The original documents are located in Box 7, folder: "National Energy Outlook - 1976" of the Frank Zarb Papers at the Gerald R. Ford Presidential Library.

Appendix A

PIES INTEGRATING MODEL

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I. INTRODUCTION

The Project Independence Evaluation System (PIES) forecasts the state of the energy system with a snapshot of the energy economy on an average day at the end of 5 to 15 year planning horizons. The system is composed of various models: a demand model, a collection of supply models, and an integrating model. The Integrating Model provides the framework for analysis and combines the outputs of the other models to estimate market clearing prices, supplies, and demands. This appendix highlights the basic components of the Integrating Model.

The model assumes a competitive economic structure with upward sloping supply curves and downward sloping demand curves. Within this framework, the model describes a static market equilibrium of the energy system. No attempt is made to endogenously forecast the trajectories by which this equilibrium is achieved; and the data are generated assuming a smooth transition to the end state. 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.

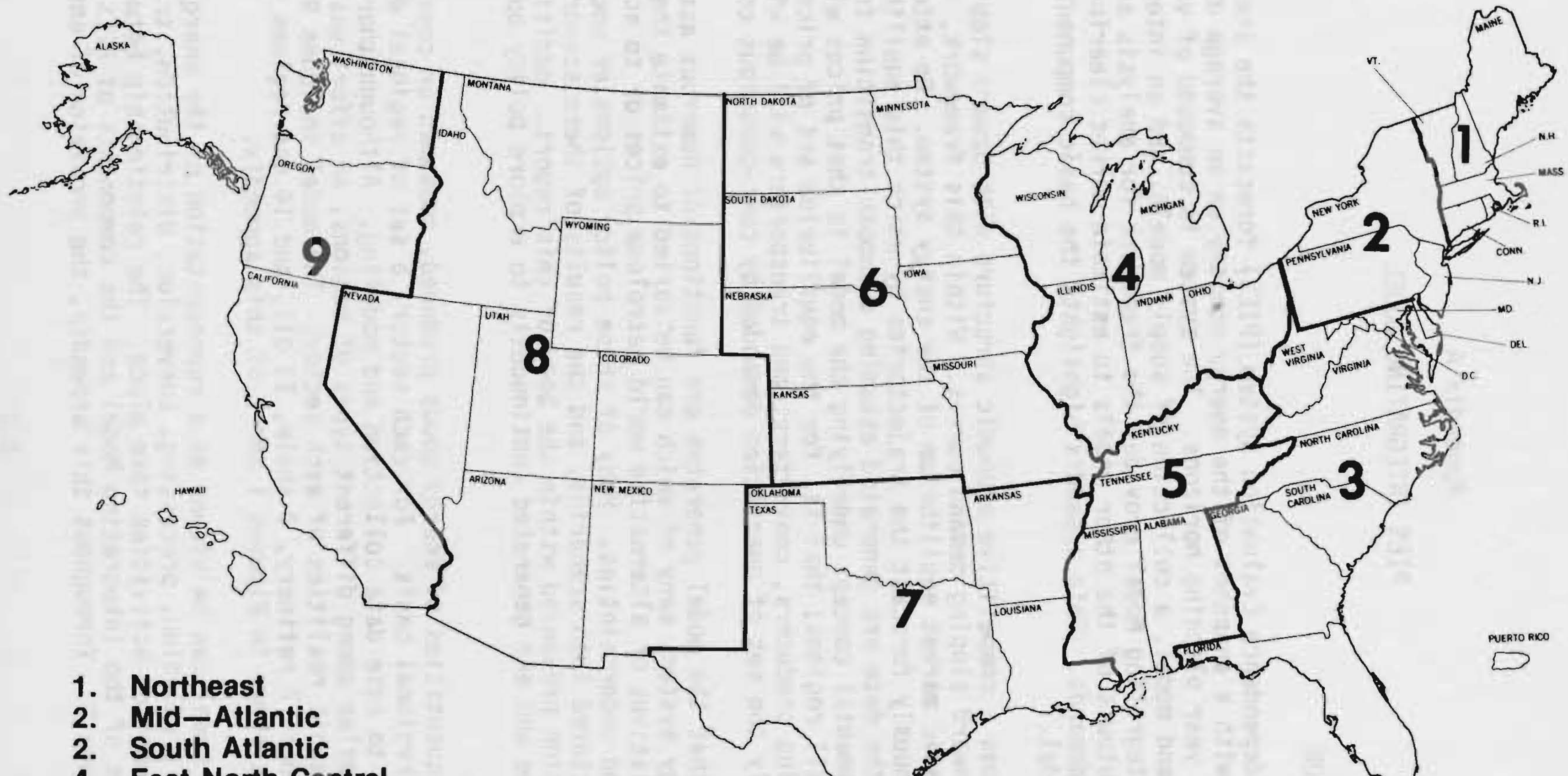
The forecasts that the model generates are functions of numerous assumptions about the energy system, many of which can be varied to estimate the impact of policy initiatives or alternative world petroleum prices or to account for supply or demand uncertainties. Many of these policy options or uncertainties have been structured into scenarios, and the results of these scenarios underlie the discussion presented within the body of this report. Additional scenarios can be and are generated continuously to explore policy options and uncertainties.

All prices and quantities of energy goods produced, consumed or converted are estimated on a regional basis. For each sector, a set of regional definitions was established to ease data collection and modeling. Although there is a considerable overlap among different types of regions, an effort was made to match the geographic realities of each sector. The model includes 9 demand, 9 utility, 12 coal, 7 refinery, 3 shale, 13 oil, and 14 gas regions in its present form, as shown in Figures 1 and 2 of this appendix.

The Integrating Model can be viewed as a representation of the energy system in which production, processing, conversion, distribution, transportation, and consumption activities take place. The relationship between these components of the Integrating Model and the components of PIES is depicted in Figure 3. Throughout this appendix, the provision of energy

Figure A-1

Electric Utility and Demand Regions

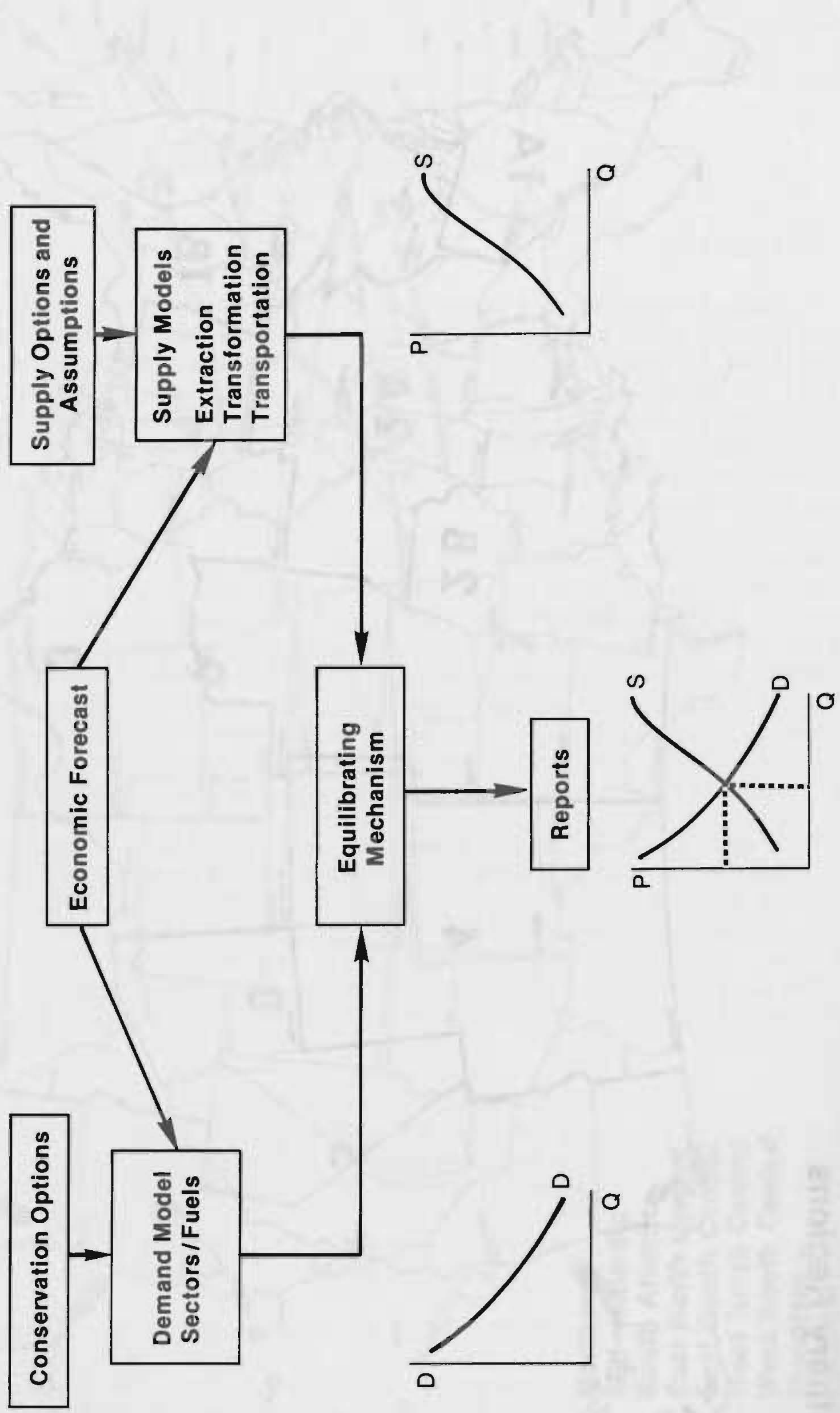


1. Northeast
2. Mid—Atlantic
2. South Atlantic
4. East North Central
5. East South Central
6. West North Central
7. West South Central
8. Mountain
9. Pacific

Figure A-2

Refinery Regions

Figure A-3
Integrating Model Framework



goods is referred to as the "supply side" of the model. The demand function approximation in the model is referred to as the "demand side" and the procedure for equating the supply side and the demand side is called the "equilibrating mechanism" of the integrating model.

For a competitive model, an equivalent supply side optimization problem is to provide consumers with prespecified quantities of end fuels at minimum cost. The mathematical equivalance between the competitive solution and the cost minimizing solution allows the use of optimization techniques to solve for the market equilibrium, and this property is exploited in the present system.

The supply side includes a set of activities that represents the flow of materials (crude oils, natural gas, electricity, coals, and refined petroleum products) from their source to a final destination. While there are many different materials which flow in the system, there are only eight final products consumed in demand regions: gasoline, distillate, residual, other petroleum, natural gas, steam coal, metallurgical coal, and electricity. The flow of materials in the system is depicted schematically in Figure 4. The generic structure of the supply side representation is illustrated in Figure 5.

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

The demand side uses a constant elasticity approximation to the demand model discussed in Appendix C. The precise specification of this approximation is discussed in section V of this appendix.

The Integrating Model operates as follows. A linear program which represents an interim approximation of the energy system is solved. The linear program includes representations of demand functions, supply functions, transportation activities, and energy conversion activities. The interim market clearing prices estimated by the linear program are used to refine the demand function approximation in order to re-solve the linear program. The process is repeated until the solution converges, determining an equilibrium of supply and demand quantities and prices.

The structure of the various approximations which comprise this model is outlined in this appendix. Sections II, III, and IV include descriptions of production and energy conversion activities and the intraregional transfer of fuels. A brief description of the supply/demand equilibrating mechanism is given in section V. In section VI, there is a discussion of the special procedures for approximating average cost pricing and simple regulatory impacts. Finally, section VII develops the underlying theoretical structure of the integrating model formulation and solution.

Figure A-4
Flow of Materials

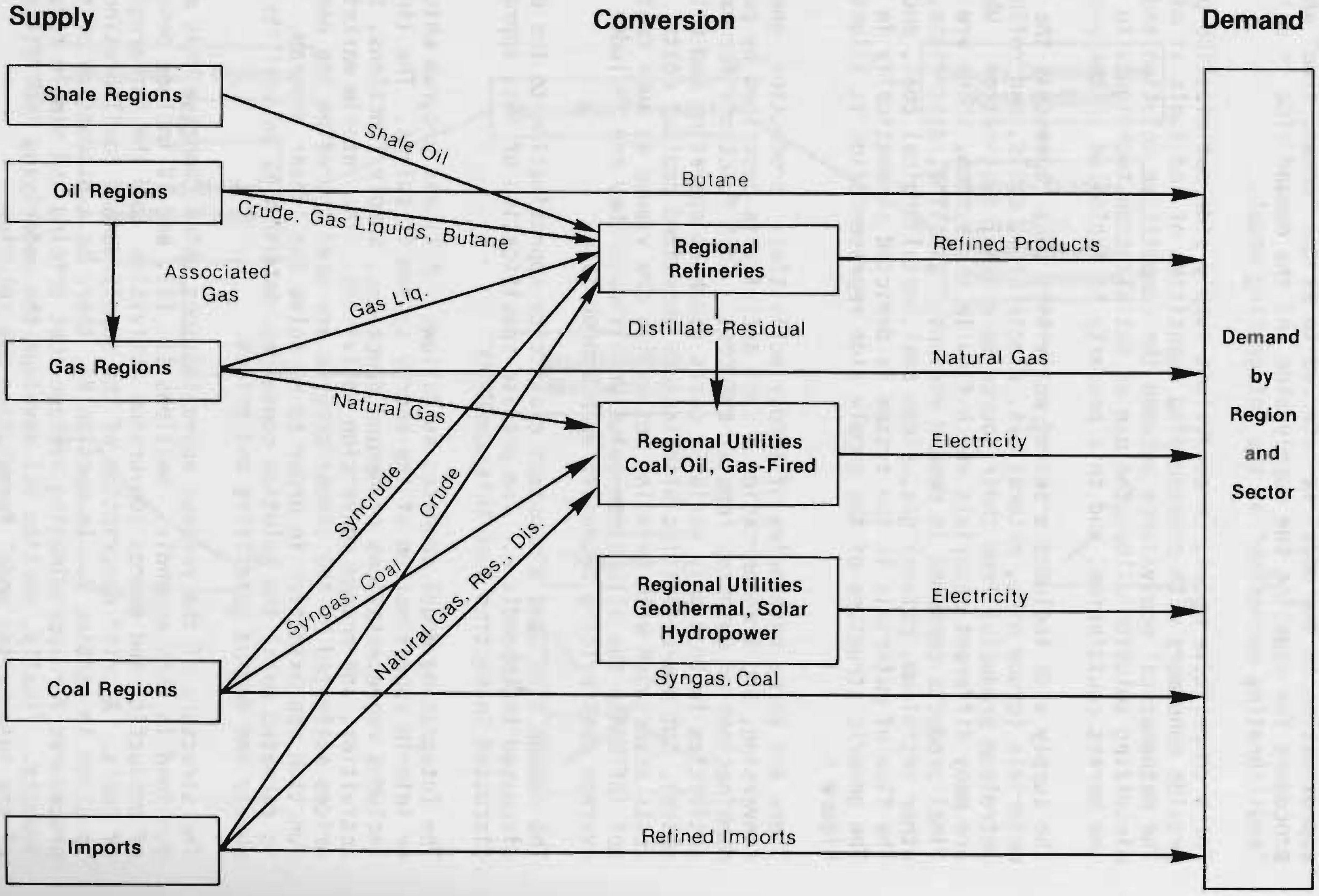


Figure A-5
Supply Model Schematic

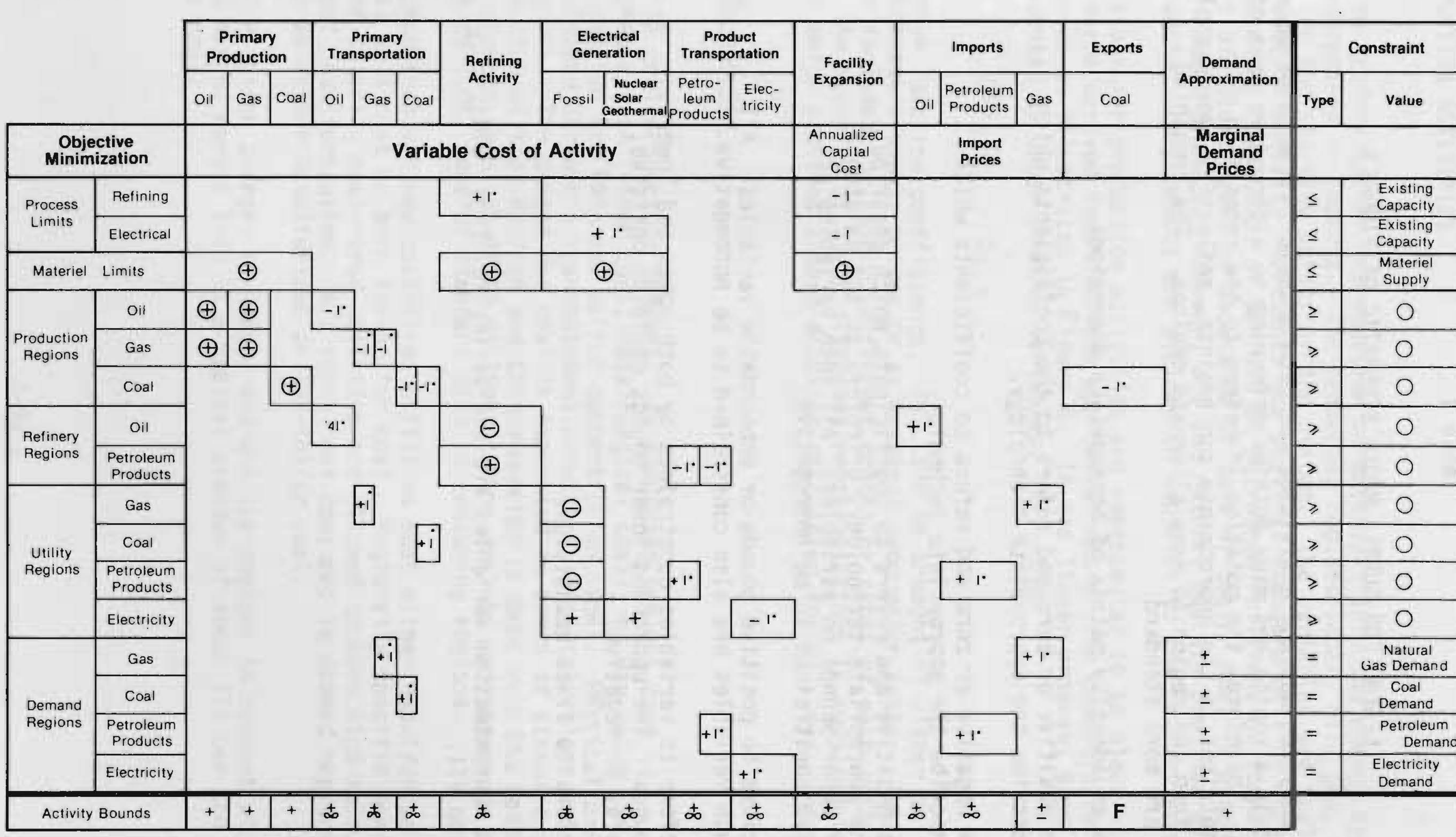


Table 1

LEGEND FOR SUPPLY MODEL SCHEMATIC OF FIGURE 5

There are many regions and activities for each material. A mass balance constraint in a region has many entries referring to alternative uses of a product. Therefore, the notation I* refers to the repetition of identity matrices in the appropriate constraints, reflecting, for example, shipments from one region to many alternate regions. The remaining notations are more standard:

- I is an identity matrix of appropriate dimensions.
- ⊕ is positive or zero and refers to the coefficients which describe the appropriate technology.
- ⊖ is negative or zero and refers to coefficients which describe the appropriate technology.
- \+ is positive and refers to coefficients which describe the appropriate technology, or refers to the existence of upper bounds on variables. All such variables are also constrained to be nonnegative.
- $\frac{+}{\infty}$ refers to positive bounds or unboundable variables. All such variables are also constrained to be nonnegative.
- ± refers to variables constrained by both upper and lower bounds. The upper and lower bounds could be positive, zero, or negative.
- F refers to fixed quantities.

The demand approximation variables are the variables $Y_{i,k}$ and $Y_{i,-k}$ from section VII.

II. PRODUCTION ACTIVITIES

Production refers to the introduction of materials into the energy system through extraction or imports. The producing regions (coal, oil, gas, and foreign) are the starting points of the system. The variables are scaled so that one unit of activity represents one physical standard unit of supply of primary material (thousands of barrels of petroleum, millions of standard cubic feet of natural gas, or thousands of tons of coal). Coal is produced as an individual product. However, oil and natural gas are produced as joint products: co-products are yielded in addition to the primary product.

Cost functions for production activities are represented to be piece-wise linear and are derived from discrete approximations of the competitive supply curves as illustrated in Figure 6. In the linear program, supplies are represented by upper-bounded variables, X_i; thus

$$0 \le X_i \le Q_i - Q_{i-1} .$$

The objective function coefficients, P_i, can be thought of either as minimum acceptable supply prices or as marginal production costs. These curves are included for several different grades or types of each primary material. An overview of these different representations is supplemented in Appendix D which provides a more detailed discussion for oil, gas, and coal.

Coal Supply and Use

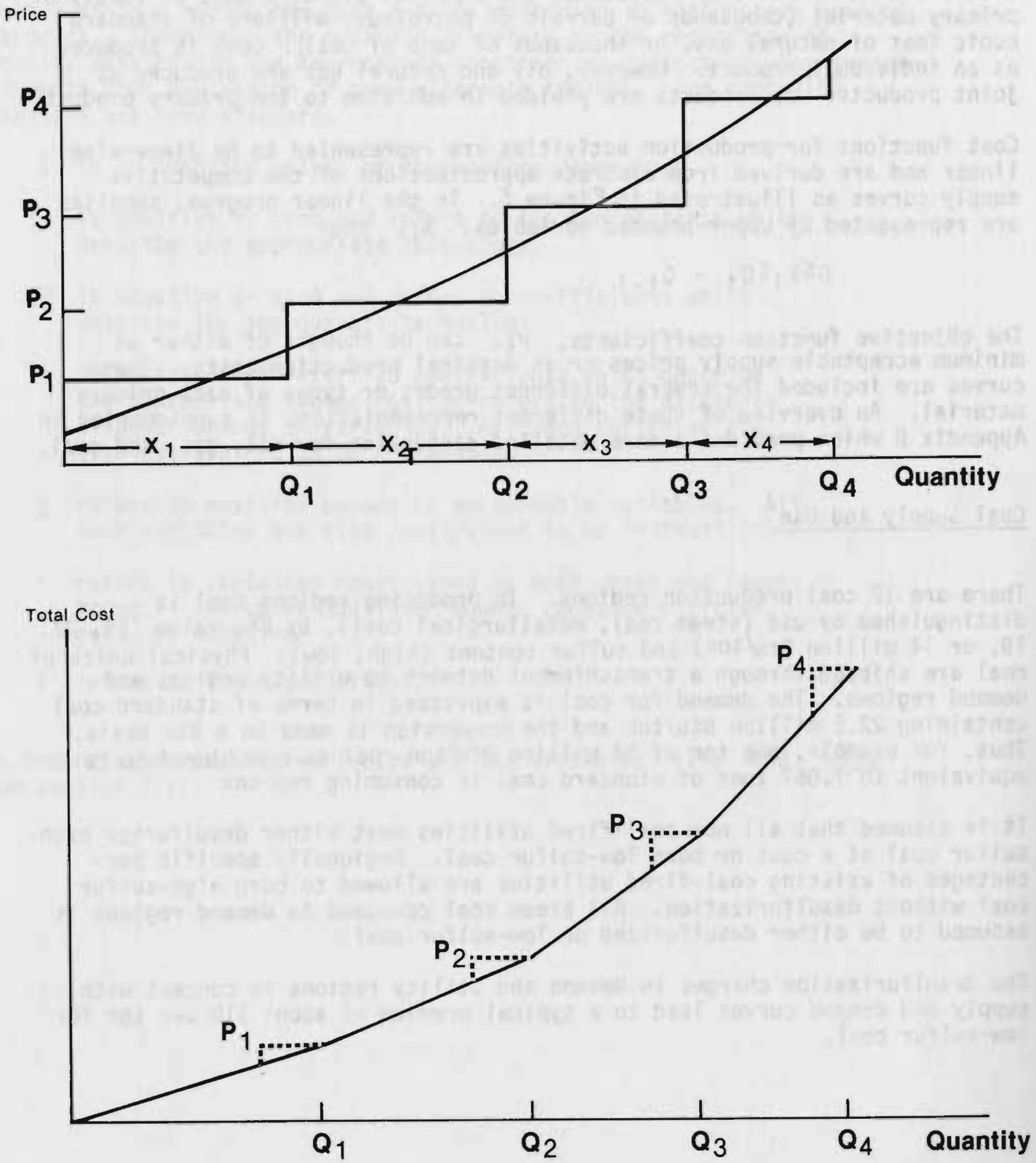
There are 12 coal production regions. In producing regions coal is distinguished by use (steam coal, metallurgical coal), by Btu value (24, 22, 19, or 14 million Btu/ton) and sulfur content (high, low). Physical units of coal are shipped through a transshipment network to utility regions and demand regions. The demand for coal is expressed in terms of standard coal containing 22.5 million Btu/ton and the conversion is made on a Btu basis. Thus, for example, one ton of 24 million Btu/ton coal is considered to be equivalent to 1.067 tons of standard coal in consuming regions.

It is assumed that all new coal-fired utilities must either desulfurize high-sulfur coal at a cost or burn low-sulfur coal. Regionally specific percentages of existing coal-fired utilities are allowed to burn high-sulfur coal without desulfurization. All steam coal consumed in demand regions is assumed to be either desulfurized or low-sulfur coal.

The desulfurization charges in demand and utility regions in concert with supply and demand curves lead to a typical premium of about $10 per ton for low-sulfur coal.

Figure A-6

Supply Functions Approximation and Resultant Cost Curves



Additional information regarding the source of each supply increment is also available (new or existing, high or low sulfur, strip mined, or deep mined, seam thickness). As a result, more than 750 coal supply increments are represented.

Oil Supply and Use

There are 13 oil producing regions. Crude oils (e.g., Wyoming mix) are classified by properties or attributes (e.g., sulfur content) in supply region data bases, but in the current implementation all crude oil, foreign and domestic, are pooled after shipment to refinery regions.

The oil supply curves stem from two sources. Supply curves from traditional domestic producing regions are generated by the FEA oil and gas supply model as described in a separate appendix. Supply curves for nontraditional sources, including the Naval Petroleum Reserve regions, Military Reserve regions, tar sands, heavy hydrocarbons, and shale summarize expert judgments and engineering analyses. A distinction between primary, secondary, and tertiary production is maintained in the supply regions and provides additional refinements for the supply curves.

Unlike coal, oil production includes a mix of co-products. The co-products in oil regions are associated natural gas, gas liquids, and butanes. In the model, crude oil, gas liquids, and butanes are shipped to refinery regions or integrated into the gas distribution system. Since the gas regions coincide with the oil regions, the associated gas production is pooled with non-associated gas for shipment to demand or utility regions. These joint products are represented by upper bounded activity vectors producing primary products and co-products in fixed proportions, and the cost per unit of activity represents the minimum acceptable price for the entire composite.

The aggregate effect produces over 75 increments in the representation of the total supply curve for oil.

Natural Gas Supply and Use

There are 14 gas producing regions. As with the oil supply curves, gas supply curves for traditional domestic sources are generated by the FEA oil and gas supply model. The nontraditional supplies estimated include north and south Alaska, and tight gas, that is, gas trapped in rock formations of low permeability.

The co-products associated with natural gas production are condensates, gas liquids, and butanes. The associated gas from oil regions is combined with nonassociated gas in gas regions and is transported to utility and demand regions. Approximately 50 supply increments are represented in the natural gas supply curve.

Imports

Included on the supply side of the model are imports of petroleum and natural gas shipped to the domestic regions in which they are consumed: utility and demand regions for natural gas, residual, and distillate; demand regions for gasoline and other petroleum; and refinery regions for crude oils. The price of imported crude is one of the key parameters of the scenario specification and the model usually assumes that unlimited imports are available at that price. From this perspective, the entire system can be viewed as a procedure for calculating adjustments in all sectors and the resulting demand for imports. The price of imported refined products is tied to the crude oil price through constant additive markups.

III. ENERGY CONVERSION ACTIVITIES

The energy conversion process explicitly represents electric utilities, refineries, and synthetic fuel plants. Conversion processes are represented in the model with two classes of activities construction of new facility capacity and the operation of facility capacity in one of various operating modes. For each type of facility, total operating capacity is constrained not to exceed existing capacity plus new capacity. The operation of a facility typically consumes certain energy materials and yields others. Thus, material balance constraints for the conversion regions require that shipments our of a facility plus losses and use equals yields from production or shipments into the facility for each material.

Refineries

Refinery capacity can be operated so as to vary final product yield in response to market demand. In order to represent the complicated and non-linear refinery process directly, sophisticated models are required and operated separately from the main system. FEA operates the Refinery

and Petrochemical Modeling System (RPMS)* to generate a moderate number of feasible refinery operating modes in each of the seven refinery regions. By choosing convex combinations of these modes, the flexibility of refinery operations is approximated.

Approximately 24 operating modes are incorporated for each refinery region. Each such mode consumes crude oils and co-products and yields refined products in a fixed proportion dependent on the mode. Some of these modes are associated with existing refinery capacity, while others reflect possible future operation and imply the use of both existing and new capacity. Constraints on the operations of existing capacity and projected aggregate capacity are expressed for each region.

Co-products in excess of that consumed by the refinery modes are either pooled with crude or converted directly to refined products at a small cost: butanes to other petroleum, and gas liquids to gasoline.

