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The Integrating Model of the Project Independence Evaluation System

Volume IV — Model Documentation

February 1979

Prepared for:
U.S. Department of Energy
Energy Information Administration
Assistant Administrator for Applied Analysis

Under Contract No. EC-77C-01-8558

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The Integrating Model of the Project Independence Evaluation System

Volume IV, Model Documentation

February 1979

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EIA Perspective

This contractor report was prepared by Logistics Management Institute and provides documentation of the version of the Project Independence Evaluation System (PIES) as it existed on January 1, 1978. Since that date, PIES has evolved into what is now called the Mid Range Energy Market Model (MEMM), a major component of the Mid Range Energy Forecasting System (MEFS). Major structural changes that have occurred between January 1, 1978 and January 1, 1979, are documented in the supplemental volume entitled, "Revisions to the Midterm Energy Market Model Relating to Natural Gas Regulation, Advanced Technologies, Coal Demand and Dynamics." Together, the six volume set of documentation, plus the supplemental volume on revisions, form the most comprehensive and up-to-date version of MEMM documentation currently available, documentation which significantly surpasses in both form and content the single volume published in January, 1977.

Although this documentation has not gone through the appropriate review process and clearance procedures to be published as an EIA endorsed report, it is currently being made available in its present form as an interim measure to satisfy many outstanding requests for MEMM documentation. As this report has not been submitted to comprehensive review, EIA does not endorse any information contained herein. The documentation is presently being subjected to comprehensive review both inside and outside the Department of Energy. A contract is currently in process to update it to the version used for the 1978 Annual Report to Congress (published in July 1979). This new version of the documentation report is intended to bring the MEMM documentation into conformity with EIA's documentation standards and to respond to any issues raised as a result of the review process. The results of the latter effort will result in a set of MEMM documentation fully cleared and endorsed by EIA, available in 1980.

PREFACE

This documentation describes the Project Independence Evaluation System (PIES) Integrating Model as it existed on January 1, 1978. The complete documentation consists of seven volumes describing the various aspects of the Integrating Model as follows:

- Volume I is an executive summary, providing a simple, nontechnical overview of PIES.
- Volume II is a primer, describing and illustrating the basic inputs to the PIES algorithm.
- Volume III is a user's guide, describing scenario specification and the operational procedures for running the Integrating Model.
- Volume IV is the main model documentation, describing the theoretical basis of the Integrating Model and each of the supply submodels.
- Volume V is code documentation, describing the data processing aspects of PIES: the data flow through the PIES programs, the functions performed by each program, the data inputs and outputs, and the PIES naming conventions.
- Volume VI is data documentation, containing the standard table data used for the April 1978 Administrator's Annual Report, along with primary data sources and the office responsible. It also contains a copy of a PIES Integrating Model Report with a description of its contents.

The data and scenarios used in these volumes are those used in the 1972 EIA Annual Report to Congress, prepared by the Energy Information Administration. In all volumes, we refer to this report as the Administrator's Annual Report (AAR).

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I. OVERVIEW

SCOPE OF THIS VOLUME

This volume is the fourth in a series of seven documenting the Project Independence Evaluation System (PIES) Integrating Model. It contains detailed descriptions of the basic assumptions behind each of the components of PIES and how they interact with one another. A number of similar and potentially confusing terms are used in this document, and the reader should refer to the glossary in Appendix A as necessary.

Chapter II of this volume presents the methodology used to integrate supply and demand. It includes a discussion of both the interface between the Demand Model and the equilibrating mechanism and the various supply models via the equilibrating algorithm used by PIES Chapters III through IX describe each supply submodel in turn: coal, oil, and natural gas supply, utilities, refineries, advanced technologies, and transportation.

Code and data documentation are covered elsewhere in this series (Volumes V and VI respectively). It is assumed that the reader is familiar with LP methods and applications.

PIES is an evolving system. As this document was being prepared, many parts of the model were being modified. This document describes the PIES Integrating Model as of January 1, 1978.[1]

---

[1] Readers wishing to compare the current model with previous versions should consult:

The Integrating Model of the Project Independence Evaluation System, FEA/N-76/411 (Washington, D. C.: Federal Energy Administration, August 1976).

An Executive Summary of the Project Independence Evaluation System (PIES), 2 vols. (Washington, D. C.: Logistics Management Institute. January 1978).

The Integrating Model of the Project Independence Evaluation System (Washington, D. C.: Logistics Management Institute, December 1977).

THE PIES SYSTEM

The Project Independence Evaluation System (PIES) is a complex computer system developed by the Department of Energy (DOE) to analyze energy policy. PIES forecasts the state of the U.S. energy system with a "snapshot" of the energy economy on an average day in a target year, with target years chosen to fall within a 5-15-year planning horizon. By varying the assumptions and data fed into the system, the effects of different energy policies can be simulated.

The PIES framework contains three major components:

- an econometric demand model of the U.S. economy which estimates consumer demands for fuels and energy as functions of prices
- a detailed representation of the U.S. energy supply network, which specifies the multitude of supply options that can be called upon to satisfy demands (i.e., an integrated supply function)
- an equilibrating mechanism, which balances the supply and demand functions by adjusting prices and quantities of fuels until a multiproduct, multiregional equilibrium is achieved, while also modeling deviations from free market conditions caused by regulatory or tax conditions.

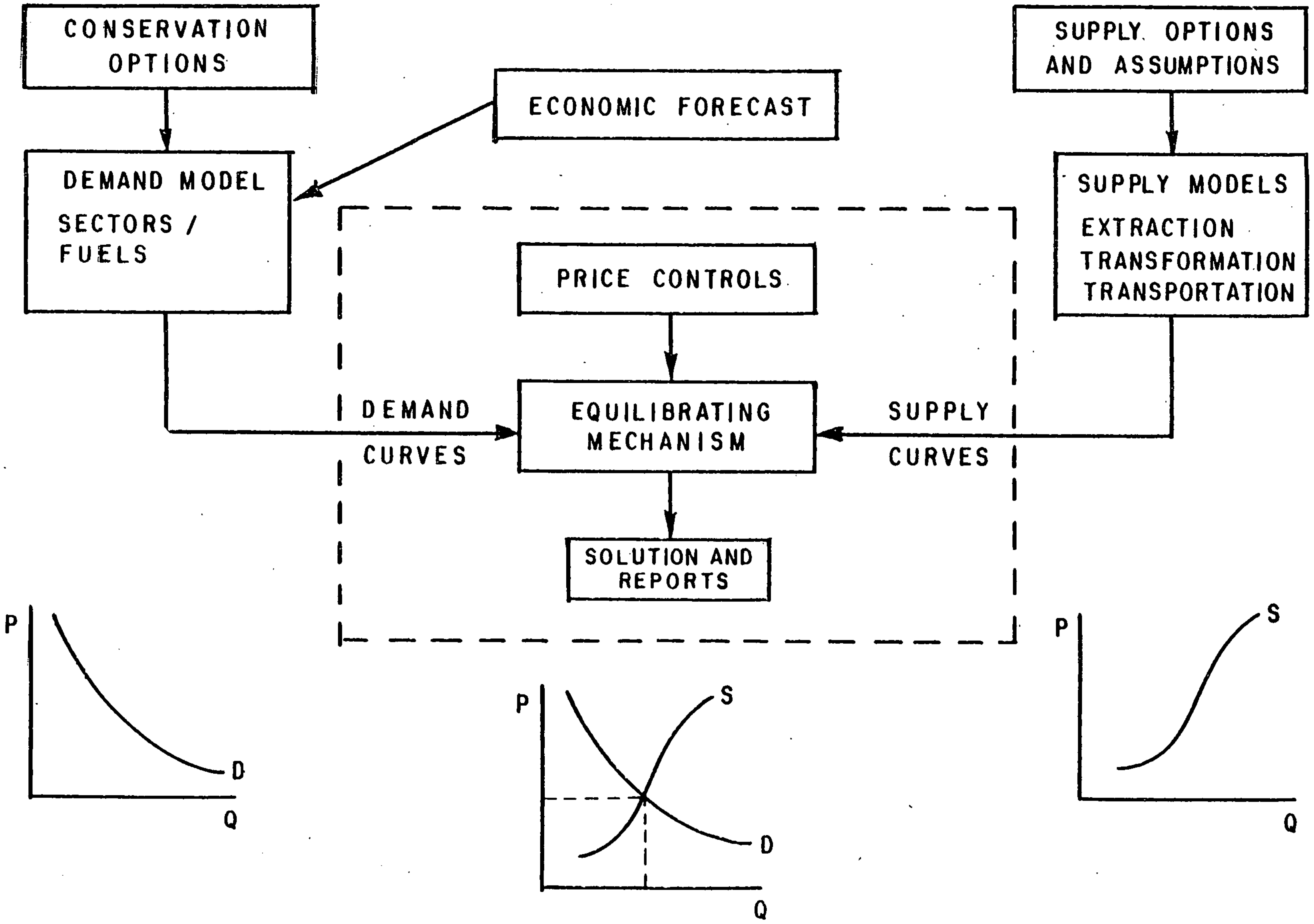
The broad relationship of these major components is depicted in Figure I-1.

PIES determines an approximate equilibrium of supply and demand for different fuel types in each of 10 DOE regions. In establishing the integrated supply representation, a set of submodels is used to represent the supply (either production or import) of each major raw material, primarily coal, oil, and natural gas, but also nuclear fuel, shale oil, synthetics, etc. The submodels are designed to simulate the response of the specific industry to price changes, and they provide the raw material supply curves. The integrated supply representation also includes submodels representing refineries, electric utilities, and synthetic fuel plants, all of which convert the raw materials into consumable forms of energy, i.e., refined fuel products or electricity.

These components of PIES are linked by means of distribution networks that represent the movement of raw materials or products from the points of production, import, or conversion to where they are converted or consumed. Within PIES, the sum of

FIGURE I-1

FRAMEWORK OF THE PIES INTEGRATING MODEL



production, conversion, and transportation costs, and the price paid for imports is considered to be the cost of supplying energy to the nation.

Specifically, PIES predicts energy consumption levels in each of the 10 DOE regions depicted in Figure I-2, and shows the distribution of consumption among the following fuel products—electricity, natural gas, liquid gas, jet fuel, distillate oil, residual oil, gasoline, crude oil, naphtha, asphalt, steam coal, and metallurgical coal—in various demand sectors. PIES also determines the sources of these fuels (e.g., specific deposits of oil, natural gas, and coal or imports), how they will be converted into energy suitable for final consumption, and how the fuel or energy is transported within the U.S. The costs of all these activities are identified and used in the cost minimization procedures to be described in this volume.

ROLE OF THE INTEGRATING MODEL IN PIES

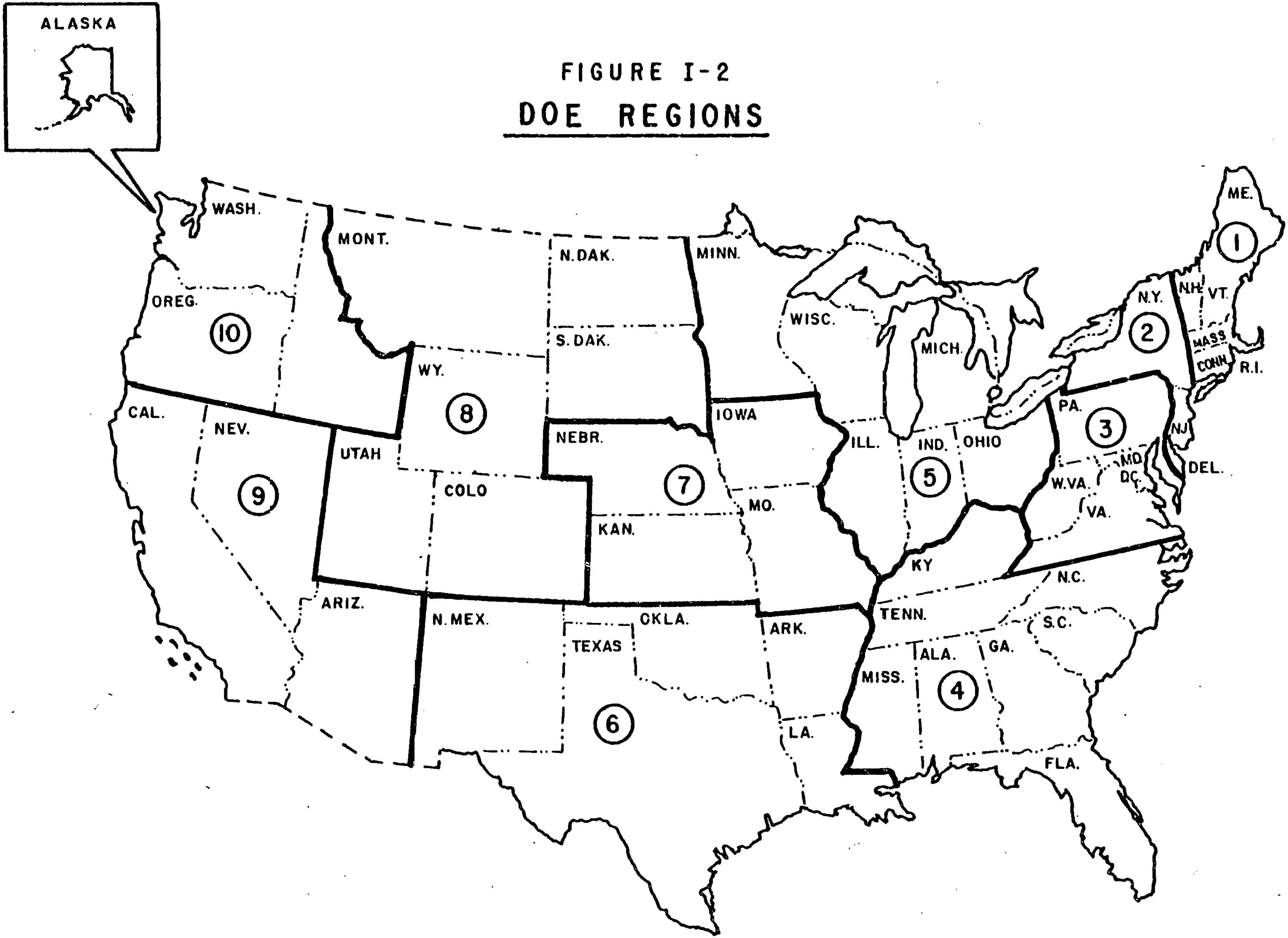
The Integrating Model (indicated by the dashed box in Figure I-1) provides the analytical framework for PIES and combines the outputs of the other models to estimate market-clearing prices and supplies and demands. The Integrating Model represents an energy system in which production, processing, conversion, distribution, transportation, and consumption activities take place. Supply and demand are equated via the equilibrating mechanism of the Integrating Model.

PIES assumes a competitive economic structure, with upward-sloping supply curves and downward-sloping demand curves of the types depicted in Figure I-1. Within this framework, the model describes a static market equilibrium of the energy system. A fundamental concept underlying the model is that prices will clear the market in all regions; that is, for the equilibrium set of prices, profit-maximizing producers, converters, and transporters will be willing to supply precisely the set of quantities demanded by cost-conscious consumers.

For a model of a competitive market, an equivalent supply-side optimization problem is to provide consumers with prespecified quantities of final fuels at minimum

FIGURE I-2

DOE REGIONS



cost. The mathematical equivalence between the competitive solution and the cost-minimizing solution allows optimization techniques to be used in solving for the market equilibrium, a property which is exploited in PIES.

In order to discuss the interface between the PIES Integrating Model and the PIES Demand Model, certain terms must be defined: Demand Model, demand function and demand approximation.

The PIES Demand Model is a stand-alone, econometric model, which provides regional demand estimates for each year between the base year (1 January 1976) and the target years (1985 and 1990). The model produces market price and quantity estimates for a variety of fuels in different economic sectors, and it is used in such a way as to provide own-price and cross-price elasticities for each fuel for which it predicts prices and quantities. A description of an earlier version of the Demand Model is given in Appendix D of the draft 1977 National Energy Outlook (1977 PIES Methodology and Data Sources), and more detailed documentation of the model is now being prepared.

The demand function is the constant elasticity approximation to the output from the Demand Model used by the PIES equilibrating mechanism. Thus, the demand function is a continuous function obtained from estimates of prices and demand elasticities supplied by the Demand Model. The demand function exists only for the target year.

The demand approximation is the discrete step-like approximation to the demand function produced within the equilibrating routine. The demand approximation is recomputed on each iteration of the equilibrating mechanism. Derivation and use of the demand function and the demand approximation are more fully discussed in Chapter II.

The Integrating Model operates by solving an LP containing an interim approximation of the demand function, step-wise supply functions, a transportation network, and energy conversion activities. The interim market-clearing prices estimated by the LP are used to recompute the demand approximations with which the LP problem is resolved. The process is repeated until either the solution converge, or a maximum number of iterations is reached determining an equilibrium of supply and demand quantities and prices. The convergence criteria are described in Chapter-II.

Other than the objective function, the equations in the LP represent material balance equations, production or process capacity constraints and material demand equations.[2] In this context, materials are crude oil, natural gas, electricity, coal, and refined petroleum products. There are 300 demand equations, one each for 30 products in 10 demand regions. These 30 products are composed of the following materials - gasoline, distillate oil, residual oil, liquid gas, naphtha, asphalt, natural gas, crude oil, jet fuel, steam coal, metallurgical coal, and electricity - distributed in one or more of the following sectors: residential, commercial, industrial, transportation, and raw material.[3] The flow of materials in PIES is depicted in Figure I-3.

There are three categories of supply activities: primary fuel production, energy conversion, and transportation. Each activity is described by possible combinations of inputs, outputs, and cost. Cost functions for existing activities include only variable costs (such as operating and maintenance costs), but for new activities, amortized capital costs are also included. Capital costs associated with existing activities are viewed as sunk costs and do not influence the allocation decision, although they are included in the average cost pricing mechanism used for electricity.

The forecasts generated by PIES depend upon numerous assumptions about the national energy system, many of which can be varied to estimate the impact of policy initiatives or alternative world petroleum prices or to account for supply or demand

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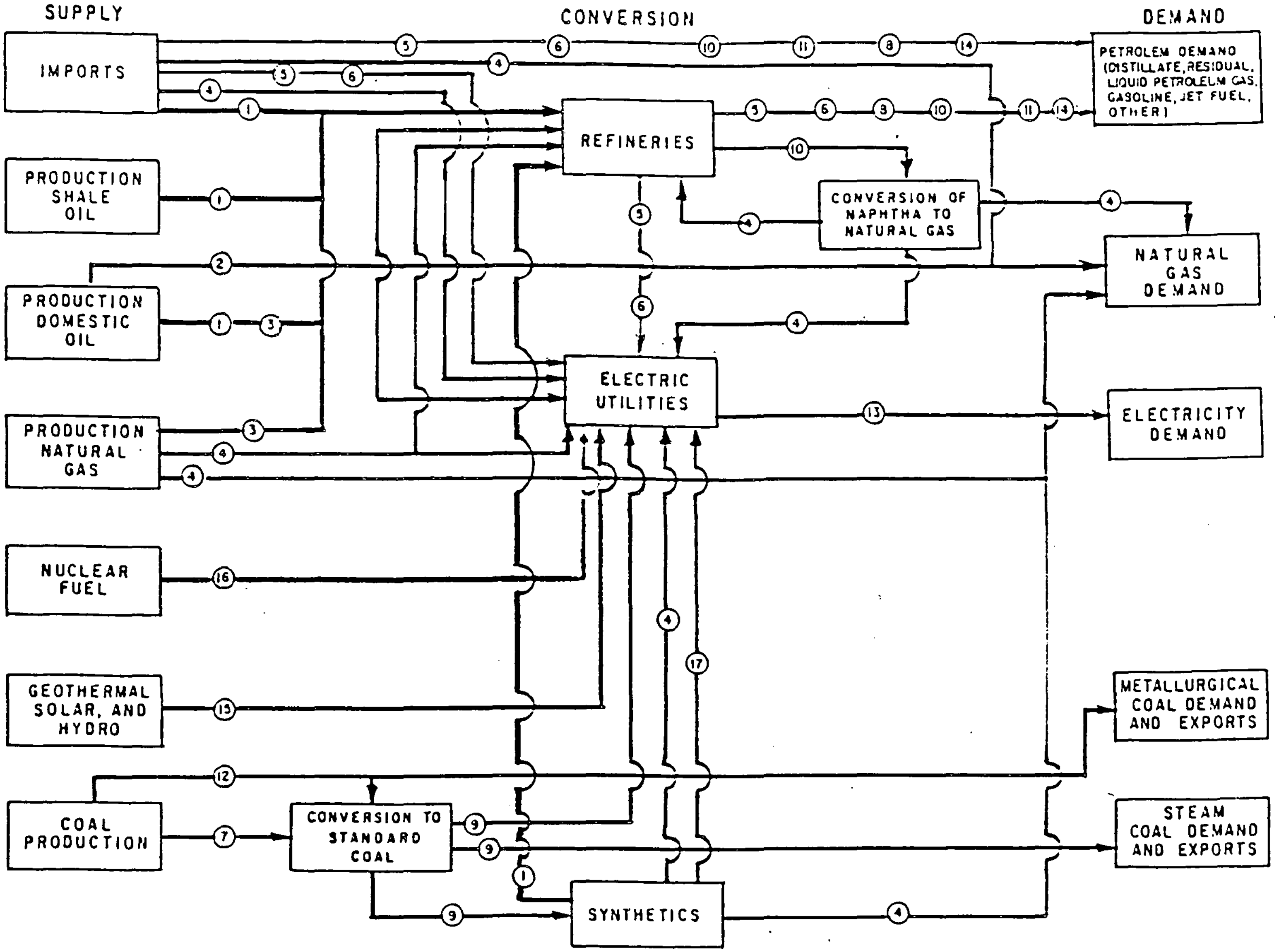
[2] These equations are further explained in Chapter II.

[3] See Table II-1 for a list of these product-sector combinations.

FIGURE I-3

FLOW OF MATERIALS IN PIES



1. CRUDE OIL
2. ASSOCIATED GAS
3. GAS LIQUIDS AND BUTANE
4. NATURAL GAS
5. DISTILLATE
6. RESIDUAL
7. PHYSICAL STEAM COAL
8. JET FUEL
9. STANDARD COAL
10. OTHER PETROLEUM
11. GASOLINE
12. METALLURGICAL COAL
13. ELECTRICITY
14. LIQUEFIED PETROLEUM GAS
15. BASE, INTERMEDIATE, OR PEAK ELECTRICITY *
16. NUCLEAR FUEL
17. FUEL GAS

* SYNTHETICS, GEOTHERMAL, AND SOLAR PRODUCE BASE LOAD ELECTRICITY ONLY.

uncertainties. A number of these policy options have been incorporated into scenarios which provide additional constraints for PIES.

All prices and quantities of energy goods produced, consumed, or converted are estimated on a regional basis. For each sector (e.g., coal, utilities, transportation, etc.), a set of regional definitions is used. In its present form, PIES considers 10 demand, 10 utility, 12 coal, 7 refinery, 1 shale, 13 oil, and 14 gas regions. The 10 demand regions are the DOE regions depicted in Figure I-2. The 10 utility regions, in which fuel is converted into electricity, coincide with these demand regions. Each utility region satisfies demand for electricity in its coincident demand region.

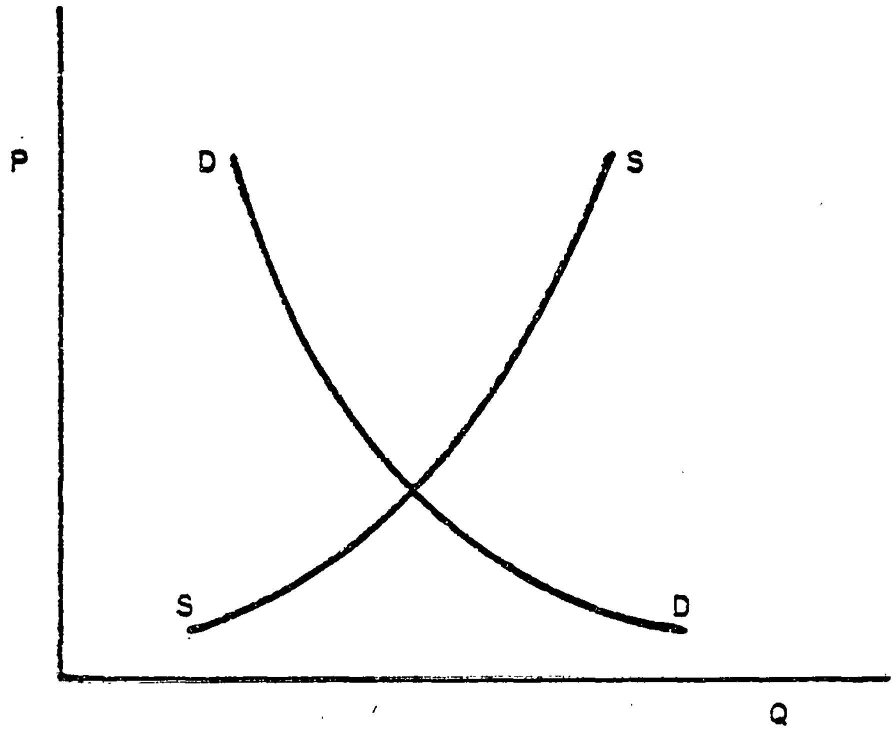
SOLUTION PROCEDURE

Underlying PIES is the assumption that, subject to the constraints imposed by Government policies, participants in the economy (i.e., consumers and suppliers) act in their own self-interest. It is assumed that consumers who act in their own self-interest are rational and maximize their benefits and that producers acting in this fashion maximize profits. With this assumption, demand will be greater with decreasing price, and supply will be greater with increasing price. In reality, considerable deviation from perfect market conditions is caused by regulation. These effects are modelled in PIES. Thus, the supply and demand functions are of the general form depicted in Figure I-4.

Consequently, the market equilibrium for fuels occurs where the supply and demand functions intersect. This occurs when fuels are purchased in a cost-conscious fashion by consumers who substitute fuels for each other on the basis of their relative price changes, and when industry operates so as to maximize its return across the entire national energy sector. Because perfect market conditions do not pertain in the real world, this clearly is an approximation to real world conditions. Thus, an equilibrium determined by PIES represents an equilibrium solution to the overall problem of energy supply and demand in a partially regulated market.

FIGURE I-4

IDEALIZED SUPPLY AND DEMAND CURVES

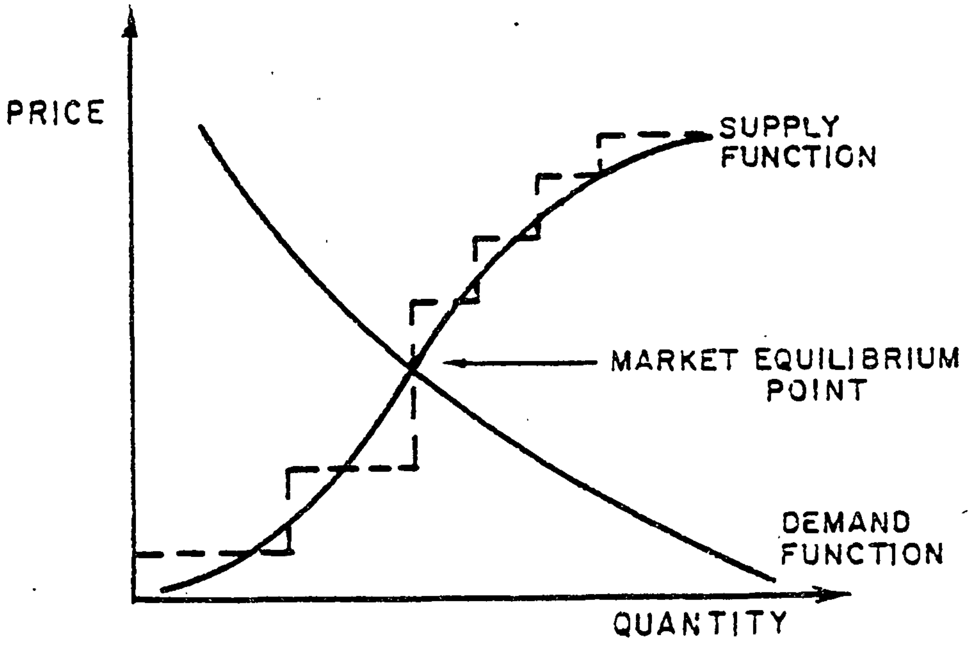


Although the Demand Model provides estimates of quantities and prices for the forecast years, these quantities have not been matched to the quantities suppliers will produce when acting in their own self-interests. Thus, in order to obtain a market equilibrium point, supply must be equated to demand. PIES does this by formulating a linear program that optimizes consumers' and producers' own self-interests and whose constraints ensure that supply equals demand.

In order to solve the equilibrium problem by linear programming techniques, step–like approximations to the supply and Demand Curves are generated, as indicated for supply in Figure I-5. The step function approximation to the demand curve is obtained by using the estimates from the Demand Model; the integrated supply network represents the supply approximation. When these step-function approximations to the supply and demand curves and the initial demand estimates are incorporated into the LP and the LP is solved, prices, demands, and activity levels are obtained which serve as a candidate equilibrium.

FIGURE I-5

TYPICAL SUPPLY AND DEMAND CURVES



The solution to the LP is not automatically an equilibrium, since the LP cannot provide directly for fuel substitution effects. To handle this problem, several iterations of the solution procedure are performed using a revised set of demand estimates on each iteration. These demand estimates are calculated using a continuous demand curve, which is a function of price, and which is based on the initial prices, quantities, and own–and cross-elasticities of demand obtained from the Demand Model.

If on a particular solution of the LP, the set of prices and associated quantities are within pre-specified tolerance limits of the previous set of prices and quantities, PIES has converged to the equilibrium solution. If not, new levels of product demand in each region are calculated from the previous solution price, taking into account cross-elasticity effects in fuel products. These new levels of product demand and a new demand approximation are inserted into the LP, which is again solved, and the process is continued until the equilibrium solution is obtained.

We can discuss this procedure in an algorithmic fashion. Assume that the Demand Model provides an estimate of prices for elastic products, quantities for 30 sector-specific products, and elasticities (both own and cross) for these products with respect to the prices of the elastic products.[4] With these demands, prices, and elasticities, and the assumption of constant elasticities, a continuous demand function is generated, dependent on price. This function is linear in the logarithms and, due to non-zero cross-elasticities, can reflect substitution of fuels. It is used between iterations of the linear program.

On the supply side, the integrated supply network is posed as an LP, with constraints that force supply to meet demand. To initiate the procedure, we input the initial demands into the LP matrix and allow the solution to have some flexibility in meeting these demands through the demand approximation. If the solution has not met the demands within a specified tolerance limit, we perform the following iterative procedure:

1. Adjust the demands by using both the prices obtained from the solution of the LP and the demand function to reflect fuel substitution.
2. Revise the demands in the LP formulation, and update the demand approximation.
3. Solve the new LP, obtaining prices and demands.
4. Check to see if these demands meet a specified tolerance limit. If so, we have obtained an approximate equilibrium. If not, return to step 1.

Several iterations are performed, where a solution to the LP is obtained and demands are updated between the solutions, to obtain a market equilibrium point. This procedure is discussed at greater length in Chapter II.

---

[4] The word "elastic" here means not perfectly inelastic.

THE PIES COMPUTER SYSTEM

PIES consists of several different computer programs, usually run at different times. A number of the programs are run in series, as the output from one provides input for the next, and the data are generally stored on permanent files.

Both the supply and demand representations in PIES begin with a data generation process that includes the operation of satellite models, which are depicted in Figure I–6. These satellite models include not only computer programs, but also analyses and external data generation. Supply data from these satellite models, called raw data, are fed into preprocessors, which reformat the data into standard tables. Demand data are entered into the PIES Demand Model,[5] whose output consists of prices, demand quantities, and elasticities that are fed to the equilibrating mechanism. The supply information in the standard tables is processed into an LP matrix, which is accessed by a program containing the equilibrating mechanism. These components of the system are depicted in Figure I–7.

Each set of data creating a new LP matrix defines a separate scenario. As the generation of an LP matrix from scratch is costly in terms of required computer time, minor changes to define similar scenarios or update data elements are entered by means of a program called REVISE, which modifies an existing matrix. This procedure is used whenever possible, and a number of "reference scenario" matrices are maintained for use in alternate scenario analysis via REVISE.

The final part of the system is a report writer which produces the PIES Integrating Model Report. A sample PIES report is given in Volume VI, Data Documentation, along with a description of its contents. Other PIES output reports include the Capital Report documented in Volume VII, and the Coal Transportation Report discussed briefly in Volume III.

The raw data, preprocessors, standard tables, REVISE program, and equilibrating mechanism are described briefly below.

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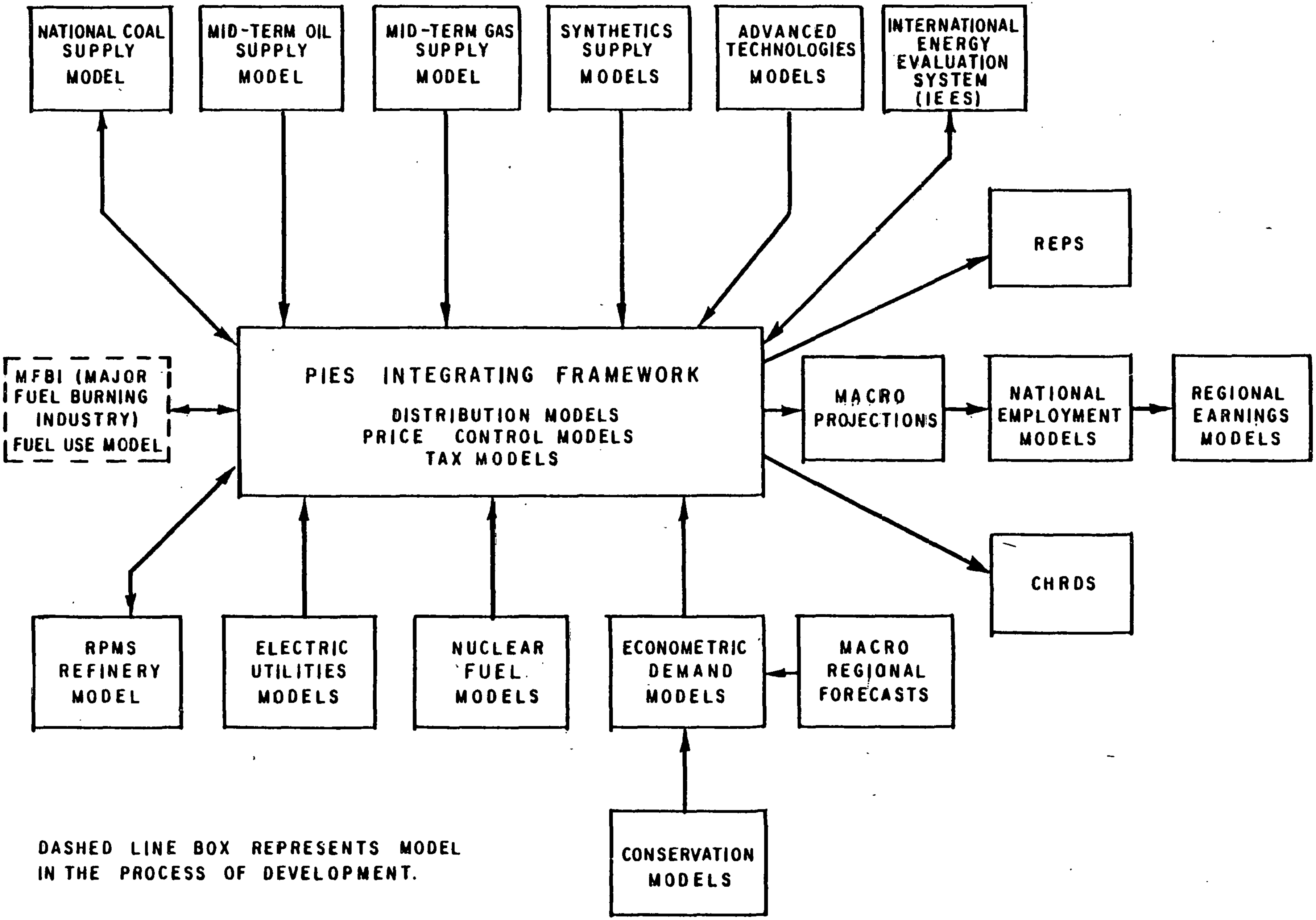
[5] The PIES Demand Model is, by our definition, a satellite model to the PIES Integrating Model.

FIGURE I-6

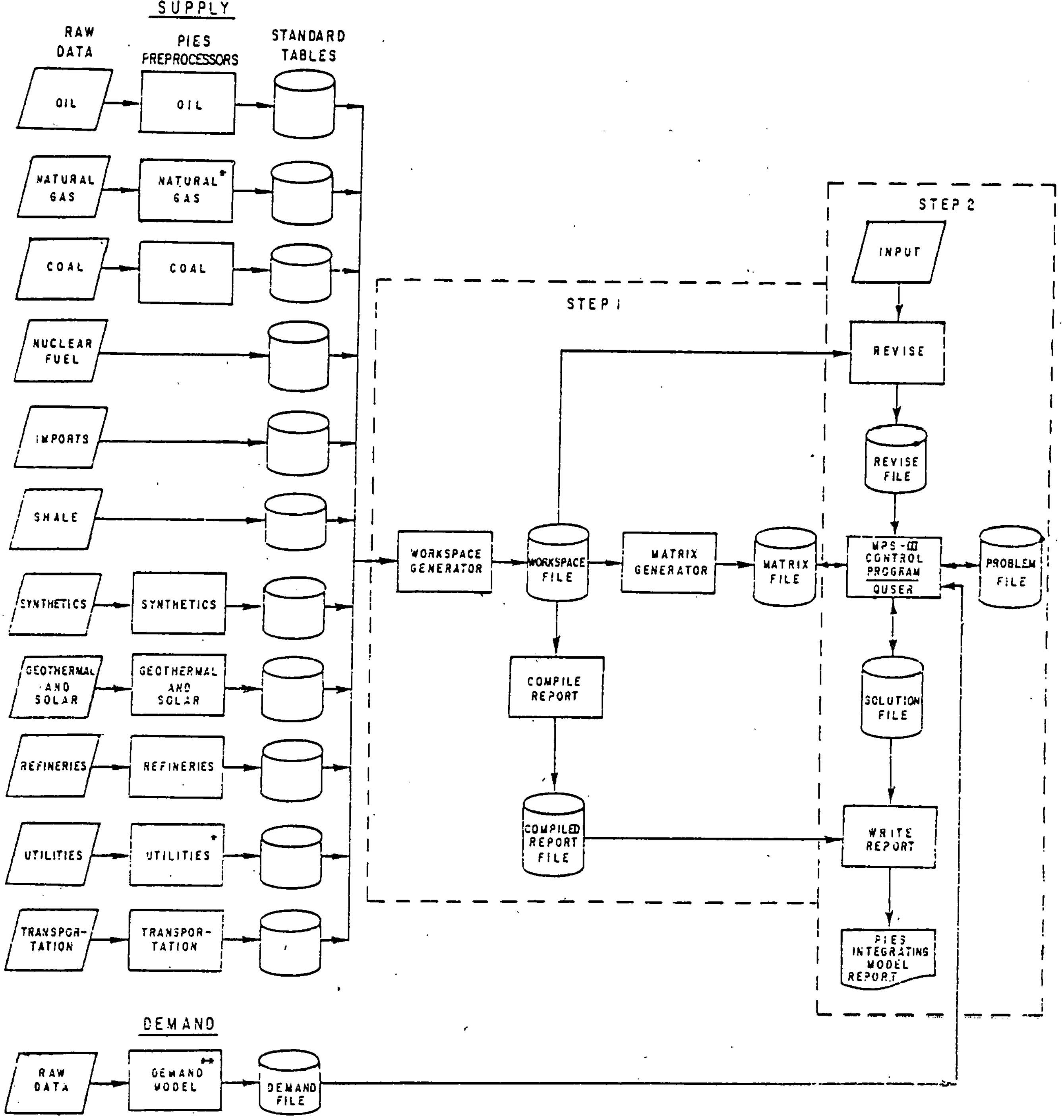
RELATIONSHIPS OF SATELLITE MODELS WITH PIES



DASHED LINE BOX REPRESENTS MODEL IN THE PROCESS OF DEVELOPMENT.

FIGURE I-7

PROCESS SCHEMATIC OF PIES



* THERE ARE ACTUALLY TWO PREPROCESSORS FOR MODELING NATURAL GAS AND UTILITY DATA.

** THE DEMAND MODEL IS A SATELLITE MODEL TO PIES.

Raw Data

In the original Project Independence Study, raw supply data were provided in various formats by numerous formal interagency task forces. Although PIES analysts can initiate formatting improvements, raw supply data are still formatted according to the convenience of the originating office. Hence, the need for preprocessors.

Preprocessors

The raw data from each supply sector must be formatted uniformly before conversion to LP format. Preprocessors convert raw data into standard table format and units. They are separate programs and can be run individually when needed. Preprocessors exist for the following product and conversion categories: coal, oil, natural gas, utilities, refineries, transportation, synthetics, and geothermal and solar.

The Standard Tables

Standard tables exist for facilities, materials, and transportation. Each column has a unique name, as does each row. The column and row names are formed according to strict naming conventions described in Volume V, Code Documentation.

The standard tables format the data so that the LP matrix can be generated for use by the equilibrating mechanism without further arithmetical change. In general, each standard table column will cause the generation of a corresponding matrix column, and each standard table row entry will become a row entry in the matrix. There are exceptions, such as the transportation standard tables.

The REVISE Program

Minor data changes usually are made through the REVISE program, a separate routine that can change matrix data. Use of the REVISE program is a convenience used so that the matrix does not need to be regenerated before each PIES run.

The REVISE program also handles the implementation of alternate scenarios in PIES. These scenarios represent different cases of price regulation, time lags, and other fuel-specific factors.

The Equilibrating Mechanism

The equilibrating mechanism performs the necessary calculations to determine an equilibrium between supply and demand. This program reads the demand files, i.e., the projected quantities, prices, and associated elasticities of 30 fuels by demand region; it sets up the demand function approximations, and controls convergence. In addition, the program performs the average cost pricing associated with the electric utilities and the calculations for oil entitlements and natural gas regulation.

The remainder of this document discusses the integrated supply submodels and the process by which an equilibrium is determined. The word submodel used in Chapters III through IX refers to the model logic found in both the preprocessors and the equilibrating mechanism. In some cases, the data from the REVISE program are included. When it is necessary to refer to a scenario in these chapters, a scenario used in the 1977 Administrator's Annual Report[6] is selected. Volume VI, Data Documentation, describes these scenarios, and presents the standard table data along with the primary sources of the raw data.

---

[6] United States Department of Energy (DOE), Energy Information Administration (EIA); Annual Report to Congress (AAR), April 1978.

II. PIES INTEGRATION: THE EQUILIBRATING MECHANISM

INTRODUCTION

As stated in Chapter I, the equilibrating mechanism serves as the interface between estimates of demand and the integrated set of supply options by using the demand estimates to approximate a demand curve and integrating the results with an LP formulation of the integrated supply network. It balances supply and demand by recursively re-estimating the demand curve and resolving the LP until a specified set of convergence criteria are met.

The equilibrating mechanism not only adjusts prices and quantities as necessary to obtain convergence to an equilibrium, but it also adjusts the prices of electricity, oil, and natural gas between iterations, under certain assumptions and conditions in order to consider such conditions as an oil entitlements program, which equalizes the cost of foreign and domestic oil to U.S. refineries; a natural gas tax and regulation program; and average cost pricing of utilities, which provides for the regulation of electric utility rates. These aspects of the equilibrating mechanism are discussed in the later chapters which discuss the individual supply and conversion sectors.

In this chapter, we present the methodology for calculating an equilibrium point in PIES, including the interface between the equilibrating mechanism and Demand Model, an outline of the calculation procedure (covering both problem formulation and algorithmic method), and the requirements for convergence. Illustrative examples are included.

OVERVIEW OF PIES SOLUTION PROCEDURE

PIES is a deterministic, steady-state model that considers the technological and economic interactions of various activities, both within and among distinct geographical calculating an equilibrium solution (one in which supply equals demand) and in forecasting corresponding fuel prices and quantities. The supply side is modeled as an optimization problem whose constraints supply equals demand.

By assuming that the energy environment can be described by downward sloping demand curves and upward sloping supply curves (i.e., as price increases, demand decreases and supply increases), a market equilibrium point for a particular fuel is determined by the intersection of these curves. Although calculating this equilibrium point may be fairly easy in the one-product case, it becomes harder in the more realistic multifuel world.[1]

For the one-product case, an equilibrium point can be found by maximizing consumers' and producers' surplus. 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. Consumers' and producers' surplus are depicted for the one-product case in Figure II-1. Here, the maximization of consumers' and producers' surplus modeled mathematically by maximizing the difference of the area between the supply and demand curves. Given the assumptions used in PIES (see appendix B), the area under the supply curve represents the total cost to the producer.

To see mathematically how the maximization of consumers' and producers' surplus in the one-product case produces an equilibrium, consider the functions $P_S(q)$ and $P_D(q)$ depicted in Figure II-1. If q* is the equilibrium quantity, then

$$P_S(q^*) = P_D(q^*). \qquad (1)$$

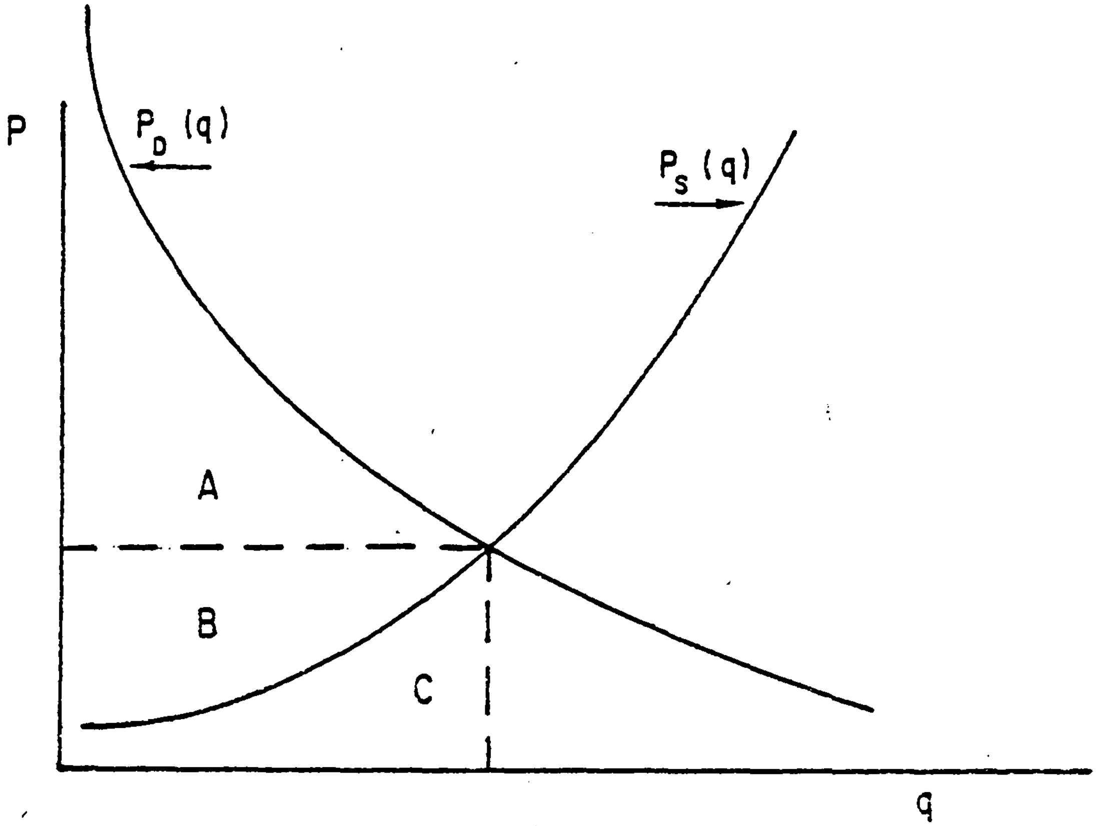
That is, equilibrium occurs when the "price" at which consumers are willing to purchase products is equal to the "price" at which business is willing to supply them.

---

[1] The detail here is greater than just the number of products considered. For instance, an equilibrium is found not only for each product, but for each product in each region.

FIGURE II-1

CONSUMERS' AND PRODUCERS' SURPLUS



AREA A: CONSUMERS' SURPLUS
AREA B: PRODUCERS' SURPLUS
AREA C: TOTAL COST TO PRODUCER

Now, total surplus (i.e., consumers' and producers' surplus) can be written:

$$TS(q) = \int_0^q \left[P_D(x) - P_S(x) \right] dx.$$

We want to determine if the maximization of total surplus, i.e., the solution to the problem:

$$\max_q TS(q) \tag{2}$$

yields an equilibrium point. For this to be true, the quantity q* solving (2) must satisfy the first order necessary condition:

$$\frac{d\,TS(q^*)}{dq} = 0.$$

Differentiating TS(q) and evaluating at q*, we obtain

$$\frac{d\ TS(q^*)}{dq} = P_D(q^*) - P_S(q^*) = 0,$$

yielding an equilibrium point, i.e.,

$$P_D(q^*) = P_S(q^*).$$

In order for q* to yield a maximum, the condition

$$\frac{d^2\ TS(q^*)}{dq^2} \quad 0$$

must also be satisfied. Differentiating TS(q*) twice yields

$$\frac{d\ P_D(q^*)}{dq} - \frac{d\ P_S(q^*)}{dq},$$

which is less than zero for curves of the form indicated in Figure II-1. (Since the slope of the demand curve is always negative and that of the supply curve is always positive, the slope of the demand curve minus the slope of the supply curve is negative.)

Thus, assuming that we can find an equilibrium by solving an optimization problem, we can formulate the energy system in the above manner. Because of the complexity of the problem (the number of variables involved), the simplest optimization formulation is that of an LP. Formulating the problem as an LP, whose objective is to maximize consumers' and producers' surplus (see Figure II-1) and whose constraint space models limited production capabilities and facility and transportation capacities, will produce an optimal level of prices and quantities of activities.

The simplification to the one product case cannot provide for fuel substitution, which will occur when prices for a given product are higher than consumers are willing to pay. To overcome this deficiency, a sequence of LP problems are solved recursively where, between LP solutions, new demand estimates are obtained, which include fuel substitution effects resulting from non-zero cross-elasticites of demand. (Iterations are also performed because an error is introduced due to approximating the continuous demand curve by a step function. The error is reduced in each iteration and these iterations continue until the convergence criteria are met.)

FORMULATION OF THE PIES LP PROBLEM

Volume II of this documentation series contains a simplified example of an energy network, which the reader should review as background for this section.

A typical LP problem is:

$$\min c_1x_1 + c_2x_2 + \ldots + c_xx_s$$

subject to

$$a_{11}x_1 + a_{12}x_2 + \ldots + a_{1s}x_s \leq b_1$$

$$\cdot$$

$$\cdot$$

$$\cdot$$

$$a_{r1}x_1 + a_{r2}x_2 + \ldots + a_{rs}x_s \leq b_r$$

$$x_1 \geq 0, \ldots, x_s \geq 0$$

where $r \leq s$ and $c_1, \ldots, c_s$; $a_{11}, \ldots, a_{1s}, \ldots, a_{r1}, \ldots a_{rs}$; and $b_1, \ldots, b_r$ are inputs and $x_1, \ldots, x_s$ are unknowns. The objective, then, is to select $x_1, \ldots, x_s$ which minimize a linear function subject to linear constraints; for instance, to minimize cost subject to some specified limitation on resources. In matrix notation this formulation is:

$$\min c^TX$$

subject to

$$AX \leq b$$

$$X \geq 0,$$

where c and X are both s-dimensional vectors, b is an r-dimensional vector, A is an r x s matrix, s is the number of energy activities modeled, and r is the number of constraints.

Expanding this general LP formulation to the specific problem modeled by PIES, we can divide the constraints into two types: those describing the supply activities and those forcing demand to be met. The constraints on the supply activities are written as $A_1X \leq b$. These constraints either bound the capacity of facilities, or restrict the amount of material available, in which case they are called process limit constraints, or they force the total inputs of a material to equal the total outputs and are thus referred to as material balance constraints. The second group of constraints, which we write as $A_2X = Q$, force the supply activities, X, to meet the demands Q.

Designating the starting demand by Q_0, and introducing the translation $Y = Q - Q_0$, we rewrite this last set of constraints as $A_2X - Y = Q_0$, where Y represents the difference between the demand estimates input to the LP at the beginning of the iteration and the demands based on the optimal activity levels at the solution of the LP.

As previously stated, the objective function in PIES maximizes consumers' and producers' surplus, which in the one-product case is equivalent mathematically to maximizing the difference of the area between the supply and demand curves.[2] Since the area under the supply curve represents the total cost to the producer, the supply portion of the objective function is equal to c^TX, as indicated above. The demand curve is obtained by taking estimates from the Demand Model, using them to obtain a continuous curve, and approximating that curve by a step function. (This approximation is described later in this chapter.)

A maximization problem can be converted into an equivalent form involving minimization by minimizing the negative of the original objective function. In the remainder of this chapter, the LP will be stated as a minimization problem rather than a maximization problem.

---

[2] In the case of more than one product, the objective function is defined as

$$TS(q) = \int_0^{q^*} P_D(q) \cdot dq - \int_0^{q^*} P_S(q) \cdot dq$$

where the dots denote inner products and the remaining notation is the same as defined previously.

Assuming that we have the demand approximation, we state the LP problem formally as follows. Let the vector $Y = Y_+ - Y_-$ where

$$Y_+ = \begin{pmatrix} \sum_{k=1}^{n} Y_{1,k} \\ \cdot \\ \cdot \\ \cdot \\ \sum_{k=1}^{n} Y_{m,k} \end{pmatrix} \quad \text{and } Y_- = \begin{pmatrix} \sum_{k=1}^{n} Y_{1,-k} \\ \cdot \\ \cdot \\ \cdot \\ {}^{n}_{k=1}\; Y_{m,-k} \end{pmatrix}$$

where Y_+ and Y_- represent positive and negative values of Y. Subscript m denotes the type of fuel, subscript n denotes the order of the discrete difference.

Let U_+ and U_- be vectors bounding the components of Y_+ and Y_- respectively. Then, the PIES problem can be stated as:

$$\min_{X,Y_{j,k}} \; c^T X - \sum_{j=1}^{m} \sum_{k=1}^{n} P_{j,k} Y_{j,k} - P_{j,-k} Y_{j,-k} \tag{3}$$

subject to

$$A_1 X \leq b$$

$$A_2 X - (Y_+ - Y_-) = Q_0$$

$$0 \leq Y_+ \leq U_+$$

$$0 \leq Y_- \leq U_-$$

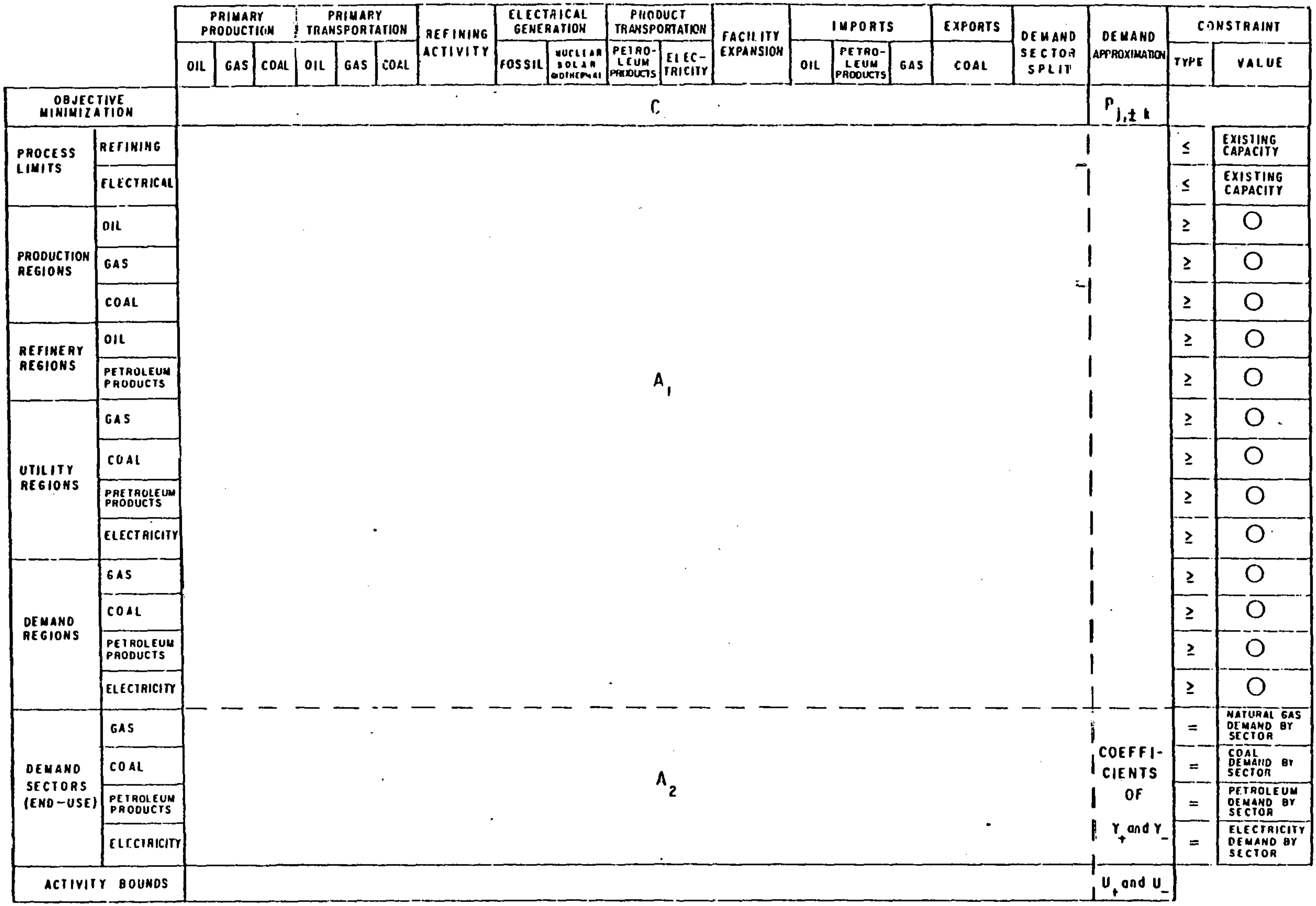
$$X \geq 0.$$

In this formulation, the terms $P_{j,k}$ and $P_{j,-k}$ represent marginal prices associated with the demand approximation variables, $Y_{j,k}$ and $Y_{j,-k}$. These prices are discussed in detail under "Algorithm" below. Also, regional detail is not expressed in (3) above, although all variables are region-specific. Figure II-2 depicts the PIES LP matrix in terms of the representation given in (3), without the regional detail.

FIGURE II-2

SCHEMATIC OF INTEGRATED SUPPLY MODEL

(LP FORMULATION)*



* SEE VOLUME V, FIGURE III-7 FOR ANOTHER VERSION OF THIS MATRIX.

The PIES Demand Model provides estimates of prices, demands and elasticities to the equilibrating mechanism, specifically:

- Initial demand estimates for 30 fuel types (see Table II-1) in each demand regions
- Initial price estimates of the 18 elastic fuel types (first 18 items in Table II-1) in each of the demand regions
- Elasticities (own and cross) of the 18 elastic fuel types with respect to the price of each fuel type for each region.

Demands for the 12 products for which prices are not given (last 12 items in Table II-1) are considered perfectly inelastic. The initial price, in standard physical units, of each inelastic product is set equal to that of related elastic product, as indicated in Table II-2. The exception is metallurgical coal, whose initial price is set exogenously at $30/ton. It should be noted that these inelastic product price estimates do not affect the solution as the algorithm equilibrates on elastic products only.

The Demand Model provides a complete set of demand information for each of the 10 PIES demand regions. In addition, demand data are provided to the equilibrating mechanism for each of the PIES target years. The price of imported oil, in the form of price trajectories over the forecast period, is an input to the Demand Model, which can be used to generate demand data for each import price postulated by DOE.

PIES solves for the prices and quantities of the 30 fuels listed in Table II-1. Demands for the other 12 products are considered to be perfectly inelastic, so no price estimates are needed from the Demand Model for them for use in the equilibration routine; they are however provided. The quantities of these products demanded do not change from iteration to iteration.

TABLE II-1. LIST OF 30 FUEL TYPES IN PIES

Code	Fuel Type
Elastic Products	
ELRS	Electricity - Residential
NGRS	Natural Gas - Residential
DFRS	Distillate Fuel - Residential
LGRS	Liquefied Petroleum Gas - Residential
ELCM	Electricity - Commercial
NGCM	Natural Gas - Commercial
DFCM	Distillate Fuel - Commercial
RFCM	Residual Fuel - Commercial
ELIN	Electricity - Industrial
NGIN	Natural Gas - Industrial
DFIN	Distillate Fuel - Industrial
RFIN	Residual Fuel - Industrial
LGIN	Liquefied Petroleum Gas - Industrial
CLIN	Coal - Industrial
GSTR	Gasoline -Transportation
DFTR	Distillate Fuel - Transportation
JFTR	Jet Fuel - Transportation
RFTR	Residual Fuel - Transportation
Inelastic Products	
ELTR	Electricity - Transportation
NGRM	Natural Gas - Raw Material
LGCM	Liquefied Petroleum Gas - Commercial
LGTR	Liquefied Petroleum Gas - Transportation
LGFS	Liquefied Petroleum Gas - Feedstock
LGRM	Liquefied Petroleum Gas - Raw Material
OLRM	Oil - Raw Material
NAIN	Naphtha - Industrial
ASCM	Asphalt - Commercial
CLHC	Coal - Residential & Commercial
CLTR	Coal - Transportation
MCIN	Metallurgical Coal - Industrial

TABLE II-2. CORRESPONDENCE BETWEEN ELASTIC AND INELASTIC PRODUCTS FOR DETERMINING INITIAL PRICES

Inelastic Product	Elastic Product Whose Price Estimate is Used as Initial Price for Inelastic Product
Electricity - Transportation	Electricity -Industrial
Natural Gas - Raw Material	Natural Gas - Industrial
Liquefied Petroleum Gas - Commercial	Liquefied Petroleum Gas - Industrial
Liquefied Petroleum Gas - Transportation	Liquefied Petroleum Gas - Industrial
Liquefied Petroleum Gas - Feedstock	Liquefied Petroleum Gas - Industrial
Liquefied Petroleum Gas - Raw Material	Liquefied Petroleum 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 equilibrating mechanism uses these demand estimates for the right hand side of the demand constraints in the LP. The prices and elasticities obtained from the Demand Model, along with the demand estimates, are used to produce a demand curve, from which the demand approximation is formed. This demand curve is used between iterations of the LP to obtain demand estimates for insertion into the next LP, as described below under "Algorithm." The form of the demand curve is discussed in the next section. We do not explicitly mention the 10 demand regions again, but the regional detail is implied throughout the remainder of this chapter.

THE DEMAND APPROXIMATION

Previously, we discussed the LP formulation, which forces supply to meet demand through the constraints given in (3). However, the LP assumes that the cross-elasticities are zero; that is, that there is no substitutability of one type of fuel for another. Since the cross-elasticities are not all zero, adjustments to the solution of the LP must be made to account for the substitutability of fuels. This adjustment can be made by rerunning the Demand Model to generate a new demand file or by approximating the demands, taking into account the cross-elasticities. Since the former approach is both costly and time consuming, the latter approach is chosen.

Constant cross-elasticities are assumed in determining the form of the demand curve approximation. With this assumption, the demand curve is log-linear and is expressed as follows. Let i index the 30-products and let j index the 18 elastic products. Then,

$$Q_i = \exp \quad K_i + \sum_{j=1}^{18} \epsilon_{ij} \ln P_j \qquad (4)$$

$$K_i = \ln Q_i^o - \sum_{j=1}^{18} \epsilon_{ij} \ln P_j^o$$

where

Q_i^o = initial quantity of product i

P_j^o = initial price of product j

ϵ_{ij} = constant elasticity of product i with respect to product j

Q_i = quantity of product i

P_i = price of product i.

Equation (4) represents a continuous demand function, which is used to approximate demands. From this equation, new demands can be obtained by using the elasticities, initial prices and quantities obtained from the Demand Model and the prices obtained from the previous solution of the LP. The incorporation of these values into the LP is discussed in the next section.

THE PIES ALGORITHM

In this section, we describe how the formulation of the LP and the above demand approximation combine to produce the algorithm used in PIES. We begin by giving a simple qualitative description of the operation of PIES and then describe the interactions in more detail.

Economic equilibria are normally modeled by using upward sloping supply and downward sloping demand curves such as those depicted in Figure I-4. The intersection of these curves determines the quantity, and hence the price, at which supply equals demand, i.e., the economic equilibrium. PIES determines approximate equilibrium levels for several products in different regions of the U.S.

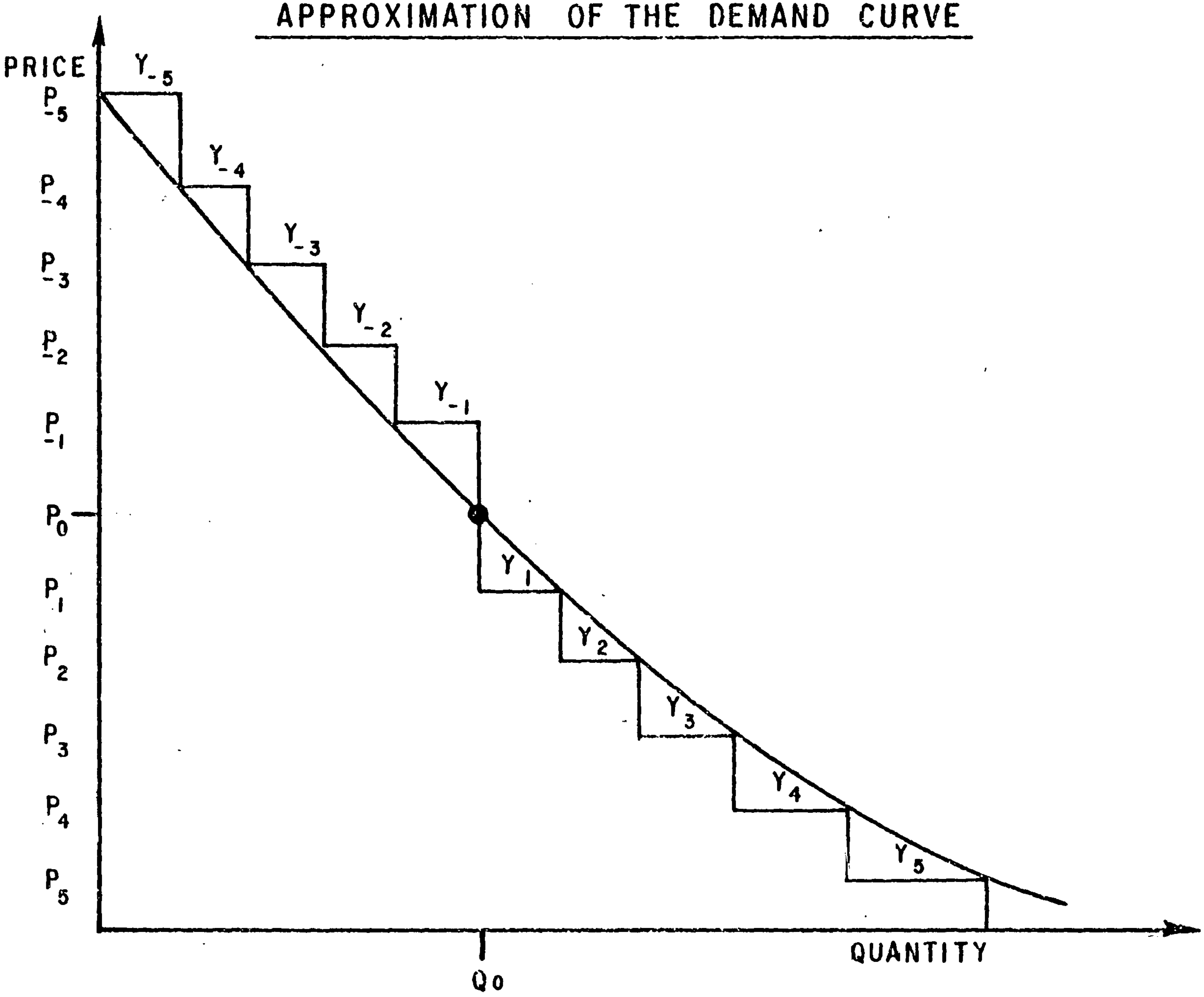
The solution of the PIES LP provides possible equilibrium prices as the marginal costs, or dual activities of the demand constraints. The iterative recalculation of the demand approximations between solutions of the LP is necessary to adjust the demand approximations to reflect interaction with the supply functions and interfuel substitutability.

In PIES, the supply and demand curves are represented by step functions, for compatibility with the LP representation. For each fuel product, the supply curves are provided as step function approximations with discrete prices for each increment of supply (see Figure I-5). The Demand Model provides initial demand estimates for each product, price estimates for each elastic product, and own-price and cross-price elasticities, which are assumed to be constant over a range of prices, for each target year. Using these estimates, a step-like demand approximation is determined for each product (see Figure II-3).

This demand approximation is made by constructing 10 steps, centered at the initial demand point (Q_0, P_0) obtained from the Demand Model. These are constructed as follows: steps 1 through 5 are respectively 1 percent, 5 percent, 15 percent, 35 percent, and 75 percent below the initial demand price, P_0; and steps -1 through -5 are respectively

FIGURE II-3

APPROXIMATION OF THE DEMAND CURVE



1 percent, 5 percent, 15 percent, 35 percent, and 75 percent above the initial demand price, P_0. Steps 1 through 5 correspond to $P_{j,k}$ in (3) for product j; steps -1 through -5 correspond to $P_{j,-k}$ in (3) for product j.

Figure II-3 displays a demand approximation generated in this fashion. The steps are called "avoids." The "avoids" may be interpreted as units of unsatisfied demand for those steps to the left of the initial point and excess demand for those steps to the right of the initial point. At equilibrium, these steps do not enter the solution, that is, there should be no advantage to being at one of the "avoids."

