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February 29, 1980

Prepared for
U.S. Department of Energy
Energy Information Administration
Assistant Administrator for Applied Analysis
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**Documentation of
Volume Three of the
1978 Energy Information
Administration
Annual Report to Congress**

February 29, 1980

Prepared by
Kilkeary, Scott & Associates, Inc.
2009 North 14th Street
Arlington, Virginia 22201
(703) 522-1300

Prepared for
U.S. Department of Energy
Energy Information Administration
Assistant Administrator for Applied Analysis
Office of Analysis Oversight and Access
Washington, DC 20461
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PART I .

INTRODUCTION

PART I

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CHAPTER 1

INTRODUCTION

1.1 Background

Section 57 of the Federal Energy Administration Act of 1974 requires the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE) to make an annual report to the Congress and the public. The Act specifies a number of areas that must be discussed, including a description of activities, a summary of reports published and statistical information gathered in the preceding year, and a comprehensive analysis of future energy trends.

The 1978 Energy Information Administration Annual Report to Congress (ARC78) has been prepared by EIA to satisfy this requirement. The ARC78 consists of three volumes, as follows:

1. Volume One describes the major activities of EIA during its first full year of existence, as well as key initiatives undertaken, in progress, and planned. Appendices to Volume One summarize all the reports and Analysis and Technical Memoranda published during 1978, and delineate the primary data-gathering systems and forecasting models operated.

2. Volume Two is a statistical summary containing, in tabular and graphic form, physical and financial energy-related data. Historical data are provided on energy supply, consumption, and trade, and on the prices of energy production, imports, and exports.
3. Volume Three presents short-, medium-, and long-term projections of energy production, consumption, and prices, as well as their economic and other related consequences. Two comprehensive supplements provide additional details and supporting data for the domestic (U.S.) forecasts and for worldwide projections.

The ARC78 is the second such report, and is essentially a revision and expansion of the projections published last year. The differences are due to the availability of additional data and to enhancements of the analysis process arising from the continuous effort within EIA to refine the analytical system.

The purpose of this report is to document the analytical process used by the EIA Office of Applied Analysis to develop the economic and energy forecasts published in Volume Three of the ARC78. In particular, this document addresses the methodologies underlying the forecasts. It is based on extensive interviews with EIA personnel who were responsible for preparing the projections; it also relies, especially in the midterm chapters, on existing detailed model documentation. More emphasis has been

placed on those areas not adequately described in existing documents. For example, the Midterm Energy Forecasting System (MEFS) is an updated version of the former Project Independence Evaluation System (PIES). The PIES models have been described in an extensive series of documents, the majority of which are completely applicable to the associated MEFS counterparts; therefore, the midterm models are not fully described here, but are discussed in terms of their contextual relationship to the analytical process. Detailed documentation is referenced. The short-term models, on the other hand, are not supported by extensive documentation; hence, they are described with a much greater degree of detail.

This report does not discuss model results, nor does it deal with the broad range of assumptions--both of which are fully addressed in Volume Three (and its supplements) of the ARC78.

Methodological assumptions are described where appropriate.

Also, model limitations, accuracy, adequacy, and proposed enhancements are not discussed; these topics are the subject of continuous oversight attention within EIA.

1.2 Organization

This document consists of four parts:

1. Part I includes this introduction and a summary of Volume Three of the ARC78.

2. Part II contains descriptions of the models used to develop short-term forecasts covering the years 1979 and 1980.
3. Part III describes the models used to develop midterm forecasts covering the years 1985, 1990, and 1995.
4. Part IV describes the analyses covering the period from 1995 to 2020.

Chapter 2, which follows this introduction, provides brief, chapter-by-chapter summaries of Volume Three of the ARC78, and thus provides a contextual framework for the models and procedures described in subsequent chapters. However, a full understanding of Volume Three in terms of its projections, scenarios and other assumptions, and terminology will enhance the usefulness of this document to the reader. Also helpful is some knowledge of the energy technology underlying the individual models.

Parts II, III, and IV address the three forecasting periods, each of which has its own unique characteristics. The short-term models, described in Chapters 3 through 10, tend to be data-driven in that they consist of applying standard time-series analysis methods and similar techniques to historical data. Very little documentation exists regarding model details and the sources of data used. The short-term model descriptions provided in subsequent chapters were derived almost entirely from examination of the computer jobstreams, including input data, used in generating the final or published reports; this examination was augmented by discussions with appropriate EIA personnel.

Some short-term forecasts were not the result of modeling efforts at all. In particular, the relatively stable, long-range planning of nuclear, hydroelectric, and geothermal plants allows a high degree of certainty regarding their generating capacities projected two years into the future. These values were aggregated from reports routinely submitted to the Federal Energy Regulatory Commission by the utility companies.

The midterm forecasts, on the other hand, tend to be process-driven in that they result from complex interactions, including extensive feedback and iteration of numerous models. These interactions are described in Chapter 11. The international-domestic interface is described first to provide the framework for discussion of the individual international model components in Chapter 12; then, the interaction between energy and the economy in the United States is further articulated to form the basis for the forecasting models described in Chapter 13 and the impact models discussed in Chapter 14.

Characteristically, the midterm models are well documented as independent components. Much of this existing documentation was prepared in connection with last year's Annual Report to Congress (ARC77), and although most models have since been improved, the basic methodology remains the same. In the case of the MEFS, model interdependencies have been documented. However, most of the interactions discussed in Chapter 11 have not been previously documented, and were developed based on discussions with EIA personnel.

Finally, the long-term forecasts derived from yet another characteristic approach--a simulation of the entire energy system from the present to the year 2020. The long-term methodology employed by EIA, as well as projections from four other energy forecasting systems, are discussed in Chapter 15.

CHAPTER 2

SUMMARY OF VOLUME THREE OF THE ARC78

As did its predecessor, Volume Two of the ARC77, Volume Three supplies forecasts of energy production, consumption, and prices, and possible economic and other consequences, as mandated by the Federal Energy Administration Act of 1974 in its outline of requirements for an annual report. However, the ARC78 projections and analyses differ from those of the ARC77 in the availability of additional data and in enhancements to the analysis process--specifically, in changes in accounting for energy system/economy interactions, in the derivation of world oil price assumptions, and in the development of midterm projections for 1995, plus projections for time periods beyond 1995.

The remainder of this chapter presents a chapter-by-chapter summarization of the contents of Volume Three.

2.1 Chapter 1: Assumptions and Methods

Chapter 1 serves as an introduction to Volume Three, beginning with a discussion of the purpose of the ARC78 forecasts and the ways in which they differ from those in the ARC77. In a

preliminary overview of the projection process, the relationship between energy prices, supply, and demand is addressed. Topics treated in detail include a description of energy-economic interactions, assumptions regarding world oil prices, and energy modeling in the long term beyond 1995. Subsequent sections present the general approach and methodology underlying the forecasts, and define and describe the alternative projection series and their associated assumptions. Finally, Chapter 1 addresses the organization of the remainder of Volume Three, very briefly describing the contents of each of its six major sections.

2.2 Chapter 2: International Energy Assessment

Chapter 2 presents forecasts of energy supply and demand, under differing assumptions, for each region of the world. It also contains forecasts of world oil prices that balance energy supply and demand, instead of the constant real prices customarily used in previous forecasts. The principal tools that were used to produce the Chapter 2 forecasts for the period 1979 through 1995 were the International Energy Evaluation System (IEES) and the Oil Market Simulation (OMS) Model.

Chapter 2 begins with a discussion of the extent of the global energy resource base--in this case, the major non-renewable energy sources that are recoverable given current technology and

prices--as well as an overview of global energy price and production trends. A brief description of the five projection series used is followed by more detailed discussions and tabular data concerning economic growth rates, energy conservation measures, world energy production and consumption, OPEC oil production and behavior assumptions, world oil prices, world oil balances, and oil import payments. Chapter 2 concludes with a comparison of the ARC78 mid-range (Series C) forecast for 1990 with the corresponding ARC77 projection, and with comparable recent forecasts made outside of EIA.

2.3 Chapter 3: Short-Term Energy Supply and Demand, 1979-1980

Chapter 3 presents annual national projections for 1979 and 1980. The first of its six sections provides an overview of the analytical methodology employed in making the projections, together with a description of the sources of uncertainty and the major assumptions that underly the three short-term projection series used in developing the forecasts. The overall energy balances are discussed in the next section, and subsequent sections present projections of energy consumption, of the conversion of energy to electricity and to petroleum products, and of the domestic production of primary energy. In the final section of Chapter 3, short-term energy balance projections are compared with those from the ARC77.

2.4 Chapter 4: Midterm Energy Supply and Demand, 1985-1995

Chapter 4 presents forecasts describing several ways in which U.S. energy producers and consumers might respond to new conditions, focusing on the years 1985, 1990, and 1995. The forecasts were made using the Midterm Energy Forecasting System (MEFS), whose workings are briefly described at the beginning of the chapter. Also discussed are characteristics of the midterm period, sources of uncertainty in the forecasts, and the major assumptions underlying the projection series (A, B, C, D, and E, plus two additional scenarios--C-High and C-Low). The remainder of Chapter 4 presents the aggregate midterm forecasts, including a summary discussion of energy supply and conversion phenomena, an overview of energy consumption, and a detailed discussion of gaseous fuels. The sensitivity of the forecasts to varying world oil price assumptions is demonstrated through a comparison of C-High and C-Low projections. Finally, the Chapter 4 forecasts are compared with those published in the ARC77 and with midterm forecasts published by other organizations.

2.5 Chapter 5: Long-Term Energy Supply and Demand

Chapter 5 presents projections of U.S. energy supply and disposition for the period from 1995 to 2020. Using Series C scenario assumptions, five major projections were prepared--one by EIA and the others by outside groups.

The chapter begins with an overview of the long-term forecasting process, describing the methodological approach, plan of presentation, sources of uncertainty, and major assumptions. The next section provides a summary presentation and comparison of the five projections, focusing on providing an integrated picture of energy supply and disposition. A discussion of the EIA-prepared forecast follows, addressing in greater detail the areas of long-term energy consumption and the role of consumer response to energy supply, pricing, and technological change; energy conversion, including the role of conventional and new technologies in relating available resources to consumption; and long-term energy supply forecasts. Finally, Chapter 5 presents a detailed comparison of the five projections, both among themselves and with the ARC77 projections.

2.6 Chapter 6: Energy System/Economy Interactions

Chapter 6 is concerned with the interactions between the energy system and the U.S. economy. Its purpose is to present the macroeconomic assumptions underlying the midterm demand projections reported in Chapter 4, and to evaluate the macroeconomic implications of the alternative energy scenarios. Economic projections presented in Chapter 6 were made using the Data Resources, Inc. (DRI) macroeconomic forecasting model, while midterm energy projections were made using the MEFS.

After an introductory section, Chapter 6 discusses the macroeconomic assumptions and the methodology used to incorporate them into the scenario projections. The projections themselves follow, along with a brief historical perspective. The next section discusses the macroeconomic projections for the world oil price sensitivity analysis, and the chapter concludes with a discussion of sources of uncertainty in the macroeconomic projections.

2.7 Chapter 7: Energy Industry Financial Requirements

Chapter 7 addresses the issue of whether the extent of financial capital investment will be sufficient to expand domestic energy production to its potential, to exploit domestic energy resources, and to introduce new technologies --an issue which has introduced an important element of uncertainty into energy supply projections. The chapter focuses on the financing of energy production and conservation in the aggregate and at sector-specific levels. The first section presents historical expenditures in energy-producing industries; then, estimates of the financial capital requirements for selected energy supply scenarios are presented. The financing of such expenditures during the period 1979 through 1990 is then assessed, both in the aggregate and through a sector-specific approach; conclusions about future capital availability are based on a synthesis of the two approaches. Finally, the qualifications surrounding the analysis are discussed.

2.8 Chapter 8: Changes in Government Regulations

Chapter 8 discusses the uncertainties that are created in the energy forecasting process by changes in the structure of law and regulation pertaining to energy markets. An introductory section points out the difficulties in describing and analyzing the existing regulatory structure and the virtual impossibility of predicting the future course of change. Then, the chapter provides examples of significant changes that occurred in 1978, and discusses the uncertainties thereby created for the ARC78 forecasts. The examples include administrative (DOE) changes, congressional changes, and the question of crude oil decontrol.

2.9 Chapter 9: Coal Supply

Chapter 9 presents the short-term and midterm projections for coal production and prices in the United States. In the first section, the chapter outlines historical trends and relationships in national and regional coal production, and discusses the uncertainties created for the industry by several recent developments. Short-term coal production capacity projections are presented in the second section, and midterm projections appear in the last. The final section also reports the results of four sensitivity tests that were performed to consider the effects on 1990 coal production and price projections that would be produced by varying imported oil prices, coal transportati

costs, and the amount of western coal production. Finally, midterm regional coal production projections appearing in the ARC78 are compared with those from the ARC77 and from two other sources.

2.10 Chapter 10: Natural Gas Supply

Chapter 10 presents short-term and midterm forecasts of domestic natural gas production. In an introductory section, the chapter describes the various short-term and midterm forecasting systems employed. Next is an overview of gas supply that describes the natural gas production process, long-term historical trends, and recent major developments affecting gas supply. The short-term and midterm supply projections are presented in the next two sections, each of which includes discussions of the relevant sensitivities and uncertainties, and comparisons with comparable ARC77 and other projections. The final two sections discuss the major oil and gas supply forecasting systems, both short-term and midterm, and briefly address the relationship of Chapter 10 to other ARC78 chapters.

2.11 Chapter 11: Oil Supply

Chapter 11 describes the short-term and midterm forecasts of domestic oil supply. The chapter begins with a methodology

section that describes the five basic projection series used in the forecasts. An overview section follows, discussing the geologic and economic factors affecting oil supply, long-term historical trends in oil production, and recent developments influencing domestic petroleum supply. The short-term and midterm supply projections are presented in the final two sections of the chapter; each includes a discussion of uncertainties and sensitivities, as well as a comparison of ARC78 projections with those published in the ARC77 and elsewhere.

2.12 Chapter 12: Nuclear Energy Supply

Chapter 12 addresses the subject of domestic nuclear energy supply, and presents short-term, midterm, and long-term forecasts of nuclear power capacity. The chapter begins with a very brief discussion of some of the uncertainties associated with forecasting nuclear capacity. An historical overview follows, examining trends and relationships of U.S. nuclear power technology and supporting fuel cycle technologies, and summarizing significant recent developments in nuclear power and the nuclear fuel cycle. The short-term projections of nuclear generating capacity are presented next, along with comparisons with ARC77 and other recent projections. Midterm projections are presented in the next section, accompanied by a detailed discussion of uncertainties in nuclear energy assumptions, and a comparison with ARC77 and other projections. The last section

presents the long-term projections for Series C, discusses uncertainties and sensitivities, and concludes with a comparison to other long-term forecasts.

2.13 Chapter 13: Coal Processing and Distribution

Chapter 13 presents short-term and midterm analyses of coal markets and coal transportation, with forecasts focusing on coal consumption by end-use sector. The first section outlines the historical trends and relationships in coal consumption by end-use sector, and discusses some of the recent developments causing uncertainties within the coal industry. The short-term projections, which were derived from the Short-Term Coal Demand Model and the MEPS utility module (adapted for short-term analysis), are presented in the next section, along with a brief discussion of some sources of uncertainty. Midterm projections and associated uncertainties and sensitivities are examined in the final section.

2.14 Chapter 14: Natural Gas Supply and Demand Balances

Chapter 14 presents short-term and midterm forecasts of natural gas supply and demand, and examines the related historical trends. First, an introductory section briefly describes the analytical tools and data sources. Next, an overview section

describes the broad relationships in natural gas supply and demand, some long-term historical trends, and significant recent developments affecting those trends. The final two sections contain analyses of the short-term and midterm projections, respectively, presenting the results and discussing variations by scenario as well as uncertainties in the forecasting assumptions.

2.15 Chapter 15: Petroleum Supply and Demand Balances

Chapter 15 examines the short-term and midterm forecasts of petroleum supply and demand in the context of historical trends. In an overview section, the broad relationships in petroleum supply and demand are described in terms of both long-term historical trends and significant recent developments. Analyses of the short-term and midterm projections are presented in the final two sections, together with discussions of variations by scenario and uncertainties in the forecasting assumptions.

2.16 Chapter 16: Electricity Generation and Transmission

Chapter 16 presents short-term and midterm projections of electricity generation, fuel usage, and prices. The first section provides an historical perspective of electricity generation, outlining the long-term trends in demand and prices and examining the recent developments affecting electricity

supply. The next two sections present short-term and midterm forecasts of fuel use and consumption by sector, together with a discussion of sources of uncertainty and, in the case of the midterm projections, a comparison with ARC77 and related forecasts.

2.17 Chapter 17: Residential Energy Use

Chapter 17 presents and discusses midterm projections of energy use by the residential sector--i.e., single-family, multi-family (excluding gang-metered apartments), and mobile homes. The chapter first describes the principal determining factors of residential energy use; then, an overview section provides an historical perspective, a description of representative Series C projections, and a discussion of the sources of uncertainty underlying the projections. Subsequent sections compare the alternative midterm projections, describe conservation programs and dispersed renewable resource estimates embedded in the projections, and examine the impacts of world oil price variations and the affects of varying assumptions concerning the level of energy conservation. Finally, the forecasts are compared with those from the ARC77 and other organizations.

2.18 Chapter 18: Commercial Energy Use

Chapter 18 presents and discusses midterm projections of energy use by the commercial sector. A discussion of the determinants of energy demand in the commercial sector is presented first, followed by an overview of selected historical and projected trends in energy consumption, prices, and quantities over the period 1962 to 1995. Subsequent sections review projected energy conservation measures and the results of several sensitivity analyses, including an examination of the effects of alternative prices of imported oil. The chapter's final sections compare the current forecasts with those published in the ARC77, and address the difficulties of comparing results with projections made by other organizations.

2.19 Chapter 19: Industrial Energy Use

Chapter 19 presents and discusses midterm projections of energy use by the industrial sector, the largest energy-using sector of the economy. The chapter begins with a discussion of the major determinants of industrial energy use; this section includes an examination of major fuels and end uses for energy consumed in the industrial sector. The next two sections address major sources of uncertainty, the history of energy use in industry, and a representative projection of industrial energy use. Alternative midterm projections are then compared. The final

sections deal with conservation and the increased reliance on coal, industrial energy efficiency, and the penetration of new technologies.

2.20 Chapter 20: Energy Use in the Transportation Sector

Chapter 20 presents and discusses midterm projections of energy use and fuel prices in the transportation sector, which includes highway, air, rail, marine, and pipeline transport. Following a brief discussion of historical and future energy use in the transportation sector, the chapter addresses major determinants of future transportation energy consumption and presents a detailed comparison of a representative projection series with recent historical trends. Subsequent sections provide an analysis of the alternative projection series, sensitivity analyses reflecting alternative prices of imported oil, a discussion of conservation in highway energy use, and an analysis of sensitivities to alternative conservation assumptions. Finally, the ARC73 transportation forecasts are compared with those from the ARC77 and other sources.

2.21 Chapter 21: Employment Projections

Chapter 21 addresses projected future levels and composition of employment by industrial sector as affected by future energy

production, consumption, prices, and associated variables. First, an analysis of employment shifts, both historical and as projected for 1985 and 1990, is presented. Two sets of scenarios are employed to represent the range of future energy production uncertainties--Series A, C, and E, which vary the assumptions influencing energy supply and demand, and Series C-High and C-Low, which vary world oil prices only. Uncertainties in the projections are related to limitations of the underlying model (the Energy Disaggregated Input-Output Model) and simulation procedures. Then, ARC78 employment projections are compared to those from the ARC77 and from the Bureau of Labor Statistics.

2.22 Chapter 22: Regional Economic Projections

Chapter 22 presents estimates of earnings changes in the 10 DOE regions based on several alternative energy scenarios (i.e., Series A, C, and E), and considers the regional effects of varying world oil prices (through Series C-High and C-Low). After a discussion of methodology, Chapter 22 examines recent national economic trends and their effects on the growth of regional economic activity. The next two sections present analyses of regional earnings, as influenced by alternative future energy developments and by varying world oil prices. Finally, ARC78 projections are compared to those published in the ARC77.

2.23 Chapter 23: Household Energy Expenditures Projections

Chapter 23 analyzes the distribution of energy expenditures (i.e., dollars spent on various fuels) by different types of households (i.e., differing location, income class, age, race, and sex), under several alternative energy scenarios and world oil prices. First, the analytical methodology and major sources of uncertainty are discussed. Then, variations in levels of energy expenditures and in expenditures as a percent of household disposable income are examined for the various energy futures, including high and low world oil prices. Finally, ARC78 household energy expenditure projections are compared with those from the ARC77.

2.24 Chapter 24: Air Emissions Projections

Chapter 24, the final chapter of Volume Three, examines the historical relationship between energy use and air pollution, and projects emissions of five key air pollutants for the years 1985 and 1990. After an introductory discussion of the pollutants selected for analysis, the chapter addresses sources of uncertainty underlying the projections, national emission trends, shares of emissions due to fuel combustion, the range of emissions over the energy projection series, regional implications, and the effects of world oil prices. Finally, projection results are compared with those from the ARC77.

2.25 Appendix, Glossary, and Supplements

An appendix to Volume Three provides a more detailed description of the assumptions underlying the forecasts. The appendix is divided into short-term, midterm, and long-term sections so as to reflect the different methodologies, data bases, and effects of parameter specifications for each time frame. Each of the three sections contains a table of key parameter specifications for each scenario, and an annotated bibliography of publications containing additional information on relevant models and data bases.

A glossary of energy-related and forecasting terms appears at the end of Volume Three.

A separately-bound Supplement One to Volume Three presents, in tabular form, the key parameters, assumptions, and data inputs used to generate the ARC78 domestic midterm energy forecasts. It contains a complete set of 1985, 1990, and 1995 computer printouts--representing the complete computer output of the Midterm Energy Market Model--for the five basic projection series, and for five variations on the mid-supply/mid-demand scenario.

Supplement Two provides an outline of the basic assumptions and methodology underlying the international energy forecasts presented in Chapter 2. It includes the detailed reports of the

IEES, the computer model used by EIA to estimate future international energy supplies and demands. One report is included for each year/projection series combination addressed in the ARC78.

PART II

SHORT-TERM FORECASTING

PART II
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CHAPTER 3

SHORT-TERM FORECASTING OVERVIEW

Part II, Short-Term Forecasting, outlines the procedures used by EIA in arriving at the short-term energy forecasts that appear in the ARC78. The forecasts of supply and demand were arrived at completely independently, except that shortfalls in petroleum products were assumed to be made up by imports. Forecasts of supply and demand for the various fuels were made separately, using the modeling programs and data sources described in the remaining chapters of Part II.

In general, the models used regression techniques to project empirically-derived econometric relationships into the future. Figure 3-1 shows the steps in the typical regression forecast procedure. Starting in the upper left of the figure, historical data were collected that quantified the dependent and independent variables that were used in the regression. A certain amount of pre-processing was normally required to convert the historical variables so that they would conform to a single geographical and temporal framework. The resulting historical time series were then input to a regression program that estimated the coefficients of the model regression equations. Note that this discussion omits the empirical work that went into the selection of the equations whose coefficients were estimated.

FIGURE 3-1

GENERAL FORM OF REGRESSION MODELS

Next, the model equations were reformatted for the forecasting portion of the process, which computed values for the dependent variables using forecasted values for the independent variables. This reformatting or transformation process included placing the estimated coefficient values into the equations and eliminating dummy variables from the formulation. The forecasting or simulation process produced a forecast of the dependent variables, which may have been modified somewhat before inclusion in the ARC78 data tables.

Clearly, not all of the modeling efforts followed all of these steps; however, it is the function of Part II to discuss the steps in detail, describing exactly what happened in each step, and explaining the reasons for skipping any steps that were skipped. One chapter is included for each of the short-term modeling programs used in producing the ARC78.

3.1 Smoothing of Exogenous Forecasts

Most of the forecasts of demand depended on exogenously-generated forecasts of income, value added, and product prices that were obtained from the Data Resources, Inc. (DRI) CONTROL, SOFTLANDING, and DEEPPRECESSION forecasts. Late in the forecasting process, it was discovered that counter-mnemonic anomalies existed in the DRI forecasts that propagated into the production forecasts in undesirable ways. To correct this

situation, most of the models were modified to recompute the values of the variables on the assumption that the change between DRI's forecasts for 78:3 and for 80:4 was due to a constant growth rate. In other words, the 78:3 and 80:4 forecasts were retained, while the intervening values were interpolated exponentially between them.

In subsequent chapters, these measures are described in detail wherever they occur.

3.2 References

More complete information about the processes used in the short-term forecasting models is included in the following documents:

- Short-Term Oil and Gas Supply Model: Model and Methodology Description (draft).
- Short-Term Petroleum Cost Distribution Model: Methodology Description (TR/ES/79-08, May, 1979).

Documentation for the following models is currently in draft form:

- Short-Term Gasoline Consumption Model
- Short-Term Non-utility Petroleum Demand Forecasting Model
- Klemm's Short-Term Monthly National Petroleum Demand Model
- Short-Term Natural Gas Demand Model

CHAPTER 4

SHORT-TERM OIL AND GAS SUPPLY MODEL

Domestic supplies of oil and gas and their co-products were all forecast by a single model, the Short-Term Oil and Gas Supply Model (STOGSM), which operates on an annual, national basis. Using a set of exogenously-estimated equations, the program, which is written in the Speakeasy language, developed forecasts of the supply of:

- Crude oil
- Lease condensate
- Natural gas withdrawals from both gas and oil wells
- Marketed natural gas--wet and dry
- Natural gas used for repressuring
- Vented and flared natural gas
- Natural gas losses in the extraction process
- Natural gas plant liquids

Figure 4-1 outlines the flow of data in general terms while the remaining sections of this chapter provide more details on the estimation and forecasting of oil and gas supplies.

4.1 Oil Estimation

The quantity of oil produced was estimated by the following equation:

FIGURE 4-1. SHORT-TERM OIL AND GAS SUPPLY MODEL DATA FLOW

$$Q_0 = \left[\begin{array}{c} 1 \\ A_0 + A_1 \frac{D_T}{D_{T-1}} \end{array} \right] Q_{0-1} + \left[\begin{array}{c} A_2 + A_3 D_U \end{array} \right] F_{OD}$$

[Estimation Frame: A50-77]

where the subscripts -1 designate the value of the variable in the previous year. The input historical variables for the regression were as follows:

D_T = Texas demand factor. Eliminates Texas's price support strategies in the years before demand exceeded production capacity. Its value was the value for market demand restrictions published by the Bureau of Mines.

D_U = Embargo dummy variable. Value of one in 1973 through 1977, zero in other years.

Q₀ = Quantity of oil produced from oil wells in 10³ barrels per year, nationwide, from the ARC77, Volume Three, page 23, "Petroleum Supply and Demand Balance, 1947-1977." Values for total production minus lease condensate and North Slope production were extracted from the table.

F_{OD} = Developmental drilling footage in 10³ feet per year, nationwide, from Gulf Publishing Company, World Oil, Annual Summary, "Total Developmental Wells Drilled in the U.S."

An equation for forecasting F_{OD} was also estimated as follows:

$$\ln F_{OD} = A_1 \ln F_{OD-1} + A_2 \ln R_0 + A_3 \ln P_{OA}$$

[Estimation Frame: A47-77]

where:

F = Same as above.
OD

R = Oil reserves added during each year in 10^3 barrels
O per year from American Petroleum Institute,
Reserves of Crude Oil, Natural Gas Liquids and
Natural Gas in the U.S. and Canada, Annual
Summary, "Annual Estimates of Proved Oil Reserves
in the U.S., 1965-1977."

P = Adjusted price of oil = $(P * WPI) / OFMTPI$
OA O

P = Price of new crude oil in current dollars
O per barrel, from EIA, Historical Review
of Domestic Oil and Gas Exploratory
Activity (draft), "Price of Crude Oil."

WPI = Wholesale price index, from DRI's variable
WPI.

OFMTPI = Price index for oil field machinery and
tools from American Petroleum Institute,
Basic Petroleum Data Book--Petroleum
Industry Statistics, Annual Summary,
"Trend of Wholesale Prices of Commodities
Utilized in the Production of Petroleum."

In order to allow for the forecasting of R in the above
equation, the following estimation of oil reserves added was
performed:

$$\ln R_O = A_0 + A_1 F_{OC} + A_2 \ln F_{OE} + A_3 \ln D_T$$

[Estimation Frame: A48-77]

where:

D_T = Texas demand factor. See above.

F_{OC} = Cumulative oil drilling footage starting with an arbitrary year.

F_{OE} = Oil exploratory drilling footage from American Petroleum Institute, Quarterly Review of Drilling Statistics for the United States, Annual Summary, "Total Exploratory Wells Drilled in the U.S."

The latter variable was in turn estimated to allow for forecasting, as follows:

$$\ln F_{OE} = A_1 \ln F_{OE-1} + A_2 \ln P_O + A_3 \ln \frac{D_T}{D_{T-1}} + A_4 \ln P_I$$

[Estimation Frame: A50-77]

Sources for all of the included variables have already been discussed, except for:

P_I = Price index = OFMTPI/WPI. The two components have already been discussed above.

4.2 Oil Forecast

Utilization of the above formulas for forecasting supplies of crude oil involved evaluating each formula, from the last through the first. The following independent variables were input to this process:

P_0 = Price of new crude oil in current dollars per barrel was available historically through 1978. The expected increase in wholesale prices was used to inflate these prices as follows:

$$P_0 = P_{078} * \frac{WPI}{WPI_{78}}$$

WPI = Wholesale price index forecasts for 1978 through 1980 were obtained from DRI's variable WPI in the CONTROL0122 scenario.

OFMTPI = Price index for oil field machinery and tools forecasts for 1978 through 1980 were obtained by assuming the same growth rate as for WPI.

F_{OC} = Cumulative oil drilling footage was extrapolated from 1977 through 1980 by:

$$F_{OC} = F_{0-1} + F_{OE-1}$$

D_T and D_U were both set to zero during the forecast period. Note also that previous-year values for some of the model variables were required as input to the forecasting step for 1977. These were P_0 , Q_0 , F_0 , F_E , and F_0 . In addition, note that there was only one truly exogenous forecast variable--WPI.

The high and low supply series for oil were obtained by varying the coefficient A_2 in the equation for Q_0 up by one standard deviation (high supply case) or down by one standard deviation (low supply case).

North Slope production for the forecast years was estimated off-line at the levels published in the ARC78:

Series	1979	1980
-----	-----	-----
High Demand	1,250	1,350
Mid Demand	1,250	1,350
Low Demand	1,120	1,120

4.3 Natural Gas Estimation

The quantity of non-associated natural gas produced was estimated by the following equation:

$$Q_N = A_1 F_{ND} P_{NA}^{**} + A_2 + A_3 D_N + Q_{N-1} - Q_{N-1}^2 / R_{NB}$$

[Estimation Frame: A68-77]

The input historical variables for the regression were as follows:

Q_N = Quantity of non-associated natural gas produced in each year from Bureau of Mines, Natural Gas Annual, "Gross Withdrawals and Disposition of Natural Gas in the United States."

F_{ND} = Natural gas developmental drilling footage from American Petroleum Institute, Quarterly Review of Drilling Statistics for the United States, Annual Summary, "Total Development Wells Drilled in the U.S."

P_{NA} = Adjusted wellhead price of non-associated natural gas in dollars per 10⁹ cubic feet = $P / OFMTPI$.

OFMTPI = Price index for oil field machinery and tools, described in Section 4.1, above.

P = Average wellhead price of natural gas.
 N Values through 1972 came from American Petroleum Institute, Basic Petroleum Data Book--Petroleum Industry Statistics, Annual Summary, "U.S. Average Wellhead Value of New and Renegotiated Contracts for Natural Gas by State." Natural gas prices shown in this table for Texas and Louisiana were averaged. Prices for 1973 through 1977 were extracted from Federal Energy Regulatory Commission (FERC), Intrastate Natural Gas Prices of FERC Jurisdictional Natural Gas Companies Selling More Than One Million MCF per Year in Intrastate Commerce (quarterly).

D = Natural gas dummy. This variable was introduced
 N to account for price-related natural gas supply anomalies in 1972. It had a value of one in 1972 and zero in all other years.

R = Non-associated natural gas reserves remaining
 NB (reserve balance) in 10^3 cubic feet from American Petroleum Institute, Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the U.S. and Canada, Annual Summary, "Estimated Total Proved Reserves of Non-Associated Natural Gas in the United States."

In the previous equation, F_{ND} , developmental non-associated natural gas drilling footage, was estimated separately to allow it to be forecasted:

$$\ln F_{ND} = A_0 + A_1 \ln F_{ND-1} + A_2 \ln P_{NA} + A_3 D_N$$

[Estimation Frame: A47-77]

There are no new variables here.

Associated-dissolved natural gas (produced by wells that produce mostly oil) was estimated separately by the following equation:

$$Q_A = A \frac{Q_R}{1 + O_{AB} + O_B}$$

[Estimation Frame: A60-77]

where:

Q_A = Quantity of associated-dissolved natural gas in 10^9 cubic feet from Bureau of Mines, Natural Gas Annual, "Gross Withdrawals and Disposition of Natural Gas in the United States."

Q_O = Quantity of crude oil produced from oil wells in 10^3 barrels, as described in Section 4.1, above.

R_{AB} = Associated-dissolved natural gas reserves remaining (reserve balance) in 10^9 cubic feet from American Petroleum Institute, Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the U.S. and Canada, "Estimated Total Proved Reserves of Associated-Dissolved Gas in the United States."

R_{OB} = Crude oil reserves remaining (reserve balance) in 10^3 barrels from American Petroleum Institute, Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the U.S. and Canada, "Estimated Total Proved Reserves of Oil in the United States."

The following variables were estimated to assist in the forecasting of the reserve balances:

$$R_{NC} = A_0 (1 - \exp(-A_1 F_{NC}))$$

[Estimation Frame: A56-77]

where:

R = Cumulative non-associated natural gas reserve
 NC additions in 10^9 cubic feet, from American Petroleum Institute, Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the U.S. and Canada, "Estimated Total Proved Reserves of Oil in the United States."

F = Cumulative gas exploratory drilling footage in 10^3
 NC feet, computed for each year by:

$$F_{NC} = F_{NC-1} + F_{NE-1}$$

where:

F_{NC-1} = Previous year's cumulative drilling, beginning with an arbitrary 1977 value of 29,428 feet.

F_{NE-1} = Exploratory gas drilling, which is estimated by:

$$\ln F_{NE} = A_0 + A_1 \ln F_{NE01} + A_2 \ln P_{NA} + A_3 D_N$$

[Estimation Frame: A47-77]

where:

P_{NA} = Same as above.

D_N = Same as above.

F_{NE} = Exploratory gas drilling footage in 10^3 feet from American Petroleum Institute, Quarterly Review of Drilling Statistics for the United States, Annual Summary, "Total Exploratory Wells Drilled in the U.S."

To forecast the amount of associated-dissolved gas used in repressuring, the following equation was used:

$$Q_R = Q_A \exp(A_0 + A_1 T)$$

[Estimation Frame: A60-77]

Here, Q_A has been defined previously as the amount of associated-dissolved gas produced annually. The variable T is time, defined here as the year minus 1944. Finally, Q_R is feet, from Bureau of Mines, Natural Gas Annual, "Gross Withdrawals and Disposition of Natural Gas in the United States."

Amounts of produced natural gas vented to the atmosphere or flared at the wellhead are estimated as:

$$Q_V = Q_A \exp(A_0 + A_1 T)$$

[Estimation Frame: A60-77]

where the variables Q_A and T are as above, and:

Q_V = Quantity of natural gas vented and flared in 10^9 cubic feet from Bureau of Mines, Natural Gas Annual, "Gross Withdrawals and Disposition of Natural Gas in the United States."