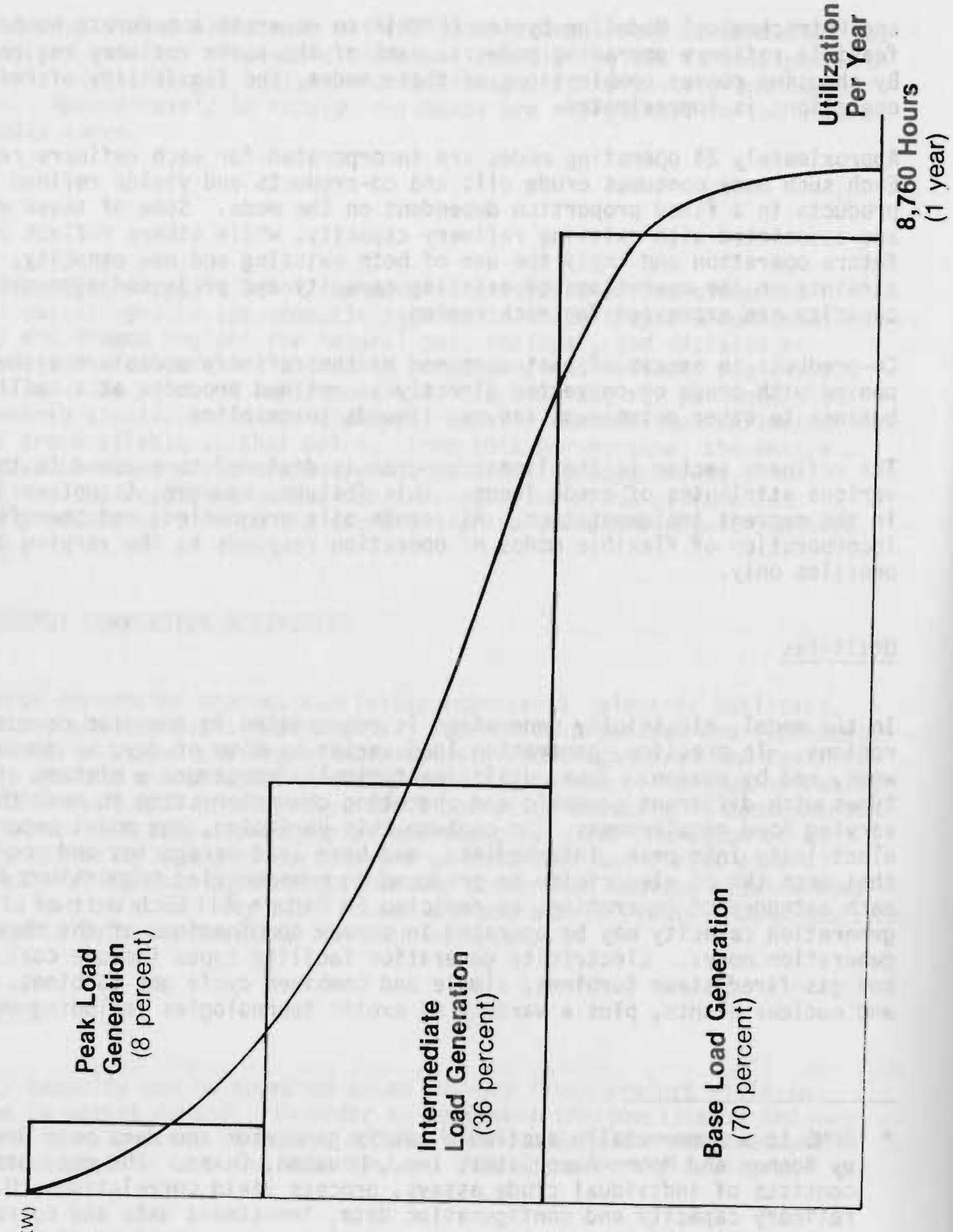
The refinery sector in the linear program is designed to respond to the various attributes of crude feeds. This feature, however, is not activated in the current implementation. All crude oils are pooled, and therefore, the incorporation of flexible modes of operation responds to the varying demand profiles only.

Utilities

In the model, electricity generation is represented in the nine census regions. In practice, generation load varies by time of day, by day of week, and by season. Thus, utilities typically construct a mixture of plant types with different economic and operating characteristics to meet the varying load requirements. To capture this variation, the model separates electricity into peak, intermediate, and base load categories and requires that each kWh of electricity be produced in prespecified proportions from each category of generation, as depicted in Figure 7. Each unit of generation capacity may be operated in convex combinations of the three generation modes. Electricity generation facility types include coal, oil, and gas-fired steam turbines, simple and combined cycle gas turbines, hydro and nuclear plants, plus a variety of exotic technologies including solar,

* RPMS is a commercially available matrix generator and data base developed by Bonner and Moore Associates, Inc., Houston, Texas. The data base consists of individual crude assays, process yield correlations, U. S. refinery capacity and configuration data, investment data and operating costs. With this system linear programming representations of the refining industry are constructed to include crude distillation, downstream unit operations, specification blending, and capacity expansion.

Figure A-7
Annual Load Duration



geothermal, and fuel gas plants. Facilities are also categorized according to initiation time: new (constructed in 1978 or later) or existing (constructed before 1978).

Coal-fired steam turbines plants are further distinguished with respect to sulfur. New facilities either scrub high-sulfur coal or burn low-sulfur coal. An additional category of existing plants is free to burn high-sulfur coal without scrubbing.

In the model, the utility sector chooses a mix of facility capacities and effective capacity factors for all plants in a fashion so as to minimize costs given the relative fuel prices, existing capacity and new capacity limitations, and electricty demand.

Synthetics

Synthetic fuel production from coal takes place in coal regions where high-sulfur coal is consumed and either synthetic gas or synthetic crude oil is produced. These synthetic fuels are shipped directly to the consuming regions. A third category of synthetics involves the production of low-Btu or medium-Btu gas to be consumed in electrical generation; this category is treated as another category of coal-fired plant which consumes high-sulfur coal in utility regions.

None of the synthetic production activities appear to be cost effective in the intermediate term at world oil prices of $16 per barrel or less. Therefore, activities are fixed in the solution at levels chosen as policy instruments (appropriate subsidies are assumed).

IV. TRANSPORTATION ACTIVITIES

Transportation activities move materials between regions via various modes. The modes by which a particular material may be shipped are prespecified and the cost of the shipment of the material depends upon the mode of transport and the regions linked.

In most cases, there is no capacity constraint on the quantities that may flow through a link. The exceptions are oil and gas pipeline constraints in Alaska. In addition, a 15 percent gas pipeline loss from Alaska is explicitly imposed on the supply side. Other transportation losses are handled in the demand model.

For all materials except coal, the network consists of simple direct links between supplying and consuming regions. Due to the significant transportation costs for coal, there is a more detailed coal transshipment network consisting of 19 population centers connected by barge and rail links.

V. DEMAND FUNCTION APPROXIMATION AND EQUILIBRATING MECHANISM

The demand model of appendix C is incorporated using a constant elasticity representation of the quantities as a function of price. Given a matrix of starting prices, P^o_{it}, a matrix of demands forecasted for these prices, Q^o_{it}, and a table of elasticities and cross elasticities, implied by the demand model, ε_{ijt}, a constant elasticity approximation to the demand function can be constructed. The demand approximation used for each year is represented in equation (1).

$$\ln Q_{it} = \ln Q^o_{it} + \sum_j \varepsilon_{ijt} \ln[P_{jt}/P^o_{jt}] \tag{1}$$

This equation has the property that $Q_{it} = Q^o_{it}$ for all i whenever $P_{jt} = P^o_{jt}$ for all j. The matrix of elasticities used for 1985 is presented in Appendix C.

For each fuel in each demand region, a material balance row requires that the shipments into the region equal the specified demand: The optimal linear program reports a shadow price for each material balance row which can be interpreted as the marginal supply cost to the region.

The joint supply/demand determination is accomplished by including special approximations of the demand functions--approximations in which cross elasticities are assumed to be zero--and iterating to improve these representations. These cross-elasticity approximations are constructed about a set of initial marginal supply prices, p, as illustrated in Figure 8, which depicts the demand for the partic lar goods as its own price is changed. The optimal linear program then provides solutions such that the marginal supply prices equal demand prices consistent with the special demand function approximation. Upon completion of the optimization,

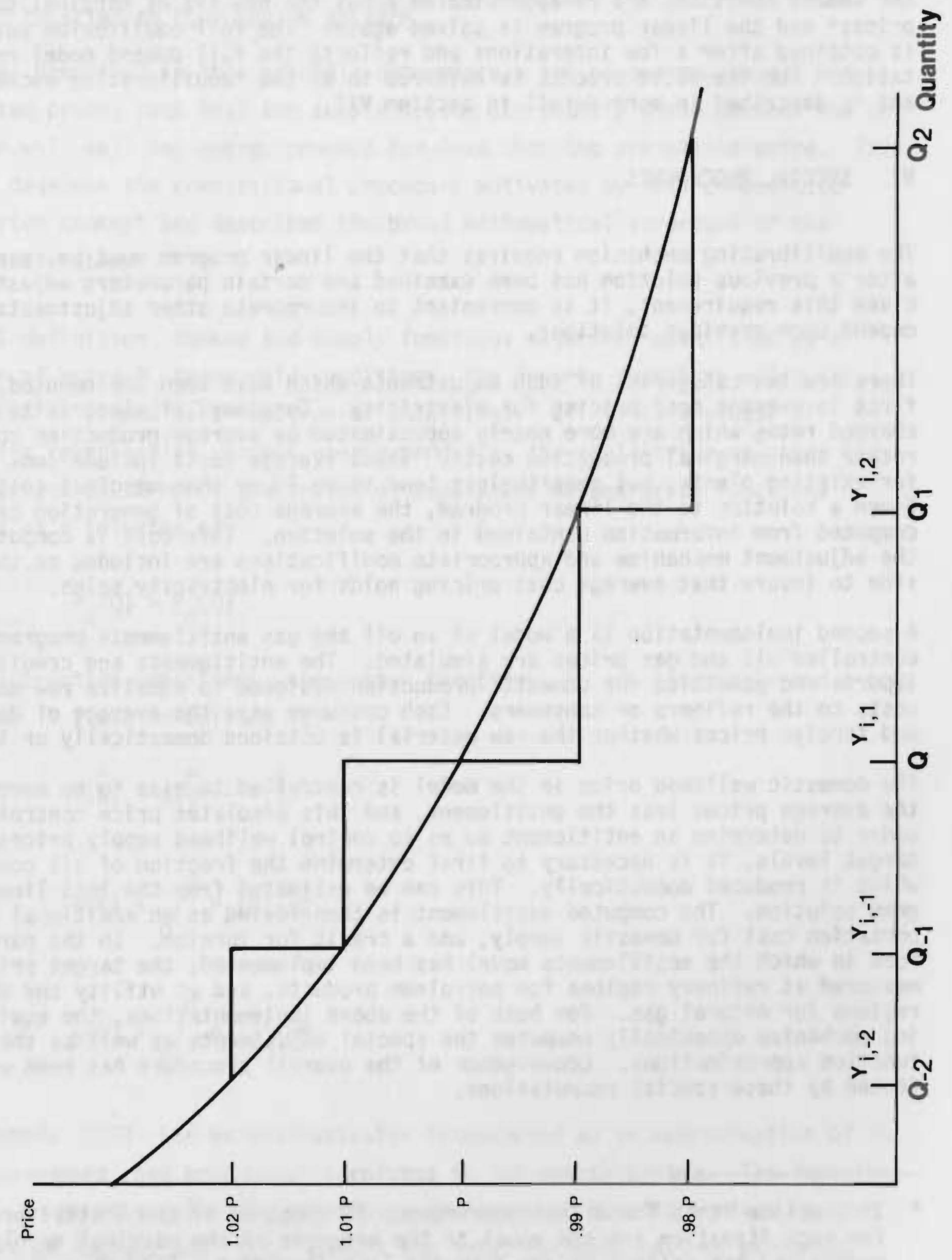


Figure A-8
Demand Function Approximation

the demand functions are re-approximated about the new set of marginal supply prices* and the linear program is solved again. The full equilibrium solution is obtained after a few interations and reflects the full demand model representation. The iterative process is referred to as the "equilibrating mechanism" and is described in more detail in section VII.

VI. SPECIAL PROCEDURES

The equilibrating mechanism requires that the linear program must be resolved after a previous solution has been examined and certain parameters adjusted. Given this requirement, it is convenient to incorporate other adjustments which depend upon previous solutions.

There are two categories of such adjustments which have been implemented. The first is average cost pricing for electricity. Consumers of electricity are charged rates which are more nearly approximated by average production costs rather than marginal production costs. These average costs include sunk costs for existing plants, but nevertheless tend to be lower than marginal costs. Given a solution to the linear program, the average cost of generation can be computed from information contained in the solution. This cost is computed in the adjustment mechanism and appropriate modifications are included on the supply side to insure that average cost pricing holds for electricity sales.

A second implementation is a model of an oil and gas entitlements program when controlled oil and gas prices are simulated. The entitlements are credits for imports and penalties for domestic production designed to equalize raw material costs to the refiners or consumers. Each consumer pays the average of domestic and foreign prices whether the raw material is obtained domestically or imported.

The domestic wellhead price in the model is controlled to rise to no more than the average prices less the entitlement, and this simulates price controls. In order to determine an entitlement so as to control wellhead supply prices at target levels, it is necessary to first determine the fraction of oil consumed which is produced domestically. This can be estimated from the last linear program solution. The computed entitlement is then levied as an additional transportation cost for domestic supply, and a credit for foreign. In the particular form in which the entitlements model has been implemented, the target price is measured at refinery regions for petroleum products, and at utility and demand regions for natural gas. For both of the above implementations, the equilibrating mechanism dynamically computes the special adjustments as well as the demand function approximations. Convergence of the overall procedure has been unaffected by these special computations.

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* In practice it is found that convergence is smoother if the initial prices for each iteration are set equal to the averages of the marginal supply prices and the initial prices from the last iteration. This procedure is currently used in the model.

VII. CALCULATING AN EQUILIBRIUM BALANCE

The model described in this appendix determines a set of energy demands and associated prices such that the supply system can satisfy these demands and no supplier will sell any energy product for less than the prevailing price. This section develops the computational procedure motivated by this competitive equilibrium concept and describes the broad mathematical structure of the evaluation system.

By usual definition, demand and supply functions determine quantities as a function of prices. Under mild conditions, the inverse functions exist and prices can be viewed as a function of quantities. If Q is a vector of quantities representing various energy products, the equilibrium solution is characterized in terms of the vector of supply and demand price functions (P_s, P_d) as a solution of

(2) $$P_s(Q) = P_d(Q) .$$

Under restrictive conditions, the vector functions P are integrable and a new function, T , can be defined as

(3) $$T(\hat{Q}) = g(\hat{Q}) - f(\hat{Q})$$

where $$f(\hat{Q}) = \int_0^{\hat{Q}} P_s(Q) \cdot dQ$$

and $$g(\hat{Q}) = \int_0^{\hat{Q}} P_d(Q) \cdot dQ .$$

The function $T(\hat{Q})$ can be heuristically interpreted as an approximation of the sum of consumers' and producers' surpluses in the energy system. The function $g(\hat{Q})$ can be heuristically interpreted as the economic benefit derived by the consumers of energy, and $f(\hat{Q})$ equals the total variable cost of producing the quantities $\hat{Q}$ of the products.

Any solution to (2) is a stationary point for T. Therefore, if T is a concave function, a solution to (2) is also a solution to the problem:

$$(4) \qquad \max_{Q} T(Q)$$

This rather heuristic discussion is motivated by the following observations:

- With the exception of requirements for the existence of the function g, the problem at hand satisfies the conditions needed to justify (4).

- Under strict assumptions about the demand functions, the problem is correctly characterized by (4). Furthermore, the problem in (4) lends itself to a straightforward linear programming approximation which may find a solution to (2).

- The solution of the linear approximation of (4) provides an estimate of a solution of (2) and this process may be iterated to search for such a solution.

The difficulty associated with the demand functions centers on the fact that $P_d(Q)$ is not integrable in the problem at hand and g does not exist.*

However, if the cross elasticities of demand are zero, then little is required to guarantee the existence of g. Therefore, assume for the present that ∇P_d is diagonal.** In this case, g is the sum of the one dimensional integrals of the component functions of the vector P_d. This fact will be exploited subsequently.

---

* If g exists then $\nabla g = P_d$ and $\nabla^2 g = \nabla P_d$. In the present problem, P_d is continuously differentiable, implying that $\nabla^2 g$ is symmetric. But ∇P_d is not symmetric.

** This is not necessary but it is convenient in that it retains the most important price effects and is amenable to linear approximation.

Figures 3 and 5 outline a linear programming specification of the supply and distribution system. If the vector of activities in the energy system is denoted by an X, the per unit cost of each activity denoted by C, and the system of equations needed to describe the energy network represented by $A_1X = b$, then the solution of the following problem provides and evaluation of f;

$$(5) \qquad f(Q) = \min_{X \in \chi} CX$$

$$(5.a) \qquad \text{subject to } A_1X = b$$

$$(5.b) \qquad A_2X = Q$$

where A_2 provides the transformation of the supply activities that serve to meet the demands Q, and χ represents the feasible set of X, as defined by the other constraints.

The dual variables, Π, associated with the constraints (5.b) provide an evaluation of the gradient of f or, equivalently, an estimate of $P_s(Q)$.

Problem (4) then becomes problem (6), in which $-T(Q)$ is minimized.

$$(6) \qquad \min_{Q} \left\{ \left\{ \begin{array}{l} \min CX \\ X\in\chi \; A_1X = b \\ \qquad A_2Q \end{array} \right\} - g(Q) \right\}$$

Introducing the perturbation Y, defined as $Y = Q - Q_o$, the problem in (6) becomes

$$(7) \qquad \min_{Y} \left\{ \left\{ \begin{array}{l} \min CX \\ X\in\chi \; A_1X = b \\ \qquad A_2X = Q_o + Y \end{array} \right\} - g(Q_o + Y) \right\}$$

or

$$(8) \qquad \min_{X,Y} \; CX - g(Q_o + Y)$$
$$A_1X = b$$
$$A_2X - Y = Q_o \; .$$

Recall that under the assumptions of a diagonal ∇P_d :

$$g(Q) = \sum_{i=1}^{m} \int_0^{\hat{Q}_i} P_i\,(Q_i)\cdot dQ_i \; ,$$

where P_i is the i^{th} component of P_d .

Then

$$(9) \qquad g(Q_o + Y) = \Theta + \sum_{i=1}^{m} \int_0^{Y_i} P_i(Q_{oi} + Y)dY_i \; ,$$

where

$$\Theta = \sum_{i=1}^{m} \int_0^{\hat{Q}_{oi}} P_i(\hat{Q}_i)dQ_i \; .$$

Since Θ is a constant, it does not affect the solution of (8) and this yields

$$(10) \qquad \min_{X,Y} \; CX - \sum_{i+1}^{m} \int_0^{Y_i} P_i(Q_{oi} + Y_i)dY_i$$

$$\text{subject to } A_1X = b$$
$$A_2Y - Y = Q_o \; .$$

VII.1 APPROXIMATION WITH INTEGRABLE DEMAND FUNCTIONS

The fact that the diagonal elements of ∇P_d are negative guarantees the convexity of (10) and permits the following approximation.* Introduce a new set of variables $Y_{i,k}$ ($K = -n, -n + 1, \ldots -1, 1, 2, \ldots n-1, n$) which will construct a partition of a sufficiently large interval centered at Q_{oi} . (See Figure 8.)

Let $U_{i,k}$ be the upper bound for $Y_{i,k}$ and $Y_{i,-k}$. Hence

$$0 \leq Y_{i,k} \leq U_{i,k}$$

$$0 \leq Y_{i,-k} \leq U_{i,k} \; .$$

Let

$$P_{i,k} = P_i(Q_{oi} + \sum_{j=1}^{k} U_{i,j})$$

$$P_{i,-k} = P_i(Q_{oi} - \sum_{j=1}^{k} U_{i,j})$$

for $k = 1, 2, \ldots n$. Then, by convexity, for any optimal selection of $Y_{i,k}$, the integrals can be approximated as

$$\int_0^{Y_i} P_i(Q_{oi} + Y_i)dY_i \simeq \sum_{k=1}^{n} (P_{i,k}\,Y_{i,k} - P_{i,-k}\,Y_{i,-k})$$

and

$$Y_i \simeq \sum_{k=1}^{n} (Y_{i,k} - Y_{i,-k}) \; .$$

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* The negative ∇P_d is equivalent to the own-price elasticities being negative, the standard definition of an economic good.

Using this approximation after dropping constants from the objective function, (10) becomes

$$\text{(11)}\qquad \underset{X,Y_{i,k}}{\text{Min}}\ CX - \sum_{i=1}^{m}\sum_{k=1}^{n}\left(P_{i,k}Y_{i,k} - P_{i,-k}Y_{i,-k}\right)$$

subject to $A_1X = b$

$$A_2X - \sum_{k=1} Y_{i,k} + \sum_{k=1} Y_{i,-k} = Q_o .$$

Hence, any solution of (11) is an approximate solution of (2) with

$$Q_i = Q_{oi} + \sum_{k=1}^{n}\left(Y_{i,k} - Y_{i,-k}\right) .$$

Furthermore, if

$$0 < Y_{i,k} < U_{i,k}$$

then

$$\Pi_i = P_{i,k} .$$

The symmetric case holds for $-k$.* Therefore,

$$\text{(12)}\qquad \Pi_i \simeq P_i(Q_i)$$

the equilibrium condition defined by (2) and (5).**

---

* Note that convexity ensures $Y_{i,k}\,Y_{i,-k} = 0$. Further, if $Y_{i,k} > 0$ then $Y_{i,k-1} = U_{i,k-1}$.

** A small but important change has occurred here. The Π values for (11) are applicable to (5) but the converse may not be true. The problem in (11) differs from (5) in that it includes the opportunity cost of competing demands and is an interim approximation to the market clearing prices.

VII.2 APPROXIMATION WITH THE GENERAL DEMAND FUNCTIONS

The heuristic for seeking a solution of (2) is based on a repeated exploitation of (11). In particular, assume that a general demand function has been specified as $Q(P)$. If a set of prices, P_o , is selected and the corresponding Q_o is chosen as

$$Q_o = Q(P_o)$$

then using the own-price elasticities implied by Q , an approximate price function with zero cross-elasticities can be constructed such that

$$\text{(13)}\qquad P_o = P_d(Q_o) .$$

This approximating price function is employed to produce problem (11).

If, in the solution of (11), the $Y_{i,k}$ increments satisfy

$$\text{(14)}\qquad \sum_{k=1}^{n}\left(Y_{i,k} - Y_{i,-k}\right) = 0 \quad \text{for all } i$$

then by (12) it follows that

$$\text{(15)}\qquad \Pi \simeq P_o$$

and Q_o is an approximate solution to (2) with the general demand function.

If (13) is not satisfied then by (12), Π is an estimate of a new set of demand prices that would produce equilibrium. The quality of this estimate should be related to the relative magnitudes of the own- and cross-price elasticities. In the approximating problem, the estimate is exact for the important special case of zero cross-elasticities. This leads to the expectation of a successful iteration to a solution of (2) via the following algorithm.

Computational Procedure

Step 1

Choose a set of demand prices, p^1 . Let $t = 1$.

Step 2

Calculate $Q^t = Q(P^t)$. Using the own-price elasticities of $Q(\cdot)$, construct (2) relative to the point (Q^t, P^t).

Step 3

Obtain (X^t, Y^t, Π^t) as an optimal solution for (11). If $\Pi^t = P^t$, go to step 4. Else, let $P^{t+1} = \Pi^t$, $t = t+1$ and go to step 2.

Step 4

Terminate with equilibrium supply pattern X^t , consumptions Q^t and market prices P^t .

Formally, this iterative scheme is attempting to solve a fixed point problem. The convergence properties in the presence of a general demand function have not been established. The well-behaved convergence properties of related processes for general equilibrium models are discussed at length in [1]. Unfortunately, this problem does not satisfy the gross substitutability or homogeneity assumptions required by those results. Quadratic optimization and complementary approaches are indicated in [2] which contains the most comprehensive discussion of the computational formulations and experience.

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Appendix B

ECONOMIC ASSUMPTIONS

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FORECAST SUMMARY

THE MANY SOURCES OF INSTABILITY

AND THE NEW DRI LONG-TERM PROJECTIONS

by Otto Eckstein and Sara Johnson

The last few years have demonstrated that the American economy has become increasingly vulnerable to external shocks. The list of exogenous shocks experienced since World War II sufficient to perturb the macro economy is a relatively short one:

1) the end of price controls in 1946;

2) the Korean War;

3) the 116-day steel strike of 1959;

4) the Kennedy-steel industry confrontation of 1962;

5) the Vietnam War (1965-6);

6) the price controls of 1971;

7) the food price explosion of early 1973;

8) the oil embargo of November 1973 and the quadrupling of the price of oil;

9) the second food price explosion and the end of controls in 1974.

The reader will notice that the frequency of shocks has been increasing. Presumably, we will not repeat precisely the mistakes of the past. The dangers of renewed agricultural disasters, price controls, or war are currently quite low since they are fresh in our memory. But there will be plenty of other sources of instability.

The international relations system is out of equilibrium. The period of U.S. hegemony is over, and the new polycentrist system will take decades to reach stability. To list the potential trouble spots around the globe is sufficient to comprehend the probabilities of future disturbances: South Korea, Taiwan, the Philippines, Rhodesia, South Africa, Portugal, Spain, Yugoslavia, Italy, and the Middle East. These are all countries or regions facing an uncertain future. They are far removed from our domestic economy, but it has been our experience that, directly or indirectly, international disturbances have a considerable effect here.

Another inevitable source of instability lies in the limited degree of coordination among the economic policies of the advanced countries. The strength and coincidence of the world business cycle upswing in 1972 and 1973, which accentuated inflation, was largely the result of expansionary fiscal and monetary policies of governments. With the volume of international trade increasing, the synchronization of the business cycles will continue. Yet, given the divergent goals and philosophies of governments, it is clear that economic policy will still be principally a national matter of internal policy.

The transformation of the world commodity situation is likely to create instability for the American economy in the years ahead. The example set by OPEC is being emulated by other groups of countries in other commodity markets. In the past, the countries have dealt with multinational companies in a relatively competitive manner. While no visible trend can be found in the long-term relationships between commodity prices and finished goods prices of the industrial countries, the advanced countries have benefitted greatly from a relatively abundant supply of materials at moderate costs. Now the less developed countries, in need of foreign exchange to pay for manufactured goods, are trying to convert these markets into politically-based cartels. Because antitrust laws do not apply internationally nor to coalitions of foreign governments, it is realistic to assume that developments in the world commodity markets will create problems for our economy.

We also have to deal with the legacy of the double-digit inflation just behind us. We are about to emerge from the deepest recession since the Second World War, a recession largely created by the preceding inflation. Full recovery cannot be quick, and the policies of the current Administration make it even more probable that the path toward reasonable resource utilization will stretch out over three or four years.

The severity of the inflation behind us has diminished quickly in response to the depth of the recession. But the inherited effects of this inflation, together with the continued energy problems, make a return to price stability virtually impossible. Even under the most sanguine assumptions, wages will be rising at 6-1/2% or more, and consequently, unit labor costs show a probable 4 to 4-1/2% trend for some time. Other costs will also continue to advance, adding to price inflation and making a moderately inflationary wage-price spiral about the best that one can hope for.

The relative prices governing the economy have been set into historically unprecedented motion. High energy prices and unstable commodity prices, together with the recent primary processing capacity shortages, have changed the relationships between materials prices, finished goods prices, wage costs, and capital costs. Unlike the trends of the preceding century, we are entering a period in which the demand for energy and raw materials will decelerate. One of the most difficult business decisions will relate to the choice of materials and energy inputs, and some of the greatest cost-saving opportunities will lie in the area of economizing on their use.

The financial condition of the economy is another source of potential future instability. Credit crunches have come with increasing frequency, as violent movements in the real economy and prices have run up against monetary policies that have too often tightened at an inopportune moment. The gradual deterioration of the liquidity position of business has made it increasingly vulnerable to variations in the cost and availability of external capital. If the economy is to resume a normal growth process, the badly distorted balance sheet of business must be restructured to ensure a sufficient base of liquidity.

Under these circumstances, it is very difficult to develop serious long-range plans for government and business. Economic planning is offered as one of the solutions to our difficulties. There are long-range matters which deserve better attention from our government. But the increasing frequency of shocks and the continued uncertainties make it totally inappropriate to draw up elaborate plans which assume that the future can be known. The rational strategy for businesses and governments in an environment such as this one is quite different: to develop quick responsive capabilities to new shocks as they may come along, and to devise policies which at least partially insulate institutions and systems from the many sources of instability.

THE NEW DRI LONG-TERM PROJECTIONS

Economic forecasters confront the same problem in slightly different forms. The models produce answers which are dependent upon the inputs that are assumed. The Data Resources Quarterly Model of the U.S. Economy has been redeveloped to explicitly represent the impacts of shocks that we understand. The new model contains a full response to the extraordinary events of 1974. It is sufficiently cyclical and sensitive to fiscal and monetary conditions that it would have simulated the unusual record of instability of the last five years quite accurately. The changes in the DRI model (described in our March Review) include the addition of a stage-of-processing price sector, a detailed international trade sector, the simultaneous treatment of the flow-of-funds of the nonfinancial corporate sector, and the inclusion of industry production and capacity utilization in the simultaneous block of the model. But a change in the model structure does not eliminate the surprise element in the inputs which must be assumed.

