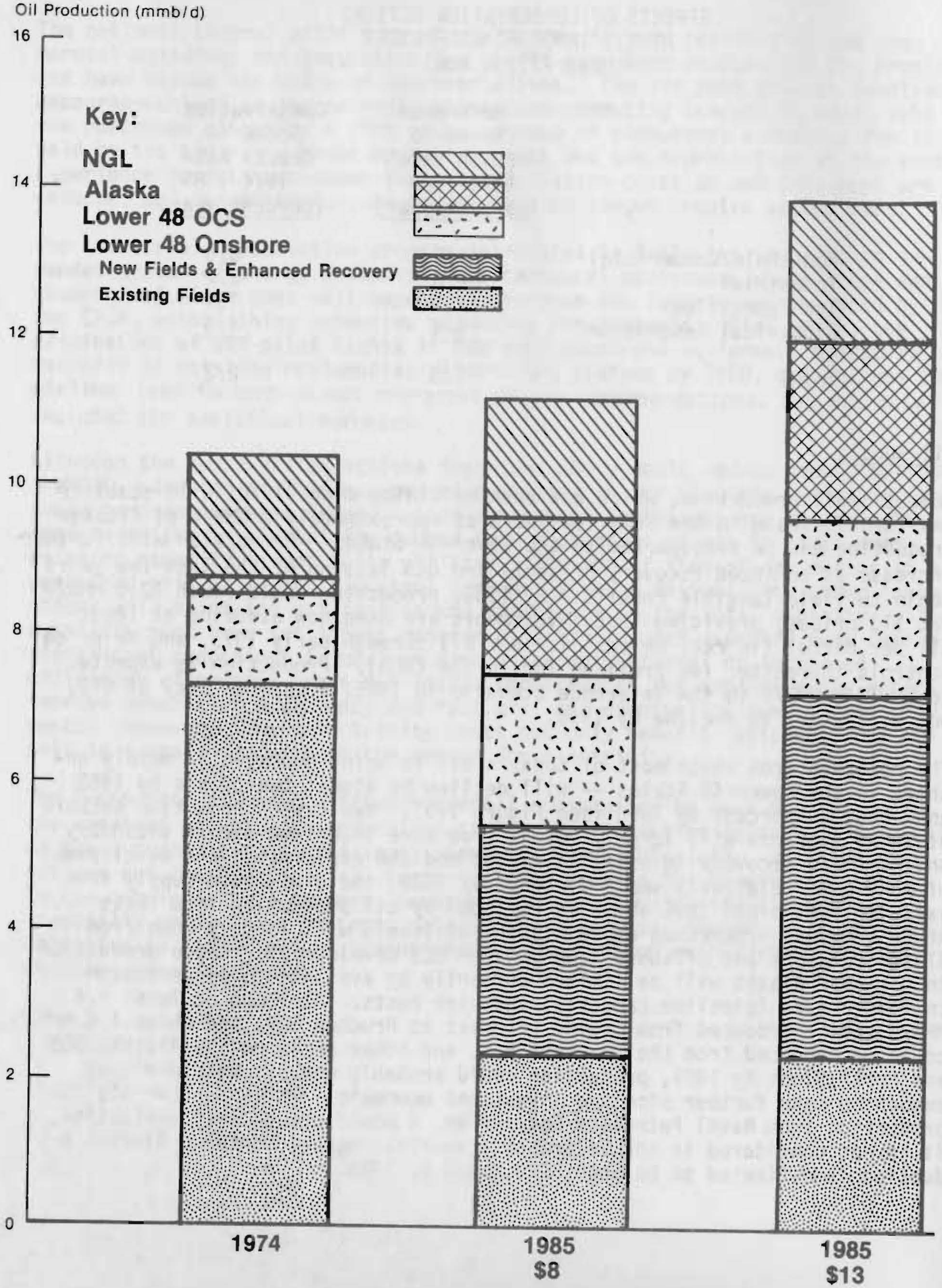
Oil Supply

Domestic oil production, which has been declining since 1970, will stablize and then increase in the next few years as approximately 2 MMB/D of Alaskan production can be transported to the Lower-48 States. Production will further increase as enhanced recovery projects and OCS leasing of the last few years begin to yield tangible results. By 1980, production could reach 12.8 MMB/D (at $13 prices) providing that investments are made now assuming at least $11 per barrel (in real prices) for new oil through early 1979, and no price controls thereafter (as provided for in the EPCA). Production is expected to be 13.9 MMB/D in the Reference Scenario in 1985, if prices stay at $13, but will start to decline by 1990.

The reserves from which most of today's oil is being produced -- mainly onshore in the Lower-48 States -- will decline by almost two-thirds by 1985 and about 80 percent by 1990 (see Figure I-9). New crude production onshore at today's prices will largely result from more intensive use of secondary and tertiary recovery in existing fields and the exploration and development of many new, relatively small fields. By 1985, the diminished supply from existing fields can just about be replaced by oil production from these other sources. Increases above historical levels will largely come from Alaska (onshore and offshore) and greater OCS development. Crude production in Northern Alaska will be limited primarily by available transportation infrastructure (pipeline capacity) and high costs. Although at least 1.6 MMB/D can be produced from proved reserves at Prudhoe Bay, and about 1.5 MMB/D could be produced from the Beaufort Sea, and other areas on the Alaskan OCS and North Slope by 1985, production could probably not be sustained long enough to make further pipeline investment economic. While further Alaskan production from Naval Petroleum Reserve No. 4 would change this evaluation, it is not considered in the Reference Scenario. Hence, Northern Alaskan production is estimated to be about 2.0 MMB/D by 1985.

Figure I-9

1985 Oil Production (Reference Scenario)



Production from the Lower-48 Outer Continental Shelf may double by 1985 if the current leasing schedule is met and the United States Geological Survey's expectations about OCS resources prove correct. If this occurs, this area could account for about 15 percent of crude production in 1985 (over 2 MMB/D). Gulf of Mexico production will require substantial additions to reserves to compensate for expected declines from today's reserves. While Pacific OCS production could increase substantially, Atlantic OCS production is expected to proceed slowly given the long leadtimes from leasing to production of expected reserve additions. Lower-48 OCS production is constrained more by leasing and leadtimes than price levels.

The expected decrease in oil supply in 1985 if prices drop from $13 to $8 per barrel, is about 2.5 MMB/D. Most of the actual decrease occurs onshore in the Lower-48 States, where many new fields and more sophisticated tertiary recovery techniques are not economic at $8 per barrel. The effects of higher or lower prices tend to magnify over time and by 1990, the difference in potential production could be as much as 4 MMB/D between $8 and $13 prices. This widening difference occurs because although higher prices bring forth new and more expensive production, it normally takes many years to move from planning to production.

It is likely that physical and institutional bottlenecks may constrain production as well as prices. The increases in oil production at $13 per barrel are based upon levels of domestic drilling activity that approach the peaks reached in the mid-1950's. Drilling activities are estimated at about 120 million feet per year from 1975-1990 at $13 oil prices, as compared to an annual average of almost 110 million feet in the last fifteen years. However, drilling has declined from a peak of 137 to 75 million feet per year in this period, and a compound growth rate of almost 7 percent will be needed to achieve Reference Scenario levels. The projected drilling profile reverses the declining trend and peaks at about 160 million feet in 1984. While these levels of drilling are economically attractive at today's world oil prices, they will only occur under a favorable regulatory and legislative climate.

Exapnded drilling, although less productive than historical drilling, must result in large additions to reserves to achieve the projected production. The Nation will have to prove 41 billion barrels of reserves out of an estimated 89 billion barrels that are economic to produce, and an additional 9 billion barrels from sub-economic reserves. Since about 50 billion barrels would be consumed during this period, it is possible that total proved reserves in 1985 could approximate current levels. However, uncertainty is increased because much of these reserves are in areas that have not been drilled previously and many require new technology to meet environmental protection standards.

