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U.S. DEPARTMENT OF COMMERCE/National Bureau of Standards

Intermediate Future Forecasting System

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Intermediate Future Forecasting System

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PREFACE

The Intermediate Future Forecasting System (IFFS) was developed in the Longer-Term Information Division, Office of Energy Markets and End Use of the Energy Information Administration. Its purpose is to provide an integrated representation of the energy system, using information from the fuel analysis divisions of EIA, in the eight- to twelve-year time horizon.

This symposium was held to provide a forum for presentation of the system and its methodologies and for critical review by external experts. In particular, critiques of the model were invited before the first published use of the model's projections in the 1982 Annual Energy Outlook (AEO). These proceedings reflect the state of the IFFS model as of July 31, 1982. Considerable modification and enhancements were made before the 1982 AEO, which was published in May 1983. For more current documentation, the IFFS Model Documentation Report, Volume I: IFFS Executive Summary will be published in August 1983. The papers in this document were prepared by the speakers using the transcription of their presentations. As such, they reflect the speakers' opinions. Questions concerning IFFS should be addressed to John D. Pearson, Director, Longer-Term Information Division (202/252-5206), and questions concerning the symposium should be directed to Susan H. Shaw, Operations Branch, Longer-Term Information Division (202/252-1469).

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INTRODUCTORY REMARKS

Wray Smith
Director
Energy Markets and End Use
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I want to welcome you on behalf of my office, The Office of Energy Markets and End Use, and also on behalf of the Energy Information Administration. I would like to take this opportunity to say that the project we are reviewing today goes much beyond the boundaries of my own office. The development has depended for its success on the efforts of staff members in the Office of Oil and Gas, and the Office of Coal, Nuclear, and Alternate Fuels. People like Dick O'Neill and Mary Hutzler have contributed heavily to this. I'm very appreciative of the cooperation we have received across office boundaries.

The purpose of the conference is really two fold. We wanted to have an occasion in which we could set forth to a wider audience of persons who are intimately involved in the kind of work that we do, to let them know what we are up to and the nature of the forecasting methodology we are planning to use in the near future. And, in the process, we wanted to convene a panel of recognized experts to examine and comment on the work to date.

We feel that it is necessary and desirable to have the commentary at this point while the system is still clearly developmental. In this way, the discussions and the comments of the reviewers can have a genuine impact on further model development and, hopefully, would have a lot to do with the way we approach the preparation of the next annual report to Congress, the projections portion of the annual report.

The system under review is called the Intermediate Future Forecasting System. It is the new energy market model that will be used for major analyses that require intergrated forecasting approaches, such as the annual report to Congress. But, it also will be used to forecast across fields, future energy supply and demand, and compare effects of energy policy and trends.

Just a word on the reasons for undertaking the project in its present form. The first was to provide a year by year methodology for examining transitional effects of energy policies on energy markets, such as the study of alternative regulatory policies toward electric utilities, or things that are going on in the natural gas markets.

The second reason was the need for a forecasting tool that was managerially and computationally simpler than prior models. We are all faced with diminishing and constrained resources. It is important for us to have a system that can be maintained, operated and improved by a much smaller cadre of analysts and specialists than we have had in the past; that conditions a great deal of our strategy.

The Intermediate Future Forecasting System does include all the major fuels, fuel conversion technologies, and consuming sectors, as several other modeling systems do. It can examine energy policies that impact several fuels, or, it can analyze both the direct effect of a policy influencing a consuming sector and the indirect effects on other sectors.

Other models have had such properties and, as you will see when Fred Murphy presents the description, the Intermediate Future Forecasting System has its own distinctions. We have brought in reviewers to provide a candid assessment of the project. We expect to get that. And, by having you in to review our progress before producing an analysis and set of projections, in an official way, on behalf of EIA, we hope to make use of your constructive comments, improve the quality of our first product, which we hope will be in the next annual report to Congress.

WELCOME

J. Erich Evered
Administrator
Energy Information Administration
Department of Energy

We are pursuing this effort because we perceive the need to do our job more effectively and more efficiently. We are just as subject to resource reductions, dollars and people, as every other component of this Department, as well as elsewhere in the government.

We are putting a lot of eggs in this basket. Because of resource constraints, we do not have the luxury of pursuing a suite of alternative approaches simultaneously. We have every confidence in the Intermediate Future Forecasting System. We see this as an essential element of EIA's mission over the coming years. We earnestly solicit your comments. We are looking forward to the input we are going to receive from the program participants. I am very pleased by the broad participation and attendance we have today. I welcome you all, and encourage you to critique mercilessly.

AN INTRODUCTION TO THE INTERMEDIATE FUTURE FORECASTING SYSTEM

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and

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Introduction

The Energy Information Administration is completing a new energy market model, the Intermediate Future Forecasting System (IFFS). The model will be used to study issues on energy markets. Broadly stated, the model is designed to study government policies affecting energy markets and transitions within energy markets.

This paper presents an overview of IFFS. There are two important aspects to the model: how the individual sectors and energy forms are represented and how the individual pieces are combined to provide a unified representation of energy markets. The system organization and an overview of the individual fuel market representations are presented here. The subsequent papers in this symposium describe in more detail how each fuel market is represented.

The Need for an Energy Market Perspective

Since the early 1970's the nation has suffered several severe economic shocks because of rapid changes in energy markets. The 1973-1974 embargo, during which oil prices increased several-fold, was followed by domestic natural gas shortages in the middle 1970's. Continued Middle East instability led to a further doubling of oil prices during 1978 and 1979.

Looking back, the original energy problem of this century was the difficulty of coping with abundance. Significant oil finds had, on occasion, forced the price per barrel down to $.20. Gas reserves were continually added as a byproduct of the search for oil, and often wasted as a nuisance instead of treated as a national resource. Coal was, and still is, readily available. The major concerns of Government were to control wasteful development of oil, assist the expanding market for gas, and soften the dislocations from decreasing coal use.

By the 1950's, the picture had changed: oil started to be imported in larger and larger quantities and the Nation's gas transmission system matured. The energy concerns of the 1950's and 1960's were to protect domestic oil producers from cheap foreign oil while limiting America's dependence on imports and protecting consumers from natural gas price increases.

The regulatory machinery for oil and gas, which lasted through most of the 1970's, was put in place in this period. There was another dimension added: an awareness of the effects of energy production and consumption on the environment. The Government developed new programs to improve air and water quality. One consequence of the environmental regulations was a simultaneous increase in oil imports and decrease in coal use. Although the State and Federal governments had been regulating aspects of individual fuel markets for years, there was no comprehensive view of the program impacts. Prior to the 1973-1974 embargo there seemed to be no need. Two earlier embargos had no serious effects on the Nation. After the 1973-1974 embargo, there was a clearly understood need for a comprehensive view of Government policy impacts and an understanding of the energy future of the Nation.

The original tools used to analyze energy markets were the Project Independence Evaluation System (PIES) and its successor, the Midterm Energy Forecasting System (MEFS). The Energy Information Administration (EIA) has replaced these models with a new model, the Intermediate Future Forecasting System (IFFS). This new model is designed to expand EIA's analytical capabilities in the 2 to 10-year time frame while actually reducing the resources required for analysis.

The purpose of policy analysis is to understand the likely consequences of a policy change. Invariably, there are losers as well as winners. The policy formulation process balances competing interests and is not fundamentally quantitative because different people weigh consequences differently. The role of energy analysis is to measure the consequences so that sound decisions can be made. IFFS is an equilibrium model; it relies on economic theory to establish the relationships necessary for measuring the repercussions of a given policy change. It, therefore, falls into the class of simulation models.

An equilibrium model is one which, when solved, results in supply equalling demand at a given set of prices. The word equilibrium in this case does not mean the model treats energy markets as static and unchanging. Far from it; the model represents the changes in domestic prices, consumption, capacity utilization and resource availability. Equilibrium simply means supplies equal demands under economic market forces.

IFFS is a partial equilibrium model, which is distinguished from a general equilibrium model in that a partial equilibrium model incorporates selected sectors of the economy, assuming all others remain unchanged, while a general equilibrium model represents the interactions of all sectors of the economy. The distinction can be illustrated in terms of the energy model discussed here. IFFS does not contain a representation of the iron and steel industry for example. Metallurgical coal demand is represented; however, the impact of energy prices on steel costs and, therefore, on the costs of drilling rigs and pipelines is not represented, unlike in a general equilibrium model.

Model Capabilities

IFFS is designed to show trends in energy markets and their underlying causes, such as trends in oil production and imports; regional shifts in coal production and consumption; price movements in oil products, natural gas, coal and electricity; and changing financial requirements of electric utilities. That is, IFFS can illustrate the directions energy is taking in the domestic economy, highlighting problems that may arise in the future or current problems that may dissipate without requiring any action. Projections with current energy policies in place are presented in the Energy Information Administration Annual Energy Outlook (formerly part of the Annual Report to Congress).

Starting with the Annual Outlook as a baseline, representations of Government policies within IFFS may be altered and new projections made for estimating the effects of these new Government policies. As no model is capable of representing all energy related policies, the capabilities of IFFS are best understood through examples of appropriate and inappropriate uses of the model.

One appropriate use is to estimate the effects of the Natural Gas Policy Act (NGPA) on energy markets. One can compare, for example, the impacts of deregulation versus the NGPA. Another use would be an estimation of the effects of a crude oil price change on oil imports. This would be a comparison of different market circumstances and their ramifications for the whole energy system. The model is also capable of estimating the effects of high railroad rates on the penetration of coal in energy markets. This would be an example of comparing different nonenergy policies on energy markets. A last example of an appropriate use is an estimation of the effects of a change in the rules concerning the inclusion of construction work in progress in the electric utility rate base. This issue is currently under discussion within the Federal Energy Regulatory Commission. The model could be a vehicle for comparing different regulatory philosophies.

No model is appropriate for meeting all analytical needs. An example of a use for which the model is not appropriate is in issues where seasonalities are important, because the model does not contain a representation of changing oil inventories or changes of gas in storage. It is also inappropriate for estimating the immediate effects of an oil embargo because that is a disequilibrium situation and IFFS is an economic equilibrium model. Finally, it is also inappropriate for estimating the local effects of Government programs. The model has regional detail, for example, Federal region detail on energy consumption, but the model is intended for producing estimates of national impacts and not local effects.

An Abstraction of Energy Markets

To understand the workings of IFFS one needs to have a conceptual view of the energy system. Energy markets, as represented in this model, are illustrated in Figure 1. The model has a representation of energy supply, conversion and demand. The model does include some new technologies, but it emphasizes the major fuels, incorporating domestic supplies of and demands for oil, gas and coal, and imports of crude oil, refined petroleum products and natural gas. It contains a representation of the conversion activities: refineries converting crude oil into petroleum products and electric utilities taking in fossil fuels, nuclear power, hydropower, and some of the new technologies to produce electricity.

Demand is measured for natural gas, electricity, coal, distillate oil, residual oil, gasoline, jet fuel, liquified petroleum gases, petrochemical feedstocks, and other petroleum products.

Demand models translate fuel and electricity prices, the level of economic activity, and the regulations affecting consumption into estimates of demands for fuel and products. That is, they measure the levels of energy consumption plus the competition among fuels. In the residential sector, for example, coal, oil, gas, electrical resistance heat and heat pumps compete for meeting home heating needs. The demand models are organized by end-use sector as follows: residential, commercial, raw material, industrial, and transportation.

The Structure of IFFS

The Department of Energy (DOE) has used several models to study energy markets: the Brookhaven Energy Systems Optimization Model (BESOM), MEFS, the Long-Term Energy Analysis Program (LEAP), and FOSSIL2. These models represent a wide range of methodologies for modeling energy markets and they predominate in domestic energy policy analyses.

The budget cuts faced by DOE and the need for large support staffs to maintain these models have led to the closing of MEFS and LEAP. Rather than abandon longer term forecasting entirely, EIA decided to extend the forecast horizon of a model under development. IFFS was originally designed to fill the forecast gap between the EIA short-term forecasts and MEFS. The reason for developing IFFS was to have a relatively inexpensive model providing year-by-year forecasts of energy markets for the time span most relevant for policies oriented to influencing a transition from oil and gas to other conventional fuels and to conservation.

Much of what makes MEFS and LEAP too expensive to maintain is the organizational structure of EIA. EIA has had, since its inception, problems in creating an organization consistent with both meeting customer requests for analysis and being efficient in producing the analyses. Customer requests are usually for analyses that are fuel-specific, e.g., natural gas regulatory alternatives, and analyst expertise is also fuel-specific: one needs to be a student of natural gas markets with all of their institutional features to produce an adequate study. EIA is organized along fuel lines for these reasons. The current market models, however, have strong integrating model cores, requiring a team of analysts to maintain software and submodel interfaces. The massive coordination required between fuel divisions running supply models, demand divisions running demand models and the integrating group led to meetings regularly attended by 30 people several times per week. Producing an Annual Report consumed up to 40-50 staff years.

A good part of the problem is that each supply or demand division found it easier to test model changes by running the whole modeling system as opposed to instituting internal validation of the results beforehand. A large model must be structured to fit into the organization that supports it. In the case of EIA, the model needs to be organized along fuel lines.

IFFS consists of a central integrating procedure, an electricity market module, an oil market module, a gas market module, and a coal market module. The current operation of the model is depicted in Figure 2. The model operates iteratively to balance supply and demand for all fuels at market clearing prices. That is, the central integrating routine calls all of the modules in turn, repeating the sequence until all prices and quantities converge to an equilibrium. When called, a fuel module computes a supply/demand balance for that fuel and then returns to the integrating routine. This means, for example, that when a trial equilibrium is being determined for electricity markets, the prices of competing fuels are fixed. When each module finds a new trial equilibrium, the new prices and quantities replace previous estimates. Before initializing the next module, the integrating routine re-evaluates all demands, incorporating the effects of the most recent estimated prices of all fuels. This captures the effect of substitutable fuels on each module-specific fuel. Consequently, the most recent trial estimates of prices initialize the demand equations when the integrating routine passes the computation to a new fuel module.

Using detailed demand models each time new trial demands are needed is prohibitively expensive. A simple analytical device is used to gain operational efficiency. A single equation is used to approximate the detailed models for each of the 10 Federal Region and sector combinations. The detailed demand models are revisited after all of the fuel modules have produced a new trial solution. This means, that once a trial equilibrium is reach, it is consistent with the fuel modules and with the detailed demand models.

To summarize each of the specific fuel or energy form modules simulates the economic forces that work within that particular fuel market, while the overall integrating routine represents the linkages among the different fuel markets within the economy.

The Individual Fuel Modules

As part of the overall logic, the model solves for an equilibrium in each year before moving on to the next. The year-by-year nature of the solution process leads to a natural organization of the individual fuel modules. Each module simulates the operating and planning activities of firms in that business. Operating activities are the day-to-day functions such as the dispatching of existing powerplants, while planning activities involve adding capacity that will be used in later time periods. Operating decisions use only the prices of the moment, and planning decisions are made based on past and future prices. "Past" prices are either historical data or forecast years where an equilibrium has already been found. "Future" prices are extrapolations of past prices, generated within the planning component. This approach allows the model to solve 1 year at a time, stepping forward to solve a new year only after the solution for the previous year is complete.

When future prices are generated in planning components, they are unlikely to be the same as the prices generated by the whole model when that future year is estimated. That is, decisions are made in the planning components using information different from the model solution. The reasons for choosing this approach are two-fold. First, achieving consistency would add another dimension of complexity to the model. Second, the gains from the added effort are unclear. A perfect foresight model would lead to over optimization of planning decisions, since in reality planners do not have perfect foresight and have to plan for a range of contingencies. The model operates under the assumption that energy producers are cost minimizers. This is consistent with the conclusion that no single coal, oil, or natural gas firm represents a significant market force. Electric utilities are modeled as cost minimizers as well. Even though electric utilities are regulated monopolies, their planning models are explicitly cost minimizing. At the same time, there is no alternative theory of economic behavior that has a broad base of support.

The search for the equilibrium within each module consists of the interaction of the operations component and the demand curves. The operations component uses the existing capacity, or what is projected to be existing capacity, to meet a trial demand estimate that comes from the demand curves. This in turn produces a new set of consumer prices which are then input to the demand curves, producing new quantity estimates. The internal cycling continues until the individual fuel module converges.

Within this overall organization, a wide range of modeling techniques are used: econometric techniques and process modeling techniques. Also, some decomposition techniques simplify the operation of the models. The econometric techniques are used, for example, to determine refinery capacities and the demand estimates. For estimating refinery capacity there are time series on petroleum product prices and capacity additions for downstream units and a simple reduced-form model to project refinery capacity. In the demand models there are structural representations of various elements of demand, such as home heating.

Process models are used to simulate decisions in industries where there is enough information to do this, or it is important to capture the extra detail. For example, linear programming is used to represent refinery operations, because this is one of the standard techniques in the industry for guiding the operations of refineries. The linear program translates estimates of capacities and demands into product prices, incorporating the effects of crude quality.

Individual submodels can grow quite large. Incorporating large models directly into IFFS would result in a cumbersome system. The overall system is streamlined through a decomposition strategy. This is known as using pseudodata. A complex model is run many times, generating many solutions. In running the refinery linear program, the solutions are known as extreme points. A simple model that expresses the relationships between the inputs and outputs of the larger model is fit to the model solutions as a way of approximating the larger model. The simplified model is then incorporated into the larger system. Refineries are modeled this way. Some of the demand models are brought into the system directly because they are simple enough, but for the more complex ones, this technique is used. Finally, this approach is also used for representing oil and gas supply.

Electricity Market Module

The electricity market module is called first as an operational convenience. Electric utilities demand oil, natural gas and coal, and these estimates are needed when finding an equilibrium within the other modules. The electric utility representation, given the initial conditions that it obtains from the central module, estimates the future capacity expansion necessary for the electric utility industry and then simulates the operation of utilities. Thus equipment is purchased, scheduled, maintained, and dispatched on the basis of minimum cost.

The electricity module finds an equilibrium in electricity markets by starting with trial demands, simulating the dispatching of an inventory of powerplants to meet those demands and costing the electricity delivered. Using a combination of the new costs and previous prices, new, end-use demands for electricity are estimated, and the costing is repeated. The process continues until two successive sets of prices and quantities are within a close tolerance. Once internal convergence is achieved, the integrating module regains control and initializes the next module.

Prices, or rates, are set by an iterative computation, which includes considerations of the revenues the utilities will obtain and of the costs and constraints that they will face in financing new expansion. Because the electric utility module estimates how each class of generating equipment is dispatched (e.g., coal, nuclear, natural gas), the model derives the utility requirements for coal, petroleum products (primarily residual and distillate fuels), and natural gas.

Oil Market Module

The oil market module consists of a representation of refineries and refined product demand. Since the world price of oil is a scenario input, the costs of refining the product mix demanded determine the prices for refined products. The demands for petroleum products are the demands for the end-use sectors at the refined product prices, plus the demands from the electric utilities module. The refinery representation provides estimates of refined product prices, the utilization of existing domestic refineries, the needs for investment in new downstream refining equipment, and the total requirement for crude oil that must be supplied from domestic production or imports.

As with the utility model, the representation of refineries is based on the models used in corporate planning. In the case of refineries, this means using linear programming. As these types of models are too complex to incorporate directly, the model used is run many times and log-linear equations are fitted to the results.

Refineries consume a portion of their output and some natural gas in their operations. Thus, the natural gas requirement for the operation of refineries is provided to the central integrating module for inclusion in the gas market module. Internal convergence within the refineries module consists of balancing supply and demand, incorporating the effects of each oil product production level on every other product.

Natural Gas Market Module

The gas market module contains the oil and gas supply representation, gas demands, and a mechanism for balancing supply and demand. This module also provides the domestic oil supply estimates because oil and gas are produced by the same industry, using the same equipment. Consequently, the supply representation has to be kept as a unit in either the oil or gas modules. Since the world oil price is an input assumption, the price of crude oil to domestic producers and refiners is fixed. The gas price, however, is highly variable, making the gas module the logical place for the oil and gas supply representation.

The oil and gas supply representation simulates the amount of domestic drilling that takes place, given the prices of oil and gas and the availability of drilling equipment. This drilling is then translated into reserve additions and, subsequently, production. The fuels produced consist of crude oil, plus associated and dissolved natural gas and nonassociated natural gas. Natural gas contains natural gas liquids, and the quantity of natural gas liquids is computed as a fixed proportion of gas production. Demands for natural gas come from end-use consuming sectors and from electric utilities and refineries. The mechanism for finding a supply/demand balance is more complex than with electric utilities and oil because of the regulations on wellhead and delivered prices and the regulations on transportation costs.

Coal Market Module

Once the gas market solution has been found, the coal module is called. This module emphasizes coal supply and transportation. Supply is estimated using the Resource and Mine Costing component of the National Coal Model. Because of the importance of transportation costs in delivered coal prices, the module contains an elaborate description of regional coal movements. Rather than using fixed transportation costs, the model increases the tariffs as increasing flows create congestion.

When the coal module has converged, the central integrating procedure reevaluates the detailed demand models, returns to the electric utilities module and proceeds through the entire model again.

A Mathematical Statement of the Solution Procedure

The problem of finding a market equilibrium is one of solving a set of simultaneous nonlinear equations. IFFS may be abstracted into a set of equations as follows:

Let $i = 1,\ldots,n$ index the fuels,
$j = 1,\ldots,m$ index the consuming sectors including the conversion activities.
p_i = price of fuel i
p = vector of prices
$S_i(p)$ = Supply of product i as a function of all fuel prices
$D_{ij}(p)$ = Demand for product i in sector j as a function of all fuel prices

Set

$$e_i(p) = \sum_j D_{ij}(p) - S_i(p).$$

Now $e_i(p)$ is known as the excess demand function for fuel i. The equilibrium problem may be stated as follows:

$$\text{find } p = (p_1,\ldots,p_n)$$

such that

$$e_1(p) = 0$$
$$\cdots$$
$$e_n(p) = 0$$

Let $p^k = (p_1^k, p_2^k, \ldots, p_n^k)$ be the trial solution from iteration k.

The k+1 iteration of the algorithm proceeds as follows:

Solve

$$e_1(p_1, p_2^k, \ldots, p_n^k) = 0.$$

Then solve

$$e_2(p_1^{k+1}, p_2, p_3^k, \ldots, p_n^k) = 0$$

repeating until the last equation is solved

$$e_n(p_1^{k+1}, p_2^{k+1}, \ldots, p_{n-1}^{k+1}, p_n) = 0$$

The algorithm continues until all equations are within tolerance for some p^k. In terms of IFFS, e_1 is the electricity module. Next, e_2 is the oil module, and it contains an estimate of utility oil consumption. Most importantly, e_3 is the natural gas module and two of the $D_{3j}(p)$ are the derived demand curves for natural gas in utilities and refineries. Finally, e_4 is coal. This mapping of modules to equations is not precise because each module contains more than one supply and demand curve, but this is incidental for the purposes of understanding how the model works.

The algorithm stated above is the Gauss-Seidel algorithm for solving simultaneous equations. This algorithm has the reputation for being relatively slow and has a linear convergence rate in the limit. However, it is very effective in this setting, taking eight to ten iterations in each year to reach a 1 percent convergence tolerance. The solution is efficient here because the structure of the fuel modules reduces the problem to the equivalent of solving four nonlinear equations. At the same time, the model contains thousands of equations. The equations with the greatest dependencies are solved within a fuel module, leaving relatively independent equations to be solved by the Gauss-Seidel algorithm.

Concluding Comments

IFFS provides a new approach for building energy market models. By providing a fuel market organization, the model fits more readily into the EIA organizational structure, and it is significantly faster, computationally, than MEFS and LEAP. The less structured model organization also allows for more natural formulations of the individual fuel markets. That is not to say this model is the uniformly dominant approach to energy modeling. The optimization elements of BESOM and MEFS can provide special insights by being explicit about cost minimization and having a large body of theory for the analyst to draw upon. LEAP is also useful for its representation of market dynamics and market penetration of new technologies. And, FOSSIL2 remains the fastest of the energy models.

There is more work that needs to be done to improve IFFS and the other energy models. These tasks involve some of the basic, unanswered questions of economics: How should one represent expectations in structural planning models? How should one represent decisionmaking in regulated utilities? The tasks also involve issues specific to energy markets: What is a good aggregate representation of forced outages and dispatching in electric utilities? What can be done to represent decisions of who buys what natural gas, given that price ceilings restrict what purchasers can pay? Also, more work can be done to improve the computational features of the model.