In response to the situation, DRI has developed two long-term solutions which serve rather different purposes. "Control Long 5/75" is a trend-line solution which indicates the probable average values for real magnitudes such as housing starts, auto sales, and production of particular industries. This solution also shows what would happen to prices, interest rates, final demands, the profit share, and other such magnitudes if there were no disruptive shocks in the future. For some long-range planning purposes, these magnitudes have to be estimated. Even this solution has a minor business cycle over the next six years as a result of the initial conditions.

On the other hand, some kinds of shocks are inevitable. The world gives no sign that all the difficulties are behind us. Such shocks will alter the character of the near-term recovery and present challenges to the attainment of sustained growth. Consequently, we have developed a solution, "Cycle Long 6/75", incorporating a collection of shocks sufficient to create significant cycles in real activity. Prices, interest rates, and numerous other variables are affected by the shocks, and even certain trend values of some variables will differ. The growth of potential GNP, considered one of the most stable secular trends, would be adversely affected by an unstable path of real output. For purposes of financial planning, for contingency analyses, or for coming to a realistic assessment of the probable rate of inflation, this alternative solution should prove helpful.

"Cycle Long 6/75" does not portray a world in as poor a state as what we have lived through in the last nine years. It is still our judgement that the frequency and severity of shocks that we have experienced since 1965 represent an unfortunate combination of events that is not likely to recur. We assume there will be disruptions, but not to the extent we have seen lately.

These two simulations are only the beginning of DRI's long-term analyses with the new version of the DRI model. In the months ahead, we will be developing solutions which explore other alternatives, some substantially worse than either of the alternatives reported in this Review. We will also be continuing our analyses of the economic structure with the goal of improving the long-term simulation properties of the model itself.

FORECAST HIGHLIGHTS

GROWTH OF POTENTIAL GNP

Potential GNP is forecast to grow at a steady 3.3% rate over the 1975 to 1990 period, substantially below the 4.0% rate of the last decade. The disruption of capital formation in the current recession, the diversion of capital to non-growth purposes, and the unreliability of commodity supplies will permanently lower macroeconomic potential. Although investment will accelerate in the 1980's, the falling growth rate of the adult population will diminish the economy's growth capacity in that decade.

The concept of potential GNP is measured on the basis of cyclically adjusted labor force, productivity and capital stock trends. It is traditional to assume a 4.0% unemployment rate as full employment for determining the level of the potential GNP. In the 1975 version of the DRI Model, potential GNP is determined endogenously from a linear, homogeneous production function that includes embodied, labor-augmenting, technological progress and that uses potential employment and the

capital stock excluding pollution abatement equipment as inputs. In the current forecast, all doubts about the inputs to this equation have been resolved on the low side. Thus, the projected 3.3% growth of potential GNP reflects the conservative nature of the overall magnitudes of the solution.

The economy is now 14% below the potential growth path. The expansionary trend of the next six years should narrow the gap to a comfortable 3-1/2%. Actual real GNP is projected to grow at average rates of 5.9% from 1975 to 1977, 5.3% from 1977 to 1981, and 3.2% from 1981 to 1990.

POPULATION

The population forecast is based on the Census Bureau's Series II Population Projections, which assumes a fertility rate of 2.1 births per woman. This assumption is consistent with recent surveys of expected family size and implies zero population growth in the long term.

Shifts in the age composition of the population and the distribution of income among age groups in the years ahead will alter macroeconomic patterns of saving and consumption. The high birth rates during the period following World War II have resulted in a relatively large young adult population in the 1960's and 1970's. By 1980 and 1990, these "baby boom" children will have moved into the 15-to-34 age group and the 25-to-44 age group, respectively. Thus, total real income in families headed by persons between the ages of 25 and 44 will rise sharply over the next 15 years. The lower traditional savings rates in the young adult age groups might imply higher levels of aggregate consumption, but this tendency will be offset by the lower involuntary expenditures associated with smaller families, changing attitudes toward the ownership of large automobiles and homes, and a relatively high return to savings.

The direct economic consequences of slower population growth will become more apparent by the late 1980's, when the growth of the labor force and households are affected. In the interim, lower birthrates will reduce the need for educational and child-related expenditures.

THE PUBLIC SECTOR

In the forecast, Control Long 5/75, it is assumed that fiscal policies will be conducted according to stable framework principles. The policy goal selected in developing the forecast is an unemployment rate of 5%. Federal expenditure and tax policies are assumed to be expansionary through the 1970's. In the near term, the economy is plagued by economic slack, warranting a continuation of some elements of the tax stimulus introduced in the Tax Reduction Act of 1975. The 1980's are pictured as a decade of balanced growth in the Control solution, with Federal government purchases of goods and services rising smoothly at a real rate of 2.0% and transfer payments to persons increasing at a real rate of 3.4% per year. By 1981, the projected Federal government deficit as a percentage of GNP is reduced to 0.6% from 5.2% in 1975.

Real purchases of goods and services by state and local governments are projected to grow at average rates of 4.7% from 1975 to 1980, 4.1% from 1980 to 1985, and 3.5% from 1985 to 1990. It is assumed that an increasing proportion of government activities will be carried out at the state and local levels. The dimensions of the public sector as a whole show little change over the forecast period. Total government spending as a percentage of GNP fluctuates within the range of 33.0% to 34.5%.

UNEMPLOYMENT AND THE LABOR FORCE

The labor market outlook to 1980 is one of the less encouraging aspects of the forecast. The unemployment rate is projected to remain above previous postwar recession peaks through early 1977. The sustained expansion of the late 1970's will bring the unemployment rate to its long-term equilibrium level of 5% by 1981. The 5% rate is believed to be consistent with stable economic growth at low inflation rates.

Labor force growth will slow appreciably from a rate of 2.5% in recent years to 1% in the late 1980's. The shifting age composition of the labor force and rising education levels should have a stabilizing influence on the labor market in the decades ahead. If the economy can be kept relatively free of external disruptions, its long-term growth will be sufficiently strong to generate and maintain high employment.

A CAPITAL SHORTAGE?

The investment surge forecast for the late 1970's in the last Long-term Review now appears to be delayed until the 1980's. The near-term investment outlook is clouded by the existence of a high margin of unutilized productive capacity, insufficient liquidity, and a heavy burden of short-term debt in the business sector. In contrast, only a year ago capacity shortages and bottlenecks in the basic materials industries fueled inflation and made prospects of a sustained physical capital shortage a serious threat. But the recession has left a deep economic slack. In real terms, business fixed investment will not recover to its 1973 peak until 1978.

The economy's long-term needs to expand capacity, break potential bottlenecks, develop new energy sources, and modernize industry will generate a strong demand for capital goods by the end of this decade. In the five years beginning in 1980, business fixed investment will grow at an 11.5% rate. This represents a real growth of 7.1% annually. During the 1980's, 11.0% of GNP will be devoted to business fixed investment. This compares with an average of 10.0% in both the 1960's and the 1970's. Between 4.5% and 5.5% of plant and equipment expenditures by nonagricultural industries will be diverted to pollution abatement equipment. The stock of productive capital is projected

to expand at rates of 2.8% from 1975 to 1980, 4.0% from 1980 to 1985, and 3.9% from 1985 to 1990. This growth should be sufficient to meet future demand requirements at normal operating rates. At the micro level, the match-up of projected output with capacity is also encouraging.

FINANCING INVESTMENT

The Control solution assumes a moderately accommodating monetary policy. The annual rates of growth in nonborrowed reserves range between 7% and 10%. The narrowly defined money stock grows at rates which vary from 6.2% to 8.5%. In periods of strong demand, the base simulation shows mild credit strains, but no repetition of the severe credit crunches that occurred during the past 10 years. Until 1980, the financing of capital outlays should be relatively easy. Cash flow will be strong and internal funds will provide approximately 69% of total funds raised. This compares with an average of 65% during the 1965-1974 period. The mix of external financing will be relatively stable, with a slight shift away from equity to bank loans and bonds. Subsequent to 1980, however, the financing of capital outlays will become more difficult. As profits growth slows, corporations are projected to increase their use of external sources of funds to 40% of total funds raised. The strong demand for loans will create pressures on financial markets. The new issue rate of high-grade corporate bonds is projected to reach 9% in the early 1980's; it will remain above 8% throughout the forecast interval. Subtracting the inflation premium, the real rate of interest will average 4.5% in the 1980's, well above the 3.6% norm for the period from 1960 to 1974. The financing of investment outlays will require a personal savings rate averaging 7.6% over the next 15 years -- a full percentage point above the postwar average.

PRICES

In the absence of shocks, the gradual character of the recovery will bring the inflation rate down to near 4% for most of the 1980's, a level substantially higher than the 1 to 2% inflation rate enjoyed during the early 1960's when price increases were moderated by steadily falling costs of key materials. Even in the absence of shocks, one must assume that materials prices will increase at a minimum rate of 3 to 4% after the adverse initial conditions wear off, which puts a floor under any price deceleration.

Wages are projected to advance at a 6-1/2% rate over the next 15 years. Productivity gains, averaging 2-1/2%, will limit the rise in unit labor costs to 4%.

AUTOMOBILES AND OTHER CONSUMER SPENDING

Automobile sales are projected to average 11.2 million units during the years 1976 to 1980, and 11.6 million units in the 1981 to 1985 period. The low scrappage rate of cars in 1974 and early 1975 is likely to generate a replacement wave later in this decade. Beyond this current cycle, the growth in long-term automobile demand will be restrained by the slower growth in the population of driving age, the approach of the number of cars per person of driving age toward the saturation point, and the likelihood that the scrappage rate will not exceed the historical average of 7.5%. The higher cost of car ownership, measured by DRI's rental price index for automobiles, will directly reduce demand. This index includes the purchase price of cars, interest costs of financing the purchase, gasoline prices, and the price index for car repairs and insurance. With the higher real price of gasoline encouraging individuals to drive less, and with producer emphasis shifting from style to operating efficiency, future scrappage rates are expected to stay in the range of 6.5% to 7.5% of the existing stock.

The distribution of real consumption will continue to shift toward durable goods (home furnishings and recreational products, in particular) and away from nondurable necessities. This trend is predicated on rising real per capita incomes, smaller family size, and relative price movements which effectively lower the real price of durables. The services share of real consumption will fall back to its pre-recession level of 38% and show no long-range trend, as rising outlays for health care offset the lower growth in services linked to housing, such as utilities and imputed rent.

HOUSING

The recovery of the housing industry in the last half of the 1970's will bring the supply and demand for housing units towards stock equilibrium, setting the stage for a decade of modest growth. Housing starts are projected to average 2.04 million units in the 1976 to 1980 period and 2.24 million units during the 1980's. This new supply of housing will be augmented by approximately 630,000 mobile home shipments per year. The growth of the housing stock, 2.0% per year, will exceed the rate of growth in population. Thus, the long-observed downward trend of the number of persons per occupied unit is expected to continue, with the figure reaching 2.4 in 1990 compared to 3.0 in 1970.

In the 1960's, most incremental households were headed by persons aged 20 to 29 or 65 and over. As a result, housing starts shifted toward multifamily units. In the 1980's, household formation will shift back toward the middle-aged groups. Their incomes and space requirements should drive residential construction expenditures per housing start upward. However, the increased relative costs of home ownership resulting from higher energy prices and high interest rates will reduce the affordable home size. Thus, by 1977 the average real expenditure per housing start will stabilize near $32,000 in 1975 dollars.

BALANCE OF TRADE

The health of the world economy will be of increasing importance to the United States. By 1980, the ratio of exports to GNP will reach 11.8%, compared to 10.0% in 1974 and 5.4% in 1960. Despite the high cost of crude petroleum imports, the forecast shows a surplus on net exports of goods and services through 1990. Crude oil imports are assumed to peak in 1985 and decline thereafter. The principal factors contributing to the favorable trade balance are the growth of sales of finished manufactures, made possible by the undiminished U.S. technological lead, and income from investments abroad.

Table 1.1
Summary of Key Economic Variables
(Average Levels)

	61-65	66-70	71-75	76-80	81-85	86-90
Ratios (Current Dollars)						
Consumption/GNP	0.636	0.623	0.631	0.627	0.618	0.612
Business Fixed Investment/GNP	0.095	0.105	0.102	0.100	0.109	0.111
Residential Construction/GNP	0.043	0.033	0.038	0.041	0.040	0.037
Government Spending/GNP	0.205	0.223	0.222	0.223	0.220	0.227
Housing Starts (million units)	1.47	1.38	1.81	2.04	2.20	2.29
Retail Car Sales (million units)	7.62	9.01	9.98	11.15	11.58	12.92
Capacity Utilization Rates						
Manufacturing	0.833	0.865	0.766	0.788	0.824	0.831
Primary Processing	0.846	0.869	0.811	0.804	0.846	0.874
Interest Rates						
New High-Grade Corp. Bond Rate (%)	4.37	6.77	7.97	8.35	8.91	8.34
Federal Funds Rate (%)	3.08	6.08	6.78	6.64	7.76	6.63
Savings Rate (%)	5.6	6.9	8.1	8.1	7.6	7.1
Unemployment Rate (%)	5.5	3.9	6.2	6.9	4.9	4.9
Federal Government Deficit (-)	-1.7	-4.6	-26.0	-39.2	-14.0	-20.0

Table 1.2

Gross National Product and Selected Economic Variables
(Average Annual Rates of Change)

	55-60	60-65	65-70	70-75	75-80	80-85	85-90
(1958 Dollars)							
Gross National Product	2.2	4.9	3.2	1.9	5.5	3.6	3.0
Personal Consumption Expenditures	2.9	4.7	3.7	2.5	4.9	3.6	2.9
Durable Goods	1.1	8.3	4.8	3.3	9.3	4.5	4.2
Automobiles and Parts	-0.0	9.3	2.9	2.7	11.8	1.7	3.3
Furniture and Household Equipment	1.9	8.0	6.2	4.3	7.9	6.6	5.0
Other Durable Goods	5.3	7.2	7.5	3.2	7.0	5.7	3.9
Nondurable Goods	2.6	3.6	3.0	1.8	3.9	3.3	2.2
Food and Beverages	2.2	2.7	1.9	1.3	2.2	1.9	1.5
Clothing and Shoes	2.1	4.7	3.2	3.4	5.6	4.2	2.3
Gasoline and Oil	4.3	4.0	5.4	2.5	2.5	3.9	3.0
Other Nondurable Goods	3.3	5.0	4.2	1.3	6.1	4.8	2.8
Services	4.1	4.6	4.2	2.9	3.8	3.3	2.9
Housing	4.7	5.3	4.6	3.8	2.6	2.2	2.3
Household Operation	4.5	4.4	5.1	2.8	3.3	4.1	3.3
Transportation	2.5	1.7	2.8	3.8	2.7	2.1	1.5
Other Services	3.8	4.7	3.7	1.9	5.4	4.3	3.4
Gross Private Domestic Investment	-0.2	6.7	1.1	-1.0	11.2	3.7	2.9
Fixed Investment	0.1	5.6	2.1	0.5	7.9	4.0	2.9
Nonresidential	1.7	7.3	3.2	1.3	6.6	5.2	3.2
Structures	1.7	5.2	1.3	0.8	2.3	3.4	3.0
Producers Durable Equip.	1.8	8.5	4.2	1.6	8.3	5.8	3.3
Residential Structures	-2.0	1.8	-1.0	-1.0	13.5	-0.4	1.4
Exports	6.0	6.6	6.9	5.6	8.0	5.7	5.2
Imports	5.5	6.4	10.0	2.5	7.9	6.3	5.2
Government Purchases of Goods and Services	2.2	3.9	4.1	1.4	3.6	3.4	3.0
Federal	0.3	2.5	2.7	-1.9	1.8	2.1	2.0
National Defense	-0.5	0.2	3.6	-4.8	1.7	2.1	2.0
Other	6.7	12.0	0.1	6.3	2.1	2.1	2.0
State and Local	4.8	5.5	5.7	4.0	4.7	4.1	3.5
Prices							
Implicit GNP Deflator	2.6	1.4	4.1	6.6	4.7	4.6	3.7
Consumer Price Index	2.0	1.3	4.3	6.8	5.2	4.8	3.9
Wholesale Price Index	1.6	0.4	2.7	9.8	5.1	3.4	2.7
Index of Unit Labor Costs	2.8	0.4	4.9	6.3	4.2	4.6	3.2
(Current Dollars)							
Gross National Product	4.9	6.4	7.4	8.6	10.5	8.3	6.8
Profits after Tax	0.6	12.0	-3.1	12.5	17.6	4.5	5.4
Corp. Capital Consumption Allowances	7.4	8.0	9.0	8.4	9.1	10.0	9.6
Federal Reserve Board Production Index	2.7	6.2	3.8	1.2	7.4	4.6	4.0

Table 1.3

Data Resources Forecast of the U.S. Economy
($ Bils. - SAAR)
CONTROL LONG 5/75

	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90
	Years															
GNP AND ITS COMPONENTS																
Total Consumption	945.8	1045.9	1152.9	1253.6	1375.0	1506.0	1637.4	1777.4	1924.0	2078.2	2225.6	2375.8	2529.8	2700.3	2871.7	3046.8
Business Fixed Investment	146.0	161.8	187.6	208.5	214.9	252.2	286.7	311.0	339.7	368.8	397.4	425.3	456.0	486.8	520.0	554.0
Residential Construction	39.3	59.7	73.2	85.1	89.6	105.7	110.4	116.1	124.6	132.1	138.2	143.2	152.8	165.6	177.7	187.1
Inventory Investment	-11.2	4.2	3.5	7.5	19.9	24.4	26.0	24.7	22.1	22.8	29.3	30.8	31.7	40.6	39.2	40.1
Net Exports	8.5	4.7	4.8	9.7	12.5	7.4	11.5	14.5	15.5	17.8	20.8	21.3	24.0	20.3	18.7	22.5
Total Federal	131.3	141.5	149.6	159.0	170.0	182.6	195.9	209.7	224.4	240.3	257.3	275.6	295.0	314.7	335.1	356.6
State and Local	212.2	237.7	262.2	286.2	314.2	346.4	382.3	418.0	458.4	500.7	540.1	582.2	630.4	682.6	740.2	802.6
Gross National Product	1471.9	1655.5	1833.8	2001.6	2196.0	2424.8	2650.2	2871.4	3108.8	3360.7	3608.7	3854.2	4119.6	4410.9	4702.5	5009.6
Real GNP (1958 dollars)	792.0	843.0	887.8	923.4	975.8	1035.9	1079.1	1116.9	1156.1	1194.4	1233.4	1272.1	1310.6	1353.9	1392.1	1427.8
PRICES AND WAGES --- ANNUAL RATES OF CHANGE																
Implicit Price Deflator	9.1	5.7	5.2	4.9	3.8	4.0	4.9	4.7	4.6	4.6	4.0	3.6	3.7	3.6	3.7	3.9
Consumer Price Index	9.2	6.1	5.6	5.1	4.4	4.6	5.1	5.0	4.9	4.6	4.3	4.0	3.9	3.9	3.9	3.9
Wholesale Price Index	9.3	7.0	6.7	4.7	3.5	3.7	3.9	3.7	3.4	3.3	2.9	2.6	2.7	2.8	2.8	2.8
Adj. Avg. Hourly Earnings Index	8.5	7.3	7.1	6.5	6.4	6.4	6.7	7.0	7.1	7.2	6.9	6.6	6.3	6.1	6.0	5.9
PRODUCTION AND OTHER KEY MEASURES																
Industrial Production (67=1)	1.119	1.218	1.305	1.373	1.474	1.601	1.683	1.747	1.818	1.907	2.000	2.086	2.171	2.278	2.361	2.435
Annual Rate of Change	-10.0	8.9	7.1	5.2	7.3	8.6	5.1	3.8	4.1	4.9	4.9	4.3	4.1	4.9	3.7	3.1
Housing Starts(mil. units)	1.250	1.809	1.953	2.198	1.967	2.266	2.097	2.233	2.227	2.211	2.222	2.132	2.234	2.303	2.351	2.412
Ret. Unit Car Sales-Total	8.2	9.3	10.4	11.3	12.0	12.7	11.7	12.1	11.5	11.1	11.5	12.4	12.7	13.0	13.2	13.2
Unemployment Rate (percent)	8.9	8.3	7.4	7.1	6.4	5.4	5.0	5.0	4.9	4.8	4.9	4.8	4.8	4.9	4.9	5.1
Federal Budget Surplus (NIA)	-76.7	-59.1	-42.8	-29.1	-40.5	-24.4	-16.9	-13.2	-9.1	-15.9	-14.9	-18.7	-19.4	-17.7	-19.7	-24.5
INTEREST RATES																
New AA Corp. Utility Rate (%)	9.11	8.69	8.85	8.54	8.26	8.83	9.26	9.29	9.26	9.23	9.06	8.83	8.68	8.60	8.52	8.51
New High-grade Corp.Bond Rate (%)	8.72	8.40	8.56	8.26	7.99	8.54	8.95	8.98	8.94	8.92	8.76	8.54	8.39	8.32	8.24	8.23
Federal Funds Rate (%)	5.56	6.54	7.74	6.69	5.84	6.37	8.04	7.53	7.76	8.11	7.38	6.80	6.50	6.67	6.68	6.49
Prime Rate (%)	7.26	7.14	8.07	7.44	6.64	6.84	8.16	8.04	8.17	8.46	7.94	7.46	7.12	7.22	7.19	7.05
INCOMES																
Personal Income	1245.1	1385.1	1516.1	1634.0	1774.9	1942.7	2129.0	2309.2	2506.7	2710.9	2902.1	3093.1	3302.3	3527.9	3755.1	3999.1
Disposable Income	1076.0	1188.9	1294.2	1390.2	1526.4	1664.8	1819.0	1963.1	2125.1	2304.7	2463.0	2619.0	2789.0	2970.9	3153.7	3344.8
Saving Rate (percent)	9.6	9.6	8.6	7.5	7.7	7.3	7.8	7.3	7.4	7.8	7.6	7.2	7.3	7.1	6.9	6.9
Corp. Cap. Cons. Allow.	83.9	91.5	99.6	108.6	118.6	129.6	142.0	156.1	171.9	189.5	208.7	229.5	252.0	276.2	302.1	329.9
Profits before Tax	106.4	132.9	155.9	174.5	205.8	242.8	254.4	265.6	274.2	286.8	307.6	319.3	337.9	364.6	389.4	406.1
Profits after Tax	65.5	81.7	95.7	106.7	125.0	146.6	153.1	159.3	163.9	170.8	182.6	188.9	199.3	214.3	228.2	238.0
Percent Change	-23.0	24.8	17.1	11.5	17.2	17.2	4.4	4.0	2.9	4.2	6.9	3.4	5.5	7.5	6.5	4.3
DETAILS OF REAL GNP --- ANNUAL RATES OF CHANGE																
Gross National Product	-3.6	6.4	5.3	4.0	5.7	6.2	4.2	3.5	3.5	3.3	3.3	3.1	3.0	3.3	2.0	2.6
Total Consumption	-0.2	4.9	4.8	3.9	5.5	5.3	3.8	3.8	3.6	3.6	3.1	3.1	2.9	3.2	2.8	2.6
Business Fixed Investment	-14.2	4.6	11.0	2.1	2.6	12.8	8.9	3.8	5.1	4.7	3.7	3.3	3.8	3.2	3.2	2.7
Equipment	-17.1	6.2	14.7	1.7	2.8	16.1	11.2	3.9	5.6	5.5	3.1	3.3	3.9	3.2	3.4	2.6
Nonresidential Construction	-6.5	0.8	2.0	3.1	2.0	3.8	2.1	3.6	3.3	2.3	5.9	3.2	3.3	3.4	2.5	2.9
Residential Construction	-23.0	39.9	14.4	7.1	-2.7	9.1	-2.0	-1.0	1.4	0.3	-0.7	-1.3	1.9	3.4	2.4	0.8
Exports	-6.1	6.9	8.8	7.9	8.2	8.1	6.6	6.1	5.7	5.0	5.6	5.7	4.9	5.2	5.1	4.9
Imports	-11.5	9.6	9.7	7.2	4.7	8.5	7.2	5.9	6.1	8.4	4.1	3.9	4.9	6.3	5.2	5.4
Federal Government	3.0	0.9	0.8	1.2	3.0	3.0	2.4	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
State and Local	1.7	4.8	4.3	4.4	5.1	5.2	4.9	4.2	4.4	4.0	3.0	3.1	3.6	3.6	3.6	3.6

HIGHLIGHTS OF THE CYCLICAL ALTERNATIVE

The alternative solution, Cycle Long 6/75, exhibits cyclical divergence from the smooth-growth baseline path in response to a combination of external price shocks and abrupt monetary policy changes. With few exceptions, the differences in the components of real demand are due to these stimuli. This cylical alternative is not an attempt to predict the future turning points of the economy. Nor is it an attempt to replicate the exceptional pattern of instability of recent times. The goal is to display the general characteristics of inflation and demand likely observed if cyclical disturbances characteristic of postwar U.S. economic history occur during the next sixteen years. The alternative simulates four cycles, with real GNP peaking in the second quarter of 1977, the third quarter of 1981, and the second quarters of 1984 and 1988. The annual results are summarized in Table 1.4. Comparisons of the real growth path and the unemployment rate under the two solutions are given in Charts 1.1 and 1.2.

Because the solution does not reflect additional instability created by the stochastic elements in the economic structure, it still understates the instability of output and prices that would be created by the shocks and policies that are assumed. Further long-term solutions will be developed that make allowance for these and other negative phenomena.

Chart 1.1

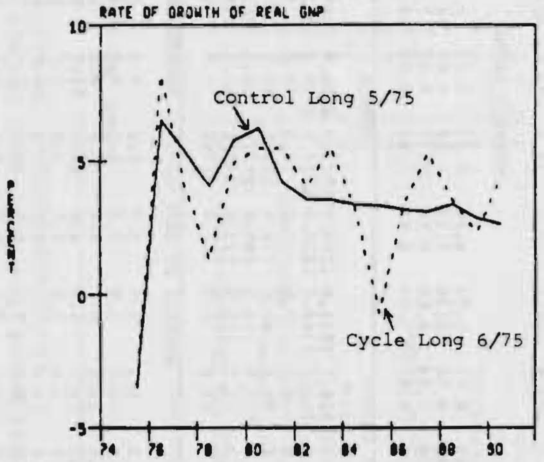
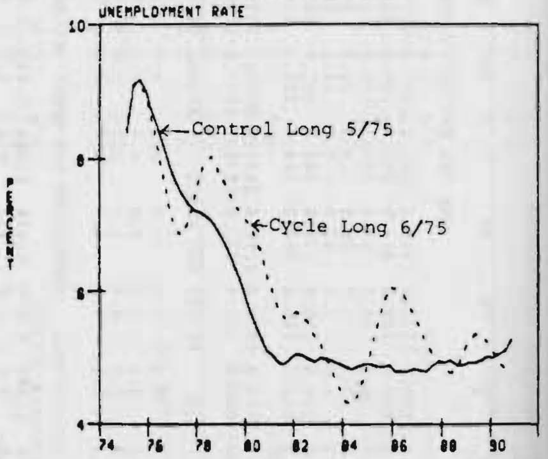


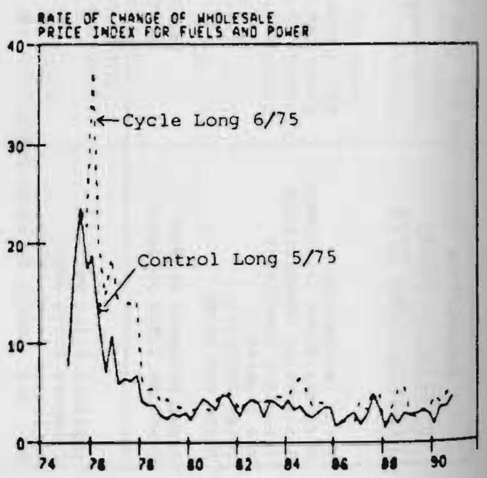
Chart 1.2



PRICE SHOCKS

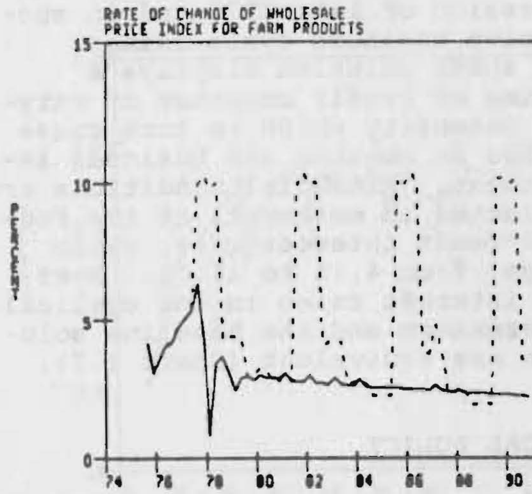
The assumptions of higher foreign oil prices, a more rapid deregulation of domestic energy prices and periodic spurts in agricultural commodity prices have been used to generate more volatile price movements in the alternative solution. The Wholesale Price Index for fuels is assumed to rise 23.8% in 1975, 15.3% in 1977 and 8.6% in 1978. Relative to the baseline solution, energy prices are 19.5% higher by 1978 and 30.5% higher by 1990. The rates of change in wholesale fuel prices under the two solutions are displayed in Chart 1.3.

Chart 1.3



Agriculture prices are exogenously accelerated every four years beginning in 1977 (see Chart 1.4). Each impulse adds 6-8% to these prices compared to the Control. These shocks are obviously minor compared to the farm price explosions of 1973 and 1974, but policy-makers are assumed to have learned from this earlier experience.

Chart 1.4



The energy-based inflation is transmitted to every sector of the economy, although gasoline and utilities prices would be affected most immediately. Secondary effects are propagated in the energy-intensive primary processing industries such as metals, paper and wood, chemicals and textiles. The combined effects of the energy and food price shocks add 10.6% to the Wholesale Price Index by 1980, and 20.2% by 1990. Inflationary pressures spread through final markets, as well, triggering a wage-price spiral. By 1985, the price level is 8.1% higher than in the smooth-growth case, while the wage index is up 6.9%. The inflation rate, measured by the GNP deflator, averages 6.5% from 1974 to 1980 and 5.0% from 1980 to 1985. (See Charts 1.5 and 1.6.)