While significant increases in oil production are forecast, the outcome would be appreciably different depending upon assumptions about the ultimate level of recoverable reserves; delays in OCS leasing schedule; extent of investment tax credit allowed; new Alaskan development; and extent of price controls.

The 1985 domestic oil production forecast ranges from a low of 9.6 MMB/D under a scenario of price regulation at $9.00 per barrel in 1975 dollars and a pessimistic assessment of resource availability to a high of 17.6 MMB/D in the Accelerated Supply Scenario (see Figure I-10). The latter scenario assumes a more aggressive OCS lease schedule, an optimistic assessment of resource potential, development of NPR-4, greater Alaskan pipeline capacity, and a more optimistic assessment of the potential for tertiary recovery. Alaska accounts for about half of the difference in production possibilities (see Table I-7).

Table I-7

FACTORS AFFECTING OIL PRODUCTION ESTIMATES
(MMB/D)

	1985 Potential Crude Oil Production	
	Optimistic Cast	Pessimistic Case
Geological	+ 1.1	- 0.7
Drilling	+ 0.3	- 0.1
Leasing	+ 0.9	- 0.4
Alaska and Other	+ 1.8	- 1.6
Total Impact of Factors	+ 4.1	- 2.8

Natural Gas Supply

Although natural gas production will continue to decline in the next few years, 1985 marketed production will be 22.3 Tcf (slightly above current levels) if new gas prices are deregulated. If completion of an Alaskan gas transportation system is accelerated and more favorable reserves are assumed, production could only rise to 25.3 Tcf (Accelerated Supply Scenario). However, without a significant increase in the price of natural gas, production is expected to fall dramatically by 1985. If present regulation of the interstate market continues through 1985, production would decline to 17.9 Tcf in that year. Further, if natural gas regulation were extended to the intrastate market at about $1.00 per Mcf, production in 1985 would decline to 17.0 Tcf (see Figure I-11 for consumption of the production under different scenarios).

Most of the increase in natural gas production at higher prices comes from more intensive production of onshore fields in the West Texas and Western Gulf regions. However, despite deeper drilling and other efforts in these regions, onshore production will decline from current levels by 1985. In fact, if United States gas production were to continue only from existing fields, production would decline by about 60 percent by 1985. Natural gas supply is further limited by the inability to extract much more gas through advanced recovery techniques, such as tertiary recovery in the cost of oil.

Figure I-10

Domestic Oil Production Under Different Scenarios
($13 Imported Oil)

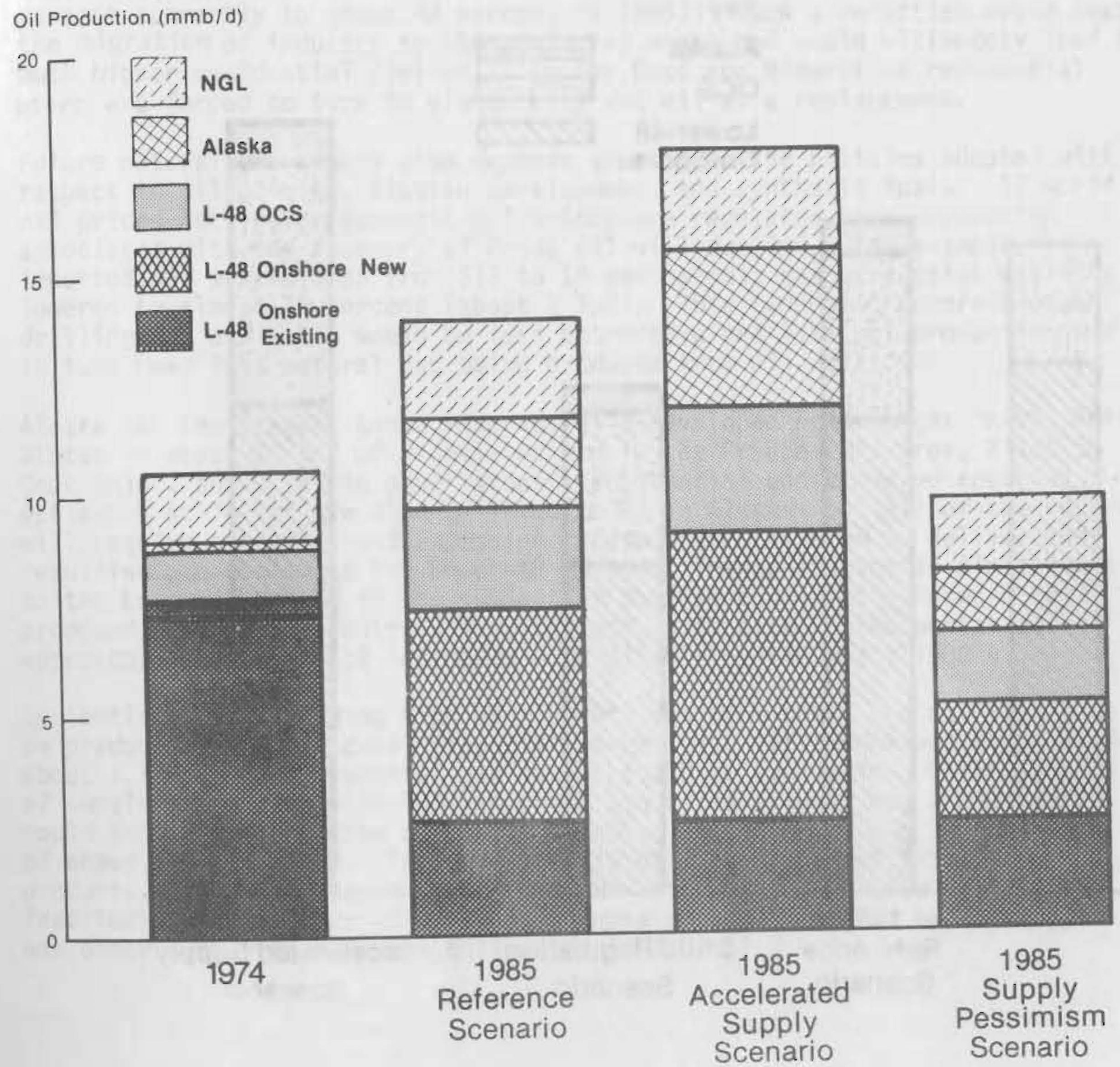
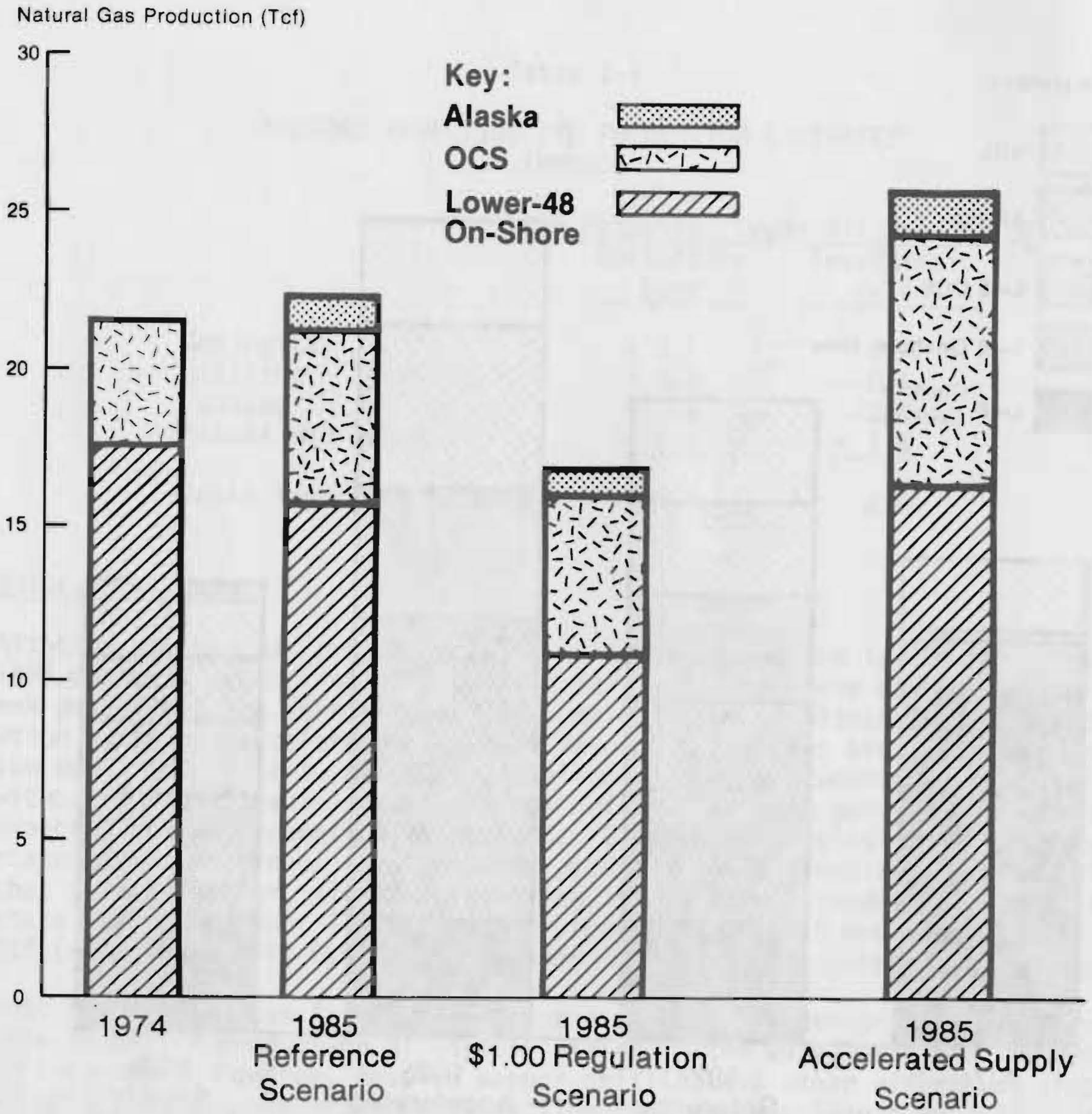