The "avoids" can also be interpreted as being used by PIES to "avoid supplying fuel." The Demand Model predicts an initial demand, and the equilibrating mechanism attempts to produce an equilibrium point that meets this demand. Either the demand will be met by suppliers' producing, processing, and transporting the required quantity of products or the "avoids" will be activated, leaving demand unsatisfied.[3]

Unsatisfied demand produces a penalty equal to the sum of the product of the price of the activated "avoid" steps times the quantity of unsatisfied demand associated with them. As many fuels as possible are supplied without activating "avoids" and introducing a penalty. Once the "avoids" are activated, a new demand point is determined, and the model iterates until a demand is found that the producers are willing to meet and where no "avoids" are activated. The model is then said to have converged. (In practice, however, a less stringent convergence criterion is used.) This criterion is discussed more fully later in this chapter.

The prices represented by the 10 steps described above and depicted in Figure II-3 determine the "avoids." The quantities associated with these prices are calculated by using equation (4). The values of Q_i^o, P_j^o, and ϵ_{ij} are obtained from the Demand Model.

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[3] Demand is unsatisfied to the left of Q_0. There is excess demand to the right of Q_0.

These values determine K_i in equation (4) completely. The "avoid" prices $P_{j,\underline{+}k}$ are substituted for P_j in equation (4) and using K_i and ϵ_{ij}, we obtain the quantities associated with the 30 products, and thus the quantities associated with each "avoid" step.

By taking the difference between the quantities associated with two successive "avoid" prices for each product, we obtain a bound on the quantity demanded at each of these price levels. (These bounds determine U_+ and U_- in (3).) Once the quantity at a price level is satisfied, either the next higher or the next lower price will be activated. In this manner, we move along the demand curve trying to obtain a demand which will be satisfied by the supplier.

Figure II-4 depicts a simplified supply curve approximation S. This representation is really of the delivered fuel (i.e., the sum of production, conversion, and transportation costs), and hence is generally the composite of several different production supply curves in different regions. Curve D in Figure II-4 is a demand approximation generated as in Figure II-3, with point G representing (Q_0, P_0).

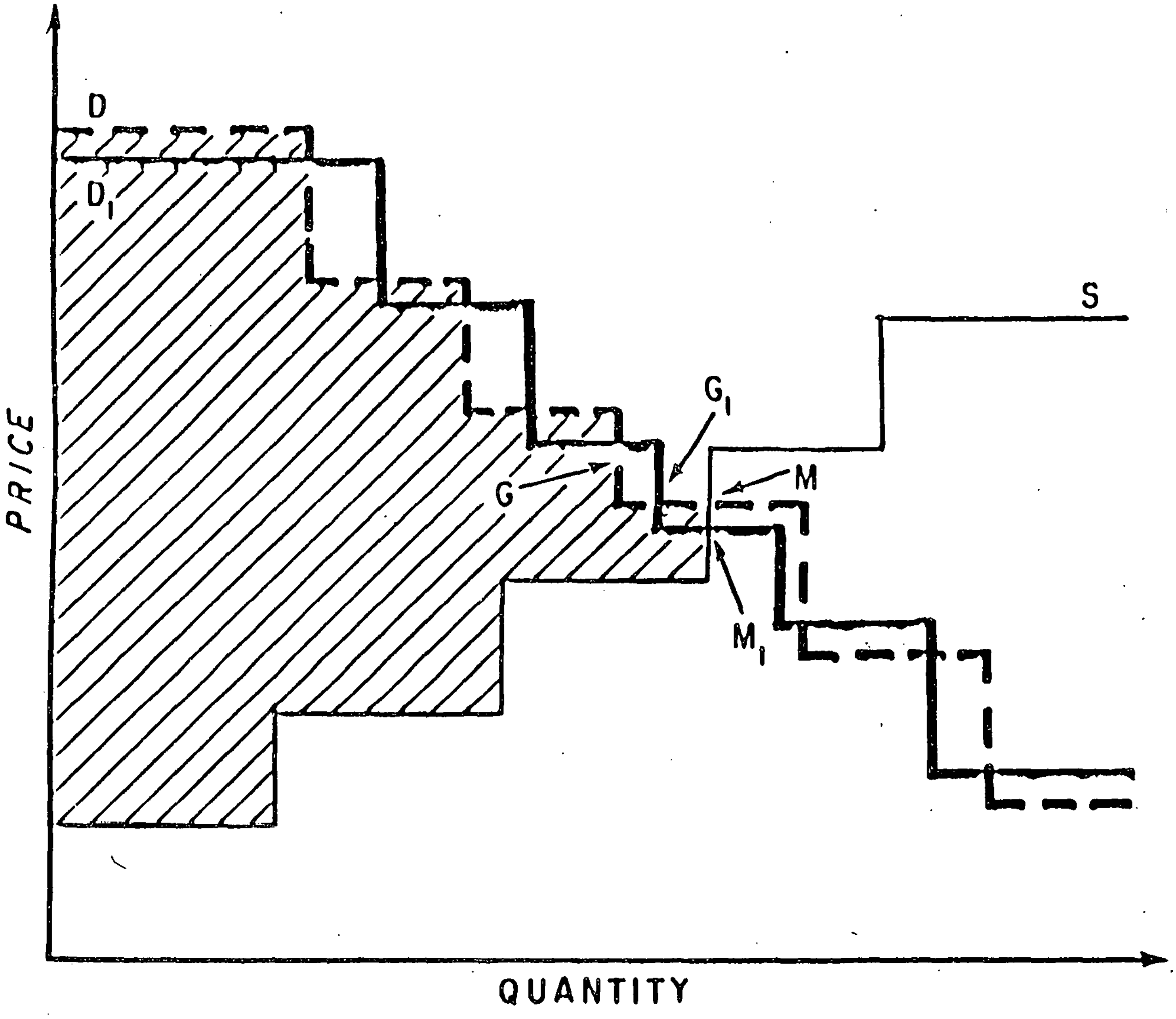
The shaded area between curves S and D represents the sum of producers' and consumers' surplus, and the maximization of this area defines the intersection point (point M in Figure II-4) of the two curves, S and D.

If points M and G do not meet a specified tolerance limit, a new initial price is set midway between the equilibrium price and the previous initial price. By using the original elasticities provided by the Demand Model, the demand associated with this new price is calculated using equation (4). This price and demand define a point G_1, and the procedure previously described is used to construct a new demand approximation D_1. The LP problem is solved again to provide a new equilibrium point M_1. This iteration continues until the successive prices meet the specified tolerance limit.

An approximate equilibrium is reached in PIES when the absolute value of either the change in price or the change in quantity between two successive iterations is less than or equal to 2 percent of the price or quantity, respectively, at the first of these iterations.

FIGURE II-4

APPROXIMATION OF SUPPLY AND DEMAND CURVES



Whenever a solution is obtained that does not meet these convergence criteria, a new initial price is determined and, the point demand estimates associated with these prices are calculated using equation (4). These point estimates are represented as Q_0 in (3). A new demand approximation is established, and the LP problem is solved again to provide a new solution. This iteration continues until the convergence criteria are met and an approximate equilibrium point is obtained.

The impact of the convergence criteria is that only the first order "avoids" (i.e., those within 1 percent of the previous equilibrium solution) are activated when the convergence criteria are met.

The above procedure for calculating an equilibrium between supply and demand can be summarized as follows. Assume that there is an LP matrix containing the demand estimates from the Demand Model for Q_0 in (3), and values for $P_{j,\pm k}$, U_+, and U_- in (3) from approximating the demand curve as described above. Then, the following iterative scheme is used.

(1) Solve the LP, obtaining a set of marginal prices, which is the solution of the dual to the LP given in (3).

(2) Test for convergence; i.e., determine whether these prices and the associated quantities are within a specified tolerance from the previous iteration. If so, the solution is written out. If not, we proceed with step (3).

(3) Determine new prices from the old prices and the equilibrium values and compute the demands associated with these prices.

(4) Calculate the demand approximation (the "avoids") and the new price quantity points.

(5) Continue with step (1).

THE EFFECT OF "AVOIDS" ON CONVERGENCE: AN EXAMPLE

The following example shows how "avoids" are used to calculate an equilibrium between supply and demand. It is included purely for illustration, and for the sake of simplicity, the equilibration of fuel types other than natural gas is omitted, and fuel substitution, taxation, and regulations are not considered.

Consider two hypothetical demand regions, D1 and D2, which obtain natural gas from a third region, D3. The initial demands obtained from the Demand Model for natural gas in D1 and D2 are 20,606 million standard cubic feet/calendar day (MMSCF/D) and 7,756 MMSCF/D respectively. To obtain a solution, the PIES Integrating Model goes through seven iterations, changing the quantity and price each time. Table II-3 shows the quantities and prices for each iteration and the final solution. Of interest here are the calculations between the seventh iteration and the final solution.

Notice first that differences in quantity and price between iterations is relatively small. For instance, the difference in quantity between the seventh iteration and the final solution is 29 MMSCF/D in D1 and 16 MMSCF/D in D2.

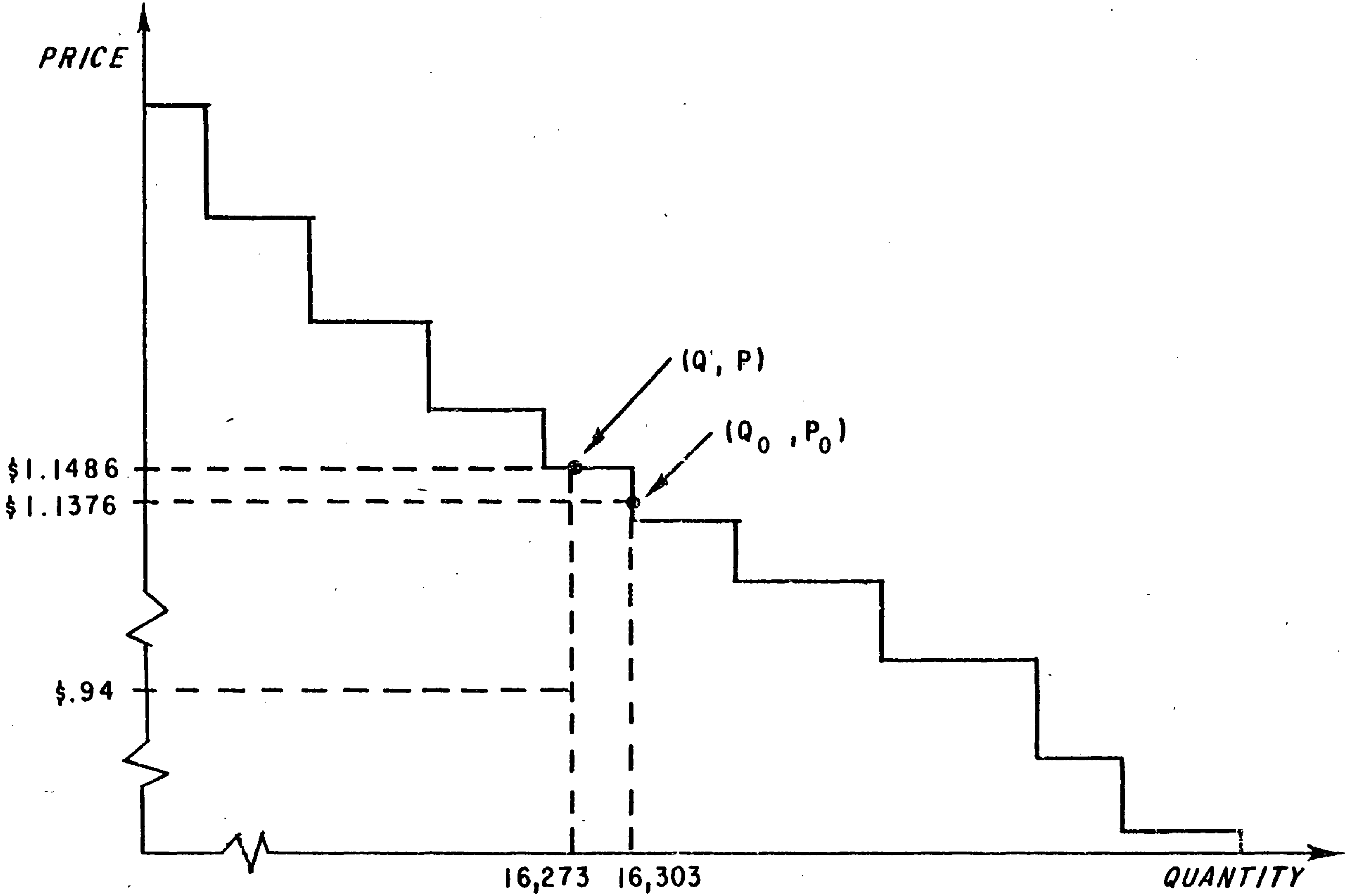
Suppose we examine D1 and use the price $1.1376/MCF and the quantity 16,303 MMSCF/D (seventh iteration) as our starting price and quantity. The equilibrating mechanism takes the $1.1376 MCF and calculates five "avoid" steps 1 percent, 5 percent, 15 percent, 35 percent, and 75 percent above and below this price as depicted in Figure II-5.

TABLE II-3. PRICES AND QUANTITIES FOR ITERATIONS IN D1 AND D2

	D1		D2	
	Price	Quantity	Price	Quantity
1st Iteration	$ .8722 /MCF	18,685 MMSCF/D	$ .779 /MCF	7,410 MMSCF/D
2nd Iteration	1.1572	16,921	1.0634	6,806
3rd Iteration	1.159	16,365	1.0652	6,575
4th Iteration	1.159	16,197	1.0652	6,469
5th Iteration	1.1375	16,259	1.0436	6,444
6th Iteration	1.1325	16,278	1.0387	6,437
7th Iteration	1.1376	16,303	1.0438	6,428
Final Solution	1.1486	16,274	1.0542	6,412

FIGURE II-5

DEMAND AND SUPPLY OF NATURAL GAS IN DEMAND REGION I



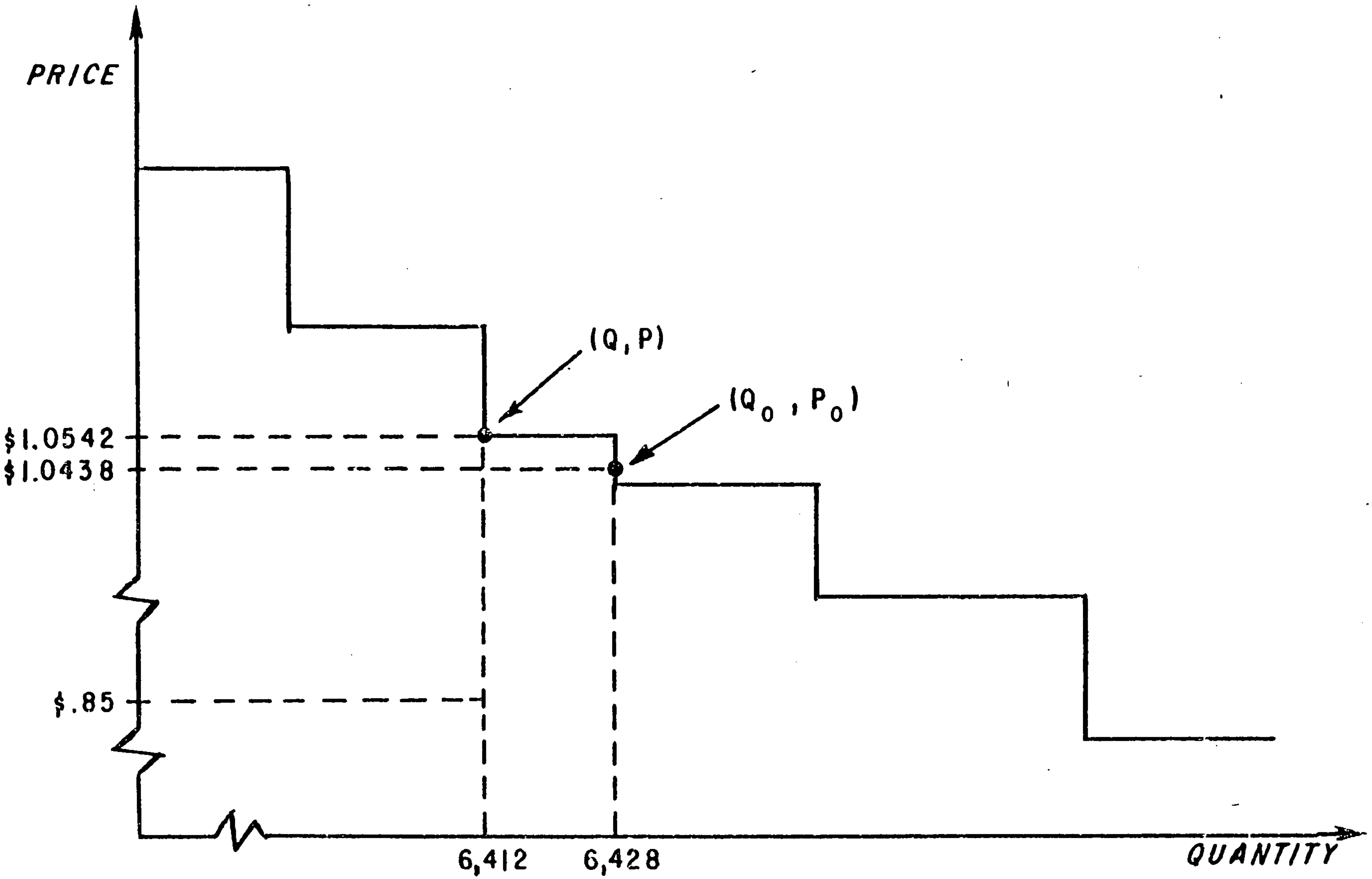
PIES must satisfy the total demand for natural gas in D1, 16,303 MMSCF/D, either by producing, processing, and transporting the product to the demand region or by activating one of the "avoids." If an "avoids" is activated, a "penalty" is levied equal to the price associated with it; the price changes according to supply and demand. Since the objective of the supply side is to minimize cost, any "avoid" that is activated whose price exceeds the starting price penalizes the model. Thus, PIES does not activate "avoids" unless it cannot meet the demand with a lower-cost fuel (including production and transportation costs).

Region D3 provides gas to D1 at a price of \$.94/MCF, \$.70 for production and \$.24 for transportation. The supply of natural gas at this price, however, is not enough to satisfy the demand for 16,303 MMSCF/D; it only satisifes 16,273 MMSCF/D. It is cheaper for PIES to activate "avoids" to satisfy the difference in demand than to obtain natural gas from another region. This activation increases the price to \$1.1486/MCF, a price change which is illustrated in Figure II-6.

Taking the example one step further, by looking at the demand for natural gas in D2 for the seventh iteration, we encounter an additional complication, because D3 also supplies natural gas to D2. The cost of natural gas to D2 is \$.86/MCF, \$.70 for production and \$.15 for transportation. Figure II-6 shows that an "avoid" was activated to meet 16–MMSCF/D. Notice that the quantity 6412–MMSCF/D is at a bound of an "avoid." Since the transportation price and thus the total price of natural gas from D3 is cheaper to D2 than to D1, the question arises of why the total demand in D2 was not met. The reason why the model allocated the gas to D1 is that providing one additional unit of gas to D1 reduces the objective function by the "avoid" price (\$1.1486) minus \$.94 (the price of natural gas from D3), resulting in a savings of \$.2086. If the model allocated one unit to D2, the savings would be \$1.0542 less \$.85, or \$.2042.

FIGURE II-6

DEMAND AND SUPPLY OF NATURAL GAS IN DEMAND REGION 2



III. COAL SUPPLY

INTRODUCTION

In this chapter we describe the coal supply sector of the PIES Integrating Model. The chapter begins with some background information about PIES coal mines, types and terminology. The following section discusses the National Coal Model (NCM), a coal-specific independent model, whose output includes the coal supply curves used within the Integrating Model. The PIES coal preprocessor, which formats the raw data input tables (output files of the NCM) into standard tables consistent with the requirements of the LP matrix, is described in the next section. The modeling of coal supply in the utilities and synthetics sectors is covered briefly in the last section.

COAL TYPES

The quality of coal varies widely among the various deposits in the U.S. Most boilers are extremely sensitive to the overall quality characteristics of the coal which they burn. In particular, heat content, or Btu value, and sulfur content are the most critical quality characteristics for steam coal. The PIES coal types and their associated Btu and sulfur contents are summarized in Table III–1.

TABLE III-1. PIES COAL TYPES

Description	Average Heat Content MMBTU/ton	Sulfur Content lbs/MMBTU
High Btu/High Sulfur	23.80	greater than 1.68
Medium Btu/High Sulfur	21.80	greater than 1.68
High/Btu/Medium Sulfur	23.80	0.67 to 1.68
Medium Btu/Medium Sulfur	21.80	0.67 to 1.68
Low Btu/Medium Sulfur	18.33	greater than 0.67
Very Low Btu/Medium Sulfur[1]	13.00	greater than 0.67
Very High Btu/Low Sulfur	27.00	less than 0.67
High Btu/Low Sulfur	23.80	less than 0.67
Medium Btu/Low Sulfur	21.80	less than 0.67
Low Btu/Low Sulfur	18.33	less than 0.67
Very Low Btu/Low Sulfur[1]	13.00	less than 0.67

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[1] These coal types are North Dakota lignites.

Coal is divided into three categories, dependent upon its Btu value: bituminous, sub-bituminous and lignite. Bituminous coal is a collection of the three highest Btu categories: very high, high and medium. Premium coal, which includes very high grade boiler fuel and all metallurgical coal, is a bituminous coal with very high Btu and low sulfur content. Sub-bituminous coal is the second lowest Btu coal; lignite is the lowest.

MINE TYPES

PIES coal mines are divided between existing mines (as of a specified date 1–1–76 in this case) and new mines (potential mine openings after the same specified date). These two mine categories are further subdivided between surface and deep mines. Surface mines are differentiated by mine size (annual production level) and the overburden ratio - the latter being the ratio between the cubic yards of topsoil and rock on top of the coal seam and the tons of coal within the seam. Deep mines are differentiated by mine size, seam thickness and seam depth. Deep mining, which requires the use of shafts to reach the seam, is the mining method required to recover the bulk of this country's coal reserves.[2]

Thirty-six surface mine types are considered in PIES. They represent various combinations of six mine sizes and seven overburden ratios. There are also 66 deep mine types, representing various combinations of five mine sizes, five seam thicknesses and four seam depths. In all, 102 coal mine types are considered in PIES (see Table III-2).

Production costs vary from one type of mine to another. Costs of production increase for surface mines as the overburden ratio increases, and for deep mines as the depth of the mine increases and the thickness of the coal seam decreases.

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[2] The Bureau of Mines estimates that U.S. reserves of coal lie in large part well below the surface and require deep mining methods for recovery. In Demonstrated Coal Reserve Base of the United States on January 1, 1974 prepared in the Division of Fossil Fuels - Mineral Supply (June, 1974).

TABLE III-2. SURFACE AND DEEP COAL MINES

SURFACE MINES

Mine Size	Overburden Ratio*						
(10^6 Tons/Year)	5:1	10:1	15:1	20:1	25:1	30:1	45:1
0.1	-	-	x	x	x	x	x
0.5	-	x	x	x	x	x	x
1.0	x	x	x	x	x	x	x
2.0	x	x	x	x	x	x	x
3.0	x	x	x	x	x	x	x
4.0	x	x	x	x	-	-	-

DEEP MINES

Mine Size	Seam Thickness					Seam Thickness				
(10^6 Tons/Year)	72"	60-71"	48-59"	36-47"	28-35"	72"	60-71"	48-59"	36-47"	28-35"
	Drift					Shaft - 400 Foot Depth				
0.1	-	x	x	x	x	x	x	x	x	x
0.5	-	x	x	x	x	x	x	x	x	x
1.0	-	x	x	x	-	x	x	x	x	-
2.0	-	-	x	-	-	x	x	x	-	-
3.0	-	-	-	-	-	x	-	-	-	-
	Shaft - 700 Foot Depth					Shaft - 1,000 Foot Depth				
0.1	x	x	x	x	x	x	x	x	x	x
0.5	x	x	x	x	x	x	x	x	x	x
1.0	x	x	x	x	-	x	x	x	x	-
2.0	x	x	x	-	-	x	x	x	-	-
3.0	x	-	-	-	-	x	-	-	-	-

---

*Cubic yards of overburden per ton of coal.
- indicates that no mine is considered with the indicated specifications.
x indicates that mine type is considered

NATIONAL COAL MODEL

The National Coal Model (NCM)[3] is designed to forecast coal production, consumption, and prices. It can be used to analyze coal-related energy policy issues and to study possible impacts of non-Governmental factors (e.g., factor price changes in coal and other energy fuels, capacity changes, and changes in utility demand). The NCM also provides a means of forecasting coal production, consumption and prices by region, coal type and target year.

Several changes have occurred within the NCM since the 1976 and 1977 documentations.[4] The allocation of resource has been adjusted to reflect marginal mining conditions in the various supply regions. Reclamation costs, severance taxes, and preparation charges (the cost for washing high and medium Btu coal), which were at one time calculated by the PIES coal preprocessor, are now included in the NCM. Preparation charges, assigned by the mine costing algorithm, are now dependent not only on coal type, as they were in previous years, but also on mine type and region.

Changes in cost include an adjustment reflecting losses from the preparation process, an addition to mine costs (varying by region and mine type) that takes into consideration the Black Lung Insurance Premium.

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[3] The National Coal Model: Description and Documentation, prepared for FEA by ICF Incorporated, Washington, D.C., October 1976.

[4] The Integrating Model of the Project Independence Evaluation System, FEA/N-761411 (Washington, D.C.: Federal Energy Administration, August 1976.);

The Integrating Model of the Project Independence Evaluation System (Washington, D.C.: Logistics Management Institute, December 1977); and The National Coal Model: Description and Documentation, prepared for FEA by ICF, Incorporated, Washington, D.C., October 1976.

The following subsections describe the correspondence between PIES coal regions and NCM regions and the sub-module of the NCM output file, which is used as input to the Integrating Model. Specifically, the NCM provides PIES with regional supply curves for each type of coal.

COAL SUPPLY REGIONS

The PIES coal supply regions are derived from the NCM supply regions, which are differentiated according to three conditions. First, each NCM region consists of only one state or portion of a state because of varying state mining laws and taxes. Second, the NCM regions have been chosen to easily allow their aggregation into 12 PIES coal supply regions. Third, the coal within a region is as homogeneous as possible. The resultant 30 NCM regions are listed in Table III-3. The 12 PIES coal supply regions appear in Figure III–1 and are also listed in Table III-3, identified with the corresponding NCM regions. Table III–4 gives the coal types available in each PIES coal supply region.

The PIES coal supply regions are based upon combinations of Bureau of Mines (BOM) mining districts. These districts were determined by the level of reserves by state, county, coal bed, and mining methods; the average physical and chemical characteristics of coal identified by the seam level (but not by mining method), and the patterns of existing mail/barge routes.

PIES COAL SUPPLY CURVES

Like PIES, the NCM has a number of sub-modules. One of these is the coal supply sub-module which generates the coal supply curves used by PIES. The supply module generates coal supply curves by utilizing a series of resource allocation and mine costing algorithms. Its output is a set of coal supply curves, which when aggregated into PIES coal supply regions by a subrouting creates a file specifically for use by the PIES coal preprocessor. This NCM becomes the PIES raw data tables. The supply curve information

TABLE III-3. SUPPLY REGION DEFINITIONS

PIES Regions	NCM Regions
Northern Appalachia	Pennsylvania (PA) Ohio (OH) Maryland (MD) West Virginia, north (NV)[1]
Central Appalachia	West Virginia, south (SV) Virginia (VA) Kentucky, east (EK) Tennessee (TN)
Southern Appalachia	Alabama (AL)
Midwest	Illinois (IL) Indiana (IN) Kentucky, west (WK)
Central West	Iowa (IA) Missouri (MO) Kansas (KN) Arkansas (AR) Oklahoma (OK)
Gulf	Texas (TX)
Eastern Northern Great Plains	North Dakota (ND) South Dakota (SD) Montana, east (EM)[2]
Western Northern Great Plains	Montana, west (MW) Wyoming (WY) Colorado, north (CN)
Rockies	Colorado, south (CS) Utah (UT)
Southwest	Arizona (AZ) New Mexico (NM)
Northwest	Washington (WA)
Alaska	Alaska (AK)

---

[1] Includes all of Nicholas County.

[2] Includes the following counties: Carter, Daniels, Fallon, McCone, Prairie, Richland, Roosevelt, Sheridan, Valley, and Widaux.

FIGURE III-1

PIES COAL REGIONS

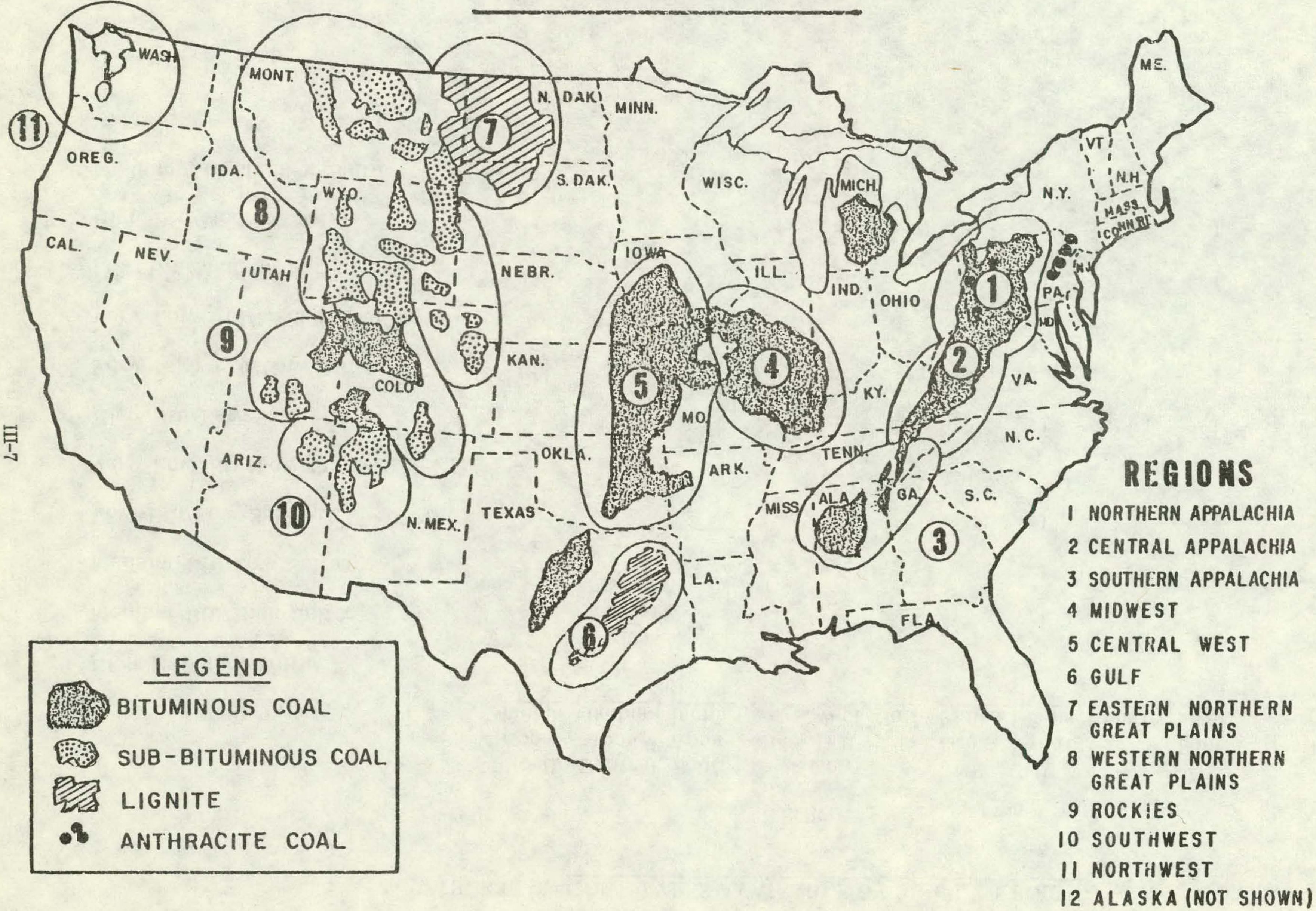


TABLE III-4. COAL TYPES AVAILABLE BY SUPPLY REGION

	REGION											
Coal Type	North Appalachia	Central Appalachia	South Appalachia	Midwest	Central West	Gulf	NE Great Plains	NW Great Plains	Rockies	Southwest	Northwest	Alaska
High Btu/High Sulfur	1	1		1	1							
Medium Btu/High Sulfur	1			1	1			1				
Medium Btu/Low Sulfur				1				1	1	1	1	
Low Btu/Low Sulfur								1			1	1
Very Low Btu/Low Sulfur							1					
High Btu/Low Sulfur	1	1	1		1			1	1	1	1	
Very High Btu/Low Sulfur	1	1	1		1				1	1		
Very Low Btu/Medium Sulfur						1	1					
Low Btu/Medium Sulfur					1			1	1	1	1	
High Btu/Medium Sulfur	1	1	1	1	1				1	1		
Medium Btu/Medium Sulfur	1			1				1	1	1		

for each of the 12 PIES coal regions and each target year (1985 and 1990), is contained in a raw data table. Each coal raw data table has five columns, showing:

- minimum acceptable selling price in dollars per ton, including all direct costs plus severance taxes, reclamation costs, and adjustments for Alaskan production where applicable
- maximum level of production in millions of tons per year for each step in the supply curve for each type of coal
- proportion of production from surface mines
- present value of the initial capital investment in millions of dollars per million tons of coal per year, or dollars per annual ton required between 1977 and the target year to open new mines
- present value of the deferred capital investment in dollars per ton per year required between 1977 and the target year to open new mines.

Table III-5 is a raw data table for the Northern Appalachia coal region and high Btu/high sulfur coal. The columns of the raw data tables are discussed in detail below. The rows are divided between new mines (to be opened and in operation by the target year specified) and existing mines (as of 1-1-78). Prices for new and existing mines are in ascending order, because as demand increases, increasingly more costly mines are operated.

The coal supply curves are step functions, giving combinations of price and production for each type of coal in each coal supply region. Each step of the coal supply curve has a production level attached to it - the length of the step. Figure III-2 is an example of a PIES coal supply curve. The production level is the maximum annual production that the BOM-demonstrated reserve base could sustain from that particular mine type and coal type for 20 years. Thus, each step gives the potential production level for each mine type/coal type combination.

The price associated with each step is the minimum acceptable selling price for the particular mine type and is based on engineering estimates of the costs to develop mines of different size, seam thickness and seam depth. This minimum acceptable selling price

TABLE III-5. SAMPLE RAW DATA TABLE: NORTHERN APPALACHIA COAL REGION

Coal Type: High Btu (23.8 MMBTU/TON)
High Sulfur (greater than 1.68 lbs/MMBTU)

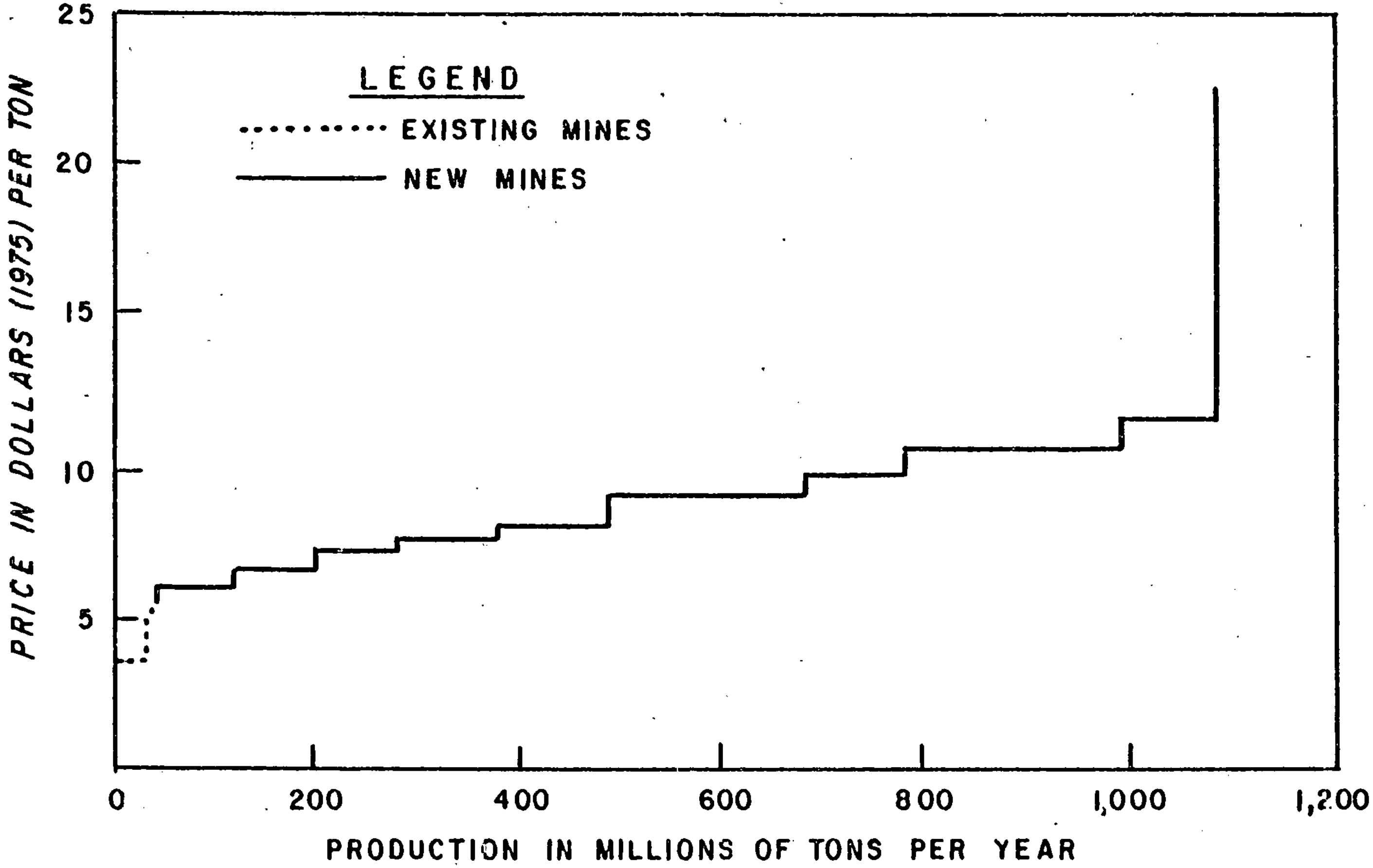
	Price Step (1975 $/Ton)	Production	Percent Surface	Initial Capital	Deferrable Capital
Existing Mines	8.77	1.329	0.960	0.	0.
	9.36	8.415	0.568	0.	0.
	10.51	17.314	0.096	0.	0.
	11.05	1.918	0.081	0.	0.
	11.53	27.354	0.290	0.	0.
	12.11	5.577	0.295	0.	0.
	12.67	7.622	0.484	0.	0.
	13.25	0.438	1.000	0.	0.
	13.89	0.438	1.000	0.	0.
New Mines	12.75	0.950	1.000	37.130	7.130
	14.53	4.275	1.000	44.568	8.581
	15.94	0.850	1.000	52.130	10.250
	16.47	4.750	1.000	53.550	10.430
	18.48	4.750	1.000	62.550	12.300
	20.04	4.000	0.	26.240	11.530
	20.96	10.000	0.	31.920	13.696
	21.43	15.360	0.	33.268	13.625
	22.01	10.160	0.	36.871	15.384
	22.52	27.550	0.172	43.819	14.959
	23.04	17.920	0.	36.645	14.345
	23.69	24.560	0.	39.845	15.197
	24.28	24.135	0.224	53.288	15.887
	24.81	18.105	0.037	46.379	15.898
	25.26	17.445	0.060	46.812	16.899
	25.91	26.160	0.	43.086	16.110
	26.61	36.985	0.347	62.125	17.451
	27.13	19.920	0.	53.505	17.016
	27.77	11.180	0.170	57.627	16.912
	28.20	7.940	0.144	58.457	17.671
	28.85	4.075	0.117	62.261	18.852
	29.41	7.570	0.176	77.777	17.367
	29.93	3.040	0.	63.510	17.260
	30.98	13.120	0.	70.917	16.498
	31.99	5.445	0.192	89.411	19.156
	32.51	7.870	0.024	84.352	16.937
	33.02	2.880	0.	65.590	18.130
	33.78	6.290	0.211	102.613	18.873
	34.04	1.520	0.	90.538	16.843
	34.52	2.320	0.	84.790	18.130
	35.42	1.120	0.	94.163	17.005
	35.75	4.240	0.	91.482	17.785
	36.98	1.120	0.	101.680	17.260
	37.48	1.840	0.	103.990	18.130
	41.03	1.085	0.263	131.560	24.353

FIGURE III-2

COAL SUPPLY CURVE:

WESTERN NORTHERN GREAT PLAINS REGION

(SUB-BITUMINOUS/LOW SULFUR COAL)



COAL TYPE:

SUB-BITUMINOUS, LOW SULFUR
15.00 – 19.99 MILLION BTU PER TON (AVG. 18.33)
0.00 – 0.67 POUNDS OF SULFUR PER MILLION BTU.

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ENERGY INFORMATION ADMINISTRATION
COAL ANALYSIS DIVISION

is the price at which a coal company would recover all of its costs (labor costs, severance taxes, and reclamation costs, for example) and earn a real (inflation-free) rate of return of 8 percent.[5] This price should not be confused with the equilibrium (market) price.

The minimum acceptable selling prices for the different mine types trace out a supply curve in order of increasing mine cost. Each existing coal company has entered the market when its minimum acceptable selling price was equal to the equilibrium price. The companies that were opened at a price lower than the current equilibrium price could economically sell their coal at any price up to but not exceeding the current price; but in general they would tend to sell at higher market clearing price. New market prices are found by solving the PIES or the NCM. Similarly, if the market price drops, companies with a minimum acceptable selling price above the current market price would not, in general, be able to sell coal and recover all of its costs and may eventually be forced out of the market. The market price, the price at the equilibrium of coal supply and demand, is the minimum acceptable selling price only for the last mine type developed.

In addition to price, each step also carries with it a specific capital requirement level. Levels of initial and deferred capital for new mines were calculated by applying an estimated inflation rate factor to the real cost of capital data, provided by TRW and BOM. The deferred capital is prorated over a 20-year mine life. The percent of deferred capital spent by each target year is shown in Table III-6.

TABLE III-6. PERCENT OF DEFERRED CAPITAL SPENT BY NEW MINES

Target Year	Percent of Deferred Capital
1985	25.0
1990	37.5

Capital associated with the operation of existing mines is provided as an exogenous input to the coal preprocessor.

---

[5] This definition assumes a constant 20 year price for the coal.

Surface and Deep Mines

The NCM also provides PIES with the percentage of a given coal production level found in surface mines for each coal type. This percentage is given by region for both new and existing mines. The PIES coal preprocessor determines the production split between deep and surface mines for use in the matrix generation and report writer using the formula:

Percentage Surface = 1 - Percentage Deep.

Table III-5 gives the percentage of surface mines at each price step and production level.

THE COAL PREPROCESSOR

The previous section discussed the coal supply curves provided to PIES by the NCM. These curves are not in a format consistent with the requirements of the PIES LP matrix. Thus, the supply curve data have to be processed before use in the LP. This processing is performed by the coal preprocessor. Three fundamental operations are performed: formatting the data, converting the data units, and performing calculations as required to produce additional data tables needed for PIES.

Formatting the Data

The NCM data are transformed into specific row and column formats according to strict naming conventions for use in the LP. This process is described in Volume V, Code Documentation.

Converting Data Units

NCM production figures for coal are converted from millions of tons per year (MMT/Y) to thousands of tons per calendar day (MT/CD). NCM costs and prices are converted to thousands of dollars per thousand tons (M$/MT). Capital data are changed from millions of dollars per million tons per year (MM$/MMT/Y) to millions of dollars per thousand tons per calendar day (MM$/MT/CD).

Calculations

One calculation that is performed is to set the retirement rate for older mining regions. A mine retirement rate of 3.5 percent per annum (starting in 1980) was assumed for the older mining regions of Appalachia and the Midwest (coal supply regions 1 through 4). This retirement rate, compounded annually, yields fractions of .84 for 1985 and .70 for 1990 production rates. In other words, in 1985, the production from mines in coal regions 1 through 4 that were producing in 1980 will yield only 84 percent of their 1980 production level. Similarly, the production from the mines producing in 1980 and still active in 1990 will be 70 percent of their 1980 production level.

The fractions giving the decrease in production for each target year are called backout factors and are given in Table III-7. These backout factors are reflected in the mines' production levels, as they cause a decrease in production over time from existing mines, and the eventual closing or retirement of a mine after 20 years of operation.

No retirements are assumed for new mines or for existing mines in any other regions; thus, their entries are 1 or 100 percent. These backout factors are reflected in the production levels of these mines and are included in the PIES coal supply curves.

TABLE III-7. BACKOUT FACTORS FOR 1985 AND 1990 COAL MINES

(Fraction of 1980 Production)

Coal Region	1985 New	1985 Existing	1990 New	1990 Existing
Northern Appalachia	1	0.84	1	0.70
Central Appalachia	1	0.84	1	0.70
Southern Appalachia	1	0.84	1	0.70
Midwest	1	0.84	1	0.70
Central West	1	1	1	1
Gulf	1	1	1	1
Eastern Northern Great Plains	1	1	1	1
Western Northern Great Plains	1	1	1	1
Rockies	1	1	1	1
Southwest	1	1	1	1
Northwest	1	1	1	1
Alaska	1	1	1	1

Besides creating the retirement rate table, the coal preprocessor creates Table III-4 which specifies coal types per region, and Table III-6, which shows the percent of deferred capital spent by new mines.

COAL DEMAND IN CONSUMPTION SECTORS

The various coal types are normalized to standard Btu coal in the utilities sector of PIES. Demand for coal in consuming (i.e., utility and demand) regions is expressed in terms of standard Btu coal containing 22.5 million Btu per ton (MMBTU/T). Coal is produced, however, in physical units of differing Btu values and transported between supply regions and consuming regions in physical units. To permit PIES to equilibrate coal supply and demand, coal supply levels are converted to five types of standard Btu coal. The conversion is made on a Btu basis. Thus, for example, 1.0 T of 23.8 MMBTU/T coal is considered equivalent to 1.058 T of standard coal in consuming regions. The conversion is modeled within the utilities preprocessor described in Chapter VII and is assumed to take place at the transshipment nodes in the coal transportation network. The five types of standard coal are defined as follows:

Category	Coal Type
1	All low sulfur coal and up to an equal amount of medium sulfur coal consumed in demand regions. Sub-bituminous and lignite areexcluded.
2	All high-grade low sulfur coal consumed in new coal-fired electric generating plants without scrubbers.
3	All low sulfur, sub-bituminous coal consumed in utility regions.
4	All lignite consumed in utility regions.
5	All coal other than categories 2, 3, and 4 coal consumed in utility regions and all coal consumed in synthetic regions.

Only standard type 1 coal is consumed in demand regions, the other four standard coal types are consumed in utility regions.

Environmental Protection Agency (EPA) regulations on utility plant emissions, and on purchase conditions, make it desirable that certain types of medium and high sulfur coal be mechanically cleaned or washed before being shipped. The cleaning and preparation costs are included in the NCM. There are also costs associated with scrubbing the flue gas resulting from the burning of high and medium sulfur coal in utilities.

The cost associated with flue gas desulfurization systems (commonly referred to as scrubbers) is handled by adding appropriate costs to plant capital costs, operations and maintenance costs, and plant efficiencies within the PIES utility sub-module.

The conversion of coal from physical units to standard Btu equivalent coal (category 5) for consumption in producing synthetic fuels is performed in the synthetics preprocessor and displayed in the synthetic fuels portion of the standard tables. Synthetic fuels are manufactured from high sulfur coal. The four modes of synthetic production permitted are: crude oil from coal, natural gas from coal, electricity from low Btu fuel gas (which in turn is produced from coal), and syngas from naphtha. Synthetics are discussed in chapter VIII.

IV. OIL SUPPLY

INTRODUCTION

Of the three major U.S. energy sources, coal, oil and natural gas, oil is the most versatile and widely used. The demand for oil has been increasing approximately 3 percent annually and is expected to continue at this rate over the next 15 years.

Figure IV-1 shows projected U.S. oil supplies from domestic and foreign sources through 1992.[1] Domestic supply from mature onshore areas in the lower 48 states is expected to decrease with time, while that from Alaskan and offshore areas is anticipated to increase, resulting in a nearly sustained domestic level. With increasing demand, the U.S. will rely more heavily on imported oil to satisfy its needs.

PIES forecasts U.S. oil supply from domestic and foreign sources. Domestic oil production is dependent on geological factors, resource assessment, and the economics of the operations. For situations where oil has been produced over a long period of time, supply is estimated from historical data with a formal modeling technique. For more recent production and for oil imports, less formal methods are used. These methods are applied through a satellite model to the PIES Integrating Model known as the Mid-Term Oil Supply Model.

The primary purpose of this chapter is to describe how oil is modeled in the PIES Integrating Model. Since much of the effort in developing the required supply data occurs within the Mid-Term Oil Supply Model, considerable discussion of that model is also presented. Scenario definition and supply conventions are important inputs for oil supply determination, and these topics are addressed as well.

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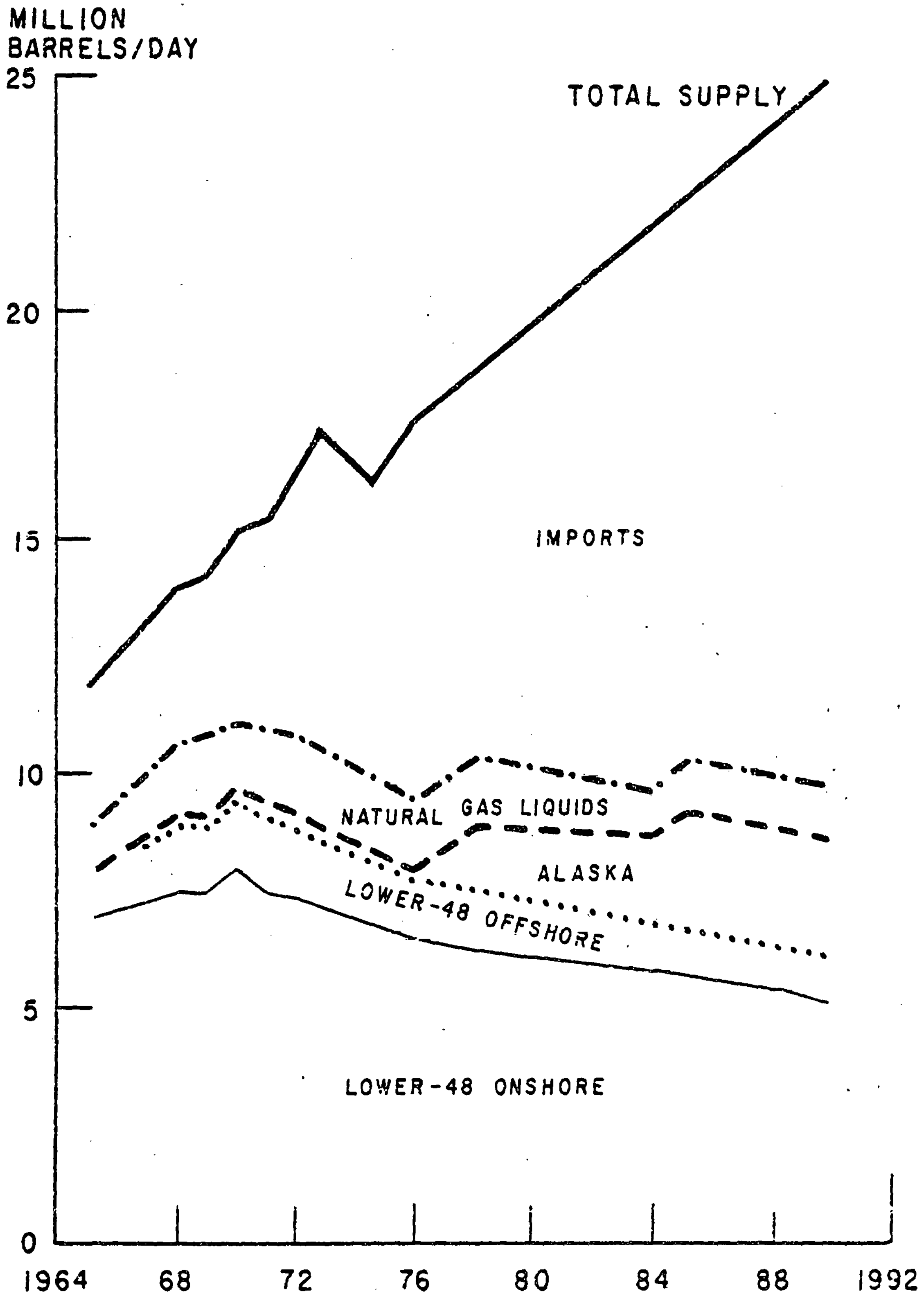
[1] A nominal case projection from: United States Department of Energy (DOE), Energy Information Administration (EIA), Annual Report to Congress (Annual Administrator's Report, AAR), 1977.

FIGURE IV-1

PROJECTED U.S. PETROLEUM LIQUIDS SUPPLY



SOURCE: AAR, PROJECTION SERIES C

There are many similarities between oil and natural gas supply, including composition, regionalization, production estimation, and model characteristics. Natural gas supply is discussed in Chapter V.

OIL SUPPLY ESTIMATES

Oil supply is estimated for domestic and foreign sources, and various oil types, source characteristics, and regions. As indicated in Figure IV-2, domestic oil production consists of crude oil and coproduct production. Coproducts can be either: associated natural gas, dissolved natural gas, gas liquids, or butane. Associated and dissolved natural gas are in a usable state at the oil wellhead and are distributed directly to natural gas users. For the purpose of the PIES Integrating Model, these coproducts are treated as one energy material, associated natural gas. The classification of associated natural gas as interstate and intrastate gas is addressed later in this chapter and in chapter V. Gas liquids and butane are coproducts that must be processed by refineries prior to final use and are converted into gasoline and liquid gas petroleum products, respectively. The refinery process is discussed in Chapter VI.

Imported oil supplies include crude oil and the following refined petroleum products: gasoline, kerosene based jet fuel, distillate, residual, liquefied petroleum gas (LPG), naphtha, and other refined products.

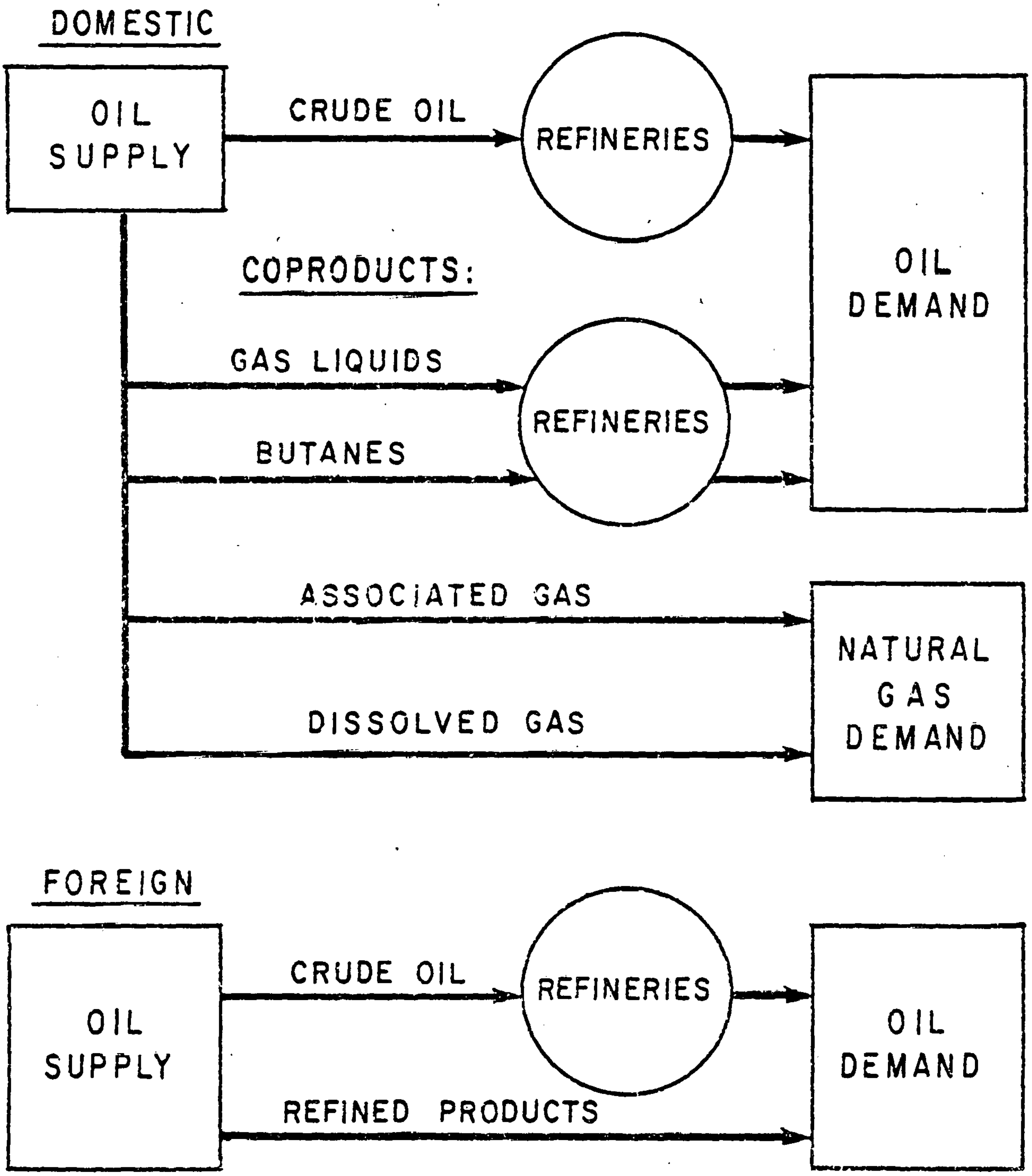
Oil supply may also be characterized by source. Oil source types are: traditional, nontraditional, imports, and synthetics.

There are traditional and nontraditional sources of domestic oil. The distinction between them is governed primarily by the length of time the production facilities have been in existence and thus defines the extent to which data are available for estimating production. Traditional sources are defined as those having an historical basis upon which oil production can be determined; they include areas of the lower 48 states and

FIGURE IV-2

OIL SUPPLY

FROM DOMESTIC AND FOREIGN SOURCES



most of the Alaskan Outer Continental Shelf (OCS). Conversely, nontraditional sources have little historical basis for determining oil supply; these areas include Alaskan military and naval reserves, heavy hydrocarbon, and tar sand regions.

Oil imports are basic to the U.S. energy system and to the PIES Integrating Model and are handled as a separate source. Synthetics are also defined separately as a source of oil supply (see Chapter VIII).

The regionalization of domestic oil supply in PIES is based upon the National Petroleum Council (NPC) regions.[2] These include the North Slope and South Alaskan areas; Atlantic, Pacific, and Gulf of Mexico offshore areas; and the remaining lower 48 states onshore areas. As indicated in Table IV-1 and illustrated by comparing Figures IV-3 and IV-4, oil supply Region 10 is an aggregate of the Michigan Basin, Eastern Interior, and Appalachian NPC regions. In addition, NPC Region 1, Alaska, is divided into North Slope and South Alaska oil supply regions for PIES. For all other regions, there is a one-to-one correspondence between PIES and NPC oil regions.

Special cases of domestic regionalization are modeled in PIES for nontraditional sources. In addition, regions are defined for the coastline of entry to the U.S. and for Canadian sources. Further, imported petroleum products are permitted from one region, "Foreign Other."

Figure IV-5 depicts the general methods for determining oil supply for the traditional, nontraditional and import source types as described above. A formalized modeling technique is used for traditional sources, since projected supply may be determined from historical data. For nontraditional sources and imports, such data are generally not available, and other estimation techniques must be used.

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[2] National Petroleum Council; Future Petroleum Provinces of the United States; July 1970.

TABLE IV-1. PIES OIL SUPPLY AND NPC REGIONS

Oil Region Name	Region Number	
	NPC	Oil
South Alaska*	1	1
Pacific Coast	2	2
Pacific Ocean	2A	3
W. Rocky Mtns.	3	4
E. Rocky Mtns.	4	5
W. Tex. & E. N. Mex.	5	6
W. Gulf Basin	6	7
Gulf of Mexico	6A	8
Midcontinent	7	9
Mi. Basin, Int.,** Appalachians	8-9-10	10
Eastern Gulf and Atlantic Coast	11	11
Atlantic Ocean	11A	12
Alaskan North Slope	1	13

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*Includes Hawaii
**Michigan Basin, Eastern Interior

Traditional Sources

Oil supply estimates for traditional domestic sources, i.e., the lower 48 states and most of the Alaskan OCS are derived from the Mid-Term Oil Supply Model. The model determines supply curves (prices and quantities) for crude oil and coproducts originating in the 13-oil supply regions. For traditional sources there are 12-regions, since the Alaskan North Slope is defined for nontraditional sources only. The supply curves are generated simultaneously for all years from 1977 to 1991.

FIGURE IV-3

OIL SUPPLY REGIONS

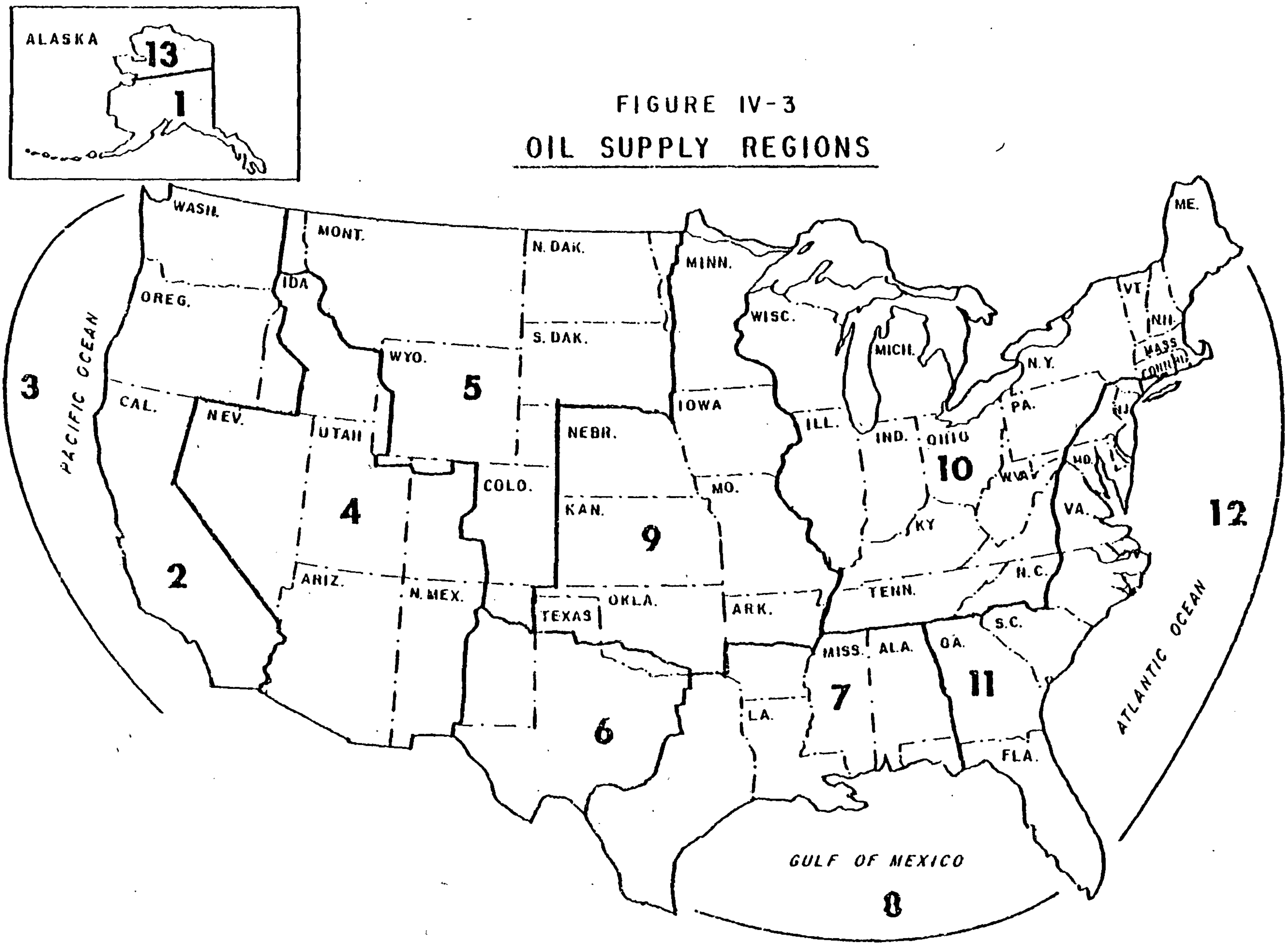
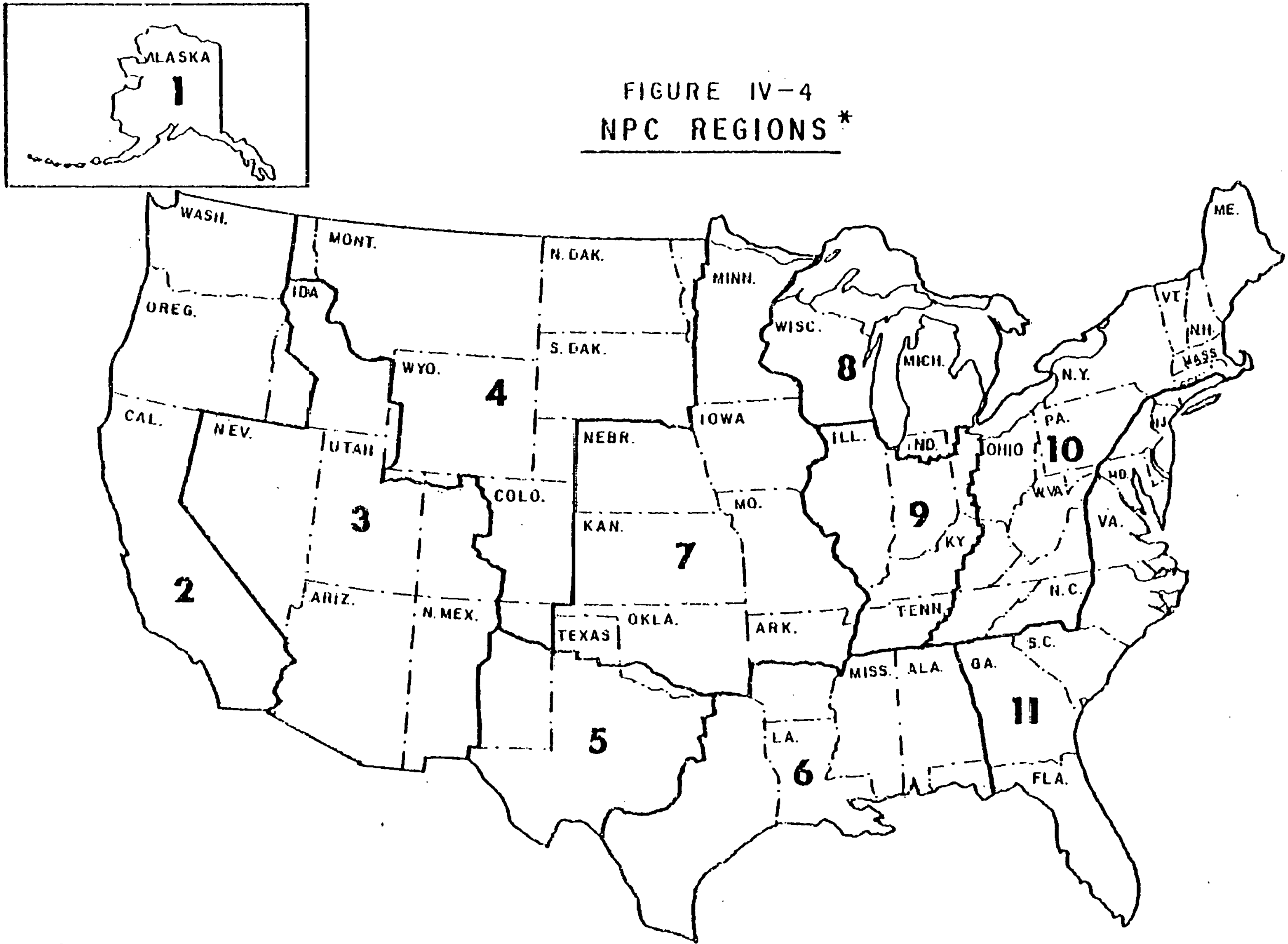


FIGURE IV-4

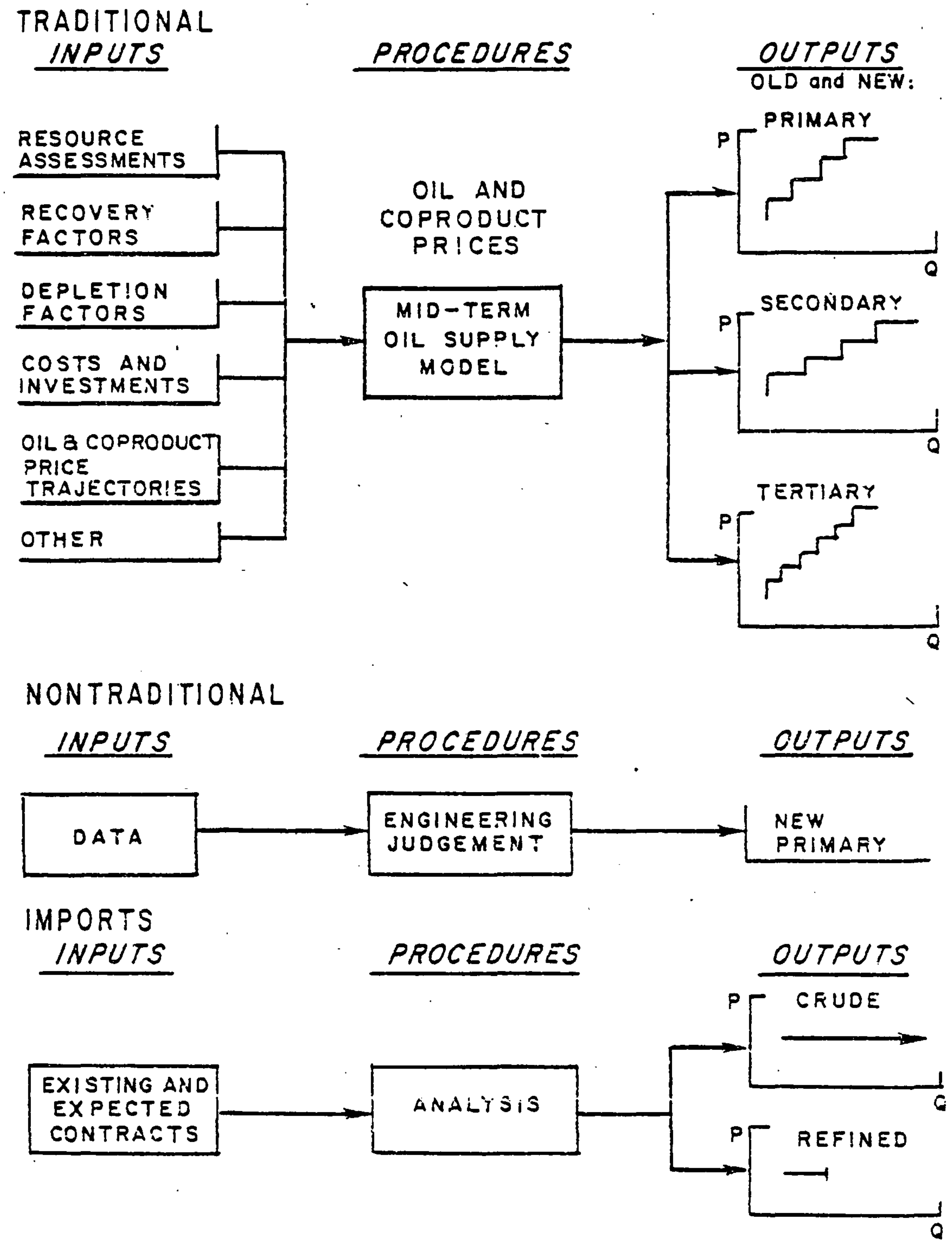
NPC REGIONS*



* REGIONAL BOUNDARIES (Reg.1-ALASKA and HAWAII; Reg.2. PACIFIC COAST STATES; Reg.3-WESTERN ROCKY MOUNTAINS; Reg.4-EASTERN ROCKY MOUNTAINS; Reg.5-WEST TEXAS and EASTERN NEW MEXICO; Reg.6-WESTERN GULF BASIN; Reg.7-MIDCONTINENT; Reg.8-MICHIGAN BASIN; Reg.9-EASTERN INTERIOR; Reg.10-APPALACHIANS; Reg.11-EASTERN GULF and ATLANTIC COAST.)