Chart 1.5

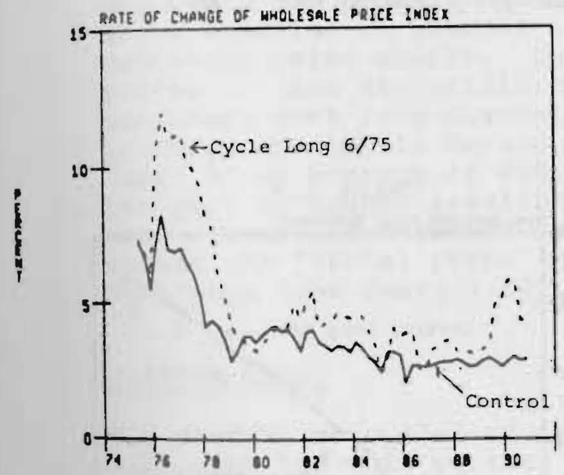
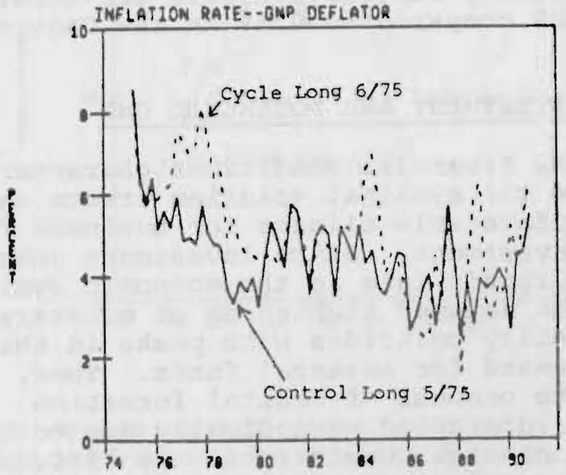


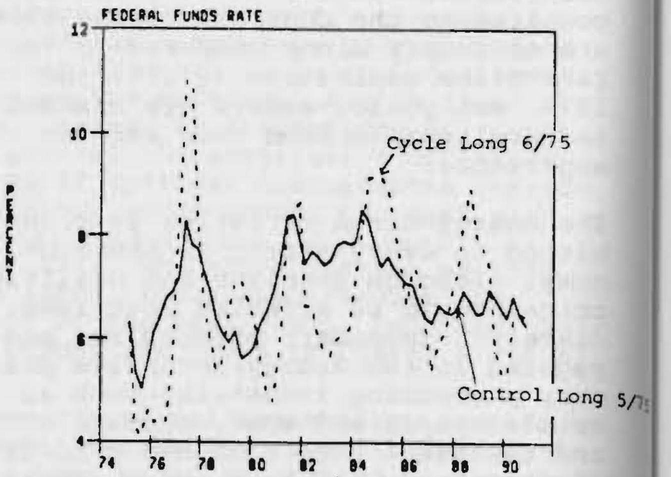
Chart 1.6



MONETARY POLICY

Monetary policy is assumed to vacillate from the extremes of accommodation to credit stringency. The near-term growth of bank reserves is accelerated to quicken the pace of economic recovery. Then, as the forces of recovery and higher inflation generate strong demands for credit, the growth of reserves is restricted. The monetary factor is the pivotal element in the growth recession of late 1977 and in successive business cycle swings. The shock solution displays a series of credit crunches of varying intensity which in turn cause cycles in housing and business investment. Financial conditions are reflected in movements of the Federal funds interest rate, which ranges from 4.1% to 11.0%. Average interest rates in the cyclical alternative and the baseline solution are equivalent (Chart 1.7).

Chart 1.7



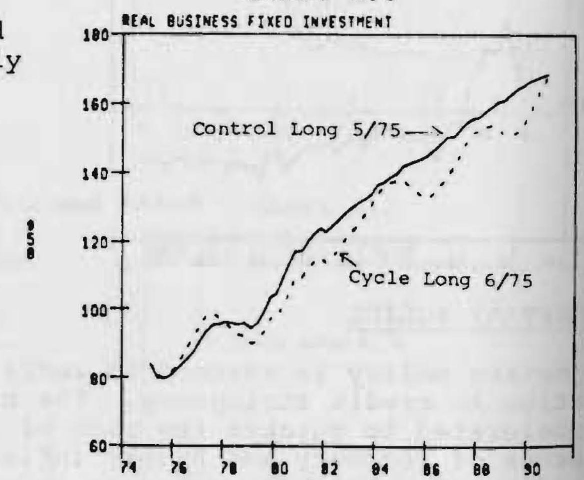
FISCAL POLICY

Fiscal policy can be characterized as a set of delayed reactions to economic downturns. The assumed nominal tax cuts are larger than those in the Control solution, in part as a response to the more severe cyclic contractions and in part to reduce the fiscal drag produced by a progressive tax structure in an environment of rapid inflation. The growth rate of constant dollar, Federal non-military expenditures is increased by 0.5% to 2.5% beginning in 1979. As a result, Federal deficits are substantially larger, averaging 1.3% of GNP compared to 0.5% in the Control path.

INVESTMENT AND POTENTIAL GNP

The financial conditions characterized in the cyclical solution create an unfavorable climate for business fixed investment. Since investment generally responds late in the economic cycle, the assumed tightening of monetary policy coincides with peaks in the demand for external funds. Thus, the process of capital formation is disrupted periodically due to financial constraints. By 1990, the decrement to the capital stock is 3%. The path of business fixed investment in constant dollars is shown in Chart 1.8.

Chart 1.8

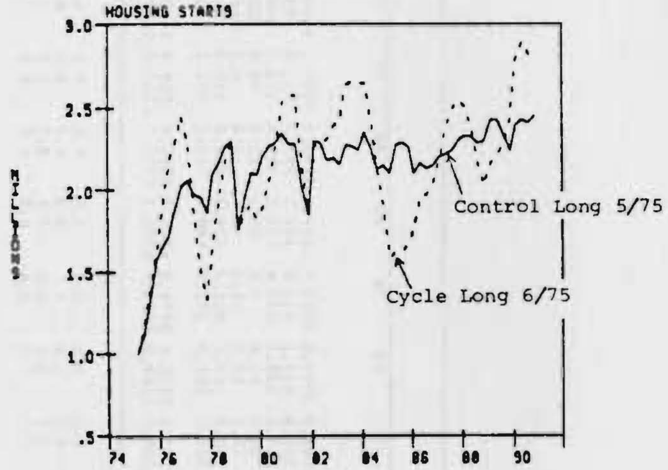


The growth of macroeconomic potential is adversely affected by the relative shortfall of capital. Growth of potential GNP averages 0.1% per year lower than the Control path and leaves potential 2% below the Control level by 1990.

HOUSING

In Cycle Long 6/75, housing starts exhibit a volatility reminiscent of the most recent housing cycle. Over the 1976-1990 period, housing starts vary in the range of 1.3 to 2.9 million units. The cyclical pattern underscores the dominant influence of monetary policy in the short run. Interest rates determine the volume of savings inflows to lending institutions which, in turn, governs the availability of mortgage credit. The total of housing starts over the fifteen year period matches the total in the smooth-growth solution, however. This reflects the dominance of demographic factors in determining the long-run demand for housing in the model. Further studies will probe this issue further.

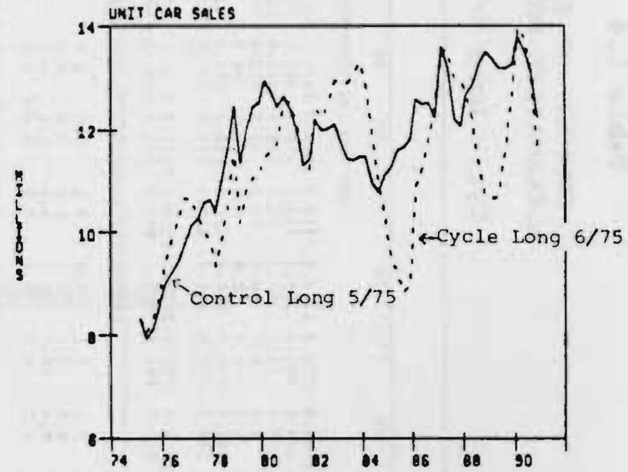
Chart 1.9



CONSUMER DEMANDS

The macroeconomic instability of the alternative solution leads to a higher rate of personal savings. Moreover, the product mix of consumer spending is altered by the exogenous price shocks. The higher prices of food and utilities leave consumers with less discretionary income. Automobile demand is reduced by an average of 400,000 units per year as higher gasoline prices, auto prices and interest rates increase the "rental price" of car ownership (see Chart 1.10).

Chart 1.10



FOREIGN TRADE

The production cycles of major foreign economies are assumed to coincide with the U.S. cycles. As a result, movements in commodity prices are accentuated. On an average, however, foreign production rates are lower than in Control Long 5/75 and thus export demand is weaker. This factor, together with the higher price of imported oil, erases the surplus on the balance of trade that is projected in the Control forecast.

Table 1.4

SUMMARY OF THE
ALTERNATIVE SOLUTION

Cycle Long 6/75

	Years															
	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90
GNP AND ITS COMPONENTS																
Total Consumption	946.9	1066.4	1185.3	1288.5	1418.0	1551.3	1695.3	1852.8	2039.7	2206.8	2309.6	2483.2	2689.7	2873.1	3057.1	3303.5
Business Fixed Investment	146.7	168.6	202.1	208.4	217.8	250.9	285.0	308.9	348.9	393.4	410.3	423.6	469.5	505.2	523.9	589.1
Residential Construction	40.0	70.4	77.5	83.3	96.3	110.9	131.4	131.9	157.8	163.1	129.2	143.6	178.5	192.4	193.3	243.3
Inventory Investment	-11.0	6.3	5.1	-0.5	11.6	15.0	22.8	22.9	26.1	28.2	13.9	7.5	15.4	21.4	24.4	25.4
Net Exports	7.6	-2.6	-4.6	2.0	4.4	0.2	-0.7	0.9	-6.1	-4.5	16.3	10.3	-3.8	-3.2	6.6	-14.2
Total Federal	131.3	141.5	149.6	166.2	181.8	198.2	214.3	230.8	248.6	269.0	292.1	315.7	339.3	364.6	392.2	422.4
State and Local	212.3	240.2	266.6	291.4	320.2	350.9	388.6	429.0	475.3	527.1	561.3	592.7	649.1	713.2	772.1	843.4
Gross National Product	1473.7	1690.9	1881.6	2039.1	2250.1	2477.2	2736.7	2977.3	3290.3	3583.0	3732.6	3976.8	4337.7	4666.6	4969.6	5412.8
Real GNP (1958 dollars)	793.3	857.7	891.8	903.1	947.0	998.1	1051.7	1093.5	1153.0	1189.1	1180.3	1218.9	1282.7	1327.3	1357.2	1415.1
PRICES AND WAGES --- ANNUAL RATES OF CHANGE																
Implicit Price Deflator	9.1	6.1	7.1	7.0	5.2	4.5	4.9	4.6	4.8	5.6	4.9	3.2	3.6	4.0	4.1	4.5
Consumer Price Index	9.2	6.6	7.4	6.9	5.5	4.9	5.0	5.2	5.2	5.3	5.0	4.1	3.9	4.2	4.2	4.5
Wholesale Price Index	9.4	9.4	10.7	8.1	4.6	3.5	4.1	4.7	4.4	4.3	3.3	3.5	3.1	3.3	3.6	5.1
Adj. Avg. Hourly Earnings Index	8.5	8.2	9.1	8.5	7.9	7.4	6.9	6.8	7.0	7.5	7.5	6.8	6.2	6.0	6.0	6.0
PRODUCTION AND OTHER KEY MEASURES																
Industrial Production (67=1)	1.122	1.260	1.324	1.315	1.393	1.495	1.612	1.685	1.823	1.912	1.855	1.922	2.092	2.202	2.260	2.404
Annual Rate of Change	-9.7	12.2	5.1	-0.7	5.9	7.3	7.8	4.6	8.2	4.9	-3.0	3.6	8.8	5.3	2.6	6.3
Housing Starts(mil. units)	1.278	2.191	1.744	2.024	1.832	2.180	2.291	2.306	2.581	2.263	1.617	1.925	2.390	2.269	2.263	2.812
Ret. Unit Car Sales-Total	8.3	10.0	10.2	10.3	10.8	11.8	11.8	12.5	13.0	11.5	9.1	11.6	13.2	11.7	11.3	13.1
Unemployment Rate (percent)	8.9	7.9	7.0	7.9	7.4	6.6	5.7	5.5	4.8	4.4	5.6	5.9	5.1	4.9	5.3	4.9
Federal Budget Surplus (NIA)	-75.9	-53.0	-40.2	-47.4	-57.9	-49.2	-33.0	-42.1	-18.5	-14.9	-61.4	-89.1	-65.3	-66.3	-74.6	-45.5
INTEREST RATES																
New AA Corp. Utility Rate (%)	9.04	8.60	9.47	9.07	8.91	9.08	9.31	9.09	9.03	9.58	9.73	8.95	8.42	8.61	8.57	8.44
New High-grade Corp.Bond Rate (%)	8.66	8.31	9.16	8.76	8.61	8.78	9.00	8.78	8.72	9.26	9.40	8.64	8.14	8.33	8.28	8.16
Federal Funds Rate (%)	4.82	4.72	9.64	5.91	6.86	5.42	7.79	6.27	5.98	8.36	8.41	6.88	6.04	8.12	6.61	6.13
Prime Rate (%)	6.81	5.79	9.22	7.87	7.34	6.42	7.74	7.20	6.73	8.34	8.85	7.63	6.77	8.17	7.40	6.64
INCOMES																
Personal Income	1245.5	1403.4	1558.4	1683.4	1844.5	2009.8	2205.5	2394.4	2634.4	2887.6	3053.2	3226.2	3471.8	3735.9	3985.9	4307.0
Disposable Income	1076.4	1211.3	1340.4	1447.8	1592.5	1726.8	1885.3	2050.9	2248.7	2457.3	2594.4	2757.8	2960.9	3178.7	3375.8	3617.0
Saving Rate (percent)	9.5	9.6	9.3	8.8	8.8	8.0	8.0	7.6	7.3	8.3	9.0	8.0	7.2	7.7	7.5	6.8
Corp. Cap. Cons. Allow.	83.9	91.5	99.8	109.3	119.8	131.2	143.7	157.9	173.7	191.4	211.3	233.0	256.0	280.8	307.4	335.9
Profits before Tax	107.8	156.0	174.0	180.4	202.2	238.7	271.6	292.6	332.7	341.2	299.7	326.4	387.6	409.4	443.3	523.9
Profits after Tax	66.3	95.9	106.8	110.3	122.8	144.1	163.5	175.5	198.9	203.3	178.0	193.2	228.6	240.6	259.8	307.0
Percent Change	-22.0	44.6	11.4	3.3	11.3	17.3	13.4	7.4	13.3	2.2	-12.4	8.5	18.3	5.3	7.9	13.2
DETAILS OF REAL GNP --- ANNUAL RATES OF CHANGE																
Gross National Product	-3.4	8.1	4.0	1.3	4.9	5.4	5.4	4.0	5.4	3.1	-0.7	3.3	5.2	3.5	2.3	4.3
Total Consumption	-0.1	6.4	3.9	2.0	4.8	4.9	4.6	4.5	5.3	2.9	-0.5	4.2	5.2	2.9	2.5	4.4
Business Fixed Investment	-13.8	7.5	11.6	-4.0	-0.9	11.0	9.4	3.8	8.2	7.4	-0.3	0.2	8.2	4.2	-0.8	7.2
Equipment	-16.8	9.4	15.3	-5.4	-0.4	15.5	12.3	3.5	8.6	7.9	-1.3	0.0	9.5	5.1	-2.0	6.7
Nonresidential Construction	-6.1	3.2	2.6	0.0	-2.1	-0.8	0.5	4.8	6.7	6.0	3.0	0.8	4.0	1.1	3.4	9.2
Residential Construction	-21.8	58.2	0.3	-3.7	4.2	5.8	9.8	-5.4	11.1	-3.3	-23.1	6.7	16.7	1.9	-4.0	17.5
Exports	-6.1	6.5	6.8	3.9	6.6	5.0	6.7	4.8	6.3	6.4	3.8	5.1	6.0	5.8	4.9	4.8
Imports	-11.3	12.6	8.1	1.4	4.3	5.6	8.2	4.8	8.2	10.0	-1.5	3.5	12.9	4.3	3.6	10.9
Federal Government	3.0	0.7	-0.7	3.0	3.0	3.0	2.4	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
State and Local	1.8	5.1	3.2	3.5	4.4	4.4	5.1	5.1	5.2	4.7	1.3	1.2	4.8	4.7	3.3	3.9

Appendix C

PIES ECONOMETRIC DEMAND MODEL

Appendix C

PIES ECONOMETRIC DEMAND MODEL

I. INTRODUCTION

The energy demand model of the Project Independence Evaluation Systems consists of a set of econometrically-based sectoral models which project regional final demands for various refined petroleum products, natural gas, electricity, and coal on a nine Census region basis (see demand region map in Appendix A). The demand model treats fuel prices and macroeconomic activity variables as exogenous. For each year in the period 1975 to 1990, quantities demanded and price elasticities of demand are forecasted at the given set of prices. This provides a complete characterization of demand in a given year which is provided to the PIES integrating model. The demand model does not produce estimates of intermediate fuel demands for electricity generation or petroleum refining; rather these intermediate energy demands are determined (by an explicit cost minimization) within the conversion sectors of the integrating model.

Table 1 provides 1974 consumption data by fuel and economic sector at the level of detail at which demand is modeled in PIES. It is presented to illustrate the importance of the various fuels in the overall energy market. Notice that transportation gasoline, plus industrial coal, plus industrial and household/commercial electricity, natural gas, distillate oil, residual oil, kerosene, and liquid gases constitute over 80 percent of final energy consumption (i.e., excluding consumption by electric utilities). These fuels in these sectors are the subjects of major submodels within the overall PIES econometric demand model. Figure 1 shows the organization of the components of the energy demand model.

The major submodels for the household/commercial (residential and commercial) and industrial sectors are sector-specific with a common structure. These sectors are discussed in section II. Gasoline demand is jointly determined with automobile fleet efficiency and utilization within a structural model. This model and the models for other transportation fuels are presented in section III. Simulation conventions and results are discussed in section IV. section V discusses the econometric methods and results of the major submodels.

Table 1

1974 ENERGY CONSUMPTION BY FUEL BY SECTOR

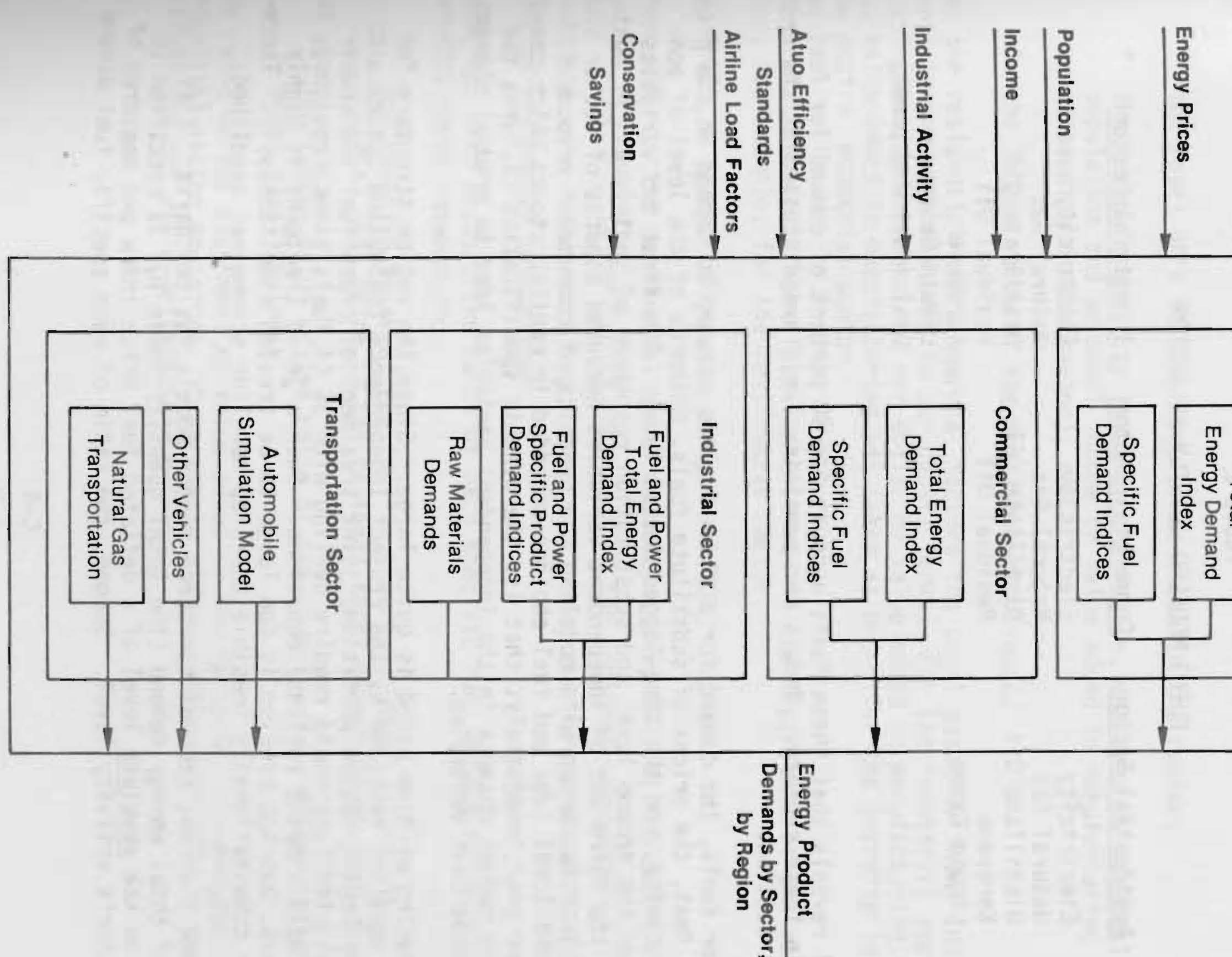
(10^{12} Btus)

	Household/ Commercial	Industrial (Fuel & Power)	Raw Materials	Transportation	Electric Utilities	Misc.	Fuel Total
Coal							
Bituminous	229	4,167		2	8,630		13,028
Anthracite	62	32			38		132
Natural Gas	7,116	10,394	689	664	3,328		22,191
Carbon Black			47				47
Petroleum Products							
Gasoline				12,596			12,596
Jet Fuel				2,006			2,006
Distillate	3,000	769		2,027	396	50	6,242
Residual	1,125	1,182		685	3,018	62	6,072
Kerosene	289	83					372
Liquid Gas	734	186		133		-	1,053
Liquid Refinery Gas			176				176
Liquid Petroleum Gas		740					740
Still Gas		1,038	61				1,099
Naphthas			291				291
Special Naphthas			165				165
Lubes and Waxes			228	160			388
Asphalt	1,241						1,241
Petroleum Coke		391	170				561
Miscellaneous			346			107	453
Fossil Fuels	13,796	18,982	2,173	18,273	15,410	219	68,853
Electricity*	3,372	2,416		16			5,804
Sector Totals	17,168	21,398	2,173	18,289	15,410	219	

*Nine percent has been deducted from electricity distributed for transmission loss.

Source: Oil, Coal, and Gas from Bureau of Mines. (1974 preliminary) Electricity from Edison Electric Institute

Figure C-1
Demand Model: Basic Configuration



II. RESIDENTIAL, COMMERCIAL, AND INDUSTRIAL SECTOR DEMANDS FOR ENERGY

Energy demands for most end uses in these sectors can be satisfied by a variety of fuels. Therefore, modeling fuel substitution choices in response to price changes is central to the major models in these sectors. Table 2 shows the fuels whose demands are jointly modeled within each sector.

Table 2

FUELS MODELED JOINTLY BY SECTOR

Residential Sector	Commercial Sector	Industrial Sector
Electricity	Electricity	Electricity
Natural Gas	Natural Gas	Natural Gas
Distillate Oil	Distillate Oil	Distillate Oil
Kerosene	Residual Oil	Residual Oil
Liquid Gases		Kerosene
		Liquid Gases
		Coal (fuel and power)

Table 1 reveals that these fuels account for 90 percent of demand for fuel and power in these sectors. Models for remaining fuels are discussed at the end of this section.

For major fuels, the demand for a given fuel is assumed to depend on the price of that fuel, the prices of substitute fuels, measures of the level of economic activity, and the time-lagged demand level. The first two variables condition the demand level and substitution responses of individuals or businesses; the third set of independent variables measures aspects of sector size, and the last factor permits modeling the dynamics of consumers' responses given behavioral lags and fuel choices embedded in capital stocks which cannot be turned over immediately; that is, the dynamic specification captures the fact that sudden changes in the independent variables lead to gradual changes in the dependent variables.

The modeling problem posed is quite large. Since the region structure for demand modeling required by the Project Independence Evaluation System uses the nine Census region partition, joint treatment of cross-fuel and cross-regional structure would require dealing with 36 (4 fuels times 9 regions), to 63 (7 fuels times 9 regions) equations. Such a joint treatment is highly desirable, but the problem is too large to be treated simultaneously. Therefore, a computationally feasible two-step modeling scheme was developed.

As Figure 1 shows, each of the three sector models has two parts. First, an index of total energy demand (the total quantity index TQ) is specified to depend on the absolute level of a deflated fuel price index and measures of the sector's activity level. Second, the ratio of each specific fuel demand

to the total energy index is specified to depend on the relative price of the fuel. The regional structure of the data is exploited by allowing the intercepts in each regional equation to vary but constraining the coefficients of all other variables to be the same across all regions. This effectively pools the data which increases the effective number of observations and the variance in the sample.

Specifically, for each sector the total quantity index in the region depends on:

- the level of a total energy price index in the region;
- the sector's activity level in the region, measured by regional population and personal income or value added in manufacturing (depending on the sector); and
- the lagged value of the total quantity index.

For the residential and commercial sectors the total quantity index and personal income were measured in per capita terms. For the industrial sector, total quantity was measured per dollar of value added in manufacturing. That is, value added in manufacturing was taken as proxy for the activity level of the entire industrial sector.

This relationship is specified to be linear in the logarithms of the variables. Thus, for example, for the residential sector,

(1) $\ln TQR_r = \alpha_r + \beta \cdot \ln TPR_r + \gamma \cdot \ln YC_r + \lambda \cdot \ln TQR_{r,-1}$,

where TQR_r is the residential total quantity index, TPR_r is the total energy price index, YC_r is per capita income, r is the regional subscript and the subscript, -1, indicates a lag. Note that among the parameters only the intercept is regionally subscripted.

Next, for each sector, the ratio of each specific fuel demand to the total quantity index depends on:

- the relative price of the fuel in the region (the ratio of the regional fuel price to the regional total energy price index); and
- the lagged value of the ratio of the specific fuel demand to the total quantity index.

The ratio of gas customers to value added in manufacturing was entered in the industrial sector equations. Experiments with a similar variable in the other sectors did not yield satisfactory results.

The relationships are linear in the logarithms of the variables. Thus, for example, for electricity in the residential sector,

$$(2)\quad \ln\left(\frac{ELQR_r}{TQR_r}\right) = \alpha_{er} + \beta_e \cdot \ln(ELPR_r/TPR_r) + \lambda_e \cdot \ln\left(\frac{ELQR_r}{TQR_r}\right)_{-1},$$

where ELQR is the residential electricity demand and ELPR is the residential electricity price. Note again that only the intercept is regionally subscripted, but in each equation parameters are specific to each fuel.

Finally, the total price and quantity indices in each region are log-linear regionally value-weighted averages of regional prices or quantities. That is,

$$(3)\quad \ln TPR_r = \sum_i v_{ir} \ln P_{ir};\ \ln TQR_r = \sum_i v_{ir} \ln Q_{ir};$$

$$v_{ir} = P_{ir} \cdot Q_{ir} \ / \sum_i P_{ir} \cdot Q_{ir}.$$

For each sector, equation (1) determines the level of the regional total energy index as a function of the regional absolute price index and regional activity levels. Equation (1) is estimated on a time series of regional cross sections. Forcing the price and activity level coefficients to be the same across regions exploits the wide cross-regional variation in the independent variables. Specific fuel ratio equations of form (2) determine regional fuel demands as functions of the regional relative price of fuels. The ratio form localizes the impacts of activity levels in the total quantity index equation. It is consistent with the assumption that sector size *per se* does not affect the mix of energy demands.

Each sectoral equation has been estimated econometrically using data from a cross section of the nine Census regions over a sample period from 1960 to 1972. These equations were completed with a statistical specification which admits a regionally specific autocorrelation parameter. The resulting equations were estimated with a consistent and efficient "minimum distance" estimation technique (essentially a nonlinear multivariate version of "least squares").

The structural parameter estimates are summarized in Table 3. A detailed statistical characterization of the estimated equations is presented in the last section of this appendix.