Figure I-11

Natural Gas Production Under Different Scenarios ($13 Oil)



The greatest increase in production under deregulation (as compared to today's levels) will be in the Gulf of Mexico as a result of recent and expected OCS leasing activities, increasing from about 4 Tcf now to about 5.3 Tcf in 1985. The OCS leasing scheudle is the prime determinant of offshore gas production at higher prices; that is, if leasing could be accelerated, more gas could be produced.

Natural gas supply is affected most significantly by the extent and level of gas price regulation. As indicated above, continuation of present regulations would reduce production to 17.9 Tcf by 1985. Of even greater importance than the absolute decline in production is the fact that continued price regulation would drastically reduce the interstate share of the market (from about 62 percent currently to about 42 percent in 1985). Such a reduction would hasten the migration of industry to the producing areas and would ultimately lead to much higher residential fuel bills in the East and Midwest as residential users are forced to turn to electricity and oil as a replacement.

Future natural gas supply also depends greatly on the policies adopted with respect to oil pricing, Alaskan development, and synthetic fuels. If world oil prices decline or domestic oil prices are regulated, gas production associated with the recovery of crude oil will decline. For example, if imported oil prices drop from $13 to $8 per barrel, gas production would be lowered by almost 10 percent (about 2 Tcf). This reduction occurs because drilling for oil wells would be less attractive and less oil production would in turn mean less natural gas being produced from oil wells.

Alaska has the largest known reserves of undeveloped natural gas in the United States -- about 26 Tcf of associated gas in the Prudhoe Bay area, 2 Tcf in Cook Inlet, and 2 Tcf in other areas. Substantial undiscovered reserves, estimated at 76 Tcf are also believed to be in Alaska, but all of the reserves will require a complex and expensive transportation system to deliver the resulting production to the Lower-48 States. Transportation of Alaskan gas to the Lower-48 States is the subject of intense competition between two proposed alternative routes. Nevertheless, with either transportation approach, as much as 1.2 Tcf could be available by the early 1980's.

Synthetic fuels including high and low Btu gas from coal, are not likely to be produced without Federal financial incentives. If incentives are provided, about 1.1 Tcf of supplemental gas supply could be available. Other sources of supplemental supply include imported liquefied natural gas (LNG), which could supply 0.4 Tcf from currently approved projects, and up to a maximum of about 2 Tcf by 1985. The availability of substitute gas from petroleum products (SNG) will depend greatly on the price of oil, availability of feedstocks, and methods of pricing, but could supply 1.0 Tcf by 1985. These and other supply sources are delineated in Table I-8.

Table I-8

POTENTIAL NATURAL GAS SUPPLY SOURCES

Source	1985 Supply (Tcf)
Lower-48 and Alaska	22.3
Accelerated OCS Leasing	0.5
Synthetic Gas from Coal	1.1
SNG from Petroleum Products	1.0
Imported LNG	0.4-2.1
Gas from Tight Formations and Devonian Shale	0.1-0.8
Total	25.4-28.3

Coal Supply

Coal production in the long run is largely contingent on the growth in electricity, as well as the price of oil. If imported oil prices drop to \$8 per barrel, coal production in the Reference Scenario (including coal for exports) would be 894 million tons in 1985; whereas at today's oil prices, coal production could reach 1040 million tons. The 1985 coal production level at \$13 per barrel represents a 5.1 percent compound annual growth rate over 1974 levels. This compares to the relatively constant coal production in the last five years.

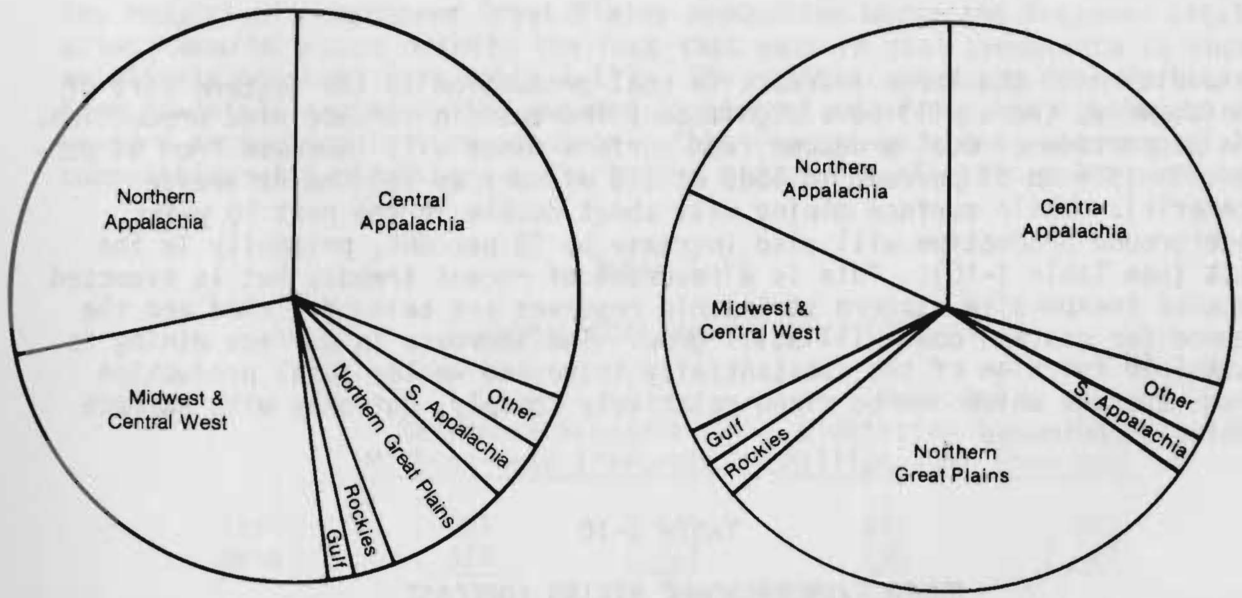
The growth in coal is faster in the 1980-1985 period (5.4 percent) than in the period from 1974-1980 (4.8 percent), as a result of relatively few new coal powerplants now scheduled for completion prior to 1980 (coal plants have a 5-8 year leadtime and many utilities in the early 1970's decided that in view of the low price of imported oil and in view of Clean Air Act restrictions it was better to burn other fuels). The analysis assumes that plants ordered for completion after 1980 can be accelerated to meet projected electricity demand.

