FUEL AND ENERGY PRICE FORECASTS
QUANTITIES AND LONG-TERM MARGINAL PRICES

EPRI EA-433
(Research Project 759-1)

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FOREWORD

EPRI and the electric utility industry require fuel price forecasts for use in their planning efforts. EPRI's Energy Analysis and Environment Division has a contract research program under way to develop information on which to base such forecasts. Work is being conducted to improve data, to design and develop improved methods of forecasting energy prices, and to reduce the margin of error in such forecasts. This work is a joint effort by the three programs in the Energy Analysis Department: Energy Supply, Energy Demand, and Energy Systems, with assistance from the Environmental Assessment Department. As it is a long range program involving considerable fundamental energy economic and analytical work, major results will not be available for some time.

In the meantime, EPRI required energy price forecasts for R&D planning and other purposes. Therefore, to assist the Energy Analysis and Environment Division staff in the preparation of interim price forecasts, the Energy Supply Studies Program let contracts with SRI International (formerly Stanford Research Institute), RP759-1, and Foster Associates, RP759-2, to prepare independent price forecasts to the year 2000. (The Foster Associates work was published as EA-411, Volumes I and II, March 1977.)

While this study prepared by SRI was designed primarily to aid the Energy Analysis and Environment Division staff, it is being published, in accordance with EPRI policy, so that it may be used by electric utility staffs and others.

It should be emphasized that the forecasts contained in this report are the contractor's, and the publishing of them does not imply their endorsement by EPRI. The draft report was reviewed by the Project Manager and other staff members. Comments and critiques were forwarded to the contractor. As the study was designed to give independent price forecasts, the contractor was free to accept or reject the staff's comments.

Not surprisingly, given the complexity of the subject, the contractor and Project Manager did not agree on all the logic, data, and assumptions going into these price forecasts. The reader is cautioned to fully examine the basis of the forecasts before using them. Much of this background information is contained in an earlier publication, "Fuel and Energy Price Forecasts", EA-433, Vol. II, February 1977.

The Project Manager does feel that this report should prove to be extremely useful and should be a valuable aid to those trying to obtain a better understanding of future energy prices and the complexities surrounding them.

Thomas E. Browne
Project Manager

Milton F. Searl
Program Manager
Energy Supply Studies

ABSTRACT

SRI International (formerly Stanford Research Institute) has performed under Research Project 759-1 a study for the Electric Power Research Institute (EPRI) in which SRI prepared forecasts of long term marginal fuel and energy prices over the period 1985 to 2000.

These projections are shown in constant 1975 dollars on a regional basis for the United States. The major sources of energy analyzed are coal, uranium, crude oil, "syncrude" (produced from coal or oil shale), petroleum products, natural gas, and synthetic gas. Prices are shown at different levels of the energy system, e.g., from the point of production through consumption. Prices of delivered fuels are presented for four sectors: electric power generation, residential/commercial, industrial, and transportation. Because all fuels in the energy system are interrelated, the emphasis in the study was to specify these relationships and to forecast prices (and quantities) at every level of the energy system. This was done within the framework of the SRI National Energy Model that explicitly models primary energy production and conversion, transportation and distribution, and end-use conversion.

The study produced three price projections, each conditional on a different set of aggregate energy and electricity demand assumptions provided by EPRI. The major findings of the study are as follows:

- The real long-term marginal prices of all fuels will increase between now and the year 2000. Reflecting the effect of depletion, oil and natural gas prices will increase at the highest rates. Nuclear fuel prices are projected to grow more slowly. Coal prices, while expected to increase in the short term, are projected to level off and remain virtually stable during the study period (1985-2000), reflecting ample availability and technological improvements in coal mining.
- Long-run resource prices are more sensitive to the cost of producing and converting the resources than the level of demand for energy. This is because long-run energy supplies are based on abundant coal, oil shale, and uranium.

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ABBREVIATIONS

HBtu	High-Btu
LBtu	Low-Btu
LS	Low-Sulfur
HS	High-sulfur
R/C	Residential/Commercial
E Coal	Eastern Coal
W Coal	Western Coal
CC	Combined-cycle
SNG	Synthetic natural gas
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
SRC	Solvent-refined coal
Resid	Residual fuel oil

EXECUTIVE SUMMARY

INTRODUCTION

In order to analyze changes in long-run energy prices and quantities resulting from different R&D or capacity expansion decisions, EPRI requires the capability to determine regional prices and quantities of all energy forms, considering all existing and potential new technologies over the next 23 years. In other words, EPRI requires the capability to generate self-consistent supply/demand forecasts under broad ranges of assumptions. The present report describes three such supply/demand forecasts made using the SRI National Energy Model and newly updated techno-economic projections. To generate the forecasts presented here, SRI has added substantial detail to its energy supply model, thoroughly reviewed and updated its information inputs, interfaced the supply model with an approximate demand model,* which was specially designed for this study, and computed a supply/demand balance. The improvements made in both the supply and demand sides of the SRI National Energy Model were incorporated to address the specific requirements of this study.

Several aspects of the SRI National Energy Model that make it particularly suitable for long-run forecasting are summarized at the end of this executive summary.

FORECAST OF FUEL QUANTITIES AND LONG-TERM MARGINAL PRICES

The main output of this study are forecasts of energy prices and the quantities of these fuels consumed at those prices on a regional basis for the United States. Prices are shown at different levels of the energy system, e.g., from the point of production through consumption. Prices of delivered fuels are presented for four sectors: electric power generation, residential/commercial, industrial, and transportation. Because all fuels in the energy system are interrelated, it is important to specify the nature of these relationships and to include prices and quantities at every level of the energy system in the forecast.

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*It should be noted that the approach is general enough so that a detailed demand model could be substituted for the approximate model if desired.

To illustrate the need to forecast fuel prices and quantities for end use and for electric power generation in the larger context of the national supply/demand balance, we will discuss the nature of the U.S. energy system in some detail. Figure 0-1 illustrates the basic structure of the U.S. energy system. For simplicity, the system has been divided into four components:

- Primary fuel production and conversion, which includes resource extraction, synthetic fuel production, importing, refining, and large-scale transportation
- End-use conversion, which includes space heaters, automobiles, industrial boilers, and industrial direct heating processes
- Electric power generation, which includes intertechnology competition in base, intermediate, and peak load applications
- Usable energy demand, which includes the demand for the various services energy provides, such as vehicle-miles of auto travel, passenger-miles of air travel, Btu's of space heat in the living room, and Btu's of heat transfer in industrial processes

In the lower right portion of the figure, we have indicated by an arrow head the point at which the forecast of prices and quantities of the fuels used in electric power generation is to be measured. Similarly, the "End-Use Conversion" box is the point at which the forecasts of delivered fuel prices and quantities are to be measured.

In the following discussion, we will illustrate how each of the four energy system components listed above can affect these fuel forecasts. A brief overview of the key insights we have obtained with regard to each of the four components will also be given, as will the key insights found in each case.

One of the obvious forces that affect the prices and quantities of fuels used for electric power generation is the economics of producing those fuels, i.e., the economics of primary resource production and conversion. In the figure, the supply curve in the box entitled "Primary Fuel Production and Conversion" is intended to indicate that the prices of the various primary fuels depend on the quantities produced. Because supply economics are central to this fuel forecast, the discussion in this report contains considerable detail on primary liquid and gaseous fuel quantities and prices (e.g., crude oil, natural gas, synthetic liquids, synthetic gases, imported liquids, imported gases).

The most important implication of the forecasts of primary fuel production and conversion is that long-run primary fuel prices are relatively unresponsive to

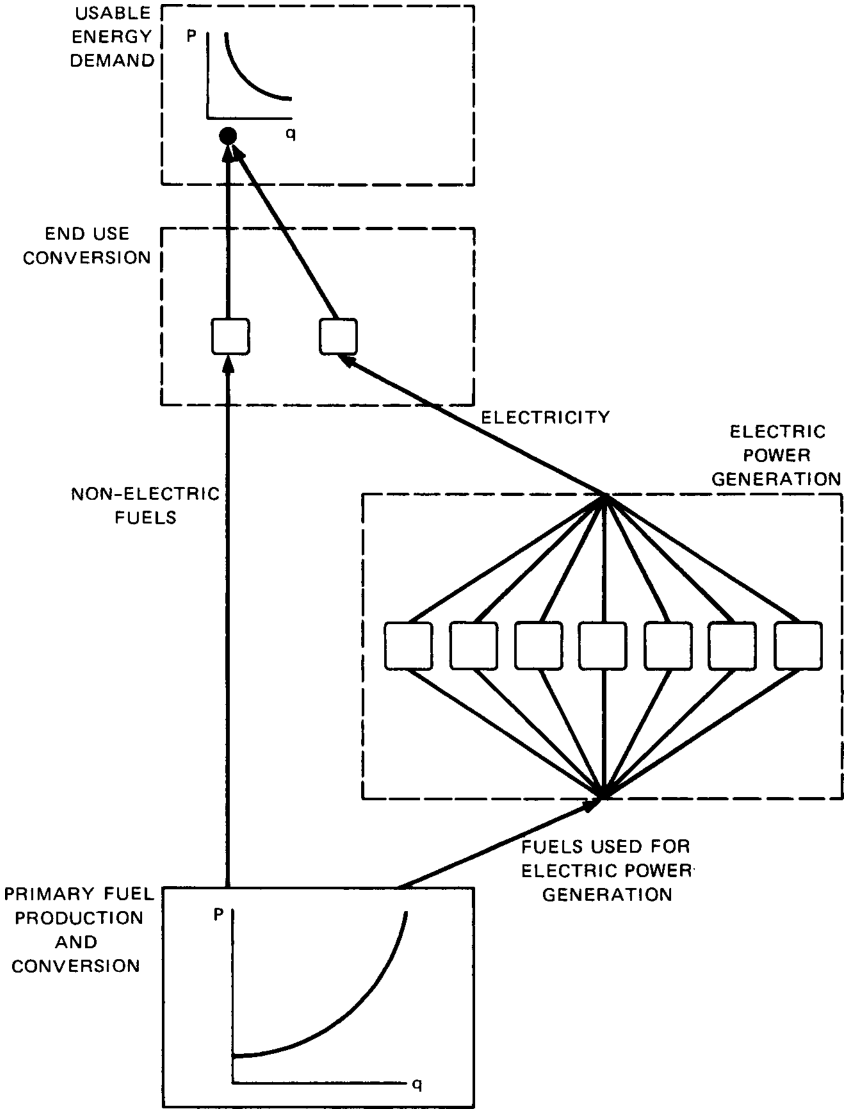

Figure 0-1. Structure of the U.S. Energy System

changes in demand. In the economist's language, long-run supplies of primary resources are highly elastic. This results from the fact that long-run energy supplies will be based on coal, shale, and nuclear fuel, all of which are highly elastic compared to conventional and imported oil and gas. This has far-reaching implications throughout the energy market. It implies that marginal energy prices are set almost entirely by the economics of primary resource production and by the economics of the various technologies available to convert those resources to usable energy forms rather than by the level of demand. This can be restated as follows: price is almost exclusively a supply-related parameter.

Figure 0-2 illustrates why price is almost exclusively supply-related when supply is elastic. Envision how the equilibrium price p* would change if the demand curve were changed. No matter what the curvature of the demand curve or where it crosses the supply curve, the equilibrium price will change very little. On the other

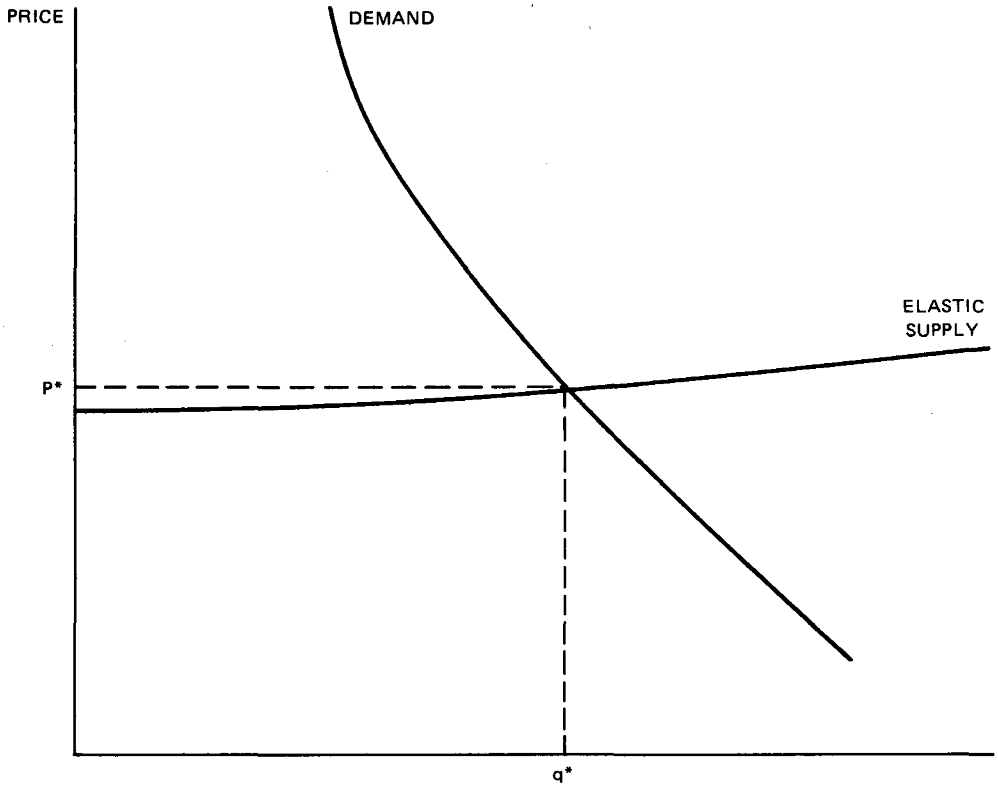

Figure 0-2. Equilibrium, Assuming Elastic Supply

hand, envision how the equilibrium price would change if the supply curve were moved up or down, reflecting different assumptions regarding supply economics. The equilibrium price p* would move in close coordination with the supply curve, almost independent of where the demand curve lies.

To describe the quantity of each fuel consumed is slightly more complicated. Quantities depend on a combination of total demand for usable energy, the market shares of the various fuels at the end-use level, and intertechnology competition among alternative electric power generation technologies. These will be discussed below.

Because long-run resource supplies are elastic, long-run resource prices tend to be constant over time (in constant dollars). For example, in this forecast at the producing location, Western coal prices are about $0.50/MMBtu over the study period, shale syncrude prices are about $3.20/MMBtu ($18.50/bbl) over a 30-year period, and nuclear fuel prices are about $0.50/MMBtu over the same period. To the extent these prices are "flat" over time, relative prices are constant over time. We shall see that market shares remain more or less constant over time, but this result depends both upon the fact that relative resource prices do not change appreciably and that the energy conversion economics remain roughly constant relative to one another. In other words, there are no "dramatic" technological advances in the long term that favor a particular resource, an assumption that will be discussed shortly.

It should be pointed out that these insights depend heavily on the information inputs and to a much lesser extent on the model structure itself. In other words, the input assumptions that coal, shale, imports, and nuclear fuel supplies that are highly elastic produce the conclusions stated above. Careful inspection of these inputs should be carried out by all readers of this report (see Volume II) before judging the validity of these insights.

Returning now to Figure 0-1, the importance of intertechnology competition among end-use conversion processes will be discussed. This competition affects the prices and quantities of fuels used for end uses as well as for electric power generation. To illustrate, suppose that nonelectric fuels satisfy a large share of the end-use market. This would imply in Figure 0-1 that the flow of nonelectric fuels up the left-hand path would be large and the flow of electricity up the right-hand path would be small, which would imply in turn a small demand for fuels used for electric power generation. The prices of these fuels consumed in electric power generation would, however, be set by the total production of primary fuels, which is the sum of production for nonelectric and electric uses. In the case where the market share of electricity in the end-use markets is high, different production levels of the various primary fuels would result, and thus different primary fuel prices would be obtained. In view of the importance of market share at the end-use level, the forecast presented in this report contains considerable detail regarding prices and quantities of fuels consumed in the industrial, residential/commercial, and transportation sectors.

The most important insight we have obtained at the end-use level is that the primary manifestation of elastic resource supply, that is, flat prices over time, appears in all end-use markets as well. When viewed at the end-use market, however, this implies that the economics of the series of the economically attractive conversion and transportation processes connecting each primary resource to each end use tends to remain constant over time, i.e., the relative costs of delivering energy from each resource to each end use via the most economical path tend to remain constant over time. As with primary resources, this insight depends principally on the input assumptions, particularly those regarding relative change among technologies, rather than details of model structure. Careful examination of the input rationale in Volume II shows that learning has been assumed to be relatively uniform for all technologies that are economically competitive, and thus the combination of elastic supplies of primary resources coupled with uniform learning across all technologies that transform these resources into delivered energy forms implies flat prices over time (i.e., elastic supply) for delivered energy forms.

Intertechnology competition among alternative electric power generation technologies affects the prices and quantities of the various fuels used in electric power generation. For example, in the event of a nuclear moratorium, one would expect the prices and quantities of nuclear fuel and coal to be different than in the event of accelerated nuclear development. Thus, in this forecast, considerable attention is focused upon the competition among the very large number of alternative electric power generation technologies. This report will discuss the following in detail:

- Total electricity generation.
- Prices and quantities of base load power generated by each competing technology.

- Prices and quantities of intermediate load power generated by each competing technology.
- Prices and quantities of peak load power generated by each competing technology.

Keeping in mind that the mix of electric power technologies is extremely sensitive to the economic assumptions for each technology and market share model assumptions, we will briefly summarize the base, intermediate, and peak load technology mixes contained in this forecast. In base load power generation, nuclear technologies are dominated in the short term by the light water reactor and in the long term by advanced converters that are more efficient fuel consumers (not the LMFBR or the gas-cooled breeder, however). In both intermediate and peak load power, the dominant technology in the long run tends to be the combined-cycle technology using pipeline high-Btu gas as a fuel, based on current input data. This is not to be confused with an integrated facility using coal as a fuel, producing low-, intermediate-, or high-Btu gas, and generating power in a combined-cycle arrangement. The reason the former scheme is more attractive is that because of the capital intensity of coal gasification, SNG can be produced more cheaply from mine-mouth gasification plants operating at a 90-percent stream factor than low-, medium-, or high-Btu gas can be produced in an integrated facility operating at a 45-percent capacity factor. In the near term, intermediate and peak load power are produced by a number of coal-, liquid-, gas-, and nuclear-based technologies.

As with primary resources and delivered fuels, we again see the characteristic behavior that electricity prices are flat over time, indicating that electricity supplies, too, are elastic in the long run.

Finally, it is important to note that competition among the many electric power technologies, while it has only a minor effect on the prices of the fuels used to generate that electricity, has a major and direct effect on the quantities of those fuels consumed. For example, because nuclear fuel is attractive and petroleum and synthetic liquids are unattractive under base case assumptions for base load power generation, the demand by electric utilities for nuclear fuel is large, while that for liquids is small. However, because nuclear fuel and liquids supplies are elastic in the long run, neither price is significantly affected by this difference in demand.

Because EPRI is interested in how the price/quantity forecasts of the various fuels for electric power generation vary with different levels of demand, a sensitivity analysis has been conducted to determine the effects of different assumptions regarding usable energy demand. In terms of Figure 0-1, this sensitivity analysis of usable energy demand is equivalent to computing the supply/demand balance using three different demand curves in the box entitled "Usable Energy Demand"--for a low case, a base case, and a high case. This sensitivity analysis is discussed in detail in Section 3 of this report.

The key insights of the demand sensitivity analysis have been alluded to above. First, the long-run prices of the fuels for electric power generation are little affected by demand over even an extremely wide range of demand assumptions. As a result, the long-run market shares are largely unaffected by changes in demand. Second, however, consumption of fuels used for electric power generation and for end use depend directly on demand, with higher usable energy demand implying roughly uniformly higher demand for each fuel in the long run.

INPUT ASSUMPTIONS

The techno-economic values used as inputs in this study were developed by SRI. The generation process began with the best information that existed at the beginning of this study. Various energy experts in SRI reviewed these values in detail, changing them wherever necessary. Thus, it is fair to characterize the techno-economics of the energy market dynamics upon which this study is based as not being highly speculative, but instead as representing the best judgments of various SRI energy experts subject, of course, to the budget limitations of this study. It is important to emphasize that, although some of the insights inherent in this forecast are very sensitive to these judgments, the major insights outlined above tend not to be sensitive to reasonable changes in these input assumptions. The entire information base used in this study is documented in detail in Volume II of this report.

THE SRI NATIONAL ENERGY MODEL

The SRI National Energy Model represents a unique approach to energy supply/demand problems and is significantly more comprehensive and robust than any other energy model in existence today. Its distinguishing features are briefly summarized below, being those that make it particularly useful for forecasting energy prices and quantities and for analyzing R&D and investment decisions. First, in building the model for this analysis and forecast, the popular "objective function" approach used in so many energy economic models today has been rejected.* Instead, each of the individual decision makers in the energy system are modeled in detail, assuming that they act in accord with their own individual interests and that their actions are interrelated. That is, an explicit dynamic, nonlinear, regional representation of each decision maker in the energy system has been constructed, based upon the assumption that he has free economic perspective in his alternatives. For example, models of the Gulf Coast refinery operator selecting among alternative crudes, the Powder River SNG industry deciding whether to add new capacity, the homeowner in New England selecting among alternative space heaters, and so forth, have been developed. Once these individual decision makers have been identified and models built to represent their decision-making processes, the SRI National Energy Model specifies how they are interrelated, that is, how decisions made by each decision maker affect the prices and quantities of energy seen by all the other decision makers. The model then determines the state of the world that results when each decision maker acts in his own interest (according to his own decision rule). This is to be contrasted with "objective function" models that assume all decision makers act according to some overriding interest as represented by the objective function. The state of the world that results when decision makers act in their individual interests might be characterized as a "balance of forces," in which every decision maker does as well as he can, given that every other decision maker is doing the same.

Second, the model assumes that decision making is an inherently dynamic process--the gas lease holder decides on an optimal production strategy over time, the shale retorting industry decides whether to build a plant by anticipating tomorrow's petroleum product prices, and so on. Thus, the model assumes that today's decisions are made by anticipating tomorrow's decisions as well as by considering yesterday's decisions and outcomes. In modeling jargon, the model is "fully simultaneous over time" and differs from all other dynamic models in this respect.

Third, the model is best characterized as an economic model with adjustments to account for imperfections (i.e., "noneconomic" behavior). The forecasts it generates are best described as reasonable end points of economic plus noneconomic forces to the extent those noneconomic forces are included in the models describing each individual decision maker. To illustrate, the present model assumes that

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*Linear and mathematical programming models take this approach. Such models are, of course, needed for individual analyses such as petroleum refinery optimization.

industry makes capacity addition decisions by using a discounted cash flow criterion--if the net present value of the cash flow from a new plant at the appropriate discount rate is positive, the industry will build that plant; if it is negative or zero, the industry will not build that plant. The model is flexible enough so that any decision rule can be specified for any decision maker in the system. For example, the cost of an environmental component could be factored into the decision making rule used by the industry. Hence, the model can be quite descriptive of the energy system.

A more complete description of the SRI National Energy Model is given in the Appendix to this volume and in Section 7 of Volume II ("Additional Model Features").

Section 1

INTRODUCTION

OBJECTIVE AND SCOPE

SRI International (formerly Stanford Research Institute), under Research Project 759-1, conducted a study for the Electric Power Research Institute (EPRI) in which SRI prepared fuel and energy price and quantity forecasts to facilitate analysis of various supply-related issues by EPRI.

The objective of the study was to generate, in constant 1975 dollars, long-term price projections for coal, uranium, crude oil, "syncrude" (from coal or oil shale), petroleum products, natural gas, and synthetic gas. Prices were to be forecast for 1985, 1990, 1995, and 2000 at different levels of the energy system, e.g., from the point of production to final consumption. Prices of primary fuels were to be disaggregated by type and by producing or import locations; prices of delivered products by end-use sector and demand (U.S. Census) regions. End-use categories were defined as electric power generation, residential/commercial, industrial, and transportation.

Price foreecasts were to be made for three given total energy and electricity demand projections developed by the Edison Electric Institute (EEI).*

METHOD OF APPROACH

Anyone familiar with energy problems recognizes the inherent uncertainty in price forecasting and the difficulties in providing a consistent framework and definition of variables within which to compare estimates and outcomes and to measure uncertainty. In this study, the SRI National Energy Model provided this consistent framework. The model computes market clearing prices and quantities of fuels by balancing supply and demand over time, and covers all major energy forms, conversion technologies, transportation modes, and demand sectors for the nine U.S.

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*"Economic Growth in the Future," Report of EEI Committee on Economic Growth, Pricing and Energy Use, Edison Electric Institute (1975).

Census regions; it also deals with market imperfections and behavioral phenomena. In modeling terminology it is called a "dynamic generalized equilibrium model" that is "fully simultaneous over time." The model is a long-term forecasting tool with a horizon of 2025. Although the study horizon is only to the year 2000, later results will be shown in the documentation because expectations of future prices and quantities of energy affect the results during the study period.

Since the model is based on a market equilibrium, its results will differ from the present and near-term energy market to the extent that this market is not in equilibrium in terms of the model's economic and behavioral assumptions. Thus, while the model's forecasting capability is quite good after 1985, particularly for fuels and technologies not affected by the 1975 to 1985 energy balances, it is less adequate in the short term. Work is under way, however, to improve the model's short-term forecasting capability by taking into account the effect of development decisions made or planned.

It must be emphasized that all prices described in this report, in fact all prices computed by the model, are marginal prices. As such they reflect the price required for the suppliers to deliver an additional Btu of each type of energy to the market place. Thus, prices are not average prices, rolled-in prices, vintage prices, or regulated prices in any sense. The difference between the marginal cost price concept and existing market prices will be discussed where appropriate.

REPORT DESCRIPTION

The report consists of two volumes. Volume I presents three detailed price/quantity forecasts made using the SRI National Energy Model. Volume II describes the underlying assumptions in comprehensive detail.

This volume (Volume I) of the report begins with an executive summary that describes the methodology used in the study, characterizes the SRI National Energy Model, and summarizes the main conclusions of the study. Prices and quantities of the fuels in the energy system are treated in considerable depth for the base case in Section 2. Section 3 analyzes the sensitivity of these prices and quantities to alternative levels of energy demand. The Appendix presents a description of the SRI National Energy Model and its salient features.

A major portion of this project was devoted to reviewing and updating the techno-economics of energy market dynamics. Within the budget limitations of the study, these estimates represent the best judgements of many SRI energy experts. However, not all the elements were reviewed because some were not included in the scope of the project and insufficient funds were available for others. Further investigation may be warranted to improve the reliability of the projections.

PROJECT TEAM

This project entailed a multidisciplinary effort by several divisions of SRI, with responsibility for coordination within the Energy Center under the direction of Dr. John P. Henry, Jr. Principal contributors were the Energy Center and the Decision Analysis-Energy Department. Responsibility was divided generally along the following lines: The Energy Center provided techno-economic evaluations of energy production, conversion, transportation, distribution, and consumption by various means, including projections of energy technology developments, costs, timing, and estimates of uncertainty. The Decision Analysis-Energy Department provided supply/demand balances using the SRI National Energy Model, which included some changes in the model network and the algorithm.

Primary responsibility within the Energy Center lay with the project supervisor, Mr. V. E. Harless, and the project leader, Dr. Hermann Attinger. Primary responsibility within the Decision Analysis-Energy Department lay initially with Dr. Edward Cazalet and ultimately with Dr. Dale Nesbitt and Mr. Louis Deziel.

Other contributors to the project were:

John A. Alich, Senior Energy Economist
C. F. Clark, Manager, Advanced Energy Processes
Dr. Stanley J. Davenport, Manager, Energy Transportation
Robert E. Fullen, Energy Economist
Claudia Grill, Research Analyst
Dr. Arvind Jain, Policy Modeling Analyst
Dr. Jay B. Kopelman, Senior Energy Economist
Marleen K. Mandt, Energy Analyst
Adrian J. Mathias, Mineral Economist
Edward P. Meko, Transportation Economist
Michael A. Moore, Manager, Petroleum Refining
Rogert G. Murray, Senior Chemical Engineer
Joseph E. Pelline, Senior Energy Economist
Stephen Regulinski, Systems Analyst
Dr. Dennis M. Rohan, Senior Industrial Economist
Dr. William F. Rousseau, Senior Research Engineer

Section 2

QUANTITIES AND LONG-TERM MARGINAL PRICES OF FUELS IN THE ENERGY SYSTEM--BASE CASE

In this section, prices and quantities in the base case forecast will be discussed in detail. Although the principal charter of this study is to develop a forecast of the prices and quantities of fuels delivered to the end users and of the fuels used in electric power generation, it will be necessary to describe the entire national supply/demand balance and how the various fuels of interest fit into this larger context. It must be reemphasized in this section that all results discussed here are sensitive to the input assumptions. These can be traced back to the base case economic and behavioral assumptions, all of which are documented in Volume II.

Discussion of the base case forecast will begin with the production of primary fuels and proceed through the energy system toward the level of usable energy. Primary fuels production will be described first, followed by primary petroleum liquid and gaseous fuel production, synthetic fuels production, imports, electric power generation, and end-use conversion. Usable energy demand will follow in the next section.

Before proceeding, we wish to emphasize again that all prices described in this report, in fact all prices computed by the model, are <u>marginal</u> prices and are expressed in constant 1975 dollars. That is, they reflect the price required for the suppliers to deliver an additional Btu of each type of energy to the marketplace. The prices are <u>not</u> average prices, rolled-in prices, vintage prices, ceiling prices, or regulated prices in any sense.

PRIMARY ENERGY

The economics of primary energy--crude oil, natural gas, coal, uranium, solar--have a major impact on the economics of all energy forms in the energy system. Thus, to understand the base case and the two sensitivity cases described in the next section, it is critical to understand the economics of primary resource production. The economics of primary resource production are input into the model in the form of marginal cost curves that describe the availability of each resource as a function of its production cost. (Production cost is the normal cost of extraction, including a calculated rate of return, but excludes lease bonus payments.) This production cost represents the minimum possible price of each resource. The model assumes, however, that the producer can actually charge a price in excess of this minimum price because the market is often willing to pay a premium for some resources. What the market is willing to pay for a resource depends on the economics of producing and utilizing that resource relative to all others over time. For example, the quantity of uranium consumed and its price may depend on whether or not breeder reactors become commercial. Similarly, today's natural gas price depends on how much gas producers will be able to sell their gas for next year. Volume II describes the marginal cost curves and shows how they are adjusted within the model to account for producer behavior over time. The reader is encouraged to carefully study the marginal cost curves for the various primary resources as part of the process of interpreting the base case results.

Total primary energy production in the year 2001 for the base case is 140 quadrillion (10^{15}) Btu/year, growing from a 1975 level of 72 quadrillion Btu/year. This corresponds to an annual average growth rate of about 2.6%. Total primary energy demand is a relatively meaningless measure of energy demand, since it is so strongly determined by the relative economics (including efficiencies) of energy conversion technologies. For example, if the most economic technologies are those with low conversion efficiencies (such as synthetic fuel technologies), economic forces will favor higher primary resource production to satisfy a given level of end-use demand. On the other hand, if the most economic technologies are those with high conversion efficiencies (say crude or natural gas production), economic forces will result in lower primary resource production to satisfy the given level of end-use demand. Under base case assumptions, highly efficient crude and natural gas production are favored in the near term, but less efficient synthetic fuels, coal, and nuclear power are favored in the long term. Thus primary resource production grows more rapidly than usable energy demand.

Figure 2-1 and Table 2-1 depict the production over time in the base case for each primary resource considered in the model. Note that domestic crude, domestic natural gas, and crude imports continue to dominate in the near term, but their share of total primary resource production diminishes relative to coal and nuclear fuel. Coal, particularly low-sulfur Western coal, grows rapidly over the entire

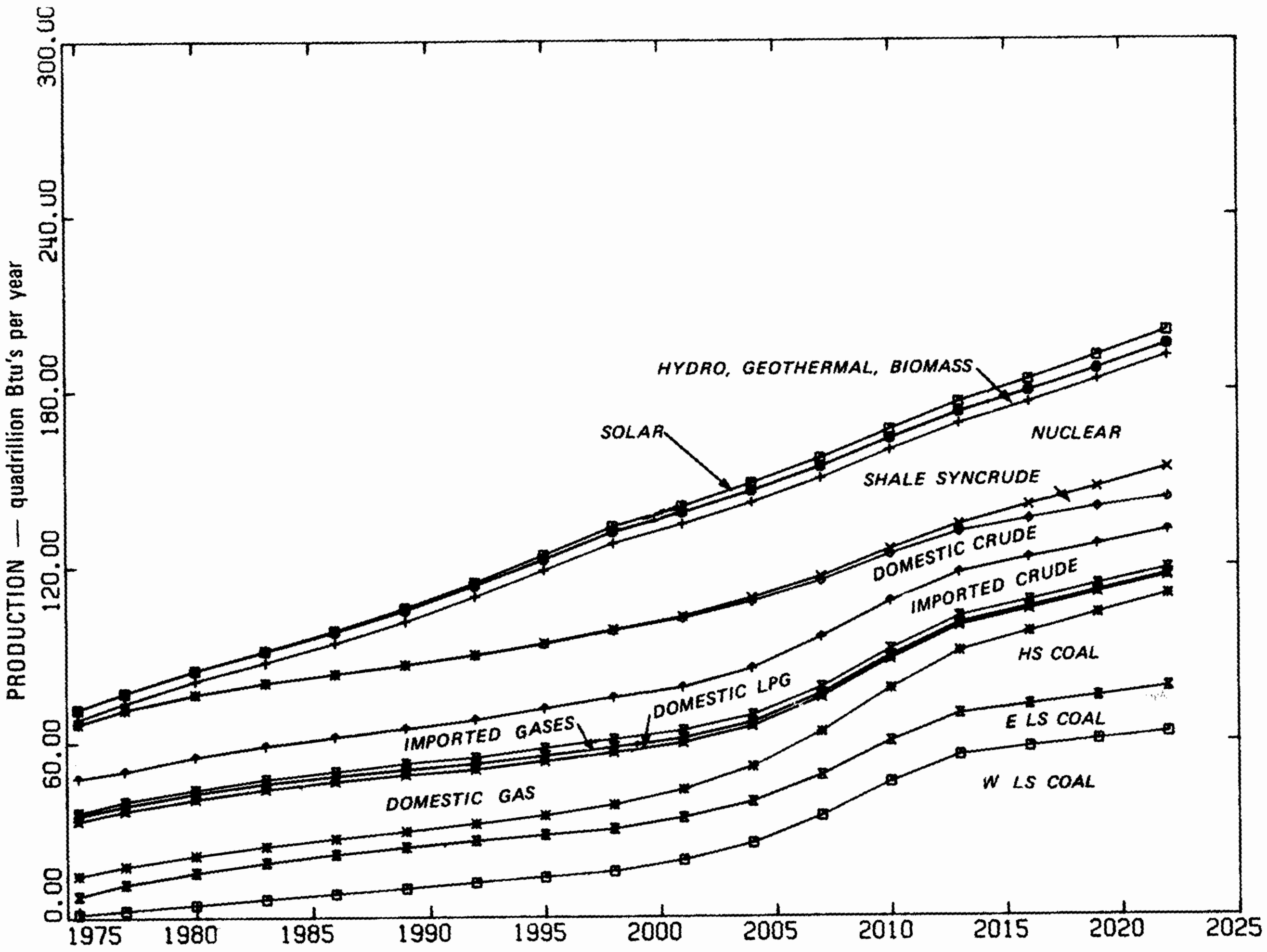

Figure 2-1. Total Primary Energy--Base Case

Table 2-1

PRODUCTION OF PRIMARY RESOURCES OVER TIME--BASE CASE

(Quadrillion Btu Per Year)

RESOURCE	1975	1977	1980	1983	1986	1989	1992	1995	1998	2001	2004	2007	2010	2013	2016	2019	2022
Solar	--	--	0.10	0.25	0.46	0.73	1.03	1.36	1.72	2.07	2.43	2.80	3.18	3.54	3.90	4.26	4.59
Biomass	--	--	--	--	0.01	0.02	0.04	0.09	0.18	0.26	0.26	0.24	0.21	0.19	0.18	0.17	0.16
Hydro and Geothermal	3.29	3.42	3.56	3.68	3.75	3.77	3.77	3.77	3.79	3.77	3.77	3.77	3.77	3.78	3.78	3.79	3.80
Nuclear Fuel	1.69	2.44	4.51	6.95	10.52	14.77	19.70	24.80	29.47	31.57	32.73	33.50	33.76	34.37	35.07	36.47	38.23
High-Sulfur Coal	7.05	6.27	5.79	5.48	5.33	5.42	5.90	6.67	8.33	9.71	11.92	14.72	17.98	21.42	24.86	28.33	31.63
Low-Sulfur Coal	7.55	11.60	15.55	19.08	21.83	24.10	26.31	28.33	30.32	34.13	39.68	48.61	60.18	69.53	72.68	75.46	78.51
Shale Syncrude	--	--	--	--	--	0.03	0.17	0.21	0.43	0.63	1.18	1.40	1.81	2.50	4.78	6.89	10.13
Domestic Crude	18.60	20.86	21.45	21.63	21.50	21.82	22.11	22.18	22.78	23.54	22.80	19.27	15.90	13.84	13.25	12.72	11.30
Crude Imports	11.73	10.59	11.29	11.55	11.80	12.13	12.88	13.58	14.41	14.93	15.89	17.11	16.54	15.15	14.55	13.74	12.90
Gas Imports	1.07	1.27	1.14	1.30	1.56	1.82	2.16	2.48	2.61	2.56	2.39	2.27	2.21	2.15	2.10	2.04	1.98
Domestic LPG	1.87	1.92	1.93	1.94	1.90	1.94	1.93	1.81	1.73	1.56	1.39	1.23	1.09	0.94	0.81	0.71	0.64
Domestic Natural Gas	18.72	18.85	19.54	19.71	19.62	19.41	18.60	18.65	17.97	15.96	13.86	11.86	10.06	8.67	7.74	6.98	6.25
Total	71.57	77.22	84.86	91.57	98.37	105.96	114.60	123.93	133.74	140.69	148.30	156.78	166.69	176.08	183.70	191.56	200.12

50-year horizon of the model. Nuclear fuel grows very rapidly in the near term (20 years) but its rate of growth ultimately decreases. As we shall see shortly, nuclear power rapidly captures the base load electric power market (at the economics assumed in the base case) in the first 20 years. Beyond this period, its rate of growth slows to the point where it is equal to the rate of growth in base load power generation itself. Early growth in Western low-sulfur coal satisfies both electric power generation and direct industrial burning demands. Later growth contributes to demands for synthetic high-Btu gas and synthetic liquids. High-sulfur coal production remains roughly constant, dropping slightly, until synthetic fuels become available in the 1990s, at which time production increases to satisfy a portion of the demand for synthetic high-Btu gas. Shale syncrude begins to grow in about the year 2000, but only grows to 10 quadrillion Btu/year by 2022, which is significantly lower than earlier projections made using the model.* This lower projection is due to the assumption that shale and coal syncrude economics are roughly equal. Thus, they contribute roughly equal shares to the liquid fuels market after 2000. Minor changes in economic assumptions regarding either shale or coal syncrude can significantly alter their relative market shares. This will be described in more detail in the next section. Note that gas imports are small because imported and regasified LNG are assumed to be more costly than SNG from coal in the base case. Crude imports increase slowly from the present until about 2010, after which the growing synthetic fuel industry and depletion of Mideast oil reserves begin to reduce imports. Oil imports increase from about 12 quadrillion Btu/year in 1975 to 17 quadrillion Btu/year in 2007 and then decline. It is significant that the more "exotic" energy forms--solar, hydro, geothermal, and biomass--are minor contributors under base case assumptions. The reasons are that solar is only competitive for water heating and space heat in certain regions of the country, and hydro, geothermal, and biomass are limited both by location and by quantity available.

Insight into the primary resource production patterns in Figure 2-1 and Table 2-1 can be gained by understanding the corresponding prices of those resources. Figure 2-2 and Table 2-2 give the market clearing prices over time of a number of key primary resources as computed by the model, expressed in 1975 dollars. They are consistent with the quantities discussed above. Note that domestic crude and

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* See "A Western Regional Energy Development Study: Economics," SRI Report, November 1976, which projected over 50 quadrillion Btu/year by 2022 using different input data.

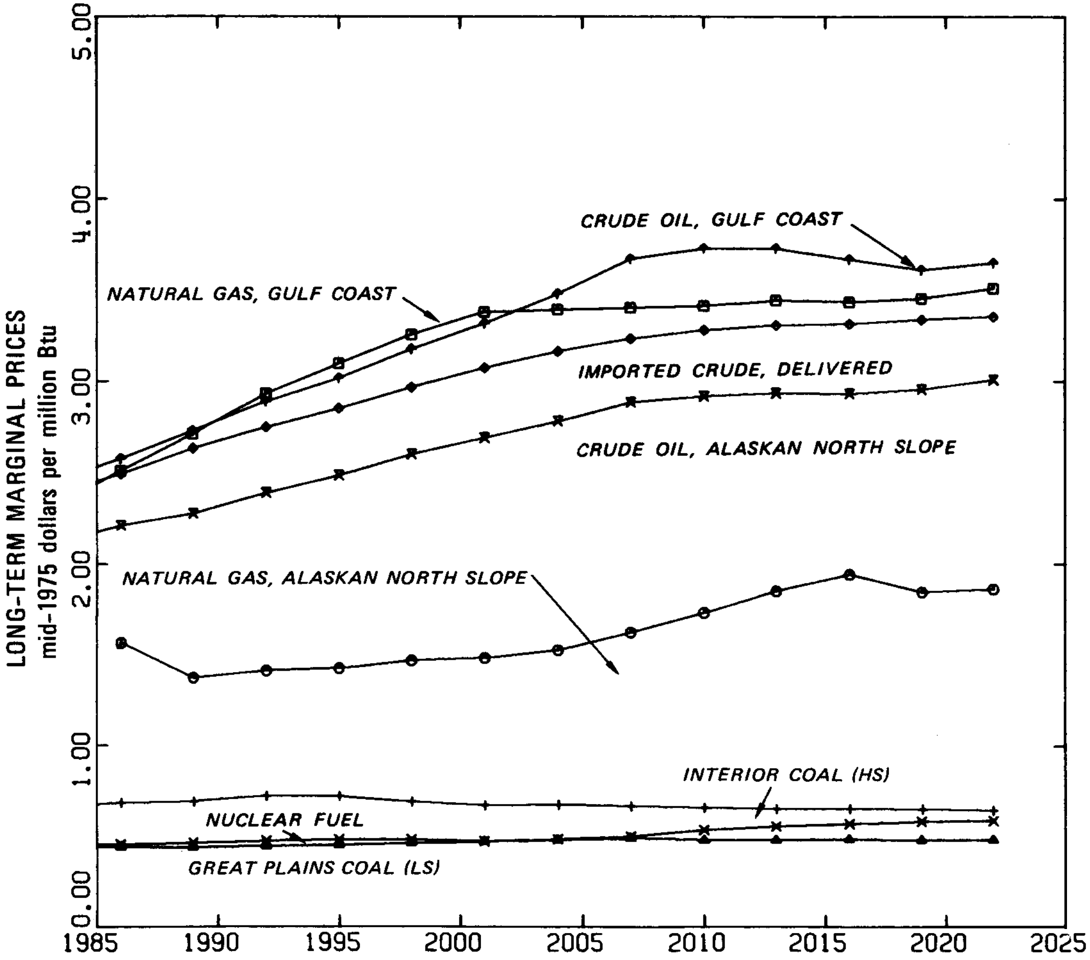

Figure 2-2. Prices of Selected Primary Resources by Location--Base Case

Table 2-2

LONG-TERM MARGINAL PRICES OF SELECTED PRIMARY RESOURCES--BASE CASE

(Mid-1975 Dollars Per Million Btu)

RESOURCE	1985	1990	1995	2000	2022
Nuclear Fuel(1)	$0.46	$0.47	$0.48	$0.47	$0.59
Interior Coal (High-Sulfur)	0.68	0.69	0.72	0.67	0.65
Great Plains Coal (Low-Sulfur)	0.44	0.44	0.45	0.48	0.48
Gulf Coast Crude	2.51	2.73	3.02	3.32	3.65
North Slope Crude	2.16	2.28	2.49	2.89	3.01
Crude Imports	2.43	2.63	2.85	3.08	3.36
Domestic LPG	2.81	2.83	3.04	3.27	4.01
Gulf Coast Gas	2.41	2.71	3.10	3.38	3.51
North Slope Gas	1.57	1.37	1.43	1.48	1.86

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(1) Based on uranium (U_3O_8) prices.

gas prices, as represented by a typical Gulf Coast well, rise to about $2.58/MMBtu in 2000. (The base case assumes no price regulation of any kind.) These price increases for domestic crude and gas reflect the depletion of oil and gas, and lead to their declining market shares over time, which we saw in Figure 2-1. In contrast with domestic oil and gas, Great Plains (Powder River) coal prices at the mine mouth vary from $0.35 to $0.50 per MMBtu over the entire time horizon of the model. This small increase in coal price indicates the abundance of coal relative to its demand. The low price assumption for Western coal at the mine mouth makes direct burning economic in the near term and helps to make synthetic gases and liquids from coal competitive in the longer term. In part because of its competition with Western coal, nuclear fuel prices remain below $0.60/MMBtu of thermal energy, and high-sulfur coal from the Illinois/Kentucky region is priced at about $0.70/MMBtu. Landed imported crude prices in the base case are assumed to be $2.20/MMBtu or $12.75/bbl until 1980 (to reflect cartel control), after which they are determined endogenously by the model using a simple model of world oil availability. By 2000, imported crude prices reach $3.10/MMBtu or $17.90/bbl. Note that domestic Gulf Coast crude prices are approximately equal to imported crude prices, except that they are about $0.10 to $0.25 per MMBtu ($0.60 to $1.45 per bbl) higher. This is because sweet (low-sulfur) Gulf Coast crude is less expensive to refine than imported sour (high-sulfur) crude and thus commands a small premium.

Obviously, oil, gas, coal, and the other primary resources are not equivalent commodities. Differences in prices persist because of the differences in energy conversion economics as well as differences in resource production economics. To illustrate, the economics of transporting and converting oil to a usable energy form are quite different than the economics of transporting and converting coal to that same energy form. Even though domestic crude oil may cost $2.30/MMBtu or so to produce, refining and distribution costs are so low that this is the most competitive source of liquid fuels. Coal, even though it may cost only $0.50/MMBtu to produce, would require an additional $3.00/MMBtu or so to produce liquid fuels that would not be competitive with liquids from domestic crude. Thus, the demand for liquid fuels implies a demand for crude oil rather than for coal even though coal prices are less than 25% of crude oil prices.

The dominant fuels for base load electric power generation in the base case--coal and nuclear--could be categorized as "abundant" primary resources. Coal and nuclear fuel supplies are very elastic and their prices tend to be low relative to the prices of the final energy form they produce. Unlike oil and gas, the key uncertainty regarding coal and nuclear fuel is not how much is in the ground but instead how much will they cost to produce. Many analysts agree that relatively low-priced coal and nuclear fuel will be available for 50 years.

LIQUID AND GASEOUS FUELS

Figures 2-1 and 2-2 are useful in understanding primary resource production but cannot fully describe the sources of liquid and gaseous fuels, since much of the coal indicated in Figure 2-1 and all of the shale are actually converted to liquids or gases. This section investigates the production over time of liquid and gaseous fuels from whatever source under base case assumptions. Figure 2-3 and Table 2-3 show total liquid and gaseous fuel production, excluding the synthetic gas used in integrated combined-cycle/low-Btu gasification facilities.*

The large quantity of coal that was indicated in Figure 2-1 can now be traced to liquid and gaseous fuel production. In the year 2001, total coal production is about 44 quadrillion Btu/yr, while total coal liquids plus synthetic gas production is 6.6 quadrillion Btu/yr. However, by the year 2016, total coal production rises to 98 quadrillion Btu/yr, while total coal liquids plus synthetic gas production rises to 41 quadrillion Btu/yr. Clearly, an increasing fraction of coal production is being used for synthetic fuels production after 2000.

In Figure 2-3, the sum of shale oil plus coal liquids grows rapidly after the two technologies become competitive by about 2000. It is significant that neither coal liquids nor shale oil captures the entire liquids market under the base case economic assumptions. The reason is that both technologies are assumed to deliver syncrude to Midwestern refineries at virtually identical prices and that these prices are on the order of $3.30/MMBtu or $19.00/bbl. Minor changes in the relative economics of coal liquids versus shale oil can affect the market shares of each.

Note that total liquids and total gases each maintain their market shares over time. When the end-use markets are discussed, we shall see that no distributed fuel dramatically gains or loses its market share in any end-use market under base case economic assumptions.

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*The three cases discussed in this report result in insignificant market penetration of such integrated facilities, so the figure contains essentially all sources.