The price elasticities can be derived from the parameters in Table 3 using equations (1)-(3). Let Q_i and P_i be the i^{th} fuel quantity and price in an equation of form (2), e.g.,

$$(4)\quad \ln(TQ_r) = \alpha_r + \beta \cdot \ln(TP_r) + \ldots,$$

$$(5)\quad \ln(Q_{ir}/TQ_r) = \alpha_{ir} + \beta_i \cdot \ln(P_{ir}/TP_r) + \ldots,$$

Table 3

PARAMETER ESTIMATES FROM ENERGY DEMAND MODEL

Residential Sector

	Price Coefficient	Lag Coefficient	Income Per Capita Coefficient
Total Energy (per capita)	-.133	.728	.300
Electricity	-.240	.869	
Natural Gas	-.193	.876	
Distillate Oil	-.450	.527	
Kerosene	-.168	.845	
Liquid Gases	-.388	.384	

Commercial Sector

	Price Coefficient	Lag Coefficient	Income Per Capita Coefficient
Total Energy (per capita)	-.140	.532	.727
Electricity	-.370	.383	
Natural Gas	-.440	.002	
Distillate Oil	-.639	0.0	
Residual Oil	-.639	0.0	

Industrial Sector

	Price Coefficient	Lag Coefficient
Total Energy (per dollar value added in manufacturing)	-.126	.588
Electricity	-.163	.857
Natural Gas	-.187	.710
Distillate Oil	-.260	.655
Residual Oil	-.363	.173
Kerosene	-.260	.655
Liquid Gases	-.260	.655
Steam Coal	-.480	.394

(6) $\ln(TP_r) = \Sigma_i\, v_{ir} \cdot \ln(P_{ir})$.

If the weights v_{ir} were fixed, the short-run price elasticity would be:

$$(7) \quad \frac{\partial \ln(Q_{ir})}{\partial \ln(P_{ir})} = (1-v_{ir})\cdot\beta_i + v_{ir}\cdot\beta \;.$$

If the price coefficients β and β_i are both negative, the own-price elasticity is negative since all the v_{ir} are between 0 and 1. Further, the cross-price elasticity would be:

$$(8) \quad \frac{\partial \ln(Q_{ir})}{\partial \ln(P_{jr})} = -v_{jr}\ (\beta_i - \beta),\ j \neq i.$$

If the "substitution" coefficient β_i is larger in absolute value than the "total energy index" coefficient β then the cross-price elasticities are positive.

Because of the lag structure these price coefficients are not constant over time. The long-run coefficient corresponding to a short-run coefficient β, is

$$(9) \quad \beta(1 + \lambda + \lambda^2 + \ldots) = \beta/(1-\lambda),$$

so that for large lag coefficients (λ's), the long-run coefficient will be much larger than the short-run coefficient β.

Table 4 gives a sample of the numerically computed elasticities for the aggregated household/commercial sector and the industrial sector for the 1985 \$13 Reference Case. These are the quantity-weighted averages of the nine sets of regional elasticities.

Note carefully that the elasticities presented in Table 4 are not the usual long-run elasticities presented in the literature. They are numerically calculated to represent rolled-in price effects along a carefully specified future price trajectory which approximates price movements to an equilibrium consistent with a given price of imported crude for 1980, 1985, and 1990. (See the section of simulation assumptions below.) The elasticities presented for 1985 are substantially lower than the final long-run price elasticities. (Further, the small, but anomolous, negative cross-price elasticities arise from the intermediate dynamics, and change sign in the long run.)

Symbols in Table 4 mean:

- EL - electricity
- NG - natural gas
- DF - distillate fuel
- RF - residual fuel
- KS - kerosene
- LG - liquid gases
- BC - bituminous coal (fuel and power)
- HC - household/commercial sector
- IN - industrial sector
- Q - quantity
- P - price

The demands for other fuels are modeled using single equation time series techniques. Fuels used as raw materials are trended with projections of industrial indices for the industry where the fuel has its primary application and are shared to census regions using projections of regional income originating for those industries. Table 5 summarizes these relationships.

Table 4

NUMERICAL COMPUTED ELASTICITIES FOR U.S.: 1985
$13 Reference Case

Household/Commercial Sector

Quantity	Price					
	ELHCP	NGHCP	DFHCP	RFHCP	KSHCP	LGHCP
ELHCQ	-.51	.075	.054	-.007	.011	.058
NGHCQ	.26	-.721	.024	.017	.008	.042
DFHCQ	.252	.063	-.75	.007	.001	.018
RFHCQ	.278	-.02	.018	-.594	-.002	-.002
KSHCQ	.178	.053	.056	.000	-.778	.046
LGHCQ	.079	.017	.025	.000	.001	-.567

Income elasticity = 1.275 (long run)

Industrial Sector

Quantity	Price						
	ELINP	NGINP	DFINP	RFINP	KSINP	LGINP	BCINP
ELINQ	-.469	.062	.048	.049	.009	.028	.029
NGINQ	.119	-.392	.010	.007	.001	.005	.006
DFINQ	.213	.108	-.701	.028	.002	.009	.013
RFINQ	.075	.049	-.006	-.416	-.002	-.006	-.002
KSINQ	.223	.093	.020	.034	-.721	.008	.015
LGINQ	.195	.138	.017	.024	.002	-.715	.01
BCINQ	.225	.084	.017	.020	.001	.006	-.562

VA elasticity = 1.00 (short run and long run)

Table 5

SUMMARY OF OTHER FUELS RELATIONSHIPS

Dependent Variable	Independent Variable
Anthracite Coal (H/C & Ind.)	Time
Bituminous Coal (H/C)	Time
Liquid Gases for Raw Materials	Petroleum Industry Production Index
Petroleum Gas for Raw Materials	Petroleum Industry Production Index
Still Gas for Raw Materials	Petroleum Industry Production Index
Still Gas Industrial	Total refinery output
Industrial Petroleum Coke	Iron and Steel Production Index
Raw Materials Petroleum Coke	Petroleum Industry Production Index
Industrial Naphtha	Petroleum Industry Production Index
Raw Materials Naphtha	Petroleum Industry Production Index
Industrial Lubes and Waxes	Synthetic Materials Production Index; Motor Vehicles Production Index
Transportation Lubes and Waxes	Industrial lubes and waxes
Industrial Carbon Black	Paints Production Index
Other Chemical Raw Materials	Basic Chemicals Production Index
Miscellaneous Distillate and Residual	Predicted to be invariant over time
Metallurgical Coal for Industry	Iron and Steel Production Index
Miscellaneous Raw Materials	Petroleum Industry Production Index

The methodology underlying the transportation sector model is quite different from that underlying the models of the other three sectors. For this sector fuel demands are modeled for the most part by end use. Interfuel substitution is not as significant in the transportation sector as it is the three sectors discussed previously. Thus fuel substitution choices are not the central features of the transportation model. Figure 2 presents a block diagram of the transportation model.

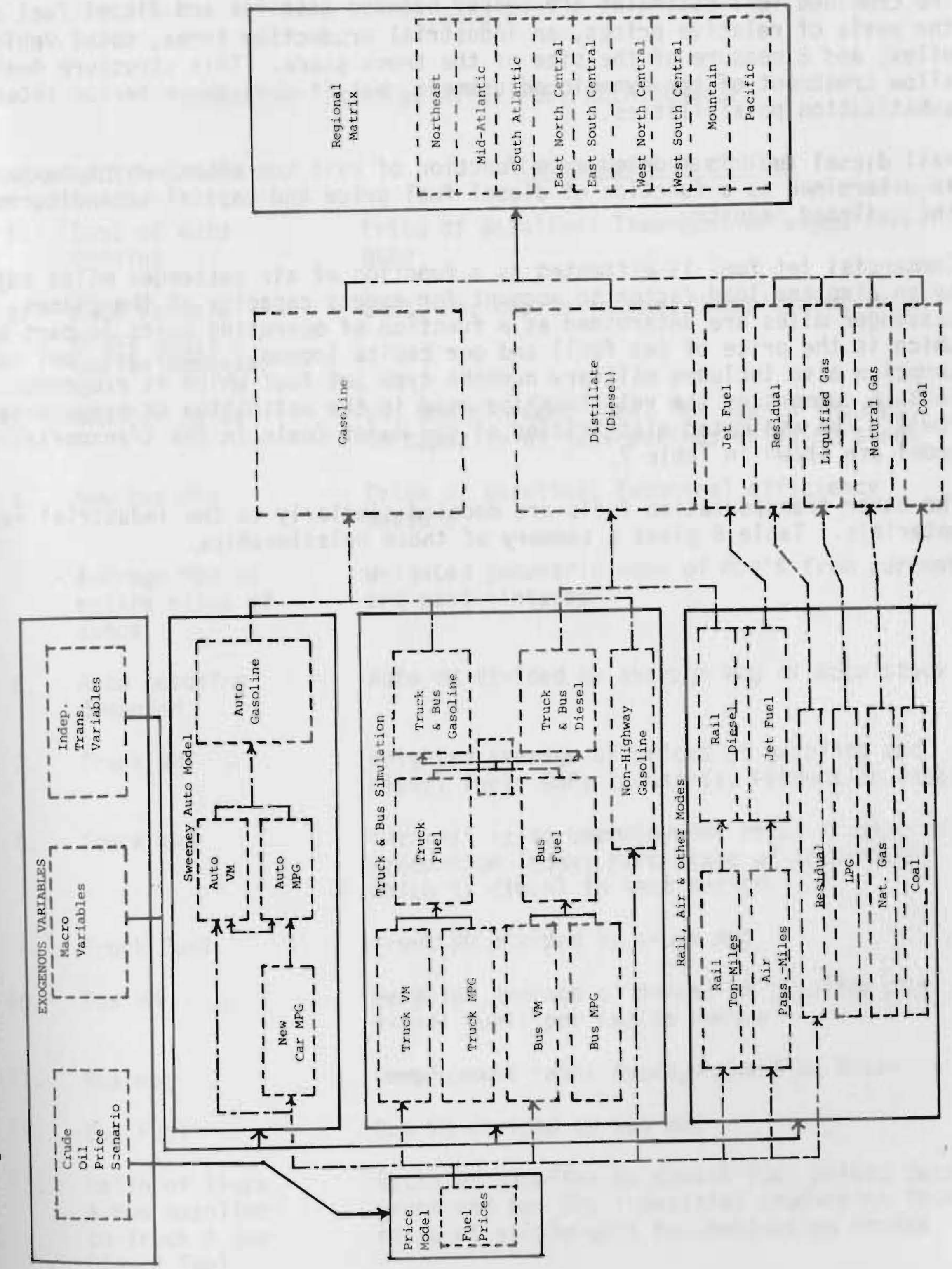
The major elements of transportation demand include auto highway gasoline use, non auto highway gasoline and diesel fuel use, rail diesel fuel use, and commercial jet fuel. These fuel demand equations were estimated using time-series single equation techniques for national consumption and then disaggregated using regional income and population projections. National data are used because crucial data elements were not available at the regional level.

Automobile gasoline is determined by separately modeling vehicle miles and fleet average miles per gallon (mpg) for automobiles. Vehicle miles (VM) is specified to be a function of per capita income, the cost of vehicle operation (both time and fuel cost), and the unemployment rate. Automobile use of gasoline is determined as the ratio of automobile vehicle miles to the average fleet efficiency. Efficiency (i.e., mpg) of the existing stock of automobiles is determined as a weighted average of efficiences of automobiles from various vintages (years produced). The weights in the averaging correspond to the product of the number of automobiles in existence from each vintage, and an index of miles driven by automobiles of various ages. Exponential scrapping of the existing fleet occurs over time in the model; newer cars are assumed to be driven more than older cars. The number of new cars purchased in a given year is endogenously determined given the desired vehicle miles and the capital stock of automobiles remaining from earlier vintages. The efficiency of new cars depends upon gasoline price in the current year and a measure of average technical efficiency of new cars when standardized for curb weights. The price dependency represents a shifting of the weight mix of automobiles; the technical efficiency measure represents changes in mpg of automobiles when the weight mix is held constant. This measure of technical efficiency is assumed to increase by 31 percent from 1975 to 1985. However, in the conservation cases, legislated efficiency standards are imposed on newly purchased cars. The statistical specification of this structure is discussed in the last section of this Appendix.

This structure is very flexible in that it allows for changes in operating costs to be reflected in incremental changes in the efficiency of the stock over a number of years. Hence, the changes in the capital stocks brought about by changes in price or income are explicitly treated.

A similar stock adjustment treatment was not feasible for trucks and buses. Rather, total fuel for each type of vehicle is estimated as a function of vehicle miles and fleet efficiency (without vintaging).

Figure C-2
Transportation Model Configuration



The combined fuel estimates are shared between gasoline and diesel fuel on the basis of relative prices, an industrial production index, total vehicle miles, and a measure of the size of the truck stock. This structure does not allow treatment of the dynamic adjustment, but it does characterize interfuel substitution possibilities.

Rail diesel fuel is modeled as a function of rail ton miles, which in turn is determined as a function of diesel fuel price and capital expenditures in the railroad industry.

Commercial jet fuel is estimated as a function of air passenger miles adjusted by an airplane load factor to account for excess capacity of the planes. Air passenger miles are determined as a function of operating costs (a part of which is the price of jet fuel) and per capita income. Total jet fuel consumption also includes military naphtha type jet fuel which is exogenous. Table 6 summarizes the relationships used in the estimation of transportation fuels. The estimated elasticities of the major fuels in the transportation model are shown in Table 7.

The other transportation fuels are modeled similarly to the industrial raw materials. Table 8 gives a summary of these relationships.

Table 6

SUMMARY OF TRANSPORTATION FUEL RELATIONSHIPS

	Dependent Variable	Independent Variables
1.	Cost of Auto Driving	Price of gasoline; Time-cost of wages foregone
2.	Auto Vehicle Miles (VM) Capita Demanded	Cost; Per capita income; Unemployment rate
3.	New Car Sales	VM; Unemployment rate; Per capita income; VM capacity of last periods existing stock
4.	New Car mpg	Price of gasoline; Technical efficiency measure
5.	Average mpg of entire stock of autos	Weighted geometric mean of mpg's from current and past vintages
6.	Auto gasoline demanded	Auto VM divided by average mpg of auto stock
7.	Truck VM	Weighted average of prices of gasoline and diesel fuel; GNP; Industrial Production Index
8.	Truck mpg	Interest rate; Unemployment rate; Industrial Production Index; Percentage of truck fuel which is diesel in last period
9.	Truck Fuel	Truck VM divided by truck mpg
10.	Bus VM	Weighted average of prices of gasoline and diesel fuel; per capita income
11.	Bus mpg	Uemployment rate; Average speed of buses
12.	Bus Fuel	Bus VM divided by bus mpg
13.	Ratio of Truck & Bus Gasoline to Truck & Bus Diesel Fuel	Ratio of gasoline to diesel fuel price; total truck and bus VM; industrial production index; ratio of single-unit to combination trucks

14.	Rail Ton Miles	Diesel fuel price (not including highway taxes); capital expenditures in the railroad industry
15.	Rail Diesel Fuel	Rail ton miles; index of employee compensation (nonfarm)
16.	Air Passenger Miles	Cost per passenger mile of aircraft operation (part of which is the price of jet fuel); per capita income
17.	Commercial Jet Fuel	Air passenger miles adjusted by CAB loadfactor

Table 7

TRANSPORTATION MODEL ELASTICITIES (LONG RUN)

	Price Elasticities	Income Elasticities
Auto Vehicle Miles	-.480	.976
Airline Passenger Miles	-.245	1.457
Truck Fuel Demand	-.545	1.740
Bus Fuel Demand	-.475	.285
Rail Diesel Fuel Demand	-.368	.144

Table 8

SUMMARY OF OTHER FUEL RELATIONSHIPS

Quantity	Independent Variable
1. Nonhighway	GNP; time
2. Bituminous Coal in Transportation	Last period's bituminous coal in transportation
3. Liquid Gases in Transportation	Industrial Production Index; Farm Production Index
4. Residual Fuel in Transportation	Rail diesel fuel; Index of activity in water transportation; ratio of distillate to residual price
5. Electricity in Transportation	Time
6. Asphalt	Gasoline demand
7. Natural Gas in Transportation	Total household/commercial; industrial and raw material natural gas demand from major fuels submodels

To interface with the PIES integrating model a constant elasticity approximation to the demand model is generated. (This interface is described more fully in Appendix A.) A base set of prices near the PIES equilibrium prices is used to calculate a base set of demands. These prices are then varied one by one to generate the matrix of own- and cross-elasticities of demand around the set of base prices. In addition, demand reductions due to certain conservation programs are represented as absolute shifts in the base demand surfaces. Technical standards associated with other conservation options such as automobile efficiency standards and Civil Aeronautics Board (CAB) load factor standards are introduced directly into the transportation model.

The complete output of the demand model includes:

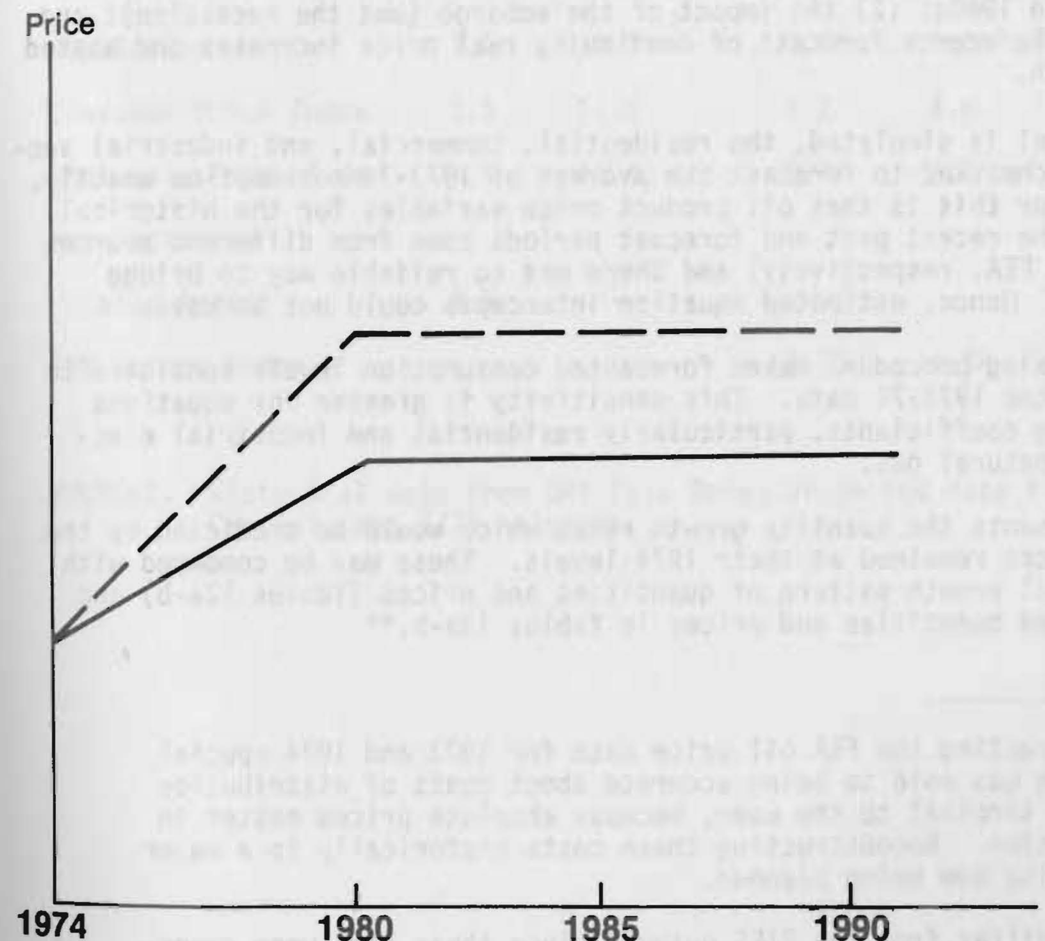
- a set of 42 tables of quantities demanded by Census region for selected years;
- tables of the 10 major fuel prices which generated those demands;
- a set of 9 regional elasticity arrays (each dimensioned 42 by 10) characterizing the quantity response of each of the 42 fuels to changes in each of the 10 fuel prices in each region.

The price trajectories are constructed using 1974 price data and the equilibrium "end point" prices from a comparable PIES run as shown in Figure 3. Prices increase (or decrease) until 1980 and remain constant, in real terms, thereafter. This "dog leg" form provides an intertemporally consistent price trajectory for the 1980, 1985, and 1990 scenario runs. It is important to note that the structure of the price paths as well as the input value of a particular year affect the quantities demanded since the demand model is dynamically specified.

Figure 3 also demonstrates the form of the price perturbation which drives the elasticity computation. The dashed line shows the price path used for comparison with the base run. The sloped segment of the price path represents the "rolling in" of policies that will allow the market to reach equilibrium price. For example, this structure is consistent with phased decontrol of oil price or deregulation of new natural gas contracts. It would not properly represent immediate shifts such as tariffs and taxes which would shift the price path up immediately.

The prices used in the demand model are all real (deflated), retail prices delivered to the skin of the house, electric meter, etc. The relationship between these prices and the supply prices presented in the PIES output is given by sets of regionally specific distribution cost markups (these are discussed in Appendix F, The PIES Report: A Guide). The markups are assumed constant in real terms for all fuels except electricity. The differential between average prices paid by the residential sector and the industrial sector has been declining over time. This decline is assumed to continue through 1980 in the demand model simulations.

Figure C-3
Demand Model Simulation Price Path Construction and Elasticity Computation



The macroeconomic input projections for the demand model simulations are summarized in Tables 9a-b and are discussed in Appendix B. Since projections of value added in manufacturing were not available, its forecasted trend is represented by that of the Federal Reserve Board (FRB) manufacturing output index. (Scale differences are subsumed into the benchmarking, discussed later.) Historical growth rates of associated series are included for comparison. The regional projections were derived from the DRI forecast by using regional shares from the Survey of Current Business, April 1974 projections. In general, the anticipated recovery from the recession of the last few years is expected to fall short of the growth rates experienced in the boom of the 1960s. Tables 10a-c compare sectoral growth rates in prices and quantities for the pre-embargo, embargo, and post-embargo periods. These tables strikingly portray (1) the strong quantity growth and declining real (deflated) prices of the 1960s; (2) the impact of the embargo (and the recession); and (3) the $13 Reference forecast of continuing real price increases and abated energy growth.

When the model is simulated, the residential, commercial, and industrial sectors are benchmarked to forecast the average of 1973-74 consumption exactly. The reason for this is that oil product price variables for the historical period and the recent past and forecast periods come from different sources (Platt's and FEA, respectively) and there was no reliable way to bridge these data.* Hence, estimated equation intercepts could not be used.

The benchmarking procedure makes forecasted consumption levels sensitive to vagaries of the 1972-74 data. This sensitivity is greater for equations with high lag coefficients, particularly residential and industrial electricity and natural gas.

Table 11 presents the quantity growth rates which would be predicted by the model if prices remained at their 1974 levels. These may be compared with the historical growth pattern of quantities and prices (Tables 12a-b) and the forecasted quantities and prices in Tables 13a-b.**

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* In constructing the FEA oil price data for 1973 and 1974 special attention was paid to being accurate about costs of distribution from the terminal to the user, because absolute prices matter in the solution. Reconstructing these costs historically is a major undertaking now being planned.

** Details differ from the PIES output, since these data were generated from a demand model run with input prices near but not identical to the PIES equilibrium prices for the 1985 $13 Reference Case.

Table 9a

GROWTH RATES OF SELECTED MACROECONOMIC VARIABLES
Compounded Annually

	Historical		Projected		
	1960-72	1973-74	1975-80	1980-85	1985-90
GNP	4.1	-2.1	5.5	3.6	3.0
Personal Income	4.6	-2.7	4.3	3.6	2.8
Population	1.2	0.7	0.9	1.0	0.9
Consumer Price Index	2.9	11.0	5.2	4.8	3.9
Wholesale Price Index	1.9	18.9	5.1	3.4	2.7
Manufacturing					
Value Added	4.7	-	-	-	-
FRB Output Index	-	-	7.93	4.58	3.99

SOURCES: Historical data from DRI Data Base; projected data from DRI Control Long 5/75 solution.

Table 9b

REGIONAL GROWTH RATES
OF SELECTED VARIABLES

	Population		Personal Income Per Capita		Value Added in Mfg.	FRB Mfg. Output Index
	1960-72	1974-85	1960-72	1974-85	1960-72	1974-85
NE	1.2	0.8	2.8	2.7	3.3	3.9
MA	0.8	0.7	2.7	2.5	3.0	4.0
ENC	1.0	0.4	2.8	2.6	4.3	4.3
WNC	0.6	0.4	3.2	2.7	5.4	4.7
SA	1.7	1.5	4.0	2.6	6.2	4.8
ESC	0.7	1.0	4.3	2.8	7.5	5.2
WSC	1.4	0.8	3.5	2.8	6.9	5.2
MT	2.1	1.1	2.9	2.6	6.7	4.5
PC	2.0	1.0	2.3	2.5	4.9	4.5
United States	1.2	0.9	3.4	2.6	4.7	4.5

Table 10a

GROWTH RATES IN QUANTITIES AND PRICES: 1960-1972
(Percent. Compounded Annually)

Sector \ Fuel	Coal Q (P)	Oil Q (P)	NG Q (P)	Elec Q (P)	Total Q (P)
Household/ Commercial	-7.8 (3.2)	3.1 (-2.7)	4.8 (-1.8)	8.5 (-4.3)	3.8 (-4.0)
Residential	- (-)	.4 (-2.4)	4.2 (-1.6)	7.7 (-4.1)	3.2 (-3.8)
Commercial	-7.8 (3.2)	5.1 (-.5)	6.7 (-1.4)	9.6 (-4.5)	4.6 (-4.2)
Industrial	-.8 (3.2)	2.6 (1.0)	4.4 (-.5)	5.5 (-1.3)	2.6 (-.5)
Fuel and Power	-1.7 (3.2)	2.3 (1.0)	4.3 (-.5)	5.5 (-1.2)	3.2 (-.8)
Raw Materials	.1 (-)	3.2 (-)	4.9 (-)	(-) (-)	2.1 (-)
Transporta-tion	-25.1 (3.2)	4.3 (-3.6)	6.6 (-.5)	-1.6 (-1.2)	4.4 (1.4)
3-Sector Total	-1.7 (3.2)	3.5 (-2.6)	4.6 (-1.2)	7.0 (-2.8)	3.5 (-1.8)
Electric Utilities	5.1 (.6)	14.2 (2.0)	6.9 (-.5)	(-) (-)	6.8 (3.2)
4-Sector Total[a]	2.2	4.1	5.0		

a 4-Sector price growth rates are not computed because they largely reflect sectoral quantity shifts

Table 10b

GROWTH RATES IN QUANTITIES AND PRICES: 1972-1974
(Percent, Compounded Annually)

Sector \ Fuel	Coal Q (P)	Oil Q (P)	NG Q (P)	Elec. Q (P)	Total Q (P)
Household/ Commercial	-14.3 (4.8)	-2.9 (37.6)	-3.6 (1.1)	3.7 (2.4)	-2.2 (5.2)
Residential	(-) (-)	-5.1 (35.6)	-4.5 (1.0)	4.1 (2.4)	-3.1 (4.8)
Commercial	-14.3 (-)	-.9 (40.5)	-1.6 (1.3)	3.3 (2.5)	-.9 (4.9)
Industrial	-2.1 (4.8)	1.5 (41.4)	2.5 (10.0)	2.7 (4.3)	1.4 (10.5)
Fuel and Power	-5.6 (4.8)	2.0 (41.2)	2.3 (10.0)	2.7 (4.3)	1.6 (8.3)
Raw Materials	4.4 (-)	.2 (-)	-3.5 (-)	(-) (-)	2.8 (-)
Transportation	-34.7 (-)	1.0 (26.3)	-8.7 (10.0)	6.7 (4.3)	.6 (26.3)
3-Sector Total	-3.0 (4.8)	.6 (29.9)	-.3 (5.2)	3.3 (3.2)	.1 (12.9)
Electric Utilities	5.0 (20.6)	5.1 (45.8)	-10.4 (15.9)	(-) (-)	1.3 (32.4)
4-Sector Total[a]	2.2	1.0	-2.0		

a 4-Sector price growth rates are not computed because they largely reflect sectoral quantity shifts

Table 10c

GROWTH RATES IN QUANTITIES AND PRICES: 1974-1985 ($13 Reference Case)
(Percent, Compounded Annually)

Sector \ Fuel	Coal Q (P)	Oil Q (P)	NG Q (P)	Elec. Q (P)	Total Q (P)
Household/ Commercial	-8.2 (2.2)	2.5 (1.1)	-0.9 (5.9)	6.0 (1.4)	2.0 (1.6)
Residential	- (-)	3.0 (1.5)	-1.8 (5.7)	7.5 (1.3)	2.1 (1.7)
Commercial	-8.2 (-)	2.0 (0.5)	0.8 (6.8)	3.9 (1.4)	1.8 (1.5)
Industrial	1.5 (2.2)	2.9 (0.8)	2.1 (7.0)	4.4 (3.4)	2.4 (2.8)
Fuel and Power	6.3 (2.2)	3.3 (0.8)	2.1 (7.0)	4.4 (3.4)	3.1 (3.1)
Raw Materials	-3.9 (-)	1.8 (-)	3.2 (-)	- (-)	-.3 (-)
Transportation	1.6 (-)	2.2 (0.6)	1.8 (-)	-1.0 (-)	2.2 (.6)
3-Sector Total	1.1 (2.2)	2.4 (0.7)	1.1 (6.2)	5.4 (2.1)	2.2 (1.5)
Electric Utilities	5.4 (1.6)	-2.1 (1.0)	-0.8 (12.0)		2.9 (2.1)
4-Sector Total[a]	4.0	2.0	.8		

a 4-Sector price growth rates are not computed because they largely reflect sectoral quantity shifts

Table 11

GROWTH RATES IN FUEL CONSUMPTION FOR 1974-1985 IF PRICES REMAINED AT 1974 REAL LEVELS

(Average Annual Percent Rates)

Region	Residential			Commercial			Industrial				RAW MATERIAL	TRANSPORTATION
	EL	NG	OIL	EL	NG	OIL	EL	NG	OIL	COAL		
NE	4.43	3.89	2.64	4.60	5.00	3.83	3.78	2.23	3.44	3.46	1.61	2.51
MA	5.97	2.46	3.28	3.61	4.21	2.48	6.65	3.69	2.99	2.06	0.75	2.89
ENC	7.08	3.26	3.19	3.35	3.06	1.82	3.38	4.30	2.61	2.00	0.26	2.23
WNC	6.82	2.55	3.32	3.51	3.04	1.70	6.94	5.38	3.93	3.99	1.88	2.48
SA	8.04	2.34	4.90	4.57	4.86	2.37	6.10	5.26	4.31	4.13	1.54	2.63
ESC	6.72	1.75	3.84	5.27	5.20	2.39	7.08	5.08	4.80	3.40	0.65	2.77
WSC	6.49	3.40	3.69	4.17	4.50	1.84	5.80	4.48	2.88	0.10	2.76	3.13
M	9.72	2.45	5.87	4.35	4.30	2.34	5.76	2.82	3.14	2.19	0.07	3.11
P	5.17	1.84	2.82	3.26	3.39	1.42	4.20	3.97	2.27	0.55	1.00	2.35
U.S.	6.82	2.74	3.56	3.93	3.78	2.43	5.49	4.43	3.16	2.52	0.71	2.63

Table 12a

REGIONAL QUANTITY GROWTH RATES: 1960-1972

	Residential Sector			Commercial Sector			Industrial Sector				RM	Transp.
	Elec.	N.G.	Oil[a]	Elec.	N.G.	Oil[a]	Elec.	N.G.	Oil[a]	Coal		
NE	8.3%	5.6%	2.7%	11.5%	9.9%	4.4%	4.2%	8.1%	.5%	-20.0%		
MA	7.0	3.6	.2	9.2	7.0	7.9	4.3	5.3	-1.9	-5.5		
ENC	7.3	4.6	-1.5	8.5	9.1	5.4	4.8	7.4	-1.2	-1.7		
WNC	7.5	3.6	1.3	8.7	5.7	13.1	5.9	5.3	1.2	-3.0		
SA	10.0	5.2	1.3	11.1	8.1	5.4	7.0	7.3	2.5	-1.4		
ESC	8.3	3.0	4.8	8.3	4.8	25.3	2.7	5.0	4.0	2.6		
WSC	10.6	2.8	3.5	10.2	3.6	8.4	9.1	4.5	3.6	-17.1		
RM	7.5	4.9	1.6	10.1	4.4	6.1	5.8	7.0	3.9	1.3		
PC	7.7	5.1	-1.1	9.9	6.6	-.1	5.6	5.5	3.5	-9.0		
US	7.7	4.2	.4	9.7	6.7	5.1	5.5	4.4	2.6	-.8	2.1%	4.3%

[a]Oil includes distillate, residual oil, kerosene, and liquified gases only, for this calculation.