Most of the growth in coal production will be in low-sulfur coal as industry strives to meet sulfur emission limitations (see Table I-9). While air quality standards permit the use of high sulfur coal accompanied by flue gas desulfurization equipment (scrubbers), it is likely that existing coal users will choose to use low-sulfur coal as much as possible.

A large part of the increased production will come from the Northern Great Plains and Central Appalachia, the two major areas with low-sulfur coal reserves (see Figure I-12). The Northern Great Plains has large low-sulfur, relatively inexpensive coal reserves. Large-scale development in this area, as is implied by about a 600 percent increase in production (about 260 million

Figure I-12

Regional Growth In Coal Production



1974 Production 604 Million Tons

1985 Production 1040 Million Tons

tons more than at present) could have significant social and environmental effects, or may be inhibited by state or regional restrictions. Central Appalachia is the only producing area in the East, near to many newly planned coal-fired powerplants, with substantial low-sulfur coal.

Table I-9

SULFUR DISTRIBUTION OF PRODUCTION
(Millions of Tons Per Year)

	1974	1985	Increase
Metallurgical Coal	114	138	24
Low-sulfur Steam Coal	90	477	387
High-sulfur Steam Coal*	400	425	25

* Defined as any coal that does not meet new source performance standards (0.6 lbs. or sulfur per million Btu)

In addition to the large increase in coal production in the Western part of the country, there will be a significant increase in surface mine production. The proportion of coal produced from surface mines will increase from 54 percent in 1974 to 63 percent in 1985 at $13 oil prices (in the Reference Scenario). While surface mining will about double in the next 10 years, underground production will also increase by 39 percent, primarily in the East (see Table I-10). This is a reversal of recent trends, but is expected because inexpensive eastern strippable reserves are being depleted and the demand for eastern coal will still grow. The increase in surface mining is largely a function of the substantially increased western coal production from reserves which can be mined relatively cheaply, but only with surface mining techniques.

Table I-10

SURFACE/UNDERGROUND MINING FORECAST
AT $13 OIL, RERERENCE SCENARIO*
(Million of Tons)

	1974			1985		
Area	Surface	Underground	Total	Surface	Underground	Total
East	245	267	512	292	368	661
West	81	11	92	362	17	379
Total	326	277	603*	655	385	1040

* Totals do not add due to rounding

Since coal production is largely a function of electricity demand, which is stable among many scenarios, the alternatives examined have little effect on the levels of expected production. With the exception of the Electrification Scenario, in which the electricity growth rate rises from 5.4 to about 6.5 percent and coal requirements rise from 1040 to 1263 million tons in 1985, all strategies forecast coal demand within a range of about 100 million tons (at current oil prices). The Electrification Scenario includes efforts to switch large boiler use to coal in both utilities and industries (industrial coal consumption increases by about 75 million tons).

The major variation in regional coal production among different scenarios occurs in the Northern Great Plains, where production drops from 305 to 221 million tons in 1985 under the Regional Limitation Scenario (still a large increase from current levels), and increases from 305 to 438 million tons under the Electrification Scenario. The increase in this region under Electrification occurs since this is the only region that has relatively inexpensive additional reserves to meet the greater demand for low-sulfur coal. The increase implies growth from 43 million tons in 1974 to 438 million tons in 1985, a growth rate of 23.5 percent per year. Such growth would be unprecedented and could potentially cause significant socioeconomic and environmental problems.

The reduction in Northern Great Plains production under the Regional Limitation Scenario occurs despite the fact that eastern coal production is kept relatively constant (see Table I-11). The shift of emphasis from West to East is mainly caused by the assumed 30 percent severance tax applied to all western production in this scenario. This assumption makes western coal less competitive with midwestern coals in the midwestern electric power markets.

Table I-11

REGIONAL COAL PRODUCTION, 1985

	Reference Scenario		Regional Limitation Scenario	
	Million Tons	(Percent)	Million Tons	(Percent)
East	661	(64)	662	(69)
West	379	(36)	296	(31)
Total	1040	(100)	958	(100)

The shift from West to East caused by a severance tax would have been even greater if reclamation costs under this strategy were not much higher in the East. Actual coal development in the West will be largely dependent on transportation rates, severance taxes, reclamation requirements, and air pollution control requirements. Either the severance tax or higher reclamation costs alone would have a more pronounced regional shift. As a result of the West to East movement, the Regional Limitation Scenario also decreases the percentage of coal that is surfaced mined.

Despite requiring all new coal-fired powerplants to burn low-sulfur coal and install scrubbers, the Regional Limitation Scenario reduces low-sulfur coal production more than high-sulfur production. This occurs because the cost of building a new plant with low-sulfur coal and scrubbers renders new plant generation costs so high that utilities in some areas would prefer to maximize the use of less expensive existing plants burning high-sulfur coal.

Nuclear Power

Despite considerably lower forecasts this year than last, the growth in nuclear power in the next ten years is expected to be substantial. Additions to nuclear capacity by 1985 are limited by the long construction and licensing period (about ten years), and thus projections of maximum capacity for 1985 are well determined already.

Last year's Project Independence Report projected that nuclear capacity could increase from about 36,000 megawatts (MWe) currently, to about 204,000 megawatts by the end of 1984; whereas FEA's current forecast is that the maximum total capacity if current licensing conditions remain the same is about 152,000 megawatts (new capacity of about 116,000 megawatts). 1/