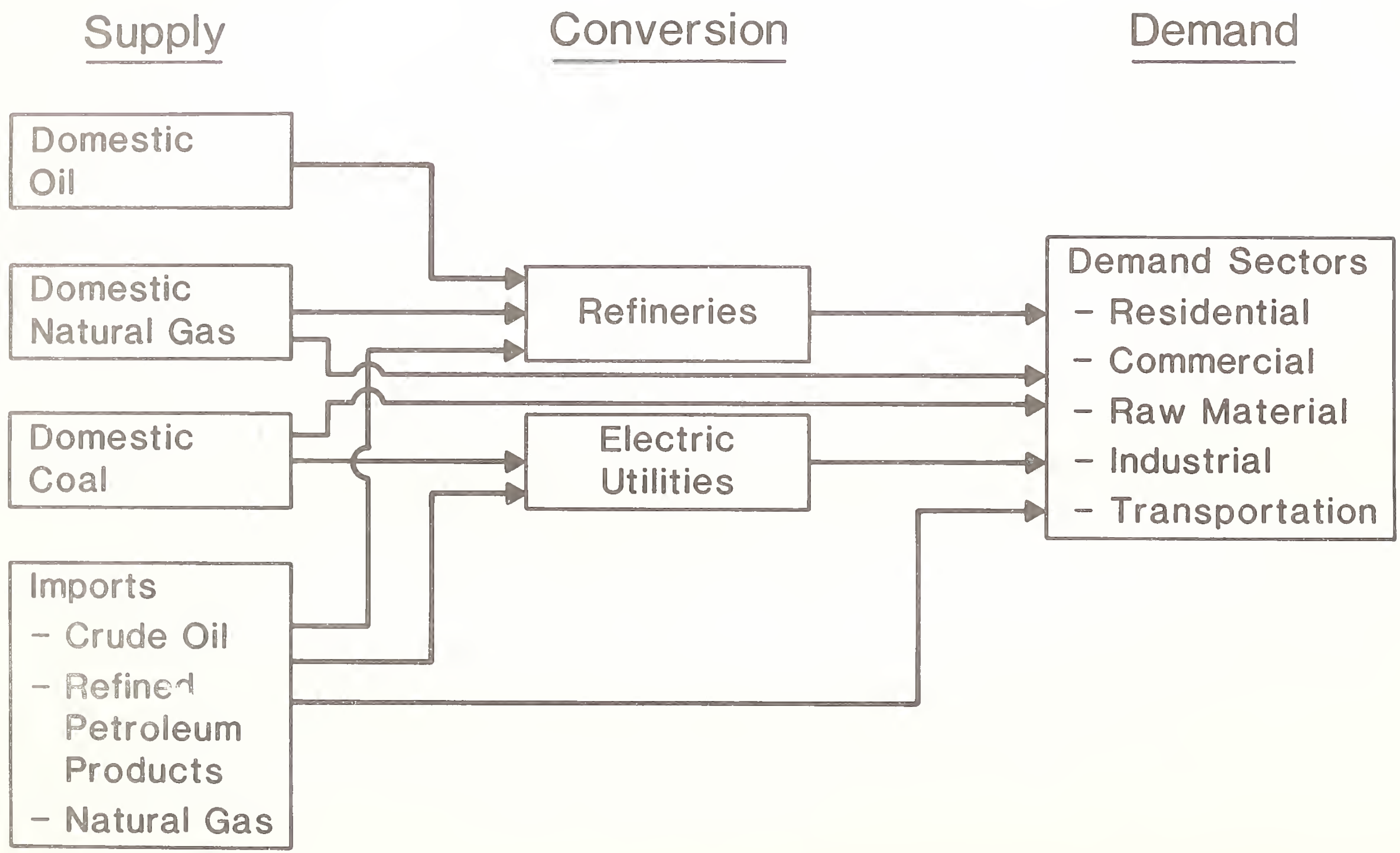

Figure 1. An Abstraction of Energy Markets

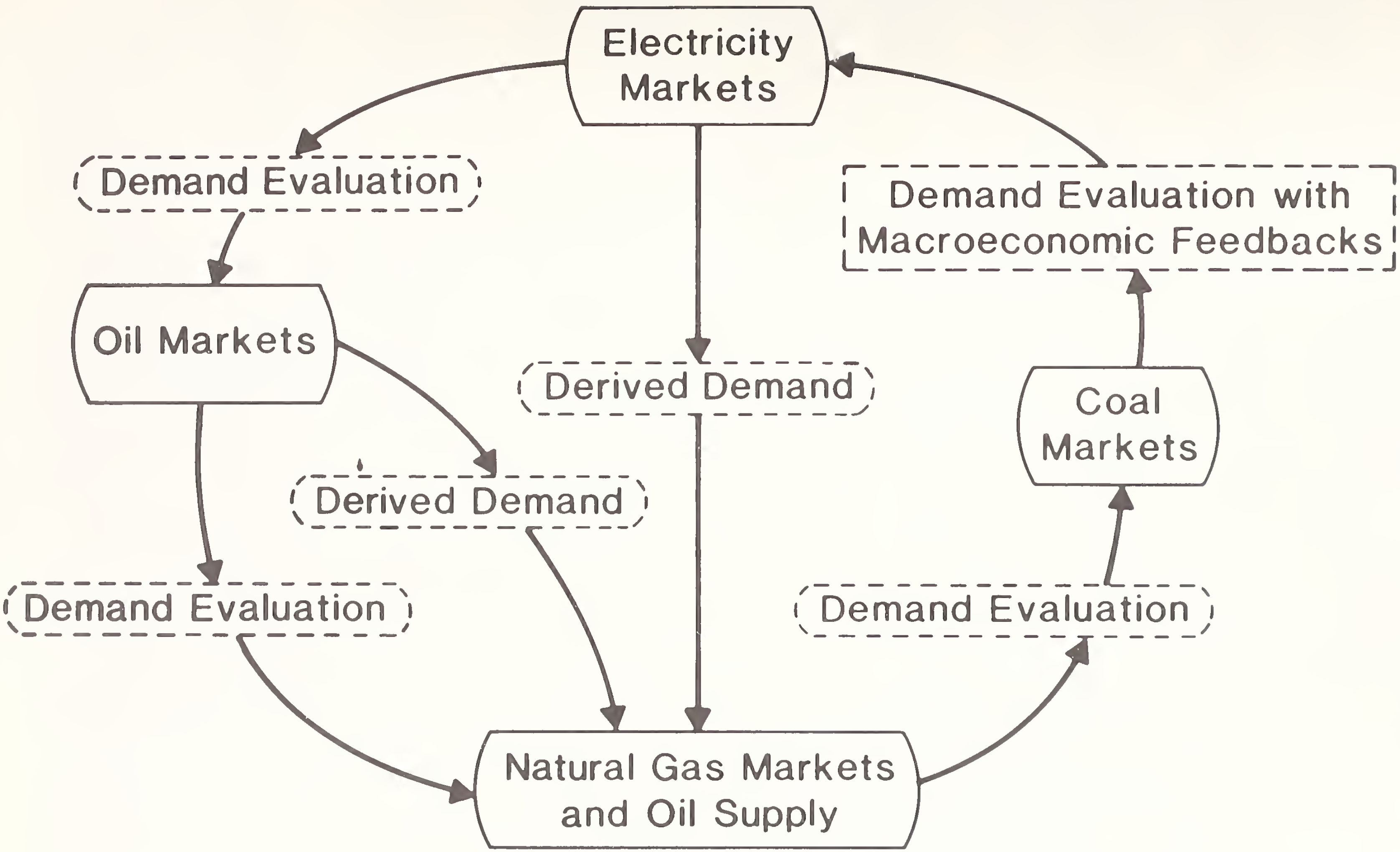

Figure 2. IFFS Organization

SYSTEM OVERVIEW: A COMMENT

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Introduction

Thank you and good morning. I extend my special thanks to Saul Gass for the opportunity to be here today. I look forward as always to these Energy Information Administration (EIA) review sessions and learning more about energy modeling and its use in the Department of Energy (DOE). The EIA staff has accumulated a great deal of expertise and experience in these matters and it is a privilege to participate in these general discussions with the wider interest group of model builders and model users.

Saul Gass asked me to make a few introductory remarks about the Intermediate Future Forecasting System (IFFS) design to provide at least the beginnings of a critique of the structure with an eye to understanding its uses and improving its applications. I intend to take advantage of my position as the first commentator to raise questions more than answer them. These questions might be answered today, or at least will establish a context for understanding the current state of the modeling exercise and the potential of the existing tools.

My first observation, of course, is to express appreciation for the work completed here in the DOE. I am favorably impressed with the ambitious project underway. The IFFS is a state-of-the-art system that meets many of the most pressing needs identified in energy policy analysis. IFFS is a powerful tool that deserves our attention and the investment required for further application.

In addition to being impressed by a model as sophisticated as IFFS, I am fascinated with its intricacies and nuances. Of course, we should admonish ourselves to avoid being too fascinated with the modeling alone. Part of our challenge here is to think more about how the model might be used, to identify the applications which justify the resources devoted to this system. Nonetheless, as someone interested in technique, as well as the results of building and using such models, I find the EIA modeling system a fascinating as well as useful tool. The EIA analysts have utilized a balanced mix of theory and pragmatism in preparing this aid for analyzing and educating us about energy policy problems.

The comments in the documentation reflect the emphasis on manageability and realism which has guided the design of much of the IFFS. Almost every twist and turn in the description of the model follows from pragmatic judgments about what is realistic and what is manageable. The authors have given attention to both objectives. For instance, most of the documentation chapters contain extensive tutorials on how to think about the sectors being modeled and the energy modeling problems faced. The modelers then confront judgments about what is manageable in the context of the kind of problems to be solved. This is the right objective. And for those of you who have not read that documentation, you will find this realism in the description of the sectors and the realistic appraisal of what can be modeled to be both instructive and helpful. In the recurring descriptions of particularly knotty problems, the reader can enjoy the candor of the EIA authors. Repeatedly we read the common characterization of the approach adopted as inadequate compared with the canons of pure theory, but at least as good as every other approach known, and far better than assuming away the modeling difficulties in a convenient simplification.

I was happy to see this candor and pragmatism. It is not uncommon in modeling documentation to see a model described as "state-of-the-art." The EIA model, in many of its dimensions, is at the boundaries of the state-of-the-art in energy model design. But the EIA analysts have surpassed their counterparts in the candid recognition of the ignorance and approximation which define the state-of-the-art.

From my perspective, and given my charge, I will address briefly three different elements of the system design. My first comments touch on the use of a network of models, including superficial observations about the individual component models. Work has been proceeding to improve the realism of the individual component models: the oil and gas supply models, the regulatory analysis description, electric utility pricing and so on. The use of the network approach addresses the 'manageability' challenge, taking models which are becoming more realistic descriptions of the components and preserving the tractability of the combined system.

The second point that interests me, particularly in comparison to the IFFS model's predecessors, is its characterization of dynamics. The IFFS time step model, solving a year at a time into the future, raises other questions which we should address.

In passing, I will indulge the modeling technician in me and make a few observations about the integrating algorithm. Finally, I will touch on the policy questions or implications raised by a review of the system.

A Network of Models

As Fred Murphy described it, IFFS is a collection models where there is an individual component to describe each relevant sector. For each, the EIA analysts use what they see to be the best approach in detail, and then link these component models together to obtain a consistent equilibrium solution in the overall system. In concept, it is a familiar approach well established in both theory and practice as a convenient organizing device. The interesting innovations, in comparison with other models, appear in the details.

For refineries, the underlying models appear as linear programming models. Who can argue with this approach, followed so often? As we now know, the argument will come from those faced with examining a future with price relationships dramatically different from those of the past. For these circumstances, the linear programming model may be correct in theory, but can be flawed in practice.

The difficulties arise when, as we must, we use a simple representation by generating modes or extreme points for such a model. These extreme points, a grid approximation of the feasible set, will be inadequately descriptive of our _a priori_ judgments. For example, we may believe that gasoline will always be more expensive than residual oil, but the empirically generated extreme points will not guarantee this relationship. Without further precautions, when we solve for periods in the future when oil prices are quite different, we will find under certain circumstances that residual oil is very expensive, and our model will see gasoline as a by-product to be given away. In short, we can and do move outside the range approximated by the extreme points.

How should the modeler deal with such an anomaly? The answer is that nobody knows the best way to solve this problem. I know of no better way than followed in EIA. What they have done is to develop a "pseudo-data" approach to impose a structure on the system of relative prices. They fit these price relationships through cases in which they have confidence, and then use the extrapolations, through reduced form models, to calculate the final prices. This is a sensible approach as long as we examine the assumptions under which those pseudo-data were generated. Particularly, if the fuel mix--the relative composition of the outputs of refineries--changes dramatically, then we would want to look back again at some of the pricing assumptions. And it might be helpful to remind the user that the familiar pattern of prices is primarily an assumption, only slightly affected by the change in the relative demand for the products.

I didn't follow completely the organization of the calculations for oil ang gas. For instance, there was a comment regarding an assumption that product imports maintain their 1979 proportions to domestic production. I don't understand why this is assumed. Perhaps we can investigate this later. The interesting part of the oil and gas effort is the elaboration of the reservoir modeling and the description of the exploration, development and production processes in oil and gas supply. The present model is similar in spirit to early versions of the oil and gas supply model, but is much more extensive in detailed characterization of reservoirs, concern with uncertainty in the estimation of reservoir size, and so on.

One problem of concern is that the new model separates many calculations from the rest of the IFFS by taking as an input the prices of oil and gas and other key variables, such as royalty rates, that determine the economic rents of producers. In the previous versions of the EIA system, the model determined the marginal cost of a given level of production and estimates prices and rents as endogenous variables with the remainder of the energy system. In principle, there is no reason why the new model could not do the same, but now we would have to iterate across royalty rates as well as iterating across prices. Hence, as a practical matter the increase in detail may force a sacrifice of an element of economic sophistication in the previous system. I noticed a schizophrenic response to this problem: the royalty rate is exogenous but the optimal price for a particular lease is endogenous. I am pleased to see the latter, but I am nervous about the former. There is no problem in principle, only in how the results are used.

The regulatory detail in the natural gas models is essential in describing this sector over the next decade. I don't understand completely how we go from the regional production to the regional demands, although there is some discussion about allocation of demands to regions. It would be useful to understand better how we obtain the regional equilibrium in this model. Such calculations will be especially important for the gas side where transportation costs are high, but probably somewhat less crucial for the oil supply model.

The electric utility chapter presents a beautiful tutorial on how different modelers approach characterizations of electric utilities. The authors review several hypotheses about objective functions of utility managers and recommend cost minimization as a good approximation to reality, at least in summarizing decisions related to the development of capacity and the operation of the system. I concur that cost minimization is the best approximation that could be incorporated in such a model.

An aggregation issue arises in the dispatch component of the model. Again, there are many different approaches for modeling this process. The biggest difference between approaches, as I understand it, is whether or not one explicitly considers uncertainty in determining the availability of different kinds of plants. If this uncertainty receives explicit attention, we need a Booth-Balereaux type convolution of load curves to estimate the full peak capacity requirement. This stochastic approach is to be preferred, in principle, over the deterministic approximation in derated dispatch.

However, the derated dispatch gives a good approximation, particularly at the national or regional level, thanks to the law of large numbers. In an individual utility, where you have a single plant modeled as interdependent segments (if the plant is out, all the segments are out), we must recognize interaction across different load curve components. But in an aggregation of utilities, this interaction presents less of a problem and the derated approach as used here should be quite satisfactory.

Compared to previous approaches, the present EIA model, through the National Utility Financial System (NUFS) model, offers the innovation of explicit accounting for utility costs, regulatory lag and the treatment of pricing. Utility pricing is an idiosyncratic process. The challenge is in getting the financial calculations about right in determining the revenue requirements. I am not familiar with the detail of the NUFS model, but the description sounds like it has all the essential elements. Hence the overall utility financial sector looks appealing as a model and an impressive improvement over previous approximations applied in the EIA.

Regarding capacity planning, there appear to be annual additions to capacity based on annual expansions of demand using a myopic rule for electric utilities. There may be a naive forecast of demand, but the model is dominated by the myopic assumption. For those who might be concerned with this short-term approximation of an inherently long-term decision, there has been interesting recent work by Sherali and his coauthors that reinforces this approach to capacity expansion modeling. In short, the myopic rule, under "reasonable" conditions, is not a bad approximation to a more sophisticated model with complete foresight.

The reasonable conditions have to do with how fast demand is growing. Intuitively, one would think that if demand is growing relatively fast, net of the depreciation rate of the equipment, then in every year one would have to add new capacity. Hence, the single year myopic approach--add capacity to meet each years demand increment--wouldn't be a bad approximation. There would be little interaction over time; we would seldom defer construction of a new plant. Hence the myopic rule is probably not a bad assumption for a national or regional model when aggregate demand is growing, as over the horizon considered in the EIA model.

The coal sector of the model is in an earlier stage of development. I found only a brief description of intended developments. In concept, the approach is similar to that being followed in the other component models. The problems in modeling coal would be in capturing the impact of long-term contracts and the regional detail of differences in both quality and costs of coal supplies. These issues have been dealt with before in other EIA models, along with a careful description of transportation, a major component of coal costs. Given the sophistication of previous EIA models of the coal economy, I look for a satisfactory module in the present system.

On the demand and macroeconomic side, I was unable to understand the details from the available documentation. However, I infer that it is the old demand model which has been in use for a few years. I am not familiar with the current details, but my guess is that the model includes a collection of several different models, one for each major energy consuming sector. The integration with the DGEM, the dynamic general equilibrium model, is a good idea which will require care and cleverness in implementation. The chapter discussing that integration raises the major issues to be considered, such as the overlap of the definitions of the accounts, and I am confident that the EIA analysts can work out the connections.

Dynamics

The one problem that I don't know how to address, and it may be just my lack of understanding of how DGEM works, is the lag adjustment in the responses of energy users in determining the intertemporal transition of energy demand. I am not sure how this is handled in the current demand model. However, the speed of adjustment is well known to be of importance in the energy system over a forecast horizon of ten years.

Apparently, the characterization of dynamics is different from the old EIA models. In the old system, in a procedure that was both ad hoc and hidden from view, there was judgmental estimate of what the time path of the trajectory of prices. With this assumption, we would obtain the trajectory of quantities of demand. A few models followed an optimization over the trajectory of prices to obtain the quantities of demand. For others, there was an econometric estimate of the speed of the lagged demand response. Given the initial trajectory, we varied the prices and quantities to trace out static demand and supply curves for each representative year. By so controlling the trajectories, we gave the modelers control over the dynamics in order to insure a sensible profile of demand to balance against supply in the integrated solution.

We know a good deal about the sensitivity of demand projections to the dynamic structure of response. For example, in systems dynamics models without adequate look ahead, there can be too much feedback and explosive model behavior results. Modeling dynamics continues to be a technical and conceptual challenge in a system with any tractable response structure.

In the new EIA models we find a different approach to the representation of the dynamics of demand responses. The new approach is also ad hoc and hidden from view. Modeling dynamics continues to be at the state-of-the-art, where theory gives us the least help. There are different options discussed in the documentation and that will be addressed today. The use of myopic rules--one year look ahead or current period decision making--can be a good approximation. I don't know the details of the experience at Brookhaven, with their time step version of a linear programming system, but this myopic approach has been used there for a few years and would be a source of practical experience.

As I mentioned, theoretical results of Sherali et al., in the study of electric utility expansion models, present sufficient conditions for the myopic rules to replicate perfect foresight optimization. As long as the overall system is growing, the myopic rule performs rather well.

Another approach to dynamics is through the use of naive forecasting. This is applied, for example, in the well-known Baughman-Joskow model. In essence, we model expansion plans as optimal choices against a naive forecast of the growth in demand. This attack is included here, for example, in the EIA oil and gas supply models and the Alaskan oil supply model. For these models, one of the inputs is the trajectory of prices for all periods of the future. This price trajectory can be interpreted as a naive forecast; a rule is specified by the user determining the growth rate of prices. We could study different rules to improve the performance of the model. For instance, in one review of the Baughman-Joskow model, the MIT Energy Lab (in report #1071) applied alternative forecasting rules. They found that the eventual solution produced by the model could be quite sensitive to the forecasting rule imposed, that the supply-demand equilibrium solution depended on which naive model was used for forecasting. Apparently a similar test would be appropriate for examining the models being used by EIA.

But in any event there would remain a conceptual dilemma in relating this naive forecast to the output of the integrated system of models. Do we assume that the subjects modeled do not have access to the information presented in the IFFS model? The modeling option at the other extreme is a perfect foresight model in which we assume that the model used by the subjects modeled is the model itself. In effect, we operate as though the market decision makers have IFFS and they run it to obtain the exact forecast we produce. Hence, once we produce our forecast, announcing the result would not cause any actor to change his plans.

The outcome is the same as the assumption of rational expectations. We know how to implement this type of computation; it appears in many models. However, this foresight model imposes a computational cost. And with the added burden of regional detail, a degree of elaboration found in many such models, there will be practical limits on the ability to include rational expectations or perfect foresight calculations.

The authors of the EIA documentation assert that it would be difficult to attempt the extensions necessary to include perfect foresight. In addition, they address the conceptual problems of the perfect foresight model. Do people have perfect foresight? Even accepting the perfect foresight assumption, we have to face the problem of dynamic inconsistency: we (especially the government) do not have the capability to write binding intertemporal contracts. In effect, we can't rely on the government to stick to its word. Yet the perfect foresight models implicitly assume such contracts are in place. Without such contracts we enter a situation where the optimal solution is a particular trajectory of prices and quantities which cannot come to pass. If we start along the optimal solution and step ahead one year, changes the circumstances and conditions can arise where it is optimal for the government to renege. This creates a new optimal solution, and so forth. There is a dynamic inconsistency, an inherent instability in the solution.

If we introduce uncertainty, we enter the rational expectations debate. Many analysts present today know more than I about the revisions of macroeconomics to accomodate foresight under uncertainty. Given the intensity of that debate, and the sharp disagreements over theory and data, I find a great deal of appeal in the EIA approach of sidestepping the complexity by adapting the ad hoc myopic model under development.

Model Integration

The EIA integration algorithm is an example of an attempt to deal with the model manageability problem. Accepting the realism of the component models, we could put the detailed component models together in a complete system and, in principle, solve for a market equilibrium. But using the full component models would require a "computational budget of staggering proportions" to quote the authors of the documentation of the oil and gas models.

For example, the Alaskan model is articulated to deal with different regions, the lumpiness of pipeline investments, the optimization of exploration expenditures, and so on. Solving that problem many times, embedded in a larger system, is not a realistic objective for any system that must be used on a daily basis. Hence the authors apply the pseudo-data approach and construct simple summary models that connect to obtain an equilibrium solution. In practice, the modelers check to make sure that final solution is consistent with the more detailed model. But it is only the summary model that serves to represent the component in the larger system. Fortunately in the integration algorithm, the nature of the summary models is irrelevant to the characterization of the final solution. They are only part of an interim computational step and so it is not important exactly how any summary model is designed. What is important is that the procedure works well.

The algorithm is equivalent to solving a system of equations. Under conditions guaranteed by the demand model, the full integration is a contraction mapping. Hence, one can start with an estimate of the solution and, comparing the error between the estimate and the ultimate answer, at each iteration the error is reduced. We always move closer to the final solution. We can obtain a bound on how fast we move and this bound is related to the pseudo-data approximation in the diagonal demand model. If the own-price effects are the most important in the model, which is almost always the case, then that bound guarantees a rapid convergence of the contraction mapping. And if we start with a good guess for the answer, then the contraction mapping can arrive quickly at a 1% error-approximation of the true solution. The experience is that only eight to ten iterations will be required to obtain a full equilibrium solution.

All of this has been discussed in detail elsewhere. Since the algorithm works and works well, and since the final answer does not depend on the algorithm used, the EIA model integration approach is an attractively feasible and practical approach for integrating the tremendous detail of the component models.

Model Applications

These few issues address primarily technical problems. Fred Murphy did a good job and I compliment him on preparing us to consider these technical issues. But before the relinquishing the podium, I want to remind us to return later today to the policy questions and help set the boundaries of application of the EIA models. The customers, as a practical matter, will be the decision makers in the executive branch and from Capitol Hill. What kind of questions should they ask? What answers can they reasonably expect?

I hope that the architecture in software design, which we will hear about more today, maintains the flexibility to allow relatively quick changes and adjustments. Flexibility will be important for making the system useful and used by people who are concerned with policy questions.

Given the size of this model, I would be worried more if I knew less about the successful uses in the past. However, it is important to preserve a concern about the trade-off between detail and insight. The particular numbers produced will not be as important as the education that flows from examining the details of energy choices and energy policies. The danger lies in losing ourselves in the detail.

For the broader public, interest must be limited to the reports produced for Congress. I have been pleased with the progress of the Energy Information Administration in producing readable reports. They've done a fine job, each year has shown an improvement. I hope that the operation of EIA will include a steady stream of policy studies applying the models to typical problems. Through these studies we will learn if the model has value, if it helps us understand energy problems and energy solutions.

In regard to the technical information provided in the documentation, I recommend using the approach followed in Energy Modeling Forum Studies; that is, to include reduced-form summaries of the characterization of the model. Much of that information needed is available because these reduced-form models play a central role in the computation algorithm. It would help the model reviewer to see the aggregate elasticities and other summaries of the component models in order to describe the output solutions and evaluate the plausibility of the conclusions.

My list of preferences and personal requests is longer, but my time is short and other speakers have been charged with the attention to further detail. In closing, let me repeat my compliments at this impressive step in the evolution of this network of models in EIA. There are many technical criticisms that we can discuss today. But we should recognize the high value of the tools before us. And we must remember how the models will be used to extract information and understand better our energy policy choices.

DISCUSSION

DR. MURPHY: Thank you very much, Bill. Since Bill has been so complimentary, it is very hard to make any general statements in response. There are two things I would like to mention. One is the questions of dynamics. Dealing with the expectations is a terrible problem.

That is, in part, one of the reasons why we are only going to 1990 right now. The question of expectations is not significant in this period, since the capacity additions to electric utilities, for example, are almost entirely determined by what is in the construction pipeline now, simplifying our problem. The reason for having the planning module in electric utilities is to project beyond 1990 after the model has matured. In preparation, we can start studying the problem now. It is a very very difficult issue.

Another activity that we are doing, as part of this modelling exercise, is backcasting selected sub-models. The electric utilities model, which is a process model and so not estimated off historical time series, is, at this moment, being backcast to see how well it would have forecasted current events starting from 1960 data. So, we are trying to do our own validation studies on these models to see how well they actually do work over periods in which we know something.

As a final comment, one of the features of this model is that the solution time is quite rapid in comparison to other models of this sort. The solution time varies substantially depending on when we insert a new piece, which usually causes the model to blow up. Our worst solution time was 100 seconds per solution year. Most of our solution times have been around 30 seconds per solution year and we are somewhere in between there and heading back down to 30 seconds in our work.

MR. RUDY HABERMAN, General Electric: I want to get positioned about where this system fits into the scheme of things. Is this replacing the short-term and the midterm and the long-term? Are we just going to have one model until 1990?

DR. MURPHY: What has happened is that the original purpose behind the model was to fill the gap between the short-term and the longer-term models. As part of the budget cutbacks, the longer-term models, the MEFS and LEAP systems, have been retired. We have retained the short-term model so this model will step off from the Short-Term Integrated Forecasting System solution.