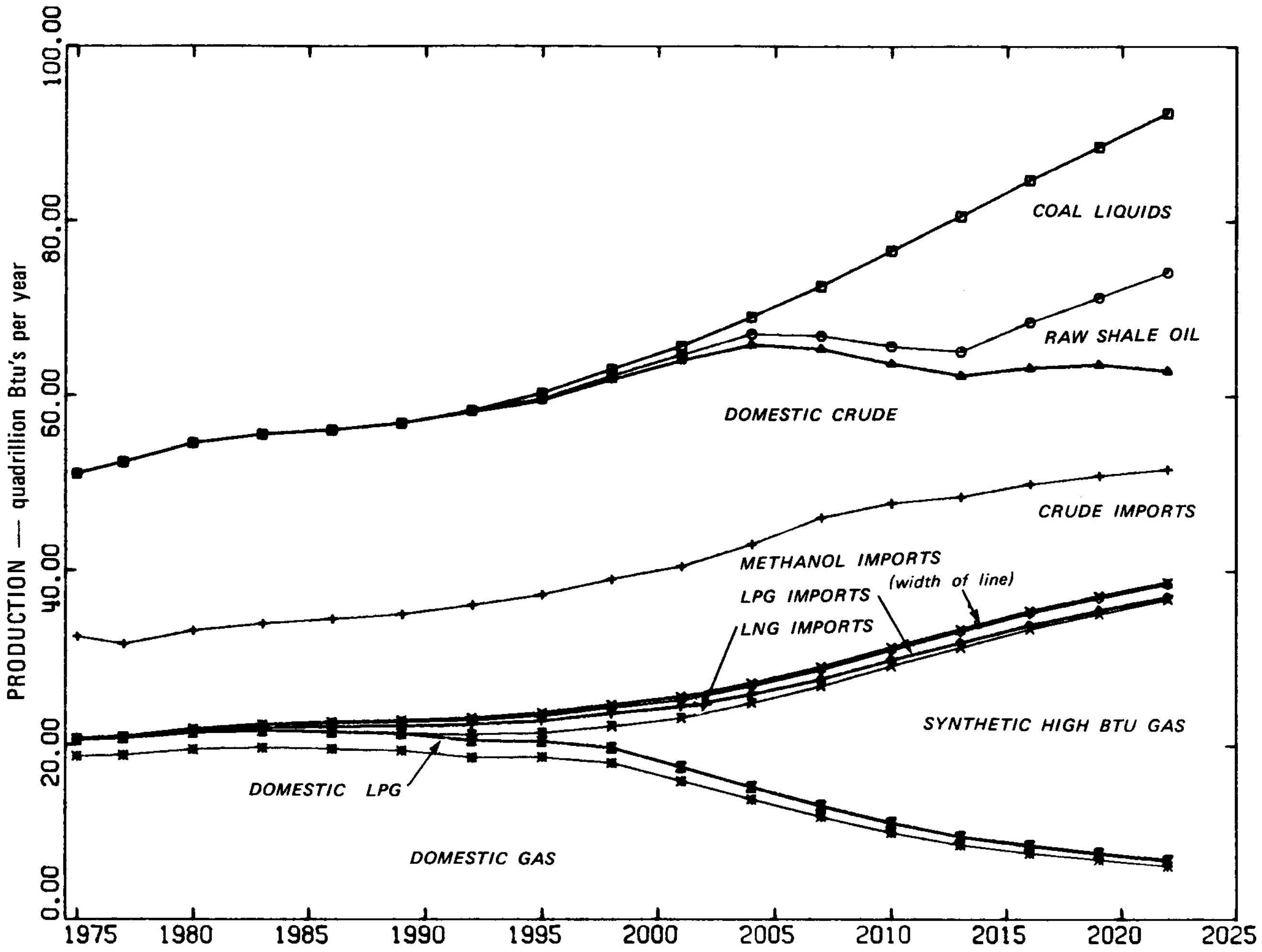

Figure 2-3. Sources of Liquid and Gaseous Fuels--Base Case

Table 2-3

LIQUID AND GASEOUS FUEL PRODUCTION

(Quadrillion Btu Per Year)

RESOURCE	1975	1977	1980	1983	1986	1989	1992	1995	1998	2001	2004	2007	2010	2013	2016	2019	2022
Coal Liquids	--	--	--	--	--	0.01	0.01	0.64	0.72	0.96	1.92	5.66	10.96	15.50	16.18	17.25	18.19
Raw Shale Oil	--	--	--	--	--	0.03	0.19	0.24	0.48	0.70	1.31	1.56	2.01	2.78	5.31	7.66	11.27
Domestic Crude	18.60	20.86	21.45	21.63	21.59	21.82	22.11	22.17	22.78	23.53	22.80	19.27	15.90	13.84	13.24	12.72	11.30
Crude Imports	11.73	10.59	11.29	11.55	11.80	12.13	12.88	13.58	14.41	14.93	15.89	17.12	16.54	15.15	14.55	13.74	12.90
Methanol Imports	--	0.01	0.01	0.08	0.15	0.22	0.27	0.31	0.35	0.37	0.37	0.35	0.32	0.29	0.27	0.25	0.24
LPG Imports	0.18	0.17	0.24	0.34	0.43	0.46	0.51	0.58	0.64	0.77	0.90	1.04	1.17	1.29	1.37	1.43	1.46
LNG Imports	--	0.03	0.12	0.34	0.58	0.87	1.17	1.43	1.50	1.33	1.05	0.82	0.67	0.54	0.44	0.34	0.27
Synthetic High-Btu Gas	--	--	--	--	--	--	0.67	0.90	2.46	5.59	9.57	13.67	17.94	21.61	24.81	27.45	29.90
Synthetic Low-Btu Gas	--	--	--	--	--	--	0.01	0.02	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02
Domestic LPG	1.87	1.92	1.93	1.94	1.90	1.94	1.93	1.81	1.73	1.56	1.39	1.23	1.09	0.94	0.81	0.71	0.64
Domestic Gas	18.72	18.85	19.54	19.71	19.62	19.41	18.60	18.65	17.97	15.96	13.86	11.86	10.06	8.67	7.74	6.98	6.25

Assuming an unregulated market, domestic crude oil provides a slowly declining percentage of liquid fuel demand until depletion becomes quite noticeable by the end of the century. During this period, imported crude accounts for the difference between total liquid fuel demand and domestic crude production until synthetic liquids become competitive. Once synthetic liquids become competitive, both domestic crude and imported crude decline quite rapidly.

The gas market is similar to the liquids market. However, the effect of imported LNG in the gas market is much smaller than the effect of imported crude in the liquids market in the intermediate term. The effect of SNG in the gas market, on the other hand, is much larger than the effect of synthetic liquids in the liquids market in the longer term. Hence, synthetics are relatively more important in the gas market and imports are relatively less important, all of course assuming the base case economic assumptions are correct.

As shown in Figure 2-3, synthetic fuels are expected to be important contributors to liquid and gaseous fuels after 1990 or so. The magnitude of their effect depends on two factors: the prices (and price elasticities) at which synthetic fuels can be produced, and the price of imported oil, gas, and methanol. We shall first discuss synthetic fuels economics and then discuss imported fuels economics.

Synthetic Fuels

The base case projection of synthetic fuels production is illustrated in Figure 2-4 and Table 2-4. The figure and table do not include low-Btu gas produced in integrated electric power facilities that gasify coal and burn the gas in a combined gas turbine/steam cycle or fuel cell configuration.

In this base case projection, synthetic fuels grow from virtually zero in 1990 to 29.0 million bbl/day of crude oil equivalent by the year 2022. Almost exactly half of synthetic fuels production is gas and half is liquids.

On the basis of thermal value, synthetic high-Btu gas from coal is the largest synthetic fuel industry. Most of the synthetic high-Btu gas shown in Figure 2-4 comes from second generation coal gasification plants. In the base case techno-economic projections, it has been assumed that advanced high-Btu gasification technologies will be commercially available two years after the Lurgi technology

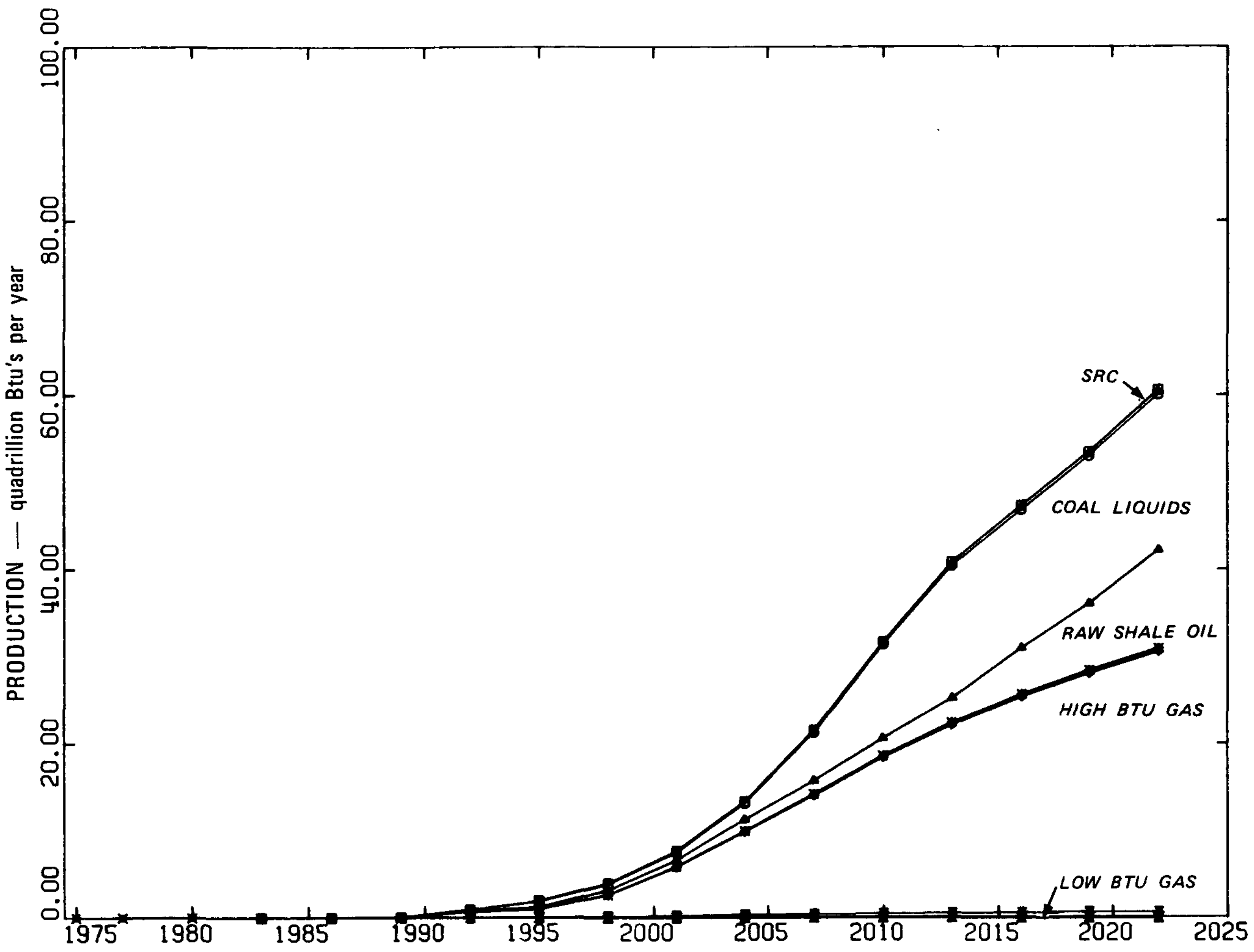

Figure 2-4. Synthetic Fuels--Base Case

Table 2-4

SYNTHETIC FUEL PRODUCTION--BASE CASE

(Quadrillion Btu Per Year)

RESOURCE	1975	1977	1980	1983	1986	1989	1992	1995	1998	2001	2004	2007	2010	2013	2016	2019	2022
SRC	--	--	--	--	--	--	0.04	0.07	0.11	0.16	0.21	0.27	0.33	0.40	0.45	0.50	0.56
Coal Liquids	--	--	--	--	--	--	--	0.62	0.70	0.91	1.84	5.54	10.77	15.25	15.89	16.92	17.82
Raw Shale Oil	--	--	--	--	--	0.03	0.19	0.24	0.48	0.70	1.31	1.56	2.01	2.77	5.32	7.67	11.27
Methanol From Coal	--	--	--	--	--	0.01	0.01	0.02	0.02	0.04	0.08	0.13	0.19	0.25	0.29	0.33	0.36
High-Btu Gas From Coal	--	--	--	--	--	--	0.66	0.90	2.46	5.59	9.57	13.66	17.94	21.61	24.81	27.45	29.90
Low-Btu Gas From Coal	--	--	--	--	--	--	0.02	0.06	0.12	0.20	0.28	0.35	0.42	0.48	0.53	0.58	0.63
Hydrogen From Coal	--	--	--	--	--	--	0.01	0.01	0.02	0.03	0.03	0.04	0.04	0.05	0.05	0.05	0.06
Total	--	--	--	--	--	0.04	0.93	1.92	3.91	7.64	13.33	21.54	31.70	40.81	47.34	53.50	60.60

is commercially available and at about 85 percent of the gas cost.[*] Under such an assumption, Lurgi gasification has only a two-year "gap" to fill, and thus would not be expected to attain high production levels. Some Lurgi plants, however, may be built to fill even this two-year gap, which indicates that accelerating the second generation coal gasification technologies may pay economic benefits. Such acceleration has been investigated in a recently completed study for the Office of Commercialization at ERDA using the SRI National Energy Model.[**]

The plant gate prices of various synthetic fuels in Figure 2-5 and Table 2-5 further emphasize the importance of second generation high-Btu gas from coal. Synthetic gas prices are shown to range between $2.50 and $2.80 per MMBtu by the year 2000, depending on coal type. These prices are lower than many published estimates of advanced synthetic gas technology prices. There are two reasons: first, in calculating electricity and gas prices, the model assumes a 12 percent current dollar discount rate. This corresponds to a 7 percent constant dollar discount rate, as discussed in Volume II. As a result of this low discount rate, the capital charge of gas produced by an SNG plant is not large. Second, it has been assumed that the capital cost of a 250 MMcf/day capacity second generation gasification facility is about $550 million (excluding interest during construction), and that of a similar sized Lurgi gasification facility is $700 million (again excluding interest during contruction). These numbers are lower than some published estimates.

Recall that both shale and coal syncrude production are fairly large after the year 2000. Notice the prices in Figure 2-5 and Table 2-5. Although shale syncrude and coal syncrude prices are quite close, the base case economic estimates slightly favor coal liquids (which include coal syncrude, methanol, and boiler fuel oil) over shale oil for several reasons.

First, as discussed in Volume II, the base case assumes a 10 percent constant dollar discount rate for all industrially financed energy conversion facilities and a

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[*] This is consistent with a recent C. F. Braun report on coal gasification economics. "Factored Estimates for Western Coal Commercial Concepts," Interim Report, October 1976 for ERDA and American Gas Association.

[**] "A Framework for Evaluation of Synthetic Fuels Commercialization Proposals" Draft Report to ERDA Office of Commercialization, January 1977.

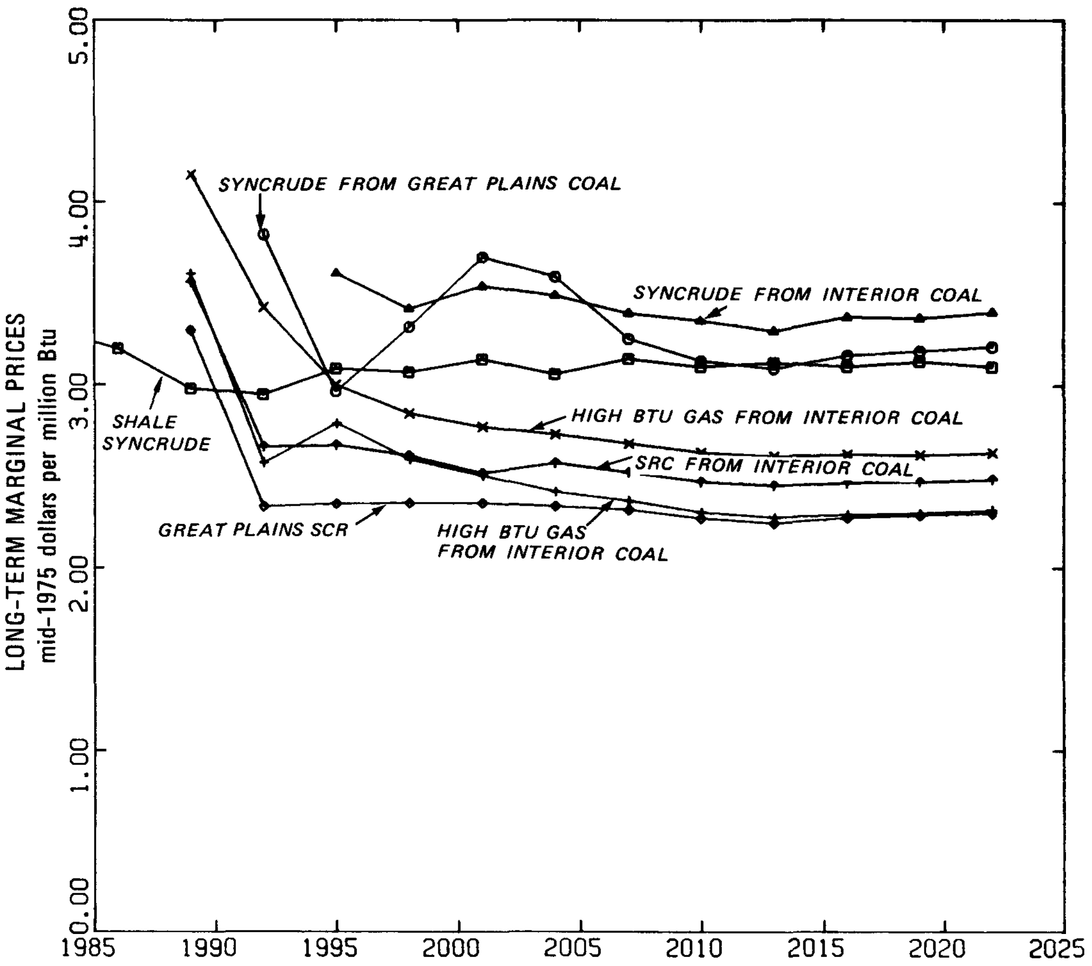

Figure 2-5. Prices of Selected Synthetic Fuels by Location--Base Case

Table 2-5

SYNTHETIC FUEL PRICES*--BASE CASE

(Dollars Per Million Btu)

RESOURCE	1985	1990	1995	2000	2022
SRC From Great Plains Coal (Loc. 14)	--	--	2.35	2.36	2.30
SRC From Interior Coal (Loc. 16)	--	--	2.67	2.52	2.49
Syncrude From Great Plains (Loc. 14)	--	--	2.97	3.70	3.21
Syncrude From Interior Coal (Loc. 16)	--	--	3.61	3.54	3.40
Shale Syncrude (Loc. 28)	--	2.98	3.09	3.14	3.10
High-Btu Gas From Great Plains Coal (Loc. 14)	-- --	3.61	2.79	2.51	2.32
High-Btu Gas From Interior Coal (Loc. 16)	--	4.16	3.00	2.77	2.63
Syncrude From Appalachian High-Sulfur Coal (Loc. 17) (Negligible Volume)	--	--	--	3.58	3.50
Syncrude From Rocky Mountain Coal (Loc. 28) (Negligible Volume)	--	--	--	3.56	3.47

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* Long-term marginal prices, mid-1975 dollars

15 percent constant dollar discount rate for all primary resource production facilities.* The reason this assumption tends to favor coal liquefaction over shale production is as follows: to produce one barrel of shale syncrude would require mining more than 1.4 tons of 30 gal/ton shale, while to produce one barrel of coal syncrude would require mining only about 0.5 tons of Western low-sulfur coal. Also, shale is likely to be mined underground and the coal is likely to be surface mined. Therefore, shale mining cost will be a substantially larger fraction of the shale syncrude price than coal mining cost will be of the coal syncrude price. Conversely, the capital equipment necessary to process the shale will constitute a lower fraction of the shale syncrude price than the capital equipment necessary to liquefy the coal will be of the coal syncrude price. Because this processing equipment is assumed to be discounted at only 10 percent while the mine equipment is assumed to be discounted at 15 percent, coal liquefaction is favored.

Second, because the model projects the coal mining industry to be large by the 1990s in both the east and west, growth in that industry from 1990 onward may be less costly than shale because there will be a large industrial and social infrastructure base in place from which to build. The model assumes that high growth rates (relative to the base in places) are accompanied by high short-term energy prices. Because shale will be penalized more severely than coal, growth in coal liquids is favored.

Third, in the base case both Eastern and Western coal prices are among the lower published estimates of coal prices. Referring to Table 2-2, the price of Great Plains coal is calculated by the model to be $0.48/MMBtu by 2000 or about $7.75/ton, while the price of Interior high-sulfur coal is calculated to be $0.67/MMBtu or about $16.40/ton. These low Western coal prices tend to favor coal liquefaction over shale. It should be clear that even slight changes in economic assumptions between shale and coal liquids could change these relative prices and thus change the balance between shale syncrude and coal liquids.

Figure 2-4 indicates that only a few of the many proposed synthetic fuels technologies will be attractive in the long run under base case assumptions, and Figure 2-5 illustrates why--the prices of their products are too high. The following

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*This assumption should be reviewed in the case of integrated mine-mouth/conversion facilities.

technologies, which are considered in the model, are not economical under the base case assumptions and thus their production is low:

- Solvent-refined coal (SRC)
- Methanol from coal
- Low-Btu gas from coal
- Hydrogen from coal

Low-Btu gas from coal is uneconomical because of the high cost of transporting both its input fuel (coal) and its product (low-Btu gas). For this reason it is more economical in most regions of the country to convert the coal to high-Btu gas (methane) or a liquid at the mine mouth and move the methane or liquid fuel. Briefly, SRC is noncompetitive with direct burning/desulfurization under base case assumptions. Methanol is noncompetitive with other liquid and gaseous fuels under base case assumptions. Hydrogen has been assumed to face production and transportation difficulties similar to low-Btu gas, thus rendering it noncompetitive at points of use.

Imported Fuels

As alluded to above, the demand for synthetic liquid and gaseous fuels is directly affected by the price and quantity of imported energy forms. Figure 2-6 and Table 2-6 give a detailed breakdown of imported fuel quantities and prices. Note that crude imports remain constant through 1985. The reason they do not increase before 1985 is that the model assumes price deregulation on domestic crude between 1975 and 1985 and, as a result, short-term production is stimulated without significant time lags. Expressed differently, the model assumes that deregulation would make enough domestic liquids available to keep import levels at roughly today's 6 MM bbl/day through 1985. After 1990, and in fact through the first decade of the 2000s, crude imports grow. By about 2007, when a viable synthetic liquids industry is in place and given that world crude reserves have been sufficiently depleted, crude imports begin to decline slowly as they are forced out of the market by coal liquids and shale oil. Recall that in Figure 2-4 the synthetic fuel industry is growing dramatically from 1992 onward, 15 years will be required to actually begin to diminish imports.

Other imported fuels are relatively minor contributors to the U.S. supply/demand balance, although imported gaseous fuels grow to 2.25 quadrillion Btu before domestic SNG dominates. Imported LNG is of minor importance because it has been

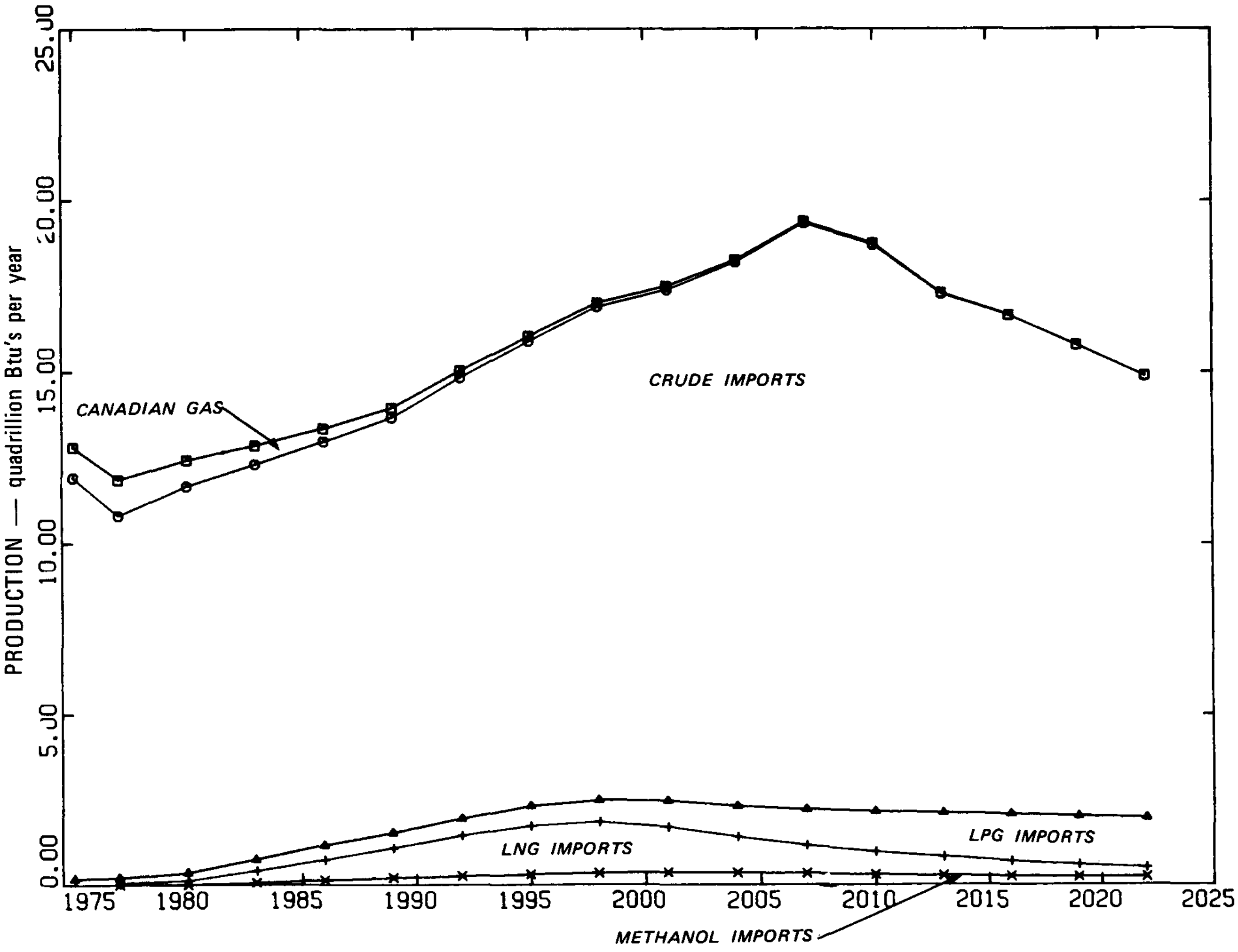

Figure 2-6. Imported Fuels--Base Case

Table 2-6

IMPORTED FUELS--BASE CASE

(a) QUANTITIES OF IMPORTED FUELS

(Quadrillion Btu Per Year)

RESOURCE	1975	1977	1980	1983	1986	1989	1992	1995	1998	2001	2004	2007	2010	2013	2016	2019	2022
Canadian Gas	0.89	1.06	0.76	0.54	0.39	0.28	0.21	0.16	0.12	0.09	0.07	0.06	0.04	0.03	0.03	0.02	0.01
Crude Imports	11.73	10.59	11.30	11.54	11.80	12.12	12.88	13.58	14.41	14.93	15.88	17.12	16.54	15.15	14.55	13.75	12.90
LPG Imports	0.18	0.17	0.24	0.34	0.43	0.46	0.51	0.58	0.64	0.77	0.90	1.04	1.17	1.29	1.37	1.43	1.46
LNG Imports	--	0.03	0.12	0.34	0.59	0.87	1.17	1.43	1.50	1.33	1.05	0.82	0.67	0.54	0.44	0.34	0.27
Methanol Imports	--	0.01	0.01	0.08	0.15	0.22	0.27	0.31	0.35	0.37	0.37	0.35	0.32	0.29	0.27	0.25	0.24
Total	12.80	11.86	12.43	12.84	13.36	13.95	15.04	16.06	17.02	17.49	18.27	19.39	18.74	17.30	16.66	15.79	14.88

(b) PRICES* OF IMPORTED FUELS

(Dollars Per Million Btu)

	1985	1990	1995	2000	2022
Canadian Gas	3.58	3.76	4.04	4.17	4.27
Crude Imports	2.44	2.56	2.75	2.98	3.27
LPG Imports	2.99	3.13	3.35	3.58	3.86
LNG Imports	2.99	3.13	3.35	3.58	3.86
Methanol Imports	3.64	3.78	4.00	4.23	4.51

* Long-term marginal prices, mid-1975 dollars

assumed in the base case that coal gasification is less expensive. Advanced technologies are assumed to produce SNG at about $2.50 to $2.75 per MMBtu, while Table 2-6(b) indicates landed and regasified LNG prices at nearly $3.60/MMBtu. Of course, changes in the relative prices of LNG and SNG can affect this result but in a manner that is difficult to predict. If LNG prices were lowered substantially, LNG would become economical first near the LNG importing and regasification facilities, but SNG may still be economical in the interior of the country near the coal regions and far from the coasts. Finally, as shown in Figure 2-6, imports of methanol are insignificant in the base case.

ELECTRIC POWER GENERATION

The electric power generation industry itself can have an effect on the economics of the fuels it must purchase. For example, industry aversion to nuclear technologies because of institutional or financial difficulties might affect not only nuclear fuel prices but also the prices of whatever fuels replace it. Furthermore, the quantity of electric power generated is set both by the competition between electricity and other energy forms in each of the end-use markets and by the level of total demand in each end-use market. To understand how these complex forces affect the demand for electric power and the fuels required to generate it, considerable attention will be given to electricity generation at three levels:

- The level of usable energy demand and how it affects the demand for electricity
- Competition in the end-use markets between electricity and other fuels
- Competition among individual electric power generation technologies in base, intermediate, and peak power generation

These three levels were discussed in the Executive Summary in conjunction with Figure 0-1.

A detailed discussion of the effects of usable energy demand will be deferred to Section 3; however, the growth rate in electric power generation in the base case will be discussed briefly here. Competition among end-use conversion technologies and competition among individual electric power generation technologies will then be discussed in considerable detail. We include these discussions as part of the overall national context within which the forecast of fuel prices and quantities for electric power generation is made.

Growth in Total Electric Power Generation

Figure 2-7 and Table 2-7 display the annual busbar generation of electric power over time as determined by the model for the base case. Table 2-7 includes the mean busbar electricity price (marginal cost) over time.* Note that from 1975 through 2001, total electric power generation roughly triples in 26 years. This corresponds to an average annual growth rate of 4.3 percent. For this same period, per capita GNP is assumed to grow at about 2.7 percent, indicating that electric power grows faster than per capita GNP under the base case economic assumptions. Making the same calculation from 2001 through 2022, the average annual growth rate for total electric power generation is 2.5 percent. The reason for the declining growth rate over time in electric power generation derives partially from the per capita GNP growth rate assumption in the demand model. As discussed in Volume II, Section 6, the growth in per capita GNP was assumed to decline over time in the base case demand projection. It was assumed to grow at 3.7 percent from 1975 to 1985, 2.1 percent from 1985 to 2000, and 1.6 percent from 2000 to 2025. To measure the "electrification" of the economy, it is instructive to analyze the rate of change in the quotient of electric generation divided by per capita GNP. The various growth rates are compared in Table 2-8. Clearly, electricity is growing relative to per capita GNP, but its rate of growth is declining over time. As discussed in Volume II, Section 6, much of the faster growth of electric power is actually input exogenously in the usable energy demand inputs themselves. In particular, industrial electromechanical end uses are assumed to grow more rapidly than per capita GNP.

It should be pointed out in conclusion that our air-conditioning demand is about one-third of that in many projections. This leads to a slightly lower rate of growth in electric power generation than would occur if we used those higher air-conditioning forecasts.

Interfuel Competition at the End-Use Level

Since the level of interfuel competition is different in the three end-use sectors--transportation, industrial, and residential/commercial--each will be discussed in some detail.

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*The mean price of electricity in this context is defined as the production weighted average of the marginal costs over all technologies in all load categories, not the regulated rate base price.

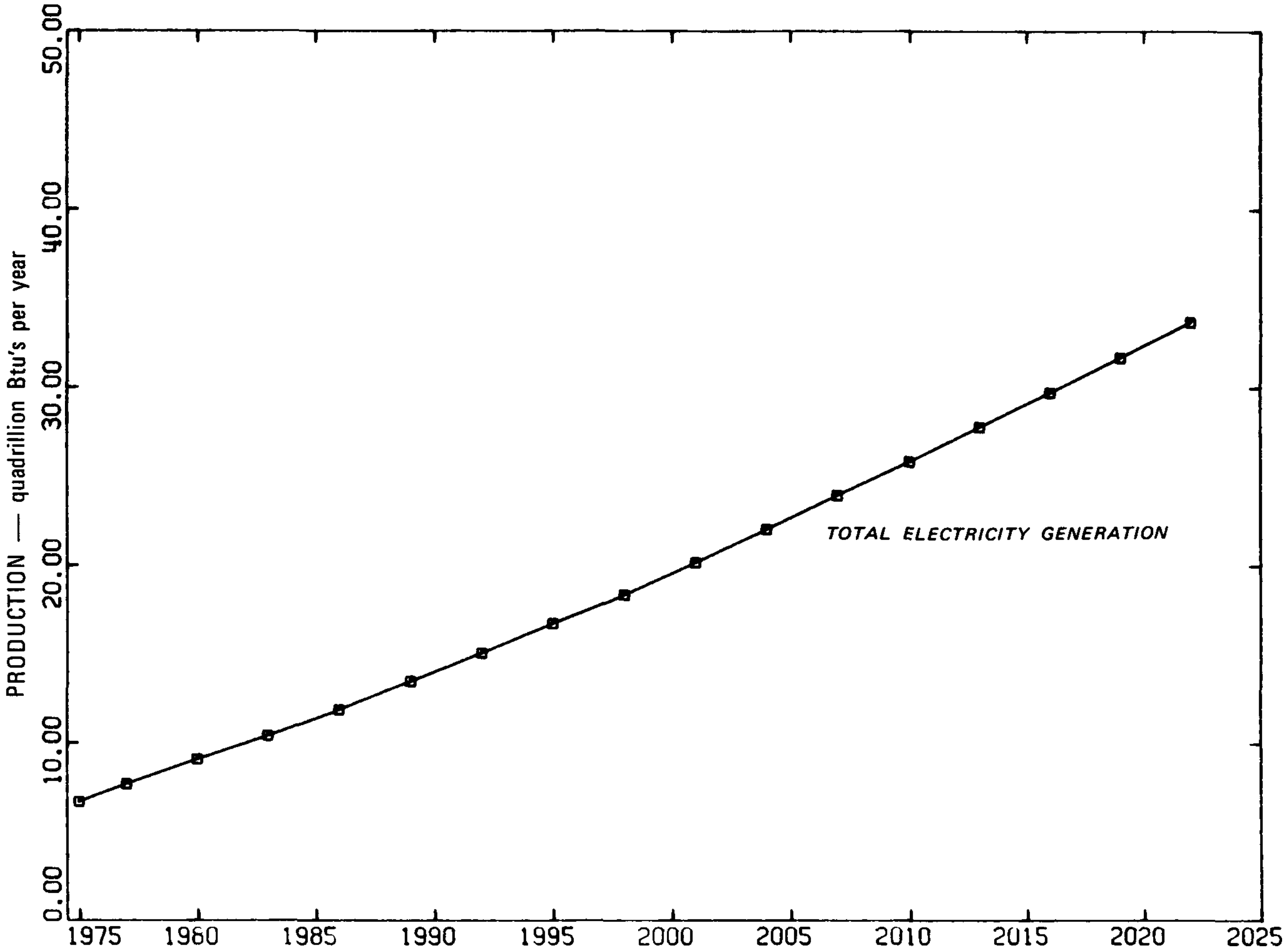

Figure 2-7. Electric Power Generation--Base Case

Table 2-7

ELECTRIC POWER GENERATION--BASE CASE

YEAR	QUANTITY		BUSBAR PRICE*	
	(Quadrillion Btu/yr)	(Trillion kWh/yr)	$/MMBtu	¢/kWh
1975	6.7	1.96	8.0	2.71
1977	7.7	2.26	8.3	2.83
1980	9.1	2.67	7.4	2.54
1983	10.4	3.06	7.5	2.56
1986	11.9	3.48	7.5	2.56
1989	13.5	3.95	7.5	2.54
1992	15.1	4.42	7.5	2.55
1995	16.7	4.90	7.3	2.48
1998	18.4	5.39	7.3	2.51
2001	20.2	5.92	7.1	2.43
2004	22.0	6.46	7.1	2.44
2007	23.9	7.01	7.0	2.40
2010	25.9	7.58	6.9	2.35
2013	27.8	8.14	6.7	2.28
2016	29.7	8.71	6.6	2.25
2019	31.7	9.29	6.4	2.19
2022	33.7	9.87	6.5	2.20

* Long-term marginal prices, mid-1975 dollars

Figure 2-8 shows the base case demand for fuels in the transportation sector. The figure illustrates that electricity is not competitive as an automotive fuel under base economics. The base case demand estimates assume that people do not change their lifestyles from private automobiles to electrically powered mass transportation. This assumption is exogenous to the model. Figure 2-9 illustrates the corresponding transportation fuel prices. (These prices do not include user excise taxes on the fuels.) Note that gasoline and distillate are moderately less expensive than electricity. Thus, electric vehicles would have to be significantly more efficient (in terms of miles traveled per million Btu of electrical energy consumed) than internal combustion vehicles in order to enjoy competitive economics. The base case economics do show a fuel cost advantage for electric vehicles

Table 2-8

GROWTH RATES

	1975-1985	1985-2000	1975-2000	2000-2022
Electric Power Generation	5.3	3.8	4.3	2.5
Total Primary Energy	2.9	2.5	2.6	1.7
GNP	4.6	2.9	3.6	2.2
GNP per Capita	3.7	2.1	2.7	1.6
Electricity Generation per GNP per capita	1.53	1.57	1.55	0.84

with a nonfuel cost disadvantage. In 2001, distributed electricity for transportation purposes is calculated by the model to be \$7.70/MMBtu and the efficiency of a new electric automobile is assumed to be 544 miles/MMBtu for intracity uses. Thus the fuel cost is only \$7.70/544 miles = 1.5 ¢/mile for intracity uses. The gasoline automobile, on the other hand, is assumed to have an efficiency of about 190 miles/MMBtu for intracity uses in 2001, and gasoline prices in 2001 (excluding tax) are calculated to be \$4.76/MMBtu by the model. This leads to a fuel cost of \$4.76/190 miles - 2.5 ¢/mile. Hence, the electric vehicle enjoys about a penny a mile fuel cost advantage.

In the base case, the nonfuel operating costs of the electric and gasoline vehicles were assessed to be roughly equal. Both vehicles require licensing, taxation, insurance, tires, lubrication, maintenance, and so forth, which cost about 15¢ per mile. The higher cost of maintaining an internal combustion engine will likely be more than offset by the cost of replacing batteries as they deteriorate due to charging and discharging.

The reason the electric vehicle is noncompetitive lies in the capital costs of the electric in comparison to competing vehicles. The electric vehicle promises to have a significantly higher capital cost than the gasoline vehicle because of the high cost (and weight) of the battery package. Hence, even though the electric vehicle can save a penny a mile in fuel cost, its capital cost is so much higher that the total driving cost per mile is significantly higher than that of the

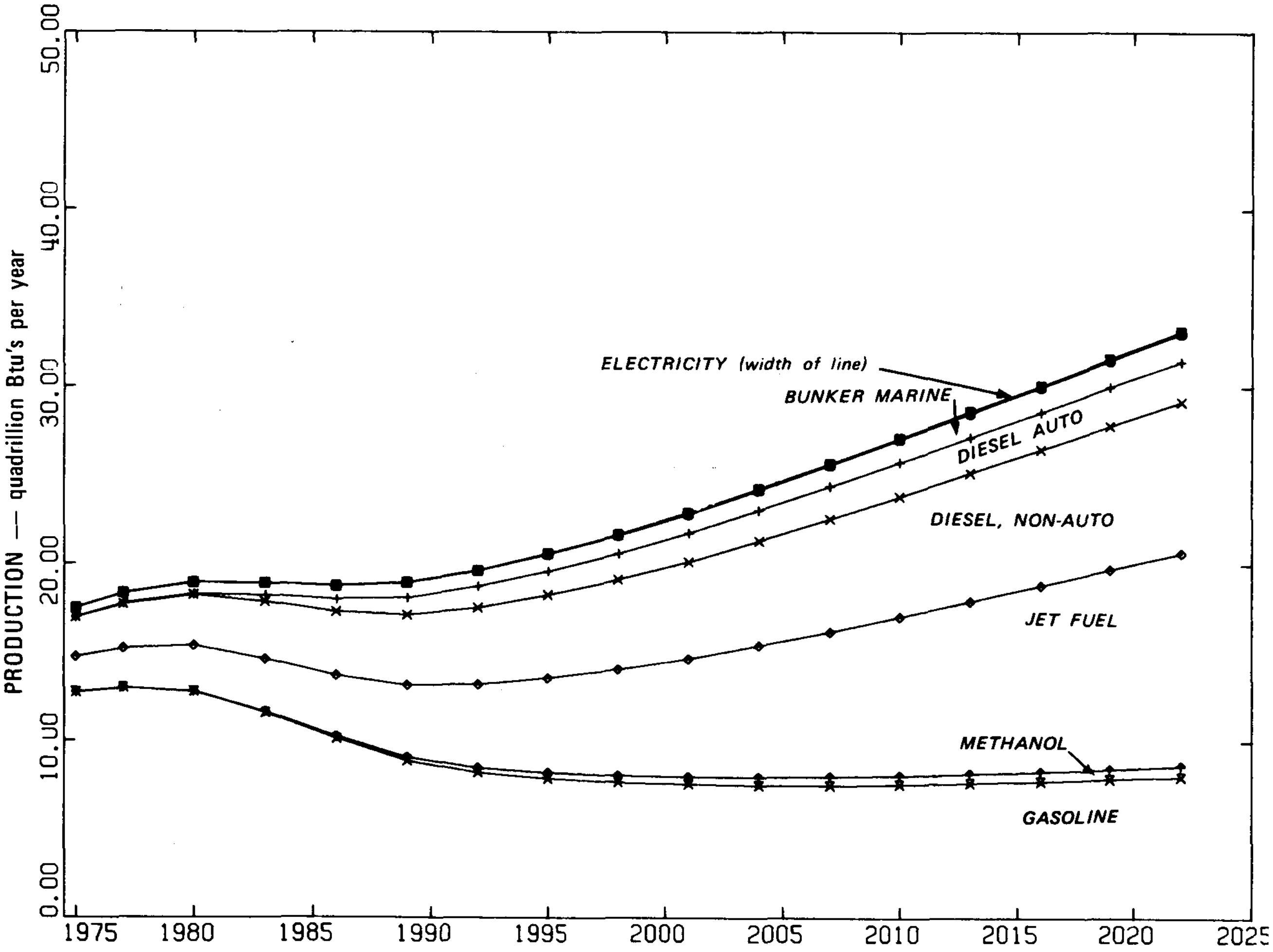

Figure 2-8. Distributed Products in the Transportation Sector--Base Case

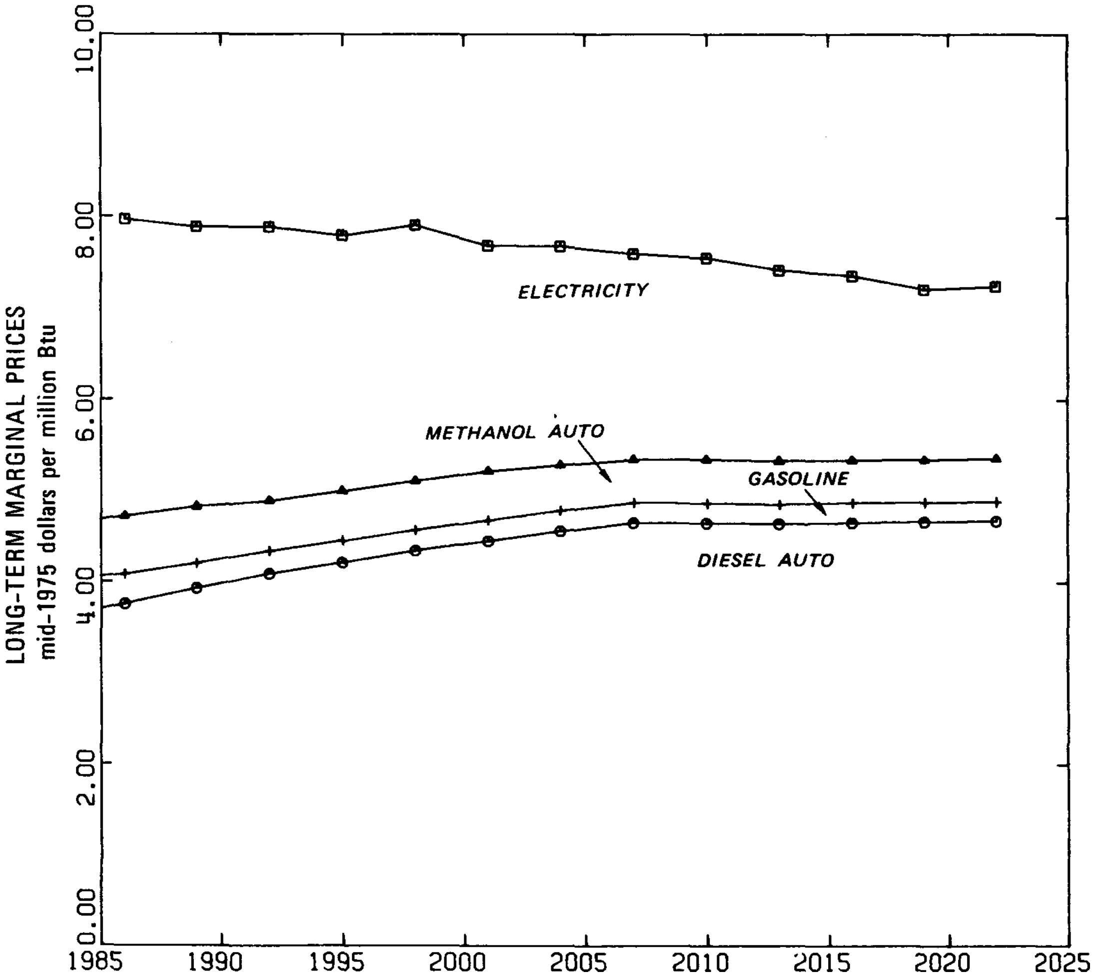

Figure 2-9. Average Prices of Distributed Products Used in the Transportation Sector--Base Case

conventional gasoline vehicle. Thus, in the base case the electric vehicle is noncompetitive with internal combustion vehicles and electricity demand for this use is essentially zero.

The distributed fuel picture in the industrial sector appears in Figure 2-10 for the base case. Clearly, electricity is not dramatically increasing its share of the industrial market outside captive electricity used. In fact, electricity is satisfying only the "captive-electric" industrial demand (electromechanical applications, electrolytic processes, lighting, and so on). It is not competitive in the categories called "direct heating" and "indirect heating" under base case economic assumptions. The reason is best seen in Figure 2-11, which shows the corresponding prices of distributed industrial fuels. Delivered electricity prices are on the order of \$8.00/MMBtu, while delivered liquid and gas prices are on the order of \$4.00/MMBtu, and delivered coal prices are on the order of \$1.00/MMBtu. Under base case assumptions, the high cost of electricity is not offset by the lower cost of converting that electricity to the various usable energy forms. This assumption renders electricity noncompetitive with liquids, gases, and coal in producing direct or indirect heat. The captive-electric uses are assumed to grow somewhat more rapidly than per capita GNP. This is a major reason why electric power grows faster than per capita GNP.

Because these industrial sector results are at variance with the opinions of energy experts who predict a shift towards an all-electric economy, we should reemphasize the assumptions that underlie them. First of all, the selection among various industrial technologies, and hence among fuel types, is assumed to be based on price alone with premiums or penalties attached to various fuels (see Volume II) to capture the effects of "intangibles." Electricity is actually favored under the currently assumed premiums. As a result, many intangibles in the technology selection, and thus in the fuel selection decisions, are lumped into this penalty/premium. Because of their importance, these numbers and the decision-making criterion itself should be carefully reviewed before judging the "reasonableness" of the industrial fuel mix.

The residential/commercial (R/C) sector differs from the other two sectors. Figure 2-12 illustrates the consumption of distributed products over time in the R/C sector. Note that liquid and gaseous fuel demands remain roughly constant over the entire horizon and that most of the new growth is electric. Hence, electricity does increase its market share in the R/C sector.