FIGURE IV-5

METHODS FOR DETERMINING OIL SUPPLY FROM TRADITIONAL, NONTRADITIONAL, AND IMPORT SOURCES



The major inputs to the Mid-Term Oil Supply Model are:

- resource assessments: These data consist of estimates of existing oil-in-place, reserve levels, and estimates of future reserves potentially available from both known and newly discovered fields.
- recovery factors: These regional factors are based on historical analysis and estimate the percentage of oil-in-place found that will consequently be produced. There are, in fact, six recovery factors for each region, one for each combination of "vintage" (new and old) and production type (primary, secondary, and tertiary).
- depletion fractions: These regional factors are based on 1974 production history for onshore regions and 1976 environmental impact statements for offshore regions, and pertain to the rate at which crude oil is produced from reserves. These factors provide for a systematic dwindling of existing reserves, which have to be replaced by new discoveries in order to maintain production levels.
- costs: Costs are of two types: drilling costs and other investments necessary to find oil and convert it to proved reserves, and operating costs necessary to produce the oil from reserves, once proved. These cost factors have been estimated from historical analyses and engineering judgment about cost escalation due to, for instance, unexpectedly deep wells.[3]

"Old" and "new" vintage describes whether a well was drilled before or after January 1, 1977. Primary, secondary, and tertiary production types are recovery techniques for crude oil. Primary production uses recovery techniques in which natural pressure facilitates the surfacing of crude oil from the well. Secondary production requires water to be pumped into the well to displace the oil, and tertiary production is a general classification for enhanced recovery techniques, such as the use of chemicals to dissolve oil from sandstone to increase yields. The inputs to the Mid-Term Oil Supply Model vary according to PIES scenarios.

These four major inputs are processed by the Mid-Term Oil Supply Model to determine oil supply curves, i.e., quantity produced as a function of price. In reality, there are threshold levels of quantity that can be economically produced at a specific level. Due to this consideration and the availability of historical oil supply data for the

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[3] DOE, EIA; Project Independence Evaluation System (PIES) Documentation, Vol. III, PIES Oil and Gas Supply Curves; September 1976.

U.S., these oil supply curves are actually determined as step functions. In addition to supply curves, the Mid-Term Oil Supply Model generates information on investment and drilling requirements.

Price levels of the step function are determined based on the actual market price of oil for the most recent updated year. Specifically, prices for forecast years are calculated by factoring the prior year's price by a constant amount, beginning with the initial market price for 1977. These factors either increase or decrease by 1.0, 2.0, 3.0 or 5.0 percent, or remain the same (0.0 percent) for a total of nine variations, thus defining nine price level steps for the supply curve. These changes in expected market price with time are referred to as price trajectories and represent assumptions about future price regulations. Sample data for 1977 through 1991 are given in Tables IV-2 and IV-3 in constant 1975 dollars for crude oil and gas liquids, and associated and dissolved gas, respectively.[4]

The Mid-Term Oil Supply Model develops supply curves and investment information for all years from 1977 to 1991 with the price trajectories described above. The model is run once for each price level step and generates the history of oil production and investment information that would result if wellhead prices were to follow the price trajectories for the given step. The general procedure for determining this history of information at each price level is as follows:[5]

- The expected oil price and drilling rig supply parameters are combined to determine total domestic oil drilling over time and its allocation among 12 traditional oil regions.
- Finding rates, derived from USGS resource assessments, are then combined with drilling rates to determine the amount of oil-in-place found by the drilling process.

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[4] DOE/EIA; Oil and Gas Supply Data Inputs to the PIES Integrating Model, 1978 Annual Administrator's Report; 1978.

[5] DOE/EIA; PIES Oil and Gas Supply Curves.

- Regional recovery rates—one for each of three recovery methods in old and new fields—are combined with various lead time factors to allocate successive portions of this oil-in-place into proved reserves.
- As each portion of the oil-in-place is proved, the minimum acceptable price at which it becomes economically attractive is calculated. The calculation consists of a discounted cash flow analysis of each reserve addition. This calculation considers the investment required to prove the oil, the operating costs subsequently required to produce and sell it (e.g., royalties), and the time profile over which it will be produced and sold.

- Depletion fractions—or decline rates—are used to calculate future annual production resulting from proved reserves added each year at each minimum-acceptable price.

When the oil production and investment history have been generated by this procedure, oil supply curves for 1985 and 1990 are developed by accumulating production and investment at successively higher price level steps individually for the two years.

As indicated, the output of the Mid-Term Oil Supply Model consists of a collection of supply curves (wellhead price and quantity produced) and concomitant investment information. Domestic supply data are classified according to: oil supply region, forecast year (1985 or 1990), oil field vintage (old or new), production type (primary, secondary, tertiary).

Each price step contains the following information: crude oil production, coproducts production (associated and dissolved natural gas, gas liquids, butane), capital investment, and drilling requirements. These data are described in detail in the subsequent sections.

Nontraditional Sources

Nontraditional sources of crude oil supply include the following:

- Alaskan North Slope
- Prudhoe Bay
- Beaufort Sea
- North Slope Other
- Military Reserve
- Naval Petroleum
- Naval Petroleum Reserve A (Alaskan North Slope Region)
- Naval Petroleum Reserve Number 1, Elk Hill (Pacific Coast Region)
- Heavy Hydrocarbons
- Tar Sands Synthetic Crude.

TABLE IV-2. PRICE TRAJECTORIES FOR OIL AND GAS LIQUIDS ($/B)

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
STEP 1	12.62	11.99	11.39	10.82	10.28	9.77	9.28	8.81	8.37	8.37	8.37	8.37	8.37	8.37	8.37
STEP 2	12.62	12.24	11.87	11.52	11.17	10.84	10.51	10.20	9.89	9.89	9.89	9.89	9.89	9.89	9.89
STEP 3	12.62	12.37	12.12	11.88	11.64	11.41	11.18	10.96	10.74	10.74	10.74	10.74	10.74	10.74	10.74
STEP 4	12.62	12.49	12.37	12.25	12.12	12.00	11.88	11.76	11.65	11.65	11.65	11.65	11.65	11.65	11.65
STEP 5	12.62	12.62	12.62	12.62	12.62	12.62	12.62	12.62	12.62	12.62	12.62	12.62	12.62	12.62	12.62
STEP 6	12.62	12.75	12.87	13.00	13.13	13.26	13.40	13.53	13.67	13.67	13.67	13.67	13.67	13.67	13.67
STEP 7	12.62	12.87	13.13	13.39	13.66	13.93	14.21	14.50	14.79	14.79	14.79	14.79	14.79	14.79	14.79
STEP 8	12.62	13.00	13.39	13.79	14.20	14.63	15.07	15.52	15.99	15.99	15.99	15.99	15.99	15.99	15.99
STEP 9	12.62	13.25	13.91	14.61	15.34	16.11	16.91	17.76	18.65	18.65	18.65	18.65	18.65	18.65	18.65

TABLE IV-3. PRICE TRAJECTORIES FOR ASSOCIATED AND DISSOLVED GAS ($/MCF)

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
STEP 1	2.17	2.06	1.96	1.86	1.77	1.68	1.60	1.52	1.44	1.44	1.44	1.44	1.44	1.44	1.44
STEP 2	2.17	2.11	2.04	1.98	1.92	1.86	1.81	1.75	1.70	1.70	1.70	1.70	1.70	1.70	1.70
STEP 3	2.17	2.13	2.08	2.04	2.00	1.96	1.92	1.88	1.85	1.85	1.85	1.85	1.85	1.85	1.85
STEP 4	2.17	2.15	2.13	2.11	2.08	2.06	2.04	2.02	2.00	2.00	2.00	2.00	2.00	2.00	2.00
STEP 5	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17
STEP 6	2.17	2.19	2.21	2.24	2.26	2.28	2.30	2.33	2.35	2.35	2.35	2.35	2.35	2.35	2.35
STEP 7	2.17	2.21	2.26	2.30	2.35	2.40	2.44	2.49	2.54	2.54	2.54	2.54	2.54	2.54	2.54
STEP 8	2.17	2.24	2.30	2.37	2.44	2.52	2.59	2.67	2.75	2.75	2.75	2.75	2.75	2.75	2.75
STEP 9	2.17	2.28	2.39	2.51	2.64	2.77	2.91	3.05	3.21	3.21	3.21	3.21	3.21	3.21	3.21

As indicated, the output of the Mid-Term Oil Supply Model consists of a collection

Nontraditional oil supply estimates are generally made from expert engineering judgment. In the present form of PIES, only Alaskan North Slope oil and some naval petroleum and heavy hydrocarbons are estimated. Naval petroleum supply is estimated at present only for the Elk Hill area (Naval Petroleum Reserve No. 1). Heavy hydrocarbon supply is estimated only for that oil generated in the East Rocky Mountains region and is implicitly included in the supply curve information for that region.

Alaskan oil supply curves for the various nontraditional sources are developed for two production cases. In one case, it is assumed that coproducts of oil, i.e., associated and dissolved natural gas, are produced at the well and supplied to demand regions, whereas in the other case, the natural gas is produced but reinjected into the well for future recovery.

Imports

As indicated in Figure IV-5, the crude oil import estimate does not really determine a supply curve, since only one price is determined. This price, referred to as the world oil price for crude, is estimated at around $13.00 per barrel ($13.00/B) in 1975 dollars, with variations dependent primarily on transportation costs. Thus, PIES allows for unlimited crude oil to be imported at the world oil price if demand cannot be met by domestic supply. From this perspective, PIES is a procedure for calculating the deficiency of supply meeting demand for energy materials in the U.S.; oil imports are used to adjust for this deficiency. Thus, the world oil price of crude oil is a key parameter of PIES scenarios.

PIES models crude imports by bundles consisting of a fixed mix of imported crudes from various countries. Each port of entry has its own specific bundle. There are four points of entry: Landed East Coast, Landed Gulf Coast, Landed West Coast, and Canada.

Imported refined petroleum includes gasoline, distillate, residual fuel oil, kerosene based jet fuel, liquefied petroleum gases, naphtha, and other refined products. In all cases, the quantities of those imports are bounded. The price of imported refined petroleum is linked to the crude oil price through constant additive markups. Imported refined petroleum has one source in PIES, "Foreign Other."

It is important to note that the world oil supply price level is tied to domestic oil price through an "entitlements program" (discussed later in this chapter). This has the effect of regulating domestic oil to one price level and, therefore, reducing the domestic supply curves to a point estimate.

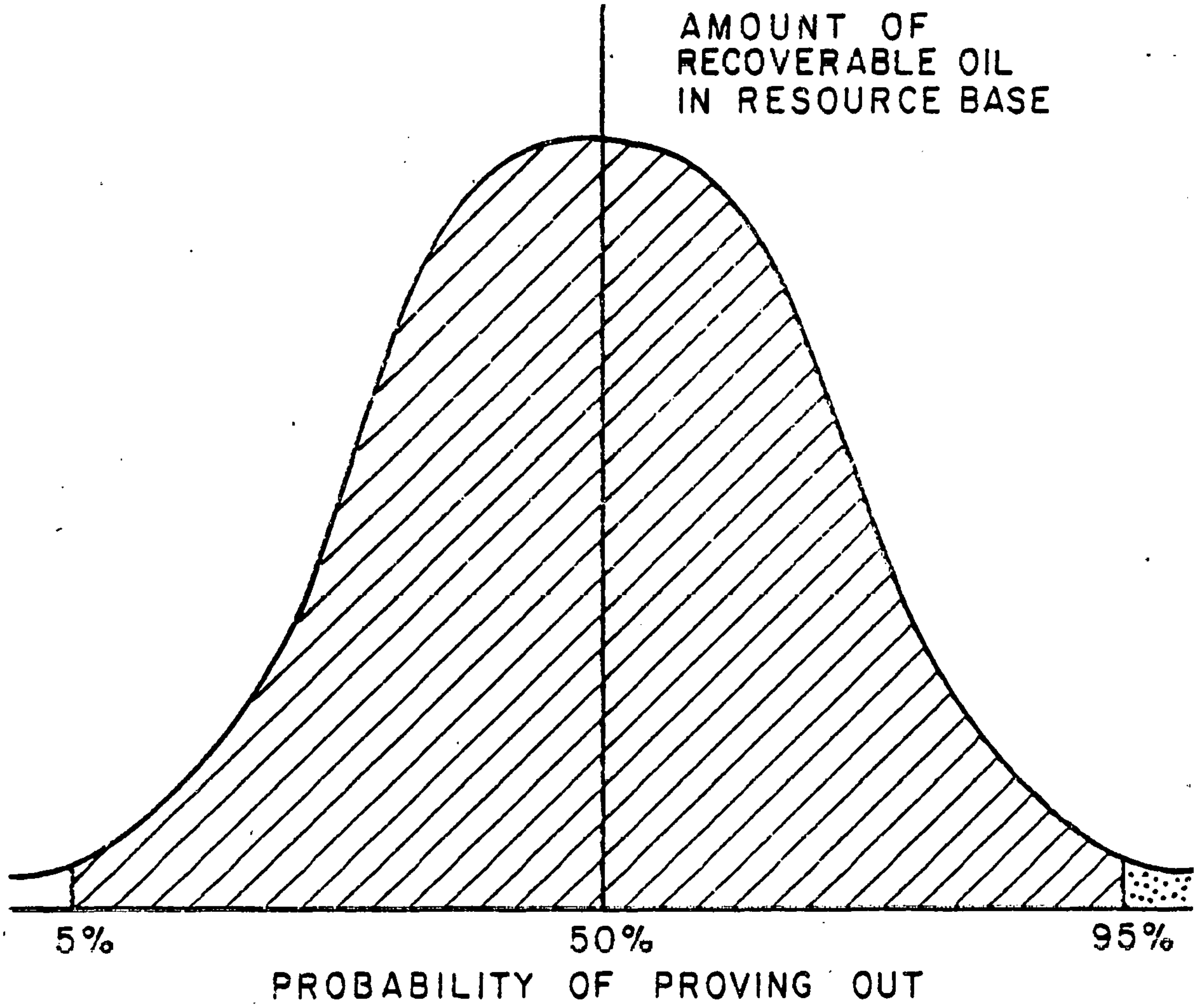
OIL SUPPLY CONVENTIONS AND SCENARIOS

Described in this section are scenario definitions and supply conventions for oil. The scenarios defined here apply to gas supply as well as oil; for a detailed discussion of gas supply, refer to chapter V. These scenarios are taken from the 1978 Annual Administrator's Report (AAR) and are explained in detail in volume VI of this documentation series.

The future domestic oil supply outlook is typically estimated for a range of geological assessments and for various pricing policies. In the 1978 AAR, this range of geological assessments is described in terms of three supply conventions: high geology, medium geology, and low geology. The medium geology convention is the reference case. This convention is estimated by the USGS as corresponding to a 50 percent chance of domestic oil resources proving out higher or lower. The high geology convention represents the conditions where there is at least a 5 percent probability of these reserves proving out in each NPC Region. That is, all but the least likely resources will be productive. Conversely, the low geology convention reflects the conditions where there is at least a 95 percent probability of proving out, or, in other words, a low estimate including only the most likely resources considered to produce crude oil. The chance of proving out for the high and low geology conventions is illustrated by the dashed and dotted areas in the sample probability distribution, Figure IV-6. Exceptions to the above conventions occur in the Naval Petroleum Reserve No. 1 and Alaskan regions.

FIGURE IV-6

ILLUSTRATIVE DISTRIBUTION OF AMOUNT OF RECOVERABLE OIL IN RESOURCE BASE



The development of Naval Petroleum Reserve No. 1 (Elk Hills) occurs under all oil supply conventions. Production is 175 thousand barrels per day (MB/D) in 1985, and 150 MB/D in 1990. PIES represents supply possibilities for Alaskan oil development in detail. For the 1985 reference convention, production from existing reserves in the Prudhoe Bay field is 1,600 MB/D. Production from the Beaufort Sea and other North Slope areas adjacent to Prudhoe Bay is 832 MB/D and 316 MB/D from southern Alaska including the Gulf of Alaska and Lower Cook Inlet. Beyond 1985, additional production increases in northern and southern Alaska are expected. Constraints on the movement of Alaskan oil are discussed in Chapter IX.

Table IV-4 presents the above supply conventions together with world oil pricing policies to produce supply scenarios based on the 1978 AAR. The supply scenarios generally follow the characteristics of the supply conventions. The reference level of the world price of crude oil, a key parameter, is $13.00/B (in 1975 dollars) for the high, mid-range, and low supply scenarios. The high oil price scenario reflects increases in the reference oil price of 5 percent per year between the forecast years 1980 and 1990.

TABLE IV-4. OIL SUPPLY SCENARIOS

Supply and Pricing Information

Scenario Name	Supply Convention	World Oil Price
High Supply	High Geology	Reference
Mid-Range (Reference)	Median Geology	Reference
Low Supply	Low Geology	Reference
High Oil Price	Median Geology	5%/Yr. Over Reference Between 1980 and 1990

THE OIL SUBMODEL

The oil preprocessor converts oil supply raw data into readily usable information for the LP matrix. The oil submodel receives oil supply curves from either the Mid-Term Oil Supply Model or engineering judgment and puts the data into standard table format.

The oil data are presented according to the various oil supply sources (traditional, non-traditional, and imports). Domestic supply data are categorized by: forecast year, oil supply region, oil field vintage, and production type. These classifications apply throughout the oil sector, although they may not always be explicitly stated in the following discussion.

Traditional Sources

Supply curves developed by the Mid-Term Oil Supply Model for traditional sources, i.e., the lower 48 states and most of the Alaskan OCS, contain information on production level, composite output price, capital investment, and drilling requirements.

The maximum level of crude oil production, along with the minimum acceptable price (i.e., supply curve), is available for each oil supply region. An important function of the oil submodel is to divide this aggregate, regional oil production among domestic crude oil types. The fraction of various crude oil types produced in each oil supply region is given in Table IV-5.

Coproduct supply curves are also input to the submodel. For associated and dissolved natural gas, the data received are reported in billions of cubic feet per year (BCF/Y). Since standard units for the PIES Integrating Model are in million cubic feet per day (MMCF/D), the submodel converts the data to standard units as follows:

$$\frac{\text{BCF}}{\text{Y}} \times \frac{10^3\text{MMCF}}{\text{BCF}} \times \frac{\text{Y}}{365.25\text{D}} = 2.74\ \frac{\text{MMCF}}{\text{D}}$$

Coproducts of gas liquids and butane are received in the standard units of MB/D.

TABLE IV-5. FRACTION OF CRUDE OIL TYPES BY OIL SUPPLY REGION OR SOURCE
(Percentages)

Oil Supply Region or Source	Type of Crude Oil															
	Alaskan So. Brooks Range	West Coast Light	West Coast Heavy	Pacific Offshore	Wyoming Mix	West Texas Mix	Heavy Crude PADD3	Louisiana Onshore	Texas Gulf	East Texas Gulf	Louisiana Offshore	Oklahoma Mix	Indigenous I1	Indigenous I2	Alaskan North Slope	Naval Petroleum
South Alaska	1.00															
Pacific Coast (Ex. Elk Hills)		.39	.61													
Pacific Ocean				1.00												
W. Rocky Mtns.					.80	.20										
E. Rocky Mtns.					.86		.14									
W. Texas & E. N. Mexico						1.00										
W. Gulf Basin						.02		.48	.40	.10						
Gulf of Mexico											1.00					
Midcontenent						.07						.93				
Mi. Basin, E. Int., Ap.*													.09	.91		
Atlantic Coast													1.00			
Atlantic Ocean													1.00			
North Slope															1.00	
Elk Hills																1.00

*Michigan Basin, Eastern Interior, Appalachians

In addition, the submodel divides associated natural gas between interstate and intrastate supply. This division follows the procedure illustrated in Figure V-6 in Chapter V and is summarized as follows:

- Natural gas from old oil fields is divided between interstate and intrastate natural gas supply, according to historical shares of each oil supply region.
- Natural gas from onshore oil fields is treated as intrastate natural gas supply.
- Natural gas from new offshore fields, oil supply regions of the Pacific Ocean, Gulf of Mexico, and Atlantic Ocean, is treated as interstate natural gas supply.
- Natural gas from oil fields of South and North Alaska is treated as interstate natural gas supply.

The historical shares used to divide associated natural gas obtained from old oil fields between interstate and intrastate markets are given in Table IV-6. This division can be revised by the equilibrating mechanism, which can shift some gas designated as intrastate into the interstate market to keep the intrastate price from falling below the interstate price (see Chapter V).

TABLE IV-6. PROPORTIONS OF INTERSTATE AND INTRASTATE NATURAL GAS COPRODUCTS

Natural Gas Type	South Alaska	Pacific Coast	Pacific Ocean	W. Rocky Mtns.	E. Rocky Mtns.	W. Tex. & E. N. Mex.	W. Gulf Basin
Interstate	1.00		1.00	.6859	.5586	.4399	.5029
Intrastate		1.00		.3141	.4414	.5601	.4971

	Gulf of Mexico	Midcontinent	Mi. Bas., Int. Ap.*	Atlantic Coast	Atlantic Ocean	North Alaska
Interstate	1.00	.5217	.4047	.0869	1.00	1.00
Intrastate		.4783	.5953	.9131		

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*Michigan Basin, Eastern Interior, Appalachians

A sample output of oil supply curves from the PIES oil submodel for the mid-range (reference) scenario and 1985 forecast year is given in Table IV-7.[6] Indicated in this table are levels of crude oil and coproduct production and price step data for traditional source oil supply regions, oil field vintages, and production types. Note, however, there is considerable other information included with the table, which is discussed subsequently.

As discussed, oil supply curves give the levels of production for crude oil and coproducts at different minimum acceptable selling prices for oil. These prices are not used in the PIES Integrating Model, since it sees the increment in production from one step to the next as a bundle of commodities that it must either produce or not produce together. Thus, a single composite output price, called the bundle price, is assigned to each step. By definition, the bundle price at each step is the ratio of the total value of the materials in the bundle for the step including crude oil and coproducts, to the quantity of crude oil for that step and is calculated as follows:

$$
\begin{aligned}
&\text{Bundle Price} = \\
&\qquad \Big[(\text{Quantity of Crude Oil}) \bullet (\text{Price of Crude Oil}) \\
&\quad + (\text{Quantity of Associated and Dissolved Natural Gas}) \bullet (\text{Price of Associated} \\
&\qquad \text{and Dissolved Natural Gas}) \; (\text{Quantity of Gas Liquids}) \bullet (\text{Price of Gas Liquids}) \\
&\quad + (\text{Quantity of Butane}) \bullet (\text{Price of Butane})\Big] / \Big[\text{Quantity of Crude Oil}\Big]
\end{aligned}
$$

The price steps for crude oil, gas liquids, and butane, and for associated and dissolved natural gas were given in Tables IV-2 and IV-3, respectively.

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[6] DOE/EIA, *Oil and Gas Supply Data Inputs*.

TABLE IV-7. OIL SUPPLY CURVES FOR 1985

	PRICE STEP	CRUDE OIL MB/D	INTERSTATE GAS (MMCF/D)	INTRASTATE GAS (MMCF/D)	BUTANE (MB/D)	GAS LIQUIDS (MB/D)	BUNDLE PRICE ($/B OIL)	CAPITAL (MMS)	FOOTAGE DRILLED (MMFT)
NPC Region-South Alaska									
New Primary	5	236.80	98.27				**	1284.00	5.99
New Secondary	5	16.70	6.84				**	47.00	
Old Primary	5	47.50	19.71				**		
Old Secondary	5	14.00	6.30				**	73.00	
NPC Region-Pacific Coast									
Excluding Elk's Hill									
New Primary	5	198.30		69.52	1.69	.79	**	2926.00	124.00
New Secondary	5	52.70		18.61	.40	.19	**	75.00	
Old Primary	5	335.10		131.96	3.08	1.57	**		
Old Secondary	5	29.50		10.40	.20	.10	**	71.00	
Old Tertiary	5	40.70					**	350.00	
Elk's Hill									
New Primary		175.00					**	728.44	
NPC Region-North Slope									
Prudhoe Bay									
New Primary		1600.00	2755.84				**	6976.00	6256.00
Beaufort Sea									
New Primary		112.00	79.24				**	1072.96	779.52
North Slope Other									
New Primary		720.00	332.64				**	5745.60	5018.40

Source AAR

Table IV-7 shows a single price step supply function representing well-head prices controlled by regulation and by import prices.

As indicated in Figure IV-5, capital investment requirements are required inputs to the Mid-Term Oil Supply Model which determines supply curves. Capital investment requirements in the Mid-Term Oil Supply Model are in units of millions of dollars (MM$) and are cumulative from 1977 to one year prior to the target year (1984 or 1989).

In Table IV-7, capital investments are in units of $MM. To obtain the standard units for the PIES Integrating Model, i.e., $M per thousand barrels per day ($M/MB/D), capital investment in $M is divided by the crude oil production level (MB/D) at the minimum acceptable supply curve price (not bundle price).

Another quantity input to the oil supply curve determination and to the Integrating Model is the drilling requirements for oil production. Drilling requirements are cumulative in the same manner as capital investment requirements. Table IV-7 shows that drilling requirements from the Mid-Term Oil Supply Model are in units of million feet drilled (MMFT). However, since standard units for the Integrating Model are in MMFT/MB/D, the quantity, MMFT, is divided by the level of crude oil produced (MB/D) to obtain standard units of MMFT/MB/D.

Nontraditional Sources

Oil supply data for nontraditional sources result from engineering judgments. The data are similar in content and format to the data for traditional sources. Table IV-7 includes data on nontraditional oil sources for the Alaskan North Slope and Elk's Hill regions.

Imports

Oil production estimates for 22 different types of foreign crude and for the following points of entry: East Coast, Gulf Coast, West Coast, and Canada are input

TABLE IV-8. CRUDE OIL IMPORT BUNDLES FOR 1985 (1978 DOLLARS)

	Canada	Landed East Coast	Landed Gulf Coast	Landed West Coast
Landed Price ($/B)	15.32	15.32	15.01	15.49
Crude Type	Percentage in Bundle			
Libya		6.40	17.80	
Norway		3.30	3.10	
United Kingdom		10.80	1.20	
Trinidad		.70	1.30	
Bolivia/Peru			.10	
Egypt/Syria/Bahrain		2.50	2.40	
Angola/Congo/Zaire		2.30	.40	
South Asia Mix			.40	17.20
Venezuela		7.50	.70	
Nigeria/Gabon		25.10	7.70	
Indonesia		2.30	1.10	72.00
Canada	100.00			
Ecuador		.20	.70	
Mexico		1.20	7.80	
Algeria		3.40	2.60	
Iran Light		4.00	12.40	
Iran Heaby		1.00	1.20	
Saudia Arabia Light		22.90	24.90	10.80
Saudi Arabia Heavy		3.50	1.90	
Kuwait		.30		
Qatar/U.A.E.		2.60	3.30	
Iraq		9.00		
Fixed Bound(MB/D)	100.00			
Lower Bound(MB/D)				200.00

TABLE IV-9. OIL PRODUCT IMPORTS FOR 1985
(1978 DOLLARS)

	Fixed Quantity (MB/D)	Price ($/B)
Gasoline, All Grades	172	21.90
Distillate, All Grades	376	16.26
Jet Fuel/Jet A	216	15.63
Naphtha	54	16.61
Other Refined Petroleum	104	16.61

	Bounded Quantity (MB/D)	Lower Bound (MB/D)	Price ($/B)
Residual, All Grades	1677	694	15.63

Liquid pet. gases are available in an unlimited quantity at $13.10/B.

directly into the PIES Integrating Model. Table IV-8 shows crude oil import bundles indicating the mix of imported crudes. These data are for the mid-range (reference case) supply scenario for 1985. Table IV-9 shows the 1985 import levels for refined petroleum products for the mid-range scenario.

Supply curves for traditional, nontraditional, and import sources are developed for the various scenarios and forecast years. Traditional and nontraditional supply curves for the 1990 forecast of the mid-range supply scenario are given in Chapter II of Volume VI, Data Documentation. These data enable comparison of forecast years with the 1985 mid-range scenario in Table IV-7. Supply curves for the low supply, high supply, and high oil price scenarios are given for 1985 and 1990 in Chapter III of Volume VI.

OIL ENTITLEMENTS

An important policy consideration for oil is the entitlements program. As a result of the fourfold increase in the price of imported crude oil during 1973-1974, the Federal Government implemented a program to equalize the cost of foreign and domestic crude, thus reducing the impact of high prices and ensuring a continued supply of imported crude. The program stipulates that "entitlements" be issued to importers who can in turn sell them to domestic suppliers, and that domestic suppliers must obtain entitlements in order to sell crude oil. In actuality, the Federal Government taxes the domestic crude supplier, and with this money pays the importer of crude. The transfer of revenues results in an equalization of prices. The mathematical expressions for determining entitlements, as modeled in the equilibrating mechanism, are derived below.

Letting E_I be the entitlements for imports, and E_D be the entitlements for domestic crude (excluding Alaskan oil), the effect of the entitlements program is to reduce the price of imported oil by an amount E_I, and to increase the price of domestic crude by an amount E_D. Thus, if we let P be the regulated price of domestic oil, and P_I be the average price of imported oil, we have:

$$P + E_D = P_I - E_I. \tag{1}$$

That is, the price of the entitlement is set such that the regulated price of domestic oil, plus the entitlement cost, is equal to the import price of crude, minus the entitlement price of imports.

In the current version of PIES, the entitlement for Alaskan oil, E_A, is set equal to the entitlement for imported oil, E_I. That is, for purposes of the entitlements program, Alaskan oil is treated like uncontrolled oil to encourage production. The program implies that the total value of entitlements issued to imported crude users equals the total value of entitlements purchased by domestic crude users. Letting Q_I, Q_D, Q_A be the quantity of crude from imports, the lower 48 states, and Alaska, respectively, we get the following equation:

$$E_I(Q_I + Q_A) = E_D Q_D. \tag{2}$$

Solving equations (1) and (2), we obtain

$$E_I = (P_I - P) \frac{Q_D}{Q_D + Q_A + Q_I}$$

$$E_D = (P_I - P) \frac{Q_I + Q_A}{Q_D + Q_A + Q_I}$$

and $E_A = E_I$ by the previous assumption. These entitlements adjust the average prices of crude oil at each iteration of the equilibrating mechanism to equalize the domestic and import refinery gate prices.

V. NATURAL GAS SUPPLY

INTRODUCTION

Natural gas supply constitutes less than 5 percent of the U.S. energy reserves, yet it satisfies nearly one-quarter of the national energy demand. Natural gas production has declined sharply over the last four years, and the trend is expected to continue, as indicated in Figure V-1, unless Alaskan gas and new supplies from the Outer Continental Shelf (OCS) exceed expectations.[1] Unlike oil imports, natural gas imports are not expected to meet domestic supply shortages in the short term.

PIES forecasts natural gas supply according to geographic area. Like the oil supply estimates, natural gas estimates are based on geological factors, resource assessments, and economics of operation. Both formal modeling techniques and engineering judgment are used. The formalized techniques are provided by the Mid-Term Oil Supply Model (explained in Chapter IV) for gas supply associated with oil production, and the Mid-Term Gas Supply Model for gas not associated with oil. The estimates developed by these satellite models are converted to data usable in the PIES LP matrix by natural gas preprocessors.

The primary purpose of this chapter is to describe how natural gas is modeled in PIES. Since inputs from the satellite models and the parameters of the supply scenarios are implicit in this process, these topics are also addressed. Much of this information is related to oil production, and references are made to Chapter IV throughout this chapter. Emphasized here are the differences between the treatment of gas supply and that of oil supply in PIES.

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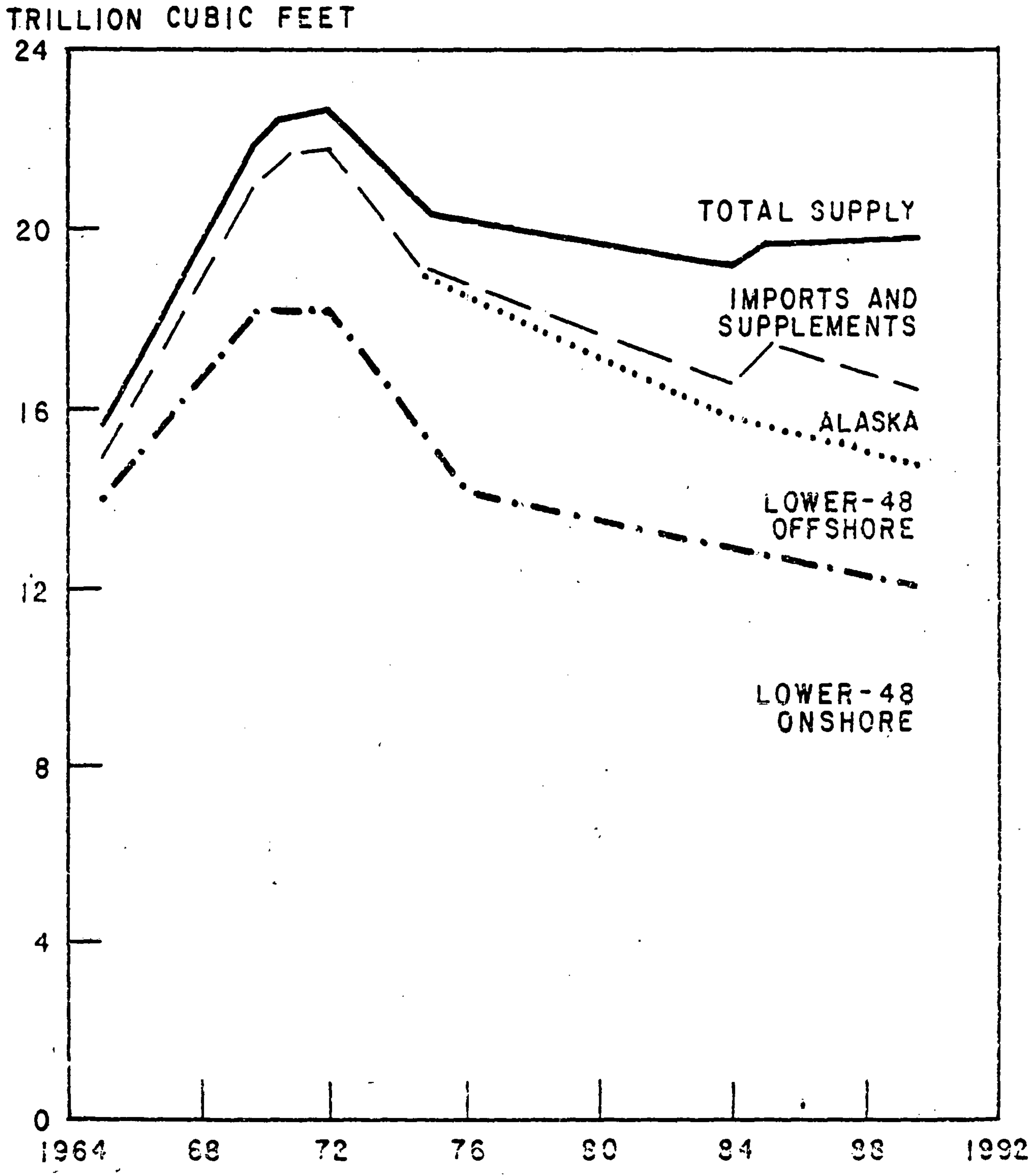
[1] A nominal case projection from: United States Department of Energy (DOE), Energy Information Administration (EIA); Annual Report to Congress (AAR), 1977.

FIGURE V-1

PROJECTED U.S. NATURAL GAS SUPPLY



SOURCE: AAR, PROJECTION SERIES C

GAS SUPPLY ESTIMATES

Natural gas supply is determined for various foreign and domestic sources, as indicated in Figure V-2. Domestic supply is estimated as production from either oil or gas wells and includes associated, dissolved, and nonassociated natural gas. Natural gas produced at an oil well (i.e., a coproduct of oil) is classified as either associated or dissolved. Associated gas exists separately from oil in the well, whereas dissolved gas is physically combined with oil in the well and released at the wellhead. For the purposes of this discussion, the distinction is not maintained, and natural gas production from oil wells is referred to as associated gas. Natural gas produced at a gas well is classified as nonassociated gas.

Gas production may involve the generation of coproducts, i.e., materials produced simultaneously with the natural gas but having different properties. These coproducts are gas liquids and butane.

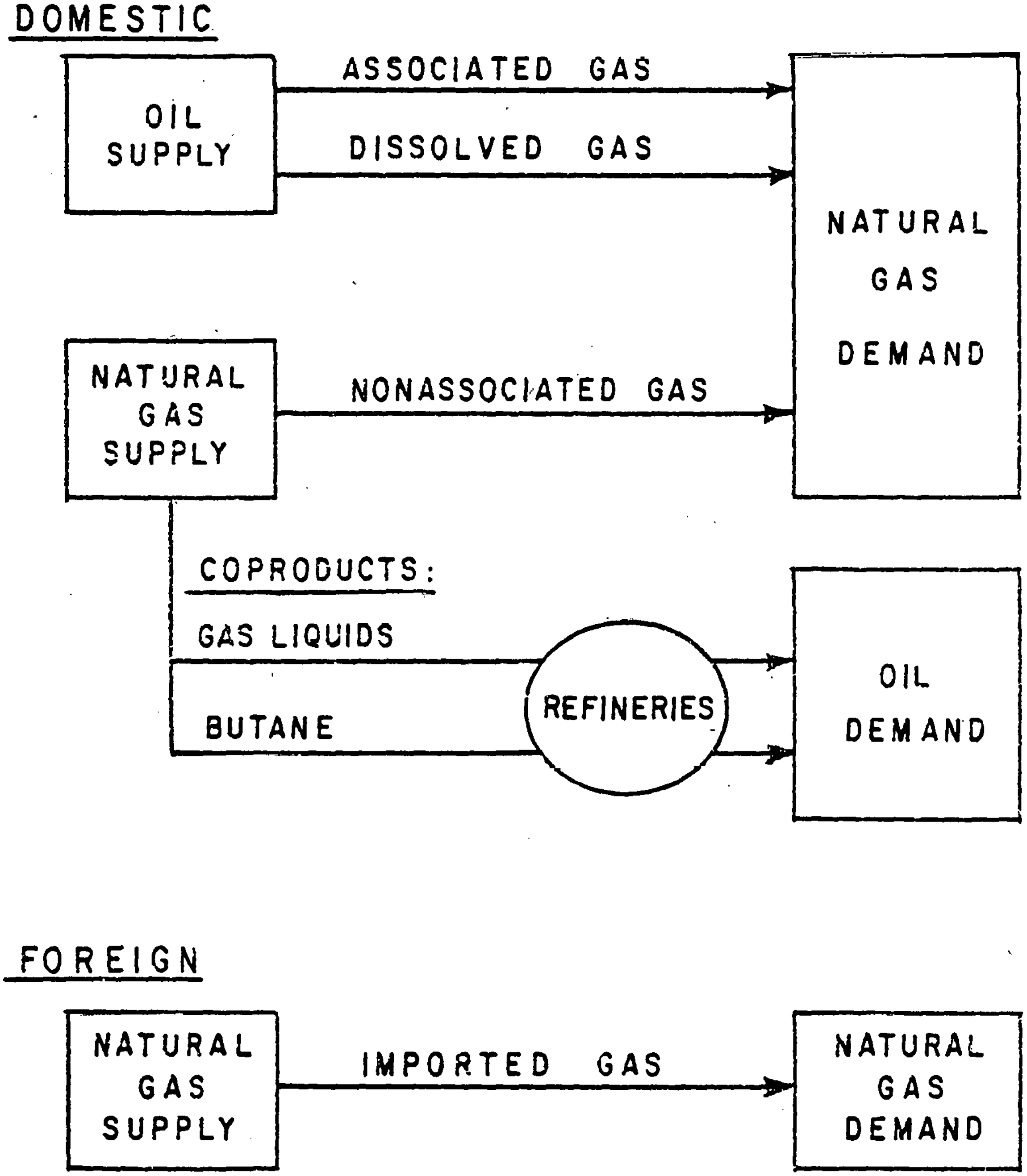
Imported natural gas, like imported oil, is treated as supplemental to domestic natural gas supply. Imported natural gas includes Canadian gas and imported liquefied natural gas (LNG). Other supplemental gas supplies are available from synthetic natural gas production. Synthetic gas is discussed later in Chapter VIII.

Due to different production methods different supply estimation methods are used for associated and nonassociated gas in PIES. These methods, together with that for imported gas, are described in the following subsections.

Regionalization of domestic natural gas supply takes into account differences in interstate and intrastate markets. Interstate natural gas supply regions are based on National Petroleum Council (NPC) regions. These NPC regions are identical to those in Figure IV-4 of the preceding chapter and are transformed into the 14 interstate natural gas regions presented in Figure V-3. The correspondence of NPC, natural gas, and oil

FIGURE V-2

NATURAL GAS SUPPLY FROM DOMESTIC AND FOREIGN SOURCES



regions is indicated in Table V-1. Note that natural gas region No. 11 is a combination of the Michigan Basin and Eastern Interior NPC regions. Observe also that there is one fewer oil region, since Appalachia is combined with the Michigan Basin and Eastern Interior NPC regions to form one oil region.

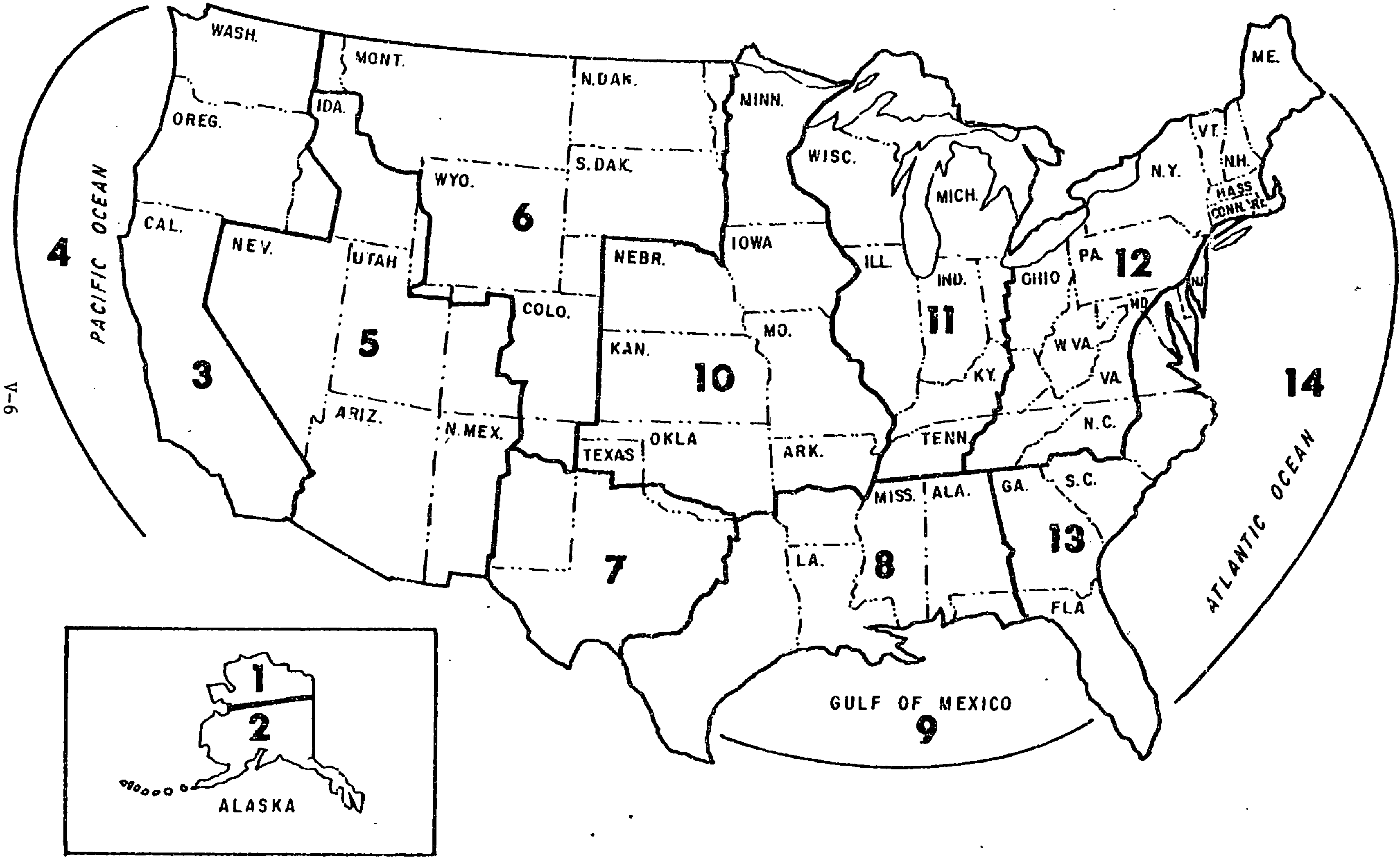
TABLE V-1. NATURAL GAS, OIL, AND NPC SUPPLY REGION CORRESPONDENCE BASED ON NATURAL GAS INTERSTATE REGIONS

	Region Number		
Region Name	Gas	NPC	Oil
Alaskan North Slope	1	N.S.	13
South Alaska	2	1	1
Pacific Coast	3	2	2
Pacific Ocean	4	2a	3
W. Rocky Mtns.	5	3	4
E. Rocky Mtns.	6	4	5
W. Tex. & E. N. Mex.	7	5	6
W. Gulf Basin	8	6	7
Gulf of Mexico	9	6a	8
Midcontinent	10	7	9
Mi. Basin, Int.*	11	8-9	10
Appalachians	12	10	10
Atlantic Coast	13	11	11
Atlantic Ocean	14	11a	12

*Michigan Basin, Eastern Interior.

FIGURE V-3

NATURAL GAS SUPPLY REGIONS



Intrastate natural gas regions coincide with the PIES demand regions, also referred to as DOE regions, and depicted in Figure I-2. The allocation of natural gas between interstate and intrastate markets is explained in the last section of this chapter.

Imported natural gas regions are defined for the East and West coastline of entry and for Canadian and Mexican sources.

Methods for estimating natural gas supply are dependent on the type of gas: associated, nonassociated, or imported, as illustrated in Figure V-4. Separate models are used to estimate associated and nonassociated gas supply. The model for associated gas is the Mid-Term Oil Supply Model, which has the capability of determining associated gas coproducts from traditional sources; the model for nonassociated gas is the Mid-Term Gas Supply Model. Other methods are used for imported gas and associated gas from nontraditional sources.

Nonassociated Gas

Nonassociated gas supply is estimated by means of the Mid-Term Gas Supply Model. The structure of this satellite model is similar to that of the Mid-Term Oil Supply Model, requiring inputs of production rates, reserve depletion, exploration, drilling rates, and investment costing on a regional basis, given estimates of the resource base for undiscovered natural gas. However, the Mid-Term Gas Supply Model differs from the Mid-Term Oil Supply Model in two respects:

- Gas finding rates are estimated as a function of total drilling (exploratory and developmental), rather than just exploratory rates, as in the Mid-Term Oil Supply Model.
- Components of the Mid-Term Oil Supply Model representing secondary and tertiary production (enhanced recovery) are not present in the Mid-Term Gas Supply Model.

The Mid-Term Gas Supply Model develops nonassociated gas supply curves through a procedure analogous to that used by the Mid-Term Oil Supply Model (see chapter IV). Gas

FIGURE V-4

METHODS FOR DETERMINING SUPPLIES OF NONASSOCIATED, ASSOCIATED AND IMPORTED GAS

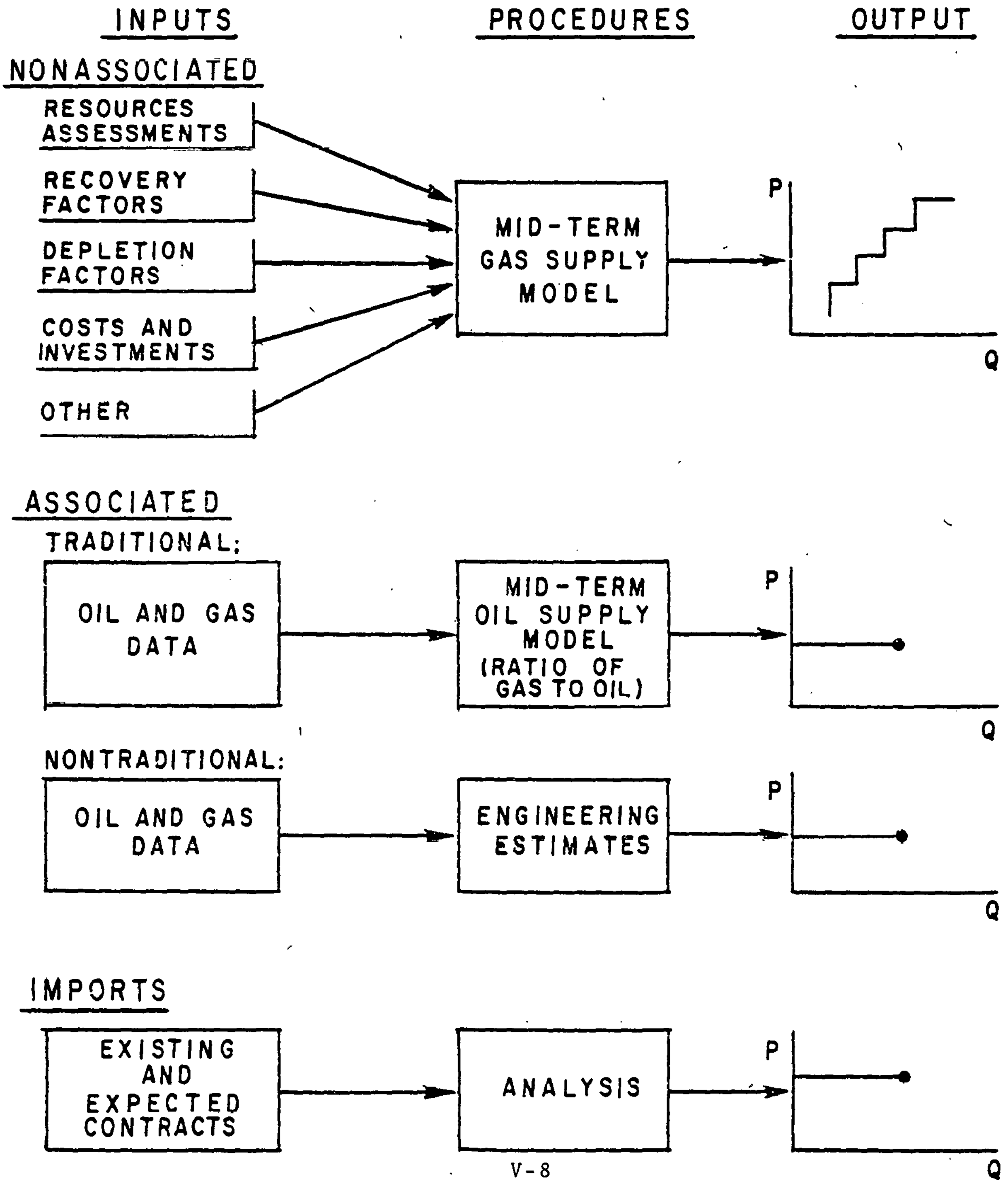


TABLE V-2. PRICE TRAJECTORIES FOR NONASSOCIATED GAS (1975 $/MCF)

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
STEP 1	1.63	1.61	1.58	1.56	1.53	1.51	1.49	1.47	1.44	1.44	1.44	1.44	1.44	1.44	1.44
STEP 2	1.63	1.61	1.60	1.58	1.57	1.55	1.53	1.52	1.50	1.50	1.50	1.50	1.50	1.50	1.50
STEP 3	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63
STEP 4	1.63	1.65	1.66	1.68	1.70	1.71	1.73	1.75	1.76	1.76	1.76	1.76	1.76	1.76	1.76
STEP 5	1.63	1.66	1.70	1.73	1.76	1.80	1.84	1.87	1.91	1.91	1.91	1.91	1.91	1.91	1.91
STEP 6	1.63	1.68	1.73	1.78	1.83	1.89	1.95	2.00	2.06	2.06	2.06	2.06	2.06	2.06	2.06
STEP 7	1.63	1.69	1.76	1.83	1.91	1.98	2.06	2.14	2.23	2.23	2.23	2.23	2.23	2.23	2.23
STEP 8	1.63	1.71	1.80	1.89	1.98	2.08	2.18	2.29	2.41	2.41	2.41	2.41	2.41	2.41	2.41
STEP 9	1.63	1.74	1.87	2.00	2.14	2.29	2.45	2.62	2.80	2.80	2.80	2.80	2.80	2.80	2.80

TABLE V-3. PRICE TRAJECTORIES FOR NATURAL GAS LIQUIDS AND BUTANE (1975 $/B)

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
STEP 1	9.48	9.33	9.19	9.06	8.92	8.79	8.66	8.53	8.40	8.40	8.40	8.40	8.40	8.40	8.40
STEP 2	9.48	9.38	9.29	9.20	9.10	9.01	8.92	8.83	8.74	8.74	8.74	8.74	8.74	8.74	8.74
STEP 3	9.48	9.48	9.48	9.48	9.48	9.48	9.48	9.48	9.48	9.48	9.48	9.48	9.48	9.48	9.48
STEP 4	9.48	9.57	9.67	9.76	9.86	9.96	10.06	10.16	10.26	10.26	10.26	10.26	10.26	10.26	10.26
STEP 5	9.48	9.67	9.86	10.06	10.26	10.46	10.67	10.89	11.10	11.10	11.10	11.10	11.10	11.10	11.10
STEP 6	9.48	9.76	10.05	10.36	10.67	10.99	11.32	11.66	12.00	12.00	12.00	12.00	12.00	12.00	12.00
STEP 7	9.48	9.86	10.25	10.66	11.09	11.53	11.99	12.47	12.97	12.97	12.97	12.97	12.97	12.97	12.97
STEP 8	9.48	9.95	10.45	10.97	11.52	12.09	12.70	13.33	14.00	14.00	14.00	14.00	14.00	14.00	14.00
STEP 9	9.48	10.14	10.85	11.61	12.42	13.29	14.22	15.22	16.28	16.28	16.28	16.28	16.28	16.28	16.28

production levels are determined in the model based on the gas price trajectories given in Tables V-2 and V-3 in constant 1975 dollars for nonassociated gas, and gas liquid and butane coproducts, respectively.

The output of the Mid-Term Gas Supply Model consists of the production levels of nonassociated gas at various price steps of the nine-step supply curve, together with related investment and drilling information. Nonassociated gas supply is categorized according to gas supply region (NPC), forecast year (1985 or 1990), and gas field vintage (old or new).[2] An example of a nonassociated gas supply curve for the mid-range supply scenario and forecast year 1985 is shown in Table V-7.

The following information is provided for each step of the supply curve: nonassociated gas production, and coproducts (gas liquids, butane, capital investment, drilling requirements). These data are further processed by a preprocessor to put them in a suitable form for the LP matrix as described later in this chapter.

The Mid-Term Supply Model produces estimates of natural gas production that are sensitive to differences in the prices at which production will occur from reserves of different size and quality. This price sensitivity is essential in evaluating the impact of interfuel competition and in assessing potential supply changes.

Associated Gas

The supply of associated gas from oil wells is determined by the Mid-Term Oil Supply Model for traditional sources and by other estimating techniques for nontraditional sources.

For traditional sources, historical data from each region are used to derive a ratio of associated gas production to total oil production. These ratios are applied to oil production at the various price steps to yield associated gas production at the

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[2] "Old" and "new" vintage merely indicates whether gas wells are drilled before or after January 1, 1977.

corresponding price steps. The price steps for associated gas are defined by the price trajectories given in Table IV-3 in the preceding chapter. Therefore, the supply curve for associated gas from traditional sources is based on the value of the product bundle developed by the Mid-Term Oil Supply Model.

For nontraditional oil sources, including the North Slope, Prudhoe Bay, Beaufort Sea, and Naval Petroleum Reserve areas in northern Alaska, independent engineering estimates are made to develop associated gas supply curves.

The resulting output is the production level of associated gas at various price steps of the nine-step supply curve. The investment and drilling requirements information is not relevant to associated gas supply and is accounted for in oil supply.

Associated gas supply data are classified like nonassociated gas data, with the additional classification of production type (primary, secondary, or tertiary). Since associated gas is a coproduct of oil production, the gas supply data take on oil production characteristics. For instance, associated gas vintage is related to the drilling date of the oil well.

Imported Gas

The determination of imported gas supply is relatively straightforward. Imported natural gas may come either from Canada and Mexico by pipeline, or to the East and West Coasts by LNG tanker. The quantity of Canadian and Mexican gas supplied has an upper bound for several price steps and each target year, based upon present and expected contracts. The quantity of LNG gas supplied also has an upper bound at various price steps. These upper bounds are based on contracts and proposals either presented before, or approved by, the Federal Energy Regulatory Commission (FERC). It is not assumed that an unlimited supply of imported natural gas is available to satisfy residual demand (such an assumption is made for imported oil supply).

GAS SUPPLY CONVENTIONS AND SCENARIOS

Alternative gas supply conventions and scenarios are provided for the 1978 AAR as parameters for determining energy supply and demand. The alternative supply conventions used are high, medium, and low geology conventions, which predict at least a 5, 50 and 95 percent chance of gas supply proving out, respectively. These conventions can be used to develop supply scenarios for PIES.

All natural gas from northern Alaska (Prudhoe Bay, other North Slope areas, and the Beaufort Sea) is treated as if produced as a coproduct of crude oil production. Since there is uncertainty associated with whether or not an Alaskan natural gas pipeline will be built, two modes of oil production are modelled; one in which natural gas is produced, the other in which it is reinjected to the oil reservoir. For the reference case, north Alaskan gas has an upper bound of 2.0 and 2.2 billion cubic feet per day (BCF/D) for 1985 and 1990, respectively. The movement of Alaskan North Slope gas is discussed in Chapter IX.

Because of these pricing differences, there may be shortages of interstate gas in areas where there is little or no intrastate gas available. The PIES Integrating Model has a mechanism to alter the free market system by allocating natural gas and substitute fuels according to the FERC priority scheme. A detailed description of natural gas regulation is presented in the last section of this chapter.

THE GAS SUBMODEL

The gas preprocessors convert gas supply raw data into a usable form for the LP matrix. The raw data are derived from two satellite models and from engineering judgment, as explained above.

Gas supply data are given for both domestic and foreign sources. Domestic gas consists of associated and nonassociated natural gas with coproducts, whereas imported gas consists of associated natural gas only. The data are classified by forecast year, natural gas region, vintage (i.e. old, new, stripper, etc.), and production (associated, non-associated) type. This classification is implicit in the following discussion.

Domestic Sources

Domestic natural gas consists of associated and nonassociated gas and coproducts. The gas submodel processes supply data related to production level, composite output of the product bundle, price, capital investment requirements, and drilling requirements.

Gas supply curves containing maximum levels of production at the minimum acceptable price for associated and nonassociated natural gas are developed for each natural gas supply region. The raw data units are billion cubic feet per year (BCF/Y). Since the standard units for the PIES LP matrix are million cubic feet per day (MMCF/D), the following operation is performed to convert the raw data to standard units:

$$\frac{\text{BCF}}{\text{Y}} \times \frac{10^3\text{MMCF}}{\text{BCF}} \times \frac{\text{Y}}{365.25\text{D}} = 2.74 \text{ MMCF/D}$$

Another essential function of the gas submodel is to distribute associated and nonassociated gas to interstate and intrastate regions, thus determining the level of production in these regions. The method of distribution is illustrated in Figure V-5, which is based on the following assumptions:

- All Alaskan and OCS (outer continental shelf) gas is considered interstate.
- All new onshore gas is considered intrastate.
- Gas from existing wells is split between intrastate and interstate markets according to historical shares for each region.

Therefore, the supply of interstate natural gas in a given year is estimated by taking the current rate of production, reducing it by the natural decline from existing wells in the onshore regions, and adding the production from Alaska and the OCS.

The supply of interstate gas from existing wells in a given year is determined by taking the current rate of production and multiplying by the historical share for the interstate market. This calculation is performed for both associated and nonassociated gas. The historical shares for nonassociated gas by interstate gas region are given in Table V-4. The market shares for associated gas, an oil coproduct, are given in

FIGURE V - 5

DISTRIBUTION OF NATURAL GAS TO INTERSTATE AND INTRASTATE MARKETS ASSUMED INITIALLY

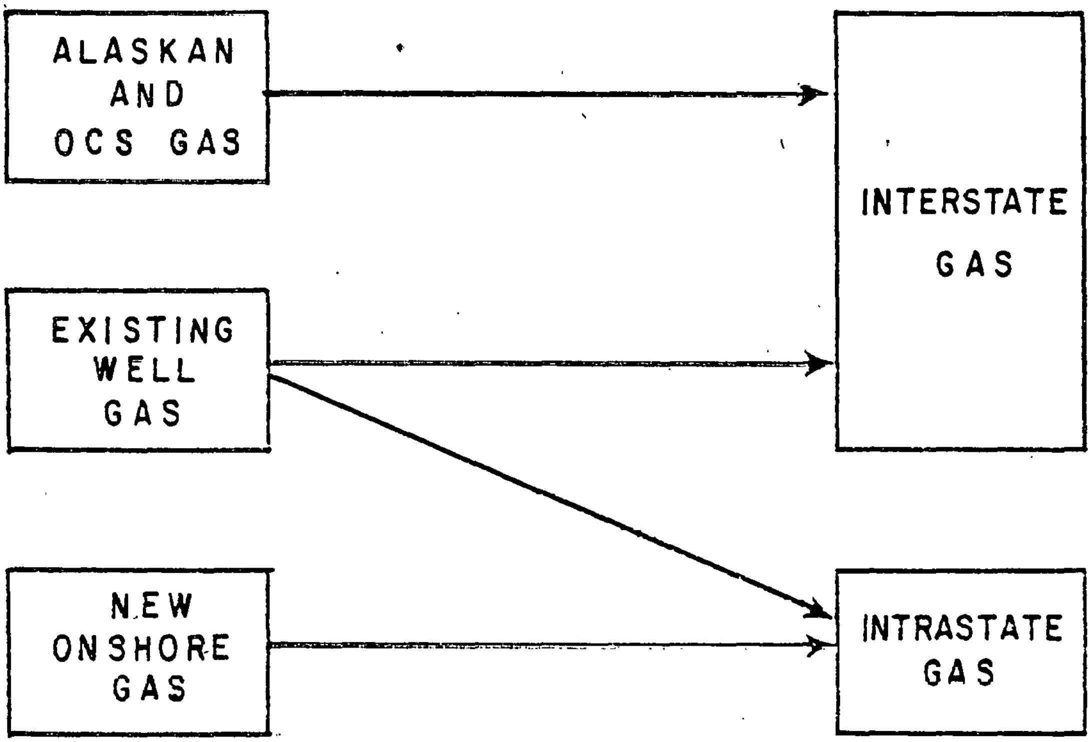

Table IV_7. Interstate associated gas, originating in the Michigan Basin, Eastern Interior, and Appalachian Oil regions is distributed to the Michigan Basin - Eastern Interior and Appalachian interstate gas regions by the proportions .52 and .48, respectively.

TABLE V-4. SHARES OF NONASSOCIATED GAS FROM EXISTING WELLS TO INTERSTATE AND INTRASTATE MARKETS

Gas Region	Interstate Market	Intrastate Market
Alaskan North Slope	1.00	0.00
South Alaska	1.00	0.00
Pacific Coast	0.00	1.00
Pacific Ocean	1.00	0.00
W. Rocky Mtns.	.6966	.3034
E. Rocky Mtns.	.4905	.5095
W. Tex. & E. N.Mex.	.3042	.6958
W. Gulf Basin	.4626	.5374
Gulf of Mexico	1.00	0.00
Midcontinent	.4587	.5413
Mi. Basin, Int.*	.0028	.9972
Appalachians	.6184	.3816
Atlantic Coast	.7604	.2396
Atlantic Ocean	1.00	0.00

*Michigan Basin, Eastern Interior.

The supply of intrastate gas is determined using the intrastate shares from Tables IV-7 and V-4. For nonassociated gas originating in interstate gas regions, the historical shares are as indicated for the intrastate market in Table V-4; for associated gas originating in oil regions, the shares are as in Table IV-7. Once the intrastate amounts are determined, they must be shifted from interstate natural gas regions, in the case of nonassociated gas, and from oil regions, in the case of associated gas, to intrastate gas regions. Nonassociated gas is distributed from interstate to intrastate gas regions by the proportions given in Table V-5. Similarly, associated gas is distributed from oil regions to intrastate gas regions by the proportions in Table V-6. Once the gas is allocated to the appropriate region, the associated and nonassociated quantities are added.

Sample output of nonassociated gas supply data for the midrange (reference) scenario and 1985 forecast year is given in Table V-7. Indicated in this table are the levels of nonassociated gas and coproduct production corresponding to each applicable price step for two interstate and intrastate gas supply regions, and old and new vintages.

TABLE V-5. PROPORTIONS OF NONASSOCIATED GAS FROM INTERSTATE TO INTRASTATE GAS REGIONS

INTERSTATE GAS REGION	INTRASTATE GAS REGIONS							
	NY/NJ	Mid-Atl	S-Atl	Midwest	S-West	Central	N-Cntrl	West
Pacific Coast								1.00
W. Rocky Mtns.					.81	.19		
E. Rocky Mtns.						1.00		
W. Tex. & E. N.Mex.					1.00			
Gulf Coast			.01		.99			
Midcontinent					.81		.19	
Appalachians				1.00				
Mi. Basin, Int.*	.01	.63	.15	.20				
Atlantic Coast			1.00					

*Michigan Basin, Interior

TABLE V-6. PROPORTIONS OF ASSOCIATED GAS FROM OIL TO INTRASTATE GAS REGIONS

OIL REGION	INTRASTATE GAS REGION							
	NY/NJ	Mid-Atl	S-Atl	Midwest	S-West	Central	N-Cntrl	West
Pacific Coast								1.00
W. Rocky Mtns.					.81	.19		
E. Rocky Mtns.						1.00		
W. Tex. & E. N.Mex.					1.00			
Gulf Coast			.01		.99			
Midcontinent					.81		.19	
Mi. Basin, Int, App.*	.01	.55	.13	.31				
Atlantic Coast			1.00					

*Michigan Basin, Interior, Appalacia

TABLE V-7. NONASSOCIATED GAS SUPPLY CURVES FOR MID-RANGE SUPPLY SCENARIO AND FORECAST YEAR 1985

	Price Step	Natural Gas (MMCF/D)	Butane (MR/D)	Gas Liquids (MB/D)	Bundle Price ($/MCF GAS)	Capital (MM$)	Drilling (MMFT)
NPC Region-Pacific Ocean Interstate Gas							
New Gas	1	55.30	.50	.70	1.63	30.00	
	4	56.67	.50	.70	1.76	31.00	
	5	57.22	.60	.70	3.94	31.00	
	8	58.32	.60	.70	2.41	31.00	
	9	59.41	.60	.70	2.80	31.00	
Old Gas	6	15.61			2.06		
NPC Region-West Rockies Interstate Gas							
Old Gas	1	663.31	1.06	.66	1.47		
DOE Region-Midwest Intrastate Gas							
Old Gas	1	92.84	.84	.41	1.56		
DOE Region-West Intrastate Gas							
New Gas	2	86.24	.70	1.10	1.69	116.00	4.99
	3	197.67	1.69	2.49	1.83	212.98	8.98
	4	299.24	2.58	3.69	1.98	330.98	13.98
	5	326.07	2.78	4.09	2.16	363.98	14.98
	6	353.45	2.98	4.49	2.33	396.98	15.98
	7	392.33	3.28	4.88	2.46	444.97	17.98
	8	441.88	3.78	5.48	2.72	508.97	20.97
	9	515.53	4.37	6.38	3.13	606.97	24.97
Old Gas	1	208.62			1.44		

Source: E1a Administrator's Annual Report

Corresponding associated gas production information is given in chapter IV. Associated and nonassociated gas production are combined in the gas submodel.