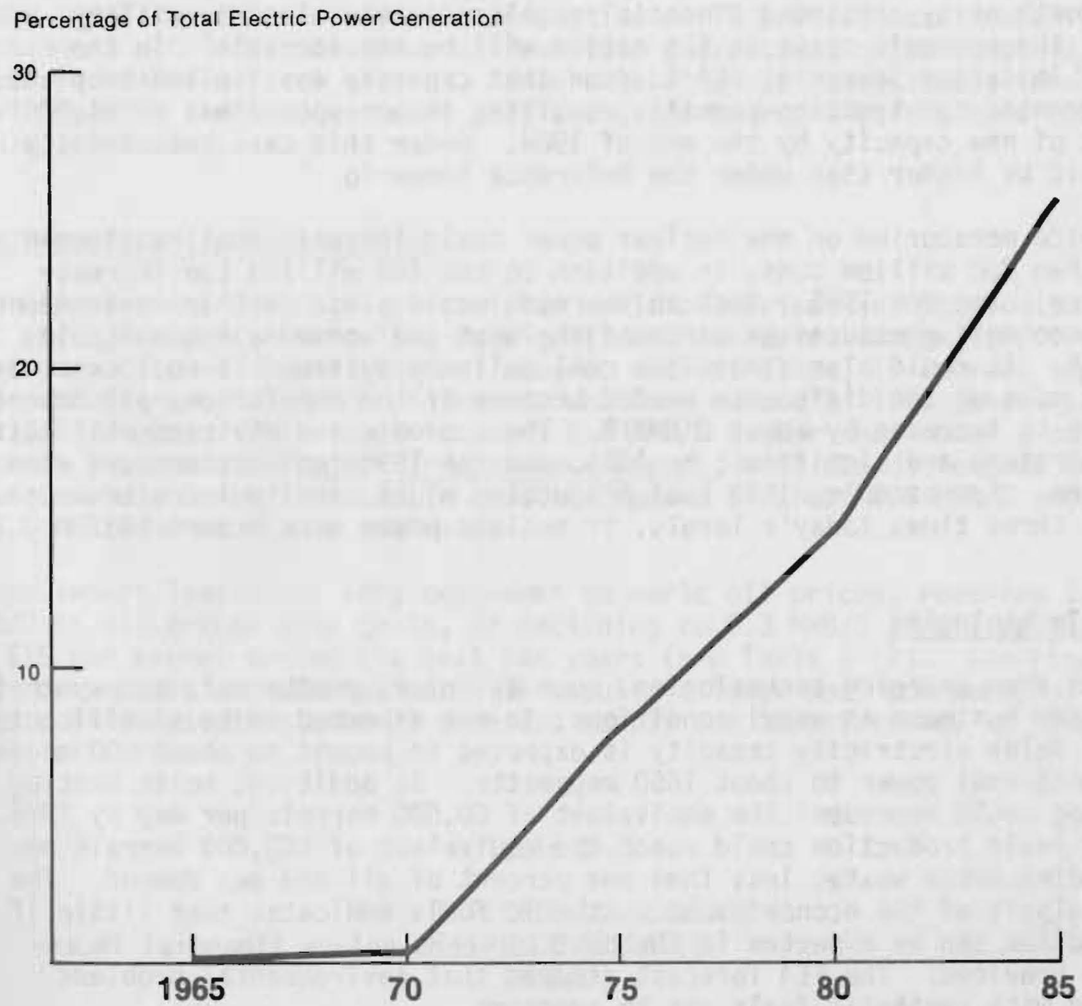
About 105,000 megawatts of new nuclear capacity were deferred or cancelled in the last 18 months. This cutback affected almost 70 percent of planned additions and has occurred because of lower projections of electricity demand, financial problems experienced by utilities, uncertainty about government policy, and continued siting and licensing problems. Nuclear power, even at these reduced levels, will still grow to almost 26 percent of electric power generation in 1985 (see Figure I-13). This compares with 8.6 percent in 1975.

The reduced forecast of nuclear power reflects constraints rather than economic desirability or technical potential. Nuclear energy is the cheapest source of baseload electric power, although not much cheaper than coal. If its growth were not constrained, there would be much more nuclear power projected and American consumers would experience lower electricity prices. FEA estimates that the cost of using baseload nuclear power is about 18 mills/kWh., as compared to coal which is almost 22 mills/kWh., at 70 percent capacity factors. The projected differential in prices is lower this year than last because the cost of capital has remained high, penalizing the more capital intensive nuclear plants.

1/ Actual capacity expected in 1985 (all capacity figures are as of December 31, 1984) under current conditions is about 142,000 megawatts, as about 10,000 megawatts of possible additions are not utilized due to reduced demand. The lower demand estimates are centered in the Western part of the country and could be a result of estimating errors caused by power curtailments experienced in the Northwest and California in 1973 and 1974 (these are the starting point years from which the forecast is based).

Figure I-13

Nuclear Power's Role in Generating Electricity



Although nuclear power estimates in the Reference Scenario are considerably lower than last year's forecast, policy and regulatory decisions could dramatically change these estimates. For example, if the leadtime from inception to operation of a nuclear plant could be reduced from 10-12 years to 5-7 years, the effects of inflation would be reduced, capital costs would decline, and more nuclear plants would be built. FEA estimates that under such an accelerated nuclear strategy, about 142,000 Mwe. of new nuclear capacity could be added by the end of 1984, rather than 116,000 Mwe. in the Reference Scenario. The additional nuclear capacity would reduce electricity costs by about 3 percent.

On the other hand, if nuclear capacity expansions are limited by moratoria on new growth or by continued financial problems in the electric utility industry, the economic costs to the nation will be considerable. In the Regional Limitation Scenario, FEA assumed that capacity was limited to plants already granted construction permits, resulting in an upper limit of 51,000 megawatts of new capacity by the end of 1984. Under this case, electricity costs would be higher than under the Reference Scenario.

A nationwide moratorium on new nuclear power could increase coal requirements by more than 200 million tons, in addition to the 400 million ton increase already projected for 1985. Such an increase would place further environmental and socioeconomic pressures on parts of the West and worsen air quality in many areas. It could also strain the coal delivery system. If coal capacity could not make up the difference needed because of the moratorium, oil imports would have to increase by about 2 MMB/D. The economic and environmental costs of this strategy are significant by 1985, and the 1990 implications are even more severe. For example, 1990 coal production might have to increase to more than three times today's levels, if nuclear power were restricted.

Emerging Technologies

Production from emerging technologies, such as solar, geothermal, and synthetic fuels, under business as usual conditions, is not expected to be significant by 1985. Solar electricity capacity is expected to amount to about 500 megawatts; geothermal power to about 1650 megawatts. In addition, solar heating and cooling could represent the equivalent of 60,000 barrels per day by 1985. Synthetic fuels production could reach the equivalent of 280,000 barrels per day excluding urban waste; less than one percent of oil and gas demand. The latest analysis of the economics of synthetic fuels indicates that little if any production can be expected in the next 10 years unless financial incentives are provided. The FEA forecast assumes that environmental problems associated with synthetic fuels can be overcome.

Each of these sources becomes more important in 1990 and the years beyond, and a strategy which accelerates development of solar, geothermal, and synthetic energy sources can substantially increase their contribution by 1985. FEA estimates that 6100 megawatts of geothermal capacity and 2550 megawatts of solar electric capacity could be available in 1985 under an accelerated

development program (about 1 percent of total electric power generation). The solar projections do not include solar heating and cooling, which are accounted for directly in the Residential and Commercial sector. Both geothermal and solar power have technological, environmental, and economic questions to resolve to meet these 1985 targets.

Synthetic fuels, excluding urban waste, could supply as much as 880,000 barrels per day by 1985 (about 3 percent of total oil and gas consumption), if additional Federal financial assistance is provided. Since the major synthetic processes are not economic at $13 per barrel (with the possible exception of shale oil which is marginally economic at this price, but still risky given the uncertainty with respect to world prices), additional production is not likely to occur without loan guarantees, price supports, or other Federal financial support. Even with financial assistance, there are environmental and socioeconomic problems to be overcome before this potential could be reached.

The Projected Import Situation

The FEA forecast indicates that higher world oil prices and phasing out of oil price controls should lead to significant increases in domestic oil production and lower than historical demand. Nevertheless, if current import prices continue, 5.9 MMB/D of imports would be needed in 1985 (about the same as 1975 levels). This level is about 2.6 MMB/D higher than under a comparable case in last year's Project Independence Report, with the difference being caused mainly by an increase in expected demand of about 1.6 MMB/D and about a 1.0 MMB/D lower supply estimate.

These import levels are very dependent on world oil prices, reaching 13.5 MMB/D if oil prices drop to $8, or declining to 3.3 MMB/D if oil prices rise to $16 per barrel during the next ten years (see Table I-12). The rise in oil consumption at lower prices will result in lower coal consumption. Figure I-14 describes overall domestic supply and import trends at different world oil prices.