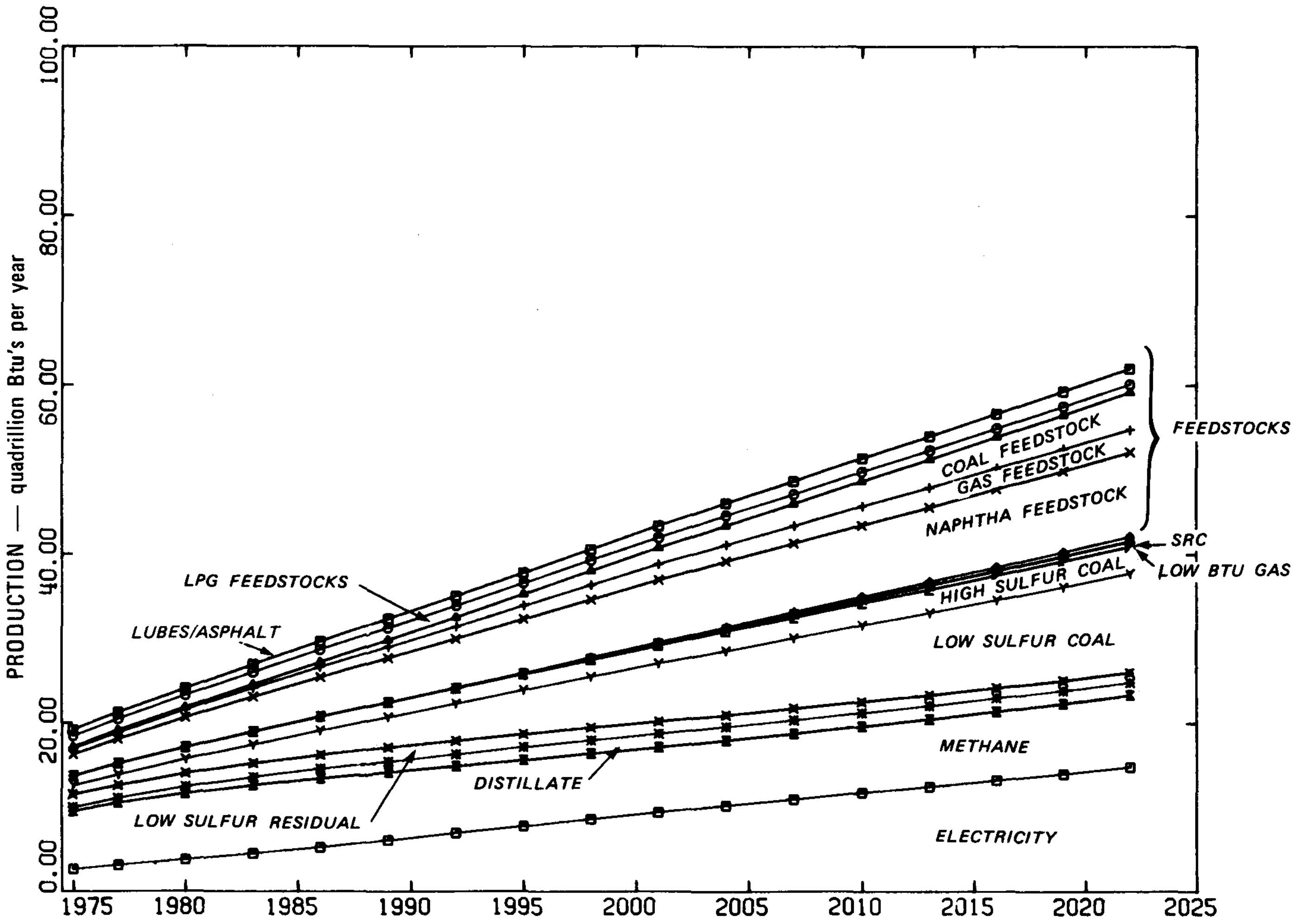

Figure 2-10. Distributed Products in the Industrial Sector--Base Case

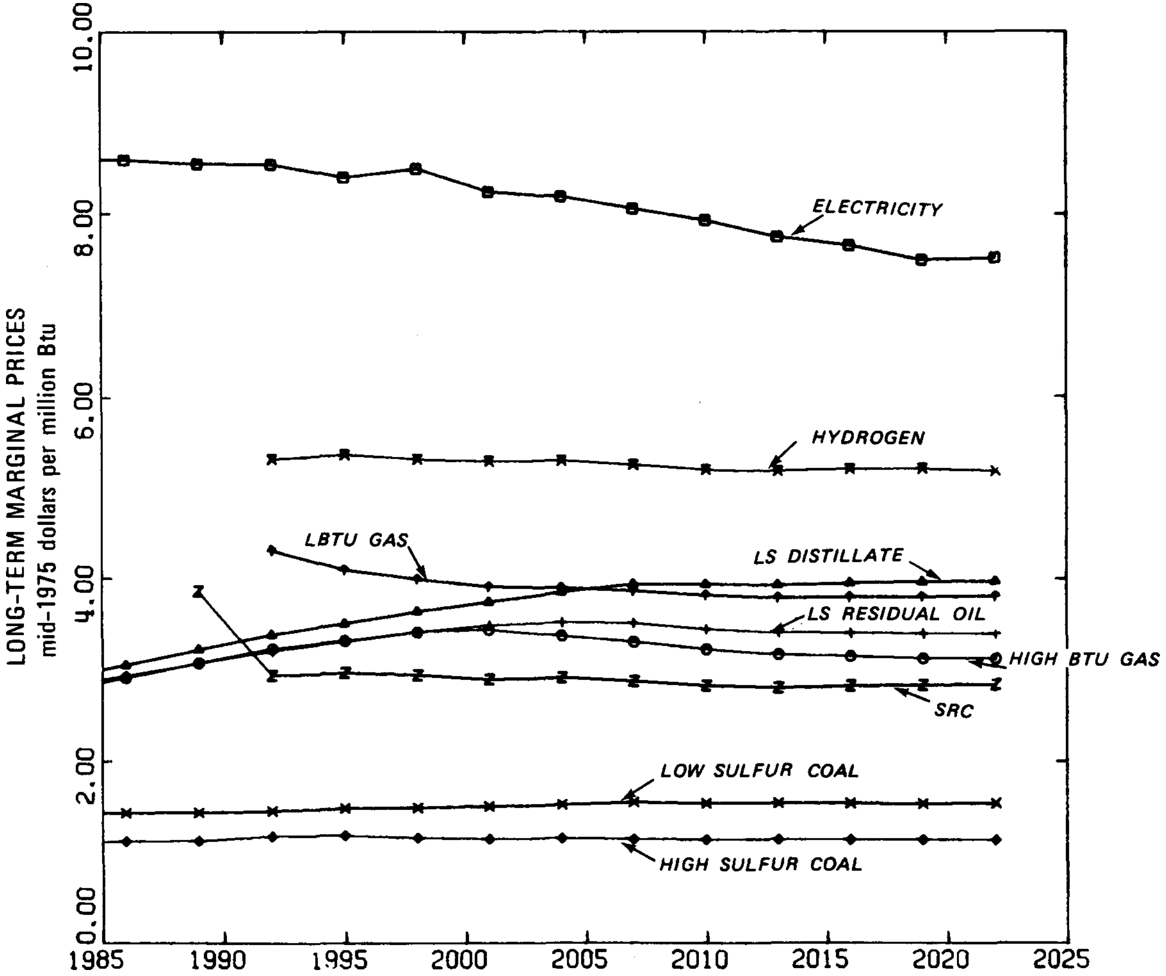

Figure 2-11. Average Prices of Distributed Products Used in the Industrial Sector--Base Case

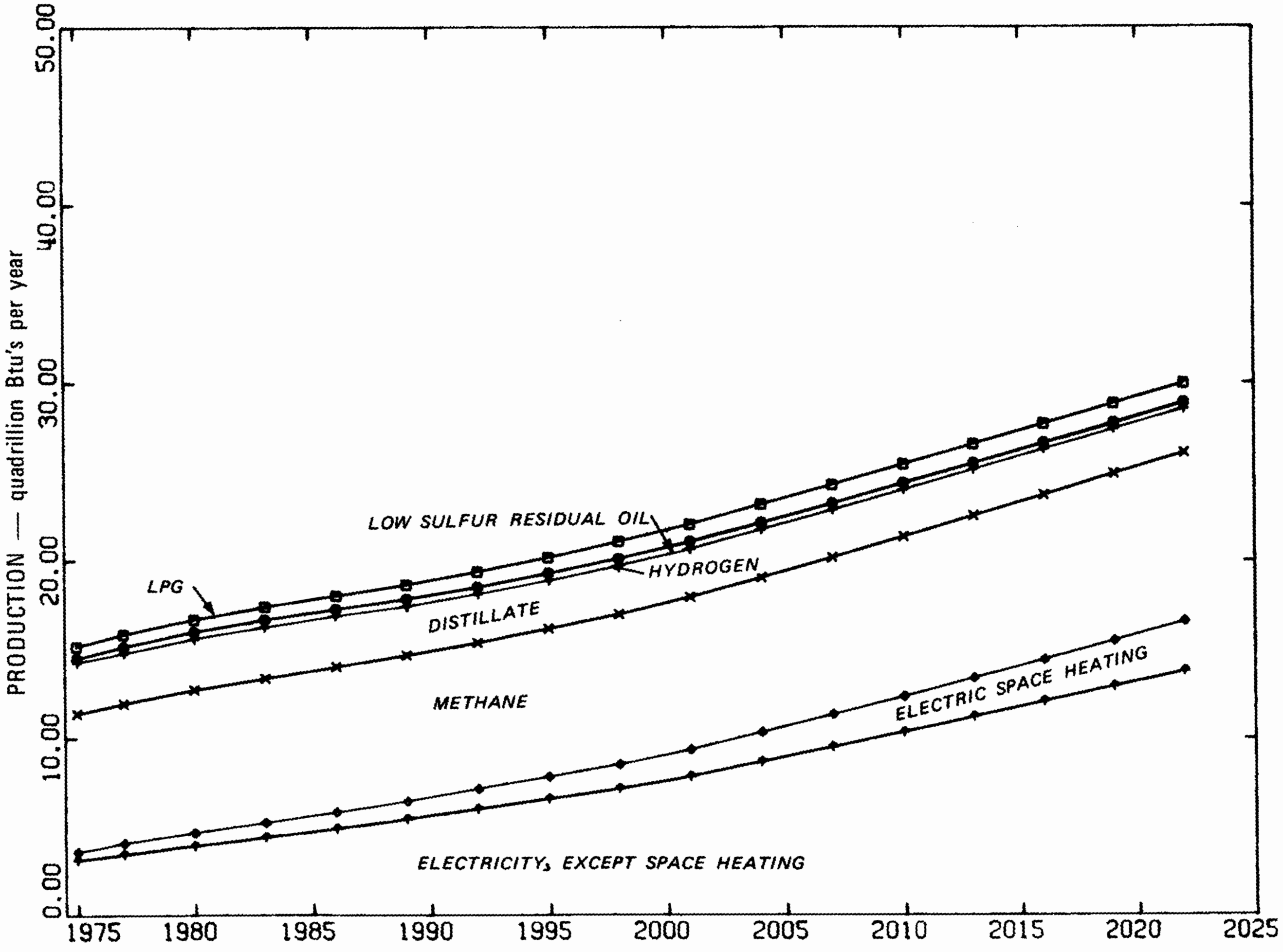

Figure 2-12. Distributed Products in the Residential/Commercial Sector--Base Case

The corresponding distributed fuel prices in the R/C sector are shown in Figure 2-13. Just as in the transportation and industrial sectors, electric prices are about double liquid and gas prices. However, electricity for space heating is assumed to be less expensive than electricity for other uses, reflecting the assumption that electric heating will increase annual load factors and reduce the distribution cost per kilowatt-hour delivered. This is true in all predominantly summer peaking regions, which is the case for most regions of the United States today.

There is a second competitive advantage that electricity is assumed to have in the R/C space heat market. Traditionally, electric space heat has enjoyed a consumer preference that allowed it to gain market share in spite of the fact that it was not competitive when compared strictly on the basis of price. Many consumers are willing to pay a premium for electric heat because of its safety, cleanliness, convenience, and perceived security of supply. Electric space heat often appeals to building contractors because the capital costs of some types of electric heaters are lower than for other heating systems. While there is no generally accepted or proven premium people are willing to pay, a $2.20/MMBtu premium has been assumed in this study for electric space heat compared to natural gas. This reflects the market's willingness to pay 25 percent more for space heat from electricity relative to space heat from gas.

Although solar heat with resistance backup is very capital intensive, due to the high cost of collectors, as much as 75 percent of the homeowner's electric bill is assumed to be saved in some regions of the country. In those regions, this technology is competitive under base case assumptions that include a consumer preference equal to that for electric space heat, which was described above.

Electricity is highly competitive in the miscellaneous heating market--water heating, cooking, and clothes drying--partially because of the consumer preference assumption discussed previously in connection with space heating and partially because the low utilization factors of these devices tend to favor less capital-intensive options, i.e., electricity.

The demand assumptions regarding air-conditioning can have a relatively large impact on R/C electric demand. However, the base case demand projections used in the forecast are about half as large as many of the forecasts published in the literature. Although we have assumed increased use of air-conditioners, we have

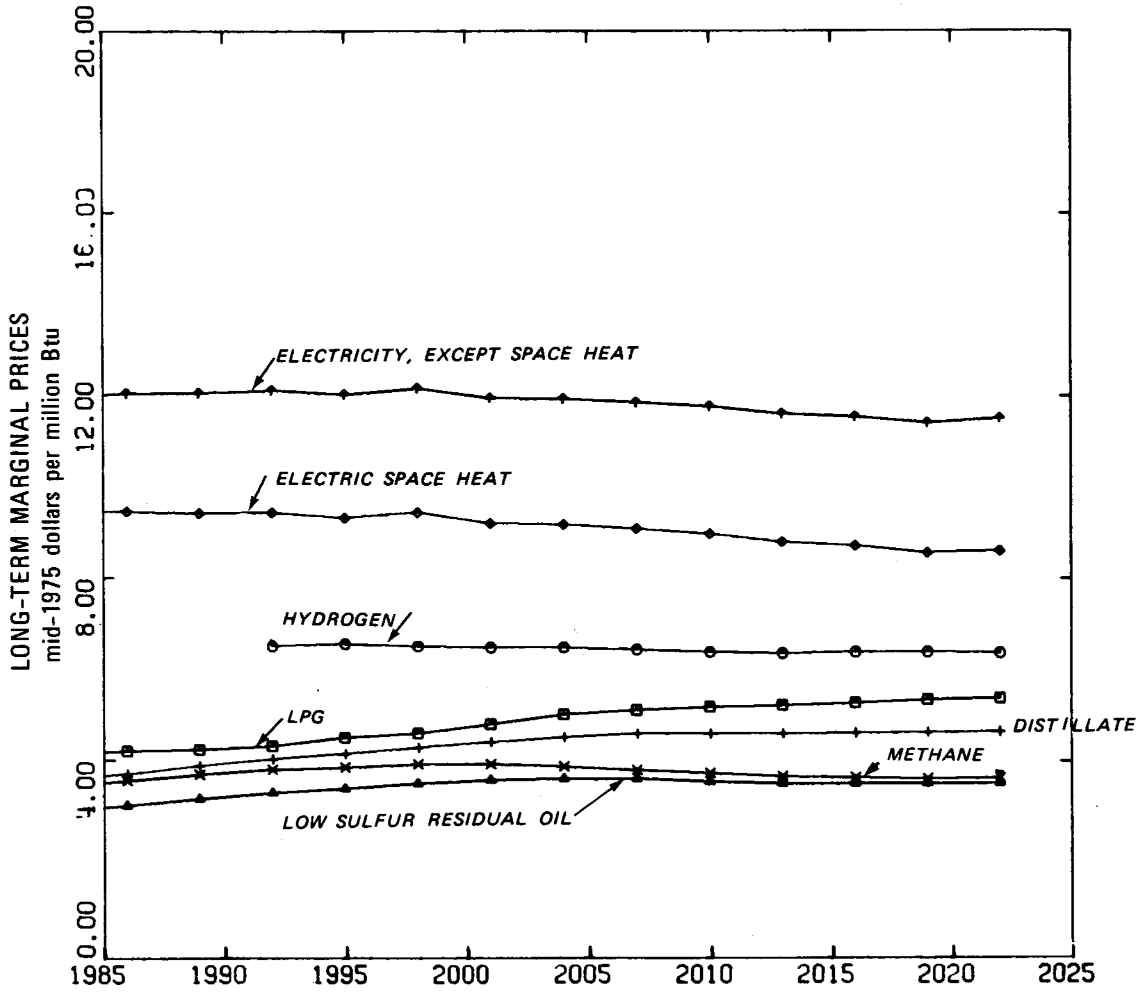

Figure 2-13. Average Prices of Distributed Products Used in the Residential/Commercial Sector--Base Case

not assumed rapid growth. Because air-conditioners typically use electricity, this assumption has the effect of lowering electric demand. Finally, the heat pump is assumed to be available in warmer southern regions but not in cooler northern regions because of technical problems. Because the heat pump produces both space heat and air-conditioning and because its electricity use is different than the use of electricity in electric space heaters or electric air-conditioners, changes in heat pump assumptions could change the consumption of electricity in the R/C sector.

Electromechanical uses (TV, lights, mixers, and so on) are "captive-electric" and are input exogenously. These are assumed to grow at a rate almost double that of per capita GNP.

Electricity is increasing its overall market share in the R/C sector because the R/C electricity demand is growing faster than the R/C demand as a whole. This will tend to increase the rate of growth of electric power generation except for one factor, conservation. In the base case, the efficiency of end-use conversion is assumed to improve over time, thus decreasing the quantity of distributed fuels required to satisfy a given level of usable energy demand. The base case assumes substantial efficiency improvements, some in excess of 25 percent, over the next 10 to 20 years. This tends to retard growth in electric power generation (as well as all other fuels) over the next 20 years or so.

To summarize the discussion of electricity in competition with other fuels in the end-use sectors, the transportation sector consumes little electricity in the base case due to the capital cost of vehicles and to the assumption that mass transit will not be important. The industrial sector consumes electricity only in captive-electric applications because electricity costs much more than other fuels. The R/C sector consumes increasingly more electricity in space heating and miscellaneous heating, as well as captive-electric applications because of consumer preferences and low capital cost.

Competition Among Electric Power Technologies

Any supply/demand analysis that forecasts electric power fuel prices and quantities must deal explicitly with the many technological options available for electric power generation. This section will deal with a large number of alternative electric power generating technologies competing in each load category: base, intermediate, and peak.

Before discussing competition among different electric power technologies, we will briefly discuss the difference between electric power price setting as determined by the regulatory system and decision-making among alternative technologies by the electric utility. In today's regulatory structure, the technology selection decision is up to the individual electric utility, subject to the scrutiny of regulatory authorities. However, electricity prices cannot be arbitrarily set by the individual utility. The utility is forced to reflect its history of capital investment in its price structure. In practice, the utility calculates a rate base reflecting the undepreciated portion of capital investment and earns a regulated return on this rate base. Operating costs are passed directly through to the consumer.

The model does not perform such a rate base price calculation to determine electric power prices; it assumes prices are equal to the marginal cost of new capacity. The marginal cost of new capacity is computed by using future prices of electricity and requiring the net present value of any incremental investment discounted at a real rate of 7 percent to be zero or greater. (See Volume II, Sections 3 and 7 for a description of the way marginal cost is calculated.) Marginal cost and average price are not significantly different except during periods where capacity is being added very rapidly or shut down very rapidly, or in the case where changes in capital costs are occurring rapidly, either as a result of cost escalation or technological change.

This forecast is characterized by slowly declining electricity prices over time as a result of technological change, particularly for base load nuclear plants and intermediate and peak load combined-cycle technologies using pipeline high-Btu gas. Although new capacity is being added very rapidly for some technologies (e.g., advanced nuclear converters and combined-cycle technologies), in the aggregate the growth in electric power is not extreme. Thus for some technologies, the error made by assuming that price equals marginal cost may be significant but in the aggregate the error will be small. In any case, because much of the demand for electricity occurs in captive-electric markets where price competition is less important, errors made in calculating electric power prices have negligible results on the forecast itself. The pricing and decision-making electric power model is documented more completely in Section 3 of Volume II of this report.

Because there are significant differences in electric power economics in each load category, we will discuss base, intermediate, and peak power generation individually in some detail. As discussed in Volume II, individual capacity factors are defined in the model for base, intermediate, and peak power generation in each of the nine demand regions and the four coal mining regions. Note that the model keeps track only of the total installed capacity of an electric power technology in a region. Capacity addition and retirement decisions are made on the basis of this total capacity, rather than on the basis of capacities in individual load categories. Thus, without dealing explicitly with the question of derating plants from base to intermediate and peak load service, the model permits an existing plant to be used in different load categories of service in different time periods.

Base Load Power Generation

Base load electric power generation is characterized in the base case by capacity factors on the order of 70 percent. In performing the calculations for base load power, it was assumed that all technologies--nuclear, coal, gas, liquids, and others--could operate at a 70 percent capacity factor at the economics assumed in the base case. This assumption should be examined further, particularly in the case of nuclear power.

The mix of base load electric power generation technologies as computed by the model is shown in Figure 2-14. Under base case assumptions, nuclear power is very competitive, particularly in the long run, and captures virtually the entire base load market by the end of the time horizon (2022). In the near term, conventional light water reactors are quite competitive (at base economics of \$600/kW, excluding interest during construction),* and, in the intermediate and long term, advanced conversion technologies, such as the HTGR, become competitive as they become available. Since all advanced nuclear technologies are unproven at this time, there is a considerable uncertainty attached to their economics and efficiencies. For our purposes, base case capital and operating costs for the advanced conversion technologies are assumed to be identical with those of the LWR, but their fuel cost is lower because they use fuel more efficiently. Should base case assumptions for advanced nuclear technologies be optimistic, nuclear development after 2000 would be slower than projected and coal use would increase.

Direct burning of low-sulfur Western coal grows rapidly in the near term, but its growth slows quickly. The reason for this behavior is that in regions very near

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*Interest during construction is handled within the discounted cash flow calculation used by the model for determining the required revenue (price) for each technology. See the description in Volume II, Section 3, under "Process Economic Bases."

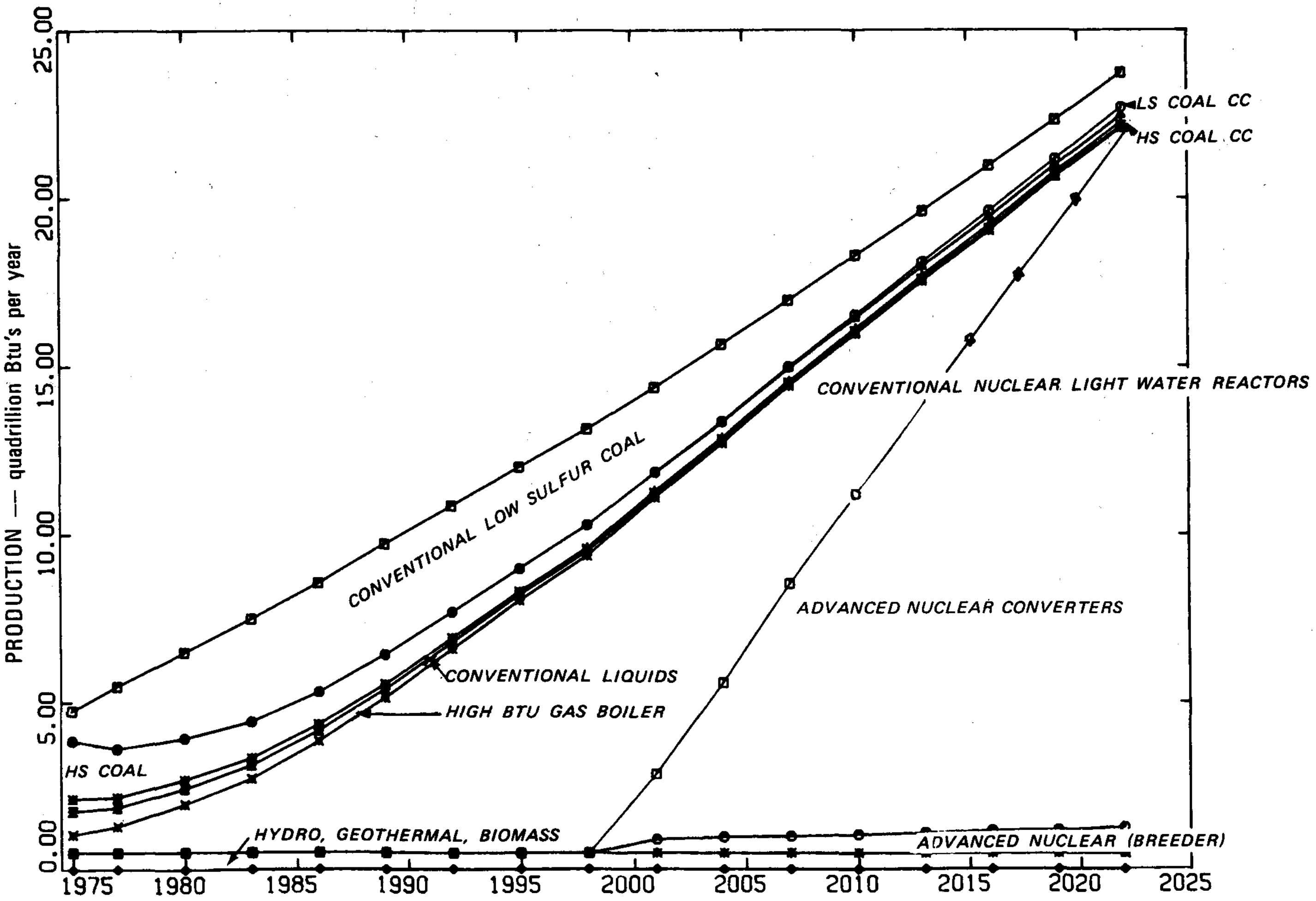

Figure 2-14. Base Load Electric Power Generation--Base Case

the Western coal deposits, coal-fired base power generation is less expensive than nuclear because the coal requires little transportation. As one moves farther from the Western coal-producing regions, coal transportation costs quickly increase the cost of coal-fired power generation relative to that of nuclear. Direct burning of high-sulfur coal declines in the near term because the base case economic estimates assume stack gas desulfurization will be required on all high-sulfur coal burning technologies. As Figure 2-14 clearly shows, requiring stack gas desulfurization on high-sulfur coal plants makes them noncompetitive with nuclear power under base case assumptions. Technologies using liquids and gases are projected to decline as their prices increase due to depletion of conventional fuel sources. Solar, biomass, geothermal, SRC, and advanced nuclear breeders will all be noncompetitive in the long run if the base case economic and behavioral assumptions are correct.

The marginal prices of base load electricity from each of the plant types considered appear in Figure 2-15. It is important to understand two key assumptions underlying these prices. First, the discount rate used by electric utilities is assumed to be 12 percent in current dollars. Using a 5 percent inflation rate, this corresponds to a 7 percent real, constant dollar discount rate. Many published electric power price calculations assume higher discount rates and thus show higher prices. We believe that the rates used in this study are more descriptive of long-run discount rates for large utilities in steady-state operation. The effect of using the lower rate is to favor capital-intensive technologies. In practice, when interest rates increase, noncapital-intensive technologies tend to be favored. The second key assumption underlying these prices is that they are expressed in constant 1975 dollars. The prices of coal and nuclear technologies are very close, lying in the range of \$5.30 to \$6.30 per MMBtu (i.e., within 20%) over the entire horizon of the model. Thus, minor changes in economic assumptions for either nuclear or coal could easily favor coal. In view of the capital intensity of both coal and nuclear power technologies and the uncertainty in their capital costs (not to mention uncertainty in coal and nuclear fuel prices), the base case projection in Figure 2-14 is to be regarded as extremely sensitive. However, the fuel price projection is not particularly sensitive to the coal/nuclear economics because the coal and nuclear fuel supply curves are so elastic, i.e., large quantities are made available as a result of very small increases in price.

Intermediate Load Power Generation

Intermediate load power generation is assumed to operate with a capacity factor on the order of 40 percent. Capacity factors are assumed to vary by region.

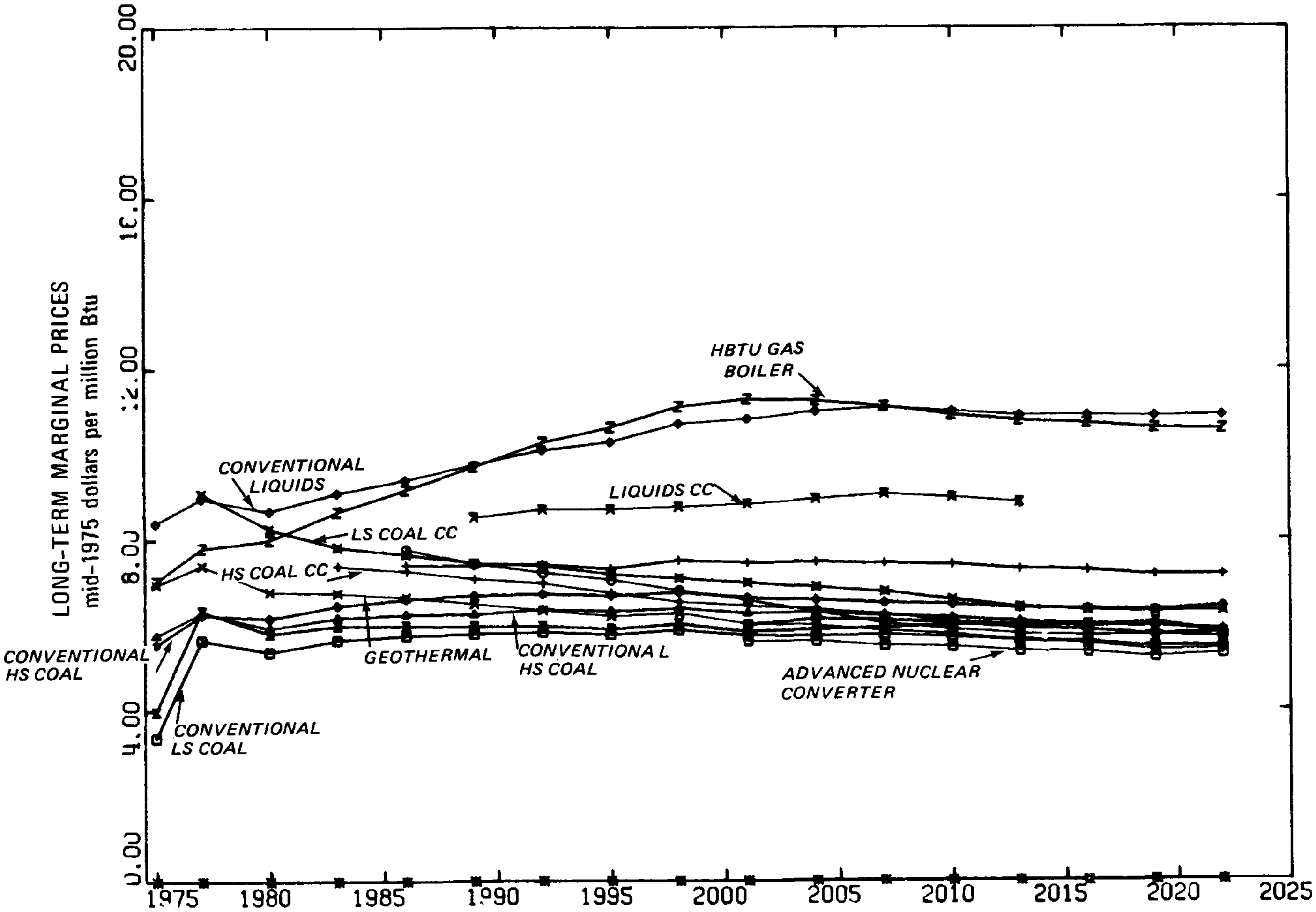

Figure 2-15. Average Marginal Busbar Cost of Base Load Power by Type of Plant--Base Case

As with base load power, it is assumed that all technologies that generate intermediate load electricity are capable of operating at a 40 percent capacity factor. Because a small quantity of nuclear generation appears in intermediate load generation, the ability of nuclear plants to cycle and maintain a 40 percent capacity factor should be further assessed. As a result of the low capacity factor, intermediate load generation is much more capital-cost sensitive and much less operating and fuel-cost sensitive than base load power. Even though intermediate load generation accounts for only 25 percent of the electrical energy actually generated (base load accounts for 70 percent), it has a significant impact on the price of distributed electricity. The projection of intermediate load power calculated by the model is given in Figure 2-16.

The most important near-term technologies for intermediate load power generation under base case assumptions are conventional low- and high-sulfur coal, and liquid and gas boilers. All, however, decline as liquid and gas prices increase and stack gas desulfurization becomes mandatory on all coal plants. In the longer term, base case economic estimates strongly favor the combined-cycle high-Btu gas technology based on high-Btu gas purchased from the pipeline and burned in a configuration that is more than 50 percent efficient.

In contrast to the combined-cycle technology, the integrated low-Btu gas/combined-cycle configurations that use coal are relatively unimportant if base case assumptions are accurate. One might think that a low-Btu gas plant could produce low-Btu gas more economically than purchasing high-Btu gas from a pipeline; however, such is not necessarily the case for two reasons. First, the integrated facility requires that either coal or electricity be transported from the coal mine to the demand site. Both of these alternatives are much more expensive than transporting methane. Thus, mine-mouth high-Btu gasification holds a transportation advantage. Secondly, the gasification portion of the integrated facility must follow the load. In intermediate load applications, this implies a capacity factor of 40 percent. Because coal gasification is quite capital intensive, this boosts the capital portion of the electricity price substantially. The mine-mouth high-Btu gasification plant, on the other hand, runs at a 90 percent capacity factor, and thus its product has a lower capital cost component. Both these forces, acting together, actually make the low-Btu integrated facility less attractive than the two-step process, in spite of the integrated facility's higher overall thermal efficiency. Direct burning of low-sulfur coal and conventional nuclear power are less competitive but nonetheless important under the present assumptions.

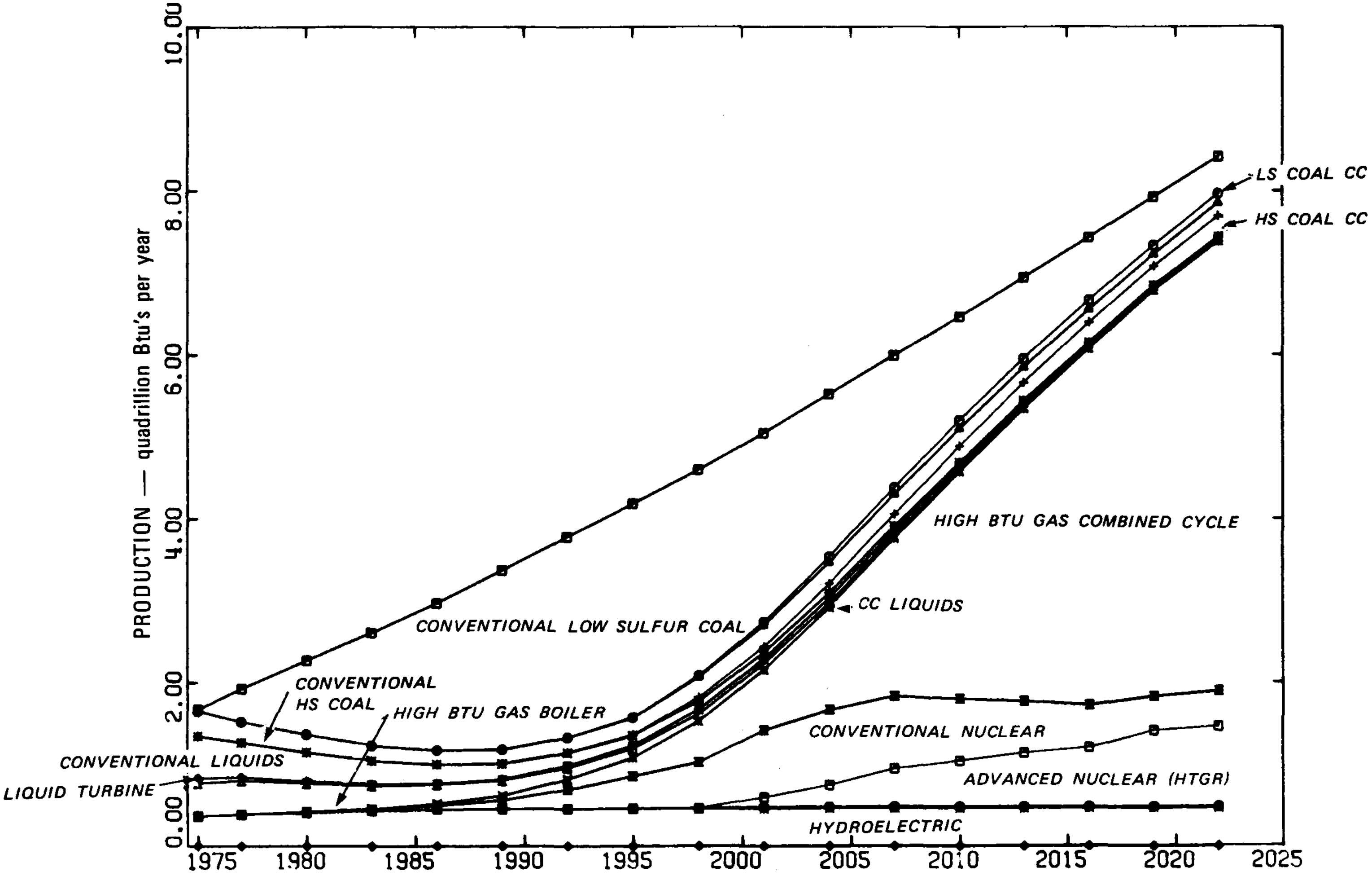

Figure 2-16. Intermediate Load Electric Power Generation--Base Case

The combined-cycle high-Btu gas facility is important in determining fuel prices for electric power generation because it uses pipeline quality gas, gas prices being sensitive to the quantity of gas consumed. This demonstrates that the selection among intermediate load technologies has an important effect on electric power fuel prices. This phenomenon is much more important than the effect of selection in the base load market between coal and nuclear.

The prices of electricity from the various intermediate load technologies appear in Figure 2-17. Again, the prices of the more attractive technologies--combined-cycle gas, conventional low-sulfur coal, and conventional nuclear--are surprisingly close, lying in the range of $7.80 to $9.50 per MMBtu. Because of the low capacity factor (40 percent) in intermediate load, slight changes in capital cost can change the relative prices and consequently the market shares of gas combined-cycle, coal, and nuclear.

Peak Load Power Generation

Peak load power generation is characterized by extremely low capacity factors, typically on the order of 13 percent. At such a low capacity factor, the economics of peak load power generation are sensitive to capital cost, almost to the exclusion of operating and fuel costs. It is assumed that all the technologies that operate to produce peak power can operate at a 13 percent capacity factor, and furthermore, with the exception of direct coal burning, that they can operate with the same operating cost and thermal efficiency per Btu output as they operate at a higher capacity factor. In other words, the forecasts assume that the operating and maintenance cost per Btu of output and the thermal efficiency of the gas turbine and combined-cycle technologies do not depend on the capacity factor.

The quantities of peak power generated by each of the technologies are illustrated in Figure 2-18. The total quantity of electrical energy in the peak load category is quite small relative to base and intermediate load power generation. Peak power accounts for only about 5 percent of the total, while intermediate accounts for 25 percent and base for 70 percent. Nonetheless, because its capacity factor is so low and thus its price so high, peak power has a significant effect on the average price of electricity.

Peak power generation is dominated in the long run by combined-cycle generation using high-Btu gas under the base case economic assumptions. This result depends

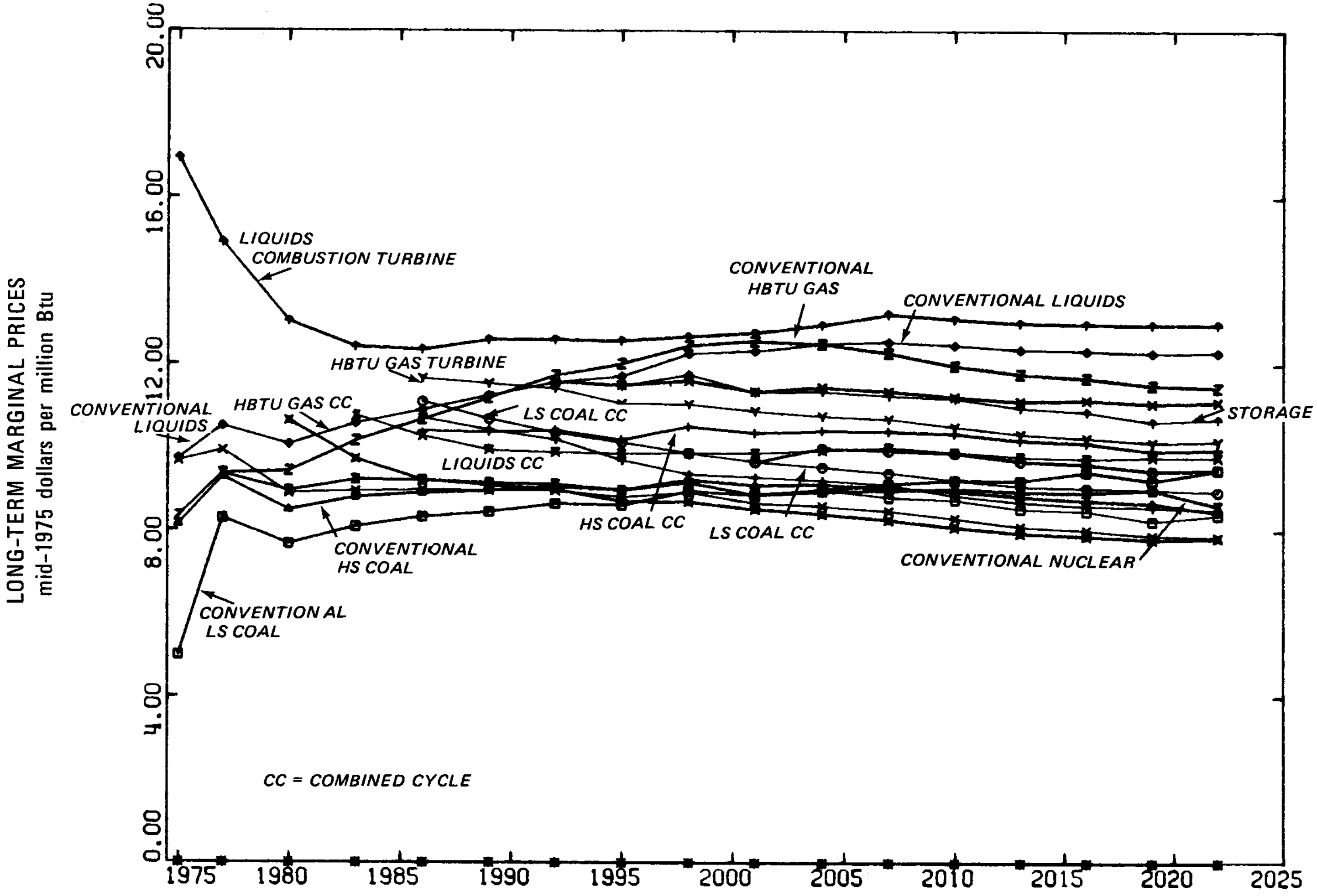

Figure 2-17. Average Marginal Busbar Cost of Intermediate Load Power by Type of Plant--Base Case

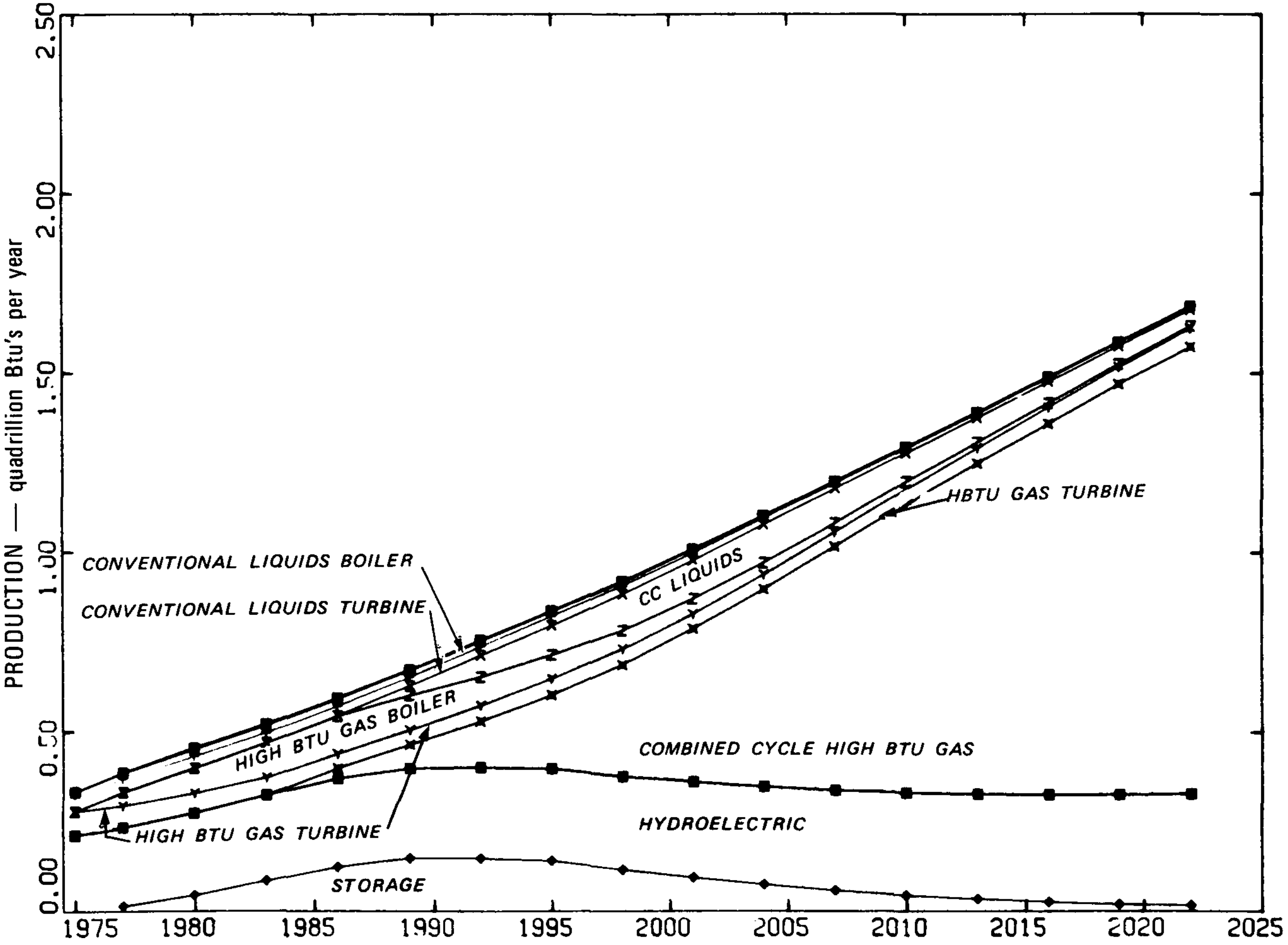

Figure 2-18. Peak Load Electric Power Generation--Base Case

on the assumption that the combined-cycle configuration can operate with the same thermal efficiency in peak loading applications that it attains in intermediate loading applications. A change in this assumption can change the attractiveness of the combined-cycle technology.

As in intermediate load, the integrated facility based on low-Btu coal gasification is noncompetitive because of the high capital cost of the gasification component coupled with the low capacity factor.

In addition to the combined-cycle high-Btu gas technology, limited numbers of liquid-powered combined-cycle plants and high-Btu gas turbines and boilers contribute to peak power generation. Hydro, which is relatively large in the figure, was specified exogenously. Most of the peak hydro generation was assumed to occur in the West at presently operating locations. Finally, the generic storage technology, which converts base load power to peak load power via pumped storage, compressed air storage, or some other scheme, is moderately attractive in the intermediate term before the efficient combined-cycle technology based on pipeline quality gas becomes available.

Although high-Btu gas combined-cycle captures a large fraction of intermediate and peak load markets, there are several prices in close competition. For this reason, the economic assumptions underlying the combined-cycle high-Btu gas technology are quite important. Since most of the gas being consumed is second generation synthetic gas, the economics of these SNG plants are also important.

The incremental prices of peak power are shown in Figure 2-19. The figure emphasizes the high degree of technological improvement assumed for the combined-cycle technology.

REGIONAL FUEL ECONOMICS

This section will now focus on the regional prices for primary fuels by supply location and distributed or delivered energy products by demand region (U.S. Census regions). While the contract only requests fuel prices, quantities produced or consumed will also be given so the reader can judge the relative importance of each fuel type by region and over time. Because of the sheer number of regional prices and quantities generated by the SRI National Energy Model, only a general overview of the regional projections will be included in this report.

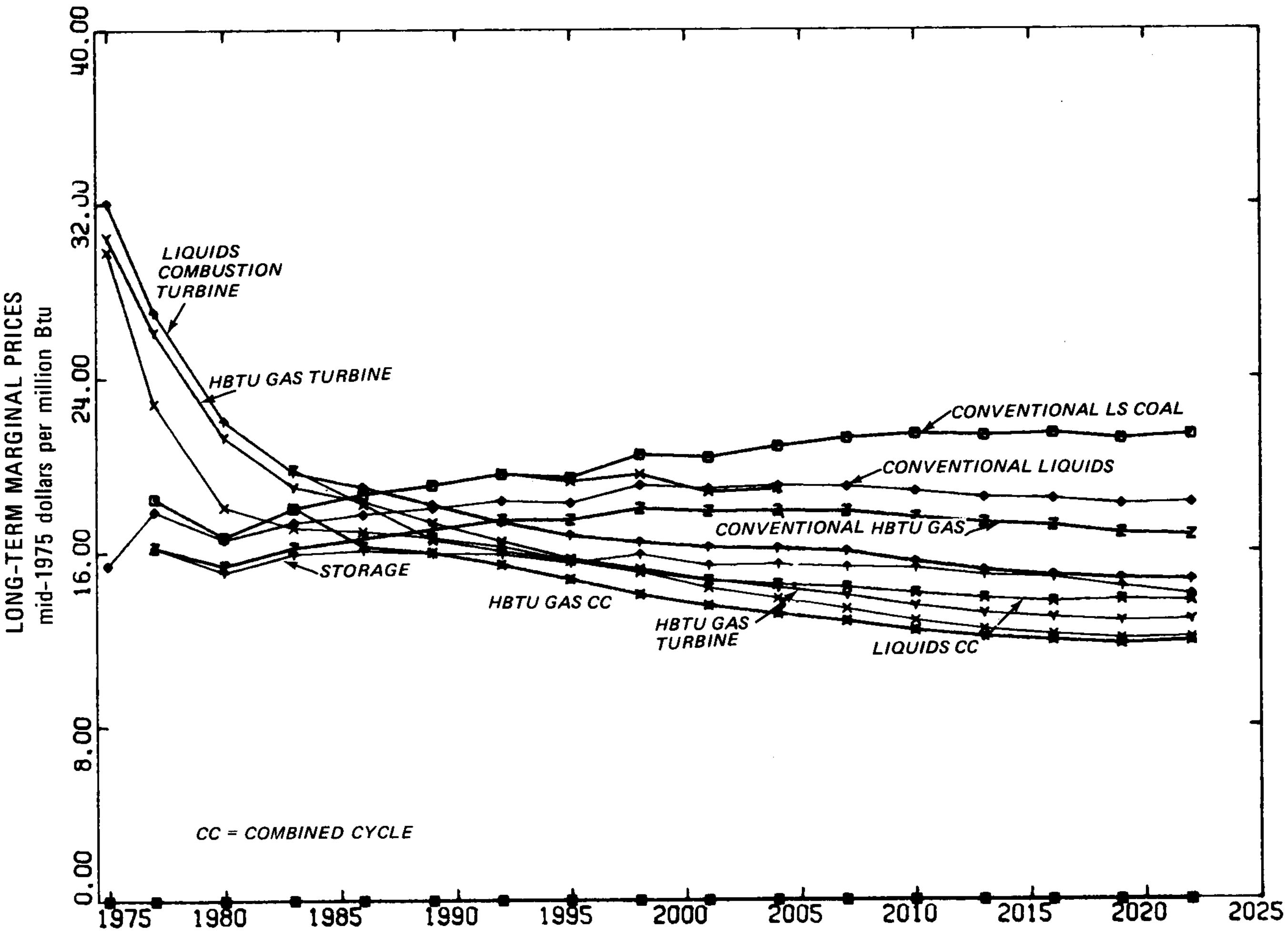

Figure 2-19. Average Marginal Busbar Cost of Peak Load Power by Type of Plant--Base Case

It should be kept in mind that the price calculations are very complex and involve the interrelationships among many primary resources and energy conversion technologies in all regions. The price of energy in one region is not independent of the price of energy in adjacent regions because all regions are competing for many of the same energy sources.

Before turning our attention to the regional price and quantity forecasts, it is useful to reemphasize the purpose of the model and hence its applicability as a forecasting tool. The model was constructed to analyze long-run R&D and investment decisions, i.e., decisions affecting the energy balance after 1985-90. Given this focus, we have implemented only a crude representation of the state of the U.S. energy system in 1975 and in particular the effect of development decisions made or planned on the 1975-85 energy balances. The model assumes that the market achieves equilibrium in the 1975-85 time frame, subject, of course, to various dynamic assumptions, but ignoring the capacity already on order or planned between 1975 and 1985. For example, for fuels used in the electric utility sector, it does not necessarily correspond to National Electrical Reliability Council (NERC) short-run (1975-85) projections. It is useful to compare the results of this equilibrium model with what is more likely to occur (the NERC projections) as both a model validity check and a check on how close the energy market now is to equilibrium. The important point to note, however, is that what happens between now and 1985 tends to have less effect on post-1985 investment decisions and hence the post-1985 forecast than do many other variables.