Table 12b

REGIONAL PRICE GROWTH RATES: 1960-1972

	Residential Sector			Commercial Sector			Industrial Sector				RM	Transp.
	Elec.	N.G.	Oil[a]	Elec.	N.G.	Oil[a]	Elec.	N.G.	Oil[a]	Coal		
NE	-3.7%	-2.3%	-.4%	-5.0%	-2.5%	.2%	-1.5%	-3.4%	2.3%	4.1%		
MA	-2.6	-2.0	.2	-2.6	-2.6	4.2	-.8	-2.2	2.8	1.2		
ENC	-3.4	-1.5	1.1	-3.7	-2.1	.7	-1.0	-2.5	0.0	1.0		
WNC	-3.8	-1.0	-1.4	-4.6	-1.4	2.0	-1.3	-.6	-1.4	2.7		
SA	-3.5	-2.2	-1.1	-3.7	-2.2	2.4	-.8	-1.7	1.1	4.5		
ESC	-3.3	-1.7	-.7	-3.6	-1.3	5.6	1.6	-.9	-.4	4.4		
WSC	-4.7	-.5	-1.4	-4.7	-.7	-.9	-2.7	1.2	.5	3.2		
RM	-3.1	-.7	-.8	-3.5	-.2	.7	-1.2	-3.2	-.1	1.0		
PC	-3.2	-1.7	-.8	-3.5	-1.2	.3	-2.5	-1.3	.9	3.3		
US	-4.1	-1.6	-2.4	-4.5	-1.4	-.5	-1.3	-.5	1.0	3.2	-	-2.6%

[a]Oil includes distillate, residual oil, kerosene, and liquified gases only, for this calculation.

Table 13a

QUANTITY GROWTH RATES: 1974-1985

$13 Reference Case[a]

Region	Residential			Commercial			Industrial				RAW MATERIAL	TRANSPORTATION
	EL	NG	OIL	EL	NG	OIL	EL	NG	OIL	COAL		
NE	6.51	1.71	1.85	5.63	3.15	3.05	4.21	1.96	3.22	3.52	1.61	2.33
MA	8.38	-1.55	2.40	4.19	1.35	1.42	7.44	0.88	2.76	0.19	0.75	2.69
ENC	8.15	-0.77	2.43	3.90	1.11	1.80	2.65	2.43	2.70	1.09	0.26	1.94
WNC	8.18	-2.38	2.52	4.32	0.59	1.62	6.45	2.63	3.94	5.20	1.88	1.80
SA	7.99	-0.27	4.50	4.10	2.13	1.44	4.85	3.63	4.09	5.78	1.54	2.44
ESC	6.18	-1.59	2.72	4.71	3.10	2.32	4.84	2.10	5.11	6.41	0.65	2.22
WSC	5.22	-2.42	2.58	2.97	0.23	1.81	3.51	2.46	3.18	0.65	2.76	2.37
M	9.92	-1.79	5.10	4.17	1.39	2.17	3.59	2.40	3.35	2.57	0.07	2.72
P	4.57	-2.16	2.81	2.83	0.39	1.15	2.66	2.62	2.41	1.62	1.00	2.11
U.S.	7.50	-1.80	3.00	3.90	.80	2.00	4.40	2.10	2.90	1.50	0.71	2.27

[a] Results may differ in detail from PIES since these are from a demand model run near but not at the PIES solution.

Table 13b

PRICE GROWTH RATES: 1974-1985
$13 Reference Case[a]

	Residential Sector			Commercial Sector			Industrial Sector				RM	Transp.[d]
	Elec.	N.G.	Oil[b]	Elec.	N.G.	Oil[b]	Elec.	N.G.	Oil[c]	Coal		
NE	-2.4	1.9	.8	-3.0	3.5	.9	-1.3	.4	.3	-.2		.4
MA	-2.4	3.7	.9	-2.9	4.6	1.0	-1.6	4.6	-.3	3.8		.5
ENC	-.5	4.5	1.0	-.8	5.4	1.0	1.7	4.5	0.0	3.3		-.3
WNC	-.8	5.3	1.1	-10	6.8	1.1	1.1	5.8	.4	.2		.3
SA	.3	3.2	.6	-.4	5.0	.7	2.3	4.0	2.2	-.7		.4
ESC	1.5	4.6	1.0	1.8	5.8	1.1	4.6	7.2	2.2	-1.9		.1
WSC	2.7	7.4	.7	2.7	10.2	.7	5.6	6.6	2.2	1.0		.2
RM	.5	5.0	.8	.3	6.9	.8	37	2.1	1.0	1.1		0.0
PC	1.6	5.2	.9	.4	6.4	1.0	30	3.9	.7	-1.3		.7
US[e]	1.3	5.7	1.5	14	6.8	.5	34	7.0	.8	2.2		.3

[a] Results may differ in detail from PIES since these are from a demand model run near but not at the PIES solution.
[b] Distillate price is used for regional calculation.
[c] Residual oil price used for regional calculation.
[d] Gasoline price is used for regional calculation.
[e] National values are indexes from table 11.

V. ECONOMETRIC METHODS AND RESULTS FOR MAJOR SUBMODELS

This section describes in greater detail the econometric methods and results for the major submodels. The joint fuel submodels for the residential, commercial, and industrial sectors are discussed first. Discussion of the gasoline demand model follows:

Joint Fuel Demand Submodels

Joint fuel demand models have been constructed for the residential, commercial, and industrial sectors. Allocation between household/commercial (H/C) and industrial (IND) sectors follows the Bureau of Mines' classification. Allocation of H/C demand to residential and commercial sectors also follows the Bureau of Mines' classification with the following additions. Liquid gases and kerosene were allocated entirely to the residential sector, residual oil was allocated entirely to the commercial sector. Distillate oil was split by a methodology employed in the American Gas Association's TERA model. The regional sector split is based on 1970 Census data on the number of oil-heated houses times an imputation of oil consumption per house based on industry sources. The regional allocations given in Table 14 were applied to all years.

Table 14

FRACTION OF H/C DISTILLATE ALLOCATED TO THE RESIDENTIAL SECTOR

NE	.57	WNC	.46	WSC	.03
MA	.74	SA	.93	MT	.34
ENC	.54	ESC	.46	PC	.62

(This procedure is admittedly crude; however, survey data which will become available soon will permit FEA to improve this allocation.)

The estimated models are typified by equations (1) and (2) of section II. Experiments with these forms as stated often yielded low Durbin-Watson statistics indicating autocorrelation of the residuals. This autocorrelation implies a correlation between the residuals and the lagged endogenous variables, which, in turn implies that direct estimation of (1) and (2) would be inconsistent; generally, seriously so.

This problem was remedied by imposing a regionally specific first-order autocorrelative transformation on the structures to yield, e.g.,

$$(10)\quad \ln TQ_r = \alpha_r \cdot (1-\rho_r) + \beta \cdot \ln TP_r - \beta \cdot \rho_r \cdot \ln TP_{r,-1} + \ldots + (\lambda + \rho_r) \cdot \ln TQ_{r,-1} - \lambda \cdot \rho_r \cdot \ln TQ_{r,-2}\ .$$

For each sector the joint fuel model consists of nine regional equations for the total energy index in the form of (10) and nine similarly transformed fuel equations for each fuel in the sector. Each set of nine equations was estimated using a "minimum distance" multivariate, nonlinear, estimation technique.*

Results of these estimations are given in Tables 15a-c which present structural coefficient estimates and regional equation R-squares and Durbin-Watson statistics.**

Unfortunately the statistical package used to estimate the model was itself under development and did not generally calculate t-statistics for coefficient estimates correctly. (In the few estimations in which this calculation appeared to be done correctly the estimated coefficients are highly significant.) The estimates can be evaluated in terms of the other statistics presented.

First, the estimated structural coefficients imply short- and long-run elasticities which are within the range of those generally found in the econometric literature. Second, with some notable exceptions for distillate (in regions in which little is consumed and with one exception for electricity and one for the industrial total energy, the individual equations fit well, as indicated by the R-squares. The reader who is not familiar with multivariate estimation of time series of cross sections should know that high R-squares do not inevitably occur as they do in single equation aggregate time series studies. It is quite possible to get sets of equations which generally do not fit well except in a few important regions.***

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* The procedure is called iterative Zellner-efficient. Under the standard regression assumptions, that the relationships between the disturbances are constant across time and that the disturbances are independent across time period, this estimation technique is consistent and efficient.

** Distillate and residual fuel were pooled with a Divisia index in the commercial sector, and the resulting coefficient estimates were assumed to hold for each fuel individually in simulation. Distillate, kerosene, and liquid gases in the industrial sector were similarly pooled and simulated.

*** Samples can be provided. The negative R-squares are not a mistake. Since the estimation is minimizing a cross equation sum of squares, with cross-equation constraints, it can easily choose estimates which give bad fits in small regions in order to improve the fit in large regions.

Table 15a

ESTIMATION RESULTS

Residential Sector

	Coefficient Estimates			R-Squares/Durbin-Watson Statistics									
	Price	Personal Income (per capita)	Lag Term		NE	MA	ENC	WNC	SA	ESC	WSC	RM	PC
Total Quantity Index (per capita)	-.133	.300	.728	R^2	.98	.99	.99	.99	.99	.98	.98	.98	.98
				D-W	2.22	1.84	1.60	1.54	1.79	1.71	1.76	2.41	1.51
Electricity	-.240		.869	R^2	.98	.99	.97	.96	.99	.88	.97	.74	.93
				D-W	2.65	1.94	2.63	1.83	2.50	1.89	1.83	2.31	1.80
Natural Gas	-.193		.876	R^2	.06	.71	.91	.88	.70	.94	.96	.57	.75
				D-W	2.38	2.18	2.34	1.95	1.79	1.97	2.03	1.77	2.44
Distillate	-.450		.527	R^2	.93	.93	.97	.85	.87	-.29	.60	-.07	.88
				D-W	1.72	2.40	2.60	1.36	2.00	1.49	1.54	2.17	2.30
Kerosene	-.168		.134	R^2	.94	.56	.84	.85	.90	.56	.54	.62	.50
				D-W	3.04	2.54	2.67	2.77	2.86	1.04	2.43	1.05	1.52
Liquid Gases	-.388		.384	R^2	.66	.24	.46	.29	.74	.25	.91	.05	.49
				D-W	2.10	1.93	2.03	2.07	1.57	2.04	1.92	2.01	1.70

Table 15b

ESTIMATION RESULTS

Commercial Sector

	Coefficient Estimates			R-Squares/Durbin-Watson Statistics									
	Price	Personal Income (per capita)	Lag Term		NE	MA	ENC	WNC	SA	ESC	WSC	RM	PC
Total Quantity Index (per capita)	-.140	.727	.532	R^2	.98	.98	.99	.99	.99	.98	.99	.99	.98
				D-W	2.58	1.01	1.81	2.14	2.81	2.13	1.42	1.71	2.14
Electricity	-.370		.383	R^2	.84	.50	.87	.86	.84	.79	.77	.94	.91
				D-W	1.50	1.22	2.92	2.23	1.79	2.19	1.79	2.70	2.34
Natural Gas	-.440		.002	R^2	.64	.61	.91	.32	.29	.95	.92	.29	.27
				D-W	1.26	2.14	2.04	2.46	.92	1.07	2.61	1.73	1.56
Distillate, Residual Oil	-.639		0.0	R^2	.97	.96	.77	.62	.77	.78	.77	.56	-.94
				D-W	1.95	.97	2.01	1.25	1.82	1.539	.57	2.50	1.40

Table 15c

ESTIMATION RESULTS

Industrial Sector

	Coefficient Estimates			R-Squares/Durbin-Watson Statistics									
	Price	Gas Shares Customers	Lag Term		NE	MA	ENC	WNC	SA	ESC	WSC	RM	PC
Total Quantity Index (per $ VA in Mfg.)	-.126	0.0	.588	R^2	.64	.13	.59	.48	.08	.63	.06	-.38	.34
				D-W	2.33	2.04	1.66	1.77	1.45	2.20	1.12	1.83	1.82
Electricity	-.163	-.031	.857	R^2	.68	.79	.76	.79	.93	.82	.95	-.13	.15
				D-W	2.98	1.24	.88	1.65	1.60	1.58	2.15	1.88	2.29
Natural Gas	-.187	.017	.710	R^2	.94	.83	.93	.27	.71	.81	.89	.26	.57
				D-W	2.46	1.97	2.21	1.96	1.71	1.77	1.65	2.59	.88
Distillate, Kerosene, & Liquid Gases	-.260	0.0	.655	R^2	.36	-.18	.45	-.13	.65	.91	.65	.65	.86
				D-W	1.92	2.55	1.88	2.50	1.55	2.25	1.82	1.32	2.72
Residual Oil	-.363	-.066	.173	R^2	.32	.74	.85	.50	.57	.09	.64	.53	.41
				D-W	1.50	1.79	1.75	1.94	.94	1.60	.91	1.83	1.42
Coal (Fuel & Power)	-.484	.860	.393	R^2	.90	.97	.90	.83	.96	.08	.26	.62	.85
				D-W	2.34	2.44	1.55	2.37	2.34	2.43	2.10	2.51	1.90

Finally, again with some exceptions, the Durbin-Watson statistics are near a value of two, and do not indicate autocorrelation of the residuals (and consequent bias of the structural parameter estimates). In the present context, however, the Durbin-Watson statistics are known to be biased toward indicating randomness of the residuals, so the acceptability of their values should be regarded as comforting but not conclusive.

The estimated autocorrelation coefficients were not used in the simulation and not reported. Their values are less than one in modulus, and hence, represent stable error processes. The autocorrelation parameters are ignored in simulation. This may be justified by the assumption that they represent errors-in-measurement in the "permanent values" of the dependent variable.

Gasoline Submodel

The basic structure of the automobile simulation model has been discussed in a previous section. This section presents several of the most important econometrically estimated equations.

The efficiency of the fleet of automobiles is calculated on a yearly basis by averaging* the efficiency of automobiles from all existing vintages, with weights corresponding to numbers of cars in existence from each vintage times an age adjustment factor, a measure of relative miles driven of automobiles of various ages. Several pieces of information are required for this averaging, including efficiency of each vintage, initial purchase of automobiles from each vintage, scrappage rates for existing cars, and the age adjustment factor. The equations for estimating these variables are discussed in this section.

The realized efficiency of newly-purchased cars is predicted as a function of the price of gasoline and a measure of technical automobile efficiency. This technical measure, EFF, is proportional to the average fuel economy for cars of a given year, standardized for the weight of the car.** The efficiency of new cars is therefore proportional to EFF if market shares of different weight automobiles are constant. However, these market shares are influenced by gasoline price and by technical efficiency.

If decisions on purchased automobile weights are influenced by gasoline price only through its impacts on automobile operating costs, then the terms capturing price induced modifications of market shares should depend upon the ratio of gasoline price to EFF. Thus average efficiency of new cars should be specified as follows: MPG = EFF * h(PGAS/EFF). Assuming log-linearity and using a

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* More precisely, a geometric mean is calculated; fuel use can be best estimated by averaging gallons used per mile driven for all cars.

** This is the factor "C" defined by the U. S. Environmental Protection Agency in Fuel Economy and Emission Control, (United States Environmental Protection Agency, Office of Air and Water Programs, Mobile Source Pollution Control Program, November 1974).

lagged price term, the equation used to estimate new car efficiency (using ordinary least squares) is as follows*:

(11) $$MPG = \exp\left[\underset{(31.9)}{3.22} + \underset{(7.6)}{.6877} * LOG\,(PGAS\,(-1)/EFF)\right] * EFF$$

$\bar{R}^2 = .83$

D.W. = 2.17

PGAS represents the gasoline price.

The equation has also been fitted with a contemporaneous price term; the coefficient does not change greatly although the R-square and the t-statistic are reduced under the specification.

New car purchases are predicted by means of a capital stock adjustment equation, which expresses new car sales as a function of vehicle miles per capita, real disposable income per capita, unemployment, and the per capita stock of cars remaining from the last year. New car price does not appear since this variable was always insignificant in the equations tested. The reasons for this insignificance are not fully understood.

(12) $$NPCR/N = EXP\left[\underset{(.7)}{4.0792} - \underset{(-6.3)}{3.7544} * LOG\,(OMEGA\,(-1)/N(-1))\right.$$

$$+ \underset{(2.5)}{2.3155} * LOG\,(VMAUTO/N)$$

$$\left. + \underset{(2.0)}{1.7780} * LOG\,(YD58\%N) - \underset{(3.6)}{.078164} * RU\right]$$

$\bar{R}^2 = .83$

D.W. = 2.2

NPCR and N represent the new car sales and the population respectively, OMEGA represents the weighted capital stock of cars existing in the last year, VMAUTO is automobile vehicle miles, YD58%N is per capita disposable income and RU is the unemployment rate.

Equation (12) is derived from specifying that people determine a desired stock of automobiles based upon their driving patterns and that new car purchases represent adjustments from the actual stock toward this desired stock. Thus, this theory assumes that increases in vehicle miles lead to increases in the

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* The constant term was adjusted from its estimated value since realized efficiency of automobiles has historically been less than EPA measured new car efficiency.

desired stock of cars, rather than the converse: greater stocks of cars cause people to drive more. The weighted stock of automobiles* OMEGA appears with a negative coefficient: the smaller is the difference between desired stock and actual stock, the smaller will be the number of new cars sold.

Scrappage of existing cars is assumed to be exponential. The following equation has been estimated:

$$(13)\quad STK = \underset{(630.)}{.93}\ STK(-1) + NPCR$$

$\bar{R}^2 = .999$

D.W. = 1.37

STK represents the number of cars in existence in the given year. It is assumed that new cars are driven more miles than older autos. Based upon Department of Transportation data,** an age adjustment factor was estimated as follows:

$$(14)\quad Agefac = (.92)^{carage},$$

where carage is the age of an automobile and Agefac is the age adjustment factor used as a weight for calculating average stock efficiency and for calculating the weighted capital stock of automobiles (OMEGA). Equation (13) was derived from the fitted relationship:

$$(15)\quad VMMY = 16.56 * (.92)^{carage}$$

$\bar{R}^2 = .84$

D. W. = .84

Vehicle miles (per capita) of the stock of automobiles is estimated as a function of per capita disposable income (YD58%N), the unemployment rate (RU), and the cost per mile of auto travel (CPM). Using nonlinear least squares with a first order autoregressive transformation, equation (15) is estimated.

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* New cars are given the weight of one; older cars are assigned lower weights based on relative miles driven as described in equation (13).

** U. S. Department of Transportation, Federal Highway Administration, <u>Nationwide Personal Transportation Study</u>, 1972

$$(16)\quad [VM/N] = \exp\Big\{\underset{(12.7)}{.80967} * LOG(VM(-1)/N(-1))$$

$$+ \underset{(12.1)}{6.5184} - \underset{(-1.8)}{.35775} * LOG\ (CPM)$$

$$+ \underset{(11.2)}{.97561} * LOG\ (YD58\%N) + \underset{(0.9)}{.0026184} * RU$$

$$- .80967 * \Big[(6.5184 - .35775 * LOG\ (CPM(-1))$$

$$+ .97561 * LOG\ (YD58\%N(-1))$$

$$+ .0026184 * RU\ (-1)\Big]\Big\}$$

$\bar{R}^2 = .996$

D.W. = 1.13

The cost per mile includes the per mile gasoline cost (gasoline price divided by average efficiency of the stock) and the time cost per mile.

The model predicts gasoline use as the simple ratio of vehicle miles to efficiency of the stock:

$$(17)\quad GASAUTO = VM/AVMPG,$$

where GASAUTO represents the auto use of gasoline and AVMPG represents the fleet average efficiency.

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* U.S. Department of Transportation, Federal Highway Administration, <u>Nationwide Personal Transportation Study</u>, 1972

Appendix D

COAL, OIL, AND GAS SUPPLY

Appendix D

COAL, OIL, AND GAS SUPPLY

This appendix contains an overview of the procedures for estimating the raw material supply curves for coal, oil, and natural gas. The first section is devoted to a discussion of the coal supply curves and their implementation into the PIES model. The second part describes the approach taken to model the oil and natural gas supply curves.

I. COAL SUPPLY CURVES

A coal model was developed in 1974 for FEA's Project Independence Report (PIR) to Congress. An Interagency Task Force headed by coal experts from the Bureau of Mines (BOM) provided the initial coal data input to PIES. The Task Force divided the country into seven coal producing regions with differentiation within the region solely by Btu content.

The Task Force developed long-run supply curves for each of seven coal supply regions. The approximation consisted of four steps. The first two steps were for existing surface and existing deep mines priced at variable cost (since the capital investment was sunk). The third step was for new surface mines and the fourth step was for new deep mines. The length of the last step was set large enough so that it never acted as a constraint on regional production. Since the demand curves typically cut the last step of the supply curves, the price of coal remained constant over a wide range of production levels. Also the prices and annual production levels attached to each of the new mine steps were based upon the judgment of BOM experts without the components of price being made explicit.

Procedures used to estimate coal supply were reviewed and revised several times during the year. Criticisms centered around three major weaknesses. First, the supply regions were considered to be too large to capture adequately the transportation costs and coal quality differences. Second, the range of quality differences needed expansion to account for the sulfur content of coal. For example, the original model did not capture the regional shift of production from the Midwest and Northern Appalachia (regions with large high-sulfur coal reserves) to the Northern Great Plains and Central Appalachia (regions with large low-sulfur reserves). Finally, a more explicit structure for the supply development was needed.

The number of regions has increased from seven to twelve, and the transportation network has been expanded. Figure 1 shows the boundaries of the new supply regions and Table 1 defines the regional breakdown by BOM mining district. This expanded detail improves the capability to represent and utilize regional detail.

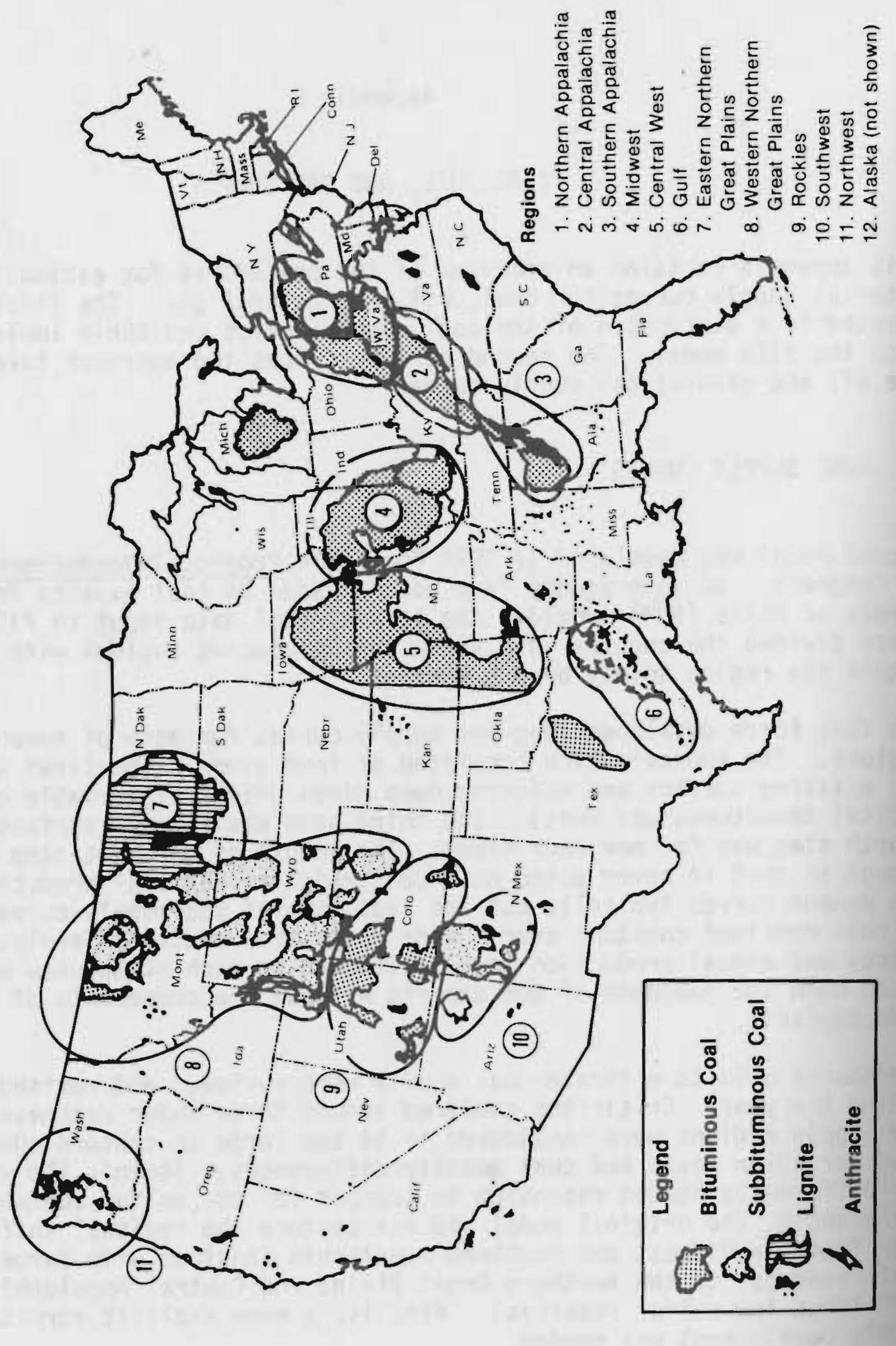


Figure D-1

PIES Coal Supply Regions

Currently, coal is divided into several product classes (metallurgical, low-sulfur and high-sulfur for several heat values). Metallurgical coal is defined as premium quality coking coal with less than 1.3 percent sulfur, less than 0.8 percent ash, and more than 26 million Btu per ton. Low-sulfur coal is defined to meet EPA's new source performance standard of 0.6 pounds sulfur per million Btu. The remaining coal is called high-sulfur. Table 1 lists the region/product class combinations for which supply curves were developed. These expanded definitions permit more detail specification of the uses and potential demands for coal.

Each step of the revised coal supply curves represents the development of a different mine type. The price attached to each step is the minimum acceptable selling price for coal from that particular mine type. The production level attached to each step is the maximum annual production that the BOM demonstrated reserve base could sustain from that particular mine type for 20 years. The costs are based upon engineering estimates of costs to develop mines of different size, seam thickness, and seam depth using a real discount rate of 8 percent.

The mix of mines is generated within the integrating model based upon mining costs and levels of demand interacting with the increasing cost supply curve.

The following steps summarize the methodology used to develop supply curves.

- Obtain BOM's demonstrated reserve base estimates of coal tonnage and quality characteristics by seam and county and assign reserves to coal supply regions. Assign reserves within each region to product classes, by Btu and sulfur content, eliminating negligible reserves that are too costly because of coal quality or amount.

- Estimate production capacity from existing mines for each forecast year and reserves committed to existing mines, including estimate of the effects of mine closings.