Table V-8 shows summarized production levels for combined associated and nonassociated gas for the scenario at the highest price step.

As explained above, gas supply curves give levels of production for nonassociated gas and coproducts at different price steps. These prices are not used in the PIES Integrating Model, however, since it sees the increment in production from one step to the next as a bundle of commodities that it must either produce or not produce together. Thus, a single composite output price, called the bundle price, is assigned to each step. By definition, the bundle price is the ratio of the total value of the materials for a particular step, including nonassociated gas and coproducts, to the quantity of nonassociated gas for that step. Therefore, the bundle price is calculated by the formula below.

$$
\begin{aligned}
\text{Bundle Price} = \quad & [(\text{Quantity of Nonassociated Gas}) \bullet (\text{Price of Nonassociated Gas}) \\
& (\text{Quantity of Gas Liquids}) \bullet (\text{Price of Gas Liquids}) \\
& (\text{Quantity of Butane}) \bullet (\text{Price of Butane})] / \\
& [\text{Quantity of Nonassociated Gas}]
\end{aligned}
$$

The price steps for nonassociated gas, and gas liquids and butane were previously given in Tables V-2 and V-3, respectively. Since associated gas is a coproduct of crude oil, its bundle price is discussed in Chapter IV.

Capital investment requirements are outputs of the Mid-Term Gas Supply Model and are used in computing minimum acceptable selling prices. These data are input to the PIES Integrating Model. The capital investment requirements from the Mid-Term Gas Supply Model are in units of millions of dollars (MM$) and are cumulative from 1977 to one year prior (1984 or 1989) to the target year (1985 or 1990).

TABLE V-8. GAS SUPPLY AT THE HIGHEST PRICE STEPS IN 1985

Interstate Region		Interstate Gas (MMCF/D)
South Alaska		1,023
Pacific Coast		
Pacific Ocean		370
W. Rocky Mtns.		764
E. Rocky Mtns.		353
W. Tex. & E. N. Mex.		874
Gulf Coast		3,437
Gulf of Mexico		6,844
Midcontinent		1,833
Mi. Basin, Int.,App.*		341
Atlantic Coast		
Atlantic Ocean		625
North Slope		3,168
	TOTAL	19,631

Intrastate Region		Intrastate Gas (MMCF/D)
NW-Eng		4
NY/NJ		3
Mid-Atl		168
S-Atl		284
Midwest		117
S-West		27,784
Central		1,520
N-Cntrl		1,414
West		955
N-West		
	TOTAL	32,243

*Michigan Basin, Interior, Appalachia

In Table V-7, capital investment requirements are in units of $MM. The standard units for the PIES Integrating Model are $MM per million cubic feet per day ($MM/MMCF/D). These units are obtained by dividing capital investment in $MM by the nonassociated gas production level (MMCF/D) at the minimum acceptable supply curve price (not bundle price).

Another quantity used as an input to the gas supply curve determination and input to the Integrating Model is the drilling requirements for gas production. Drilling requirements are cumulative in the same manner as capital investment requirements.

From Table V-7 it is observed that drilling requirements from the Mid-Term Gas Supply Model are in units of million feet drilled (MMFT). However, standard units for the Integrating Model are in MMFT/MMCF/D. Therefore, units for drilling requirements are converted in the same way as capital investment requirements, and the quantity, MMFT, is divided by the level of nonassociated gas produced (MMCF/D) to obtain standard units of MMFT/MMCF/D.

IMPORTS

Natural gas imports in PIES come either from Canada and Mexico by pipeline or from other areas via LNG tanker. Supply estimates for these sources are determined for target years 1985 and 1990 as given in Tables V-9 and V-10, respectively.

In addition to determining supply as a probability of proving out, the submodel sets upper bounds of supply levels for Canadian and north Alaskan gas. For Canadian pipeline gas imports, the Canadian National Energy Board's current schedule of deliveries to the U.S. is assumed, resulting in maximum levels of .91 and .68 trillion standard cubic feet per year (TCF/Y) for 1985 and 1990, priced at the current market price of $1.78/MCF in 1975 dollars. For LNG imports, a minimum supply level of .40 TCF/Y in 1985 and 1.0 TCF/Y for 1990 is assumed, reflecting unconditionally approved import contracts; beyond that level, maximum supply increments of 1.0 and 1.08 TCF/Y for 1985 and 1990, respectively, are assumed to be available.

For each foreign source, imported gas is designated according to demand region. Imported oil, on the other hand, is only designated for the port of importation, and not to a demand region. There are two reasons for this difference in treatment. Gas companies tend to have longer-term contracts that tie the gas to specific demand sectors and regions. Further, the transportation possibilities for natural gas are limited compared to those for oil (see Chapter IX). On the mainland, natural gas can only be transported by pipeline, and pipeline facilities are owned by the gas companies, which further restricts their use. Conversely, oil can be transported via alternative modes and by independent common carriers. As a result, imported natural gas is given predetermined demand destinations in PIES.

Supply information for various forecast years and scenarios is presented in Volume VI of this documentation series, Data Documentation. For example, nonassociated gas supply information for the 1990 forecast of the mid-range supply scenario is given in Table 7 of oil and gas supply, Chapter II, Volume VI. This table can be compared with the 1985 forecast given in Table V-8 of this chapter. In addition, sample nonassociated gas supply information for the low and high supply scenarios is given in Chapter III of Volume VI for 1985 and 1990.

TABLE V-9. NATURAL GAS IMPORTS FOR 1985 (1975 DOLLARS)

	LIQUEFIED NATURAL GAS			CANADIAN NATURAL GAS	
Demand Region	Port of Entry	Upper Bound (MMCF/D)	Price ($/MCF)	Upper Bound (MMCF/D)	Price ($/MCF)
NW-Eng.	East Coast	323.29	3.25	10.96	1.78
NY/NJ	East Coast	241.10	3.00	16.44	1.78
Mid-Atl	East Coast	884.93	2.30		
S-Atl	East Coast	671.23	3.00		
Midwest	East Coast	460.27	3.60	698.63	1.78
N-Cntrl				98.63	1.78
West	West Coast	1268.49	3.70	1073.97	1.78
N-West				583.56	1.78

TABLE V-10. NATURAL GAS IMPORTS FOR 1990 (1975 DOLLARS)

	LIQUEFIED NATURAL GAS			CANADIAN NATURAL GAS	
Demand Region	Port of Entry	Upper Bound (MMCF/D)	Price ($/MCF)	Upper Bound (MMCF/D)	Price ($/MCF)
NW-Eng.	East Coast	728.77	4.30		
NY/NJ	East Coast	1326.03	4.50		
Mid-Atl	East Coast	1068.49	3.00		
S-Atl	East Coast	679.45	3.40		
Midwest	East Coast	1024.66	3.70	698.63	1.78
Central	East Coast	246.58	4.20		
N-Cntrl				98.63	1.78
West	West Coast	624.66	4.00	1073.97	1.78

NATURAL GAS TAX PROGRAM

The equilibrating mechanism performs two calculations related to natural gas. The first is an optional feature which models an end use tax for natural gas. The tax is intended to raise the cost of gas to industrial and utility users and to create incentives for conversion to other energy sources. It is levied on industrial and utility users and is equal to the difference between their cost of natural gas and a price based on distillate oil. This tax program will affect high volume industrial users beginning in 1979.

To implement this tax program, the equilibrating mechanism calculates an average price of distillate per barrel in both the industrial sector and the utility sector. This average price is converted to a price per Btu by dividing by the Btu content of distillate, 5.825 Btu/B. After the tax on distillate is subtracted and the tax on natural gas is added, the price is multiplied by 1.032 Btu/MCF, the Btu content of natural gas. The tax on natural gas to the industrial and utility sectors is the difference between these computed prices and the price of natural gas in the appropriate sector. Like the oil entitlements program, the natural gas tax is implemented in the LP as an input cost.

NATURAL GAS REGULATION

The other calculation concerns natural gas regulation. In gas regulation scenarios, the distribution of interstate gas is essentially fixed. For the 1985 mid-range scenario, the distribution of interstate gas from gas supply regions to demand regions is shown in Table V-11; the resulting deliveries, which are input to the equilibrating mechanism, are given in Table V-12. The equilibrating mechanism can alter these distributions as follows:

- A region may take less interstate gas than is assigned to it.
- Excess interstate gas in one region may be reassigned to another region.
- Gas originally designated as intrastate but shifted to the interstate market can augment the original distribution.

For this discussion of natural gas in PIES, two markets must be differentiated: the unregulated intrastate market and the Federally regulated interstate market. Because of this difference in regulation, intrastate gas sells at a higher price than interstate gas. Consequently, the only new sales of interstate gas are either from onshore areas, where fields are close to interstate pipelines and where there are no intrastate pipelines, or from the OCS, which is under Federal jurisdiction. Due to these pricing differences, there is a shortage of supply of interstate gas in demand regions where there is little or no intrastate gas available.

Because of this shortage and the differences in price between interstate and intrastate natural gas, the Federal Energy Regulatory Commission (FERC) has developed a priority scheme for allocating natural gas to states by classes of users for a given pipeline. Each state then allocates the gas available from the pipeline to customers within the state, based on its own priority scheme.

The approach taken in PIES to model the supply of natural gas is to provide interstate gas to customers according to a priority scheme until the source is depleted or all demands are satisfied, and, when necessary, to provide the remaining customers with intrastate gas or other fuels that are substituted for the natural gas. Customers are supplied interstate gas in accordance with the FERC priority scheme, except that the gas is allocated by demand region rather than by individual pipeline. The priority classes in

TABLE V-11. DISTRIBUTION OF INTERSTATE GAS IN 1985 FOR THE MID-RANGE SCENARIO (MMCF/D)

INTERSTATE GAS REGION	DEMAND REGION NW Eng.	NY/NJ	Mid-Atl	S-Atl	Midwest	S-West	Central	N-Cntrl	West	N-West
Pacific Coast										
Pacific Ocean									352	
West Rockies						27		174	520	40
East Rockies					27		44	267	6	8
W.Tex./E. N.Mex				18	131	142	126	9	445	
Gulf Coast	106	343	460	852	1044	536	93			
Gulf of Mexico	253	807	1074	1464	2586	609	48			
Midcontinent		22	31	37	743	225	624	109	38	
Mi.Basin & Int.					12					
Appalachia		88	118	23	99					
Atlantic Coast										
Atlantic Ocean	49	174	221	162						
North Slope	37	119	158	249	721	134	114	22	606	42
South Alaska									827	

Quantities given do not show effect of transportation losses.

Stated distribution of North Slope gas to the East Coast represents net effect of displacement.

TABLE V-12. INTERSTATE GAS DELIVERIES IN 1985

DEMAND REGION

	NW Eng	NY/NJ	Mid-Atl	S-Atl	Midwest	S-West	Central	N-Cntrl	West	N-West
Lower 48 and S. Alaska Quantity Delivered (MMCF/D)	380	1352	1813	2486	4445	1509	918	548	2039	45
Average Price ($/MCF)	1.58	1.43	1.34	1.11	1.15	.85	.68	.65	1.38	1.05
Alaskan North Slope Quantity Delivered (MMCF/D)	34	108	145	235	667	129	107	21	577	40
Delivered Price ($/MCF)	3.05	3.01	2.94	2.76	2.89	2.61	2.81	2.69	2.68	2.52

Stated distribution of North Slope gas to the East Coast represents net effect of displacement.

the FERC allocation are, in order, residential, commercial, raw material, and industrial. These classes are called sectors in PIES.

If the supply of interstate gas is sufficient to meet all demands, the regulated scenario is essentially reduced to a deregulated scenario, since a free economic environment would result in using all of the cheaper gas first. Demand not satisfied by interstate gas is satisfied by intrastate gas, until the price of intrastate gas is no longer less than the market price of substitute fuels. These substitute fuels are grouped according to sectors, and each group is called a substitute fuel bundle.

The following subsections discuss the modeling of natural gas in PIES: first, the allocation of interstate natural gas to sectors and demand regions, and, second, the supply of, and demand for, natural gas in terms of interstate gas, intrastate gas, and substitute fuel bundles.

Allocation of Natural Gas

To model the effects of interstate gas curtailment in the face of declining production, available supply (with corresponding prices) must first be allocated to demand regions. This allocation is performed in a natural gas preprocessor, where a table is created, giving the amount and the quantity weighted average price of interstate gas deliveries to each demand region from all lower-48 gas supply regions, and the South Alaska and Alaskan North Slope gas supply regions. These results are presented to the integrating mechanism for combinations of oil and gas supply conventions and target years for the Alaskan gas pipeline proposal.[3]

The following procedure is used for allocating the interstate natural gas to demand regions. The amounts of associated natural gas produced for the interstate market are determined from the oil standard tables. A distinction is made between associated

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[3] Natural gas movement from Alaska by Alcan pipeline is discussed in Chapter IX.

natural gas produced from old and new oil fields for later use in a pricing algorithm. The production data that were originally expressed in terms of oil regions are translated in terms of interstate gas regions.

The amounts of nonassociated natural gas produced for interstate markets from both old and new gas fields are found from the gas standard tables for all gas supply regions except the Alaskan North Slope. Alaskan North Slope gas production is taken to be 2000 MCF/D and 2200 MCF/D in 1985 and 1990, respectively. These associated and nonassociated natural gas production amounts are then combined.

The weighted average price of interstate gas deliveries to each demand region is a quantity weighted average for old and new gas types. This average delivered price is based on wellhead prices and transportation costs.[4] With the exception of the North Slope, the wellhead price is $0.37/MCF and $1.46/MCF for gas from old and new fields, respectively, which includes acquisition costs and severance tax.[5]. The wellhead price for gas from the North Slope is taken as $1.51/MCF in both 1985 and 1990. Transportation costs of interstate gas are presented in Chapter IX, "Transportation."

The interstate natural gas from each supply region is then distributed to demand regions, based upon 1974 historical shares for lower-48 gas. These factors are shown in Table V-13. The resulting figures on amounts of interstate gas distributed serve as upper bounds on interstate deliveries from each gas supply region to each demand region.

These upper bounds are then multiplied by throughput factors to yield the total deliveries of interstate gas from supply to demand regions. The throughput factors reflect changes in heat values, and, for example purposes, Table V-14 shows the

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[4] The "wellhead price" or "field price" is the price of gas as it comes from the well. It does not include transportation or processing charges.

[5] The cost of gas from oil fields is estimated, and the cost from new fields is the FERC ceiling price.

TABLE V-13. APPORTIONMENT FACTORS FOR LOWER-48 AND ALASKAN GAS*

Gas Region	Demand Region									
	NW-Eng	NY/NJ	Mid-Atl	S-Atl	Midwest	S-West	Central	N-Cntrl	West	N-West
North Slope (Alcan)	.017	.054	.072	.113	.327	.061	.052	.010	.275	.019
South Alaska (Alcan)									1.000	
Pacific Coast									1.000	
Pacific Ocean									1.000	
W.Rocky Mtns.						.036		.229	.682	.053
E.Rocky Mtns.					.076		.126	.759	.017	.022
W.Tex.& E.N.Mex				.021	.151	.163	.145	.010	.510	
W.Gulf Basin	.031	.100	.134	.248	.304	.156	.027			
Gulf of Mexico	.037	.118	.157	.214	.378	.089	.007			
Midcontinent		.012	.017	.020	.406	.123	.341	.060	.021	
Mi. Basin, Int.					1.000					
Appalachians		.269	.361	.070	.300					
Atlantic Coast	.081	.287	.364	.268						
Atlantic Ocean	.081	.287	.364	.268						

*Source for lower-48 figures: Bureau of Natural Gas, FPC, Natural Gas Transported in 1974 by FPC Regulated Pipelines, Washington, D.C., August 1976.

Source for Alaskan North Slope figures: "PIES Analysis of Alaskan Gas Distribution," FEA discussion paper, forthcoming.

TABLE V-14. THROUGHPUT FACTORS FOR THE ALCAN SYSTEM*

Demand Region	Alcan
NW-Eng	.90
NY/NJ	.90
Mid-Atl	.91
S-Atl	.94
Midwest	.92
S-West	.96
Central	.93
N-Cntrl	.94
West	.95
N-West	.95

*Source: "PIES Analysis of Alaskan Gas Distribution Options," FEA discussion paper forthcoming.

throughput factors for the Alcan pipeline. For throughput factors for the other interstate natural gas pipelines, refer to Chapter IX.

The delivered amounts of interstate gas are found by summing deliveries from all lower-48 gas supply regions. Alaskan North Slope deliveries to each demand region are given for the Alcan pipeline. The corresponding delivered prices are found by adding transportation link prices between supply and demand regions to the average wellhead prices and weighing the prices by the maximum amounts (upper bounds) permitted to move between supply and demand regions. The transportation link prices for moving lower-48 gas and Alaskan gas by pipeline are shown in Table IX-31. The transportation link prices for moving Alaskan gas by pipeline are the prices quoted in Table V-15, multiplied by 1.1027[6] and increased by 30 percent due to a construction cost overrun. In the 1990 case, the price is again increased by $.05, which is the American contribution towards the construction of a pipeline by the Canadians from the MacKenzie Delta to the Alcan pipeline. These topics are further discussed in Chapter IX.

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[6] The conversion factor 1.1027 ($= \frac{1}{.9069}$) accounts for the change from the heat content of Alaskan gas, 1138 B/CF, to the standard heat content of gas, 1032 B/CF.

TABLE V-15. LINK PRICES FOR THE ALCAN SYSTEM*

Demand Region	Alcan	
	1985	1990
NW-Eng	1.39	0.92
NY/NJ	1.35	0.88
Mid/Atl	1.31	0.84
S-Atl	1.21	0.74
Midwest	1.29	0.83
S-West	1.11	0.65
Central	1.23	0.87
N-Cntrl	1.14	0.78
West	1.15	0.79
N-West	0.99	0.63

*Source: "PIES Analysis of Alaskan Gas Distribution Options," FEA discussion paper, forthcoming.

The allocation of domestic, imported, and synthetic interstate natural gas to sectors within each demand region is performed at each iteration of the equilibrating mechanism. The procedure begins with a list of natural gas supply quantities, ordered by price, which are allocated to the sectors according to FERC priorities.[7] The list of natural gas supply quantities contains, in order of increasing cost, lower-48, imported Canadian, synthetic, Alaskan, liquefied, and surplus natural gas. The Alaskan gas refers to the gas from the Alaskan North Slope, Beaufort Sea, and the Naval Petroleum Reserve. South Alaskan gas is included in the lower-48 category. Surplus gas is excess gas originally allocated to a region whose demands were totally satisfied and subsequently made available to other regions still needing gas.

In the current PIES, it is assumed that the South Atlantic and Midwest demand regions will suffer the most severe shortages of natural gas and that the New England, New York/New Jersey, and Mid-Atlantic demand regions may have some excess gas available. The surplus gas from the regions having excess supply is added to the list

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[7] Although the reference case for PIES uses the FERC priorities for the sectors, residential, commercial, raw material, and industrial, the methodology can handle any priority scheme.

of gas sources for the South Atlantic and Midwest regions on a 25 percent/75 percent basis. Thus, the regions having excess supply have their demands satisfied first, with 25 percent of their excess gas assigned to the South Atlantic region's list, and 75 percent of their excess gas assigned to the Midwest region's list. The South Atlantic region's demands are satisfied next, with any surplus gas added to the Midwest region's list. The remaining regions' demands are processed in order: Southwest, Central, North Central, West, and Northwest. In order to keep the order of increasing price in each list, the cost of the surplus gas is the quantity-weighted average cost from the New England, New York/New Jersey, and Mid-Atlantic demand regions, plus a $.25 charge.

Given these quantities of natural gas supplied to the 10 demand regions, gas is allocated by priority to the four sectors by a rolled-in pricing mechanism. Essentially, the sectors select the available gas from the list, starting with the cheapest gas. When all demands are filled for each sector, the price of natural gas to that sector is a quantity-weighted average of the gas that fulfilled the demand for all sectors, plus the appropriate markup for that sector.[8] For instance, suppose the demand for natural gas in the New England demand region required all the lower-48 gas and a fraction of the Canadian gas supplied to that region. Then, the price of natural gas to the residential sector in the New England demand region is the quantity-weighted price of the lower-48 gas and the Canadian gas, plus the appropriate markup for the residential sector. The commercial sector in the New England demand region would see a price equal to the same quantity-weighted average price of these sources of supply, plus the appropriate markup for the commercial sector. Thus, the price of gas in each sector differs only by the appropriate markup.

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[8] Sectoral markups are designed to reflect differences in average prices paid by different consuming sectors due to such factors as different qualities of service.

Since demands are based on the average price, which changes relative to the quantity and the source of the natural gas, the demands need to be recalculated with the new average price. This process is iterated until the average price, and hence demand, stabilize. The final quantities demanded are then used in the LP.

The natural gas regulation calculations are performed in the equilibrating mechanism. The routine first selects the sources of natural gas that meet the demand for gas in the sectors according to the following order: domestic lower-48 gas, Canadian gas, SNG, Alaskan gas, and LNG. If there is an insufficient supply of interstate natural gas, the unfulfilled demand is satisfied by intrastate gas and substitute fuel bundles. If the supply of interstate gas exceeds demand, an interval bisection procedure determines the quantity of each source of natural gas demanded and the corresponding price.

In performing the interval bisection calculations, a maximum of five iterations is allowed for the average price and demand to stabilize. PIES does not equilibrate between iterations. The algorithm begins the first of these five iterations by trying one-half the quantity of the most expensive source of natural gas that meets the demand and all quantities from the sources prior to this one on the list. The demand is calculated based on the quantity-weighted average price of these gas sources. If this quantity of gas is greater than the demand, the next quantity used is $(.5-(.5)^{n+1})$ times the quantity of the most expensive gas source that meets the demand, plus all of the quantities from the preceding sources, where n is the iteration number, $n \leq 5$. Likewise, if the quantity of gas is less than the demand, the new quantity used is $(.5+(.5)^{n+1})$ times the quantity from the most expensive gas source that meets the demand, plus all of the quantities from the sources prior to it on the list. This iterative process continues until either the demand has stablized or five iterations have been performed.

After all of the interstate sources of natural gas are allocated, the remaining gas demands are satisfied by intrastate gas and substitute fuels through the LP, as explained in the following sections.

Supply and Demand of Natural Gas

Whenever natural gas demands cannot be satisfied by interstate natural gas supplies, the remaining demands are satisfied by intrastate natural gas and substitute fuels. Figure V-6 depicts the resultant piecewise supply curve.

Figure V-7 depicts the supply and demand curves for natural gas considering the three sources of supply. (For convenience, imports have been included in the rolled-in mechanism discussed in the previous section and are included here in the interstate category.) If we ignore cross-elasticities, the demand for natural gas is $Q = aP^{\epsilon}$, where P is the price of natural gas, ϵ is the own-price elasticity of demand for natural gas, and a is a constant. If there were a sufficient supply of natural gas, the equilibrium point would be (D_R, P_R) as depicted in Figure V-7. Since (D_R, P_R) is a point on the demand curve D^1, we have $D_R = aP_R^{\epsilon}$, which implies

$$a = \frac{D_R}{P_R^{\epsilon}} . \tag{1}$$

If there is an insufficient supply of interstate natural gas, the quantity of gas demand met by interstate gas is

$$Q_R = \alpha \; a \; P_R^{\epsilon}, \tag{2}$$

where is a fraction between zero and one. Thus, the demand curve for the intrastate natural gas and the substitute fuel bundle is $(1 - \alpha)aP^{\epsilon}$. Since the interstate and the intrastate markets for natural gas are separate, the total demand for natural gas represented by curve D in Figure V-7 is

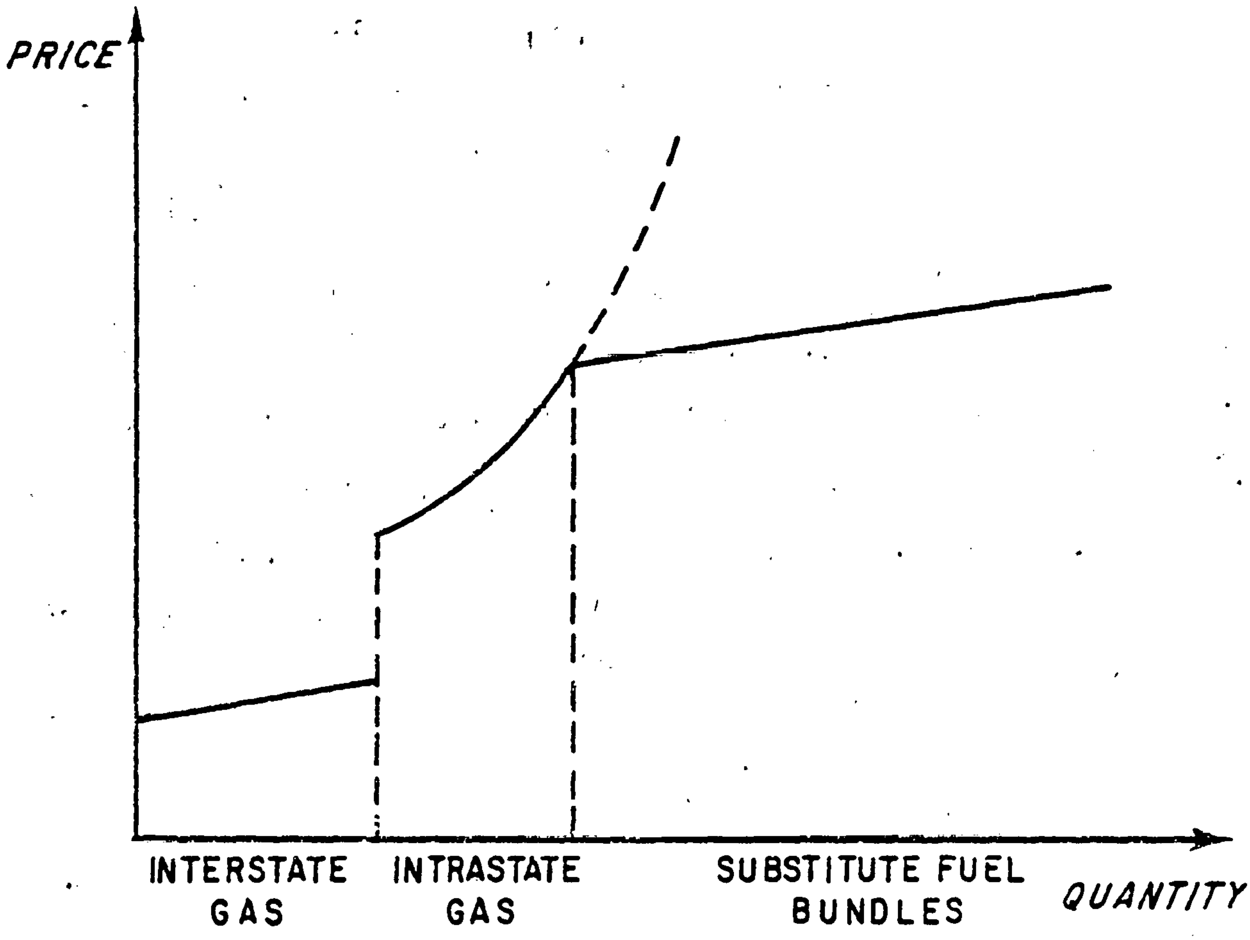
$$Q = Q_R + (1-\alpha)a \; P^{\epsilon} , \qquad Q > Q_R. \tag{3}$$

Substituting equation (1) into equation (2), we get

$$\alpha = Q_R/D_R. \tag{4}$$

FIGURE V-6

NATURAL GAS SUPPLY CURVE



Thus, substituting equations (1) and (4) into equation (3), curve D can be expressed as

$$Q = Q_R + \frac{D_R - Q_R}{P_R} P^{\epsilon}, \qquad Q \geq Q_R \tag{5}$$

or in logarithmic terms,

$$\ln (Q-Q_R) = A^1 + \epsilon \ln P, \qquad Q \geq Q_R, \tag{6}$$

where

$$A^1 = \ln (D_R-Q_R) - \epsilon \ln P_R.$$

Notice that curve D represents the demand for gas that was not satisfied by the supply of interstate gas.

By examining Figure V-7, we see that the total quantity of intrastate gas and substitute fuels demanded is Q_E-Q_R, where Q_A-Q_R is the amount of intrastate gas consumed, and Q_E-Q_A is the quantity of demand met by the substitute fuel bundle. The intrastate gas and the substitute fuel bundles are demanded at a price P_E. We can also see that the total quantity of gas demanded with demand curve D is greater than the quantity demanded with the original demand curve D^1 at higher prices. This is a result of interstate gas customers' seeing the lower interstate price rather than the higher intrastate price.

Substitute Fuel Bundles

An interesting point about Figure V-7 is the supply curve transition from the intrastate supply to the substitute fuel bundle supply curve. This transition occurs according to the market prices of intrastate gas and the price of the fuels comprising the substitute fuel bundle and thus is tied intimately to the LP. The contents of the substitute fuel bundles are sector-specific and are identified in Table V-16. Their contents are in the same proportion as total gas usage for the sector. Each substitute fuel, such as distillate oil, is converted to an equal calorific value of natural gas for each sector in each region. This conversion is in terms of efficiency and Btu content of the fuel.

Since the end use of a fuel determines the level of price response, it is assumed that the consumer will continue to respond with the natural gas elasticity even if substitute fuels are used. For example, industry may continue to use a boiler that generates steam after substituting oil for gas.

FIGURE V-7

SUPPLY AND DEMAND CURVES FOR NATURAL GAS

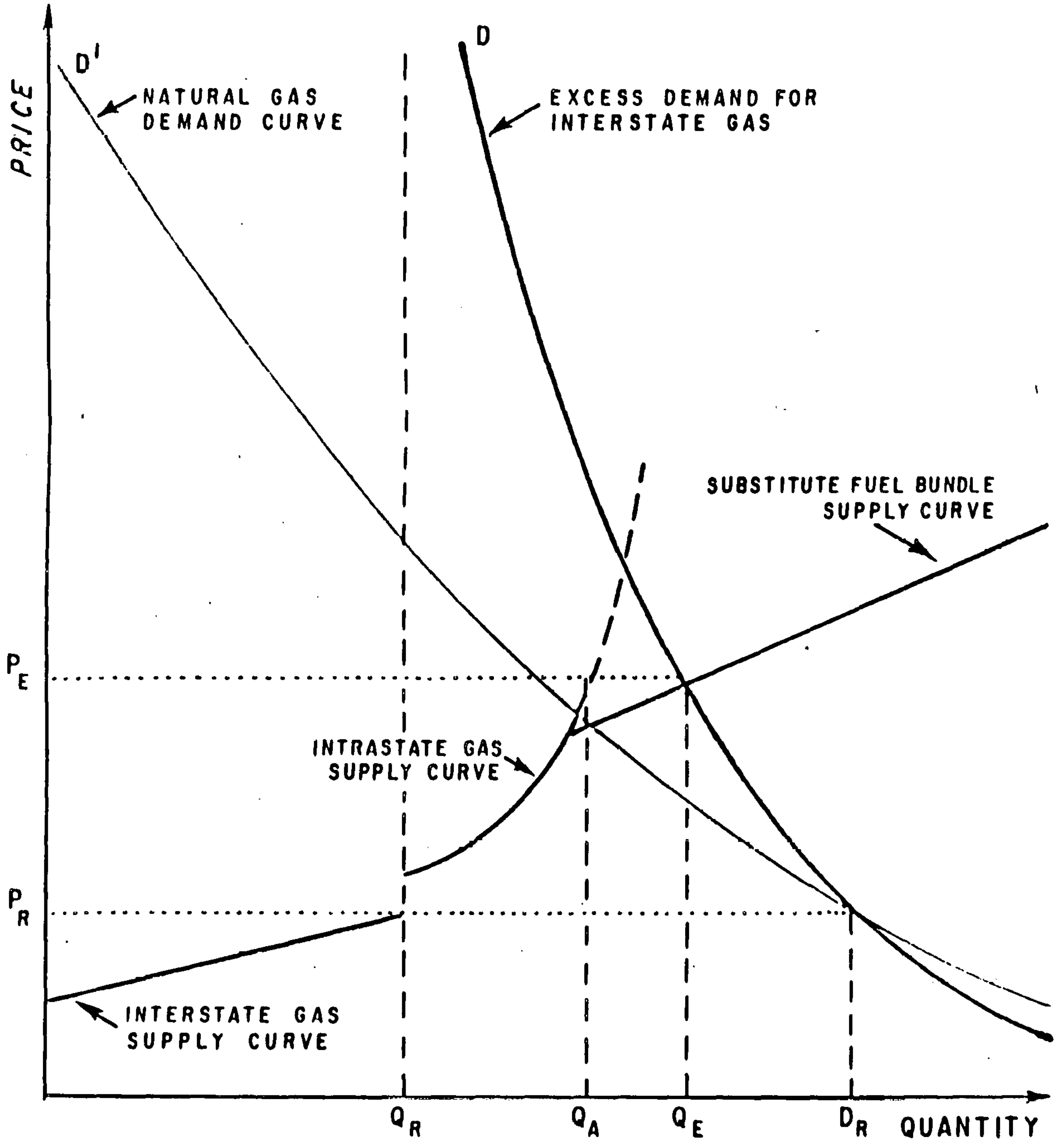


TABLE V-16. SUBSTITUTE FUEL CONVERSION FACTORS*

Sector	Fuel (f)	Btu (B_f)	Efficiency $(\;_f)$	Conversion Factor $(\;_{ng}B_{ng}\;\;_fB_f)$
Residential	Distillate	5.825	.44	.21
	Liquid Gas	4.01	.50	.26
	Natural Gas	1.032	.51	1.0
	Electricity	3.412	1.01	.15
Commercial	Distillate	5.825	.48	.19
	Residual	6.287	.42	.20
	Liquid Gas	4.05	.52	.25
	Natural Gas	1.032	.52	1.0
	Electricity	3.412	1.0	.15
Raw Material	Natural Gas	1.032	1.0	1.0
	Other	5.0	1.0	.21
Industrial	Distillate	5.825	.65	.17
	Residual	6.287	.68	.15
	Liquid Gas	4.05	.65	.25
	Natural Gas	1.032	.63	1.0
	Coal	22.5	.53	.05

*Source: M. Beller, ed., Source Book for Energy Assessment, prepared for ERDA by Brookhaven National Laboratory, BNL-50483, December 1975.

In the LP, the equivalence of substitute fuels to natural gas for a given region and sector is represented in the following form:

$$\begin{array}{|c|l}
\hline
C & \text{objective value} \\
\hline
1 & \text{natural gas demand} \\
-A_1 & \text{electricity demand} \\
-A_2 & \text{distillate oil demand} \\
\cdot & \quad\quad\quad\quad\quad\quad \cdot \\
\cdot & \quad\quad\quad\quad\quad\quad \cdot \\
\cdot & \quad\quad\quad\quad\quad\quad \cdot \\
-A_n & \text{coal demand} \\
\hline
\end{array} \qquad (7)$$

The coefficients A_f represent the amount of each fuel f in the substitute bundle, expressed in physical units (e.g., MMKWH, MB), to fulfill a demand for 1 MCF of natural gas.[9] The value of the A_f is the efficiency-corrected Btu equivalent of fuel f to natural gas and is given by

$$A_f = \frac{\alpha_f \; \eta_{ng} \; B_{ng}}{\eta_f \; B_f} .$$

where

α_f = fraction of fuel f in the bundle

η_f = end-use efficiency of fuel f

η_{ng} = end-use efficiency of natural gas

B_{ng} = Btu content of natural gas

B_f = Btu content of fuel f.

Table V-16 lists the Btu factors and the efficiencies for the substitute fuels in each sector.

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[9] A_f represents the coefficient for fuel f, designated by one of the A_i, i=1, ...,n, in the column above.

Letting π_{ng} be the marginal price (dual variable) of the natural gas demand row, and letting π_f be the marginal price of the fuel f demand row, and by using (7), the reduced cost of the substitute fuel bundle is

$$D = C - \pi_{ng} + \sum_f A_f \pi_f.$$

If there is a shortage of natural gas and the substitute fuel bundle is active, then the reduced cost D must equal zero, and the retail price of intrastate gas must equal the price of the substitute fuel bundle. From the first condition, we obtain:

$$C = \pi_{ng} - \sum_f A_f \pi_f \tag{8}$$

and from the second:

$$\pi_{ng} + M_{ng} = \sum_f A_f (\pi_f + M_f), \tag{9}$$

where M_f = markup of fuel f.

Solving (9) for π_{ng} and substituting into equation (8), we get

$$C = \sum_f A_f M_f - M_{ng}. \tag{10}$$

Using (10), the reduced cost becomes

$$D = \sum_f A_f(\pi_f + M_f) - (\pi_{ng} + M_{ng})$$

$$= \sum_f A_f R_f - R_{ng}$$

where R_f is the retail price of fuel f.

Thus, as long as the retail price of intrastate natural gas is less than the retail price of the substitute fuel bundle (i.e., $R_{ng} \leq \sum_f A_f R_f$), no substitute fuel bundles will be activated. At a sufficiently high level of demand, where the retail price of the substitute fuel bundle is less than the retail price of intrastate natural gas, the fuel bundle is substituted for the natural gas. (A "hurdle rate," representing a nuisance charge of $.10 is added to (10) to prevent switching on the margin between intrastate gas and substitute fuels.)

A_f is calculated once in the first iteration of the equilibrating mechanism for the appropriate scenarios, since the contents of the substitute fuel bundles and their efficiency and Btu factors do not change between iterations.

Super Iterations

If intrastate gas is moved across state boundaries, by law it comes under the jurisdiction of, and has its wellhead prices set by, the FERC. If the market price of intrastate gas falls below the FERC price, the intrastate producer, unencumbered by contractual obligations, would sell his gas to interstate pipelines. The process of allocating this excess gas to the interstate market and calculating a new equilibrium point is called a super iteration.

When an equilibrium is established, and if the price of intrastate gas has fallen below the interstate price, the excess intrastate gas is sold to interstate pipelines, which carry it to demand regions in predetermined portions, based on historical data. These quantities are placed on the list of supply for interstate natural gas used for the rolling-in mechanism. Since this new source of supply for interstate consumers changes the demand for interstate gas, the equilibrium procedure is repeated and continued for up to three computations.

The data for distributing the excess gas consist of two matrices, one indicating the fraction of intrastate gas to be shipped from the 10 intrastate gas regions to 9 interstate gas regions, and the other indicating the fraction of interstate gas to be shipped from 9 interstate gas regions to the 10 demand regions. These data are given in Tables V-17 and V-18. Coproducts of nonassociated gas (gas liquids and butane) are shifted from intrastate gas regions to oil supply regions by the proportions given in Table V-17, with the exception of combining the Michigan Basin and Eastern Interior region with the Appalachian region. Thus, the proportion from the Midwest intrastate gas region to the combined region is 1.0.

The following small example demonstrates the need for these super iterations. Suppose that the regulated price of interstate natural gas is $1.42/MCF, while that of intrastate natural gas has slipped to $1.30/MCF. Further suppose that this price difference has created 1,000 MCF/D of excess intrastate natural gas in each of three intrastate gas regions. This excess 3,000 MCF/D of intrastate natural gas would be parcelled out to demand regions by the appropriate fraction. Thus, if the fractions of intrastate gas to be shipped from three intrastate gas regions to three demand regions are those in Table V-19, there would be an extra 768 MCF/D, 1,056 MCF/D, and 1,056 MCF/D of natural gas available in demand regions 1, 2, and 3, respectively. Notice the 4 percent loss due to transmission.[10]

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[10] Demand Region 1: $3000 \left(\frac{.8}{3.0}\right) (.96) = 768$ MCF/D

Demand Region 2: $3000 \left(\frac{1.1}{3.0}\right) (.96) = 1,056$ MCF/D

Demand Region 3: $3000 \left(\frac{1.1}{3.0}\right) (.96) = 1,056$ MCF/D

TABLE V-17. FRACTION OF INTRASTATE GAS TO INTERSTATE MARKET

INTERSTATE GAS REGION

INTRASTATE GAS REGION	Pacific Coast	W.Rocky Mtns.	E.Rocky Mtns.	W.Tex. & E.N.Mex.	W.Gulf Basin	Mid-continent	Mi.Basin, Int.	Appalachians	Atlantic Coast
NW-Eng.									
NY/NJ								1.00	
Mid-Atl								1.00	
S-Atl					.49			.33	.18
Midwest							.43	.57	
S-West		.04		.26	.45	.25			
Central						1.00			
N-Central		.26	.74						
West	.99	.01							
N-West									

TABLE V-18. FRACTION OF INTERSTATE GAS TO DEMAND REGIONS

DEMAND REGION

INTERSTATE GAS REGION	NW-Eng	NY/NJ	Mid-Atl	S-Atl	Midwest	S-West	Central	W-Central	West	N-West
Pacific Coast									.990	
W.Rocky Mtns.						.034		.222	.641	.049
E.Rocky Mtns					.072		.120	.743	.016	.020
W.Tex.& E.N.Mex.				.019	.141	.159	.139	.009	.474	
W.Gulf Basin	.028	.092	.124	.238	.285	.152	.025			
Midcontinent		.011	.015	.019	.393	.120	.337	.058	.019	
Mi.Basin, Int.					.990					
Appalachians		.260	.350	.067	.294					
Atlantic Coast	.076	.272	.345	.262						

TABLE V-19. DISTRIBUTION OF INTRASTATE GAS TO DEMAND REGIONS

Intrastate Gas Region	Demand Region 1	2	3	Total
1	0.0	0.4	0.6	1.0
2	0.5	0.0	0.5	1.0
3	0.3	0.7	0.0	1.0
TOTAL	.8	1.1	1.1	3.0

Summary

The following is a series of steps by which PIES undertakes the regulation of natural gas.

(1) Using the average wellhead price for lower-48 interstate gas, plus the appropriate transportation charge and markups, and the prices for competing fuels, the residential demand for each region is calculated and subtracted from the available supply.

(2) If there is excess gas, the process is repeated for the commercial, raw material, and industrial sectors successively, until either all demand is satisfied or the supply runs out.

(3) The prices and quantities of Canadian gas, synthetic gas, Alaskan gas, and liquefied natural gas are successively rolled into the supply of gas available to a region. Each sector's demands are reevaluated with the new prices. The rolling-in is continued until either no more supply is available or demand is satisfied.

(4) In the sector for which demand is not satisfied by interstate gas (including the supplemental sources listed in (3)), the ratio of total gas available from these sources to the sector and the regional demand in that sector is used to determine the amount of interstate gas available to it.

(5) The demands met by these sources of natural gas are input into the LP matrix.

(6) The demand for intrastate gas and the substitute fuel bundles is determined by taking the fraction of unmet demand for a curtailed sector; evaluating the Demand Model with the appropriate gas prices from the previous iteration, as well as the other fuel prices; and multiplying by the fraction of unmet demand. A demand curve approximation is then built around this point to approximate D in Figure V-7.

(7) The LP is solved, and the process is repeated for the new approximation.

(8) After an equilibrium is computed, intrastate wellhead prices are examined. If any price is below the regulated ceiling (i.e., the current interstate wellhead price), the amount that would be sold at the higher price is transferred to the interstate market by increasing interstate (and decreasing intrastate) supply. A new equilibrium is then computed. This process is repeated for successive equilibria, allowing transfer from the intrastate to the interstate market, based upon wellhead prices. (Generally, only one or two "super equilibria" are necessary to converge.)

VI. REFINERIES

INTRODUCTION

The PIES equilibrating mechanism calculates the equilibrium prices and quantities of 30 different products. These products are composed of 12 fuels in 5 demand sectors. Seven of these 12 fuels are petroleum products, namely, gasoline, residual fuel oil, distillate oil, jet fuel, liquid gas, naphtha, and "other" petroleum products. The conversion of crude oils into these seven products is modeled by the PIES refineries submodel, which describes the operation and economics of existing refineries, and the construction of new refineries in the U.S.

The character of the refineries model is largely governed by the fact that the various crude oils processed by refineries have different physical and chemical characteristics (different qualities); consequently, each type must be processed slightly differently, implying differing product yields, costs of operation, and utilization of capacities.

The refineries submodel is one of the two industry-specific "process"[1] submodels which are part of the integrated PIES supply network (the other is the utilities submodel).

This chapter describes the general characteristics of the refineries submodel in five sections. The first describes refinery operation and its relation to the modeling that occurs in PIES. The basic assumptions of the refineries submodel are discussed in the second section; the derivation of refinery values for the PIES LP matrix in the third section; the meaning of these values within the matrix in the fourth section; and the refinery calculations made within the equilibrating mechanism in the fifth section.

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[1] A "process" model is one that models the processes that occur within a specific sector and relates the level of activity of these processes to fuel requirements.

THE REFINING PROCESS

Refineries convert crude oils into a number of refined products, which are used both as fuels and petrochemicals. Normally, a refinery can process many different types of crude oil which may differ in chemical composition and cost.

In general, each crude oil is a complex mixture of different hydrocarbon molecules. In refineries, the hydrocarbons in these mixtures are separated from each other and selectively processed by means of chemical reactions and blended such that the characteristics of the resulting products are those of the refined products required. Product specifications (such as octane number, sulfur content, etc.) are used to determine the physical and chemical characteristics of the products.

Thus, a refinery consists of a number of units which separate, convert, or combine the crude oil or intermediate product streams to form the final products. Refineries also typically have a large amount of storage space for raw materials, intermediate materials, and final products.

The crudes contain complex mixtures of relatively small and simple molecules, which are highly volatile (i.e., have low boiling points), and progressively larger and more complex molecules, which are progressively less volatile (i.e., have high boiling points). Because the different hydrocarbons have different boiling points, they can be separated by distillation, which is usually the first process in a refinery.

The crude is heated in a series of stills or in a fractionating tower. As the more volatile hydrocarbons boil off, the product is separated into a number of different fractions, each distinguished by a range of boiling temperatures. Thus, for example, fuel gas, the lightest product, boils off and can be separated below 85°F, kerosene boils off between 400° and 500°F and distillate fuel boils off between 550° and 650°F.

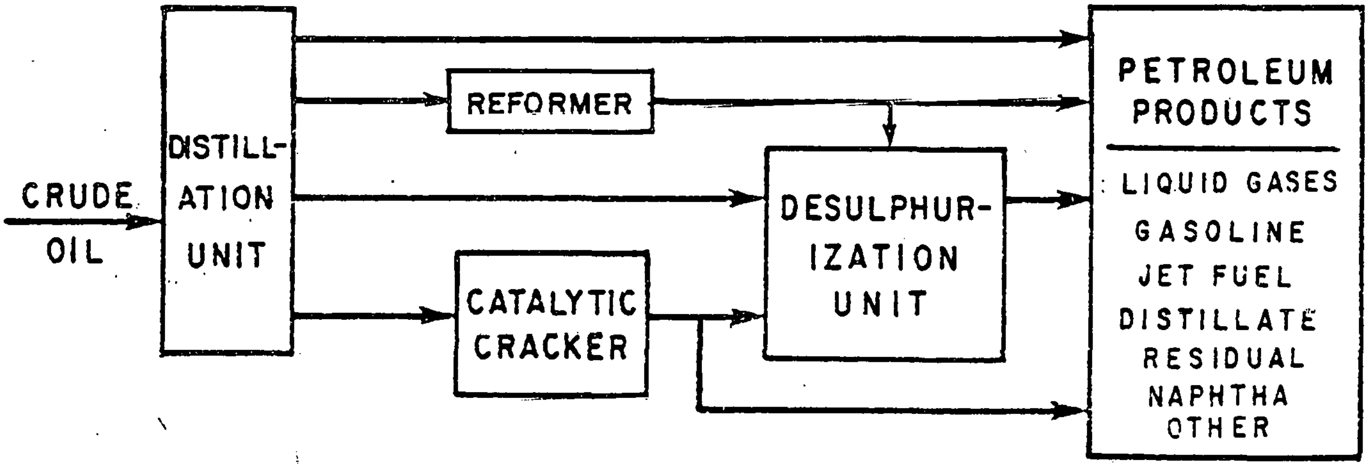
Distillation, therefore, produces the first set of intermediate products in the refinery. The relative magnitude of each fraction is a function solely of the physical and chemical characteristics of the crude and the market requirements. Adjustments to the operating characteristics of the distillation units such as altering the temperature at which fractions are separated, are used to control the product yields.

It would be coincidental if the relative demands for final products matched the relative volumes of the fractions, and they generally do not. To improve the matching, two sets of chemical processes are used: "reforming," which alters the structure of hydrocarbons to form high octane products, and "cracking," which breaks up heavier molecules into lighter ones.

A number of other chemical processes, such as alkylation, coking, and isomerization, are also used on parts of the intermediate product stream to change the relative product yields obtained. Other processes, such as desulfurization, are included to improve product quality for environmental reasons. Figure VI-1 is a simplified diagram of chemical processes in a refinery.

FIGURE VI -1

SIMPLIFIED MATERIAL FLOW THROUGH A REFINERY



Further progress towards optimizing the product yield by blending intermediate products is done by the use of tank farms at the refineries.

Most refineries have considerable flexibility to vary their product yields to meet changing demands, both periodic and long-term. This flexibility is also necessary to permit the processing of a variety of different crude types, each with unique chemical and physical characteristics.

Because the cracking processes break up heavier hydrocarbons into lighter hydrocarbons it is usual to experience a "volumetric gain" in the refinery, i.e., more barrels of refined products are produced than there were barrels of crude. The volumetric gain, however, may be accompanied by a "Btu loss," which represents the heat losses taking place during the chemical reactions.

PIES REFINERY SUBMODEL

Because PIES is a forecasting tool, the refinery submodel is intended to simulate planning and operational behavior (rather than necessarily compute an optimum). Over the past 25 years, refineries have used LP techniques to determine least-cost methods of operation. These techniques, like the ones used in PIES, represent the physical process by a system of linear equations.

The central activities in the PIES refineries submodel correspond to the operation of distillation units and the blending of intermediate products (e.g., naphthas) to make marketable products (e.g., gasolines). PIES can recognize 45 different types of crude oil. Refinery capacity may be expanded either by adding equipment to existing refineries or by constructing new refineries. The refineries submodel also has the option, currently unused, to model desulfurization, reforming, and catalytic cracking capacity.

PIES models refineries in the aggregate by combining the characteristics of all refineries in a region into one composite refined representation of existing ones in that region. This approach captures most of the flexibility of individual refineries but simplifies the model significantly.

PIES represents the operation of refineries in seven refinery regions, corresponding to Petroleum Administration for Defense Districts (PADDs). Table VI-1 shows the correspondence between PIES refinery regions and PADDs. Figure VI-2 shows the location of each PADD.

TABLE VI-1. PIES REFINERY REGIONS

Refinery Region	PADD
R1	1A
R2	2A
R3	3
R4	4
R5	5
R6	1B
R7	2B

Domestic crudes are transported from oil-producing regions to refinery regions; the transportation links are represented by the crude oil material balance equations. Not all domestic crudes are available for processing in all refinery regions. For example, Californian refineries do not process Gulf Coast crudes. Restrictions on availability of crudes are imposed on the refineries submodel in two ways. First, unavailable crudes are excluded from the raw data provided to the refineries pre-processor. Second, the model does not represent transportation links between producing and refinery regions where none exist. Table VI-2 shows the regional availability of specific domestic crudes. Table VI-3 lists the American Petroleum Institute (API) gravity and sulfur content for each of these crudes.

PIES represents imports as fixed bundles with differing proportions of crude types. Table IV-8 (Chapter IV) details the composition of imports to each import region and shows the fixed fraction of each barrel of imported oil transported to a refinery region. Like domestic crudes, imported crudes enter the refineries submodel via the crude oil material balance equations. The exception is Canadian crude which is available to all refinery regions as a single crude type. Once a bundle of crudes has been imported, the individual crudes can be transported to certain other refinery regions, as indicated by the PIES transportation links. Table VI-2 shows the availability of imported crude to each refinery region. Table VI-4 lists the sulfur content and API gravity for imported crudes.

FIGURE VI-2

PIES REFINERY REGIONS

(PADD REGIONS)

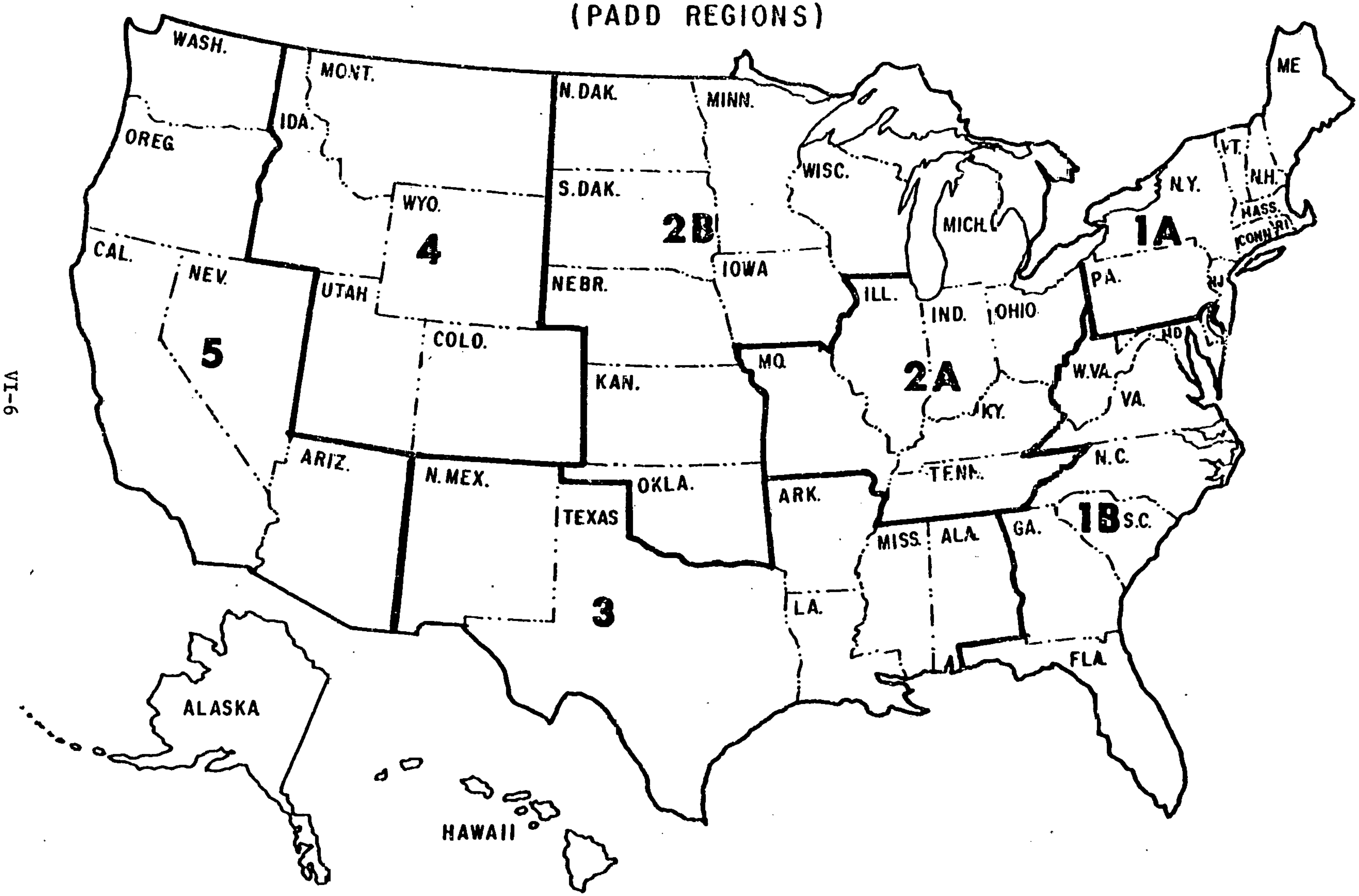


TABLE VI-2. REGIONAL AVAILABILITY OF SPECIFIC CRUDES FOR REFINING*

	Refinery Region						
Crude Type	1	2	3	4	5	6	7
Angola/Congo/Zaire	1	1	1	1	1	1	1
Ecuador	1	1	1	1	1	1	1
Indonesia	1	1	1	1	1	1	1
China				1			
Venezuela	1	1	1	1	1	1	1
Mexico	1	1	1	1	1	1	1
Norway	1	1	1	1	1	1	1
Russia	1	1	1	1		1	1
Alaska North Slope	1	1	1	1	1	1	1
Libya 1	1	1	1	1	1	1	
Algeria	1	1	1	1	1	1	1
Nigeria/Gabon	1	1	1	1	1	1	1
Iran Light	1	1	1	1	1	1	1
Iran Heavy	1	1	1	1	1	1	1
Iraq	1	1	1	1	1	1	1
Kuwait	1	1	1	1	1	1	1
Saudi Arabia Light	1	1	1	1	1	1	1
Saudi Arabia Heavy	1	1	1	1	1	1	1
Qatar/U.A.E.	1	1	1	1	1	1	1
Alaska South					1		
Pacific Offshore			1		1		
Wyoming Mix		1	1	1			1
Shale Oil	1	1	1	1		1	1
Louisiana Onshore	1	1	1	1		1	1
Louisiana Offshore	1	1	1	1		1	1
Texas Gulf Coast	1	1	1	1		1	1
East Texas Mix	1	1	1	1		1	1
West Texas Mix	1	1	1	1		1	1
PADD II, Indig.	1	1	1	1		1	1
Oklahoma Mix	1	1	1	1		1	1
PADD I, Indig.	1	1	1	1		1	1
Heavy Crude, V					1		
Heavy Crude, IV				1			
Heavy Crude, III			1	1			
Heavy Crude, II		1					
Canada	1	1	1	1	1	1	1
Syn Crude	1	1	1	1	1	1	1
Naval Petroleum Reserve 1			1		1		
San Joaquin Valley			1		1		
Los Angeles Basin			1		1		
United Kingdom	1	1	1	1	1	1	1
South Asia Mix	1	1	1	1	1	1	1
Egypt/Syria/Bahrain	1	1	1	1	1	1	1
Bolivia/Peru	1	1	1	1	1	1	1
Trinidad	1	1	1	1	1	1	1

TABLE VI-3. DOMESTIC CRUDE CHARACTERISTICS

	Percentage Sulfur	API Gravity
Alaska North Slope	1.0	27
South Alaska	0.8	37
Pacific Offshore	0.9	31
Wyoming Mix	1.7	31
Shale Oil	0.1	35
Louisiana Onshore	0.3	33
Louisiana Offshore	0.3	33
Texas Gulf	0.2	34
East Texas Mix	0.3	38
West Texas Mix	1.3	36
PADD II Indigenous	0.4	38
PADD I Indigenous	0.3	38
Oklahoma Mix	0.8	35
PADD V Heavy	1.2	10
PADD IV Heavy	1.2	10
PADD III Heavy	1.2	10
PADD II Heavy	1.2	10
Naval Petroleum Reserve 1	0.5	35
Syncrude	0.1	35
San Joaquin	0.3	35
Los Angeles	1.5	22

TABLE VI-4. IMPORTED CRUDE CHARACTERISTICS

	Percentage Sulfur	API Gravity
Arabian Light	1.7	35
Arabian Heavy	3.0	27
Kuwait	2.5	31
Iraqi	1.4	38
Iranian Light	1.4	34
Iranian Heavy	1.6	31
Mid-East Mix	1.9	34
Libyan	0.3	39
Algerian	0.1	44
Nigerian	0.1	33
Indonesian	0.1	36
Ecuadorian	1.6	28
Venezuelan Mix	2.1	17.5
Mexican	1.6	26
African	0.1	33
Russian	1.7	35
Chinese	0.1	36
Canadian Mix	0.6	37
North Sea	0.2	36

The activities that take place within the PIES refineries submodel are the operation of existing and new refineries, the construction of new refineries, and the blending (or pooling) of refined products. PIES assumes that the operating characteristics of new and existing facilities are identical except for more efficient fuel use in new refineries.

Operation of Refineries

Conversion of specific types of crude to the seven refined products is modeled by relationships that define the volumes of each finished product derived from each unit of crude. A separate relationship describes each crude available in a region. Typically, a PIES equilibrium between supply and demand activates a number of these relationships in each region, reflecting the use of a mix of crudes.

As well as describing the proportions of the yields, these relationships also contain information about the capacity of refining facility required to process each unit of each type of crude. For example, processing one barrel of a crude may require that one barrel of distillation capacity be available. Equations relating levels of capacity sum all of these requirements across all crude types and ensure that sufficient capacity is available by permitting the building of new capacity and constraining new capacity as needed. Associated with these relationships are the costs of processing each barrel of crude.

Building New Refineries

The cost of building new capacity and limits on this new capacity are represented in the LP matrix.

Blending of Products

The blending of products in PIES reflects refinery flexibility to alter their operations to satisfy demands. PIES permits any product to be converted to any other product on a Btu equivalent basis, but at a cost (which includes the effect of volume changes). Such flexibility is reasonable only if the activity levels are small. PIES models product blending by shift activities, which are described later in this chapter.

DERIVATION OF REFINERY VALUES FOR LP MATRIX

The modeling of refinery operations within PIES requires an aggregate approximation to the operating characteristics of existing and planned refineries in the U.S.

The operation of a refinery is expressed mathematically by indicating the quantity of each refined product that is obtained from a barrel of crude. This procedure produces a solution space from which an optimal solution for the operation of refineries is selected.

For each crude type, average yield relationships are provided, which represent an intermediate point of the solution space. Other points of the solution space are achieved through shift activities, which are discussed later in this chapter.

The petroleum product prices obtained from a PIES solution reflect the joint product costing capability of the refineries submodel based on the shift activity costs.

Within each of the seven regional refineries, the modeling procedure, which supplies the necessary data to the PIES matrix, is identical. There are 12 steps, described below. Figure VI-3 illustrates the relationships between the steps; the step numbers appear beneath the right corner of the appropriate box. This procedure determines the values used to model the refinery operation in the PIES LP matrix. The following section discusses the values obtained from this procedure and their meaning in relationship to the matrix.

Step 1 - Input Base Year Crude Slate

Data are provided on the quantities of each type of crude refined in the region in the base year, 1976. Table VI-5 shows the values used. These volumes of crude are referred to as the set v_i, where the subscript i denotes the crude type (i = 1, 2..., 33).

Step 2 - Normalize the Crude Slate

The volumes of each crude type refined are converted to fractions of the total volume of crude refined in the region. These fractions are called f_i, where

$$f_i = \frac{v_i}{\Sigma v_i}$$

for each region. These volumes determine the average crude slate for the base year.

FIGURE VI-3

FLOW CHART OF REFINERIES SUBMODEL STRUCTURE

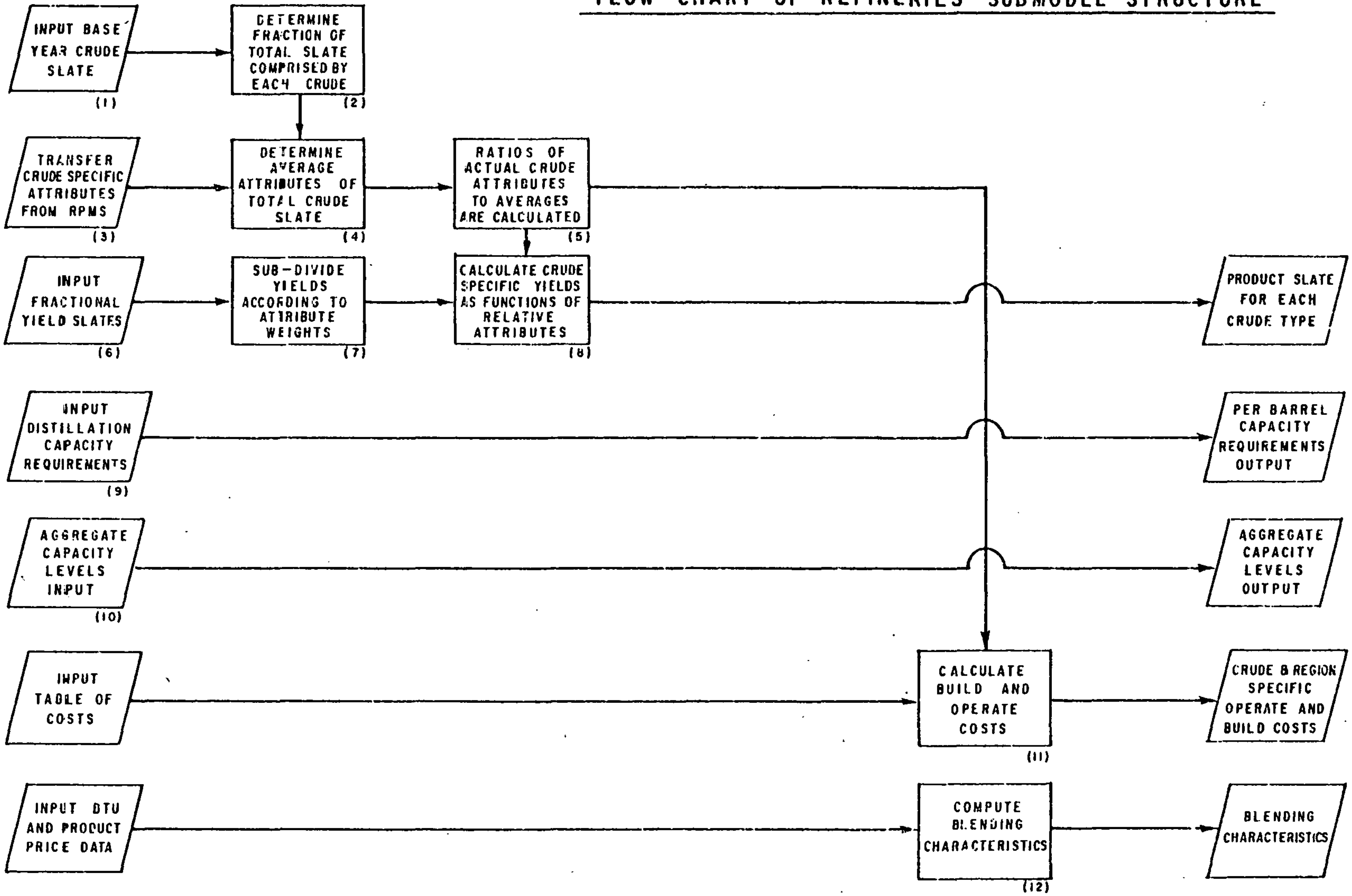


TABLE VI-5. QUANTITIES OF CRUDE REFINED IN 1976
(MB/D)

			PADD		
CRUDE TYPE	I	II	III	IV	V
Foreign					
Canadian Mix	16	214		54	87
Mexican	7	3	77		
Trinidad	4	38	61		
Venezuelan Mix	161	17	56		7
Norwegian	5	15	15		
United Kingdom	2	8	3		
Iranian Light	62	13	30		45
Iranian Heavy	62	13	30		45
Saudi Arabian Light	433	153	456		179
Qatar/U.A.E.	42	58	108		108
Indonesian	35		54		448
Algerian	189	76	138		5
Angola/Congo/Zaire	24	2	7		
Egypt/Syria/Bahrain	19		9		
Libyan	57	227	153		9
Nigerian	295	156	543		48
Iraqi	6	19			
Bolivian/Peruvian			5		4
Ecuadorian			11		38
Russian			2		
South Asian Mix					15
Domestic					
Lousiana Onshore	42	438	1593		
Texas Gulf Coast	82		672		
PADD I, Indigenous	51		163		
PADD II, Indigenous	43	518		175	
Wyoming Mix		180		219	284
East Texas Mix		43	443		
West Texas Mix		954	1008		
Oklahoma Mix		469	19		
Alaskan South					191
Heavy Crude					282
San Joaquin Valley					110
Los Angeles Basin					175

Step 3 - Obtain the Crude Slate Attributes

A set of attributes describes the physical and chemical behavior of each crude type when processed in a refinery. Table VI-6 lists the attributes used in PIES. This list is a subset of a more extensive list contained in the RPMS[2] (Refinery and Petrochemical Modeling System) library, which is a library of attributes for most of the world's crude oils. The PIES refineries submodel accesses the RPMS library to obtain the attributes where a_{ij} is the value of the jth attribute of the ith crude.

TABLE VI-6. CRUDE OIL ATTRIBUTES USED IN PIES*

Description	Type of Attribute	Units per Barrel of Crude
N2A Reformer Feedstock	Conversion	N2A-barrels
KFC Catalytic Feedstock	Conversion	K-factor-barrels
Turbine Fuel	Yield	Volume Fraction
CBN Distillate	Blend	CBN-barrels
Atmospheric Bottoms	Yield	Volume Fraction
Gasoline	Yield	Volume Fraction
Reformer Feedstock	Yield	Volume Fraction
Catalytic Feedstock	Yield	Volume Fraction
Crude	Yield	Volume Fraction
Sulfur Remaining	Sulfur Content	Lbs sulfur in cut

---

*More detailed descriptions of these attributes are given in Bonner & Moore's RPMS User's Manual, MSH 021, July 1974, Houston, Texas.

Step 4 - Average the Attributes

A set of average attributes is calculated for the base year crude slate, denoted as A_j where

$$A_j = \Sigma (f_i \times a_{ij}).$$

These average attributes characterize the base year slate of crudes.

---

[2] RPMS is a proprietary product of Bonner & Moore Associates, Inc.

Step 5 - Normalize Crude-Specific Attributes

The ratios of the actual attributes of each crude used in the base year in the region to the average attributes are calculated. These ratios (denoted z_{ij}) will be used to determine the variation of yields in the refineries.

The ratios, known as relative crude attributes, are given by

$$z_{ij} = \frac{a_{ij}}{A_j}$$

Step 6 - Provide Product Slates

The region's yield slate (i.e., mix of refined products) for the base year is input to the model. The yields y_k (where k denotes the product, k = 1, ..., 7) are fractions of the total yield for the region. Table VI-7 shows these region specific yield fractions.