Primary Fuels

The production of coal, oil, and natural gas and the corresponding wellhead/minemouth prices are summarized in Tables 2-9 through 2-11. These tables cover all coal-, oil-, and gas-producing regions included in the model. Prices at import locations (cif U.S. ports) were given earlier in Table 2-2. Nuclear fuel prices are assumed to be uniform throughout the country and were also given in Table 2-2.

Domestic crude oil prices vary relatively little from region to region to about 2000 but diverge thereafter. This is because regional oil wellhead prices in the near term are primarily set by economic rent and transportation differentials, but in the long term increased production costs due to resource depletion become the price determinant in some regions.

Table 2-9

CRUDE OIL WELLHEAD PRICES AND QUANTITIES BY PRODUCING LOCATION--BASE CASE

(Quantities in Quadrillion Btus; Long-Term Marginal Prices in 1975 Dollars Per MMBtu)

LOCATION	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
Appalachia Oil	0.492	2.63	0.566	2.82	0.732	3.01	0.757	3.24	0.213	3.62
Atlantic Offshore Oil	0.351	2.61	0.486	2.81	0.585	3.06	0.615	3.29	0.196	3.85
Gulf Coast Oil	7.068	2.51	5.857	2.73	4.160	3.02	2.730	3.32	1.353	3.65
West Texas Oil	4.282	2.53	3.817	2.75	3.287	3.01	3.127	3.23	0.768	3.64
Midcontinent Oil	1.814	2.58	1.777	2.78	1.573	3.04	1.577	3.26	0.616	3.74
Rocky Mountain Oil	1.947	2.53	1.683	2.75	1.187	3.01	0.794	3.31	0.422	4.41
Pacific Coast Oil	3.132	2.43	3.160	2.65	3.023	2.90	2.870	3.14	0.898	3.48
South Alaska Oil	1.882	2.26	2.457	2.46	3.067	2.70	3.463	2.92	1.957	3.23
North Alaska Oil	0.645	2.16	2.017	2.28	4.560	2.49	7.593	2.69	4.873	3.01

Table 2-10

NATURAL GAS WELLHEAD PRICES AND QUANTITIES BY PRODUCING LOCATION--BASE CASE

(Quantities in Quadrillion Btus; Long-Term Marginal Prices in 1975 Dollars Per MMBtu)

LOCATION	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
Appalachia Gas	0.736	2.83	0.657	3.09	0.353	3.44	0.229	4.53	0.100	3.96
Atlantic Offshore Gas	0.519	2.80	0.669	3.06	0.671	3.39	0.473	3.64	0.086	3.33
Gulf Coast Gas	9.635	2.41	8.260	2.71	6.477	3.10	4.230	3.38	0.649	3.51
West Texas Gas	2.532	2.59	2.027	2.84	1.367	3.30	0.889	3.68	0.161	3.66
Midcontinent Gas	2.772	2.55	2.150	2.79	1.277	3.15	0.721	3.68	0.117	3.17
Rocky Mountain Gas	2.669	2.07	3.127	2.22	3.380	2.35	2.940	2.48	2.233	2.55
Pacific Coast Gas	0.619	2.46	0.477	2.68	0.287	3.05	0.170	3.70	0.022	3.89
South Alaska Gas	0.147	0.81	0.387	1.01	0.826	1.13	1.310	1.24	1.897	1.41
North Alaska Gas	0.042	1.57	1.653	1.37	4.010	1.43	4.993	1.48	0.984	1.86

Table 2-11

COAL MINE-MOUTH PRICES AND QUANTITIES BY PRODUCING LOCATION--BASE CASE

(Quantities in Quadrillion Btus; Long-Term Marginal Prices in 1975 Dollars Per Million Btu)

LOCATION	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
Appalachia Coal										
Low-Sulfur	13.083	0.92	14.033	0.94	14.533	0.97	14.567	0.99	15.467	1.05
High-Sulfur	2.369	0.65	2.343	0.68	2.460	0.78	3.280	0.74	11.767	0.73
Interior Coal										
High-Sulfur	3.040	0.68	3.080	0.69	4.213	0.72	6.433	0.67	19.867	0.65
Great Plains Coal										
Low-Sulfur	5.352	0.44	7.643	0.44	10.933	0.45	16.333	0.48	57.133	0.48
Rocky Mountain Coal										
Low-Sulfur	2.024	0.71	2.437	0.71	2.867	0.70	3.233	0.67	5.907	0.63
US Metallurgical Coal										
Low-Sulfur	2.872	0.92	3.053	0.94	3.233	0.97	3.463	0.99	4.930	1.05
Metallurgical Coal Exports										
Low-Sulfur	2.302	0.92	2.627	0.94	3.103	0.97	3.590	0.99	5.437	1.05

A similar phenomenon can be observed for natural gas prices.

Coal, on the other hand, shows sizable percentage differences that are maintained over time among mine-mouth prices at different locations. Because of generally very flat supply curves for coal, at least over the next 50 years, coal prices almost entirely reflect mining costs (including return on capital), thus, little economic rent can be extracted. Some effect of resource depletion is evident, particularly in the case of Appalachian low-sulfur coal. Note that metallurgical coal prices are expressed at the Appalachian coal resource location.

Fuels Used for Electric Power Generation

The regional price projections for fuels used by electric utilities are given at the demand region gateway, that is, they do not include local delivery costs. These price projections for the various fuels can help explain the differences that exist among electric utilities because of their locations. For example, because base load power is generated either by coal or nuclear technology under the base case economic assumptions, the regional differences in coal prices can be quite significant in determining a region's share of coal compared to nuclear fuel in generating electric power. The base case shows that in regions of the country very near the coal mining regions, coal-based electric power is less expensive than nuclear because of inexpensive coal. On the other hand, in regions far from the various coal-producing regions, nuclear power holds a competitive advantage over coal. Hence, the split between coal and nuclear energy is a complex question, depending on the mine-mouth price of coal and the cost of transporting that coal to the various demand regions. Electric utilities near coal regions would be expected to make different decisions than those located some distance away.

The marginal prices of the fuels for electric power generation in each of the nine regions are recorded in Tables 2-12 through 2-20. Many prices do not vary significantly from region to region; however, regional price differences can be significant for those fuels that are produced in a limited number of regions and are expensive to transport. Because liquid fuels can be transported thousands of miles at very low cost, the regional price differences for liquid fuels are quite small. Also, because electric power is generated largely from nuclear fuel, whose price does not vary significantly from region to region, regional variations in electric power prices are not large.

Table 2-12

REGION 1 - NEW ENGLAND

PRICES AND QUANTITIES OF FUELS USED FOR ELECTRIC POWER GENERATION--BASE CASE

(Quantities in Quadrillions of Btu; Long-Term Marginal Prices in 1975 Dollars Per Million Btu)

RESOURCE	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
High-Btu Gas	0.0051	3.31	0.0066	3.54	0.0093	3.75	0.0298	3.85	0.3336	3.28
Distillate	0.0067	2.93	0.0144	3.18	0.0219	3.44	0.0329	3.71	0.0131	3.99
Low-Sulfur Residual	0.1704	2.76	0.1068	2.95	0.0845	3.18	0.0520	3.42	0.0086	3.66
High-Sulfur Coal	0.0272	1.04	0.0231	1.07	0.0230	1.16	0.0253	1.12	0.0239	1.11
Low-Sulfur Coal	0.2635	1.39	0.2604	1.41	0.2313	1.48	0.1663	1.50	0.0333	1.57
SRC	0	--	0	--	0	--	0	--	0	--
Methanol	0	--	0.0002	3.91	0.0003	4.13	0.0007	4.36	0.0004	4.60
Nuclear Fuel	0.8508	0.46	1.3184	0.47	1.5703	0.49	1.8889	0.48	1.9837	0.59
Utility Coal Residual	0	--	0	--	0	--	0	--	0	--
Biomass	0	--	0.0011	1.05	0.0013	1.15	0.0012	1.22	0.0005	1.08
Hydro	0.016	--	0.015	--	0.015	--	0.015	--	0.015	--
Total Fuels	1.3397	--	1.7460	--	1.9569	--	2.2121	--	2.4121	--

Table 2-13

REGION 2 - MIDDLE ATLANTIC

PRICES AND QUANTITIES OF FUELS USED FOR ELECTRIC POWER GENERATION--BASE CASE

(Quantities in Quadrillions of Btu; Long-Term Marginal Prices in 1975 Dollars Per Million Btu)

RESOURCE	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
High-Btu Gas	0.0653	3.13	0.0707	3.35	0.0787	3.53	0.1864	3.63	1.8055	3.09
Distillate	0.0029	2.94	0.0290	3.19	0.0403	3.46	0.0669	3.73	0.0226	3.97
Low-Sulfur Residual	0.3184	2.79	0.2066	2.99	0.1674	3.22	0.1053	3.41	0.0194	3.15
High-Sulfur High-Btu Coal	0.2548	0.89	0.2148	0.92	0.1996	1.00	0.2110	0.97	0.1271	0.96
Low-Sulfur Low-Btu Coal	1.6595	1.20	1.7287	1.22	1.6838	1.28	1.3869	1.29	0.2791	1.36
SRC	0	--	0	--	0	--	0	--	0	--
Methanol	0.0001	3.65	0.0004	3.86	0.0016	4.09	0.0029	4.32	0.0010	4.55
Nuclear Fuel	1.5350	0.46	2.9418	0.47	3.7752	0.49	5.0916	0.48	5.1677	0.59
Utility Coal Residual	0	--	0	--	0.0003	2.92	0.0007	2.87	0.0004	2.76
Sunshine	0	--	0	--	0	--	0	--	0	--
Biomass	0.0008	1.01	0.0021	1.03	0.0031	1.09	0.0037	1.13	0.0013	1.05
Hydro	0.133	--	0.132	--	0.132	--	0.132	--	0.132	--
Total Fuels	3.9698	--	5.3261	--	6.0820	--	7.1874	--	8.0561	--

Table 2-14

REGION 3 - SOUTH ATLANTIC

PRICES AND QUANTITIES OF FUELS USED FOR ELECTRIC POWER GENERATION--BASE CASE

(Quantities in Quadrillions of Btu; Long-Term Marginal Prices in 1975 Dollars Per Million Btu)

RESOURCE	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
High-Btu Gas	0.1009	2.90	0.0931	3.25	0.0984	3.59	0.1498	3.74	1.2932	3.11
Distillate	0.0247	2.91	0.0513	3.17	0.0614	3.45	0.0827	3.72	0.0264	3.95
Low-Sulfur Residual	0.2023	2.75	0.1242	2.96	0.0993	3.20	0.0621	3.45	0.0098	3.70
High-Sulfur High-Btu Coal	0.4617	0.93	0.3425	0.96	0.2971	1.05	0.2279	1.01	0.1458	1.01
Low-Sulfur Low-Btu Coal	1.5727	1.25	1.4901	1.28	1.3802	1.34	1.0137	1.35	0.1975	1.42
SRC	0	--	0	--	0	--	0	--	0	--
Methanol	0	--	0.0004	3.86	0.0018	4.09	0.0040	4.32	0.0012	4.58
Nuclear Fuel	2.3076	0.46	3.8390	0.47	4.6760	0.49	5.5540	0.48	5.8412	0.59
Utility Coal Residual	0	--	0	--	0	--	0	--	0	--
Sunshine	0	--	0	--	0	--	0	--	0	--
Biomass	0.0010	1.01	0.0035	1.01	0.0062	1.03	0.0067	1.08	0.0038	0.95
Hydro	0.066	--	0.058	--	0.044	--	0.034	--	0.034	--
Total Fuels	4.7369	--	6.0021	--	6.6644	--	7.1349	--	7.5529	--

Table 2-15

REGION 4 - EAST SOUTH CENTRAL

PRICES AND QUANTITIES OF FUELS USED FOR ELECTRIC POWER GENERATION--BASE CASE

(Quantities in Quadrillions of Btu; Long-Term Marginal Prices in 1975 Dollars Per Million Btu)

RESOURCE	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
High-Btu Gas	0.0255	2.67	0.0378	3.02	0.0489	3.46	0.0871	3.50	0.7907	2.84
Distillate	0.0071	2.88	0.0086	3.16	0.0101	3.45	0.0154	3.72	0.0036	3.88
Low-Sulfur Residual	0.0224	2.71	0.0144	2.95	0.0115	3.19	0.0074	3.33	0.0015	3.01
High-Sulfur High-Btu Coal	0.4900	0.81	0.4534	0.80	0.4576	0.82	0.5338	0.75	0.3877	0.71
Low-Sulfur Low-Btu Coal	0.7036	1.24	0.6612	1.25	0.6146	1.29	0.4589	1.29	0.0795	1.34
SRC	0	--	0	--	0	--	0	--	0	--
Methanol	0	--	0.0001	3.91	0.0001	4.14	0.0003	4.37	0.0001	4.56
Nuclear Fuel	0.9915	0.46	1.6487	0.47	1.9722	0.49	2.3158	0.48	2.2526	0.59
Utility Coal Residual	0	--	0	--	0.0001	2.81	0.0003	2.75	0.0001	2.65
Sunshine	0	--	0	--	0	--	0	--	0	--
Biomass	0.0004	1.00	0.0013	1.01	0.0020	1.02	0.0025	1.03	0.0038	0.98
Hydro	0.096	--	0.096	--	0.095	--	0.095	--	0.098	--
Total Fuels	2.3365	--	2.9215	--	3.2121	--	3.5165	--	3.6176	--

Table 2-16

REGION 5 - EAST NORTH CENTRAL

PRICES AND QUANTITIES OF FUELS USED FOR ELECTRIC POWER GENERATION--BASE CASE

(Quantities in Quadrillions of Btu; Long-Term Marginal Prices in 1975 Dollars Per Million Btu)

RESOURCE	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
High-Btu Gas	0.1041	3.01	0.1390	3.20	0.1809	3.25	0.5359	3.23	3.2922	2.92
Distillate	0.0368	2.93	0.0488	3.19	0.0555	3.46	0.0515	3.70	0.0134	3.90
Low-Sulfur Residual	0.0843	2.71	0.0597	2.94	0.0498	3.17	0.0319	3.32	0.0064	3.06
High-Sulfur High-Btu Coal	2.7234	0.79	1.2326	0.81	1.2075	0.84	1.1980	0.78	0.9577	0.75
Low-Sulfur Low-Btu Coal	2.9828	1.14	3.4289	1.13	3.3762	1.17	2.6232	1.18	0.5382	1.21
SRC	0	--	0	--	0.0001	2.76	0.0001	2.67	0	--
Methanol	0.0001	3.77	0.0005	3.98	0.0010	4.21	0.0010	4.44	0.0004	4.45
Nuclear Fuel	2.4390	0.46	4.6451	0.47	5.9712	0.49	7.4853	0.48	9.1231	0.59
Utility Coal Residual	0	--	0	--	0.0004	2.86	0.0004	2.80	0.0002	2.70
Sunshine	0	--	0	--	0	--	0	--	0	--
Biomass	0.0009	1.01	0.0032	1.01	0.0050	1.01	0.0065	1.02	0.0023	1.01
Hydro	0.035	--	0.035	--	0.035	--	0.035	--	0.035	--
Total Fuels	8.4064	--	9.5928	--	10.8826	--	11.9688	--	13.9689	--

Table 2-17

REGION 6 - WEST SOUTH CENTRAL

PRICES AND QUANTITIES OF FUELS USED FOR ELECTRIC POWER GENERATION--BASE CASE

(Quantities in Quadrillions of Btu; Long-Term Marginal Prices in 1975 Dollars Per Million Btu)

RESOURCE	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
High-Btu Gas	1.3570	2.54	0.9561	2.87	0.8204	3.30	0.7598	3.57	2.0003	3.29
Distillate	0.0127	2.84	0.0381	3.12	0.0509	3.40	0.0920	3.66	0.0511	3.85
Low-Sulfur Residual	0.0432	2.67	0.0325	2.90	0.0289	3.16	0.0204	3.38	0.0136	3.07
High-Sulfur High-Btu Coal	0.1091	0.98	0.0916	0.99	0.0990	1.02	0.1601	0.97	0.1903	0.95
Low-Sulfur Low-Btu Coal	1.8550	1.16	2.4222	1.14	2.5453	1.18	2.1862	1.20	0.5556	1.24
SRC	0	--	0.0001	3.66	0.0001	2.75	0.0003	2.69	0.0002	2.63
Methanol	0.0001	3.63	0.0007	3.84	0.0017	4.07	0.0033	4.29	0.0018	4.51
Nuclear Fuel	1.5577	0.46	2.9553	0.47	3.7370	0.49	5.2634	0.48	6.4026	0.59
Utility Coal Residual	0	--	0	--	0.0004	2.86	0.0011	2.80	0.0011	2.70
Sunshine	0	--	0	--	0	--	0	--	0	--
Biomass	0.0008	1.01	0.0030	1.01	0.0051	1.02	0.0060	1.09	0.0026	1.02
Hydro	0.028	--	0.028	--	0.028	--	0.028	--	0.028	--
Total Fuels	4.9636	--	6.5276	--	7.3168	--	8.5206	--	9.2352	--

Table 2-18

REGION 7 - WEST NORTH CENTRAL

PRICES AND QUANTITIES OF FUELS USED FOR ELECTRIC POWER GENERATION--BASE CASE

(Quantities in Quadrillions of Btu; Long-Term Marginal Prices in 1975 Dollars Per Million Btu)

RESOURCE	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
High-Btu Gas	0.1523	2.67	0.1222	2.82	0.1211	2.93	0.2053	2.95	1.1368	2.58
Distillate	0.0109	2.93	0.0075	3.18	0.0069	3.45	0.0049	3.71	0.0010	3.87
Low-Sulfur Residual	0.0153	2.76	0.0092	2.96	0.0072	3.14	0.0045	3.19	0.0011	2.91
High-Sulfur High-Btu Coal	0.0001	0.82	0.0004	0.83	0.0008	0.87	0.0042	0.82	0.0678	0.79
Low-Sulfur Low-Btu Coal	1.4832	0.73	1.7643	0.73	1.8837	0.76	1.8743	0.78	1.2072	0.80
SRC	0	--	0	--	0	--	0	--	0	--
Methanol	0	--	0	--	0	--	0	--	0	--
Nuclear Fuel	0.0976	0.46	0.0622	0.47	0.0550	0.49	0.1834	0.48	1.1262	0.59
Utility Coal Residual	0	--	0	--	0	--	0	--	0	--
Sunshine	0	--	0	--	0	--	0	--	0	--
Biomass	0	--	0	--	0	--	0	--	0.0001	1.00
Hydro	0.055	--	0.054	--	0.054	--	0.054	--	0.054	--
Total Fuels	1.8144	--	2.0198	--	2.1287	--	2.3307	--	3.5942	--

Table 2-19

REGION 8 - PACIFIC

PRICES AND QUANTITIES OF FUELS USED FOR ELECTRIC POWER GENERATION--BASE CASE

(Quantities in Quadrillions of Btu; Long-Term Marginal Prices in 1975 Dollars Per Million Btu)

RESOURCE	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
High-Btu Gas	0.1950	2.70	0.2909	2.84	0.4166	2.93	0.7557	3.01	1.6526	3.09
Distillate	0.0136	2.80	0.0237	3.06	0.0267	3.33	0.0238	3.57	0.0091	3.86
Low-Sulfur Residual	0.3012	2.61	0.2211	2.82	0.1835	3.05	0.1196	3.25	0.0209	3.51
High-Sulfur High-Btu Coal	0	--	0	--	0	--	0	--	0	--
Low-Sulfur Low-Btu Coal	0.4756	1.28	0.5909	1.28	0.5537	1.30	0.3972	1.28	0.1139	1.26
SRC	0	--	0	--	0	--	0	--	0	--
Methanol	0.0001	3.63	0.0001	3.84	0.0002	4.07	0.0002	4.31	0.0002	4.53
Nuclear Fuel	1.1208	0.46	2.1704	0.47	2.7696	0.48	3.5470	0.47	4.4061	0.59
Utility Coal Residual	0	--	0	--	0	--	0	--	0	--
Geothermal Dry Steam	0.1911	0.81	0.1933	0.84	0.1861	0.85	0.1700	0.83	0.0577	0.80
Sunshine	0	--	0	--	0	--	0	--	0	--
Geothermal Hot Water	0.0004	0.34	0.0009	0.34	0.0013	0.34	0.0016	0.34	0.0005	0.34
Biomass	0.0008	1.00	0.0024	1.00	0.0034	1.00	0.0036	1.00	0.0015	1.00
Hydro	0.627	--	0.647	--	0.666	--	0.682	--	0.726	--
Total Fuels	2.9256	--	4.1407	--	4.8071	--	5.7007	--	6.9885	--

Table 2-20

REGION 15 - MOUNTAIN

PRICES AND QUANTITIES OF FUELS USED FOR ELECTRIC POWER GENERATION--BASE CASE

(Quantities in Quadrillions of Btu; Long-Term Marginal Prices in 1975 Dollars Per Million Btu)

RESOURCE	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
High-Btu Gas	0.0910	2.32	0.1111	2.45	0.1392	2.56	0.2427	2.67	0.6694	2.70
Distillate	0.0593	2.84	0.0412	3.11	0.0343	3.38	0.0226	3.61	0.0038	3.87
Low-Sulfur Residual	0.0307	2.70	0.0198	2.91	0.0157	3.13	0.0096	3.22	0.0017	2.95
High-Sulfur High-Btu Coal	0	--	0	--	0	--	0	--	0	--
Low-Sulfur Low-Btu Coal	0.9458	0.88	1.2686	0.88	1.4032	0.88	1.4593	0.85	0.6534	0.82
SRC	0	--	0	--	0	--	0	--	0	--
Methanol	0	--	0	--	0	--	0	--	0	--
Nuclear Fuel	0.0453	0.46	0.1161	0.47	0.1983	0.48	0.3734	0.47	1.4335	0.59
Utility Coal Residual	0	--	0	--	0	--	0	--	0	--
Sunshine	0	--	0	--	0	--	0	--	0	--
Biomass	0	--	0	--	0.0001	1.00	0.0001	1.00	0.0001	1.00
Hydro	0.130	--	0.129	--	0.128	--	0.127	--	0.125	--
Total Fuels	1.3021	--	1.6858	--	1.9188	--	2.2347	--	2.8869	--

Coal is different from the other resources. On a heat unit basis, the price of coal at the mine mouth in the various coal-producing regions of the country is low, ranging from 45¢/MMBtu for Western low-sulfur coal to 75¢/MMBtu for high-sulfur coal in the East. Because the number of coal-producing regions is limited, and because coal transportation is so expensive, regional variations in coal prices can be quite large.

Examining the economics of electric power transmission, one finds that it is probably the most expensive mode of moving energy. Thus, one might be tempted to assume that the economics of electric power transmission are a very important component of the energy system. On the contrary, they tend not to be. In the base case where nuclear power is assumed to be essentially unrestricted in each of the demand locations, it is more economical to build nuclear power plants near the load centers and thus minimize electric power transmission than to build coal plants farther away. Hence, in the base case there is very little long-distance transmission of electric power.

In sensitivity cases where nuclear power might be eliminated, one would not expect to see electric power transmitted over large distances but would instead expect to see coal transported because power can be delivered to the demand regions cheaper by moving coal to the demand regions than by burning the coal at the mine mouth and transporting electric power under base case assumptions. Of course, a dramatic breakthrough in electrical transmission technology (such as superconductive transmission) could change this argument. This discussion is intended to reemphasize the importance of coal transportation economics, which contain a number of subtle assumptions outlined in Volume II.

Regional variations in natural gas prices can be significant, particularly in regions far from the major gas-producing regions of the country. In the near term, gas prices in the Midwest tend to be higher than gas prices on the Gulf Coast simply because the major gas-producing region of the country is the Gulf Coast and transportation costs to the Midwest are substantial. In the long run, however, gas prices at the Gulf Coast promise to be higher than gas prices in the Midwest because the major gas-producing regions of the country will be the coal regions within which synthetic gas from coal will be the major source of methane, if base case economics are correct.

Fuels Used in End-Use Sectors

Prices and quantities of all distributed fuels in each of the demand regions appear in Tables 2-21 through 2-29. Prices are stated as delivered to the residential dwelling, commercial building, or industrial plant. In the transportation sector, prices and quantities are as delivered to the vehicle itself, except for jet fuel and marine bunker, which are priced at the demand region gateway (pipeline or other wholesale terminal). Feedstocks are expressed at the demand region gateway. Most of the discussion on regional price differences in the preceding section is equally applicable to this section and will, therefore, not be repeated.

Table 2-21

REGION 1 - NEW ENGLAND

PRICES AND QUANTITIES OF DELIVERED PRODUCTS BY END-USE SECTOR BY PRODUCT--BASE CASE

(Quantities in Quadrillions of Btu; Long-Term Marginal Prices in 1975 Dollars Per Million Btu)

RESOURCE	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
Residential and Commercial										
High-Btu Gas	0.236	4.46	0.243	4.69	0.255	4.92	0.267	5.00	0.328	4.44
Distillate	0.384	3.65	0.368	3.90	0.359	4.18	0.352	4.43	0.288	4.71
Low-Sulfur Residual	0.070	3.00	0.070	3.19	0.066	3.43	0.062	3.66	0.045	3.90
LPG	0.034	4.44	0.041	4.57	0.050	4.82	0.059	5.07	0.072	5.42
Electric Space	0.059	9.90	0.075	9.80	0.105	9.63	0.139	9.41	0.289	8.78
Electric Nonspace	0.227	12.39	0.267	12.36	0.324	12.26	0.387	12.11	0.682	11.66
Transportation										
Gasoline	0.652	3.95	0.541	4.15	0.487	4.40	0.470	4.64	0.499	4.91
Diesel Auto	0.029	3.70	0.056	3.95	0.078	4.23	0.097	4.48	0.139	4.76
Diesel Other	0.107	3.70	0.125	3.95	0.149	4.23	0.175	4.48	0.278	4.76
Jet Fuel	0.134	2.93	0.171	3.18	0.226	3.46	0.283	3.71	0.508	3.99
Marine Bunker	0.050	2.76	0.056	2.95	0.063	3.19	0.071	3.42	0.098	3.66
Methanol	0.007	4.56	0.013	4.76	0.020	4.99	0.025	5.22	0.037	5.46
Electricity	0	--	0.001	8.12	0.002	7.93	0.003	7.75	0.006	7.21
Industrial										
High-Btu Gas	0.031	3.80	0.033	4.04	0.034	4.27	0.036	4.35	0.061	3.77
Distillate	0.029	2.99	0.036	3.24	0.042	3.52	0.047	3.77	0.049	4.05
Low-Sulfur Residual	0.213	2.88	0.206	3.07	0.190	3.31	0.176	3.54	0.122	3.78
Low-Sulfur Coal	0.049	1.70	0.079	1.72	0.124	1.79	0.166	1.81	0.291	1.88
High-Sulfur Coal	0.034	1.31	0.045	1.34	0.058	1.42	0.074	1.99	0.137	1.38
SRC	0	--	0	--	0.002	3.21	0.005	3.13	0.021	3.06
Low-Btu Gas	0	--	0	--	0.002	4.48	0.006	4.31	0.019	4.15
Electricity	0.123	8.92	0.149	8.79	0.185	8.58	0.220	8.34	0.329	7.64
Feedstocks										
Naptha Feedstocks	0.016	3.18	0.017	3.38	0.023	3.63	0.026	3.87	0.036	4.14
Coal Feedstocks (Ex Exports)	0	--	0	--	0	--	0	--	0	--
Gas Feedstocks	0.004	3.31	0.005	3.56	0.005	3.77	0.006	3.85	0.009	3.28
LPG Feedstocks	0.018	3.16	0.017	3.29	0.016	3.54	0.015	3.79	0.012	4.14

Table 2-22

REGION 2 - MIDDLE ATLANTIC

PRICES AND QUANTITIES OF DELIVERED PRODUCTS BY END-USE SECTOR BY PRODUCT--BASE CASE

(Quantities in Quadrillions of Btu; Long-Term Marginal Prices in 1975 Dollars Per Million Btu)

RESOURCE	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
Residential and Commercial										
High-Btu Gas	1.130	4.03	1.130	4.25	1.157	4.46	1.193	4.52	1.397	4.00
Distillate	0.742	3.66	0.719	3.91	0.708	4.20	0.709	4.45	0.586	4.69
Low-Sulfur Residual	0.092	3.03	0.092	3.23	0.090	3.47	0.086	3.65	0.074	3.39
LPG	0.054	4.38	0.066	4.50	0.079	4.76	0.094	5.01	0.114	5.36
Electric Space	0.150	9.84	0.182	9.83	0.236	9.73	0.297	9.63	0.600	8.81
Electric Nonspace	0.661	12.32	0.784	12.39	0.958	12.37	1.150	12.33	2.050	11.69
Transportation										
Gasoline	1.282	4.00	1.052	4.18	0.935	4.42	0.899	4.67	0.955	4.92
Diesel Auto	0.057	3.71	0.109	3.96	0.005	4.25	0.187	4.50	0.267	4.74
Diesel Other	0.371	3.71	0.434	3.96	0.517	4.25	0.604	4.50	0.931	4.74
Jet Fuel	0.687	2.94	0.870	3.19	1.143	3.48	1.427	3.73	2.557	3.97
Marine Bunker	0.233	2.79	0.257	2.99	0.287	3.23	0.319	3.41	0.467	3.15
Methanol	0.014	4.51	0.027	4.71	0.039	4.95	0.049	5.18	0.072	5.41
Electricity	0	--	0.001	8.24	0.004	8.12	0.006	8.00	0.011	7.36
Industrial										
High-Btu Gas	0.500	3.39	0.488	3.61	0.483	3.82	0.498	3.88	0.773	3.35
Distillate	0.199	3.00	0.253	3.25	0.300	3.54	0.337	3.79	0.320	4.03
Low-Sulfur Residual	0.565	2.91	0.538	3.11	0.491	3.35	0.448	3.53	0.328	3.27
Low-Sulfur Coal	0.295	1.51	0.406	1.53	0.569	1.58	0.728	1.60	1.173	1.67
High-Sulfur Coal	0.220	1.16	0.248	1.18	0.278	1.27	0.316	1.24	0.469	1.23
SRC	0	--	0	--	0.007	3.10	0.015	3.02	0.056	2.95
Low-Btu Gas	0	--	0	--	0.012	4.26	0.038	4.10	0.121	3.98
Electricity	0.555	8.85	0.690	8.82	0.879	8.69	1.064	8.57	1.663	7.68
Feedstocks										
Naptha Feedstocks	0.138	3.23	0.166	3.41	0.023	3.63	0.026	3.87	0.036	4.14
Coal Feedstocks (Ex Exports)	0.074	0.89	0.125	0.92	0.208	1.01	0.296	0.98	0.664	3.98
Gas Feedstocks	0.035	3.13	0.041	3.35	0.050	3.56	0.059	3.63	0.085	3.09
LPG Feedstocks	0.038	3.10	0.037	3.22	0.034	3.48	0.032	3.73	0.026	4.08

Table 2-23

REGION 3 - SOUTH ATLANTIC

PRICES AND QUANTITIES OF DELIVERED PRODUCTS BY END-USE SECTOR BY PRODUCT--BASE CASE

(Quantities in Quadrillions of Btu; Long-Term Marginal Prices in 1975 Dollars Per Million Btu)

RESOURCE	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
Residential and Commercial										
High-Btu Gas	0.651	3.72	0.668	4.07	0.685	4.42	0.707	4.56	0.835	3.94
Distillate	0.176	3.63	0.166	3.89	0.163	4.19	0.161	4.44	0.138	4.67
Low-Sulfur Residual	0.042	2.99	0.044	3.20	0.044	3.47	0.044	3.69	0.037	3.94
LPG	0.093	4.37	0.103	4.55	0.117	4.84	0.131	5.09	0.158	5.28
Electric Space	0.135	9.43	0.141	9.42	0.156	9.37	0.176	9.17	0.260	8.54
Electric Nonspace	0.752	11.92	0.861	11.99	1.017	12.02	1.190	11.86	2.030	11.41
Transportation										
Gasoline	1.692	4.06	1.380	4.22	1.220	4.48	1.170	4.72	1.243	4.94
Diesel Auto	0.079	3.68	0.149	3.94	0.206	4.24	0.251	4.49	0.354	4.72
Diesel Other	0.536	3.68	0.621	3.94	0.734	4.24	0.853	4.49	1.343	4.72
Jet Fuel	0.531	2.91	0.668	3.17	0.874	3.47	1.090	3.72	1.953	3.95
Marine Bunker	0.109	2.75	0.121	2.96	0.137	3.23	0.153	3.45	0.215	3.70
Methanol	0.018	4.51	0.036	4.71	0.051	4.95	0.064	5.18	0.094	5.44
Electricity	0	--	0.002	7.79	0.005	7.72	0.008	7.51	0.016	7.05
Industrial										
High-Btu Gas	0.738	3.02	0.732	3.37	0.707	3.72	0.691	3.86	0.857	3.23
Distillate	0.146	2.97	0.176	3.23	0.206	3.53	0.232	3.78	0.216	4.01
Low-Sulfur Residual	0.278	2.87	0.276	3.08	0.260	3.35	0.243	3.57	0.179	3.82
Low-Sulfur Coal	0.540	1.56	0.662	1.59	0.846	1.64	1.034	1.66	1.557	1.73
High-Sulfur Coal	0.209	1.20	0.244	1.23	0.284	1.32	0.336	1.28	0.539	1.28
SRC	0	--	0	--	0.010	3.10	0.024	2.97	0.096	2.91
Low-Btu Gas	0	--	0	--	0.007	4.32	0.024	4.15	0.070	3.99
Electricity	0.608	8.45	0.746	8.42	0.940	8.33	1.133	8.11	1.747	7.41
Feedstocks										
Naptha Feedstocks	0.351	3.29	0.420	3.45	0.512	3.71	0.598	3.95	0.808	4.17
Coal Feedstocks (Ex Exports)	0.073	0.93	0.123	0.97	0.203	1.06	0.288	1.03	0.648	1.02
Gas Feedstocks	0.094	2.90	0.111	3.25	0.135	3.60	0.158	3.74	0.230	3.11
LPG Feedstocks	0.078	3.09	0.075	3.27	0.070	3.56	0.064	3.81	0.052	4.00

Table 2-24

REGION 4 - EAST SOUTH CENTRAL

PRICES AND QUANTITIES OF DELIVERED PRODUCTS BY END-USE SECTOR BY PRODUCT--BASE CASE

(Quantities in Quadrillions of Btu; Long-Term Marginal Prices in 1975 Dollars Per Million Btu)

RESOURCE	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
Residential and Commercial										
High-Btu Gas	0.431	3.29	0.436	3.64	0.437	4.06	0.446	4.12	0.513	3.47
Distillate	0.031	3.60	0.033	3.88	0.035	4.19	0.037	4.44	0.035	4.60
Low-Sulfur Residual	0.014	2.95	0.015	3.19	0.015	3.45	0.015	3.57	0.015	3.25
LPG	0.080	4.33	0.083	4.54	0.091	4.82	0.100	5.12	0.113	5.33
Electric Space	0.067	7.47	0.067	9.51	0.071	9.42	0.076	9.33	0.101	8.50
Electric Nonspace	0.229	11.95	0.245	12.07	0.268	12.06	0.298	12.02	0.463	11.38
Transportation										
Gasoline	0.679	4.07	0.547	4.23	0.477	4.50	0.453	4.74	0.480	4.87
Diesel Auto	0.031	3.65	0.059	3.93	0.080	4.24	0.097	4.49	0.137	4.65
Diesel Other	0.249	3.65	0.284	3.93	0.329	4.24	0.378	4.49	0.584	4.65
Jet Fuel	0.068	2.88	0.084	3.16	0.109	3.47	0.134	3.72	0.242	3.88
Marine Bunker	0.016	2.71	0.019	2.95	0.023	3.21	0.028	3.33	0.050	3.01
Methanol	0.007	4.56	0.014	4.77	0.019	5.00	0.024	5.23	0.036	5.42
Electricity	0	--	0.001	7.97	0.002	7.87	0.003	7.75	0.006	7.20
Industrial										
High-Btu Gas	0.619	2.73	0.623	3.08	0.595	3.50	0.569	3.56	0.661	2.90
Distillate	0.056	2.94	0.068	3.22	0.081	3.53	0.090	3.78	0.076	3.94
Low-Sulfur Residual	0.054	2.83	0.058	3.07	0.057	3.33	0.056	3.45	0.065	3.13
Low-Sulfur Coal	0.148	1.55	0.220	1.56	0.334	1.59	0.442	1.60	0.699	1.65
High-Sulfur Coal	0.185	1.08	0.200	1.07	0.221	1.09	0.253	1.02	0.380	0.98
SRC	0	--	0	--	0.007	2.93	0.017	2.80	0.058	2.74
Low-Btu Gas	0	--	0	--	0.005	3.98	0.019	3.76	0.049	3.56
Electricity	0.508	8.49	0.609	8.50	0.748	8.39	0.886	8.27	1.353	7.37
Feedstocks										
Naptha Feedstocks	0.640	3.30	0.759	3.46	0.913	3.73	1.057	3.97	1.430	4.10
Coal Feedstocks (Ex Exports)	0.050	0.82	0.084	0.81	0.137	0.82	0.194	0.75	0.437	2.71
Gas Feedstocks	0.093	2.67	0.108	3.02	0.130	3.44	0.151	3.50	0.220	2.84
LPG Feedstocks	0.300	3.05	0.290	3.26	0.264	3.54	0.241	3.84	0.195	4.05

Table 2-25

REGION 5 - EAST NORTH CENTRAL

PRICES AND QUANTITIES OF DELIVERED PRODUCTS BY END-USE SECTOR BY PRODUCT--BASE CASE

(Quantities in Quadrillions of Btu; Long-Term Marginal Prices in 1975 Dollars Per Million Btu)

RESOURCE	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
Residential and Commercial										
High-Btu Gas	2.394	3.60	2.353	3.79	2.373	3.87	2.453	3.82	2.743	3.51
Distillate	0.355	3.65	0.375	3.91	0.408	4.19	0.422	4.42	0.381	4.62
Low-Sulfur Residual	0.087	2.95	0.087	3.18	0.085	3.42	0.081	3.56	0.068	3.30
LPG	0.157	4.31	0.172	4.29	0.197	4.56	0.222	4.85	0.221	5.56
Electric Space	0.199	9.23	0.253	9.24	0.339	9.13	0.425	9.01	0.801	8.40
Electric Nonspace	0.944	11.71	1.117	11.81	1.360	11.77	1.637	11.71	2.907	11.27
Transportation										
Gasoline	2.193	4.10	1.797	4.25	1.607	4.48	1.547	4.71	1.640	4.89
Diesel Auto	0.113	3.70	0.208	3.96	0.277	4.24	0.338	4.47	0.469	4.67
Diesel Other	0.589	3.70	0.686	3.96	0.816	4.24	0.951	4.47	1.493	4.67
Jet Fuel	0.441	2.93	0.559	3.19	0.737	3.47	0.921	3.70	1.653	3.90
Marine Bunker	0.011	2.71	0.014	2.94	0.018	3.18	0.022	3.32	0.039	3.06
Methanol	0.023	4.63	0.046	4.83	0.066	5.07	0.083	5.30	0.124	5.31
Electricity	0	--	0.002	7.79	0.007	7.66	0.011	7.51	0.021	7.04
Industrial										
High-Btu Gas	1.617	3.21	1.580	3.40	1.553	3.49	1.600	3.43	2.063	3.12
Distillate	0.337	2.99	0.429	3.25	0.499	3.53	0.525	3.76	0.452	3.96
Low-Sulfur Residual	0.198	2.83	0.203	3.06	0.196	3.30	0.187	3.44	0.175	3.18
Low-Sulfur Coal	0.511	1.45	0.733	1.44	1.059	1.47	1.367	1.49	2.247	1.52
High-Sulfur Coal	0.838	1.06	0.858	1.08	0.868	1.11	0.900	1.05	1.063	1.02
SRC	0	--	0	--	0.014	2.92	0.031	2.85	0.104	2.79
Low-Btu Gas	0	--	0	--	0.026	3.96	0.081	3.75	0.246	3.67
Electricity	1.123	8.24	1.427	8.23	1.857	8.08	2.273	7.95	3.610	7.26
Feedstocks										
Naptha Feedstocks	0.529	3.33	0.639	3.48	0.784	3.71	0.918	3.94	1.240	4.12
Coal Feedstocks (Ex Exports)	0.247	0.80	0.419	0.81	0.698	0.85	0.993	0.79	2.233	0.75
Gas Feedstocks	0.093	3.24	0.111	3.20	0.135	3.29	0.159	3.23	0.233	2.92
LPG Feedstocks	0.104	3.03	0.101	3.01	0.095	3.28	0.088	3.57	0.071	4.28

Table 2-26

REGION 7 - WEST NORTH CENTRAL

PRICES AND QUANTITIES OF DELIVERED PRODUCTS BY END-USE SECTOR BY PRODUCT--BASE CASE

(Quantities in Quadrillions of Btu; Long-Term Marginal Prices in 1975 Dollars Per Million Btu)

RESOURCE	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
Residential and Commercial										
High-Btu Gas	0.821	3.05	0.811	3.39	0.790	3.81	0.780	4.09	0.782	3.81
Distillate	0.058	3.56	0.055	3.84	0.053	4.13	0.053	4.38	0.048	4.57
Low-Sulfur Residual	0.017	2.91	0.017	3.14	0.017	3.42	0.017	3.62	0.017	3.31
LPG	0.104	4.25	0.095	4.46	0.092	4.75	0.092	5.05	0.094	5.26
Electric Space	0.032	10.14	0.033	10.17	0.037	10.02	0.044	9.88	0.081	9.04
Electric Nonspace	0.634	12.64	0.745	12.73	0.894	12.65	1.063	12.58	1.900	11.95
Transportation										
Gasoline	1.056	4.02	0.848	4.18	0.733	4.45	0.690	4.69	0.725	4.85
Diesel Auto	0.049	3.61	0.092	3.89	0.124	4.18	0.149	4.43	0.208	4.62
Diesel Other	0.423	3.61	0.481	3.89	0.555	4.18	0.635	4.43	0.975	4.62
Jet Fuel	0.307	2.84	0.380	3.12	0.486	3.41	0.598	3.66	1.072	3.85
Marine Bunker	0.171	2.67	0.187	2.90	0.206	3.18	0.226	3.38	0.340	3.07
Methanol	0.011	4.49	0.021	4.70	0.030	4.93	0.037	5.15	0.055	5.37
Electricity	0	--	0.001	8.68	0.003	8.50	0.005	8.30	0.009	7.51
Industrial										
High-Btu Gas	2.857	2.55	2.823	2.89	2.630	3.30	2.447	3.58	2.080	3.30
Distillate	0.114	2.90	0.137	3.18	0.164	3.47	0.192	3.72	0.208	3.91
Low-Sulfur Residual	0.198	2.79	0.115	3.02	0.119	3.30	0.119	3.50	0.155	3.19
Low-Sulfur Coal	0.329	1.47	0.600	1.45	1.046	1.48	1.503	1.51	2.950	1.55
High-Sulfur Coal	0.069	1.25	0.108	1.26	0.165	1.29	0.231	1.24	0.493	1.22
SRC	0	--	0	--	0.021	2.91	0.046	2.85	0.161	2.79
Low-Btu Gas	0	--	0	--	0.005	4.27	0.019	4.11	0.080	3.93
Electricity	0.964	9.17	1.193	9.16	1.507	8.98	1.817	8.82	2.880	7.93
Feedstocks										
Naptha Feedstocks	2.080	3.25	2.450	3.41	2.917	3.68	3.357	3.92	4.533	4.08
Coal Feedstocks (Ex Exports)	0.005	0.99	0.007	1.00	0.011	1.04	0.016	1.00	0.036	0.98
Gas Feedstocks	0.706	2.54	0.824	2.87	0.979	3.29	1.133	3.57	1.647	3.29
LPG Feedstocks	0.813	2.97	0.783	3.18	0.707	3.47	0.640	3.77	0.516	3.98

Table 2-27

REGION 7 - WEST NORTH CENTRAL

PRICES AND QUANTITIES OF DELIVERED PRODUCTS BY END-USE SECTOR BY PRODUCT--BASE CASE

(Quantities in Quadrillions of Btu; Long-Term Marginal Prices in 1975 Dollars Per Million Btu)

RESOURCE	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
Residential and Commercial										
High-Btu Gas	0.934	3.19	0.891	3.33	0.851	3.46	0.837	3.47	0.988	3.11
Distillate	0.079	3.65	0.079	3.90	0.079	4.19	0.080	4.43	0.078	4.59
Low-Sulfur Residual	0.021	3.00	0.020	3.20	0.018	3.40	0.017	3.43	0.017	3.15
LPG	0.141	3.94	0.138	3.91	0.143	4.15	0.149	4.52	0.128	6.42
Electric Space	0.083	8.60	0.102	8.63	0.125	8.67	0.147	8.81	0.209	8.70
Electric Nonspace	0.383	11.10	0.438	11.20	0.511	11.31	0.599	11.50	1.063	11.57
Transportation										
Gasoline	1.462	4.03	1.167	4.22	0.990	4.50	0.922	4.73	0.979	4.87
Diesel Auto	0.069	3.70	0.128	3.95	0.168	4.24	0.198	4.48	0.279	4.64
Diesel Other	0.414	3.70	0.468	3.95	0.533	4.24	0.605	4.48	0.957	4.64
Jet Fuel	0.237	2.93	0.289	3.18	0.363	3.47	0.443	3.71	0.793	3.87
Marine Bunker	0	--	0	--	0	--	0	--	0	--
Methanol	0.015	4.58	0.029	4.78	0.041	5.02	0.049	5.24	0.074	5.23
Electricity	0	--	0.001	7.06	0.004	7.17	0.007	7.38	0.012	7.64
Industrial										
High-Btu Gas	0.628	2.69	0.605	2.84	0.567	2.96	0.550	2.97	0.600	2.60
Distillate	0.038	2.99	0.040	3.24	0.039	3.53	0.038	3.77	0.028	3.93
Low-Sulfur Residual	0.043	2.88	0.041	3.08	0.036	3.28	0.033	3.31	0.028	3.03
Low-Sulfur Coal	0.329	1.04	0.411	1.04	0.513	1.06	0.611	1.09	0.948	1.11
High-Sulfur Coal	0.024	1.09	0.031	1.10	0.036	1.14	0.047	1.09	0.095	1.06
SRC	0	--	0	--	0.002	2.68	0.004	2.69	0.013	2.64
Low-Btu Gas	0	--	0	--	0.003	3.71	0.008	3.64	0.016	3.55
Electricity	0.305	7.62	0.373	7.62	0.463	7.63	0.554	7.75	0.878	7.56
Feedstocks										
Naptha Feedstocks	0.260	3.26	0.302	3.45	0.353	3.73	0.402	3.96	0.544	4.10
Coal Feedstocks (Ex Exports)	0.022	0.74	0.035	0.74	0.056	0.77	0.079	0.79	0.176	0.79
Gas Feedstocks	0.048	2.67	0.055	2.82	0.064	2.94	0.074	2.95	0.106	2.58
LPG Feedstocks	0.092	2.66	0.087	2.63	0.077	2.87	0.069	3.24	0.056	5.14

Table 2-28

REGION 8 - PACIFIC

PRICES AND QUANTITIES OF DELIVERED PRODUCTS BY END-USE SECTOR BY PRODUCT--BASE CASE

(Quantities in Quadrillions of Btu; Long-Term Marginal Prices in 1975 Dollars Per Million Btu)

RESOURCE	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
Residential and Commercial										
High-Btu Gas	1.102	3.27	1.173	3.41	1.267	3.50	1.347	3.59	1.327	3.68
Distillate	0.125	3.51	0.145	3.77	0.165	4.05	0.179	4.29	0.177	4.58
Low-Sulfur Residual	0.057	2.85	0.057	3.05	0.057	3.29	0.054	3.49	0.040	3.75
LPG	0.044	3.69	0.053	3.78	0.066	4.00	0.080	4.25	0.105	4.59
Electric Space	0.107	9.95	0.113	9.85	0.130	9.50	0.157	9.22	0.326	8.06
Electric Nonspace	0.584	12.44	0.711	12.43	0.904	12.15	1.107	11.91	1.943	11.54
Transportation										
Gasoline	1.387	3.95	1.167	4.11	1.093	4.36	1.087	4.59	1.157	4.85
Diesel Auto	0.065	3.56	0.126	3.82	0.184	4.10	0.233	4.34	0.329	4.63
Diesel Other	0.492	3.56	0.594	3.82	0.740	4.10	0.886	4.34	1.400	4.63
Jet Fuel	0.655	2.79	0.863	3.05	1.187	3.33	1.517	3.57	2.723	3.86
Marine Bunker	0.164	2.61	0.188	2.81	0,223	3.05	0.257	3.25	0.362	3.51
Methanol	0.014	4.49	0.030	4.70	0.049	4.93	0.059	5.17	0.087	5.39
Electricity	0	--	0.001	8.32	0.004	8.01	0.007	7.83	0.014	7.24
Industrial										
High-Btu Gas	0.757	2.76	0.794	2.90	0.839	3.00	0.871	3.09	0.876	3.17
Distillate	0.093	2.85	0.104	3.11	0.112	3.39	0.115	3.63	0.100	3.92
Low-Sulfur Residual	0.151	2.73	0.159	2.93	0.162	3.17	0.159	3.37	0.119	3.63
Low-Sulfur Coal	0.155	1.59	0.257	1.59	0.429	1.61	0.620	1.59	1.250	1.57
High-Sulfur Coal	0	--	0	--	0	--	0	--	0	--
SRC	0	--	0	--	0.007	3.03	0.015	3.04	0.045	2.96
Low-Btu Gas	0	--	0	--	0.001	4.43	0.003	4.30	0.016	4.16
Electricity	0.507	8.97	0.662	8.85	0.892	8.46	1.110	8.15	1.750	7.52
Feedstocks										
Naptha Feedstocks	0.386	3.18	0.482	3.34	0.619	3.59	0.743	3.82	1.005	4.08
Coal Feedstocks (Ex Exports)	0.005	1.28	0.008	1.28	0.013	1.30	0.019	1.28	0.043	1.26
Gas Feedstocks	0.053	2.69	0.065	2.83	0.084	2.93	0.101	3.01	0.147	3.09
LPG Feedstocks	0.043	2.41	0.042	2.50	0.041	2.72	0.040	2.97	0.032	3.31

Table 2-29

REGION 15 - MOUNTAIN

PRICES AND QUANTITIES OF DELIVERED PRODUCTS BY END-USE SECTOR BY PRODUCT--BASE CASE

(Quantities in Quadrillions of Btu; Long-Term Marginal Prices in 1975 Dollars Per Million Btu)

RESOURCE	1985		1990		1995		2000		2022	
	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU	QUAD BTU	$/MM BTU
Residential and Commercial										
High-Btu Gas	0.512	2.84	0.521	2.97	0.536	3.08	0.550	3.19	0.574	3.22
Distillate	0.034	3.56	0.034	3.83	0.035	4.10	0.037	4.33	0.038	4.59
Low-Sulfur Residual	0.013	2.94	0.012	3.15	0.011	3.37	0.011	3.46	0.010	3.19
LPG	0.050	3.63	0.053	3.64	0.057	3.96	0.062	4.32	0.073	4.73
Electric Space	0.029	9.09	0.033	9.04	0.041	8.83	0.053	8.74	0.117	8.33
Electric Nonspace	0.255	11.58	0.300	11.60	0.362	11.46	0.433	11.44	0.770	11.19
Transportation										
Gasoline	0.459	4.03	0.373	4.17	0.329	4.40	0.315	4.63	0.338	4.86
Diesel Auto	0.024	3.61	0.043	3.88	0.057	4.15	0.069	4.38	0.097	4.64
Diesel Other	0.232	3.61	0.269	3.88	0.318	4.15	0.370	4.38	0.585	4.64
Jet Fuel	0.137	2.84	0.172	3.11	0.224	3.38	0.279	3.61	0.500	3.87
Marine Bunker	0	--	0	--	0	--	0	--	0	--
Methanol	0.003	8.63	0.007	7.03	0.012	5.32	0.016	5.30	0.025	5.23
Electricity	0	--	0.001	7.50	0.002	7.46	0.003	7.49	0.004	7.20
Industrial										
High-Btu Gas	0.428	2.34	0.443	2.47	0.459	2.58	0.478	2.69	0.554	2.72
Distillate	0.051	2.90	0.048	3.17	0.044	3.44	0.042	3.67	0.032	3.93
Low-Sulfur Residual	0.047	2.82	0.045	3.03	0.041	3.25	0.038	3.34	0.029	3.07
Low-Sulfur Coal	0.168	1.19	0.210	1.19	0.271	1.19	0.341	1.16	0.586	1.13
High-Sulfur Coal	0	--	0	--	0	--	0	--	0	--
SRC	0	--	0	--	0.001	2.79	0.003	2.80	0.007	2.73
Low-Btu Gas	0	--	0	--	0.001	3.87	0.002	3.73	0.013	3.56
Electricity	0.212	8.11	0.267	8.03	0.343	7.79	0.418	7.68	0.665	7.20
Feedstocks										
Naptha Feedstocks	0.021	3.26	0.024	3.40	0.030	3.63	0.034	3.86	0.046	4.09
Coal Feedstocks (Ex Exports)	0.013	0.88	0.022	0.88	0.036	0.88	0.051	0.85	0.116	0.82
Gas Feedstocks	0.008	2.32	0.010	2.45	0.012	2.56	0.014	2.67	0.020	2.70
LPG Feedstocks	0.016	2.36	0.015	2.36	0.014	2.68	0.013	3.04	0.010	3.45

Section 3

SENSITIVITY ANALYSIS

INTRODUCTION

The SRI National Energy Model is a deterministic (i.e., nonprobabilistic) tool for understanding the forces that set the quantities and prices of the various energy forms in the U.S. energy market. Because many of the techno-economic inputs to the model are highly uncertain, and in fact many of the relationships within the model are also uncertain, it is important to test the effects of alternative information and logic assumptions.