The quantity of gas lost in the extraction of liquid components was estimated by:

$$Q_E = A \frac{Q}{O_M}$$

[Estimation Frame: A60-77]

where Q_M is the marketed quantity of gas (wet), which is, of course:

$$Q_M = Q_N + Q_A - Q_V - Q_R$$

and:

Q_E = Extraction loss quantity for natural gas in 10^9 cubic feet, from Bureau of Mines, Natural Gas Annual, "Marketed Production, Interstate Shipments and Total Consumption of Natural Gas in the United States."

One component of the oil picture was estimated as an adjunct to natural gas processing:

$$Q_L = A \frac{Q}{U_M}$$

[Estimation Frame: A60-77]

where Q_L is the quantity of natural gas liquids produced in 10^3 barrels, from two sources: from 1960 through 1967, American Petroleum Institute, Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the U.S. and Canada; and, afterwards, the ARC77, Volume Three, "Petroleum Supply and Demand Balance, 1947-1977."

4.4 Natural Gas Forecast

When the estimated coefficients were inserted in the above formulas in place of A_i , forecasted values for the natural gas variables were calculated. In this process, the following exogenously-forecast variables were utilized:

P_N = Price of natural gas in current dollars per 10^3 cubic feet was obtained historically through 1978. The expected increase in wholesale prices was used to inflate these prices as follows:

$$P_N = P_{N78} * \left[\frac{WPI}{WPI_{78}} + 3.7\% \right]$$

For the low supply and high supply series, the price increase was augmented or diminished by .04 index points, respectively.

WPI = Same as for oil (Section 4.2).

$OFMTPI$ = Same as for oil (Section 4.2).

D_N was set to zero during the forecast period.

The natural gas forecasting process made use of the reserve balances for oil, associated-dissolved gas, and non-associated gas (R_{OB} , R_{AB} , and R_{NB}) because of their function as incentives to production. It would be expected that each year's reserve balance could be calculated by adding reserve additions to last year's balance and subtracting the annual production. However,

for a variety of reasons, reserve additions seem to be miscalculated each year and revised in the following year. The unrevised estimates of remaining reserves (reserve balance), however, influenced the amount of production activity in the meantime. Therefore, reserve balances were propagated from one year to the next in the model by means of the following formulas:

$$R_{NB} = R_{NB-1} + R_{NC} + R_{VNG} - Q_N$$

$$R_{AB} = R_{AB-1} + R_{AA} + R_{VAG} - Q_A + Q_R$$

$$R_{OB} = R_{OB-1} + R_O + R_{VOIL} - Q_O$$

where R_{VNG} , R_{VAG} , and R_{VOIL} are revisions to non-associated gas, associated-dissolved gas, and oil reserve additions, respectively, averaged over the past 12 years.

Previous-year values for variables F_{NE} , P_N , F_{NE} , and Q_N were all input to the program for 1977 to get the process started. The only exogenously-forecast variable used in forecasting natural gas supply was WPI.

The high and low supply series for gas were obtained by varying the coefficient A_1 in the equation for Q_N up by one standard deviation (high supply case) or down by one standard deviation (low supply case).

North Slope production for the forecast years was assumed to continue at negligible levels due to the lack of gas pipeline facilities.

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CHAPTER 5

SHORT-TERM PETROLEUM COST DISTRIBUTION MODEL

Prices for petroleum fuels were forecast by this program. It operates on a monthly, national basis, taking into account a series of coefficients, forecasted quantities, and assumptions about the factors that influence petroleum costs. The program, which is written in the Speakeasy language, produced monthly forecasts of prices for:

- Regular gasoline--retail
- Kerosene--wholesale
- Aviation kerosene
- Distillate #2--diesel fuel
- Residual oil

All prices were in cents per gallon. In addition, the program output quarterly prices for heating fuels that were computed as the unweighted means of the constituent months' prices.

Forecasting here followed a strictly structural approach, with no estimation of coefficients nor other advanced econometric techniques.

For the period from January, 1979, through December, 1980, the program calculated the price for each product according to the following formula:

$$P = P_{7812} S + P_{C-1} - P_{C7812} + M - M_{7812} + (I_{-1} - I_{7811}) C$$

where:

P_C = Price of crude oil in cents per gallon, computed as the mean of costs of natural gas liquids (P_N), imported crude (P_I), and domestic crude (P_D), weighted by their respective production quantities (Q_N , Q_I , and Q_D).

P_N = November, 1978, P_N inflated using the GNP price deflator from DRI (PGNP)

$$= \frac{PGNP}{PGNP_{7811}} * P_{N7811} (P_{N7811} = .65 P_{NG} + .35 P_{BUT})$$

P_I = P_{I7812} * OPEC in 1979, where OPEC = assumed OPEC price index based on December, 1978,

= P_{I7912} in 1980--the December, 1979, OPEC price is assumed to be held constant from December, 1979, through December, 1980.

P_D = mean of costs for old, new, stripper, North Slope, and Elk Hill oil, weighted by supply. Here, historical wellhead prices for old and new oil were grown by PGNP from historical 79:11 values while the other oil types were grown by the assumed OPEC price increases. The resulting wellhead prices were increased by a transportation cost value grown by PGNP

from 90 cents per barrel in December, 1977, to give total cost of each oil type. The production quantities were output from the CRUDPROJ program.

Q_N , Q_I , and Q_D =

Quantities of natural gas liquids, imported crude, and domestic crude processed by refineries under assumed conditions of refinery capacity and productivity on the assumptions that domestic crude and natural gas liquids were processed before imported crude and that natural gas liquids production was declining as it did in 1974 through 1977. It was assumed that imported crude oil will be available in sufficient quantities to fulfill refinery demands. A 90-percent refinery productivity was used in 1979 and 1980. The quantities of domestic crude oil used in the above calculations were estimated by the program CRUDPROJ, which is discussed below.

M = Refiners' margin for the product. It was defined by their December, 1978, margins grown over the period of the forecast by PGNP.

I = Contribution of imported products to the product's price. This set of values was determined by growing the cost of the imported product in December, 1978, by the assumed OPEC price schedule, and multiplying by the market share of imports of the product.

S = A set of monthly seasonal factors that represented the monthly cost variation of the product, independently of other variables.

C = A constant that represented the contribution of imports to the supply of the product.

Summary of Inputs

The following forecasted monthly variables were input to this process:

<u>Variable</u>	<u>Description</u>
OLD	= Production of old oil.
NEW	= Production of new oil.
STRIP	= Production of stripper oil.
NORSLOPE	= Production of North Slope oil.
ELKHILL	= Production of Elk Hill oil.
REFCAP	= Refinery capacity in barrels. Input annually, allocated to months in same proportions as 1977.
PGNP	= GNP price deflator, adjusted to various bases, depending on use with the program. From DRI.
OPEC	= OPEC price increase index (7901 = 1).

Seasonal factors that represented the monthly percent deviation from an annual average were:

<u>Variable</u>	<u>Description</u>
CRDRNFAC	Refinery operations.
CRDINFAC	Ratio of crude inventory to crude refinery runs.
RGPUFAC	Price of regular gasoline.
KEROFAC	Price of kerosene.
DSPUFAC	Price of diesel fuel (#2 distillate oil).
RESIDFAC	Price of residual oil.

The following variables were extrapolated by the program from a single monthly value:

<u>Variable</u>	<u>Month</u>	<u>Description--Method</u>
REFNGL	78:11	Natural gas liquids supply--average 1974 to 1977.
REFRUN	78:11	Refinery run efficiency (percent of distillation capacity used)--value of 90 percent, seasonalized using CRDRNPAC.
OLDPR	78:11	Wellhead price of old oil--PGNP.
NEWPR	78:11	Wellhead price of new oil--PGNP.
STRPR	78:11	Wellhead price of stripper oil--OPEC.
ELKHILPR	78:11	Wellhead price of Elk Hill oil--OPEC.
NORSLPR	78:11	Wellhead price of North Slope oil--OPEC.
NORSLCST	77:12	Pipehead price of North Slope oil--OPEC.
TRANCOST	77:12	Transportation cost for domestic oil--PGNP.
IMPRGWHS	78:11	Wholesale price for imported gasoline --OPEC.
IMPKJWHS	78:11	Wholesale price for imported kerosene jet fuel--OPEC.
IMPDSWHS	78:11	Wholesale price for imported #2 distillate--OPEC.
IMPRESID	78:11	Wholesale price for imported residual oil--OPEC.
IMPKEWHS	--	Wholesale price for imported kerosene --assumed to be invariant.

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CHAPTER 6
SHORT-TERM GASOLINE CONSUMPTION MODEL

This program, which is written in the Time Series Processor (TSP) language, estimated separately the number of miles traveled per vehicle, the number of vehicles, and the efficiency of the vehicles in each Petroleum Administration for Defense (PAD) region. The forecasted values for the three variables were then combined to determine the actual forecast of total consumption per day:

$$Q_G = \text{Consumption} = \frac{M \cdot S}{E}$$

6.1 Estimation

The following formulas were estimated:

$$\begin{aligned} \ln M = & B_0 + B_1 \ln I + B_2 \ln P + B_3 \ln H_1 + B_4 \ln H_2 \\ & + B_5 \ln H_3 + B_6 \ln H_4 \end{aligned}$$

[Estimation Frame: Q74:1-76:4]

$$\ln S = A_0 + A_1 \ln I$$

[Estimation Frame: Q75:1-76:4]

A pooled estimation technique was used in this process, which ensured that identical values for B were obtained in PAD1 and PAD2 and in PAD3, PAD4, and PAD5. Note that the estimation process used only data through the end of 1976, since 1977 data were not available for some variables as of the time the ARC78 work was done. The variables for the estimation were as follows:

$M = 10^6$ miles per vehicle per quarter = VMT/S .

VMT = Vehicle miles traveled from DRI (VMT) in millions of miles per quarter. DRI's annual VMT for each PAD was divided equally among the quarters in each year, then reseasonalized using factors derived from historical gasoline consumption figures for the PAD.

S = Stock of vehicles in 10^3 units. From DRI's vehicles registered (VR).

I = Per capita personal income in 10^3 dollars per person = $YP/(POP \cdot CPI)$.

YP = Total personal income for the PAD by quarter in 10^9 current dollars from DRI variable YP .

POP = PAD population for the quarter in 10^6 persons from DRI variable NR .

CPI = National consumer price index by quarter, for converting the current dollars of YP to constant 1967 dollars, from DRI variable CPI .

P = Price of gasoline in 1967 dollars per barrel =
PMG/CPI.

PMG = Price of gasoline in current dollars per
barrel. Prices in cents per gallon from Oil
and Gas Journal, "Industry Statistics," were
multiplied by 2.38 to convert cents per gallon
to dollars per barrel.

CPI = Same as above; convert price to constant 1967
dollars.

H₁, H₂, H₃, H₄ =

Quarterly heating degree days. State-level heating
degree days from the National Oceanographic and
Atmospheric Administration (NOAA) were converted to
PAD's by population-weighted averages of the
component states' values. Each of the four time
series was filled with zeroes except for the quarter
corresponding to the subscript of H, which contained
the number of heating degree days in that quarter.

6.2 Forecast

Data used for the independent variables in the forecast step were
rather complex because historical data spans varied considerably
among the various data sources. The means of obtaining the
independent variables for the forecasts were as follows:

I = Per capita personal income = YC/CPI.

YC = In the mid-demand series, DRI's DEEPRECESSION
forecast of per capita personal income (YC)
was used for 78:3 in each PAD. These values
were extrapolated to 80:4 at a growth rate of
2.4 percent per quarter, the average rate of

increase of DRI's PAD1 forecast between 78:3 and 80:4. DRI's SOFTLANDING forecast of YC was grown smoothly between 78:3 and 80:4 in all PAD's for the high demand series. DRI's DEEPPRECESSION forecast of YC was grown smoothly between 78:3 and 80:4 in all PAD's for the low demand series. Quarters 79:2 through 80:4 of the three smoothed time series were then reseasonalized using seasonal factors based upon the history of YP (see above) between 74:1 and 78:4, where YP was zero in 78:4.

CPI = National consumer price index to convert DRI's forecasts of per capita personal income and prices to 1967 dollars. In the mid and high demand series, DRI's SOFTLANDING forecast was grown smoothly between 78:3 and 80:4, while the DEEPPRECESSION forecast was similarly smoothed for the low demand series. In all three series, seasonal factors from the historical data for 74:1 through 78:4 (some forecasted) were applied to the smoothed 79:2 through 80:4 CPI's five times in a row.

P = PAD price of gasoline in 1967 dollars per barrel = PMG/CPI.

PMG = Price of gasoline in current dollars per barrel by PAD. In the high demand series, prices in all PAD's were grown at the rate of 2.4 percent per quarter from the historical value in 78:4 through 80:4. Growth rates of 2.79 percent and 3.2 percent were used in the mid and low demand series, respectively.

CPI = Same as above.

$H_1, H_2, H_3, H_4 =$

PAD heating degree days. The forecast values for this variable between 78:3 and 80:4 were averages of the NOAA data used in the historical portion, averaged over the past 30 years. All three demand series used the same values.

E = Vehicle stock efficiency in $(1/90) \cdot 10^3$ miles per barrel. The strange units are due to the means by which the initial value was computed. E for 76:4 is computed as:

$$E = \frac{\text{VMT}_{76:4}}{Q_{G76:4}}$$

where VMT was in 10^6 miles per quarter, as shown above, and Q was in 10^3 barrels per day, which gave E in 10^6 mile-days per 10^3 barrel-quarter, or $(10^3 \text{ miles per barrel-day})/90$. Since this efficiency was subsequently used in the consumption equation

$$\frac{Q}{G} = \frac{M \cdot S}{E}$$

which also contained quarters on the left and days on the right, it was convenient to maintain the unwieldy efficiency units. The efficiency computed for quarter 76:4 was forecasted on the assumption that 2.5 percent of the vehicle stock was replaced each quarter (about 10 percent per year). Values of efficiency after 1976 were therefore represented by:

$$E = E_{-1} \cdot .975 + \text{AVGMPG} \cdot F \cdot .025$$

where:

E_{-1} = Efficiency in the previous quarter.

AVGMPG = Average efficiency of new cars produced. The legislatively-mandated new-car efficiencies available from DRI in variable AVGMPG were converted to actual efficiencies by the formula:

$$\text{AVGMPG} = A \cdot 1.12 \cdot \text{AVGMPG} + B$$

where A and B are series-dependent coefficients, as follows:

Series	A	B
-----	----	----
Low Demand	.74	2.32
Mid Demand	.69	2.65
High Demand	.65	2.98

F = Factor for converting miles per gallon
to our strange efficiency units =
.00378.

This program, which is written in the Time Series Processor (TSP) language, estimated the coefficients of demand equations and forecasted the demand for residual fuel separately from distillate. In this model, demand was assumed to be synonymous with consumption. Demand was forecast by calendar quarter in each of the five Petroleum Administration for Defense (PAD) districts, the regions were aggregated, and the quarters were averaged to provide the annual national forecasts that appear in the ARC78.

The following formulas were estimated for each PAD in the model:

[Estimation Frame: 074:3-78:2]

$$\ln Q_D = B_0 + B_1 \ln I + B_2 \ln P_G + B_3 H + B_4 \ln P_{D14} + B_5 \ln P_{D23}$$

[Estimation Frame: Q74:3-78:2]

Here, a pooling technique was employed to keep certain coefficients constant across PAD's:

- B_1 and B_2 pooled between PAD1 and PAD2.
- B_1 and B_2 pooled among PAD3, PAD4, and PAD5.
- B_1 , B_2 , B_4 , and B_5 pooled between PAD1 and PAD5.
- B_1 , B_2 , B_4 , B_5 , and B_6 pooled among PAD2, PAD3, and PAD4.

The autocorrelation coefficient R, used to minimize the effects of serial correlation upon the estimated coefficients, was not pooled. The input historical variables used in the estimation step were as follows:

Q_R = Quantity of non-utility residual oil consumed in barrels per quarter = $T_R - E_R$.

T_R = Total amount of residual oil consumed in each PAD, from EIA, Energy Data Report (monthly), which shows daily average oil consumption. Each average was converted to barrels per quarter by multiplying by the number of days in the quarter.

E_R = Amount of residual oil used for electrical generation in each PAD, from Federal Energy Regulatory Commission (FERC) Form 423, which was submitted routinely by power plants.

V = Industrial value added in 1975 dollars for each PAD. These figures are available from Bureau of the Census, Annual Survey of Manufacturers, by census region. The census regions were converted to PAD's by summing the census regions or portions thereof. Apportionment of regions not coterminous with PAD's was achieved by factors derived from state-level DRI value added. Each factor for a portion of a region to be allocated to a certain PAD was the proportion of DRI's value added in the region that was attributable to the PAD.

P = Price of residual oil in 1972 dollars per barrel
R for each PAD = $PRS/PGNP$.

PRS = Price of residual oil in current dollars per barrel for each region. They were derived by selecting the highest spot prices for intrastate oil (#6) reported in Oil and Gas Journal, "Industry Statistics," published weekly, averaged over the quarter. The reported prices were allocated to PAD's as follows:

- PAD1--N.Y. Harbor
- PAD2--Chicago
- PAD3--Mid-Continent
- PAD4--Mid-Continent
- PAD5--Mid-Continent

PGNP = GNP price deflator, used to convert prices in current dollars to 1972 constant dollars. DRI's variable PGNP was used here--one series for all PAD's.

$H_1, H_2, H_3, H_4 =$

Quarterly heating degree days for each PAD. These were obtained from the National Oceanographic and Atmospheric Administration (NOAA) at the state level, aggregated to PAD's by population-weighted averages of the component states' values. Each subscript refers to an array that contained zero in all cells except the one for the indicated quarter, which was given the appropriate degree day value.

Q = Quantity of non-utility distillate fuel consumed in
D barrels per quarter = $\frac{T}{D} - \frac{E}{D}$.

T = Total amount of distillate oil consumed in
D each PAD, from EIA, Energy Data Report
(monthly), which shows daily average oil
consumption. Each average was converted to
barrels per quarter by multiplying by the
number of days in the quarter.

E = Amount of distillate oil used for electric
D utility generation in each PAD, from FERC Form
423, which is submitted routinely by a sample
of power plants.

I = Total personal income in millions of 1972 dollars
for each PAD = $\frac{YPER}{PGNP}$.

YPER = DRI's total personal income variable YP by
state aggregated to PAD's.

PGNP = Same as above.

P = Price of natural gas in 1972 dollars per billion
G Btu in each PAD = $\frac{IREV}{IBTU/PGNP}$.

IREV = Industrial natural gas revenues to suppliers
in 10^3 dollars by PAD, from American Gas
Association, Quarterly Report of Gas
Industry Operations, "Gas Utility Industry
Consumers, Sales and Revenues, By Division."

IBTU = Industrial natural gas consumption in
 10^{12} Btu by PAD, from American Gas
Association, Quarterly Report of Gas
Industry Operations, "Gas Utility Industry
Consumers, Sales and Revenues, By Division."

PGNP = Same as above.

P and P =
D14 D23

Winter and summer quarterly prices for distillate oil in 1972 dollars per barrel for each PAD. The quarterly prices $P = PDS/PGNP$.

D

PDS = Price of distillate oil in current dollars per barrel. They were derived by selecting the highest spot price for intrastate distillate oil (#2) reported in Oil and Gas Journal, "Industry Statistics," averaged over the quarter and converted from cents per gallon to dollars per barrel. The reported prices were allocated to PAD's as follows:

- PAD1--N.Y. Harbor
- PAD2--Chicago
- PAD3--Mid-Continent
- PAD4--Mid-Continent
- PAD5--Mid-Continent

PGNP = Same as above.

7.2 Forecast

Forecasted values for the independent variables were obtained from various sources, along different tracks for the three short-term series:

V = Industrial value added in 1975 dollars. These values were extrapolated using the REGSHARE model, which shares out the national DRI forecasts among the states, as described in Chapter 13. Historical data were available through 78:2. REGSHARE forecasts based upon DRI's SOFTLANDING, CONTROL, and DEEPPRECESSION forecasts of value added (variable FVA) were used in 78:3, 78:4, and 80:4. The quarters between 78:4 and 80:4 were then filled in with values obtained using a constant growth rate computed to pass through the 78:4 and 80:4 values. No reseasonalization was attempted.

P = Price of residual oil in 1972 dollars per barrel.
 R Historical data were available through 78:4.
 Forecast data were based upon the residual prices output by the Short-Term Petroleum Cost Distribution Model (STPCDM), documented in Chapter 5. The price forecasts used were derived from the STPCDM outputs by multiplying the 78:4 price for residual by the ratios of the quarterly STPCDM residual prices for the series to their 78:4 levels.

H and H₁, H₂, H₃, H₄ =

Heating degree days in each PAD. The mid demand forecast values for this variable between 78:1 and 80:4 were averages of the NOAA data used in the historical portion averaged over the past 30 years. The low and high demand forecasts used values one standard deviation higher and lower, respectively, than the averages used in the mid demand case.

I = Total personal income in millions of 1972 dollars = YPER/PGNP.

YPER = Total personal income in current dollars in each PAD from DRI's variable YPER was used for the period 78:4 through 80:4. The low demand series used DEEPRECESSION; mid demand used CONTROL and high demand used SOFTLANDING. In each series for each PAD, DRI's values between 78:4 and 80:4 were smoothed using a constant growth rate, then reseasonalized using seasonal factors based upon the historical data from 76:1 through 78:3.

PGNP = GNP price deflator used to convert income in current dollars to 1972 constant dollars. DRI's variable PGNP was used here, each of the three series using its appropriate forecast, with the usual smoothing and reseasonalization.

P = Price of natural gas in 1972 dollars per billion
 G Btu by PAD. The price forecasts used here were
 derived from the STPCDM outputs by multiplying the
 78:4 price for natural gas by the ratios of the
 quarterly STPCDM prices to their 78:4 levels.

P = Price of distillate oil in 1972 dollars per barrel.
 D Forecast data were based upon the high, medium, and
 low natural gas prices output by the STPCDM. The
 price forecasts used here were derived from the
 STPCDM outputs by multiplying the 78:4 price for
 natural gas by the ratios of the quarterly STPCDM
 prices to their 78:4 levels.

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CHAPTER 8

KLEMM'S SHORT-TERM MONTHLY NATIONAL PETROLEUM DEMAND MODEL

Klemm's Short-Term Monthly National Petroleum Demand Model (KMONAP) consists of a single program, written in the Speakeasy language, which separately forecasted the demand for eight petroleum products: gasoline, distillate, residual, propane, kerosene, kerosene-based jet fuel, petrochemical feedstocks, and other minor products. Inasmuch as other models (Short-Term Gasoline Consumption Model and Short-Term Non-Utility Petroleum Demand Forecasting Model) were the sources of gasoline, distillate, and residual figures published in the ARC78, this document will ignore measures within the program used to forecast these three fuels. Demand was forecasted for the remaining five products on a monthly, national basis from 78:06 through 80:12, the months being averaged to produce the annual forecasts appearing in the ARC78 petroleum tables as "other products." The KMONAP model performed only the forecast step for petroleum; estimation of the coefficients was performed exogenously using procedures that had not been codified into a program. Any estimation procedures described below are, therefore, descriptions not of KMONAP processing, but of independent analytical activities that feed the KMONAP model.

8.1 Estimation

The equations involved in the program are the following:

$$\ln Q_P = A_0 + A_1 H + A_2 \ln I + A_3 \ln P_P + A_4 \frac{T}{A_5}$$

$$\ln Q_J = A_0 + A_1 H + A_2 \ln I + A_3 \ln P_J + A_4 D_E + A_5 \ln Q_{J-1}$$

$$\ln Q_F = A_0 + A_1 \ln I + A_2 D_E + A_3 \ln Q_{F-1}$$

$$\ln Q_K = A_0 + A_1 H + A_2 \ln P_K + A_3 D_E + A_4 \ln Q_{K-12}$$

$$\ln Q_O = A_0 + A_1 H + A_2 \ln I + A_3 \ln P_O + A_4 \ln Q_{O-1}$$

Here, the coefficients A were estimated separately for each product. The subscript -1 describes the value of the variable in the previous month, while -12 refers to its value in the same month of the previous year. The input historical variables for the estimation were all for 68:01 through 78:06, as follows:

Q = Nationwide demand for products in barrels per day, monthly from DRI. The DRI variables used were:

Q_P = DPROE = demand for propane and propylene.

Q_J = DMD291JETKRNS = demand for oil products--jet fuel, kerosene type.

Q_F = DPF& = demand for petrochemical feedstocks.

Q = DK& = demand for kerosene.

K

Q = Demand for other refined petroleum
O products.

H = Heating degree days by month from National Oceanographic and Atmospheric Administration (NOAA) state-level data. The national figures were obtained by population-weighted averages of the monthly state data.

I = Per capita disposable income in 1967 dollars =
YD/CPI.

YD = Per capita disposable income in current dollars, nationwide, monthly, from DRI's variable YD.

CPI = Consumer price index used to convert incomes in current dollars to 1967 constant dollars, from DRI's variable CPINS.

P = Nationwide price of products. These prices were modeled in the estimation step as the ratio between the wholesale price index for the particular product and the overall wholesale price index for all industry. The denominator in each price was DRI's variable WPINS--wholesale price index for all commodities. The following wholesale price indices were used as numerators in defining the estimation prices:

P = Price of propane. Used WPI05320103NS,
P wholesale price index for gas, propane, Oklahoma, group 3. After this index was discontinued in 77:06, WPI05320104NS, wholesale price index for propane, was substituted.

P = Price of jet fuel. Used WPI0572NS, wholesale
J price index for light distillate.

P = Price of kerosene. Used WPI0572NS, wholesale
K price index for light distillate.

P = Price of other minor fuels. Used WPI057NS,
O wholesale price index for refined petroleum
products.

Here, all of the indices used in both numerator
and denominator were indexed with respect to
1967 = 100.

T - Time, beginning with some arbitrary value and
incrementing by one for each month.

D = Embargo dummy variable. This variable was
E introduced into the estimation equations to
account for the effects of the 1973-74 oil embargo.
It contained zero in all months except for the
embargo period (M73:12-74:4), when it contained one.

8.2 Forecast

In the forecast step, the following independent variables were
used:

H = Heating degree days, monthly, nationwide.
Historical values were available as described above
through 78:08. Thereafter, values used in the mid
demand series were 30-year averages of the NOAA
data used in the historical portion. The high
demand series used the same average values, with
one standard deviation from the average added to
simulate colder weather. The low demand series
assumed one standard deviation--warmer weather.

I = Per capita disposable income in 1967 dollars =
YD/CPI. Forecasted values used here for YD and CPI

were from DRI's macro model forecasts of YD and CPINS using the CONTROL, SOFTLANDING, and DEEPRECESSION scenarios, smoothed between 78:08 and 80:12 assuming a constant growth rate.

P = Nationwide price of products. Whereas the estimation of model coefficients used the ratio of the product's wholesale price index to the wholesale price index for all commodities, the forecast used prices for products supplied by the Short-Term Petroleum Cost Distribution Model (STPCDM). Each price series was converted to the estimation scheme by:

- 1) normalizing the price series by dividing through by the 78:07 price value;
- 2) converting to product WPI by multiplying by the historical product WPI for 78:06; and
- 3) dividing by the forecasted WPINS from the corresponding DRI macro series: CONTROL, SOFTLANDING, or DEEPRECESSION.

Since the STPCDM did not supply price time series for all products forecasted by the KMONAP model, step 1 above selected prices as follows:

<u>KMONAP Variable</u>	<u>STPCDM Variable Used</u>
P	Distillate
P	
P	Jet fuel
J	
P	Kerosene
K	
P	Distillate
O	

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CHAPTER 9

STRUCTURED SHORT-TERM ELECTRICITY FORECASTING MODEL

This model forecasted electricity sales in each of four economic sectors--residential, commercial, industrial, and other--by DOE region, monthly. The model consists of three programs:

- STEP1. This FORTRAN program reads a series of small input data files, formatting them for input to STEP2.
- STEP2. This Time Series Processor (TSP) program estimates the coefficients of the model equations, then forecasts electricity sales.
- STEP3. This FORTRAN program forecasts the "other" sector and aggregates the historical and forecasted electricity sales figures.

The three programs are not discussed separately, as their interactions are quite simple.

9.1 Estimation

In each DOE region, for the residential, commercial, and industrial sectors, the model estimated electrical sales according to the formula:

$$\ln Q_E = A_0 + A_1 \ln H + A_2 \ln C + A_3 \ln I + A_4 \ln P_E - R \left[A_0 + A_1 \ln H_{-1} + A_2 \ln C_{-1} + A_3 \ln I_{-1} + A_4 \ln P_{E-1} - \ln Q_{E-1} \right]$$

[Estimation Frame: M75:01-77:12]

where A_0 through A_4 and the autoregression coefficient R --the latter introduced to eliminate the effects of serial correlation upon the other coefficients--were estimated separately in each region and sector. A total of 30 equations was therefore estimated. Variables subscripted with -1 indicate that the value of the variable in the previous month was used in the estimation and forecast. In the following equations, I was omitted because it gave non-intuitive values for A_3 :

<u>Region</u>	<u>Sector</u>
5	Industrial
7	Residential
7	Industrial
8	Industrial
9	Commercial

The input historical variables for the estimation were as follows:

Q_E = Quantity of electricity sold in 10^3 Kwh. State-level quantities by sector and month from Federal Energy Regulatory Commission (FERC) Form 5 utility survey were aggregated to DOE regions.

- H = Heating degree days, obtained from the National Oceanographic and Atmospheric Administration (NOAA) monthly at the state level. DOE regional values were estimated by simple arithmetic means of the component states' values.
- C = Cooling degree days, obtained from NOAA, monthly at the state level. DOE regional values were estimated by simple arithmetic means of the component states' values.
- P = Price of electricity in 1967 constant dollars per
E Kwh. Electricity revenues in dollars and sales in 10³ Kwh from FERC Form 5 by state, month, and sector were used in computing price by DOE region, month, and sector. Within each month and sector, state-level revenues and sales were aggregated to region. Price was then computed as:

$$P = \text{Revenues} / \text{Sales}$$

E

These current-dollar values were then converted to 1967 constant dollars by dividing by CPI in the residential sector and WPI in the commercial and industrial sectors, where CPI and WPI are as described below.

- I = Total personal income in 10⁹ dollars by month and state from DRI's variable YP, aggregated to DOE regions. These current-dollar values were then converted to 1967 constant dollars by dividing by CPI in the residential sector and WPI in the commercial and industrial sectors, where CPI and WPI are as described below.

CPI = Consumer price index from DRI's variable CPI.

WPI = Wholesale price index from DRI's variable WPI.

As discussed in Section 9.2, no estimation step was involved in the forecast of the "other" sector.

9.2 Forecast

For forecasting purposes, values for the independent variables were derived as follows:

- H and C. Heating and cooling degree days were both forecast in the same way. Monthly, state-level data from NOAA were averaged over 30 years to determine typical weather conditions for each calendar month. A simple arithmetic mean of the values for the states within each DOE region produced monthly regional degree days which were used in the mid demand series.
- I and P. Income and price were forecast in similar ways in this model. A constant annual growth rate was applied to the value of the variable in each month of 1977, which gave a set of 12 independent forecasts. The following growth rates were used:

<u>Series</u>	<u>I Rate(%)</u>	<u>P Rate(%)</u>
Low Demand	1.7333	2.4000
Mid Demand	2.7005	2.2670
High Demand	2.8167	1.7000

Electricity sales in the "other" sector were forecast at the national, annual level, at the average rate of the other three sectors. This was accomplished by the computation of an annual rate of change in the national totals of electricity sales in each of the three sectors. The mean of the three sectors' rates of change, weighted by their sales, was used as the "other" sector's rate of change in each year.

CHAPTER 10

SHORT-TERM NATURAL GAS DEMAND MODEL

The Short-Term Natural Gas Demand Model (STNGDM) consists of three programs, each written in the Time Series Processor (TSP) language. One program each is included for both estimation and forecasting of residential, commercial, and industrial natural gas demand. In this model, demand was assumed to be synonymous with consumption and sales except in the industrial sector, where the demand equations were estimated for the sum of consumption and firm curtailments. The three programs all forecasted demand by calendar quarter in each of the nine census regions, aggregating the quarters and regions to produce the annual national forecasts that appear in the ARC78. A separate section below is devoted to each program's processing.

10.1 Residential Natural Gas Consumption

This program estimated separately the amount of natural gas consumed by each customer and the number of customers using natural gas. The forecasted values for these two variables were then multiplied to determine the actual forecast of total consumption:

$$\text{Consumption} = S * C$$

where:

$$\begin{aligned} \ln S = & A_0 + A_1 \ln I + A_2 \ln H + A_3 \ln H + A_4 \ln H \\ & + A_5 \ln H + A_6 \ln P + A_7 \ln P + A_8 \ln P \\ & + A_9 \ln P + A_{10} \ln P \end{aligned}$$

[Estimation Frame: Q68:2-77:4]

$$\begin{aligned} \ln C = & B_0 + B_1 \ln I + B_2 \ln P - R(B_0 + B_1 \ln I \\ & + B_2 \ln P - \ln C_{-1}) \end{aligned}$$

[Estimation Frame: Q75:1-77:4]

Here, the coefficients A_0 through A_{10} and B_0 through B_2 and the autocorrelation coefficient R --the latter introduced to eliminate the effects of serial correlation upon the other coefficients--were estimated separately in each of the nine census regions using quarterly time series for the input variables. Variables subscripted with -1 indicate that the value of the variable in the previous quarter was used in the estimation and forecast. The input historical variables for the estimation were as follows:

S = Sales per residential customer = $BTUR/RCUST$.

$BTUR$ = Regional residential natural gas consumption by quarter in 10^{12} Btu, from American Gas Association, Quarterly Report of Gas Industry Operations, "Gas Utility Industry Consumers, Sales and Revenues, By Division."

RCUST = Number of residential natural gas customers in each region by quarter, from American Gas Association, Quarterly Report of Gas Industry Operations, "Gas Utility Industry Consumers, Sales and Revenues, By Division."

$H_1, H_2, H_3, H_4 =$

Quarterly regional heating degree days, obtained from the National Oceanographic and Atmospheric Administration (NOAA) at the state level, aggregated to census regions by population-weighted averages of the component states' values.

$I = \text{Income per person} = YPR/POP/CPI.$

YPR = Total personal income for the region by quarter in 10⁹ dollars, from DRI's variable YPR.

POP = Regional population in millions by quarter, from DRI's variable POP.

CPI = National consumer price index by quarter, for converting the current dollars in YPR to constant 1967 dollars, from DRI's variable CPI.

$P = \text{Price of residential natural gas} = RREV/BTUR/CPI.$

RREV = Regional residential natural gas revenues to suppliers in dollars, from American Gas Association, Quarterly Report of Gas Industry Operations, "Gas Utility Industry Consumers, Sales and Revenues, By Division."

BTUR = Same as above.

CPI = Same as above.

Better fits were achieved in some regions by estimating separate price coefficients for all quarters using coefficients A_7 through A_{10} . The variables P_1 through P_4 are time series that contained zero in all quarters except the ones designated by the subscript. The non-zero quarterly values were excerpted from the corresponding quarters of the time series P . The following census regions were forecast using coefficients A_7 through A_{10} , rather than A_6 :

- 2 - Middle Atlantic
- 8 - Mountain
- 9 - Pacific

All other regions used coefficient A_6 rather than A_7 through A_{10} .

C = Number of residential natural gas customers in each region by quarter, from American Gas Association, Quarterly Report of Gas Industry Operations, "Gas Utility Industry Consumers, Sales and Revenues, By Division." (Same as RCUST, above.)