Mr. Warren Langley, RDA: Would you contrast managing this model and operating this model in terms of resources required by other models?

DR. MURPHY: The resources are substantially less than we have had in the past because of the budget cuts. We have achieved a certain amount of efficiency with this modeling system because, by having individual fuel modules, we are able to allocate staff to individual pieces that can be developed and operated separately.

One of the problems that we always had in operating the MEFS system in a policy analysis environment is that there was always one person who had to be the central focus of everything. And, that person was usually worn out by the end of any single analysis. The decentralization by fuel module has balanced the work load and actually reduced the staffing requirements because there is less coordination necessary.

System Implementation and Software Design

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Introduction

To understand the system implementation, it is useful to review the overall system design. The first design decision made in this model development was its organization by fuel types. That is, one sector of the model follows the particular fuel through its production, processing, transportation, and end-use consumption. This is unlike some other integrated energy systems which are organized around a large central integrating model.

Solution Process

Figure 1 illustrates the overall system solution of IFFS. Each module continues to solve until it has converged to an equilibrium within its own fuel market. This convergence is measured with the end-use prices of each product in the other modules remaining fixed at their most recently computed values.

Because of the effects of one fuel's price upon other fuels' end-use demands and prices, the overall sequence of fuel module solutions is repeated until the global convergence is achieved. This convergence is measured by comparing the product prices and quantities on entering a fuel module to the prices and quantities after the module solution and computing the differences between them. Once the differences are within the specified tolerance for each module the system has converged. This convergence occurs for each year in sequence and there is no feedback from a later year's solution to an earlier year's, a technique that would imply perfect foresight.

Fuel Module Organization

Each fuel module can be regarded as a stand-alone system with its own unique organization. The oil market module, however, can be used to illustrate how a fuel module is organized. The Refinery and Petrochemical Modeling System and its associated database is executed independently of IFFS to generate a set of pseudo-data which can be used to estimate the response of the RPMS refinery model to variations in product demand levels. The information flow moves from a detailed refinery model and its database, outside of IFFS, to a set of pseudo data that are estimated to produce the parameters that are retained in the IFFS refinery module. How this is done is detailed in the refinery discussion. These parameters as well as other information contained within the refinery module are combined with inputs from the small central database to produce a market equilibrium for petroleum products.

Databases

Because the model represents a decentralized competitive economy, the system is designed for the minimal interfaces between the fuel modules. The key pieces of information that must be passed between fuel modules, and therefore must be in a central database, are the end-use prices and quantities of each of the products in each sector and region. In this way, each fuel module can solve to a market equilibrium knowing the prices of all competitive fuels.

The central database also contains general input assumptions and parameters, such as Btu contents and price deflators, and specific run parameters. Most other data is fuel-specific and maintained in the fuel sector databases.

In order for the fuel modules to come to a supply/demand balance, the central database also stores the own-price elasticity of each product and a term for each product that combines the effects of the product's lag term and of all the cross-elasticities and prices from other products. In this way the fuel module has a simplified demand curve for its internal solution. Each time a module completes its solution, the central integrating procedure recomputes all the cross-elasticity terms using the recently computed prices and stores them in the central database.

Modularity

The fuel-sector modularity has several major advantages. One key advantage is the flexibility for each module to use the data organization and solution algorithms that appear most suitable. This variation of methodologies becomes apparent in the individual fuel module presentations.

The arrangement by fuel module has substantially simplified the solution process. The central database is initialized for each module every time the model is run. Any module or subset of modules can be executed, thus creating a small, single fuel-model from the larger one. This allows development and debugging of each module to occur quickly and independently of other modules, greatly simplifying the tasks of parallel development across fuels.

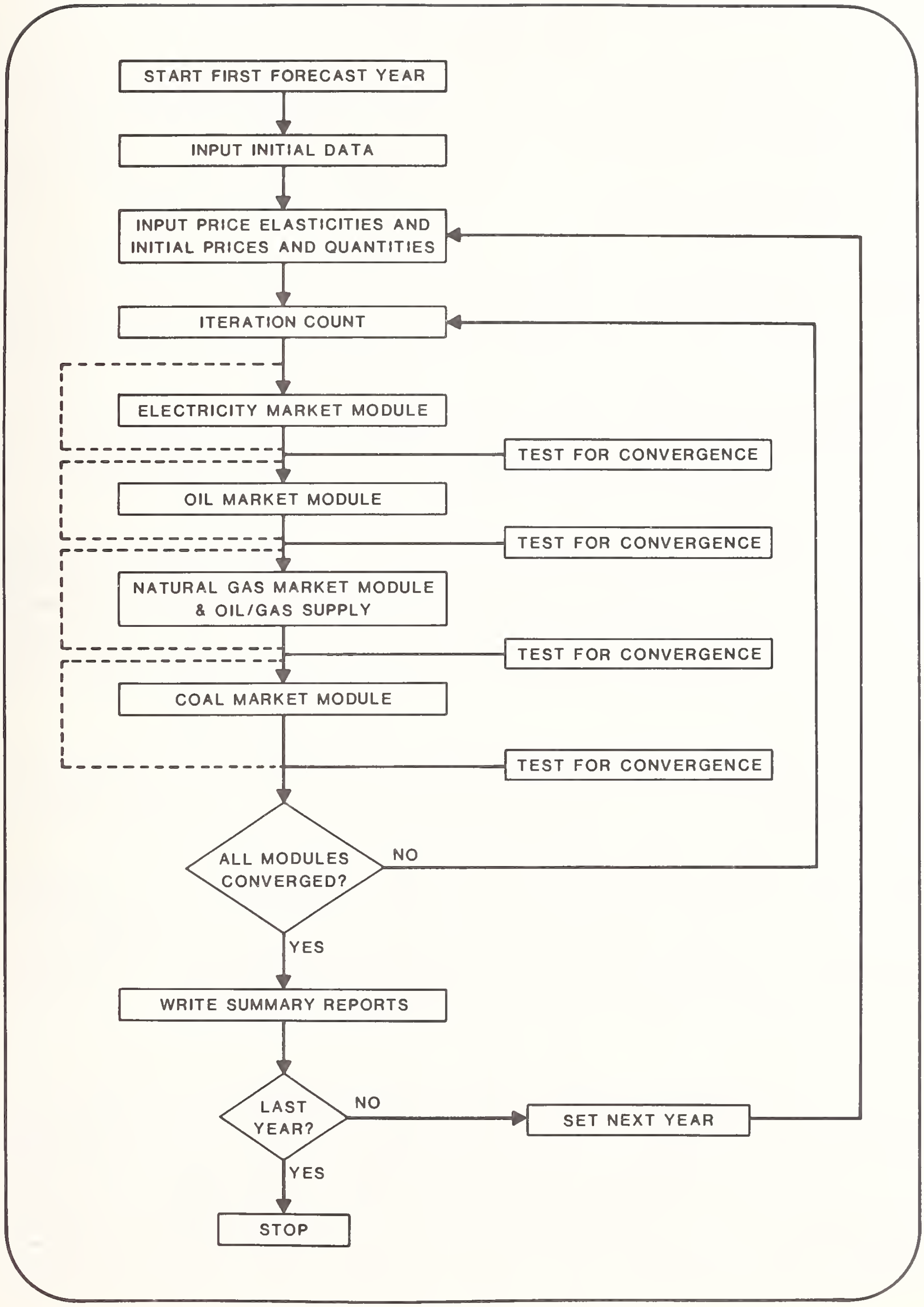

Figure 1. Model Solution

INTRODUCTION TO THE OIL AND GAS SUPPLY SUBSYSTEM

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I have been asked to talk about the oil and gas supply models, as they will be used eventually in IFFS. There are three basic supply models, one of which I am going to spend some time on with you today because it hasn't been in the public domain for very long. The other two have been around for quite a while so I will say a lot less about them.

The newest model in the suite of oil and gas models is the Lower-48 onshore model, PROLOG. It has two very important orientations. First of all, it is very data intensive because it deals with the Lower-48 where there has been a lot of historical information. An example of the data intensive nature is that, instead of using the classic API/AAPE drilling statistics, we have obtained the API well ticket tapes. We have reoriented the data so that we are analyzing information by completion year of the well as opposed to the report year of the well, which is what most people generally use.

Also, we have chosen to use the API well tickets over things like the census data because the census data, although it does report drilling, has had major inconsistencies in the past with the API well ticket data, and that is confounded by the fact that the census data is reported by some accounting standards that are put forth in the Financial Accounting Standards Board opinion on oil and gas.

Also, we did try to stay away from over dependence on one resource estimate and tried to stay with data on reserves that we have available to us. Secondly, we have tried our very best to document exactly what we have done in great detail. And, I think I am correct in saying that this is the first EIA model to be documented before it has been used in forecasting. If anybody is interested, you can walk up to the National Energy Information Center and ask for EIA-0345 and that will be the data and methodology documentation for the Lower-48 model. I will say a little more about that after I talk about the other two models that are used as input.

The Outer Continental Shelf (OCS) model has been around for a while. It was used in the last annual report and its basic features that differentiate it from the Lower-48 model and the Alaskan model is that its exploration process is a Monte Carlo simulation of a prospect level data base. After the discovery, the development process is modelled with a detailed representation of the platform in gathering economics necessary in the OCS.

The Alaskan model has been around for quite a while and this year we are using the ultimate in reduced form for this model. That is, it is not used in the 1990 horizon. Essentially through the 1990 horizon, we simply do an offline analysis of TAPS capacity and exactly what can run through the line. And now, the late 1990's is the earliest completion date for the natural gas pipeline (ANGTS) system. With that as a general overall introduction, I would like to talk a little bit more about the Lower-48 onshore model, PROLOG.

Rigs are used both to explore for and to develop oil and gas, to put resources into inventory, and to take things out of inventory. Exploration deals with issues of federal land availability and private land availability feeding into questions of leases and bonuses which Bill Hogan talked about earlier, which are still very perplexing in terms of the way you are supposed to model them.

As you acquire land, you drill and find reserves. Reserves are put into inventory and then development generates production, production generates funds; funds also come and go in other ways, from the proverbial doctors and dentists in drilling funds, sometimes from banks and obviously, there is a cash flow component. One of the most difficult processes that we are trying to deal with now is the recent change in the tax structure, which apparently has driven people out of drilling funds to the extent that only momentum is carrying the drilling funds at this point in time. They appear to be off about 50 percent in 1982 over 1981.

Well, that is a simple representation. Let me say that we do not know very much about federal land availability or resources on federal lands. We thought that there was going to be information on that coming out in the past year but it is not yet available. So, we have not separated out federal from privately owned lands.

First of all, let me talk about the way we are modelling the discovery process. Although everybody has their problems and dislikes this approach, it seems to us to be the only one available to us in the Lower-48, at the present time. First of all, we use statistically estimated finding rates. We let the data tell us about the finding rates and not some judgement about what is there.

If you look at the basic functional form that we use, we have what a lot of purists would object to; in the finding rate equation we have an asymptote that is not zero. Now, the purists would argue that that will give you an infinite resource if you integrate to infinity, but we are going to 1990.

When we discover resources via finding rates, through exploratory drilling, we evaluate what we found. We calculate the present value of discovery using an expected development schedule, that is, how the discovery would be produced over time after finding. There are obviously two approaches to foresight. One is perfect, and one we have come to call the banker's foresight, which is what you could get if you wanted to mortgage your reserves at the bank; that is, one or two years of foresight and then flat thereafter.

One of the things we have done that is new to the modelling approach in the Lower-48 is that we have separated out the development process. We have separated out existing reserves and sliced them up by their windfall profit tax tier, if oil, and by their NGPA title I category, if they are gas. This gives us a rather detailed set of information on the existing reserves, and we develop them based on the pricing for the tiers or the NGPA category.

Then we have a second set which are the development of the reserves discovered by the model, which, in our case, is going to be tier 3 for oil and sections 102 and 107 for gas. Each year, and this is somewhat important, the development options are reevaluated on the basis of current prices and projected future prices which have the same foresight as in the exploration process. And essentially you calculate how the reserves would be produced if you did not do any development. You look at incremental steps of development and then look at the difference in the cash flow that you would get from that development, and that is essentially how the development options are evaluated.

Both the discovery and the exploration process are based on these kinds of cash flow calculations which involve revenues, excise taxes and royalty payments (we have essentially assumed the traditional royalty payments). We have also included co-product revenues in the case of oil and gas evaluations. We have a whole plethora of other costs, both expensed and depreciated and lots of taxes and also tax credits.

All this information is presented in a context of a linear program, with some regional drilling constraints which do not allow drilling to get terribly away from historical patterns in the supply regions of the model. We have rig availability constraints that are based on historical expenditures and revenues, short term cost inflation for drilling, and merit order selection of the drilling activities that is based on their present value.

Each year the system is solved and restarted over again with a new set of activities. The model is up and running and the most fascinating part about the current base case is that the model starts with 1980 data and has captured the rig peak in 1981 and it has a trough in 1982, meaning that the rigs' utilization will go back up again. I am not sure I would go to the bank with this kind of information or go to the stock market, but it is rather interesting that the model has, in some sense, caught the peak and the possibility of a trough in '81 and '82.

We have also looked at sensitivity analyses with respect to world oil prices, marginal gas prices, discount rates, cost, and finding rates; and we have found that the first partial derivative, that is the response to the model to these various changes, has the expected sign and pretty close to what we would expect is the magnitude of response. We are currently in a phase where we are putting in minor enhancements and, of course in later times, there may be major enhancements to the system.

OIL AND NATURAL GAS SUPPLY SUBSYSTEM: A CRITIQUE

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The oil and natural gas supply subsystem within the Intermediate Future Forecasting System (IFFS) is a substantial enhancement of DOE's forecasting methodology in hydrocarbon supply modeling. For frontier areas, the new supply model attempts to represent in much more explicit detail the geology, processes, and information entailed in hydrocarbon discovery and development. The profitability module of the onshore Lower-48 sub-model is essentially statistical, but is developed and presented in much greater detail than previous versions. For these reasons, the present system is better structured, and more readily understood and evaluated, when used for forecasting and policy analysis.

The supply model comprises three sub-models:

- the Alaskan Hydrocarbons Model (AHM) -- representing onshore and offshore oil and gas production in Alaska,

- the Outer Continental Shelf Model (OCS) -- representing offshore oil and gas production for the lower 48 states, and

- the Production of Onshore Lower-48 Oil and Gas Model (PROLOG) -- representing onshore production.

We discuss the first two of these sub-models rather briefly, since they are mature models, by now fully discussed in the open literature [1,5]. PROLOG, recently developed inhouse in the Energy Information Administration (DOE), is examined more extensively. Finally, we examine the simple, parametrically-fitted minimodel of the aggregate price response of oil and gas supply used to represent these models in IFFS.

These sub-models differ in their representation of the geological unit to be explored (geologic structures or geographical regions) and in the level of detail of their treatment of the exploration and development process. These differences are to some extent dictated by the availability of data. (In the Federally-owned regions, Alaska and Lower-48 offshore, geological information is publicly available to a much greater extent and there are vastly fewer wells.) They are also dictated by inherent differences in the hydrocarbon supply process among these regions. In the frontier regions, the investment process and the accrual of information is lengthier and more complex.

The trend represented in these developments -- aggressive exploitation of disaggregated data and detailed representation of geology, processes, costs, and finances -- is the right direction for the development of public sector modeling in support of forecasting and policy analysis. The closer that modeling gets to the data and problem constructs used by industry, the more clearly and completely can technical and policy issues be separated and resolved in the policy evaluation process.

ALASKAN HYDROCARBONS MODEL

The AHM has two modules, a resource module and an integrating framework. The resource module describes hydrocarbon resources and the cost of their exploration and development. This establishes a feasible set of hydrocarbon production possibilities. Given this set, the integrating framework (an inter-temporal, mixed-integer-linear program) chooses, on an economic basis, which of these exploration/development possibilities and, jointly, which transportation facilities (oil and gas pipeline capacities) to implement.

Within the resource module, resources are distinguished by geologic structure and the degree of geologic knowledge. For producing structures (presently only the Sadlerochit reservoir), production possibilities are furnished to AHM from an external reservoir model.

For structures with proven but undeveloped resources, production possibilities are developed with volumetric/decline curve methods. For unexplored areas, a Monte Carlo technique is used to generate distributions of resource base characteristics and production costs. A fairly detailed level of resource description (structure number, area, pay, depth, fill, drive mechanism, recovery factor, permeability, and viscosity) permits a fairly detailed description of the exploration, development and operating facilities required for production.

Thus the geological and engineering aspects of production can be calibrated to empirical or hypothesized experience. Profiles of feasible resource exploration and development costs and production volumes are then furnished to integrating framework.

Modeling at this level of detail is attractive in principle, but expensive. In practice, the full-fledged exploration/development/transportation optimization is designed for analysis of policy (taxation and resource access) and has not been extensively used in forecasting.

OUTER CONTINENTAL SHELF MODEL

In the OCS model, the representation of geology is prospect-specific, as in AHM. Existing reserves data are taken from the API/AGA Joint Survey. Inferred reserves are characterized through a Hubbert-type analysis inferring total oil-in-place from the relationship of cumulative reserve additions to cumulative drilling.

The novel feature of this model is its explicit treatment of uncertainty and information-development in the characterization of the economic quantity of undiscovered reserves. The economics of prospective exploration are specified through a detailed, prospect-by-prospect simulation of the drillers' decision-making. For each prospect, the process costs of exploration and development are modeled. A prior distribution of the geological factors affecting reservoir behavior and costs is specified. The exploration decision is made on the basis of the expected value of the exploration/development/production commitment. After exploration, there is a probabilistic assessment of the hydrocarbon show/no show outcome for each prospect. The geological prior for each prospect is updated on the basis of information gained throughout all prospects in the OCS. For explored prospects with hydrocarbon shows the decision to develop or not is made. For prospects yielding dry holes the decision to explore (again) or not is made. (The underlying distributions on which this sampling-without-replacement/ decision-making process operates are generated in such a way that the consequences of alternative economic parameters can be modeled and evaluated on a given structural characterization of the underlying geology.) Thus the model contains an explicit representation of the process by which information is generated and decisions are made in the hydrocarbon exploration and development process, rather than depending on some "average" representation of the underlying geological uncertainty as the input for decision-making.

The representation of the exploration and development technology in the OCS model is also highly explicit, so that the impacts of geology, technology, and input costs on exploration and development costs can be distinguished. Over time, as each of these cost factors changes substantially, this provides an explicit basis for cost projecting.

PRODUCTION OF ONSHORE LOWER-48 OIL AND GAS MODEL

PROLOG differs from the previous models in its representation of the geology, the supply process technology and costs, and the drillers' economic motivation.

The onshore lower-48 states are divided into six geographical regions (rather than geologic prospects). In each region, the profitability of exploration and development drilling opportunities distinguished by product (oil or gas), type (exploratory or developmental), and regulatory regime (old/new oil, old/new and inter/intrastate gas) is projected based on statistical relationships. This profitability module comprises the interaction of geology, technology, and costs. Then national drilling capacity is projected and allocated down the profitability seriatum subject to regional growth constraints. This projection and allocation of national drilling capacity constitutes the specification of drilling factor supply and drillers' economic behavior.

For conventional oil and gas, reserve additions and revisions for oil and gas are modeled through statistically-fitted functions of drilling and remaining resources. (Unconventional oil and gas supplies are exogenous.) In each region, costs of exploration, development, and production are modeled through statistically-fitted functions for five cost categories:

- geological and geophysical (G&G) -- cost per well is trended;

- lease acquisition -- costs are input at model execution time and do not depend on endogenously determined resource exhaustion rents;

- drilling -- costs distinguished by well type (oil, gas or dry) and drilling type (exploratory or developmental) are specified as functions of depth and are trended;

- lease equipment -- cost per well is specified as a quadratic function of depth and is trended; and

- operating costs -- cost per well is estimated as a trended function either of depth or production. (Both functions are estimated and the choice is specified at model execution time.)

These relationships are inputted to a discounted cash flow evaluation of drilling profitability distinguished by region, product, type, and regulatory regime. Product prices are combined with finding rates and pro forma development/production profiles to give the revenue side. Costs are provided the appropriate tax treatment and combined with royalties, depreciation, and taxes to project cash outlay.

Drilling prospects are then selected in order of their profitability subject to two sets of constraints:

- an overall constraint on drilling, made up of rig availability (which, in turn, depends on a distributed lag function of overall industry <u>revenue</u>), and an exogenous specification of rig productivity (feet-per-year rig); and

- regional historical limits on the maximum and minimum change in drilling activity, in order "to keep the model from <u>unreasonable</u> changes in drilling levels over the forecast horizon" ([2,p.14], emphasis added).

Within this framework, the critical determinant of hydrocarbon supply over time is the supply of drilling capacity (specified as the rig supply times the productivity of rigs):

- The increment to the stock of rigs depends only on industry <u>revenue</u>. Apparently, this is to proxy for profits or cash flow, but though expenses, taxes, and depreciation (as well as revenues) are treated in the profitability module, no attempt is made to relate the income and flow-of-funds statement of the industry to rig demand.

- Profitability of rig use does not affect overall drilling. Profitability affects only the regional allocation and, in fact, the model will invest in drilling prospects with negative profitability when minimum drilling constraints are binding.

- Rig productivity is specified exogenously. Rig costs are not treated explicitly and, in fact, drilling costs generally depend only on the conditions of their use, not their supply.

This model of aggregate drilling activity is wholly inadequate. It fails to identify past and future profitability as the key determinants of the demand for drilling. It fails to model the interaction of rig capacity, utilization, productivity, and costs in determining the both conditions of supply and the profitability of drilling. There is no place in this framework to incorporate detailed information about the costs of drilling factors of production.

In fact, recognizing recent changes in oil price prospects, the correlation among changes in prospective profitability, utilization, and drilling productivity in the last four years is striking:

Onshore Lower-48 Drilling Statistics

	1979	1980	1981	1982
Wells (no.)	49938	63187	79167	84805
Feet (M ft.)	230.1	280.9	353.8	389.1
Rigs (no.)	1961	2667	3694	2834
Wells/Rig	25.5	23.7	21.4	29.9
Feet/Rig (no.)	117.3	105.3	95.8	137.3
Feet/Well (K ft.)	4608	4446	4469	4588
Average Cost/ Foot (1982$)	74.54[a]	76.44[a]	86.67[a]	77.75-92.38[b]

Sources: Wells, rigs, and feet: Oil & Gas Journal, various issues.
Cost/foot, a. Joint Association Survey. b. Reprint of the Cost Study Committee, Independent Petroleum Association of America, Mid-Year Meeting (May 24-27, 1983).

The rig count grew by two-thirds in the two years between 1979 and 1981 and then declined by about one-fourth in the next year. Rig productivity moved in an inverse pattern. Wells per rig declined mildly and feet per rig dropped sharply through '81, as shallower wells were drilled, but then productivity rebounded by more than 25% in one year as the oil-field service market went slack. (Reporting lags in well completion may somewhat amplify the actual swing in productivity.) At the mid-year meeting of the Independent Petroleum Association of America Cost Study, a range of 1982 cost indices were developed as indicated in the above table (1982 Joint Association Survey data are not yet available). The low end of the range is thought to represent actual 1982 "field experience" whereas the upper end of the range includes all experience which includes contracts negotiated prior to 1982 but executed in 1982. Over the period shown, costs moved more than proportionally to productivity as rents came and went in the changing market. It is these considerations which must be modeled in the supply and demand for drilling.

As a final comment on the drilling allocation module, the imposition of regional bounds on drilling growth (which, we understand, largely determine the behavior of the model), in order to achieve "reasonable" behavior, finesses the whole question for which the model is built, namely, "What is reasonable behavior?" (Some idea of the extremely simple character of this allocation mechanism can be gained by realizing that, though cast as a linear program, it can actually be solved with a two-key sort of the drilling prospect profitability file).

In sum, in its present state, PROLOG's aggregate hydrocarbon supply model rests on a formulation of the market for drilling factors which is misspecified on the demand side and unspecified on the supply side; the regional allocation of drilling activity with historical bounds on drilling rate changes comes close to "dialing in" the answer.

The potentially more valuable part of PROLOG is the drilling profitability module. To assess the success of this module in statistically projecting profitability, the results of this module should be made available independently (not just simply inputted to the allocation module). Pending this, we have some technical comments on its components:

- o Generally, the lack of explicit sequential treatment of exploration/development decisions at the prospect level, makes this treatment harder to compare with industry calculations, in contrast to the previous models. Further, the imposition of a pro forma development/production schedule blurs the variety of intensive/extensive margin decisions made in the hydrocarbon supply process. (See Stitt [7], for a discussion of the margins at choice in hydrocarbon supply.)

- o Trending G&G costs fails to reflect the market for factors entailed in G&G.

- o The role of exhaustion rents in onshore lease acquisition costs should be investigated.

- o The finding rate equations are specified with a functional form which implies infinite resources. This is defended as a statistical convenience, but there is strong precedent for the value of taking physical constraints seriously in hydrocarbon supply forecasting (M. King Hubbert, who did so [4], is the only energy analyst we know of who today can use, to effect, charts he prepared over 35 years ago).

- o The constant-elasticity form for the drilling cost equation is not motivated in terms of the underlying technology. In any case, it fails to separate technological and factor cost considerations. The market for drilling factors must be treated much more explicitly here.

- o Lease equipment costs appear to decrease with depth in four of the six regional equations -- an apparently anomolous result.

Again, an explicit presentation of the profitability results is required for assessment of this module.

IFFS MINIMODEL

The aggregate response of oil and gas supply to prices is represented in IFFS by a simple pair of equations fitted to results of model runs exercised on a variety of price paths.