To fulfill the requirements of this study, two variations from the base case were analyzed. They were designed to test the sensitivity of fuel prices and quantities to high and low growth in demand for energy services. This section will discuss the approach underlying the high- and low-demand cases and then will compare their results to those of the base case. The description of the high- and low-demand cases will not be carried out at the same level of detail as for the base case. Instead, this section will focus on pointing out differences between them. Much of the discussion of the base case in the previous section has implications for the high- and low-demand cases.

DESIGN OF THE HIGH- AND LOW-DEMAND CASES

The prices of various fuels are very complicated functions of a number of different elements in the energy sector. There are several ways to test their sensitivity to high and low demand, and these different ways have drastically different implications. Thus it is important to carefully design the high- and low-demand cases.

There are basically two ways to design a high-demand case. First, we might assume that the demand for energy services increases but that the economics and efficiencies in the energy system remain constant. This might result from, say, higher per capita GNP growth. On the other hand, we might assume that the demand for energy services remains constant but that the efficiencies in the energy system are lower. Referring to Figure 0-1 in the Executive Summary, we could rearrange either "Usable Energy Demand" or we could change "End-Use Conversion" efficiencies (or perhaps both).

It was agreed in this study that we would test the effects of low- and high-per capita GNP assumptions, that is, low and high demands for energy services. All process economic estimates (including efficiencies) were left identical to the base case. The different per capita GNP assumptions are summarized in Table 3-1.

This implies the average annual growth rates shown in Table 3-1(b).

Table 3-1

ASSUMPTIONS

(a) Per Capita Gross National Products (1975 Dollars)

CASE	1975	1985	2000	2025
High Demand	$7,030	$11,200	$18,700	$40,600
Base	7,030	10,081	13,783	20,713
Low Demand	7,030	8,800	10,100	9,600

(b) Growth in Per Capita Gross National Products

CASE	1975-1985	1985-2000	1975-2000	2000-2022
High Demand	4.8%	3.5%	4.0%	3.1%
Base	3.7	2.1	2.7	1.6
Low Demand	2.3	0.9	1.5	0.2

The high-GNP case represents a significantly different world from the low-GNP case. The high case assumes a very rapid growth in GNP after 2000. In the low-demand case, the U.S. economy is weak over the next 50 years. (The reader is encouraged to read Section 5 in Volume II of this report; it describes how the usable energy demand model uses these per capita GNP projections.)

All figures in this section pertain to model output for the high- and low-GNP growth sensitivity cases. We will indicate where the corresponding figures can be found for the base case in Section 2.

PRIMARY ENERGY

The production of each of the primary resources is presented in Figures 3-1 and 3-2 and Tables 3-2 and 3-3. They are comparable to Figure 2-1 and Table 2-1. Total primary energy consumption and its growth rate are compared in Tables 3-4 and 3-5. They are based on the corresponding per capita GNP scenarios shown in Table 3-1. Primary energy grows quite rapidly in the high-demand case and quite slowly in the low-demand case relative to the base case. Because conversion economics and efficiencies are identical in all cases, total primary resource production follows per capita GNP quite closely in all three cases. All three cases assume a significant amount of conservation over the next 50 years.

In contrast to many forecasts, we do not find high- or low-demand trends to differentially favor one fuel over another in the long run. This insight, of course, depends strongly on our base case economic assumptions. In fact, this is but another manifestation of the assumption that if the supplies of coal, shale, and nuclear fuel are highly elastic, the supplies of coal, synthetic gas, synthetic liquids, and electricity will all be highly elastic in the long run. Once domestic oil and gas have been depleted to the point where their prices rise to those of competing synthetic fuels, interfuel and intertechnology competition will be dominated by these elastic resources. Higher demand will accelerate the time at which we get to those elastic supplies, and lower demand will delay it, but neither will affect what happens once we get there to any great degree. Once we reach these elastic supplies, market shares will tend to stabilize because relative resource prices and technology costs have been assumed to remain nearly constant.

To illustrate this point, the market share of each primary fuel in the base, low- and high-demand cases is shown in Table 3-6. Given the extreme changes in demand implied by these sensitivities, it is interesting to note that the market shares change very little. However, as demand increases, Table 3-6 indicates that the

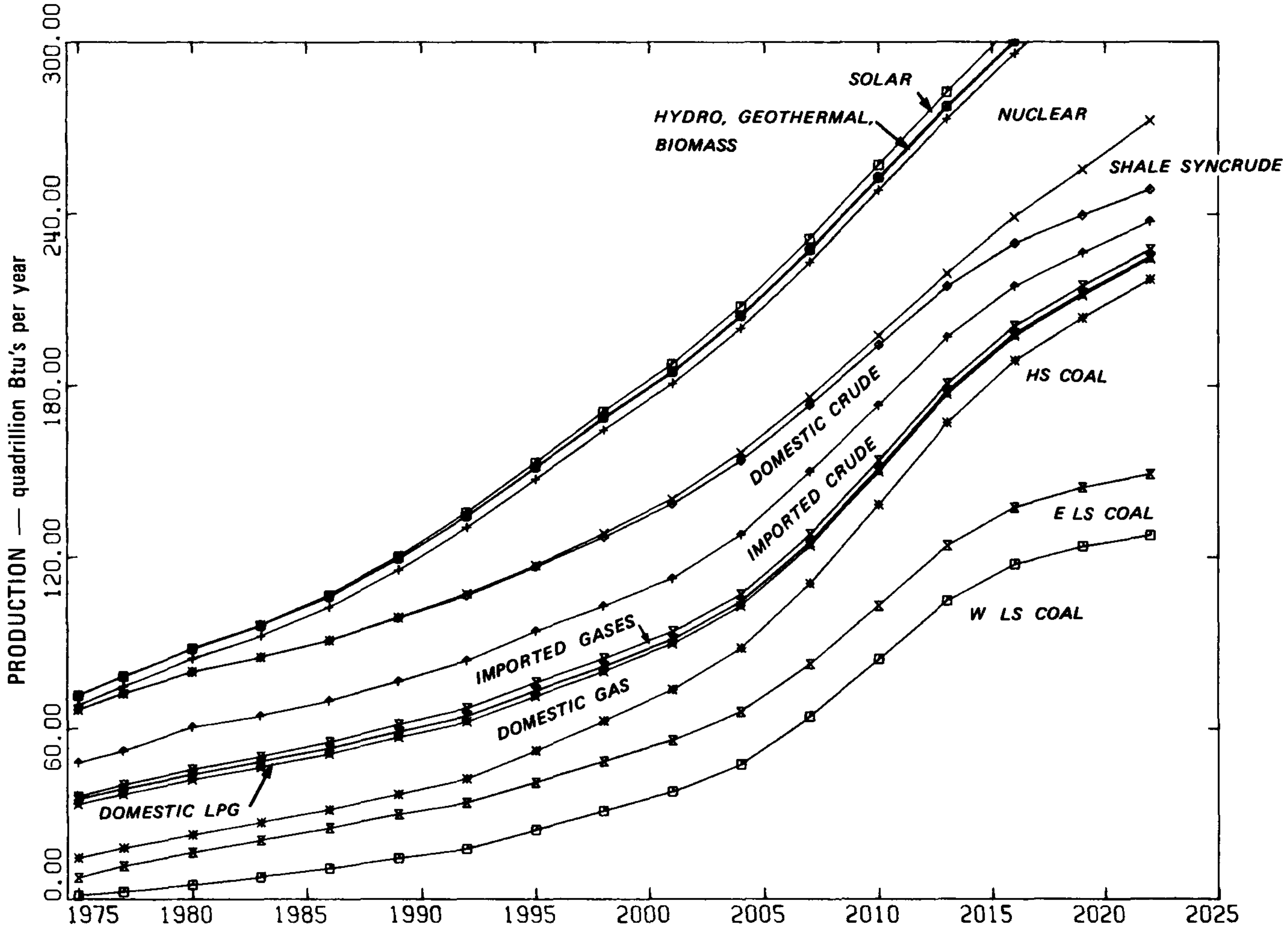

Figure 3-1. Total Primary Energy--High-Demand Case

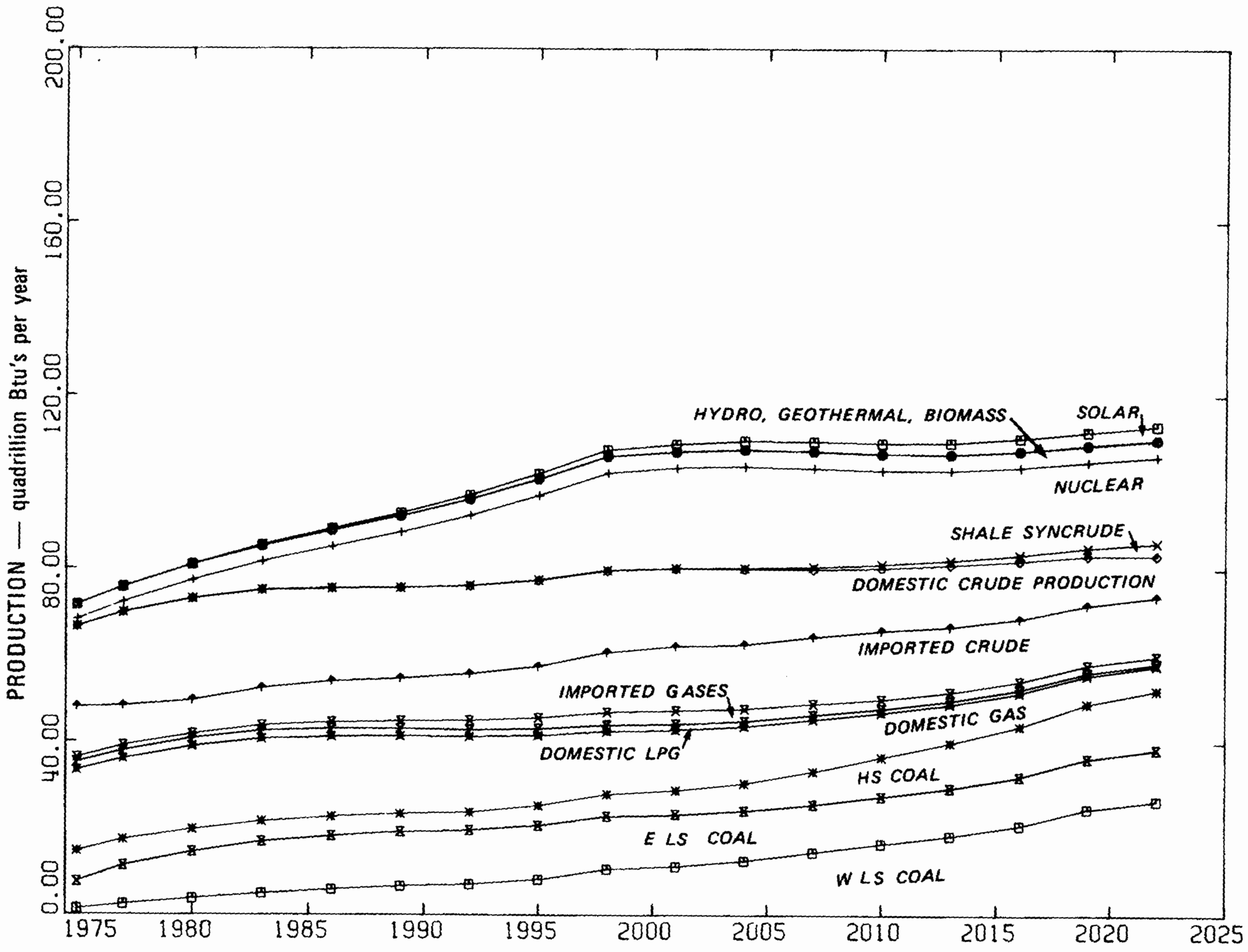

Figure 3-2. Total Primary Energy--Low-Demand Case

Table 3-2

PRODUCTION OF PRIMARY RESOURCES--HIGH-DEMAND CASE

(Quadrillion Btus Per Year)

RESOURCE	1975	1977	1980	1983	1986	1989	1992	1995	1998	2001	2004	2007	2010	2013	2016	2019	2022
Solar	--	--	0.12	0.30	0.56	0.88	1.23	1.64	2.07	2.57	3.16	3.77	4.40	5.05	5.71	6.38	7.02
Biomass	--	--	--	--	0.02	0.09	0.24	0.40	0.51	0.59	0.67	0.70	0.65	0.61	0.59	0.61	0.64
Hydro and Geothermal	3.29	3.46	3.58	3.68	3.74	3.77	3.79	3.80	3.81	3.80	3.79	3.79	3.79	3.79	3.80	3.80	3.81
Nuclear Fuel	1.69	2.52	4.57	7.25	11.50	16.70	23.20	30.06	36.23	40.26	43.48	47.07	50.67	53.96	57.03	60.70	64.73
High-Sulfur Coal	7.05	6.46	6.25	6.17	6.44	7.08	8.51	11.12	14.36	17.79	22.37	28.26	35.27	43.06	51.30	59.20	67.93
Low-Sulfur Coal	7.55	11.82	16.61	21.00	25.22	29.96	33.90	41.28	48.54	56.04	65.95	82.84	103.29	124.23	137.70	144.56	149.27
Shale Syncrude	--	--	--	--	0.01	0.08	0.50	0.50	1.24	1.66	2.71	2.77	3.34	4.46	9.16	16.00	23.97
Domestic Crude	18.60	20.31	19.34	20.75	21.28	22.36	22.99	22.63	24.13	26.12	25.96	23.30	21.03	17.83	15.04	13.24	11.28
Crude Imports	11.73	11.73	14.88	14.11	14.38	14.98	16.46	17.74	18.10	18.44	20.81	21.88	19.34	16.07	13.79	11.42	9.66
Gas Imports	1.07	1.46	1.72	1.83	2.15	2.50	2.94	3.03	2.86	2.72	2.70	2.71	2.73	2.72	2.72	2.68	2.66
Domestic LPG	1.87	1.87	1.89	1.98	2.01	2.05	1.98	1.90	1.80	1.66	1.50	1.33	1.17	1.02	0.89	0.80	0.73
Domestic Natural Gas	18.72	18.80	19.25	19.42	19.51	19.94	19.91	19.06	17.32	16.00	14.75	13.05	11.49	9.80	8.46	7.75	7.11
Total	71.57	78.43	88.21	96.49	106.82	120.39	135.65	153.16	170.97	187.65	207.85	231.47	257.17	282.60	306.19	327.14	348.81

Table 3-3

PRODUCTION OF PRIMARY RESOURCES--LOW-DEMAND CASE

(Quadrillion Btus Per Year)

RESOURCE	1975	1977	1980	1983	1986	1989	1992	1995	1998	2001	2004	2007	2010	2013	2016	2019	2022
Solar	--	--	0.09	0.21	0.38	0.62	0.87	1.14	1.45	1.73	1.98	2.23	2.46	2.69	2.91	3.11	3.29
Biomass	--	--	--	--	--	--	0.01	0.01	0.02	0.04	0.05	0.05	0.05	0.04	0.03	0.03	0.02
Hydro and Geothermal	3.29	3.42	3.56	3.68	3.75	3.76	3.76	3.76	3.77	3.76	3.75	3.75	3.75	3.76	3.77	3.77	3.78
Nuclear Fuel	1.69	2.46	4.28	6.54	9.61	12.80	16.20	19.47	22.37	23.00	23.47	22.90	21.60	20.63	20.03	19.77	19.90
High-Sulfur Coal	7.05	5.97	5.24	4.74	4.35	4.16	4.19	4.65	5.07	5.59	6.29	7.60	9.05	10.35	11.62	12.72	13.65
Low-Sulfur Coal	7.55	11.30	14.50	16.88	18.27	19.20	19.56	20.70	22.97	23.40	24.27	25.73	27.60	29.62	32.29	36.40	38.56
Shale Syncrude	--	--	--	--	--	--	0.07	0.09	0.14	0.18	0.34	0.51	0.96	1.07	1.50	1.89	2.93
Domestic Crude	18.60	21.60	23.46	22.58	21.39	20,89	20.31	19.97	18.85	17.92	17.38	15.60	14.40	14.17	13.36	11.35	9.49
Crude Imports	11.73	9.19	7.87	8.77	9.54	9.88	10.78	11.83	13.83	14.87	14.81	15.47	15.85	15.12	14.44	13.85	13.63
Gas Imports	1.07	1.17	0.88	1.08	1.36	1.67	2.10	2.53	2.97	3.14	2.85	2.47	2.22	2.00	1.85	1.73	1.65
Domestic LPG	1.87	1.91	1.96	1.92	1.85	1.79	1.68	1.55	1.45	1.32	1.19	1.07	0.93	0.84	0.73	0.62	0.52
Domestic Natural Gas	18.72	18.72	19.13	19.06	18.65	17.97	17.40	16.17	14.52	13.89	13.20	12.04	10.24	8.94	7.72	6.50	5.68
Total	71.57	75.74	80.97	85.46	89.15	92.74	96.93	101.87	107.41	108.84	109.58	109.42	109.11	109.23	110.25	111.74	113.10

Table 3-4

CONSUMPTION OF TOTAL PRIMARY RESOURCES

(Quadrillion Btus per Year)

CASE	1975	1985	2001	2010	2022
High Demand	71.6	102	188	257	349
Base	71.6	95	141	167	200
Low Demand	71.6	87	109	109	113

Table 3-5

GROWTH RATE IN CONSUMPTION OF TOTAL PRIMARY RESOURCES

(Average Annual Percentage Increase)

CASE	1975-1985	1985-2000	1975-2001	2001-2022
High Demand	3.6%	3.9%	3.8%	3.0%
Base	2.9	2.5	2.6	1.7
Low Demand	2.0	1.4	1.6	0.17

market does shift slightly toward high-sulfur coal, low-sulfur coal, and shale. The reason is that if demand is higher, domestic oil and gas and imported fuels are depleted more rapidly and the market moves to synthetics more rapidly and more completely.

Both the high-demand case and the low-demand case employ a simple self-elasticity* of usable energy demand model developed especially for this project. This model works by specifying an operating point on each end-use demand curve in each year and then specifying short- and long-run elasticities to describe the demand curve that passes through these operating points. In both sensitivity cases, the operating points correspond to base case prices and sensitivity case quantities, which are based on the GNP forecasts in Table 3-1. The self-elasticity demand

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*Self-elasticity is defined as the price response of each usable energy demand category to a change in its <u>own</u> price.

Table 3-6

MARKET SHARES OF PRIMARY RESOURCES IN 2022(1)

RESOURCE	LOW DEMAND	BASE CASE	HIGH DEMAND
Solar	3%	2%	2%
Biomass	1	1	1
Hydro and Geothermal	3	2	1
Nuclear Fuel	18	19	19
High-Sulfur Coal	12	16	19
Low-Sulfur Coal	34	39	43
Shale Syncrude	3	5	7
Domestic Crude	8	6	3
Crude Imports	12	6	3
Gas Imports	1	1	1
LPG Imports	1	1	1
Domestic Natural Gas	5%	3%	2%

---

(1) Columns do not add due to rounding.

model is described in Volume II, Section 6. Once these price/quantity points have been specified in each year, the annual demand curves are constructed by passing a demand curve with an exogenously given elasticity through the specified points.

The effect of self-elasticity of end-use demand is felt at all levels of the energy system, extending downward even to the primary resource level. If energy prices increase, perhaps due to resource depletion, the self-elasticity end-use demand model assumes that the quantity required will decrease in response to the higher price. The magnitude of the decrease is determined by the elasticity that has been assumed and the interfuel and intertechnology readjustments that would occur. For comparison with other model results, we have included Figures 3-1 and 3-2, which show total primary energy; these contain elasticity effects.

The prices of selected primary resources pictured in Figures 3-3 and 3-4 should be compared with those in Figure 2-2. It is significant that qualitatively these price plots appear quite similar. It appears that long-run (marginal) resource

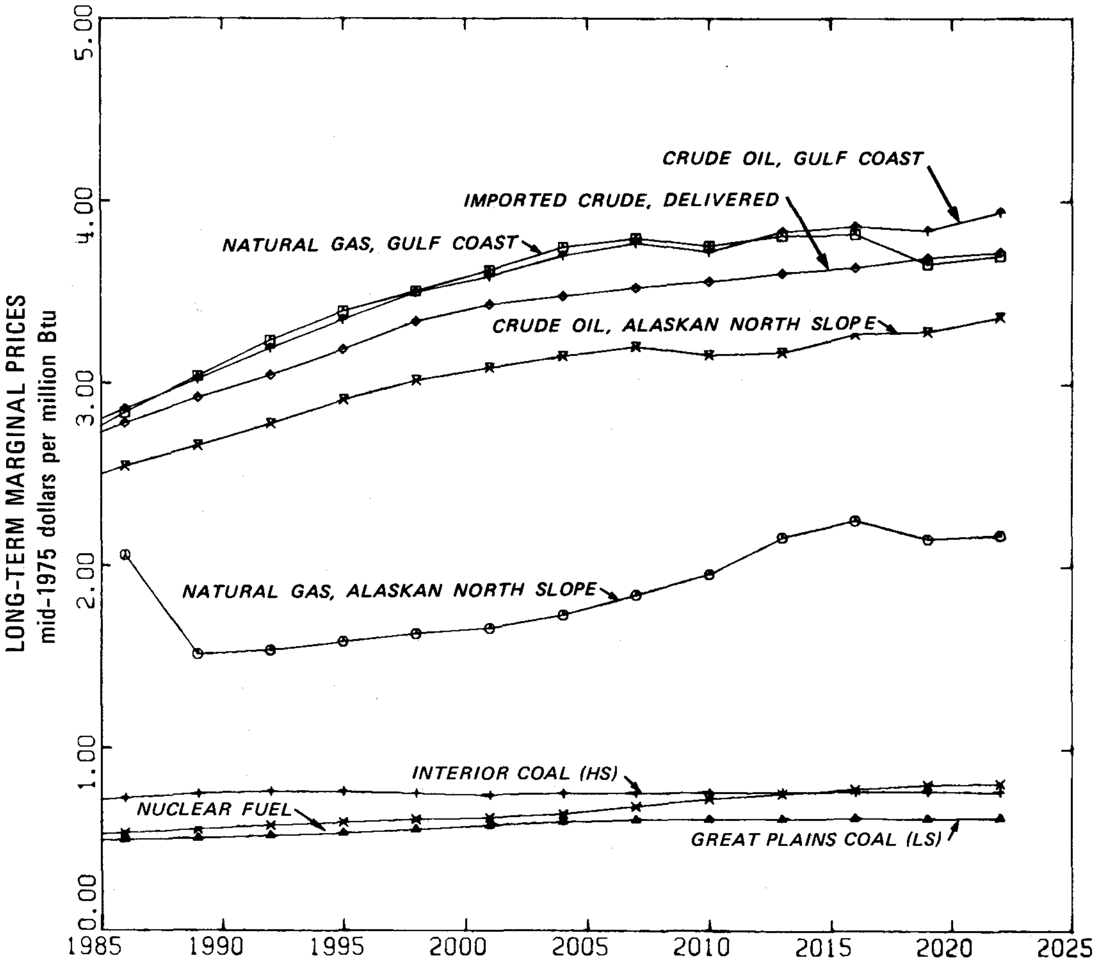

Figure 3-3. Prices of Selected Primary Resources by Location--High-Demand Case

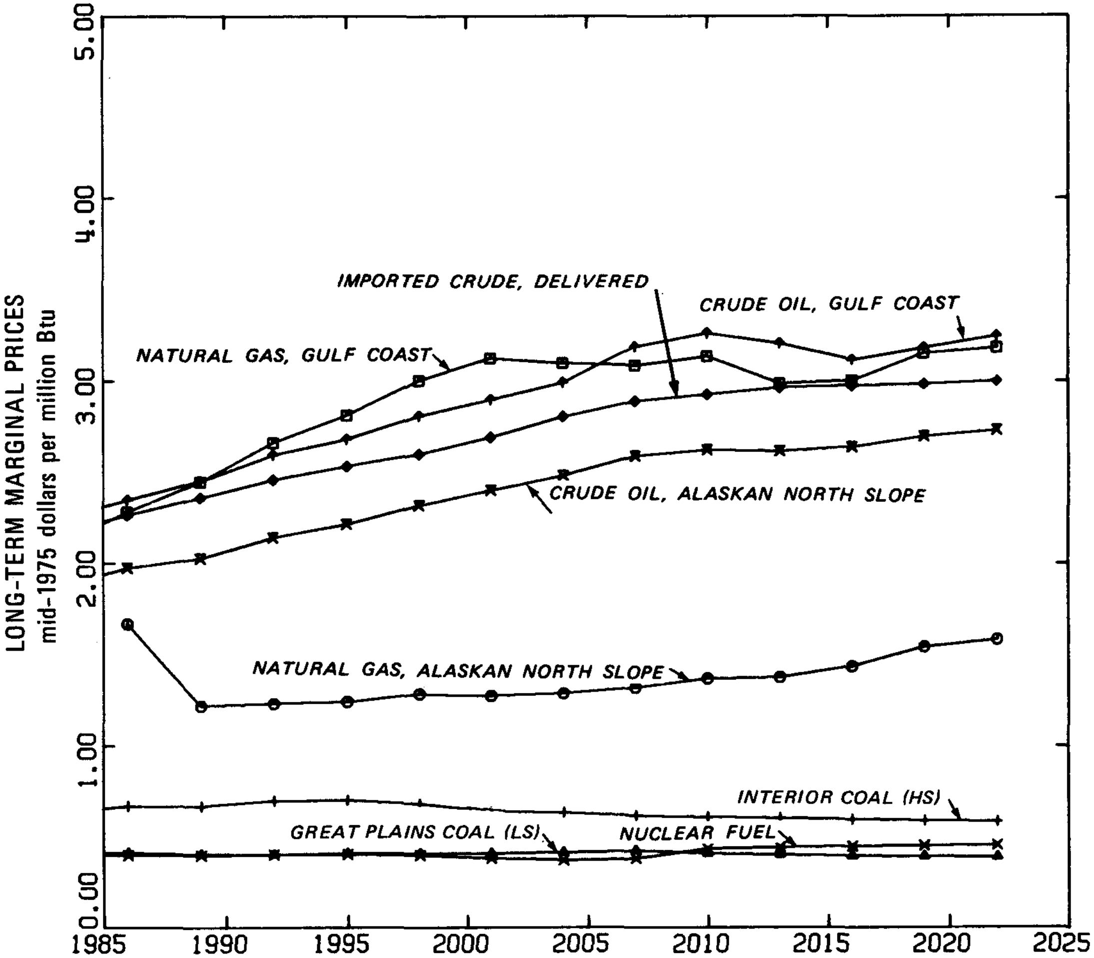

Figure 3-4. Prices of Selected Primary Resources by Location--Low-Demand Case

prices are not dramatically affected by energy demand. As discussed previously, the reason is that long-run (marginal) energy supplies are elastic because they are based on coal, nuclear fuel, and shale. We will illustrate that long-run (marginal) energy prices are more sensitive to the cost to produce and convert those resources than to the quantity of those resources demanded. Tables 3-7 and 3-8 explore price and quantity changes relative to the base case. They give some insight into the dynamic behavior of depletable relative to abundant resources.

Table 3-7

PERCENTAGE CHANGES IN PRICES AND QUANTITIES--HIGH-DEMAND COMPARED TO BASE CASE

RESOURCE	1985		2000		2025	
	QUANTITY	PRICE	QUANTITY	PRICE	QUANTITY	PRICE
Nuclear Fuel	+7%	+15%	+27%	+32%	+69%	+37%
Interior Coal (High-Sulfur)	+22	+4	+91	+12	+137	+18
Great Plains Coal (Low-Sulfur)	+29	+14	+94	+21	+95	+29
Gulf Coast Crude	-0.9	+10	+47	+8	+13	+8
North Slope Crude	+18	+15	-20	+15	-17	+12
Crude Imports	+24	+12	+21	+12	-17	+11
Gulf Coast Gas	+2	+13	-6	+7	+74	+6
North Slope Gas	-9	+31	-6	+12	+25	+17
Shale Syncrude	--	--	+161	+6	+136	+10
Uranium (U_3O_8)	--	+49	--	+60	--	+47

In both sensitivity cases there is a tendency for oil and gas to show greater price sensitivity to demand in early years than in later years. This results from the price sensitivity of depletable resources. However, in all three cases price sensitivity to demand declines over time because all three cases are driven in the long run by the prices of synthetics, whose supplies are elastic. Note further that the prices of the abundant resources tend to grow further apart over time among the three cases. This is caused by the high penalty for rapid growth paid in the high-demand case relative to the base case driving prices apart between

Table 3-8

PERCENTAGE CHANGES IN PRICES AND QUANTITIES--LOW DEMAND COMPARED TO BASE CASE

RESOURCE	1985		2000		2022	
	QUANTITY	PRICE	QUANTITY	PRICE	QUANTITY	PRICE
Nuclear Fuel	-7%	-13%	-27%	-19%	-48%	-22%
Interior Coal (High-Sulfur)	-21	-4	-46	-4	-63	-9
Great Plains Coal (Low-Sulfur)	-26	-7	-40	-15	-56	-19
Gulf Coast Crude	+10	-8	+6	-13	-30	-11
North Slope Crude	+20	-11	-39	-11	-14	-9
Crude Imports	-21	-9	+3	-13	+3	-11
Gulf Coast Gas	+0.1	-9	-11	-7	-48	-5
North Slope Gas	+7	-6	-19	-13	+0.3	-15
Shale Syncrude	--	--	-71	-5	-69	-7
Uranium (U_3O_8)	--	-33	--	-41	--	-44

these two cases. Similarly, the base case incurs some penalty for rapid growth while the low-demand case incurs almost none, thus driving prices apart between these two cases.

A typical response to a scenario such as the high-demand case is disbelief. This scenario might be questioned on the basis that "coal could not grow that fast", or "the nation would not allow that much nuclear capacity." It is important to note that such statements implicitly question the validity of the inputs to the model--in this case, the believability of the per capita GNP projections and/or the economics of coal compared to nuclear fuel. While we recognize that the coal and nuclear fuel forecasts in the high-demand case are large, they are consistent with the extreme growth in per capita GNP assumed as input, given the fact that the model is driven by market forces. It is very likely that in the high-demand case public policy would slow down coal and/or nuclear production. The effect of such policies on energy prices could be studied by using sensitivity runs on the model. In such a high-demand case with restrictions on the supply side, energy prices could be expected to be higher than in our case.

LIQUID AND GASEOUS FUEL PRODUCTION

Figures 3-5 and 3-6 illustrate the demand for liquids and gases from the various sources. They compare to Figure 2-3. Just as with total primary resource production, liquid and gaseous fuel production levels tend to follow the demand for usable energy. In the low-demand case, production of gaseous fuels never increases from today's level (although the sources of that gas do change over time) and the production of liquid fuels never increases from today's level (although the sources of those liquids change as well).

Even more so than in the base case, the high-demand case implies that an increasing fraction of coal production goes to produce synthetic fuels. Between the years 2001 and 2022, total coal production goes from 74 to 217 quadrillion Btu/yr, while synthetic coal liquids and gases grow from 14 to 100 quadrillion Btu/yr. The same phenomenon occurs in the low-demand case, but to a much lesser extent.

In the base case it is difficult to determine whether coal liquids or shale oil is the most economic source of liquid fuels in the long run. However, as demand increases, the balance swings more in favor of coal liquids because shale oil is penalized more heavily due to rapid growth than coal liquids. In the early 1990s, there is a larger coal industry from which to grow than in the base case. This results in a lower economic penalty for increases in coal production. The shale oil industry, however, must begin its industrial base even more rapidly in the early 1990s than in the base case. Thus, in the high-demand case, more coal liquid plants are built during this initial period of stress in the shale industry, and because these plants operate for 20 to 30 years, coal liquids have an initial edge.

Just as in the base case, these insights are sensitive to the base case economic assumptions for shale and coal liquids. Believing that shale oil will ultimately be produced at prices somewhat lower than those of coal liquids would imply about the same level of total synthetic liquids production as indicated in Figure 3-5, but the mix would shift in favor of shale oil.

A much clearer picture holds for synthetic methane than for synthetic liquids. Under the base case assumptions, recall that synthetic high-Btu gas from coal using advanced technology is a very attractive product. Increasing demand heightens the need for this technology. Thus, one would expect that if the cost

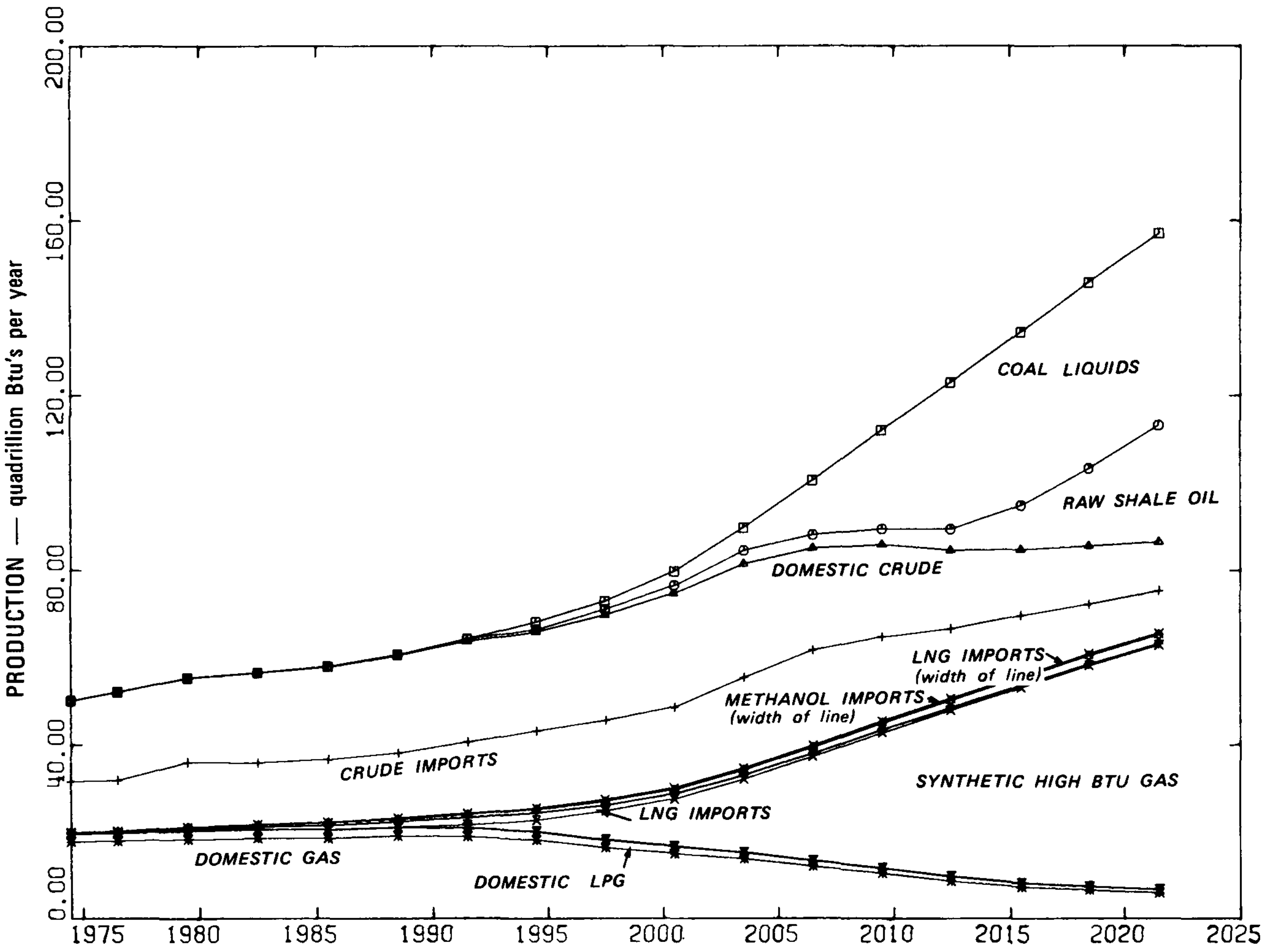

Figure 3-5. Sources of Liquid and Gaseous Fuels--High-Demand Case

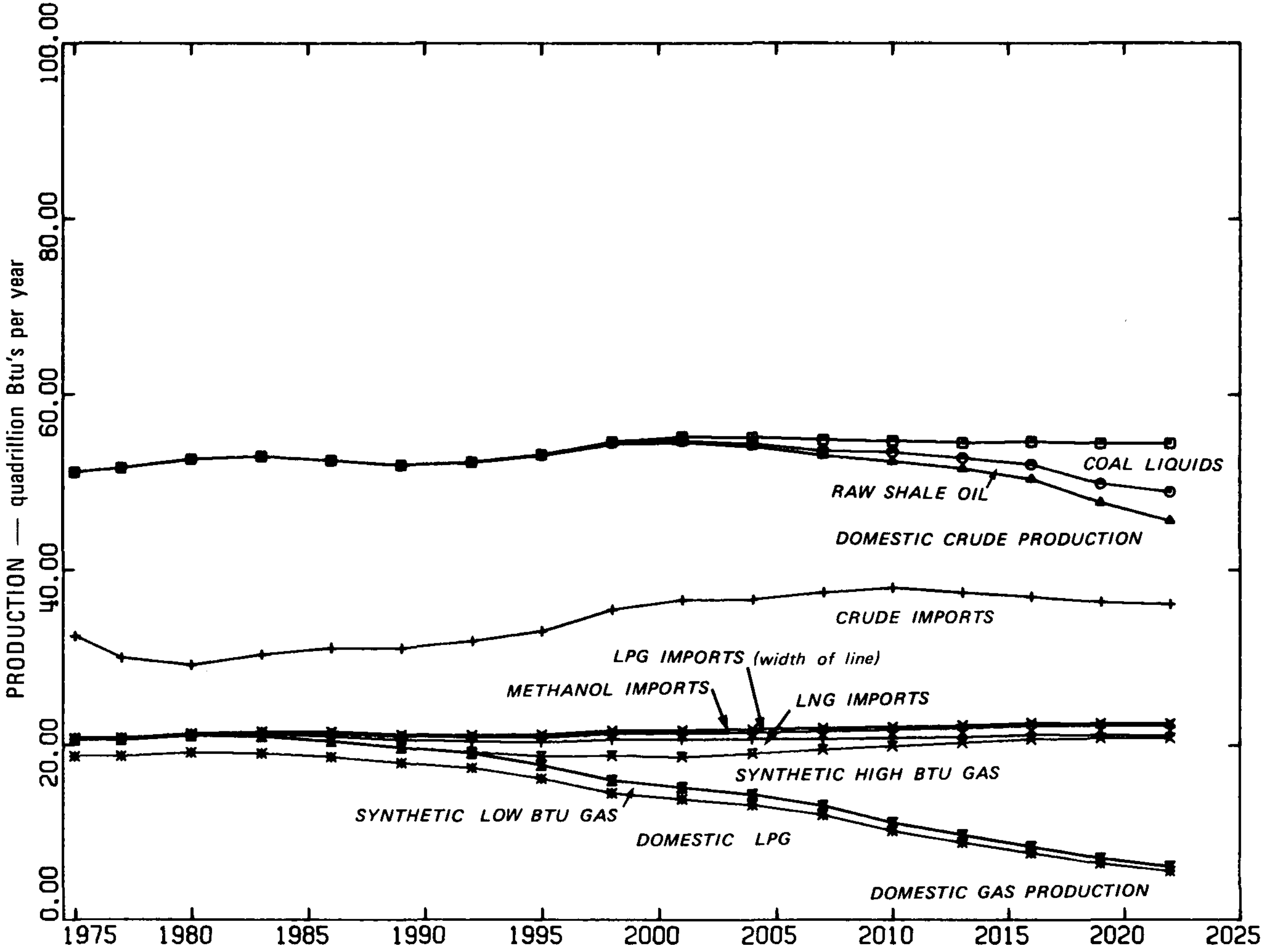

Figure 3-6. Sources of Liquid and Gaseous Fuels--Low-Demand Case

of advanced gasification technologies could be lowered, substantial benefits could accrue and those benefits would be higher in high-demand scenarios.

Such questions as, do we need high-Btu gas from coal? or, do we need shale oil? do not depend on demand for usable energy. However, the questions of when we need these technologies is affected by the level of usable energy demand. From the standpoint of analyzing the costs and benefits of R&D on various supply technologies, lower demand delays the need for new technologies and thus lessens the national benefit from those technologies because it pushes those benefits further into the future. It does not, however, obviate the need for those new technologies. Conversely, high demand accelerates the time at which these technologies are needed.

Domestic crude oil becomes noncompetitive as its price rises to depletion under all but the lowest demand cases. Total cumulative production of domestic crude varies with demand by only a few percentage points but that of synthetics varies dramatically.

In the high-demand case, total cumulative imports of crude are 15 percent higher than in the base case. This indicates that imports are somewhat more elastic than domestic crude supplies. Imports act as a backup supply of energy until they are sufficiently depleted or the synthetic liquids industry has been developed.

Synthetic Fuels

Figures 3-7 and 3-8 illustrate the production of synthetic fuels by type in the two cases. These should be compared to Figure 2-4. A useful way to interpret this forecast is to regard the production level determined by the model as a measure of the "need" at any point in time for a technology. In this sense, the need for synthetic fuels grows proportionally faster than total primary energy as demand increases. In the high-demand case in the year 2000, synthetic fuels provide 8.8 percent of total primary energy, whereas they provide only 4.0 percent in the low demand case. This compares to 5.4 percent in the base case.

Total synthetic fuel production in the year 2001 is 7.6 quadrillion Btu/yr in the base case and 16.5 quadrillion Btu/yr in the high-demand case. In judging the credibility of these very high synthetic fuel projections, keep in mind that they

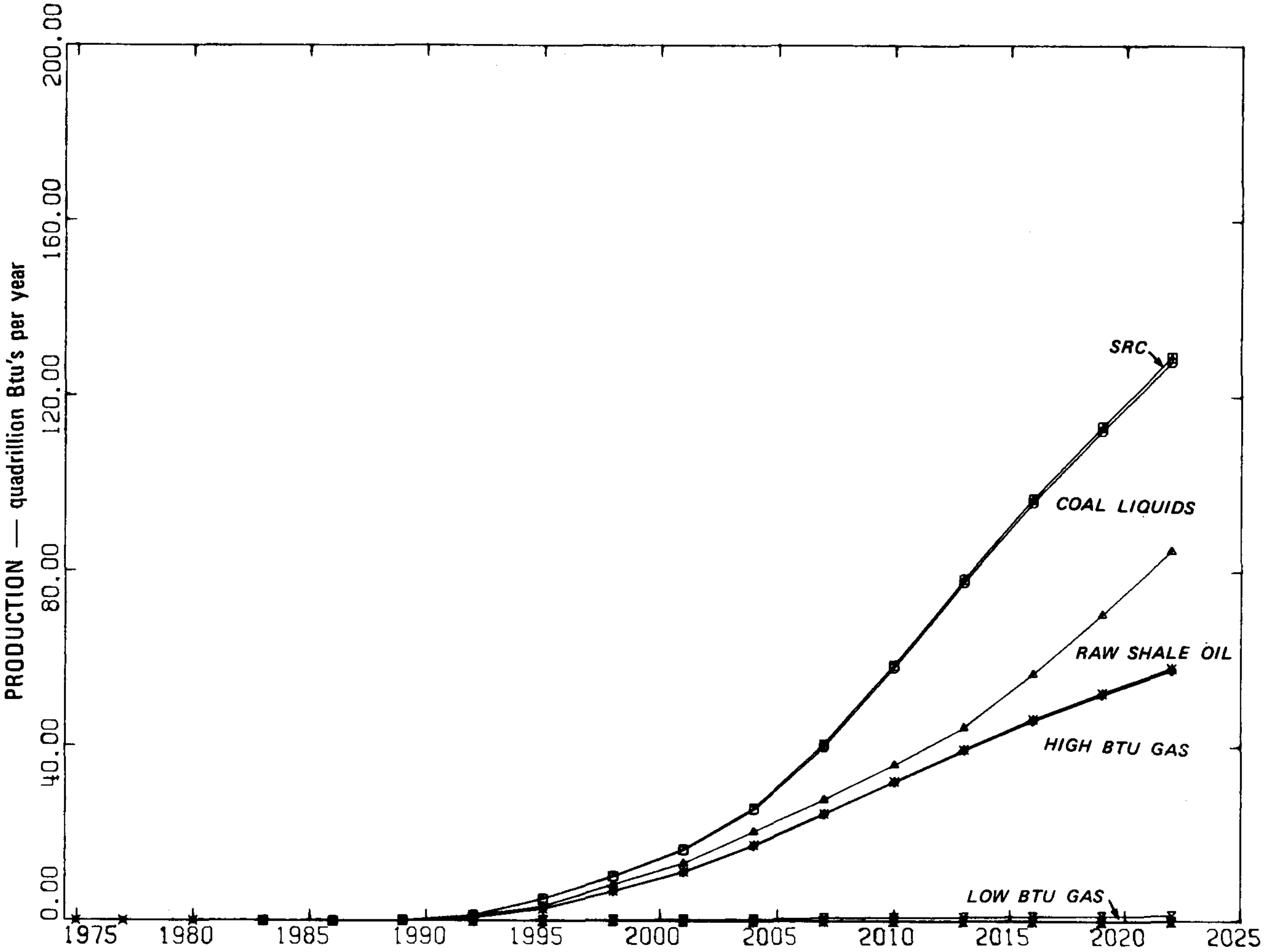

Figure 3-7. Synthetic Fuels--High-Demand Case

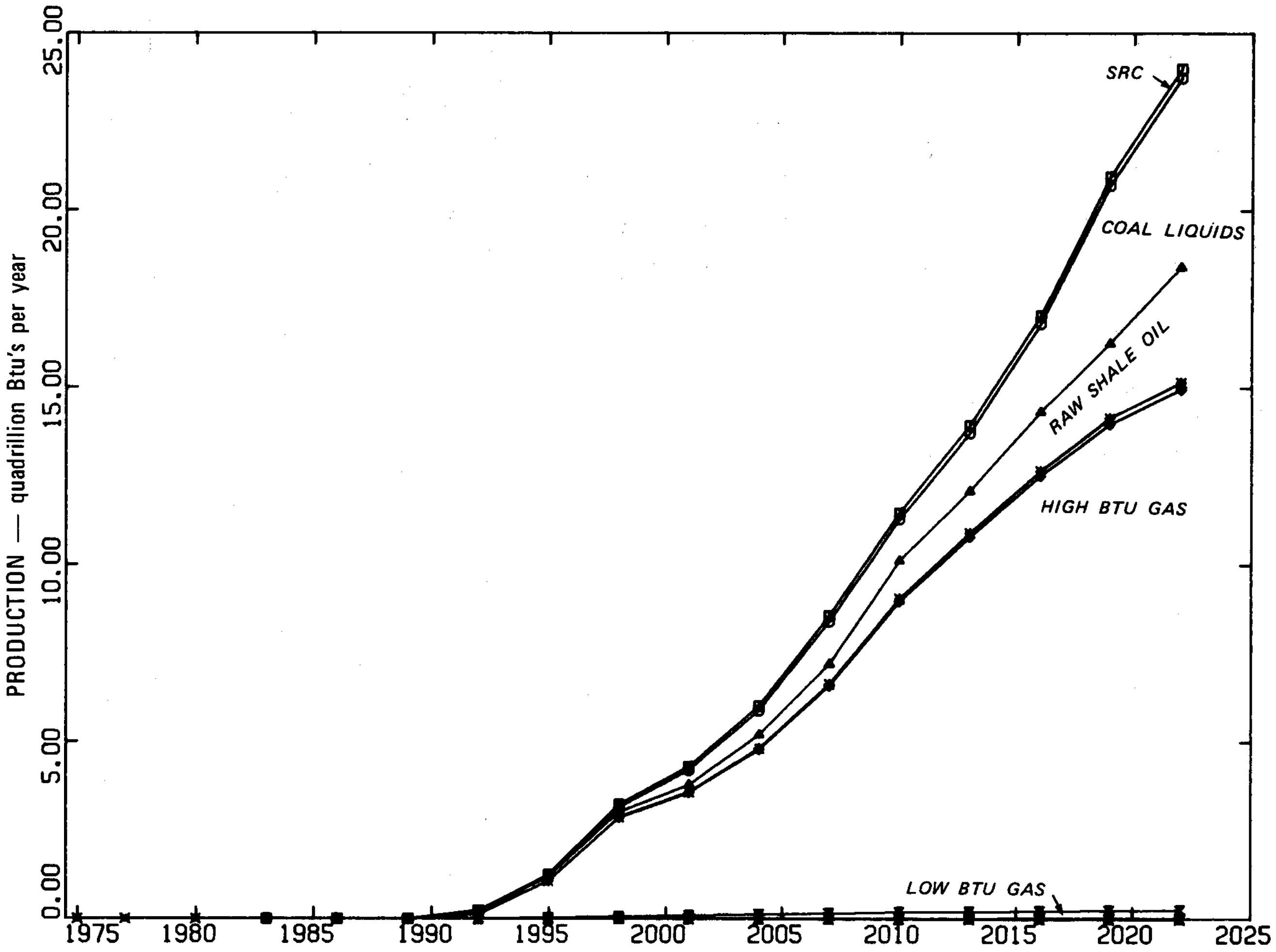

Figure 3-8. Synthetic Fuels--Low-Demand Case

are consistent with an extremely high projection of per capita GNP. In the low-demand case, total synthetic fuel production is only 4.3 quadrillion Btu/yr in the year 2001.