TABLE VI-7. REFINED PRODUCT YIELDS AS FRACTIONS OF TOTAL YIELD

	PADD				
Product	I	II	III	IV	V
Liquid Gases	.031	.021	.012	.011	.019
Gasoline	.460	.526	.414	.455	.438
Naphtha	.017	.015	.093	.009	.014
Jet Fuel	.032	.046	.076	.060	.117
Distillate	.251	.245	.245	.292	.125
Residual	.113	.065	.090	.089	.198
Other	.102	.090	.062	.078	.083

Source: "PADD District Supply/Demand, Year 1976", Bureau of Mines

Step 7 - Weight the Attributes

The yields of five of the seven refined products are each assumed to be dependent solely on the value of one crude attribute, although the attribute is not the same for each product. The remaining two products are each dependent on a pair of attributes. Table VI-8 shows the full dependence of products on attributes.

TABLE VI-8. RELATIONSHIP BETWEEN ATTRIBUTES AND PRODUCTS

Product	Related to Attribute
Gasoline Liquid Gases	50% KFC Catalytic Feedstock 50% N2A Reformer Feedstock
Jet Fuel	Turbine Fuel
Distillate	CBN Distillate
Residual	Atmospheric Bottoms
Naphtha	Gasoline
Other	Atmospheric Bottoms

To model the dependence on a pair of attributes, the yields for the two products concerned are subdivided into subproducts according to the weights given the attributes. For gasoline and liquid gases, the dependence on pairs of attributes is equivalent to saying that 50 percent of the liquid gas (and gasoline) yields depends only on the value of attribute "KFC Catalytic Feedstock," while the remaining 50 percent of the yield depends only on attribute "N2A Reformer Feedstock." Thus, to model the dependence on a pair of attributes, the product yields are subdivided in proportion to the weight given the attributes.

To see this mathematically, let w_{kj} equal the percentage of attribute j on which product k is dependent. Note from Table VI-8 that w_{kj} is equal to either 0,.5, or 1.0. Then, the subdivision of product yields results in:

$$s_{kj} = y_k w_{kj} .$$

where y_k is the yield of product k.

Step 8 - Determine Crude-Specific Yields

This step determines the relationship between the yields expected from specific crudes and the average yields in a refinery region. The procedure uses the subdivided yields determined in step 7 and the ratio of the actual attributes to the average for the refinery region determined in step 5. For example, if the base yield for jet fuel is 7.5 percent per year, the average regional value of the "turbine fuel" attribute is 9 percent (A_j), and a specific crude contains a "turbine fuel" value of 12 percent, (a_{ij}), then that crude should be expected to yield 10 percent of its yield as jet fuel ($10\% = 7.5\% \times \frac{12\%}{9\%}$). These yields are then normalized for each refined product.

Mathematically, we obtain

$$u_{ikj} = \frac{s_{kj}\ z_{ij}}{\sum_k s_{kj}\, z_{ij}}$$

where z_{ij} and s_{kj} are determined from steps 5 and 7, respectively. The products that were divided into two parts in step 7 are now aggregated as follows:

$$r_{ik} = \sum_j u_{ikj}$$

resulting in a ratio dependent on the crude type i and product type k.

These relative yields will be used in the LP matrix to provide the operating characteristics of refineries when supplied with specific crude types.

Step 9 - Input Distillation Capacity Requirements

Thus far, processing within the refineries submodel has been concerned with determining the operating characteristics of the refineries. The next step determines the capacity requirements in each of the seven refinery regions. PIES refineries are currently constrained by the capacity of a crude distillation unit. PIES has the option to model a reformer unit, a desulfurization unit, and a catalytic cracker as well, but this option is not currently exercised. For each barrel of crude that is refined daily, a refinery must have one barrel of crude distillation capacity.

Step 10 - Set Aggregate Capacity Requirements

The region-specific aggregate capacity values given in Table VI-9 are input to the refineries submodel. These values are all factored by 0.90 because capacity typically can only achieve a utilization factor of 90 percent.

TABLE VI-9. LIMITS ON EXISTING CRUDE DISTILLATION CAPACITY (MB/D)

Refinery Region	Capacity
1	1630
2	2885
3	7382
4	581
5	2956
6	278
7	1335

Step 11 - Calculate Operating and Construction Costs

The costs required are operating costs, the costs of constructing new equipment, and the costs of blending products. A table of regional costs (Table VI-10) is input to the refineries submodel.

TABLE VI-10. REFINERY COSTS (DOLLARS/BARREL)

Refinery Region	Net Investment	Operating
1	1.100	1.687
2	1.004	1.687
3	0.907	1.591
4	0.980	1.687
5	1.003	1.687
6	1.100	1.687
7	1.004	1.687

Costs of construction for new facilities are given by the values in the net investment column which represent incremental investment costs above the capital recovery costs included in the operating cost column. Costs of operation are given by operating cost from Table VI-10, based on the Nelson cost indexes in the Oil and Gas Journal and a desulfurization charge based on the sulfur content of the residual fractions of crude oils.

Step 12 - Calculate Blending Relationships

The PIES refineries submodel models the blending of refined products in order to represent the flexibility that refineries have to change their crude and product slates, and to alter their operations to meet demands.

Each of the seven refined products can be converted to any of the other products at a cost. The costs reflect the difference in product prices, plus \$0.05 per barrel. The calculation is based on the Btu content of the two products. Table VI-11 shows the data needed for these calculations.

TABLE VI-11. DATA FOR BLENDING CALCULATIONS

Product	Btu Content per Barrel (MMBTU)	Assumed Product Price* (\$/B)
Liquid Gases	4.010	10.50
Gasoline	5.248	16.44
Jet Fuel	4.318	16.19
Distillate	5.825	15.77
Residual	6.287	14.74
Naphtha	5.248	15.82
Other	5.000	16.24

*Source: Sobotka and Company, Inc., Washington, D.C.

For example, 1 barrel of liquid gases can be converted to 0.764 ($= \frac{4.010}{5.248}$) barrels of gasoline at a cost of \$2.61/barrel ($= \frac{4.010}{5.248} \times 16.44 - 10.50 + 0.05$).

REFINERY ELEMENTS IN THE LP MATRIX

Conversion activities like the refinery process are modeled by specifying two types of constraints: one conserves mass, the other restricts operating capacities.

The first type of equation conserves mass by specifying that crudes entering a refinery region must be balanced by their transportation from the supply regions. Likewise, refined products leaving a refinery region must be balanced by their transportation to the demand regions. Conservation of mass must also occur in the refinery operation. Thus, the total volume of a product produced must equal the volume of that product produced from processing crudes and from blending other products, less the volume that was blended into other products.

The other constraint type is related to refining facilities. PIES models capacity levels of distillation facilities. In general, the total capacity needed in the refinery operation must exceed the existing refinery capacity, plus the capacity of any new facilities that are built.

In this section, we describe the refinery constraints and relationships within the LP matrix. Thus, we will see how the data generated in the previous section are used within the matrix.

Crude Conversion

The PIES refineries submodel provides for the conversion of crude oil into seven refined petroleum products - liquid gas (LG), gasoline (GA), naphtha (NA), jet fuel (JF), distillate (DS), residual (RS), and a miscellaneous category, "other" petroleum products (OT). The potential yield of each refinery product from a barrel of crude varies according to each crude type. Table VI-12 describes the refinery product yield per barrel of crude consumed in refinery region 3. The crude types appear as rows, and the refinery products appear as columns. Still gas (SG) is modeled the same way as the other products given above, but because it is used only as a refinery fuel it is excluded from our description of refinery products.

In Table VI-12, we see that one barrel (B) of Arabian Light (AL) crude is converted into:

.0108 B LG + .3729 B GA + .1048 B NA
+ .0734 B JF + .2356 B DS + .1176 B RS
+ .0770 B OT + .0350 B SG,

using one barrel of distillation capacity. Adding these products, we see that one barrel of AL-type crude has been converted to approximately 1.027 B of refined products. This

TABLE VI-12. BARRELS OF REFINERY PRODUCTS PRODUCED PER BARREL OF CRUDE CONSUMED

Crude Type	Liquid Petroleum Gases	Gasoline	Naphtha	Jet Fuel	Distil-late	Residual	Other Petroleum Products	Still Gas	Total Refinery Product
Arabian Light	.0108	.3729	.1048	.0734	.2356	.1176	.0770	.0350	1.027
Arabian Heavy	.0108	.3730	.0713	.0528	.2007	.1713	.1120	.0350	1.027
Kuwaiti Export	.0111	.3837	.1039	.0625	.1922	.1449	.0936	.0350	1.027
Iraqi	.0108	.3729	.1048	.0734	.2356	.1176	.0770	.0350	1.027
Iranian Light	.0100	.3463	.1261	.0846	.2431	.1101	.0718	.0350	1.027
Iranian Heavy	.0108	.3716	.0931	.0611	.2176	.1434	.0944	.0350	1.027
Mid-Eastern Mix	.0103	.3574	.1316	.0695	.2199	.1231	.0801	.0350	1.027
Libyan	.0119	.4122	.1277	.0716	.2197	.0894	.0595	.0350	1.027
Algerian	.0116	.4014	.1582	.0672	.2073	.0879	.0582	.0350	1.027
Nigerian & Gabon	.0139	.4807	.1022	.0782	.1952	.0714	.0502	.0350	1.027
Indonesian	.0122	.4211	.0532	.0506	.2412	.1267	.0868	.0350	1.027
Ecuadorian	.0128	.4416	.1637	.0608	.1495	.0974	.0662	.0350	1.027
Venezuelan Mix	.0109	.3749	.0786	.0605	.1674	.1818	.1178	.0350	1.027
Mexican	.0108	.3729	.1048	.0734	.2356	.1176	.0770	.0350	1.027
Russian Export	.0108	.3729	.1048	.0734	.2356	.1176	.0770	.0350	1.027
Canadian Mix	.0115	.3966	.1064	.0586	.1996	.1322	.0871	.0350	1.027
Egyptian/Syrian	.0108	.3738	.0949	.0617	.2178	.1404	.0925	.0350	1.027
Angola/Congo/Zaire	.0122	.4211	.0532	.0506	.2412	.1267	.0868	.0350	1.027
Bolivian/Peruvian	.0116	.4014	.1582	.0672	.2073	.0879	.0582	.0350	1.027
Norwegian	.0134	.4634	.0776	.0705	.2068	.0956	.0647	.0350	1.027
South Asian	.0108	.3729	.1048	.0734	.2356	.1176	.0770	.0350	1.027
Trinidad	.0134	.4634	.0776	.0705	.2068	.0956	.0647	.0350	1.027
United Kingdom	.0108	.3729	.1048	.0734	.2356	.1176	.0770	.0350	1.027
Synthetic Crude	.0144	.4959	.0146	.0906	.2881	.0523	.0361	.0350	1.027
Alaskan North Slope	.0133	.4576	.0700	.0585	.1760	.1298	.0868	.0350	1.027
West Coast Light	.0120	.4137	.0221	.0248	.1008	.2535	.1650	.0350	1.027
West Coast Heavy	.0133	.4609	.0725	.0514	.1376	.1543	.1027	.0350	1.027
Pacific Offshore	.0128	.4416	.1637	.0608	.1495	.0974	.0662	.0350	1.207
Wyoming Mix	.0126	.4333	.1380	.0606	.1856	.0965	.0653	.0350	1.027
Shale Oil	.0144	.4959	.0146	.0906	.2881	.0523	.0361	.0350	1.027
Louisiana Onshore	.0119	.4123	.0544	.0737	.2782	.0955	.0659	.0350	1.027
Lousiana Offshore	.0119	.4123	.0544	.0737	.2782	.0955	.0659	.0350	1.027
Texas Gulf Coast	.0106	.3654	.0553	.0996	.3152	.0872	.0586	.0350	1.027
East Texas Mix	.0127	.4388	.1524	.0615	.1812	.0860	.0593	.0350	1.027
West Texas Mix	.0123	.4241	.1267	.0766	.2242	.0762	.0518	.0350	1.027
PADD II Indigenous	.0110	.3805	.1673	.0698	.2079	.0934	.0621	.0350	1.027
PADD I Indigenous	.0118	.4082	.0936	.0713	.2515	.0926	.0630	.0350	1.027
Oklahoma Mix	.0120	.4133	.0993	.0823	.2509	.0807	.0536	.0350	1.027
PADD III Heavy Crude	.0112	.3855	.0991	.0639	.1587	.1656	.1079	.0350	1.027
Naval Reserve #1 Crude	.0160	.5537	.0553	.0674	.1823	.0681	.0491	.0350	1.027

conversion represents a volumetric gain of .027 B, which occurs because crudes are generally denser than refined products. PIES models the volumetric gain for each region as the historic gain plus one percent. (Thus in refinery region 3, the historic gain is .017 barrels).

Similarly, each barrel (B) of Libyan crude is converted into:

$$.0119 \text{ B LG} + .4122 \text{ B GA} + .1277 \text{ B NA} + .0716 \text{ B JF}$$
$$+ .2197 \text{ B DS} + .0894 \text{ B RS} + .0595 \text{ B OT} + .035 \text{ B SG},$$

using one barrel of distillation capacity.

The equations for the remaining crude types, both foreign and domestic, can be found in the same way from Table VI-12.

Refinery Costs

Refinery costs for the conversion of crude into refined products, as described above, are given in Table VI-13. For example, in refinery region 3, the cost of converting Arabian Light crude into the seven refined products plus still gas is $2.568/B, and the conversion cost for Libyan crude is $2.052/B.

The costs for refining crude in the remaining six regions are given as a factor of the region 3 costs. These cost factors are shown in the last column of Table VI-13.

Not all crude types are refined in each region, as is indicated by the dashes in Table VI-13.

Refinery Consumption of Fuels

The refineries submodel explicitly models the consumption of fuels to operate refineries. Such consumption represents a loss of final product yield. Two fuel consumption processes are modeled in each refinery region: one each for existing and new capacity. A third type of consumption is allowed in refinery regions 3 and 5, where natural gas is used as a refinery fuel.

All three processes are modeled similarly. Each unit of capacity operated consumes fixed slates of distillate, residual, "other" refined products, and still gas (and intrastate natural gas for regions 3 and 5).

TABLE VI-13. REFINERY COSTS FOR BASE YIELDS
(1975 DOLLARS/BARREL)

	REFINERY REGIONS							
Crude Type	1	2	3	4	5	6	7	Cost Factor
Imported								
Arabian Light	2.664	2.664	2.568	2.664	2.664	2.664	2.664	1.037
Arabian Heavy	3.297	3.297	3.201	3.297	3.297	3.297	3.297	1.030
Kuwaiti Export	2.997	2.997	2.901	2.997	2.997	2.997	2.997	1.033
Iraqi	2.664	2.664	2.568	2.664	2.664	2.664	2.664	1.037
Iranian Light	2.529	2.529	2.433	2.529	2.529	2.529	2.529	1.039
Iranian Heavy	2.683	2.683	2.587	2.683	2.683	2.683	2.683	1.037
Mid-Eastern Mix	2.819	2.189	2.723	2.819	2.189	2.189	2.189	1.035
Libyan	2.148	2.148	2.052	2.148	2.148	2.148	2.148	1.047
Algerian	2.038	2.038	1.942	3.038	2.038	2.038	2.038	1.049
Nigerian & Gabon	2.094	2.094	1.998	2.094	2.094	2.094	2.094	1.048
Indonesian	2.047	2.047	1.951	2.047	2.047	2.047	2.047	1.049
Ecuadorian	2.350	2.350	2.254	2.350	2.350	2.350	2.350	1.043
Venezuelan Mix	2.862	2.862	2.766	2.862	2.862	2.862	2.862	1.035
Mexican	2.664	2.664	2.568	2.664	2.664	2.664	2.664	1.037
Russian Export	2.664	2.664	2.568	2.664	-	2.664	2.664	1.037
Chinese Export	-	-	-	-	2.047	-	-	-
Canadian Mix	2.636	2.636	2.540	2.636	2.636	2.636	2.636	1.038
Egyptian/Syrian	2.656	2.656	2.560	2.656	2.656	2.656	2.656	1.038
Angola/Congo/Zaire	2.047	2.047	1.951	2.047	2.047	2.047	2.047	1.049
Bolivian/Peruvian	2.038	2.038	1.942	2.038	2.038	2.038	2.038	1.049
Norwegian	2.077	2.077	1.981	2.077	2.077	2.077	2.077	1.048
South Asian	2.664	2.664	2.568	2.664	2.664	2.664	2.664	1.037
Trinidad	2.077	2.077	1.981	2.077	2.077	2.077	2.077	1.037
United Kingdom	2.664	2.664	2.568	2.664	2.664	2.664	2.664	1.050
Domestic								
Synthetic Crude	2.031	2.031	1.935	2.031	2.031	2.031	2.031	1.041
Alaskan North Slope	2.448	2.448	2.352	2.448	2.448	2.448	2.448	-
South Alaskan	-	-	-	-	2.139	-	-	1.039
West Coast Light	-	-	2.442	-	2.538	-	-	1.038
West Coast Heavy	-	-	2.517	-	2.613	-	-	1.043
Pacific Offshore	-	-	2.254	-	2.350	-	-	1.041
Wyoming Mix	-	2.428	2.332	2.428	-	-	2.428	1.050
Shale Oil	2.031	2.031	1.935	2.031	-	2.031	2.031	1.048
Louisiana Onshore	2.112	2.112	2.016	2.112	-	2.112	2.112	1.048
Louisiana Offshore	2.112	2.112	2.016	2.112	-	2.112	2.112	1.048
Texas Gulf Coast	2.081	2.081	1.985	2.081	-	2.081	2.081	1.047
East Texas Mix	2.150	2.150	2.054	2.150	-	2.150	2.150	1.040
West Texas Mix	2.502	2.502	2.406	2.502	-	2.502	2.502	1.047
PADD II Indigenous	2.146	2.146	2.050	2.146	-	2.146	2.146	1.048
PADD II Indigenous	2.082	2.082	1.986	2.082	-	2.082	2.082	1.046
Oklahoma Mix	2.179	2.179	2.083	2.179	-	2.179	2.179	-
PADD V Heavy Crude	-	-	-	-	2.583	-	-	-
PADD IV Heavy Crude	-	-	-	2.815	-	-	-	1.037
PADD III Heavy Crude	-	-	2.580	2.676	-	-	-	-
PADD II Heavy Crude	-	2.583	-	-	-	-	2.583	1.045
Naval Reserve #1 Crude	-	-	2.114	-	2.210	-	-	-

The following formula describes the consumption of petroleum products in region 3, for each unit of existing capacity used:

.002 B DS + .055 B RS + .012 B OT + .038 B SG

This implies that .107 (or 11 percent) of every barrel of crude refined is lost in the refinery process.

For a unit of new capacity, the following amounts of refined products are consumed:

.0018 B DS + .0495 B RS + .0108 B OT + .0342 B SG.

That is, the operation of new refineries to produce refined products requires approximately one barrel out of every ten produced.

In region 3, intrastate natural gas (DG) is consumed in addition to the four products shown above, according to the following formula:

.002 B DS + .003 B RS + .012 B OT + .038 B SG + .353 B DG,

yielding a loss of approximately 41 percent per unit of refinery capacity. The formula for region 5, the only other region using natural gas in refineries, is:

.004 B DS + .029 B RS + .013 B OT + .045 B SG + .176 B DG

which indicates a 27 percent loss per unit of refinery capacity.

Refinery Capacity

In PIES, the capacity of existing refineries can be increased by adding capacity to the distillation capacity constraints. Existing capacity may be increased if the cost of providing fuel via a new refinery is less than or equal to the regional marginal cost of obtaining that fuel in some other way.

Table VI-14 gives the existing capacity build limits and build costs for each refinery region. Existing capacity is defined to be capacity in existence before 1/1/78. Build limits are the additional units of capacity for each refinery region that can be added between now and the target year (1985 in Table VI-14). The build costs are the costs to build one additional unit of capacity.

The existing capacity figures in Table VI-14 are 90 percent of the figures in Table VI-9, reflecting a 90 percent refinery utilization factor.

TABLE VI-14. REFINERY CAPACITY DATA FOR 1985

Refinery Regions	Existing Capacity (MB/D)	Build Limits (MB/CD)	Build Costs (1975 M Dollars/B)
Refinery Region 1 - PADD 1A	1467	348	.6062
Refinery Region 2 - PADD 2A	2596	221	.5563
Refinery Region 3 - PADD 3	6644	-	.5013
Refinery Region 4 - PADD 4	523	46	.5415
Refinery Region 5 - PADD 5	2660	207	.5512
Refinery Region 6 - PADD 1B	250	175	.6062
Refinery Region 7 - PADD 2B	1201	124	.5563

Shift Activities

Shift activities serve several functions. They blend butane and gas liquids into products which flow from refinery to demand regions; they model the capability of most refineries to blend intermediate and final refined products to produce alternative products; and they enable alteration of product yield relationships to increase the flexibility of modeling actual refinery operation.

The shift capability is important because it permits manipulation of the base yields per barrel of crude given in Table VI-12 to satisfy changing demands for refined products. In our example above, Arabian Light crude was to be converted into each of seven refined products. If there is more demand for gasoline and less for distillate than is supplied by the base yield proportions, the crude which was to be converted to distillate could be converted into gasoline instead by using the following relationship (for region 3): 1.0 barrel of distillate yields 1.109 barrels of gasoline at a cost of $2.527/B. The volumetric gain experienced is .109 barrels of product. Similarly, crude used to produce one barrel of gasoline can be converted to .90094 barrels of distillate at a cost of -$2.182/B.

In shifting from distillate to gasoline, we experience a volumetric gain and a cost of $2.527/B because gasoline is both denser and more expensive to refine than distillate.

In shifting from distillate to gasoline we experience a volumetric gain and a cost of $2.527/B. because gasoline is both denser and more expensive to refine than distillate. In shifting from gasoline to distillate, we experience a negative cost or a credit ($2.182/B), because we are actually refining crude into the cheaper distillate rather than the more expensive gasoline.

Table VI-15 gives additional examples of refinery shifts and their costs (or credit) for region 3. Although gasoline and naphtha yield the same volumes upon shifting, gasoline is more expensive and thus has a higher cost associated with it. All costs include the effects of the volume changes.

TABLE VI-15. SAMPLE SHIFT RELATIONSHIPS WITH ASSOCIATED COSTS

	$/B
Relationship	Cost (+) Credit (-)
1.0 B GA converts to .94185 B JF	-1.1410
1.0 B GA converts to .83473 B RS	-4.0850
1.0 B GA converts to 1.0 B NA	- .5700
1.0 B NA converts to 1.0 B GA	.6700
1.0 B NA converts to .90094 B DS	-1.5620
1.0 B JF converts to .95656 B DS	-1.0540
1.0 B JF converts to .92866 B SG	-3.0730
1.0 B DS converts to .92651 B RS	-2.0630
1.0 B DS converts to .97083 B OT	.0463
1.0 B RS converts to 1.197 B GA	5.0040
1.0 B RS converts to 1.197 B NA	4.2620
1.0 B OT converts to 1.143 B JF	1.2430
1.0 B OT converts to .95435 B RS	-2.1220
1.0 B SG converts to 1.03 B DS	2.2230
1.0 B SG converts to 1.0 B OT	2.2190

Since a refinery's activities are limited both physically and economically, the constraint space of the PIES LP must contain relationships to ensure that the solution does not exceed the capability of actual refineries. The relationships which constrain the above shift activities are given in Table VI-16 for the dual problem which is expressed in terms of prices.

The first relationship indicates that the price of gasoline minus the price of naphtha must be less than or equal to $.67 and greater than or equal to $.57. There is no volumetric gain or loss associated with this process because each product is converted into an equal volume of the other product.

Liquid Gas and Butane

Liquid gas (LG) and butane (BU) are coproducts produced with non-associated natural gas (see chapter V). The refineries submodel allows gas liquids and butane to flow into the refinery system to be converted into refined products.

For all regions, one unit of liquid gas is converted into .88033 units of gasoline and one unit of butane is converted into:

$$.15285 \text{ B GA} + .32864 \text{ B NA} + .36999 \text{ B LG.}$$

The slates in each region remain the same, but the volumetric gain or loss differs.

REFINERY CALCULATIONS WITHIN THE EQUILIBRATING MECHANISM

The equilibrating mechanism performs a dynamics calculation to provide intertemporal consistency of new plant capacity for utilities and refineries.[3] The dynamics calculations prevent PIES from building less capacity by 1990 than the capacity in 1985.

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[3] New plant capacity is defined as any plant capacity built after January 1, 1978.

TABLE VI-16. RELATIVE PRODUCT PRICING RELATIONSHIPS FOR SHIFT ACTIVITIES

Minimum Price Differential	Product Price Coefficient		Product Price of		Product Price Coefficient		Product Price of		Volume Cost Coefficient		Volume Deviation Costs	Maximum Price Differential
.570	(1.000	x	Gasoline)	-	(1.000	x	Naphtha)					.670
.570	-(1.000	x	Naphtha)	+	(1.000	x	Gasoline)					.670
1.141	(1.000	x	Gasoline)	-	(.942	x	Jet Fuel)	+	(.058	x	Vol. Cost)	1.238
1.211	-(1.000	x	Jet Fuel)	+	(1.061	x	Gasoline)	+	(.062	x	Vol. Cost)	1.314
2.182	(1.000	x	Gasoline)	-	(.901	x	Distillate)	+	(.099	x	Vol. Cost)	2.277
2.422	-(1.000	x	Distillate)	+	(1.109	x	Gasoline)	+	(.110	x	Vol. Cost)	2.527
4.085	(1.000	x	Gasoline)	-	(.835	x	Residual)	+	(.165	x	Vol. Cost)	4.177
4.894	-(1.000	x	Residual)	+	(1.197	x	Gasoline)	+	(.198	x	Vol. Cost)	5.004
2.185	(1.000	x	Gasoline)	-	(.875	x	Other)	+	(.125	x	Vol. Cost)	2.278
2.498	-(1.000	x	Other)	+	(1.143	x	Gasoline)	+	(.143	x	Vol. Cost)	2.605
4.083	(1.000	x	Gasoline)	-	(.875	x	Still Gas)	+	(.125	x	Vol. Cost)	4.177
4.668	-(1.000	x	Still Gas)	+	(1.143	x	Gasoline)	+	(.143	x	Vol. Cost)	4.775
.521	(1.000	x	Naphtha)	-	(.942	x	Jet Fuel)	+	(.058	x	Vol. Cost)	.618
.554	-(1.000	x	Jet Fuel)	+	(1.061	x	Naphtha)	+	(.062	x	Vol. Cost)	.657
1.562	(1.000	x	Naphtha)	-	(.901	x	Distillate)	+	(.099	x	Vol. Cost)	1.657
1.734	-(1.000	x	Distillate)	+	(1.109	x	Naphtha)	+	(.110	x	Vol. Cost)	1.839
3.465	(1.000	x	Naphtha)	-	(.835	x	Residual)	+	(.165	x	Vol. Cost)	3.558
4.151	-(1.000	x	Residual)	+	(1.197	x	Naphtha)	+	(.198	x	Vol. Cost)	4.282
1.565	(1.000	x	Naphtha)	-	(.875	x	Other)	+	(.125	x	Vol. Cost)	1.658
1.789	-(1.000	x	Other)	+	(1.143	x	Naphtha)	+	(.143	x	Vol. Cost)	1.896
3.463	(1.000	x	Naphtha)	-	(.875	x	Still Gas)	+	(.125	x	Vol. cost)	3.556
3.959	-(1.000	x	Still Gas)	+	(1.143	x	Naphtha)	+	(.143	x	Vol. Cost)	4.066
1.054	(1.000	x	Jet Fuel)	-	(.957	x	Distillate)	+	(.043	x	Vol. Cost)	1.153
1.102	-(1.000	x	Distillate)	+	(1.045	x	Jet Fuel)	+	(.045	x	Vol. Cost)	1.205
3.076	(1.000	x	Jet Fuel)	-	(.886	x	Residual)	+	(.114	x	Vol. Cost)	3.170
3.471	-(1.000	x	Residual)	+	(1.128	x	Jet Fuel)	+	(.128	x	Vol. Cost)	3.577
3.073	(1.000	x	Jet Fuel)	-	(.929	x	Still Gas)	+	(.071	x	Vol. Cost)	3.170
3.309	-(1.000	x	Still Gas)	+	(1.076	x	Jet Fuel)	+	(.077	x	Vol. Cost)	3.413
1.058	(1.000	x	Jet Fuel)	-	(.929	x	Other)	+	(.071	x	Vol. Cost)	1.154
1.139	-(1.000	x	Other)	+	(1.076	x	Jet Fuel)	+	(.077	x	Vol. Cost)	1.243
2.063	(1.000	x	Distillate)	-	(.927	x	Residual)	+	(.073	x	Vol. Cost)	2.159
2.227	-(1.000	x	Residual)	+	(1.079	x	Distillate	+	(.079	x	Vol. Cost)	2.330
.046-	(1.000	x	Distillate)	-	(.971	x	Other)	+	(.029	x	Vol. Cost)	.052
.048-	-(1.000	x	Other)	+	(1.030	x	Distillate)	+	(.030	x	Vol. Cost)	.054
2.060	(1.000	x	Distillate	-	(.971	x	Other)	+	(.029	x	Vol. Cost)	2.158
2.122	-(1.000	x	Still Gas)	+	(1.030	x	Distillate)	+	(.030	x	Vol. Cost)	2.223
2.122	(1.000	x	Other)	-	(.954	x	Residual)	+	(.046	x	Vol. Cost)	2.220
2.224	-(1.000	x	Residual)	+	(1.047	x	Other)	+	(.048	x	Vol. Cost)	2.326
2.119	(1.000	x	Other)	-	(1.000	x	Still Gas)					2.219
2.119	-(1.000	x	Still Gas)	+	(1.000	x	Other)					2.219
.047-	(1.000	x	Still Gas)	-	(.954	x	Residual)	+	(.046	x	Vol. Cost)	.051
.049-	-(1.000	x	Residual)	+	(1.047	x	Still Gas)	+	(.048	x	Vol. Cost)	.053

PIES makes dynamics calculations for the base year, 1985. When a solution is obtained for 1985, the capacity of each plant type is saved for use with the matching scenario in 1990. For a 1990 run, PIES compares the existing capacities in 1985 to those input for 1990. The bound on the total capacities that can be built in 1990 is the difference between the 1990 input bound and the amount built for 1985.

The equilibrating mechanism also makes the translation between refined products and demanded products. The 30 products for which PIES calculates an equilibrium were given in Chapter II. The correspondence between the seven refined products and the products given in Table II-1 is given in Table VI-17.

TABLE VI-17. CORRESPONDENCE BETWEEN REFINED AND DEMAND PRODUCTS

Refined Product	Product		Sector
Gasoline	Gasoline		Transportation
Distillate	Distillate		Residential
	Distillate		Commercial
	Distillate		Industrial
	Distillate		Transportation
Residual	Residual		Commercial
	Residual	-	Industrial
	Residual	-	Transportation
Jet Fuel	Jet Fuel	-	Transportation
Liquid Gas	Liquid Gas	-	Residential
	Liquid Gas	-	Industrial
	Liquid Gas	-	Commercial
	Liquid Gas	-	Transportation
Naphtha	Naphtha	-	Industrial
	Liquid Gas	-	Feedstock
	Liquid Gas	-	Raw Material
Other	Oil	-	Raw Material
	Asphalt	-	Commercial

VII. UTILITIES

INTRODUCTION

The PIES utilities submodel models activities necessary to produce the electricity for the ten PIES demand regions shown in Figure I-2. The activities modeled are: utility plant operation, new facility construction, boiler conversion, and electricity transmission and distribution. The PIES utilities submodel is a process model, representing the technological processes of the industry -the consumption of input resources (capacities and fuels) and the production of output (electricity), as well as the constraints on operation and construction within the industry. This chapter describes the salient features of the utilities sector, its representation in PIES, and the data available.

OPERATION OF UTILITY SYSTEMS

Electric utilities operate by consuming fuels as raw material input (i.e., coal, residual oil, distillate oil, natural gas, nuclear fuel, etc.) and converting them into another fuel, electricity. There are two major factors in modeling utilities. First, because electricity cannot be stored, it must be produced on demand; second, demands are subject to significant daily, weekly, and seasonal variations. The economic and technological aspects of supplying power to meet changing demands require the acquisition of diverse types of generating equipment for efficient operation of the overall utility system.

In PIES, utility systems consist of fossil-fuel generating plants (that consume oil, gas, and coal) and hydroelectric generators, nuclear plants, and geothermal plants that do not consume fossil fuels. Utilities operate existing plants and build and operate new facilities. Facilities are brought into operation in order of increasing marginal cost of generating electricity.

The cost of producing a standard unit of output, e.g., one kilowatt hour of electricity, can vary widely, depending on the type and characteristics of the fuel used, the age of the generating plant, environmental restrictions, and the cost of capital. The modeling procedure for electric utilities used in PIES accounts for all these factors quantitatively.

Twelve types of generating facilities are modeled in the utilities submodel, representing the capacity (existing, newly built, or to be constructed) required to satisfy demand in each of ten utility regions. (These regions are coincident with the ten demand regions.) There are also subclassifications of plant types. For instance, those plants that require long construction lead times, e.g., nuclear plants, are grouped into existing, committed, and deferrable and completely new facilities. Plants in the middle two categories can be brought into operation sooner and at less cost than completely new plants can be built.

Capacity for operating generating facilities can be either new or existing. New capacity is distinguished from existing capacity in that new plants usually operate more efficiently, that is, the heat rates are lower.

Operating Characteristics of Generating Plants

Each plant type is differentiated by fuel, efficiency, capital costs, and operating and maintenance costs and has both fixed and variable costs associated with its operation.

For new plants, the fixed costs consist of an annual capital charge, which depends upon the initial capital cost of the plant. The variable costs are of operation and maintenance costs and costs for fuel consumed. Because both variable costs are assumed to increase linearly with production, the total cost varies with production, as shown in Figure VII-1.

Although this type of cost relationship is common to all types of utility plants, there is considerable variation between plant types. Typically, nuclear or coal-fired steam plants have high capital costs but relatively low fuel costs. Gas turbine and distillate-fired turbine plants have low capital costs but high fuel costs.

For new nuclear plants, the ratio of capital costs to fuel expense is about two to one, in base-load operation. For coal plants with scrubbers, the ratio is about unity in both base-load and cycling operation; and, for a combined-cycle plant in cycling operation, the ratio is about one to three. As a result, decisions to build new nuclear facilities are more sensitive to changes in capital costs, and, conversely, combined-cycle plants are more sensitive to fuel-cost changes. Also, different plant types are used to generate electricity for different loads, that is, when fuel costs are high relative to capital (fixed) costs, the facilities are not used constantly but are turned on and off to satisfy peak demand for electricity.

Figure VII-2 shows the superposition of typical total cost curves for three different plant types. It can be seen that for capacity factors below C_1, investment in gas turbines would be cheapest; between C_1 and C_2, oil-fired plants are preferable; and above C_2, nuclear plants. Thus, investment decisions for new plants depend on the fraction of time for which they will be operated. This fraction is usually known as the unit capacity factor or unit load factor and is the ratio of actual output (in kwh) over possible output.

The operation of fossil fuel plants requires the consumption of fuel. The quantity of fuel consumed per unit of output (i.e., per kwh) is a measure of the thermal efficiency of the plant. Typical thermal efficiencies for utility plants lie in the 30 to 40 percent range, i.e., 30 to 40 percent of the heat content in the fuel is converted to electricity. In utilities, efficiencies are usually expressed in terms of heat rates, i.e., Btu of fuel input per kwh output. Within plant types, heat rates, by definition vary depending on the mode of operation, i.e., base, cycling or peak. Fuel consumption for each unit of electricity can then be defined by:

$$\frac{\text{Heat Rate}}{\text{Btu Content of Fuel}}$$

Costs for fuels used to generate electricity are excluded from plant operating costs, but are included as part of generating costs, as discussed in the section on average cost

FIGURE VII-1

TYPICAL ELECTRIC UTILITY COST CURVE

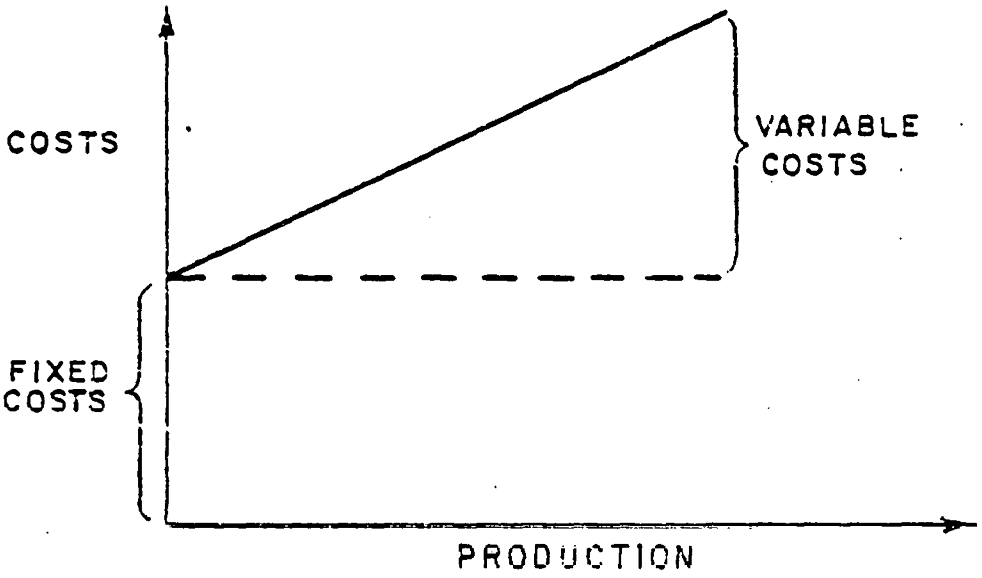
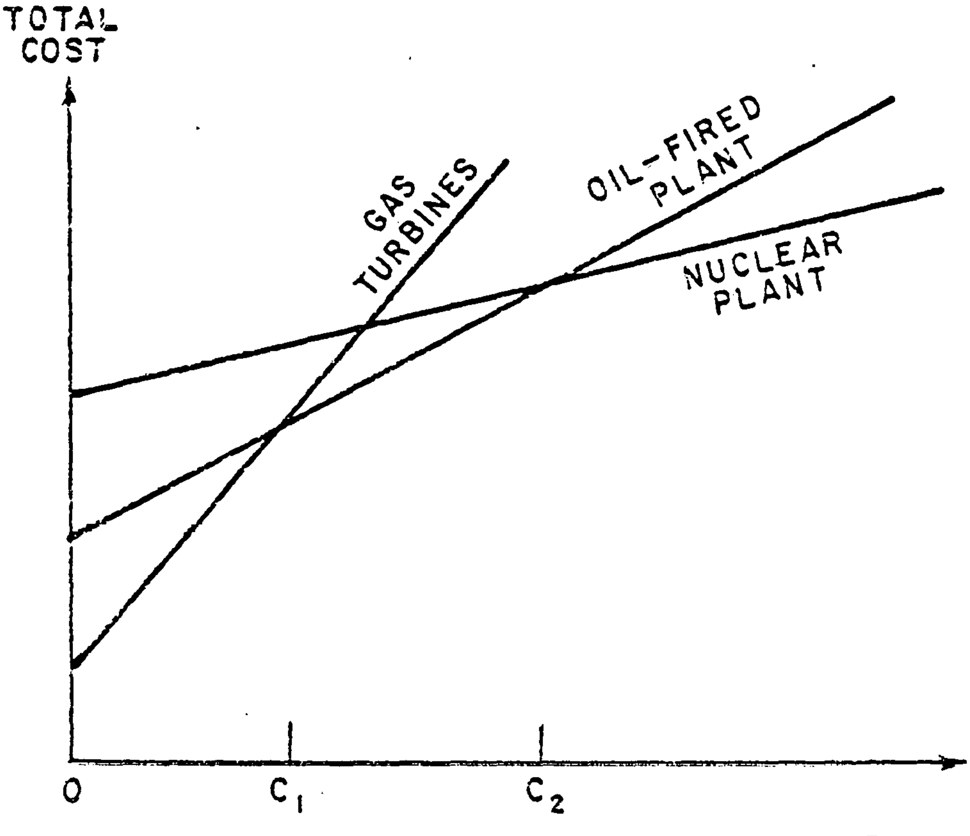


FIGURE VII-2

COST FUNCTIONS FOR DIFFERENT PLANT TYPES



pricing. These costs are further discussed on an individual basis in the chapters on the specific fuel submodels.

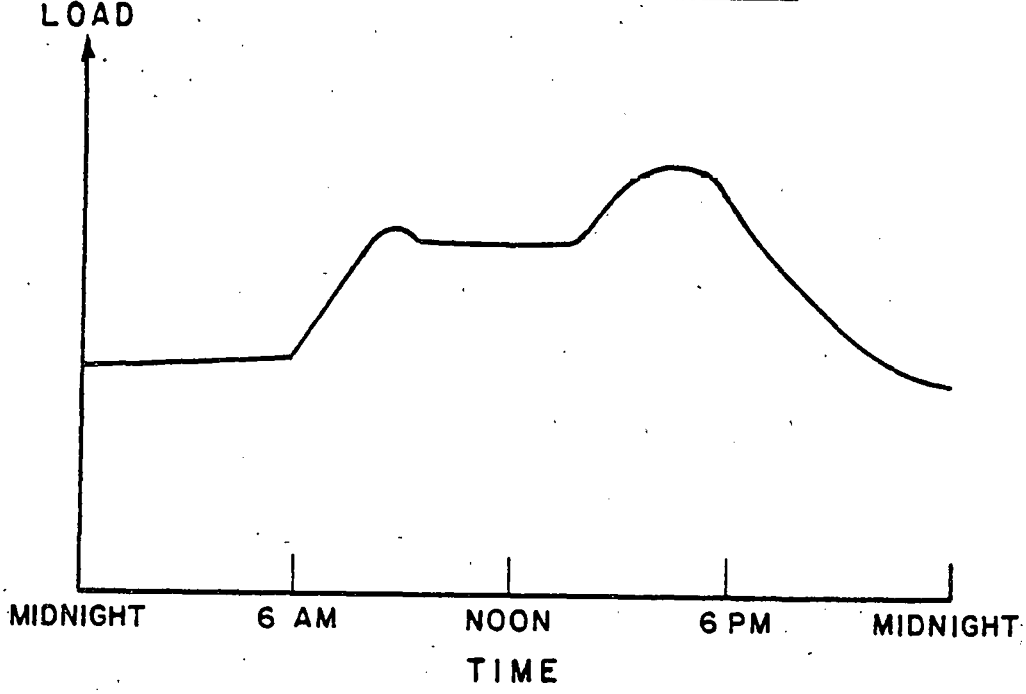
Transportation activities are used artifically to specify certain pricing adjustments; there is no actual inter-regional transportation of electric power.

Nonuniformity of Electricity Demand

Demand for electricity exhibits significant daily, weekly, and seasonal variations. Figure VII-3 shows a typical daily summer load profile in North America. The load is fairly constant overnight, but increases as people wake up, switch on appliances, and begin the working day. Towards the end of the afternoon, domestic and commercial air conditioning loads increase until a load peak is reached at about 5:00 P.M. The load then decreases as businesses close down, and air conditioning and appliances are switched off. The winter load profile is somewhat different, but there is considerable daily variation in all seasons.

FIGURE VII-3

TYPICAL DIURNAL VARIATION OF ELECTRIC UTILITY LOAD



All of these variations in demand can be integrated into a single annual load duration curve of the type shown in Figure VII-4, which is ordered by demand levels and decreases monotonically. Total demand for electricity is the area under the curve. Utilities must dispatch plants to satisfy the load defined by the shape of this curve. The load duration curve can be approximated by a series of rectangles which characterize the various load segments.

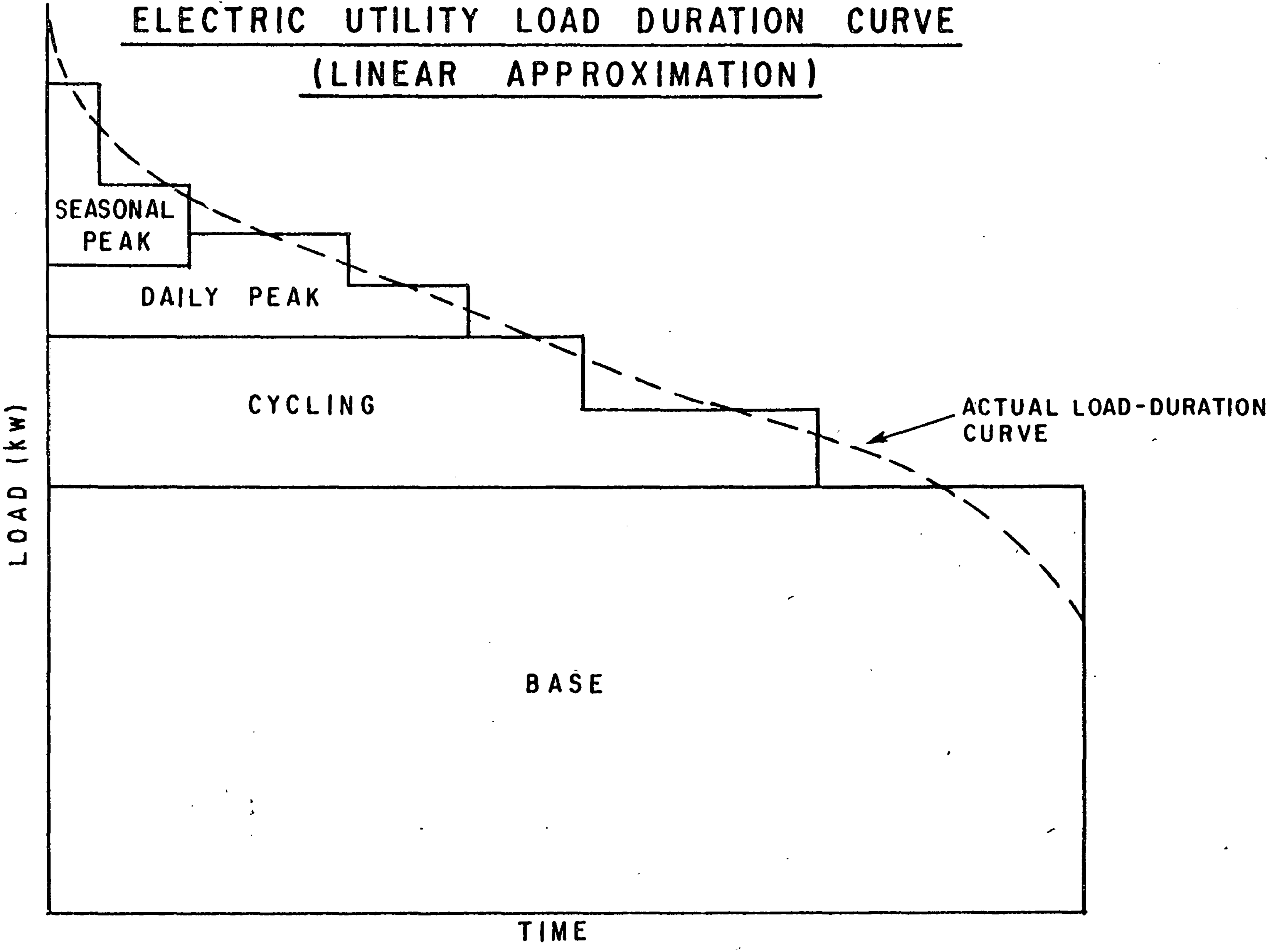
In modeling demand for electricity in PIES, the assumption is made that demand has four discrete parts: seasonal and daily peak load demands, a cycling or intermediate demand, and a base load demand. (See Figure VII-4.) The relative areas of the four parts are in proportion to the ratio of demands between daily and seasonal peak, cycling, and base loads.

The capacity constraints for existing plants state that the operation of a particular plant type in all four modes must be less than the existing capacity of that plant type, i.e., the operation in base plus cycling plus peak modes should be less than or equal to the existing capacity. For new capacity, the operation of a particular plant type in all four modes must be less than the capacity of the plant type to be built.

The cost functions in Figure VII-2 shows that certain types of plants are most efficient at producing base load (nuclear and coal-fired), others at producing cycling load (oil), and yet others at producing peak load (gas turbines). Thus, to satisfy demands for electricity, utilities will purchase a variety of plant types. There are also technological reasons for operating plants only in certain modes. These reasons relate to the time required to "heat up" and "cool down" generating plants. Large nuclear and coal-fired steam plants are designed to be operated continuously and hence are considered to be base load, while, conversely, continuous operation of peak load plants would be impractical. Thus, within the utilities submodel, some plants are permitted to operate in several modes, while others (such as nuclear) are permitted to operate in only one mode (base mode). These topics will be discussed in more detail later in this chapter.

FIGURE VII-4

ELECTRIC UTILITY LOAD DURATION CURVE
(LINEAR APPROXIMATION)



THE UTILITIES SUBMODEL

The modeling of utilities is identical in each of the ten PIES utility regions, with generating capacity in each region being aggregated over all plant types of a particular type. The utility regions coincide with the ten PIES demand regions and electricity is produced in a region to satisfy demand for that particular region only -- no interregional transmission modeled.

Plant Types

Plant types (designated by the fuels they use) include those that burn both fossil and non-fossil fuels. Fossil-fuel plants modeled are: oil-fed steam (residual fuel oil), simple-cycle turbine with distillate, combined-cycle with distillate, gas turbine, gas-fed steam, and coal-burning facilities. The coal-burning facilities use bituminous coal, sub-bituminous coal and lignite with heat contents greater than 21.8, 18.33 and 13 million Btu/ton, respectively. They include facilities without scrubbers (for burning low-sulfur coal), facilities with scrubbers (fuel gas desulfurizing equipment), and facilities using sub-bituminous coal and lignite.

Coal is differentiated on the basis of sulfur and Btu content (see Chapter III). Plants burning high-sulfur coal either use scrubbers or can be retrofitted with them to remove sulfur from the flue gas emissions. Sub-bituminous coal and lignite, which require special burners, have low-Btu contents and either medium- or low-sulfur contents.

Operation of both existing and new coal-burning facilities is modeled. For a specified price, a unit of capacity, plus some amount of fuel is consumed to produce base, cycle or daily-peak load of electricity to meet demand in a region. Coal burners are excluded from generating electricity for seasonal peak demand. (One unit of transmission and distribution capacity is also used for each unit of generating capacity.)

Coal-burning plants with scrubbers consume a unit of coal-burner capacity and a unit of scrubber capacity. Coal burners with scrubbers are permitted to consume coal with more than 1.67 pounds of sulfur per million Btu. Coal burners without scrubbers can consume only low-sulfur coal. Unless they meet SIP (State Implementation Plan) standards without the retrofit of scrubbers. Existing coal plants are split into plants which meet the SIP standards without scrubbing and those which must burn low-sulfur coal or retrofit a scrubber. Coal-burning plants with scrubbers can burn coal with any amount of sulfur.

The costs of FGD equipment depend on whether the equipment is installed in a new plant or is retrofitted to an existing plant. Because some states have very stringent emission standards, PIES requires plants in the Northeastern, Western, Northwestern and utility regions to have scrubbers (with 90 percent sulfur removal efficiency regardless of the coal type used). PIES also models capital costs for retrofitting scrubbers on existing plants for burning high-sulfur coal.

Oil and gas steam plants are modeled analogously to coal-burning plants. PIES models the operation of new and existing facilities by specifying a cost for operation and maintenance, by consuming a specified fuel, and by using both generating capacity and transmission and distribution capacities to supply electricity. Steam plants are dispatched in base, cycling and daily peak modes only.

Gas and distillate turbines are permitted to operate in all four loads, but the cost of generating base-load electricity is about ten times that for generating seasonal peak. Turbines are one of the few plant types used for peak loads. Turbine capacity expansion is permitted for distillate turbines only since gas use in utilities will be restricted in the future. Distillate fired combined-cycle plants, which use both combustion and steam turbines are treated as steam plants and are excluded from seasonal-peak generation. Gas steam plants are permitted to convert to distillate fuel in 1990 when natural gas use in utility plants will be restricted.

Two types of hydroelectric plants are modeled for operation of existing and new facilities - those using just pondage (static reservoirs) and those using pumped storage where water is pumped back to the holding location. This distinction represents a recent modification to PIES. Pondage capacities are fixed at the level scheduled to be available in the target year and service all four loads. Pumped-storage facilities service only the two peak loads (daily and seasonal).

Energy consumed for pumped storage is accounted for in the model by the consumption of one and one-half units of base-load electricity input for each unit of peak-load generation, which simulates the off-peak recharging of the pumping facilities. Capacity for generation and transmission is used, of course, but no consumption of fuel is modeled for either type of hydroelectric plant. The operation of pondage and dumped storage facilities in each of the operating modes is constrained by a maximum energy generation limit. This limit or capacity factor represents an average regional performance for the last five years.

Both new and existing nuclear generators are assumed to supply base-load electricity only and consume plant capacity and nuclear fuel. Solar and geothermal facilities, using the sun and underground steam sources, supply only a small fraction of the electricity consumed (see Chapter VIII).

When operation of existing generating capacity is not sufficient to satisfy the demand for electricity in a region, the utilities submodel permits for the building of new facilities. New facilities having long construction lead times and high capital costs (nuclear, and coal plants) are categorized according to the amount of capital that has been expended and the amount of construction completed. These categories are: committed (capital is considered fully committed, and the plant is scheduled for completion within two years), deferrable (ten percent of the capital is invested, but less than two percent of the plant has been constructed), and completely new facilities (capital is not committed and no construction has started). Deferrable plants will be built before new plants when additional capacity is needed, since ten percent of the capital cost has already been invested. Tables VII-1, VII-2, and VII-3 give committed, deferred, and new plant capacities for 1985.

TABLE VII-1. COMMITTED* CAPACITY FOR 1985
(Megawatts)

	DOE REGION										
PLANT TYPE	1	2	3	4	5	6	7	8	9	10	Totals
Nuclear	-	2001	5925	13226	7579	3227	-	330	4470	1103	37861
Residual-Fired Steam	600	850	-	688	2340	480	-	-	292	198	5448
Bituminous Coal-Fired Steam (Without Scrubbers)	-	-	400	1532	1892	-	1250	600	1200	-	6874
Bituminous Coal-Fired Steam (With Scrubbers)	-	-	2077	2905	4853	-	-	-	-	-	9835
Sub-Bituminous Coal-Fired Steam	-	-	-	-	897	4541	2066	2090	-	-	9594
Lignite Coal-Fired Steam	-	-	-	-	641	2685	-	339	-	-	3665
Distillate-Fired Simple Cycle Turbine	6	-	200	300	405	239	778	246	198	-	2372
Distillate-Fired Combined Cycle Turbine	230	-	-	-	-	-	-	-	809	-	1039
Gas-Fired Steam	-	-	-	-	-	550	-	-	-	-	550
Regional and National Totals	836	2851	8602	18651	18607	11722	4094	3605	6969	1301	77238

*All Capital Sunk and Construction Nearly Completed

TABLE VII-2. DEFERRABLE* CAPACITY FOR 1985
(Upper Limits for Megawatts)

	DOE REGION										
PLANT TYPE	1	2	3	4	5	6	7	8	9	10	Totals
Nuclear	-	1067	3065	1145	4154	3367	1150	-	340	1267	15555
Bituminous Coal-Fired Steam	-	-	1300	2710	2143	1100	1275	400	700	-	9628
Sub-Bituminous Coal-Fired Steam	-	-	-	-	580	6346	1910	2780	-	500	12116
Lignite Coal-Fired Steam	-	-	-	-	556	1978	-	294	-	-	2828
Regional and National Totals	-	1067	4365	3855	7433	12791	4335	3474	1040	1767	40127

*Approximately 10% of Capital Sunk, Ground has Been Broken and Plant Scheduled to Operate By 1985

TABLE VII-3. NEW PLANT CAPACITY UPPER LIMITS FOR 1985
(Megawatts)

	DOE REGION										
PLANT TYPE	1	2	3	4	5	6	7	8	9	10	Totals
Residual-Fired Steam	-	-	610	-	-	-	-	-	-	864	1474
Bituminous Coal-Fired Steam	-	2400	3490	15058	9933	1053	1183	504	1751	-	35372
Sub-Bituminous Coal-Fired Steam	-	-	-	-	1228	5880	1774	3476	-	3581	15939
Lignite Coal-Fired Steam	-	-	-	-	691	1843	-	367	-	-	2901
Hydroelectric (Pondage)	10	-	-	818	69	32	27	577	975	7346	9854
Hydroelectric (Pump Storage)	-	1000	3204	2514	-	-	1191	200	2405	200	10714
Regional and National Totals	10	3400	7304	18390	11921	8808	4175	5124	5131	11991	76254

The building of new plants in PIES requires that capital coefficients (dollar cost to provide a kilowatt of capacity for each plant type), and bounds (fixed, upper, or lower) be specified: The bounds represent limits on new construction for environmental or regulatory reasons, and reflect construction lead times. They also ensure that plants built in one period are counted in the following period (i.e., plants build in a 1985 model run would be accounted for by lower bounds in the corresponding 1990 run).

Tables VII-4 and VII-5 show operation and maintenance costs and capital costs by DOE region for each plant type.

TABLE VII-4. OPERATION AND MAINTENANCE COSTS
(1975 Mills Per Kilowatt Hour)

PLANT TYPE	O&M Cost
Residual-Fired Steam	.90
Bituminous Coal* (With Scrubber)	2.80
(Without Scrubber)	1.10
Sub-Bituminous Coal** (With Scrubber)	2.00
(Without Scrubber)	1.10
Lignite Coal*** (With Scrubber)	2.00
(Without Scrubber)	1.10
Distillate-Fired Simple Cycle	2.75
Distillate-Fired Combined Cycle	1.25
Gas-Fired Turbine	2.75
Gas-Fired Steam	.50
Hydroelectric (Pondage)	.70
Hydroelectric (Pump Storage)	.70
Nuclear	1.65

*Bituminous plants may be scrubbed or unscrubbed except for new plants in DOE Regions 8, 9 and 10 which must be scrubbed and use low sulfur coal

**Sub-Bituminous plants are assumed to be unscrubbed except for new plants in DOE Regions 8, 9 and 10 which are assumed to be scrubbed

***New Lignite plants are assumed to be scrubbed: while existing plants are assumed to be unscrubbed

TABLE VII-5. CAPITAL COSTS OF NEW PLANTS IN 1985 (1975 Dollars Per Kilowatt)

PLANT TYPE	DOE REGION 1	2	3	4	5	6	7	8	9	10
Residual-Fired Steam	385	407	365	346	380	348	377	363	392	374
Bituminous Coal (With Scrubber)*	516	546	491	465	510	467	506	487	526	502
Bituminous Coal (Without Scrubber)*	415	439	394	373	410	376	407	487	526	502
Sub-Bituminous Coal*	450	476	428	405	445	408	442	520	562	537
Lignite Coal*	553	553	553	553	553	553	553	553	553	553
Distillate-Fired Simple Cycle	151	151	151	151	151	151	151	151	151	151
Distillate-Fired Combined Cycle	290	290	290	290	290	290	290	290	290	290
Gas-Fired Steam	325	325	325	265	290	265	290	305	300	300
Hydroelectric (Pondage)	390	330	300	270	290	230	300	330	320	180
Hydroelectric (Pump Storage)	390	330	300	270	290	230	300	330	320	180
Nuclear (Deferrable)	-	596	347	214	211	280	441	-	286	478
Nuclear (New)	-	-	-	-	-	-	-	-	-	-

*Capital cost of deferrable coal plants is .90 of new plant costs for investment purposes.

Note: Retrofitting an existing bituminous coal plant using high sulfur coal costs $131 per kilowatt

Transmission and distribution costs and efficiency rates by region are given in Table VII-6. For Region 1, the efficiency rate indicates that for every kilowatt generated, only .914 kilowatts are distributed.

TABLE VII-6. TRANSMISSION AND DISTRIBUTION DATA

DOE Region	Average Efficiency Rate (Percentage)	Operation and Maintenance Cost* (Mills/Kilowatt-Hour)	Capital Cost ($/Kilowatt)
1	91.40	5.7	493
2	91.80	5.2	626
3	92.40	4.7	304
4	91.40	5.0	262
5	92.30	4.3	361
6	92.50	4.6	228
7	91.20	5.5	354
8	88.30	5.6	309
9	90.80	5.3	514
10	91.00	5.6	279

*Includes general and administrative costs.

Transmission Losses

Utilities must generate more electricity than is consumed, partly because losses occur between the power station and the consumer. PIES includes the loss factors which are specified regionally and average about 9%.

Reserve Margins

Utilities normally operate more generating capacity than required to meet demand at any given time for two primary reasons. First, utilities should have sufficient capacity to meet the highest reasonable estimate of future demand. Secondly, there must be sufficient capacity on-line to satisfy demand should a generation transmission failure occur in the system. Thus, utilities are required to have reserve capacity available to satisfy unexpected changes in demand or forced outages. Some of this reserve must be operating or "spinning," because the start-up times required are such that units could not otherwise be ready to meet an emergency in time. In addition to a "spinning" reserve, utilities maintain a "cold" reserve, which is idle and does not consume fuel.

The current implementation of the utilities submodel separates capacity requirements for generation associated with demand from reserve requirements for planned and unplanned outages. This improvement allows idle capacity to count as reserves to satisfy a twenty percent reserve constraint. Therefore, less plant capacity needs to be built than with previous versions resulting in a reduction in total capital expenditures and decreased in prices to consumers.

Merit Order Dispatch

As load increases through the day, utilities are first switch units on and bring them up to temperature (i.e., dispatch them), and then connect them to the grid (i.e., commit them). Each decision to dispatch an additional unit is made such that the total cost of system operation is minimized at any time. This is known as the principle of merit order dispatch and corresponds to adding units in the order of their marginal costs. PIES uses this principle of economic dispatch in deciding which additional units to operate.

Demand Side of the Load-Duration Curve

As previously stated, demand for electricity is not constant over time but varies across a day, a week, and a year. Demands for electricity can be depicted graphically by a continuous load-duration curve, showing the relationship of demand vs. time (Figure VII-4). For example, demand may be at its maximum for three hours during the year, slightly less than maximum for a few hours, and decrease until it reaches base load.

The load-duration curve is normally discussed in terms of a year, but PIES characterizes supply and demand as of a single day in the future. The daily load-duration curve for the "typical" day is equated to the annual curve, scaled down on the time axis. The area under the curve represents the total electricity demanded during the period. (The ratio of peak to average demand is roughly 1.7 nationally, but there are substantial regional differences.)

The continuous load-duration function is first normalized, by dividing by the total electricity demanded. The normalized function is then approximated by a step function with four steps. (See Figure VII-4.) The segmenting of the load-duration curve into four loads enables the model to approximate actual dispatching patterns more closely than the three loads previously used in PIES. (Last year's cycling load was separated into this year's cycling and daily peak loads.) This facilitates better dispatching of existing oil steam plants and the competing coal plants. With the current version, coal plants are more economic for cycling, while oil steam plants will satisfy daily peak requirements rather than one plant type being used to satisfy both modes as often happened in the earlier version.

The load-duration curve is assumed to be independent of short-run supply technology. That is, whether electricity is generated from coal-burning or gas-burning plants is not expected to alter the basic shape of the curve.

Table VII-7 shows regional composition factors for base, cycling, daily peak, and seasonal peak loads, as well as system load factors (the ratio of average to peak load). Composition factors are the fractions of electrical power in each load. For example, in the first region, 68.7 percent of the electricity demanded during the year is base, 24.7 percent is cycling, 4.4 percent is daily peak, and 2.2 percent is seasonal peak.

TABLE VII-7. LOAD-DURATION CURVE DATA FOR 1985

DOE Region	COMPOSITION FACTORS (i.e., Fraction of Total in Each Mode)				System Load Factor
	Base	Cycling	Daily Peak	Seasonal Peak	
NW-Eng.	.687	.247	.044	.022	.590
NY/NJ	.746	.188	.042	.023	.630
Mid-Atl.	.766	.166	.042	.026	.600
S.-Atl.	.770	.158	.043	.029	.600
Midwest	.758	.185	.037	.020	.630
S.-West	.756	.144	.067	.033	.540
Central	.749	.156	.063	.033	.550
N-Central	.783	.167	.026	.024	.600
West	.758	.173	.043	.026	.630
N.-West	.810	.130	.036	.024	.620

Load Management

PIES allows the modeling of changes in energy and economic policies. In the utilities submodel, the load-duration curve allows the user to examine different load-management scenarios. With incentives, consumers can be induced to change their patterns of demand for electricity. For instance, peak demand could be decreased by the imposition of peak load pricing so that a more uniform level of demand would result reduced (peak load) capacity requirements, and lower average prices to consumers.

Capacity Factors

While there are a possible 8,760 hours a year that any plant could generate electricity, in practice, the fraction of possible time used in generation is less than 1.0. There are planned, preventive maintenance stoppages of operation and unplanned maintenance and forced outages. A capacity factor represents the fraction of hours a plant is operated and not shut down for repairs or scheduled maintenance. Table VII-8 gives capacity factors for each of the four load types.

If an existing residual-fired plant is operated in base load for a year, the actual number of kilowatt-years of electricity generated, on the average, will be its capacity (in kilowatts) multiplied by its capacity factor, which from Table VII-8 is .70. Since base plants are operated almost continuously when they are available, this indicates that the plant will be shut down approximately thirty percent of the time. For this same plant operating in cycling load, the capacity factor is .55, reflecting the periods the plant will not operate because demand does not warrant bringing in cycling plants, as well as periods when the plant is forced out of service or shut down for maintenance.

TABLE VII-8. CAPACITY FACTORS

Existing Plants	Base	Cycling	Daily Peak	Seasonal Peak
Residual-Fired Steam	.700	.548	.274	-
Distillate-Fired Simple Cycle Turbine	.800	.616	.308	.082
Gas-Fired Steam	.700	.548	.274	-
Gas-Fired Turbine	.800	.616	.308	.082
Distillate-Fired Combined Cycle Turbine	.800	.616	.308	-
Btuminous Coal-Fired Steam (With Scrubbing Required)	.650	.514	.257	-
Bituminous Coal-Fired Steam (Unscrubbed Using Low Sulfur Coal)	.650	.514	.257	-
Bituminous Coal-Fired Steam (With No Scrubbing Required)	.650	.514	.257	-
Hydroelectric (Pondage)	.850	.651	.325	.087
Hydroelectric (Pump Storage)	-	-	.325	.087
Nuclear	.650	-	-	-
New Plants				
Residual-Fired Steam	.700	.548	.274	-
Distillate-Fired Simple Cycle Turbine	.800	.616	.308	.082
Gas-Fired Steam	.700	.548	.274	-
Distillate-Fired Combined Cycle Turbine	.800	.616	.308	-
Bituminous Coal-Fired Steam (With Scrubbing Required)	.650	.514	.257	-
Bituminous Coal-Fired Steam (Unscrubbed Using Low Sulfur Coal)	.650	.514	.257	-
Sub-Bituminous Coal-Fired Steam	.650	.514	.257	-
Hydroelectric (Pondage)	.850	.651	.325	.087
Hydroelectric (Pump Storage)	.850	.651	.325	.087
Nuclear	.650	-	-	-

Table VII-9 shows the existing capacity for each plant type in each utility (DOE) region.

Heat Rates

The PIES optimization process prefers to operate newly built plants over older, existing ones because of their greater efficiency. Values specifying heat rates represent the relative efficiencies of different plant types. The heat rate is defined as the energy (in Btus) required to produce one kilowatt-hour. Tables VII-10, VII-11, and VII-12 show heat rates by region for existing equipment operated in base load, cycling and daily peak load, and seasonal peak load, respectively. The heat rates for new equipment, which are the same for all regions, are given in Table VII-13.

The ratio of heat rate to heat value determines the amount of fuel needed to generate one kilowatt. Specifically, the fuel required to operate a plant to generate one megawatt of electricity in a particular load (i.e., base, cycling, daily peak or seasonal peak) is:

$$\text{Fuel Requirement} = \text{Heat Rate}/\text{Heat Value},$$

where the amount of fuel required is measured in physical units (i.e., tons, barrels, thousands of standard cubic feet, etc.).

Plant Conversions

The utilities submodel allows the conversion of oil- and gas-burning plants to coal-burning plants in accordance with the ESECA (Energy Supply and Environmental Coordination Act). Conversions between oil-and gas-burning plants are modeled, explicitly including capital investment cost. The utilities submodel specifies the exact amount of conversion that may occur (via fixed bounds in the LP) based on plants that have received letters of intent to issue conversion orders.