The fitted model can be written as:

$$\begin{matrix} Q^{oil} \\ Q^{gas} \end{matrix} = K + B \cdot \begin{bmatrix} P^{oil} \\ P^{gas} \end{bmatrix} + L \cdot \begin{bmatrix} Q_{-1}^{oil} \\ Q_{-1}^{gas} \end{bmatrix}$$

where the Qs and Ps represent, respectively, the logarithm of quantity and price relative to a reference case and the subscript, -1, indicates a value lagged one year.

The coefficient matrix

$$B = \begin{bmatrix} 0.069 & -0.009 \\ 0.047 & 0.095 \end{bmatrix}$$

gives the short-term (one year) elasticities of oil and gas supply (rows) with respect to the oil and gas price (columns). The coefficient matrix

$$L = \begin{bmatrix} 0.951 & -0.132 \\ -0.645 & 0.690 \end{bmatrix}$$

gives the proportional impact on oil and gas supply (rows) of changes in lagged oil and gas supply (columns).

Looking first at the B-matrix, the on-diagonal elements show small, positive, short-run own-price supply elasticities, which look reasonable. These positive price effects on supply arise from two sources. First, increased industry revenue induces greater rig availability. Second, increased product profitability induces a larger allocation of drilling resources to that product. In interpreting the off-diagonal, cross-price elasticities, the revenue effect offsets the allocation effect with the net effect being qualitatively indeterminate. Since oil has a larger revenue share, it is reasonable that an oil price increase raises gas supply (with an elasticity of 0.047), but a gas price increase lowers oil supply (with an elasticity of -0.009).

In the L-matrix, the substantial positive on-diagonal terms indicate that a supply response, once started, gains momentum. The negative off-diagonal terms indicate this momentum takes drilling resources from the competing product.

To identify the net result of these forces over time, we calculate the long-run price elasticities of supply from the equation (familiar, say, in input-output analysis),

$$B \cdot (1-L)^{-1} = \begin{bmatrix} -0.09 & -0.13 \\ -0.65 & 0.69 \end{bmatrix}$$

giving the long-run elasticities of oil and gas supply (rows) with respect to oil and gas prices (columns).

The gas price effects here (second column) are perhaps reasonable. The on-diagonal element (0.69), is a substantial, positive long-run own-price supply elasticity for gas. The negative off-diagonal element (-0.13) implies that with the oil price constant, increased gas supply takes resources from oil supply (i.e., the increased rig effect doesn't compensate the reallocation of drilling resources to gas).

The oil-price effects (first column), however, are not acceptable. The negative own-price response of oil supply (-0.09), and the large negative cross-price response of gas supply to the oil price (-0.65), are simply anomalous in the light of the literature and the evidence.

Two lessons emerge. First, examination of their minimodels, or simply their aggregate response to shocks, is an important part of the evaluation of large models. Second, the price response behavior of the oil and gas supply subsystem in IFFS, as presently constituted, is not satisfactory for forecasting or policy analysis.

CONCLUSIONS

The development of the oil and gas supply subsystem in IFFS dispels much of the mystery that surrounded prior public sector analysis in hydrocarbon supply and, as such, is a welcome advance.

Methodologies in the various components of the model differ sharply. The frontier area models (AHM and OCS) are process and prospect-oriented. Thus they are highly explicit, but at the same time expensive to operate. The onshore Lower-48 model (PROLOG), essentially statistically-based, is a cheaper and less cumbersome way of dealing with a much larger and more varied collection of activities.

If modeling is to be useful in the public policy debate, this may represent the right set of methodological choices, but the returns are not yet in. Specifically, PROLOG needs further development before it can be used seriously:

- the whole structure for modeling the supply and demand for drilling factors needs to be rethought; and

- the results of the profitability module need to be examined explicitly, with attention to the micro-foundations of the functional forms to be estimated.

Finally, the aggregate behavior of the model must be carefully assessed before it is incorporated in large models like IFFS.

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This paper is intended as a contribution to understanding public sector energy forecasting and policy analysis. It represents our personal, professional views, not necessarily those of our employer. We are grateful for aid and advice to Frank Morra (Lewin and Associates), Fred Murphy (DOE), Dick O'Neill (DOE), John Pearson (DOE), and Bill Stitt (ICF, Inc.), but, again, the views expressed are entirely ours.

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DISCUSSION

DR. O'NEILL: I guess what I would like to say is that we agree with you completely in terms of the direction. We did not have the information to take the direction before. We may be on a path to have more detailed information including field size distributions and things of that nature. The argument about having a finite asymptote being intuitively unappealing was initially unappealing to me also. But after looking at other people's work and realizing these asymptotes are fairly low, and may be close to some kind of an economic limit, or net energy limit, they did not bother me that much. In other words, I am not sure that they could effect the outcome significantly.

Secondly, it is not clear, but King Hubbert is here today, so I think he could tell us himself; it was my impression that King took the historical data and fit it without any intuitive notion of what was left and came out with these prediction turning points, although his models consisted of a finite ultimate resource base.

MR. HUBBERT: Hi, I am the King Hubbert who is being mentioned. The approach I have taken to a very important aspect of this problem is not the economic approach as is dominant here today, but, simply, what are the constraints in its production and, therefore, a means of predicting about what the complete cycle would be.

Instead of taking the short-term view of 5 years or 10 years, I find it much more useful to predict the entire cycle first, because we know a future point on this production curve, namely zero. We know where we are now and the problem, then, is to interpret between that future point zero and where we are now. Now, there was a conference sponsored by the DOE and the Bureau of Standards 2 years ago last June, and I gave a more detailed analysis of the methods that I have developed over the years. It is presented in Bureau of Standards report number 631, June 1980.

DR. GASS: Thank you. For those of you who would like a copy of that report, if you would write to me or to Fred, we will send copies out until the supply is depleted. Dick has some copies he would like to give away.

INTRODUCTION TO THE OIL SUBSYSTEM

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Introduction

The function of the oil market module is to determine supply prices of petroleum products given a supply/demand equilibrium in the petroleum market. Because this is a model of domestic energy markets, the price of crude oil is determined exogenously for each of the forecast years using the international models.

What the model then tries to capture are the differentials between the price of crude oil and the prices of refined products. The size of these differentials depends on: (1) the downstream processing units that are needed to produce this slate of petroleum products, (2) the quality of the crude oils available, and (3) legislation that affects fuel standards. To state it differently, the model tries to capture the costs associated with changing the mix of hydrocarbons found in a barrel of distilled crude oil into the mix of hydrocarbons that are demanded by petroleum consumers.

Some of the processes associated with these costs include changing the molecular structure of heavier hydrocarbons into lighter ones, extracting sulfur to produce lower-sulfur products, and changing the gasoline yield from lower to higher octane levels. An imbalance exists between the fractions that are derived from a barrel of distilled crude and fractions demanded by the petroleum product market. This imbalance will continue to grow over the long run, because the quality of available crude oils is declining and the market for heavier products is shrinking more rapidly than the market for lighter products.

With the decline in crude quality, an increasing percentage of an average barrel of distilled crude becomes heavier and the amount of contaminating metals found in the oil increases. Both of these results exacerbate the need for downstream capacities. The yield of lighter products from a barrel of crude can be increased by expanding downstream capacities or by increasing the severity at which they are operated; but, the marginal cost of transformation increases more rapidly. That is, for example, as one tries to change an increasing percentage of a barrel from heavier products into lighter products, the price per barrel of the lighter products will increase. Similarly, if one tries to lower the average sulfur content found in the oil, the marginal cost of transformation also increases.

Estimating Refined Product Prices

Representing refined product prices in IFFS is a three-step task. First, a model of refinery operations is built, incorporating the same techniques as refiners use in managing their operations. Second, econometric equations representing changes in capital stock determine the capacities for the following aggregate unit types: cracking units, octane boosting units, and desulfurization units. The availability of these units determines how much flexibility refineries have, influencing the product prices. Third, the capacity equations are combined with the operations model to produce the estimates of product prices. Since this model is too large to fit into the overall modelling system, results from the larger model are used to produce price/quantity vectors, known as pseudo-data (see Adams and Griffen [1]), that are used to estimate a simple, aggregate model, which is incorporated in the overall IFFS modelling system.

The modelling is performed in terms of the ten Federal regions used throughout the IFFS model. Demands for eight distinct petroleum products are modelled. They are gasoline, distillate fuel oil, high-sulfur residual fuel oil, low-sulfur residual fuel oil, jet fuel, liquefied petroleum gases, petrochemical feedstocks, and a category designated as other, which includes asphalt, lubricants, waxes, and petroleum coke. The production of still gas by refineries is also modelled, but still gas is considered to be used exclusively for refinery fuel. A feature of the sub-model is that it determines internally the refinery sector demand for specific petroleum products that it uses as fuel.

Refiners have long used linear programs to model their operations. In fact, the first major computer codes to solve linear programs were built to solve refinery models. Refiners use linear programs to calculate the value of a given quality of crude oil, the least cost way of meeting a given level of demand, and the maximum profit product mix for given product prices.

Refinery operations are modelled by using a linear program of an aggregate refinery, which combines the unit capacities within a region as if they were in a single modern refinery.
In every important refinery area in the country, there are many refineries and not all of them are large, modern, and efficient refineries. This technique for modelling refineries, however, has had a history of success. Alan Manne [3] was the first to use this process modelling approach, and he was able to replicate refinery product prices for the United States. This aggregate approach is reasonable apparently because the larger, modern refineries are the price setters. This approach was also used by the National Petroleum Council on a study of the U.S. refinery industry [4].

The objective of the linear program (LP) is to minimize cost subject to meeting given product demand levels. Part of the solution to the linear program is the marginal cost of producing another barrel of each product. These values are used as the market prices associated with the given demand level, consistent with the IFFS assumption of industry competitiveness.

The LP used in generating the pseudo-data is based on the Refinery and Petrochemical Modelling System (RPMS), a proprietary software system developed by Bonner and Moore, Management Consultants, Inc. RPMS provides a data base containing crude qualities, operating characteristics of refinery units, product qualities, and software to simplify the generation of a refinery process. The RPMS-based LP models are widely used in the refining industry and have been used for several years by EIA in its midterm forecasts.

The columns of the LP represent purchases of different crude oils and other inputs such as electricity, distillation of each crude, modes of operation of downstream units (such as varying temperature/pressure specifications), blending of intermediate streams, sales of refined products and construction of new capacity. The rows represent internal balances, unit capacity limits, quality specifications of products, a variety of engineering limits restricting modes of operation, and yields of refinery units. Full documentation of the RPMS system is available from Bonner and Moore.

In building an energy market model, one has to control the size of the model for each sector to have an overall, solvable energy model. A linear program of a refinery cannot fit directly into IFFS because of the model size that is necessary for adequately representing refinery behavior [2]. In order to circumvent this obstacle a pseudo-data approach is used. This is done by solving RPMS for a base solution value. A parametric analysis is then performed on individual petroleum product quantities and downstream capacities. For example, the quantity of gasoline is varied in 2-percent increments, 20 percent above and below the base solution value. Products are varied alone and in combination with other variables to create a series of observations on petroleum product prices as a function of how the refinery is operated. The prices are the dual variables from the linear program. These observations can be considered to be a data base showing all of the different ways in which a refinery could operate and the resulting product prices. These observations are used to perform regressions that relate quantities to prices.

Equations for the price of gasoline are of form:

$$\begin{aligned} \mathrm{LOG(PGASO)} = {} & \mathrm{B0} + \mathrm{B1*LOG(CRDP)} + \mathrm{B2*LOG(UNLQ/OCTANE)} + \\ & \mathrm{B3*LOG(LEADQ/OCTANE)} + \mathrm{B4*LOG(GASQ/CRACK)} + \\ & \mathrm{B5*LOG(DSTQ)} + \mathrm{B6*LOG(RESQ)} \end{aligned}$$

Where:

PGASO is the price of gasoline at the refinery gate in dollars per barrel
CRDP is the Refinery Acquisition Cost of crude in dollars per barrel
GASQ is refinery production of gasoline in millions of barrels per day
UNLQ is refinery production of unleaded gasoline in millions of barrels per day
LEADQ is refinery production of leaded gasoline in millions of barrels per day
DSTQ is refinery production of distillate in millions of barrels per day
RESQ is refinery production of residual in millions of barrels per day
CRACK is the capacity of cracking units in millions of barrels per day
OCTANE is the capacity of octane-boosting units in millions of barrels per day
and BØ, B1, B2, B3, B4, B5, B6 are estimated parameters.

The B's in the equation are estimated coefficients from the regressed pseudo-data. The other terms are model inputs. In the pricing equations, two variables besides quantity shares and crude price are significant factors, octane boosting and cracking capacity. As represented here, these are not actually refinery processes but rather aggregations of processes that can be categorized into either breaking hydrocarbon molecules or raising the octane level.

Equations for the price of distillate are of form:

```
LOG(PDIST) = BØ + B1*LOG(CRDP) + B2*LOG(GASQ/OCTANE) +
             B3*LOG(GASQ/CRACK) + B4*LOG(DSTQ) + B5*LOG(RESQ)
```

Where:

PDIST is the price of distillate at the refinery gate in dollars per barrel
CRDP is the Refinery Acquisition Cost of crude in dollars per barrel
GASQ is refinery production of gasoline in millions of barrels per day
DSTQ is refinery production of distillate in millions of barrels per day
RESQ is refinery production of residual in millions of barrels per day
CRACK is the capacity of cracking units in millions of barrels per day
OCTANE is the capacity of octane-boosting units in millions of barrels per day
and BØ, B1, B2, B3, B4, B5 are estimated parameters.

Equations for the price of jet fuel are of form:

```
LOG(PJTF) = BØ + B1*LOG(CRDP) + B2*LOG(GASQ/OCTANE) +
            B3*LOG(GASQ/CRACK) + B4*LOG(DSTQ)
```

Where:

PJTF is the price of jet fuel at the refinery gate in dollars per barrel
CRDP is the Refinery Acquisition Cost of crude in dollars per barrel
GASQ is refinery production of gasoline in millions of barrels per day
CRACK is the capacity of cracking units in millions of barrels per day
OCTANE is the capacity of octane-boosting units in millions of barrels per day
and BØ, B1, B2, B3, B4 are estimated parameters.

Equations for the price of high-sulfur residual are of form:

```
LOG(PHS6) = BØ + B1*LOG(CRDP) + B2*LOG(GASQ/OCTANE) +
            B3*LOG(GASQ/CRACK) + B4*LOG(DSTQ) + B5*LOG(HS6Q) +
            B6*LOG(LS6Q)
```

Where:

PHS6 is the price of high-sulfur residual at the refinery gate in dollars per barrel
CRDP is the Refinery Acquisition Cost of crude in dollars per barrel
GASQ is refinery production of gasoline in millions of barrels per day
DSTQ is refinery production of distillate in millions of barrels per day
HS6Q is refinery production of high-sulfur residual in millions of barrels per day
LS6Q is refinery production of low-sulfur residual in millions of barrels per day
CRACK is the capacity of cracking units in millions of barrels per day
OCTANE is the capacity of octane-boosting units in millions of barrels per day
and BØ, B1, B2, B3, B4, B5, B6 are estimated parameters.

Equations for the price of low-sulfur residual are of form:

```
LOG(PLS6) = BØ + B1*LOG(CRDP) + B2*LOG(GASQ/OCTANE) +
            B3*LOG(GASQ/CRACK) + B4*LOG(DSTQ) + B5*LOG(HS6Q)
            + B6*LOG(LS6Q)
```

Where:

PLS6 is the price of low-sulfur residual at the refinery gate in dollars per barrel
CRDP is the Refinery Acquisition Cost of crude in dollars per barrel
GASQ is refinery production of gasoline in millions of barrels per day
DSTQ is refinery production of distillate in millions of barrels per day
HS6Q is refinery production of high-sulfur residual in millions of barrels per day
LS6Q is refinery production of low-sulfur residual in millions of barrels per day
CRACK is the capacity of cracking units in millions of barrels per day
OCTANE is the capacity of octane-boosting units in millions of barrels per day
and BØ, B1, B2, B3, B4, B5, B6 are estimated parameters.

Estimating Downstream Unit Capacities

The downstream unit capacities available in the forecast year are calculated within the refinery module. The capacity of octane-boosting units in a given year is generated as the weighted sum of the capacities of the alkylation and reformation units. The weights are based on the number of octane-barrels of output obtained by processing one barrel of input through the unit.

The capacity of cracking units is the weighted sum of the capacities of thermal crackers, catalytic crackers, and hydrocrackers. The weights are based on the percentage of a barrel of residual feed that is converted to lighter products by the unit. Cokers, which are included in thermal cracking capacity, convert all of their input to lighter products. Other cracking units crack only part of their feed. The exact percentage of residual output from these units depends on the temperature and pressure at which they are operated. The weights for these units correspond to typical operating severities used in determining operable capacity.
The equation for determining octane-boosting capacity in year t takes the form:

$$\mathrm{OCTANE}(t) = B\emptyset + B1*\mathrm{OCTANE}(t-1) + B2*\mathrm{LDPG}(t-2) + B3*(\mathrm{GASQ}(t-2)-\mathrm{GASQ}(t-3))$$

Where:

OCTANE is the octane-boosting capacity in millions of barrels per day
LDPG is the difference in refinery-gate price between premium and regular gasoline
GASQ is refinery production of gasoline in millions of barrels per day
and B0, B1, B2, B3 are estimated parameters.

The equation for determining cracking capacity in year t takes the form:

```
CRACK (t) = BØ + B1*CRACK(t-1) + B2*LDPGR(t-2)
              + B3*(QGAS(t-2)-QGAS(t-3)) + B4*(RESQ(t-2)
              - RESQ(t-3))
```

Where:

CRACK is the cracking capacity in millions of barrels per day
LDPGR is the difference in refinery-gate price between regular gasoline and low-sulfur residual
GASQ is refinery production of gasoline in millions of barrels per day
RESQ is refinery production of residual in millions of barrels per day
and B0, B1, B2, B3, B4 are estimated parameters.

Octane capacity is based on octane capacity in some previous year plus a decision that was made by refiners to create new capacity approximately two years ago. In this equation we determined that the significant variable for adding on octane capacity was the difference that existed between the price of premium and the price of regular two years ago and the difference between the quantity of gasoline between two and three years ago, basically the change in gasoline production.

Referring back to the Introduction to IFFS, the modules are categorized into two pieces, a planning component and an operations component. The time series estimated equations fall into the planning component of the module, while the pricing equations fall into the operations part of the module.

Model Solution

A quick overview of the module algorithm shows how the individual pieces fall into place. First, capacities are based on the time series estimated capacity equations. The solution process begins with a slate of demands for petroleum products. From this slate of demands, net imports and natural gas liquids from processing plants are removed. Petroleum product prices are determined from the pseudo-data-estimated pricing equations. Refinery fuel consumption is based on product production levels and historical patterns. The final wholesale and retail prices include transportation and wholesale to retail markups. Demands are then re-estimated with these new end-use prices and the calculations are continued until there is a supply/demand balance in the oil market module.

The development of the oil market module is still in progress. Among some of the minor tasks to be accomplished is estimation of the pricing equations on a regional basis versus a national basis, the way it is presently being done. Alternative functional forms of the pricing equations need to be examined, and the time series used for estimating the capacity equations should be based on EIA data series.

Another major task which should be studied is the question of approximating the surface of the LP directly, eliminating the need for the pseudo-data approach presently in use; but, still yielding a simple set of equations that can be used in the module. Some of the aspects of the module of concern are whether the general approach used is valid, the functional forms presently being used are acceptable, and whether or not some of the basic assumptions that were made are correct.

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REFINERIES SUBSYSTEM: A CRITIQUE

Neil J. Cleary
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Standard Oil Company (Indiana)
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First, I would like to say that the opinions you hear are mine and not Standard Oil of Indiana's.

I would like to start out by saying that the overall approach taken by the Intermediate Future Forecasting System (IFFS) is very good, including the refinery submodel approach. At Standard Oil, we have successfully used the approach that is being used for the refinery modeling subsystem called pseudo data--we call it response surface modeling--on several occasions with considerable success.

The documentation provided to me was extremely poor, and I'm glad to hear that you plan to do more work on the refinery model subsystem because there is a lot more work that needs to be done. I suggest that you take out the basic organic chemistry lesson and the description of all the refinery processing models. Either remove them completely or put them into an appendix, because they are unnecessary. I also found that there was no discussion about how the cost equations were determined. I don't know whether or not a large number of different regressions and models were developed and the best ones selected. I also don't know where the functional form came from. They appeared sort of by magic.

I have some serious reservations about the functional form of the cost equations. Since they all are in logarithmic terms, they imply that a multiplicative form was used; I would suggest that a linear form would be more appropriate. If you look at a refinery process, part of the cost of gasoline is the cost of the crude oil used in a distillation unit; another part of it is the cost of the crude unit, the cost of the alkylation unit, the cost of the reformer, and the cost of the cat cracker. Thus the cost should be an additive function. Another reason for considering an additive form is that you are using an LP to get the basic underlying data.

Bonner and Moore's Refining and Petrochemical Modeling System (RPMS) is a very useful modeling tool. We've used it for over 10 years, with considerable success. I'm glad to hear that you do intend to look at those functional forms of the cost equations and hopefully will come up with somewhat better forms.

I don't understand why some of the variables were lagged two years and some of them were lagged three years. If this was the result of a statistical analysis or due to construction time lags, I have no objection, but this is not clear from the report.

In some of your equations, there were typographical errors. In the cat cracking capacity equation, one of the variables is the price difference between regular and premium gasoline; the question is, is that leaded or unleaded gasoline or did you average them. This equation has as one of its variables low sulfur resid. It would be more reasonable to have distillate demand as a variable. In the equation for the cracking capacity as a function of time, the last term (B4) is positive according to the documentation which, in effect, says that as the resid demand increases, cat cracking capacity increases, and that is not logical; it should be the other way around.

In the beta coefficients that are reported, there is no test or indication of statistical significance. T test statistics are not given. Some of those coefficients are pretty small and maybe could just as easily be left out.

In making the RPMS runs, you mentioned something like 540 runs were made. You said there were 18 RPMS input variables that were modified. It would be nice to know what the variables were. Also, when you changed the demands, the way the documentation reads, it indicates that you increased all products in 20 per cent increments. I think this would introduce a serious error because that would mean that you kept the gasoline to distillate ratio constant. The gasoline to distillate ratio has a very important effect on the cost of gasoline and distillate, a very strong effect. And that certainly would make the results suspect. I guess you are aware there is a typo on page 316. It should read 1 barrel; gives 1.59 barrels.

I also would like to know when you made the RPMS runs; did you use the build option, and therefore, are you calculating the incremental costs, including capacity expansion? It would also be nice to mention what the base crude was and what its properties were. What was the API and sulfur content of the crude? In our modeling efforts we have found it necessary to use a number of crudes to reflect reality in meeting low-sulfur resid demand.

The ratio of leaded to unleaded gasoline is not stated. This brings up another question. One of the products is premium leaded gasoline. My understanding is that that represents less than 2 per cent of the total gasoline market and in the future is going to be even less. I know our company doesn't even sell it anymore, and a lot of the oil companies don't, so that product might just be dropped out of consideration.

Another important variable that we found in our modeling work is how sulfur is handled. What sulfur crudes did you use? Did you use a crude with just one sulfur content? The product prices are very dependent upon the sulfur level of the crude. And that's not balanced, incidentally, by the difference in the cost of the crude. High sulfur crude is not selling at that much of a differential to low sulfur crude at present. A lot of the oil companies, including our own, are making a major investment in desulfurization equipment to handle high sulfur crude.

Some of the variables in the cost equations don't make sense. I see you use the same variables in all the equations, and maybe that is why these terms appear in all of the equations.

For example, the octane and cracking capacity should not have much of an effect on jet fuel prices, yet it is used in the equation for jet fuel prices.

If the gasoline equation is differentiated with respect to the price of crude, you find that gasoline prices will not go up as fast as the price of crude. I don't think that's a reasonable result.

I also assume you use the same demand equations for each demand region but plan to look at that in the future.

Standard Oil has participated in an NPC study, which was referenced in your document, on refinery flexibility. It took us about one month to build a model, about a two man-month effort; it took us seven months and two man-years of effort to validate it, and I'm not sure we did validate it completely. Model validation is a very difficult task.

We also found in that study that in order to get a realistic representation of the U.S. refining industry it was necessary to separate PAD 5, which is California and the West Coast, from PADs 1 through 4. Refineries in PAD 5 are so different in design and operate differently because of the low demand for resid and distillate. The West Coast refineries are designed differently than those in the rest of the U.S., and you can't represent the oil refining industry in the U.S. in an acceptable manner in one model.

We also had a problem in trying to validate our model for each of the geographical areas. We had to look at refineries with different complexity. I don't know the effect they are going to have on your overall big energy model. The effect of not considering refinery complexity may not be significant enough to affect it, but we ended up using three different complexity levels. A simple refinery which has only distillation and reforming capacity and then a more complex refinery that has cat crackers and then finally refineries that can handle the bottom of the barrel. Incidentally, I have with me microfiche output describing that model and can leave you a copy if you'd like.

There are a lot more specific points which I don't think I want to take up everybody's time with; I've got a list of them that I can give to you. I do want to mention, however, that what we did was take the NPC model that we had generated and reran it for 1978 and 1982 using your numbers. We also put the same numbers in your cost equations and compared results.

Our initial runs used a crude cost of $12.05 a barrel, so the results were definitely wrong. We reran it at the $33 a barrel used in your study, and our first attempt showed that there is reasonable agreement except for the gasoline prices. We subsequently discovered that one of the factors in your equation (the octane capacity) was in error by a factor of 10.

So we divided by 10 and then made some additional runs. The comparison between the prices obtained from your model and ours are given in Table 1 attached.

I don't know how significant these differences are. We will be willing to work further with you and continue to evaluate your models. Thank you.