For forecasting purposes, forecasted values for the independent variables were obtained from various sources, along different tracks for the three short-term series. These sources were as follows:

I = Income per person. This time series was derived by using DRI's SOFTLANDING, CONTROL, and DEEPPRECESSION forecasts for per capita personal income (YCAP) for 78:1 through 78:4 and 80:4. The quarters between 78:4 and 80:4 were evaluated by determining the quarterly growth rate between the two quarters:

$$\text{Rate} = \left[\frac{\begin{matrix} I \\ 80:4 \end{matrix}}{\begin{matrix} I \\ 78:4 \end{matrix}} \right]^{\frac{1}{8}}$$

and applying this rate to each quarter in succession. Here, the DRI values in 1972 dollars were converted to the 1967 dollars used in the estimation by dividing by 1.25.

$$H_1, H_2, H_3, H_4 =$$

Regional heating degree days. The forecast values for this variable between 78:1 and 80:4 were averages of the NOAA data used in the historical portion, averaged over the past 30 years. The high demand series used one standard deviation more heating degree days than the average; the low demand used one standard deviation less.

P = Price of residential natural gas. Forecasts of this variable were computed in the Short-Term Petroleum Cost Distribution Model (STPCDM), documented in Chapter 5. The STPCDM forecast, which was national and annual, was reduced to growth rates by assigning one quarter of each annual percent change to each quarter. Each resulting quarterly growth rate was then applied to the previous quarter's regional prices, starting with 77:4. Quarterly rates of price increase in the three series for 1979 and 1980 were:

- High demand--.65 percent
- Mid demand--1.15 percent
- Low demand--1.65 percent

while the 1978 quarterly rate was -.45 percent. These values were then reseasonalized using seasonal factors derived from the 68:1 through 77:4 prices.

$$P_1, P_2, P_3, P_4 =$$

Quarterly residential natural gas prices. These prices were generated from P in the same way as in the historical case.

10.2 Commercial Natural Gas Consumption

This program estimated separately the coefficients that determine the amount of natural gas consumed by each commercial customer and the number of commercial natural gas customers. In the forecast step, these two variables were then multiplied to obtain the actual forecast of consumption (demand):

$$\text{Consumption} = S * C$$

where:

$$\begin{aligned} \ln S = & A_0 + A_1 \ln I + A_2 \ln P + A_3 \ln H_1 + A_4 \ln H_2 \\ & + A_5 \ln H_3 + A_6 \ln H_4 \end{aligned}$$

[Estimation Frame: Q68:1-77:4]

$$\begin{aligned} \ln C = & B_0 + B_1 \ln I + B_2 \ln P - R(B_0 + B_1 \ln I \\ & + B_2 \ln P - \ln C_{-1}) \end{aligned}$$

[Estimation Frame: Q75:1-77:4]

Here, the coefficients A_0 through A_6 and B_0 through B_2 and the autocorrelation coefficient R --the latter introduced to eliminate the effects of serial correlation upon the other coefficients--were estimated separately in each of the nine census regions using quarterly time series for the input variables. Variables

subscripted with -1 indicate that the value of the variable in the previous quarter was used in the estimation and forecast. The input historical variables for the estimation were as follows:

S = Sales per commercial customer = $BTUC/CCUST$.

$BTUC$ = Regional commercial natural gas consumption by quarter in 10^{12} Btu, from American Gas Association, Quarterly Report of Gas Industry Operations, "Gas Utility Industry Consumers, Sales and Revenues, By Division."

$CCUST$ = Number of commercial natural gas customers in each region by quarter, from American Gas Association, Quarterly Report of Gas Industry Operations, "Gas Utility Industry Consumers, Sales and Revenues, By Division."

$H_1, H_2, H_3, H_4 =$

Quarterly regional heating degree days, obtained from NOAA at the state level, aggregated to census regions by population-weighted averages of the component states' values.

I = Income per person = $YPR/POP/CPI$.

YPR = Total nominal personal income for the region by quarter in 10^9 dollars, from DRI's variable YPR .

POP = Regional population in millions by quarter, from DRI's variable POP .

CPI = National consumer price index by quarter, for converting the current dollars in YPR to constant 1967 dollars, from DRI's variable CPI .

C = Number of commercial customers = CCUST, as described above.

P = Commercial natural gas prices = CREV/BTUC/CPI.

CREV = Regional commercial natural gas revenues to suppliers in dollars, from American Gas Association, Quarterly Report of Gas Industry Operations, "Gas Utility Industry Consumers, Sales and Revenues, By Division."

BTUC = Same as above.

CPI = Same as above.

For forecasting purposes, forecasted values for the independent variables were obtained from a variety of sources, along different tracks for the three short-term series. These sources were as follows:

I = Income per person. This time series was derived by using DRI's SOFTLANDING, CONTROL, and DEEPPRECESSION forecasts for per capita personal income (YCAP) for 78:1 through 78:4 and 80:4. The quarters between 78:4 and 80:4 were evaluated by determining the quarterly growth rate between the two quarters:

$$\text{Rate} = \left[\frac{I_{80:4}}{I_{78:4}} \right]^{\frac{1}{8}}$$

and applying this rate to each quarter in succession. Here, the DRI values in 1972 dollars are converted to the 1967 dollars used in the estimation by dividing by 1.25.

$H_1, H_2, H_3, H_4 =$

Regional heating degree days. The forecast values for this variable between 78:1 and 80:4 were averages of the NOAA data used in the historical portion, averaged over the past 30 years. The high demand series used one standard deviation more heating degree days than the average; the low demand used one standard deviation less.

P = Price of commercial natural gas. Forecasts of this variable were computed in the Short-Term Petroleum Cost Distribution Model. The STPCDM forecast, which was national and annual, was reduced to growth rates by assigning one quarter of each annual percent change to each quarter. Each resulting quarterly growth rate was then applied to the previous quarter's regional prices, starting with 77:4. Quarterly rates of price increase in the three series for 1979 and 1980 were:

- High demand--.65 percent
- Mid demand--1.15 percent
- Low demand--1.65 percent

while the 1978 quarterly rate was -.45 percent. These values were then reseasonalized using seasonal factors derived from the 68:1 through 77:4 prices.

$P_1, P_2, P_3, P_4 =$

Quarterly commercial natural gas prices. These prices were generated from P in the same way as in the historical case.

10.3 Industrial Natural Gas Consumption

This program estimated directly the demand for natural gas, according to the following formula:

$$\ln D = A_0 + A_1 \ln V + A_2 \ln P_1 + A_3 \ln P_2 + A_4 \ln P_3 + A_5 \ln P_4$$

[Estimation Frame: Q71:4-77:4]

The coefficients A_0 through A_5 were estimated separately in each of the nine census regions using quarterly time series for the input variables. The input historical variables for this estimation were as follows:

D = Demand for industrial natural gas = BTUI + FCUR.

BTUI = Regional industrial natural gas consumption by quarter in 10^{12} Btu, from American Gas Association, Quarterly Report of Gas Industry Operations, "Gas Utility Industry Consumers, Sales and Revenues, By Division."

FCUR = Regional firm curtailments to industrial natural gas users in 10^{12} Btu.

V = Industrial value added in 1975 dollars for each census region. These figures are available from Bureau of the Census, Annual Survey of Manufacturers, by census region. The census regions were converted to PAD's by summing the census regions or portions thereof. Apportionment of regions not coterminous with PAD's was achieved by factors derived from state-level DRI value added. Each factor for a portion of a region to be allocated to a certain PAD was the proportion of DRI's value added in the region that was attributable to the PAD.

$P_1, P_2, P_3, P_4 =$

Seasonal industrial prices for natural gas = IREV/
BTUI/CPI.

IREV = Regional industrial natural gas revenues to suppliers in dollars, from American Gas Association, Quarterly Report of Gas Industry Operations, "Gas Utility Industry Consumers, Sales and Revenues, By Division."

BTUI = Same as above.

CPI = Same as above.

For forecasting purposes, forecasted values for the independent variables were obtained from various sources, along different tracks for the three short-term series. These sources were as follows:

V = Industrial value added in 1975 dollars for each census region. These figures are available from Bureau of the Census, Annual Survey of Manufacturers, by census region. The census regions were converted to PAD's by summing the census regions or portions thereof. Apportionment of regions not coterminous with PAD's was achieved by factors derived from state-level DRI value added. Each factor for a portion of a region to be allocated to a certain PAD was the proportion of DRI's value added in the region that was attributable to the PAD.

$P_1, P_2, P_3, P_4 =$

Quarterly industrial natural gas prices. Forecasts of this variable were computed in the Short-Term Petroleum Cost Distribution Model. The STPCDM forecast, which was national and annual, was reduced to growth rates by assigning one quarter of each annual percent change to each quarter. Each resulting quarterly growth rate was then applied to the previous quarter's regional prices, starting with 77:4. The 1978 quarterly rate of increase was .4 percent, while the three forecast series used in each quarter the following rates of increase:

- High demand--1.05 percent
- Mid demand--1.55 percent
- Low demand--2.05 percent

The resulting prices were then reseasonalized using seasonal factors derived from 68:1 through 77:4 prices.

PART III

MIDTERM FORECASTING

PART III

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CHAPTER 11

SUMMARY OF MAJOR COMPONENTS

11.1 Introduction

Of the three forecasting periods, the midterm, covering 1985, 1990, and 1995, is currently the most extensively developed in terms of forecasting models and associated procedures. Furthermore, for the ARC78, the midterm models were interrelated in a way that allowed the examination of cause-and-effect relationships between the U.S. energy system, the U.S. economy, and international energy and economic systems. This model interaction represented a substantial improvement in the methodological basis used to generate the midterm forecasts. In this chapter, the major interfaces between models are discussed to serve as an introduction to the more detailed model descriptions provided in Chapters 12, 13, and 14. The two primary interactions described are:

- international-domestic, which relates to the interaction between the world price of oil, OPEC production, and international and domestic energy and economic systems; and
- U.S. economy-energy, which relates in a more detailed way to the interaction between the U.S. economy and domestic supply and demand of energy.

11.2 International-Domestic Interactions

At the world scale, the United States is in competition with other nations for energy. Key determinants in this competition are the world price of crude oil and OPEC production capacity, which influence the levels of crude oil imports by nations and, in turn, the levels of energy consumption and economic growth. The system interactions described in this section attempt to capture the cause-and-effect relationships at this worldwide level.

Figure 11-1 shows, in a simplified manner, the major components of the midterm forecasting process and their primary interfaces at the international level. The major modeling components are:

- the Oil Market Simulation (OMS) Model;
- the Data Resources, Inc., Quarterly Econometric Model of the U.S. Economy (DRI);
- foreign econometric forecasts;
- the Midterm Energy Forecasting System (MEFS); and
- the International Energy Evaluation System (IEES).

The Oil Market Simulation Model is a parametric representation of the world oil market. This model includes a reduced form representation of the other four major modeling components--the DRI, IEES, MEFS, and foreign economic models. It simulates world oil supplies and demands by region (the United States, Canada, Japan, OECD-Europe, developing countries, and net-communist

FIGURE 11-1
MAJOR MIDTERM FORECASTING COMPONENTS AND INTERACTIONS

trade) on an annual basis through 1995. The model consists of regional oil supply and demand equations with oil demand determined as a function of both prices and income. It can be used to simulate OPEC production, given a projection of world crude oil prices, or, conversely, to simulate world crude oil prices for given levels of OPEC production. Input to the model consists of reference supply and demand paths and price elasticities over time for each region, elasticities of the growth in gross domestic product (GDP) for each region with respect to price (feedback elasticities), and assumptions regarding OPEC production behavior. Output from the model includes regional petroleum demand, quantities of petroleum supplied by OPEC and non-OPEC sources, the level of U.S. imports, and world crude oil prices.

The Data Resources, Inc., Quarterly Econometric Model of the U.S. Economy is a large-scale, simultaneous-equation econometric model. It forecasts detailed breakdowns of consumer spending; business investment in plant, equipment, and inventories; construction activity; government receipts and expenditures; wages, profits, and interest; major price indices; and imports and exports. Financial projections such as interest rates, monetary aggregates, and household and corporate flows of funds and mortgage activity are also produced. The DRI model interfaces with the OMS model and the MEFS as well as with other short-term and midterm models, as discussed in other chapters. In general, the model is used to generate macroeconomic forecasts

based on energy scenarios such as the impact of real world crude oil prices on the U.S. economy, on potential U.S. gross national product (GNP), and on foreign industrialized economies.

For the ARC78, the foreign economic forecasts were derived from a variety of sources, including DRI data and models, World Bank data, and OECD figures.

The Midterm Energy Forecasting System is the major midterm (six to 19 years) integrated forecasting and analysis capability for projecting the state of the domestic energy market. The MEFS is not a model, but rather a system of numerous interrelated models that together form an extensively-developed forecasting system. It is used to make forecasts of domestic energy prices, supplies, demand, and conversion activities. The system is an analytical tool that can be used to examine the potential impact of changes in federal energy policies, to compare differing resource and technological option assumptions (e.g., high versus low discovery rates for oil), and to project the impacts of varying political, tax, and regulatory environments. As a system, the MEFS consists of a series of supply models for each major energy fuel, a demand model to project fuel demands by end-use sector, and numerous other models and methodologies for fuel conversion by refineries and utilities, and for transportation of energy products. These supply and demand components are integrated in the Midterm Energy Market Model (MEMM), which produces forecasts for:

- U.S. energy requirements for the next six to 19 years (through 1995);
- the mix of fuels necessary to satisfy these demand requirements, and their market prices;
- the geographic regions from which these fuels will be extracted or imported;
- the methods for converting raw materials to petroleum products or electricity;
- the modes of distribution of these fuels throughout the country; and
- the types and capacities of new energy-related facilities required to satisfy energy demands.

The International Energy Evaluation System is a partial equilibrium model of world energy supply and demand, which can be simulated for the years 1985, 1990, and 1995. It can be used to analyze the effects of crude oil pricing and production strategies and U.S. energy policy on world energy supplies, demands, and trade. The IEES, like the MEFS, is a system consisting of numerous supply, demand, conversion, and transportation models integrated by a model similar to the MEMM. For each major industrialized country in the western world, the IEES simulates total energy demands by product type, consuming sector, and source of supply. Energy-specific supplies and demands are equilibrated vis-a-vis market prices for each energy product. The system can incorporate assumptions concerning OPEC policies, U.S. energy policies, and constraints on world energy production. Input consists of specification of a world transportation network linking major ports and demand centers, capacity and performance data for major refineries and electric

utilities, estimates of hydroelectric and nuclear generation, and world energy supply and demand curves that reflect their sensitivity to price. Output consists of energy supply and demand balances and price by region and by energy products.

The primary interactions between the five modeling components to produce the ARC78 forecasts were as follows:

- A base, or reference, case was developed using results obtained from recent runs of all the major components. This base case consisted of worldwide regional estimates for crude oil supply and demand; assumptions regarding OPEC production capacity; and supply, demand, and feedback elasticities with respect to price. The feedback elasticities represented the percent decrease in domestic GNP or foreign GDP's resulting from a one-percent increase in world oil price.
- The OMS model was run using this base case to obtain an initial projection of world regional supply and demand balances and world oil price paths over time.
- World oil prices are affected by many factors, the most important of which is world economic growth, which drives the demand for petroleum. Hence, a series of iterations was performed, involving the OMS, DRI, and foreign macroeconomic models. The purpose here was to improve on

the economic feedback elasticities that reflect world regional economic growths. The OMS model produced world oil price paths that were input to the macroeconomic models; these models then produced feedback elasticities which were, in turn, input back into the OMS model to obtain improved world oil price paths. In theory, this iterative process should be continued until it converges--that is, until changes in prices and elasticities between iterations are minimal. In practice, the number of iterations was limited by constraints on computer time and other resources. The non-U.S., or foreign, feedback elasticities were developed without benefit of extensive iteration. Non-OPEC production was assumed to vary with price; OPEC-production was not assumed to be price-elastic.

- The OMS model was then iterated with the IEES to calibrate worldwide supply and demand elasticities with respect to world oil price for all regions except the United States. The world oil price path resulting from the feedback elasticity calibration runs was input to the IEES, and supply and demand curves were determined. From these new curves, a revised set of supply and demand elasticities with respect to price was computed. The OMS model was rerun with the revised elasticities and a new price path was obtained. This process was repeated until the elasticities converged.

- Similarly, an iteration between the OMS model and the MEFS was run to calibrate the domestic supply and demand elasticities. The final run of the elasticities determined from the MEFS in the OMS model yielded the final world oil price paths--the price profiles for imported oil. This completed the domestic-international interaction process. From that point on, the domestic and international models were exercised independently to produce the detailed forecasts presented in the ARC78.

For additional detail regarding model input and outputs, see Chapters 12 and 13; Section 12.1 of Chapter 12, which addresses the OMS model, its structure, and calibration of elasticities, is of particular interest. The outputs of this process were supply, demand, and price equilibrium solutions, at the world-region level, which set world crude oil price paths and regional imports of OPEC production under varying assumptions regarding OPEC productive capacity. These oil price trajectories and import levels were then used as input to the MEFS, DRI, and IEES to conduct the more detailed analyses.

11.3 U.S. Economy Energy Interactions

This section details the domestic side of the model components shown in Figure 11-1. To some extent, the process described below was performed to achieve calibration of the elasticities

for the OMS model. For example, the macroeconomic forecasts from the DRI model, resulting from the DRI-OMS iterations to refine the feedback elasticities, were also used in the MEFS during the MEFS-OMS iterations to refine the supply, demand, and income response elasticities. In general, however, the process described here was performed to forecast domestic energy and economic futures.

Figure 11-2 shows the components and major interactions for the U.S. economy and energy systems. First, each of the model components is described; then, the interactions are discussed. For continuity, several of the brief model descriptions are repeated from the preceding section.

The DRI model, a large-scale, simultaneous-equation econometric model, forecasts detailed breakdowns of consumer spending; business investment in plant, equipment, and inventories; construction activity; government receipts and expenditures; wages, profits, and interest; major price indices; and imports and exports. Financial projections such as interest rates, monetary aggregates, and household and corporate flows of funds and mortgage activity are also produced. The DRI model interfaces with the OMS model and the MEFS as well as with other short-term and midterm models, as discussed in other chapters. In general, the model is used to generate macroeconomic forecasts based on energy scenarios such as the impact of real world crude oil prices on the U.S. economy, on potential U.S. GNP, and on foreign industrialized economies.

FIGURE 11-2

ENERGY-ECONOMIC INTERACTIONS AND IMPACTS

The REGSHARE model develops projections, for each DOE region, of population, disposable income, and value added by industry. It uses projected regional distribution patterns to allocate national totals output by the DRI model. REGSHARE model results, which reflect how DOE regional trends in population, disposable income, and value added are affected by changes in the national economy, serve as input to the Regional Energy Demand Forecasting (RDFOR) Model.

The MEFS, the major midterm (six to 19 years) integrated forecasting and analysis capability for projecting the state of the domestic energy market, is not a model, but rather a system of numerous interrelated models that together form the most extensively-developed forecasting system in use at EIA. It is used to make forecasts of domestic energy prices, supplies, demand, and conversion activities. The system is an analytical tool that can be used to examine the potential impact of changes in federal energy policies, to compare differing resource and technological option assumptions (e.g., high versus low discovery rates for oil), and to project the impacts of varying political, tax, and regulatory environments. As a system, the MEFS consists of a series of supply models for each major energy fuel, a demand model to project fuel demands by end-use sector, and numerous other models and methodologies for fuel conversion by refineries and utilities, and for transportation of energy products. These supply and demand components are integrated in the MEMM, which produces forecasts for:

- U.S. energy requirements for the next six to 19 years (through 1995);
- the mix of fuels necessary to satisfy these demand requirements, and their market prices;
- the geographic regions from which these fuels will be extracted or imported;
- the methods for converting raw materials to petroleum products or electricity;
- the modes of distribution of these fuels throughout the country; and
- the types and capacities of new energy-related facilities required to satisfy energy demands.

A set of four impact models, which operate off DRI and MEFS output, produces projections of various implications resulting from the economic and energy forecasts. Briefly, these models have the following characteristics:

- The Energy Disaggregated Input-Output (EDIO) Model uses economic forecasts from the DRI model to produce target year projections of output and employment for 117 sectors of the U.S. economy, including 17 energy sectors.
- The Regional Earnings Impact System (REIS) uses the output of the EDIO model to forecast changes in annual earnings by state in each of 37 industrial sectors.
- The Micro Analysis Transfers to Households/Comprehensive Human Resources Data System (MATH/CHRDS) uses output from the MEFS to project the impacts of energy forecasts at the household level by socioeconomic variables such as age, sex, race, income, and location.
- The Regional Emission Projection System (REPS) uses MEFS energy forecasts to project target year levels of selected air pollutants by airshed, aggregated to DOE region.

For the ARC78, the model components cited above interacted in the following ways:

- The DRI model was run using world crude oil prices and import projections (from the OMS model, for example).
- The DRI national economic forecasts were regionalized using the REGSHARE model.
- The regional economic forecasts were input to the RDFOR model to produce demand curve inputs to the MEMM.
- The MEMM was run, using appropriate supply curves and iterating with the RDFOR model to adjust demand until a supply/demand equilibrium was achieved.
- The MEFS energy projection was input back into the DRI model to produce a new economic projection.
- This new economic forecast was then input back into the MEFS, through the REGSHARE model, to obtain a revised energy projection.
- This cycle was repeated until the DRI and MEFS projections converged to within one percent or less.
- The resultant economic and energy projections were then used as input to the impact models--EDIO, REIS, MATH/CHRDS, and REPS.
- The entire process was repeated for each scenario.

The three chapters that follow provide additional details regarding the models cited in this chapter. Chapter 12 addresses the international models that form the focus of Section 11.2, above. The DRI, REGSHARE, and MEFS models are covered in Chapter 13; the MEFS, in particular, is described in substantially greater detail than that provided here. Finally, the four impact models are discussed in Chapter 14.

CHAPTER 12

WORLD ENERGY SUPPLY AND DEMAND

12.1 Oil Market Simulation Model12.1.1 Introduction

The Oil Market Simulation (OMS) Model is a parametric representation of the world crude oil market. The model incorporates in a reduced form aspects of the International Energy Evaluation System (IEES), the DRI macroeconomic model (DRI), and the Midterm Energy Forecasting System (MEFS) that relate to crude oil supply, demand, and prices. The model can be used to project OPEC production given a projection of world crude oil prices, or to project world crude oil prices for given levels of OPEC production. Output from the model includes regional crude oil demand, quantities of crude oil supplied by OPEC and non-OPEC sources, the level of U.S. imports, and world crude oil prices. For the ARC78, the primary outputs of interest from the OMS model were annual world oil price paths through 1995.

12.1.2 Methodology

The OMS model consists of supply and demand relationships for major oil-producing and oil-consuming regions of the world. These relationships can be classified as either price-dependent or price-independent, based upon whether or not supply or demand responds to the level of world oil prices. The demand and supply regions considered in the model are:

<u>Demand Regions</u>	<u>Price-dependent?</u>
U.S. 50-state area	Yes
U.S. territories	No
U.S. strategic petroleum reserves	No
Canada	Yes
Japan	Yes
Western Europe	Yes
OPEC	No
Other countries	Yes
 <u>Supply Regions</u>	
United States	Yes
Canada	Yes
Japan	Yes
Western Europe	Yes
OPEC (residual supplier)	Yes
Other countries	Yes
Non-U.S. synthetics	No
Centrally-planned economies (CPE's)	No

In addition to the regional supply and demand relationships, the OMS model incorporates an integrating equation that effects a supply-demand balance with OPEC as the residual supplier. Within this integrating equation, supplies and demands for the regions that are price-dependent affect the extent to which the worldwide

oil market is in equilibrium. The regions that are not price-dependent are simply accounted for in the balancing equation.

The second major aspect of the model concerns the market-clearing mechanism, whereby the model adjusts price when there is an imbalance in the market equilibrium during a price run of the model. The market-clearing price algorithm is illustrated below in Figure 12-1. OPEC demand in Figure 12-1 refers to the required imports of OPEC oil by the free-world regions to fulfill their otherwise unsatisfied demand. As shown in the figure, demand for OPEC oil is determined and compared with OPEC capacity. If capacity exceeds demand, oil prices are decreased (if greater than optionally-specified minimum, or floor, prices), and the demand and supply relationships are utilized to adjust world oil forecasts. Similarly, if demand exceeds OPEC capacity, oil prices are increased, and forecasts are adjusted accordingly. When demand for OPEC oil is equal to OPEC capacity, the market-clearing price has been determined.

The OMS model consists of the following relationships:

$$(1) \sum_i \left[\text{DEMAND}_i(t) \right] = \text{OPEC PRODUCTION}(t) + \sum_j \left[\text{SUPPLY}_j(t) \right]$$

$$(2) \frac{\left[\text{SUPPLY}_j(t) \right]}{\left[\text{SUPPLY}_{Rj}(t) \right]} = \frac{\left[\text{SUPPLY}_j(t-1) \right]^A}{\left[\text{SUPPLY}_{Rj}(t-1) \right]} * \frac{\left[\text{PRICE}(t) \right]^B}{\left[\text{PRICE}(t) \right]^B}$$

FIGURE 12-1. OMS PRICING ALGORITHM

$$(3) \begin{bmatrix} \text{DEMAND (t)} \\ i \\ \text{DEMAND (t)} \\ R_i \end{bmatrix} = \begin{bmatrix} \text{DEMAND (t-1)} \\ i \\ \text{DEMAND (t-1)} \\ R_i \end{bmatrix}^C_i * \begin{bmatrix} \text{PRICE (t)} \\ i \\ \text{PRICE (t)} \\ R \end{bmatrix}^D_i$$

$$* \begin{bmatrix} \text{GNP (t)} \\ i \\ \text{GNP (t)} \\ R_i \end{bmatrix}^G_i$$

$$(4) \begin{bmatrix} \text{GNP (t)} \\ i \\ \text{GNP (t)} \\ R_i \end{bmatrix} = \begin{bmatrix} \text{PRICE (t)} \\ i \\ \text{PRICE (t)} \\ R \end{bmatrix}^F_i$$

where i is an index for demand regions, j is an index for non-OPEC supply regions, t represents a given year, and R refers to a supply, demand, and price reference case. Hence, while equation (1) deals with the actual level of regional supplies and demands, equations (2), (3), and (4) all have price, supply, demand, and income (GNP) expressed relative to the reference case.

The model coefficients that control the model response to price are calibrated exogenously to simulate the behavior of the large-scale EIA models. The lag terms in (2) and (3) control the speed at which a market response to price accumulates over time.

For the ARC78, the model was used in conjunction with the IEES, the MEFS, the DRI macro model, and other macroeconomic models and data. The process involving the OMS model was as follows:

- A reference case was developed using recent runs of all major components. This reference case consisted of regional estimates of petroleum supply and demand, price forecasts, and OPEC production capacity projections. Using the reference case, model parameters were initially estimated; this included lagged supply and demand coefficients, supply and demand price elasticities, income response parameters, and economic feedback elasticities.
- The OMS model was then run, using the reference case, to obtain an initial projection of world regional supply and demand balances--including imports--and the resultant world oil price path.
- A series of iterations was then performed involving the OMS model, the DRI U.S. macro model, and the foreign macroeconomic models for the purpose of improving the estimates of the economic feedback elasticities and income response parameters. World oil price paths produced by the OMS model were used as input by the macroeconomic models; the macro models' output was then used to calculate revised feedback elasticities and income response parameters, which were in turn used in the OMS model to obtain improved price

forecasts. In theory, this iterative process should be continued until changes in prices and economic activity between iterations are minimal--that is, until convergence is achieved. In practice, however, the number of iterations performed between models throughout the ARC78 forecasting process was limited by constraints on computer time and other resources.

- Next, iterations were performed using the OMS model and the IEES to calibrate regional supply and demand price elasticities and lagged supply and demand coefficients for all regions except the United States. Price paths produced by the OMS model were used in the IEES, and IEES output was used to compute revised OMS parameters. The OMS model was then run again to produce a new price forecast. This process was repeated several times to improve the parameter estimates.
- Similarly, iterations were performed using the OMS model and the MEFS to calibrate model parameters associated with domestic supply and demand. After reasonable convergence, a final run of the OMS model was made to compute a world oil price path.
- Using the final price path, the domestic and foreign models and modeling systems were then run independently to produce the detailed energy and economic forecasts presented in the

ARC78. The entire process described above was repeated as appropriate for each major ARC78 scenario to obtain the scenario-dependent world oil price path that was used by the other models.

12.1.3 References

Brief descriptions of the OMS model are provided in the following documents:

- Energy Information Administration, National Energy Supply Strategy Project Team, An Evaluation of Future World Oil Prices, DOE/EIA-0102/4, June 2, 1978.
- Energy Information Administration, A Sensitivity Analysis of World Oil Prices, DOE/EIA-0184/20, September, 1979.

12.2 World Economic Growth Forecasts

As described in Section 12.1, above, economic feedback elasticities were used in the OMS model to simulate the effects of rising world oil prices on the economic growth of world regions. The feedback elasticities for the United States were calibrated using the DRI model for use in the OMS model. First, a base case projection (at constant real oil prices) of economic growth was determined using the DRI model. Then, the feedback elasticities were calibrated by iterating between the OMS model

and the DRI model until the two growth paths exhibited little or no change.

For other world regions, however, it was necessary to use methods tailored to the availability of models and data for each of these regions. The base case projections were derived from several sources. For Germany, France, Italy, and the United Kingdom, a DRI model forecast of growth rates to 1985, assuming constant real world prices, was used. For these countries, the rates of growth to 1995 were determined by extending the trend productivity growth of gross domestic product (GDP) per employee plus the rate of population growth, assuming a constant labor participation rate, to obtain rates of growth of GDP. United Nations projections were used for population growth. The smaller European OECD (Organization for Economic Cooperation and Development) country growth rates were estimated for the near term using OECD and other collaborative data. Canadian and Japanese forecasts are based on DRI model projections, except that Canadian growth from 1985 to 1995 was adjusted to more nearly reflect that of the U.S. economy. The developing country projections were based on forecasts from the International Bank for Reconstruction and Development.

Using these regional base case growth projections in the OMS model resulted in a real growth in world oil prices. This price path was input to the available DRI macroeconomic models to derive a revised set of economic growth projections and regional economic feedback elasticities for use in subsequent analyses.

12.3 International Energy Evaluation System

12.3.1 Introduction

The International Energy Evaluation System is a major integrated forecasting system for making worldwide projections of energy prices, supplies, demands, and conversion activities for the midterm period of six to 19 years. For each major industrialized country in the western world, the IEES models total energy demands by product type, consuming sector, and sources of supply. Energy-specific supplies and demands are balanced through adjusting market prices for each energy product. The IEES simulations are driven by assumptions regarding OPEC policies, U.S. energy policy, and constraints on world energy production. Other areas of the world, such as the Eastern Bloc nations and the LDC's (less developed countries), are treated in less detail than the United States, OECD countries, and similar industrialized free-world nations.

Structurally, the IEES and the MEFS, described in Chapter 13, share a common methodology. The IEES is a linear programming (LP) representation of the world energy system consisting of a set of energy supply curves, demand curves, a transportation network, an OECD electric utility process model, a refinery process model, a synthetic conversion process model, and an integrating model. The integrating model balances supply and

demand by serving as the interface between estimates of demand and the integrated set of supply options. It provides this interface by using the demand estimates to approximate a demand curve and integrating the results with a linear programming formulation of the integrated supply network. A solution to the linear program is a candidate for an equilibrium point. This candidate becomes an approximate equilibrium point if it meets a specified set of convergence criteria. If it does not, a new demand curve is determined and a revised linear program is solved.

The IEES and the MEFS differ primarily in the level of detail incorporated in each model. Because energy data outside of the United States are often unreliable or unavailable, a detailed modeling of some energy market components is not possible. Hence, most of the detail in the IEES is incorporated into the modeling of OECD (excluding the United States) energy consumption.

The IEES model consists of three major components:

- an econometric demand model,
- a supply network, and
- an integrating model.

The demand model actually consists of several component models that provide estimates of consumer demand for fuels and energy as functions of price for OECD (excluding the United States) and

non-OECD countries. Demand depends on the general level of economic activity, the nature and extent of conservation activities, and other assumptions. In the IEES, demands are calculated for refined petroleum products, natural gas, coal, and electricity in 33 world geographic regions.

The IEES supply network represents the flow of fuels from production through conversion to points of demand. This involves four models: supply, refineries, electricity and synthetic fuel production, and transportation. Supply curves relating price and quantity of fuel that will be extracted at that price vary by region depending on the price and quantity dynamics. The IEES refineries model is an aggregate planning model that combines actual refinery capability into a single refinery for each region. An IEES conversion model represents electric utilities, synthetic fuel production, and miscellaneous processes, and a transportation model simulates the activities associated with movement of energy products between extraction, conversion, and demand activities.

Lastly, the integrating model combines the results of the demand, supply, refineries, conversion, and transportation models to achieve equilibrium where supply and demand are equal. Each of the six IEES models is described in more detail in the following sections. The purpose of this brief overview and the descriptions that follow is to provide a basic understanding of the IEES model. The comprehensiveness and complexity of the IEES

cannot, however, be adequately treated in full detail, given the purpose and scope of this document. For a more extensive description of the IEES, the references cited at the end of this chapter should be consulted.

12.3.2 IEES Demand Models

To illustrate relative coverage of energy demand within the IEES, total free-world demand is broken down as follows:

- United States--42 percent
- OECD countries (except United States)--40 percent
- Non-OECD countries--18 percent

Within the IEES, U.S. exports and imports are obtained from the MEFS and are treated as fixed demands. Export levels for steam and metallurgical coal and import levels for crude oil, refined petroleum products, and natural gas are specified. For the non-OECD countries--including OPEC, the LDC oil exporters, and others such as Africa, Asia, and the Sino-Soviet bloc--a simple approach to demand modeling is taken, partly because there are fewer historical data available upon which to base estimates, and because they represent a small percentage of the world's energy consumption. For the remaining OECD countries, an econometric model is employed to produce demand curves by fuel type, economic sector, and region. This OECD demand--the primary component addressed by the IEES demand model--is discussed below, followed by a brief description of the non-OECD model.

Energy demand in the OECD countries is estimated using econometric modeling, which involves the application of multiple regression techniques to data such as energy prices, per capita income, production levels, and prior energy consumption to determine relationships for estimating future demand.

Sources for the historical data used in the estimating process were:

- Energy consumption--OECD energy statistics.
- Energy wholesale prices, country price deflators, foreign exchange rates, and gross domestic products--OECD statistics and Economic Outlook; and United Nations/International Bank for Reconstruction and Development, World Economic Tables.
- Population--United Nations, World Population Forecast.
- Steel production--International Iron and Steel Institute, annual statistical reports.
- Canadian auto registration--U.S. Department of Commerce, World Motor Vehicle Production and Registration, annual issues.

Sector and product combinations gave rise to four basic demand function variations:

1. Demands for coking fuels used in the iron and steel industry were considered to be sensitive only to steel production.
2. Demands for major fuels associated with the transportation sector (motor gasoline, diesel oil, and jet fuel) were considered to be price-sensitive.
3. Demands for minor fuels such as transportation coal or residential/commercial coke were considered sensitive to variables other than price.

4. Demands for budget fuels were considered to be interchangeable based on their relative prices.

The budget fuels category includes products generally used in iron and steel, other manufacturing, and residential and commercial sectors for heat and power. They were treated as being potentially sensitive to price and subject to shifts in fuel shares from one to another, based on their relative prices. These products were handled in a special Btu budget and product shares submodel within the IEES OECD demand model. In this submodel, a total Btu requirement for the country and the selected sectors is determined as a function of average energy prices, incomes, and prior demand. Product shares within this Btu demand budget are then computed based on prior year product shares, relative prices and expenditures, and fuel efficiencies. The Btu budget is then allocated to products based on the product shares. Cross-elasticities are computed by examining the effects of changing individual product prices in the submodel.