TABLE VII-9. EXISTING CAPACITY*
(Megawatts)*

PLANT TYPE	DOE REGION 1	2	3	4	5	6	7	8	9	10	Total
Residual-Fired Steam	10286	21489	13690	16117	10122	3676	1150	394	25074	204	102202
Distillate-Fired Simple Cycle Turbine	1276	8583	4473	7900	6534	543	3373	936	3567	960	38145
Distillate-Fired Combined Cycle Turbine	170	931	203	619	217	1112	70	-	1219	612	5153
Gas-Fired Steam	-	50	-	2981	1035	55052	4957	248	1053	35	65411
Gas-Fired Turbine	-	130	414	2418	1110	1806	700	44	59	50	6731
Bituminous Coal-Fired Steam (Unscrubbed Using Low Sulfur Coal)	1024	1624		3589	12802		706	1170	1772		22687
Bituminous Coal-Fired Steam (With Scrubbing Required)	-	-	3263	2370	1470	-	965	-	490	-	8558
Bituminous Coal-Fired Steam (With No Scrubbing Required)	485	2950	26908	48731	40296	-	9486	2215	1616	-	132687
Sub-Bituminous Coal-Fired Steam	-	-	-	-	13385	3338	3248	4554	-	1300	25825
Lignite Coal-Fired Steam	-	-	-	-	141	4857	-	2039	-	-	7037
Hydroelectric (Pondage)	1303	5187	1101	10445	1436	2004	636	5390	10128	23861	61491
Hydroelectric (Pump Storage)	1607	1629	1432	921	1979	299	408	334	1646	100	10355
Nuclear	4199	6132	6112	12838	11391	850	2010	-	1411	1130	46073
Regional and National Totals	20350	48705	57596	108929	101918	73537	27709	17324	48035	28252	532355

*As of 1/1/78

TABLE VII-10. HEAT RATES FOR EXISTING EQUIPMENT OPERATED IN BASE LOAD
(Btu Per Kilowatt-Hour)

	DOE REGION									
PLANT TYPE	1	2	3	4	5	6	7	8	9	10
Residual-Fired Steam	10000	10300	10700	10000	12100	10300	11200	14500	9800	11000
Distillate-Fired Simple Cycle	14500	14600	12500	13000	14500	12800	12500	12000	15700	12800
Distillate-Fired Combined Cycle	8500	8500	8500	8500	8500	8500	8500	-	8500	8500
Gas-Fired Steam	12500	10900	10900	11100	13400	10100	11300	11900	10400	11500
Gas-Fired Turbine	14000	15400	14300	16500	14700	13000	14700	12200	13700	12600
Bituminous Coal (With Scrubber)	10510	11000	10300	10300	10500	-	10900	11600	10700	-
Bituminous Coal (Without Scrubber)	10110	10500	9900	9900	10200	-	10500	11200	10300	-
Sub-Bituminous Coal	-	-	-	-	10300	10100	10600	10700	-	10700
Lignite	-	-	-	-	12400	10500	-	11900	-	-

TABLE VII-11. HEAT RATES FOR EXISTING EQUIPMENT OPERATED IN CYCLING AND DAILY PEAK LOAD
(Btu Per Kilowatt-Hour)

	DOE REGION									
PLANT TYPE	1	2	3	4	5	6	7	8	9	10
Residual-Fired Steam	10500	10800	11200	10500	12600	10800	11700	15000	10300	11500
Distillate-Fired Simple Cycle	14500	15100	13000	13500	15000	13300	13000	12500	16200	12500
Distillate-Fired Combined Cycle	9000	9000	9000	9000	9000	9000	9000	-	9000	9000
Gas-Fired Steam	13000	11400	11400	11600	13900	10600	11800	12400	10900	12000
Gas-Fired Turbine	14500	15900	14800	17000	15200	13500	15200	12700	14200	13100
Bituminus Coal (With Scrubber)	11000	11500	10800	10800	11000	-	11400	12100	11200	-
Bituminous Coal (Without Scrubber)	10600	11000	10400	10400	10700	-	11000	11700	10800	-
Sub-Bituminous Coal	-	-	-	-	10800	10600	11100	11200	-	11200
Lignite	-	-	-	-	12900	11000	-	12400	-	-

TABLE VII-12. HEAT RATES FOR EXISTING EQUIPMENT OPERATED IN SEASONAL PEAK LOAD

(Btu Per Kilowatt-Hour)

	DOE REGION									
PLANT TYPE	1	2	3	4	5	6	7	8	9	10
Residual Fired Steam	-	-	-	-	-	-	-	-	-	-
Distillate-Fired Simple Cycle	14500	15100	13000	13500	15000	13300	13000	12500	16200	12500
Distillate-Fired Combined Cycle	-	-	-	-	-	-	-	-	-	-
Gas-Fired Steam	-	-	-	-	-	-	-	-	-	-
Gas-Fired Turbine	14500	15900	14800	17000	15200	13500	15200	12700	14200	13100
Bituminous Coal (With Scrubber)	-	-	-	-	-	-	-	-	-	-
Bituminous Coal (Without Scrubber)	-	-	-	-	-	-	-	-	-	-
Sub-Bituminous Coal	-	-	-	-	-	-	-	-	-	-
Lignite	-	-	-	-	-	-	-	-	-	-

TABLE VII-13. HEAT RATES FOR NEW EQUIPMENT
(Millions of Btu Per Kilowatt)

Plant Type	Base	Cycling	Daily Peak	Seasonal Peak
Residual-Fired Steam	9650	10300	10300	-
Distillate-Fired Simple Cycle	10000	10500	10500	10750
Distillate-Fired Comboned Cycle	7500	8000	8000	-
Gas-Fired Steam	10010	10760	10760	-
Gas-Fired Turbine	10000	10500	10500	10750
Bituminous Coal (With Scrubber)	9840	10300	10300	-
Bituminous Coal (Without Scrubber)	9870	10350	10350	-
Sub-Bituminous Coal	10230	10710	10710	-
Lignite	10500	11000	11000	-

Conversions are modeled for existing and new facilities; these include oil (residual oil-fed steam plants) to gas facilities. Three other conversions between existing plant types are modeled: gas to oil, distillate to gas, and gas turbine to distillate.

Table VII-14 shows existing capacities, which can be converted and mandated conversions according to the ESECA as of June 30, 1977.

Coal Conversion

Coal exists and is supplied in forms differentiated by physical and chemical composition. Among the coal characteristics important to the utilities industry are Btu and sulfur content. The utilities submodel consumes standard high-sulfur, low-sulfur and sub-bituminous coal and lignite. In addition, metallurgical coal can be converted to low-sulfur coal. (Coal for industrial use must be either standard or metallurgical.) The utilities submodel provides for the conversion of physical coal to standard coal after it has been transported to demand regions, based on ratios of the Btu content of the various coal types. For instance, given a physical coal type rated at 23.8 x 10^6 Btu/ton, one unit of that coal type can be converted to 1.058 units of standard coal rated at 22.5 x 10^6 Btu/ton.

Average Cost Pricing

Although the utilities submodel chooses the generating plant configuration and operating mix on the basis of marginal costs, the price paid by the consumer is a function of average generating costs. Accordingly, in order to reflect actual utility practice better, electricity supply and demand are balanced on the basis of average cost prices rather than marginal prices.

In general, marginal prices of fuels are obtained from the LP solution and are used in integrating supply and demand. For electricity, the prices used to revise the demand model approximation[1] are average cost prices rather than marginal prices. The modeling of average cost pricing requires that electricity prices must be calculated on an average cost basis, and an adjustment must be entered into the objective function of the LP, which accounts for the difference between marginal and average cost prices and which is included as a price wedge by the optimization procedure on the next iteration. PIES calculates average cost prices by region by summing the regional consumption of each type of utility fuel.

The average price for each region is computed with the formula:

$$AV = \frac{C + \sum_{f} (\pi_f K_f + FC_f)\, MMKWH_f}{\sum_{f} MMKWH_f}$$

where:

C = capital charges for existing plants and those committed by 1979. (These are necessary to determine the capital component of the rate base).

π_f = marginal price of fuel f

K_f = amount of fuel f (in physical units) to generate 1 kwh

FC_f = fixed charges of type f fuel-specific plant (includes operation and maintenance, taxes, capital and interest, transmission and distribution)

$MMKWH_f$ = one million kilowatt hours (MMKWH) generated by fuel-specific plant.

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[1] See Chapter II for a discussion of the demand model approximation.

TABLE VII-14. EXISTING CAPACITIES WHICH MAY BE CONVERTED TO BURN ALTERNATE FUEL TYPES

	DOE REGION										
PLANT TYPE	1	2	3	4	5	6	7	8	9	10	Totals
Residual-Fired Steam Plants Which * Must be Converted to Coal	2488	6822	4063	1794	656	-	46	68	-	-	15937
Gas-Fired Steam Plants Which Can be Converted to Residual	-	-	-	1764	68	45968	2700	168	744	35	51447
Residual-Fired Steam Which Can be Converted to Gas	185	4539	443	6513	2288	1578	231	123	22936	53	38889
Gas-Fired Turbines Which Can be Converted to Distillate	-	-	-	2396	628	327	531	31	59	50	4022
Distillate-Fired Turbines which Can be Converted to Gas	291	3208	386	2851	2610	106	616	314	2399	256	13037
Gas-Fired Steam Plants Which * Must be Converted to Coal	-	-	-	-	-	-	685	-	-	-	685
Regional and National Totals	2964	14569	4892	15318	6250	47979	4809	704	26138	394	124017

*Mandated conversions according to the Energy Supply and Environmental Coordination Act (ESECA) as of June 30, 1977.

Figure VII-5 illustrates the contrast between average cost pricing and a marginal pricing. For example, the marginal price supply function could have four steps. In terms of ascending costs, they might be in step 1 corresponding to operating an existing hydro plant, step 2 corresponding to operating an existing nuclear plant, step 3 corresponding to operating a new coal plant, and step 4 corresponding to operating a new nuclear plant. Due to the capital charges, C, the average price curve, is initially at $C/MMKWH_{hydro}$, and as the hydro plant is operated, we obtain

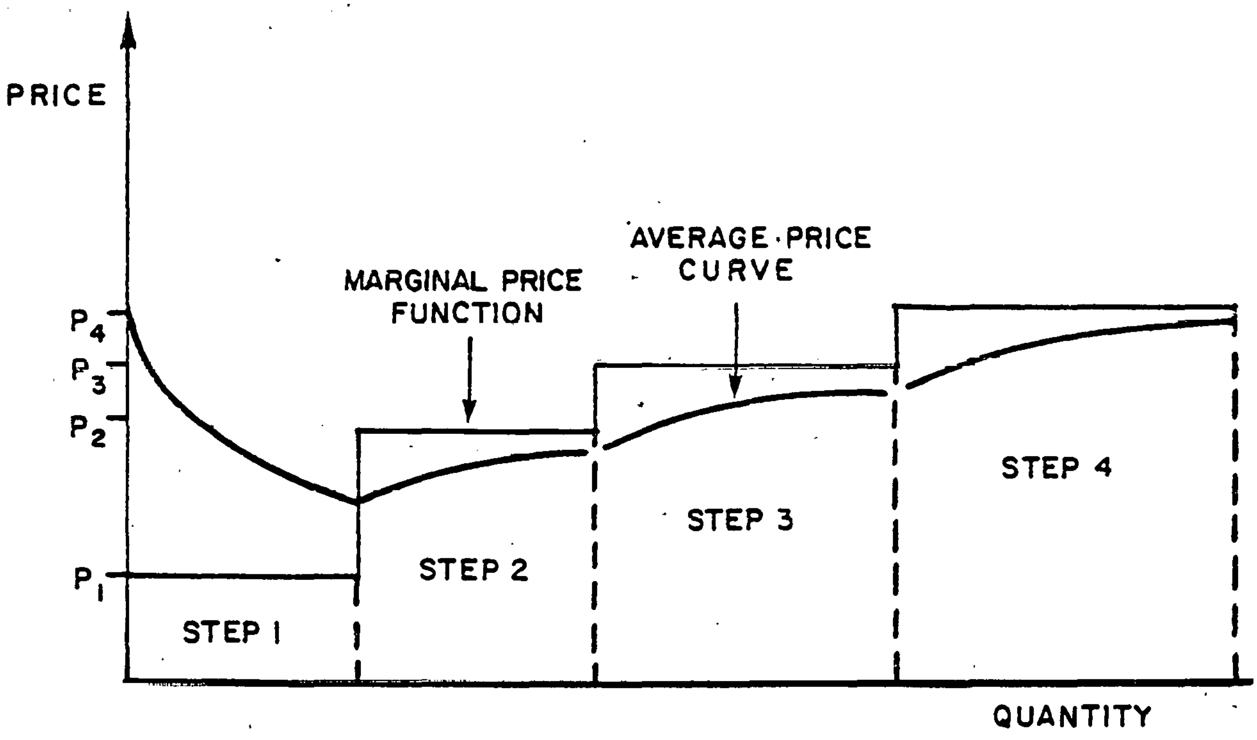
$$\frac{C+(\pi_{hydro} K_{hydro} + FC_{hydro})\, MMKWH_{hydro}}{MMKWH_{hydro}} =$$

$$\frac{C}{MMKWH_{hydro}} + \pi_{hydro} K_{hydro} + FC_{hydro}$$

as the form of the average cost price curve. At step 2, we add in the appropriate charges for operating the existing nuclear plant, and thus the average cost price curve increases towards the price at step 2. This process is repeated for the remaining steps.

FIGURE VII-5

AVERAGE PRICE CURVE VERSUS MARGINAL PRICE FUNCTION



To simulate average costs, a price wedge equal to the difference between average and marginal costs must be entered into the objective function of the LP. The correction for each region is included in the form of a cost supplement or credits for electricity. Thus, PIES simulates a situation where utilities act on the basis of marginal costs, while consumers respond to the average cost price.

REPRESENTATION OF UTILITY OPERATIONS IN THE MATRIX

Within each solution of the LP, the utilities submodel consumes fuels and builds and operates the mix of generating equipment is consistent with overall optimization by representing the construction and operation of each type of generating plant as independent activities within the LP. Solving the LP chooses the subset of activities and the levels that will satisfy demands in an optimal fashion.

Two major types of constraints link the activities together: the material (or resource) balance relationships and the process limit constraints. Resource balance relationships based on conservation of mass require the amount of a material produced at, or transported to, a location be greater than the amount transported from, or consumed at, the location. Process limit constraints require that the amount of any type of facility capacity operated be less than, or equal to, the sum of existing capacity plus the new capacity. Within the utilities submodel, material balance equations model the flow of fossil fuels to the generating plant and the flow of electricity from the generating plant to the consumer. In principle, each type of generating plant may be operated in each of the four operating modes, base, cycling, and daily and seasonal peak. However, as discussed earlier, there may be restrictions on the operation of specific types of plants in one or more of the modes.

Operation of a particular plant type in each region is modeled as a single activity within the LP. The information associated with each activity is the operation and maintenance cost of producing one kwh of electricity, the type and quantity of the fuel assumed to produce it, and the amount of capacity of that type that can be operated in that mode. Costs and efficiencies (i.e., quantity of fuel consumed/kwh) differ according to the mode. In each region, different cost, efficiency and capacity measures are used for new and existing plant types. These values were given in Tables VII-1 through VII-6.

VIII. ADVANCED TECHNOLOGIES

INTRODUCTION

The advanced technologies modeled in PIES include synthetic fuels (mainly gas and oil produced from coal), solar (energy captured directly from the sun), geothermal, wind, shale oil, and nuclear fuel. This chapter discusses the PIES solar/geothermal supply submodel, the nuclear fuel supply submodel, the shale oil standard-table specifications, and the synthetic fuel supply submodel.

SOLAR/GEOTHERMAL SUPPLY SUBMODEL

The solar/geothermal submodel models the use of the sun, wind, and ground steam to generate electricity. These power sources are little used currently, but if the cost of more traditional hydrocarbon fuels (e.g., gas and oil) continues to increase, these "renewable" resources will certainly become more popular.

The only class of electricity modeled within the solar/geothermal submodel is base-load electricity; i.e., electricity supplied to satisfy the steady base loads. Operation of these facilities is very costly. The capital cost coefficient for base-load production of electricity by geothermal means is about twenty times that of the heavily used hydro, nuclear, and coal-burning plants. Operation of solar (thermal) facilities is about one hundred times more costly (see the standard-table entries in Table VIII-1, below).

Solar

As traditional hydrocarbon power sources become scarcer, subject to additional anti-pollution regulations, and more expensive, the use of solar power will become relatively more attractive. Mass production of solar collectors could lead to a drop in their unit costs, and the conversion of even a small percentage of U. S. buildings to solar heating could decrease total oil consumption appreciably.

TABLE VIII-1. CHARACTERISTICS OF SOLAR, GEOTHERMAL, AND WIND FACILITIES

	Solar		Geothermal		Wind	
	Operation of Facilities	Build New Facilities	Operation of Facilities	Build New Facilities	Operation of Facilities	Build New Facilities
Cost/Unit of Output*	114.00		19.30		27.00	
Availability Factor	.40		.80		.40	
T&D Capacity Required/Unit of Capacity**	1.0		1.0		1.0	
Thermal Capacity Added/Unit of Capacity	1.0	1.0	1.0	1.0	1.0	1.0
Capital Costs	125.00				29.17	
Fixed Bound	.456		55.20		1.716	
Upper Bound						

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*Bounds are in millions of kilowatt hours per calendar day (MMKWH/D). Costs are in $/KWH/D.

**Transmission and Distribution

Current use of solar (or thermal) power is to a large extent dispersed, that is, individual structures each have their own converters. There are no large centralized solar plants comparable to coal, hydro, and nuclear generating facilities. The most promising use of solar power seems to be in heating and cooling (via air conditioners driven by solar energy) of individual buildings.

The solar columns of the standard tables (see Table VIII-1) show that the use of solar power to generate electricity is the most costly process modeled by the solar/geothermal submodel—$114/MMKWH/D. Without some level of capacity prespecified as operational in the submodel (.456 MMKWH/D) or some special incentive for solar power, the Integrating Model would not select the operation of solar generators over currently used processes.

The submodel limits the capacity of solar generating facilities to 40 percent, since the sun shines only part of each day. The model permits solar capacity to satisfy base-load demand only. For each unit of solar generating capacity used in producing electricity, the submodel requires a unit of transmission and distribution capacity. There is no upper bound on building new solar generating facilities.

Geothermal

Geothermal power comes from the heat of the earth, tapping the steam trapped in the ground under pressure. This steam can exist in a superheated and dry state, or as a wet mixture with water. The latter is more abundant but less efficient to use, and there is difficulty in disposing of its waste water. The steam drives turbines that generate electricity.

The first commercial geothermal steam turbine in the U. S. was a 12.5 MW unit installed in 1960. By 1975 U.S. capacity exceeded 500 MW.

Geothermal power is modeled in base-load only—at an 80 percent availability level. For each unit of generating capacity used, a unit of transmission and distribution capacity is also used. No consumption of fuel material is modeled; only existing ground steam is used.

Geothermal power is modeled with an unlimited upper bound on the amount of generating capacity that can be built, but high operating cost ($19.30/MMKWH/D, including the capital cost.) As a result, the activity is unlikely to be chosen in the optimization process, except when fixed levels are specified—as there currently are, at 55.2 MMKWH/D, (2300 kilowatts, multiplied by .024 to convert to MMKWH/D).

Wind

Wind is still used on a very limited, dispersed basis; it accounts for a very small portion of total electricity generation.

The structure of the wind segment of the solar/geothermal submodel is much like that for solar energy. The availability of wind power is modeled at 40 percent, because wind fluctuates over hours of the day and over seasons of the year.

For each unit of generating capacity in operation, it is specified that a unit of transmission and distribution capacity be available. The level of operation of wind facilities is currently fixed (at 1.716 MMKWH/D), but the number of new facilities that can be built is left essentially unbounded. The high cost of generating electricity via wind prevents the submodel from substituting wind generators for other plant types when more capacity is required, except for the fixed level of operation specified.

NUCLEAR FUEL SUPPLY SUBMODEL

The nuclear fuel submodel of PIES provides a supply curve, i.e., a relationship between price and quantity. It determines supply-curve steps for each target year. The supply activity occurs in only one region—the entire U.S.

For additional units of nuclear fuel to be supplied, there is a price that elicits that supply amount. The supply curve is modeled as a step function, that is, as a discrete rather than a continuous function. At each step, a unit of nuclear fuel supply capacity is used. Bounds are specified in the standard tables showing just how much nuclear fuel would be forthcoming at each price.

Standard table values enter PIES directly in the format given in Table VIII-2. No preprocessor formatting or transformation of the raw data occurs.

TABLE VIII-2. NUCLEAR FUEL STANDARD TABLE

(Activities Showing Operation of Existing Uranium Conversion Supply-Step Specifications--Target Year 1985)

	(A)	(B)	(C)
Supply Price/Unit	5.77	5.99	6.29
Nuclear Fuel Produced*	1.	1.	1.
Upper Limit	2016.	456.	888.

*Standard units: MMKWH/D

For instance, the first two columns, (A) and (B), show that at $5.77/MMKWH/D, 2016 MMKWH/D will be made available, and at $5.99 per standard unit, 456 more will be supplied. For each unit of nuclear fuel supplied (+1), one unit of fuel conversion capacity is used (-1).

SHALE OIL

Oil can be produced from sedimentary rock (shale) by a process of distillation, or retorting. Whether or not this oil is a practical alternative to other energy sources depends not only on the extent of the oil-bearing shale rock, but also on the costs of mining and transforming it, which are quite high.

Most of the shale reserves lie in Colorado, Utah, and Wyoming. PIES models only one shale oil region, which encompasses the entire U.S.

The PIES shale standard tables are simple and straightforward; there is one activity that represents the operation of existing facilities and one representing the building of new capacity.

For instance, Table VIII-3 shows that a fixed amount, 47,000 barrels, of shale oil are produced (per day). (This value can be respecified in the table for each target year and for each different scenario run.) This level of production costs $15.08 per barrel and uses one unit of shale oil capacity. New capacity can be built at a capital cost of $11.00 per unit. The bound on new capacity is high enough not to affect the building activity level.

TABLE VIII-3. SHALE OIL STANDARD TABLE

	Operate Existing Facilities	Build New Capacity
Cost/Unit	15.08	
Shale Oil Produced	1*	
Capacity	-1	1
Capital Cost		11.0
Upper Bound		
Fixed Bound	47*	

* Units of output are thousands of barrels/CD.

SYNTHETIC FUEL SUPPLY SUBMODEL

The synthetic fuel submodel models production of four fuels: gas and oil products from coal gasification and liquefaction, (called syngas and syncrude respectively), syngas produced from naphtha (one of the petroleum products produced in refineries), and fuel gas, which is a low Btu gas produced from coal used to produce electricity close to the coal mine.

PIES models fixed production levels for synthetics. High Btu gas can be obtained by processing coal (coal gasification). This synthetic gas has a high heating value, is of pipeline quality (high Btu content), and can supplement the supply of natural gas. The gasification process converts coal and water to methane and carbon dioxide in several steps. The raw gas output contains undesirable components (carbon dioxide, ash, ammonia, etc.) which must be removed through further processing. There are gasification plants producing synthetic pipeline gas by means of a commercially applicable technique called Lurgi, and other processes are under development in research institutions.

In general, the efficiency of the conversion process ranges from 50 to 70 percent. To produce 250 million standard cubic feet (SCF) per day of high Btu gas, 15,000 to 30,000 tons of coal are needed for the conversion input alone (depending on the process used and the coal type), plus approximately a further 15 percent of the input to run the conversion equipment.

A coal liquefaction process plant that produces 100,000 barrels of oil a day for generation of electricity requires 30,000 tons of coal a day. The capital cost is around $20,000 per daily barrel of capacity or about six times the cost of new refinery capacity. This high cost prevents the process from being commercially viable. The output, liquefied coal, can range from light distillates to solid material that can be burned directly in generation equipment. The output characteristics depend on the processes used in the conversion.

Synthetic fuel supplies are modeled as conversion activities. Activities include the operation and building of new conversion facilities. The conversion of coal to oil and natural gas takes place in PIES coal regions; oil is then transported to refinery regions and gas to demand or utility regions. The submodel assumes no existing generating capacity.

Table VIII-4, from the syngas and syncrude standard table, shows the conversion cost to be \$20 per barrel of oil equivalent per day. The entry for syngas of 5.62 in the operate activity column is based on the Btu equivalence of standard units of oil and natural gas, that is, $(5.8 \times 10^6$ BTU/B $\times 10^3$ B) / (1.032 BTU/SCF $\times 10^3$ SCF). The conversion of steam coal to standard coal is modeled in the utilities submodel, on a Btu basis. The coefficient specifying the consumption rate of coal, i.e. the process efficiency, 65 percent, that is, $(5.8 \times 10^6$ BTU/B)/$(22.5 \times 10^6$ BTU/T $\times .65) = .397$ thousand tons per thousand barrels, where 22.5 is the standard coal million-Btu-per-ton rate.

A unit of production capacity produces each unit of crude or (equivalent) unit of syngas produced; new capacity can be built for a capital cost of 13.6 and 16.3 for syncrude and syngas, respectively. The synthetics submodel currently specifies upper bounds for build activities, but these are extremely high. The operate activity bounds are now fixed at zero; that is, no production is allowed.

TABLE VIII-4. SYNCRUDE AND SYNGAS STANDARD TABLE

	SYNCRUDE FACILITIES		SYNGAS FACILITIES	
	Operate	Build	Operate	Build
Cost (\$/Barrel)	19.32		20.98	
Syncrude and Syngas Output	1.0		5.62	
Standard Coal	- .397		- .397	
Capital Coefficient		13.6		16.3
Upper Bound				

Standard table entries for producing electricity from fuel gas (produced from coal) and syngas from naphtha are given in Table-VIII-5.

TABLE VIII-5. FUEL GAS AND SYNGAS (FROM NAPHTHA)

	FUEL GAS FACILITIES		SYNGAS FROM NAPHTHA	
	Operate	Build	Operate	Build
Conversion Cost ($/Barrel Equivalent)	23.30		.47	
Base-Load Electricity	.584			
Standard Coal				
T&D Capacity	-1.0			
Capital Cost		21.20		
Upper Bound		9999.0		130.68
Existing Capacity				13.05
Natural Gas			1.0	
Naphtha			-.218	

IX. TRANSPORTATION

INTRODUCTION

A transportation system moves energy materials from supply to consumption regions. Because transportation costs influence the price of energy to the consumer (representing more than 50 percent of the final cost for some fuels), they are crucial to the equilibrium of energy supply and demand.

The PIES transportation submodel provides inter-regional connections, referred to as links, between supply, conversion, and demand regions. Energy materials flow along the links. The materials represented are predominantly coal, oil, and natural gas. The transportation modes available consist primarily of rail, barge, tanker, and pipeline.

Separate transportation networks from origin to final destination are generally provided for every allowable material/mode combination from the above possibilities. A more detailed network, involving two interconnected modes (rail and barge), is provided for the transportation of coal in the U.S.

Capacity constraints along links are generally not provided in PIES. In reality, when links are saturated, fuels must be transferred to a different route, transported by an alternative mode, or accommodated by the construction of additional capacity. However, PIES does not now incorporate these possibilities, except for capacity constraints in regard to the Trans-Alaskan Pipeline System and crude oil pipelines connecting the West coast to the rest of the United States. (TAPS), and crude oil pipelines connecting the West Coast to the rest of the United States.

The following section describes the material/mode combinations modeled within PIES. Subsequent sections describe transportation networks and costs for coal, oil, natural gas, electricity, and nuclear fuel.

MATERIAL/MODE COMBINATIONS

Table IX-1 shows the energy material/transportation mode combinations occurring in the U.S. energy system and modeled in PIES. In the case of coal, the transportation network involves two interconnected modes, rail and barge, and is referred to as a transshipment network. This transshipment network is provided because the costs of moving coal are a significant fraction of the delivered price.

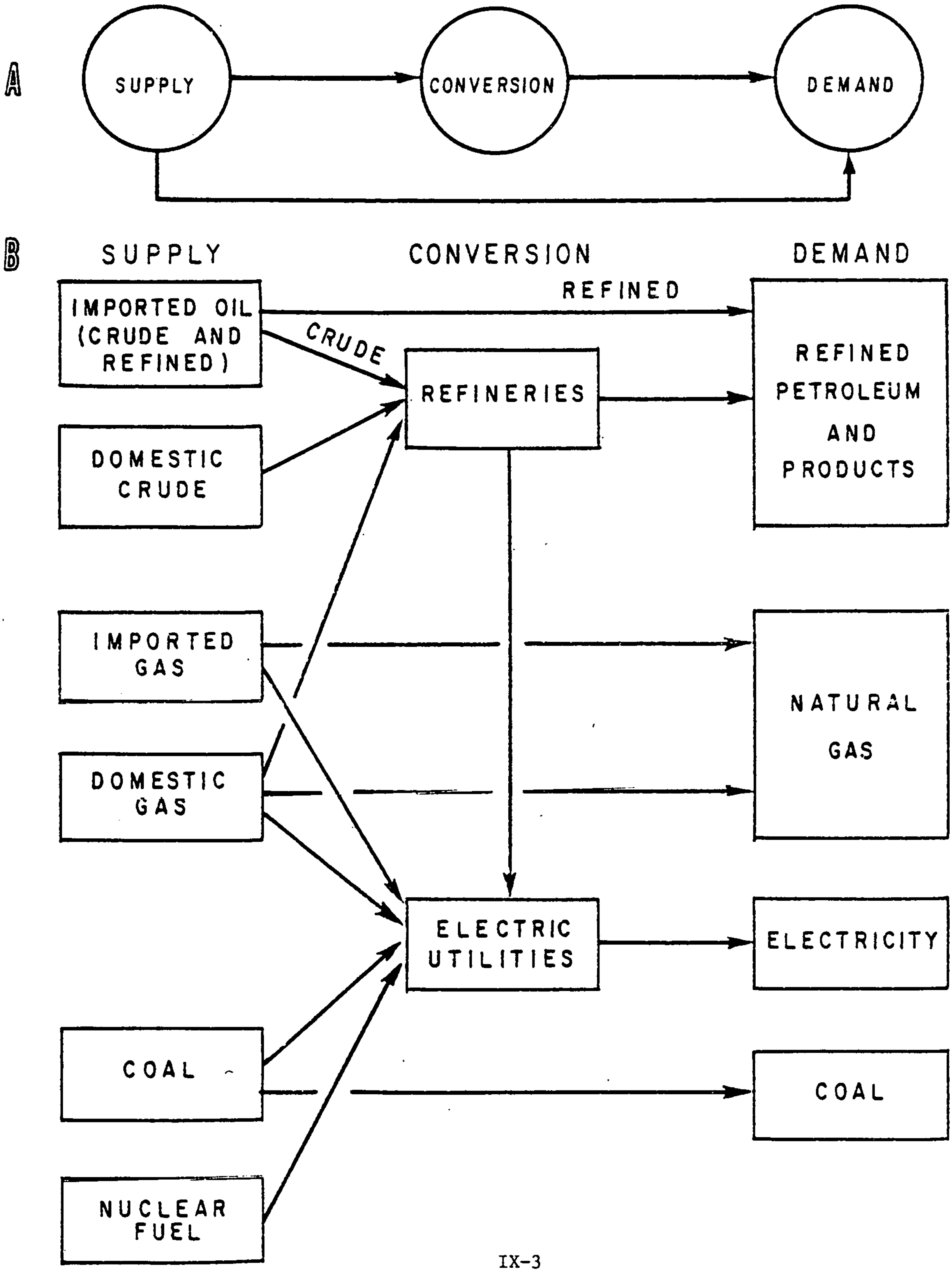
TABLE IX-1. ENERGY MATERIAL TRANSPORTATION MODE COMBINATIONS

Material	Transportation Mode
Coal	Barge and Rail (Transshipment)
Oil	
-Crude	Tanker Pipeline
- Product	Tanker Barge Pipeline
-Residual	Tanker Barge
Natural Gas	Pipeline
Other	
-Nuclear Fuel	Transport
-Electricity	Transmission

Within the transportation submodel, energy materials move from supply regions to demand regions, if necessary passing through conversion regions (refineries or utilities). These flows are shown in Figure IX-1. Refined petroleum products are moved directly to demand regions, whereas crude oil is shipped to refineries for processing. Natural gas and coal may be moved either directly to demand regions or to electric utilities, where the fuel is converted to electric power. Nuclear fuel must go via electric utilities.

FIGURE IX-1

FLOW OF ENERGY MATERIALS



In some instances in PIES, the production of one energy material is a coproduct of the production of another. Associated natural gas, for example, is a coproduct of oil production. The associated natural gas produced in an oil supply region is transferred to a natural gas supply region in a notional sense. This transfer is called a logical shift. A logical shift also occurs in the production of synthetic oil and gas from coal. To provide for these logical shifts, a correspondence must be made between coal, oil and gas supply regions (see Table IX-2).

Offshore oil and gas regions are not shown in Table IX-2. Coal regions are generally not geographically identical to oil or gas regions. Oil and gas regions are geographically identical, except for the Michigan Basin-Eastern Interior, Appalachian area, which is counted as one oil region but two natural gas regions.

For each material/mode combination, the transportation submodel provides a series of possible origins and destinations which will generally be in different types of regions. Thus, for example, crude oil produced in Texas can be transported by pipeline from oil region 8 to the PADD 3 refinery region, (the West Gulf states), or to PADDs 1A and 1B, (the Northeast and Atlantic Coast states, respectively). In addition, alternative transportation modes, e.g., rail or barge, can also be used.

These transportation possibilities form a network made up of a series of transportation links connecting supply, conversion, and demand regions. The transportation links contain the following information: origin region, destination region, mode, and cost.

The choice of material, origin, destination and route depends upon the overall optimization of PIES. Thus, it may appear that the cheapest way of obtaining distillate oil in the Mid-Atlantic states is to transport it from Texas. However, although that choice may lead to the lowest distillate price in those states, it may not be consistent with the determination of equilibrium prices across the nation and the oil from Texas could perhaps be transported to the Midwestern states, instead.

The remainder of this chapter describes the transportation network and the costs of transporting energy material through it for each material/mode combination. Matrices of origin-destination (O-D) pairs are used to facilitate presentation of this information. The methods for determining the cost for each material/mode combination are given. These methods generally involve calculations of fixed and variable (per mile) costs per unit as well as adjustment costs, where applicable, for domestic and foreign supply in the O-D matrix. Data presented are either parameters used directly in the cost calculations or outputs from the transportation submodel. Input data, such as transportation route mileage, are not presented.

TABLE IX-2. CORRESPONDENCE AMONG COAL, OIL, AND GAS SUPPLY REGIONS FOR LOGICAL SHIFTS OF ENERGY MATERIALS

Coal Region	Oil Region	Natural Gas Region
Northern Appalachian	Mi. Bas., Int., Ap.*	Appalachians
Central Appalachian	Mi. Bas., Int., Ap.	Appalachians
Southern Appalachian	W. Gulf Basin	W. Gulf Basin
Midwest	Mi. Bas., Int., Ap.	Mi. Basin, Int.
Central West	Midcontinent	Midcontinent
Gulf	W. Gulf Basin	W. Gulf Basin
N.E. Great Plains	E. Rocky Mtns.	E. Rocky Mtns.
N.W. Great Plains	E. Rocky Mtns.	E. Rocky Mtns.
Rockies	W. Rocky Mtns.	W. Rocky Mtns.
Southwest	W. Rocky Mtns.	W. Rocky Mtns.
Northwest	Pacific Coast	Pacific Coast
Alaska South Alaska	South Alaska	

---

*Michigan Basin, Eastern Interior, Appalachians.

The order of presentation here follows the general direction from supply to demand, for a particular energy material as shown in Figure IX-1. Each material/mode combination is discussed in terms of the network (links and distribution characteristics) and costs (methods, units and types, data tables and results).

The information applies to the target years 1985 and 1990. Costs are in 1975 dollars. Units of tons in this chapter are short tons, (i.e. 2000 lbs) for coal, barrels for oil and thousands of cubic feet for natural gas.

COAL

The movement of coal is modeled primarily by a transshipment network. However, the consumption of coal at the minemouth and the movement of lignite is also modeled.

The Coal Transshipment Network

The coal network is more detailed than for other fuels because coal transport action constitutes a high proportion of the final costs to the consumer. The coal transshipment network models barge and rail movements, with transfer between the modes permitted. Multi-mode movements are not modeled in PIES for the transport of other energy materials.

The general movement of coal from supply to demand regions by the transshipment network is shown in Figure IX-2. The boxes denote three different types of connections between intermediate points, which are explained below.

The coal transshipment network for the rail and barge modes is depicted in Figures IX-3 and IX-4, respectively. The figures indicate the movement of coal to intermediate points (nodes) enroute to a final destination. A list of the transshipment nodes (barge and rail types) and the cities they are coterminous with is given in Table IX-3. Barge nodes do not exist for the nodes coded 6, E and F, which are not on waterways, and, in consequence, there are 20 nodes in the rail portion of the network and 17 nodes in the barge portion.

FIGURE IX-2
GENERAL MOVEMENT OF COAL FROM SUPPLY TO DEMAND

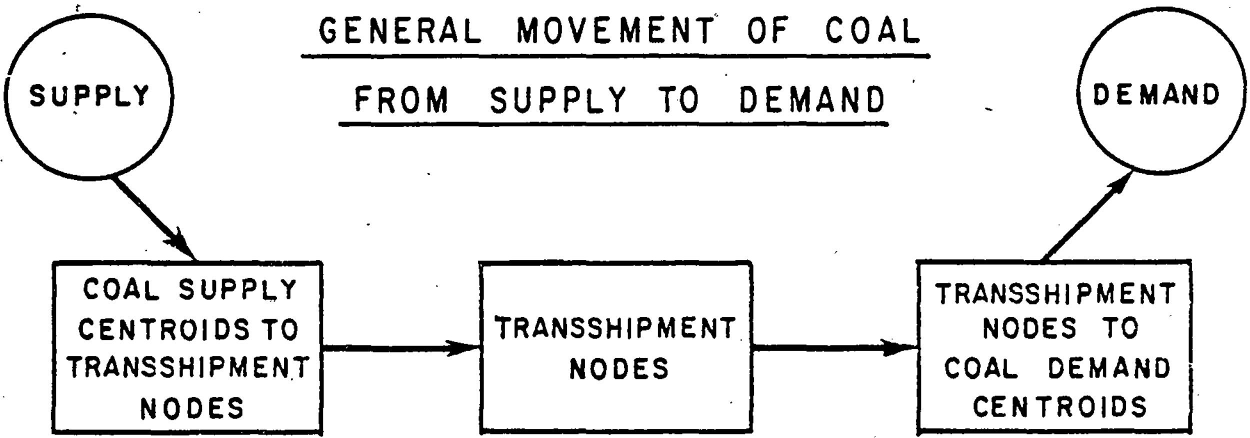


TABLE IX-3. COAL TRANSSHIPMENT NETWORK NODES

Notation	City Groups
1	Boston
2	New York
3	Baltimore Washington Philadelphia
4	Miami
5	Pittsburgh
6	Atlanta
7	Cincinnati, South
8	Detroit
9	Chicago
A	St. Louis, East (Illinois)
B	Minneapolis/St. Paul
C	Kansas City (Missouri & Kansas)
D	Houston
E	Dallas/Fort Worth
F	Denver
G	Los Angeles
H	San Francisco
I	Seattle
J	New Orleans
K	Cincinnati, North
L	St.Louis, West (Missouri)

Note: Barge nodes do not exist for number 6 and Letters E and F.

FIGURE IX-3

THE RAIL TRANSSHIPMENT NETWORK

(DISTANCE IN SHORT LINE MILES/COST IN 1975 DOLLARS PER TON)

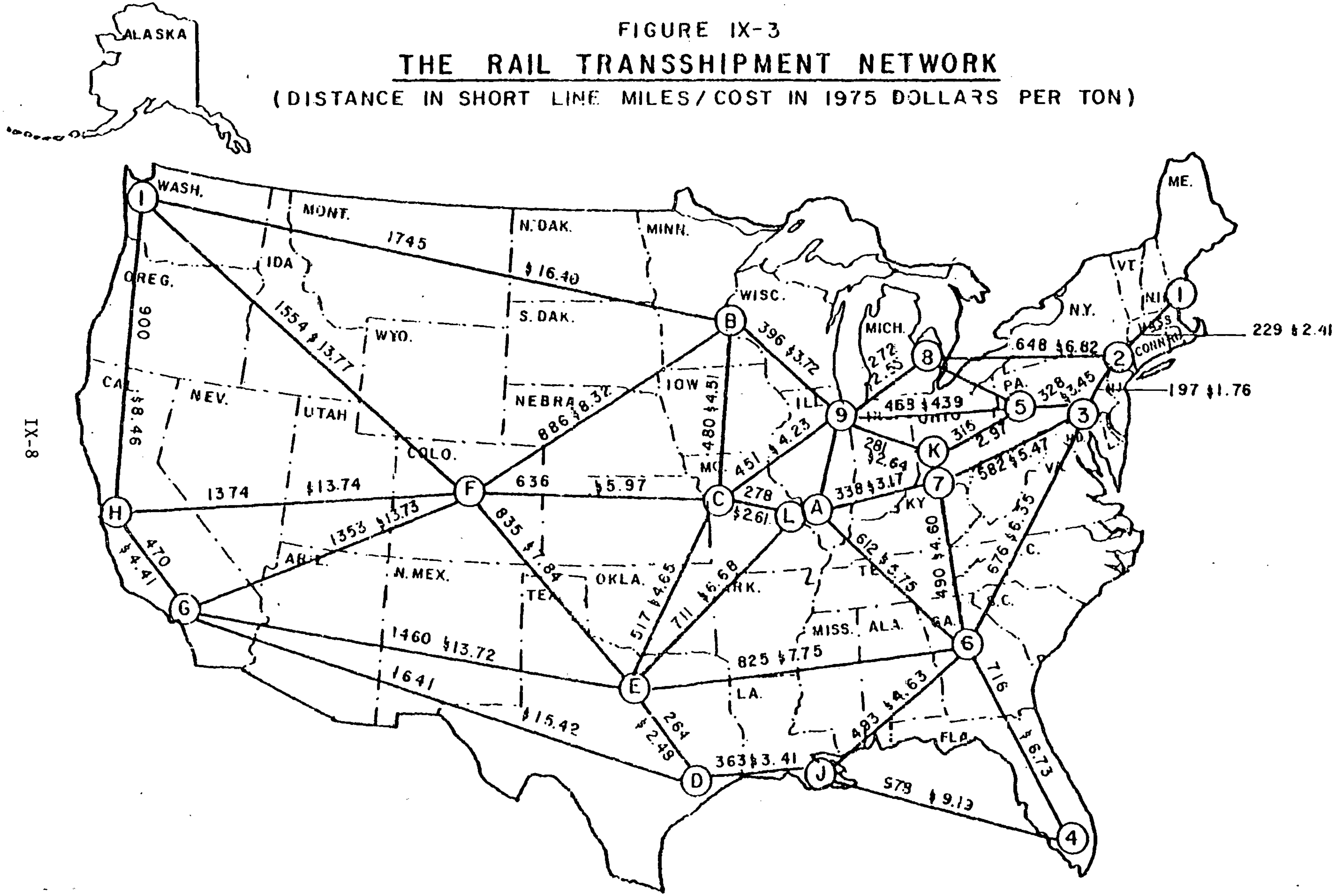
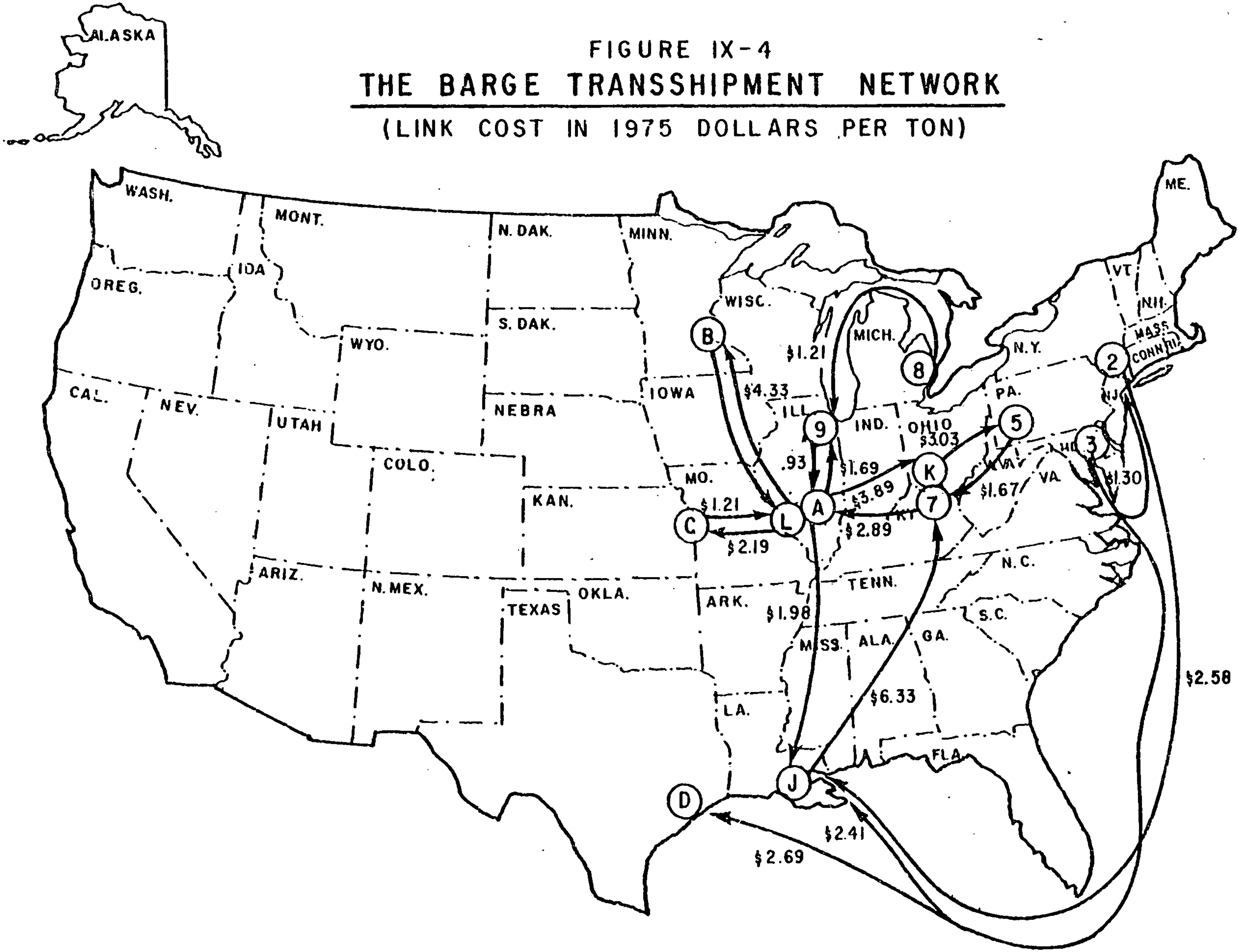


FIGURE IX-4

THE BARGE TRANSSHIPMENT NETWORK

(LINK COST IN 1975 DOLLARS PER TON)



The connections between nodes are referred to as links. As indicated in Figure IX-2, links are provided between the following node-pairs: coal supply region center nodes (centroids) and transshipment nodes; transshipment nodes; and transshipment nodes and coal demand region centroids. Links between transshipment nodes are provided for either the same mode (barge or rail) at different locations or different modes at the same location. Links between transshipment nodes and demand region centroids are permitted for the rail mode only. The links between transshipment nodes and supply regions are shown in Figures IX-5 and IX-6, for rail and barge, respectively.

There are a total of seven link types, as shown in Table IX-4, where they are grouped according to the node-pair types in Figure IX-2 and according to movement and transfer characteristics.

Coal is distributed through the network to each utility or demand center from representative cities in that region connected by the rail links. Distribution within the region is in prespecified proportions, based on Standard Metropolitan Statistical Area (SMSA) population, as depicted in Figure IX-7. For example, in demand region 4 Miami, Atlanta, and Cincinnati receive 40, 30 and 30 percent respectively of the coal transported to the region.

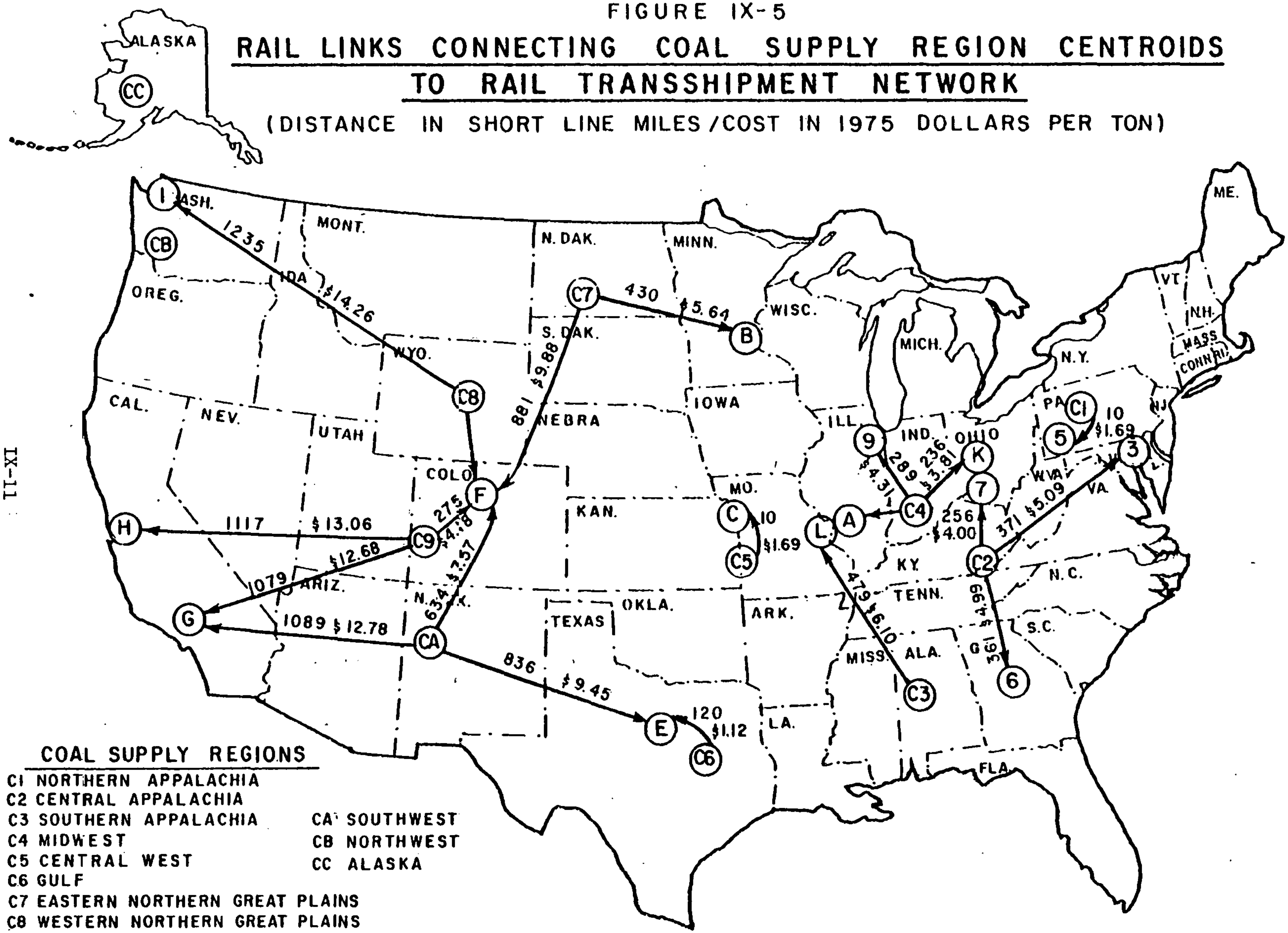
TABLE IX-4. NODE-PAIR AND CORRESPONDING LINK TYPES IN COAL TRANSSHIPMENT NETWORK

Node-Pair Type	Link Group	Link Type
Supply to Transshipment	Movement	Coal Supply to Rail Coal Supply to Barge
Transshipment		
Same Mode	Movement	Rail to Rail Barge to Barge
Different Mode	Transfer	Rail to Barge Barge to Rail
Demand from Transshipment	Transfer	Rail to Demand

FIGURE IX-5

RAIL LINKS CONNECTING COAL SUPPLY REGION CENTROIDS TO RAIL TRANSSHIPMENT NETWORK

(DISTANCE IN SHORT LINE MILES/COST IN 1975 DOLLARS PER TON)



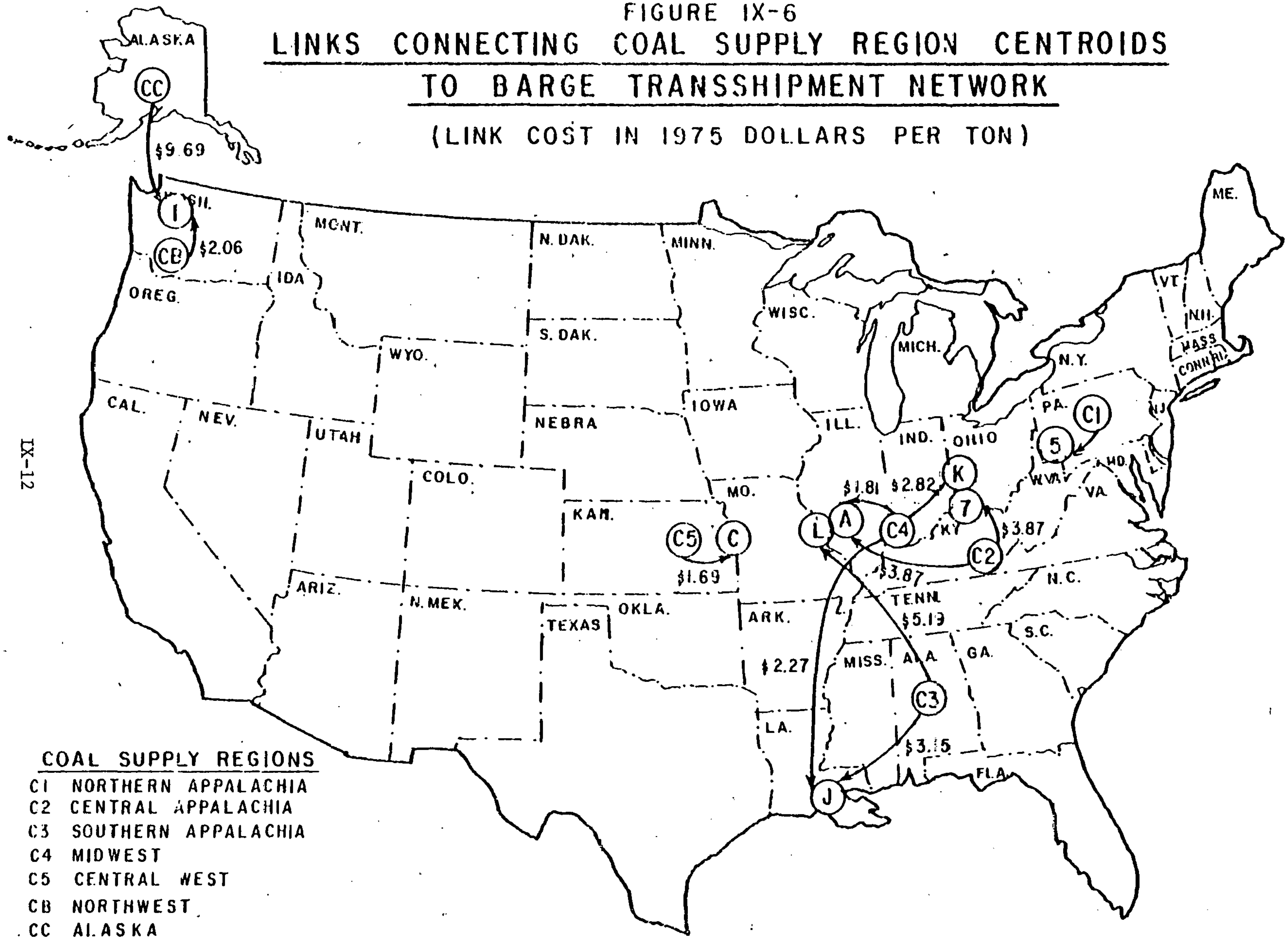
COAL SUPPLY REGIONS

C1 NORTHERN APPALACHIA
C2 CENTRAL APPALACHIA
C3 SOUTHERN APPALACHIA
C4 MIDWEST
C5 CENTRAL WEST
C6 GULF
C7 EASTERN NORTHERN GREAT PLAINS
C8 WESTERN NORTHERN GREAT PLAINS
C9 ROCKIES
CA SOUTHWEST
CB NORTHWEST
CC ALASKA

FIGURE IX-6

LINKS CONNECTING COAL SUPPLY REGION CENTROIDS TO BARGE TRANSSHIPMENT NETWORK

(LINK COST IN 1975 DOLLARS PER TON)



Coal Transport Costs

Associated with each link in the coal network and used to determine the transportation cost component of supplying coal are unit costs ($/ton). These costs are derived from fixed costs ($/ton) and variable or mileage costs ($/ton/mile) associated with the various network links displayed in Table IX-5. A description of the charge for each link is given in the table.

The mileage charges are determined exogeneously. The charge is $.0094/ton/mile for the rail mode, based on regression analysis of the fully allocated operating cost as a function of distance for trains operating as 100-car unit trains.[1] For the barge mode, the mileage charge is based on actual shipping cost data.[2] In addition, the fixed charges for the movement links are associated with the coal supply-to-rail and coal supply-to-barge links only. The charge is due to handling and is $1.60/ton for the rail mode and the actual ICC charge for the barge mode. The charges for lignite and minemouth-burned coal are considerably less, as explained below.

Associated with the transfer links are handling charges of $.20/ton to switch from barge to rail and $.25/ton from rail to barge. For transporting coal along the rail-to-demand center link, there is a non-unit-train surcharge of $2.50/ton to account for higher single car rates. An additional $5.50/ton surcharge for small lot orders is included, for a total of $8.00/ton, resulting from the disparity between small lot industrial users and large lot utility users. There is no link charge for shipping coal from rail to utility centers since the above rail rate analysis is based on costs to utilities.

The method for calculating total unit costs of coal for any link type is presented in Table IX-6. Each bracketed term in the table represents the formula for determining the total unit cost for individual links of the transshipment network, as classified in Table IX-4 by node-pair type. A generic example applying these equations to various link types is given in Figure IX-8.

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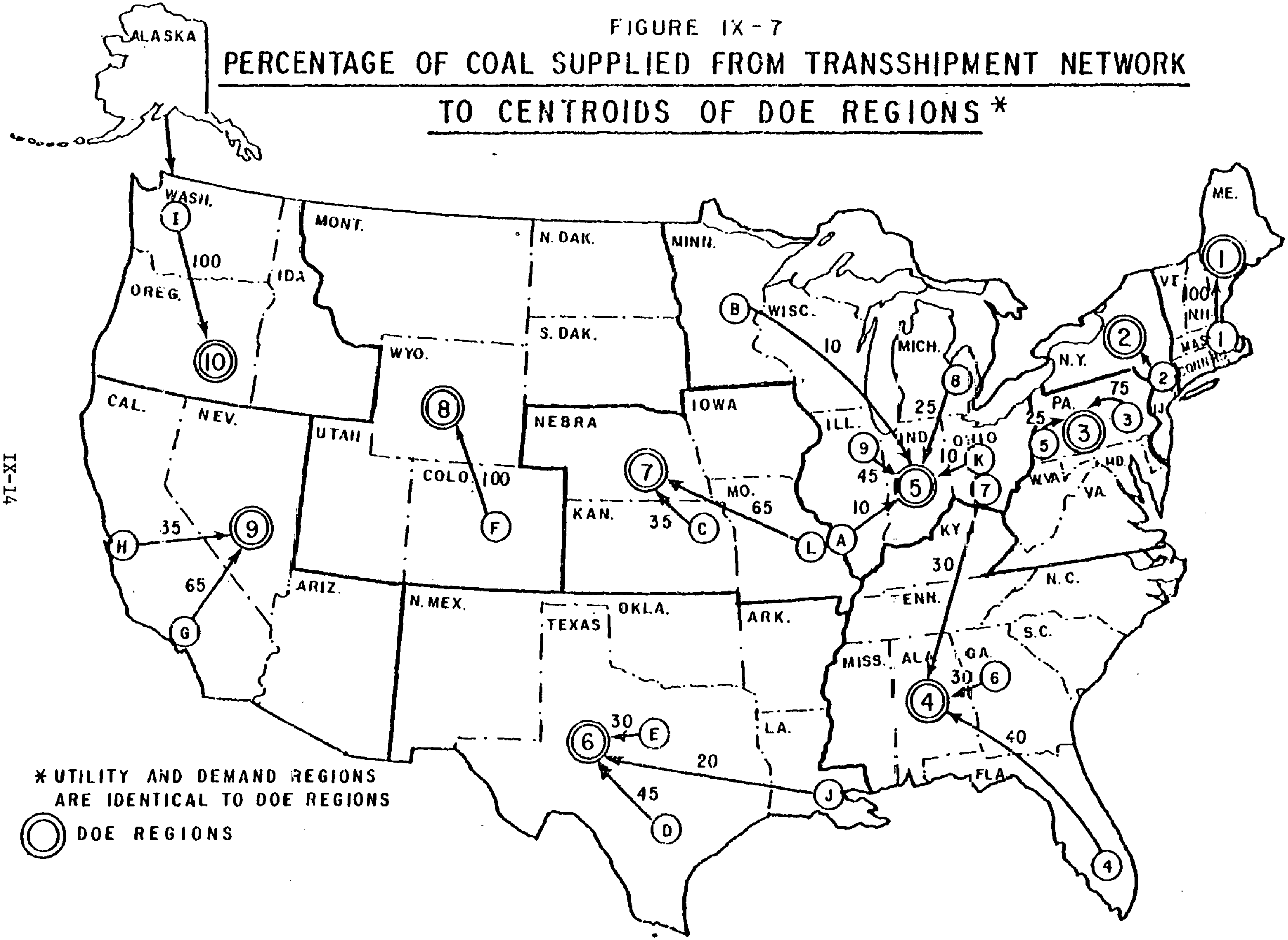
[1] Data from ICC Report: "Investigation of Freight Rate Structure-Coal."

[2] Kearney, "Domestic Waterborne Shipping Analyses."

FIGURE IX - 7

PERCENTAGE OF COAL SUPPLIED FROM TRANSSHIPMENT NETWORK TO CENTROIDS OF DOE REGIONS *



* UTILITY AND DEMAND REGIONS ARE IDENTICAL TO DOE REGIONS

◎ DOE REGIONS

TABLE IX-5. COSTS ASSOCIATED WITH COAL TRANSSHIPMENT NETWORK LINKS

Link Type	Fixed	Variable	Description of Charge	Amount of Charge ($/Ton) Movement
Movement				
- Coal Supply to Rail	X	X	Handling and Mileage (regression)	$1.60 + .0094y^{(a)}$
- Coal Supply to Barge	X	X	Handling and Mileage (actual)	_____
- Rail to Rail		X	Mileage (regression)	.0094y
- Barge to Barge		X	Mileage (actual)	_____
Transfer				
- Barge to Rail	X		Handling	.20
- Rail to Barge	X		Handling	.25
- Rail to Coal Demand	X		Non-unit train small lot surcharge for industrial coal	2.50(b)

Notes: (a) y refers to mileage

(b) Added to this is a $5.50 surcharge for non-utility small lot orders due to the disparity in costs with large lot orders negotiated by utilities. Since utility costs are the reference point, no charges apply to utilities.

TABLE IX-6. METHOD FOR ESTIMATING TRANSPORTATION COSTS FOR THE COAL TRANSSHIPMENT NETWORK

Coal Supply Region to Transshipment Network Cost		Transshipment Network Cost		Transshipment Network to Coal Demand Region Cost
$\left[a_m + b_{mij}x_{mij}\right]$	$+$	$\left[c_{kl} + (d_{mij}y_{mij})\right]$	$+$	$\left[e_n\right]$

Where:

m = transport mode (r for rail, b for barge)

n = demand type (d for demand center, u for utility)

i = origin node of link

j = destination node of link

k = node transferred from

l = node transferred to

And:

a = fixed charge at coal supply for loading

$1.60/ton for rail
actual $/ton for barge

b = mileage charge from coal supply to transshipment network

$.0094/ton/mi. for rail
actual $/ton for barge

x = mileage of link between nodes for rail (1.0 for barge)

c = fixed charge for transfer between nodes

$.20/ton from train to barge
$.25/ton from barge to train

d = cost of shipping between transshipment nodes in network for similar mode constant for rail mode

$.0094/ton/mi. for rail
actual $/ton/mi. for barge

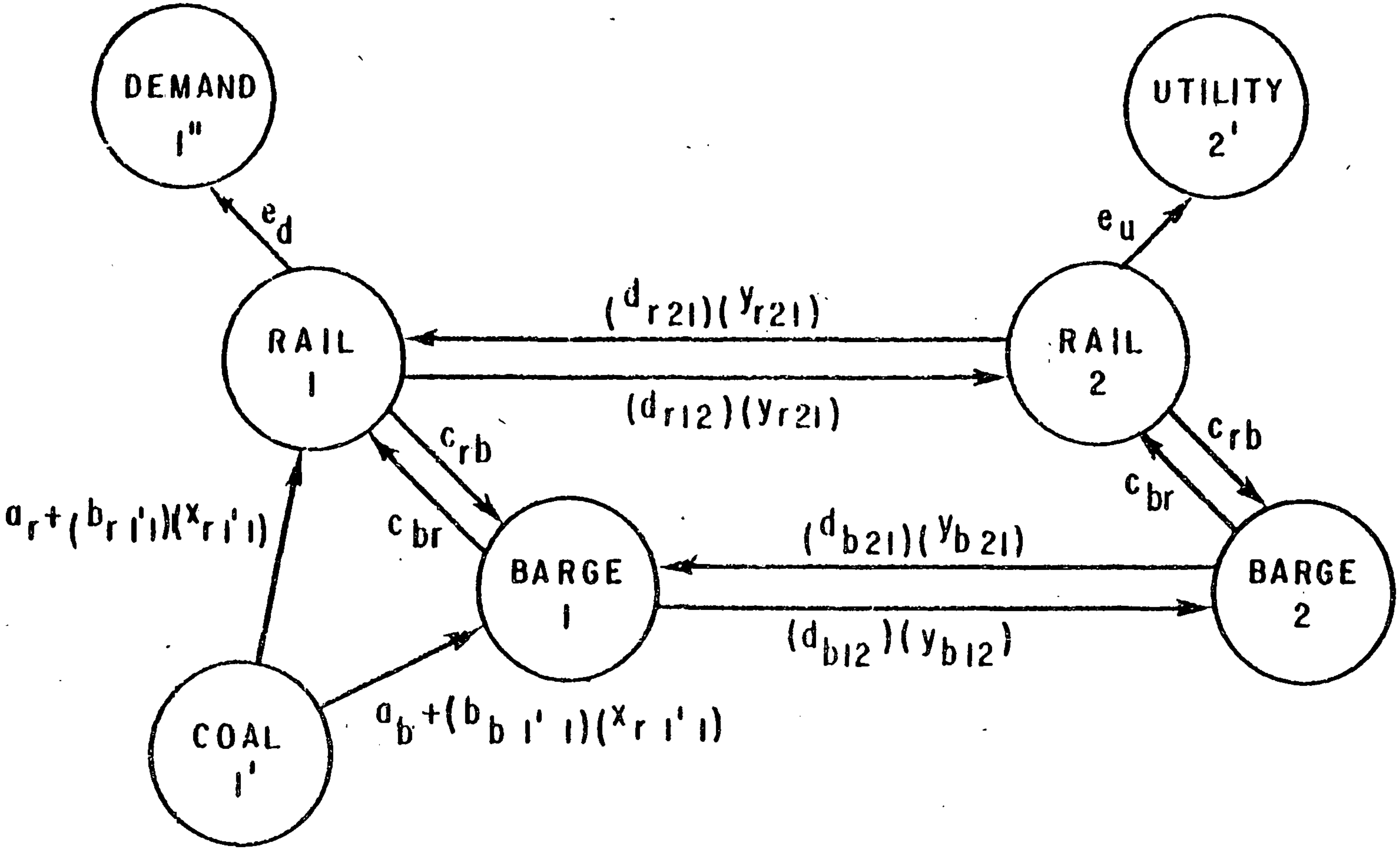
y = mileage between nodes in network for rail (1.0 for barge)

e = cost of shipping between rail mode and demand or utility region

$0.00/ton for utility center
$8.00/ton for demand center

FIGURE IX-8

A REPRESENTATIVE COAL TRANSSHIPMENT MODEL



The above method will result in three origin-destination (O-D) unit cost matrices for the three different link types. The combination of these matrices results in an aggregate matrix of unit costs for all possible links in the coal transshipment network. A sample portion of the unit cost matrix formed by PIES for links in the coal transshipment model is given in Table IX-7. This matrix provides a basis for mapping the various routes and modes possible between specified coal supply and demand regions.

The above unit cost matrix for all possible links is processed by PIES to determine the least costly route between all coal supply and demand regions. This calculation is made by:

- determining all possible routes between a supply and demand region
- calculating the unit costs for each link along the route and summing them
- taking the least costly route between a supply and demand region.

This calculation is performed for all supply-demand pairs, and the results are presented in Table IX-8.

The least costly route calculation for coal transshipment is performed in PIES prior to the linear programming (LP) calculation for determining the equilibrium of coal supply and demand. Thus, the results in Table IX-8 are used directly in the LP and significantly improve computer efficiency by reducing LP calculation time. These calculations are performed only when cost or network data are changed.

Minemouth Coal and Lignite

Coal burned in minemouth plants and lignite does not move via the transshipment network in PIES. Coal burned at the minemouth is consumed at the supply location, and lignite is moved only short distances. In both cases, links run directly from supply to demand regions.

A notional transportation cost of $.01/ton is charged for coal burned at the minemouth. Inclusion of this cost prevents degeneracy of the LP.