Comparison of NPC Price and IFFS Price
for 1978 With Crude Price of $33/BBL

Product	NPC Price $/BBL	IFFS Price $/BBL	Difference $/BBL	Difference %
Distillate	33.05	39.58	-6.53	-19.76
Jet Fuel	33.10	36.02	-2.92	-8.82
High Sulfur Resid	31.40	29.22	2.18	+6.94
Low Sulfur Resid	32.40	31.52	.88	+2.70
Unleaded Regular Gasoline	36.80	30.95	5.85	+16.90
Lead Premium Gasoline	36.93	31.74	5.19	+14.05
Leaded Regular Gasoline	35.84	29.75	6.09	+17.00
Unleaded Premium Gasoline	--	31.46	--	--

Table 1

DISCUSSION

MR. CONTI: I would first like to thank Mr. Cleary and all the people of Standard of Indiana for the work they did. We hope to keep in contact with them and try and put into the model as many of their suggestions as we can. I think what I first should do is talk about the documentation, since that is what many of the comments are concerned with.

In the documentation, I believe the units are not carried through correctly. But, in the model itself, for example with respect to that octane capacity, the equations are kept consistent. So, we have to reexamine the documentation for its accuracy.

Secondly, more should be said about how the pseudo-data was generated, since you had a few questions on that. All petroleum product quantities were not changed by the same percentages simultaneously. First, they were varied separately, then they were changed in combination with other variables. Secondly, the downstream capacities were changed alone and also in combination with other variables, by 2-percent increments, 20 percent above and 20 percent below the base solution value. I think that deals with most of the comments you have made. As far as the variables that were used, I probably could not name them all, but I could tell you that it was all four types of gasoline, two types of jet fuel, distillate, low- and high-sulfur residual, and a few other minor products. In some of the perturbations to the model the products were aggregated, but the identities of the individual products were kept available in the model.

As far as the estimation of the equations is concerned, a stepwise approximation was performed. You would examine statistics for alternative functional forms for many different variables, depending on the particular petroleum product. Returning for a second to the problem with the documentation, the documentation says that all the variables, with associated coefficients, were used in every equation. That is not true, only coefficients with t-statistics that were significant were used.

Regarding the assumptions about qualities of the crude slate, I could not tell you what the gravities were, but what was done was to take a weighted average of the qualities of crude that are believed to be available in the future. The average API gravity for the crudes was 32.55. So, I am assured that we do not have the component characteristics of only one type of oil, but rather a weighted sum of a few different types.

We want to investigate in greater depth the regional issue which could clarify some present difficulties. We also hope to estimate linear as opposed to log-linear equations, but, there is a problem in the limitations of nonlinear regression packages.

Your note about the comparison of PADD 5 model results to data I am afraid is valid; however, as we try to estimate these equations regionally, we hope to eliminate that problem. I am not exactly sure how we should deal with the complexity of refineries that you suggested, but I will be in touch with you about generating some possibilities. I do not know whether I said this already, but, the way that the gasoline quantity is determined is a weighted average of all the different types: premium leaded, premium unleaded, regular and unleaded regular.

In the octane equation, you asked how we determined the price of premium and the price of regular. Premium price is a weighted average of the unleaded and leaded premium and the regular price is a weighted average of the unleaded and leaded regular. I hope I answered all your questions. I know a problem you brought up to us previously was with vis-breaking being included with the thermal processing units in the data base. As we re-estimate the capacity equations with EIA data series, we will revise the definition of thermal processes and examine alternative functional forms.

MR. CLEARY: I suggest you change the terminology of thermal cracking. It is an obsolete process.

MR. CONTI: OK. I think that covers just about everything. Did I leave out something that you could think of off the top of your head?

MR. CLEARY: No. I think that when you clear up the documentation, most of these problems will be cleared up. I might also mention that if you are looking at different crude slates by region, you look at the NPC study. We put a great deal of effort into determining appropriate crude slates.

MR. CONTI: I would like to thank you again very much for the effort you have put into this. I am sure it will be a fruitful experience in working with you and putting these changes that we do not already have in there in the model. Thank you.

DR. GASS: Thank you, John. I would like to open it up for general questions, answers, and discussion. I think all the speakers from this morning are here and so if anybody has any particular question to address to a particular person, or a question in general that could be answered by any of the EIA people, I welcome any questions. Yes, please. Identify yourself in the microphone, thank you.

MR. SHEEHAN: I am Tom Sheehan from the National Bureau of Standards and as background my question is motivated by the fact that a study has been done by the Congress's Office of Technology Assessment, looking at the effects of various legislative options such as tax credits, fuel price increases and so forth, on the demand side of oil and gas. Now, Richard O'Neill, in his presentation, pointed out that it is a little tough to keep up with some of the things Congress is doing and also observed that the doctors and dentists were fleeing from the oil drilling rig business, presumably because they are now only 50 percent tax brackets instead of 70 percent tax bracket. What I am wondering is, is there anything in any of EIA models that is capable of handling congressional requests or other inputs from changes in the law and seeing how they affect the projected prices or demands or supplies out to the vicinity of 1990 or so?

DR. MURPHY: The answer is yes because one of the chief purposes of this system is to make information available on the impacts of alternative congressional policies on energy markets. The only reason for generating any information about the future is because you want to make some decisions. Even though we have not talked much beyond my first slide on the possible uses of the model for policy analysis, that is the main reason for going into this activity.

MR. SHEEHAN: Just a minor clarification. Maybe I did not phrase the question right but the real question was not is policy analysis involved, but how sensitive are the models or how fine is the granularity you find in changes produced by Congress?

DR. MURPHY: It depends on how significant the changes. It is sector specific; for example, when you see the electric utility presentation, you will see more detail there. And, as was described by Dick O'Neill, the oil and gas supply models have the necessary cash flow equations for studying the tax structure. The models clearly cannot handle every policy. There is no explicit representation of changing highway programs, for example, on transportation fuel demand.

We have oriented the model development toward the kinds of issues that we have had to treat in the past, hopefully we have not done the equivalent of going into World War II with a horse cavalry on new questions. I think we have designed a system that can adapt to new issues, but, we do not know what they are yet. So, we have designed the models around the typical issues we have been treating in the past. They do not seem to go away.

MR. ALEXANDER: Mark Alexander of the Department of Interior. To what extent does your analysis system incorporate international models such as PAL?

DR. MURPHY: There are a whole group of international models in EIA. PAL is one of them. Another one is the Oil Market Simulation Model. These models are used to determine the world price of crude oil, which we use as an input in this model. There have been some preliminary discussions in terms of linking OMS to this system so that we get the feedback from changing U.S. oil import requirements on the world price of oil as characterized in OMS. Our models are in the same division within EIA, so, although they are not physically connected, analyses are linked at this point.

DR. GASS: Are there any comments from the EIA speakers to clarify any points?

DR. MURPHY: I would like to clarify two points. One is that the reason why we did not have, say, a linear term for the crude price and then a log-linear term for other oil product prices is that when you mix linear and loglinear terms you have a problem in finding statistical estimation packages that work for any moderate size nonlinear systems. And there is another whole question associated with the use of pseudo-data that has not really been resolved. The data are not independent random observations; we are talking about formally generated material used to estimate an approximating function.

What does this mean? The statistical tests are based on an underlying notion of randomness that does not exist here. We are approximating a model with a model and there is a lot of work that needs to be done in understanding the bounds on the usefulness of this procedure and the meanings of the results.

We have chosen it for pragmatic reasons as have other people, but, it is a subject that needs quite a bit further study. It is really not so much a statistical process as a technique of numerical analysis in function approximation. So, we have some people investigating this for us and we hope to have some reasonable results this fall.

INTRODUCTION TO THE AFTERNOON SESSION

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I would like to welcome you back to the afternoon session on the Intermediate Future Forecasting System. My name is John Todd and I am Director of the Short-Term Information Division, which has responsibility for short-term domestic forecasting and international forecasting. I assumed responsibility for the longer-term division last December.

The virtues of having all these activities under one roof is that we have a better sense of what everybody else is doing and it is a little more efficient to allocate manpower. Some of the development agendas for the future include trying to capitalize on that communication by making the short-term system, the STIFS system, more consistent with the longer-term system, the IFFS system. This is one of the things we will be working on over the next year. We are going to get as much consistency as we can this year. Also, on the international models, the quality of the crude runs and the world oil prices that we use in the IFFS system come as well from the Oil Market Simulation Model which is operated in the International Branch.
The difficulty, of course, of having all these activities under one roof is that there is an awful lot to do, and it is very difficult to give detailed supervision. Fortunately, I am blessed by having a group of very fine managers, and I am particularly grateful for both the creativity and leadership that Fred Murphy has shown in helping to manage what Bill Hogan called this ambitious and impressive venture and, also for Julie Zalkind and John Pearson, who have joined us and are helping to manage this operation.

We have additional copies of the Oil and Gas Supply Modelling proceedings of the 1980 symposium that was mentioned earlier this morning; some right outside and, if we run out there, we even have a few more available. So, those of you who would like to get a copy of this, you probably can do so before you leave today.

As you can see from the afternoon schedule, we have three pairs of presentations of electric utilities, coal, and the macroeconomic interactions, followed by a summary presentation. The remaining time will be allotted to a panel discussion and questions, by which we mean an opportunity for all of the presenters today to offer any last minute comments that have come to their attention and for all of you to have a chance to ask questions, not only of EIA personnel but of the other people who have made presentations from outside DOE as well.

INTRODUCTION TO THE
ELECTRIC UTILITIES SUBSYSTEM

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Introduction

As emphasized in the overview, modularity is a design feature for the overall IFFS system. In the electricity market module this concept is extended to include a division of the module into four basic components. As illustrated in Figure 1, there is a planning component, a production costing or supply component, a pricing component, and a demand component. The interaction of these components can best be illustrated by following the information flows through the module.

Input from other IFFS modules consists of electricity demand estimates and fuel prices. The planning module provides capital accounts to the pricing module and determines available capacity in the current forecast year for the production costing component. The production costing component allocates available generation capacity to satisfy electricity demands and tabulates the resulting operating cost and fuel consumption patterns. The pricing component combines the financial accounts from the planning component and the operating costs from the production costing component to produce an electricity price. The demand component adjusts the electricity demand to be consistent with the current electricity price estimate.

Thus, an iterative cycle is established between the production costing, pricing, and demand components. This cycle terminates when electricity price and demand estimates remain constant through one full cycle. Output to the other IFFS modules consist of resulting fuel consumption patterns and electricity prices.

The Planning Component

The planning component is unique in that it is executed only once each forecast year. Planning decisions are based on previous year's solutions or historical data. First-order exponential smoothing is used to determine an expected growth rate for electricity demand and fuel prices for planning purposes. There are a number of planning functions that take place in this component, which include simulating the capital outlays necessary to build and maintain the transmission and distribution network, as well as short-term concerns for maintenance scheduling. However, the emphasis is on formulating an expansion profile for generation capacity.

This component determines how much and what type of capacity must be initiated in the current forecast year such that an "optimal capacity mix" is maintained over the planning horizon. Thus construction lags for each capacity type are explicitly dealt with in this planning framework. For example, the decision as to how much coal steam capacity to initiate in the current year is made by solving the static capacity mix problem in the first year that construction could be completed. This procedure is repeated for each capacity type.

A breakeven analysis is the basis of the solution technique used to solve the capacity mix problem. However, to understand this procedure, it is necessary to introduce the concept of a load duration curve.

The need for the concept of a load duration curve results from the fact that electricity cannot be inventoried; and, therefore, sufficient capacity must be available to meet instantaneous demand. Figure 2 shows a typical daily load curve which plots demand as a function of time. The area under the curve gives total demand and the height of the curve provides a measure of capacity requirements. A load duration curve is created by reordering the load curve from highest to lowest demand levels, as shown in Figure 3. Like the load curve, the load duration curve provides total demand information and more clearly illustrates capacity utilization requirements.

Illustrated in Figure 4 is a simplified representation of the planning methodology. The bottom half of Figure 4 is an annual load duration curve. The top half is a breakeven chart. This chart plots annual operating costs for three competing capacity types as a function of capacity utilization. The chart shows that for utilization less than the first breakeven point the oil turbine is the best choice. For utilization between the two breakpoints, the natural gas steam capacity is best. The coal steam capacity is best for utilization greater than the second breakpoint. If these breakpoints are projected down to the load duration curve, the optimal mix can be read from the vertical axis. Oil turbines are selected to meet load at the top of the load curve, coal steam at the bottom, and natural gas steam the remainder. The utilization of the equipment is the area in the load duration curve covered by each plant type. This methodology can be easily modified to deal with existing capacity. Since the capital cost for existing capacity is already sunk, this cost is eliminated from the breakeven analysis and the total cost curve for existing capacity begins at the origin. However, with these cost curves, the model selects a capacity mix which includes more existing capacity than is available. The remedy is to slide the cost curve up the breakeven chart, without altering its slope. At some point, the model will select a mix which includes the precise amount of existing capacity. This is the optimal mix.

It is important to note that within the time frame considered by this model, most capacity expansion decisions have already been made. This committed capacity is captured by the model through the actual electric utility plans as reported in the Generation Unit Reference File (GURF) as maintained by the Energy Information Administration (EIA). Thus the importance of the planning component is in projecting a construction profile used within the pricing component since few of the expansion decisions made by the model come to fruition in the forecast horizon. However, this is sufficient cause to be concerned about the reasonableness of the expansion plans. Two important steps can aid in insuring this. First, financial feasibility is being made a factor in the expansion decision. The model incorporates the effect of balance sheet weakness on the cost of capital and the economics of new equipment. The higher the cost of capital, the less desirable the capital-intensive plants become. Second, electric utilities have, in the past, tended to order more capacity than necessary. This is because it is more costly to be caught short in the face of increasing demand than to have some excess capacity. Also, demand growth has been below some of the most pessimistic expectations.

What is needed is a way of including in the capacity expansion component a method for delaying the additions of new capacity, slipping the construction schedules the way utilities do when demand growth expectations are not met. The latter task may not be completed in time for the Annual Energy Outlook.

The Production Costing Component

Available electricity generation capacity by seasonal period for each forecast year is determined by the planning component and passed to the production costing component. The preparation of this data is a two-step process. First, new and existing generation assets are sorted and combined by capacity type. Second a maintenance schedule is developed in the following manner. Peak load requirements are constructed for four seasonal groupings: summer, winter, spring, and fall. Electricity demand is generally lowest in the fall and spring periods. The base load units are scheduled for maintenance during these periods to the extent there is an adequate reserve margin. Plants are then scheduled for maintenance in either the summer or winter, whichever has the lowest peak demand. If there is any more need for maintenance downtime, it is scheduled in the remaining period. Given the maintenance schedule, the equipment available in each seasonal period for dispatching is now known. The capacities are fixed for the current forecast year, therefore, capital costs are of little concern in making the dispatch decisions. The only concern is with operating costs.

The production costing methodology is relatively simple. For each capacity type the variable cost of producing one unit of electricity is calculated, the capacity types are sorted according to these costs and stacked under the seasonal load duration curve until sufficient capacity has been allocated to fully meet demand. In Figure 5, for example, nuclear is at the bottom of load curve with coal steam, oil steam and oil turbines stacked on top. The area under the load curve in each of the four strips represents the electricity generation required of each capacity type. Fuel consumption and operating costs for each capacity type can be determined from their assigned generation requirements. The operating costs are summed and passed to the pricing component, and the fuel consumption patterns are sent to the other IFFS supply modules.

To better emulate actual dispatch decisions, this methodology is modified to reflect additional constraints on the electricity generation network. For example, hydroelectric capacity is limited by water flow and thus has both a capacity and energy constraint. The production costing component allocates hydroelectric capacity to that unique position under the load curve such that both constraints are exactly met. Other concerns include: utilization constraints on steam and turbine capacity (turbines cannot operate on a continuous basis and it is impractical to operate steam units to satisfy peak demand); determination of availability rates by capacity type; and the development of load following rates for base load equipment. Load following refers to the practice of lowering utilization of base load and intermediate load capacity to some critical level during off peak-periods to avoid start up costs on intermediate load capacity when demand again rises.

The Pricing and Demand Components

The pricing component simulates the financial flows and status of electric utilities. It produces income statements and balance sheets, for private and public utilities, treating all of the utilities of each type in each Federal region as two integrated systems. By following utility accounting practices, the rate base and the attendant revenue necessary to meet the allowed rate of return is estimated while covering depreciation, fuel, and other operating costs. Given the total quantity of electricity demanded, the price is the required revenue divided by demand.

The demand component consists of the load duration curves and equations that relate the price of electricity in each sector to the demand for electricity. The sectoral demands are summed and the function that defines the load curve, a fifth degree polynomial, is multiplied by a constant so that the area under the load curve is the kilowatt-hours demanded.

The supply/demand balance is found by iterating between the production costing, pricing, and demand components until the price from the pricing component is consistent with the demands produced using those prices in the demand component. Once an equilibrium is reached in electricity markets, IFFS moves to find an equilibrium in the other market modules.

Conclusions

The status of the system is that there is something in place for every component of the utility module. Given a working module, individual pieces are being upgraded with improved data and occasionally with structure, as experience is gained and the model is calibrated to historical experience. Given the number of simplifications and approximations in this kind of enterprise, we would like to solicit comments as to the appropriateness of the methodology and, perhaps, some of the pitfalls that may occur once the model is used.

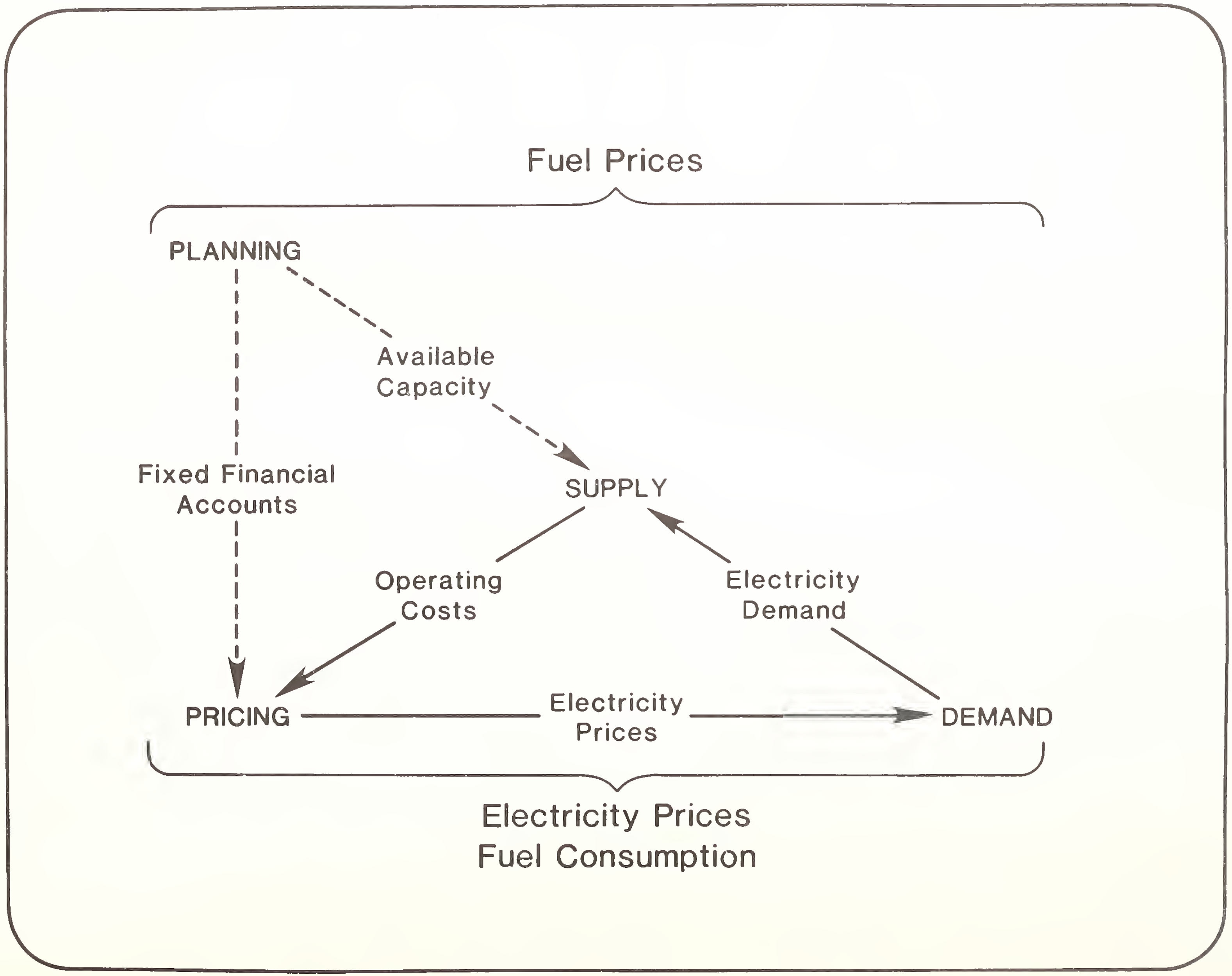

Figure 1. Electric Utility Module

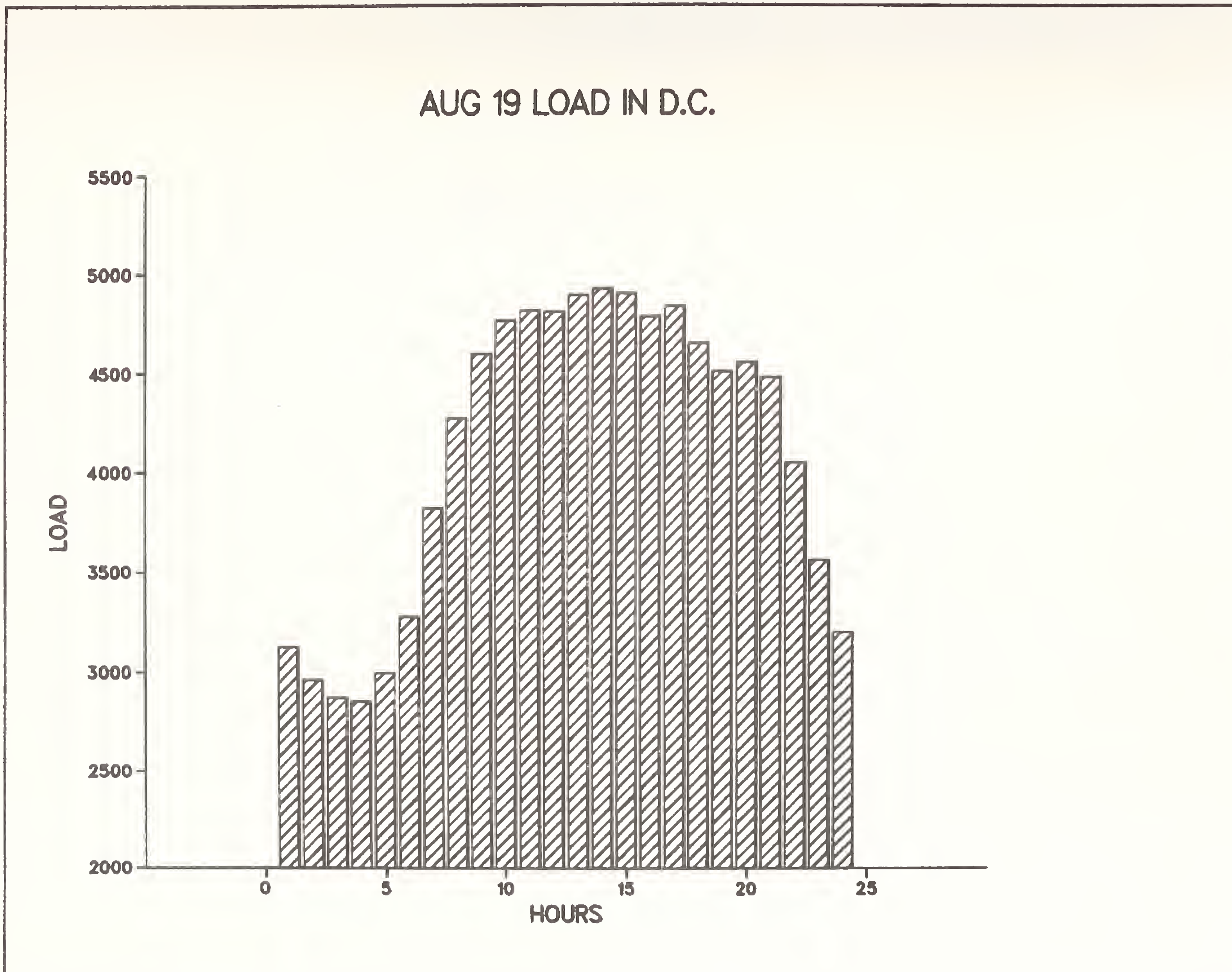
AUG 19 LOAD IN D.C.
LOAD
5500
5000
4500
4000
3500
3000
2500
2000
0
5
10
15
20
25
HOURS