Difficulties arise when the OECD demand model approach is applied to Communist Bloc countries that have centrally-planned economies, and to lesser developed countries. For Communist countries, prices and incomes are not the only factors affecting demand; hence, econometric modeling techniques may not apply. In the LDC's, demand is very small and complex; methods are not warranted. In both cases, historical data are insufficient to support the OECD approach.

Therefore, a non-OECD model was used. In the non-OECD model, the number of products is greatly reduced, sector estimates within countries are eliminated, and no regression is used. All non-OECD estimates are made at the IEES regional level. Projections for 1985, 1990, and 1995 were made based on GDP and energy supply growth rates developed mainly from OECD and World Bank sources. Separate analyses were conducted for the Sino-Soviet countries. Separate growth rates were estimated for oil, gas, and coal in all cases.

12.3.3 IEES Integrated Supply Network

An IEES supply model, part of the IEES integrated supply network, is used to develop a set of extraction price-quantity relationships, known as supply curves, for the primary fossil fuels--crude oil, coal (steam, metallurgical, and lignite), and natural gas--for 1985, 1990, and 1995. The IEES supply curves consist of step function approximations to the standard upward-sloping economic supply functions. Each step represents a range of quantities that can be brought into production for a given price; this formulation is necessitated by the linear programming integrating model. The approach used to develop the supply functions is similar for all fuels.

To develop each supply function, it is assumed that the general nature of the curve is described by:

$$S_a = S * \left[\frac{P_a}{P} \right]^e$$

where S and P are initial estimates of quantity and price, S_a is the quantity that will be supplied at price P_a , and e is the price elasticity of supply. Like the demand functions, described in the preceding section, a logarithmic transformation to linear form is used throughout. Price increments are specified, and at each price, the corresponding supply quantity is calculated. A number of supply quantities are computed on each side of the initial point, using a constant price increment. This leads to construction of the stepwise approximations used in the integrating model.

For crude oil supplies, to reflect OPEC control over world oil prices and reactions of oil producers to price changes, crude oil producing nations are grouped as follows in the IEES:

- full production countries--countries that will produce at maximum capacity given the OPEC price,
- price-sensitive production countries--countries that will vary production depending on world market oil price, and
- swing production countries--countries that will maintain the OPEC price by pro-rating their production.

Supplies from the full production and swing production countries are not considered to be price-sensitive; hence, their production

is considered to be fixed or at maximum capacity levels regardless of market prices. Production estimates were prepared by DOE, outside of the IEES, using data on reserves, production rates, drilling and finding rates, and similar factors from the following sources:

- Bureau of Mines, U.S. Department of the Interior, International Petroleum Annual.
- Central Intelligence Agency, International Oil Developments Statistical Survey. (Bi-weekly, unclassified.)
- Energy Information Administration, World Energy Prospects, September, 1977. (Limited-access EIA publication.)
- The Petroleum Encyclopedia.
- Statistical reports of the centrally-planned economies, published annually by individual countries.
- United Nations, World Energy Supplies, 1950-74, Series J, No. 19.
- Wilson, Carroll L., Energy Global Prospects, 1985-2000. (Workshop on Alternative Energy Strategies, Massachusetts Institute of Technology.)
- World Bank unpublished staff study on GDP growth rates, 1976.

For the price-sensitive producers, about 25 percent of 1976 world oil production took place in countries where activity responds to the market price of oil; of that 25 percent, 14 percent was in the United States and 11 percent was in other countries. Since the United States is a net importer of crude oil, U.S. production is not considered in the IEES. U.S. imports were considered as fixed requirements. Price-sensitive producers considered are

Mexico, the United Kingdom, Norway, Egypt, and Canada. Again, production estimates for these countries were made by DOE outside of the IEES, using data from the sources cited for full and swing production countries. Further detail on these production estimates is available in the EIA publication, World Energy Prospects. For the IEES, uniform pricing throughout the world was assumed, and price elasticities were considered to be equal for all price-sensitive producers.

Coal production rates for the United States and Australia, the two countries where significant coal mining expansion is realistic, are based on estimates published in national plans of coal mining growth. Estimates for other regions were prepared by DOE using contractor support. Uniform price elasticities were assumed. Similarly, natural gas production estimates were also prepared outside of the IEES.

The resultant supply curves are used in the LP integrating model where the prices appear in the objective function and the quantities appear as right-hand sides in supply constraints.

Transportation Model

A second component of the IEES integrated supply network is the transportation model. The IEES transportation model embodies a network to simulate the movement of energy products among the 33

IEES regions. One of the IEES regions, Suez-Mediterranean and Lebanon pipelines, is included solely for transportation purposes. The movement of crude oil, refined petroleum products, natural gas, and coal by tanker, pipeline, barge, and rail, as appropriate, is modeled. For each energy material-transport mode combination, costs are included for shipment and, in the case of natural gas, for conversion activities. Capacities of the various modes are also considered, where capacity represents the upper limit on total shipments between regions. When capacity is exceeded, a more costly route may have to be selected to ship the fuel products. The transshipment costs are introduced in the LP integrating model as part of the objective function; network links and capacities become part of the constraint matrix.

The following material-mode combinations were examined:

- Crude and refined product shipment by tanker
- Crude and refined product shipment by pipeline
- Coal shipment by bulk carrier
- Coal shipment by barge and rail
- Natural gas shipment by pipeline
- Natural gas shipment by LNG carrier

For each material-mode combination, the IEES approach is basically the same:

1. A supply network of links, or routes, between exporters and importers is developed, either graphically or in the form of a from-to matrix.
2. A shipping rate in terms of costs per unit of product shipped is computed.

3. Constraints on link capacities, if applicable, are calculated.

In general, the shipping rate is expressed in terms of a variable charge and a fixed charge per long ton of material transported:

$$\text{Shipping Rate} = (A * \text{Distance}) + B$$

where A is the variable cost in dollars per long ton per mile, and B is the fixed cost in dollars per long ton. The values for A and B are derived using linear regression techniques on available data. In addition to the shipping costs, canal charges were added where available for transiting the Suez and Panama canals, and a liquefaction and gasification charge was added for shipment by LNG (liquefied natural gas) carrier.

Capacity constraints centered on tanker availability and pipeline throughput limits.

Refineries Model

The IEES integrated supply network incorporates two "process" models: one for refineries and one for other conversions. Six of the 13 different products addressed in the IEES are refined from crude oil. This includes gasoline, residual fuel oil, distillate oil, jet fuel, liquefied gases, and other minor petroleum products. The conversion of crude oil into the six

products is modeled in the IEES refineries model. Outputs of the refineries model are incorporated into the IEES integrating model. Refining costs go into the objective function. Refinery build limits and capacities are incorporated into capacity constraints, and blend and yield outputs go into material balance constraints.

In the IEES refineries model, the characteristics of all refineries in a region are aggregated in one representative composite refinery. Refineries are modeled in 19 of the 33 IEES regions. To further simplify the analysis, the 19 regions are represented by only eight generic sets of refinery operating characteristics. Within this aggregated grouping, however, some country-specific characteristics such as capacity limits are maintained.

The activities modeled include the operation of existing and new refineries, the construction of new refineries, and the blending (or pooling) of refined products. The operation functions, or "base operate" activities, include relationships that define the volume of each refined product that can be derived from each unit of crude. In the integrating model, the process of equating supply and demand may activate a number of these relationships, reflecting the mix of available crudes in a region. These relationships also contain information about the type and quantity of refinery capacity required to process each unit of crude. This gives rise to building of new capacity within

constraints on build units. Also, appropriate costs are produced. The blend activities ensure a conservation of mass as crudes are converted to refined products and blends. Similarly, constraints are derived to ensure a material balance between supply and shipment to a refinery, and between demand and shipment from a refinery.

Energy Conversion Model

The second major process model incorporated by the IEES integrated supply network is the conversion model, which includes electric utilities and synthetic fuel production functions.

For electric utilities, only the generation of electricity in OECD countries, excluding the United States, was modeled.

Non-OECD demands were derived from the non-OECD demand model, and U.S. demand was obtained from the MEFS. These requirements were explicitly-stated constant demands that had to be met. Both fossil-fueled plants--those that consume coal, crude oil, natural gas, and similar fuels--and those that produce electricity without consuming fuels--such as geothermal, hydroelectric, and nuclear plants--were considered.

Utilities could not inventory, or store, electricity that had to be produced upon demand. Demand varied daily and seasonally. To satisfy this demand, the model selected the required types and

mix of generating capacity. In doing so, the model simulated, using material balance and process limit constraints in the integrating model, the transportation of fuels from producer to utility, the conversion of fuels to electricity with appropriate losses, and the transmission of the electricity by the distribution network to satisfy demand.

Demand for electricity was met by three types of load generation --base load, intermediate (or cycling) load, and peak load, which represent about 70, 28, and two percent, respectively, of all demand. Generation was provided by either hydro, residual, natural gas, nuclear, or coal plants; intermediate load was provided by hydro, coal, residual, or combined-cycle plants, and peak load by hydro or turbines. Each type of generating plant had its own cost and load factor characteristics. Equipment with high capital costs and lower operating costs was best suited for base load demand. On the other hand, equipment with low capital costs but higher operating costs was better suited for satisfying peak load.

The rate that utilities could charge for electricity was considered to be regulated, so that a customer is charged an average rate based on actual equipment costs rather than replacement costs. Hence, in the IEES, customers responded on the basis of average prices, while utility investment decisions were based on marginal production costs.

Base year data on existing capacity were obtained from OECD. Where available, EEC (European Economic Community) data for the nine Common Market countries were also used. In general, where data were missing, estimates were derived from MEFS data; in particular, operating, maintenance, and capital costs--both historical and projected--were obtained from the MEFS. Other projections were obtained from OECD, EEC, and specific reports of individual countries.

The second major function of the conversion model was to simulate the conversion of one fossil fuel to another. This included coal to lignite and fossil fuel to alternative hydrocarbon fuels, known collectively as synthetic fuel production. In this latter category, four types of conversion were modeled:

1. Metallurgical coal and small quantities of residual fuel oil are used in making steel in blast furnaces and thereby produce blast furnace gas and coke.
2. Steam coal, along with small quantities of liquefied gases, distillate and residual oils, and natural gas, are consumed in coke ovens to produce blast furnace gas and coke.
3. Lignite is transformed into briquettes.
4. The blast furnace gas produced in the first two of these processes is treated to make it suitable for use as a boiler fuel.

Each of these four processes incurs costs that reflect the economics of the process. The capacities and costs for each process are obtained directly from OECD's 1975 Industry Survey.

12.3.4 IEES Integrating Model

The IEES integrating model is a linear programming formulation where elements of the objective function and constraint set are derived from the supply network and demand models cited above. Underlying the LP formulation is the assumption that, subject to policy constraints imposed by governments, energy consumers and suppliers act in their own best interests. Consumers seek to maximize their benefits, and producers act to maximize profits. Under these conditions, demands will increase as prices decrease, and supplies will increase as prices decrease. Hence, the supply and demand functions are of the general form depicted in Figure 12-2.

Consequently, the market equilibrium for fuels occurs where the supply and demand functions intersect. In the LP formulation, the shaded area between the supply and demand curves in Figure 12-2 represents consumers' and producers' surplus for the one-product case, and maximization of this area defines the intersection point of the two curves. Consumers' surplus is the difference between what consumers would be willing to pay for a product and what they actually pay; producers' surplus is the difference between what producers get for their products and what they would be willing to accept. The shaded area represents the total consumers' and producers' surplus. This surplus is maximized subject to constraints on the energy system--such as the material balance and process limit constraints imposed by the

FIGURE 12-2

IEES SUPPLY AND DEMAND FUNCTIONS

production, processing, and transportation of raw fuels that are subject to quantity and capacity limitations. The energy system is also constrained to meet the final demand for fuel products.

To implement the LP formulation, it is necessary to approximate the fuel supply curves by a step function such as that illustrated in Figure 12-2. Each step represents a quantity range of energy fuel that will be supplied at a given minimum acceptable price. Once determined, these supply curves are unchanged by the LP solution process. The demand function is also input as a step function. The OECD demand models were used to compute initial demand estimates for each energy product, as well as price estimates for each elastic product, and own-price and cross-price elasticities for each product, which are assumed to remain constant over a range of prices. From these data, demand step functions are developed for each product. The LP is then solved to obtain prices, demands, and energy industry activity levels, which serve as a candidate equilibrium solution.

However, the LP solution is not necessarily an equilibrium. The elasticities from the demand model are only valid in the vicinity of the initial price and quantity point on the demand curve. In particular, fuel substitution effects as prices change cannot be modeled in the LP formulation (except for the limited case of electrical utilities). Therefore, if the LP solution represents a substantial departure from the initial demand points, the solution will not embody the dynamics of fuel substitution. To

alleviate this condition, the LP solution obtained is re-introduced into the demand model, and revised initial demand point and associated demand curves are developed. These revised curves reflect demand, including fuel substitution effects, in the price vicinity of the previous LP solution. These curves are again used as input to the integrating LP model, and a new solution is obtained. This new solution is compared to the previous one, and the iterative process is repeated until convergence (equilibrium) is achieved.

For the ARC78, the IEES also interacted with the OMS model and the MEFS, described in the next chapter, to achieve conformity with OPEC crude oil prices, U.S. imports of crude oil, and other components of U.S. demand that are specified as fixed inputs to the IEES.

12.3.5 References

The following documents provide an expanded description of the IEES. Volume II, in particular, discusses in detail the system, its inputs and outputs, and each of the major components.

- Logistics Management Institute, The International Energy Evaluation System--Volume I: Executive Summary, September 1, 1978.
- Logistics Management Institute, The International Energy Evaluation System--Volume II: Technical Documentation, September 1, 1978.

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CHAPTER 13

U.S. ENERGY SUPPLY AND DEMAND

This chapter describes the models that were used to generate the majority of the midterm projections of domestic energy supply and demand published in the ARC78. It covers the following systems and models:

- DRI macroeconomic model
- REGSHARE model
- Midterm Energy Forecasting System, (MEFS)

The relationship between the major modeling components discussed below was represented in Figure 11-1 and described in Section 11.3 of Chapter 11.

13.1 DRI Econometric Model of the U.S. Economy

13.1.1 Introduction

The Data Resources, Inc., Quarterly Econometric Model of the U.S. Economy, known as the DRI model, is a computer representation of the national economy. The model provides macroeconomic forecasts at the national level for numerous variables such as consumer

spending; business investment in plant, equipment, and inventories; construction activity; government receipts and expenditures; wages, profits, and interest; major price indices; and imports and exports. The model is driven by exogenous variables that reflect assumptions about monetary and fiscal policy, resource availability, productivity growth, population, and similar factors. Output from the DRI model is regionalized in the REGSHARE model for subsequent input to the MEFS, and is provided to the Energy Disaggregated Input-Output (EDIO) Model.

13.1.2 Methodology

The DRI model is a large-scale, simultaneous-equation, econometric model consisting of approximately 900 variables related by a series of equations, each of which expresses one variable, such as real personal consumption expenditures for housing, as a function of other appropriate variables, such as capital stock of housing and disposable personal income. Certain independent variables, termed exogenous variables, are specified by the user; these variables are unchanged by the model and serve to drive the solution of the other variables. Given the specification by the user of one or more exogenous variables, the entire set of equations is solved for the remaining variables using the Gauss-Seidel algorithm.

The individual relationships, or equations, are estimated by Data Resources, Inc., based on historical and forecasted values for

some 30,000 economic and related variables. These data are maintained in a data base by DRI, and are accessible to model users. DRI assembles these data from numerous sources such as the Bureau of Economic Analysis, Bureau of Labor Statistics, and the Federal Reserve System. Using this extensive data base, DRI continually updates the form of, and coefficients contained in, the equations.

For the DRI-OMS (Oil Market Simulation Model) interactions described in Chapter 11, the DRI model first produced (for each scenario) a forecast of GNP through 1995 assuming constant real world crude oil prices. This economic forecast was then input to the OMS model, and crude oil quantity and price paths for U.S. imports were calculated. The revised crude oil projections were introduced back into the DRI model, and the process was repeated until convergence was achieved. This produced a calibration of the OMS model feedback elasticities, which were subsequently used--together with supply, demand, and income elasticities--to develop final world oil prices and import levels for the United States and other world regions.

In the DRI-MEFS interface, also described in Chapter 11, the DRI model produced output used by the REGSHARE, MEFS, and EDIO models, as follows:

1. DRI to REGSHARE:

- Disposable personal income--1972 dollars

- Implicit price deflator for personal consumption expenditures
- Industrial production indices for 21 manufacturing sectors (foods, petroleum products, primary metals, etc.)

2. DRI to MEFS (RDFOR):

- GNP
- GNP--1972 dollars
- Implicit price deflator for GNP
- Implicit price deflator for personal income expenditures
- Disposable personal income--1972 dollars
- Unemployment rate--all civilian workers
- Wholesale price index--all commodities
- Consumer price index--all items
- Industrial production index--total
- Index of hourly earnings of production workers--private non-farm
- Index of compensation per hour--non-farm business sector
- Farm proprietor's income (with inventory valuation adjustment and capital consumption adjustment)

3. DRI to EDIO:

- 28 GNP components of final demand

In the iterative process leading to convergence of the economic and energy projections, the MEFS produced the following data for re-introduction to the DRI model:

- Wholesale price of coal
- Wholesale price of electricity
- Wholesale price of motor gasoline
- Wholesale price of distillate oil
- Wholesale price of residual oil
- Wholesale price of natural gas
- Wholesale price of other refined products
- Wholesale price of domestically-produced crude oil
- Price of imported crude oil
- Price of imported refined petroleum products
- Quantity of imported crude oil
- Quantity of imported refined petroleum products
- Consumption of motor gasoline
- Retail price of motor gasoline

The DRI model is a proprietary model, and forecasts are generated by Data Resources, Inc. Short-term forecasts are made for up to 10 quarters and are revised monthly. Long-term forecasts are currently made through 1990 and are revised quarterly. Three DRI forecasts extending through 1995, HIGHTREND1995, TRENDLONG1995, and LOWTREND1995, were developed under contract to DOE for use in developing the ARC78 energy forecasts.

13.1.3 References

Since the DRI macroeconomic model is proprietary, all model documentation is available from Data Resources, Inc.

Documentation of the 1977 version of the model is contained in:

- Data Resources, Inc., U.S./Macro MODEL--General Reference, December, 1977.
- Data Resources, Inc., U.S./Macro MODEL--Model Description, December, 1977.

13.2 Regional Economic Forecasts (REGSHARE Model)

13.2.1 Introduction

The REGSHARE model was used to derive regional economic projections for use in the Regional Energy Demand Forecasting (RDFOR) Model. Input to the model consisted of national-level economic forecasts from the DRI macroeconomic model, and data obtained from the Bureau of the Census and the Bureau of Economic Analysis (BEA). The BEA data consisted of unpublished state-level economic projections prepared for the Environmental Protection Agency in 1977. Output consisted of regional economic projections, through 1995, of population, disposable income, and value added by industry. In all cases, projections were made at the state level and then aggregated to the DOE regional level for input to the RDFOR model.

13.2.2 Methodology

Population projections for the regions were developed directly from the BEA projections by simply summing projections for states within each DOE region.

Disposable income projections were made using the following approach:

1. The DRI model provided projections through 1995 of national disposable income and personal income in 1972 constant dollars.
2. The DRI projections were converted from 1972 to 1975 constant dollars using the implicit price deflator for personal consumption expenditures.
3. BEA state projections of disposable income were adjusted, as explained below, to incorporate the dynamic energy-economy interactions represented by the DRI national forecasts.
4. Using the adjusted projections of state disposable income, state shares were developed.
5. The national projections of disposable income were distributed in accordance with the state shares.
6. The national shares of disposable income were added for states within regions to obtain the aggregated regional totals.

As noted above, the BEA projection of disposable income by state was adjusted slightly to reflect the dynamic effects of the energy-economy interactions implicit in the DRI forecasts. In effect, the BEA ratio of disposable income to personal income for each state was adjusted slightly toward the national DRI ratio of the same two variables, using a relationship such as the following:

r_{ij} = Adjusted BEA ratio of disposable income to personal income for state i in year j

$$r_{ij} = x * \frac{d_{ij}}{p_{ij}} + (1-x) * \frac{D_j}{P_j}$$

where:

d_{ij} = BEA projection of disposable income in state i for year j .

p_{ij} = BEA projection of personal income in state i for year j .

D_j = DRI projection of disposable income for year j .

P_j = DRI projection of personal income for year j .

x = Adjustment factor.

By varying the adjustment factor x between zero and one, the ratios can be moved closer together. In practice, the factor was increased over time from zero in 1975 to approximately 0.3 in 1995.

The r_{ij} was then used to compute an adjusted BEA projection of state disposable income for each year, using:

d'_{ij} = Adjusted BEA projection of disposable income for state i in year j

$$= r_{ij} * p_{ij}$$

The shares were computed using the adjusted projections:

S_{ij} = State i share of national disposable income in year j

$$= \frac{d'_{ij}}{\sum_i (d'_{ij})}$$

where the sum is across all states.

The disposable income for each state was then calculated by simply multiplying the national total by the state share; the resulting state estimates were then aggregated to DOE regional levels.

Value added projections were developed using the following information:

- DRI national projections through 1995 of production indices for 21 manufacturing sectors
- Census 1976 levels of state and national value added for the 21 manufacturing sectors
- BEA projections through 1995 of state earnings

Briefly, the 1976 national value added data from Census were projected using the DRI production projections. Then, the 1976 state value added data, also from Census, were projected using the BEA state earnings projections. Finally, shares were developed from the state value added data and were applied to the national value added projections to obtain state projections that were compatible with the national-level data. Throughout, necessary temporal adjustments were made using appropriate price deflators.

The detailed approach was as follows:

1. Federal Reserve Board production indices, projected by the DRI model for 21 manufacturing sectors, were used to determine growth rates in national production for each sector.
2. 1976 levels of national value added for the 21 sectors were obtained from the Bureau of Census Annual Survey of Manufacturers Data.
3. These 1976 figures were converted to 1975 constant dollars using a gross product originating deflator provided by BEA.
4. The production growth rates, obtained from the DRI model in step 1, were then applied to the national value added figures (in 1975 dollars) to obtain future year national projections through 1995 of value added for each of the 21 sectors.
5. 1976 levels of value added for each state and sector were obtained from the Annual Survey data. State values not listed in the survey because of disclosure requirements were estimated using state earnings data provided by BEA. All state estimates were then converted to 1975 dollars using the appropriate gross product originating deflators.

6. These state value added data were used to compute state shares for each sector.
7. The state shares, by sector, were then projected through 1995 using changes in state earnings shares developed from BEA projections. This resulted in projections of state value added shares by sector.
8. The resulting 21 sector shares for each state were added in each target year. If the sum was between 95 percent and 105 percent, the shares were normalized so that their sum was 100 percent. If any of the share sums for a given state were outside the 95-105 percent range, the entire adjustment approach was rejected for that state, and the 1975 state-sector shares from step 6 were used as the projections.
9. The resulting state-sector share projections were then applied to national value added projections to obtain state-sector value added projections.
10. The state-sector results were added for states within regions to obtain the DOE regional estimates of value added in the 21 sectors.
11. These values were passed to the RDFOR model, where seven of the 21 sector estimates were used directly; the

remaining 14 were added to represent "other manufacturing." All 21 were added to represent "total manufacturing."

13.2.3 References

The following document describes the methods employed within the REGSHARE model:

- Sandoval, David A., and Robert M. Schnapp, "Methods for Deriving Regional Value Added, Population, and Disposable Income Projections for Regional Energy Demand Modeling." (EIA Technical Memorandum #78, unpublished.)

13.3 Midterm Energy Forecasting System

13.3.1 System Overview

The Midterm Energy Forecasting System is the major integrated forecasting and analytical capability for making national forecasts of energy prices, supplies, demands, and conversion activities for the midterm period of six to 19 years, and is the most extensively-developed forecasting system used by the Department of Energy. The MEFS is an outgrowth of the Project Independence Evaluation System (PIES), which was developed in

1974 to provide the analytical basis for the 1974 Project Independence Report. The PIES system has been used to examine the potential impacts of changes in federal policies, differing resource and technological assumptions, and the comparative impacts of alternative political, tax, and regulatory environments. More specifically, PIES, at various stages in its continuous evolution, was used for the 1976 National Energy Outlook, the 1977 National Energy Plan Analysis, and the 1977 EIA Annual Report to Congress (ARC77), as well as for analysis of natural gas pricing proposals and energy-related tax and tax credit proposals. In the fall of 1978, PIES was substantially revised and renamed the MEFS. The MEFS was used for the National Energy Strategy Study (NESS) analyses and for the 1978 EIA Annual Report to Congress (ARC78), the subject of this document. The majority of the midterm national projections published in the ARC78 were obtained from MEFS output reports. The system is constantly being enhanced and updated, with new operational versions becoming available approximately every six months.

In brief, the MEFS is a regional forecasting system that can provide snapshots, at five-year intervals, of national and regional market supply, demand, and prices for major fuels; import levels; and patterns of activity in each of the major energy industries--consisting primarily of the electric utility, oil, gas, coal, and refinery industries--and the major demand sectors, consisting of residential, commercial, transportation, and industrial end users.

The purpose of this overview is to provide a framework for the more detailed sections that follow, which further discuss the major components of the MEFS. It should be noted, however, that the comprehensiveness and complexity of the MEFS cannot possibly be treated in full detail here, given the purpose and scope of this document. Hence, the subsequent descriptions are presented only to provide a basic understanding of the principal components of the MEFS. For a fuller understanding, the extensive MEFS (PIES) documentation, some of which is referenced below, should be consulted.

The MEFS is not a model, but rather an integrated system of numerous models, methodologies, and procedures. This collection is embodied in three major elements:

- a log-linear demand function, which calculates regional fuel-specific quantities that are demanded at specified fuel prices;
- an integrated supply network, which calculates the fuel prices at which the energy market would be willing to produce and deliver the specified fuel quantities demanded; and
- an equilibrium linear programming (LP) mechanism, which integrates the supply network with a linear approximation of the demand function and iterates on supply and demand

quantities and prices, recursively solving the resulting LP problem, until an equilibrium price solution is reached at which demand and supply are equal.

The principal components within each of these three elements are illustrated in the MEFS overview shown in Figure 13-1. Final demand for a particular fuel depends upon the price of that fuel, the price of substitute fuels, the general level of economic activity, and the nature and extent of energy conservation programs. From the demand side, separate demand relationships for each major refined petroleum product and for natural gas, electricity, and coal, in each of the 10 DOE regions, and for the major consuming sectors (residential, commercial, industrial, and transportation), are passed to the integrating mechanism contained within the Midterm Energy Market Model (MEMM). These demand functions do not include fuel consumed by refineries, electric utilities, or natural gas transportation activities; these are treated as part of the conversion and distribution processes embedded in the MEMM.

On the supply side, the integrated supply network consists of energy production supply curves passed to the MEMM, usually from other satellite models, and conversion and distribution activities embedded in the MEMM. These activities are dealt with individually for each fuel and producing region. Resource base estimates, together with technological and cost information, are used to construct the supply curves that show the cost at which

FIGURE 13-1. OVERVIEW OF THE MIDTERM ENERGY FORECASTING SYSTEM (MEFS).

additional fuel supplies can be produced. The integrated supply network also includes the costs involved in refining petroleum into a slate of products, in generating electricity, in transporting final energy commodities to meet regional demand, and in constructing new refineries and electrical generation capacity as needed.

In addition to the embedded conversion and distribution processes, the MEMM contains the equilibrating mechanism for matching energy demand with energy supply by fuel and region. Using an LP formulation to determine if a supply-demand balance has been achieved, the mechanism adjusts fuel prices until equilibrium is reached. The mechanism also makes required modifications to prices and quantities to account for controls such as those that apply to natural gas regulation and allocation, and to oil entitlements.

Documentation that is generally applicable to the MEFS is delineated in the next section. In subsequent sections, the individual MEFS components are further described, using the framework illustrated in Figure 13-1. The demand models are described in Section 13.3.3. Models and other procedures for developing the fuel supply curves and the distribution and conversion activities are discussed in Section 13.3.4. Finally, the MEMM integrating mechanism is treated in Section 13.3.5.

13.3.2 General MEFS References

In succeeding sections, individual components of the MEFS are discussed, and specific references are cited for each component. There exists, however, a substantial amount of documentation that was developed for PIES but is generally applicable to the MEFS, as well.

PIES was fully documented in a 15-volume set of reports published in September, 1976, covering all aspects of the system and its components as it existed on January 1, 1976. This documentation is available, by specifying FEA/N-76/411 as the initial volume, from:

National Technical Information Service
Springfield, Virginia 22161

The following list identifies the 15 volumes in the set:

- I. The Integrating Model of the Project Independence Evaluation System. This is the primary volume in the PIES documentation series. The integrating model, which integrates demand, supply, conversion, and distribution activities by regions, is described in considerable detail, with special emphasis placed on the assumptions made in structuring the model, and on how they are incorporated. Since most of the structure of PIES is concerned with supply and distribution, the bulk of the discussion in this volume is related to the supply side of the energy market and the equilibrating process by which supply is matched with demand. The details of the demand model are described in Volume II. Subsequent volumes describe the various components of PIES, and are identified by title only.

- II. PIES Economic Demand Model
- III. PIES Oil and Gas Supply Curves
- IV. FEA Model of Oil and Gas Supply: Data Validation and Update
- V. Drilling Profile and Regional Allocation by Profit Maximization
- VI. Methodology for Improving the Price Sensitivity of the PIES Oil and Gas Supply Curves
- VII. Methodology for Developing More Complex Investment and Production Profiles in the FEA Oil and Gas Supply Models
- VIII. Methodology for Enabling the PIES Oil and Gas Supply Curves to Respond to Non-Constant Prices
- IX. Allocation of Exploratory Activity to Oil and Natural Gas in the FEA Oil and Gas Supply Models
- X. Automation of Finding Rates and Discount Rates in the FEA Gas Supply Model
- XI. Finance Submodel to the FEA Oil and Gas Supply Models
- XII. Coal Supply Analysis
- XIII. Coal and Electric Utility Conventions for PIES
- XIV. Project Independence Evaluation System: A User's Guide
- XV. Standard Data Tables for PIES

Volume I, which documents the PIES integrating model (now called the MEMM), is currently being updated and expanded into a multi-volume set describing various PIES components as they existed on January 1, 1978. The set is entitled The Integrating Model of the Project Independence Evaluation System, and contains the following:

- Volume I--executive summary. Provides a simple, non-technical overview of PIES.
- Volume II--primer. Describes and illustrates the basic inputs to the PIES algorithm.
- Volume III--user's guide. Describes scenario specification and the operational procedures for running the integrating model.
- Volume IV--main model documentation. Describes the theoretical basis of the integrating model and each of the supply submodels.
- Volume V--code documentation. Describes the data processing aspects of PIES--data flow through the PIES programs, functions performed by each program, data inputs and outputs, and PIES naming conventions.
- Volume VI--data documentation. Contains the standard table data used for the ARC77 (along with primary data sources and the office responsible) and a copy of a PIES Integrating Model report, with a description of its contents.

A supplemental volume is available that describes updates made to the MEMM for the ARC78.

13.3.3 MEFS Econometric Demand Models

Introduction

For the ARC78, the demand side of the MEFS consisted of a system of interrelated energy models that operated to forecast annual energy demand by fuel, consuming sector, and DOE region through 1995. The primary components of this system were:

- the RDFOR model, which forecasted demand in the residential, commercial, industrial, transportation, and minor fuels sectors;
- the Structural Residential Energy Use (HIRST) Model, which is embedded in the RDFOR model, but was also used as a stand-alone model to produce conservation shifts for the residential sector;
- the Structural Commercial Energy Use (JACKSON) Model, which forecasted fuel shares and conservation shifts for the commercial sector;
- the Industrial Fuel Choice Analysis Model (IFCAM), which forecasted non-electricity fuel shares for the industrial sector; and
- the DOE/Faucett Automobile Model and the Light Duty Vehicle Fuel Consumption Model, which produced conservation shifts for the transportation sector.

Within the RDFOR model, a post-processor (DFACE) prepared all output for subsequent input to the MEMM.

Demand estimates were developed for 14 fuels:

- Gasoline
- Electricity
- Natural gas
- Distillate fuel
- Liquid gases
- Jet fuel
- Residual fuel
- Coal
- Oil
- Petroleum
- Asphalt
- Petroleum coke
- Metallurgical coal
- Total fuels

These fuels were consumed in four sectors--residential, commercial, industrial, and transportation. In addition, feedstocks and raw materials constitute two smaller sectors that

are modeled, but in which the demand for fuel is assumed to be inelastic.

The demand models provided the following estimates for each of the 10 DOE regions:

- demand estimates for 30 fuel/sector pairs,
- initial price estimates of 18 fuel/sector pairs, and
- elasticities (own and cross) of 18 fuel/sector pairs with respect to price of each fuel/sector pair.

A fuel/sector pair consists of a fuel allocated over a specific sector of the economy. For example, the fuel/sector pair natural gas/residential is the allocation of the fuel natural gas over the residential sector. Table 13-1 shows all of the 30 fuel/sector pairs, of which the first 18 types in the table are also given initial price estimates and elasticities. The final 12 products are considered to have inelastic demand, and the initial price is set equal to that of an elastic price, as indicated by Table 13-2. The only exception is metallurgical coal, whose initial price is set exogenously at \$34 per ton. The models also produced aggregate totals across fuels and sectors.

Previously, all of the demand forecasts were produced by only one model, the RDFOR model. This year, however, other demand models were used in addition to the RDFOR model to generate demand forecasts for certain sectors and to generate conservation shifts. The following major models were used:

TABLE 13-1

FUEL TYPES COVERED IN THE
MEFS ECONOMETRIC DEMAND MODELS

ELASTIC PRODUCTS

FUEL TYPE	SECTOR
Electricity	Residential
Natural Gas	Residential
Distillate Fuel	Residential
Liquid Gas	Residential
Electricity	Commercial
Natural Gas	Commercial
Distillate Fuel	Commercial
Residual Fuel	Commercial
Electricity	Industrial
Natural Gas	Industrial
Distillate Fuel	Industrial
Residual Fuel	Industrial
Liquid Gas	Industrial
Coal	Industrial
Gasoline	Transportation
Distillate Fuel	Transportation
Jet Fuel	Transportation
Residual Fuel	Transportation

INELASTIC PRODUCTS

FUEL TYPE	SECTOR
Electricity	Transportation
Natural Gas	Raw Material
Liquid Gas	Commercial
Liquid Gas	Transportation
Liquid Gas	Feedstock
Liquid Gas	Raw Material
Oil	Raw Material
Naphtha	Industrial
Asphalt	Commercial
Coal	Residential, Commercial
Coal	Transportation
Metallurgical Coal	Industrial

TABLE 13-2

CORRESPONDENCE BETWEEN ELASTIC AND INELASTIC PRODUCTS
FOR DETERMINING INITIAL PRICES

INELASTIC PRODUCT/SECTOR	ELASTIC PRODUCT/SECTOR SUBSTITUTE
Electricity--Transportation	Electricity--Industrial
Natural Gas--Raw Material	Natural Gas--Industrial
Liquid Gas--Commercial	Liquid Gas--Industrial
Liquid Gas--Transportation	Liquid Gas--Industrial
Liquid Gas--Feedstock	Liquid Gas--Industrial
Liquid Gas--Raw Material	Liquid Gas--Industrial
Oil--Raw Material	Liquid Gas--Industrial
Petroleum Coke--Industrial	Residual Fuel--Industrial
Asphalt--Commercial	Gasoline--Transportation
Coal--Residential, Commercial	Coal--Industrial
Coal--Transportation	Coal--Industrial

- The RDFOR model forecasted demand for the residential, transportation, and minor fuels sectors, and produced elasticities for all sectors.
- The HIRST model generated conservation shifts for the residential sector. The residential demand forecasting section of the model is embedded within the RDFOR model.
- The JACKSON model forecasted fuel shares and conservation shifts for the commercial sector.
- The IFCAM forecasted fuel shares for the industrial sector.
- The DOE/Faucett Automobile Model and the Light Duty Vehicle Fuel Consumption Model generated conservation shifts for the transportation sector.