Table I-12

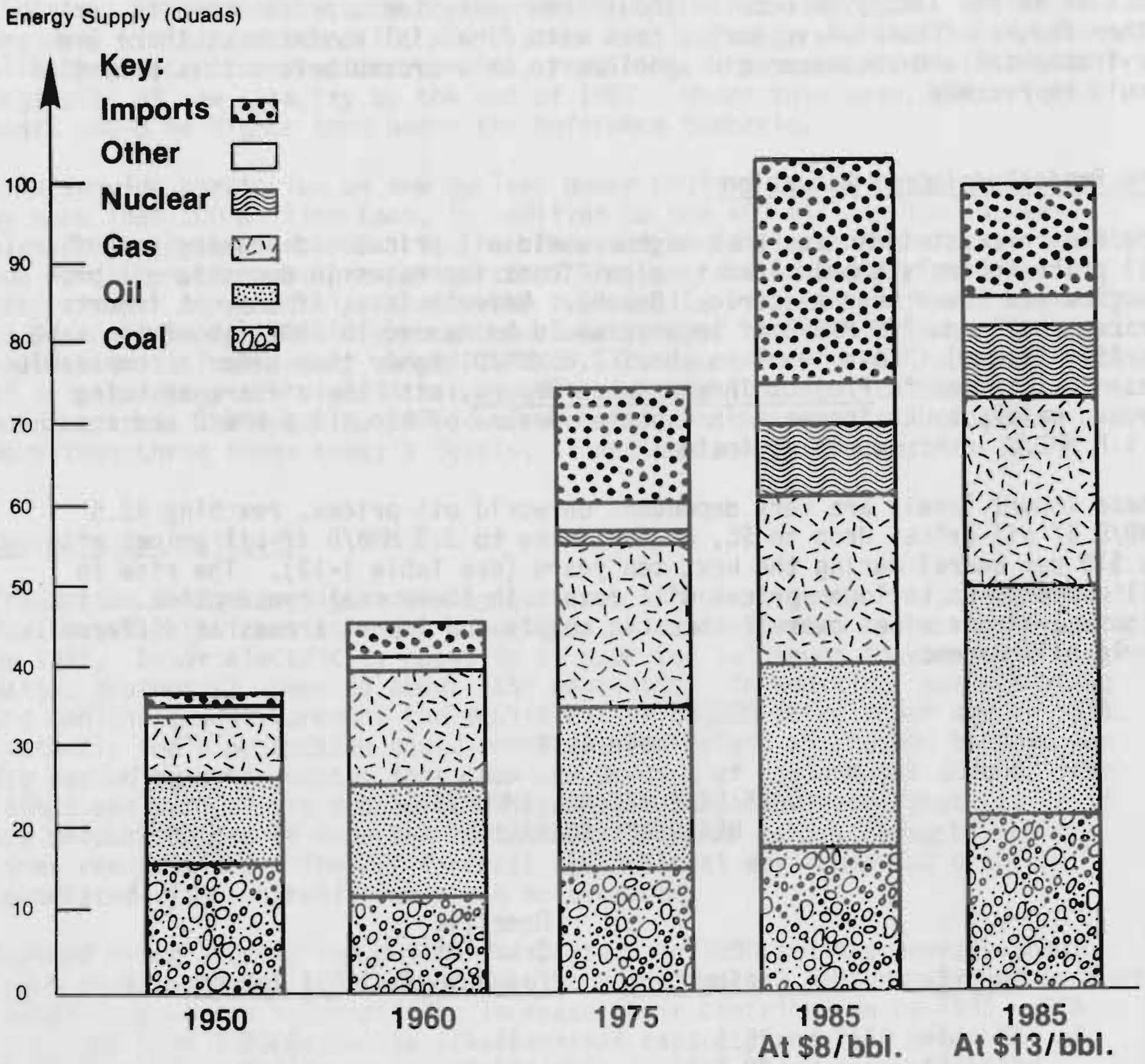
1985 EXPECTED OIL IMPORTS
REFERENCE SCENARIO
(MMB/D)

Import	Oil Consumption	Domestic Crude Oil Production*	Oil Imports
$8/bbl.	25.5	11.4	13.5
$13/bbl.	20.7	13.9	5.9
$16/bbl.	19.4	15.0	3.3

* Excludes refinery gain and shale oil

Figure I-14

Energy Outlook Under Different Oil Prices



Oil import projections are as much a function of government policy actions as price (see Table I-13). For example, an accelerated OCS leasing program, greater production from shale oil and tertiary recovery techniques, and more optimistic resource estimates, could reduce imports to essentially zero by 1985 (1.7 MMB/D of imports, mainly from the Caribbean, are still used because of proximity and relative secCurity of supply). An aggressive conservation program alone would reduce demand by about 2 MMB/D and thus cut imports to 3.8 MMB/D. Alternatively, if all oil prices are regulated at a maximum of $7.50 per barrel, imports could be 11.3 MMB/D (even at $13 import prices) due to the reduced domestic production and greater petroleum use encouraged by lower prices(would be as high as 13.5 MMB/D to satisfy unfeasible gas import levels).

Table I-13

1985 OIL IMPORTS UNDER DIFFERENT SCENARIOS
$13 IMPORTED OIL
(MMB/D)

Scenario	Consumption	Domestic* Oil Production	Imports
Reference	20.7	13.9	5.9
Accelerated Supply	20.3	17.6	1.7
Conservation	18.7	14.0	3.8
Accelerated Supply/ Conservation	18.3	15.6	1.7
$7.50/bbl. Oil Regulation	22.1	9.9	11.3
Supply Pessimism	23.2	9.6	12.6

* Oil production figures exclude shale oil and refinery gain

The Energy Policy and Conservation Act will also affect our import situation. Its impact depends upon the period oil price controls are in effect. The law provides for a statutory domestic composite crude oil price of $7.66 per barrel that may be escalated by an adjusted GNP deflator and other incentives to increase production. The price control authorities convert from mandatory to standby after 40 months (the Reference Scenario is designed with a similar phase-out of controls). If price controls expire in 40 months and world oil is at $13 per barrel, the conservation measures in the EPCA would reduce import needs to 3.4 MMB/D by 1985. If price controls remain in effect through 1985, imports would be 6.5 MMB/D. However, if present natural gas price regulations are also continued, imports under these alternative oil price control cases would be 6.2 and 8.3 MMB/D, respectively.

Energy Prices

Coal and electricity prices are expected to remain relatively stable in real terms, even if import prices change (see Table I-14). Coal prices are stable because in the long-term, coal production can be substantially increased at little or no increase in costs. It should be noted that these conclusions might not hold if large production increases were needed in the next few years. Spot coal prices would then increase until new mines were opened. Long-run electricity prices remain stable because about half of the cost is fixed investment, and as oil prices increase, utilities can switch to nuclear power or coal, which are priced lower than oil. These conclusions, of course, are highly dependent upon national, State and local energy actions. It should also be noted that constant real prices would imply $21 per barrel oil in nominal dollars in 1985 and similar changes for other fuels.

Table I-14

ENERGY PRICE FORECAST, REFERENCE SCENARIO
(1975 Dollars)

	1985 at $8/bbl.	1985 at $13/bbl.	1985 at $16/bbl.
Distillate oil ($/bbl.)	9.84	14.16	16.95
Coal* ($/ton)	26.47	27.82	28.11
Natural Gas ($/Mcf	1.79	2.03	2.07
Electricity (mils/kWh)	28.17	29.73	30.15

* Includes $12/ton surcharge to represent scrubbing costs.

Oil prices would vary directly with import prices if domestic price controls are removed. Thus, distillate oil would be $9.84 per barrel at $8 prices and $14.16 per barrel at $13 prices. As long as world oil prices increase no faster than the rate of inflation and decontrol is gradual, large increases in domestic product prices should not occur.

Natural gas prices are expected to increase significantly if prices are deregulated and to track oil prices in the long-run. However, residential fuel bills are expected to rise regardless of whether natural gas prices are deregulated, since if gas is unavailable to some consumers in the interstate market, they will have to use expensive oil or electricity . Energy prices vary significantly in the alternative scenarios. The Accelerated Supply/Conservation Scenario actually lowers natural gas and electricity prices dramatically (gas lowered from $2.03/mcf to $1.35 mcf; electricity from 29.73 mills/kWh to about 26 mills/kWh). Electricity prices decline due to the more efficient use of equipment and resulting lower capital costs (load management), and to lower costs on new plants because of shorter

construction leadtimes. Natural gas prices decline as more supply is made available at lower prices. Oil prices are considerably lower in regulated cases as domestic prices are held below the world price, however, the greater percentage of higher priced imports reduce this price advantage. Coal prices are relatively invariant among strategies because the production can be expanded at little extra cost.