Figure 2

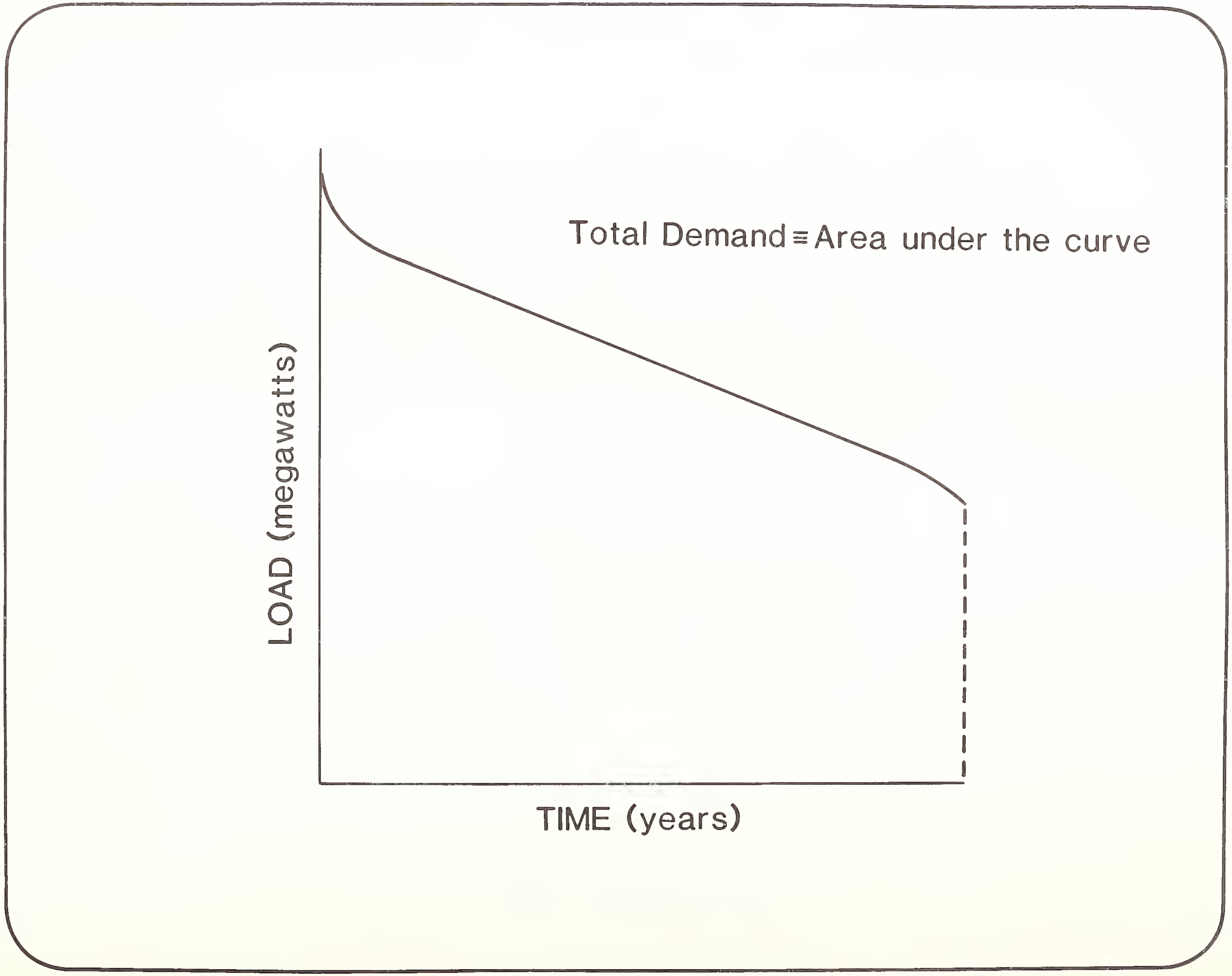

Figure 3. Load Duration Curve

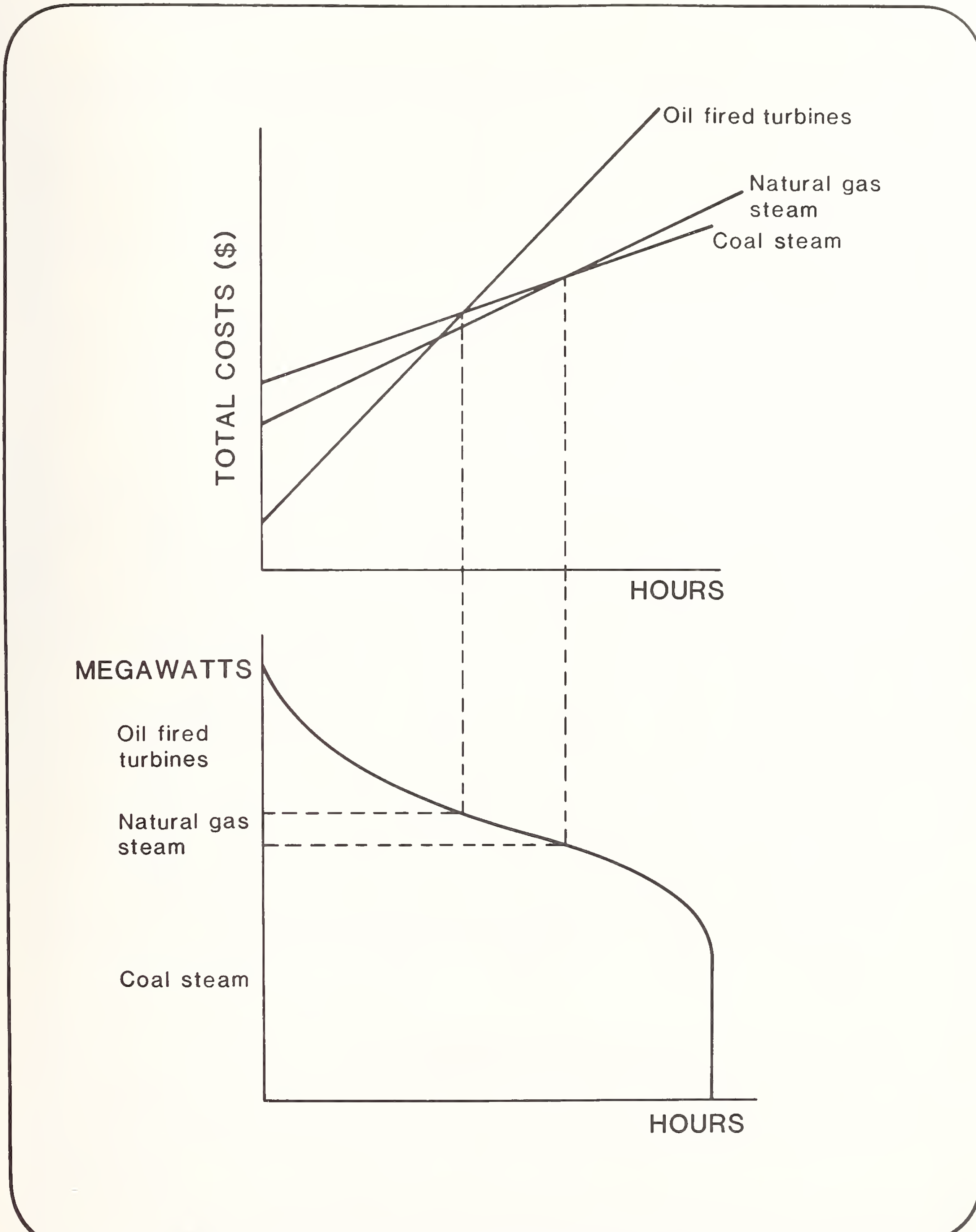

Figure ' . Planning Methodology

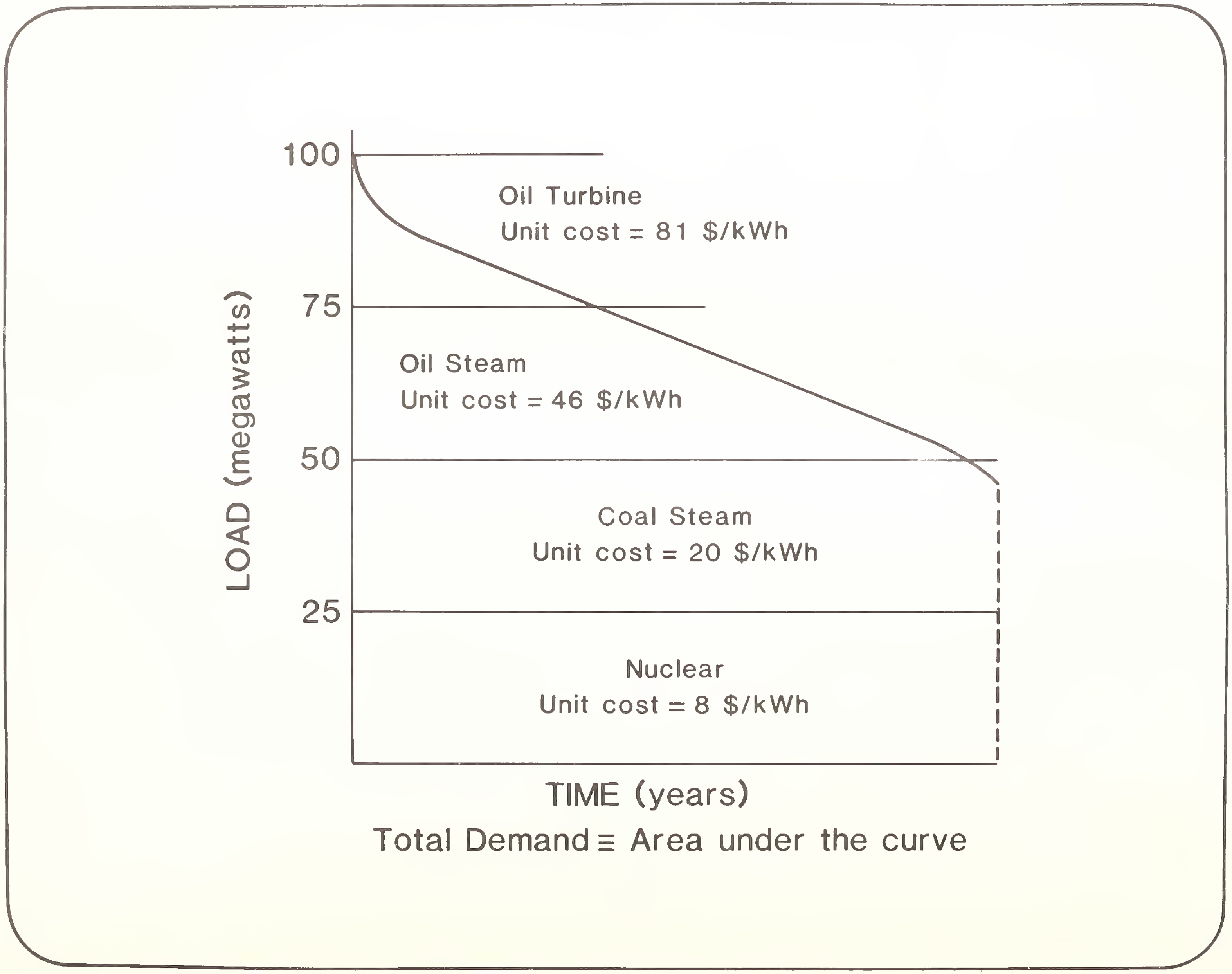

Figure 5. Production Costing Methodology

ELECTRIC UTILITIES SUBSYSTEM: A CRITIQUE

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I. Introduction

The Intermediate Future Forecasting System (IFFS) is an integrated energy system model being developed by the Energy Information Administration (EIA) of DOE to use in forecasting and analysis over a medium-term horizon (8-10 years). Specific pieces of the energy system have been modeled individually and then linked together to form the integrated representation. This paper focuses exclusively on the electric utility module of the system, and attempts to review and critique the design and philosophy underlying it.

This critique is meant to be constructive, in every sense of the term. It is hoped that the observations and comments made in this paper will be helpful to the modelers in their continuing efforts in development, refinement and eventual use of the model in the analytical support of energy policy-making.

For the most part, an understanding of the module design decisions and the principles underlying those decisions has been developed from the documentation provided by the modelers. Sample output reports have also been provided by the modelers, but these have been less useful as they are quite preliminary and the results are not particularly insightful. Also the modelers themselves have been questioned on certain specific issues, and their comments have helped to complete the information base necessary to this critique.

Section II makes several general observations about the module, including underlying philosophy, purpose, and uses. Section III comments in depth on the underlying principle of decision-making - that of cost minimization - implicit in the module. Section IV addresses the production costing issue and its treatment in this module. Section V comments on the two principles of demand uncertainty and foresight in capacity planning, and attempts to point out potential difficulties with respect to their treatment in the design of the module. Finally, Section VI concludes by consolidating and summarizing the specific cautions and recommendations suggested to the modelers.

II. General Comments

Several important considerations of context and usage underlie the design decisions made by the modelers. These considerations are presented in order to define the environment in which the module will be used and thus to help explain the rationale for specific design decisions. These considerations include the following:

1. The time-frame of the module and of the entire IFFS system is medium-term. The system will run and produce results over an eight- to ten-year forecasting period.

2. The module is designed to simulate electric utility operations in an entire region, rather than in an individual company.

3. The module must be structured in such a way as to sensibly interface with other modules in the IFFS system.

4. In order to be responsive and valuable in the policy-oriented environment in which it exists, the module must avoid overly complex, slow or difficult-to-use algorithms and procedures.

In subsequent sections of this paper, these considerations will be referenced again as direct motivation for many of the design decisions made by the developers.

The documentation of this module also deserves comment. The chapter on the electric utilities module is excellent, both in terms of structure and information content. It is quite clear and well-written.

Further, it is very well organized. It is essentially divided into three sections: The first section presents a comprehensive discussion on the nature of the electric utility industry, including planning, technology options and regulatory constraints; the second section discusses a number of different approaches to modeling the industry, including state-of-the-art attempts to incorporate such difficult issues as demand uncertainty and contingency planning; finally, the third section discusses the current model design and the motivation behind it. With the first two sections of the chapter as motivating background, the reader is well prepared for the discussion of the IFFS electric utility module, and understands clearly the context and rationale of its design.

Finally, the output reports of the system deserve a short comment. At this stage in the development process they are not very useful. There are no summary-type reports yet developed; and thus there is no way to develop any summary insights into any particular scenario or run of the model.

Currently the output reports of the system produce nothing but long lists of prices and quantities, by region and year. More sophisticated and insightful reports will have to evolve as the model is used to support real-world analyses.

III. The Cost-Minimization Principle

In simulating the planning and operations of any firm or business, a modeler must be guided by some underlying principle of behavior. In this electric utility module development, the modelers have chosen, not surprisingly, to be guided by the cost-minimization principle of neoclassical economics.

In essence, this principle states that the utility, in order to produce electricity, will use its factors of production (capital, labor and fuel, for example) in some combination so as to minimize total costs across all factors. This is a standard and sensible principle in almost all business environments, but one area where it has had serious competition from an alternative principle is among firms under rate of return regulation.

The alternative principle is the Averch-Johnson (A-J) hypothesis (see references 1 and 2.). A-J states simply that a firm under rate of return regulation will tend to choose a factor mix which is more capital-intensive than the optimal, cost-minimizing mix <u>if</u> its regulated rate of return is greater than its cost of capital. In the era when this hypothesis was originally developed - the early 1960s - it was generally considered to be true that the rate of return allowed to most regulated firms, electric utilities included, was greater than their cost of capital.

The hypothesis was thus offered in part to help explain such observed phenomena in the utility industry as redundancy of equipment and "gold-plating" in order to ensure maximum reliability.

The A-J hypothesis, as a guide to and predictor of managerial behavior in regulated industries, has been quite controversial. The original Averch-Johnson article has spawned an enormous number of apologies and refutations, both theoretical and empirical, over the last two decades. It is now generally acknowledged that A-J is not a particularly good model of utility behavior; thus the cost-minimization principle is a reasonable and relatively simple substitute to use in this modeling effort.

However, in recent years still another alternative model has surfaced, and its rationale is at least qualitatively compelling. The so-called "reverse Averch-Johnson" hypothesis questions what kind of behavior will ensue in a regulated firm if the allowed rate of return is <u>less</u> than the cost of capital. This question is compelling, of course, because many observers of the industry feel that in recent years the allowed rate of return for electric utilities has fallen below the cost of capital. Recent trends in the market value of utility common stocks tend to corroborate this (Figure 1).

Analogous to the original A-J hypothesis, the reverse A-J predicts a mix of productive factors containing <u>less</u> than the cost-minimizing share of capital. Once again, observers of the utility industry in the late 1970s feel that this condition may become increasingly prevalent due to severe financial difficulties within the industry. (See reference 3 for a fuller discussion of these phenomena.)

Utility executives are publicly stating more and more often their reluctance to undertake or even finish large capital projects due to problems of equity dilution and the difficulties of raising money. Instead, a host of other, less capital-intensive means of satisfying load growth are being discussed and experimented with, both by utilities themselves and also by regulators and intervenors. It is not yet clear whether such techniques as conservation, load management, dispersed sources and cogeneration represent a least-cost alternative overall; what is generally true is that they are less capital-intensive, so that they may in fact be chosen as the capital stock of the future even though they do not represent a most efficient utilization of resources.

The preceding discussion is speculative; no one knows how the mix of capital equipment available to utilities will evolve, or how utility executives will make capacity addition decisions. There is the potential however, if "reverse A-J" has any predictive power, for the world to evolve quite differently than the IFFS model will predict. In particular, the asset bases of many utilities may be much smaller, and contain much higher amounts of demand-side equipment and old, refurbished plants than IFFS projections. It is a phenomenon which the modelers should be aware of and be prepared to adjust to according to circumstances.

IV. Production Costing

Another area of choice for the modelers was the algorithm by which production costing, or dispatch, was treated. In general, two techniques, one deterministic and the other probabilistic, are available. The modelers chose the deterministic technique in this context, and their choice appears to be proper.

Any simulation of electric utility operations must specify a method to determine which plants to operate - or dispatch - at what capacity levels at any given point in time. These decisions are complicated by several factors:

- Load - electricity demanded by the system - fluctuates from instant to instant over the course of any arbitrary time period as time-of-day, season, and weather change. Further, load must be satisfied through production as it is demanded as electricity is not generally storable.

- At any given instant one or more of the power plants available to the system may be out of service, either because of a planned, maintenance outage or because of an unplanned, forced outage.

Typically, in long-term utility planning and operating studies, the load fluctuation problem is dealt with in an aggregate way. Rather than attempting to dispatch plants in operating order at each instant, sequentially, over the time period, such aggregate methods rely on a load duration curve (Figure 2) as a representation of demand. The load duration curve represents a set of estimates of demand levels at each instant over the time period - a season or a year, typically - reordered, for convenience, from highest to lowest. It is, in effect, a cumulative probability distribution of load over the period.

Aggregate methods then dispatch against the load duration curve - in effect, treating the entire time period instantaneously - by simply filling in the area under the curve with the energy capability of each plant, from the cheapest to the most expensive.

Analogously, the treatment of plant outages instant-by-instant is also dealt with in an aggregate manner. Typically, an outage rate is specified for each plant, representing some estimate of the average fraction of time that plant is expected to be unavailable over the time period. The outage rate is typically an enginering parameter associated with a specific plant type and technology.

In a utility system, outage rates of individual plants are not independent of one another. At any given instant, the fact that a particular plant is unavailable might influence the availabilities of other plants because it will place increased burdens on the other plants to pick up the slack. Further, the availability of a given plant is at least partially random and can thus be described by a probability distribution. The availability of the system, then, can be thought of as a combination of the interdependent probability distributions of the plants, and can also be described by a probability distribution.

Probabilistic production costing techniques, then, are fundamentally motivated by the above complexities. Specifically, they attempt to incorporate: a) the interdependence among the outages of individual plants; and, b) the interaction between the probability distribution of system availability and the probability distribution of load across a given time period, into their simulation algorithm.

On the other hand, deterministic techniques are much simpler and more straightforward. They essentially abstract from the complexities of interacting probability distributions and treat both load and individual plant capacities independently and deterministically. A fuller but still readable discussion of these issues can be found in the electric utility chapter of the IFFS documentation itself. Other sources include references 4 and 5.

Clearly, probabilistic techniques of production costing are more accurate and more rigorous as simulators of the way an individual utility system actually operates. These techniques were in fact developed in the mid-1960s in direct response to inaccuracies which were experienced in the use of deterministic techniques, particularly in describing system behavior at the high, "peak" end of the load duration curve. On the other hand, deterministic techniques are much simpler, faster, and computationally less burdensome.

Simplicity and speed are quite important in the IFFS system, but the primary reason the modelers chose a deterministic technique for their production costing was because they lost very little accuracy in using it. This in turn is because they are modeling an entire region, not an individual utility system.

In effect, a region is a set of interconnected utility systems. It is much larger and more heterogeneous than an individual system, and the natural diversity factor among customer loads is greater. Further, the ratio of typical plant size to system size is much lower; therefore, the interdependence among individual plants is much weaker.

Essentially the interdependence among all probability distributions within the system, both load and plant outages, is much weaker; thus, the need for probabilistic methods is also much weaker. The degree of error introduced by the use of deterministic methods is much smaller at the regional level, and the increased speed and simplicity achieved further help to justify the modelers' decision on this issue.

V. Demand Uncertainty and Myopic Capacity Planning

Two final areas where the modelers were forced to make explicit design decisions were:

- o the treatment of demand uncertainty
- o the treatment of foresight in capacity planning

In both of these areas the simpler, more straightforward path was chosen, for several reasons which will be discussed. Again, these decisions appear to be generaly correct, but under certain circumstances problems could arise.

The treatment of demand uncertainty is an issue which has arisen only recently in utility capacity planning (see reference 6). In essence, two approaches exist. The traditional method involves utilizing a point estimate load forecast, and planning a sequence of plant additions over time to meet it. An alternative approach is to estimate an explicit probability distribution of load in any given future year, and to then build contingencies into the system plan, allowing for and minimizing the costs of having either excess or deficient capacity.

Treating foresight in capacity planning is also a fairly recent phenomenon (see reference 7 as an example). The issue here is one of dynamic vs. static optimization. In simulation, a capacity planning model is faced with the task of specifying an optimal sequence of plant additions over time, subject to some forecasts of load requirements and prices. Traditionally, the load forecast is derived independently from the capacity plan; there is no interaction between the two and thus no need to reconcile them over time. This describes, in essence, the static optimization approach, in which each year the capacity planning algorithm has available to it only past information about demand and prices, and some simple forecasting rules. The technique simulates imperfect foresight, and allows for the possibility of surprises.

Dynamic optimization, on the other hand, explicitly attempts to reconcile capacity planning decisions with the future behavior of demand and prices, iteratively, until a convergence is achieved. This technique simulates perfect foresight of demand and prices on the part of the capacity planners. Planning is optimized dynamically as well as statically.

In the electric utilities module of IFFS, the modelers have decided to specify the simpler representation on both of these questions. This is, generally speaking, the most reasonable decision to make because of the following:

- Both dynamic optimization and the explicit recognition of demand uncertainty require complex and time-consuming algorithms. In the interest of keeping IFFS simple and fast, these techniques were rejected.

- Dynamic optimization and demand uncertainty both require complexity in the electric utilities module; furthermore, they would require additional complexity in other modules of the IFFS system as well. Specifically, demand uncertainty would require a range of forecasts, along with associated probabilities, to be produced by the demand module. Also, dynamic optimization would require the entire IFFS system to converge to a solution dynamically as well as statically, presumably causing many more iterations in order to reach a solution. These additional requirements on the entire system were rightly judged to be prohibitive.

- Given the relatively short time frame over which IFFS must operate (8-10 years), the majority of system plans are already known in advance from commitment and construction schedule data from the National Electric Reliability Council (NERC) and other sources. The system planning algorithm is really only responsible for incremental additions and changes, so it need not be so sophisticated.

- At least in the case of dynamic optimization, the simpler approach is generally a more realistic simulation of the way plans are actually made.

There is still one additional aspect of the system planning algorithm of the IFFS utility module which should be noted. This is the fact that the algorithm always makes capacity additions continuously and smoothly. It does not consider such things as minimum unit sizes, minimum construction lead times or the inflexibilities inherent in modifying construction plans on short notice. This fact, when combined with point estimate load forecasts and static optimization techniques, can lead to difficulties in certain circumstances. In particular:

- Use of point estimate load forecasts does not allow the simulation of contingency planning, i.e., the building of excess capacity in case the forecast turns out to be low.

- Forecasts can in fact turn out to be low (or high) because foresight is imperfect and optimization is static.

- If mistakes are made, however, the ability to add capacity smoothly and quickly precludes any ability to simulate either a deficiency or an excess of capacity. Adjustment in this model is virtually instantaneous.

- As a consequence, there is no ability to simulate either delays or accelerations in construction schedules, and their attendant financial and reliability consequences.

As previously stated, in most instances the above issues will not cause problems because of the largely fixed nature of capacity plans over a ten-year horizon. However, in some instances, such as the simulation of radically different scenarios, misleading results are possible. The modelers should be aware of the potential problems in this area, and make appropriate adjustments.

VI. Conclusions

In this critique of the IFFS electric utility module, three major issues in design philosophy have been addresssed. These are:

1. The Cost Minimization Principle -

This is clearly the simplest underlying philosophy of behavior which the modelers could use. As such, it is probably the best. However, in an era of serious financial difficulty in the utility industry and of the popularity of many "soft-path," capital non-intensive options, the "reverse A-J" theory and the type of behavior which it might predict deserve scrutiny.

2. Deterministic Production Costing -

Again, this decision is the simplest option and therefore the best under the circumstances. Furthermore this is probably the most robust of the three major design decisions. Given the stated uses of the model, particularly its use at a regional level, it is difficult to conceive of a situation where this simplification will create problems.

3. Demand Uncertainty/Capacity Planning -

Given the largely determined nature of capacity plans over a 10-year horizon, the simple options appear to be the best options in these areas also. However, it should be recognized that there are potentially serious limitations in this approach, in terms of simulating a) contingency planning and b) surprises caused by inaccurate forecasting.

Finally, it should be noted that this critique is based entirely on an evaluation of the module in the context of its stated purpose and uses. Most of the cautions raised in this paper have to do with nonstandard situations and uses outside of the stated ones. Inevitably a model like IFFS, existing as it does in a volatile, policy-making environment, will be used for purposes it is not really equipped to handle. When that happens, the cautions pointed out in this critique may become even more useful to the modelers than they will be in normal usage.

VII. Reference

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2. "Input Choices and Rate of Return Regulation: An Overview of the Discussion," Baumol & Klevorick, Bell Journal of Economics, 1970.

3. "Electric Utility Capacity Expansion: Its Implications for Customers and Stockholders," S. C. Peck, submitted to Public Utilities Fortnightly, 1982.

4. "The A-B-C of Probabilistic Simulation," R. R. Booth, State Electricity Commission of Victoria, Australia, 1971.