Figures 3-9 and 3-10 give the prices of selected synthetic fuels by location. These compare with Figure 2-5. In the high-demand case, the synthetic fuels prices are higher than in the base case because of the penalty paid for the more rapid growth. This is best illustrated by the price plot for second generation high-Btu gas from coal in the Great Plains region shown in Table 3-9.

Table 3-9

PRICES OF GREAT PLAINS SNG--HIGH-DEMAND CASE

(1975 Dollars/MMBtu)

	2001	2010	2022
Base Case	$2.46	$2.29	$2.31
High-Demand Case	2.58	2.49	2.51
Differential	+4.9%	+8.7%	+8.7%

One of the reasons these prices are not further apart is that the discount rates used to calculate SNG prices used in both the base case and the high-demand case are lower than many used in the literature. As a result, this model is less sensitive to capital costs and more sensitive to operating and coal costs than model runs using different time preference assumptions. This insensitivity to capital cost implies that the model is less sensitive to market "inertia" (resistance to change), which tends to be capital cost-driven.

To illustrate how the penalty for rapid growth is lower in the low-demand case, we have tabulated the prices of SNG produced in the base case and the low-demand case in Table 3-10.

The table illustrates that by significantly reducing demand, the price of SNG is reduced by only about 10 percent or less. This indicates that in the base case, the penalty paid for rapid growth is about 10 percent.

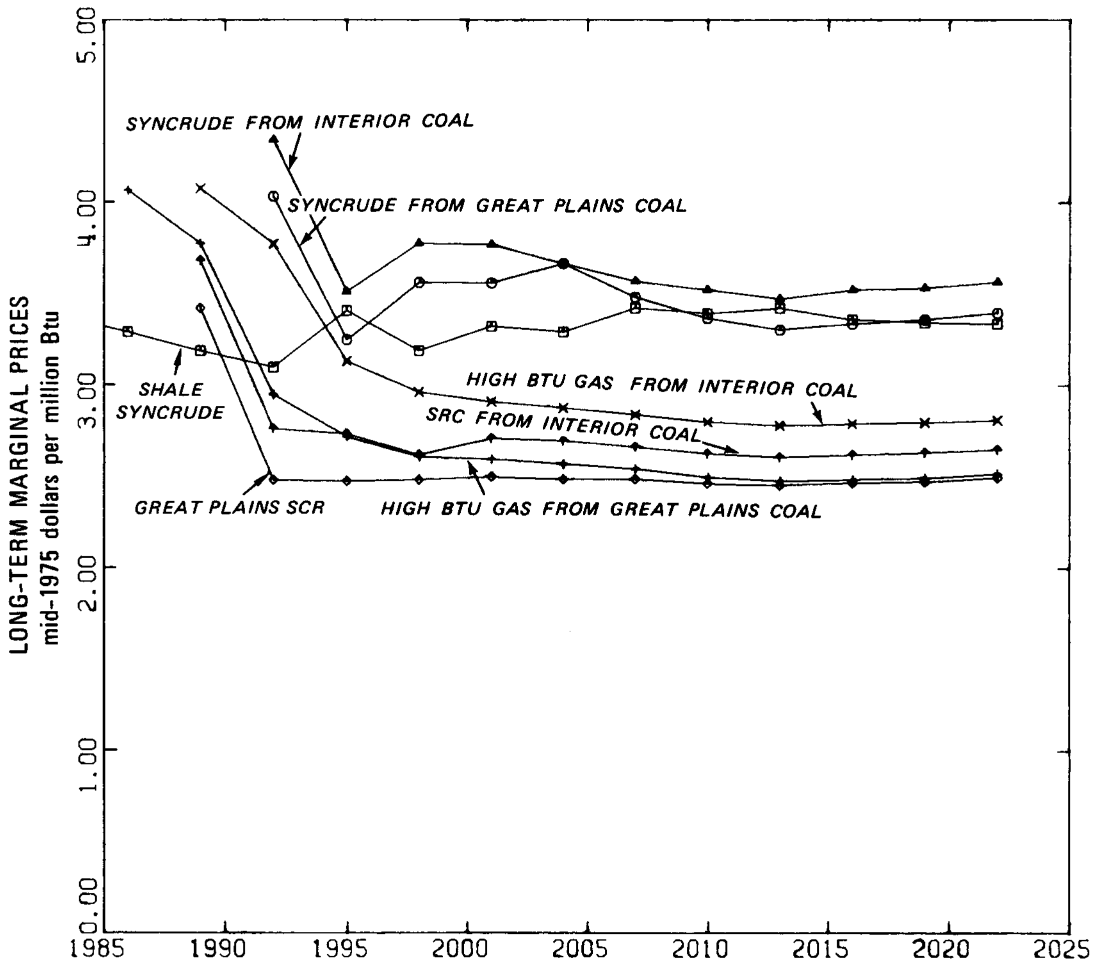

Figure 3-9. Prices of Selected Synthetic Fuels by Location--High-Demand Case

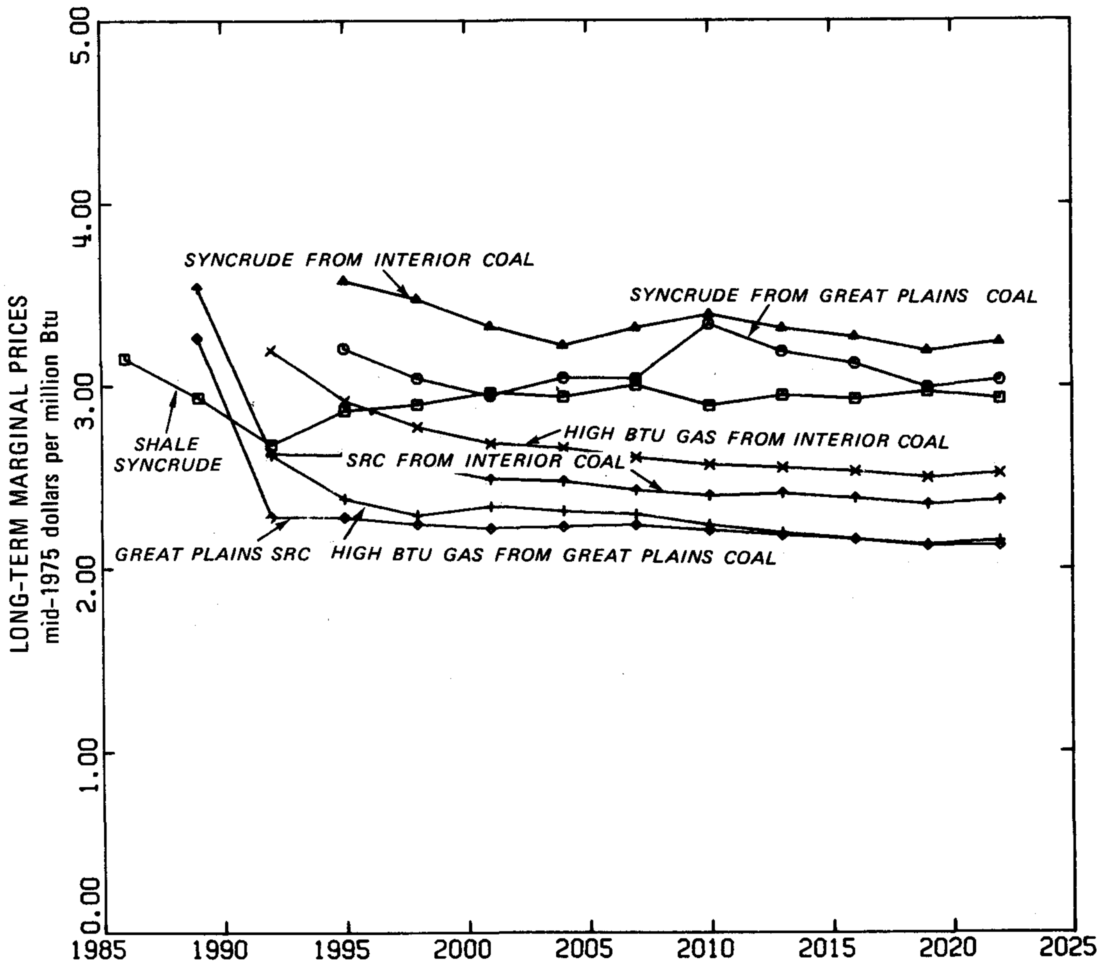

Figure 3-10. Prices of Selected Synthetic Fuels by Location--Low-Demand Case

Table 3-10

PRICES OF GREAT PLAINS SNG--LOW-DEMAND CASE

(1975 Dollars/MMBtu)

	2001	2010	2022
Base Case	$2.46	$2.29	$2.31
Low-Demand Case	2.32	2.23	2.15
Decrease	-5.7%	-2.6%	-12.6%

ELECTRIC POWER GENERATION

Growth in Electric Power Generation

Figures 3-11 and 3-12 and Tables 3-11 and 3-12 illustrate the growth in electric power generation. Table 3-13 is useful in comparing electric power growth to the growth of total primary energy and per capita GNP.

In all three cases, electricity grows considerable faster than total primary energy and somewhat faster than per capita GNP. The growth rate of electric power changes as demand changes, but this change is smaller than the corresponding changes in growth rates of total primary energy and per capita GNP. Observe the ratios between the growth rate in electric power and the other two growth rates in the three cases. The ratio is small for the high-demand case (1.5 when compared to total primary energy during 1975 to 2000), and larger in the low-demand case or 1.8.

Interfuel Competition at the End-Use Level

In this section, we will address the question of whether increased or decreased usable energy demand tends to favor one distributed fuel (and hence one end-use conversion process) over another. This discussion depends heavily on the corresponding discussion in Section 2. It will illustrate that the mix of distributed fuel forms (i.e., fuels at the "meter") is relatively insensitive to the level of usable energy demand in the transportation sector, the industrial sector, and the residential/commercial sector.

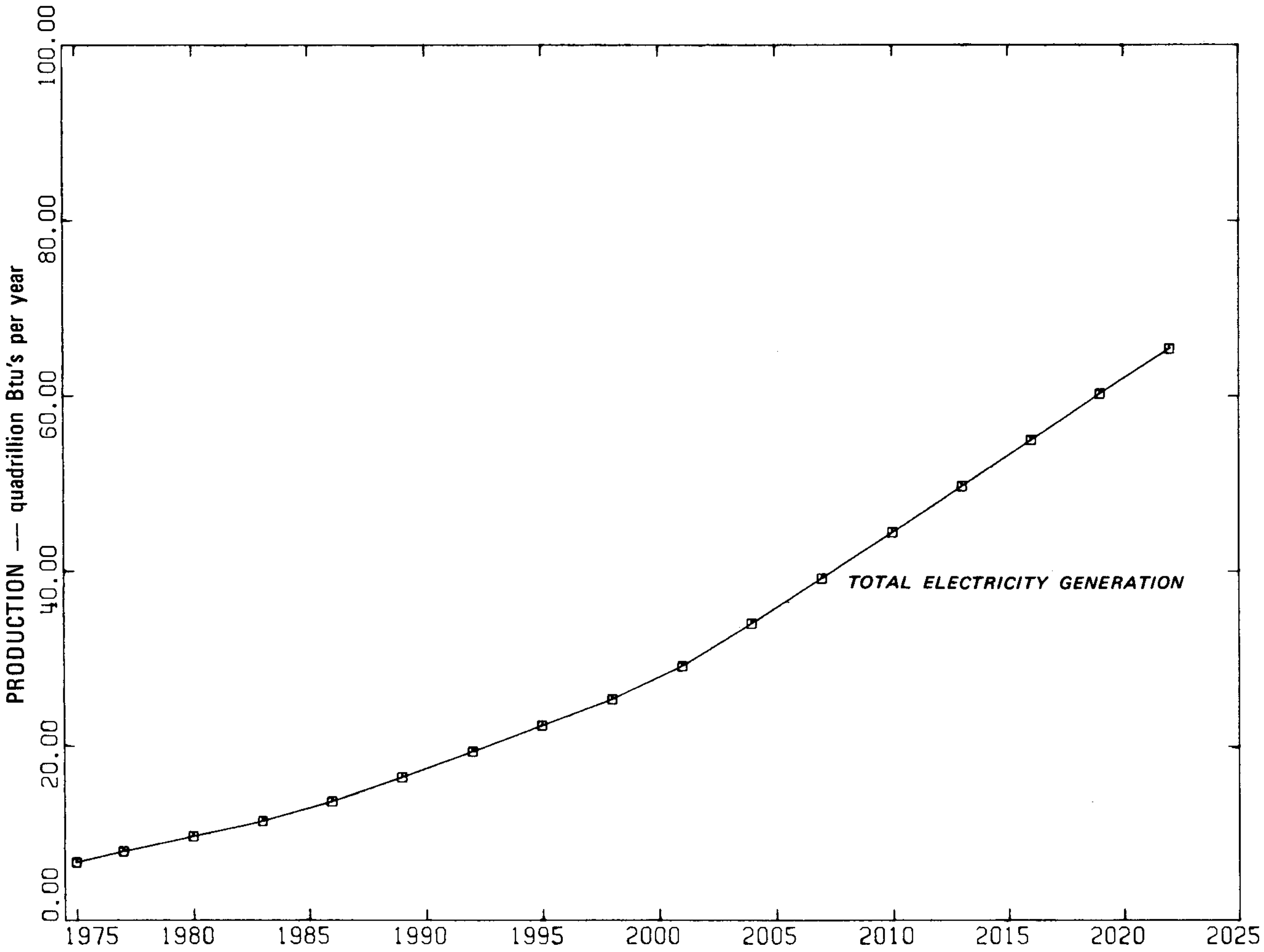

Figure 3-11. Electric Power Generation--High-Demand Case

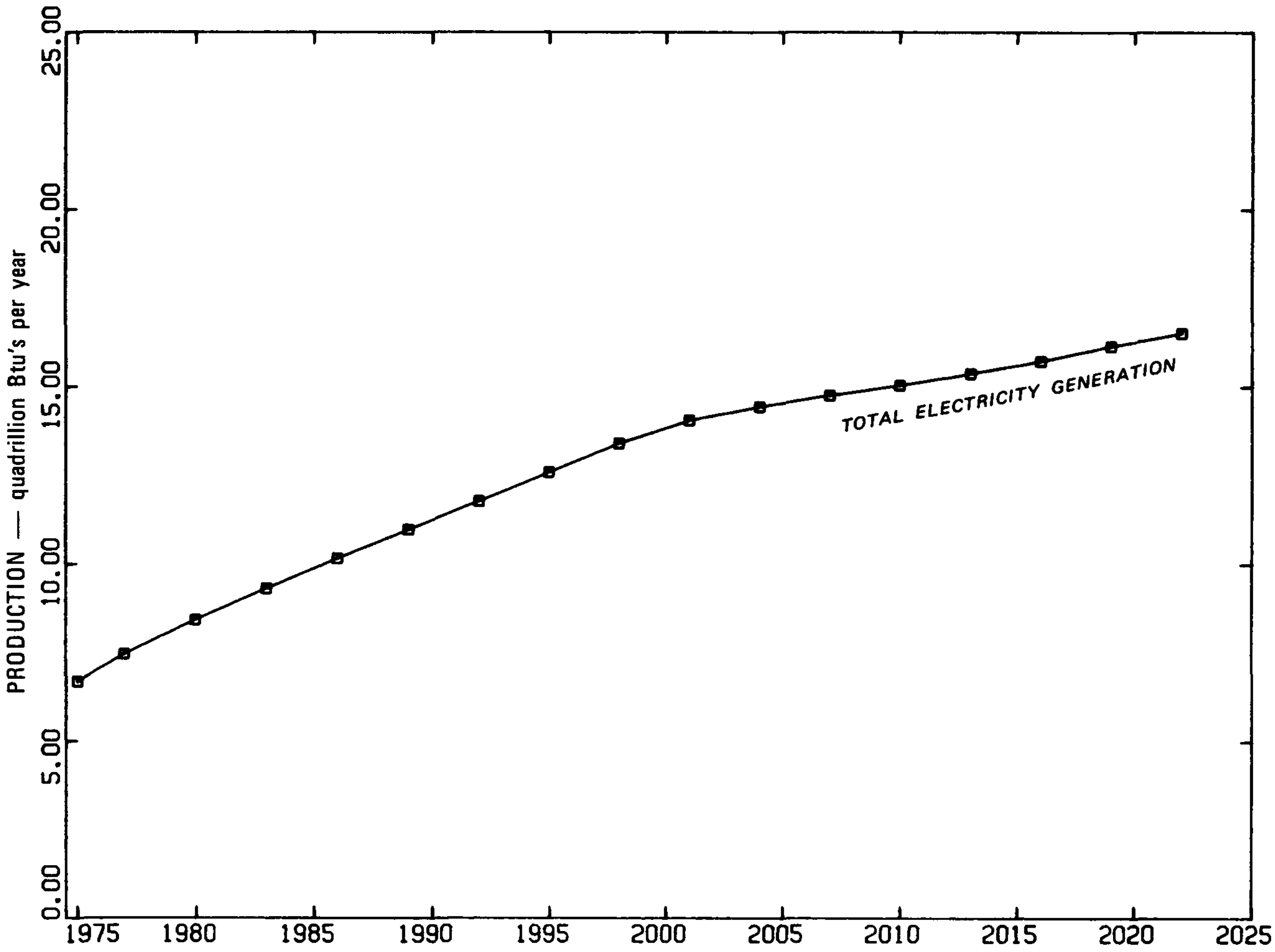

Figure 3-12. Electric Power Generation--Low-Demand Case

Table 3-11

ELECTRIC POWER GENERATION--HIGH-DEMAND CASE

YEAR	QUANTITY		PRICE *	
	(QUADRILLION BTU)	(TRILLION KWH)	($/MMBTU)	(¢/KWH)
1975	6.7	1.96	$7.5	2.54¢
1977	7.9	2.32	8.7	2.97
1980	9.7	2.84	7.6	2.60
1983	11.4	3.35	7.7	2.64
1986	13.7	4.00	7.8	2.66
1989	16.5	4.82	7.8	2.67
1992	19.4	5.67	7.8	2.67
1995	22.4	6.56	7.6	2.60
1998	25.4	7.44	7.7	2.62
2001	29.2	8.56	7.6	2.58
2004	34.1	9.98	7.6	2.59
2007	39.2	11.48	7.4	2.53
2010	44.5	13.02	7.2	2.45
2013	49.7	14.57	7.0	2.40
2016	55.0	16.12	6.9	2.37
2019	60.3	17.65	6.8	2.32
2022	65.4	19.17	6.9	2.34

* Long-term marginal, mid-1975 dollars

In the transportation sector, Figures 3-13 and 3-14 depict the mix of delivered fuels. These figures can be compared to Figure 2-8. Note that the long-run market shares of each of the fuels is roughly the same in all three cases although the level of transportation fuel demand is quite different. This phenomenon depends strongly on the assumption that transportation sector economics are the same in all three cases. This assumption should be reviewed; if changed, major changes in the transportation fuel mix could occur. The figures indicate, however, that electricity is not economical as a transportation fuel under the assumptions outlined in Volume II no matter what the demand. Figures 3-15 and 3-16 illustrate the corresponding prices of transportation sector fuels in the high- and low-demand cases, which are comparable to Figure 2-9 in the base case. Note that the relative fuel prices are largely unaffected by demand and hence one would not expect market shares to change.

Table 3-12

ELECTRIC POWER GENERATION--LOW-DEMAND CASE

YEAR	QUANTITY		PRICE *	
	(QUADRILLION BTU)	(TRILLION KWH)	($/MMBTU)	(¢/KWH)
1975	6.7	1.96	$8.4	2.87¢
1977	7.5	2.19	7.9	2.70
1980	8.4	2.47	7.2	2.47
1983	9.3	2.73	7.3	2.50
1986	10.2	2.98	7.3	2.49
1989	11.0	3.22	7.2	2.44
1992	11.8	3.45	7.1	2.43
1995	12.6	3.69	7.0	2.40
1998	13.4	3.93	7.1	2.42
2001	14.1	4.12	6.8	2.32
2004	14.5	4.23	6.7	2.30
2007	14.8	4.33	6.7	2.28
2010	15.1	4.41	6.6	2.26
2013	15.4	4.51	6.4	2.19
2016	15.7	4.61	6.3	2.16
2019	16.1	4.73	6.1	2.09
2022	16.5	4.84	6.1	2.09

* Long-term marginal, mid-1975 dollars

The industrial sector fuel mix is quite similar in all three demand cases. Figures 3-17 and 3-18 illustrate the distributed industrial fuels measured at the plant gate. These figures can be compared with Figure 2-10 of the base case. Although the total level of industrial demand varies substantially between cases, the mix of industrial fuels varies much less.

Just as in the base case, the demand for electricity in the industrial sector emanates almost entirely from captive-electric uses (e.g., electromechanical applications, electrolysis, lighting). Electricity is noncompetitive with liquid and gaseous fuels in industrial direct and indirect heating applications in all three demand cases under base case economic assumptions. The reader is referred to Section 2 for a discussion of the caveats to this assertion. Since the high-case assumes a higher demand for captive-electric uses than the base case, the

Table 3-13

ELECTRIC POWER GROWTH--THREE CASES

(a) High-Demand Case

	1975-1985	1985-2000	1975-2000
Electric Power Generation	6.5%	5.4%	5.8%
Total Primary Energy	3.6	3.9	3.8
Per Capita GNP (1975 $)	4.8	3.5	4.0

(b) Base Case

	1975-1985	1985-2000	1975-2000
Electric Power Generation	5.3%	3.8%	4.3%
Total Primary Energy	2.9	2.5	2.6
Per Capita GNP (1975 $)	3.7	2.1	2.7

(c) Low-Demand Case

	1975-1985	1985-2000	1975-2000
Electric Power Generation	3.8%	2.3%	2.9%
Total Primary Energy	2.0	1.4	1.6
Per Capita GNP (1975 $)	2.3	0.9	1.5

amount of industrial electricity consumed in the high-demand case is correspondingly higher. To more accurately specify captive electricity demand requires a more detailed analysis to understand how the demand for industrial products determines the industrial demand for the various energy forms and a more detailed "interindustry" model than exists in the SRI National Energy Model.

The prices for the various industrial fuels appear in Figures 3-19 and 3-20. They should be compared to Figure 2-11 in the base case. In all three figures, note the characteristic pattern that prices increase in the first 25 years or so and then flatten as the energy market moves to coal, nuclear, and shale.

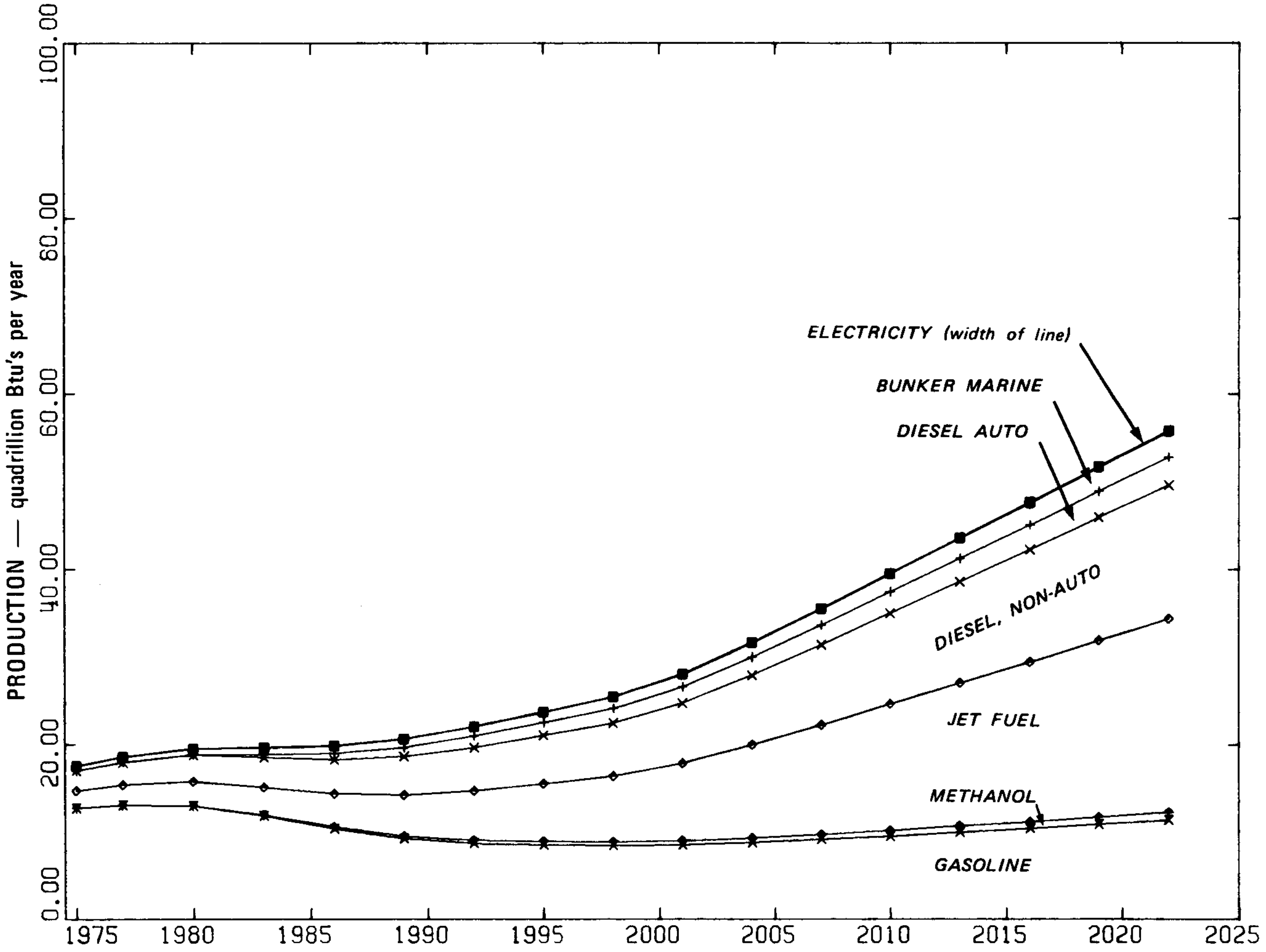

Figure 3-13. Distributed Products in the Transportation Sector--High-Demand Case

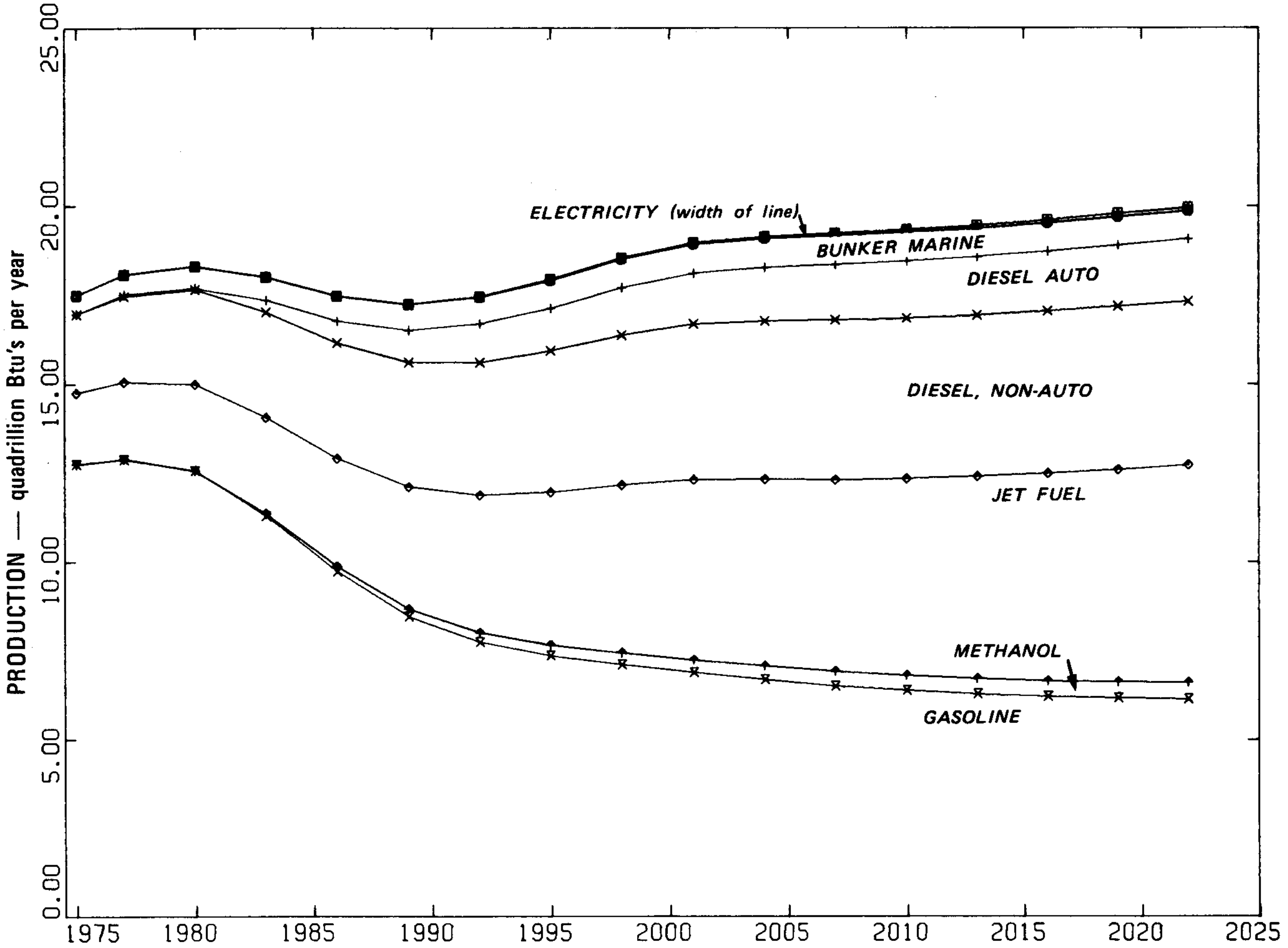

Figure 3-14. Distributed Products in the Transportation Sector--Low-Demand Case

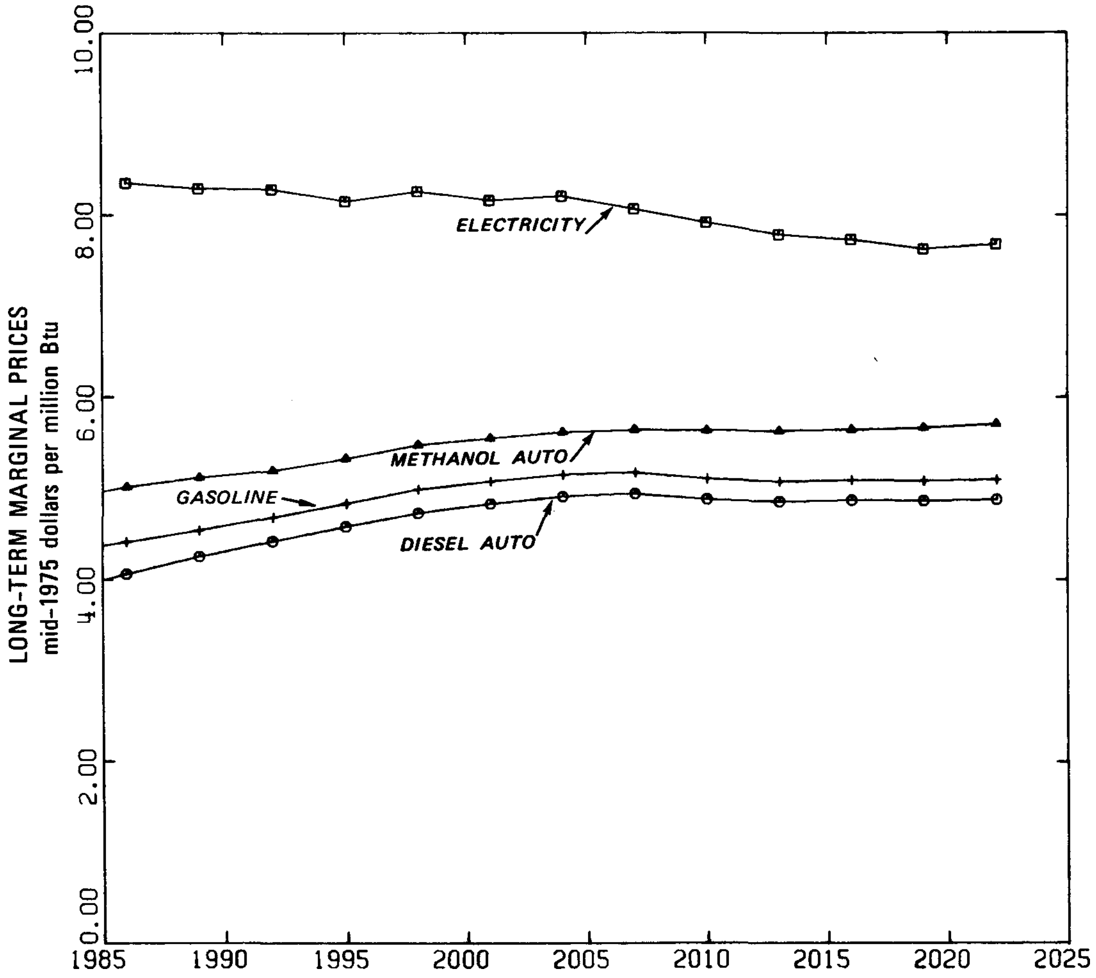

Figure 3-15. Average Prices of Distributed Products Used in the Transportation Sector--High-Demand Case

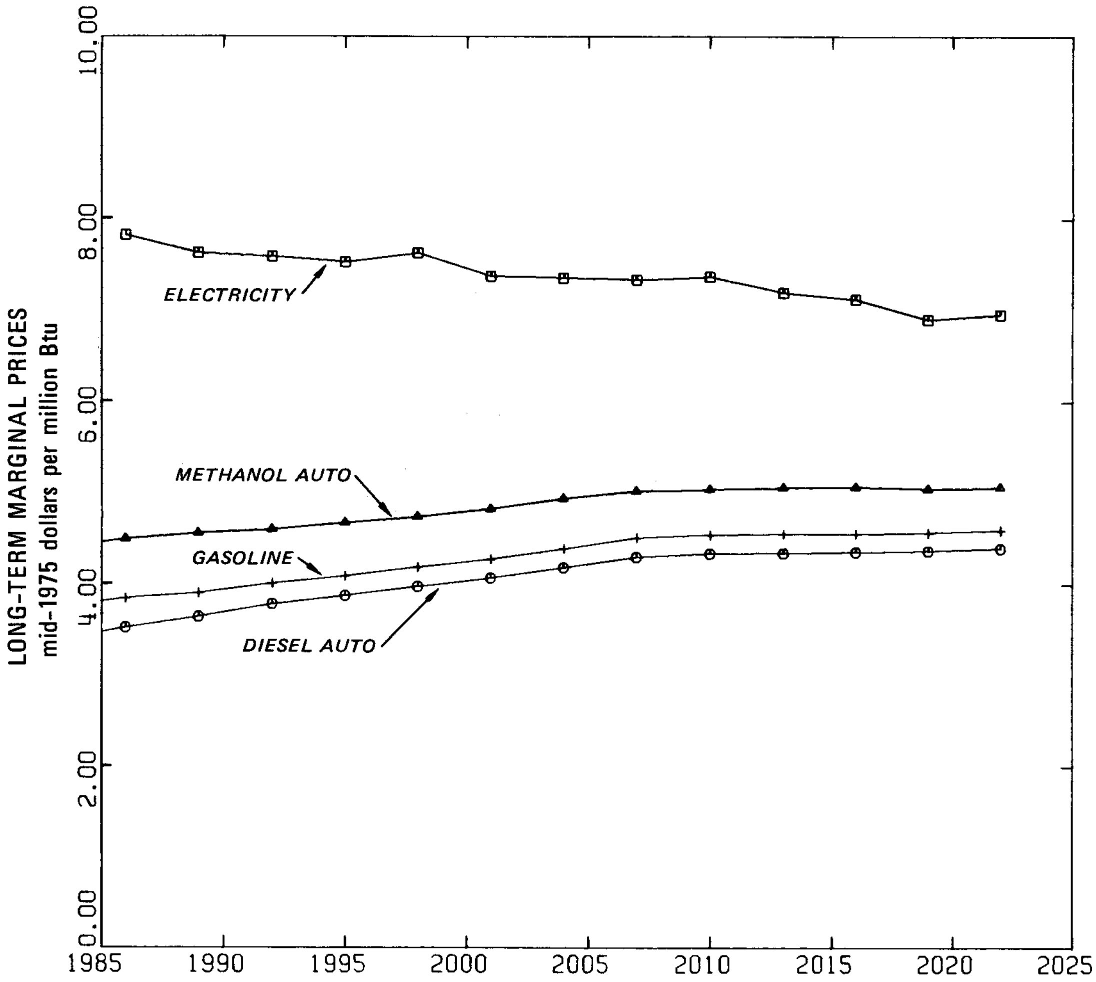

Figure 3-16. Average Prices of Distributed Products Used in the Transportation Sector--Low-Demand Case

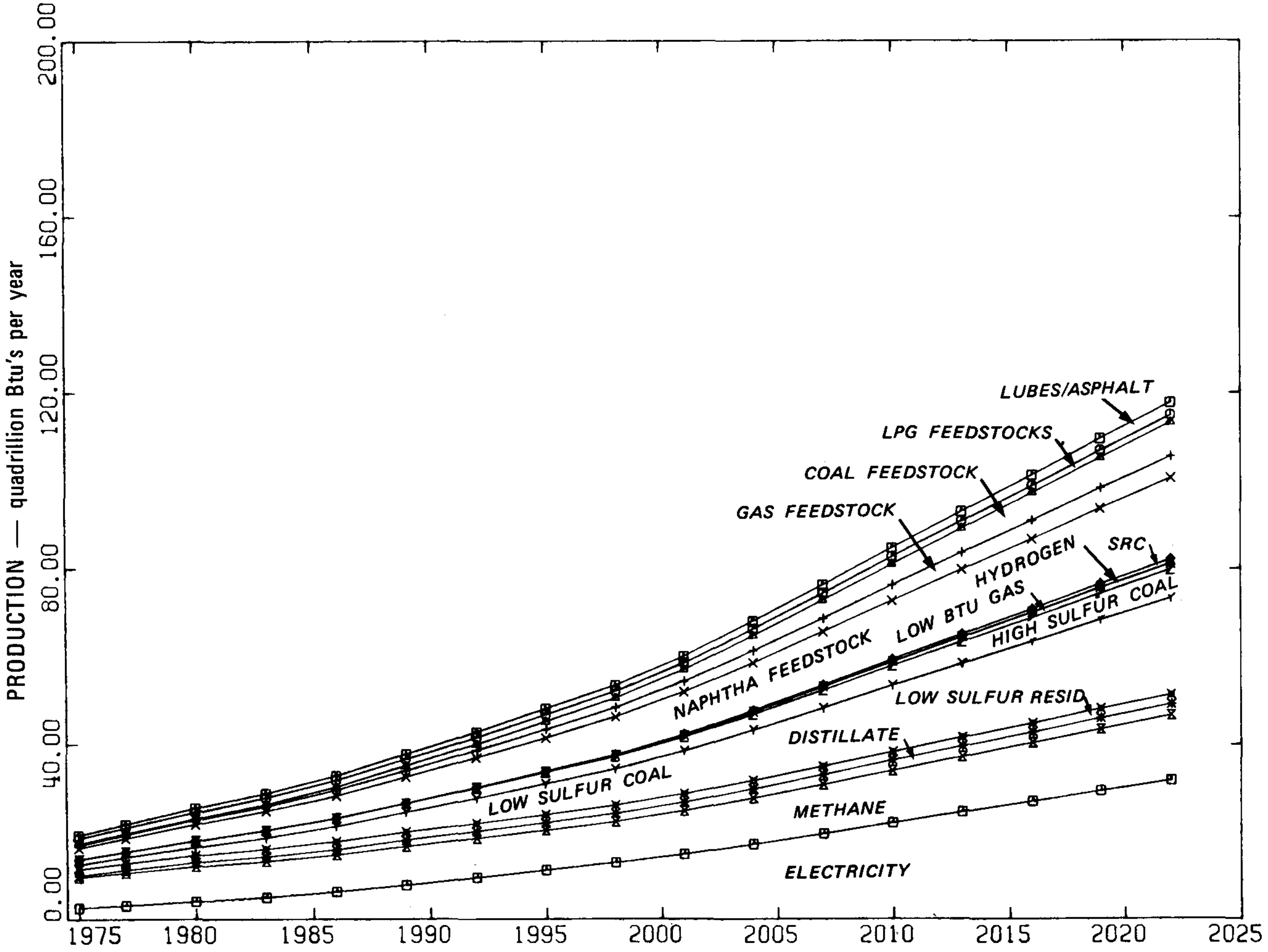

Figure 3-17. Distributed Products in the Industrial Sector--High-Demand Case

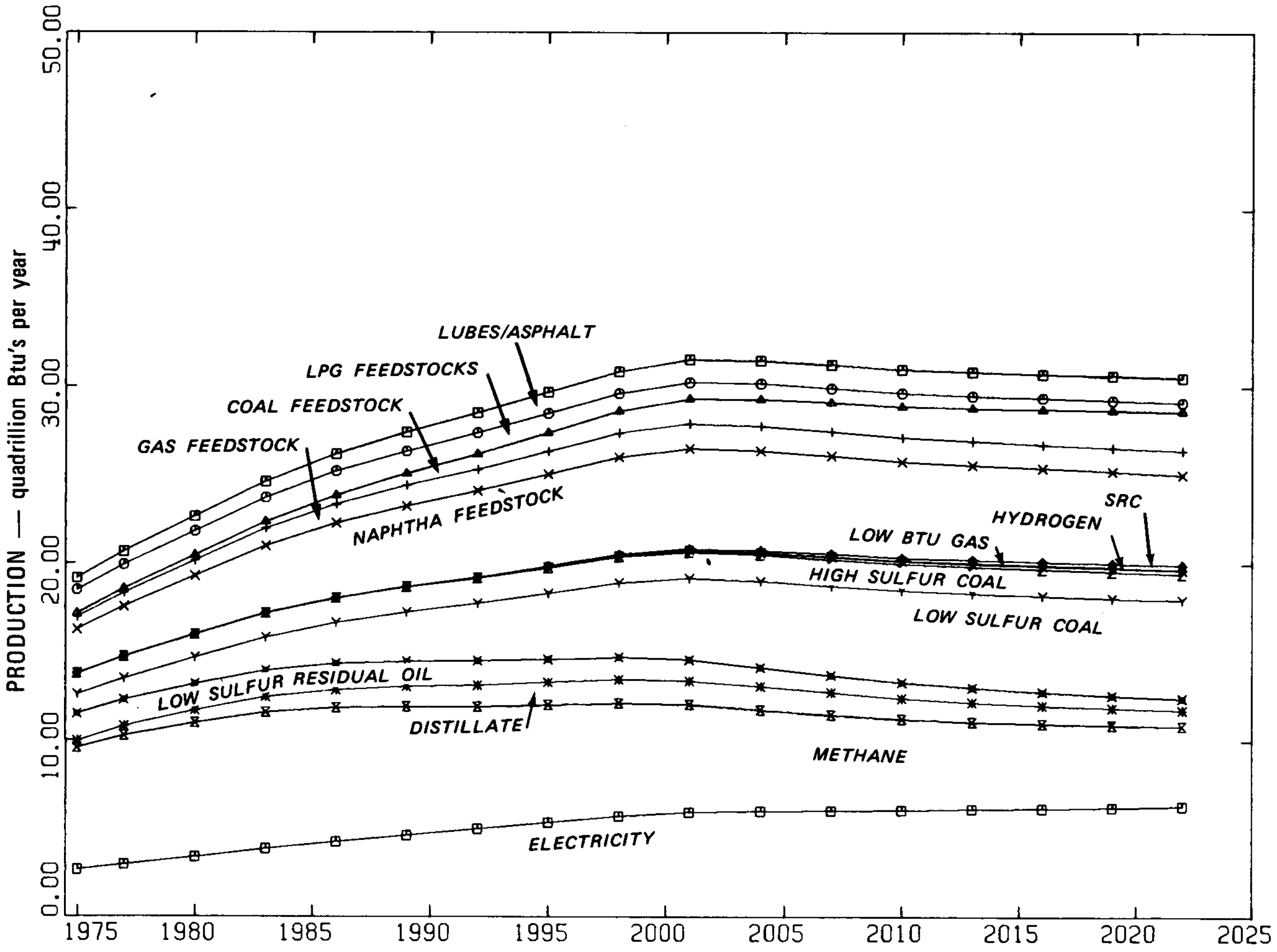

Figure 3-18. Distributed Products in the Industrial Sector--Low-Demand Case

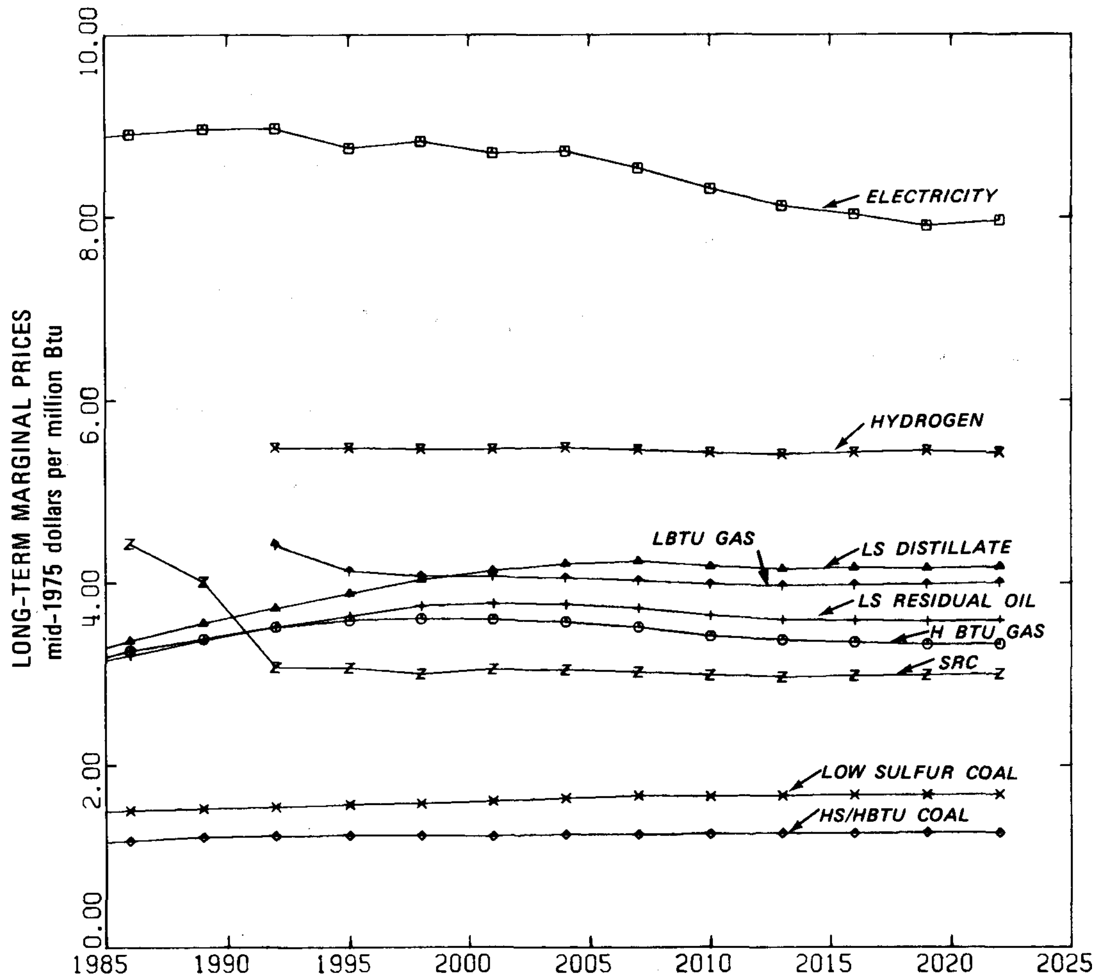

Figure 3-19. Average Prices of Distributed Products Used in the Industrial Sector--High-Demand Case

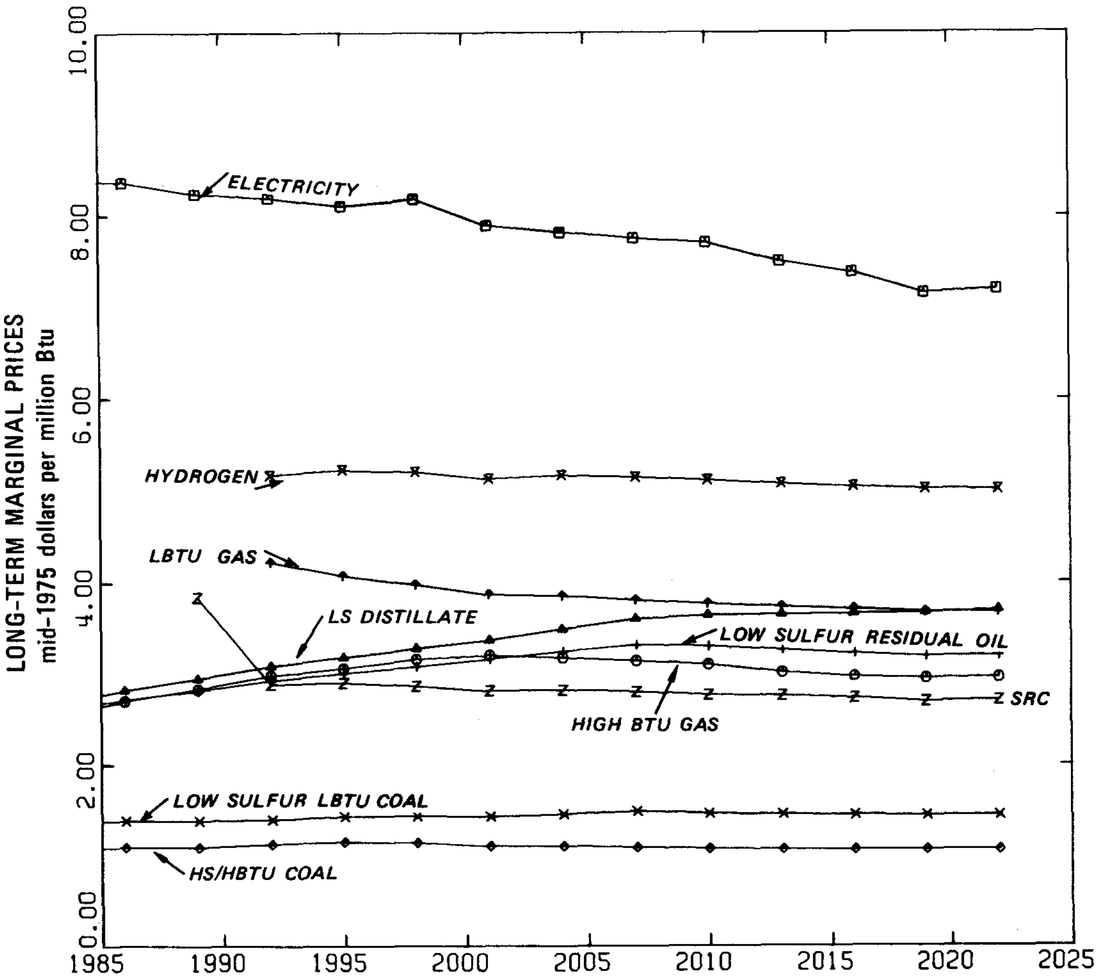

Figure 3-20. Average Prices of Distributed Products Used in the Industrial Sector--Low-Demand Case

In the residential/commercial (R/C) sector, market shares of the various distributed fuels are similar for the high-demand, low-demand, and base cases as shown in Figures 3-21, 3-22, and 2-12, respectively. However, there is one subtle difference in the residential/commercial sector that should be highlighted. In the base case (Figure 2-12), the level of liquid plus gaseous fuel consumption remains constant and all growth is electric. In the high-demand case, liquid plus gaseous fuel consumption actually increases over time even though electricity increases considerably more rapidly than in the base case. In the low-demand case, the liquid plus gaseous fuel consumption actually declines slightly over time. Thus, the market share of electricity in the R/C sector is sensitive to the level of usable energy demand. The prices of distributed fuels in the R/C sector appear in Figures 3-23 and 3-24 for the sensitivity cases, and can be compared to Figure 2-13 (base case). A comparison reveals that prices are very similar in all these cases.