TABLE IX-7. TRANSPORTATION COSTS OF COAL TRANSSHIPMENT NETWORK FOR INDIVIDUAL LINKS

	RAIL NODES											BARGE NODES		
ORIGIN	Boston	New York	Balt/ Phil	Miami	Pitts- burgh	Atlanta	Cincin- nati	Detroit	Chicago	St. Louis, E.	St. Paul, Minn.	Boston	New York	Balt/ Phil
Coal Centroid														
North Appalachia					1.69									
Central Appalachia			5.08			4.99	4.00							
South Appalachia						3.16				6.10				
Midwest							3.81		4.31	3.15				
Central West														
Gulf														
N.E. Great Plains											5.64			
Rail Nodes														
Boston		2.41										.25		
New York	2.41		1.96										.25	
Balt/Phil		1.96			3.08									.25
Miami														
Pittsburgh			3.45				2.97	2.78	4.39					
Atlanta			6.35	6.73			4.60			5.75				
Cincinnati			5.47		2.97	4.60			2.64	3.17				
Detroit		6.82			2.78				2.55					
Chicago					4.39		2.64	2.55		2.66	3.72			
St. Louis, E.						5.75	3.17		2.66					
St. Paul, Minn.									3.72					
Barge Nodes														
Boston	.20													
New York		.20												
Balt/Phil			.20											
Miami				.20										
Pittsburgh					.20									
Atlanta						.20								
Cincinnati							.20							
Detroit								.20						
Chicago									.20					
St. Louis, E.										.20				
St. Paul, Minn.											.20			

TABLE IX-8. COAL TRANSPORTATION COSTS FOR LEAST COSTLY ROUTE ($/SHORT TON)

DESTINATION

Coal Region	Boston	New York	Balt / Phil	Pitts-burgh	Miami	Atlanta	Cincin-nati,S.	Cincin-nati,N.	Detroit	Chicago	St. Louis,E.
North Appalachian	9.30	6.89	5.14	1.69	14.77	8.04	3.44	3.44	4.47	6.08	6.33
Central Appalachian	9.24	6.83	5.08	6.97	11.72	4.99	4.00	4.00	8.31	5.76	4.07
South Appalachian	13.67	11.26	9.51	10.73	9.89	3.16	7.76	7.76	9.63	7.08	5.39
Midwest	12.65	10.24	8.49	5.99	11.66	7.10	3.02	3.02	6.25	3.70	2.01
Central West	15.90	13.49	11.74	9.18	14.27	8.85	6.27	6.27	7.34	4.79	3.10
Gulf	19.38	16.97	15.22	13.71	14.55	8.87	10.80	10.80	11.87	9.32	7.63
N.E. Great Plains	21.14	18.73	17.11	13.75	19.64	14.22	11.64	11.64	11.91	9.36	8.47
N.W. Great Plains	24.55	22.14	20.52	17.16	23.05	17.63	15.05	15.05	15.32	12.77	11.88
Rockies	24.61	22.20	20.45	17.89	22.98	17.56	14.98	14.98	16.05	13.50	11.81
Southwest	27.71	25.30	23.55	21.28	23.93	17.20	18.37	18.37	19.44	16.89	15.20
Northwest	33.88	31.47	29.85	26.49	32.38	26.96	24.38	24.38	24.65	22.10	21.21
Alaska	41.79	39.38	37.76	34.40	40.29	34.87	32.29	32.29	32.56	30.01	29.12

DESTINATION

Coal Region	St. Paul/ Minn.	New Orleans	Houston	Dallas	St. Louis,W.	Kansas	Denver	Los Angeles	San Francisco	Seattle
North Appalachian	9.80	8.00	8.28	10.76	6.33	8.52	14.49	23.70	28.11	26.20
Central Appalachian	8.40	6.05	8.22	10.70	4.07	6.26	12.23	23.64	26.17	24.80
South Appalachian	9.72	3.35	6.76	9.24	5.39	7.58	13.55	22.18	26.59	26.12
Midwest	6.34	2.47	5.88	8.36	2.01	4.20	10.17	21.30	24.11	22.74
Central West	6.20	5.08	8.49	6.54	3.10	1.69	7.66	20.26	21.60	22.60
Gulf	10.45	5.36	1.95	1.12	7.63	5.97	8.96	14.84	19.25	24.73
N.E. Great Plains	5.64	10.45	13.86	15.00	8.47	10.15	9.88	23.61	22.74	14.28
N.W. Great Plains	9.05	13.86	14.99	12.51	11.88	10.64	4.67	18.40	18.61	14.26
Rockies	12.56	13.79	14.50	12.02	11.81	10.15	4.18	12.68	13.06	15.55
Southwest	15.89	15.34	11.93	9.45	15.20	13.54	7.57	12.78	17.19	23.34
Northwest	18.33	23.19	26.60	24.42	21.21	22.55	16.58	14.85	10.44	1.98
Alaska	26.29	31.10	34.51	32.33	29.12	30.46	24.49	22.76	18.35	9.89

Although lignite is shipped only short distances, it may be shipped to demand regions different from its supply region, as shown in Figure IX-9. Such links are provided from the Gulf to the Central states, and from the Northeast Great Plains to the Midwest and North Central states.

Table IX-9 shows that transportation costs for lignite are considerably lower than those for other coal types (Table IX-8). The highest-cost link, Northeast Great Plains to the Midwest, is exceptional. This lignite is used mainly to produce electricity, and the shipment cost includes both a charge for transporting lignite to the Dakotas and a charge for transmitting electricity from there to Minnesota. This is the only instance of interregional transmission of electricity in PIES.

TABLE IX-9. COAL TRANSPORTATION COSTS AT MINEMOUTH AND FOR LIGNITE

($/Ton)

	DOE REGION					
Coal Region	Mid-Atl.	S.-Atl.	Midwest	S.-West	Central	N-.Central
North Appalachian	.01					
Central Appalachian		.01				
Midwest			.01			
Central West				.01		
Gulf					1.00	
N.E. Great Plains			2.00			1.50
N.W. Great Plains						.01

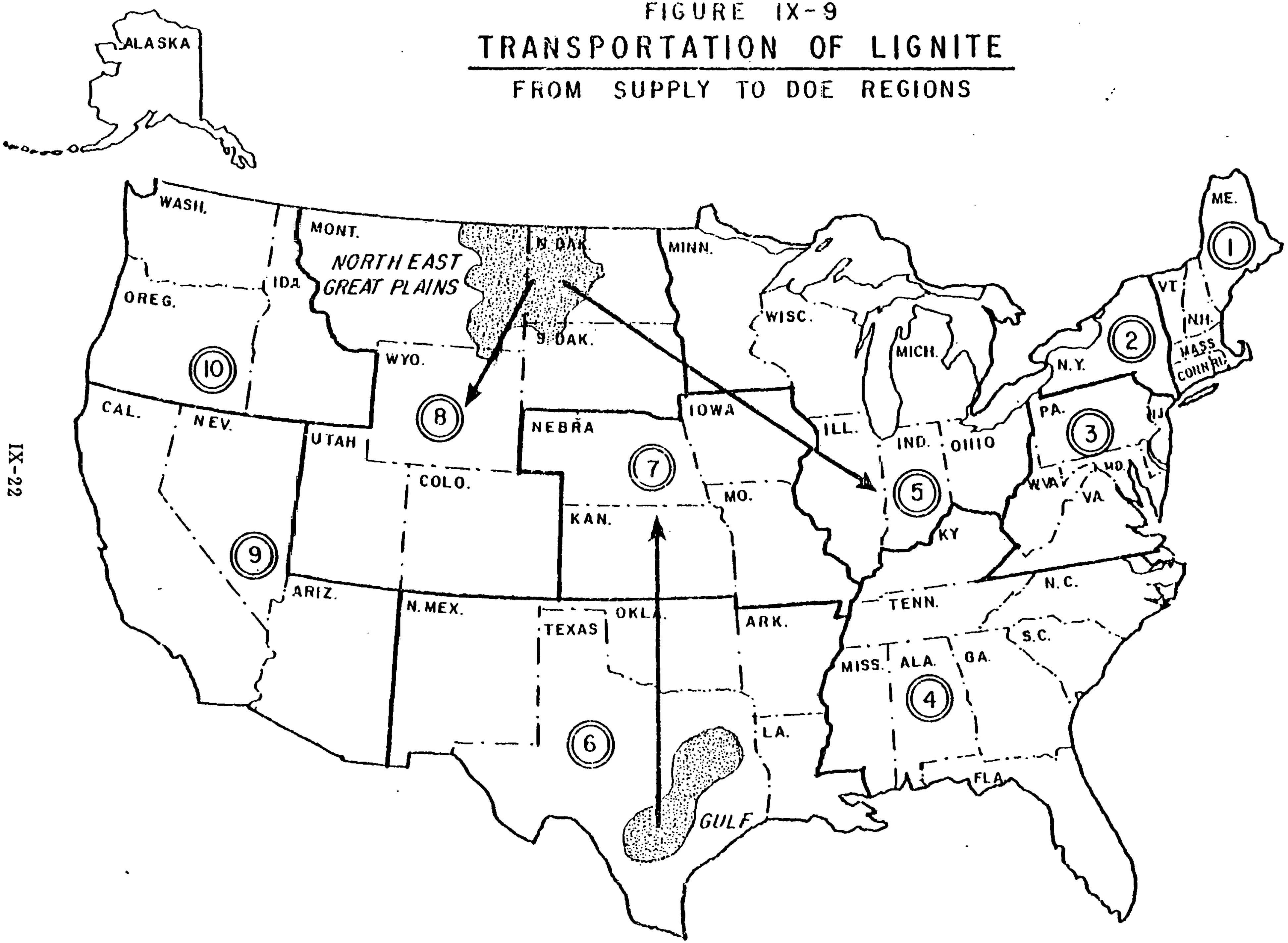
OIL

The oil transportation network is somewhat less complex than the coal transshipment network since transshipment only occurs implicitly in the movement of Alaskan and imported crude oil. That is, the actual transshipment is not modeled, but the cost of moving Alaskan and imported crude includes the cost of two transport modes. However, oil transportation is complicated by diverse oil types, two types of origin (foreign and domestic) and the existence of intermediate links to refineries.

FIGURE IX-9

TRANSPORTATION OF LIGNITE

FROM SUPPLY TO DOE REGIONS



In the PIES transportation submodel, oil includes three energy material types, crude oil, petroleum products (except residual) and residual oil. Petroleum products represent oil that has been refined and includes gasoline and distillate. Residual, although technically a petroleum product and having nearly similar transportation needs, is considered separately here due to viscosity and density differences that affect how it is carried.

The transportation modes considered for oil are pipeline, tanker, and barge. Generally speaking, tankers are used on oceangoing routes, and barges are used on inland waterways. The material/mode combinations possible for oil transportation are: crude by tanker, product by tanker and barge, residual by tanker and barge, crude by pipeline, and product by pipeline. The transportation submodel does not model transportation of residual by pipeline.

Oil moves from supply to demand regions, with intermediate links to and from refineries as shown in Figure IX-10. The transport modes for the networks indicated by the three boxes in the figure are specified in Table IX-10. Note that domestic crudes are shipped to refinery regions by pipeline and tanker. Foreign crudes are transported by tanker, and may require transshipment inland by pipeline. Domestic products are transported from refinery to demand and utility regions by pipeline, barge and tanker, whereas foreign product residual are transported directly from supply to demand and utility regions by tanker. Domestic residual is not transported by pipeline.

Crude by Tanker

Crude may be transported from foreign and domestic supply regions to domestic refinery regions by tanker.

The transportation network for domestic crude by tanker is specified according to whether or not passage is made through the Panama Canal. The routes for tankers through and bypassing the canal are given in Figure IX-11 and IX-12, respectively. Routes include those from Valdez and other supply region ports to refinery region ports in the lower 48 states.

FIGURE IX-10

GENERAL MOVEMENT OF OIL FROM SUPPLY TO DEMAND

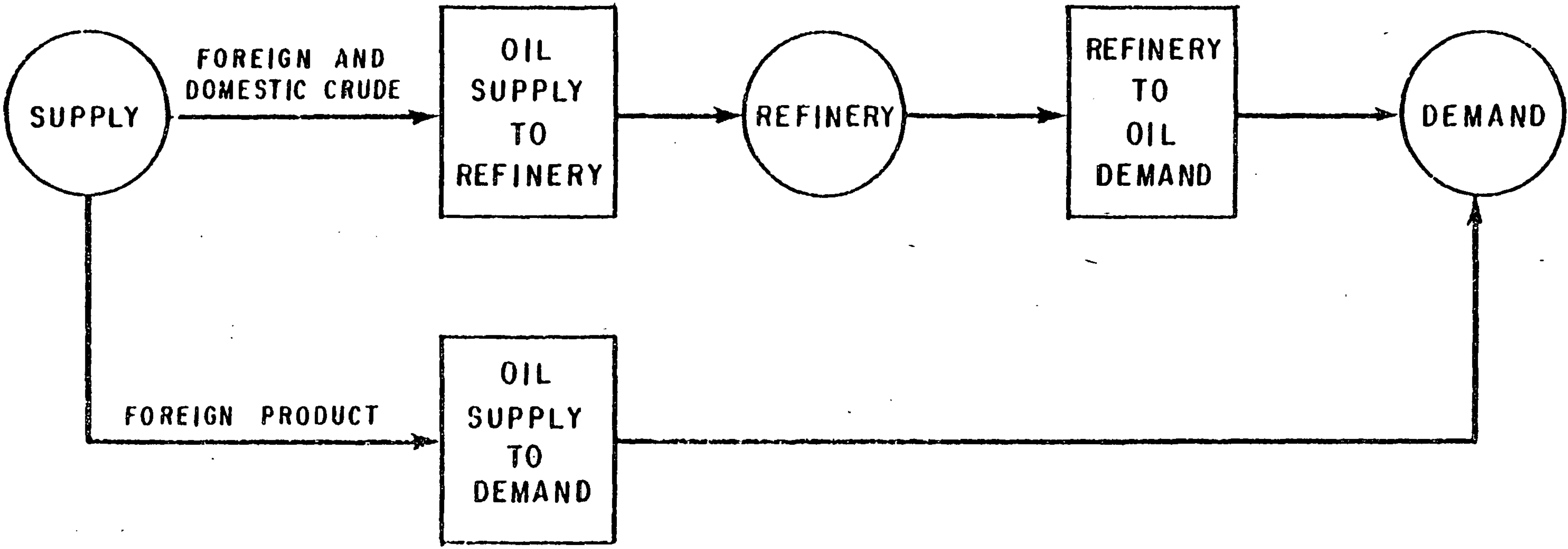


TABLE IX-10. TRANSPORTATION OF OIL BY MATERIAL/MODE BETWEEN REGIONS[1]

	Oil Supply to Refinery Region[2]	Refinery Region to Demand and Utility Region	Oil Supply to Demand and Utility Region
Material/Mode			
Crude			
Pipeline (domestic and foreign)	X		
Tanker (domestic and foreign)	X		
Product			
Pipeline (domestic)		X	
Barge (domestic)		X	
Tanker - domestic		X	
- foreign X			
Residual			
Barge (domestic)		X	
Tanker - domestic		X	
- foreign			X

---

[1] X's indicate what material/mode combinations move between regions.

[2] Foreign crude oil may be transshipped inland by pipeline between refinery regions after being transported to the U.S. by tanker.

FIGURE IX-11

DOMESTIC CRUDE OIL TANKER ROUTES

FROM SUPPLY TO REFINERY REGION PORTS
THROUGH THE PANAMA CANAL

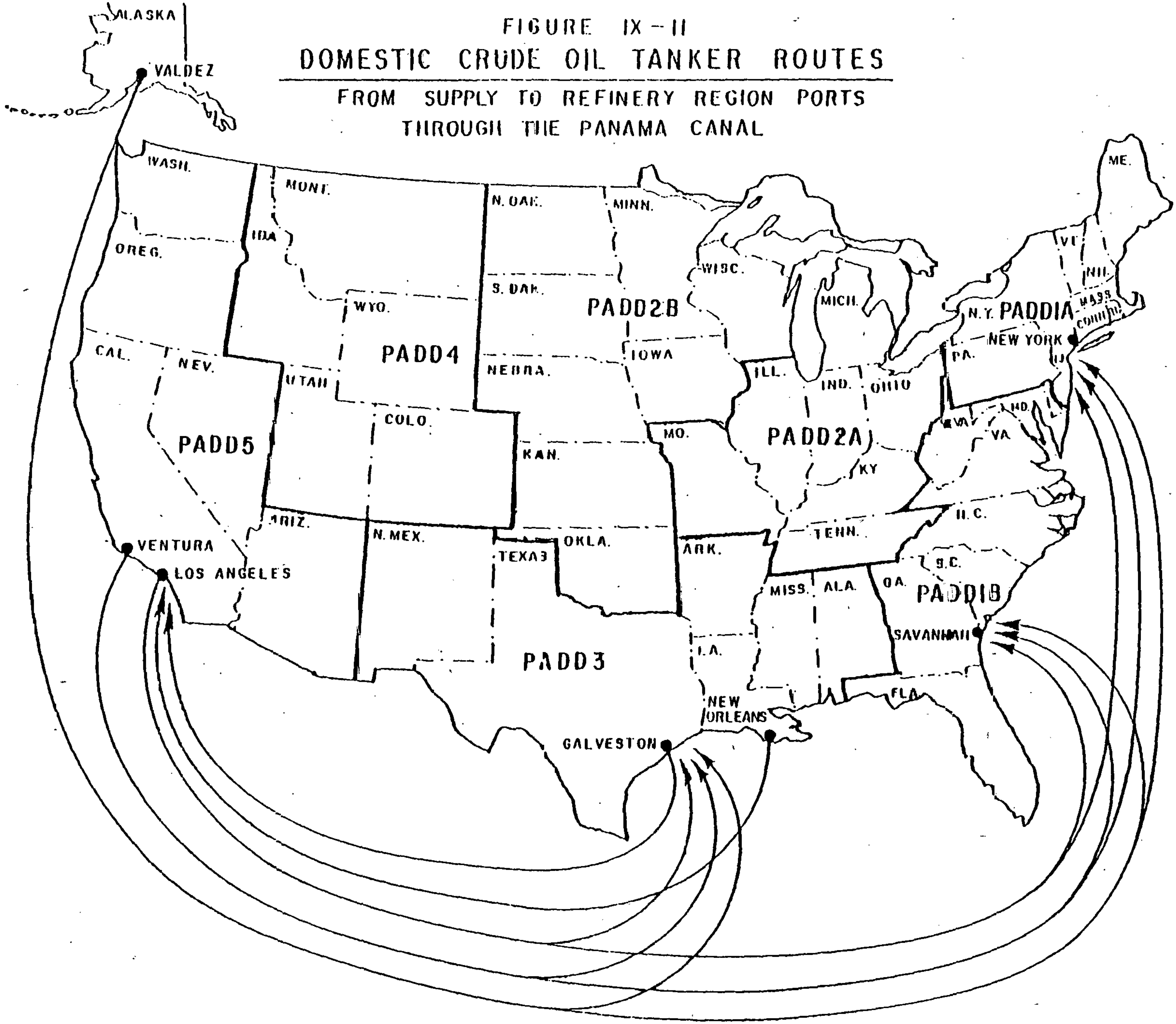


FIGURE IX-12

DOMESTIC CRUDE OIL TANKER ROUTES

FROM SUPPLY TO REFINERY REGION PORTS BYPASSING THE PANAMA CANAL

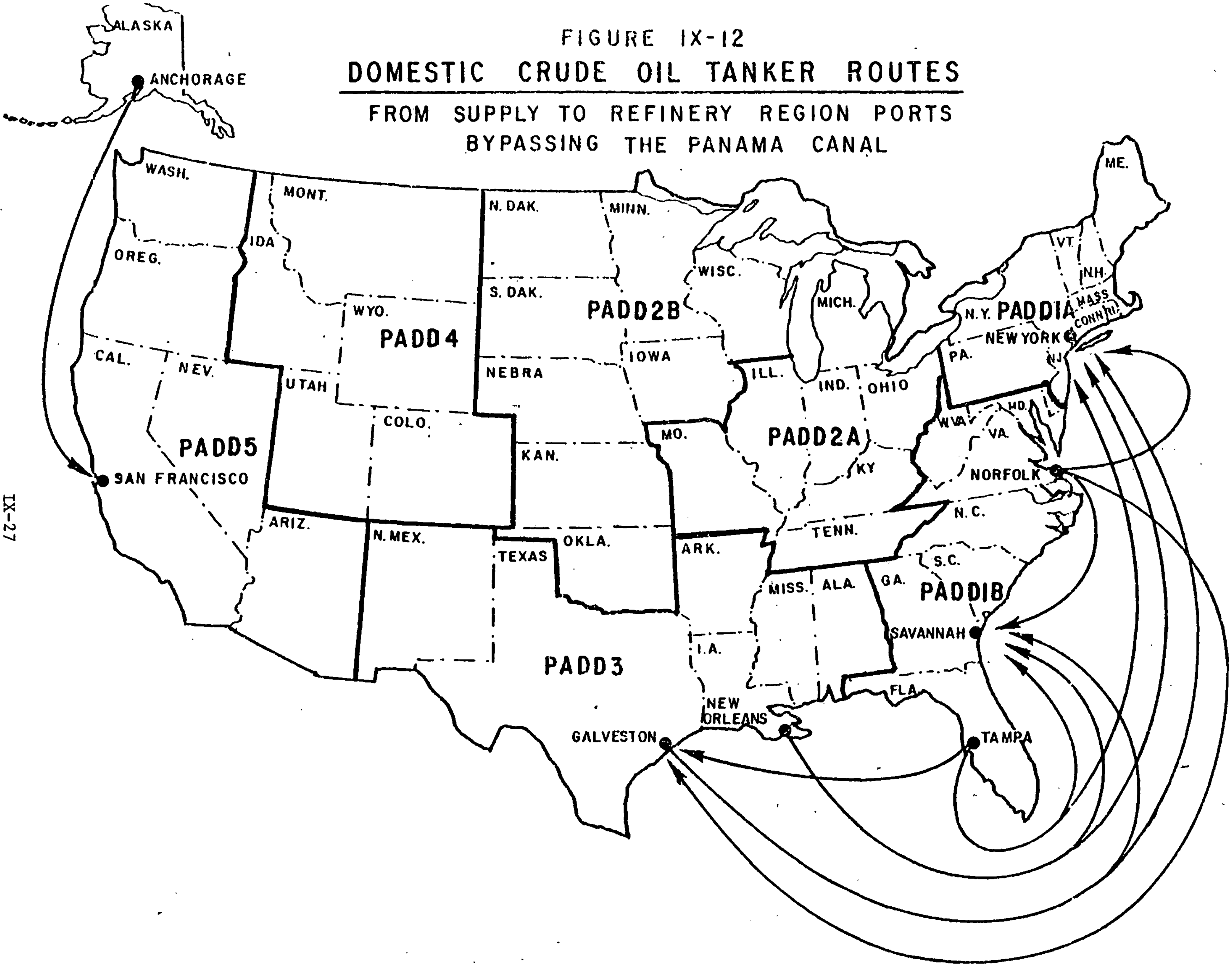


Figure IX-13 indicates tanker routes for importing crude to refinery regions. Imported crude is classified as Landed East Coast, Landed Gulf Coast, Landed West Coast, Canadian, Caribbean, or Other. Imported crude is assumed to enter the U.S. at single points on each of the Atlantic, Gulf, or Pacific coasts. To simulate additional ports, crude is moved from the refinery region at the point of entry to other coastal refinery regions at zero cost. Movement to inland refinery regions is also permitted at cost, either through New Orleans or Houston.[3]

Unit costs ($/B) of transporting crude by tanker are determined from mileage charges for domestic transport and predetermined charges for foreign transport according to the method shown in Table IX-11.

The route charge for domestic tanker transport is determined by a formula taken from a Maritime Administration report and given in Table IX-11.[4] The transportation cost depends primarily on route mileage, time in port, and whether tankers pass through the Panama Canal. The factor of 2.0 is based on the assumption that the tanker makes the return trip empty. Data for use in the formula are given in Table IX-12.

The costs of gathering the crude are included in the calculation and are given in Table IX-13. Gathering cost is the cost of removing the crude from the field and moving it to the tanker port. The costs are $.05/B for onshore and $.10/B for offshore, for new pipeline systems. For oil supply regions not yet producing oil, the gathering charge is assumed to be $.15/B. Gathering costs for existing systems are supported by ICC tariff data and are provided for the East and West Rocky Mountains, West Texas/East New Mexico, and Midcontinent oil supply regions.

The result of the calculation displayed in Table IX-11 is the matrix of unit costs of transporting domestic crude by tanker between domestic supply and refinery regions, shown in Table IX-14.

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[3] FEA Memo, P.H. Randolph; "Transportation Data for PIES: Crude Oil Pipeline Link Prices"; June 15, 1977.

[4] Maritime Administration, "Estimated Vessel Operating Expenses-1976."

FIGURE IX-13

IMPORTED CRUDE OIL TANKER ROUTES

FROM FOREIGN SUPPLY TO DOMESTIC REFINERY REGIONS

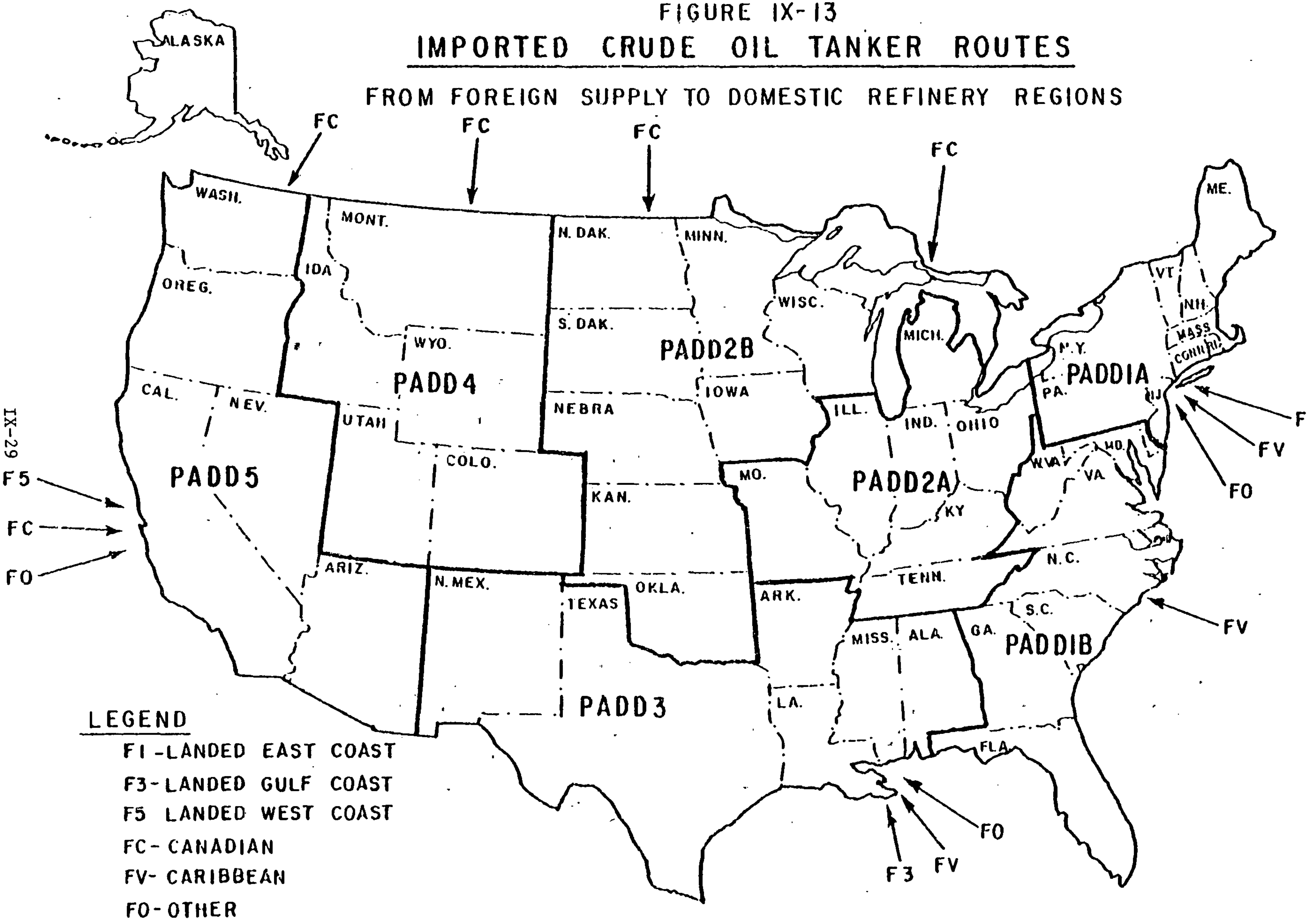


TABLE IX-11. METHOD FOR ESTIMATING COSTS FOR TRANSPORTING DOMESTIC AND FOREIGN CRUDE BY TANKER ($/B)

DOMESTIC:

$$\underset{(\$/B)}{\text{Unit Cost}} = \overbrace{\overbrace{\overset{\text{Cost from Supply to Refinery Region}}{2\ \frac{(\text{Turn})\,(\text{Port}) + (\text{Mileage/Speed})\,(\text{Sea})}{(\text{LWT})\quad(\text{Scale})}}}^{\text{Not Thru Panama Canal}} + \overset{\text{Additional Charge for Panama Canal}}{\frac{(\text{PCC})}{(\text{LWT})\ \ (\text{Scale})}}}^{\text{Thru Panama Canal}} + \overset{\text{Gathering Charge}}{\frac{}{(\text{Table IX-13})}}$$

Where

Turn = Turnaround Time in Port (Hours)
Port = Cost/Hour of Staying in Port,
Mileage = Mileage One way (Nautical Miles),
Speed = Speed in Knots
Sea = Cost/Hour at Sea
LWT = Tanker Capacity in Long Tons
Scale = Number of Barrels of Crude Per Ton
PCC = Panama Canal Charge

(Input in Table IX12)

= Domestic Unit Costs = (Table IX-14)

FOREIGN:

Foreign Unit Costs = (Table IX-15)

TABLE IX-12. DATA ON CRUDE OIL TANKERS BY PANAMA CANAL AND OTHER ROUTES

TANKER CAPACITY

	Dead-weight Tons	Long Tons	Cost at Sea ($/Hr)	Cost at Port ($/Hr)	Turn Around Time (Hrs)	Panama Canal Charge ($)	Speed (Knots)	Scale (B/Ton)
Panama Canal	66000	60000	1035	875	30	67861	16	7.3
Other	66000	60000	1035	875	30		16	7.3

TABLE IX-13. GATHERING CHARGES FOR CRUDE OIL ($/B)

Region	Charge
South Alaska	0.10
Pacific Coast	0.05
Pacific Ocean	0.10
W. Rocky Mtns.	0.10
E. Rocky Mtns.	0.055
W. Tex. & E.N. Mex.	0.05
W. Gulf Basin	0.05
Gulf of Mexico	0.10
Midcontinent	0.14
Mi. Bas. Int. Ap.	0.15
Atlantic Coast	0.15
Atlantic Ocean	0.15
North Slope	0.15

TABLE IX-14. TRANSPORTATION COSTS FOR DOMESTIC CRUDE OIL BY TANKER ($/B)

	REFINERY REGION			
NPC Region	PADD 1A	PADD 1B	PADD 3	PADD 5
Pac. Coast	2.04	1.92	1.90	
Pac. Ocean	2.09	1.97	1.95	
W. Gulf Basin	.72	.55		1.90
Gulf of Mex.	.72	.55		1.92
Atl. Coast	.68	.51	.46	
Atl. Ocean	.35	.41	.76	
S. Alaska	2.63	2.51	2.49	.60

For foreign transportation unit costs, reference is made to Table IX-15. The table indicates zero costs for all origin-destination pairs. The reason for this is that actual transportation costs are included in the purchase price (reported elsewhere in the PIES import tables). However, a .00 in the matrix indicates that a transportation link is provided, whereas blanks mean that the corresponding link is not available in the model.

Product and Residual by Tanker and Barge

Domestic refined products and residual are shipped from refinery regions to demand regions either by seagoing tankers or inland waterway barges. Refined product imports are transported directly by tanker from foreign supply regions to demand regions. The transportation characteristics and costing of product and residual are similar, and residual costs are determined from product costs.

Domestic product and residual tanker routes are classified as either passing through or bypassing the Panama Canal and are shown in Figures IX-14 and IX-15, respectively. Inland barge routes are presented in Figure IX-16.

Imported products and residual are shipped directly from foreign supply regions to demand regions, using the routes indicated in Figure IX-17. The foreign regions from which imported product and residual are shipped are: Canadian, Caribbean, and Other.

The method for determining product and residual unit costs ($/B) for shipping by tanker and barge from domestic and foreign sources to domestic demand regions is presented in Table IX-16.

As indicated for domestic products, the unit costs are either for tanker or barge transport. The matrix of product tanker costs for transportation between refinery and demand regions is derived with a formula similar to that used to determine crude transportation costs (Table IX-11). The appropriate product tanker data are input, as given in Table IX-17, along with the mileage for these shipping rates. Additionally, barge

TABLE IX-15. TRANSPORTATION COSTS FOR FOREIGN CRUDE OIL BY TANKER ($/B)

	REFINERY REGION						
Foreign Region	PADD 1A	PADD 1B	PADD 2A	PADD 2B	PADD 3	PADD 4	PADD 5
Landed East Coast	.00						
Landed Gulf Coast					.00		
Landed West Coast							.00
Canada			.00	.00		.00	.00
Caribbean	.00	.00			.00		
Foreign Other	.00				.00		.00

FIGURE IX-14

DOMESTIC PRODUCT AND RESIDUAL OIL TANKER ROUTES

FROM REFINERY PORT TO DEMAND AND UTILITY REGION

THROUGH THE PANAMA CANAL

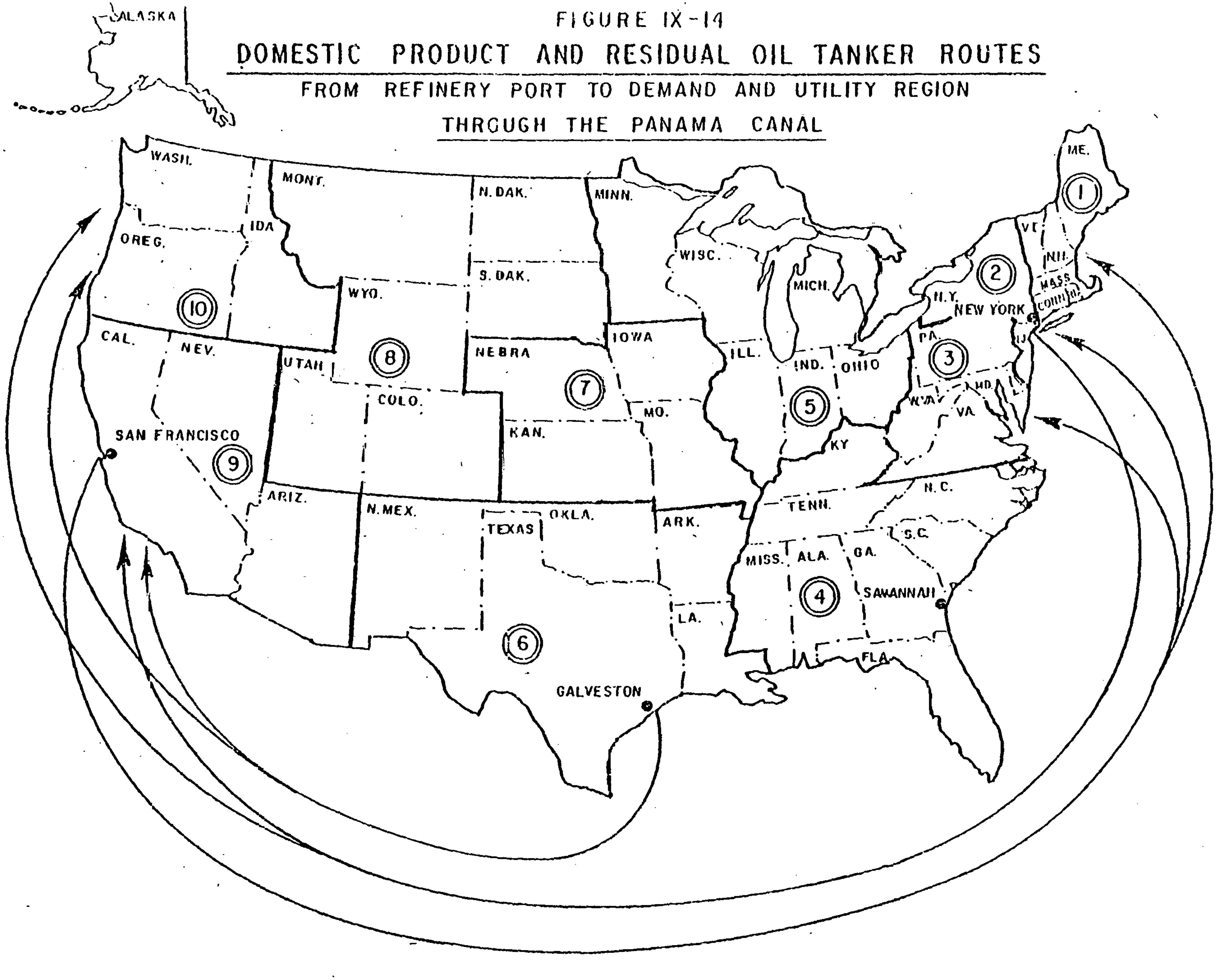


FIGURE IX-15

DOMESTIC PRODUCT AND RESIDUAL OIL TANKER ROUTES

FROM REFINERY PORT TO DEMAND AND UTILITY REGION
BYPASSING THE PANAMA CANAL

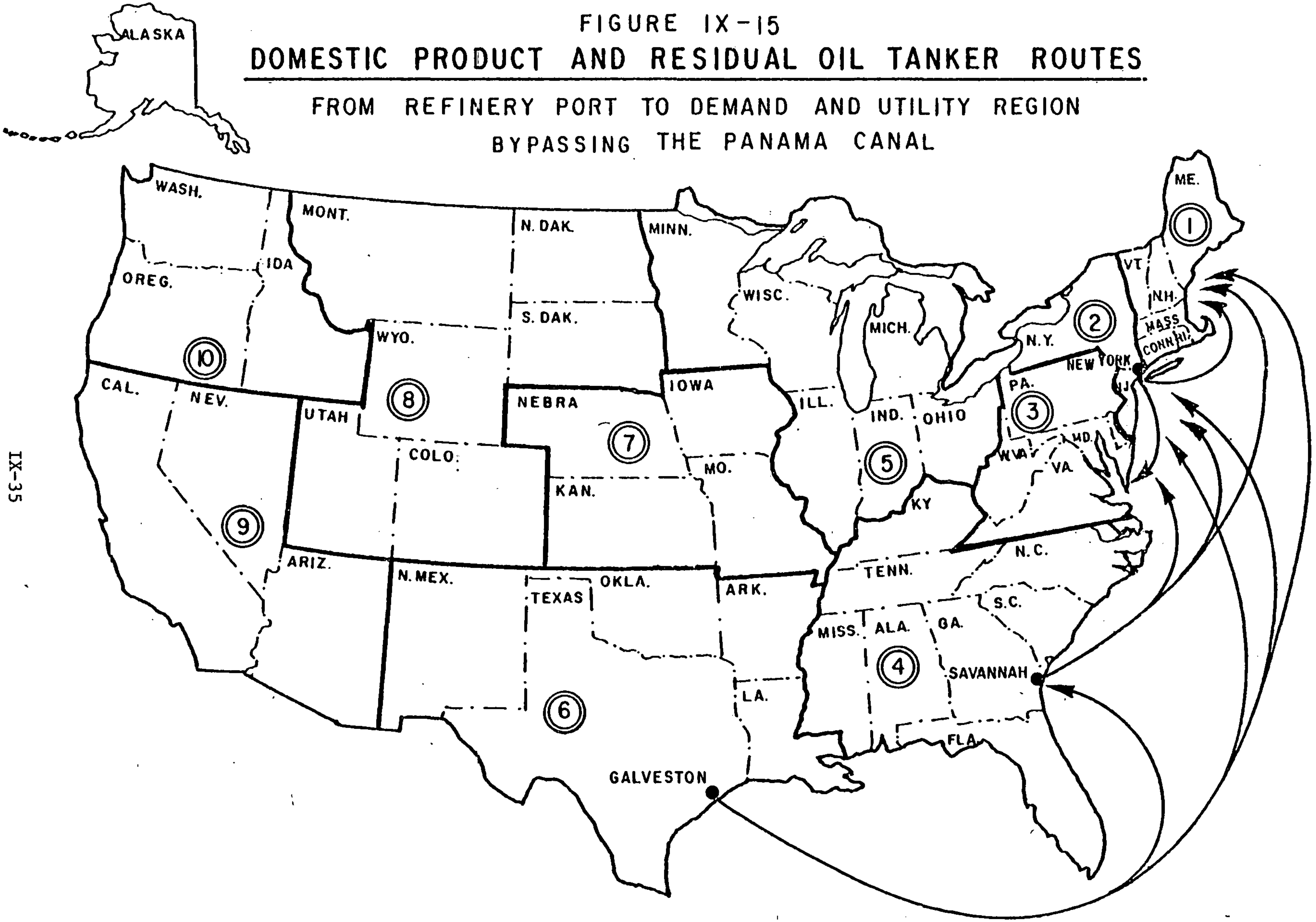


FIGURE IX-16

DOMESTIC PRODUCT AND RESIDUAL OIL INLAND BARGE ROUTES

FROM REFINERY TO DEMAND AND UTILITY REGION PORTS

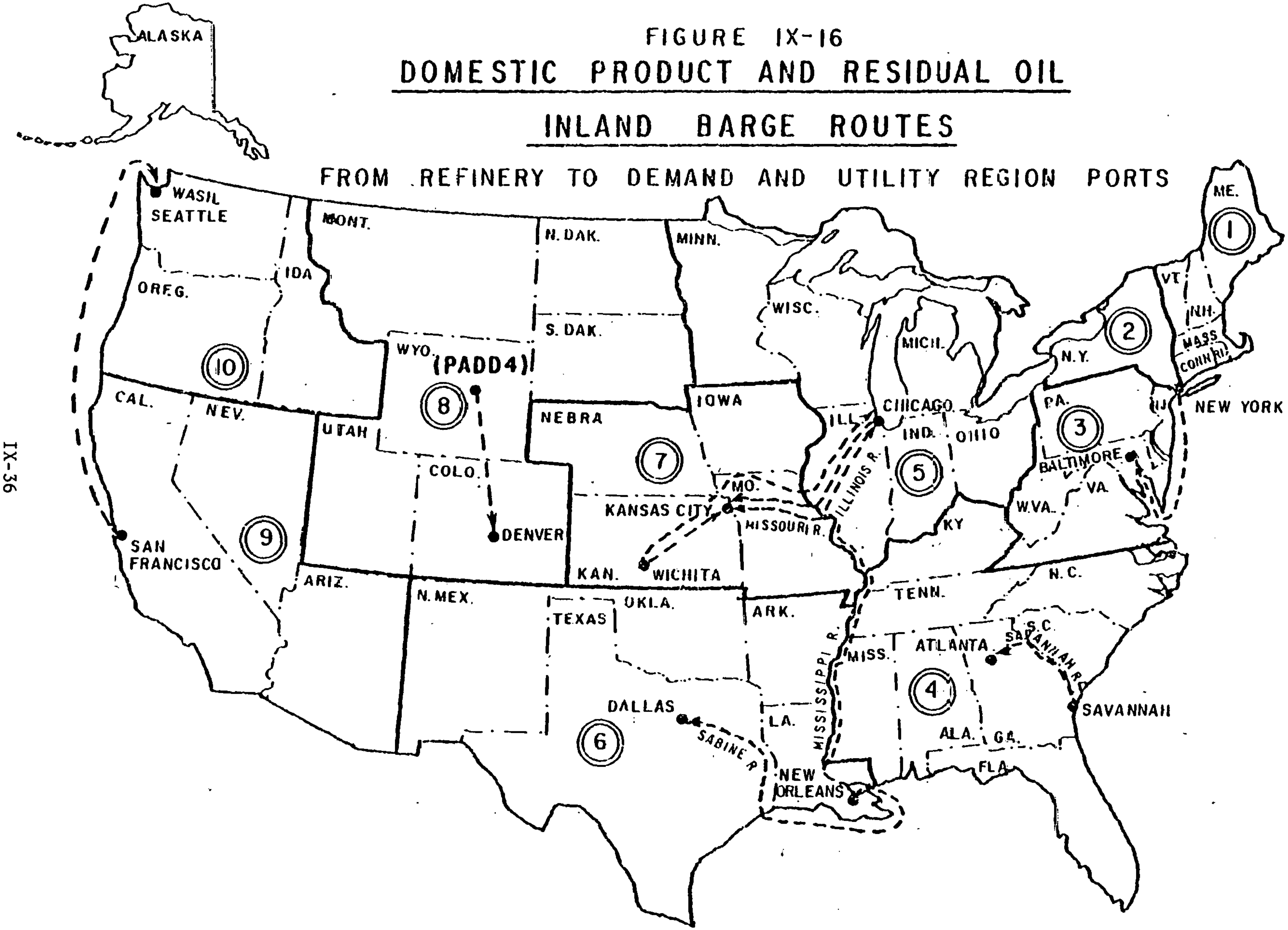
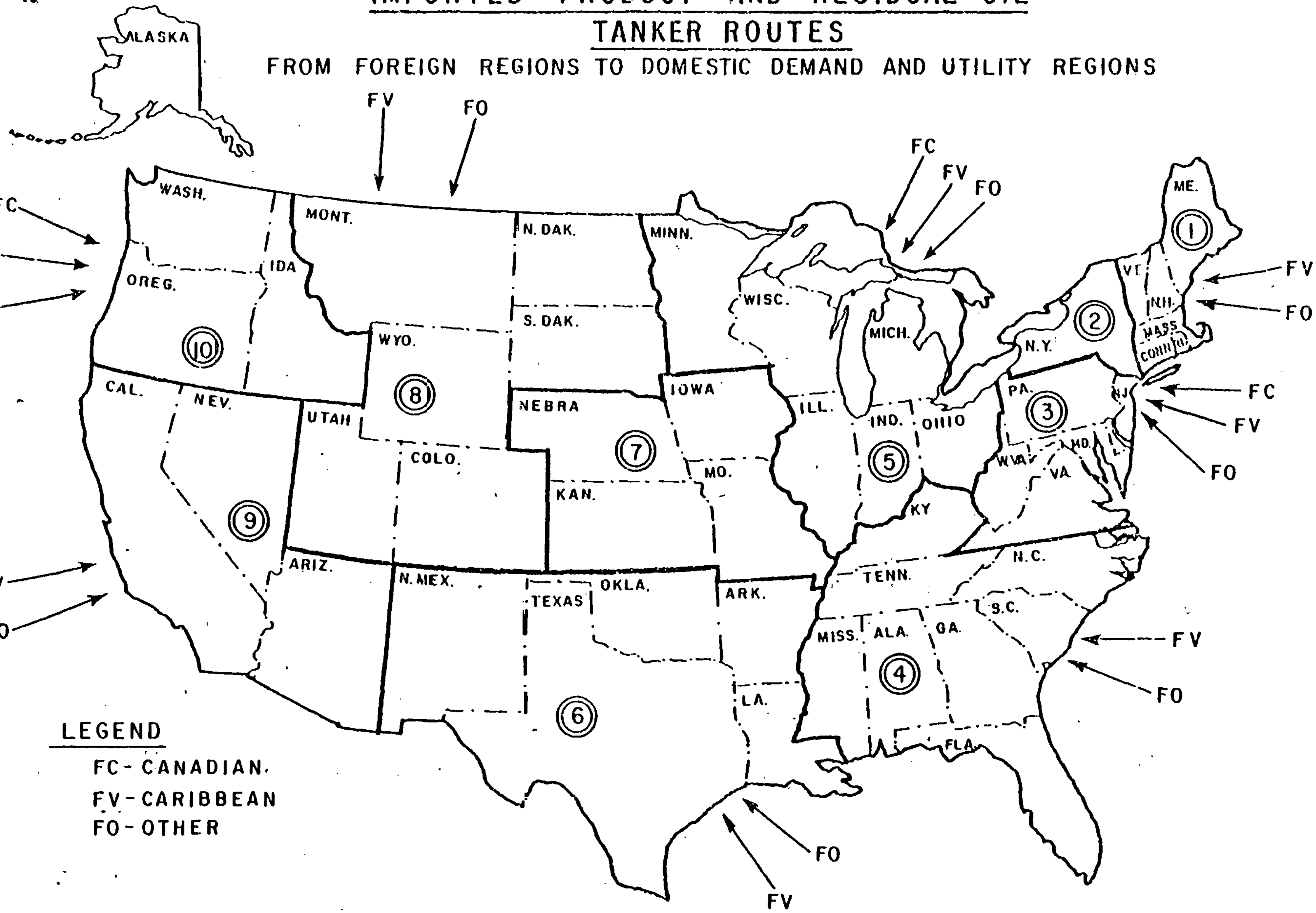


FIGURE IX-17

IMPORTED PRODUCT AND RESIDUAL OIL TANKER ROUTES

FROM FOREIGN REGIONS TO DOMESTIC DEMAND AND UTILITY REGIONS



LEGEND

FC - CANADIAN
FV - CARIBBEAN
FO - OTHER

TABLE IX-16. METHOD FOR ESTIMATING TRANSPORTATION COSTS FOR DOMESTIC AND FOREIGN PRODUCT AND RESIDUAL OIL BY TANKER AND BARGE

DOMESTIC

Product:

Cost from Refinery to Demand or Utility Region
By Oceangoing Tanker

Same Equation as Crude Tanker
Without Gathering Charge
(Table IX-11)
(Input: Table IX-17)

+

Cost from Refinery to Demand or Utility Region
By Inland Waterway Barge

(Table IX-18 + .25) 7.5

= Domestic Product Unit Costs = (Table IX-19)

Residual:

Cost from Refinery to Demand or Utility Region
By Oceangoing Tanker

(Product Unit Cost by Tanker) (1.10)

+

Cost from Refinery to Demand or Utility Region
By Inland Waterway Barge

(Product Unit Cost by Barge) (1.21)

= Domestic Residual Unit Costs = (Table IX-20)

FOREIGN

Product:

Cost from Supply to Demand and Utility Region

Foreign Product Unit Costs = (Table IX-21)

Residual:

Cost from Supply to Demand or Utility Region

Foreign Residual Unit Costs = (Table IX-22)

TABLE IX-17. DATA ON PRODUCT AND RESIDUAL TANKERS BY PANAMA CANAL AND OTHER ROUTES

TANKER CAPACITY

Oil Type	Routing	Deadweight Tons	Long Tons	Cost At Sea ($/Hr)	Cost At Port ($/Hr)	Turn Around Time (Hrs)	Panama Canal Charge ($)	Speed (Knots)	Scale (B/Ton)
Product	Panama Canal	25000	24500	505	250	24	48500	17	7.7
	Other	25000	24500	505	250	24		17	7.7
Residual	Panama Canal	25000	24500	505	250	24	48500	17	7.0
	Other	25000	24500	505	250	24		17	7.0

unit costs for transporting products between refinery and demand regions are derived by the equation shown in Table IX-16. The data for this equation are barge unit costs ($/ton) obtained from a Federal Energy Administration report and presented in Table IX-18.[5] Added to these values is a handling and storage charge of $.25/ton. A density conversion factor for petroleum products of 7.5 B/ton is applied to convert from tons to barrels of oil. Adding the matrices together results in the total unit cost matrix for transporting domestic product by barge and tanker, Table IX-19.

Domestic residual transportation costs are determined in exactly the same manner as for products with the appropriate data in Table IX-17 for the tanker estimation, and with Table IX-18 and a 6.2 B/ton density conversion factor for the barge estimation. Since the calculations for tanker and barge vary only by the ratio of densities, factors can be applied to the product estimation to determine residual costs, as shown in Table IX-16. The result of using this equation is the total unit cost matrix of transporting domestic residual by tanker and barge, as presented in Table IX-20.

For foreign products and residual, the unit costs can be obtained from Tables IX-21 and IX-22, respectively, as indicated in Table IX-16. As for crude, the 0.0 in the matrix indicates that actual transportation costs for imported oil are included in the purchase price (the delivered city-gate price of the demand region of the entry point reported in the PIES import tables). The 0.0 is significant in identifying existing links because the existence of a non-zero cost for product and residual indicates the cost for additional transportation inland.

The combination of the domestic and foreign costs of barge and tanker transportation separately for each oil type results in the final product and residual unit cost matrices used to determine an equilibrium in PIES.

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[5] Federal Energy Administration "Inputs to Project Independence Evaluation System Integration Model for the Transport of Energy Materials, Volume II."

TABLE IX-18. TRANSPORTATION COSTS FOR DOMESTIC PETROLEUM PRODUCTS BY BARGE AND TANKER VIA INLAND WATERWAYS ($/BL)

	DOE REGION (Port City)				
Refinery Region (Port City)	New Eng. (Boston)	N.Y./N.J. (NY)	Mid-Atl. (Balt.)	S-Atl. (Atlanta)	Midwest (Chicago)
PADD 1A (New York)		0.40	0.40		
PADD 1B (Savannah)				1.35	
PADD 2A (Chicago)					0.40
PADD 2B (Wichita)					3.60
PADD 3 (New Orleans)					5.24
	S-West (Dallas)	Central (KC)	N-Cntrl. (Denver)	West (SF)	N-West (Seattle)
PADD 2A (Chicago)		2.22			
PADD 2B (Wichita)		1.35			
PADD 3 (New Orleans)		0.40	5.46		
PADD 4			1.35		
PADD 5 (San Francisco)				0.40	0.40

TABLE IX-19. TRANSPORTATION COSTS FOR DOMESTIC PETROLEUM PRODUCTS (EXCEPT RESIDUAL) BY BARGE AND TANKER ($/B)

	DOE REGION									
Refinery Region	New Eng.	NY/NJ	MidAtl.	S.Atl.	Midwest	S.West	Central	N.Cntrl	West	N.West
PADD 1A	.28	.08	.08						2.24	2.48
PADD 1B	.36	.28	.26	.21					2.11	2.35
PADD 2A					.08		.32			
PADD 2B					.51		.21			
PADD 3	.72	.65	.62	.36	.73	.08	.76		2.09	2.33
PADD 4								.21		
PADD 5	2.29	2.24	2.22						.08	.08

TABLE IX-20. COSTS OF TRANSPORTING DOMESTIC RESIDUAL FUEL BY BARGE AND TANKER ($/B)

DOE REGION										
Refinery Region	New Eng.	NY/NJ	Mid-Atl.	S.-Atl.	Midwest	S.-West	Central	N.-Cntrl	West	N.West
PADD 1A	.31	.10	.10						2.46	2.73
PADD 1B	.39	.31	.28	.25					2.32	2.59
PADD 2A					.10		.39			
PADD 2B					.62		.25			
PADD 3	.80	.71	.69	.40	.88	.10	.92		2.30	2.56
PADD 4								.25		
PADD 5	2.52	2.46	2.44						.10	.10

TABLE IX-21. TRANSPORTATION COSTS FOR IMPORTED PETROLEUM PRODUCTS (EXCEPT RESIDUAL) BY BARGE AND TANKER ($/B)

	DOE REGION									
Foreign Region	New Eng.	NY /NJ	Mid-Atl.	S.-Atl.	Midwest	S.-West	Central	N.-Cntrl	West	N .-West
Canada		.00			.00					.00
Caribbean	.52	.43	.41	.18	.75	.00	.66	2.80	1.93	2.12
Foreign Other	.00	.00	.00	.00	.75	.00	.66	2.80	.00	.00

TABLE IX-22. TRANSPORTATION COSTS FOR IMPORTED RESIDUAL FUEL BY BARGE AND TANKER ($/B)

	DOE REGION									
Foreign Region	New Eng.	NY/NJ	Mid-Atl.	S.-Atl.	Midwest	S.-West	Central	N.-Cntrl	West	N.-West
Canada		.00			.00					.00
Caribbean	.55	.46	.44	.20	.80	.00	.70	3.00	2.05	2.26
Foreign Other	.00	.00	.00	.00	.80	.00	.70	3.00	.00	.00

Crude by Pipeline

Generally, crude moves by pipeline directly from oil supply to refinery regions. Synthetically produced crude (syncrude) is also included in the crude pipeline network. Syncrude is modeled for production in all twelve coal supply regions and in the single PIES shale region.

In the pipeline network, the direct links are modeled from every oil and syncrude supply region in the lower 48 states to every refinery region. PIES assumes that the mileage between regions is, in general, the shortest distance railroad mileage between region centroids.

Two instances of oil transshipment occur in the transportation of Alaskan and foreign crude to the lower 48 states. The transport of Alaskan crude from supply regions to inland refinery regions in the lower 48 states involves a pipeline-tanker-pipeline transshipment as illustrated in Figure IX-18. The following movements are made:

(1) From the Alaskan North Slope (Prudhoe Bay) supply region to Valdez via the Trans-Alaskan Pipeline System (TAPS) (capacity: 2 million barrels per day (2 MMB/D))

(2) From Valdez, via tanker, to the West Coast (refinery region PADD 5), either:

  (a) Port Angeles, Washington (capacity: 120 thousand deadweight tons (120 M DWT))

  or

  (b) Long Beach, California (capacity: 150 M DWT)

(3) From the West Coast to inland refineries via two proposed pipeline systems as follows:

  (a) Northern Tier pipeline from Port Angeles, Washington to Clearbrook, Minnesota (refinery region PADD 2B) (capacity: 800 MB/D)

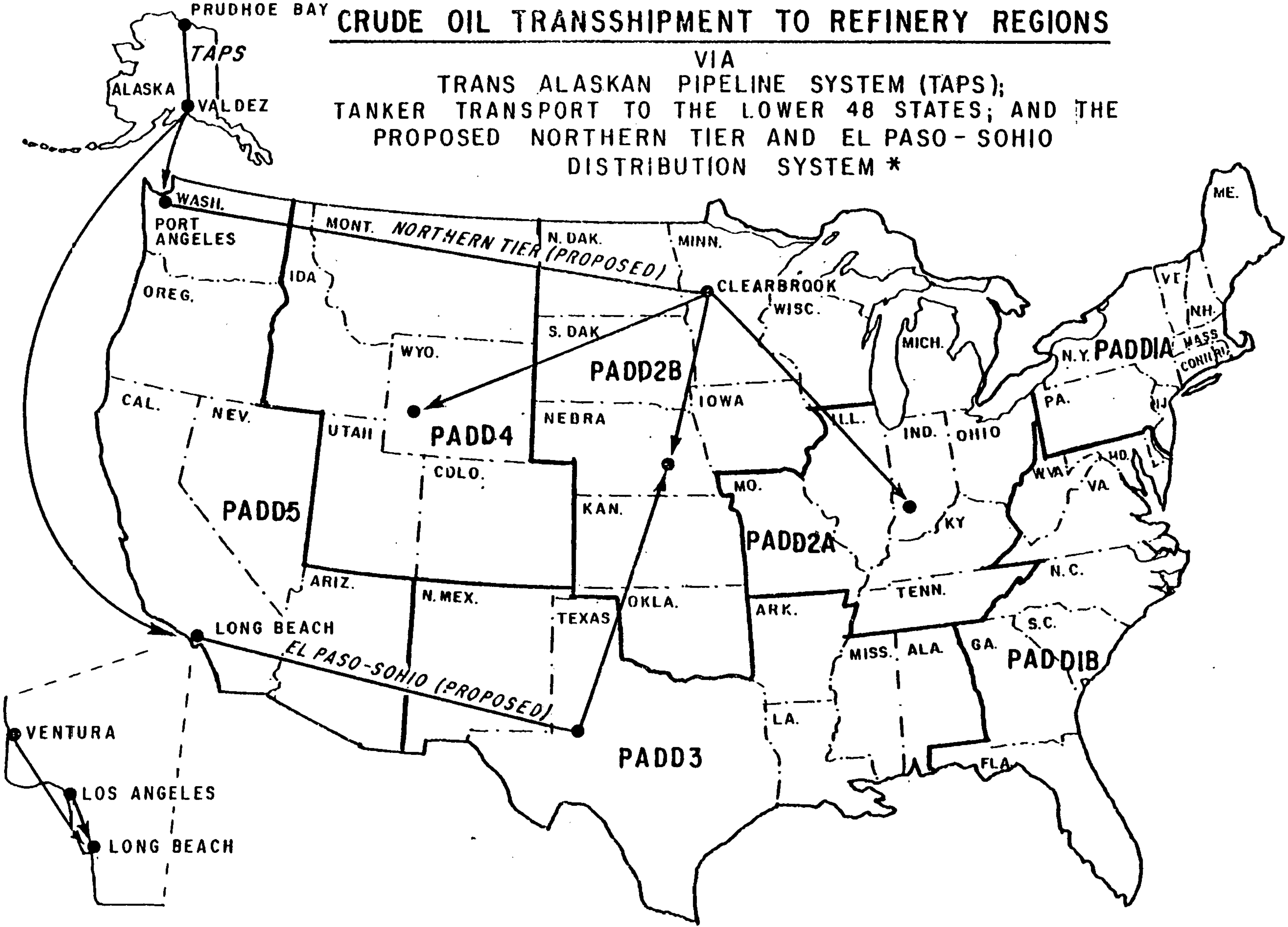
  or

  (b) El Paso - Sohio pipeline from Long Beach, California to Midland, Texas (refinery region PADD 3) (capacity: 500 MB/D)

FIGURE IX-18

CRUDE OIL TRANSSHIPMENT TO REFINERY REGIONS

VIA
TRANS ALASKAN PIPELINE SYSTEM (TAPS);
TANKER TRANSPORT TO THE LOWER 48 STATES; AND THE
PROPOSED NORTHERN TIER AND EL PASO-SOHIO
DISTRIBUTION SYSTEM *



* INCLUDED IS SUPPLY OF CRUDE OIL FROM LOS ANGELES AND PACIFIC COAST (VENTURA) TO LONG BEACH.

As indicated in Figure IX-18, the proposed Northern Tier Pipeline would distribute crude to refinery regions PADD 2A, PADD 2B, and PADD 4. The proposed El Paso-Sohio pipeline would distribute crude to refinery regions PADD 2B and PADD 3. In addition to transportation of Alaskan crude, the El Paso-Sohio system has the capability to transport West Coast crude oil from Los Angeles and Ventura, California. The link from Ventura (offshore, Pacific Ocean) is not used in PIES at present.[6]

The transshipment of foreign crude involves a tanker-pipeline movement from foreign supply regions to domestic refinery regions other than those coterminous with the port of landing. The network allows for this by providing movement of landed crude between refinery regions by pipeline. As shown in Figure IX-19, foreign crude can move from refinery region PADD 3 to regions PADD 2A, PADD 2B, and PADD 4. Further, a link is provided for movement from PADD 1A to PADD 1B.

The crude oil tanker and pipeline movements are handled separately in their respective networks. Therefore, for this transshipment, foreign crude movement by pipeline between refinery regions is included in the crude pipeline network only.

The method for determining unit costs ($/B) of transporting crude oil by pipeline is presented in Table IX-23. The method generally provides a sum of origin-destination unit cost matrices for the various segments of the crude pipeline network previously described. The segments of the pipeline network include transportation of crude oil from the lower 48 states, foreign regions, and Alaska, as well as syncrude. Furthermore, gathering costs from oil fields to pipeline sources are added in, and where pipeline systems in the lower 48 states exist, actual cost data override calculated estimates.

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[6] FEA Memo, Paul Randolle; "Transportation Data for PIES: Crude Oil Pipeline Link Prices"; July 15, 1977.

FIGURE IX-19

FOREIGN CRUDE OIL TRANSPORT BY PIPELINE
BETWEEN REFINERY REGIONS

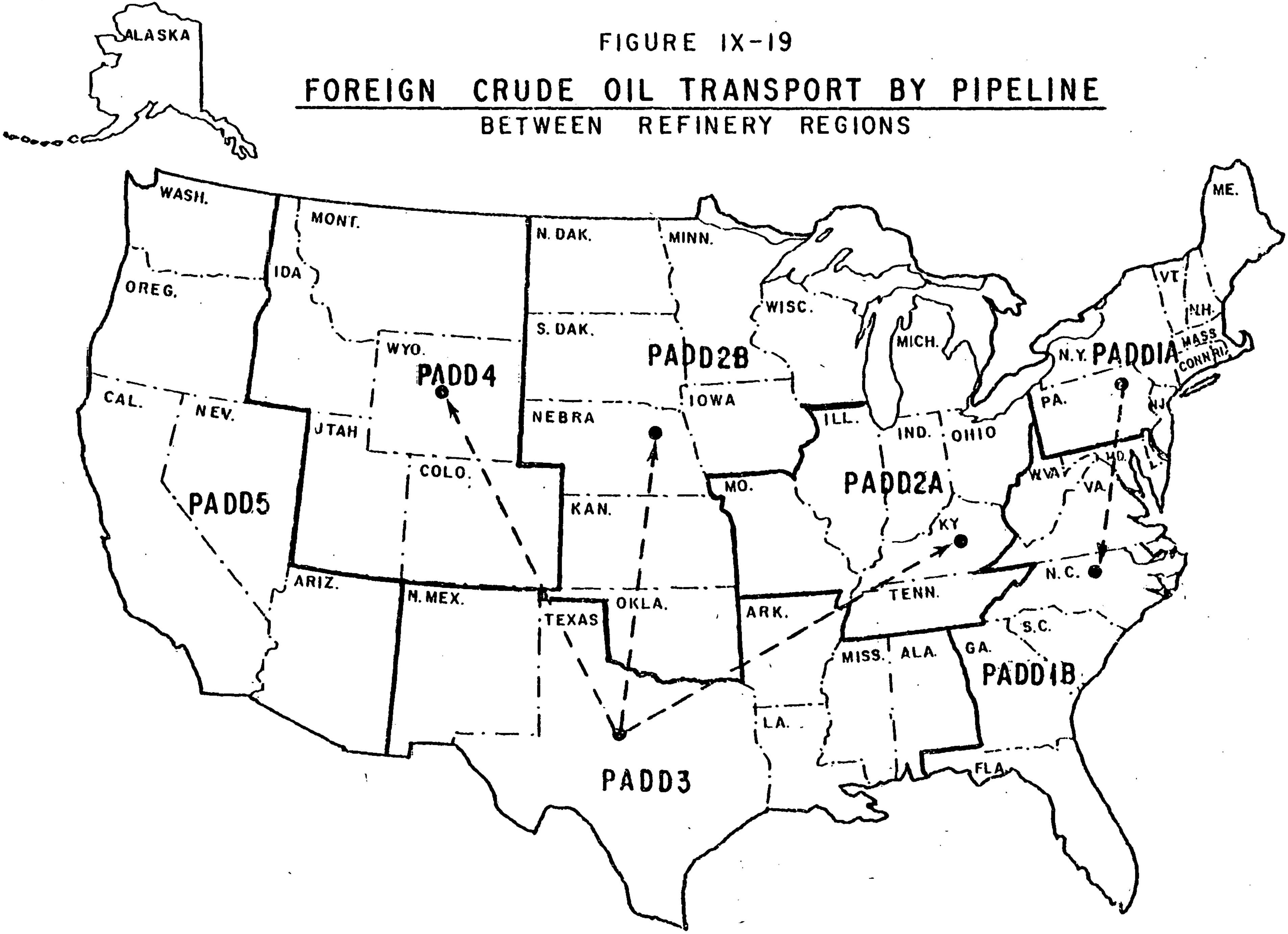

TABLE IX-23. METHOD FOR ESTIMATING TRANSPORTATION COSTS FOR CRUDE OIL MOVED BY PIPELINE

Costs from Lower 48 States Supply to Refinery Regions		Gathering Costs from Oil Fields to S ly Region		Actual Data Override (ICC Tariffs, Includes Gathering Costs)		Foreign Oil Movement Between Refinery Regions	Alaskan Oil TAPS and Proposed (Includes Tanker Costs for Proposed)		Syncrude and Shale Oil From Supply to Refinery Regions
ax_{ij}	+	b_{ij}	or	c_i	+	djk	e_{lij}	+	f_{mj}
		(Table IX-24)							

Where:

i = supply region
j = refinery region for movement between supply and demand regions
k = refinery region for movement between two refinery regions
l = pipeline type: Northern Tier or El Paso-Sohio (proposed)

And:

a = unit cost ($/B/100 mi.) = .06
b = gathering cost at supply region ($/B) (Table IX-13)
c = actual costs (ICC and gathering) ($/B)
d = costs between refinery regions for foreign crude oil ($/B) (Table IX-25)
e = Alaskan crude oil unit cost ($/B Table IX-26)
f = syncrude and shale oil unit costs corresponding to crude oil cost ($/B) (Table IX-27)
x = mileage between supply and refinery region centroids

Also, from the previous discussion on transshipment networks, it follows that to move crude from the Alaskan North Slope to the inland U.S., tanker transport costs are included with the costs of the inland pipeline network section of the movement. However, for other crude transshipment, transportation unit costs are accounted for in the separate networks that make up the transshipment.

The cost of transporting crude oil by pipelines in the lower 48 states is determined from a mileage charge ($/B/100 miles). A cost of $.06/B/100 miles is used for new pipeline links and multiplied by the mileage. Mileage data are determined from shortest distance railroad mileage from supply to refinery regions. For existing pipelines, the actual Interstate Commerce Commission (ICC) tariffs are used.

The gathering costs are the same as those given previously in Table IX-13 for the crude oil tanker movement. The result of including the above crude oil pipeline transportation unit costs in the lower 48 states is given in Table IX-24.

The unit costs of transshipping foreign crude from the Gulf Coast inland via pipeline between refinery regions are given in Table IX-25. These costs are for the movement of foreign crude from Gulf Coast refinery region PADD 3 to regions PADD 2A, PADD 2B, and PADD 4 and are the same as the ICC tariffs (excluding gathering charges) of moving crude from the West Gulf Basin oil supply region to the various destinations, i.e., the refinery regions stated above. There is no charge for the movement of crude from PADD 1A to PADD 1B, since the link is for crude imports actually landing in PADD 1B. A blank entry means the corresponding link is not available in the network.

For the movement of Alaskan crude by pipeline, the unit costs are given in Table IX-26. Since the flow rate is expected to increase, the $3.40/B unit cost listed for TAPS is the tariff the shippers would have to charge at a volume of 2 million barrels per day (MMB/D) to receive the same return as they would under the existing average tariff

TABLE IX-24. TRANSPORTATION COSTS FOR CRUDE OIL BY PIPELINE INCLUDING GATHERING COSTS ($/B)

REFINERY REGION

Oil Supply Region	PADD 1A	PADD 1B	PADD 2A	PADD 2B	PADD 3	PADD 4	PADD 5
Pacific Coast	1.89	1.57	1.26	.63	.41	.75	.10
Pacific Ocean	1.99	1.67	1.36	1.06	1.13	.85	.32
W. Rocky Mtns.	1.50	1.24	.86	.58	.72	.60	.55
E. Rocky Mtns.	1.45	1.39	.43	.26	1.03	.10	.79
W. Tex. & E. N. Mex.	1.23	.90	.46	.22	.36	.65	.72
W. Gulf Basin	1.02	.66	.33	.58	.10	.91	1.08
Gulf of Mexico	.97	.61	.60	.80	.32	1.16	1.33
Midcontinent	1.05	.88	.41	.19	.38	.68	1.06
Mi. Bas. Int, Ap.*	.70	.62	.24	.52	.79	.92	1.45
Atlantic Coast	.87	.20	.77	1.09	.76	1.45	1.72
Atlantic Ocean	.45	.45	.74	1.03	1.05	1.43	1.90

*Michigan Basin, Interior, Appalachia.