5. "Production Costing Using the Cumulant Method of Representing Equivalent Load Curve," Stremel, Jenkins, Bolt & Boyless, Presented at IEEE PES Summer Meeting, 1979.

6. "Costs and Benefits of Over/Under Capacity in Electric Power System Planning," EPRI EA-927, Decision Focus, Inc., 1978.

7. "Evaluating R&D Options Under Uncertainty - Volume 3: An Electric Utility Generation Expansion Planning Model," EPRI EA-1964, Applied Decision Analysis, 1981.

Source: EEI Statistical Yearbooks, Section VIII, Table 595.

Figure 1. Moody's 24 utility common stocks (weighted average).

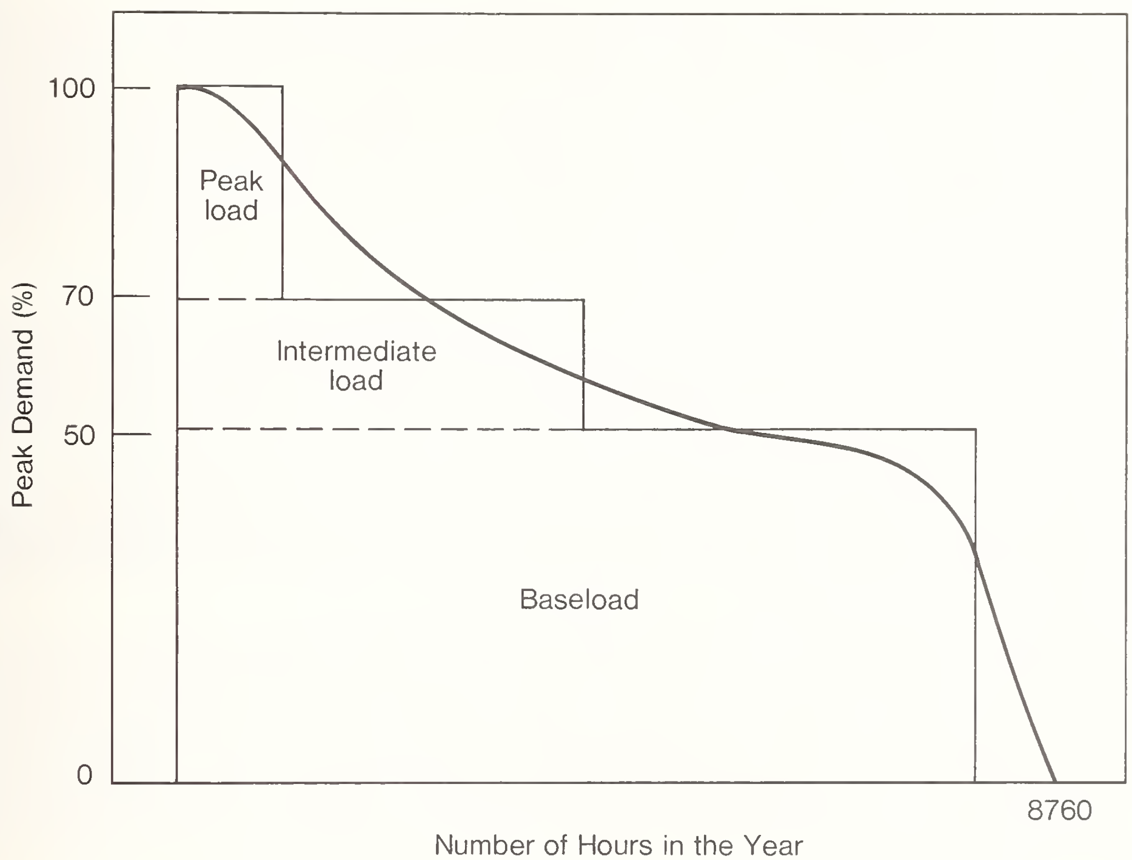

Figure 2. A typical load duration curve for an annual time period.

INTRODUCTION TO THE COAL SUBSYSTEM

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The IFFS coal market module is currently under development. The purpose of the coal module is twofold. First, it is to be a policy tool with which the Coal Division can examine legislation that affects the coal industry (e.g., the proposed legislation on coal slurry pipelines that is currently being considered). Second it is to be used to develop integrated projections of coal supply that are consistent throughout EIA. There are three major components of the module (coal supply, coal transportation, and the demand interface component) and they are in different stages of completion. I'll mention their status as I describe them.

Figure 1 is a flow diagram of the coal module. It begins with a component that produces annual short-run coal supply curves. These are given for 31 supply regions and for 30 coal types--5 Btu categories and 6 sulfar categories. The curves generated by the coal supply component are piecewise linear and are used in conjunction with the transportation component of the system. The purpose of the coal transportation module is to capture the distribution patterns of coal movements from supply regions to demand regions and to determine the supplies of coal that can be delivered to the demand regions at the least cost.

The transportation module feeds the demand interface program with delivered prices of coal to each of the consuming sectors within 44 demand regions. These prices are aggregated within the demand interface program to the 10 demand region levels considered by IFFS and the 9 coal types considered by the IFFS utility module. A backward flow also exists where the main module of IFFS supplies demands to the demand interface module, which disaggregates them and feeds them to the coal transportation module.

There are two levels of iteration between the coal market module and the IFFS integrating program. The first level is between the coal transportation module and the demand interface module. The demand interface module contains a condensed demand equation that has a constant term reflecting the cross-elasticity effects of other fuels. These two components are solved until the delivered price form the transportation component results in no change in demand from the demand interface component. Once the coal module is solved, the second level of iteration is with the IFFS main module where the constant cross-elasticity term is updated.

For each forecast year, the supply curve component is reentered to obtain the supply curve for that year. EIA has traditionally used long-run supply curves in modeling coal. Developing short-run supply curves ia a nontrivial task. Price fluctuations caused by the interactions of the spot and contract markets and the planning decision of coal companies must be captured in the short term. That is, the curves must capture how coal companies decide to increase capacity, through expansion of existing mines or by opening new mines. Richard Gordon will discuss the methodology and the status of the supply curve component of the coal module in a later section of this report.

Figure 2 shows the major coal fields in the United States. There are three major coal-producing regions: the Appalachian region, the Interior region, and the Western region. The Appalachian region contains mostly bituminous coals. Moving from the eastern to the western United States, the trend is towards lower Btu coal and lower sulfur content in the coal. The Interior region contains bituminous coal fields and also some lignite seams in Texas, Louisiana, Arkansas, Mississippi and Alabama. The Western region contains mostly subbituminous coal with some lignite and bituminous coal.

We would like to superimpose a transportation network over these coal supply fields. Figure 3 shows the major rail lines in the United States. The rail lines are fairly dense in the East and quite sparse in the West, reflecting less competition among railroads in the West and the potential for exceeding rail capacity as Western coal production grows.

The major barge routes are represented by Figure 4. They are on the Great Lakes and the Ohio, Tennessee, Mississippi and Tombigbee Rivers. There are also barge routes going from New Orleans, Louisiana to Florida and collier routes supplying New England from East coast ports.

The coal transportation module of the IFFS model contains a detailed network of about 725 links representing all mainline railroad routes and major barge routes (Figure 5). Oceangoing routes for the coal export market are also represented. The rail routes represent movements by unit trains for the utility market, multi-car movements for the industrial market, trainloads for the metallurgical market, and single carloads for the residential and commercial markets. There are about 285 nodes in the model representing loading points, unloading points, rail intersections and rail barge transshipment points.

The rail costs are a function of (1) distance on the link, (2) terrain, (flat or mountainous), (3) congestion, (bottlenecks in cities or congestion of barges on rivers), and (4) competition of parallel lines (rail versus rail or rail versus barge) (Figure 6). The base rates are also calibrated to historical data. Currently, 1982 rates are used in an attempt to capture the initial effects of the Staggers Rail Act of 1980, which provided the first step towards deregulation of railroads.

The base rates represent both coal and non-coal movements. They are escalated for congestion by a function that depends on the tonnage moved and also the capacity of the line. The congestion factor serves to divert coal shipments to longer routes as the flow increases.

The transportation module is complete. Two improvements are anticipated. The first is to add coal slurry pipelines to the network. Currently, there is one pipeline in operation--the Black Mesa. The second improvement is to imbed a network of long-term contracts as lower bounds in the module.

The demand interface module has two purposes (Figure 7). First, it aggregates and disaggregates regional demands and coal types. Second, it contains a condensed demand equation that allows the coal module to be solved independently from the rest of IFFS. The demand interface module is not complete.

In case the sophistication of the coal module dramatically increases the running time of IFFS, two alternative methodologies have been proposed (Figure 8). One is to use a function that can be calibrated to the entire coal module--sort of a pseudo data approach. The other is to use a combination of the two approaches where the entire module will be used for, perhaps, the first iteration and a simplified representation will be used for the other iterations.

I've asked the reviewer to focus on three questions. First, which methodology should be used and what other alternatives are there? Second, have we considered the major factors affecting the coal industry in the short term for development of the annual supply curve component? Third, should we represent the spot and contract markets explicitly in IFFS? This would mean a major change, not only to the supply module but to the demand module of IFFS as well. I would like to encourage comments on the coal module since it is under development and major changes can still be made.

COAL MODULE FLOW DIAGRAM

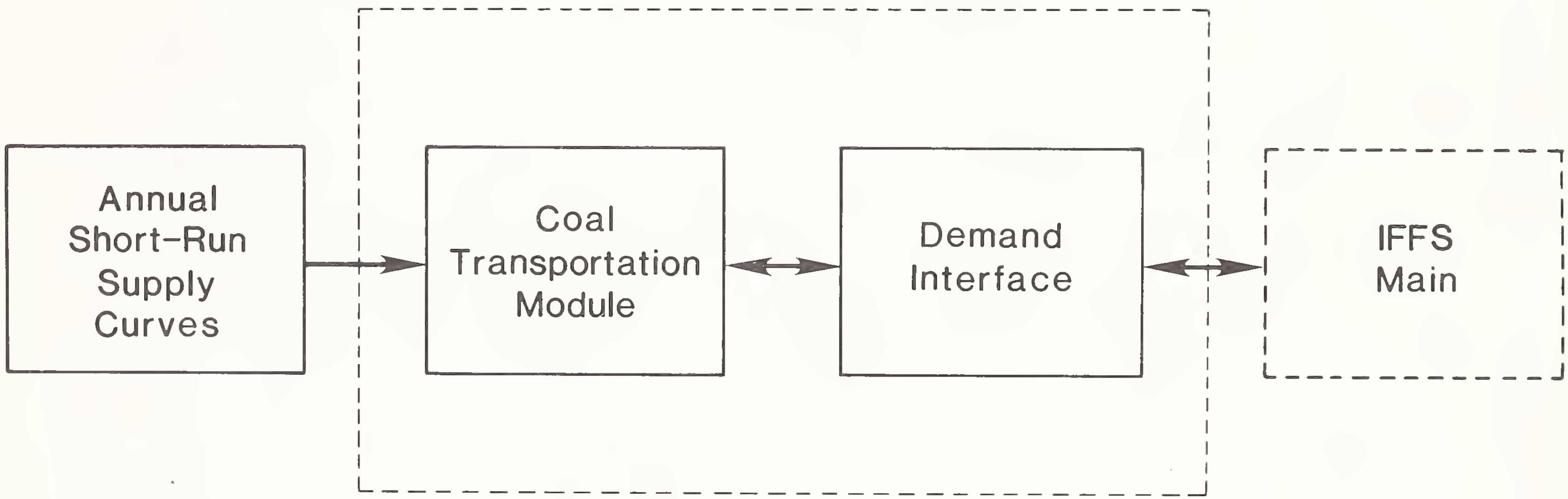


Figure 1

COALFIELDS OF THE UNITED STATES

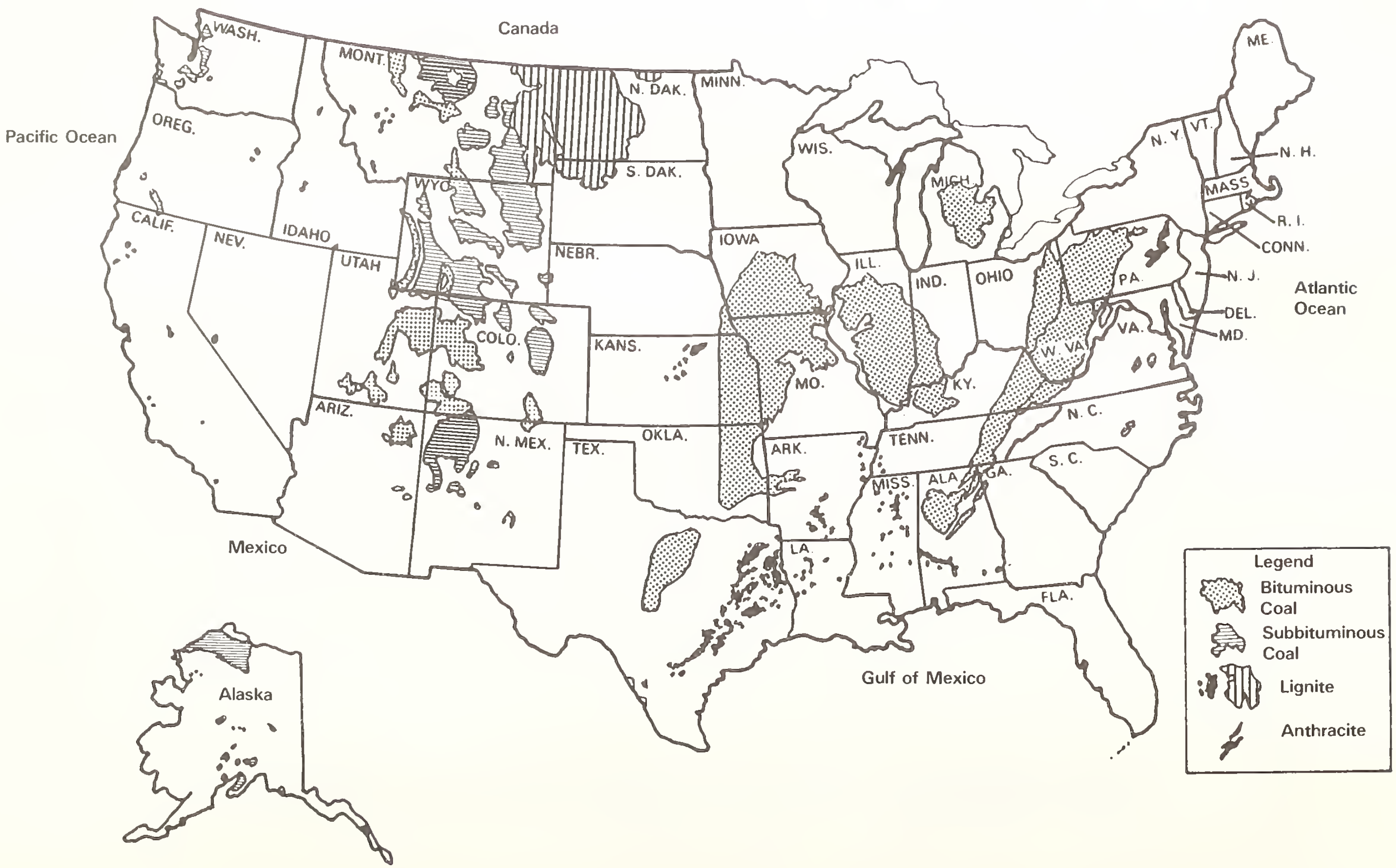
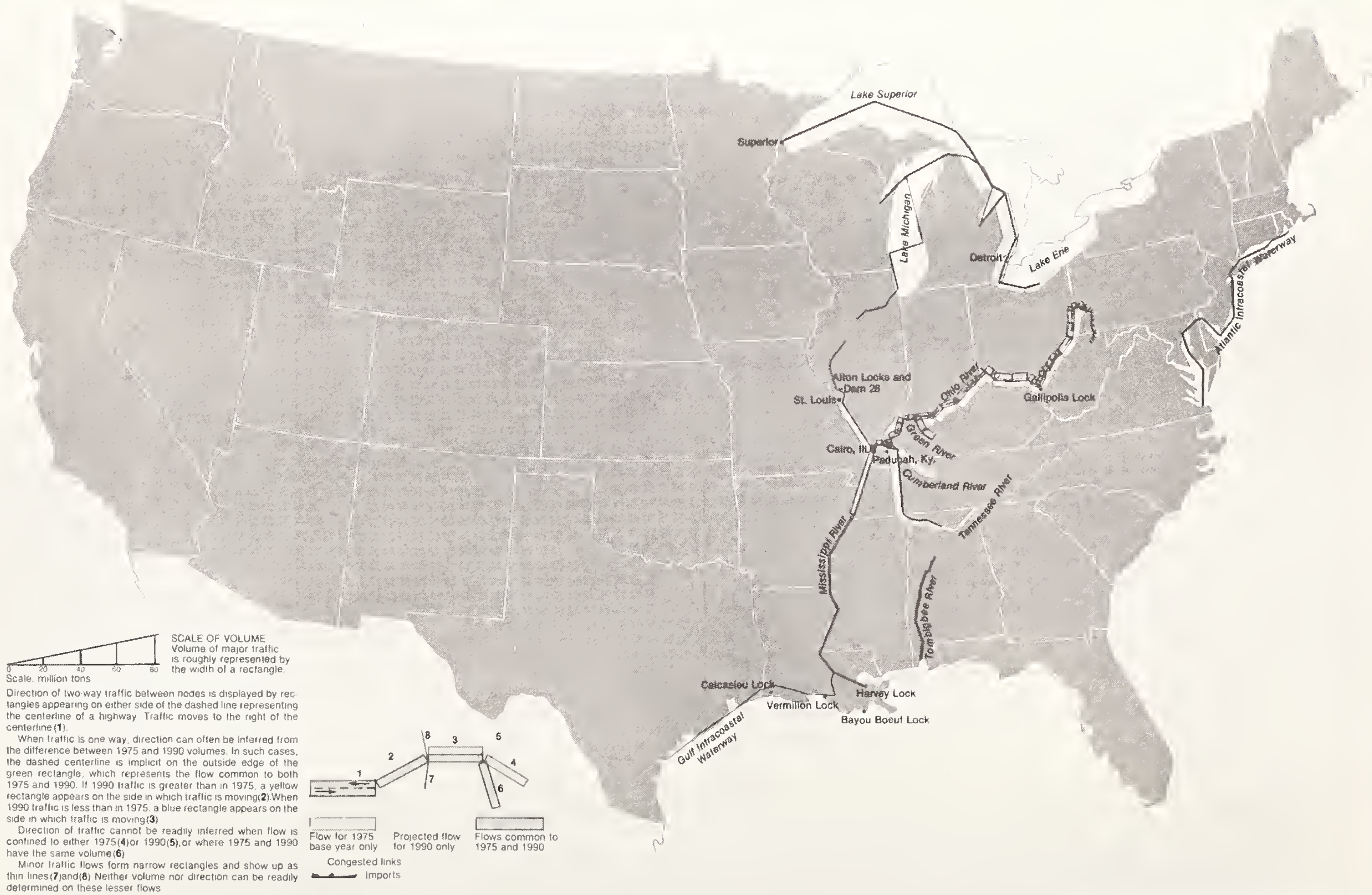


Figure 2

U.S. Rail Network for Coal Transportation

Figure 3



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U.S. Water Routes for Coal Transportation

Figure 4

TRANSPORTATION MODULE

- Detailed Network
  - All Mainline Railroad Routes
  - Major Barge Routes
  - Transshipment Nodes
- Nodes
  - Loading Points
  - Unloading Points
  - Rail Intersection
  - Rail/Barge Transshipment

Figure 5

RAIL COSTS

- Function of
  - Distance
  - Terrain
  - Congestion
  - Competition
- Calibrated to Historical Data

Figure 6

DEMAND INTERFACE

- Aggregates/Disaggregates
  - Regional Demands
  - Coal Types
- Contains a Condensed Demand Equation

Figure 7

ALTERNATIVE METHODOLOGIES

- Simple Function Calibrated To the Detailed Coal Module (Pseudo-Data Approach)
- Combination of Entire Module and Simple Functional Representation

Figure 8

IFFS COAL SUPPLY MODEL

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This paper sketches our long-run goals for coal supply analysis. The actual work was at a preliminary stage at the time of the conference and subsequently it was decided to concentrate on simpler first approximation analyses in the present work and delay implementation of the more elaborate approach noted here until later in 1983. To suggest what we are attempting to do, let me sketch, very briefly, coal supply analysis as it presently exists.

IFFS, and for that matter, all forms of mineral supply analysis have to involve two processes. The first is devising the relationship between mining characteristics in the broadest possible sense and the supply price of coal (or whatever other mineral is being treated). Thus, in existing models such factors as seam thickness, the size of the mine, the depth of the mine, and the method of mining are included as determinants of the required supply price.

The second step in the analysis is to estimate the amount of coal available that possesses given combinations of mining characteristics. The usual starting point for coal supply analysis is the Demonstrated Reserve Base--an estimate of the magnitude of the best delineated, most readily mineable portion of U.S. coal resources. Reserve base data were originally reported in several detailed U.S. Bureau of Mines reports. EIA has provided annual updates. The Reserve Base provides little information about the mining characteristics of the reserves. Analysts, therefore, have tried to piece together ways to deduce ways to assign reserves to characteristic classes.

By taking these two steps, we have a supply function. Over the years I have said much, often highly critical, about this supply estimation process. However, I would say that generally speaking it has been sensibly done, cleverly executed, and gives plausible results despite its faults. This appraisal applies, for example, to the work done in the original National Coal Model and its supply curve component RAMC and to the various modifications of RAMC, both by EIA and its contractors on the one hand and ICF Incorporated, on the other.

A quite different but equally well-done approach was taken by Martin B. Zimmerman of the Massachusetts Institute of Technology. I am less impressed with the originality of most of the other studies that have become publicly available up to the end of 1982. Most are imitations, often admittedly, of RAMC or Zimmerman. A more impressive contribution has been made in studies to develop mine costing rules for use in appraising a specific mining project. Bonner and Moore did one such study on surface mining for ERDA; NUS did another for EPRI covering both surface and underground mining. These studies provide more complex analyses of the determinants of cost than do RAMC or Zimmerman. In particular, NUS and Bonner and Moore try to incorporate all the major cost influences. The NUS model, for example, deals with such factors as roof and floor conditions in underground mines. The costing rules are more realistic but require even more data than are readily available.

With all the virtues of the existing systems, they have one characteristic that becomes problematic when you move to a forecasting system such as IFFS. IFFS involves moving forward year by year from the present. There is little or no tie to the present in the existing models. In particular, there is limited use in coal supply analysis of the great mass of available data on historical performance of the coal industry. Data, such as all the EIA coal and energy data systems, EIA's utility fuel purchase reporting system, the MSHA data on individual mines, the detailed reports by the individual states, and finally, the various information that people in the private sector (such as Coal Outlook and McGraw Hill's various services) make available.

The neglect is understandable. The data systems contain an overwhelming amount of material that, under the best of circumstances, would be difficult to handle. The mass of inconsistencies and gaps and the inaccessibility of much of the material are further barriers to use. Conversely, the time emphasis in existing models has been on 10, 20, or more years into the future, a period in which the details of the past are rather irrelevant. Thus, it has not seemed worthwhile to plow through the indigestible mass of available historical material.

As I indicated, this is not the case with IFFS and that is why we are proposing an alternative, more data-driven approach to a supply estimation. As with most of the people who have been talking about supply development work, we make the distinction between a supply expansion module, on the one hand, and a mine operating module, on the other hand.

For both modules, we will build on principles established in prior work, particularly in our approach to costing. We believe existing methods such as the various versions of RAMC and the NUS model provides a framework on which we can rely. We are particularly interested in seeing the adaptability of the NUS methods for our purposes, but we will also work with the latest DOE version of RAMC.

The critical problem in our work is in developing a more realistic characterization of the attributes of the coal industry as it presently exists and as it will expand, incrementally year by year, over the next 10 years. This characteristic is most relevant to our assignment of quantities given prices over this 10 year period.

It is here that we want to draw upon as much of the available data as we possibly can. Those of you familiar with the data base and its great magnitude and fragmentation will realize that we could not, at this stage of the game, effect the incorporation of all the data that I have mentioned. We, therefore, will focus on the more readily available information on the characteristics of existing mining operation.

Where the mines are large and visible, we will, in fact, try explicitly to model them. Where there are a large number of mines in a category, such as the smaller mines in states such as Kentucky, Tennessee, West Virginia, and Pennsylvania, then we will model generic mine types. One way or the other, we will get, from readily available sources, descriptions of the characteristics of these mines in terms of their size, seam thickness, depth, methods of mining and similar information as a basis for data to go into a costing model such as that of NUS. Initially, we are going to assume that coal is produced as a composite commodity and has a composite price.

We have already done extensive work analyzing the data reported to the Federal Energy Regulatory Commission on the cost of fuels to electric utilities. This has produced estimates of how coal prices vary with coal characteristics. The effort to simulate the evolution of the coal industry by use of detailed data would produce estimates of the price of a coal having a Btu and sulfur content equal to the average for the supply area. The work we have done on rules showing how the prices in the region vary with Btu and sulfur content then would be used to produce the estimates for the different coal types actually included, as Ms. Hutzler has noted, in IFFS.

We obviously have much work to do to implement these goals. We expect that as this full proposal is implemented important contributions will be made in the form of an interesting alternative way to approaching coal supply in this project for EIA.

COAL SUBSYSTEM: A CRITIQUE

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This critique addresses design options of the Coal Subsystem. In particular, the following issues are discussed:

1. Does the coal subsystem contain too much or too little detail?
2. Should the subsystem include an explicit representation of the contract spot market differentiation?
3. Should the supply curves be integrated as stepwise vectors or represented by equations?
4. The "excess capacity" question.
5. The migration of coals among categories as a result of preparation.