All of the above models combine engineering estimates with econometric model representations to determine the demand forecasts. In general, this process involves the use of historical data through an estimation procedure to obtain regional demand parameter estimates for different fuels. These parameters determine how responsive demand is to changing prices and economic conditions. Then, a simulation procedure is invoked using macroeconomic forecasts to determine regional demand forecasts for the 30 fuel/sector pairs. More detail on the actual process is provided later in this section.

Much of the input for the demand process is the same for all of the models. Common historical data include fuel prices, fuel quantities, and macroeconomic variables, the latter consisting of variables such as disposable income, value added for manufacturing, heating degree days, cooling degree days, gas service customers, and population. Other standard inputs include initial fuel prices and quantities for the past two years, fuel

price trajectories by sector and region, and macroeconomic forecasts of population, income, and industrial activity. These inputs are derived from various data sources, but mainly from the Federal Energy Data System (FEDS), the Bureau of Mines, the DRI forecasting model, and numerous printed tables.

The remainder of this section is devoted to a more detailed discussion of the demand process.

Demand Forecasting Components

The remainder of this section provides brief descriptions of the major models and related components that compose the demand side of the MEPS as it was applied for the ARC78. More detailed descriptions of demand model structures, data bases, outputs, and estimation and simulation procedures are provided in the references cited at the end of this section.

Figure 13-2 shows the relationship between the components discussed below.

The RDFOR Model. The RDFOR model, the primary component in the ARC78 demand forecasting process, is an econometric and simulation model that forecasts quantities of fuel demanded by region as a function of prices, macroeconomic variables, and population. The model is composed of three distinct submodels and a post-processor, as follows:

FIGURE 13-2

ECONOMETRIC DEMAND MODEL INTERACTIONS

- A major fuels submodel predicts quantities of competing fuels used for heat and power in the residential, commercial, and industrial sectors.
- A transportation submodel predicts transportation fuel demand across all end uses.
- A minor fuels submodel forecasts the demand for raw material feedstocks and specialty fuels as a function of economic activity in the industries in which they are most commonly used.
- A post-processor accepts demand curve shifts (e.g., conservation effects), and formats all demand-related variables for output and subsequent input to the MEMM.

In the major fuels submodel, the residential sector was represented by the embedded HIRST model, which is described below. In the commercial and industrial sectors, there were two basic demand relationships. The first related the total demand for fuel on a regional basis to other goods and services in the economy. The second represented the distribution of this total demand between different types of fuel. This type of structure implies interaction between fuels and non-fuel goods, and reflects the way changes in the rest of the economy affect the various types of fuels demanded.

For the commercial sector, total demand was expressed as a geometric function of prices, lagged quantities, population, and personal disposable income. Control totals produced by the RDFOR model were allocated to fuel types using fuel shares obtained from the JACKSON model. Similarly, total demand in the industrial sector was allocated to fuel types based on fuel shares produced by the IFCAM. The RDFOR model then computed

price-quantity pairs and elasticities for input to the DFACE post-processor.

The demand for fuel in the transportation sector was modeled by end use. The major components of demand were auto highway gasoline use, non-auto highway gasoline and diesel fuel use, rail diesel fuel use, and commercial jet fuel. The demand for auto gasoline was specified as the ratio of automobile vehicle-miles to average fleet efficiency. The number of vehicle-miles was determined as a function of per capita income, the cost of vehicle operation (including both fuel and time costs), and the unemployment rate. The fleet efficiency was specified as a weighted average of the efficiency of automobiles of various ages. For trucks and buses, total fuel demand was estimated as a function of vehicle-miles and fleet efficiency without a vintaging effect. Combined automobile, truck, and bus fuel was split between gasoline and diesel fuel on the basis of relative fuel prices, an industrial production index, total vehicle-miles, and a measure of the size of the truck stock. Rail diesel fuel was specified as a function of rail ton-miles which were, in turn, estimated from diesel fuel prices and capital expenditures in the railroad industry. Commercial jet fuel was specified as a function of air passenger-miles adjusted by an airplane load factor, where air passenger-miles were estimated using the price of jet fuel, per capita income, and the price of military-type jet fuel.

The third submodel of the RDFOR model included the demand for natural gas, liquid gas, and coal in the raw materials sector; the commercial demand for asphalt and liquid gas; the industrial demand for petroleum gases and metallurgical coal; and the household/commercial demand for coal. The explanatory variables for these fuel categories included industrial value added, time trends, and lagged consumption variables.

Exogenous inputs to the RDFOR model included forecasts of independent variables, estimated model parameters, and demand shifts such as those due to conservation programs. Forecasts were provided for the macroeconomic, industrial activity, demographic, and price variables. Model equations were generally estimated in reduced form, using pooled cross-sectional time series data. Demand curve shifts for conservation were estimated using DOE models. Although numerous sources were used to obtain these data, the Federal Energy Data System (FEDS) provided much of the required information.

Price-quantity pairs were computed using the submodels, which were simulated using a base case and a perturbed price path. Price elasticities were then computed using the two prices and corresponding quantities. The unperturbed prices and quantities and calculated elasticities were next input to the RDFOR post-processor, where they were prepared for output and subsequent input to the MEMM.

The remaining components of demand forecasting are discussed below.

Residential Sector (HIRST Model). The Structural Residential Energy Use (HIRST) Model is embedded within the RDFOR model, although the residential conservation shifts are produced separately. The HIRST model forecasts residential demand for energy by four fuel types (electricity, gas, oil, and other); by eight end uses (space heating, water heating, refrigeration, freezing, cooking, air conditioning, lighting, and other); and for three types of housing (single-family, multi-family, and mobile homes). Household energy use for each component is computed in response to changes in stocks of occupied housing units and new residential construction, equipment ownership by fuel and end use, size and thermal performance of housing units, average unit energy requirements for each type of equipment, and usage factors that reflect household behavior.

The residential model consists of three submodels and a simulation model. The submodels are the following:

- Demographics. This submodel calculates stocks of occupied housing units by type for each year of the simulation. Based on calculations of household formation and retirements from the existing stock of occupied housing units, new construction requirements are calculated for each year to ensure that the stock of housing units matches demand.

- Technologies. This submodel evaluates changes in equipment energy requirements and purchase price as functions of alternative designs (detailed engineering submodels). The process determines relationships between equipment energy use and initial cost for the other end uses. Similarly, changes in thermal performance for new and existing structures are evaluated as functions of increased capital cost for each housing type.
- Economics. This submodel calculates elasticities that determine the responsiveness of households to changes in economic variables--i.e., incomes, fuel prices, and equipment prices. Each fuel price and income elasticity is decomposed into three components: equipment ownership, equipment and structure efficiencies, and equipment usage. The first gives changes in equipment fuel choice (market share), the second gives changes in equipment and structure efficiencies, and the third gives changes in household usage of equipment, holding ownership and efficiencies constant.

The simulation model then combines outputs from the submodels with the appropriate initial conditions and policy assumptions in order to forecast the annual demand for energy for each of the fuel use components.

In addition to the macroeconomic forecasts and fuel price projections input to all the demand models, inputs to this model

also include residential behavioral characteristics, housing stocks and construction trajectories, new equipment and structure possibilities, and the economic and energy effects of equipment policies. Various projections may be made using these additional inputs, the source for which is the Oak Ridge National Laboratory.

Commercial Sector (JACKSON Model). The Structural Commercial Energy Use (JACKSON) Model is used to provide forecasts of energy by five end uses (space heating, water heating, cooling, lighting, and other), by four fuel types (electricity, natural gas, oil, and other), in 10 commercial subsectors (retail and wholesale auto repair, finance and other office activities, public administration, education services, warehouse activities, hotels and motels, and miscellaneous commercial activities). The process is similar to the other demand models: estimates are obtained, and then a simulation program is run. Additional inputs to the model include initial estimates on a regional basis of building stocks and additions for commercial building types, and energy use requirements (in Btu's) for heating, cooling, lighting, and other uses. Oak Ridge National Laboratory is the source for these inputs.

The approach taken in the model disaggregates previous fuel use estimates, and combines economic factors with technological factors to determine the energy usage. The economic factors consist of fuel prices, growth of energy-using stocks,

utilization rates, and capital-energy substitutions.. The major technological factor included is equipment efficiency.

Inputs to the post-processor program from the JACKSON model pertain to conservation shifts. Although conservation shifts are explained later in this section, the ones associated with commercial demand include new building standards, federal energy management programs, grant programs for non-profit institutions, and tax credits for conservation investment.

Industrial Sector (IFCAM). The Industrial Fuel Choice Analysis Model is used to forecast the demand for energy for four fuel uses (residual oil, distillate oil, natural gas, and coal use) in the industrial sector for nine groups of existing and new combustors. The industrial sector includes manufacturing, construction, and mining activities. Industrial energy use is considered to be boilers and process heat energy. Fuel choice is based on fuel prices, government policy proposals, costs associated with firing alternative fuels, and parameters such as size distribution of new industrial boilers.

The source for historical data on energy consumption in the industrial sector is the Energy Consumption Data Base. This includes engineering boiler and process heat equipment cost and performance data. Additional inputs to the IFCAM include DRI forecasts of industrial activity.

Transportation Sector. This subsection deals only with transportation conservation shifts. Several models are used to generate the conservation shifts; then, the shifts are pre-processed and are input to the post-processor program. The transportation conservation shifts take into account vehicle efficiency standards and excise taxes.

Most of the data sources that feed the transportation models derive from DOT/NHTSA studies. There are two models that receive most of this input. The first is the DOE/Faucett Automobile Model, which analyzes automobile fuel consumption. The input to this model includes gasoline prices, income, population, unemployment rate, and stock of vehicles (ownership). The model varies government policies and regulations in terms of car prices and fuel economies. Then, consumption of fuel by new cars, which is based on fuel efficiency, is determined by examining economic trade-offs between the cost of improved efficiency and the cost of penalties for not meeting standards. The second model is the Light Duty Vehicle Fuel Consumption Model, which determines the conservation shifts for trucks and diesel penetration. The major inputs include vehicle registrations, fuel economies, scrappage rates, and various economic and auto use forecasts.

In summary, the transportation conservation shifts are based on whether the consumption of gasoline and diesel fuel is increasing or decreasing, dependent upon fuel efficiencies and standards. The shifts are then input to the post-processor program.

Conservation. In addition to transportation, there are other conservation shifts that may alter the demand curves. The amount the curves may be shifted is input to the post-processor program, and may be either manually- or computer-driven. The manual shifts consist of solar/geothermal shifts and boiler (industrial) shifts, with the data being pre-processed into computer files before input. The other conservation shifts are generated by computer models for either the residential (HIRST model) or commercial (JACKSON model) sectors.

Once the shifts are determined, the demand curves are shifted by the amount of savings. This results in showing, for the same price, less quality being demanded. It is important to note that there is an assumption of constant elasticity; thus, the curves are shifted by the same percentage at each point. The actual shift of the demand curves occurs in the post-processor program.

Post-processor Program. The post-processor program merges the output from the demand models and produces the files to be input to the MEMM. The following were input to the post-processor:

- Elasticities (RDFOR)
- Price-quantity pairs (RDFOR)
- Conservation shifts (RDFOR, HIRST, JACKSON, and manual)

The post-processor program incorporated the conservation shifts into the demand curves, and then reformatted the files for input to the MEMM. The information on the files consisted of forecasts

for the years 1985, 1990, and 1995, which were broken down into the 10 DOE demand regions. The final output included:

- initial demand estimates for 30 fuel types,
- initial price estimates for 18 fuel types, and
- own and cross elasticities of 18 fuel types with respect to price of each fuel type.

The combination of prices, quantities, and elasticities were used by the MEMM to specify the demand function. The MEMM used the elasticities to change the quantities demanded when fuel prices were changed in order to find equilibrium between supply and demand. Elasticities, however, were only valid over a range of prices for a target year. Although the demand curves assumed constant elasticity, the assumption of constant elasticity did not hold when prices changed too much, and, therefore, new demand curves were needed. The demand models for all sectors were executed again, producing new demand curves (quantities demanded, elasticities) associated with the latest prices from the MEMM.

References

The following documents detail the models and submodels used to generate sectoral forecasts of energy demand for the ARC78 analyses:

- Energy and Environmental Analysis, Inc., Industrial Fuel Choice Analysis Method, January, 1979.

- Energy and Environmental Analysis, Inc., Light Duty Vehicle Fuel Consumption Model, 1975-1986, April, 1978.
- Hirst, E., et al., Oak Ridge National Laboratory, The ORNL Engineering-Economic Model of Residential Energy Use, ORNL/CON 24, July, 1978.
- Jack Faucett Associates, Automobile Sector Forecasting Model Documentation--Final Report, August, 1978.
- Jackson, J., Oak Ridge National Laboratory, Energy Use and Conservation in the Commercial Sector: An Econometric-Engineering Analysis, 1978.
- Jackson, J., et al., Oak Ridge National Laboratory, The Commercial Demand for Energy: A Disaggregated Approach, ORNL/CON-15, April, 1978.
- Synergy, Inc., The Regional Demand Forecasting and Simulation Model--User's Manual, June, 1978.
- Synergy, Inc., The Regional Demand Forecasting Model, 1977 and 1978 Versions, September, 1978.

13.3.4 MEFS Integrated Supply Network

1. Introduction

The supply side of the MEFS consists of the integrated supply network, which encompasses all activities related to production of raw fuels, conversion to electricity and petroleum products, and distribution from suppliers to consumers. Basically, supply is modeled in three ways:

- A series of satellite models produce supply price-quantity relationships (curves) for major fuels for input to the MEMM.

- Two process models, one for refineries and one for electric utilities, simulate the operation of these facilities through submodels embedded in the MEMM.
- Transportation of fuels--from supplier to conversion facilities, if applicable, and subsequently to consumers--is simulated through a submodel embedded in the MEMM.

The satellite models that produce the supply curves for direct input to the MEMM are:

- The Midterm Oil and Gas Supply Modeling System
- The Alaskan Hydrocarbon Supply Model
- The Enhanced Oil Recovery Model
- The Reserve Allocation and Mine Costing Program (a module of the National Coal Model)
- Nuclear fuel supply models

Each of these models is discussed below.

Simplified supply price-quantity information, estimated without the use of computer models, is also input for various synthetic fuels and advanced technologies such as solar and geothermal power. These elements are clearly part of the energy supply network, and are discussed below in Subsection 10, Advanced Technologies.

Supply curves generally have the characteristic stepwise linear form shown in Figure 13-3. Each step of the curve represents the range of increased supply quantities expected to result from a specified fuel price. In this context, the price is the minimum

FIGURE 13-3

TYPICAL SUPPLY CURVE
(STEP FUNCTION APPROXIMATION)

acceptable price at which producers would respond by increasing the quantity supplied over the previous amount that they supplied at the lower minimum acceptable price. Separate supply curves are developed for each fuel type within each producing region.

The conversion activities associated with electric utilities and refineries and the distributional activities associated with the transportation of energy fuels are considered part of the integrated supply network. The conversion submodels are process models in that they replicate the actual energy conversion processes. This is accomplished by appropriate process limit, material balance, and demand balance constraints in the LP matrix, with associated decisions (such as the construction of new conversion capacity) controlled by the cost optimization aspects of the LP objective function. Similarly, the distribution of energy fuels between producers and consumers --through conversion, if applicable--is embedded in the MEMM transportation submodel. Constraints ensure that material flows are balanced and that required quantities are transported. The objective function influences the choice of routes and shipping modes. Each of these three submodels is discussed below.

2. Midterm Oil and Gas Supply Modeling System

Introduction

The Midterm Oil and Gas Supply Modeling System is a computer-based model that projects domestic oil and natural gas

production for 30 years based on economic and engineering factors that affect oil and gas supply. This model projects onshore and offshore recovery for oil (primary and secondary) and gas for the Lower 48 states and for Alaska, south of the Brooks Range. The regional oil and gas supply curves developed are input to the MEFS.

The system's Oil Supply Model consists primarily of three interconnected submodels:

- 1) a drilling submodel, which considers information about the economic gradations of the resource base, the level of future expected prices, and various constraints to exploratory drilling activity to project regional exploratory drilling;
- 2) a resource submodel that translates exploratory drilling, the prospects for finding oil, the intensity of development, the fraction of oil-in-place (OIP) that can be recovered by either primary, secondary, or tertiary methods, and the fraction of proved reserves that can be produced each year into annual regional production quantities; and
- 3) an economic submodel that calculates a minimum acceptable price for each year's quantity of reserves proved.

The Gas Supply Model, which produced supply projections for non-associated natural gas and its co-products, is identical to the Oil Supply Model with only two exceptions: first, gas finding rates are estimated as a function of total drilling (exploratory and developmental) rather than exploratory drilling, and, second, the components of the oil model that represent secondary recovery are not present.

Methodology

In describing the oil and gas supply modeling methodology, the focus is on oil supply. After the oil supply process has been established, a summary of differences in the estimation process applicable to gas supply is provided. Also, the methodology described here applies to onshore and offshore oil (primary and secondary recovery) and natural gas, both for the Lower 48 states and for Alaska, south of the Brooks Range. Forecasts of onshore and offshore oil and natural gas for the region north of the Brooks Range are covered by the Alaskan Hydrocarbon Supply Model, described below. Tertiary recovery of oil is covered by the Enhanced Oil Recovery Model, also described below.

For both oil and natural gas, the results of the estimating process are regional oil and gas supply curves; these become input for the MEMM. A typical curve for 1985 is shown in Figure 13-4. These supply curves represent the relationship between supply and prices. Within the MEMM, these curves provide the basis for balancing future supply possibilities with demands for

FIGURE 13-4

refined petroleum and natural gas. The MEMM accounts for other related interactions such as the world price of oil, imports, transportation, and prices of alternative fuels.

An overview of the estimation process for oil supply is presented in Figure 13-5. Each of the three major submodels is described below. To facilitate the discussion, they are described in the following order:

1. Resource submodel
2. Economic submodel
3. Drilling submodel

Resource Submodel. The first submodel discussed is the resource submodel, an engineering simulation model that translates the resource base into production. This model component forms the core of the modeling process. Within the resource submodel, oil supply from old fields, which are identified or discovered resources, is estimated separately from that of new or undiscovered resources. This division represents the investment choice between development (old fields) and exploration (new fields). For old fields, the following approach is used to translate resources (OIP) into production, or supply:

- Production from known, economically-recoverable resources (measured or proved reserves) is estimated by simply applying a decline rate to the reported reserves quantity for each region. The decline rate is the percentage of reserves that will be produced in a given year.

FIGURE 13-5. ESTIMATION PROCESS FOR OIL SUPPLY

- Initial reserves and decline rates are obtained from American Petroleum Institute (API) data.
- For onshore regions, the decline rate is applied uniformly to the measured reserves remaining at the start of each year. For offshore regions, the decline rates vary based on years after discovery to account for the time lags between exploration and production. The offshore production profiles are developed using production and reserves data from Environmental Impact Statements prepared for the latest lease sales in each offshore region.
- The measured reserves, which form the basis for production in a given year, are increased, if appropriate, by reserve additions that represent the growth from extensions, revisions, and new discoveries associated with known fields.
- The reserve additions are estimated using "Hubbert factors." These factors represent the ratio between ultimate production and proved reserves to date as a function of years after discovery. Hence, for a given year, the ultimate production, or recoverable OIP, can be estimated by multiplying the current estimate of proved reserves by the time-dependent Hubbert factor. The resultant change in the ultimate expected production over proved reserves represents a reserve addition that is then subject to production.

- In summary, the annual production in a given region is computed by multiplying the proved reserves, including prior-year reserve additions, by the appropriate decline rate.

For new fields, the methodology for calculating production is more complicated. The key determinant for translating undiscovered resources into OIP is the amount of exploratory drilling that is conducted. Regional relationships of the following type are utilized:

COIP = Cumulative OIP discovered

$$= Q (1 - e^{-b * CMFT})$$

where:

$$Q = \frac{\text{U.S. Geological Survey (USGS) Ultimate Recoverable Resources}}{0.32 \text{ (Recovery Factor)}} + \text{1956 to Present Year Cumulative OIP Discoveries.}$$

CMFT = Cumulative exploratory drilling.

b = Constant.

The above relationship reflects the distribution of resources and expected outcome of the exploration process. It is based on the theory that the largest undiscovered pools will be found first,

and that average pool size will decline over time as exploration continues. The variable Q in the above equation represents the total OIP that can be discovered after 1956, and is the upper limit of cumulative discoveries. Total discoveries include the resources discovered between 1956 and the present year and the latest USGS estimates of undiscovered resources. Remaining discoverable OIP is derived from USGS Circular 725 estimates of undiscovered recoverable oil, divided by regional recovery factors. Also, the USGS estimates exclude resources beyond a 200-meter offshore water depth. To remove the 200-meter depth constraint, the USGS offshore estimates were multiplied by 1.6 (except for the Alaskan offshore, where depths greater than 200 meters are not expected to overlay discoverable resources). This factor is based on the National Petroleum Council's (NPC) Ocean Petroleum Resources report (1974), which estimates that oil resources beyond a 200-meter water depth exceed by .6 the resources within 200 meters.

The parameter b is estimated through regression analysis, using historical data for cumulative OIP and cumulative exploratory drilling. The sources of historical OIP data are the NPC's U.S. Energy Outlook: Oil and Gas Availability for 1956-1969 and the API's Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada for 1970 through the current year. The data sources for historical exploratory drilling are the NPC study for 1956-1969 and the API's Quarterly Review of Drilling Statistics for 1970 through the current year (dry hole

footage is allocated to oil according to the proportion of successful oil drilling footage to total successful drilling footage).

In the resource submodel, cumulative OIP is estimated for each region and year using the equations and estimates of cumulative oil exploratory drilling obtained from the drilling submodel, as described below. The submodel then translates OIP to reserves by using regional recovery factors for each recovery method on new fields and regional time lags between discovery and each subsequent phase of development.

The secondary factors for new fields are calculated by the same procedure as for old field secondary factors. The ultimate recovery expected in each region is estimated by use of Hubbert factors. In turn, the portion expected to be recovered through primary methods is subtracted to estimate the quantity of secondary recovery. This quantity is divided by the amount of OIP to derive a secondary recovery factor for the region. The reserves proved by each of three recovery methods (primary, secondary, and tertiary) are then produced according to the regional decline rates noted earlier.

Production estimates for the principal co-products of oil wells (associated-dissolved natural gas and associated-dissolved natural gas liquids) are projected using historical ratios. Historical data are used to develop a gas-oil ratio for each

region that is the quotient of the previous year's marketed associated-dissolved gas production and oil production. This factor sets the gas-oil ratio for the first year of the forecast. The ratio expected at the end of the forecast period represents an engineering judgment, influenced by regional geology (particularly the ratio of remaining undiscovered associated-dissolved gas and oil reserves) and by the likely trends of enhanced recovery techniques. Ratios for associated-dissolved natural gas liquids are derived in a similar fashion.

The modeling system calculates annual ratios from the first and last year values through linear interpolation. It then multiplies the quantity of each year's primary product (oil in the case of associated-dissolved gas, and associated-dissolved gas in the case of associated-dissolved natural gas liquids) by the appropriate ratio to calculate the co-product production level.

Economic Submodel. The second major component of the Oil Supply Model is the economic submodel, which estimates the minimum acceptable price (MAP) associated with each reserve addition by region, by year, and by type of recovery. It assumes that the relevant costs are the incremental expenditures required to convert resources from their current state (measured, inferred, or undiscovered) to the "proved" category, and, subsequently, to produce them. For example, the incremental costs of producing today's proved reserves (principally well-operating costs) are

much less than the costs of producing undiscovered resources (exploration, development, and production investments, plus well-operating costs).

In the submodel, each of the activities requiring expenditures has a cash flow category allied with it. These cash flow categories form the basis for the MAP calculation. The basic computation of the MAP associated with each reserve addition is made using a discounted cash flow analysis. All cost elements, including return on investment, are discounted to a common year, as are all production quantities. Production quantities are discounted to represent the time value of the revenues that would accrue from the production over time. This discounted production quantity can then be multiplied by a price (which remains constant) to provide discounted revenues. In this case, discounted costs divided by discounted quantity equals the minimum acceptable price required to generate sufficient revenue to cover costs plus provide a competitive return. A project, either exploratory or developmental, is included in the forecast only if its MAP is less than or equal to the expected future market price.

For projects that involve the full range of exploration, development, and production expenditures (undiscovered resources), the costs and revenues generated from both primary and secondary recovery projects typically are combined in the MAP calculation. This reflects the common practice of establishing a

proposed development program early on that will consider the application of secondary recovery methods.

Drilling Submodel. The last major component of the Oil Supply Model is the drilling submodel, which forecasts levels of oil exploratory drilling by region and year. These forecasts are used by the resource submodel to determine estimated OIP found.

For onshore regions, the expected market price for crude oil and its co-products defines the segment of the undiscovered resource base that is economical to pursue. To determine this quantity of economical resources in each region, a special run of the engineering and MAP sections of the system is executed with a hypothetical, ambitious exploratory drilling program in all geographical regions. This produces regional curves of the "latent" demand for drilling at alternative future oil prices. These curves represent an estimate of the time-independent gradations of resources in each region. Due primarily to decreasing finding rates and increasing drilling costs as more and more OIP is discovered, the latent demand for drilling curves will be approximately exponential. Each region, however, evidences a unique relationship between price and the latent demand for drilling.

At a given market price, each region contains a discrete quantity of resources that is economical to explore. These regional quantities can then be summed to produce a quantity that

represents total U.S. exploratory drilling for undiscovered resources, the development of which would be economically attractive at alternative future market prices.

Given this ultimate latent demand, a drilling profile program estimates how this amount of exploratory drilling would occur over time. It takes into account various impediments and constraints to drilling build-up (i.e., the availability of capital, labor, and equipment). Lacking an empirical basis for estimating supply curves for these inputs, the submodel uses rig availability as a proxy for the mix of factors that constrain drilling.

To project exploratory drilling, the submodel assumes that each year's total drilling is made up of three parts--footage available from rigs that are operational at the beginning of the forecast, drilling from new rigs constructed with existing rig-building facilities, and drilling from new rigs built by new rig-building capacity. It further assumes that rig-building capacity and the economic lives of rigs determine rig availability. The total latent demand for drilling at alternative oil prices can then be satisfied by drilling footage from each of these three sources.

The amount of drilling footage available from existing rigs is allocated over time by retiring a constant fraction of rigs each year. If the total footage available from old rigs is less than

the total latent demand, some of the new rigs produced from old plants will be needed. The amount of drilling footage available from new rigs constructed at old plants is then allocated over time (old plant capacity is assumed to decline linearly from current levels over one plant-life). If this amount of drilling still cannot satisfy the total latent demand, new rig capacity is added. The capacity is added in a manner that ensures that each rig produced can be utilized over its entire rig-life. The time-distribution of these three sources of drilling footage availability is then summed for each year to derive the total annual U.S. onshore exploratory drilling footage available.

The MEFS requires that supplies of crude oil and its co-products also be estimated for situations where prices might increase or decline over time. The changes in the drilling program to handle this additional capability are complicated. In its basic form, the one-time calculation of the total exploratory footage available at a given price is replaced by an interactive calculation that changes from year to year as the expected market prices change. Based on this dynamic latent demand for drilling, the drilling footage from the three sources is estimated for each year. Wherever new rigs are required to satisfy the latent demand, the model considers the economic life of new plants and new rigs and avoids increases in capacity that would later lead to a surplus.

Finally, the total exploratory footage in each year is allocated among the eight onshore regions. The allocations follow two rules:

1. A period of adjustment is provided, during which time regional drilling will adjust from current patterns to a point at which each region is drilling equal minimum-acceptable-priced oil.
2. Thereafter, annual drilling capacity is allocated among the regions to maintain this relationship.

These rules recognize that established drilling patterns cannot be changed instantaneously, but that drilling will shift to areas that have the more attractive drilling opportunities until opportunities being drilled in all areas at all times are equally attractive.

Because leasing constraints hamper access to more attractive prospects in the federal Outer Continental Shelf, drilling profiles for the four offshore regions are derived from leasing schedules. Once the leasing schedule is set, the drilling profile model transforms the acreage available for lease in each year to the quantity of exploratory footage drilled in each year.

The Gas Supply Model. As noted earlier, the modeling system that produces supply projections for non-associated natural gas and

its co-products is almost identical to the Oil Supply Model described above. The economic basis for estimating minimum acceptable prices is the same, as is the basis for estimating latent demand for drilling and for regulating the rate of drilling over time. There are, however, two main distinctions. First, gas finding rates are estimated as a function of total drilling (exploratory and developmental) rather than just exploratory drilling. Second, the components of the oil model that represent secondary recovery are not present.

Scenario Implementation. The three critical data inputs to the Oil and Gas Supply Modeling System were the assessment of the resource base, the market price, and the leasing schedule. Each of these three critical inputs was varied to produce supply curves for a wide array of MEFS scenarios. The effects of alternative future market prices of oil and natural gas were evaluated in the MEFS by use of the different steps on the supply curves generated by the supply modeling system. As a result, separate oil and gas supply curves were not needed for MEFS scenarios that only vary market prices. However, alternative geological assessments and leasing schedules did require changes in the inputs to the supply models, and separate sets of supply curves were generated.

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References

The following documents describe the 1978 version of the Midterm Oil and Gas Supply Modeling System, which was used to prepare supply curves for input to the MEMM:

- Everett, Charles, et al., Midterm Oil and Gas Supply Modeling System--Methodology Description, TM/ES/79-05, November, 1978.
- Molineaux, John, Midterm Oil and Gas Supply Modeling System--System Guide, draft, April, 1979.
- Molineaux, John, Midterm Oil and Gas Supply Modeling System--User Guide, draft, May, 1979.
- Scott, William G., Midterm Oil and Gas Supply Modeling System--1978 Input Data Description, forthcoming.

3. Alaskan Hydrocarbon Supply Model

Introduction

The Alaskan Hydrocarbon Supply Model is a computer-based forecasting model that makes midterm projections of Alaskan production of crude oil and natural gas. It also addresses questions concerning the effect on supply of resource availability, supplies of natural gas liquids, the construction of new pipelines, and governmental policies on leasing. It is a component of the MEFS, and its output becomes part of the data base for the MEMM.

The model uses different price levels to generate a set of supply curves for both onshore and offshore production. These curves cover supply regions in the northernmost area of Alaska, onshore and offshore. The forecasting time horizon is 40 years in five-year increments.

The modeling approach relies upon two major submodels. A resource submodel establishes a set of production possibilities. To do this, it employs Monte Carlo methods in conjunction with geological descriptions of each supply region to determine the possible level of new gas and oil at different price levels. An integrating submodel then uses economic factors to decide which resources to develop and which pipeline links to build or expand at any given time. This submodel employs linear programming to project actual production and pipeline construction as a matter of cost minimization.

The model's data base includes an extensive description of the geology for different supply regions. This includes the number of structures per region; distributions describing structure depth, structure size, and sedimentation for offshore areas; the physical characteristics of possible pipeline routes; and the volume of proved reserves. Also part of the data base are pipeline capacities and the costs of constructing different pipeline links. Sources for the data are the USGS, State of Alaska energy reports, and engineering and cost estimates developed by consultants.

Methodology

As described above and illustrated in Figure 13-6, the Alaskan Hydrocarbon Supply Model consists of two major submodels:

FIGURE 13-6

INFORMATION FLOW THROUGH THE
ALASKAN HYDROCARBON SUPPLY MODEL

- the resource submodel, which is used to estimate the amount and characteristics of potentially recoverable oil and gas contained within Alaska; and
- the integrating submodel, which examines Alaskan transportation system alternatives, integrating them with the resource base alternatives in order to forecast the timing and extent of resource exploitation and transportation system development over time under varying assumptions regarding oil and natural gas market prices.

Each of the submodels is described below.

The resource submodel is divided according to three different levels of current geological knowledge of Alaska--areas of proven hydrocarbons, explored but undeveloped areas where some geologic data exist, and areas that are totally unexplored. The resource modeling approach is tailored to these level-of-knowledge categories. Estimates of alternative production possibilities for areas with proven hydrocarbons are developed outside of the model, using the results from detailed reservoir simulation models for the other areas. Production is estimated using a more straightforward, volumetric/decline curve analysis applied to various hydrocarbon possibilities within a Monte Carlo framework.

For the areas of proven hydrocarbons--that is, the developed fields--the physical analysis of development alternatives is

accomplished outside of the resource submodel. The analysis consists of evaluating a range of alternative development plans that leads to a range of production trajectories resulting from the application of additional development effort or investment to proven reserves. The actual procedures applied vary with the level of development accomplished thus far. For example, a detailed reservoir simulator has been developed to generate alternative development plans for the Sadlerochit formation of the Prudhoe Bay field because it is sufficiently well developed and understood.

In addition to production profiles for these proven areas, corresponding physical and investment data are also developed. This includes the number of wells required, processing equipment capacity, and similar factors of investment. This information is used to compute minimum acceptable supply prices for each production plan, which, together with the production profiles, are input to the integrating submodel data base.

For the explored but undeveloped areas, a Monte Carlo approach is utilized to deal with the uncertainties regarding the extent and quality of the resource base, and the development and production parameters characterizing these resources. The simulation develops a multi-dimensional picture of the resource base. Then, a sorting algorithm simulates the exploratory search process. Finally, a development model calculates expected reserve additions over incremental segments of the search process. These

reserves are classified according to the cost of developing them with a least intensive schedule using a discounted cash-flow technique. The simulation technique provides a capability for generating complete distributions for reserves as well as for estimating the effects on remote exploration and development of direct financial incentives (e.g., alterations in the tax code).

The Monte Carlo simulation technique and related variables are part of the resource description submodel described below.

The last category, unexplored areas with little available geologic data, does not lend itself to the Monte Carlo simulation approach due to the lack of data. The procedure incorporated in the resource submodel treats these areas by analogy. The basic assumption underlying this approach is that, for a remote region with expected geologic characteristics that mirror an explored region, the expected results of a Monte Carlo simulation will be a scalar multiple of the resources-in-place. Hence, the results of the Monte Carlo simulation for the reference region are proportionately adjusted by the ratio of resources-in-place for the two regions; this approach yields reserve estimates for the unexplored regions.

The resource description submodel depicts the resource base along several dimensions that describe its size, its depth, and its general productive potential. The probabilistic variables, their distributions, and the submodel's logic are shown in Figure 13-7. The variables are summarized below:

FIGURE 13-7

RESOURCE DESCRIPTION SUBMODEL OF THE
 ALASKAN HYDROCARBON SUPPLY MODEL

- Number of Structures. This variable represents the number of distinct formations within a region. For an iteration, the simulation samples once from the distribution for this variable (see Figure 13-6). The value determines the number of structures to be generated during that iteration.
- Structure Area. This variable, measured in acres, represents the average horizontal cross-section of a structure. Given the present unavailability of more detailed information, the distributions were derived from actual field sizes experienced in analogous Lower 48 producing regions.
- Structure Thickness. Measured in feet, this variable represents the average vertical cross-section of a structure. Estimates of these distributions were based on the structural configuration and stratigraphic characteristics within each region; where such information was lacking, the distributions instead were estimated from analogous fields in the Lower 48.
- Structure Depth. This variable represents the depth interval in which a structure is located. Five depth intervals, each spanning a vertical distance of 5,000 feet, are used for each new reservoir. The depth interval for each reservoir is determined by sampling from a discrete distribution containing the five point estimates for the

probability of finding the reservoir at each depth interval. The distributions of structures by depth for the Alaskan provinces were obtained directly from worksheets used for data in USGS Circular 725.