To summarize, the prices of delivered fuels tend to rise in the near term and become flat over time in the intermediate and long term. Because these prices become flat, the market shares of the various delivered fuels tend to be sensitive to the economics of converting those fuels to usable energy forms, behavioral assumptions reflecting market imperfections, and the prices of those fuels themselves. The market shares are much less sensitive to the level of usable energy demand.

Competition Among Electric Power Technologies

In the previous discussions, technology selection decisions tended to be insensitive to demand, implying similar market shares for primary resources, liquid and gaseous fuels, and end uses. In this section we will show the same general behavior in the electric power sector--the selection among electric generation technologies tends not to be sensitive to the level of demand for electricity under base case assumptions. Base, intermediate, and peak-load power generation will be explored individually.

Base Load Power Generation. The demand for base load power generation by technology appears in Figures 3-25 and 3-26. These compare with Figure 2-14 of the base case. Even though the level of base load power generation is different by a factor of about four between the low- and high-demand cases, similar market shares prevail for each of the electric power generation technologies. In both

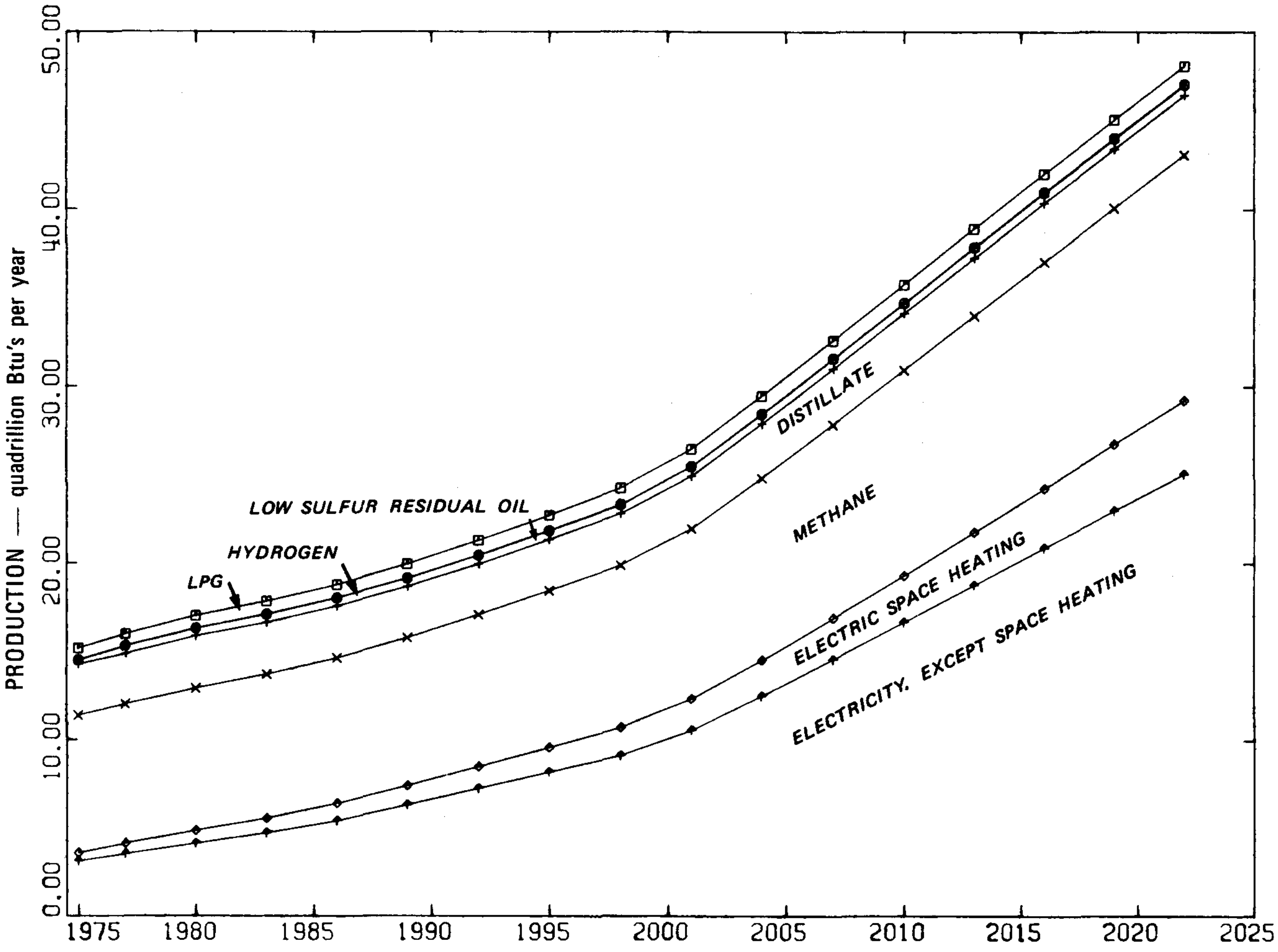

Figure 3-21. Distributed Products in the Residential/Commercial Sector--High-Demand Case

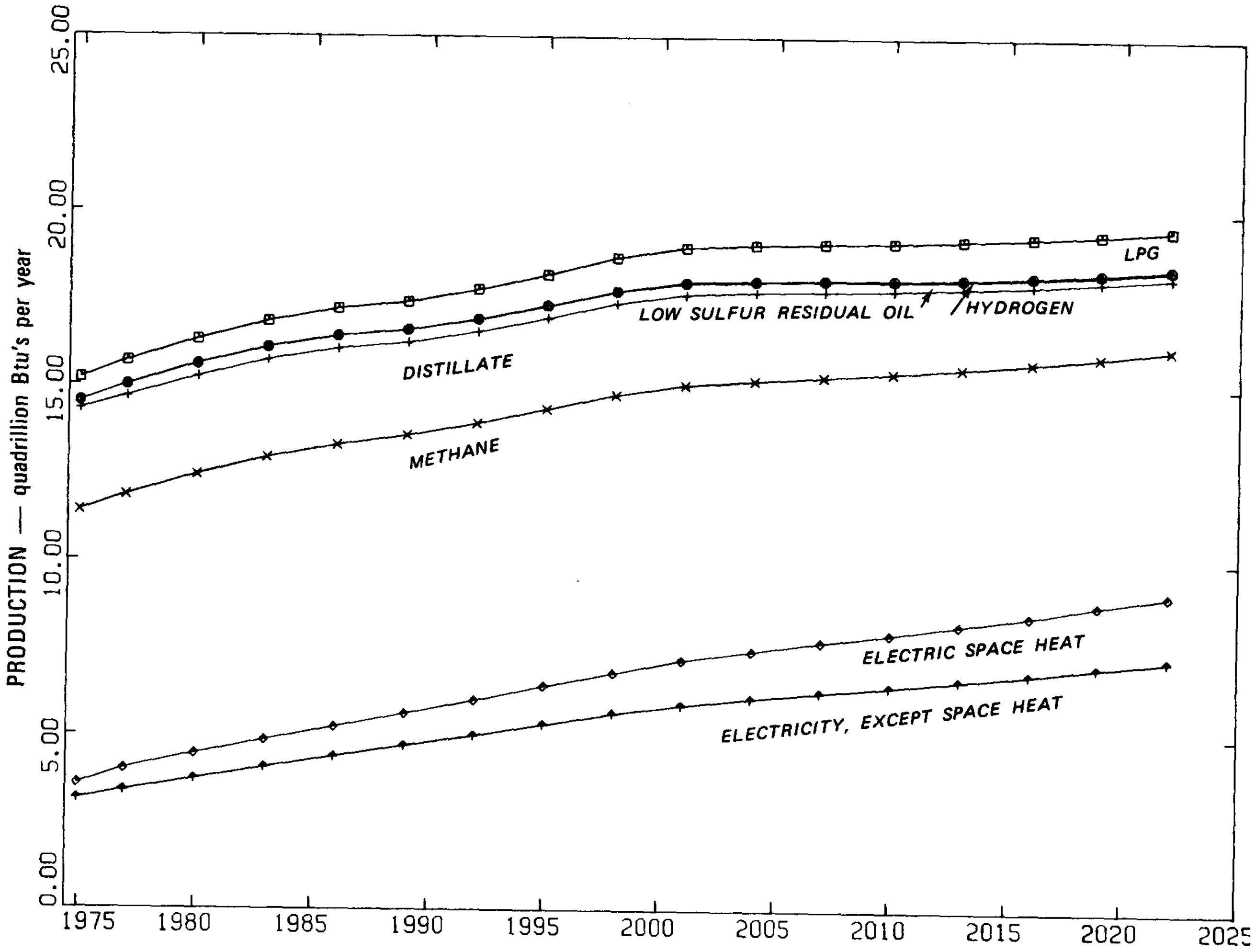

Figure 3-22. Distributed Products in the Residential/Commercial Sector--Low-Demand Case

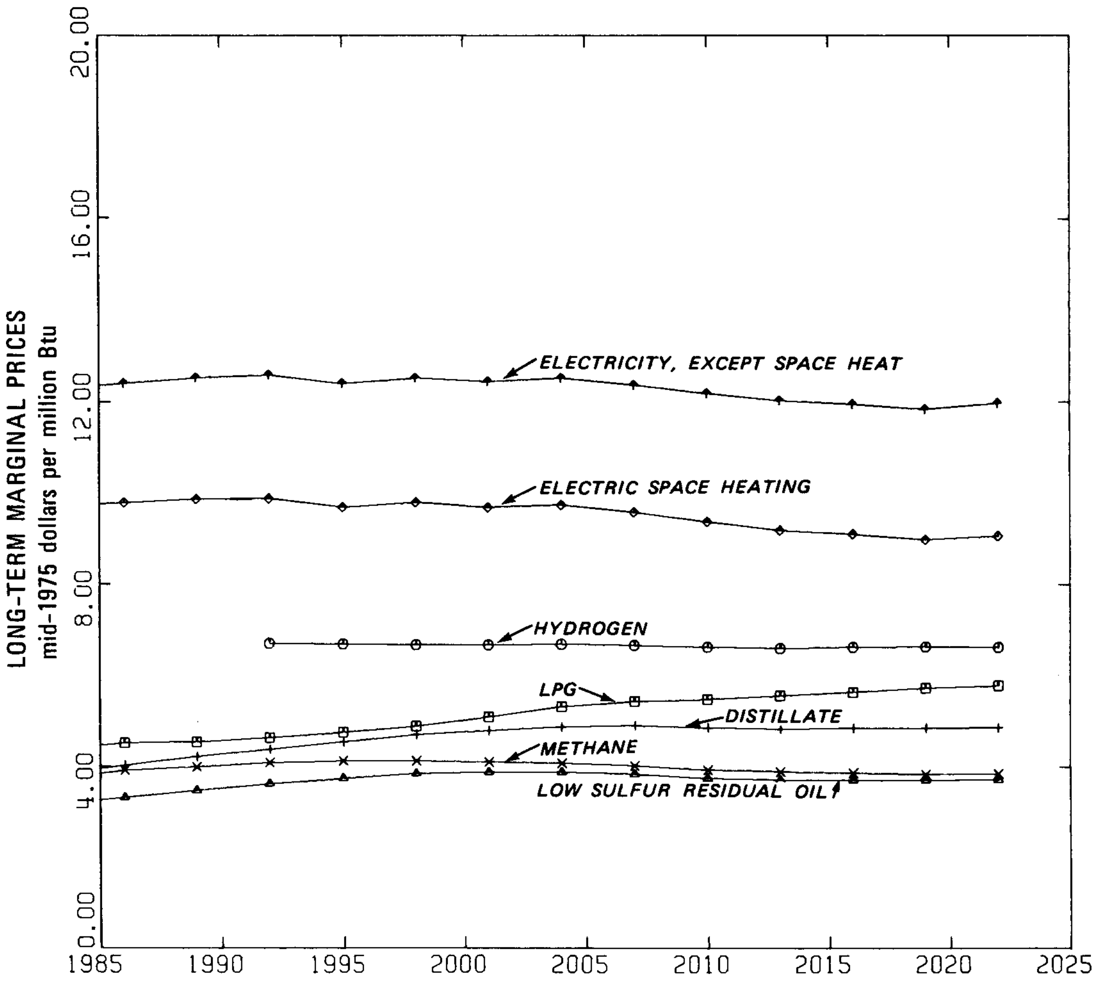

Figure 3-23. Average Prices of Distributed Products Used in the Residential/Commercial Sector--High-Demand Case

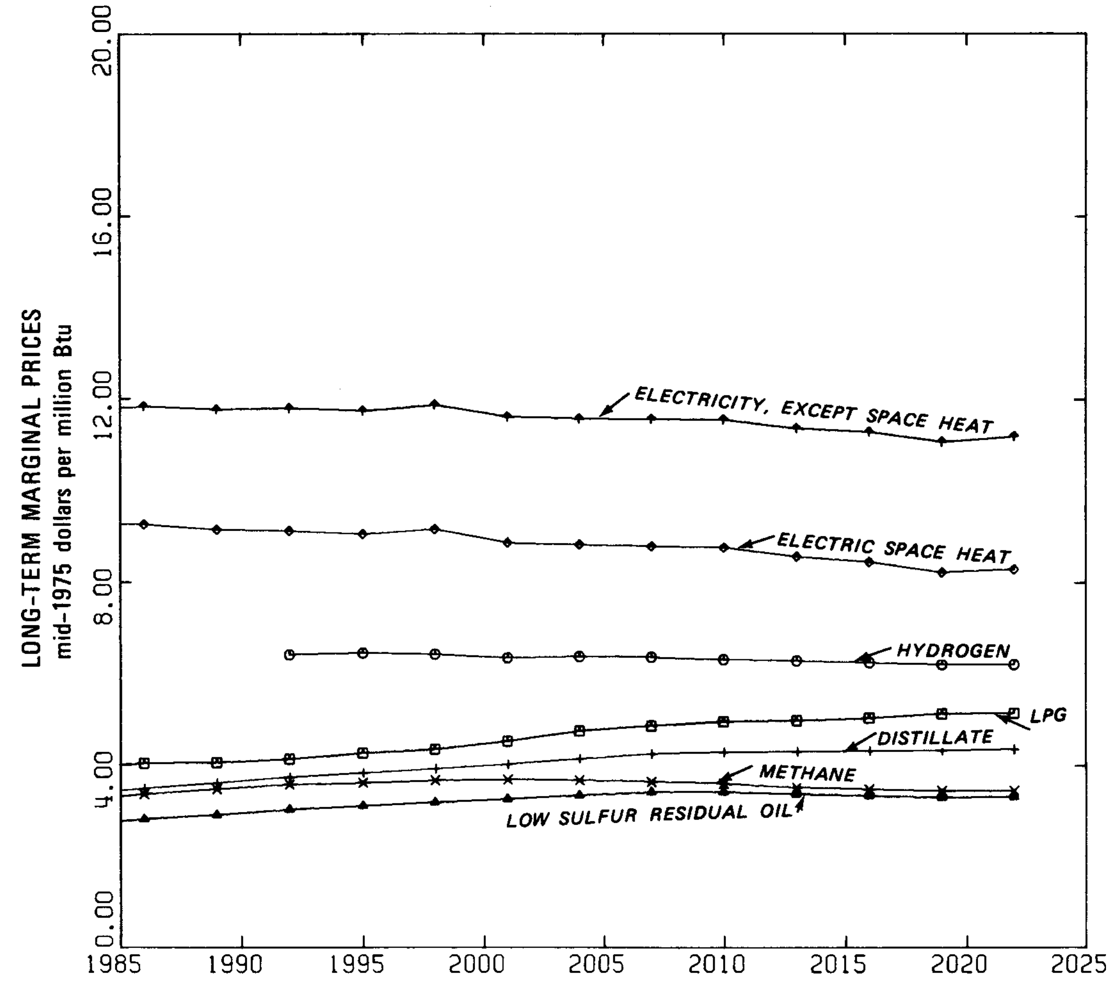

Figure 3-24. Average Prices of Distributed Products Used in the Residential/Commercial Sector--Low-Demand Case

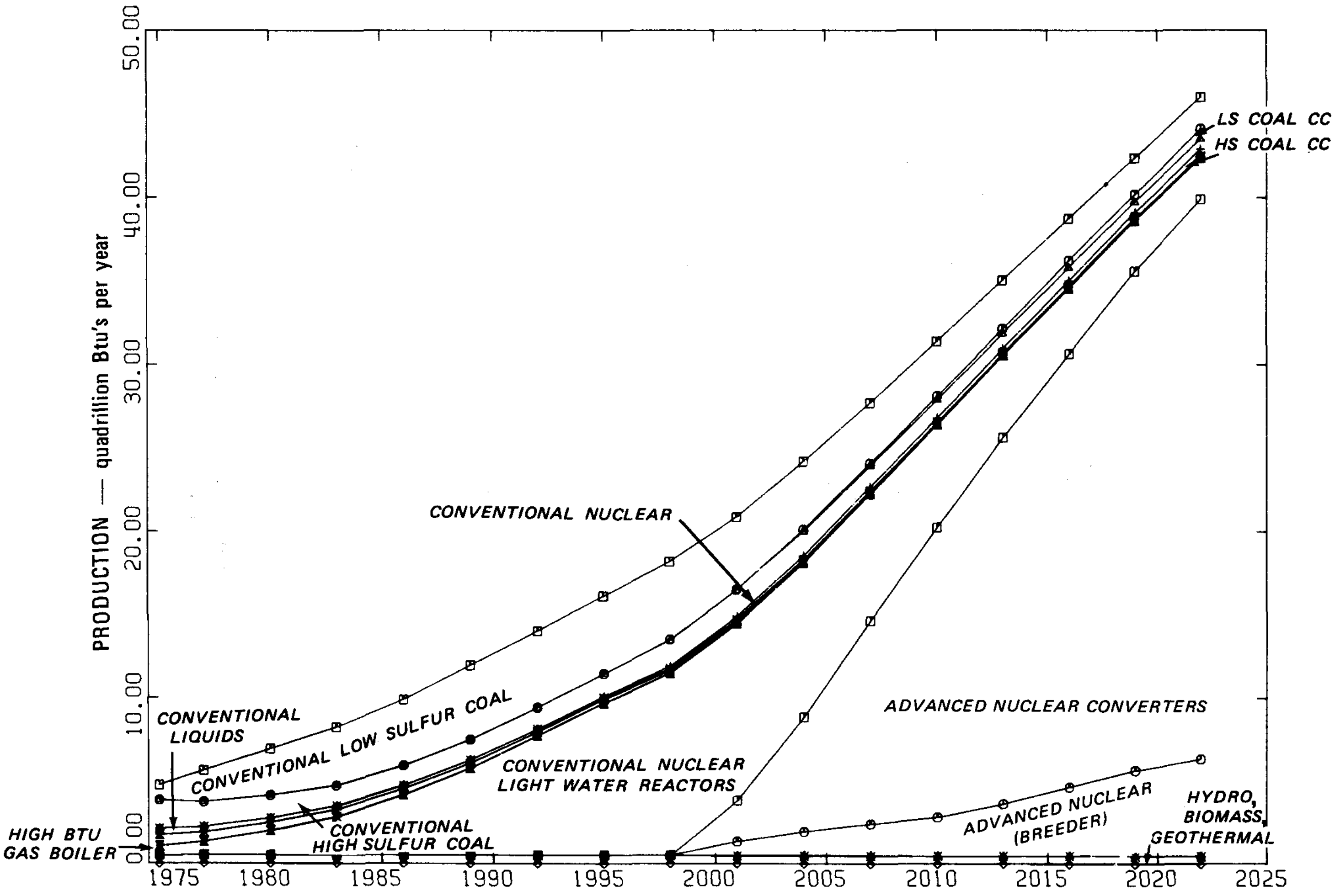

Figure 3-25. Base Load Electric Power Generation--High-Demand Case

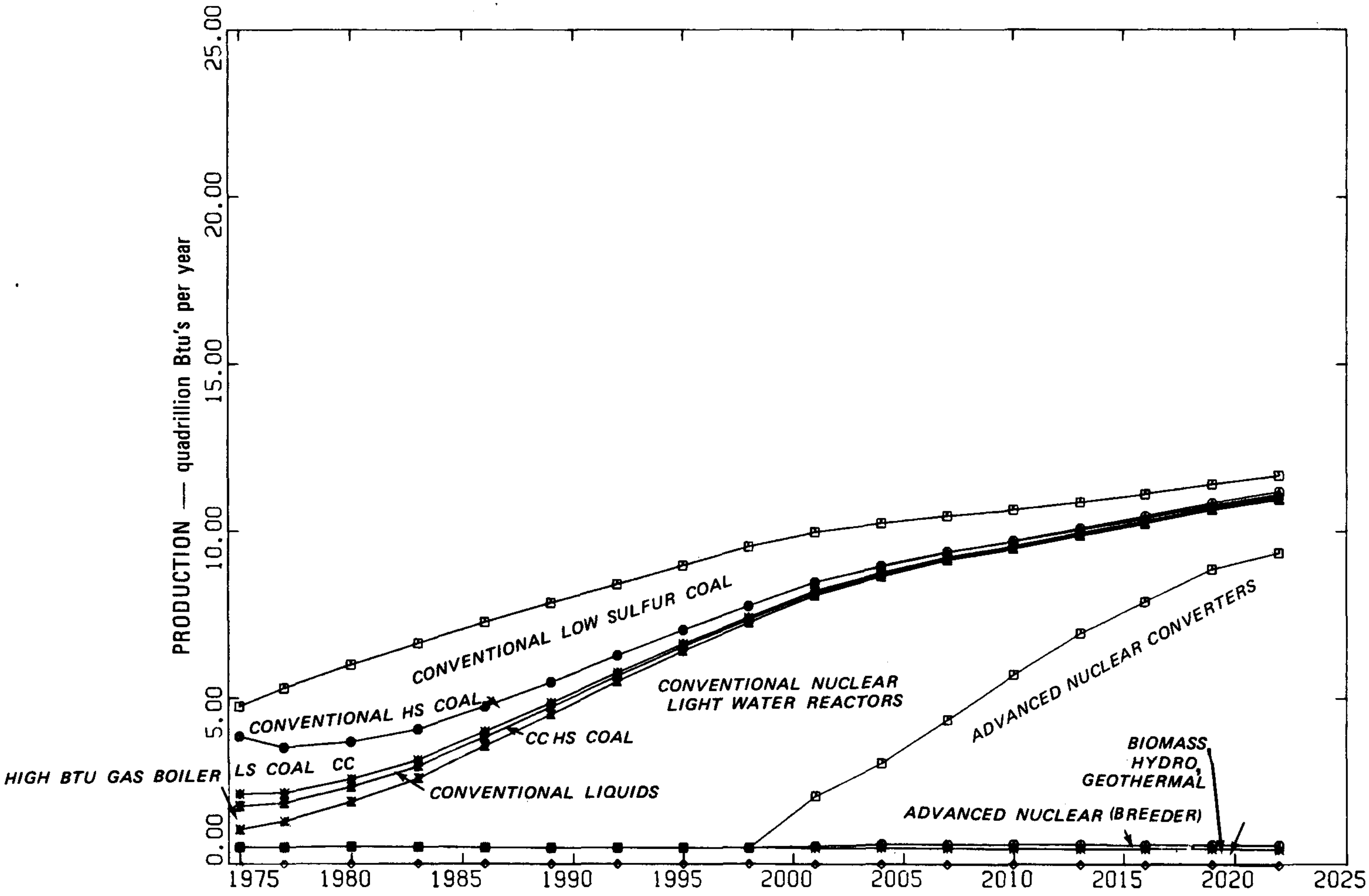

Figure 3-26. Base Load Electric Power Generation--Low-Demand Case

cases, nuclear technologies penetrate the market rapidly until they account for more than 80 percent in the long run. In the low-demand case, however, the advanced converter technology does not compete strongly with conventional nuclear technology as it does in the high-demand case. The reason is that in the high-demand case, nuclear fuel prices are higher and thus the more efficient advanced converter technology is relatively more attractive than in the low-demand case. Nuclear fuel prices are higher in the high-demand case, both because of more rapid depletion of uranium reserves and because of the higher cost of more rapid exploitation of those uranium reserves. Based on these figures, however, one can infer that the competitive position of the technologies that produce base load power is relatively unaffected by demand.

The price of base load power at the busbar in the sensitivity cases follows the pattern shown in the base case Figure 2-15 quite closely. The same phenomenon observed earlier in prices of distributed fuels, namely that price differences between the low and high cases are small, holds true for base load electric power as well. The price plots for the sensitivity cases appear in Figures 3-27 and 3-28. It is interesting to note that high demand, which leads to higher fuel costs and higher construction costs, does not drive technology costs apart to a significant degree.

Intermediate and Peak Load Power Generation. The generation of intermediate load power is illustrated in Figures 3-29, 3-30, and 2-16. Exactly as we have seen for base load power generation, the mix of generation technologies remains relatively constant even though demand is varied over a broad range. The reasons are identical with those discussed in base load power generation above. Intermediate power price plots appear in Figures 3-31 and 3-32 for comparison with Figure 2-17.

Peak load power generation in the high- and low-demand cases appears in Figures 3-33 and 3-34. They compare with Figure 2-18. Peak load power prices appear in Figures 3-35 and 3-36. They compare to Figure 2-19.

Regional Fuel Economics

The prices of various fuels differ among the three cases on the order of 25 percent or less, and all usually vary in the same direction. This results in a constant mix of technologies independent of the level of demand. Since all prices move simultaneously in each region, the regional market shares of each fuel remain relatively constant, independent of demand. The rationale was discussed above.

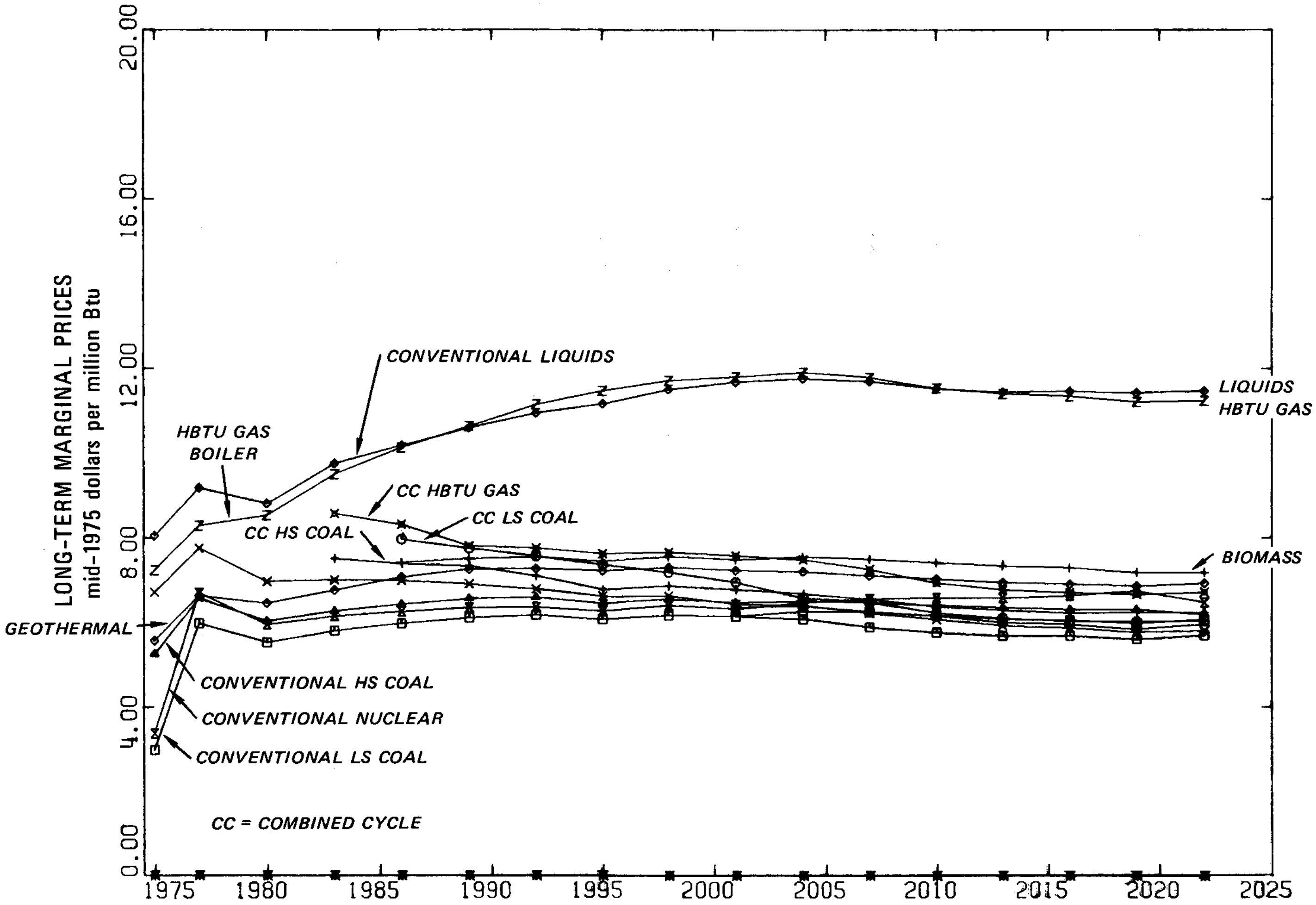

Figure 3-27. Average Marginal Busbar Cost of Base Load Power by Type of Plant--High-Demand Case

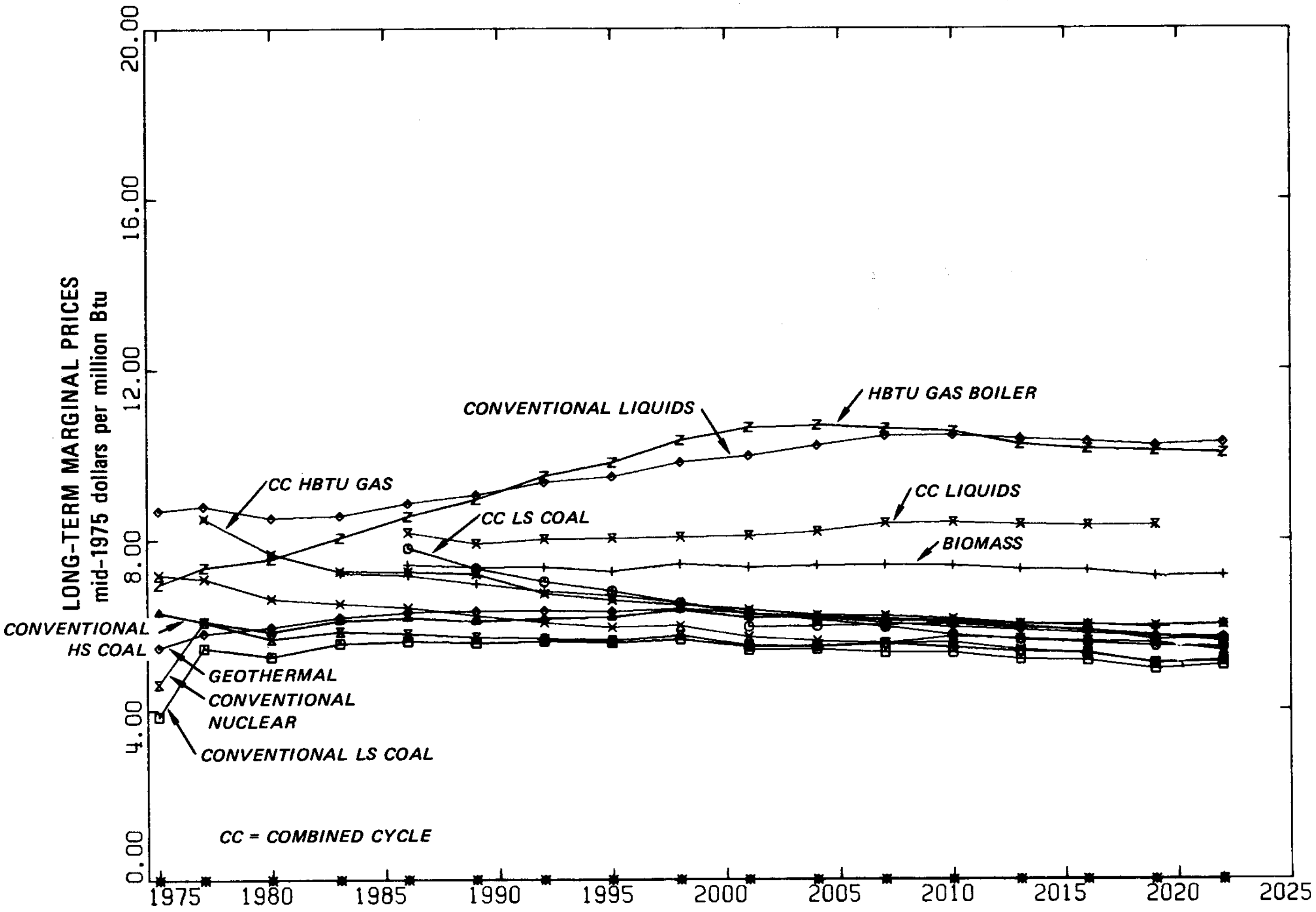

Figure 3-28. Average Marginal Busbar Cost of Base Load Power by Type of Plant--Low-Demand Case

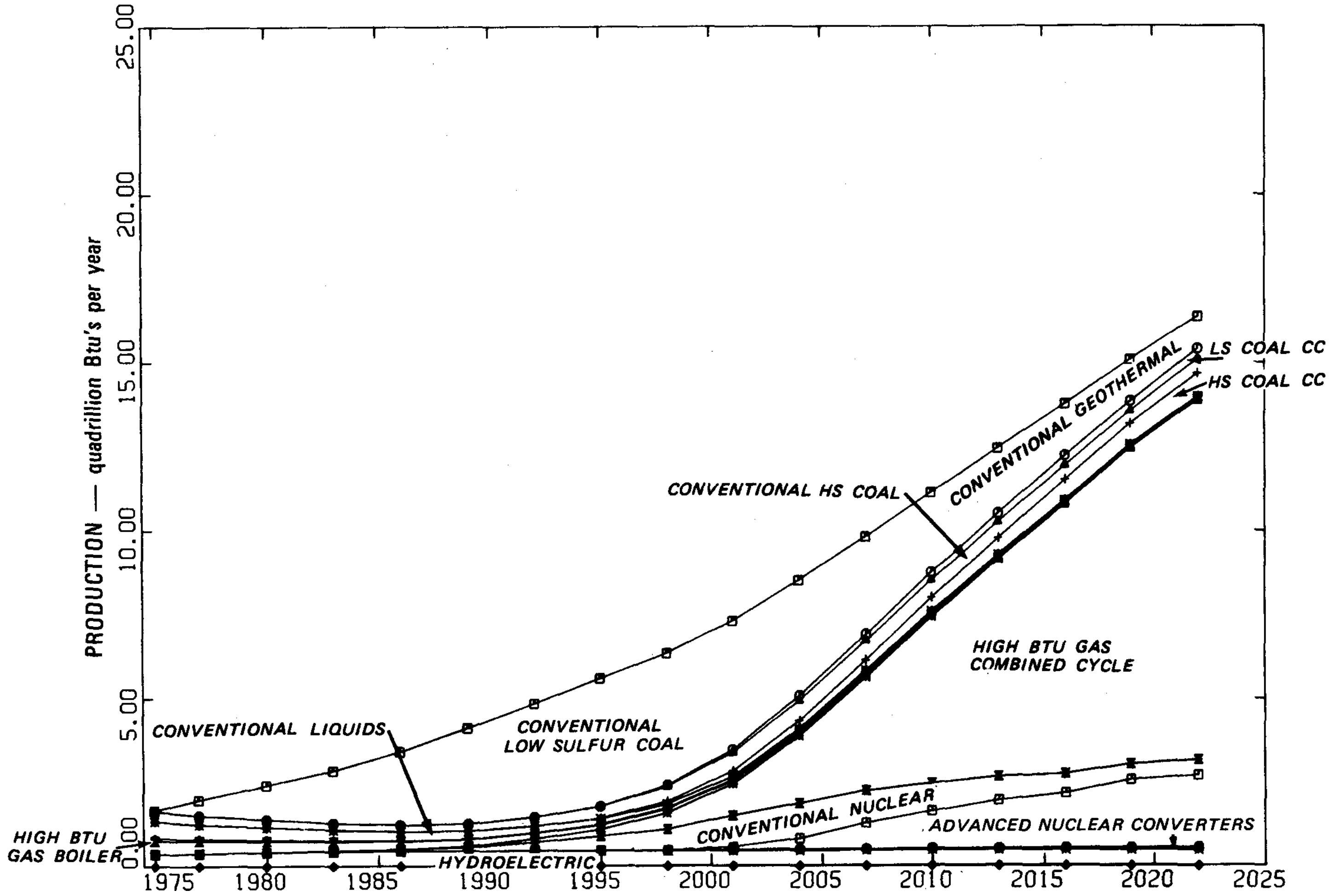

Figure 3-29. Intermediate Load Electric Power Generation--High-Demand Case

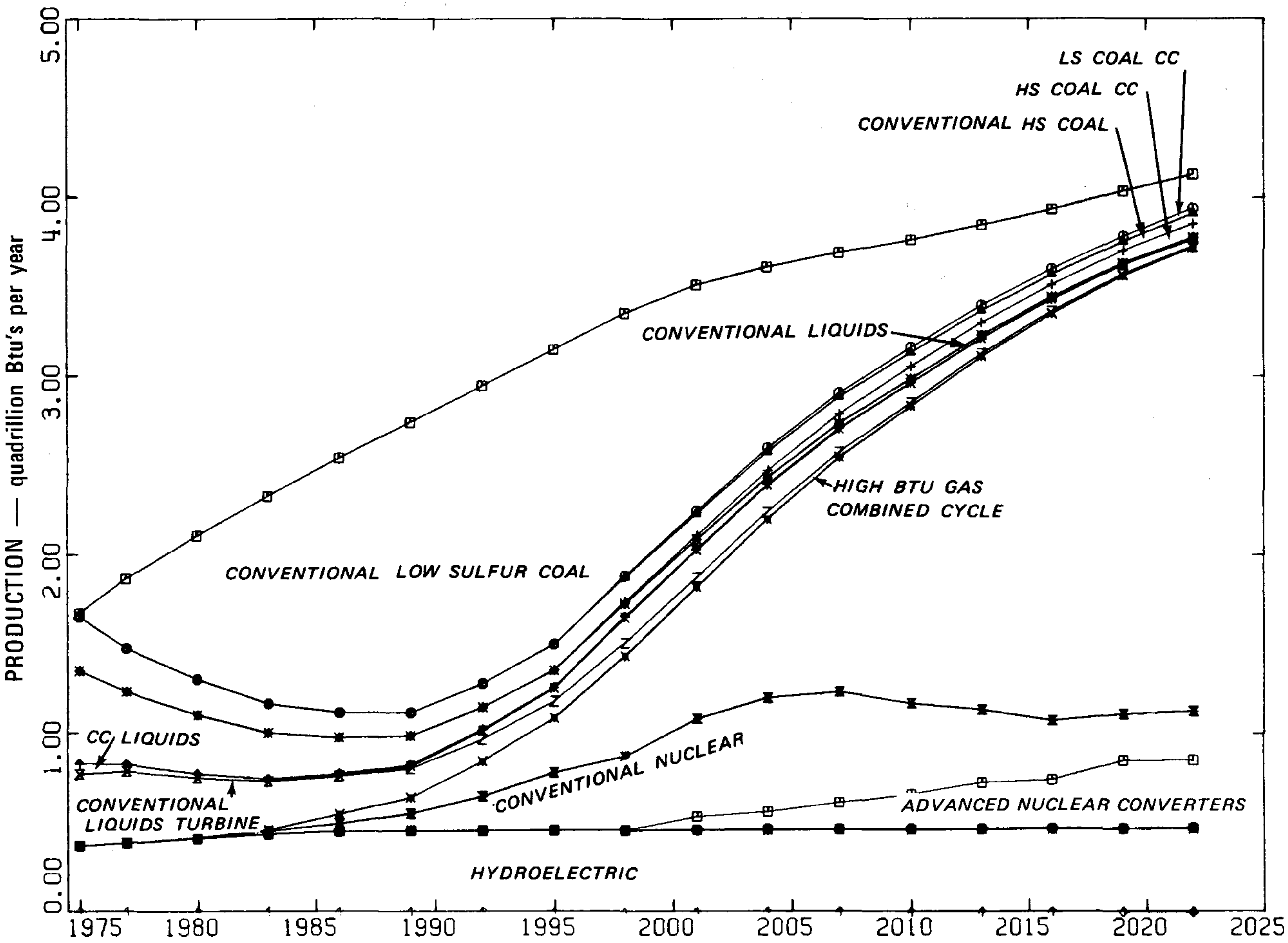

Figure 3-30. Intermediate Load Electric Power Generation--Low-Demand Case

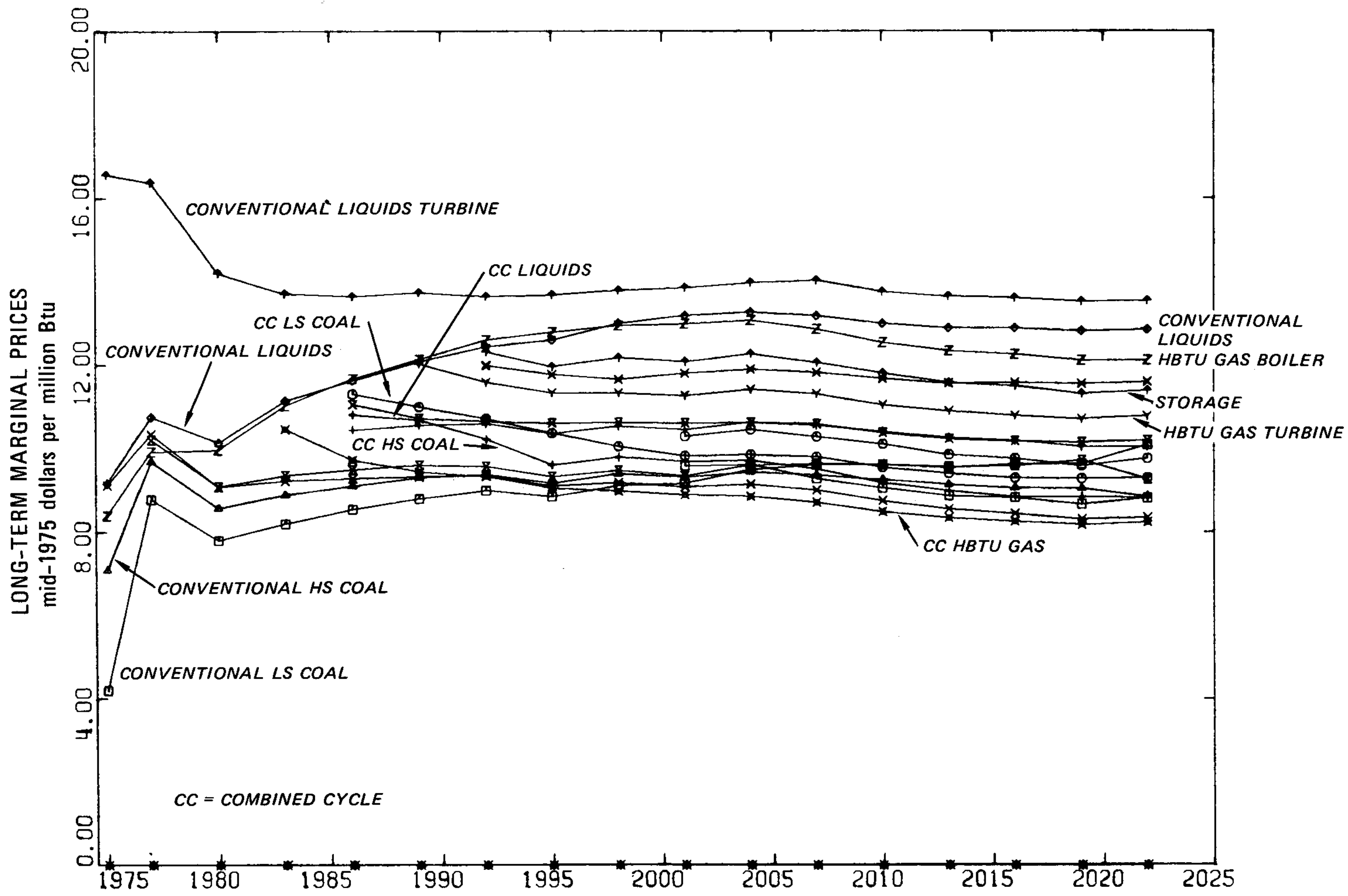

Figure 3-31. Average Marginal Busbar Cost of Intermediate Load Power by Type of Plant--High-Demand Case