Capital Requirements

A possible constraint on increasing domestic energy supply is the enormous capital requirement that will be faced by United States industry. It is expected that investments to increase energy supply will amount to about 580 billion dollars (in 1975 dollars) in the next ten years (or almost $800 billion in nominal dollars). These investments will represent about 30 percent of total business fixed investment in this period -- about equal to the almost 29 percent average from 1947-1974.

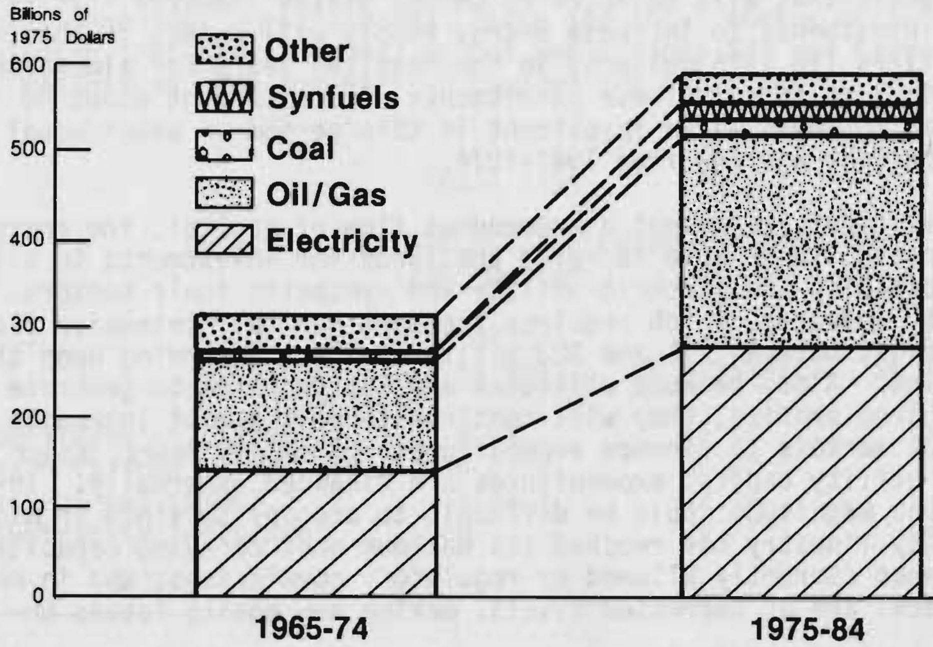
While these investments represent a tremendous flow of capital, the energy industry is expected to be able to raise the funds for investments in all areas except possibily the electric utility and synthetic fuels sectors. The electric utility industry, which requires the most capital intensive plants, will need to invest between 215 and 323 billion dollars depending upon the policy strategies. Also, because utilities are not expected to generate much of these funds from profits, they will continue to be the most intensive users of capital markets to finance expenditures. In recent years, about 70-75 percent of the utility capital expenditures are financed externally. Investments of this magnitude could be difficult to accomplish since in many cases the utility industry has reached its maximum debt carrying capacity given the revenues currently allowed by regulatory commissions, and in many cases their stocks are at depressed levels, making new equity issues unattractive.

Synthetic fuel investments may not be forthcoming due to the economic and technological risks of the processes and institutional uncertainties (see Figure I-15 for sectoral distribution of all energy investment needs).

A further area of investment not previously considered is the investment that could be required over the next 10 years to utilize higher priced energy more efficiently, i.e., the investment to conserve energy. Using a return on investment consistent with that used to judge the viability of investments in energy supply, a midrange investment estimate of 250 billion dollars is consistent with the savings anticipated both from higher prices and governmental actions. To illustrate, investments will be made: by industry to purchase more efficient process equipment, by homeowners and building managers to add insulation and improve heating and lighting, and by auto manufacturers to produce more efficient cars. Thus, increased initial outlays will be required to reduce expected fuel costs, but if conservation investments proceed they must make economic sense. Financing these conservation investments will not be difficult since they are spread throughout the economy and are often an integral part of investments made for other purposes.

Figure I-15

Cost of Energy Supply Investments



Environmental Impacts

The environmental impacts of a specific energy scenario are hard to measure without performing an analysis of existing environmental quality and potential changes at individual energy producing or consuming locations. However, general trends can be depicted. At higher oil prices, less oil and more coal are consumed. Thus, despite the reduced levels of demand at $13 oil prices, air emissions of nitrogen oxides, for example, are likely to be significantly higher in some regions. Reduced forecasts for nuclear power growth will tend to increase coal use and could adversely affect air quality near powerplants, and create greater land and water quality problems in the Western States.

The Conservation Scenario exhibits the lowest levels of air pollution, whereas the Electrification Scenario has the highest air emissions (as measured by an FEA model of environmental discharges). The Regional Limitation Scenario results in the lowest levels of sulfur oxides from coal-fired powerplants, but these levels are offset by increased emissions from oil- and gas-fired powerplants and greater use of existing coal-fired plants in baseload. Since powerplant emission requirements are less stringent for existing plants, their use is expanded.

The major environmental issues associated with energy will focus on regional development questions. These include OCS development, oil and gas production from Alaska, western coal development, commercialization of synthetic fuels, and nuclear power growth. The resolution of these issues will largely determine the future of energy production.

Post-1985 Trends and Issues

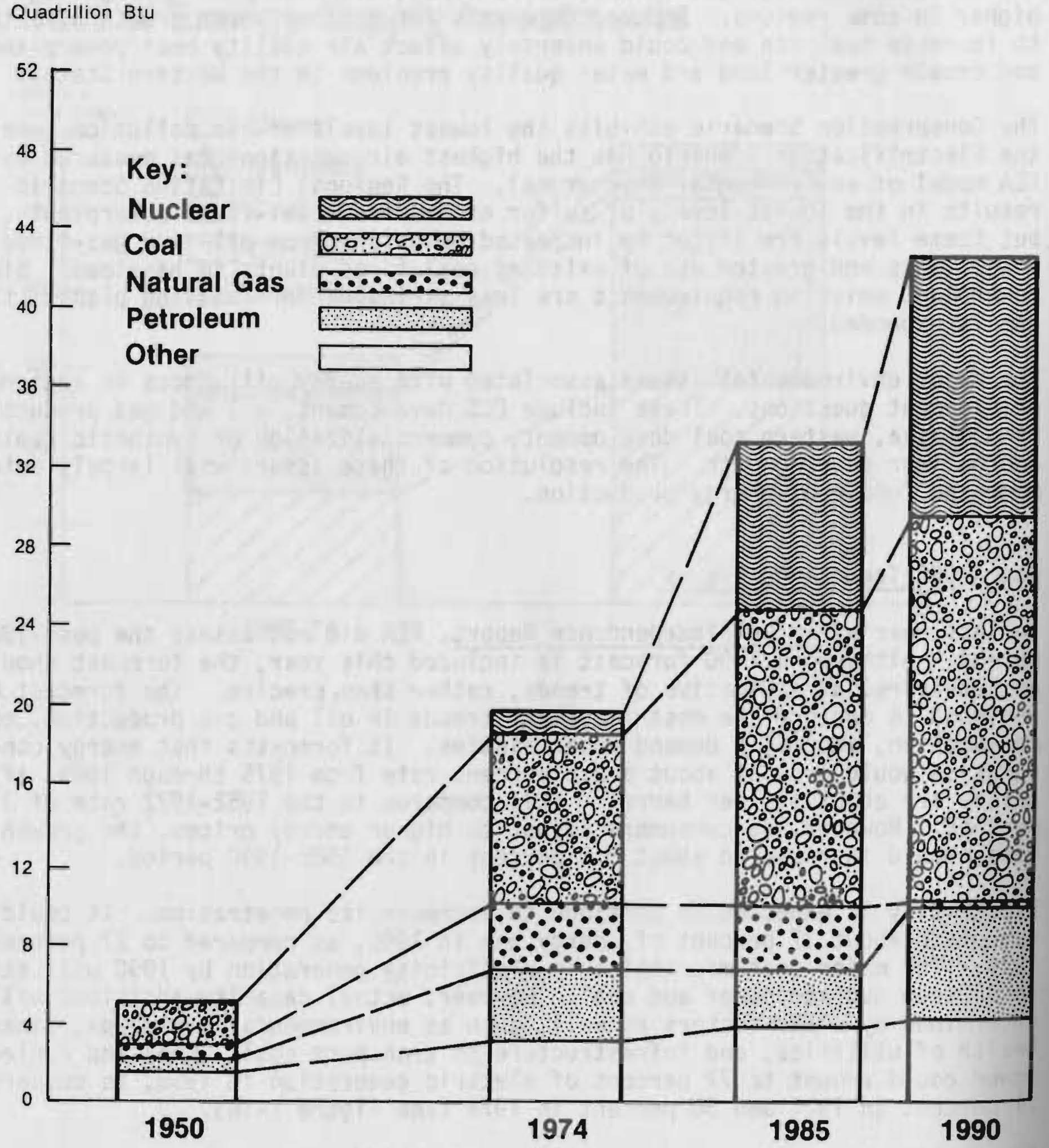
In last year's Project Independence Report, FEA did not assess the post-1985 period. Although a 1990 forecast is included this year, the forecast should be considered as indicative of trends, rather than precise. The forecast was designed to capture the most important trends in oil and gas production, coal consumption, and major demand uncertainties. It forecasts that energy consumption would grow at about a 2.8 percent rate from 1975 through 1985, if oil prices are about $13 per barrel. This compares to the 1952-1972 rate of 3.6 percent. However, as consumers adjust to higher energy prices, the growth rate should increase to about 3.3 percent in the 1985-1990 period.