TABLE IX-25. TRANSPORTATION COSTS FOR FOREIGN CRUDE OIL BY PIPELINE ($/B)

REFINERY REGION

Refinery Region	PADD 1A	PADD 1B	PADD 2A	PADD 2B	PADD 3	PADD 4	PADD 5
PADD 1		.00					
PADD 3			.28	.53		.86	

of \$5.60/B at a volume of 1.6 MMB/D.[7] The unit costs for transshipping crude from South Alaska (Valdez) to the inland U.S. refinery regions by tanker and the proposed Northern Tier and El Paso-Sohio pipelines are also included in Table IX-26.[8]

In addition to the above movements, the crude pipeline network permits transport of West Coast oil supplied from Los Angeles and Ventura by the proposed El Paso-Sohio pipeline. The unit cost for this system is \$.41/B and \$.63/B from Los Angeles to refinery regions PADD 3 and PADD 2B, respectively; and \$.63/B and \$.85/B from Ventura to refinery regions PADD 3 and PADD 2B, respectively.

The unit costs of transporting syncrude and shale by pipeline are assumed to be the same as those for moving crude from oil supply regions. These transportation costs are given in Table IX-27.

The combination of the unit cost matrices developed in Table IX-23 yields a matrix of unit costs for crude shipped by pipeline for the LP matrix.

TABLE IX-26. TRANSPORTATION COSTS FOR ALASKAN CRUDE OIL BY PIPELINE (\$/B)

Transportation System	Origin	Destination	Cost
Trans-Alaskan Pipeline	North Slope	South Alaska	3.40
Tanker and El Paso-Sohio	South Alaska	PADD 2A	1.12
Tanker and El Paso-Sohio	South Alaska	PADD 2B	1.10
Tanker and Northern Tier	South Alaska	PADD 2B	1.13
Tanker and Northern Tier	South Alaska	PADD 3	.91
Tanker and Northern Tier	South Alaska	PADD 4	1.07

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[7] United States Department of Energy, "Transportation Data Input to the PIES Integrating Model," 1978 Annual Administrator's Report.

[8] Study by the Transportation and Energy Research Associates on the disposition of North Slope oil.

TABLE IX-27. TRANSPORTATION COSTS FOR SYNCRUDE AND SHALE OIL BY PIPELINE, INCLUDING GATHERING ($/B)

	REFINERY REGION						
Syncrude and Shale Oil Supply Regions	PADD 1A	PADD 1B	PADD 2A	PADD 2B	PADD 3	PADD 4	PADD 5
Coal							
Northern Appalachian	.70	.62	.24	.52	.79	.92	1.45
Central Appalachian	.70	.62	.24	.52	.79	.92	1.45
Southern Appalachian	1.02	.66	.33	.58	.10	.91	1.08
Midwest	.70	.62	.24	.52	.79	.92	1.45
Central West	1.05	.88	.41	.19	.38	.68	1.06
Gulf	1.02	.66	.33	.58	.10	.91	1.08
N.E. Great Plains	1.45	1.39	.43	.26	1.03	.10	.79
N.W. Great Plains	1.45	1.39	.43	.26	1.03	.10	.79
Rockies	1.50	1.24	.86	.58	.72	.60	.55
Southwest	1.50	1.24	.86	.58	.72	.60	.55
Northwest	1.89	1.57	1.26	.63	.41	.75	.10
Alaska				1.13	.91		
Shale	1.50	1.24	.86	.58	.72	.60	.55

Production by Pipeline

The transportation of product by pipeline is from refinery to demand and utility regions, in the lower 48 states. The determination of product pipeline transportation costs is a simplified version of that for crude.

The product pipeline network can be represented quite simply. It has transportation links from every refinery region to every demand and utility region in the lower 48 states. No schematic is presented for this network.

The method for determining unit cost ($/B) of moving product by pipeline as presented in Table IX-28 is similar to that for crude by pipeline (Table IX-23). Yet the process is simpler here because for transportation purposes, petroleum products are not diversified and no gathering charges are applied. Thus, product unit costs are simply a function of the mileage charge, or alternatively actual ICC tariffs, from refinery to demand and utility regions as indicated in Table IX-28.

TABLE IX-28. METHOD FOR ESTIMATING TRANSPORTATION COSTS FOR PETROLEUM PRODUCTS BY PIPELINE

Cost from Refinery to Demand and Utility Regions		Cost Override from Actual ICC Tariff
$(a)(x_{ij})$	or	b_{ij}

Where:

i = refinery origin region
j = demand or utility destination region

And:

a = unit cost ($/B/100 mi.) = .07
b = override cost ($/BL)
x = mileage between refinery and demand/utility region centroids

The mileage charge is estimated at $.07/B/100 miles and used for pipelines other than existing ones; however, an exception occurs at Atlanta, where a slightly higher charge of $.10/B is assigned, since the refineries are scattered and delivery is largely by truck. For the existing pipeline system, ICC tariffs are utilized. Lastly, where a centroid for a demand or utility region is also a major refinery center, for example Philadelphia, a nominal cost of $.05/B is used as the cost of shipping products from the refinery to the consuming region. The resulting transportation costs for product by pipeline mileage are given in Table IX-29.

NATURAL GAS

Transportation of natural gas in PIES differs from that of coal and oil, since natural gas has only one explicit model--pipeline. Transportation of imported natural gas by LNG tanker or pipeline is considered implicitly in the network, because the cost of transportation is included in the price at the final destination.

Natural gas moves from supply to demand or utility regions. Because interstate transport of natural gas is subject to Federal regulation, interstate and intrastate natural gas systems are modeled separately. Transportation costs are determined for both intrastate and interstate systems. In addition, intrastate natural gas can be distributed to interstate regions under certain economic conditions.

Natural Gas Pipeline-Interstate

Interstate natural gas comes from both domestic and foreign sources and is supplied to demand and utility regions. Only one pipeline system (the proposed Alcan pipeline) is modeled from Alaska to the lower 48 states. This pipeline connects all interstate gas regions to all demand and utility regions. As modeled in PIES, the Alcan pipeline would parallel the Trans-Alaskan Pipeline System (TAPS) from Prudhoe Bay to Fairbanks, and then follow the Alcan highway across Canada, where it would connect with existing systems. About 60 percent of the gas would be delivered to the north central states and about 40 percent to the west coast. PIES models pipeline links within the lower 48 states for distribution of Alaskan natural gas to all demand and utility regions. The Alcan pipeline is shown in Figure IX-20.

TABLE IX-29. TRANSPORTATION COSTS FOR PETROLEUM PRODUCTS BY PIPELINE

($/B)

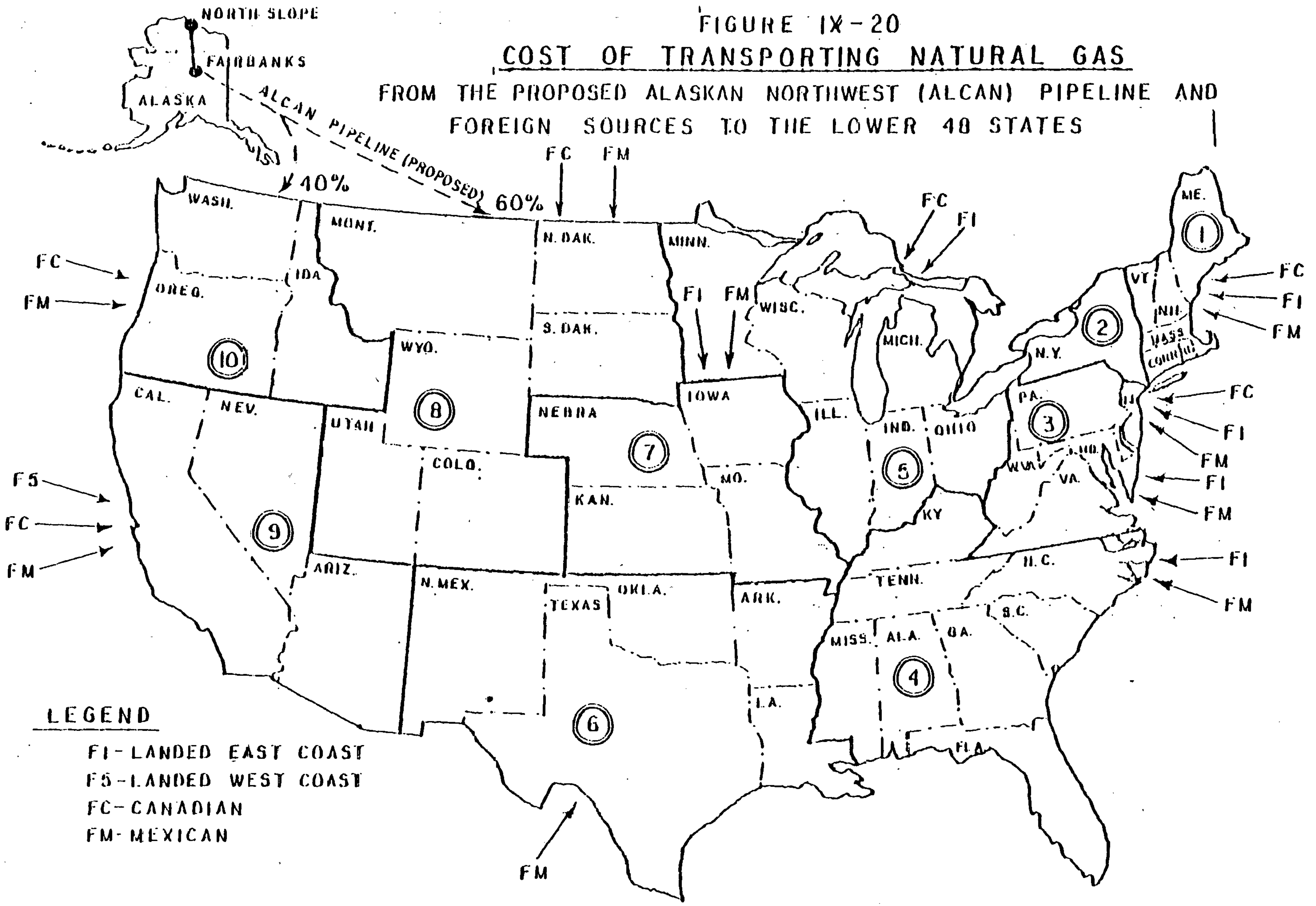
DOE REGION

Refinery Region	New Eng.	NY/NJ	Mid.-Atl	S.-Atl.	Midwest	S.-West	Central	N.-Cntrl	West	N.-West
PADD 1A	.16	.05	.05	.60	.63	1.14	.93	1.35	2.21	2.13
PADD 1B	.67	.59	.46	.18	.69	.70	.80	1.25	2.08	2.15
PADD 2A	.84	.73	.64	.42	.05	.49	.19	.63	1.53	1.54
PADD 2B	1.17	1.07	.98	.69	.34	.28	.05	.42	1.31	1.49
PADD 3	1.35	.44	.40	.29	.45	.20	.38	.40	1.47	1.85
PADD 4	1.56	1.48	1.40	1.22	.85	.81	.64	.18	.83	.37
PADD 5	2.27	2.15	2.03	1.59	1.55	1.02	1.24	.94	.05	.05

FIGURE IX-20

COST OF TRANSPORTING NATURAL GAS

FROM THE PROPOSED ALASKAN NORTHWEST (ALCAN) PIPELINE AND FOREIGN SOURCES TO THE LOWER 48 STATES



LEGEND

FI - LANDED EAST COAST
F5 - LANDED WEST COAST
FC - CANADIAN
FM - MEXICAN

Foreign natural gas can be supplied from various regions, classified as follows: Landed East Coast, Landed West Coast, Canadian, and Mexican. Landed natural gas is assumed to be supplied by LNG tanker. Canadian and Mexican gas is transported by pipeline to the U.S border. All imported gas is distributed inland by the domestic pipeline system. Figure IX-20 indicates the supply of foreign natural gas to demand and utility regions.

The method for determining unit costs ($/MCF) for the transportation of interstate natural gas is similar to that for crude oil and is presented in Table IX-30. Data related to natural gas volumes are based on a 1032 Btu/CF standard heat value.

The cost of moving domestic natural gas in the lower 48 states is determined from a mileage charge multiplied by the short line railroad mileage between centroids of interstate gas supply regions and demand and utility regions. The mileage charge is $.033/MCF/100 miles for existing links, determined from a weighted average of transportation costs for eight large gas pipelines.[9] For other links, the charge is $.04/MCF/100 miles.

Unit costs for the Alcan pipeline are derived from Federal Energy Regulatory Commission (FERC) data, are increased by 30 percent for projected construction cost overruns and are adjusted to give regional cost estimates.[10] The links to the East Coast are intended to represent delivery by displacement. That is, Alcan natural gas will be supplied to the Midwest which will free traditional Midwestern supplies from the East Coast.

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[9] Department of Energy, "Transportation Data Inputs to the PIES Integrating Model, 1978 Annual Administrators Report".

[10] Federal Power Commission (FPC), "Recommendations to the President-Alaskan Natural Gas Transportation Systems," (Exhibit V-5).

TABLE IX-30. METHOD FOR ESTIMATING INTERSTATE TRANSPORTATION COSTS FOR NATURAL GAS BY PIPELINE

Cost from U.S. Supply to Demand Regions (Excluding Alaska)	Alaskan Natural Gas Cost from Supply to Demand Regions	Adjustment for Offshore Regions and Gathering Charges	Foreign Natural Gas Cost from Supply to Demand Regions	Adjustment for Industrial Prices	Syngas from Coal Supply to Demand Regions
ax_{ij} +	b_{ij} +	c_i +	d +	e +	$f\,y_{kj}$
	(Table IX-31)		(Table IX-32)	($.02/MCF)	(Table IX-33)

Where:

i = natural gas supply region
j = natural gas demand region
k = syngas supply region corresponding to natural gas supply region
x = distance from natural gas supply to demand regions
y = distance from corresponding syngas supply region to natural gas demand region

And:

a = unit costs ($/MCF*/100 miles) = $.033/MCF/100 (for existing systems)
= .04/MCF/100 (for new systems)
b = Alaskan unit costs ($/MCF)
c = adjustment: gathering, on-shore = $.12/MCF
adjustment, off-shore = $.20/MCF
adjustment, G8 = (.12 + .16)/MCF
d = foreign charges; $0.0 means transport cost included in price ($/MCF)
e = industrial price adjustment = $.02/MCF
f = syngas unit costs corresponding to natural gas cost

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*Note: MCF = thousand cubic feet.

Adjustments are added to domestic unit costs to better approximate the current markup between wellhead prices and city gate prices for specific gas supply regions: $.12/MCF for all onshore supply regions except the West Gulf Basin, $.20/MCF for the Pacific Ocean, Atlantic Ocean, and Gulf of Mexico, and $.28/MCF for the West Gulf Basin.

The results of including the above domestic transportation unit costs are given in Table IX-31. Note that for the transport of natural gas from Alaska, the costs are dependent on the forecast year, 1985 or 1990. Costs for other material/mode combinations are assumed constant with time. However, for the transport of natural gas via the Alcan pipeline the relatively large initial capital investment and subsequent depreciation incurred for the facility results in a high initial cost of transportation which decreases over time. This cost reduction varies according to region of final destination. Costs for lower 48 pipelines are not computed in the same way, but on the basis of average per mile costs for eight typical interstate pipelines.

Foreign natural gas transportation costs are given in Table IX-32. Imported LNG and Canadian gas are assigned zero transportation charges, since their purchase price, as reported in the import tables, is already the delivered city-gate price. The transportation charges shown for Mexican gas begin at the border, and the cost of transporting to the border is included in the price.

The costs of transporting syngas from coal regions are also modelled. Mileage charges are used, which are associated with interstate gas regions. The correct mileage charges for use in this calculation are determined by establishing correspondences between coal and interstate gas supply regions, as shown in Table IX-2 above. The resultant syngas costs are given in Table IX-33.

The combination of the unit cost matrices developed in Table IX-30 yields the resultant transportation unit costs ($/MCF) for the natural gas pipeline network.

TABLE IX-31. TRANSPORTATION COSTS FOR DOMESTIC INTERSTATE NATURAL GAS BY PIPELINE ($/MCF)

	DOE REGION									
NPC Region	New Eng.	NY/NJ	Mid-Atl.	S.-Atl.	Midwest	S.-West	Centrl	N.-Centrl	West	N.-West
Pacific Coast	1.41	1.37	1.33	1.19	1.01	.87	.89	.65	.16	.50
Pacific Ocean	1.54	1.48	1.41	1.16	1.14	.83	.96	.79	.33	.74
W. Rocky Mtns.	1.13	1.07	1.01	.79	.73	.41	.55	.26	.55	.63
E. Rocky Mtns.	1.03	.98	.94	.84	.54	.60	.44	.23	.53	.54
W. Texas & E. N. Mex.	1.02	.93	.85	.52	.57	.25	.40	.50	.66	1.04
N. Gulf Basin	.87	.76	.69	.48	.59	.28	.45	.68	1.03	1.26
Gulf of Mexico	.73	.66	.60	.38	.52	.34	.50	.79	1.19	1.38
Midcontinent	.81	.64	.60	.46	.35	.27	.20	.33	.76	.99
Mi. Basin, Int.	.57	.51	.45	.35	.23	.48	.31	.56	1.07	1.08
Appalachia	.51	.37	.23	.32	.25	.64	.47	.72	1.27	1.34
Atlantic Coast	.59	.53	.47	.30	.63	.60	.69	.94	1.42	1.46
Atlantic Ocean	.43	.35	.29	.44	.59	.82	.72	.98	1.49	1.45
North Slope (1985)	1.77	1.73	1.68	1.56	1.66	1.44	1.59	1.48	1.49	1.30
North Slope (1990)	1.27	1.22	1.18	1.06	1.16	.95	1.21	1.10	1.12	.93
South Alaska (1985)									.89	
South Alaska (1990)									.69	

TABLE IX-32. TRANSPORTATION COSTS FOR IMPORTED NATURAL GAS BY TRANSSHIPMENT ($/MCF)*

DOE REGION

Foreign Region	New Eng.	NY/NJ	Mid-Atl.	S.-Atl	Midwest	S.-West	Central	N.-Centrl	West	N.-West
Landed East Coast	.00	.00	.00	.00	.00		.00			
Landed West Coast									.00	
Canada	.00	.00			.00			.00	.00	.00
Mexico	.89	.78	.71	.50	.61	.30	.47	.64	1.03	1.26

*Transshipment consists of LNG tankers and/or pipeline modes. Where 0.0 costs are shown, transport costs are included in price.

TABLE IX-33. TRANSPORTATION COSTS FOR INTERSTATE SYNGAS FROM CORRESPONDING COAL REGIONS BY PIPELINE ($/MCF)

DOE REGION

Coal Regions	New Eng.	NY/NJ	Mid-Atl	S-Atl	Midwest	S-West	Central	N-Cntrl	West	N.-West
Northern Appalachian	.51	.37	.23	.32	.25	.64	.47	.72	1.27	1.34
Central Appalachian	.51	.37	.23	.32	.25	.64	.47	.72	1.27	1.34
Southern Appalachian	.87	.76	.69	.48	.59	.28	.45	.64	1.03	1.26
Midwest	.57	.51	.45	.35	.23	.48	.31	.56	1.07	1.08
Central West	.81	.64	.60	.46	.35	.27	.20	.33	.76	.99
Gulf	.87	.76	.69	.48	.59	.28	.45	.64	1.03	1.26
N.E. Great Plains	1.03	.98	.94	.84	.54	.60	.44	.23	.53	.54
N.W. Great Plains	1.03	.98	.94	.84	.54	.60	.44	.23	.53	.54
Rockies	1.13	1.07	1.01	.79	.73	.41	.55	.26	.55	.63
Southwest	1.13	1.07	1.01	.79	.73	.41	.55	.26	.55	.63
Northwest	1.41	1.37	1.33	1.19	1.01	.87	.89	.65	.16	.50
Alaska									.89	

Together with this matrix, information on transmission efficiency, given in Table IX-34 and based upon a transmission loss rate of 4%/1000 miles for interstate gas, is used to determine quantity of supply.

Natural Gas Pipeline-Intrastate

The intrastate network represents the movement of intrastate natural gas by pipeline from gas supply regions to collocated utility, refinery and demand regions, and, under certain economic conditions, to interstate regions. Intrastate gas suppy regions correspond to demand and utility regions and differ from interstate gas supply regions, which correspond to National Petroleum Council (NPC) regions.

The intrastate natural gas transportation network is simple because supply and demand regions are coterminous. The transportation links, therefore, represent minimal movement within interstate regions.

The cost of intrastate natural gas movement is set at a nominal $.10/MCF. This cost is not associated with mileage and is the same for all interstate regions. Efficiency of intrastate gas transmission between supply and demand regions is assumed to be 99 percent for all links of the intrastate network.

ELECTRICITY

While most electric utility activities are covered in the utilities submodel of PIES described in Chapter VII, one transmission activity is included in the transportation tables. The transportation network permits the transmission of electricity from utility regions to collocated demand regions at a nuisance cost of $.01/kilowatt hour per day ($/KWH/D). This cost prevents degeneracy of the LP.

NUCLEAR FUEL

The current costs of transportation of nuclear fuel to utility regions are 0.0, indicating that the price of nuclear fuel is a delivered price that includes transportation charges.

TABLE IX-34. LOSS FACTORS FOR TRANSPORTING INTERSTATE NATURAL GAS BY PIPELINE (PERCENT LOST)

	DOE REGION									
NPC Region	New Eng.	NY/NJ	Mid-Atl.	S.-Atl.	Midwest	S.-West	Central	N.-Cntrl	West	N.-West
Pacific Coast	13	13	12	16	9	8	8	6	1	4
Pacific Ocean	14	13	12	10	10	7	8	6	2	6
W. Rocky Mtns.	10	10	9	7	6	4	5	2	5	6
E. Rocky Mtns	9	9	9	8	5	5	4	2	5	5
W. Texas & E. N. Mex	9	8	8	5	6	2	4	5	7	10
W. Gulf Basin	9	8	7	4	6	2	4	5	9	11
Gulf of Mexico	7	6	5	2	4	2	4	6	10	12
Midcontinent	7	7	6	4	3	2	1	3	8	9
Mi. Basin, Int.	5	4	4	3	2	4	2	5	10	10
Appalachia	4	3	2	3	2	6	4	6	12	13
Atlantic Coast	6	5	5	2	35	5	6	9	13	14
Atlantic Ocean	3	2	1	3	4	7	6	8	13	13
North Slope	10	10	9	6	8	4	7	6	5	5
South Alaska									11	

APPENDIX A. GLOSSARY OF TERMS

Availability (of a plant) - That fraction of time that a plant is capable of servicing demand (net of planned, unplanned, and forced outages).

Avoids The activity vectors that are the step-like approximations to the demand function produced by the equilibrating mechanism and used in the linear program.

Base load - Component of demand for electricity characterized by an essentially unvarying level for all hours of the year.

Capacity factor - A measure of utilization of capacity defined in the electric utilities industry to be the ratio of kwh production for the year divided by 8760 hours and the design capacity in kw.

CEASPIRIT - A Data Resources, Inc. macroeconomic projection of Spring 1977 of relatively high GNP Growth.

Combined cycle plants - A two-stage electricity generating plant with the first stage composed of combustion turbines and the second stage a waste-heat steam generator system which operates with the exhaust heat of the first stage.

Composition factors - The fraction of electric power in each load, e.g., base load 76 %, cycling 17%, daily peak 4.4%, seasonal peak 2.6%.

Cycling load - Component of demand for electricity that varies above base load levels or by time of day.

Daily peak - Component of demand for electricity that occurs above cycling load and occurs a few hours per day.

Demand approximation - In PIES, the demand approximation is the discrete step-like approximation to the demand function produced within the equilibrating mechanism. The demand approximation parameter are recomputed on each iteration of the equilibrating mechanism.

Demand function - A constant elasticity approximation to the output from the Demand Model used by the PIES equilibrating mechanism. The demand function is a continuous function obtained from estimates of prices and demand elasticities supplied by the Demand Model. It exists only for the target year.

Demand Model - A stand-alone, econometric model, which provides regional demand estimates for each year between the base year (1976) and the target years (1985 and 1990). The Demand Model produces market price and quantity estimates for a variety of fuels in different economic sectors. It provides own-price and cross-price elasticities for each of the fuels for which it predicts prices and quantities.

Demand sectors - There are five demand sectors in PIES - residential, commercial, industrial, transportation, and raw material. The PIES Demand Model forecasts demand quantities for fuels within one or more of these sectors as functions of prices.

Department of Energy Regions-Ten regions organized by states as follows:

Region 1
Connecticut
Maine
Massachusetts
New Hampshire
Rhode Island
Vermont

Region 2
New Jersey
New York

Region 3
Delaware
District of Columbia
Maryland
Pennsylvania
Virginia
West Virginia

Region 4
Alabama
Florida
Georgia
Kentucky
Mississippi
North Carolina
South Carolina
Tennessee

Region 5
Illinois
Indiana
Michigan
Minnesota
Ohio
Wisconsin

Region 6
Arkansas
Louisiana
New Mexico
Oklahoma
Texas

Region 7
Iowa
Kansas
Missouri
Nebraska

Region 8
Colorado
Montana
North Dakota
South Dakota
Utah
Wyoming

Region 9
Arizona
California
Hawaii
Nevada

Region 10
Alaska
Idaho
Oregon
Washington

Dispatch - The commitment of a utility's generating units to generate electricity to meet demand in a fashion determined to be most efficient by the system controllers.

Distillate fuel oil - The lighter fuel oil distilled off during the refining process. Included are products known as ASTM grades Nos. 1 and 2 heating oils, diesel fuels, and No. 4 fuel oil. The major uses of distillate fuel oils including heating, fuel for on- and off-highway diesel engines, and railroad diesel fuel. Minor quantities of distillate fuel oils produced and/or held as stocks at natural gas processing plants are not included in this series.

Elasticity - A measure of the percentage impact of a change in one economic variable on another. Own elasticity measures the percentage change in the quantity of a product demanded with respect to a change in the same product's price. Cross elasticity measures the percentage change in one product's quantity with respect to a change in some other product's price.

Energy consumption - The amount of energy consumed in the form in which it is acquired by the user. The term excludes electrical generation and distribution losses. Also called net energy consumption.

Enhanced recovery - (enhanced oil recovery) - Increased recovery of crude oil (and natural gas in the case of enhanced gas recovery) from a reservoir, which is achieved by the external application of physical or chemical processes that supplement naturally occurring or simple fluid injection processes.

Equilibrating mechanism - The component of PIES that contains the algorithm to find a price vector resulting in supply equalling demand. It also models regulatory effects during the execution of the algorithm.

Feedstock - A raw material. For example, petroleum distillates used for producing petrochemicals are referred to as petrochemical feedstocks.

F.O.B. - An abbreviation for free on board, i.e., the price of fuel loaded prior to transit.

Heat rate - A measure of plant efficiency: the energy input required to generate one kilowatt-hour of electricity. The ratio of heat rate to per unit heat content gives the amount of fuel (in standard physical units) needed to generate one kilowatt-hour of electricity.

High sulfur coal - In PIES coal with sulfur content of greater than 1.68 pounds of sulfur per million Btu is considered high sulfur coal.

Integrated supply network - The set of PIES submodels dealing with supply, conversion, and transportation activities.

Integrating model - A subset of PIES components, which include raw data, the integrated supply submodels, the standard tables, the equilibrating mechanism, the REVISE routine, report writers, and the demand files, which are output from the Demand Model. It does not include satellite models.

Interstate gas - Natural gas which enters interstate commerce and hence is subject to Federal price controls. Natural gas sold to pipelines under the jurisdiction of the FERC (Federal Energy Regulatory Commission).

Intrastate gas - Natural gas which is both produced and consumed within the same state. It is not subject to Federal (FERC) price controls.

Jet Fuel - Includes both naphtha-type and kerosene-type fuels meeting standards for use in aircraft turbine engines. Although most jet fuel is used in aircraft, some is used for other purposes, such as for generating electricity in gas turbines.

Lignite - A low Btu brownish coal. Significant amounts can be found in Texas and North Dakota.

Links - A connection between an origin and destination along which movement of an energy material is defined. A link contains information on origin, destination, transport mode, and cost.

Liquefied natural gas - Natural gas which has been cooled to about - 160°C for storage or shipment as a liquid in high pressure cryogenic containers.

Load factor - A measure of variation in electric utility system demands. Specifically, it is the ratio of the system average demand to the highest or "peak" system demand.

Load management - Techniques applied to electric utility customers to improve the utility's load factor.

Low sulfur coal - In PIES coal with a sulfur content of less than 0.67 pounds of sulfur per million Btu is considered to be low sulfur coal.

Metallurgical coal - Coal used to produce metallurgical coke, a primary input in the production of steel. Such coal is characterized by high Btu content, low sulfur and low ash content and high volatility. In PIES, metallurgical coal is a distinct product.

Mode - Facilities for transporting energy fuels by rail, barge, pipeline, tanker, transmission lines and nuclear transport.

Natural gas, associated-dissolved - Gas occurring in the form of a gas cap associated with an oil depositor in solution with the oil.

Natural gas liquids - Those portions of reservoir gas heavier than methane which are liquefied at the surface. Includes ethanes, propanes, butanes, pentanes, and natural gasoline.

Natural gas, nonassociated - Free gas not in contact with crude oil in a reservoir.

Naval Petroleum Reserves (NPR) - Federally owned petroleum reserves in California (NPR-1, 2), Wyoming (NPR-3), Utah, Colorado, and Alaska (NPR-4). Most of current and projected production comes from NPR-1, Elk Hills. Management of the reserves was recently transferred from the Navy to DOE and, in the case of Alaska, to the Department of the Interior.

Network - A collection of links.

Nuclear fuel cycle - The generic term for all stages of nuclear fuel processing from uranium exploration through radioactive waste disposal.

Nuclear fuel reprocessing - The chemical separation of spent (used) nuclear fuel into salvageable fuel material and radioactive waste.

"Off peak" - A period of the day specified under a time of day electricity pricing scheme where usually cheaper rates are charged for electricity.

PIES - (Project Independence Evaluation System) A system composed of satellite models, supply submodels, a demand model, an equilibrating mechanism, report writers, a series of data tables, called raw data and standard tables.

Preprocessors - Computer routines which process raw data into standard table format.

Price tier - The tiers refer to classes of crude oil production established for pricing purposes.

(i) Third tier - New discoveries after April 20, 1977, as proposed in the National Energy Plan, which are a specified distance and depth from previous wells.
(ii) Lower tier - Under EPCA (Energy Production and Conservation Act) provisions, refers to quantities of oil under production in a pre-embargo base period.
(iii) Upper tier - Oil produced in excess of the lower tier base quantity, but not a new discovery.
(iv) Incremental tertiary - Incremental oil produced using tertiary methods after April 20, 1977.
(v) Naval Petroleum Reserves - Oil production from Naval Petroleum Reserves.
(vi) Stripper - Oil produced from wells producing under 10 barrels per day.
(vii) North Slope - Oil produced from the Prudhoe Bay field on the North Slope of Alaska.

Production function - A mathematical relationship between inputs of the factors of production (labor, capital, etc.) and output.

Projection Series - The combination of demand and supply scenarios used by EIA to conditionally project equilibrium energy levels for the target years.

Prudhoe Bay Field - The reservoirs located in Alaska's North Slope, proved in 1970, and currently in production. This includes reserves of 9.6 billion barrels of oil and 26 Tcf of associated-dissolved gas.

Pumped Storage - Hydroelectric facilities with two reservoirs. Excess off-peak electricity is used to pump water from the lower to higher reservoir from which it is later released to generate peak load electricity.

Quad - Quadrillion Btu (10^{15} Btu).

Raw data - The inputs into the integrated supply submodels. They are either outputs of the satellite models or data obtained from outside sources.

Real income - Current dollar income corrected for price level changes relative to some base period as measured by a suitable price index, or the Implicit GNP Deflator. Also termed "constant dollar" income.

Refiner acquisition cost - The cost to the refiner, including transportation and fees, of crude oil. The composite cost is the average of domestic and imported crude costs and represents the amount of crude cost which refiners may pass on to their customers.

Refinery gate - The point at which oil or natural gas enters or leaves refinery facilities via pipeline, ship, truck, rail, or other transport mode.

Report writers - Computer programs which produce output reports - for example, in PIES, the PIES Integrating Model Report (WONDERCOOKIE)[1], the Capital Report, the Transportation Report.

Reserves - Identified deposits of minerals known to be recoverable with current technology under present economic conditions.

Categories of reserves are:

- Measured Reserves (or Proved Reserves): Identified sources from which an energy commodity can be economically extracted with existing technology, and whose location, quality, and quantity are known on the basis of geologic evidence supported by engineering evidence.

- Indicated Reserves: Reserves that include additional recoveries in known reservoirs (in excess of the measured reserves) which engineering knowledge and judgment indicate will be economically available by application of fluid injection, whether or not such a program is currently installed (API, 1974).

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[1] The PIES Integrating Model Report is known informally as "WONDERCOOKIE" or "COOKIE."

- Inferred Reserves: Reserves based on broad geological knowledge for which quantitative measurements are not available. Such reserves are estimated to be recoverable in future years as a result of extensions, revisions, and additional drilling in known fields.

- Extensions: Reserves credited to a reservoir because of enlargement of its proved area, generally due to additional drilling activity.

- Revisions: Changes in earlier proved reserve estimates, either upward or downward, resulting from new information, not necessarily from additional drilling.

Residual fuel oil - The heavier oils that remain after the distillate fuel oils and lighter hydrocarbons are boiled off in refinery operations. Included are products known as ASTM grades Nos. 5 and 6 oil, heavy diesel oil, Navy Special Oil, Bunker C oil, and acid sludge and pitch used as refinery fuels. Residual fuel oil is used for the production of electric power, for heating and for various industrial purposes.

Resources - Concentrations of naturally occurring solid, liquid, or gaseous materials in or on the earth's crust in such form that economic extraction of a commodity is currently or potentially feasible.

REVISE routine - A computer routine that provides a means to change values in the PIES linear programming matrix without rerunning any PIES submodels, or the matrix generator.

Routes - A series of interconnected links from origin to final destination.

Satellite models - Models that produce raw data, which are fed into PIES submodels. Examples of PIES satellite models are the National Coal Supply Model and the RPMS Refinery Model.

Scenarios - A set of assumptions used in making energy supply and demand forecasts.

Scrubber - Equipment used to remove sulfur from flue gas emissions.

Seam - A layer of mineral matter, for example, coal seams.

Seasonal peak - Component of demand for electricity at levels above daily peak that occur during extreme weather conditions (winter heating, summer cooling).

Standard tables - Data tables in units needed for the linear programming matrix. They are outputs of the preprocessors and are in standard formats.

Strip mining - One of the two principal methods for mining coal. Materials above the coal bed (overburden) are removed to expose the coal.

Sub-bituminous coal - Coal with a heat content of about 18 million Btu/ton.

Supply submodels - Submodels relating to each component of the integrated supply network - oil, natural gas, coal, nuclear, synthetics, geothermal and solar, refineries, utilities, and transportation. They process raw data into standard table format and model special features of the energy area. (The computer routines which process the raw data into standard table format are called preprocessors.)

Synthetic natural gas - Gas manufactured from coal, petroleum, or biological waste that can be interchanged with pipeline quality gas.

System capacity factor - The fraction of electricity generated relative to that possible if all plants are run continuously.

Tertiary recovery - (See Enhanced recovery).

TRENDLONG - A Data Resources, Inc. macroeconomic projection as of September 1977 of relatively moderate GNP growth.

Wellhead - The point at which oil or natural gas is transferred from the well to pipeline or other nonwell facility. This term is used to refer to "wellhead price," which is the price received by the producers of oil, and natural gas.

APPENDIX B. THEORETICAL DEVELOPMENT OF THE INTEGRATING MODEL

INTRODUCTION

In this appendix, we present the mathematical theory underlying the functional description of the PIES Integrating Model presented in this volume. This appendix addresses an overall problem of modeling a free market equilibrium between supply and demand and does not address the modeling of disturbances in the free market introduced by natural gas regulation, oil entitlements, taxes, etc., which is described in other chapters of this report.

The basic algorithm used in PIES was given in Chapter II. The purpose of this appendix is to outline a theoretical basis for PIES, which is presented without proof. In the following sections, we explain how PIES obtains a solution to the multi-product economic equilibrium problem for energy. The problem of finding an equilibrium point is discussed and formulated as a sequence of non-linear mathematical programs, which is then translated into a sequence of LP problems. At the end of the appendix, we summarize the computational procedure.

A knowledge of linear programming and some background in mathematics and economics are required for understanding the material here.

THE PIES EQUILIBRIUM PROBLEM

In conventional economic terms, equilibrium occurs when the "price" at which consumers are willing to purchase products is equal to the "price" at which business is willing to supply them. Thus, if we let P^s and P^d be the price functions of supply and demand, respectively, and let Q be a vector of quantities representing m products, then equilibrium occurs when

$$P_i^s(Q) = P_i^d(Q)\,, \qquad\qquad i = 1, \ldots, m, \qquad\qquad (1)$$

where $P_i^s(Q)$ and $P_i^d(Q)$ represent the i^{th} component of $P^s(Q)$ and $P^d(Q)$, respectively.

In solving for an equilibrium point, PIES uses an LP formulation of the national energy economy. This LP formulation uses piecewise step function approximations to the supply and demand curves, representing a network of resources, energy conversion technologies, transportation technologies, and final demands. With these supply and demand curves, we can obtain a solution to a series of LP problems which gives prices and quantities. We will expand on the PIES procedure for calculating an approximation to an equilibrium point by discussing first the supply and demand formulations and then the general equilibrium problem, resulting finally in an LP formulation.

The Demand Side

The demand side of PIES is represented by a log-linear demand function $P^d(Q) = (P_1^d(Q), \ldots, P_m^d(Q))$ written in inverse form as follows:

$$Q_i = k_i \prod_{j=1}^{m} (P_j^d)^{\epsilon_{ij}} \qquad\qquad (2)$$

where

Q_i = the demand for the i^{th} product

P_j^d = the price of the j^{th} product

ϵ_{ij} = elasticity of demand for the i^{th} product with respect to the j^{th} product

k_i = a constant dependent on product i.

In order to solve for the constants, k_i, an initial point (Q_{0i}, P_{0i}) and the associated elasticities are obtained from the demand model for each product. Substituting these values into (2), we get

$$Q_{0i} = k_i \prod_{j=1}^{m} \left(P_{0j}^d\right)^{\epsilon_{ij}} .$$

Dividing (2) by this equation, we obtain

$$\frac{Q_i}{Q_{0i}} = \prod_{j=1}^{m} \left(\frac{P_j^d}{P_{0j}^d} \right)^{\epsilon_{ij}} . \tag{3}$$

The approximations to (3) and the LP formulation of demand used in PIES to obtain an algorithm for calculating an equilibrium point are explained below under "Equilibration by Successive Non-Linear Programming Approximations" and "Linear Programming Approximations."

The Supply Side

In order to accommodate the structure of an LP model, the supply side is modeled as a step function. The production levels of resources, the capacities of refineries and utilities, and the transportation of products between regions are represented by linear inequalities which in matrix notation can be written as

$$A_1X \leq b. \tag{4}$$

X denotes the vector of activities in the energy system, b represents the vector of capacity limitations, and A_1 is a matrix of technology coefficients.

Additional constraints are added to make the supply activities equal the demands, Q, for energy products. Expressing this requirement in matrix notation, we get

$$A_2X = Q\ . \tag{5}$$

Now, assuming that the supplier wants to minimize cost subject to (4) and (5), and letting h(Q) represent the total cost to the supplier of producing quantity Q, the supply side in PIES is modeled by the following LP

$$\begin{aligned} h(Q) &= \min CX \\ \text{s.t. } A_1X &\leq b \\ A_2X &= Q \\ X &\geq 0 \end{aligned} \tag{6}$$

where the row vector C denotes the unit cost of each activity.[1]

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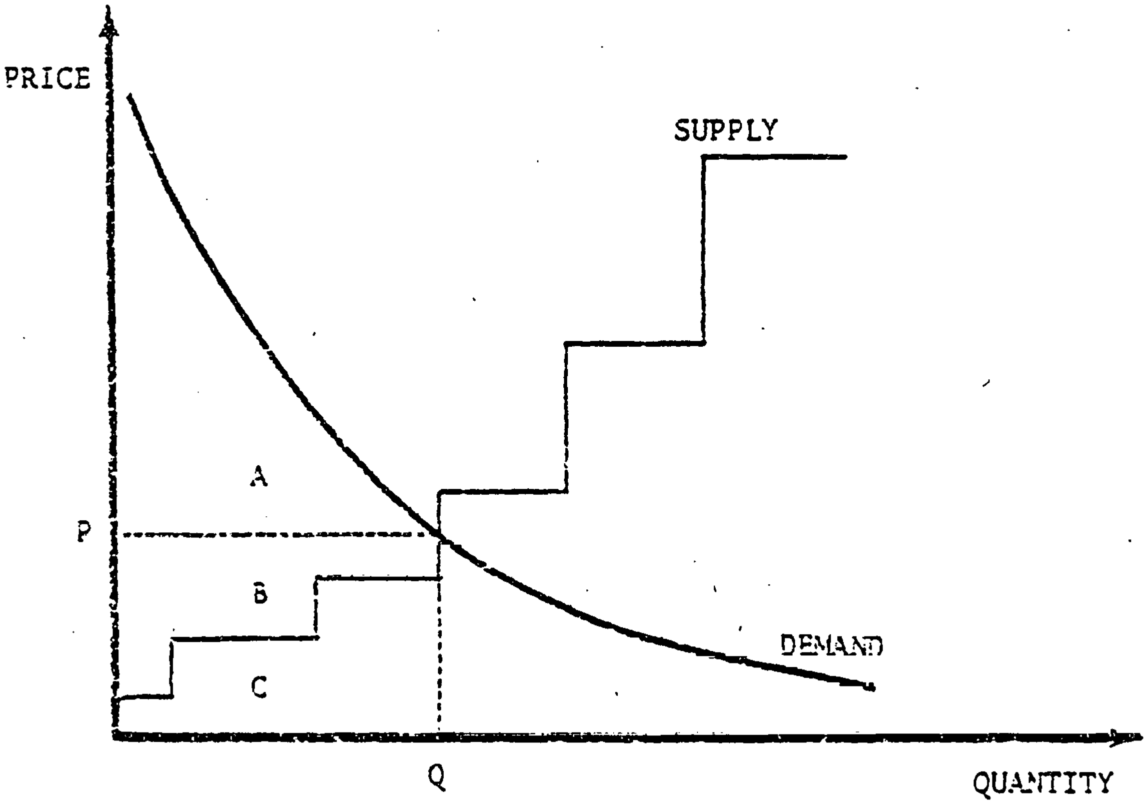
[1] The notation s.t. means "subject to."

For the one-dimensional (one-product) case, Figure B-1 displays the supply curve as a "step function." Notice that the supply function $P^S(Q)$ is really a point-to-set mapping. Along the vertical parts of the supply curve, there exists a set of prices which correspond to this supply.

FIGURE B-1. CONSUMERS' AND PRODUCERS' SURPLUS



AREA A: Consumers' Surplus
AREA B: Producers' Surplus
AREA C: Total Cost to the Producer

In the next section, we show how this formulation of supply is applied to the solution of the general equilibrium problem.

Solution of the General Equilibrium Problem

The approach used in PIES to solve (1) is the maximization of consumers' and producers' surplus. 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. Figure B-1 depicts consumers' and producers' surplus in the one-dimensional case.

Consider the following problem:

$$\max_{Q} T(Q) \tag{7}$$

where

$$T(Q) = g(Q) - f(Q),$$

$$f(Q) = \int_0^Q P^s(q) \cdot dq$$

$$g(Q) = \int_0^Q P^d(q) \cdot dq .$$

In the above expressions for f(Q) and g(Q), the dot denotes an inner product and the integral is a line integral in m-space, where the dependence on path is indicated below. The function T(Q) represents the sum of consumers' and producers' surplus in the energy system. Now, if the matrices of partial derivatives of P^s and P^d are symmetric; i.e., if ∇P^d and ∇P^s are symmetric, then the above line integrals are independent of the path chosen (see (1)). Furthermore, if the line integrals are independent of path and $\nabla P^d - \nabla P^s$ is negative semi-definite, then a solution of (7) is also a solution of (1) and vice versa (see (2)).

In the one-dimensional case ($m = 1$) or under the assumption that the cross-elasticities are zero, the matrix of partial derivatives is symmetric and thus problem (7) is equivalent to problem (1). In the one-dimensional case, a stationary point of T(Q) (a point where $\frac{dT(Q)}{dQ} = 0$) is a solution to (1). If we assume that the demand function P_1^d is a monotonic non-increasing function and the supply function P_1^s is a monotonic non-decreasing function, then, in fact, we have a maximum of T(Q). By examining $\frac{dT(Q)}{dQ} = P_1^d - P_1^s$, under these assumptions for P_1^d and P_1^s, we see that $\frac{dT(Q)}{dQ}$ is initially positive, decreases until it reaches the equilibrium point, at which time it is zero and then becomes increasingly negative. Thus, examination of the slope of T(Q) indicates that T(Q) is concave, and a solution to

$$\max_{Q} T(Q) \tag{8}$$

is also a solution to (1).

In the m-dimensional (multi-product) case, assume that the cross elasticities are zero. Consider

$$g(Q) = \int_0^Q P^d(q) \cdot dq. \tag{9}$$

If the cross elasticities are zero, then each P_i^d, (i=1, . . ., m), is a function only of Q_i, that is

$$P_i^d(Q) = \hat{P}_i^d(Q_i) . \tag{10}$$

Using (10),

$$g(Q) = \sum_{i=1}^{m} \int_0^{Q_i} \hat{P}_i^d (q_i)\, dq_i . \tag{11}$$

For simplicity of notation, we will write $\hat{P}_i^d(Q_i)$ as $P_i^d(Q_i)$ throughout the remainder of this appendix.

Continuing with the assumption of zero cross elasticities we will expand (8) by using (6), (7), and (11). That is, we want to expand:

$$\max_{Q} T(Q) = \max_{Q} \left[g(Q) - f(Q) \right] . \tag{12}$$

Under the assumption of zero cross elasticities, f(Q) represents the sum of the areas under the supply price function for each product. Under certain assumptions this total area is the total cost to the supplier represented by h(Q) in (6). Certain economic conditions are implied by the form of the supply curve: the cost to the supplier includes normal profit, and firms produce efficiently and maximize profits. If we assume a continuous supply curve and the additional economic conditions that fixed costs are zero and total cost increases at a non-decreasing rate,[2] f(Q) and h(Q) are equivalent. Since PIES treats fixed costs as either sunk or variable costs and assumes all the other economic conditions above, we can replace f(Q) by h(Q) in (12).

By substituting (6) for f(Q), expression (12) becomes

$$\max_{Q} \left\{ g(Q) - \left(\begin{array}{l} \min_{X} CX \\ \text{s.t.} \quad A_1X \leq b \\ \qquad\quad A_2X = Q \\ \qquad\qquad X \geq 0 \end{array} \right) \right\}$$

Since max T(Q) = min (-T(Q)), we obtain

$$\min_{Q} \left\{ \left\{ \begin{array}{l} \min_{X} CX \\ \text{s.t.} \quad A_1X \leq b \\ \qquad\quad A_2X = Q \\ \qquad\qquad X \geq 0 \end{array} \right\} -g(Q) \right\} ,$$

which is equivalent to

$$\min_{X,Q} \left\{ \begin{array}{l} CX - g(Q) \\ \text{s.t.} \quad A_1X \leq b \\ \qquad\quad A_2X = Q \\ \qquad\qquad X \geq 0 \end{array} \right\} . \tag{13}$$

Substituting (11) for g(Q) into (13) we get

$$\min_{X,Q} \left\{ \begin{array}{l} CX - \sum_{i=1}^{m} \int_{0}^{Q_i} P_i^d (q_i)\, dq_i \\ \text{s.t.} \qquad A_1X \leq b \\ \qquad\qquad A_2X = Q \\ \qquad\qquad\quad X \geq 0 \end{array} \right\} . \tag{14}$$

At this point, given the above assumptions (in particular, that the cross elasticities are zero), the equilibrium problem is equivalent to a single non-linear programming

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[2] If marginal cost is greater than average cost, total cost will increase at a non-decreasing rate.

problem. In the next section, we discuss the approximations to the demand function (as represented by (2)) that PIES uses.

EQUILIBRATION BY SUCCESSIVE NON-LINEAR PROGRAMMING APPROXIMATIONS

Given that we can obtain an expression for P_i^d, $(i = 1, \ldots, m)$, we can solve (1) by using a non-linear program (NLP), as expressed in (14). This procedure will be outlined subsequently, but first we will discuss the approximations used in PIES to obtain an expression for P_i^d consistent with the assumption of zero cross elasticities.

The demand function was given in (2) in inverse form. Given a point on the demand curve, we obtain (3). Two different approximations to (3) have been used in PIES. We will denote the approximation function to (3) by the following form

$$\hat{Q}_i = \hat{k}_i (P_i^d)^{\hat{\epsilon}} ,$$

where Q_i is an approximation for Q_i.

One approximation previously used in PIES is

$$\hat{Q}_i = Q_{0i} \left\{ \frac{P_i^d}{P_{0i}^d} \right\}^{\epsilon_{ii}} \tag{15}$$

In this case, since $\epsilon = \epsilon_{ii}$, $\hat{Q}_i = Q_i$, provided $P_j^d = P_{0j}^d$, for all $j \neq i$ (that is, when $\epsilon_{ij} = 0$ for $j \neq i$). We can express (15) in equivalent form by using logarithms. This latter form, which is used in the PIES computer program, is

$$\ln Q_i = B_i + \epsilon_{ii} \ln P_i^d ,$$

where

$$B_i = \ln Q_{0i} - \epsilon_{ii} \ln P_{0i}^d$$

or

$$Q_i = \exp \left[B_i + \epsilon_{ii} \ln P_i^d \right] .$$

Another approximation, and the one presently used in PIES, is

$$\hat{Q}_i = Q_{0i}\left(\frac{P_i^d}{P_{0i}^d}\right)^{\left(\sum_{j=1}^{m} \epsilon_{ij}\right)} . \qquad (16)$$

In this case, with $\hat{\epsilon} = \sum_{j=1}^{m} \epsilon_{ij}$, $\hat{Q}_i$ will equal Q_i provided that

$$\frac{P_j^d}{P_{0j}^d} = \frac{P_i^d}{P_{0i}^d}$$

for all i and j. That is, in the case that these ratios of prices are equal for all products, (3) and (16) are identical.

In this case, expressing (16) in log form, we have

$$\ln Q_i = S_i + \left(\sum_{j=1}^{m} \epsilon_{ij}\right) \ln P_i^d ,$$

where

$$S_i = \ln Q_{0i} - \left(\sum_{j=1}^{m} \epsilon_{ij}\right) \ln P_{0i}^d$$

or

$$Q_i = \left[\exp S_i + \left(\sum_{j=1}^{m} \epsilon_{ij}\right) \ln P_i^d\right] .$$

In the case that approximations (15) or (16) are exact, the demand function represented by (2) can be used in the algorithm. The log form is as follows

$$\ln Q_i = A_i + \sum_{j=1}^{m} \epsilon_{ij} \ln P_{ij}^d ,$$

where

$$A_i = \ln Q_{0i} - \sum_{j=1}^{m} \epsilon_{ij} \ln P_{0j}^d .$$

Thus, $$Q_i = \exp\left[A_i + \sum_{j=1}^{m} \epsilon_{ij} \ln P_{ij}^d\right].$$

We can make the following observations about both approximations. First, $\hat{Q} = (\hat{Q}_1, \ldots, \hat{Q}_m)$ is a function of both $P^d = (P_1^d, \ldots, P_m^d)$ and $P_0^d = (P_{01}^d, \ldots, P_{0m}^d)$, and $Q = Q_0$ if $P^d = P_0^d$. Therefore, if $P^d = P_0^d$, the demand approximation is exact. Thus by continuity, we expect the demand approximation to be good for P^d close to P_0^d.

We can express both approximations (15) and (16) as functions of $P^d(Q)$. Doing so, (15) becomes

$$\hat{P}_i^d = P_{0i}^d \left(\frac{Q_i}{Q_{0i}}\right)^{\frac{1}{\epsilon_{ii}}} \tag{17}$$

and (16) becomes

$$\hat{P}_i^d = P_{0i}^d \left(\frac{Q_i}{Q_{0i}}\right)^{\left(\sum_{j=1}^{m} \epsilon_{ij}\right)^{-1}} \tag{18}$$

Now, using either (17) or (18), we can solve (14) by the following equilibration procedure, which uses an NLP.

(1) Choose a set of initial demands $Q^{(0)}$ and let the iteration counter t = 0.

(2) Use $Q^{(t)}$ to calculate $P^t = P(Q^{(t)})$ by using either (17) or (18) and solve (14) for $Q^{(t+1)}$.

(3) If $Q^{(t+1)} = Q^{(t)}$, stop. If not, set t = t + 1, and return to (2).

This problem can also be solved by using either approximations (15) or (16) and solving the dual form of (14). The procedure, similar to the one above, is as follows:

(1) Choose a set of initial demand prices $P^{(0)}$ and let the iteration counter t = 0.

(2) Use $P^{(t)}$ to calculate $Q^{(t)} = Q(P^{(t)})$ by using either (15) or (16) and obtain an approximate solution, $\hat{P}^d(Q)$, to the equilibrium problem $P^d(Q) \epsilon P^s(Q)$ using the dual to (14).[3] Set $P^{(t+1)} = \pi$, the dual variables corresponding to the subsystem of equalities $A_2X = Q$.

(3) If $P^{(t+1)} = P^{(t)}$, stop. If not, set t = t + 1 and return to (2).

Notice that whether we are solving the dual or the primal problem, the procedure is iterative. The intent is for this algorithm to converge to an equilibrium point. If the prices from two successive iterations are equal, i.e., if $P^{(t+1)} = P^{(t)}$, then we have an exact solution to $P^d(Q) \epsilon P^s(Q)$. However, PIES uses a tolerance limit as a convergence criterion, so that only an approximate solution is obtained. This convergence criterion is stated in the last section of this appendix.

Observe also that the price estimate $P^{(t+1)} = \pi$ may be replaced by

$$P^{(t+1)} = \alpha\, \pi + (1 - \alpha)\, P^{(t)}.$$

PIES currently uses the value $\alpha = \frac{1}{2}$, as indicated by the computational procedure stated in the last section of this appendix.

We now have a computational procedure for finding an approximation to the equilibrium point using an NLP. However, since PIES does not use an NLP, we will approximate (14) by an LP. This approximation is discussed in the next section.

LINEAR PROGRAMMING APPROXIMATIONS

Although we have modeled f(Q) by an LP, (14) is not amenable to linear programming. Thus, it is desirable to try to approximate the integral in (14). Since the constraints in (14) are linear and since ∇P^d is negative definite,[4] it can be shown (using results from the LP) that (14) is convex and, therefore we can make the following approximation to (14). Throughout, we will continue to let i indicate the product type.

First, we introduce a change of variables. The reason for this step will become clear as we proceed with this section. Let (Q_{0i}, P_{0i}) be an initial estimate of a point on the

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[3] Throughout the remainder of this appendix, when an iteration counter notation is needed, the superscript "t" will denote it and the "d" denoting demand will be omitted on the demand price function.

[4] ∇P^d is negative definite if for any vector $X = 0$, $X^T \nabla P^d X < 0$. Since the diagonal elements of ∇P^d have the same sign as the own - price elasticities of demand and these elasticities are negative, ∇P^d is negative definite.

demand curve.[5] By introducing the change of variable $Y = Q - Q_0$, the origin of our coordinate system shifts from (0,0) to $(Q_0, 0)$. Using the substitution $Y_i = Q_i - Q_{0i}$, the integral term in (14) becomes

$$\sum_{i=1}^{m} \int_{0}^{Q_i} P_i^d (q_i)\, dq_i = \sum_{i=1}^{m} \int_{-Q_{0i}}^{Q_i - Q_{0i}} P_i^d (y_i + Q_{0i})\, dy_i$$

$$= \sum_{i-1}^{m} \int_{-Q_{0i}}^{0} P_i^d (y_i + Q_{0i})\, dy_i$$

$$+ \sum_{i=1}^{m} \int_{0}^{Q_i - Q_{0i}} P_i^d (y_i + Q_{0i})\, dy_i$$

$$= \theta + \sum_{i=1}^{m} \int_{0}^{Y_i} P_i^d (y_i + Q_{0i})\, dy_i \;,$$

where

$$\theta = \sum_{i=1}^{m} \int_{-Q_{0i}}^{0} P_i^d (y_i + Q_{0i})\, dy_i = \sum_{i=1}^{m} \int_{0}^{Q_{0i}} P_i^d (q_i)\, dq_i \;.$$

Since θ is a constant, it does not affect the solution. By deleting θ and substituting the above expression into (14), we obtain

$$\min_{X,Y} \quad CX - \sum_{i=1}^{m} \int_{0}^{Y_i} P_i^d (Q_{0i} + y_i)\, dy_i \tag{19}$$

$$\text{s.t.} \quad A_1 X \leq b$$

$$A_2 X - Y = Q_0$$

$$X \geq 0 \;.$$

---

[5] The point (Q_{0i}, P_{0i}) is either the initial estimate from the demand model or a new initial point calculated at each iteration of the equilibrating mechanism.

We next partition an interval centered about the point (Q_{0i}, P_{0i}) such that the increment at each interval is $U_{i,k}$, $k = -n, -n + 1, \ldots, -1, 1, \ldots, n-1, n$. This partition is depicted in Figure B-2 for product i. Notice that for $k = 1, 2, \ldots, n$,

$$P^d_{i,k} = P^d_i(Q_{0i} + \sum_{j=1}^{k} U_{i,j})$$

and

$$P^d_{i,-k} = P^d_i(Q_{0i} - \sum_{j=1}^{k} U_{i,-j}).$$

Now, consider the variables $Y_{i,k}$ and $Y_{i,-k}$ such that

$$0 \leq Y_{i,k} \leq U_{i,k} \tag{20}$$

$$0 \leq Y_{i,-k} \leq U_{i,-k}$$

and $Y = \sum_{k=1}^{n} Y_{i,k} - \sum_{k=1}^{n} Y_{i,-k}$. If $Y > 0$, then each $Y_{i,-k}$ is at its lower bound, zero; and, likewise, if $Y < 0$, then each $Y_{i,k}$ is equal to zero. If $Y=0$, then each $Y_{i,k}$ and each $Y_{i,-k}$ is equal to zero.

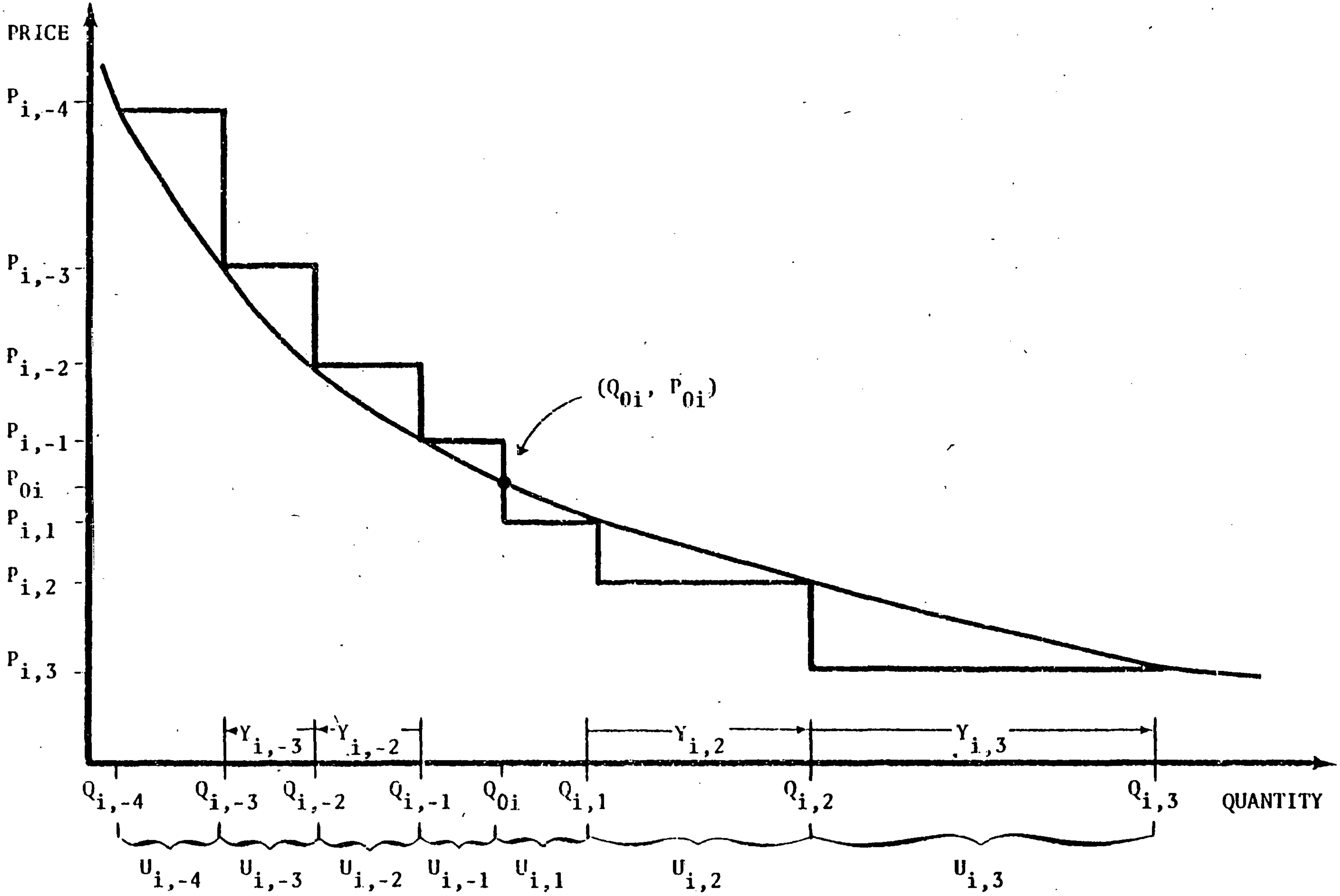
As previously mentioned, the substitution $Y_i = Q_i - Q_{0i}$ has translated the origin from 0 to Q_{0i}. We want to approximate the area under the demand curve either to the left or right of Q_{0i}. Assume for this discussion that we want to approximate the area to the right of Q_{0i} (i.e., $Y > 0$). In doing so, we will make use of the following three properties, which can be shown to always hold. (The analogous properties hold for $Y < 0$.)

(1) At most one $Y_{i,k}$ is not equal to zero or $U_{i,k}$.

(2) If $Y_{i,k}$ is not equal to one of its limits, then $Y_{i,j}$, for all $j < k$, is equal to its upper limit $U_{i,j}$ and $Y_{i,j}$, for all $j > k$, is equal to zero, its lower limit.

(3) If all $Y_{i,k}$ are equal to either their upper or lower limit, then there exists a k such that all $Y_{i,j}$ are equal to their upper limit for $j \leq k$ and all $Y_{i,j}$ are equal to their lower limit for $j > k$.

FIGURE B-2. APPROXIMATION OF THE DEMAND MODEL



$0 \leq Y_{i,k} \leq U_{i,k} \qquad 0 \leq Y_{i,-k} \leq U_{i,-k}$

Given $$Y = \sum_{k=1}^{n} (Y_{i,k} - Y_{i,-k}), \tag{21}$$

and assuming that we can assign values to each $Y_{i,k}$ such that the above conditions hold, we can approximate the integral in (19) as follows

$$\int_0^{Y_i} P_i^d (Q_{0i} + y_i) dy_i = \sum_{k=1}^{n} (P_{i,k}^d \; Y_{i,k} - P_{i,-k}^d \; Y_{i,-k}) \tag{22}$$

If $Y_{i,k}$ is zero for all k, then the above formulation approximates the area under the demand curve to the left of (Q_{0i}, P_{0i}). Thus, Y_i essentially represents the distance (here, quantity) either to the right or left of the initial point (Q_{0i}, P_{0i}) and we are integrating to that point. Also notice that, for Y_i negative, the integral is negative, and thus the need for the minus sign on the right hand side of the above approximation.

By substituting (21) and (22) into (19) and adding the constraints represented by (20), we get the following LP formulation. Let $Q_0 = (Q_{01}, \ldots, Q_{0m})$, let the m-dimensional vector $Y = Y_+ - Y_-$ where

$$Y_+ = \begin{pmatrix} \sum_{k=1}^{n} Y_{1,k} \\ \cdot \\ \cdot \\ \cdot \\ \sum_{k=1}^{n} Y_{m,k} \end{pmatrix} \quad \text{and } Y_- = \begin{pmatrix} \sum_{k=1}^{n} Y_{1,-k} \\ \cdot \\ \cdot \\ \cdot \\ \sum_{k=1}^{n} Y_{m,-k} \end{pmatrix},$$

and let U_+ and U_- be m-dimensional vectors which bound the components of Y_+ and Y_-, respectively. Then, we obtain

$$\min_{X, Y_{i,k}} \quad CX - \sum_{i=1}^{m} \sum_{k=1}^{n} (P_{i,k}^d \; Y_{i,k} - P_{i,-k}^d \; Y_{i,-k}) \tag{23}$$

$$\begin{aligned} \text{subject to } & A_1 X \leq b \\ & A_2 X - (Y_+ - Y_-) = Q_0 \\ & 0 \leq Y_+ \leq U_+ \\ & 0 < Y_- \leq U_- \\ & X \geq 0 \quad . \end{aligned}$$

At optimality, the three conditions listed above for $Y_{i,k}$ hold. To see why either all of the $Y_{i,k}$ are zero or all of the $Y_{i,-k}$ are zero (i.e., are not basic variables), we will consider the reduced cost, i.e., the row in the LP tableau that indicates which variable will enter the basis. The objective function in (23) indicates that as long as the constraints are not violated, $Y_{i,1}$ would enter the basis on the first iteration of the tableau since the coefficients of the $Y_{i,k}$ terms are negative and $-P_{i,1}$ is less than $-P_{i,k}$, k = 2, . . ., n. In fact, the reduced cost for $Y_{i,k}$ will always be of the opposite sign from the reduced cost for $Y_{i,-k}$. Suppose the marginal prices, i.e., the dual variables, associated with the second vector constraint are π_i. Then the reduced cost associated with $Y_{i,k}$ would be $-\pi_i + P_{i,k}$ and the reduced cost associated with $Y_{i,-k}$ would be $\pi_i - P_{i,-k}$. Now, if $-\pi_i + P_{i,k} > 0$ and since $P_{i,-k} - P_{i,k} > 0$, we obtain by adding these two inequalities, $-\pi_i + P_{i,-k} > 0$ or $+\pi_i - P_{i,-k} < 0$. Likewise, if $\pi_i - P_{i,-k} > 0$ and since $P_{i,-k} - P_{i,k} > 0$, we get, by adding $\pi_i - P_{i,k} > 0$ or $-\pi_i + P_{i,k} < 0$. Thus, the reduced cost of $Y_{i,k}$ is also of the opposite sign from the reduced cost of $Y_{i,-k}$. As a result, either $Y_{i,k}$ or $Y_{i,-k}$ must be zero for all positive k. Hence, $Y_{i,k}$. $Y_{i,-k} = 0$ for all k. Notice if we bring $Y_{i,k}$ into the basis, then the reduced cost will equal zero, i.e., $-\pi_i + P_{i,k} = 0$, which implies that $\pi_i = P_{i,k}$.

Due to the construction of the demand curve approximation, if $Y_{i,k}$ is activated, $Y_{i,k-1}$ must be at its upper bound, $U_{i,k-1}$, for all k > 1. It will always be more beneficial to bring in more of quantity $Y_{i,k-1}$ than to bring in any of $Y_{i,k}$ since the coefficient of $Y_{i,k}$ is negative and $P_{i,k} > P_{i,k+1}$ for all k greater than zero. Likewise, if $Y_{i,-k}$ is activated, $Y_{i,-k+1}$ must be at its upper bound, $U_{i,-k+1}$ for all k > 1. Since the coefficient of $Y_{i,-k}$ is positive and $P_{i,-k} < P_{i,-k-1}$ for all positive k, it is more beneficial to bring in more of $Y_{i,-k+1}$ than to bring in any of $Y_{i,-k}$. Thus, if $Y_{i,k}$ is in the basis, $Y_{i,k-1} = U_{i,k-1}$ and if $Y_{i,-k}$ is in the basis, $Y_{i,-k+1} = U_{i,-k+1}$, for all k > 1.

Summary

The quality of the estimate obtained for demand, whether (15) or (16) is used, depends upon the relative magnitude of the own- and cross-elasticities. In (15) the estimate is exact in the special case of zero cross-elasticities, and in (16) the estimate is exact if

$$\frac{P_j^d}{P_{0j}^d} = \frac{P_i^d}{P_{0i}^d} .$$

Given an initial estimate of demand and the demand curve approximation given by (15) or (16), we can solve (23) to obtain a level of supply activities and a set of prices at which supply will meet demand. By means of the demand curve approximation, this set of prices can produce a new set of demands, which can be used in (23). When the prices and hence the demands are the same between two successive iterations, equilibrium is attained. Thus, it seems reasonable that an iterative process, integrating supply and demand, could be used to converge to a solution of (1). If the initial estimate of demand is close to equilibrium, then a convergence criterion comparing successive iterations is appropriate.

The following computational procedure used in PIES solves for an approximate solution to (1) by a sequence of LPs.

Step 1

Choose a set of demand prices, P^t. Let $t = 1$.

Step 2

Calculate $Q^t = Q(P^t)$. Using elasticities and either approximation (15) or (16),[6] construct the demand curve relative to the point (Q^t, P^t).

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[6] The current version of PIES uses (16).

Step 3

Obtain (X^t, Y^t, π^t) as an optimal solution for the dual to (23). If either

$$\frac{|\pi^t - P^t|}{P^t} \leq .02, \text{ or } \frac{\left|Q(\frac{\pi^t + P^t}{2}) - Q^t\right|}{Q^t} \leq .02, \text{ or } t = 15,$$

go to step 4. Otherwise, let $P^{t+1} = \frac{P^t + \pi^t}{2}$, $t = t + 1$ and go to step 2.

Step 4

Terminate with equilibrium supply pattern X^t, consumptions Q^t, and market prices P^t.

This iterative procedure attempts to solve a fixed point problem. The convergence properties of this procedure with a general demand function have not yet been established.

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