- Hydrocarbon Occurrence. This variable represents the probability that any single structure contains hydrocarbons. Review of geologic data suggested a strong correlation between hydrocarbon occurrence and the depth of a structure. As a result, this variable is represented by five distinct sets of probability distributions. Depending upon the depth interval selected for a given reservoir, the model will sample from one of the five distributions to determine hydrocarbon occurrence. These probabilities have been assessed from historical wildcat success rates in Lower 48 onshore regions.
- Structure Fill. This variable, measured in barrels or thousands of cubic feet (Mcf) per acre-foot, represents the density of hydrocarbons per unit of structure volume. In the absence of a strong basis for analogy to Lower 48 regions, this variable has been derived from a review of worldwide producing basins. In the simulation, the product of a trial value for structure area, structure volume, and fill equals the barrels of oil-in-place (or Mcf of gas-in-place) for that structure. Since the distributions are mutually independent, the expected quantity of OIP for

a given region is the OIP per structure (as calculated above), multiplied by the number of structures and the overall probability (weighted by depth) of oil.

- Drive Mechanism. This variable represents the probability that a single structure is dominated by a particular drive mechanism. Active drive mechanisms--gas cap and water drive--generally produce higher recovery rates. Consequently, two classes of drive mechanisms--active and inactive--are depicted for both oil and gas reservoirs. The probabilities for obtaining a given drive mechanism were based on historical Lower 48 experience.
- Recovery Factor. This variable represents the fraction of the total OIP that can be recovered with primary recovery techniques from a reservoir with a particular drive mechanism. For oil reservoirs with inactive drive, secondary recovery operations could provide significant levels of additional production. A table of volumes showing secondary recovery rates as a function of primary rates has been developed for these reservoirs. All recovery statistics have been based on historical Lower 48 regional experience.
- Permeability. This variable, measured in millidarcies, expresses the fluid conductivity characteristics of the reservoir rock. Reservoir permeability has a direct effect

upon the initial flow rates from each well; this effect is represented explicitly within the model. Permeability distributions are estimated separately for oil and gas reservoirs based upon statistics from commercial U.S. oil fields.

- Oil Viscosity. This variable, measured in centipoises, also is a factor used in determining initial flow from an oil reservoir. Its distribution was developed from nationwide statistics.

Five of the 14 probabilistic variables used to characterize the resource base--the number of structures and their areas, thicknesses, structure fill, and the probability of hydrocarbon occurrence--directly affect total OIP. Because these variables are mutually independent, the mean value of the distribution obtained by multiplying them together equals the product of the mean values of each distribution. The variables have been defined in such a way that the product of the five distributions is simply a distribution for the total regional OIP. In the calibration mode, therefore, the means of these five distributions can easily be adjusted a priori to set the OIP distribution derived from the resource submodel equal to the mean estimates, for instance, of USGS Circular 725.

By experimenting with the standard deviations of the input distributions, a nearly perfect fit with the entire aggregate

distribution of USGS Circular 725 can be obtained. Such effort, however, is likely to be unwarranted. Existing detailed distributions, where available, have been based mostly on fitting a lognormal distribution through the mean estimates from several independent appraisals, rather than having been developed from a single geological data source. The importance of replicating such a distribution, consequently, would seem to be low. OIP distributions derived by this mode will, however, be similar in shape to most existing distributions (i.e., lognormal), since most of the individual variables included in the simulator are themselves lognormal.

The basin exploration and evaluation submodel arranges the reservoirs identified in the resource description submodel into a sequence in which they would be tested during the exploratory search process. Next, it estimates the total exploratory footage required to test and, where appropriate, to delineate each reservoir. It then evaluates commercial viability, also estimating for each reservoir the required amount of exploratory effort. After a sufficiently large number of simulation iterations, the expected values for reserve additions within each minimum acceptable supply price category and each interval of exploratory drilling stabilize. These values are passed directly to the integrating submodel data base. The submodel repeats this process for each supply region to generate a full set of supply possibilities for the integrating submodel.

To evaluate the commercial viability of each generated reservoir, the basin exploration and evaluation submodel uses a discounted cash flow (DCF) algorithm linked to a base-level development plan. The physical ingredients of the plan and their functional relationships are presented in Table 13-3. As shown, the development plans include both primary and secondary development. Thus, development in the base-level plan includes reinjection of any produced water as well as injection of source water.

The DCF procedure includes two probabilistic variables to represent the uncertainty associated with changes in the level of the exploration, development, and production costs over time. One variable, the "inflation contingency factor," measures the rate of change in factor costs relative to a constant price trajectory. The overall economic setting of the resource model is one of constant rather than nominal dollars. The inflation cost factor thus reflects uncertainty about the relative rate of nominal inflation between hydrocarbon prices and factor costs. The distribution for this inflation contingency factor is triangular and, for most regions, is skewed slightly to the low side to reflect the possibility of technological improvement over time.

A second probabilistic variable, the "cost contingency factor," represents the basic uncertainty associated with the costs of exploration, development, and production within a region. This variable is used to scale only the most uncertain costs, namely

TABLE 13-3

PHYSICAL INGREDIENTS OF BASIN
EXPLORATION AND EVALUATION^{a/}

Element	Function of	Units
<u>Exploration</u>		
• Geological/Geophysical	Exploratory Drilling Expenditures	Non-Dimensional
• Exploratory Wells	Structure Area, Exploratory Well Success Rate	Wells
<u>Primary Development</u>		
• Development Wells, Drilling Pads	Recoverable Reserves; Maximum Production Rate; Flow Rate per Well, Development Success Rate	Wells
• Gas Processing Capacity	Gas-Oil Ratio; Maximum Production Rate	Units/(MMCF/day)
• Surface Equipment Capacity	Structure Area, Maximum Production Rate, Number of Producing Wells	(Units/(barrel/day)) ^{b/}
— Gathering Lines		
-- Treating Facilities		
<u>Secondary Development</u>		
• Injection Wells	Number of Primary Development Wells, Structure Thickness	Wells
• Water Source Wells	Number of Primary Development Wells	Wells
• Water Disposal Wells	Number of Primary Development Wells	Wells
• Treating and Distribution Facilities	Maximum Production Rate - Secondary	Units/(barrels/day)

^{a/} "Units" indicate a package of surface or other equipment; (barrels/day) represents units of capacity for that equipment designed for oil structures.

^{b/} The development plan for non-associated natural gas consists of similar physical parameters. To simplify this exposition, the description of this segment of our model is confined to oil.

exploratory and development drilling costs per foot. It, too, has been given a triangular distribution, although, in most regions, it is either symmetric about its mean or skewed slightly to the high side. The submodel samples distributions for both economic factors once per simulation iteration to provide a set of unit costs applicable to all reservoirs.

The resource submodel, in short, estimates the extent and economic viability of resources on a regional basis in Alaska. The manner in which the integrating submodel combines this resource data with transportation data to estimate future Alaskan oil and gas supply is discussed in the next section.

The supply curves output by the resource submodel are used as input to the MEMM.

Integrating Submodel. The integrating submodel has four important features:

1. A time-staged, mixed-integer linear program is used to select the levels and initiation dates for all investment projects so as to maximize total profits. Five activities are represented:
 - exploration--an investment activity that yields additions to discovered reserves by cost category (as determined by the resource submodel);

- development--a second investment activity that yields production over time of primary and associated products from discovered resources in a single development class;
 - transportation network expansion--a third investment activity that enables movement of products to the Alaskan boundary through construction of new pipelines or terminals for tankers;
 - transportation--that moves hydrocarbons through the network at a variable cost; and
 - sales--that return revenues to reimburse these activities.
2. The model permits specification of different market price trajectories. In each time period, the prices of crude oil and natural gas at the Alaskan border are exogenously determined--that is, Alaskan oil and gas producers are assumed to be "price-takers."
 3. Leasing policy and technological constraints on resource extraction or transportation development are explicitly recognized. Exploratory drilling segments or even entire regions may be eliminated from the formulation for any number of time periods.
 4. As currently formulated, the model does not calculate pipeline tariffs in accordance with Interstate Commerce Commission rate-making rules. Instead, the ingredients of a tariff computation (capital and operating costs, oil and gas flows over time, etc.) are available from the model's report writer.

The integrating submodel is structured as a finite-horizon, time-staged, linear program. The linear programming methodology was selected over heuristic solution approaches for two reasons. First, a large number of potential Alaskan pipeline network configurations potentially must be considered. Second, the data-driven nature of the linear program provides flexibility for easily modifying the model formulation in response to changed scenario specifications or to evolution and enhancement of the model and its data base.

A key formulation concept in the integrating submodel centers around the categorization of potential hydrocarbon reserves according to their minimum acceptable supply prices (or development cost classes) and by exploratory intervals. In the linear program, exploration activities yield additions to reserves in each development cost class. The additions are joint--that is, each increment of exploratory activity leads to discoveries potentially distributed across all cost categories.

In turn, development activities "consume" the reserves included within a particular cost category and yield over time production of both primary products (crude oil or non-associated gas) and co-products (associated-dissolved gas and/or natural gas liquids). The shapes of these "production profiles" include the base-level plan used in the resource submodel to calculate minimum acceptable supply prices and to grade potential reserves into cost categories. Consequently, these profiles and cost

categories serve as the critical linkage between the stand-alone resource submodel and the integrating submodel.

In addition to the base-level plan or profile, the integrating submodel also includes alternative production profiles. These additional profiles represent increasingly more intensive development strategies which permit the extraction rate, extraction costs, and prices to interact in a way that maximizes profits (e.g., by pushing development intensity to the point where marginal costs equal marginal revenues).

Downstream from production, crude oil and natural gas are transported to terminals located at the Alaskan boundary in a pipeline and/or tanker transshipment network. The network consists of three kinds of activities. Network expansion adds capacity to the links of the network. These expansion activities are comprehensive projects in the sense that capacity is added jointly to any number of links in the network. Transportation activity moves products unidirectionally between pairs of regions. The transportation activity consumes capacity of a link. A spur also moves products between regions, but does not consume capacity. Spurs connect supply regions to the network at a unit cost based upon an exogenously estimated pipeline size. They are included in the model as a simplification of the transportation network and, as such, can be employed at the user's discretion.

All of the production and transportation activities involve cash expenditures that are discounted in relation to the time of their initiation. Sales activities at the Alaskan terminals provide the discounted revenues that drive the system. These activities are simply variables that consume the delivered product at an exogenously supplied price.

In summary, the model's point of view is that of a global optimizer of the current value of pre-income-tax profits. The solution characterizes a dynamic, competitive equilibrium for the case in which expected values represent all uncertainties, with the discount rate serving as a measure of risk.

References

Extensive documentation, including data descriptions and a user's guide, is currently in preparation. The following document is available and describes the model methodology:

- Energy Information Administration, Division of Oil and Gas Analysis, Alaskan Hydrocarbon Supply Model--Methodology Description, TM/ES/79-09, January, 1979.

4. Enhanced Oil Recovery Model

Introduction

The Enhanced Oil Recovery Model projects U.S. tertiary production potential from known reservoirs using five technologies known

collectively as enhanced oil recovery (EOR) techniques. The technologies include:

- Steam drive
- In situ combustion
- Carbon dioxide miscible flooding
- Surfactant/polymer flooding
- Polymer augmented water flooding

Input to the EOR model consists of detailed physical and production characteristics for approximately 835 reservoirs, and appropriate investment and operating costs, market prices, and specified rates of return. The model then develops engineering estimates of recovery potential, examines economic feasibility based on a specified price path, and develops supply curves and the timing of production. Output includes estimates of:

- ultimate recovery of crude oil,
- reserve additions and production on an annual basis, and
- the minimum acceptable price sufficient to reimburse all costs and provide an adequate rate of return on investment.

The estimates are normally reported as state or national totals. They are aggregated to the DOE regions to form the supply data input to the MEMM.

Methodology

Structurally, the EOR model has three basic parts:

- a technical screening process that examines each reservoir based on physical characteristics and assigns a feasible EOR technique,
- a recovery submodel that estimates the potential production quantity and timing for each reservoir and technique combination, and
- an economical submodel that determines minimum acceptable prices.

The technical screen operates on the physical characteristics of each reservoir to determine which EOR techniques, if any, are suitable for application. Typical screening criteria include:

- Oil viscosity
- Reservoir depth
- API gravity
- Reservoir temperature
- Reservoir permeability
- Residual oil saturation

Reservoirs that are amenable to an EOR process are analyzed, using the recovery submodel, to predict the amount of oil that can be recovered and the rate at which the oil can be produced. While the recovery calculations differ among techniques, the following generally describes the approach associated with a given reservoir:

- The original oil-in-place is either determined from the input file, or computed based on reservoir porosity, net thickness, saturation, and similar characteristics.
- Drawing upon production history and reserve estimates, the amount of oil that will ultimately be produced by primary and secondary methods is estimated.
- The original OIP is reduced by the estimated primary and secondary recovery to obtain the remaining OIP for potential EOR (tertiary) recovery.

- EOR recovery is then estimated as a function of the remaining OIP, reservoir characteristics, and a technique-specific recovery model.
- A technique-specific production schedule is applied that is a function of the injection schedule and normal decline factors.
- Operating costs are computed for subsequent use in the economic submodel.
- The process is repeated for each feasible technique.

In the economic submodel, the production schedule and operating costs are augmented by a development schedule and associated development costs.

The model uses a standard discounted cash flow analysis methodology to determine the minimum acceptable price required to ensure that the revenues yielded (cash inflows) from production equal cash outflows plus a specified minimum rate of return on investment. Appropriate federal and state taxes are incorporated into the calculations. Cash flows are discounted at a selected interest rate.

At an assumed crude oil price level, a project is initiated if it earns or exceeds a specified rate of return. There are two important timing considerations contained in the model that have a major impact on the initiation and development of projects:

1. Limitations in manpower, equipment, and capital argue that the industry will pursue a phased approach in developing their EOR prospects. The industry starts with

those projects that have the highest rate of return, followed by the next best until the minimum economic return level is reached. For example, a project that earns only the minimum rate of return may not be started for over 10 years as the industry develops the better prospects. This accounts for the risk associated with these projects, in which higher-return projects are begun when the technology is uncertain. As experience with the technology is gained through these projects, the technological and economic risks are reduced, and industry will move to the projects earning lower returns.

2. The development of a project from initiation to production is a lengthy process. For reservoirs in which no previous work has been done, there is a period in which the reservoir is evaluated and technical and economic pilots are undertaken before commercial production is initiated. The initial study phase varies by technique from seven to nine years.

In the final step of the methodology, results of the reservoir simulations are extrapolated to state- or national-level totals.

The primary source of input to the EOR model is a data base known as the "big fields file." This file contains detailed information concerning 835 reservoirs contained in 385 fields and 19 states, accounting for about 52 percent of the known remaining

OIP in the United States. The following types of data are collected for each reservoir:

1. Identification data
2. Geology
3. Reservoir conditions, such as depth and temperature
4. Reservoir volume
5. Initial and residual oil saturations
6. Water characteristics
7. Oil characteristics, including viscosity and API gravity
8. Reservoirs and field production and development history

The sources for the reservoir data include the files and publications of the following:

- The American Petroleum Institute
- The National Petroleum Council
- The Oil and Gas Journal
- The Bureau of Mines
- The Society of Petroleum Engineers
- The American Association of Petroleum Geologists
- Other federal, state, university, and other sources

Economic data were also compiled for use in the model from Joint Association Survey data and internal Bureau of Mines studies.

Detailed output from the model includes economic data at the reservoir level and production data aggregated to the state or national level. For the ARC78, supply curves for the DOE regions were produced.

References

The following document describes the Enhanced Oil Recovery Model, its underlying methodology and assumptions, and the reservoir data base:

- Energy Information Administration, Enhanced Oil Recovery Model: Model and Methodology Description, draft, December, 1979.

5. Coal Supply

Introduction

Within the MEFS, coal supply curves, for input to the MEMM, are produced by the Reserve Allocation and Mine Costing (RAMC) Program, which is a part of the National Coal Model (NCM). This section presents a brief description of the NCM and a more detailed description of the RAMC program in terms of its methodology, inputs, and outputs.

The NCM is a highly disaggregated representation of domestic coal production, transportation, consumption, and pricing. Its high degree of resolution includes 30 supply regions, 35 demand regions, 40 possible coal types, and six consuming economic sectors. The NCM is designed to project future levels of coal production, consumption, and pricing activities, and to permit the analysis of the impacts of coal-related public issues on these activities.

Structurally, the NCM uses a linear programming formulation to produce a general equilibrium solution for supply, demand, and price. Within the model, coal supply is described in terms of alternative annual tonnages and their associated extraction and

preparation costs for each coal type mined in each supply region; these relationships are produced by the RAMC program, described below. Coal demand is described in terms of the consumption of coal-generated electricity, plus non-utility Btu requirements, for each demand region. Environmental constraints, associated with the burning of alternative types of coal in the various demand regions, are included. The NCM handles four generation load categories: baseload, intermediate load, seasonal peak load, and daily peak load. Utility load duration curve approximations are incorporated. Coal blending and flue gas desulfurization technologies are provided for in the utility sector. Power generated in one demand region can be transmitted to another demand region for consumption.

The NCM provides a flexible reporting capability to produce output related to:

- Coal production quantities and prices by coal type, mine type, and regions
- Coal transportation and distribution
- Electricity transmission
- Coal washing
- Coal consumption by coal type, consuming sector, and region
- Electric utility capacity utilization
- Coal blending
- Extraction and preparation costs by coal type and supply and demand regions
- Etc.

When used as a stand-alone model, outside of the MEFS context, the NCM can provide detailed coal activity data to augment the regional, aggregated output produced by the MEFS.

Methodology

The supply side of the NCM consists of the Reserve Allocation and Mine Costing Program. As a MEFS satellite model, the RAMC program produces the coal supply curves that are input to the MEMM. The underlying concept in the development of the supply curves is that supply, in the long run, is determined primarily by the price that potential producers can expect to receive for their coal products. At lower prices, some existing mines would eventually be closed as the costs of production exceeded the revenue generated by coal sales. As the market price increases, producers will be motivated to open new mines, as well as to continue to operate existing mines. The coal supply curve represents this relationship between market prices and coal supply.

Figure 13-8 illustrates a representative coal supply curve. The curve is stepwise increasing, indicating the general tendency to introduce new production capacity as prices rise. Typically, a coal supply curve will consist of an initial set of three steps, indicated by a broken line, which represents production from existing mines. The first step indicates production of coal under long-term fixed-price contracts. The next broken-line steps represent "surge" or short-term increases in capacity

FIGURE 13-8

brought about by increased spot market coal prices. The solid line portion of the curve applies to increases in production due to opening of new mines.

The vertical portion of each step in the supply curve indicates the amount by which prices would have to rise to induce a producer to open a new mine, or mines, to production. The horizontal portion indicates the annual production to be expected from new mines opened as a result of that market price. These supply curves, therefore, are based on the assumption that less expensive mines will be developed before more expensive ones. The decision to bring a new mine into production will depend on the costs to start up and operate the mine at a reasonable return on investment, and on the price that can be expected for the coal produced.

The minimum acceptable selling price for coal produced by new mines is the price the producer has to receive in order to recover all of its production costs, in addition to a pre-specified return on investment. Since the costs involved are influenced by various physical and economic factors such as depth and thickness of seam, wage rates, and costs of power and supplies, different types of mines have different per-ton production costs and, therefore, different minimum acceptable prices. When production from different types of mines is ordered by minimum acceptable price and accumulated, the result is the coal supply curve.

Supply curves are developed in five major steps:

- 1) definition of coal supply regions and types,
- 2) estimation of future output from existing mines,
- 3) determination of the selling price for the future output from existing mines,
- 4) estimation of future output from new mines, and
- 5) determination of the minimum acceptable price for new mine production.

The first step is to define appropriate coal supply regions and coal types that will form the basis for allocating Bureau of Mines (BOM) demonstrated coal reserves to regional coal type categories. In the second and third steps, the model estimates the output of existing mines by region and coal type, and determines the selling price for the future output of these existing mines. In the fourth and fifth steps, which encompass the primary functions of the RAMC program, demonstrated reserves that have not yet been developed are examined. These "uncommitted" reserves are assigned to mine categories by regions and coal type, and estimates of ultimate production from new mines are developed. Minimum acceptable prices are estimated for the new mine production, and the prices and associated quantities are used to generate a supply curve.

Each step is described in more detail below.

Step 1: Define Coal Supply Regions and Types. The RAMC program operates on 30 domestic supply regions, of which 22 are entire

states. West Virginia, Kentucky, Montana, and Colorado are each divided into two regions to ensure homogeneity of coal supplies. No region is larger than one state. By type, coal is categorized according to heat (Btu) content and sulfur content. The RAMC program employs five heat content categories and eight sulfur content categories for a total of 40 coal types.

Coal reserves by region and type are obtained from the BOM. The BOM data contain estimates of demonstrated coal reserves by coal beds within counties. For each bed of reserves, the BOM data provide tonnage estimates and average quality information in terms of Btu heat content and sulfur content. The location of the beds is used to determine region, while the quality data are used to determine type.

Step 2: Estimate Future Production Capacity from Existing Mines.

Estimates of future production capacity were made in two stages. First, an estimate of 1975 production capacity by NCM regions, coal type, and mining method (surface or deep) was made. Then, regional retirement rates reflecting expected mine closings were used to reduce the future capacity of mines that existed in 1975.

The 1975 annual production estimates for total tonnage by NCM region were obtained from BOM weekly production reports. These regional tonnage estimates were then subdivided based on quality characteristics using shares developed from Federal Power Commission (FPC) Form 423 data for utility coal shipments, and

BOM data on bituminous coal and lignite shipments for non-utility coal.

Regional tonnages, by coal type, were allocated by surface or deep mining methods, using shares developed from BOM reserves data, and BOM regional estimates of strippable reserves of coal currently in production.

S_{ij} = 1975 surface production quantity of coal type j in region i

$$= S_i * \frac{R_{ik}}{R_i}$$

where:

S_i = Total surface production in region i (BOM regional estimate of strippable reserves currently in production).

R_{ik} = Total surface mineable reserves of coal type j currently being mined in region i (BOM reserves data).

R_i = Total surface mineable reserves of all coal types currently being mined in region i (BOM reserves data).

The portion allocated to deep mining is simply the 1975 total tonnage, by region and type, minus the surface-mined portion, by region and type.

To estimate future production, regional mine closing estimates were developed. Only large mines were considered; small mine capacity was assumed to remain constant, with small mine openings and closings offsetting each other. The average annual production loss, in millions of tons, was estimated for MEPS regions based on an analysis of large mine changes in production during the period 1945 through 1950. An average loss for all mines of 3.5 percent was observed. This factor was applied to average production by MEPS region to compute the annual production quantity loss due to closing of existing large mines. The MEPS region quantities were distributed to NCM regions, coal types, and mining methods based on ratios developed earlier.

Production quantities from existing mines for 1975 and future periods were assigned to contract and to spot supply curve steps based on production from mines producing over 100,000 tons annually, versus smaller mines. It was assumed that the large mines serve contract production (the first supply curve step) and that smaller mines serve the spot market production (the second and third curve steps). Surge production (the fourth and fifth supply curve steps) occurs only at high spot market prices, and production from existing mines was estimated by EIA.

The output of this step produces up to five production quantities for existing mines, by NCM region and coal type:

1. Long-term fixed-price contracts (large mines)
2. Spot market (small mines)--1975

3. Spot market (small mines)--1980
4. Surge--1975
5. Surge--1980

Step 3: Estimate Existing Gas Prices. Prices for the five existing mine supply quantities computed in the previous step were all based on an analysis of 1973 average regional coal prices, and various assumptions concerning prices in the spot and surge markets. The following approach was followed:

- The 1973 average price of coal in each NCM region was computed from BOM data.
- It was assumed that producers receive a 10-percent premium on the spot market over the average price for the same coal under long-term contracts.
- Using the percentages of large mines (serving the contract supply) and small mines (serving the spot market), the contract price was computed. For example, assume that the regional average price is \$10.30 per ton, and that large mines represent seven percent of all mines and small mines, 30 percent; then:

$$(0.7x) + (0.3) (1.1) x = \$10.30$$

where x = contract price. Solving for x yields a contract price of \$10.00. The corresponding average spot price is \$11.00.

- These prices were used, together with the average Btu content for the coal produced in each region (from BOM data), to compute an average price per million Btu.
- This price was then applied to each coal type on the basis of Btu content to obtain a price for each coal type mined in that region.
- These prices were then inflated to 1975 dollars.

- The computed contract and spot prices relate to the first and third supply curve steps. The second-step spot price was set at 1.05 times the contract price, and the fourth and fifth prices were set at 1.5 and 2.0 times the third-step spot price, respectively.

Step 4: Estimate Future Production from New Mines. This step, which represents a primary function of the RAMC program, is the reserve allocation procedure. The procedure, which begins with the BOM estimates of the demonstrated reserves base, proceeds as follows:

1. First, an estimate was made of those coal reserves committed to existing mining operations, based on a summation of production from existing mines through 1990 and corrected by a recovery factor. (A recovery factor attempts to correct for the coal that must be left in the ground during mining operations.) These "committed reserves" were removed from the demonstrated reserve base.
2. Second, because significant quantities of coal cannot be mined because the coal seams exist under parks, urban areas, and highways, a fraction of the demonstrated reserve base was removed from the model to account for these "unmineable" reserves. The percentages removed were arbitrary estimates for each region, ranging from a high of 25 percent in the midwest, where urban development was assumed to have the greatest impact on

coal production, to a low of 10 percent in the western states.

3. Third, the remaining, or "uncommitted," coal reserves were allocated among a variety of overburden categories (for strippable surface reserves), seam thickness and seam depth categories (for deep reserves), and mine size categories (for both surface and deep reserves). The distribution of reserves to different mine sizes was determined by reviewing existing capacity and planned new capacity through 1985. Allocation of reserves to mine size was done on a region-by-region basis to simulate local mining conditions.
4. The final substep in the reserves allocation procedure involved conversion of the stock of coal reserves into potential production flows from the hypothetical mines. This was accomplished by assuming a mine life of 30 years--over which time a mine was assumed to exhaust its coal reserves--and by assigning a recovery factor--i.e., a factor identifying how many tons of production result from each ton of reserves in the ground. The recovery factor for surface mines was set at 80 percent and for deep mines at 50 percent.

Since the lead time required for opening large new mines is from three to five years, most of the new capacity that will be on

line in 1980 is already under development or planned. By limiting the NCM's new mine openings to that capacity already considered to be "in the pipeline" by the coal industry, the realism of the model's output is enhanced.

Step 5: Estimate Minimum Acceptable Selling Prices for New Mines. The final step in the generation of the NCM coal supply curves involved the estimation of the minimum acceptable selling price for each of the new mine types developed in Step 4. The minimum acceptable selling price is an engineering-based estimate of production costs for a given mine. In other words, the minimum acceptable selling price at a given mine is the minimum price a coal producer could accept for his product and still operate profitably in the long run.

Different mines have different production costs, and thus different minimum acceptable selling prices. For example, all other things being equal, a deep mine clearing a coal seam six feet thick and 500 feet down will cost less to build and operate (and will thus produce a ton of coal more cheaply) than a mine clearing a four-foot seam at 1,000 feet. Similarly, larger mines generally experience greater output per man-day (i.e., higher productivity) than their smaller counterparts, due to the economies of scale associated with large-scale production. (A variety of factors influence the cost of producing a ton of coal at a given mine.)

The estimation of minimum acceptable selling price for each of the mine types developed in Step 4, above, proceeded as follows:

1. First, a detailed costing summary for each of two base case model mines (one surface mine and one deep mine) was developed. This summary of balance sheet information contained such cost data as initial and deferred capital requirements, sales operating costs, profits, taxes, etc., for each of the two base case mines.
2. Second, the minimum acceptable selling price of the coal from each of the two base case mines was estimated.
3. Third, the model returned to the many hypothetical new mine types developed in Step 4 and developed detailed costing summaries (balance sheets) for each. These costing summaries were based on extrapolations from the base case mines--that is, since all of the hypothetical mines were described in terms of mine size and overburden ratio (for surface mines) or mine size, seam thickness, and seam depth (for underground mines), variations in any one of these factors from the base case mines affected one or more cost-related variables in the model (i.e., productivity of labor, initial capital, deferred capital requirements, and/or costs of power and supplies).

4. Once these costing summaries were completed, the model estimated minimum acceptable selling price for each of the hypothetical new mines.
5. Finally, for each coal type and coal supply region defined in Step 1, the model arrayed all of the "new" mines in that region producing a given type of coal in order of ascending minimum acceptable selling price. In other words, the model assumed that less-costly coal seams would be developed before their more expensive counterparts. This ordering of mines and their potential production in terms of production costs resulted in the supply curves that are the primary output of the model.

References

The following documents contain material that describes elements of the National Coal Model, including the Reserve Allocation and Mine Costing Program:

- Gaffen, Mike, National Coal Model--Coal Supply Curves, September, 1978.
- ICF Incorporated, The National Coal Model: Description and Documentation, October, 1976.

6. Nuclear Fuel

Nuclear fuel supply curves for input to the MEMM were similar to those for fossil fuel supply, and took the form of step functions

relating the production of nuclear fuel to its cost. Production was expressed in terms of millions of kilowatt-hours per calendar day (MMkWh/D). Costs were expressed as mils per kilowatt-hour, and reflected the price that utilities must charge customers per unit of generated electricity to recover nuclear fuel costs. Curves were produced for each target year. Supply activity was not regionalized and was assumed to occur for the United States as a whole; hence, only one curve was produced for each target year.

Methodology

The nuclear fuel supply curves were developed using available data on reactor schedules, fuel processing parameters, and fuel-related costs, together with special-purpose models.

The NUFUEL module of the Nuclear Fuel Economy Model was used to determine the demand for uranium. Input to NUFUEL consisted of the schedule of nuclear power plants, and reactor fuel and fuel processing technical parameters. The module incorporates the ideal enrichment cascade theory as the core algorithm for fuel cycle computations, and produces a schedule of fuel process requirements, including uranium demand.

This demand was input to the EUREKA model, which then computed uranium prices. EUREKA simulates uranium mining and milling operations, and produces direct mining and development costs, mining support costs, and the costs of associated operations to

obtain the processed uranium concentrate that represents the basic nuclear fuel raw material.

Enrichment costs were obtained from the Report on Providing Uranium Enrichment Services, a DCE report published in draft form in February, 1979. In addition, spent fuel disposal prices were obtained from Preliminary Estimates of the Charges for Spent Fuel Storage and Disposal Services (DOE/ET-0055, July, 1978).

The resulting nuclear fuel services and uranium product unit prices were next input to the Levelized Nuclear Fuel Cycle Cost (LNFCC) Code Model. The LNFCC model computes the cost of a batch of fuel for a nuclear electric power plant per unit of electricity produced, given requirements and costs for nuclear fuel and fuel cycle services. The result is the price a nuclear electric utility company must charge its customers per unit of production to recover its expenses.

The LNFCC is a process model that simulates the fuel cycle (and recycle) for plutonium and uranium fuel elements. The process begins with an analysis of fuel utilization efficiency inside the reactor core, and then proceeds both backward through the fuel cycle stages prior to fuel use, and forward through the radioactive waste management activities. Within this process, the economies were analyzed at each stage. Fuel recycling was not considered for the ARC78, as a result of current government policy to indefinitely defer the commercial reprocessing of spent nuclear fuel. Cost factors were applied to each component of the

fuel cycle, based on the quantity of nuclear fuel being processed, and an appropriate levelized fuel cost was computed.

The resultant nuclear fuel supply requirements and associated nuclear fuel prices required per unit of generated electricity to recover fuel costs were used to develop the supply curves input to the MEMM.

References

The following documents describe models and related procedures that were used to develop inputs to the MEMM to generate the ARC78 projections:

- Energy Information Administration, Levelized Nuclear Fuel Code Cost Program User's Guide, TR-78W-037, September, 1978.
- Energy Research and Development Administration, A Computer Code for Conceptual Cost Estimates of Steam Electric Power Plants, June, 1975. (CONCEPT V technical documentation.)
- McVey, W. H., et al., Calculating U-235 Outputs and Charges, TID-8539, 1963.
- Snyder, A. J., U.S. Atomic Energy Commission, Computer Program NUFUEL for Forecasting Nuclear Fuel Requirements and Related Quantities, WASH-1348, October, 1974.

7. Transportation

As described in Subsection 1, Introduction, above, the MEFS transportation network is embedded in the MEMM. The movement of

energy materials from supply to consumption points influences the price to the consumer; for some fuels, transportation represents more than 50 percent of their price. Hence, transport costs were required for use in the MEMM linear programming objective function. In general, capacity constraints for transportation network links were not included in the MEMM, with the exception of the Trans-Alaskan Pipeline System (TAPS) and the Sohio pipeline.

The following energy material/transport mode network combinations were modeled in the MEMM:

1. Crude oil
 - Tanker
 - Pipeline
2. Refined petroleum products
 - Tanker and barge
 - Pipeline
3. Residual oil
 - Tanker and barge
4. Natural gas
 - Pipeline
5. Coal
 - Barge and rail (transshipment)

Within the transportation submodel, each material is moved from supply regions to demand regions via the appropriate modes, passing, if necessary, through conversion regions (refineries and utilities). Crude oil is shipped to refineries for processing, while refined petroleum products are moved directly to demand regions. Natural gas and coal may be moved directly to demand regions or to electric utilities where the fuel is converted to electricity. Nuclear fuel goes to electric utilities. In the case of coal, where transportation costs represent a significant portion of the cost, the transportation network is composed of two interconnected modes--barge and rail--and is referred to as a transshipment network.

Given the specification of material/mode network links and associated costs, the choice of mode and route for shipping an energy material from an origin to a destination will depend on the objective function optimization within the MEMM. Basically, inputs to the MEMM, for each material/mode combination, were derived by constructing the allocated network in terms of its interconnecting links, and then specifying a shipment cost for that link. Costs generally were stated in terms of appropriate unit costs (dollars per barrel, dollars per thousands of cubic feet, or dollars per ton) for each network link. Details for each material/mode are provided below.

For oil transportation, transshipment of fuels is not modeled, although the cost of moving Alaskan and imported crude does

involve the costs associated with two transport modes. Oil transportation is complicated by the diversity of oil types, the need to consider foreign and domestic origins, and the existence of intermediate links to refineries. Residual oil, while technically a petroleum product, is considered separately due to its density and viscosity, which affect its transportation. Generally, tankers are used on ocean-going routes and barges are used on inland waterways.

Crude oil may be transported from foreign and domestic supply regions to domestic refinery regions by tanker. The crude oil/tanker network includes passages through the Panama Canal. The domestic unit cost in dollars per barrel for transporting domestic crude by tanker is computed as the sum of three terms divided by the number of barrels shipped:

- cost for time in port plus cost for time at sea representing the actual shipment costs; plus
- additional fixed charge for using the Panama Canal, if applicable; plus
- additional gathering costs for removing crude from the field and transporting it to the tanker port.

These domestic cost terms were developed for each link. Tanker costs were based on 1976 Maritime Administration estimates of tanker capital, and operating and maintenance costs. Foreign crude oil transportation costs by tanker were included in the price of the fuel, and were therefore not input as part of the transportation submodel.