Electricity is expected to continue to increase its penetration. It could represent about 37 percent of energy use in 1990, as compared to 27 percent in 1974. The major economic choice in electricity generation by 1990 will still be between nuclear power and coal. However, actual capacity additions will be determined by other factors as well, such as environmental standards, financial health of utilities, and infrastructure to transport coal. Coal and nuclear power could amount to 77 percent of electric generation in 1990, as compared to 71 percent in 1985 and 50 percent in 1974 (see Figure I-16).

If electrical energy grows at the anticipated rate, there will be a strong need to increase coal production and to resolve the nuclear fuel cycle problems. Coal production in the $13 Reference Scenario will have to increase to about 1.6 billion tons in 1990, with most of the additional increase in the Northern

Figure I-16

Electricity Generation By Energy Source
(Reference Scenario, $13 Oil)



Great Plains, and Northern and Central Appalachia. These areas will supply 80 percent of the coal, with the Northern Great Plains alone supplying about 40 percent. Nuclear capacity additions will have to occur at greatly accelerated rates in the 1985-1990 period to meet electrical generation needs. Installed nuclear capacity in 1990 could be as high as 227,000 megawatts in the Reference Scenario.

The oil and gas supply projections for 1990 depend greatly on geology and institutional constraints. If the price of domestic oil is below $10 per barrel, oil production by 1990 will be below 1985 levels. Even if higher prices are maintained, however, production would begin to decline around 1990; Alaskan production would also decline in this period, unless significant NPR-4 reserves are proved and produced. Natural gas production declines even sooner--in the 1980's--at all prices reviewed by FEA.

With demand increasing and supply of oil and gas either stable or declining, oil imports in 1990 could be 9.7 MMB/D at $13 import prices, unless synthetic fuels or other new technologies expand more rapidly than anticipated.

This scenario indicates a rapidly increasing requirement for imported oil if the projected demand pattern is to be satisfied. However, by 1990, a number of existing OPEC countries can be expected to have dropped out as exporters of large quantities of oil. Many of the countries will have passed their peak of production and/or will have developed domestic markets of such size that they will not have substantial production available for export. The reduced number of major exporters could present a physical difficulty in meeting U.S. import requirements by 1990, unless major new sources of oil are found in countries that are not currently active as exporters.

The 1990 Reference Scenario raises several major national issues, and suggests three basic directions for the future domestic energy economy. The first would be to develop an aggressive program to provide more liquid and gaseous hydrocarbon sources to feed existing demand patterns as they expand. The second would be to substitute ever increasing amounts of electricity where possible for some of the expected hydrocarbon fuel demand and thereby substitute coal and uranium. Finally, there is the option to reduce the rate of growth of total demand. These options are not necessarily mutually exclusive.

The first approach would be that of finding means for providing artificial sources of liquid or gaseous hydrocarbons. While synthetic fuels hold promise for the long term, there are technical, economic, and environmental problems to be overcome before it can be a major source of energy, even by 1990.

The second option is greater use of electricity. The success of this approach depends on overcoming several problems. First, there are a limited number of possibilities for substituting electricity for substantial amounts of oil or natural gas unless a major breakthrough is made in electrifying transportation and in storage technology for electricity. Also, this approach is the most capital intensive of the available alternatives, which might place additional burdens on the Nation's capital markets. As is pointed out in Chapter VI, the expected energy investments as a percentage of total investments is near the high end of historical levels. In addition to the investment required for the generation of electric power, there will also be significant new investment to convert users of other fuels to electric power. Finally, electrification would prove expensive to consumers. The major areas of potential substitution would be in residential, commercial, and industrial heating. While widespread use of heat pumps would reduce the cost differential by making electricity use more efficient, the cost of the capital needed to generage and transfer the electricity would still have to be paid, raising prices at the consumer levels. However, many of the technological developments that could improve efficiency and make such options more attractive are still in early stages of development.

The third option open to the Nation is the option of reducing demand through an aggressive conservation program in order to use the remaining supplies of the available fuels as judiciously as possible. The existing and proposed conservation program can reduce demand growth significantly. However, these conservation programs involve extensive regulation and are largely designed to reduce aggregate energy usage, but not necessarily directed to conserving the specific fuels that will be in short supply.

Natural gas appears to be the fuel most likely to be in short supply in the 1975-1990 period. Unless an economically feasible approach can be found for producing synthetic gas from coal in large quantities, either growing quantities of imported liquid natural gas may have to be used or conservation will have to be pursued intensively for this fuel.

In order to conserve petroleum, it is clear that the major attention must be paid to the Transportation Sector. Almost half of total petroleum usage in 1974 was for transportation and this percentage is expected to remain unchanged through 1990, unless major modifications are made in the transportation system. While automobiles are likely to be made much more efficient over the next decade, gasoline demand will ultimately increase again as the number of autos increase, unless a basic change in the pattern of usage is made or transportation fuel use is shifted, probably to electricity. Both alternatives involve large capital investment, technological uncertainties, and difficult social and environmental decisions.

In summary, the Nation faces difficult decisions relating the post-1985 period. The choice is among a continuation of existing energy demand patterns, while substituting synthetic fuels for declining natural sources; attempting to shift end-use patterns to electricity generated from coal, nuclear, solar, and geothermal sources; or greater efforts to conserve energy. Each of these alternatives involves difficult technical, economic, environmental, and social choices; but the longer we delay, the more difficult and expensive the transition. If these policies are not successful the result will be greater reliance on foreign energy imports. The choice is difficult; none of the alternatives are easy. But the course that is set will determine the well-being of future generations.

The rest of this Report examines the major energy trends and issues now facing the Nation. The people who contributed to this effort are listed in Appendix H.