- Allocate uncommitted strippable reserves to overburden ratio categories. (The overburden ratio of a coal seam is the cubic yards of overburden per ton of coal.) Allocate uncommitted deep reserves to seam thickness and seam depth categories. Allocate uncommitted reserves to mine size categories so that production may be sustained for 20 years.

- Assign production estimates to mine types. Estimate minimum acceptable selling price for each mine type and size using a discounted cash flow analysis.

- Arrange mine types with associated production levels in order of minimum acceptable selling prices.

An example of a supply curve is shown in Figure 2.

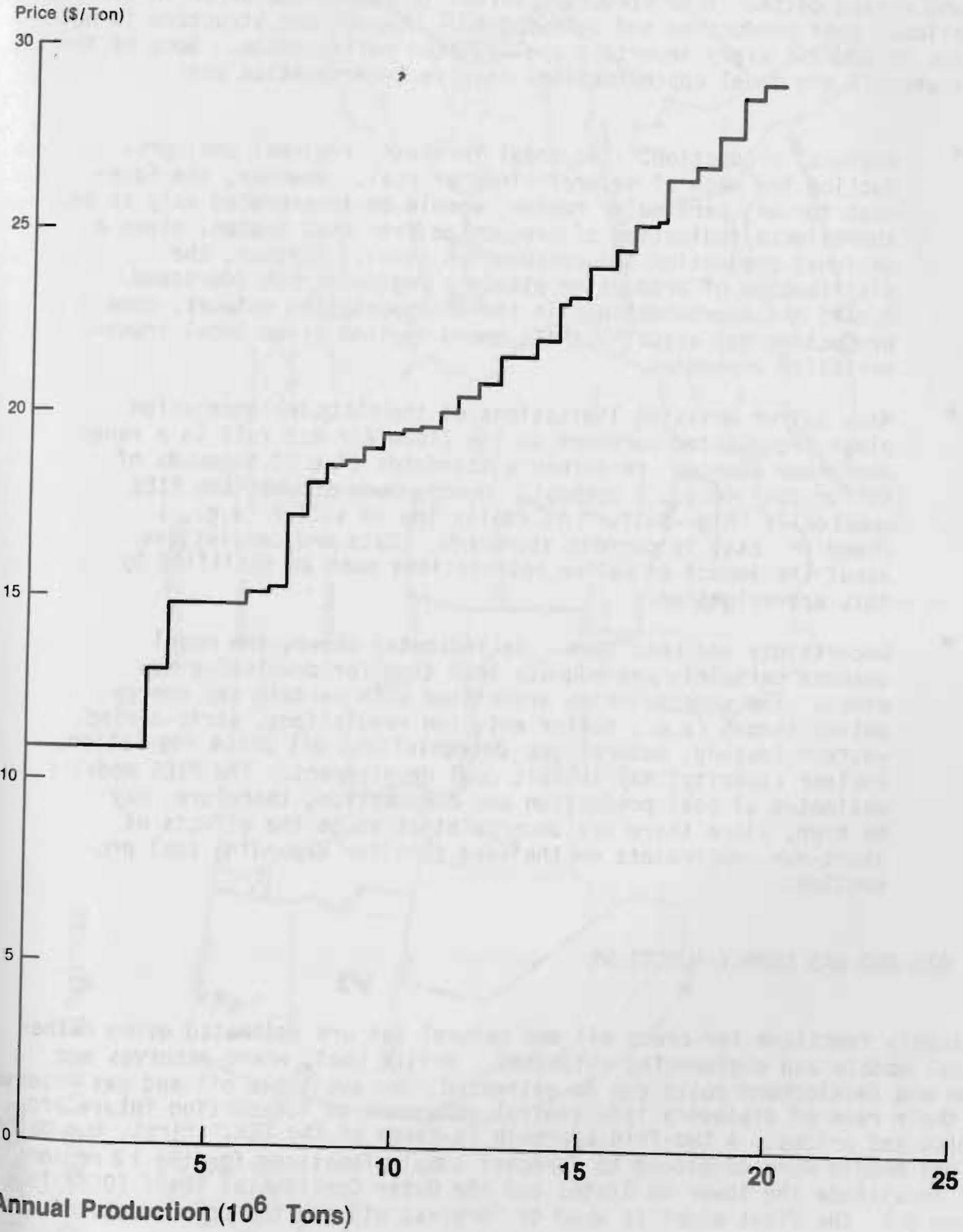
Table 1

COAL SUPPLY REGIONS AND PRODUCT CLASSES FOR PIES MODEL

Region	BOM Mining Districts	Product Classes	Heat Value (10^6 Btu/Ton)
1. Northern Appalachia	1-6	Metallurgical Low-Sulfur High-Sulfur	> 26 24 24
2. Central Appalachia	7&8	Metallurgical Low-Sulfur High-Sulfur	> 26 24 24
3. Southern Appalachia	13	Metallurgical Low-Sulfur High-Sulfur	> 26 24 24
4. Midwest	9-11	Low-Sulfur High-Sulfur	22 22
5. Central West	12,14&15 (except Texas)	Metallurgical High-Sulfur	> 26 22
6. Gulf	Texas	High-Sulfur	14
7. Eastern Northern Great Plains	21&22 (only lignite reserves)	Low-Sulfur High-Sulfur	14 14
8. Western Northern Great Plains	16,19&22 (excluding lignite reserves)	Low-Sulfur High-Sulfur	19 19
9. Rockies	17&20	Metallurgical Low-Sulfur	> 26 22
10. Southwest	18	Low-Sulfur High-Sulfur	19 19
11. Northwest	23 (except Alaska)	High-Sulfur	19
12. Alaska	Alaska	Low-Sulfur	19

Figure D-2

Midwest Low Sulfur PIES Coal Supply Curve



The model is structured to indicate the effects on national coal production and consumption of changes in such key energy policy variables as the price of oil, the growth of electricity, nuclear capacity, synthetic fuel production, and mining costs. This structure serves to reduce the error in forecasting national coal production and consumption. However, the structure is not adequate to address every important coal-related policy issue. Some of the issues wherein the model approximations involve uncertainties are:

- Regional production. The model forecasts regional coal production for each of several kinds of coal. However, the forecast for any particular region should be interpreted only as an approximate indication of production from that region, given a national production and consumption level. Further, the distribution of production within a region is not addressed. Due to the approximations in the transportation network, some production may actually shift among regions given local transportation economies.

- Many sulfur emission limitations of the state implementation plans promulgated pursuant to the Clean Air Act fall in a range above new sources performance standards (i.e., 0.6 pounds of sulfur coal (e.g., 2 pounds). Hence, much of what the PIES model calls "high-sulfur" is really low in sulfur (e.g., 1 pound or less) by current standards. Data and conclusions about the impact of sulfur restrictions must be qualified by this approximation.

- Uncertainty and Lead Time. As indicated above, the model assumes certainty and adquate lead time for developing new mines. The uncertainties associated with certain key energy policy issues (e.g., sulfur emission regulations, strip-mining, western leasing, natural gas deregulation, oil price regulation, nuclear capacity) may inhibit coal development. The PIES model's estimates of coal production and consumption, therefore, may be high, since there are uncertainties as to the effects of short-run constraints on the lead time for expanding coal production.

II. OIL AND GAS SUPPLY FUNCTIONS

The supply functions for crude oil and natural gas are estimated using mathematical models and engineering estimates. Unlike coal, where reserves are known and development costs can be estimated, the available oil and gas reserves and their rate of discovery is a central component of forecasting future production and prices. A two-fold approach is taken at the FEA. First, two mathematical models were developed to forecast supply functions for the 12 regions that constitute the lower 48 States and the Outer Continental Shelf (OCS). (See Figure 3.) The first model is used to forecast oil and the co-products of crude

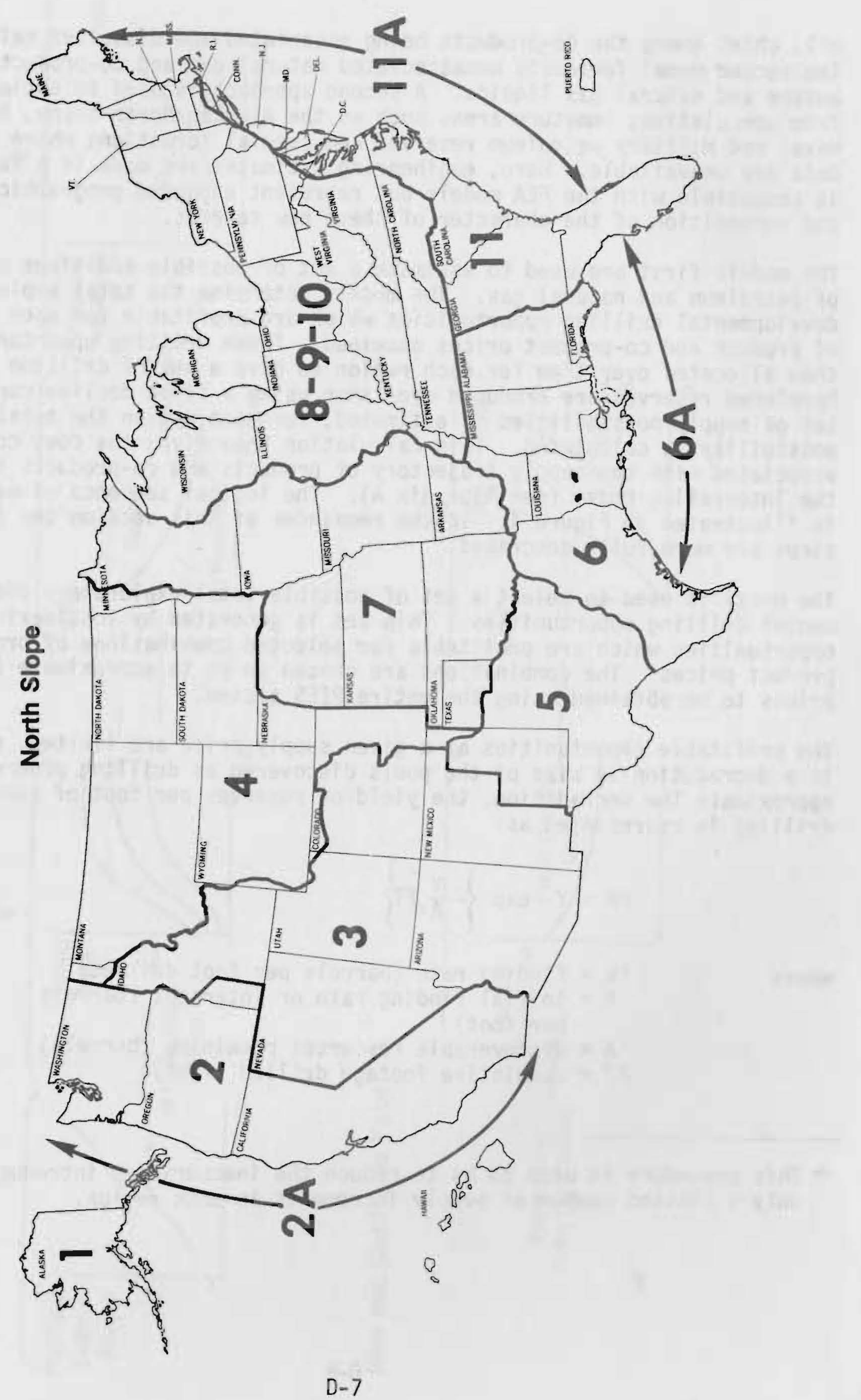


Figure D-3
Oil and Gas Regions

oil, chief among the co-products being associated and dissolved natural gas. The second model forecasts nonassociated natural gas and co-products such as butane and natural gas liquids. A second approach is used to estimate supplies from speculative, immature areas such as the Alaskan North Slope, Beaufort Sea, Naval and Military petroleum reserves, and special formations where historical data are unavailable. Here, engineering estimates are made in a fashion that is compatible with the FEA models but represent expanded geographical detail and recognition of the character of these new sources.

The models first are used to estimate a set of possible additions to reserves of petroleum and natural gas. The models determine the total exploratory and developmental drilling opportunities which are profitable for each combination of product and co-product prices examined. These drilling opportunities are then allocated over time for each region to give a set of drilling opportunities. Developed reserves are produced over time using a fixed decline curve. Once the set of supply possibilities is estimated, for each region the total cost of each possibility is calculated. This calculation then gives the cost coefficient associated with the supply trajectory of products and co-products to be used in the Integrating Model (see Appendix A). The logical sequence of calculations is illustrated in Figure 4. In the remainder of this section the individual steps are more fully described.

The model is used to select a set of possible total exploratory and developmental drilling opportunities. This set is generated by considering those opportunities which are profitable for selected combinations of product and co-product prices* The combinations are chosen so as to approximate the expected prices to be obtained using the entire PIES system.

The profitable opportunities at a given supply price are limited, since there is a degradation in size of the pools discovered as drilling progresses. To approximate the degradation, the yield of reserves per foot of cumulative drilling is represented as:

$$FR = Y \exp\left\{-\frac{Y}{A} FT\right\}$$

where
- FR = finding rate (barrels per foot drilled)
- Y = initial finding rate or intercept (barrels per foot)
- A = discoverable resources remaining (barrels)
- FT = cumulative footage drilled (feet)

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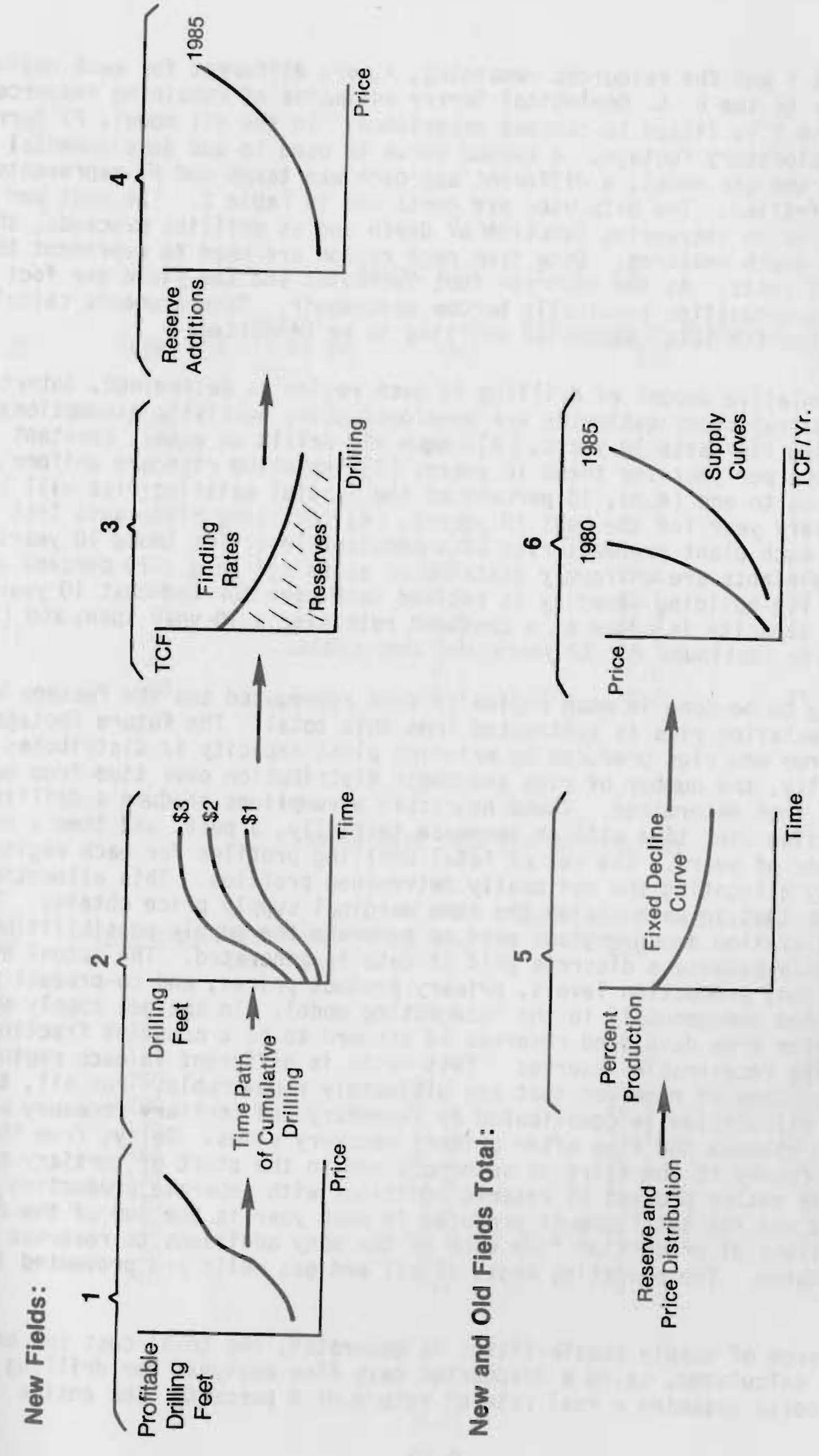
* This procedure is used so as to reduce the inaccuracies introduced by having only a limited number of supply increments in each region.

Figure D-4

Structure of FEA Gas Supply Model



The intercept Y and the resources remaining, A, are different for each region. A corresponds to the U. S. Geological Survey estimates of remaining resources in place while Y is fitted to current experience. In the oil model, FT corresponds to exploratory footage. A second curve is used to add developmental footage. In the gas model, a different approach was taken and FT represents all footage frilled. The data used are contained in Table 2. The cost per foot drilled is an increasing function of depth and as drilling proceeds, the average well depth measures. Data from each region are used to represent this escalation of costs. As the cost per foot increases and the yield per foot decreases, opportunities eventually become uneconomic. This economic calculation determines the total amount of drilling to be conducted.

Once the cumulative amount of drilling in each region is determined, intertemporal drilling trajectory estimates are developed using heuristic assumptions: (1) a drilling rig lasts 10 years; (2) each rig drills an equal, constant number of feet per year for these 10 years; (3) existing rigs are uniformly distributed as to age (e.g., 10 percent of the initial existing rigs will be abandoned every year for the next 10 years); (4) drilling rig plants last 10 years; (5) each plant produces rigs at a constant level for those 10 years; (6) existing plants are uniformly distributed as to age (e.g., 10 percent of the initial rig-building capacity is retired each year for the next 10 years); (7) new rig capacity is added at a constant rate over a 10-year span; and (8) rig production continues for 20 years and then ceases.

The drilling to be done in each region is then aggregated and the footage remaining in existing rigs is subtracted from this total. The future footage available from new rigs produced by existing plant capacity is distributed over time. Finally, the number of rigs and their distribution over time from new capacity is then determined. These heuristic assumptions produce a drilling rate allocation over time with an increase initially, a peak, and then a decline over a number of years. The set of total drilling profiles for each region is generated by allocating the nationally determined profiles. This allocation is performed so that in each region the same marginal supply price obtains. The specific allocation among regions used to generate the supply possibilities is important only because a discrete grid of data is generated. The actual drilling allocation, production levels, primary product prices, and co-product prices are determined endogenously in the integrating model. In the gas supply model, the production from developed reserves is assumed to be a constant fraction of the remaining recoverable reserves. This ratio is different in each region, as is the percentage of reserves that are ultimately recoverable. For oil, the production calculation is complicated by secondary and tertiary recovery additions which enhance the flow after primary recovery slows. Delays from the time of discovery to the start of secondary and to the start of tertiary are included. The entire process of reserve additions with separate production ratios is vintaged and the total amount produced in each year is the sum of the constant fractions of production from each of the many additions to reserves by year and region. The operating costs of oil and gas wells are presented in Table 3.

Once the range of supply possibilities is generated, the total cost for each profile is calculated, using a discounted cash flow analysis for drilling and operating costs assuming a real rate of return of 8 percent. The entire

Table 2

FINDING RATE DATA FOR OIL

Region	Intercept (barrels found per foot)	Undiscovered Resources (billion barrels) BAU	A.D.	Pess
1A	2000	46.9	84.7	9.1
2	325	21.9	28.8	15.0
2A	1000	15.0	19.3	10.7
3	170	12.5	18.0	7.0
4	40	21.9	27.2	16.6
5	110	25.0	34.9	15.1
6	55	25.0	32.6	18.2
6A	660	25.0	32.6	17.4
7	70	18.8	27.0	10.5
8-10	95	9.4	14.1	4.6
11	95	3.1	5.6	.6
11A	600	15.0	18.2	11.8

FINDING RATE DATA FOR NATURAL GAS

Region	Intercept (Mcf found per foot)	Undiscovered Resources (Tcf) Pess	BAU	A.D.
2	140	10.4	13.3	16.1
2A	750	2.9	4.2	5.5
3	115	8.4	13.5	18.6
4	150	19.2	25.7	32.2
5	220	51.9	69.0	86.2
6	170	144.8	176.4	207.9
6A	820	90.4	126.2	162.5
7	170	67.8	81.5	95.2
8,9	70	2.4	3.6	4.7
10	75	7.8	11.0	14.2
11	20	0.4	1.0	1.2
11A	740	8.2	10.0	16.1

Table 3

OPERATING COSTS PER GAS WELL PER YEAR

Region	Cost/Well
2	$4,950
2A	55,000
3	7,012
4	8,387
5	13,268
6	8,387
6A	55,000
7	6,187
8,9	1,375
10	1,375
11	8,387
11A	55,000

OPERATING COSTS PER OIL WELL PER YEAR

Region	Operating Cost/Well*
1	$148,390
2	6,795
2A	55,000
3	21,400
4	6,795
5	4,826
6	6,795
6A	55,000
7	4,826
8-10	1,233
11	21,400
11A	55,000

* These costs are increased when enhanced recovery is conducted.

process produces a different supply price, drilling, and production pattern for each reserve addition by year, region, and method of recovery. The total costs for each such increment are calculated individually to build the approximation to the cost curve. These increments are aggregated for representation in the integrating model with more than 75 steps for crude oil and 50 steps for natural gas.

The net result of the entire procedure is to generate a range of supply possibilities and their associated costs. These possibilities and costs are used as input data to the integrating model, which in turn selects those possibilities consistent with a competitive equilibrium.

For offshore regions, drilling is constrained by leasing schedules and thus the possible range of profiles is restricted. The leasing schedules for offshore areas are supplied in the form of acres leased; they are converted to annual footages using the following procedure:

- The acres leased in a given year are drilled over the 5-year period of the lease in the following proportions: 8 percent is drilled in the first year, 24 percent in the second, 36 percent in the third, 24 percent in the fourth, and the remaining 8 percent in the fifth.

- Acreage is converted to exploratory wells. In region 1A, one exploratory well is drilled per 14,000 acres leased; in region 2A, one is drilled per 800 acres leased; in region 6A, one well per 2,000 is drilled; and in region 11A, one is drilled per 21,400 acres leased.

- Exploratory wells are converted to exploratory footage based on average depth curves. Exploratory footage is converted to total footage based on total to exploratory drilling ratio curves.

- Total footage is allocated to oil and gas based on a Btu equivalent minimum-acceptable price profile, so that each year the leasing footage would be drilled for oil or gas based on a Btu-equivalent marginal price, except in region 1A, in which footage is allocated on a basis of a Btu-equivalence of undiscovered resources. This allocation figure is 57 percent oil, 43 percent gas.

Once the model establishes a pattern of reserve additions over a period of time, it calculates production from those reserves. Developmental drilling is assumed to occur in the year after discovery of reserves.

The approach described above is similar to that used for the 1974 PIR. There are, however, several important differences. The previous model did not include a drilling response to higher oil prices. Drilling proceeded at a constant pace and until it was no longer economic, at this point drilling abruptly terminated. Second, for the 1974 PIR, finding curves were not directly linked to U.S. Geological Survey reserves estimates as they are in this version. Finally, the cost structure has been altered to reflect higher costs and the recently legislated changes in the oil depletion allowance.

Appendix E

SCENARIO DESCRIPTIONS

Appendix E

SCENARIO DESCRIPTIONS

There are two major objectives to be met by scenario analysis through the Project Independence Evaluation Systems (PIES):

- Update the 1974 version of PIES to reflect knowledge gained over the past year, and improvements in modelling structure and data.
- Submit for public consideration and debate a limited number of future energy scenarios which characterize expectations and outcomes under various sets of assumptions.

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

SCENARIO OVERVIEW

Scenarios are built up through the following procedure:

- Each of the major fuels or resources, defined as oil and gas, coal, electric utilities, synthetics, and geothermal and solar energy, is described in terms of a high/medium/low, or regular/restricted set of conventions; this terminology and the underlying assumptions are detailed in the Fuel Convention tables (Tables III-IX).
- The individual fuel or resource conventions are then combined into one of six supply cases, as shown in the Supply Case Specifications table (Table II).
- Three demand cases are specified: BAU, Conservation, and Electrification.

- The demand and supply cases are combined into scenarios, each having the unique characteristics of a particular combination of demand and supply cases; Table I shows in matrix form the scenarios which are defined through this procedure.

Last year's Project Independence Report (PIR) energy scenario concepts focused on differences among BAU, accelerated supply development and conservation outcomes. These scenario concepts have been extended this year in the following manner:

- Reference Scenario;
- Conservation Scenario;
- Accelerated Scenario;
- Regulatory Scenario (two price levels);
- Electrification Scenario;
- Regional Limitation Scenario;
- Supply Pessimism Scenario.

Several points concerning this general approach in defining energy scenarios should be emphasized at the outset:

- As these energy outcomes are defined into energy scenarios, they are not intended to simulate any specific set of policy recommendations, or action programs; rather, each scenario is designed to assess the impacts of several major policy initiatives, none of which can be realistically assumed to dominate future energy policy to the exclusion of other counter-vailing initiatives.
- These energy scenarios are not mutually-exclusive, or collectively-exhaustive of all possible energy outcomes; there is some degree of overlap among the scenarios. Each scenario is intended to simulate a pronounced emphasis upon the theme which characterizes it, e.g., supply development or conservation, but not to the exclusion of underlying assumptions and conventions which may be common to other scenarios, e.g., magnitude of undiscovered oil and gas reserves, or cost of strip-mining land reclamation.

These scenarios are described more fully in subsequent sections; they are discussed in summary terms, with a description of each scenario theme or expectation, immediately below.

Reference Scenario

This consists of BAU demand and supply cases, combined into a scenario to illustrate technical changes in PIES between 1974 and the present; this combination of supply and demand cases is the one most nearly comparable to the 1974 version of the BAU scenario.

Conservation Scenario

This scenario reflects a full set of conservation actions on the demand side, including auto efficiency standards, van pooling, thermal efficiency standards, appliance efficiency improvements, accelerated industrial energy conservation, improved airline load factors, electric utility load management, and elimination of gas pilot lights. On the supply side, a BAU case is assumed.

Accelerated Scenario

On the supply side, this scenario is designed to illustrate the effects of an aggressive but achieveable effort to increase domestic energy resource development.

On the other side, this scenario reflects the energy conservation actions described in the Conservation Scenario.

Regulatory Scenario

This scenario is designed to illustrate principally the domestic supply, demand and import impacts of price regulation and controls. The scenario's supply case assumes that price controls and regulations are in effect for all domestic oil and gas. Two sets of assumptions about price regulation have been developed: in the higher case, domestic oil and gas are regulated at approximately $9/barrel and $1.20/Mcf respectively, wellhead prices, 1975 year of denomination. In the lower case, the regulated oil and gas prices are approximately $7.50/barrel and $1.00/Mcf. Imports of oil and gas are unconstrained, at world prices. Other assumptions concerning supply are identical with the BAU supply case. The demand case assumed is BAU.

Electrification Scenario

This scenario is designed to show the impact upon the growth of electricity of a strategy to promote increased electrification of energy end-use. On the supply side, an accelerated coal-nuclear case is used; the demand case embodies increased electrification in the household/commercial and industrial sectors.

Regional Limitation Scenario

On the demand side, this scenario assumes the business-as-usual case. On the supply side, the scenario assumes that energy development is restricted through a moratorium imposed on nuclear power plant construction, beyond projects currently granted construction permits, decelerated leasing of the OCS through 1980, restrictions on mining and burning of coal including heavier reclamation costs and severance taxes, and mandatory use of scrubbers on all new power plants in conjunction with low-sulfur coal.

Supply Pessimism Scenario

This scenario is designed to show the adverse impact upon supply of the combined effect of price regulation, regional supply limitation, and geological pessimism with respect to oil and gas finding rates. The major supply assumptions are the conventions for the Regional Limitation Scenario, combined with oil and gas price regulation at approximately $9/barrel and $1.20/Mcf and with less favorable geological experience, less rapid leasing of OCS acreage, and diminished ability of the Alaskan North Slope to sustain high rates of oil production in the 1980's.

GENERAL CONVENTIONS

Time Frame

The PIES structure develops an equilibrium solution for a given benchmark year. For this version of PIR, the benchmark years are 1980, 1985 and 1990. The analysis is focused upon 1985, with all scenarios run for that year. In addition, to evaluate longer and shorter run phenomena, Reference Scenarios have been run for 1990 and 1980.

World Oil Prices

All scenarios assume unlimited availability of oil imports delivered to the United States at one of three C.I.F. prices: $8; $13; $16. These prices are expressed in constant dollars, denominated as of July 1975.

The $8 assumption is an inflation adjustment for the 1974 PIR $7 world oil price assumption. The $13 assumption reflects an inflation adjustment to the 1974 PIR $11 assumption, and the estimated impact of OPEC's recent ten percent increase in marker crude prices. The $16 assumption represents a new case for 1975 PIR analysis.