Domestic refined products may be shipped from refinery regions to demand regions either by tankers or by barges. Refined products are also transported directly by tanker from foreign supply regions to U.S. demand regions. On the domestic side, refined product transportation costs for shipments by tanker from refinery regions to demand regions are computed as they were for crude oil tanker shipments, except that no gathering charge is added. To this must be added the unit charge for that portion of the route, if any, that was by inland waterway barge; these costs were developed from an analysis of transportation costs conducted by the original Project Independence Task Force. Domestic residual oil shipment costs were similar to those for refined products, except that tanker costs were increased 10 percent and barge costs 21 percent to account for the effect of differences in fuel densities on shipping costs per ton. Foreign unit costs for shipments of refined products and residual fuel were route-specific estimates.

In addition to shipments by tanker and barge, foreign and domestic crude and domestic petroleum products may be shipped by pipeline. Unit costs in dollars per barrel per 100 miles for shipments of petroleum by pipeline were developed for most pipelines, using tariffs published by the Interstate Commerce Commission. The Trans-Alaskan Pipeline System data were based on analyses performed by the EIA Division of Midrange Analysis. The Sohio pipeline tariffs were taken from estimates prepared by the DOE Office of Policy and Evaluation.

For natural gas shipments by pipeline, separate analyses of unit costs, in dollars per thousand cubic feet per 100 miles, were conducted for interstate and for intrastate shipments, due to the imposition of federal regulations on the transport of interstate gas. The proposed pipeline, the Alaskan Natural Gas Transportation System, was modeled from Alaska to the Lower 48 states, where it connects with existing pipeline systems. Unit costs for interstate shipments were aggregated from appropriate component costs consisting of the following:

- Lower 48 unit costs (\$/Mcf/100 miles)
- Alaskan unit costs (\$/Mcf)
- Gathering cost adjustments (\$/Mcf)
- Foreign charges (\$/Mcf)
- Industrial price adjustment (\$/Mcf)
- Syngas unit costs

Component unit costs were developed from FERC and Federal Communications Commission data. For intrastate gas shipments, a fixed unit cost in dollars per thousand cubic feet was used with no variance due to mileage.

The coal transportation network within the NEMM is the most complex of all the material/mode combinations, involving multiple transport modes and multiple modes per route. There are seven link types employed to describe the coal network, as follows:

<u>Mode Pair</u>	<u>Link Group</u>	<u>Link Type</u>
Supply to Transshipment	Movement	Supply to Rail Supply to Barge
Transshipment		
• Same mode	Movement	Rail to Rail Barge to Barge
• Different mode	Transfer	Rail to Barge Barge to Rail
Transshipment to Demand	Transfer	Rail to Demand

By using the link types, possible routes can be specified to simulate the movement and transfer of coal within the transshipment network. For example, shipment of coal first by rail, then by barge, and then by rail to a demand point would involve the following links:

- Supply to rail (movement)
- Rail to barge (transfer)
- Barge to barge (movement)
- Barge to rail (transfer)
- Rail to rail (movement)
- Rail to demand (transfer)

Each link within the transshipment network has its associated unit costs (in dollars per ton), which can be characterized by link type:

1. Movement

- Coal supply to rail--fixed handling charge and variable mileage charge (determined by regression analysis)

- Coal supply to barge--fixed handling charge and variable mileage charge (from actual costs)
- Rail to rail--variable mileage charge (regression)
- Barge to barge--variable mileage charge (actual)

2. Transfer

- Barge to rail--fixed handling charge
- Rail to barge--fixed handling charge
- Rail to coal demand--surcharges

The rail to coal demand surcharges are imposed per ton shipped for small lot orders and non-unit train shipments, as applicable. For large utility demand centers, these surcharges would probably not be applied.

Estimated unit costs for coal barge rates were developed by the original Project Independence Task Force, and coal rail rates were derived from analysis of unit train shipment costs. All costs were updated for the ARC78 by the TERA studies.

The following document describes the development of the coal transportation network:

- Transportation and Economic Research Associates, Inc., Disaggregating PIES Fuel Forecasts, Validating PIES Transportation Data Base, and Other Technical Services, September 15, 1978. (Technical documentation covering MEMM [PIES] support activities.)

8. Refineries

Within the MEFS, the modeling of refineries is accomplished using two primary elements:

- 1) the MEFS refineries submodel, a reduced-form process model integrated in the MEMM that simulates the activities of refineries on an aggregated regional basis; and
- 2) the National Aggregated Refineries Model (NARM), a highly-detailed linear programming model of refinery activities developed by EIA, based on the use of the Refinery and Petrochemical Modeling System (RPMS) developed by Bonner and Moore Associates, Inc., of Houston, Texas.

The refineries submodel represents the conversion of domestic and imported crude oils to seven major refined products demanded by consumers in five sectors. A summary of the relationship between refined products, products demanded, and consuming sectors is shown in Table 13-4. Crude oils processed by refineries differ in their physical and chemical characteristics, such as specific gravity; the submodel can distinguish approximately 45 different domestic and imported crudes. Consequently, the submodel represents the processing of each type of crude in a slightly different way, with varying activity costs and different mixes of resulting refined products.

The conversion of crude oil to refined petroleum products is accomplished in the submodel using "distillation" vectors that define the quantities of each refined product resulting from the refining of a given crude type. Refinery fuel used in the

TABLE 13-4

SUMMARY OF MEPS REFINERIES SUBMODEL PRODUCTS
AND CONSUMER SECTORS

REFINED PRODUCT	PRODUCT DEMANDED	CONSUMING SECTOR
GASOLINE	• GASOLINE	• TRANSPORTATION
DISTILLATE	• DISTILLATE	• RESIDENTIAL • COMMERCIAL • INDUSTRIAL • TRANSPORTATION
RESIDUAL	• RESIDUAL	• COMMERCIAL • INDUSTRIAL • TRANSPORTATION
JET FUEL	• JET FUEL	• TRANSPORTATION
LIQUID GAS	• LIQUID GAS	• RESIDENTIAL • COMMERCIAL • INDUSTRIAL • TRANSPORTATION
NAPTHA	• NAPTHA • LIQUID GAS	• INDUSTRIAL • FEEDSTOCK • RAW MATERIAL
OTHER	• OIL • ASPHALT	• RAW MATERIAL • COMMERCIAL

process and refinery gains are accounted for. A vector, or equation, is included for each type of domestic or imported crude; that is, they produce a refined product slate for each crude type. These vectors were derived on a regional basis from recent refinery activity and product yields. Data were obtained from the RPMS data base and from the Bureau of Mines.

The MEFS submodel also employs shift vectors to permit the base yields per barrel of crude to be altered to satisfy changing demand. For example, if the demand for gasoline is not satisfied by the base refinery yield, the excess demand could be made up by drawing upon the distillate product yield; hence, a shift from distillate to gasoline, on a Btu-equivalent basis, can be simulated. These product shifts must be accompanied by corresponding increases or decreases in costs. The shift from distillate to gasoline would incur an additional cost reflecting the more expensive refining process required to produce gasoline. These costs were derived from the relative prices of the products among which the shifts are occurring.

The relative product prices input to the MEMM as part of the shift vectors were developed as follows:

1. Using estimated product prices, an initial MEMM run was made to obtain refinery product demand quantities.
2. The NARM was run with the MEMM product demands.
3. Relative product prices were then obtained from the dual solution of the NARM linear programming formulation.

4. The relative product prices were used to derive the MEMM objective function coefficients for the product shift vectors, and the MEMM was run again.
5. Similarly, the MEMM demand outputs were input to the NARM, and the iterative process was continued.
6. The process was terminated when the prices had converged sufficiently.

The NARM, used in the above process, is a detailed national aggregate linear programming model based on the RPMS, a set of data bases and submodel formulations that can be used to model refinery operations at different levels of aggregation. The RPMS data base contains extensive information concerning crude oil attributes, process yield correlations, and investment and operating costs. Capital costs and operating costs used in the MEMM were historical costs that had been adjusted using the Nelson index of refinery costs, which is published in the Oil and Gas Journal.

In addition to the constraints associated with the operation of refineries, the refineries submodel also incorporates constraints on existing aggregate refinery capacity by region. Capacity constraints were obtained from the annual report entitled Trends in Refinery Capacity and Utilization (DOE/RA-0010, 1978).

The following documents, available from Bonner and Moore Associates, Inc., contain material describing the basis for the constraints and related data used in the MEPS refineries submodel and in the NARM:

- RPMS User Manual, September, 1977.
- RPMS Data Base, September, 1977.

9. Utilities

The Electric Utilities Dispatching Model is the MEMM utilities submodel, the second process model integrated within the MEMM. It models the activities necessary to convert fuel into the electricity needed to meet demand in the 10 DOE (demand) regions. The activities modeled are utility plant operation, new facility construction, boiler conversion, and electricity transmission and distribution. Basically, the submodel is given fuel prices, capital costs, fixed charges, and other costs in order to determine the mix of plants to satisfy demand in base, cycling, daily peak, and seasonal peak loads. Fuel is then consumed and electricity is produced in historical demand patterns at demand levels specified.

As noted above, the submodel is embedded within the MEMM; it is a linear program that dispatches generating plants and expands capacity to satisfy a representation of the annualized load duration curve. Generating plants are differentiated by type of technology and fuel used. The model involves 23 conventional types of plants and eight new technologies. Coal-fired power plants are further differentiated by type of coal burned, sulfur content, and whether or not flue gas desulfurization equipment is present. Utilities operate existing plants and build and operate

new facilities, where the new plants are brought into operation in order of increasing marginal cost of generating electricity.

Inputs to the submodel included existing capacity, capacity factors, fixed charge factors, conversion and heat rates, load duration curves, retirement rates, transmission and distribution losses, capacity expansion limits, fuel prices, electricity pricing factors, capital costs, and operating and maintenance costs. The sources for much of the data included various PERC/FPC forms, utilities, and user studies. Also, many of the costs were obtained from computer models such as CONCEPT V.

Each plant has both fixed and variable costs associated with its operation. For new plants, the fixed costs are taken to be an annual capital charge, dependent upon the initial capital cost. The variable costs consist of operation and maintenance costs and costs for fuel consumed, both of which increase linearly with production. The cost relationships vary among plant types; for example, nuclear plants have high capital costs, but low variable costs. There is also a difference between new and existing plants, as new plants have higher thermal efficiencies than existing plants.

The submodel is regional, with no interregional transmission allowed. Within each region, generating capacity is aggregated over all plants of a particular type. The plant types are oil-fed steam (residual fuel oil); simple-cycle with distillate;

combined-cycle with distillate; combined-cycle with gas; gas turbine; gas-fed steam; bituminous coal (high, medium, and low sulfur), with and without scrubbers; sub-bituminous (medium and low sulfur), with and without scrubbers; lignite (medium and low sulfur), with and without scrubbers; hydroelectric, static reservoirs; hydroelectric, pumped storage; nuclear; and solar thermal, wind, photovoltaics, biomass, central electric, low/medium-Btu combined-cycle, ocean thermal, and geothermal. Some of the plant types can meet only certain types of loads. The four loads are base, cycling (intermediate), daily (peak), and seasonal (peak). Nuclear plants, for example, are only used for base loads, while gas turbines are preferable for peak loads.

When operation of new and existing capacity cannot meet the demand for electricity in a region, the submodel provides for the building of new facilities. Those with long construction lead times and high capital costs are categorized by amount of capital expended and construction completed--i.e., committed (fully capitalized, more than 90 percent construction completed); deferrable (10 percent capital invested, less than two percent construction completed); and new (no capital invested, no construction completed). The plants are built based on the above order, deferrable before new.

The submodel uses a normalized annual load-duration curve (i.e., total demand = 1) to represent a single day's operation, which is approximated by a four-step function. The area under the curve

then represents the total electricity demand for the period. The load-duration curves are satisfied by an optimization process, where the appropriate type of generating facility selected is characterized by capital and operating costs, fuel type, heat rate, and reliability. This process entails the specification of constraints on base, cycling, and peak loads as well as on reserve margin requirements and total capacity limits.

The submodel also allows conversion of oil and gas plants to coal, and from oil to gas (or gas to oil). No capital investment is required for the latter, but conversion to coal is modeled at the cost of the conversion capital, amortized at the annual specified rate.

The utilities submodel is described in the MEFS documentation cited in Section 13.3.2. The following documents describe inputs to the submodel:

- Energy Research and Development Administration, A Computer Code for Conceptual Cost Estimates of Steam Electric Power Plants, June, 1975. (CONCEPT V technical documentation.)
- Logistics Management Institute, Evaluation of the Electrical Utility Sector Data Base in the DOE Mid-Range Energy Market Model (MEMM), February 2, 1979. (Technical document containing equations and procedures for developing electric utilities inputs to the MEMM; currently being updated.)
- Oak Ridge National Laboratory, User's Instructions for Preliminary Version of the Concept V Computer Code, February, 1978. (Technical documentation for users of the CONCEPT V program, which produces capital costs for oil and coal utilities.)

10. Advanced Technologies

Seventeen advanced technologies were modeled in the MEMM, as follows:

- Oil shale
- Coal liquids
- Methanol from coal
- High-Btu coal gasification
- Medium-Btu gas gasification (utility scale)
- Low-to-medium-Btu gas (combined-cycle base load electric)
- Central electric
- Ocean thermal
- Biomass (electric)
- Solar thermal
- Hydropower
- Photovoltaics
- Wind energy
- Hydrothermal
- Solid waste
- Geopressured methane
- Enhanced oil and gas recovery

The last advanced technology, enhanced oil and gas recovery, was discussed in a previous section.

Estimates of the following data were developed for each advanced technology to be input to the MEMM:

- Maximum potential production in each target year.
- Marginal capital costs (in 1978 dollars) at maximum potential production.
- Capacity factors representing the expected operating rate, expressed as the ratio of annual output to rated capacity, after start-up and initial shakedown.
- Operating and maintenance costs (in 1978 dollars) associated with the supply capacity indicated by the capacity factor.

- Conversion efficiency, if applicable, representing the ratio of process output to raw material input, both expressed on a Btu basis.
- Minimum acceptable (marginal) supply price to provide the last unit of capacity at maximum production.

The above estimates were developed by an EIA Energy Task Force using data derived from numerous sources. Most of the estimates used for the ARC78 were prepared in conjunction with the National Energy Strategy Study.

In general, the advanced technology energy sources produce base load electricity. Gas produced from coal gasification is used in combined-cycle turbines to produce electricity. Most geothermal and renewable resource technologies such as wind, solar, or hydropower are applied to electricity generation. Central electric technology derives from the burning of coal in an atmospheric fluidized bed (AFB) to produce electricity. The major exceptions to this base load electricity application are the dispersed technologies involving wind conversion systems, geothermal installation, and solar heating (including hot water) and cooling of buildings. These technologies are directly applicable to residential and commercial buildings and, in effect, reduce the demand for electricity and fossil fuels.

13.3.5 Midterm Energy Market Model

The MEMM, the integrating model of the MEFS, is an LP formulation where elements of the objective function and constraint set are derived from the supply network and demand models cited above. Underlying the LP formulation is the assumption that, subject to governmental policy constraints, energy consumers and suppliers act in their own best interests. Consumers seek to maximize their benefits, and producers act to maximize profits. Under these conditions, demands will increase as prices decrease, and supplies will increase as prices decrease. Hence, the supply and demand functions are of the general form depicted in Figure 13-9.

Consequently, the market equilibrium for fuels occurs where the supply and demand functions intersect. In the LP formulation, the shaded area between the supply and demand curves in Figure 13-9 represents consumers' and producers' surplus for the one-product case, and maximization of this area defines the intersection point of the two curves. Consumers' surplus is the difference between what consumers would be willing to pay for a product and what they actually pay; producers' surplus is the difference between what producers get for their products and what they would be willing to accept. The shaded area represents the total consumers' and producers' surplus. This surplus is maximized subject to constraints on the energy system--such as the material balance and process limit constraints imposed by the

FIGURE 13-9

MEFS SUPPLY AND DEMAND FUNCTIONS

production, processing, and transportation of raw fuels that are subject to quantity and capacity limitations. The energy system is also constrained to meet the final demand for fuel products.

To implement the LP formulation, it is necessary to approximate the fuel supply curves by step functions such as that illustrated in Figure 13-9. Each step represents a quantity range of energy fuel that will be supplied at a given minimum acceptable price. Once determined, these supply curves are unchanged by the LP solution process. The demand function is also input as a step function. The demand models were used to compute initial demand estimates for each energy product, as well as price estimates for each elastic product, and own-price and cross-price elasticities for each product, which were assumed to remain constant over a range of prices. From these data, demand functions were developed for each product. The LP was then solved to obtain prices, demands, and energy industry activity levels, which serve as a candidate equilibrium solution.

However, an LP solution is not necessarily an equilibrium. The elasticities from the demand models are only valid in the vicinity of the initial price and quantity point on the demand curve. In particular, fuel substitution effects as prices change cannot be modeled in the LP formulation (except for the limited case of electrical utilities). Therefore, if the LP solution represents a substantial departure from the initial demand points, the solution will not embody the dynamics of fuel

substitution. To alleviate this condition, the LP solution obtained was re-introduced into the demand models, and revised initial demand point and associated demand curves were developed. These revised curves reflected demand, including fuel substitution effects, in the price vicinity of the previous LP solution. These curves are again used as input to the MEMM, and a new solution is obtained. This new solution was compared to the previous one, and the iterative process was repeated until convergence (equilibrium) is achieved.

When equilibrium was reached, the MEMM reporting module generated an extensive series of reports related to fuel prices, supply and demand balances, transportation, capital requirements, and similar related data. During the economic-energy interaction, many of these data would be input back into the DRI econometric model, and iterations through the MEFS would be continued until convergence of economic growth and energy projections was achieved. When this convergence was obtained, the resultant MEMM output consisted of energy forecasts that reflected the various scenario assumptions underlying the analysis. This entire process was repeated for each scenario. The MEMM results associated with the ARC78 projections were provided in Supplement One to Volume Three of the ARC78.

CHAPTER 14

ENERGY FORECAST IMPACTS

This chapter describes four models used to assess the impact of the economic and energy projections produced by the models and model interactions described in Chapters 11, 12, and 13. The relationships of these models within the overall framework is depicted in Figure 11-2 of Chapter 11. The four models described in this chapter are the following:

- the Energy Disaggregated Input-Output (EDIO) Model, used to evaluate sectoral employment impacts of the economy-energy projections;
- the Regional Earnings Impact System (REIS), used to examine state-level economic impacts, in terms of earnings, for the midterm projections;
- the MATH/CHRDS model, used to measure the impact of the midterm projections at the micro-level of households; and
- the Regional Emission Projection System (REPS), used to assess the environmental impacts of the midterm forecasts.

14.1 Interindustry Impacts (EDIO)

14.1.1 Introduction

The Energy Disaggregated Input-Output (EDIO) Model was used to evaluate sectoral employment impacts associated with alternative

economic-energy projections for 1985 and 1990. The model simulated output and associated employment (jobs) for 117 sectors of the economy and 470 occupational categories. The model is highly disaggregated from an energy perspective, containing 17 energy sectors involving coal, petroleum products, and utilities. The model is driven by vector of final demand for 28 GNP components derived from the DRI macroeconomic model, and includes:

- Personal consumption
- Investment in structures and producers' durable equipment
- Inventory change
- Imports
- Exports
- Federal, state, and local government expenditures

The components are transformed within the model using input-output tables and related elements prepared under an interagency agreement with the Bureau of Labor Statistics (BLS). Model results consisted of gross output and employment in the 117 sectors and 470 occupational categories. The aggregated sectoral employment was also used as input to the Regional Earnings Impact System (REIS).

14.1.2 Methodology

The EDIO model employs static input-output analysis techniques to represent the interrelationships between sectors of the economy--specifically, the direct and indirect output and

employment requirements, by sector, to satisfy a specified level and composition of total final demand (GNP). For the ARC78, the model was used primarily to evaluate the future job market implications resulting from projections of economy-energy interactions.

The model incorporates the following six components developed by the BLS:

1. Projected transaction tables for 1985 and 1990 show the dollar value of transactions among the various industries, the sales of each industry to final demand, and the value added originating in each industry. The row entries of the tables are the sales of one industry's output to each of the other industries, to itself, and to the components of final demand. The columns represent the inputs to one industry from the other industries and itself that are used to produce its output.
2. Projected direct coefficient matrices for 1985 and 1990 are derived directly from the above transaction tables by dividing each cell on an industry column (excluding the value added cells) by the total value of the output for that industry. This generates a matrix of direct requirements per dollar of output (direct coefficients) that represents the basic structural relationship of the entire industrial system.

3. Projected inverse matrices for 1985 and 1990 specify the total dollar output requirements (direct and indirect) for each industry per dollar of delivery to final demand by each industry.
4. Projected employment-output ratios for 1985 and 1990 specify the employment requirements per million dollars of gross output for each of the 117 sectors. Employment is defined in terms of the number of jobs, as opposed to persons employed.
5. A bridge table distributes the 28 GNP components of final demand to the 117 sectors, and places the value of trade and transportation services in the trade and transportation sectors.
6. An occupational matrix reflects the percentage distribution for the 470 occupational categories in each of the 117 sectors.

The above tables and matrices were developed by the BLS under an interagency agreement with DOE. The BLS updated existing tables for 1963 and 1967, and developed new tables, using available historical data, for 1973. These tables were then projected for 1985 and 1990 using MEFS projections as controls to reflect changing patterns in energy consumption. The first two components discussed above, the transaction tables and direct

coefficient matrices, were used to develop the inverse matrices. Only the inverse matrices, employment-output ratios, bridge table, and occupational matrix were actually used within the EDIO model.

The process employed within the EDIO model is shown in Figure 14-1. Input to the model consisted of the 28 components of final demand, as forecasted by the DRI model. These values entered the EDIO model bridge program.

Within the bridge program, the vector of 28 GNP components of final demand is transformed into a form consistent with the EDIO framework. The DRI components represent consumption on a commodity basis, such as autos and parts, or furniture. The EDIO model operates on the basis of sales to final demand by each of the 117 sectors. This conversion is accomplished using the BLS bridge table. The bridge table serves two purposes--first, to distribute final demands to producing sectors; and, second, to remove the cost of trade and transportation from the value of producing sector outputs, and to distribute these costs to the trade and transportation sectors. The result of this re-distribution is referred to as a "bill of goods," which is simply the allocation of the 28 GNP components of final demand to the 117 sectors of the EDIO model. The bill of goods vector is used as input to the output and employment program of the EDIO model.

FIGURE 14-1

ENERGY DISAGGREGATED INPUT-OUTPUT (EDIO) MODEL OVERVIEW

The total gross output required by each sector to satisfy a given bill of goods is determined by multiplying the inverse matrix and the bill of goods vector. The general set of equations underlying this step is as follows:

$$AX + Y = X$$

where A represents the direct coefficients matrix, X represents the vector of gross output, and Y represents the vector of final demand. The above equation can be written in terms of X as:

$$Y = (I - A) X$$

so that:

$$(I - A)^{-1} Y = X.$$

The term $(I - A)^{-1}$ is the inverse matrix, which, when multiplied by the vector of final demand, Y, yields the gross output X.

Hence, the gross output requirements for each of the 117 sectors are obtained by multiplying the inverse matrix and the bill of goods. The resulting vector is input to the employment program of the EDIO model.

In the employment program, an employment matrix is first formed by multiplying each row of the inverse matrix by the BLS

employment-output ratio of the sector corresponding to that row. This results in a matrix of employment coefficients that reflects the direct and indirect employment requirements per dollar of sales to final demand (the bill of goods). This employment matrix is then multiplied by the bill of goods vector to generate a matrix of employment requirements by sector necessary to satisfy each component of the bill of goods. The vector of row totals represents the job requirements for each of the 117 sectors. These data are input to the occupational program.

In the final model step, the job requirements vector by sector is input to the occupational matrix to obtain a vector of job requirements by the 470 occupational categories. The BLS occupational categories simply reflect the percentage distribution of jobs by occupational category within each sector. The model results are then aggregated, as required, into major sectoral and/or occupational groups for subsequent use. The above process was repeated for each specified scenario. Employment requirements were used by the REIS, and were reported in Chapter 22 of the ARC78.

14.1.3 References

The following documents describe the methodology used in the EDIO model, and cite additional references:

- Earley, Ronald F., and Malek M. Mohtadi, Energy Information Administration, Office of Integrative Analysis, EIA Input-Output Model Simulation Procedures, Technical Memorandum TM/IA/78-03, July 31, 1978.
- Earley, Ronald F., and Malek M. Mohtadi, Energy Information Administration, Office of Integrative Analysis, Sector Employment Implications of Alternative Energy Scenarios, Analysis Memorandum AM/EA/78-24, August 21, 1978.

14.2 Regional Earnings Impacts (REIS)

14.2.1 Introduction

Earnings, or income from production, are frequently used as a measure of overall economic activity, just as GNP is used at the national level. Therefore, regional economic analysis to examine the implications of alternative energy forecasts on different regions of the country focused on earnings changes. The analysis results were presented in Chapter 22 of the ARC78.

Estimates of regional earnings changes were made using the Regional Earnings Impact System. The REIS provides a quick and detailed response capability that allows analysis of state-level industrial impacts of alternative energy futures. It was used to estimate the earnings impacts of the alternative mid-range forecasts for 1985 and 1990 shown in the ARC78. The REIS is an impact model, rather than a forecasting model; that is, it describes the ways in which state economies respond to changes in

the national economy. Output of the REIS consists of annual earnings by state in each of 37 industrial sectors. An overview of the REIS is shown in Figure 14-2. As a system, the REIS encompasses the MEFS and the DRI macroeconomic model, which produce the energy and economic forecasts. These forecasts provide input, together with other data, to the EDIO model, which produces employment (jobs) projections for 129 sectors of the national economy. These national sector employment projections are used by the Department of Commerce's Bureau of Economic Analysis (BEA) to estimate earnings in 37 two-digit standard industrial classification (SIC) categories or sectors. The resultant sector earnings are then input to the regional distribution model that computes annual earnings by state and sector.

14.2.2 Methodology

The regional distribution model (RDM) in the REIS uses export-base theory, which states that economic forces external to a region are the major determinants of its growth. Accordingly, industries of a region are classified as basic--that is, producing exports and providing new income for the region--or residentiary (non-basic), producing for local consumption purchased with local resources. Demand for the basic products of a region is determined by the national demand for those products. Like similar export-base models, the RDM used multipliers--the

FIGURE 14-2

OVERVIEW OF THE REGIONAL
EARNINGS IMPACT SYSTEM (REIS)

ratio of "basic" industry production to total production in a region--to determine the total earnings impact given a change in regional basic earnings.

Determination of what industries, or sectors, are basic to a region is specified by definition, or is made using a measure known as the location quotient (LQ). Of the 37 sectors considered, 19 are considered basic and seven are considered residentiary, by definition, in all states. The 11 remaining sectors are classified according to the location quotient. If LQ is equal to or greater than 1.5, the sector within a given region is basic; otherwise, it is residentiary, where:

$$LQ = \frac{\text{Sector-to-State Share of Earnings}}{\text{Sector-to-Nation Share of Earnings}}$$

That is, within a given state, if the ratio of sector earnings to total state earnings exceeds by 50 percent the similar ratio at the national level, the sector is basic for that state. This classification was accomplished using BEA historical data on earnings by sector within state.

A description of the distribution model follows. In this discussion, basic and residentiary sectors are denoted as B-sectors and R-sectors, respectively. In general, capital letters are used for earnings (in appropriate dollar-saved

units), and lower-case letters are used to denote shares--that is, ratios of earnings. The index i is used for states, and j for sectors.

The model completes a series of steps:

(1) Compute basic sector earnings by state.

B_i = B-sector earnings for state i

$$= \sum_j a_{ij} * x_j$$

where:

a_{ij} = BEA state-to-nation sector ratios,

x_j = national sector earnings derived from EDIO output, and

j is indexed across B-sectors only.

Steps (2) through (8) that follow address the computation of the basic-to-total earnings multipliers that imply residentiary earnings.

(2) Compute R-sector shares by state.

r_{ij} = R-sector j share of earnings for state i

$$= \left[\frac{x_j}{\text{SUM}(x_j)} \right] * Q_{ij}$$

where Q_{ij} is the location quotient for R-sector j in state i . This value is computed only for R-sectors in each state, and represents the expected share of total state earnings provided by a specified residentiary sector. Furthermore:

$$Q_{ij} = \left[\frac{x_{ij}}{\text{SUM}(x_{ij})} \right] / \left[\frac{x_j}{\text{SUM}(x_j)} \right]$$

so that:

$$r_{ij} = \frac{x_{ij}}{x_j}$$

where x_{ij} = earnings for sector j in state i . Hence, r_{ij} represents the share of R-sector j earnings in state i relative to the national R-sector j earnings.

- (3) Compute total expected share of R-sector earnings for each state.

r_i = expected share of state i earnings from all R-sectors

$$= \sum_j (r_{ij})$$

where j is indexed across R-sectors only.

- (4) Compute corresponding total expected share of B-sector earnings for each state.

b_i = expected share of state i earnings from all B-sectors

$$= 1 - r_i$$

- (5) Compute total expected earnings for each state.

E_i = total expected earnings for state i from both B-sectors and R-sectors

$$= \frac{B_i}{b_i}$$

where B_i is from step (1).

- (6) Distribute R-sector share of total expected earnings to R-sectors within each state.

R_{ij} = expected R-sector j earnings for state i

$$= r_{ij} * E_i$$

where r_{ij} is from step (3). The R_{ij} computed in this step represents the relative distribution of residuary sector earnings across all sectors and states.

- (7) Adjust R-sector earnings to reflect national earnings totals. The national sector earnings, derived from EDIO model output, can be summed to obtain national total earnings. This total serves as a control in the national-to-state distribution process. The R_{ij} computed in step (6), although they reflect the relative expected distribution of residuary sector earnings, may not yield the national total when added to the B-sector earnings of step (1). In this step, the R_{ij} are normalized to yield the national totals:

$$\begin{aligned} R'_{ij} &= \text{normalized } R_{ij} \\ &= F * R_{ij} \end{aligned}$$

where F is a factor that normalizes each of the R_{ij} to achieve the national total.

$$F = \frac{\sum_j (x_j) - \sum_i (B_i)}{\sum_i \left[\sum_j (R_{ij}) \right]}$$

Note that F ensures that the following relationship holds:

$$\sum_i (B_i) + \sum_i (R'_i) = \sum_j (x_j)$$

since:

$$F * \sum_i \left[\sum_j (R'_{ij}) \right] = \sum_i \left[\sum_j (F * R'_{ij}) \right]$$

$$= \sum_i \left[\sum_j (R'_{ij}) \right]$$

$$= \sum_i (R'_i)$$

(8) Compute total earnings for each state.

$$E'_i = \text{total earnings for state } i$$

$$= B_i + R'_i$$

The state earnings computed in step (8) constitute the REIS output.

14.2.3 References

The following document, applicable to the ARC77, provides a description of the REIS as it was used to generate ARC78 projections:

- Sandoval, David A., et al., State Earnings Analysis for the Administrator's Annual Report, DOE/EIA-0102/18, May, 1978.

14.3 Socioeconomic Impacts (MATH/CHRDS)

14.3.1 Introduction

The MATH/CHRDS model was used to analyze the impact of changing energy prices on household direct energy expenditures. The model allowed these impacts to be examined across numerous socioeconomic variables such as age, race, sex, income, and location. The MATH/CHRDS model simulates a large-scale survey of households; projects this survey to a future target year by updating demographic, economic, and energy characteristics; and then analyses household energy expenditures as a function of the updated characteristics. Input to the MATH/CHRDS model consisted of a basic data file developed from a subsample of the Public Use Sample (PUS) of the 1970 Census, augmented with auto and energy data. Other inputs were provided from outputs of the MEPS and the DRI macro model. Output consisted of a file identical to the sample household input file with modified and newly-created data for each household. From this file, household energy expenditures across various demographic groups and locations, in the target year, were developed.

14.3.2 Methodology

The MATH/CRHDS model incorporates the concepts of distributional analysis and microsimulation. Distributional analysis refers to the different impacts on various disaggregated groups within the population, such as persons or households, which result from, in the case of MATH/CHRDS, energy-related events. Microanalytic simulation, or microsimulation, is a method for analyzing these impacts that uses individual, family, or household as the disaggregate unit of observation. Impacts are estimated as changes in the characteristics of this micro unit. Distributional effects are calculated by summing impacts across units having common characteristics.

The MATH/CHRDS model evolved from a combination of the Mathematica Micro Analysis Transfers to Households (MATH) Model, which did not include detailed characteristics of energy-related variables, and the Comprehensive Human Resources Data System (CHRDS), which includes energy-related information.

In brief, the methodology proceeded by creating a synthetic data base for 1975 from a sample of approximately 200,000 households; the data base contained extensive energy, demographic, and socioeconomic data derived from the PUS of the 1970 Census. The demographic and economic characteristics relevant to energy consumption for households in the data base were then updated to the future target year using information from the DRI forecasts.

Energy characteristics were updated from information derived from the RDPOR demand model within the MEFS. The resulting synthetic data base for the target year represented an estimate of the results that might be obtained from a large energy-demographic-socioeconomic survey of households conducted in the future year, assuming the economic and energy projections associated with the MEFS and the DRI model.

A flowchart showing the major components of the MATH/CHRDS model is shown in Figure 14-3. The process begins with the development of the 1975 MATH/CHRDS benchmark data file. The basic portion of this file was developed from a special subsample of approximately 200,000 households drawn from a five-percent state PUS of the 1970 Census on population and housing. The PUS provides information on income, employment status, age, race, and sex of each household member, and housing characteristics such as cooking fuel, space and water heating fuel, number of rooms, type of structure, appliance ownership, presence of basement and garage, and age of house. These basic data were augmented with the following data elements:

- energy consumption determinants such as ownership of air conditioning, house dimensions, and thermostat and insulation data;
- estimated energy expenditures; and
- transportation-related data such as number of automobiles, make and model, miles driven, distance to work, and commuting mode.

FIGURE 14-3

OVERVIEW OF THE MATH/CHRS MODEL

These data were derived using recent historical data. For example, transportation data were obtained from the 1975 Michigan Panel on Income Dynamics and the 1970 National Personal Transportation Survey conducted by the Survey Research Center in Michigan. Similarly, energy expenditure data were validated using available survey data. By matching household characteristics between the PUS and other sources, other data elements were input for each household. As required, the projection methodology inherent in the MATH/CHRDS model was used to develop the 1975 benchmark data file.

Using this file as input, the aging model performed two functions:

- demographic aging, and
- economic aging.

The demographic aging routine uses census population projections as control totals to effect changes in the number of households, persons, and average household size for each household category. The economic aging routine first changes the employment status of each household member using DRI national forecasts of unemployment rates as controls. Then, each individual's income is adjusted to reflect changed economic conditions. Income is projected for 14 sources such as wages, Social Security, welfare, and interest. Income growth for some sources was projected using DRI forecasted rates of change; this included income from wages

and salaries, farm and non-farm proprietor's income, rental income, dividends, and interest.

The tax and transfers simulation begins by organizing the households by filing status and determining the number of dependents per filing unit. Then, payments of state and federal taxes and FICA are computed using current tax law. The basis for payroll taxes was projected using the DRI consumer price index (CPI). Transfer income, including Social Security pensions and unemployment compensation, were assumed to follow changes in the CPI. Social security was increased an additional amount to reflect early retirement, statutory changes in benefits, and the gradual increase in benefits due to rising wage levels. Public assistance was assumed to lag the CPI by two percent, based on Department of Health, Education, and Welfare trend analyses. In the model, each family is screened for eligibility for the transfer programs, and, if eligible, the amount of program assistance is computed based on program provisions. Since not all families participate in available programs, empirical probabilities are used to select participating families.