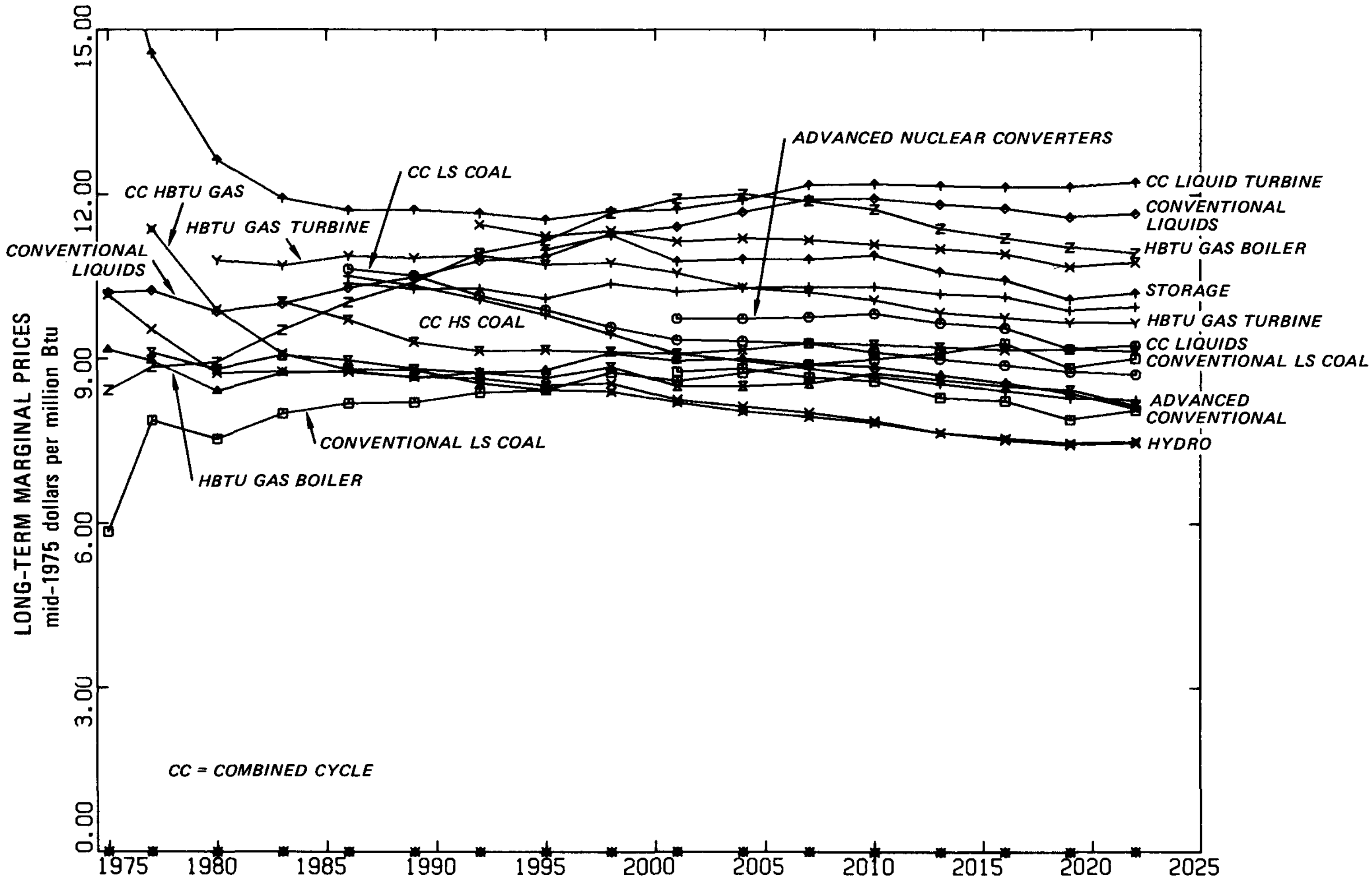

Figure 3-32. Average Marginal Busbar Cost of Intermediate Load Power by Type of Plant--Low-Demand Case

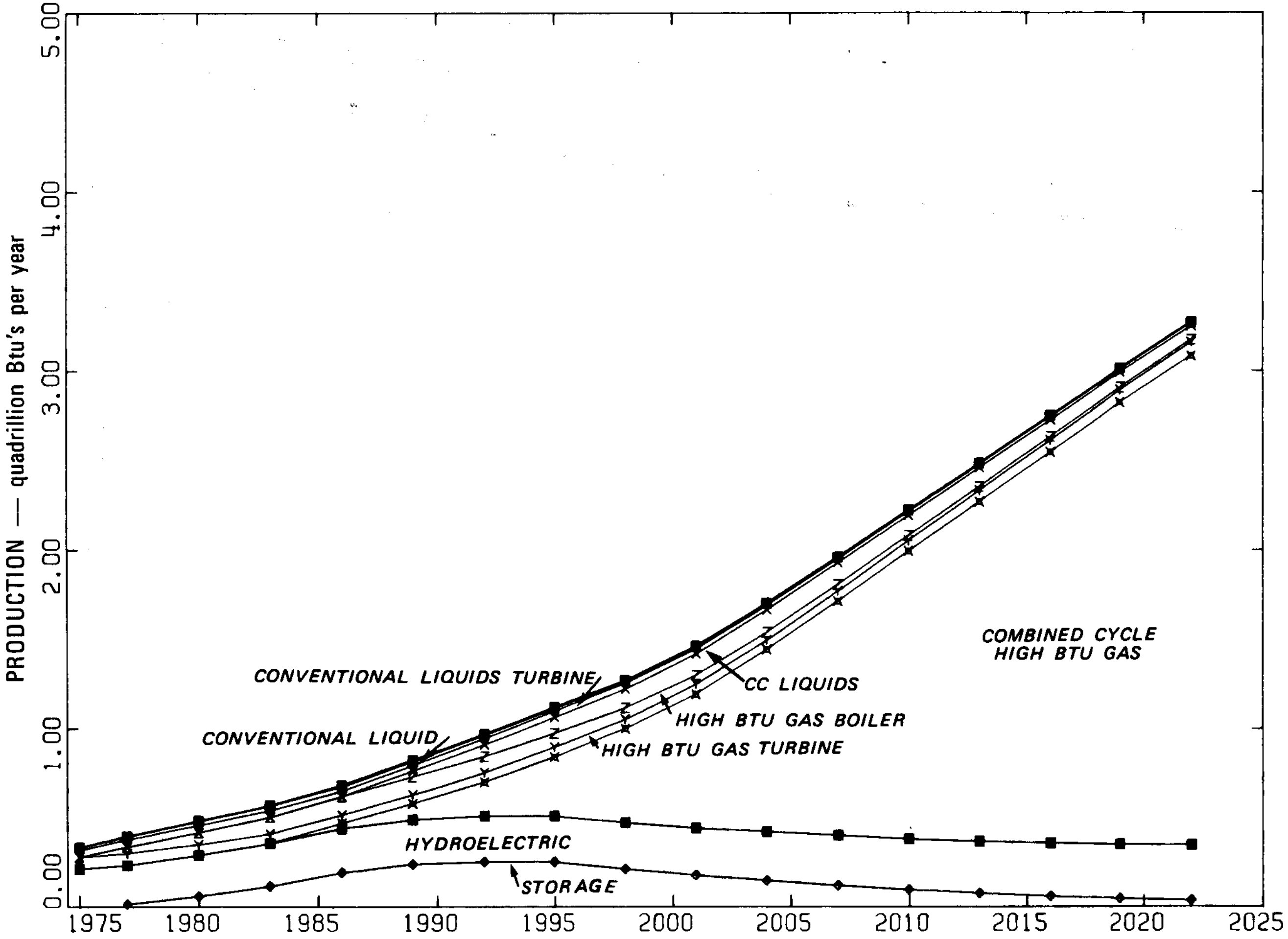

Figure 3-33. Peak Load Electric Power Generation--High-Demand Case

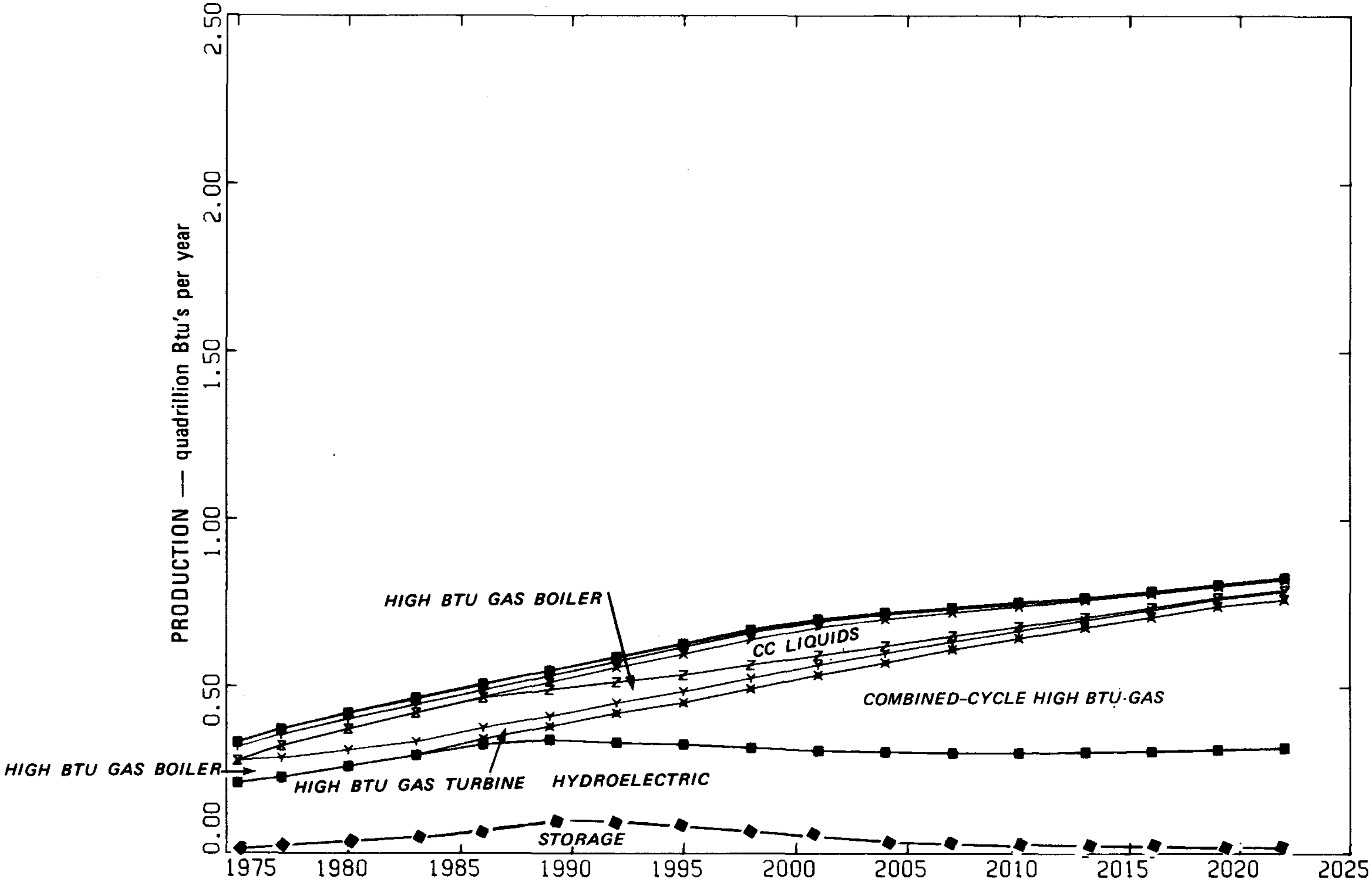

Figure 3-34. Peak Load Electric Power Generation--Low-Demand Case

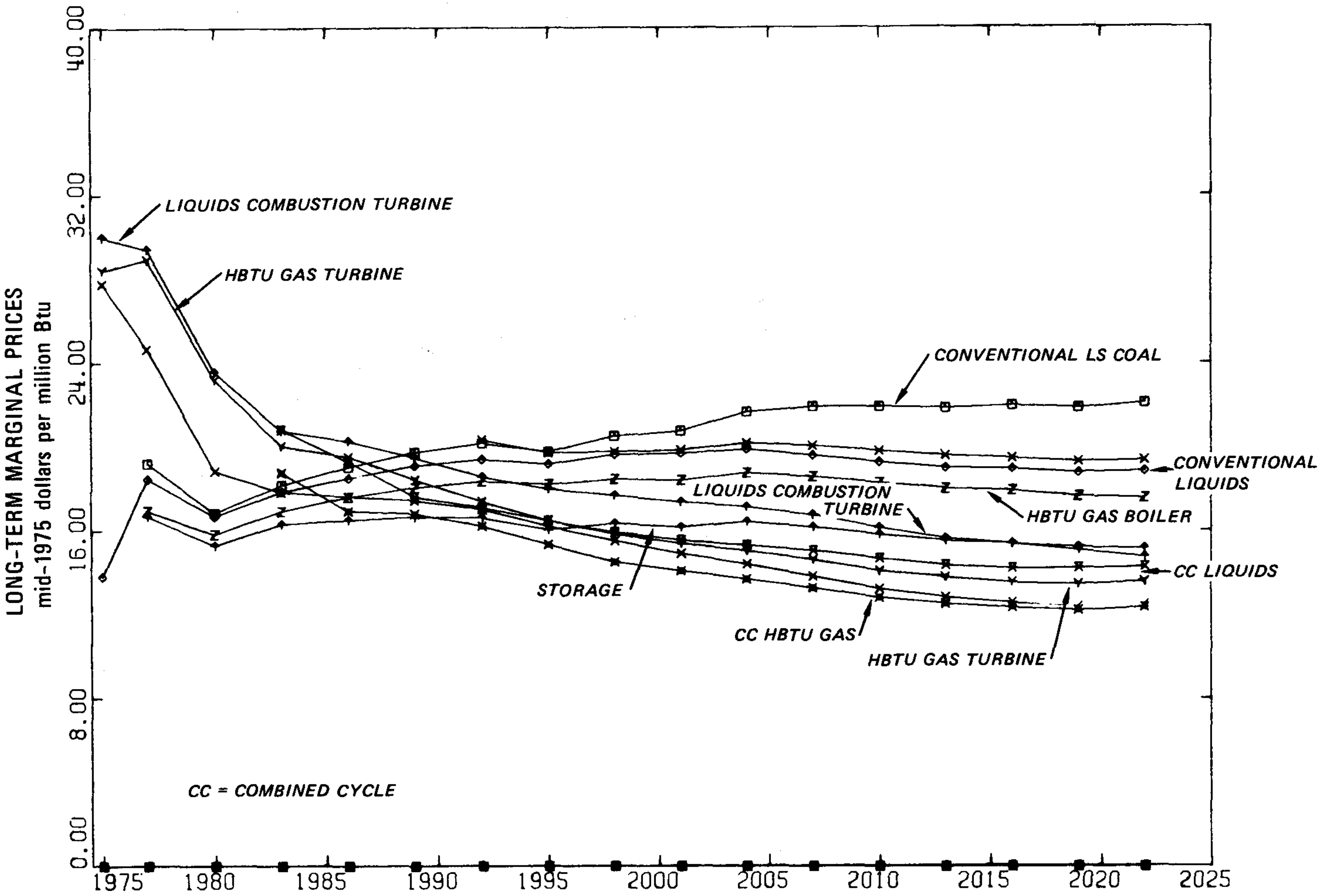

Figure 3-35. Average Marginal Busbar Cost of Peak Load Power by Type of Plant--High-Demand Case

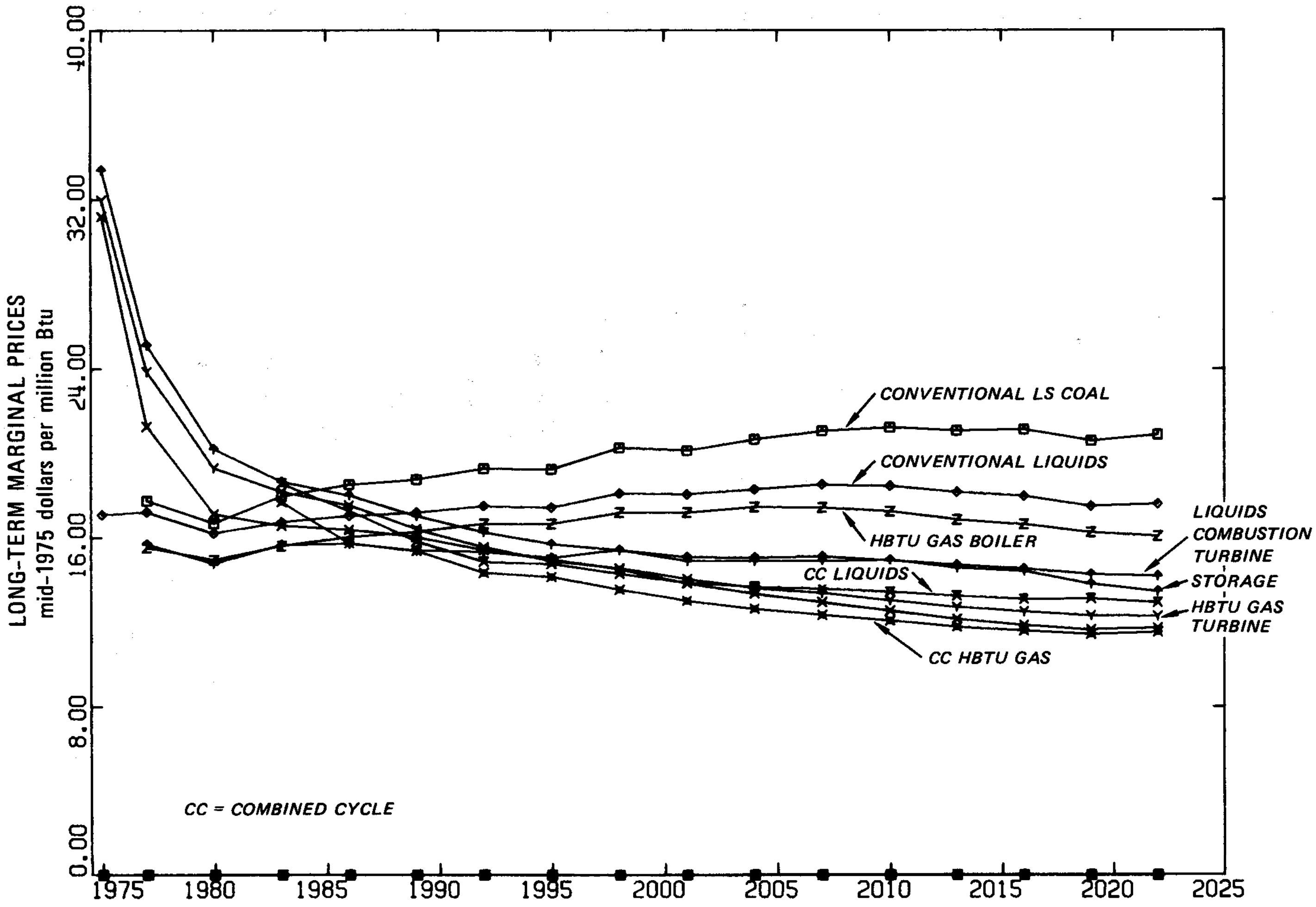

Figure 3-36. Average Marginal Busbar Cost of Peak Load Power by Type of Plant--Low-Demand Case

On a regional basis, just as on a national basis, we note that the prices of delivered fuels in the transportation, industrial, and residential/commercial sectors are not drastically different between the extreme demand cases, and the market shares of the fuels are essentially demand-independent.

Appendix A

DESCRIPTION OF THE SRI NATIONAL ENERGY MODEL

INTRODUCTION

Over the past eight years, SRI International (formerly Stanford Research Institute) has developed a methodology for creating computerized models that describe complex and dynamic market situations typical of the energy field. An outgrowth of client-supported project work, SRI internal research, and Stanford University dissertation research, this methodology was designed to allow modeling of markets characterized by interproduct competition, regional differences arising from product transportation costs, depletable resources, changing technology, and government regulatory factors. Thus, the models generated by the methodology can be used to support analysis of energy-related decisions in such areas as plant capacity expansion, transportation, resource exploration, research and development strategy, and various aspects of government energy policy.

This modeling capability has been applied to develop a comprehensive U.S. energy model which was first used in a decision analysis of synthetic fuels strategy for a major U.S. oil company.* The SRI National Energy Model covers all major energy forms, conversion technologies, transportation modes, demand sectors, and U.S. geographical regions; it explicitly models supply elasticity, interfuel competition, and end-use demands; it treats energy market dynamics (such as investment, financing, technological change, demand growth, and resource depletion) from the present out to the year 2025; and computes market clearing prices and quantities by balancing supply and demand.

The modeling approach is based on the economic concept of balancing supply and demand at a market clearing price. Normally, this concept is considered in terms of a single supply curve and a single demand curve with a single price that balances supply and demand; however, in the SRI National Energy Model this concept

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*The model is used by SRI under an agreement with the Gulf Oil Corporation.

has been extended to the simultaneous balancing of thousands of supplies and demands that evolve over time and are connected by a complex network. The result is thousands of market clearing prices, each specifying the economics of a fuel at a particular location and time. Using submodels that incorporate engineering, geological, environmental, economic, and behavioral information and advanced computer modeling techniques has enabled implementation of a detailed, national energy model on a commercially available computer.

The principal outputs of the energy model are the regional market clearing prices for fuels over time, associated production quantities, flows through transmission links, capacities of conversion processes, and demands for distributed fuels. Clearly, these outputs can be sensitive to the inputs to the model. Thus, the energy modeling capability is most useful for decision-focused analysis in which the importance of uncertainty in the input information can be measured in terms of the effect on the choice among specific alternatives.

BACKGROUND: SYNTHETIC FUELS DECISION ANALYSIS FOR A MAJOR OIL COMPANY

During 1973 and 1974, SRI worked with the Gulf Oil Corporation to perform a decision analysis of alternatives for producing synthetic fuels. One of the important alternatives facing Gulf was whether to participate in potential coal gasification ventures in the Powder River Basin (Montana and Wyoming). Such an undertaking would require investments in a gasification plant costing approximately $500 million, new coal mines, and a pipeline to deliver pipeline-quality synthetic gas to Chicago or other distant markets. This gas would compete there with natural or synthetic gas from other sources.

At the beginning of the decision analysis, intuitive arguments and conventional profit analyses demonstrated that the profitability of a gasification venture would be determined essentially by the future prices of pipeline quality gas in such markets as Chicago and the prices of coal in the Powder River Basin. The projections of these prices over the 30- to 40-year construction and operating life of a gasification plant were highly uncertain. Although the technical and other business aspects of the venture were of concern, the major determinants of the venture's profitability--and hence the strategic decision to build or not--were the projections of future prices of gas and coal.

In 1973, the future price projections for gas were very confused because of uncertain government regulatory policy and uncertain natural gas supplies and consumption. Many energy specialists were forecasting a gap between the quantities of gas that consumers would buy at the projected prices and the quantities that would be produced at the projected prices. Some specialists argued that this gap provided an attractive market for synthetic gas. Their projected prices of gas, however, were considerably below the prices required for a profitable coal gasification venture. Clearly, the prices of gas would have to increase in order to bring supply and demand into balance, but the important question to be resolved was when the prices would be high enough to justify production of synthetic gas.

As a result of the confusion in future price estimates for gas, the projections had to be built from more basic information on natural gas resources and on the effect of higher prices on natural gas production. Similar information was required on other energy resources, as well as economic and technical information on energy use, conversion, transportation, and information on government regulatory policy. This additional information was required because interfuel competition in several markets geographically distant from each other and evolving over time has a major effect on the prices of coal and gas.

Synthesizing the basic information necessary for projecting prices requires a comprehensive dynamic model of energy supply, demand, and pricing. Simple models or hand calculations cannot cope with the necessary detail. The scope and detail of the SRI National Energy Model are discussed below. It should be emphasized that this model was developed to address decisions on synthetic fuel ventures. Its basic purpose is to provide an understanding of the economic viability of synthetics in competition with imported and natural fuels in the U.S. energy economy.

FEATURES

Energy models must be tailored to specific decision problems. Features required in a model for one problem may not be required in the next problem, or the next problem may require additional features. On the other hand, considerable overlap often occurs between features required for one energy decision problem and those required in the next. With this in mind, we will describe some of the energy model features that are important in strategic energy decision problems, such as commercialization of synthetic fuels.

Complexity

In most cases, a decision problem concerning a new energy conversion technology, such as coal gasification, is very difficult or impossible to isolate from the energy system within which it must operate. Often, the economics of end use, transportation, and resource production will play a major role in determining what resources are produced, how they are transported, and how they are used. The complexity of the modeling problem is illustrated by Figure A-1. This shows the various steps in the U.S. energy system--beginning with primary resources in the ground and their conversion into useful energy (heat in the living room or steam from a boiler).

Within the U.S. energy system thousands of different paths lead from availability of primary resources to satisfaction of end-use demands. The path in Figure A-1 begins with low-sulfur coal that is mined underground, transported by slurry pipeline, converted into a gas, and used in a combined-cycle power plant to generate electricity that is distributed to residential consumers for use in a resistance-heating device to produce space heat in the living room.

Logistics

The cost of moving energy from one location to another can be a crucial factor in the overall economics of using primary resources to satisfy end uses. For example, the cost of transporting coal by train from Western mines to Eastern markets is such that the price of coal in the East can be three times the price of coal in the West. Whereas, if this coal is converted to a liquid fuel, the transportation costs over the same distance are relatively small. Thus, in problems where transportation costs are important, the model must be geographically segmented to allow for regional price differences. Figure A-2, a map of the United States, shows the nine demand regions and numerous coal, crude oil, natural gas, and shale resource basins used in the analysis undertaken for EPRI.

Dynamics

Most corporate investment decisions and public policy decisions have implications over long periods of time. A model that characterizes the energy system only at specific points in time cannot reflect important changes in technology and demand or the effect of depletion of the resource base. Also, the capacities of the energy system in any time period are highly dependent on previous investment, and current investment decisions depend on projections of future prices. Finally, in the short term, secondary markets for scarce commodities--such as pressure vessels, surface mining equipment, drilling rigs, and human and institutional behavioral characteristics--limit rapid change and have long-term consequences. All these dynamic effects are incorporated in the general methodology and the existing SRI National Energy Model.

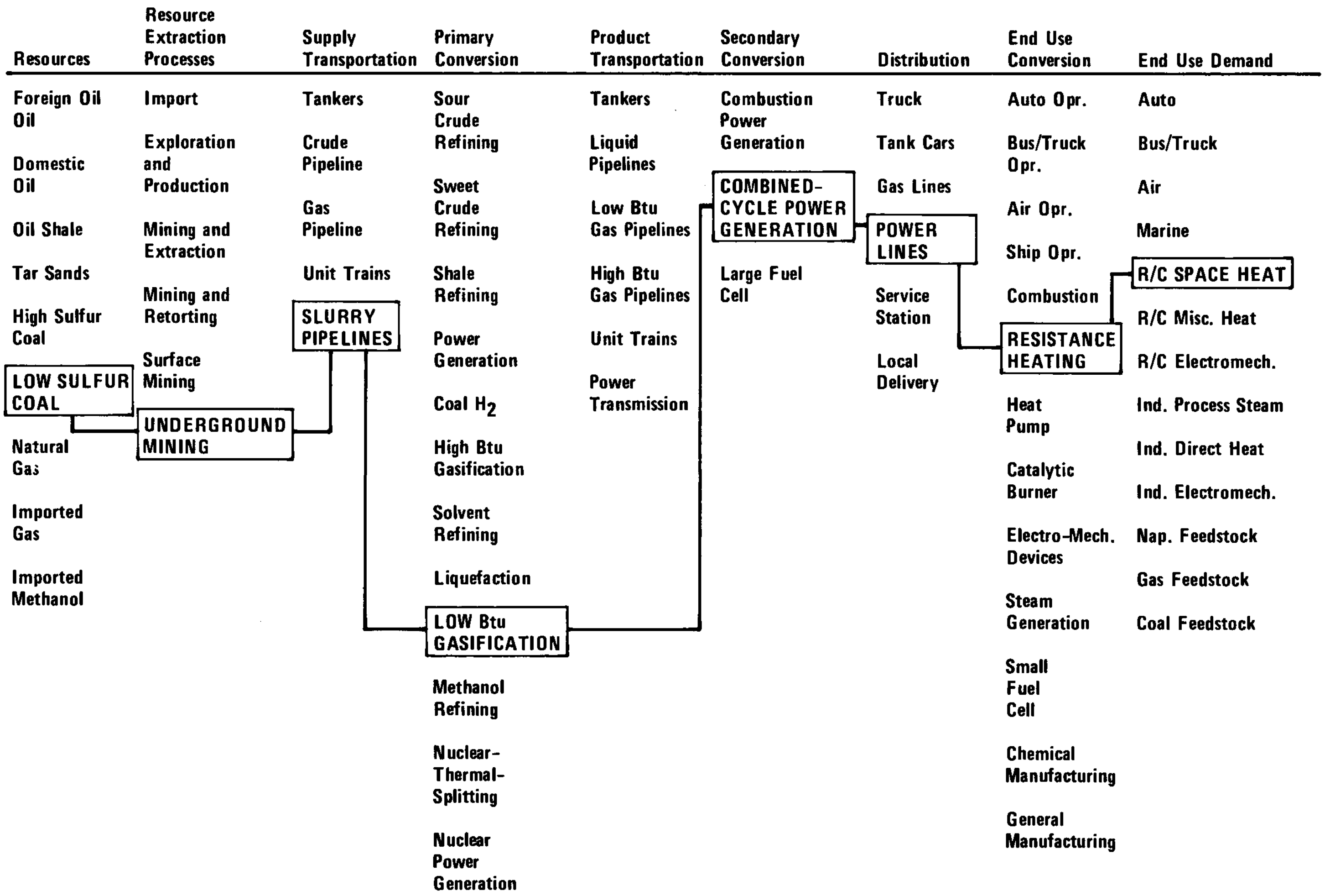

Figure A-1. Complexity of the Energy Market

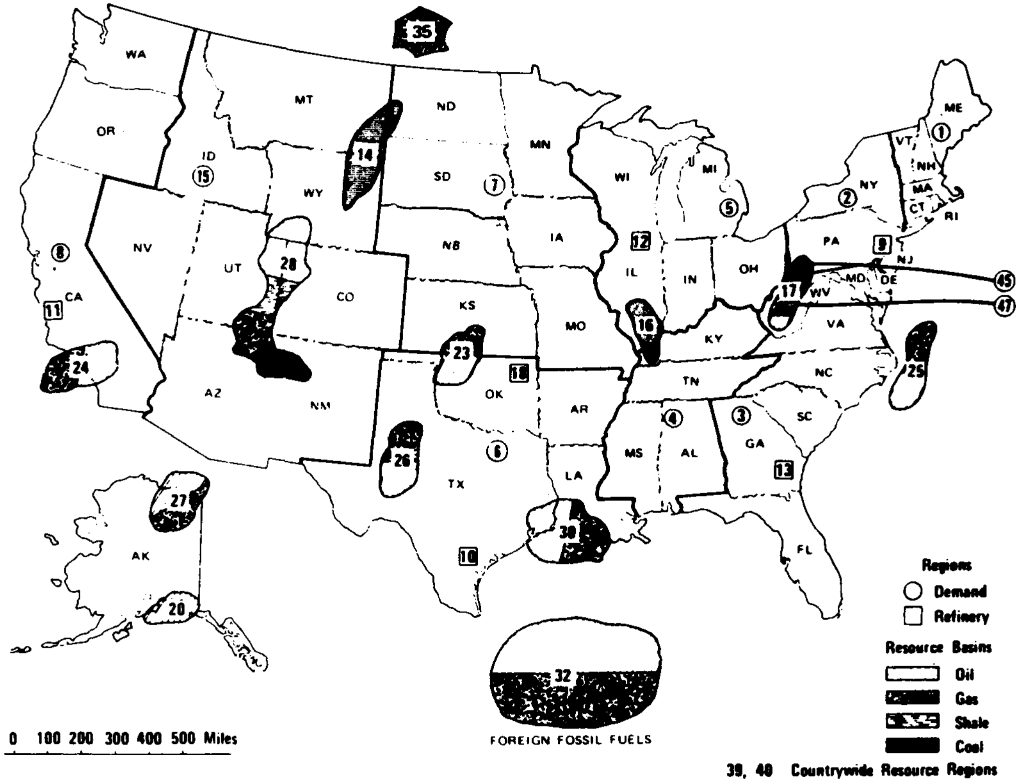

Figure A-2. U.S. Energy Model Resource Locations and Demand Regions

The Basic Approach: Economics of Supply and Demand for Competing Fuels

Given that the supply and demand of a resource both vary with price, what is the price that will balance demand with supply? Every basic economics text discusses the solution for the case of a single resource, illustrated in Figure A-3, but real situations typically entail multiple competing resources and dynamic effects. Because of the resulting complexity, many approaches to energy modeling avoid explicit balancing of supply and demand at a market clearing price. In this methodology, a computer model is used to combine curves, such as those in Figure A-3, with a network representation of the U.S. energy system and realistic models of the elements of the energy system, such as transportation links and conversion industries. This gives the advantages of both the basic economic approach and the detail required for realism.

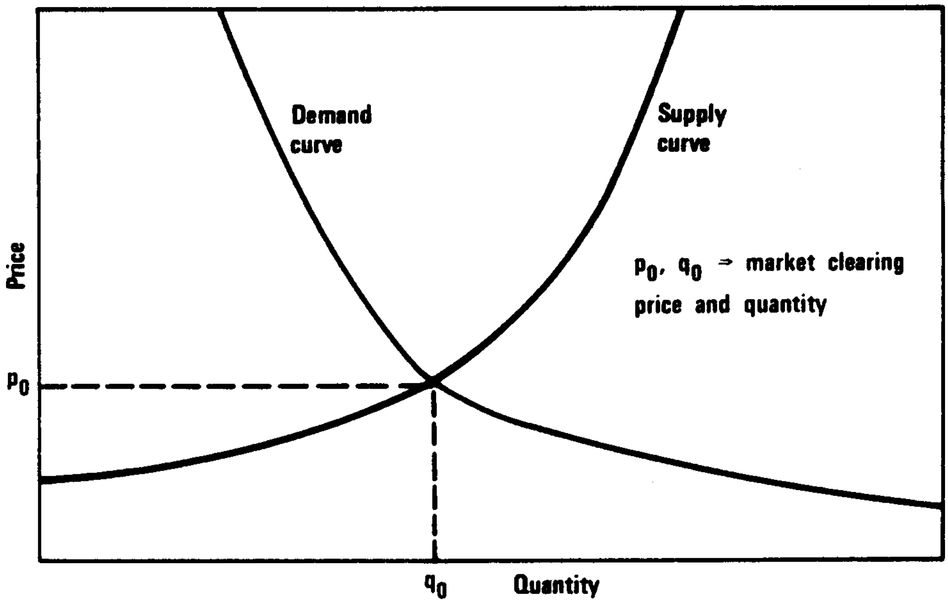

Figure A-3. Fundamental Economics of Supply and Demand

For example, the existing model uses supply curves to describe the total quantity of a primary resource that could be produced in a resource region at various prices. These curves are developed by holding costs and technology fixed and using available data and the judgment of exploration and production specialists to estimate the quantity of a resource that could ultimately be recovered at various price levels. Then the model is used to compute the cumulative production, plus required reserves of a resource to a given year in a specific location. This quantity is then used to find the price on the supply curve that would be required for additional production in that location and year. Finally, these prices are adjusted for the effects of inflation, technological change, short-run dynamic effects, and economic rent (the difference between the price of a resource and its cost). The result is a realistic, dynamic description of resource supply that is consistent with basic economics.

Meaningful Data

A crucial aspect of any model is to make the inputs meaningful to those who must provide and review them. Some approaches to modeling use regression analysis or large amounts of historical data to determine the parameters of the equations that make up the model. Other approaches use abstract inputs, such as cross-elasticity coefficients and input-output coefficients, or arbitrary constraints on growth rates and resource availability. The problem with such input is that the data are often unintelligible to specialists who have the knowledge to judge its accuracy. However, a model that decomposes an energy system into its basic elements--such as production, transportation, conservation, and end-use technologies and behavioral considerations--facilitates description of each of these elements in the most meaningful way. For example, the SRI National Energy Model uses capital cost, operating cost, and thermal efficiency data obtained from industry specialists to describe conversion and transportation industries. Structuring model input into numerous specialized data areas enables experts with in-depth, specialized knowledge to contribute data without having to understand all the details of the model. Furthermore, this form of data can be communicated easily to anyone who wants to understand the model.

Specific Features

Some of the specific features in the SRI National Energy Model are described below:

- Economic Rent--Owners of energy resources will not sell their resources at cost plus return on investment if they believe that they can obtain a higher price. Thus, the price of a resource is determined not only by the cost of producing it, but also by competitive fuel prices and the scarcity of the resource. Economic rent, the increment above marginal cost that must be paid to a resource owner to induce him to sell, is large when the price of a resource is rising rapidly as a result of rapid depletion. This phenomena of economic rent is fundamental to energy pricing and incorporates lease bonus payments and windfall profits.

- End-Use Demand Elasticity--In response to higher prices of a fuel, users may reduce consumption by turning down the thermostat, using less steam, or driving less. Alternatively, they may substitute a less expensive fuel. In modeling end-use demand, it is important to distinguish between the effects of true reduction in the consumption of usable energy and the substitution of other fuels. The existing model emphasizes the substitution effect because synthetic fuels decisions are sensitive to it. The existing model excludes usable energy elasticity because sensitivity analysis showed that the decisions were relatively insensitive to the price elasticity of usable energy over the range of prices encountered. Detailed price elasticities for usable energy demand could be incorporated within the existing model for analysis of problems sensitive to usable energy elasticity.

- Financing, Accounting, and Taxes--Significant differences in financing practice, accounting conventions, and taxation exist among the various sectors of the energy market. For instance, the financing of regulated public utility investments differs significantly from that of oil company investments. Also, accounting and tax conventions differ from project to project. The model explicitly accounts for these differences.

- Market Share--Under perfect competition, the allocation of demand among alternative sources is trivial--the demand is always allocated to the lowest priced source. In the real market, however, behavioral considerations and market imperfections, such as consumer fuel preferences, discriminating pricing, and variations in costs, come into play. The model describes such phenomena by using empirically developed market share curves to relate market shares to prices.

- Initial Energy Balance--The current U.S. energy balance is a starting point for the evolution of the energy system over time. The current allocation of demand among existing sources must be included as input to the model so that the dynamic effects incorporated in the model are provided the proper initial conditions.

- Secondary Industries--In time of rapid expansion of capacity, growth is often discouraged by high prices of equipment and manpower used to construct new plants. Thus, the model includes approximate submodels of secondary industries producing such critical items as drilling rigs and surface mining equipment. These submodels compute the prices of secondary items for a given demand pattern. When a higher price is required for a secondary item, the result is higher capital costs for those plants requiring the items.

- Behavioral Lag--Most organizations and individuals respond slowly to changing economic conditions. We often wait to see proven success before we change our ways. In addition, lags are caused by the time required to plan and construct new facilities. The net effect is that economic actions respond in part to past prices as well as to current ones. Clearly, uncertainty and risk aversion contribute to this effect. Because of the importance of this effect, empirically determined lag parameters are used in the model.

- Technological Change--Learning effects are important in determining the prices of future energy products. Over time, technological improvements lower the capital cost of existing processes (expressed in constant dollars). In addition, entirely new technologies, such as fusion or coal liquefaction, become commercially available and must be included. Technological change is incorporated in the model by using simple learning curves and nominal dates for commercial availability.

The features described above illustrate the degree of realism that is built into the SRI National Energy Model. Many aspects of the national energy system are integrated into this energy model. A major by-product of the model is the understanding developed concerning how these aspects relate to each other and to decisions on synthetic fuel commercialization.

COMPUTATION

The application of the basic economic concept of balancing supply and demand to an imperfect market system that contains essentially thousands of supply and demand curves is an important consideration. The equilibrium mechanism of the market supplies a clue on how to apply this concept. If the market price is too low, demand exceeds supply and the price will rise to the point where supply and demand balance. Conversely, if the market price is too high, supply exceeds demand and thus the price will fall. The network price iteration algorithm that provides the foundation for the SRI methodology takes advantage of this basic market mechanism.

The Energy Network

To illustrate, we will use the partial network shown in Figure A-4. The resource supply curves are at the bottom; the usable energy demand curves are at the top. In between these curves is the network describing the entire energy system. The SRI National Energy Model has about 2,400 materials, processes, and transportation links. A material is a primary resource, product, or usable form of energy at a specific location. A process represents a sector of the energy industry, such as coal mining or gasification at a specific location, or a class of consumers using a particular energy-consuming device. A transportation link represents the economics of moving a material from one location to another.

To get a sense of the many paths in the network, consider first the path where coal is mined, converted into synthetic (high-Btu) gas, piped to a demand center in a demand region, distributed to industrial users, and consumed as boiler fuel

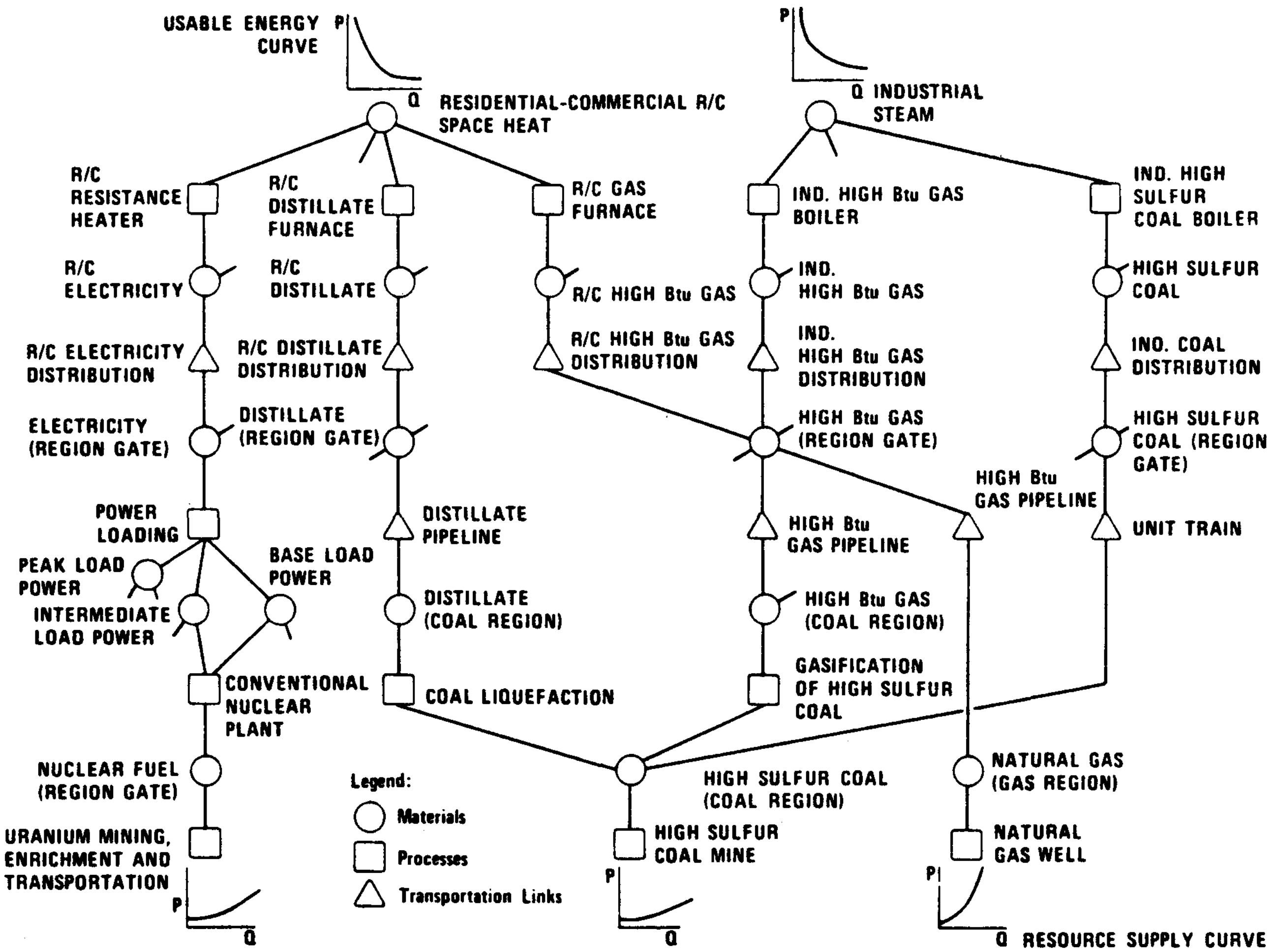

Figure A-4. Elements of the Energy Network to produce steam. The same end-use market could be supplied by coal transported by unit train, distributed to the same industrial users, and used in a boiler to produce steam. These two paths can be traced in Figure A-4. In the SRI National Energy Model, there are 14 end uses (such as industrial steam) in each of 8 demand regions, and 30 primary resource supplies (such as coal) in the various resource basins illustrated in Figure A-2. The alternative technologies in the model include all important types of electric power generation (producing base, intermediate, and peak load power), sweet and sour crude oil refining, shale oil refining, high- and low-Btu coal gasification, coal liquefaction, solvent refining of coal, methanol from coal, and hydrogen production from coal and nuclear fuel.

Network Price Iteration Algorithm

The network price iteration algorithm operates in much the same way that the U.S. energy system operates to determine the prices that result in a balance between supply and demand. To illustrate, we begin at the bottom of Figure A-4 and roughly estimate the quantity produced over time of each of the primary resources and products throughout the network.* On the basis of these estimates of primary resource production, the resource supply curve and other dynamic information are used to compute tentative prices of primary resources in each time period.**

We then move up the network along all paths simultaneously, and compute tentative prices of the products. These product prices are computed by using models that account for the capital and operating costs of each of the conversion processes that describe the energy network. Where two or more sources of a material compete, we use appropriate rules for determining the price of the material, given the prices from the sources. When we reach the top of the network, we have computed tentative prices of usable energy for each end-use sector in each demand region over time.

At the top of the network, we begin a downward pass. We apply the prices of usable energy to the usable energy demand curves to determine the quantity of

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[*] In the current version of the SRI National Energy Model, the time horizon is the year 2025. The 50 years from 1975 to 2025 are broken into 17 time periods. These time periods are of unequal duration to allow more detail in the years that are important for the decision problem.

[**] The price of a primary resource also depends on economic rent and the price of secondary materials, such as drilling rigs and surface mining equipment.

energy needed for each end use in each time period. As we work down the network, we allocate the required quantity of materials to competing sources based on the tentative prices computed on the upward pass. In addition, the required quantities are increased to account for the thermal losses in energy conversion and transportation. When we reach the bottom of the network, we have a new estimate of the required quantity in each time period for each of the primary resources. We then repeat the iterative process: the new estimates of production lead to new prices that are passed up the network and result in new demands that are passed down the network. This iterative process is continued until it converges; that is, until no significant change in prices and quantities occurs on two successive iterations.

This network pricing algorithm is summarized in Figure A-5. In practice, additional techniques are incorporated in the algorithm to guarantee convergence and to account for the behavioral and other features of the methodology mentioned earlier.

It is important to recognize that the dynamic aspects of this approach are not equivalent to using a static model in each of the time periods. Rather, the prices and quantities in each period are determined by dynamic relationships that interrelate both past and future prices and quantities. Current prices depend on future prices because the price of a product required to justify a new plant to produce that product is affected by projections of future prices. Also, current capacity decisions depend on previous prices and decisions because of resource depletion, existing capacity, and behavioral lag.

Another important computational consideration is that models produced by this methodology are nonlinear and usually unconstrained. Linear programming is not used as a computational tool. The mathematics of this methodology reduce to the iterative solution of a system of nonlinear equations that are the economic, technical, and behavioral relationships that describe an energy system. The solution of these equations is the set of prices and quantities that form the output of the model. Arbitrary constraints on the availability of scarce resources, such as limitations on plant capacity, primary resources, and surface mining equipment, are not needed in the model as they are in some other approaches. In this methodology, we explicitly model the higher costs of such resources as they are depleted (resource supply curves) or when there is a temporary shortage (secondary industries model).

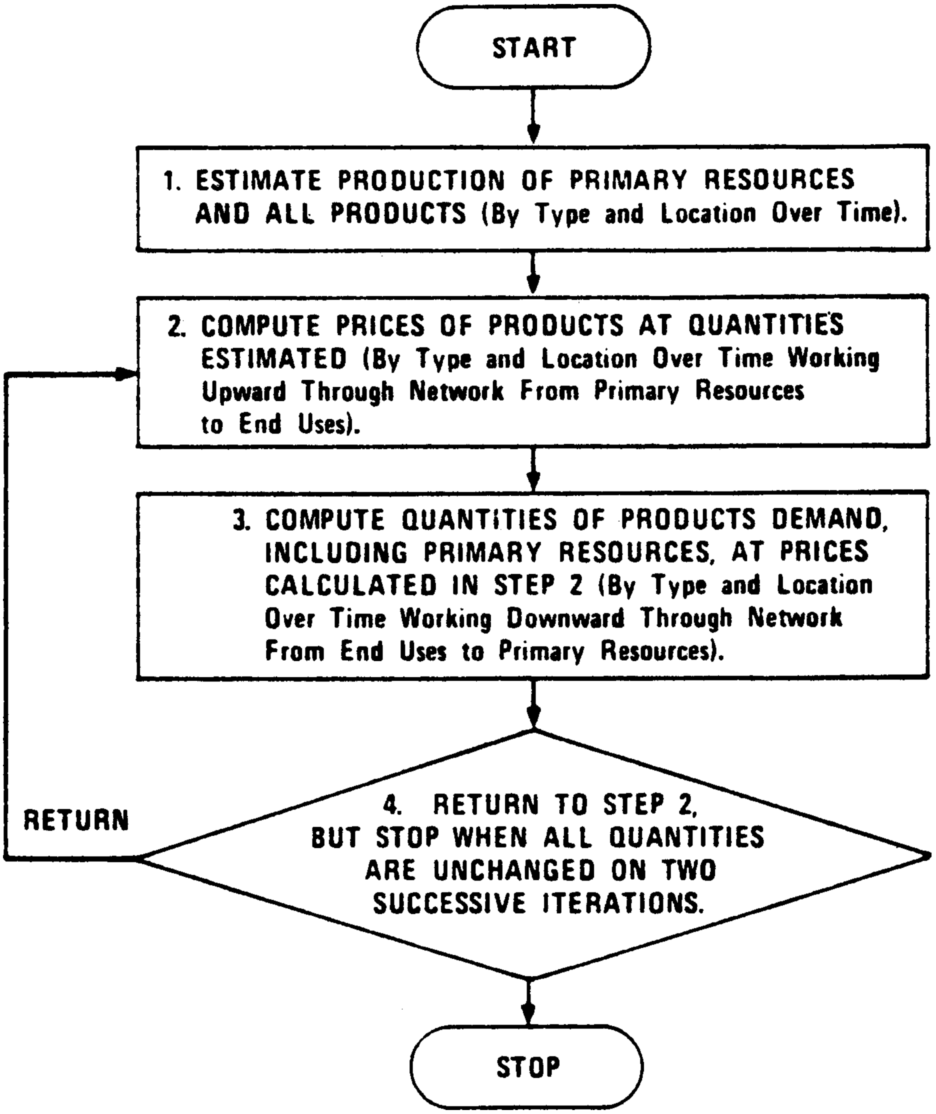

Figure A-5. Network Price Iteration Algorithm

Driving Forces of the Model

A question that is often asked is, what drives the model? Paradoxically, supply and demand curves are the key inputs required to forecast supply, demand, and prices. The important difference between the input data and output forecasts is that the inputs are price-quantity curves while the outputs are market clearing (equilibrium) quantities and prices. To illustrate, in the textbook cases of Figure A-3, supply and demand curves are inputs while the market clearing price and quantity, p_o and q_o, are outputs. Many conventional approaches to energy forecasting attempt to directly predict market clearing prices and quantities over time, whereas in this approach prices and quantities are calculated on the basis of more fundamental inputs, such as supply and demand curves and the economics of conversion, transportation, and distribution. Thus, the model does not eliminate the need for expert judgment. Rather, it changes the task from directly predicting future prices and quantities to modeling relationships between prices and quantities.