Macroeconomic Outlook

A single macroeconomic forecast is used for all scenarios; this is Data Resources, Inc.'s Control Long 5/75, which is described in detail in Appendix B. Some of the major assumptions are summarized below:

	Average Annual Rates of Change (%)	
	1975-1980	1980-1985
GNP	5.5	3.6
Gross Private Domestic Investment	11.2	3.7
Exports	8.0	5.7
CPI	5.2	4.8
WPI	5.1	3.4

World LNG Prices

For the $8 world oil price, a corresponding LNG import price of $2.50/Mcf, regasified and at the demand center's city gate, is assumed.

For the $13 and $16 oil prices, the corresponding LNG import prices are $3/Mcf and $3.70/Mcf, respectively; the methodology is discussed in Table V, under Supplemental Gas Supply conventions.

Storage

No assumptions about a national petroleum storage program are incorporated into the PIES structure, either on the demand or the supply side.

NPR #1 Development

The development of Naval Petroleum Reserve #1 (Elk Hills) is assumed to occur under all oil and gas development conventions. NPR #1 production is assumed at a level rate of 200 thousand barrels per day (MB/D) throughout the 1980's. This amounts to a ten year output of 730 MMB, which is a rate of development consistent with estimated proven reserves of 1.3 billion barrels, recoverable by primary methods alone.

Estimates of NPR #1 production published earlier this year have ranged as high as 300 MB/D production by 1978 under an accelerated schedule, with output declining to 82 MB/D by 1985. The slower build-up assumed for the 1975 PIR, and the level output through the 1980's, are more consistent with the limitations on the rapid development of NPR #1, principally:

° Need for another 1,000 production wells, to be completed by 1980;

° Current pipeline capacity limitation of 160 MB/D, with lead time of 3-4 years to augment capacity to 350 MB/D.

SPECIFIC CONVENTIONS: DEMAND

There are three demand cases used in the integrating framework:

° Case 1: BAU

° Case 2: Conservation

° Case 3: Electrification

Demand Case 1: BAU

This is based upon FEA's Project Independence Econometric Demand Model (PIEDM) described in Appendix C. This BAU demand case does not assume passage of any of the energy conservation actions currently under consideration by the Congress and the Administration, but does include the conservation effect of higher energy prices.

Demand Case 2: Conservation

This demand case consists of the PIEDM, modified by the following conservation actions, industrial coal conversion, and dispersed solar heating and cooling actions.

Conservation Actions:

° Transportation
- Auto efficiency standards of 20 MPG, 25 MPG and 28 MPG in 1980, 1985 and 1990;
- Incentives for national van pool program; expected savings are 100 MB/D, 125 MB/D and 160 MB/D for 1980, 1985 and 1990, respectively;
- Change in CAB regulations to increase airline load factors from 55 to 65 percent, expected savings are 50 MB/D, 100 MB/D and 150 MB/D for 1980, 1985 and 1990.

° Residential and Commercial
- National thermal efficiency standards for new residential and commercial buildings;
- Appliance efficiency improvements and mandatory labelling;
- Tax incentives for insulation retrofit of homes and commercial buildings;

- Elimination of gas pilot lights in all new appliances and equipment, and mandatory retrofit of existing residential heating systems by 1980; expected savings are 15 MB/D, 100 MB/D and 250 MB/D for 1980, 1985 and 1990.

° Industrial
- Expanded energy accounting and SEC reporting system, with technical assistance programs and efficiency guidelines for selected industrial equipment; expected energy savings of 485 MB/D, 590 MB/D and 300 MB/D for 1980, 1985 and 1990.

° Electric Utilities
- Incentives to stimulate load management actions designed to keep peak load annual growth one percent below total load growth. This results in an average capacity factor of .57 vs. the BAU level of .48.

Industrial Coal Conversion and Dispersed Solar Energy:

The impact of shifts from industrial coal conversion, biomass and dispersed solar is shown in oil-equivalent terms below, for a 1985/$13 scenario:

	Conservation Effect
Dispersed Solar	60 MB/D
Industrial Coal Conversion	205 MB/D
Biomass and other	160 MB/D

Industrial coal conversion savings are based upon a 1975 FEA survey of 90 percent of all major industrial users of oil and gas. The magnitude of the estimated savings reflects those respondents who currently have coal conversion capability.

No additional coal conversion savings by the industrial sector are incorporated in the Conservation case.

Demand Case 3: Electrification

This demand case incorporates into the Demand Case 1, BAU, certain measures aimed at substituting coal and electricity in place of oil and gas in the residential and commercial and industrial sectors.

° Residential and Commercial
- Ban on oil and natural gas heating equipment including water heating in new buildings effective January 1977. The impact of this measure is to eliminate any growth in gas and oil consumption in this sector. The existing uses of oil and gas are not affected by the ban.

° Industrial
- Most of the growth in natural gas demand is filled by either coal or electricity.
- The growth in natural gas requirements follows the existing pattern (65 percent, 30 percent and 5 percent for boiler fuel, heating processes and feedstock, respectively).
- Coal-fired boilers will be available and will be built in place of new large size gas fired boilers (greater than 100 MMBtu/hour), amounting to about 40 percent of natural gas requirements.
- Fifty percent of new natural gas required for heating processes (ovens, kilns, etc.,) will be replaced by electricity, while natural gas will still be required for the other 50 percent.
- Industrial coal conversion of existing oil and gas boilers of 205 MB/D.

SPECIFIC CONVENTIONS: SUPPLY

Six supply cases have been developed as part of the PIES integrating framework:

° Case A: BAU;

° Case B: Accelerated Supply;

° Case C: Price Regulation;

° Case D: Regional Limitation;

° Case E: Combined C & D, i.e., Price Regulation and Regional Limitation;

° Case F: Coal-Nuclear.

Table II describes the supply cases in terms of general assumptions (e.g., high/medium/low) about fuel development; Tables III through IX describe the technical conventions which underlie the general assumptions in Table II. The comments which follow are intended to provide a quick characterization of major fuel conventions, and a summary description of each supply case; more detail is available in Tables III-IX.

Oil and Gas

Alaskan Logistics

A second Alaskan oil pipeline is assumed to be in place by 1985 under the high convention. Movement of North Slope and South Alaskan gas is also assumed to be unconstrained as of 1985, under the high convention. Under the

medium convention, capacity to deliver North Slope gas to the Lower-48 States is limited to an estimated annual delivery capability of 1.2 Tcf in 1985. These assumptions are consistent with either of the current proposals, Trans-Alaska and Trans-Canada.

Canadian Pipeline Gas Imports

The National Energy Board's current schedule of deliveries to the United States is assumed resulting in maximum levels of 1.0 Tcf/y, .87 Tcf/y, and 1.3 Tcf/y for 1980, 1985 and 1990.

LNG Imports

A lower bound, minimum supply volume of .4 Tcf/y in 1980 and 1985 is assumed, reflecting unconditionally-approved import contracts; beyond that level, maximum supply increments of 1.1 and 1.7 Tcf/y for 1985 are assumed to be available under medium and high conventions respectively; however, no upper limit is set on LNG imports for scenarios that contain a new gas price regulation provision.

Military Reservations

The California Military Reservation is a DOD controlled area off Santa Cruz island, beyond the 3 mile limit. Reserve estimates of 1-2 billion barrels would support output at 100 MB/D throughout the 1980's. There are two major obstacles to development:

° The State of California has a moratorium on pipelines in the 3 mile wide strip along the high water mark; court action would be necessary to overturn this.

° Depth of water ranges between 200 and 700 meters, requiring perhaps advanced technology sub-sea completions.

Because of these factors, the California Military Reservation is assumed to contribute only under the high oil supply convention. Because of recent disappointing results in the East Florida area, no contribution is assumed from the Florida Military Reserve.

Electric Utilities

Limitations are imposed on possible additions to nuclear power plant capacity, to reflect long lead times, and technical, regulatory and financial impediments. Under the medium and high conventions, additions between 1975 and 1984 have an upper bound of 116 Gwe and 142 Gwe respectively.

Additions to coal-fired capacity are also limited for the period 1975-1979; under the medium and high conventions the limitation is 70 Gwe and 80 Gwe respectively.

Plant capital costs for baseloaded nuclear and coal plants are assumed to decrease slightly from the medium to the high convention; for a nuclear power plant, costs/Kwe drop from $550 to $500.

The supply limitation case embodies a moratorium on new neclear construction permits which limits nuclear plant additions to 61 Gwe by 1985.

Coal

Under the regular convention, reclamation charges for surface-mined coal average 25¢/ton. Non-deterioration standards are met with either high-sulfur coal and scrubbers, or low-sulfur coal without scrubbers.

Under the restricted convention, reclamation costs increase to a range of .40-1.40/ton for surface Western coal, and .85-2.10/ton for surface Eastern coal. All new coal-fired capacity for the electric utility industry is built with scrubbers, and only low-sulfur coal is burned in new plants. A severance tax of 30 percent of the mine-mouth price is imposed on Western coal.

Synthetic Fuels

For the 1985 scenarios, at world oil prices of $13 the convention for synthetic fuel contribution is 880 MB/D. Only oil shale, however, is produced at unsubsidized prices; at $12/barrel the estimate for shale is 300 MB/D; the other technologies, syncrude and high and low Btu gas, are produced at unsubsidized oil equivalent prices of $16-24/barrel.

The various fuel conventions are combined to define supply cases; the summary characteristics of these supply cases are as follows:

Supply Case A: BAU

- Decontrol of old oil and deregulation of new natural gas;
- Medium oil and gas conventions;
- Special region oil potential of 3,200 MB/D in 1985/$13 scenario;
- Nuclear capacity additions limited to a projected maximum of 116 Gwe during 1975-1984;
- Coal capacity additions limited to a projected maximum of 70 Gwe during 1975-1979;

- Electricity peak demand grows half a percent faster than average demand;
- Synthetic fuel development of 880 MB/D oil equivalent in 1985/$13 scenario.

Supply Case B: Accelerated Supply

- Decontrol and deregulation as above;
- High oil and gas conventions;
- Special region oil potential of 5,120 MB/D in 1985/$13 scenario;
- Nuclear capacity additions limited to a projected maximum of 142 Gwe during 1975-1984;
- Electric utility plant capital costs decline due to reduction in construction delays;
- Coal capacity additions limited to a projected maximum of 80 Gwe during 1975-1979;
- Electricity peak demand grows one percent lower than average demand;
- High case capacity of 8.4 Gwe by 1985 from geothermal and solar electricity.

Supply Case C: Price Regulation

- Domestic oil and gas price caps at approximately $9/barrel and $1.20/Mcf for the higher case, and $7.50/barrel and $1.00/Mcf for the lower case;
- Extension of gas price regulation into intrastate markets with contract price rollbacks where necessary;
- Medium oil and gas conventions;
- Oil imports unconstrained, at scenario world oil prices;
- LNG imports unconstrained, at scenario LNG import prices;
- Oil and gas price entitlements feature to equalize regulated prices with import prices, as faces by demand sector;
- Medium case capacity of 2.1 Gwe by 1985 from geothermal and solar electricity.

Supply Case D: Regional Limitation

- Medium oil and gas conventions, as in BAU supply case;
- LNG imports unconstrained, at scenario LNG import prices;
- Coal restricted conventions:
  - Only low sulfur coal, with scrubbers on new utility plants;
  - Severance tax of 30 percent of FOB mine selling price, on all coal mined in PIES coal Regions 5 through 12, all west of the Mississippi; precedent for this is Montana's recently-enacted severance tax;
  - Reclamation charges;
- Nuclear moratorium, limiting capacity to plants already granted construction permits; this results in upper limit of 61 Gwe added during 1975-1984;
- Medium case contribution of 2.1 Gwe by 1985 from geothermal and solar energy;
- No contribution from synthetic fuels.

Supply Case E: Combined C & D, Price Regulation and Regional Limitation

- In this combined case, the low oil and gas conventions are used in conjunction with price caps of $9/barrel and $1.20/Mcf;
- Low oil and gas conventions include:
  - Decelerated OCS leasing through 1980;
  - Limited North Slope oil production;
  - No logistical link to move Alaskan gas to Lower-48;
  - Adverse geological experience;
  - Pessimistic tertiary recovery estimates.
- In other fuel areas, the more pessimistic assumptions are used when combining the two supply cases, namely;
  - Nuclear moratorium;
  - Restricted coal;
  - Medium availability of supplemental gas;
  - No synthetic fuel contribution.

Supply Case F: High Coal, Nuclear and Electricity

Supply Case A, modified as follows:

- Prohibition on the use of all (new and existing) oil or natural gas in any base load electricity generation;

- Prohibition on any new oil or gas power plants built after 1977 for intermediate load;
- Accelerated conversion of oil and gas boilers in electric utilities to coal;
- Nuclear capacity additions limited to a projected maximum of 142 Gwe during 1975-1984;
- Synthetic fuel development of 880 MB/D of oil equivalent in 1985;
- High Convention for 1985 capacity from geothermal and solar energy, totalling 8.4 Gwe.

Table 1

SCENARIO DEFINITION: SUPPLY AND DEMAND CASES/1985

Demand Cases: / Supply Cases:	Case A: BAU	Case B: Accelerated Supply	Case C: Price Regulation	Case D: Regional Limitation	Case E: Combined/ Price Reg. & Regional Limitation	Case F: Coal-Nuclear
Case 1: BAU	Reference Scenario		Regulatory Scenario (two price Levels)	Regional Limitation Scenario	Supply Pessimism Scenario	
Case 2: Conservation	Conservation Scenario	Accelerated Scenario				
Case 3: Electrification						Electrification Scenario

Table II

SUPPLY CASE SPECIFICATIONS*

Supply Cases: / Fuel	Oil/Gas	Supplemental Gas**	Coal	Electric Utilities	Synthetics	Solar and Geothermal Energy
A: BAU	medium	medium	regular	medium	medium	medium
B: Accelerated Development	high	high	regular	high	medium	high
C: Price Regulation	medium w/caps	high (no limit in 1985)	regular	medium	medium	medium
D: Regional	medium	medium	restricted	medium w/ nuclear moratorium, load mgt.	(none)	medium
E: Combined Cases C & D	low w/ caps	medium (no LNG limit in 1985)	restricted	medium w/ nuclear moratorium, load mgt	(none)	medium
F: Coal-Nuclear	medium	medium	regular	medium, modified***	medium	high

* High/medium/low and regular/restricted terminology is defined for each of the fuels in Table III through IX.
** Consists of Canadian pipeline imports and LNG imports.
*** High coal conversion, and prohibition of oil and gas in baseload electricity generation.

Table IIIA

OIL AND GAS CONVENTIONS; GENERAL PARAMETERS

	High	Medium	Low
° Finding rates	USGS Statistical Mean: Plus One Standard Deviation	USGS Statistical Mean	USGS Statistical Mean: Minus One Standard Deviation
° OCS Leasing 1975-1985 (MMacres)			
Offered	74.1	50.9	36.3
Leased	39.7	27.7	18.7
° Old Field Secondary	Inferred Reserves per USGS-725	Region 6 per A.P.I.	Region 6 per A.P.I.
° Old Field Tertiary			
1980	600 MB/D	450 MB/D	300 MB/D
1985	1,200	900	600
1990	2,400	1,800	900
° Royalties			
Onshore	1/8	1/8	1/8
Offshore	1/6	1/6	1/6
° Investment Tax Credit	10%	10% through 1977; 7% after	10% through 1977; 7% after

Table IIIB

OIL AND GAS CONVENTIONS: SPECIAL REGIONS

1985/$13	High Oil (MB/D)	High Gas (BCF/Y)	Medium Oil (MB/D)	Medium Gas (BCF/Y)	Low Oil (MB/D)	Low Gas (BCF/Y)
Northern Alaska						
Prudhoe Bay	1,800	821	1,600	730	1,400	693
Other, North Slope	924	306	720	110	495	66
NPR #4	864	210	0*	0	0	0
Beaufort Sea	739	224	448	105	0	0
Southern Alaska**	0	750	0	290	0	0
SUB-TOTAL ALASKA***	4,327	2,311	2,768	1,235	1,895	705
Military Reservations						
California	100	0	0	0	0	0

* Larue, Moore & Schafer (LM & S) estimate 378 MB/D at minimum acceptable wellhead price of $7.16/barrel.

** Includes only non-associated gas; oil and associated gas are estimated as part of the NPC model, Regions 1 and 1A.

*** Minimum acceptable wellhead price of $12; gas @ Btu equivalent:
- Transportation from Prudhoe Bay Field pipeline terminal to Los Angeles estimated @ additional $4.00/barrel;
- Transportation of NPR #4 and Beaufort Sea production to Prudhoe Bay estimated @ additional $1/barrel.

Table IIIB (Continued)

OIL AND GAS CONVENTIONS; SPECIAL REGIONS

1985/$13	High Oil (MB/D)	High Gas (BCF/Y)	Medium Oil (MB/D)	Medium Gas (BCF/Y)	Low Oil (MB/D)	Low Gas (BCF/Y)
Heavy Hydrocarbons						
NPC 2	185	0	129	0	103	0
NPC 4	9	0	6	0	5	0
NPC 6	144	0	78	0	63	0
NPC 7	10	0	9	0	3	0
Tar Sands	150	0	10	0	10	0
NPR #1	200	0	200	0	200	0
Tight Gas	0	868	0	168	0	0
TOTAL, SPECIAL REGIONS	5,125	3,179	3,200	1,403	2,279	705

Table IIIC

OIL AND GAS CONVENTIONS; ALASKAN LOGISTICS: NORTH SLOPE OIL

	High	Medium	Low
1980			
TAPS, unlooped	2.0	2.0	2.0
1985			
TAPS, unlooped	2.0	2.0	2.0
Looped increment	.5	.5	---
Second oil line	2.0	---	---
TOTAL, 1985	4.5	2.5	2.0
1990			
TAPS, unlooped	2.0	2.0	2.0
Looped increment	1.0	1.0	---
Second oil line	2.0	---	---
TOTAL, 1990	5.0	3.0	2.0

NOTES:

1: Transportation charge from wellhead to L-48 via TAPS, unlooped, is $1.31/barrel; charge via looped increment, or via second oil line is $4.01/barrel.

Table IIID

OIL AND GAS CONVENTIONS:
ALASKAN LOGISTICS: NATURAL GAS (1985/$13)

[Case 1: Transcanada Pipeline]
(BCF/Y)

	High	Medium
North Slope Production Potential	1,561	945
Transcanada Capacity	1,200*	1,200
South Alaska Production Potential	940	440
LNG Transfer to Lower 48	2,140** (feasible)	440*** (feasible)

---

* Constraint on North Slope production transfer into Canada.

** Under Accelerated Development supply cases, it appears reasonable to assume that logistical link can be put in place by 1985:
- 2-3 baseload liquefaction plants, each @ 300-350 BCF/Y, are required;
- Eleven LNG tankers of standard 125,000 CM size are needed; nine tankers of 160,000 CM alternative.

*** Infrastructure expansion to enable transfer of South Alaskan gas to L-48 by LNG link; expansion from currently-planned level of 100 BCF/Y is feasible, requiring one additional baseload liquefaction plant, and three large tankers.

Table IIIE

OIL AND GAS CONVENTIONS:
ALASKAN LOGISTICS: NATURAL GAS (1985/$13)

[Case 2: El Paso LNG Link]
(BCF/Y)

	High	Medium
North Slope Production Potential	1,561	945
Pipeline Capacity to South Alaska	1,200*	1,200
South Alaska Production Potential	940	440
LNG Transfer Requirement to L-48	2,140	1,385
LNG Transfer Capability to L-48	2,140** (feasible)	1,385***

---

* Constraint on transfer of Northern Alaska gas production to South Alaska; gas pipeline looping by 1985 does not appear realistic.

** LNG infrastructural requirement is high, but feasible under "high" assumption:
- Twenty-seven LNG tankers;
- Six baseload liquefaction facilities in South Alaska (350 BCF/Y each);
- Accelerated development of regasification facilities in L-48 may pose environmental problems.

*** Slightly higher than estimate of El Paso capacity of 1,200 BCF/Y in place by 1985; augmentation, however, appears feasible under Medium convention:
- Two additional tankers;
- Fifty percent expansion of one baseloaded liquefaction facility.

Table IVA

ELECTRIC UTILITY CONVENTIONS; BUILD LIMITS

Nuclear build limits on post-1974 additions; nuclear builds after 1977 may not exceed 75 percent of all base and intermediate builds.

	High	Medium
1980	36	33
1985	141	116*
1990	271**	191*

* A moratorium on all nuclear plants not currently granted construction permits would limit growth to 61 more Gwe installed by 1985, and 73 Gwe by 1990.

** This reflects ERDA's estimate of potential additions during 1985-1989.

Coal build limits will be used for 1980 scenarios, based on the following estimates of limitations due to manufacturing capacity and regulatory delays:

	High	Medium
Coal Build limits 1975-1979 (Gwe)	80	70

Table IVB

ELECTRIC UTILITY CONVENTIONS; PLANT CAPITAL COSTS

Plant capital costs ($/Kwe)

Costs based on last year's Facilities Task Force recommendation scaled up to 1975 dollars. Scrubber cost for a new plant is $100 per Kwe.** These estimates are designed to reflect the cost of the average plant of each type delivered throughout the United States between January 1, 1975, and December 31, 1984. The costs include charges for AFDC at eight percent and are based on delivery of the average plant in 1982 with 7.5 percent average inflation of construction costs deflated in 1975 dollars using the projected consumer price index.

	High	Medium
Nuclear	500	550
Coal with scrubber**	440	480
Coal without scrubber	360	380
Combined cycle	210	230
Simple cycle	140	140
Hydroelectric	310	310
Oil (baseload)*	310	310
Natural gas (baseload)*	270	270
Scrubber retrofit**	135	135

* These are unlikely to be built after 1977 because of fuel price outcomes.

** Scrubber costs include cost of installation, replacement capacity of five percent at $480 per Kwe, and AFDC at eight percent.

Table IVC

ELECTRIC UTILITY CONVENTIONS: SPECIAL PARAMETERS

Peak Load Growth

Peak load is to be defined strictly as intraday peak which can only be met by gas turbines and hydroelectric. All other cycling loads that previously had been included in peak will now be included in intermediate load. There are two sets of assumptions concerning the relative growth rates of peak demand and average demand:

	High		Medium	
	Peak 1% slower than average		Peak 0.5% faster than average	
Reserve margins	17.5%		20%	
	% of* KWh	Capacity Factor	% of KWh	Capacity Factor
Plant Mix				
Base	66	.70	65	.70
Intermediate	33	.47	33	.36
Peak	1	.09	2	.08

Utility Coal Conversion

There are 11 GWh of capacity currently under conversion orders; five more have been identified as feasible, but no orders have been issued.

	High	Medium
GWh converted to coal	16	11

Plant Retirements

Non-nuclear/hydroelectric plant in existing base will be retired at the rate of .3 percent per year of capacity existing in that year.

* This convention is used in all conservation runs to model the projected effects of an active load management program.

Table IVC (continued)

ELECTRIC UTILITY CONVENTIONS: SPECIAL PARAMETERS

Oil and Gas Fired Plants

In the high coal/nuclear case oil and gas fired plants will be prohibited from base load operation. No new oil or gas fired plants may be built for intermediate load after 1977.

Table V

SUPPLEMENTAL GAS SUPPLY
(Tcf/y)

Canadian Pipeline Imports*, **

	High	Medium
1980	1.0	1.0
1985	.87	.87
1990	.3	.3

* Assumed price is derived as follows: $2.05 (Btu equivalent of distillate) times scenario world oil price divided by $11; at $13, derived price is $2.42/Mcf at city gate.

** For the $8 and $13 scenarios, it is assumed that all of this contracted-for volume is imported by the United States; for the $16 scenario, the PIES structure presents Canadian imports to selected United States consuming regions as another gas supply option.

LNG Import Volumes

A lower bound, minimum supply quantity of .4 Tcf/y in 1980 and 1985, both high and medium cases, is assumed; this reflects projects unconditionally-approved by the FPC for East Coast delivery.

Beyond the lower bound quantity, the following upper bounds on supply are assumed;

	High	Medium
1980	.9	.5
1985	1.7*	1.1*
1990	no limit	no limit

* Under assumptions of gas price regulation or regional suplly limitation (Supply Cases C and E), LNG import volumes in 1985 do not have an upper bound.

Table V (continued)

SUPPLEMENTAL GAS SUPPLY
(Tcf/y)

LNG Import Prices

$8 Scenario

° Price of $2.50/Mcf regasified and at the city gate of the demand center, is used to reflect price floor of $1.30/Mcf, FOB lifting, plus 80¢ maritime charges, plus 40¢ regasification and transmission within the United States.

$13 Scenario

° Price of $3/Mcf is assumed, reflecting current delivered prices.

$16 Scenario

° Price of $3.70/Mcf is assumed, reflecting current LNG price escalation formulas which are tied to world oil price movements.

Table VI

COAL CONVENTIONS

	Regular	Restricted
° Scrubbers on New Plants	Where high sulfur coal is used	All new plants
° Sulfur Content	Economic choice for all new and certain existing plants between high sulfur with scrubbers and low sulfur coal without scrubbers; remaining plants burn cheapest available coal	Low sulfur only
° Reclamation Costs		
Additional charges per ton on average:		
West:		
Deep Mine	0	$ .15
Surface	$ .25	$ .40 to 1.40
East:		
Deep Mine	0	$ .15
Surface	$ .25	$ .85 to 2.10

Deep mine reclamation charge would be a 15¢/ton reclamation fee for abandoned mines.

Reclamation costs for surface mining are a function of geographic location and mine characteristics. Costs shown here are a combination of reclamation taxes, reclamation costs required by law and an environmental assessment (usually less than 1¢/ton and no greater than 3¢/ton).

Steep slope reclamation requirements are not expected to have a material effect on production by 1980.

	Regular	Restricted
° Regional Limitations		
Severance Tax	None	30 percent of mine mouth price on coal mined West of the Mississippi (Coal Supply Regions 5-12)

Table VII

GEOTHERMAL ELECTRICITY CONVENTIONS

	1980	1985	1990
Medium			
Capacity (Mwe)			
- Dry Steam	700	1,550	2,150
- Hot Brine	10	100	2,000
- Hot Rock	---	---	10
- Geopressure	---	---	10
Total	710	1,650	4,170
High			
Capacity (Mwe)			
- Dry Steam	710	2,700	4,000
- Hot Brine	10	2,900	7,100
- Hot Rock	---	---	80
- Geopressure	---	500	950
Total	720	6,100	12,130

NOTES:

1. Costs range between 10 and 36 mils/Kwhr.
2. Capacity utilization factor is .8.
3. Plant is located in Census Regions 7, 8 and 9 (West South Central, Mountain and Pacific).

Table VIII

SOLAR ELECTRICITY SUPPLY CONVENTIONS

	1980	1985	1990
Medium			
Capacity (Mwe)	200	520	1,235
Cost Range (mils/Kwhr)	10.2	10.2-25	10.2-20
High			
Capacity (Mwe)	810	2,300	6,450
Cost Range (mils/Kwhr)	10.2-25	10.2-25	10.2-25

NOTE:

Processes and capacity factors as follows: solar biomass @ .8; wind @ .45; ocean thermal @ .85; thermal @ .45; photo-electricity @ .45.

Table IXA

SYNTHETIC FUELS/$8 WORLD OIL PRICE

Process	Non-Subsidized Price	1980	1985	1990
Shale Oil	$12/Bbl	0	100	100
Syncrude	$24/Bbl	0	0	0
High Btu Gas	$19/Bbl equivalent	0	120	120
Low Btu Gas	$15/Bbl equivalent	0	100	100
Total Synthetics		0	320	320

NOTES:

1. Representative mix of plants for analysis purposes includes 2 (50K each) oil shale, 3 (40 K each) high Btu gas, and 4 (25K each) low Btu gasification plants.
2. Excludes Biomass of 30,000 Bbl/day crude oil equivalent.
3. Assumes: - World oil prices fall in 1979/1980 time frame.
   - No second generation price effects as a result of either technological change or learning effects.

Table IXB

SYNTHETIC FUELS/$13 WORLD OLD PRICE

Process	Non-Subsidized Price	1980	1985	1990 Medium	1990 High
Shale Oil	$12/Bbl	-	300	400	500
Syncrude	$24/Bbl-till 1985 $20/Bbl-1985 after	0	50	50	50
High Btu Gas	$19/Bbl equivalent -till 1985 $16/Bbl equivalent -1985 after	0	280	280	320
Low Btu Gas	$15/Bbl equivalent -till 1985 $14/Bbl equivalent -1985 after	0	250	250	400
TOTAL SYNTHETICS		0	880	980	1,270

NOTES:

1: The representative mix of plants for analysis purposes includes six (50K each) oil shale, one syncrude, seven (40K each) high Btu, and 10 (25K each) low Btu gasification plants.

2: Excludes Biomass of 48,000 Bbls/day of crude oil equivalent.

Table IXB (continued)

SYNTHETIC FUELS/$13 WORLD OIL PRICE

NOTES:

3: Assumes:
- World oil prices are constant.
- Second generation price effect is a result of both technological change and learning effects which take place after 1985, and range from eight to twenty percent depending on process.
- No delays in construction due to institutional or legal problems.

Table IXC

SYNTHETIC FUELS/$16 WORLD OIL PRICE

Process	Non-Subsidized Price	1980	1985	1990 Medium	1990 High
Shale	$12/Bbl	0	350	450	700
Syncrude	$24/Bbl-till 1985 $20/Bbl-1985 after	0	50	100	100
High Btu Gas	$19/Bbl equivalent -till 1985 $16/Bbl equivalent -1985 after	0	280	320	480
Low Btu Gas	$15/Bbl equivalent -till 1985 $14/Bbl equivalent -1985 after	0	300	350	500
Total Synthetics		0	980	1,170	1,780

NOTES:

1. Excludes Biomass of 48,000 Bbls/day of Crude Oil equivalent.
2. Assumes: - World oil prices rise in 1979/1980 time frame.
   - Second generation price effects same as in $13 case.
   - No delays in construction due to institutional or legal problems.