In the ENERGY module, projected household energy expenditures for five types of fuel--electricity, natural gas, bottled gas, fuel oil, and coal--were estimated. The following functions were performed:

- Housing stock adjustments were made to reflect changes in age and type of structures using DRI forecasts of housing

starts and demolition rates and historical housing stocks by age from the 1975 U.S. Statistical Abstracts.

- Trends in new home fuels and conversion of existing home fuels were obtained from the 1974 Annual Housing Survey (AHS).
- Additional adjustments were made to account for increased space heating efficiencies due to increased use of insulation.
- Projected changes in appliance ownership were estimated and randomly assigned to households.

Once these determinants of home fuel consumption were changed, home fuel expenditures for the target year by household category and location were computed. Regression analyses were performed on available consumption data, by fuel type, using the following explanatory variables:

- Cooking fuel type
- Home space and water heating fuel type
- Number of rooms
- Type of structure
- Household size
- Appliance ownership
- Family income
- Price of fuel
- Urban/rural location

The resulting relationships were used to impute an annual energy expenditure for each household, using forecasted fuel prices obtained from the MEFS.

The last step in the ENERGY module consisted of adjusting the energy expenditure for each household based on price and income elasticities obtained from the MEFS.

In the AUTOS module, a procedure similar to that employed in the ENERGY module was used:

- Auto ownership adjustments were forecast using the DOE/Faucett Automobile Model, and are distributed to households.
- Annual mileage driven per household was adjusted to account for changes in driving patterns such as carpooling.
- Miles per gallon were estimated by car age and size using data from sources such as the 1975 Platt's Oil Handbook and Almanac.
- Auto fuel efficiency was estimated by size and type and is applied to each household.
- Mileage driven and miles per gallon were used to compute household annual gasoline consumption.
- MEFS forecasted gasoline prices were used to compute annual gasoline expenditures.
- Price and income elasticities from the MEFS were used to adjust expenditures for each household.

The final step in the MATH/CHRS model consisted of estimating the effects of possible energy tax, transfer, or rebate programs among households. The output of the completed microsimulation was a target year data file representing a synthetic survey of households in that projection year.

14.3.3 References

The following document, applicable to the ARC77, describes the MATH/CHRS model as it was used to generate the ARC78 projections:

- Brazzel, John M., et al., A Distributional Analysis of the 1985 Energy Projections for the Annual Report to Congress of the Energy Information Administration, DOE/EIA-0102/25, June, 1978.

14.4 Environmental Impacts (REPS)

14.4.1 Introduction

Energy-related activities such as exploration, extraction, processing, transportation, conversion, and combustion can be linked closely to environmental impacts on land, sea, air, and aesthetics. The close relationship between energy activities and resulting environmental impacts will continue to have a major effect on national energy and environmental policy. To provide insight into the nature of these impacts, an analysis was conducted to estimate the air emissions expected to result from the midterm energy forecasts. The results of this analysis, together with a discussion of the historical relationship between energy use and air pollution, were presented in Chapter 24 of the ARC78.

Five key air pollutants were considered in terms of their expected emission levels in the years 1985 and 1990. The emission of air pollutants was considered as a measure of general environmental quality rather than air quality, which is subject to highly-localized conditions. The analysis was conducted for

five of the seven key pollutants identified as criteria pollutants by the Environmental Protection Agency (EPA) under the Clean Air Act. The five pollutants considered were total suspended particulates, sulfur oxides, nitrogen oxides, hydrocarbons, and carbon monoxide; photochemical oxidants and lead were not covered.

Emission projections were based upon a detailed base year emission inventory to which factors were applied to reflect changes in fuel use that, in turn, affect future emissions. The method employed considered the following major factors:

- an inventory of all domestic emission sources as of 1975 in the form of the National Emissions Data System (NEDS), which is maintained by EPA, based on information submitted by the states;
- the future emissions of current sources, based on compliance status, schedules, and permitted levels contained in the NEDS;
- retirement of current emitters;
- changes in fuel use based on MEFS projections; and
- estimates of economic growth in the non-fuel sectors.

The development of emission projections was accomplished with the use of the Regional Emission Projection System (REPS). The REPS describes changes in domestic air pollution emissions resulting from energy and non-energy activities, including effects resulting from changes in environmental regulations, for 243 Air Quality Control Regions (AQCR's) and their aggregates. The model considers each of 100,000 major air pollution sources in the

United States (point sources) and minor sources aggregated to the county level. Activities simulated within the model include retirement of current facilities, reductions in emissions based on environmental standards, construction of new facilities with emissions at appropriate levels, fuel switching, and conservation. Output of the model consisted of emissions projected by source type for each of the 243 AQCR's, and geographic aggregations, for each of the five pollutants.

14.4.2 Methodology

An overview of the REPS is shown in Figure 14-4. The system consists of two major stages. The first stage uses inputs consisting of environmental policy, NEDS emissions data, and OBERS data. The emissions projections module operates on these data to aggregate the source-specific historical emissions from the NEDS, and to estimate future emissions and fuel use based on OBERS growth projections and implementation of environmental controls. The output of this first state is a set of fuel use and air emission estimates for the projection year.

The estimates are input to the REPS second stage, which consists of a conservation and growth adjustment module, along with fuel use forecasts for the projection year from the MEFS. The adjustments are made to incorporate changes in fuel mix and the effects of fuel conservation embodied in the MEFS forecasts.

FIGURE 14-4

OVERVIEW OF THE
REGIONAL EMISSION PROJECTION SYSTEM (REPS)

Additional details regarding the two major stages are provided below. Finally, the REPS has a reporting module that can produce both tabular printouts and graphic displays.

The sources and nature of input data to the REPS were as follows:

1. U.S. Environmental Protection Agency

- National Emissions Data System
 - 1975 emissions of TSP, SOX, NOX, HC, and CO, and fuel use by type, from 100,000 point sources
 - Point source emission compliance status, schedule, and permitted levels
 - 1975 emissions and fuel use from minor (area) sources by county
- Environmental Control Policy
 - New source performance standards
 - Additional controls on coal required by the Clean Air Act amendments of 1977

2. U.S. Department of Commerce

- Water Resources Council OBERS data
 - Earnings by industry type and AQCR for 1975, and projections for 1985 and 1990

3. U.S. Department of Energy

- Midterm Energy Forecasting System
 - Total fuel use by economic sector, federal region, and fuel type for 1975, 1985, and 1990

- Federal Power Commission

- 1975 utility fuel use

In the REPS first stage, leading to development of the fuel use and air emission estimates prior to adjustment, the following steps are conducted:

- Each point source is examined. Data from the NEDS on 1975 reported emissions for the five criteria pollutants are tabulated.
- Compliance data from the NEDS, together with additional controls embodied in environmental control policy, are applied to the 1975 emissions to compute revised emissions from current sources after meeting compliance requirements.
- These compliance-adjusted emissions are then used to estimate emissions in the projection year, based on growth rates implied by the OBERS earnings data.
- Fuel use for each point source is estimated for the projection year by adjusting 1975 fuel use data based on the OBERS growth projections.
- Fuel use and air emissions are aggregated by AQCR, pollutant, and fuel-service categories, defined below.

The output from the last step was the first-stage fuel use and air emissions output, as shown in Figure 14-4. This output consisted of:

- 1975 reported air emissions after meeting compliance requirements,
- projection year estimated air emissions (based on OBERS growth rates),
- 1975 fuel use, and
- projection year estimated fuel use (based on OBERS growth rates).

These outputs were aggregated by AQCR, by pollutant, and by the following 15 fuel type-economic sector categories:

- Coal use by utilities
- Oil use by utilities
- Gas use by utilities
- Coal use in industrial boilers
- Oil use in industrial boilers
- Gas use in industrial boilers
- Coal use for non-boiler industrial heat
- Oil use for non-boiler industrial heat
- Gas use for non-boiler industrial heat
- Coal use for industrial processes
- Oil use for industrial processes
- Gas use for industrial processes
- Other point sources
- Transportation
- Other area sources

The projection year estimates contained in these data reflect environmental standards and control, and the effects of projected economic growth. However, they do not take into account fuel switching and/or conservation effects that may occur between 1975 and the projection year as a result of changes in energy-related variables, such as increases in the world price of oil or changes to the energy resource base. To account for these effects, the estimates are input to the conservation and growth adjustment module, together with regional fuel use data developed in the MEFS. The MEFS data reflect the change in the energy system in the projection year.

The second-stage analysis was conducted for each AQCR, pollutant, and fuel-sector category. The fuel use and mix estimates from the MEFS for each federal region were assumed to apply for each

AQCR in the region. Using 1975 and 1985 as the base year and projection year, respectively, the 1985 air emissions were computed using the following variables:

E85 = the adjusted emissions estimate by AQCR, pollutant, and fuel-sector category for 1985 (the dependent variable).

E75C = the 1975 emissions after meeting compliance requirements, by AQCR, pollutant, and fuel-sector category.

E850 = the 1985 estimated emissions, based on OBERS growth rates, by AQCR, pollutant, and fuel-sector category.

F75M = 1975 fuel use, from the MEFS, by region, fuel type, and economic sector, for the AQCR and fuel-sector category being examined.

F85M = 1985 estimated fuel use from the MEFS, by region, fuel type, and economic sector, for the AQCR and fuel-sector category being examined.

F850 = 1985 estimated fuel use, based on OBERS growth rates, by AQCR, pollutant, and fuel-sector category.

F75N = 1975 fuel use, from NEDS data, by AQCR, pollutant, and fuel-sector category.

When 1985 estimated fuel use, from the MEFS, was lower than 1975 fuel use, the implication was that 1985 emissions were a fraction of the 1975 compliance case emissions due to the net retirement of facilities existing in 1975. In this case, the 1985 emissions were computed as:

E85 = 1985 air emissions

$$= \left[\frac{F85M}{F75M} \right] * E75C$$

where $F85M < F75$.

When 1985 estimated fuel use, from the MEFS, was greater than 1975 fuel use, it was assumed that additional emissions, over those associated with the 1975 compliance case, resulted from a net increase in facilities (new facilities and/or expansion of 1975 existing facilities). The increase in emissions was proportional to the net increase in fuel use and the share of facilities expansion emissions and fuel use derived from the OBERS growth implications. This increase in emissions would then be allocated to the fuel, or fuels, showing the net increase in use. In this case, 1985 emissions were computed as:

$$E85 = E75C + \left[\begin{array}{c} \text{AQCR} \\ \text{NET FUEL} * \\ \text{INCREASE} \end{array} \frac{E85O - E75C}{F85O - F75N} \right]$$

In the above formula, the AQCR net fuel increase is estimated from the MEFS regional fuel increase allocated to AQCR's on the basis of OBERS shares. The OBERS shares are the ratio of each AQCR's 1985 OBERS fuel use ($F85O$) to the sum of all $F85O$ values across the AQCR's in a federal region. Thus, the 1975-to-1985 increase in fuel use from the MEFS ($F85M-F75M$), by fuel type and sector, is allocated to an AQCR based on its 1985 OBERS share of fuel use.

If the MEFS output showed no increase in fuel use from 1975 to 1985, then $E85$ equalled $E75C$ by either of the above formulas.

14.4.3 References

The following documents provide additional details related to the REPS:

- Pechan, Edward H., An Air Emissions Analysis of Energy Projections for the Annual Report to Congress, AM/IA/78-18, September 6, 1978.
- Pechan, Edward H., 1985 Air Pollution Emissions, DOE/PE-0001, December, 1977.

PART IV

LONG-TERM FORECASTING

PART IV

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CHAPTER 15

LONG-TERM FORECASTING PROCESS

15.1 Introduction

For the ARC78, five major long-term projections, representing the range of possible energy futures through the year 2020, were developed. A single projection was prepared using the EIA Long-Term Energy Analysis Package for comparison with four independent forecasts made by other energy forecasting groups outside of DOE. All projections were based on ARC78 Projection Series C, using a set of primary coordinating assumptions to secure broadly comparable forecasts. The diversity of energy system representations, coupled with variation in other specific assumptions, produced five projections that illustrate the range of uncertainty in long-term energy futures; this is similar to the manner in which the different project series serve to bracket the uncertainty in midterm energy futures.

The models used by EIA and the independent groups were:

- the Long-Term Energy Analysis Package (LEAP), a series of process models and an iterative solution procedure used by EIA to produce equilibrium price and quantity forecasts;
- the FOSSIL2 model system, a systems dynamics model, used by the DOE Office of Policy and Evaluation, that relies on the integration of a series of differential equations over time;

- the PILOT modeling system, an energy model system incorporating a linear programming model to maximize the discounted sum of personal consumption over time, used by George Dantzig and others at Stanford University;
- the ETA-MACRO modeling system, a merger of an energy model and an economy model linked through the equilibrium price and quantity of domestic energy, used by Alan Manne and others at Stanford University; and
- The BNL/DJA model system, a linkage of an economic growth model available from Dale Jorgenson Associates (DJA) with an energy model developed by Brookhaven National Laboratory (BNL).

Each of these modeling systems is discussed more fully in subsequent sections.

To ensure compatibility of the five independent forecasts, all projections were based on a series of major coordinating assumptions that, in turn, are related to the assumptions for the midterm Projection Series C. The independent groups were allowed to vary any assumptions that were not part of the coordinating set. The EIA projection, in particular, basically followed the midterm Series C assumptions through 1995. The long-term assumptions were derived from a number of sources; a discussion and tabulation of both the coordinating and the specific EIA assumptions were provided in the Appendix to Volume Three of the ARC78.

The five modeling systems are discussed in the following sections.

15.2 Long-Term Energy Analysis Package

The Long-Term Energy Analysis Package is part of the LEAP Energy Modeling System (LEAP-EMS), a comprehensive system of computer programs, consisting of analysis and data management modules, that allows users to examine long-term energy and economic activities. The discussion below centers on the structure of the specific modeling process within the LEAP-EMS that produces forecasts of energy prices and quantities; for simplicity, this process will be referred to as the LEAP model.

The LEAP model is a highly detailed, dynamic model of domestic supply and demand for energy from 1975 to 2025. The LEAP model is a general equilibrium model that employs a methodology for the coordinated decomposition of complex energy decision problems, complicated by the proliferation of supply and demand activities, uncertainty, and time, into a number of simpler sub-processes. Within this decomposed structure, the LEAP model does not attempt to optimize a single objective; rather, it attempts to achieve a general equilibrium that operates through decentralized decision-making. In this way, the LEAP model attempts to simulate the marketplace, where optimizing behavior occurs within each sub-process of the overall energy-economic system.

The methodology used in the LEAP model was developed in 1973 to analyze synthetic fuel strategy for the Gulf Oil Corporation. Since then, it has been substantially extended and modified for use by EIA for long-term forecasting.

A dominant characteristic of the model is its underlying structure, which simulates the flow of energy materials from sources to end uses. The ARC78 LEAP network, which consisted of 10 major energy sectors between which energy materials flow, is represented in Figure 15-1. Each process contains activities, which are expressed by mathematical relationships that describe the physical or behavioral characteristics of each activity. The links connecting sectors represent flows of prices and quantities of energy materials. Links can also represent environmental controls, interactions with the economy, and constraints on prices and quantities.

At the bottom of the network are processes describing primary resource supply: oil, gas, coal, and uranium. Processes at the top of the network represent end-use demands for energy by sector: residential, commercial, industrial, and transportation. The two representations between supply and demand are the electrical utilities sector and the energy distribution sector, which describe market behavior, energy conversion, and transportation. The LEAP model also includes an explicit representation of energy imports and exports.

The supply processes describe the production of primary energy resources, disaggregated into appropriate supply regions. These representations use long-run supply curves based on available geologic data and price assumptions. Prices are derived from the marginal cost of producing an additional quantity of energy plus

FIGURE 15-1. THE LEAP NETWORK

an economic rent term that represents resource scarcity and short-run supply dynamics. Resource availability is modeled in the economic sense that costs increase as depletion ensues. Technological change and learning effects on production and operating costs can partially offset these depletion-based cost increases. Production decisions are based on each producer maximizing the present value of future profits. The central assumption of perfect foresight, or knowledge of all future prices, allows producers to withhold resources or shift production across time to maximize profit.

The end-use processes represent demands for various types of energy services such as fuel heat or vehicle miles. Unlike many energy models that use energy product demand as the final energy demand, the LEAP model represents the final demand in terms of services derived from projections of end-use consumption. Thus, the end-use demand processes are not concerned with fuel or technology competition since these are treated in conversion and allocation processes, described below. Energy service demand is described as a function of population, economic activity, and price (marginal cost) of energy services. Basically, the LEAP model takes projections of aggregate economic activity and population growth and determines sector activity and the price elasticity of demand and for each end-use service. The effect of price on energy demand is accounted for by constant elasticity demand curves combined with a lagged adjustment process.

Many of the activities between primary energy supply and end-use demand represent conversion processes, which describe representative energy technologies. Model parameters account for technological change, thermal efficiency, and capital and operating cost changes. A capital cost premium is incurred for use of a technology before the date of commercial availability. The relations for a simple conversion process are straightforward physical accounting flows of one input, a conversion process, and one output for an activity. A complex conversion process describes a multiple-input or multiple-output activity like electric power generation or oil refining. For example, the model must consider the fluctuating demand for electricity, the high cost of storing electricity, and the cost and efficiencies of different technologies available to generate electricity. In this case, a sub-network composed of an electric power load disaggregation process, an allocation process for each load category, and several electric power conversion processes is used. A similar sub-network represents the economics of refining, where the model must consider the interdependencies of output fuel shares and product prices.

The algorithm used to solve this generalized equilibrium model finds the set of prices and quantities that satisfies the physical and behavior relations embodied in the processes and linkages, as defined by the network. Because an explicit solution of the model is usually not possible, iterative techniques are used to successively adjust prices and quantities

until a solution is found. Starting with initial estimates of prices and quantities for all energy processes, the LEAP algorithm makes two basic sweeps through the entire network. Tentative prices are computed on the downward iteration (holding prices constant). The resulting equilibrium solution reflects whatever market imperfections and human behavior are built into the processes. Moreover, the equilibrium position is dynamic because the solution for a given time period depends on the solutions in past and future time periods.

Inputs to the model, which consisted of physical data such as quantities and technological parameters and economic values such as cost, tax, and regulatory data, were developed in-house and under contract with the Brookhaven National Laboratory. Output data consisted of prices and quantities, and shadow prices for each process and time period.

15.3 FOSSIL2 Model System

The FOSSIL2 model is a systems dynamics simulation model developed by the Dartmouth Systems Dynamics Group. It provides a means for evaluating the potential magnitude of the domestic energy problem and for assessing the impact of energy policy options on the U.S. energy system. The model is easy to use and can handle a number of different types of policy options; therefore, the FOSSIL2 model is very useful as an indicator of general energy system response under varying conditions.

The FOSSIL2 model relies on the integration of a series of difference equations over time. Unlike general equilibrium models whose structures permit optimization over time, the FOSSIL2 model is a dynamic, disequilibrium model which does not assume that U.S. energy markets always function in an optimal manner. The use of difference equations simulates the quantity of activity at any given period of time as a function of activity levels from previous and current time periods. The model also incorporates exogenous decision rules governing the flow of investment, resources, and energy-consuming goods. The non-linear (differential) relationships that compose the model show, for example, how energy production costs and prices change as a result of resource depletion, or how consumers change their use of fuels as incomes rise or as relative energy prices change.

The model is essentially a supply representation of energy flows from extraction to delivered end fuel product, including synthetics and electric conversion. As shown in Figure 15-2, below, the energy system in the FOSSIL2 model is divided into five sectors--a demand sector and four production sectors (oil, gas, coal, and electricity). Each of the production sectors is further subdivided into supply/demand balance, financing, and production subsectors. Given fuel-specific demands, the four production sectors try to meet the demands so as to maximize profits (or, identically, by minimizing costs). As the demand for energy "flows" into a sector, the sector adjusts both its production rate (within the constraints of its production

FIGURE 15-2

MAJOR SECTORS IN THE FOSSIL2 MODEL

capacity) and its price to try to meet that demand (supply/demand subsector). Over the long term, each sector adjusts its production capacity to meet demand through investments in new facilities and technologies (financing subsector). However, the production sectors face several constraints in developing new capacity, including the availability of funds and construction lags. In addition, environmental constraints and regulatory policies can limit investment, and can prevent an industry from reaching an optimal production capacity and mix of technologies.

Within each sector there is more than one way of producing the form of energy needed to meet the fuel-specific demand (production subsector). Oil can be produced from conventional wells, shale oil, coal liquids, or by enhanced recovery methods. The electricity sector can use up to 14 different processes to produce electricity, including gas, oil, coal, nuclear, and renewable resources. Figure 15-2 shows the full range of energy supply technologies included in the FOSSIL2 model. As energy is produced and non-renewable resources are developed, the model assumes that the least expensive, most easily-obtained portions of the resource base are consumed first, leaving the more costly portions for future use. The model allocates investment among the alternative production processes based on the relative costs of each technology.

The demand sector of the FOSSIL2 model is aggregated. Total end-use demand for energy in the United States is computed based

on the movement of GNP and the average energy price. End-use demand is then broken down into demand for several specific forms of energy--gas, oil, coal, electricity, and decentralized energy. Interfuel substitution is modeled explicitly and is influenced by the availability (e.g., gas curtailments) and the convenience of the four fuels--oil, gas, coal, and electricity. In addition, sector-specific differences in delivered fuel prices feed back to influence the interfuel substitution possibilities.

The aggregated treatment of demand limits the analytical usefulness of the model in several ways:

- Changes in GNP are determined exogenously to the model, although energy prices do feed back to affect GNP and energy demand as a function of GNP.
- There is no sectoral definition in the FOSSIL2 model for residential, commercial, industrial, and transportation categories. End-use technology, such as device costs and, obviously, conversion efficiencies, are not taken into account.

The energy production sectors also demand energy from each other. Since electricity converts gas, oil, and coal (as well as other energy sources) to electrical energy, the electricity sector must demand feedstocks from those three production sectors.

Similarly, synthetic gas and oil are produced from coal; therefore, the oil and gas sectors will demand coal once synthetic conversion plants have been constructed in the model.

15.4 PILOT Modeling System

The PILOT energy modeling system, developed by the System Optimization Laboratory of Stanford University, consists of several energy models. Of these models, two dynamic energy/economic growth models were used to produce a long-term forecast for the ARC78:

- the PILOT Welfare Equilibrium Model (WEM), and
- the PILOT Process Integrated Model (PPIM).

The EIA coordinating assumptions were fed to the WEM, an economic growth model containing a process submodel of energy supply and a variable coefficient input/output industrial system, which is driven by a household welfare function of consumption and leisure time. The WEM produced a dynamic, economic equilibrium solution. The labor, capital, energy input/output coefficients of the nonconsumer sectors, and the workweek hours, all in time profile indices form, together with the appropriate EIA assumptions, were next fed to the PPIM. The PPIM is also an economic growth model, with a fixed coefficient input/output industrial system, but it contains a more detailed process submodel of energy supply than the WEM, and it yields a detailed physical flow solution. The shadow prices of the WEM and the energy supply/demand balances and the macroeconomic variables of the PPIM are the outputs.

The WEM is a linear programming formulation in which the objective function is the discounted sum of consumer economic

welfare over the forecast period. Welfare is assumed to be a function of per capita consumption, average workweek, and population. Substitution across labor, capital, and energy permit the economic system to adjust to energy scarcities. Within the WEM, sector-specific labor/capital substitution, sector-specific energy/value added substitution, fuel shifts, and import-export activities are modeled. The time profile indices, output by the WEM and subsequently input to the PPIM, provide the means to compensate for the otherwise fixed industrial input/output coefficients used in the PPIM, and to reflect industrial interfuel substitution and cost-effective conservation.

The PPIM is also a linear programming formulation in which the objective function is the discounted sum of personal consumption over the forecast period. This model, unlike the WEM, includes a detailed process submodel of energy extraction, conversion, and supply, and a process submodel of residential and automobile energy services consumption. The input information required for the model can be grouped into six categories:

1. Population, labor force, and labor productivity projections.
2. Projected non-energy sectors input/output coefficients.
3. Resource bases for oil, natural gas, uranium, and eastern and western coal in the form of quantities and extraction costs.
4. Energy import prices.
5. Cost and efficiencies of energy conversion and delivery systems.

6. Upper bounds to represent environmental, technological, and penetration restrictions on growth of energy technologies.

Within the model, economic activity is represented by 12 producing sectors, seven of which are non-energy and five of which are energy sectors. The energy sectors are modeled through a detailed description of raw energy extraction and conversion processes, including exhaustible and renewable resources and existing and new technologies. The inputs into production of the non-energy sectors are characterized by fixed input/output coefficients, including labor and non-competitive imports. These coefficients for each of the time periods must be provided exogenously. The GNP of each period is divided endogenously between capital formation, for replacement of retired capacity and for capacity expansion, and consumption that provides the nation's current standard of living. Imports cannot exceed the available revenue from exports in any five-year period. Consumers' demands for goods and services, including energy services, are described by linear functions of population and personal income. The ability of consumers to select residential end-use energy systems of different types and efficiencies, to insulate homes, and to select different automobile prototypes, is modeled through the process-type consumers end-use submodel.

Economic output data include the macroeconomic aggregates of consumption, capital formation, government expenditures, imports, and exports, as well as industrial production and factor returns.

Energy outputs include oil and gas drilling; reserve additions and production; eastern and western coal production and transportation; uranium mining and milling and stocks of nuclear materials; new energy technologies introduction and output levels; electricity production by type of power plant; fuels used by type of conversion process; fuels consumption by each sector of the economy; energy imports and exports; cumulative and added capital stocks of all energy extraction, conversion, and delivery systems and their utilization factors; electrification; coal use in utilities, industry, and synthetic fuel production; residential, transportation, and industrial energy consumption by sector and type of fuel; cumulative and added capital stocks of residential end-use energy stocks and automobiles; new homes insulation levels; fuels consumption by type of residential end-use energy system and energy service; and automobile fuel consumption and efficiency levels.

15.5 ETA-MACRO Modeling System

The ETA-MACRO model, developed by Alan Manne of Stanford University to study the interrelationships between U.S. economic growth, conservation, and energy technologies, is a normative optimization model. Constraints with respect to energy demand and supplies from existing and new technologies, and factors associated with development of supply technologies are incorporated.

The ETA-MACRO model represents a merger of a process analysis model for energy technology assessment (ETA) with a macroeconomic growth model (MACRO) that captures substitution possibilities between capital, labor, and energy inputs. The ETA model is linked to the MACRO model through the equilibrium price and quantity of energy in the domestic economy. This system is a tool for integrating long-term energy supply and demand projections. It is designed to compare the options that are available to the United States as we move away from our present heavy dependence upon oil and gas resources toward a more diversified future energy economy.

The ETA-MACRO model accounts for the following:

- Energy-economy interactions--the prospect that rising energy costs and limited supplies will prevent the economy from achieving its full potential GNP growth rate, and that this in turn will slow down future capital accumulation.
- Cost-effective conservation--the reduction of energy demands below the amounts projected from historical trends.
- Interfuel substitution--changing conditions inducing consumers to replace oil and gas with electricity (e.g., heat pumps in place of fuel burners).
- New supply technologies--synfuels and nuclear and solar power, each with its own difficulties and uncertainties regarding costs, dates, and rates of introduction.

In the MACRO model, the economy uses energy in two basic forms: electric and non-electric. The gross output of the economy, expressed in GNP terms, depends upon the inputs of energy, labor, and capital. In turn, economic output is allocated between

current consumption, investment in building the stock of capital, and current payments for energy costs. A macroeconomic production function in the MACRO model provides for substitution among the factor inputs--capital, labor, and energy. The response of the economy to energy price increases and supply shortages is to initially substitute labor and capital for energy.

In the ETA model, estimates of the demand for energy are determined through a hybrid of econometrics and engineering process analysis techniques. The energy demand functions provide for substitutability between energy and other economic inputs. The allocation of demand between the two forms of energy to obtain the market share for electric and non-electric energy is accomplished through the use of individual price elasticities.

The supply side of the ETA model is handled through a conventional linear programming process analysis. Electric energy can be produced by coal-fired power plants, light-water reactors, and advanced electric technologies (e.g., solar, fusion, or an advanced breeder). Non-electric energy (liquids, gases, or solids) may be supplied by oil, natural gas, coal or shale-based synthetic fuels, or hydrogen via electrolysis. The depiction of these sources of energy is performed via a price-quantity schedule for each future year, reflecting capital and associated costs involved in extraction, generation, and conversion of the final form of energy. An intertemporal market

equilibrium for the energy sector is approximated by optimizing for the minimum of the sum of the costs of conservation, interfuel substitution, and energy supply. The objective function, which is non-linear, treats the costs and benefits in present dollars by the use of a 75-year planning horizon and a social discount rate. The optimization is conducted in a deterministic framework.

Trends in the labor force productivity growth index provide the principal driving force for the potential GNP and, hence, the expansion of energy demands over time. Demand growth in the two sectors--electric and non-electric--is expressed as a function of the annual rate of GNP growth, own and cross-price elasticities (exogenously determined), and the annual rates of own price increase and competing fuel price increase (endogenously determined). A unitary elasticity of substitution for electric and non-electric energy demand is assumed; however, the equilibrium electric energy demand has an upper bound, expressed as a fixed value share of total primary energy.

All numerical input data for the ETA-MACRO model can be organized into six categories, as follows:

1. Macroeconomic parameters--the potential GNP growth rate at constant energy prices, the elasticity of aggregate energy demand substitution, and "value shares" for the nested production function.
2. Upper bounds (if any) to represent environmental restrictions upon total coal consumption.

3. Cumulative supply curves--quantity versus marginal selling price (replacement cost) for oil, gas, coal, and uranium resources.
4. Introduction limits (if any) and input/output coefficients for each supply technology.
5. Miscellaneous input data.
6. Technology groups for the standard ETA-MACRO report.

The output data consist of domestic energy consumption (by source), petroleum and gas imports, total energy consumption, electricity generation (by source), cumulative resource requirements, nuclear fuel requirements, energy prices, GNP, present value of consumption at a five-percent and 10-percent discount rate, annual investment rates for electric utilities, and production capacity levels for all technologies.

Energy prices are derived from the dual variables of the non-linear programming algorithm. Hence, they measure marginal replacement costs, rather than legislative formulas for price regulation.

15.6 BNL-DJA Model System

The combined BNL/DJA energy-economy model system consists of a coupling of an economic growth model--the Hudson-Jorgenson Long-term Interindustry Transactions Model (HJ/LITM), available from Dale W. Jorgenson Associates--with an energy model, Brookhaven's Time-stepped Energy System Optimization Model (TESOM). The

coupling is accomplished through an integrative interface that is essentially a "reduced-form" version of the Brookhaven/University of Illinois Input-Output Linear Programming Model.

The DJA and TESOM models are naturally complementary; the DJA system models energy demand and economic effects but not energy supply, while the TESOM models energy supply and conversion but not energy demand. The two models, therefore, interface at energy demand with the DJA model covering aggregate energy demand through the general economy, and with the TESOM covering resources through energy demand. The linked system extends the coverage and applicability of both models. Furthermore, the linked system provides a framework for the consistent analysis of the role of energy technologies, energy supply and conversion, energy use, and energy-economy interactions.

The DJA model is a simulation model of the structure and growth of the U.S. economy. It combines a two-sector (consumption and investment) and two-factor (capital and labor) neoclassical model of macroeconomic growth with a multi-sector input/output model using flexible coefficients. For each year, it analyzes economic activity on a sectoral basis. There are 10 producing sectors, of which four are non-energy and six are energy. The energy sectors consist of energy extraction and processing activities, and include the following:

- Agriculture, non-fuel mining, and construction
- Manufacturing

- Transportation
- Services, trade, and communications
- Coal mining
- Crude petroleum
- Petroleum refining
- Electric utilities
- Gas extraction
- Gas utilities

In addition, there are three other sources of inputs into production (capital, labor, and competitive imports) and four categories of final demand for goods and services (personal consumption expenditures, investment, government purchases, and exports). These activities are organized into a matrix of interindustry transactions with 13 supply sectors and 14 purchasing sectors. Within this interindustry framework:

- Price formation must be such that sectoral output prices cover average costs of production, including a normal rate of return.
- Quantities must be such that, for every sector, the output of a sector exactly matches the quantity of that good or service required for input into other producing sectors together with the quantity used to satisfy final demand.
- Prices and quantities must be such that the revenue received by a sector is exactly accounted for by payments to inputs, including income to capital, and by payments to governments.
- The demands for capital and labor inputs must be consistent with the supplies of these resources.
- Imports are constrained by the available revenue from exports together with a limited foreign deficit.

Activity patterns within this framework are represented by econometric models. The submodels for consumption and for each of the producing sectors incorporate the patterns of behavioral

and technical responses observed for these activities. The submodels provide a framework for the analysis of output price formation by determining the system of relative prices that characterizes the economy, and determine the particular pattern of input purchases (the input/output coefficients) that, of all feasible input patterns, represents the cost-minimizing pattern given prevailing prices. This means that the input/output coefficients are endogenous, being functions of, among other things, relative prices. As a result, some of the principal adjustment mechanisms in the economic system are explicitly incorporated in the model.

The DJA model is a dynamic equilibrium model of the U.S. economy. For each of the endogenous commodities in the model, an algorithm determines relative prices based on the balance between demand and supply. Equivalently, the pattern of economic activity in each year is consistent with prices as determined by the observed patterns of substitution and other responses by producers and consumers. In addition, the model includes a balance between saving and investment that determines the rate of return and the rate of growth of capital stock. Economic growth is modeled as a sequence of one-period equilibria determining demand and supply and relative prices for all commodities. Investment in each period determines the level of capital stock available in the following period. Dynamic adjustment to energy changes is modeled by tracing through the impact on future levels of capital stock and the rates of change of factor productivities.

The BNL model, TESOM, is a national energy system model based on Brookhaven's Reference Energy System (RES). The RES provides a complete and consistent accounting system, in physical units, for energy flows through energy technologies (stocks).

The TESOM optimally allocates energy resources and products and selects the optimal mix of supply, conversion, and demand technologies according to least cost or other selected energy, environmental, or economic criteria to satisfy a specified set of energy service demands. Resource supply representations are specified as long- or short-term supply curves, or fixed prices and availabilities by year. The TESOM provides a "vintage" representation of the nation's energy system in that the optimal levels of the decision variables for any time period are determined from:

- the optimal levels established for previous periods;
- the retirement and deterioration rates, the lifetimes, and the associated costs of vintage capital stocks; and
- economic and technological factors affecting the feasible levels of the decision variables for the period under investigation (e.g., decline rates, supply elasticities, cumulative resource availabilities, market penetration considerations, etc.).

Mathematically, the model is formulated as a sequence of expanding linear programming formulations of the RES--one for each time period. For a given time period, the solutions derived for earlier periods, along with assumptions regarding retirement and decline rates, average lifetimes, age-dependent conversion

efficiencies, plant factors, O&M costs, and the capital charges for the stocks-in-place, are incorporated into the sequenced formulation. Then, at least cost or other quantifiable criteria, the energy demands are satisfied in accordance with the supply expansions and increased penetrations that are attainable for the period and the net availabilities from the evolution of the energy system to date. In meeting future energy demands, the TESOM has a memory of the net availabilities from the past augmented by that which is attainable in the near term. The updating and sequencing procedures are repeated until solutions for the entire time horizon are determined.

The DJA and BNL models are coupled so that, in each year, there is consistency between the energy and economic information obtainable from each model. This coupling is achieved through an iterative process.

15.7 References

A discussion of the models used for the ARC78 long-term forecasting, a comparative analysis of results, and citations of additional reference materials will be provided in:

- Kydes, A. S., et al., A Comparative Assessment of Calibrated Long-Term Energy Projections, Brookhaven National Laboratory, forthcoming.

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