Level of Detail

As constituted, the subsystem contains 30 types of coal, 31 supply regions and 44 demand regions. With regard to the level of detail in types of coal, the greater the number of categories, the greater the difficulity in acquiring and processing data, and in calibrating the system. For the U.S. coal industry, with over 2000 mines in Appalachia alone, a very large number of seams, and considering the inherently difficult process of measuring reserves, the raw data from the Bureau of Mines (BOM) may contain significant errors.

Similarly, a complaint often heard from industrial sources is that the BOM data for reserves do not contain sufficient information on the other important characteristics of coals such as grindability, fusion temperature, trace elements, etc. Thus, the detail is built solely on the dimensions of BTU and sulfur content.

Having substantial degrees of detail also opens the problem identified as issue No. 5 above: the migration of coals across categories. If, for example, Southern Appalachian coal, normally mined for coking purposes, can also be sold in compliance markets, how does one represent such a practice? Probably more serious is the movement of coals among steam coal categories. It is, according to Schmidt, quite feasible to take a moderate sulfur coal and clean it to compliance standards, and, in the process, raise the BTU content by the reduction of ash. The degree to which sulfur can be removed depends upon the mix of pyritic and elemental sulfur, information which is not normally available. In the relatively short term, the ability to do so depends upon existing capacity for deep cleaning and upon the cost of the process relative to the price of coal. As a result, it will be necessary to obtain information on capacity and costs for coal preparation of various degrees of cleaning. Thus, if the purpose of greater detail is to obtain greater accuracy, there are serious questions as to whether the lack of necessary information to characterize coals will lead to errors. It may be more efficient to use fewer coal categories: e.g., three heat content and three sulfur content ranges, reducing the necessary data by two thirds and the computation by a significant amount.

With regard to geographic detail, the use of 31 supply and 44 demand regions appears quite reasonable.

Contract and Spot Markets

Contracts between domestic coal buyers and sellers are enforceable. These contracts carry prices which are normally based on a negotiated base price and escalators tied to mining costs. As a result, transactions tend to be rigid and the physical flows in the system may be expected to have substantial inertia. When relative prices change, reallocation is highly damped. Thus, even if the system is at an optimal solution in one year, given a change in relative prices, it is highly unlikely to remain in an optimal position in the following periods. Any model system that represents the coal markets must include a representation of the contract stratum of the market. If a system is used without such a dampening mechanism, the model will tend to show much more rapid shifting among supply sources than actually occurs.

It may be useful to understand why this inertia comes to exist. Briefly one may point to three causes:

- Boilers are normally designed for relatively narrow ranges of coal variation, especially boilers in large power generating units. Thus, continuous supplies from the same seam reduce the fuel use problems faced by the buyer.

- In utilities and large captives, reliability of supply is a paramount consideration, in many cases overshadowing price.

- Habit.

In the future, we may expect an increasing tendency towards captive mines. In metallurgical coal, captive mines have long been predominant. However, the regulated nature of utilities has tended to provide an obstacle to electrics owning mines. We expect a slow emergence of the utility holding company which can effectively remove the mine from the regulatory commission's aegis and, considering the dominance of supply reliability, captive mines will increase. In a modeling system, one way to represent such a mine-utility relationship is by a very long contract. As more mines are owned, we may expect the average life of contracts for steam coal to lengthen.

On the other hand, the spot market, which represents a relatively small proportion of the steam coal market and a very small proportion of met coal, tends to show a highly volatile price behavior.

Implications of the Market Structure

Average prices are of little value in analysis, especially short term. Contract prices tend to be tied to mine costs and therefore do not, on the whole, reflect market movements. Spot prices react to market movements, and the ability to obtain spot prices information on a consistent basis appears difficult.

These results stem from the fact that the elasticity of supply with respect to price appears to be significantly higher than the demand elasticity. Also, the rigidity in demand is institutionalized by the contract system.

Problems in Modeling

If one is to introduce contract/spot strata into a coal modeling system, a number of issues need to be considered.

Contracts should be recognized as containing two basics — price and volume. To characterize a contract segment of the market, it is necessary to obtain empirical information on (1) the average volume lives of contracts; (2) how much coal is contracted in various areas? (3) how "hard" are the contract terms i.e., are there min-max offtake bands and how wide are they? Obtaining such data tends to be a considerable task, especially as the regional detail increases.

Supply Curves: Numeric vs. Analytic

The choice of numeric, stepwise supply curves derived (from geologic and engineering information) versus an analytic equation approach is by no means clear. It appears necessary to derive the former so as to be able to estimate an equation. Numeric supply curves exhibit complex shapes which may be difficult to estimate. Moreover, the equations are not easily understood by industry analysts — there being, of course, the exceptions. However, the information required in computation is greatly reduced by use of an equation, and the modeling process can be simplified.

Thus, if computational capacity is not a constraint, and if the model is to be discussed outside of the immediate circle of its architects, numeric methods are likely to be preferred over analytic. Numeric methods also allow explicit consideration of depletion.

Short Run vs. Long Run Curves

The issue here is the feasibility and desirability of developing short-run cost (SRC) curves. A common source of concern is the observed behavior in market contractions where there is a shift down a much steeper SRC curve, a behavior consistent with standard micro theory.

How then can a SRC curve be estimated? It appears that a picture of the existing debt structure of the industry in different regions could be obtained by survey, and at least rough estimates of the cost structure of mines could be represented. It would then be necessary to determine if spot market suppliers face the same cost structure as the representative mines. Thus, the construction of SRC curves appears feasible, but probably expensive.

The desirability question is another issue. Development of SRC curves for 31 regions and several types of coal is a significant task, and integrating a set of curves into a fully described coal model, as DOE presently envisions, would complicate the system substantially. Moreover, it is not clear as to what information would be gained that could not be gained from a separate analysis of the financial structure of the industry.

One aspect which the SRC curves and their construction would shed light on is the excess capacity issue. Indeed, capacity in any natural resource extraction industry is a hazy measure at best. However, one suspects, on the basis of information for individual mines, that maximum capacity and optimum capacity are significantly different. While excess capacity in the true sense of redundant capacity at optimum mine operating levels probable exists in the high sulfur Illinois Basincoals (due to demand shift caused by the Clean Air Act and subsequent amendments), it appears that most of what is viewed as excess is simply the difference between optima and maxima. Thus, it is not a temporary phenomenon depressing prices, but is probably a permanent one which has little to do with prices.

Discussion

Mr. Todd: Mary, do you have anything you would like to add to the reviewer's comments?

Ms. Hutzler: I would like to respond to two issues raised by the reviewer. First, we do consider the metallurgical coal market. The scaricity of documentation that was provided to Michael must have misled him on that point. The other issue concerns the spot versus the contract market. I do agree that we should look more closely at representing them explicitly in the coal module. However, as I said previously, it is not a simple task because the IFFS demand module would need to represent stocks explicitly, particularly within the utility component. It would mean a major overhaul of the present structure of IFFS.

INTRODUCTION TO THE ENERGY-ECONOMY INTERACTIONS

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Let me start out by refreshing your memory about the purpose of this modeling effort. One possible purpose for building a modeling system like this would be to provide input to the very important considerations of the Treasury Department, the Council of Economic Advisors, the Federal Reserve Board, the Department of Commerce, and so on, as well as the Department of Energy. That is precisely the opposite of the orientation that we have chosen.

Our intention here is to analyze the impact of alternative energy policies with other policies fixed, in other words, with monetary and fiscal policy in place. That is not to say that monetary and fiscal policy is irrelevant to the evaluation of alternative energy policies. But the policy levers that people who are consuming the output of this system manipulate are not those of monetary and fiscal policy. They are those of energy policy alone. The problem we face is to obtain a realistic assessment of what monetary and fiscal policy will be. We will then attempt to analyze the impact of different energy policies against that background.

Our point of view is that what is relevant to the analysis of energy policy is relative, rather than nominal or absolute prices. What matters from the point of view of energy policy impacts, given monetary and fiscal policy, is what happens to the price of energy relative to other prices -- for example, energy prices relative to the wage rate, energy prices relative to the price of capital, and so on. What consequences does this have for the growth of the output of the economy and for the composition of its output?

The strategy that has been adopted in order to achieve these objectives is portrayed in the view graph*, where it is appropriately labeled Systems Design. The basic design is a modular design which is intended to provide self contained models that can be used either by themselves or in cooperation with other models to produce analytical results. You have already heard a great deal about some of these models today. You have heard a detailed description of IFFS. You have heard references, at least, to the demand system. I am going to focus on the economic models. The purpose of this module of the complete system is to analyze the impact of energy on the economy and to analyze the feedback from the economy through demands for energy into the composition of energy supply.

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*See Figure 1

The modular structure I have mentioned plays a very essential role in the design. The purpose of this structure is to make it possible to manage the individual model components in an efficient way and to use only those components that are relevant to a particular analysis. Each of the components, as you can see, is developed by those that are, hopefully at least, expert in a particular area. Economists can take responsibility for the economic models. Energy analysts can take responsibility for the demand system, and so on.

In terms of flexibility of application, it is possible to select the models, or modeling system, that are appropriate to a particular kind of analysis. For global analysis, involving a complete energy analysis of the type that would be characteristic of the annual Administrator's Report required from the Energy Information Administration by statute, it is necessary to use the whole modeling system. Given a global analysis, which would not be done frequently, the modeling system provides the capability of doing analyses that are smaller in scope. In these smaller analyses, fewer inputs are changed and only part of the total output of the system is recomputed.

One mode of analysis illustrated by the view graph is the mode of economic impacts, where one would attempt to focus on the economic implications of a particular change in energy policy. It may turn out that some of those economic impacts have to be analyzed by tomorrow morning because the Assistant Secretary is due for a meeting with the Secretary, or maybe the relevant officer of OMB, or perhaps, someone in the Congress, and needs a quick response. Of course, one has to be in a position to respond quickly.

The flexibility of this modular approach is that one can select the appropriate tool for each task. This requires that the managers of the system must preserve flexibility by having links among the different models. These links must work in a fairly automatic way and must provide for the capability of combining the models for different purposes in an effective and efficient way. For this purpose it is necessary to link the models in a way that provides a picture of the basic feedbacks among the different components of the model. The linkage has been discussed in detail in the paper which is being written for this symposium on energy-economic modeling.

With regard to the general philosophy of linking models of this type, I would be remiss if I fail to mention my paper with Kenneth Hoffman, as a classical reference. Even those who haven't read it might find it beneficial to do so. A much more recent version of the story that is more extensive and more informative, I think, because it covers a wider scope, is the paper by Hogan and Weyant that discusses linking different models. In the system that we're dealing with here, we can see that the basic purpose of the energy part of the modeling system, which consists of IFFS and DAS, is to produce, as outputs, world oil prices, oil imports quantities, prices of delivered fuels, and quantities, and levels of operation of new energy technologies and their costs.

The purpose of the economy part of the system, is to take the output of the energy part of the system to produce impacts on the real GNP and on changes in relative prices -- prices, for example, of GNP versus wages, or prices of energy versus capital, and so on. The economy part of the system produces a breakdown by different industries where that is required, produces interest rates or rates of return and generates disposable income. Those outputs are fed back into the energy system; hopefully, the two can be brought into some kind of consistency.

I would like to turn next to the economic models themselves. There are two models in the complete modeling system. The two models that are used for the economic module of our system are models that differ in one fundamental dimension, that is, whether or not it's necessary to break down energy into its components and to deal with the price of electricity relative to natural gas, or the price of oil relative to coal, or, in general, the price of any specific fuel relative to another fuel. If that is an issue in the analysis in question, then the model of choice would be DGEM, the Dynamic General Equilibrium Model, which is a nine sector model that distinguishes among five different energy sectors that include the four primary fuels and electricity.

Let me mention the capabilities of the DGEM modeling framework. If the word had not been used for a completely different purpose, you might think of DGEM as a supply side model. But, it is not a Laffer supply side model. It covers non-energy production and breaks it down into four components -- manufacturing, services and trade, agriculture and transportation. It includes a household sector so that it contains an endogenous explanation of the breakdown of personal consumption and the final demand patterns that result, and, also, analyzes saving patterns and finally, it provides a way of incorporating energy effects, like those that I just mentioned, on the prices, inputs and outputs and spending on the non-energy sectors of the economy.

Mini-macro is a small model which has only about 20 equations. It is a relatively small system and is an attempt to deal with issues, as I mentioned before, that focus on energy prices as opposed to non-energy prices. Mini-macro attempts to deal with the issues in which the impact of energy can be adequately summarized by a single energy price and quantity as opposed to the breakdown of the type provided in DGEM. Mini-macro is like DGEM in the sense that it is a neoclassical supply side general equilibrium model. It's relationships are modeled on those in DGEM as well as other well known relationships.

Next, I would like to describe very briefly the modeling framework that is appropriate where relative prices of different fuels, say, electricity versus primary fuels, are germane to the analysis in terms of the economic impact. I would like to talk about DGEM very briefly and to describe its critical features. As I say, it has four non-energy producing sectors, five energy supplying sectors and a feature that you may not recognize from our earlier work, five new energy technology groups, one for each of the energy supplying sectors. These are essentially activity analysis representations of new technologies that substitute for existing fuels -- for example, synthetic oil in place of oil, synthetic gas in place of gas and so on.

There are four categories of final demand in DGEM and three primary inputs -- capital, labor and imports. These are analyzed in terms of a supply-demand framework. The nine products and the three factors of production are determined by markets that have to be cleared by means of prices. That means that we can only determine, for example, employment. We can't determine unemployment. It is also that case that we can determine the amount of capital which is actually used in terms of the capital service flows. There is no concept here that you would think of as capital utilization.

DGEM is a neoclassical general equilibrium system which acquires a dynamic character through the equilibration of saving and investment by means of the rate of return. In general, increases in the rate of return will increase saving as a proportion of wealth. That creates additional capacity for the following period. You should bear in mind that the time structure of a growth path in a neoclassical model is characterized by fixed capacity in the short run. The amount of capital on hand is unchangeable. It's an immutable constant of nature at the time that an analyst enters the scene. If you want to use economic terminology, you have a vertical supply function for capital in the short run.

By contrast, you have a horizontal supply function for capital in the long run since we have a saving function that represents optimization over time. The rate of return appropriate for saving behavior always reestablishes itself in a sufficiently long run. In between the behavior of the model is determined by this gradual shift from a vertical supply function to a horizontal supply function, which takes from 10 to 12 years. So there is a process of dynamic adjustment that is built into this highly neoclassical story.

The other features that are extremely important to the qualitative character of the model output are those that involve productivity. Output per unit of input is an endogenous variable in the model and is dependent on relative prices. Of course, the quantities of the inputs themselves result from substitution among the different fuels and substitution between energy and other things in terms of the relative prices of those inputs.

The message I would like to have you carry away is that the advantages from using DGEM accrue from the fact that the energy information that can be produced by the IFFS system and by DAS is very complete. In particular, it provides separate prices and quantities for the individual fuels. To make use of all that detail, it is essential to use DGEM. On the other hand, if that detail is unessential, or if you don't have time to take account of the detail because the Secretary wants an answer by tomorrow morning, then it is necessary to make use of a more aggregative approach. The aggregative approach has the advantage of being a lot cheaper and easier to use.

You can think of the basic framework of mini-macro as one in which nominal GNP depends on the money supply. That is a very common point of view in Washington these days. Nominal GNP is divided between the price changes and quantity changes in a way that is responsive to energy. When we determine the rate of inflation and the level of real GNP, we can then break it down into components that reflect the production structure of the economy at a very highly aggregated level. That, of course, includes determination of investment which determines future productive capacity. The rate of inflation itself determines the momentum, so to speak, in the price system that then becomes part of the future inflation.

My overall conclusion is, then, that we have a very highly modular system. It is possible to look at the energy sub-system of the economy in isolation by focusing on the IFFS modeling system on the supply side and the DAS modeling system on the demand side. The new feature of the system is the addition of an economic module that is part of the same system. This module can be operated and managed within the same apparatus here at EIA. This makes it possible to augment the energy modeling system by providing feedbacks from energy to the economy and from the economy to energy. This reflects one of two different kinds of information that would be relevant to an economic analysis.

One mode of analysis would involve the energy prices and quantities in total. These totals can be used to structure a macroeconomic scenario. The other mode of analysis involves a more detailed story about the role of specific fuels. The relative prices of different fuels would come out of the use of IFFS and DAS. For that purpose we have a model, DGEM, that absorbs that detail, spins out an econmic story that corresponds. The results can be fed back into a complete system. The complete system provides a supply-demand picture for the economy in which prices are determined along with the quantities. The prices and quantities are determined not only for energy and for all the non-energy commodities, but also for the factors of production -- capital and labor.

Of course, we can exit here to economic impact analysis and we can take the detailed output of the economic models and spin out a story about welfare impacts. That is to say, we can find out how good a particular outcome is from the point of view of the national objectives that have to be served. Economic impact analysis, of course, is the final goal, the bottom line, of the modeling system that we described here.

SYSTEM DESIGN

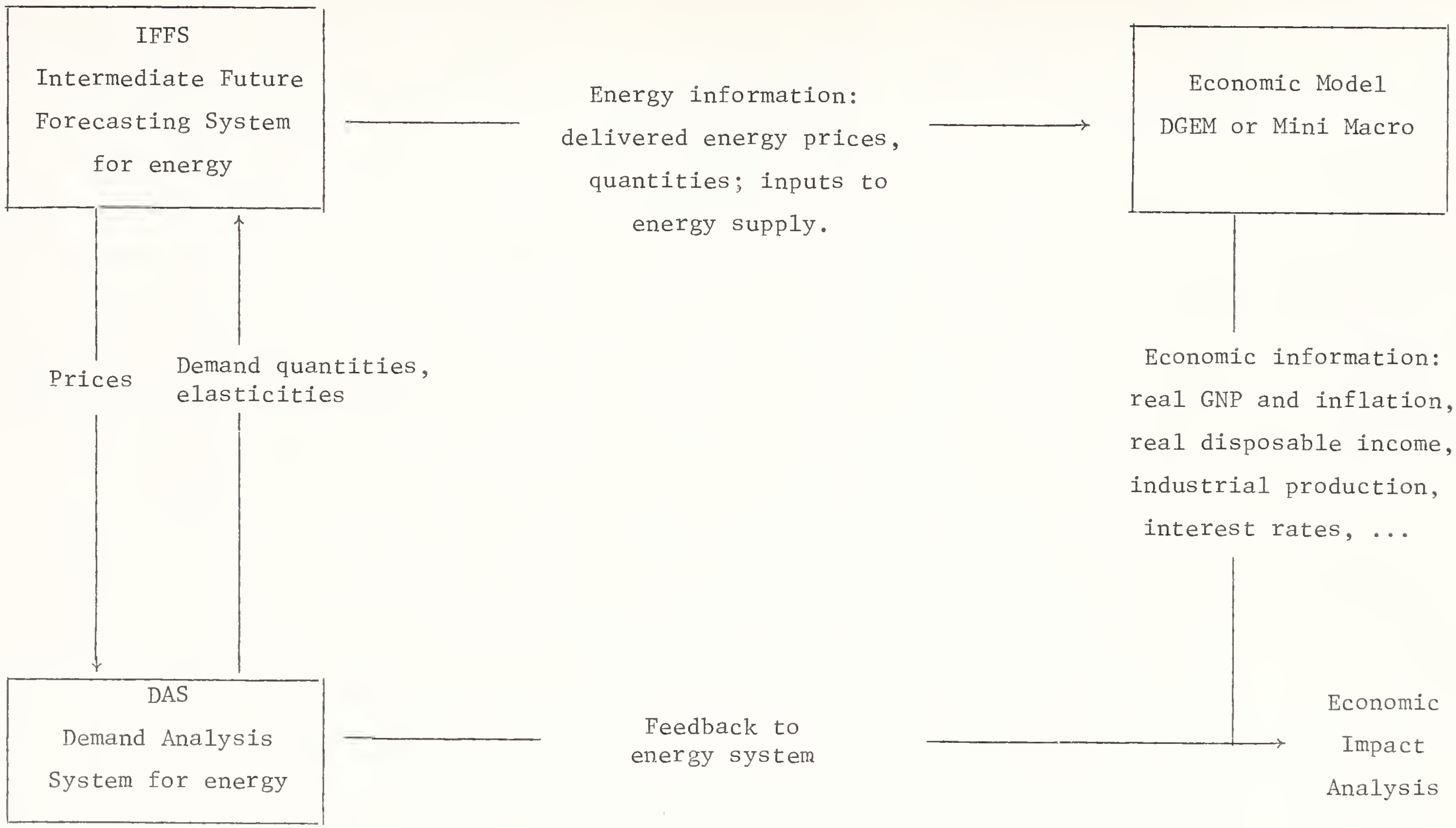

Figure 1

ENERGY-ECONOMY INTERACTIONS--A CRITIQUE

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You may well ask, what am I doing here? It is fair to say I am an outsider compared to everyone else on this program. I am not now, nor have I ever been, a contractor for the Energy Department or its predecessors. I opposed the creation of the Energy Department and I support its abolition. I am a free-market economist when it comes to energy issues and an opponent of federal intervention in energy markets. That much I have in common with quite a few other economists in this room. What may set me apart is that I am a little concerned about federal surveillance of energy markets. There is a question in my mind, for example, whether we should even have an EIA.

Let me try to give an outside macroeconomist's perspective about how you would go from thinking about energy issues in particular to thinking about the macroeconomy in general. I think it's a good idea to look at these issues at this point in the conference. So far, we have had presentations where energy economists are making their way into the tough issues of macroeconomics and it's probably good to hear from a macroeconomist who has done the opposite, namely invade the territory of energy economists.

I want to start by discussing what kinds of questions might be answered with the type of analysis we are looking at today. Bill Hogan and others have mentioned that it's easy to get wrapped up in the modeling details and to fail to keep in mind why we build these models and what type of advice we would like to derive from them for policy makers and the public. It seems to me that there are two rather specific classes of questions we would like to answer in the area of energy-economy interactions. The first one is, what happens to the domestic economy when world energy prices change dramatically, as they have in the past decade? In particular, what can we say about the effects of those changes in energy prices on output and income?

The second class of questions has to do with energy policy. What happens to domestic economic performance as we change energy policy? What happens to output, income, interest rates, employment, investment, and all the other variables that we care about, as the different knobs of energy policy are turned?

Free-market ideas have dominated energy policy under Presidents Carter and Reagan. I applaud this liberalization, but it raises questions about what will happen to the macroeconomy as the result of shocks that come from changes in policy.

I am going to depart from the format of other speakers and say a little about what I think are the answers to some of these questions. I will speak as a macroeconomist who has thought about energy issues but I will not be giving results from a particular quantitative model. I have dabbled with models but have never reached the point where I would want to use those models to speak to policy questions in public.

To take the first question, suppose that the world oil price rises. The first effect on the U.S. is obvious, though its magnitude is sometimes misunderstood--U.S. real income falls when the world oil price rises. The reason is simply that the U.S. is a small importer of energy. Higher world oil prices have an adverse effect because we are an importer. Were we an exporter, the situation would be the opposite--real income would rise as world energy prices rose. The point I want to stress is that the effect on U.S. real income is not very large because we are close to self-sufficient in energy, so changes in energy prices have close to a neutral effect.

Of course, the net effect of close to zero carries with it very important redistributional effects. The owners of energy resources become better off and the consumers become worse off.

The second point I want to make is one where complete misunderstanding has reigned. Full employment output, measured specifically as real GNP, should not be affected to a first approximation by world energy prices. Prices don't affect production functions. The capacity of the U.S. economy to produce is not hurt by higher energy prices and it's not helped by lower energy prices. Furthermore, a characteristic of the concept of real GNP is that even when more expensive energy causes the U.S. to substitute away from imported energy and towards capital and labor as ways of producing, that substitution should not affect real GNP, again to a first approximation.

An immediate implication of the small theoretical effects of energy prices on U.S. macroeconomic performance is that the very poor performance of the economy in the 1970s can't be blamed on higher energy prices in any obvious way. If poor performance has something to do with energy, as many macroeconomists including myself suspect, it is not a first-order effect. A straightforward neoclassical analysis of the type embodied in the most respectable work on energy-economy interactions is probably not going to give the answer. We can anticipate that disappointment without doing the research.

Where should we turn in building models that give sensible answers about the impact of energy prices on total output? The crucial message I want to convey is that full employment is not a good way to think about the economy with respect to energy issues. We especially are aware of that point today with the unemployment rate close to 10 percent. Unemployment has been a severe problem in the U.S. economy since the first increase in energy prices in 1973-74. We have failed to achieve consistent full employment ever since.

The obvious conclusion is that higher energy prices induce economic slack. If that's true, it has a very important implication for energy-macro modeling. Any model that assumes full employment is going to miss the biggest point. A market-clearing, neoclassical model can't handle the dominant way that energy prices influence real GNP.

I would guess that the costs of the short-run dislocation, increase in unemployment, decrease in real output, and other effects of energy prices not comprehended by a neoclassical model far exceed the long-run costs from the terms of trade effect and other effects that are included in a neoclassical model. The hundreds of billions of dollars in real GNP we seem to have lost in the past decade from economic slack far exceed the terms of trade effect. Even though the recessions brought on by energy shocks are short-run phenomena, they are tremendously expensive. Therefore, I would plead for consideration of the short-run macro issues on the same level as the longer run issues that have occupied most of the attention in this area so far.

Why does the economy undergo recession in the face of an energy price increase instead of behaving in a neoclassical way and remaining at full employment? The finger points to wage and price rigidity. That's the key macro issue. The role of energy prices seems reasonably clear. Higher energy prices drive up the prices of all products containing energy directly or indirectly. In a neoclassial full-employment model, higher prices of energy-intensive products would occur, but prices of other products would fall correspondingly, and, in particular, wages would fall to keep the overall price level about the same. With exogenous monetary policy, the overall price level would remain at its full-employment level.

Flexibility of non-energy prices, especially wages, is not a good description of the U.S. economy. Because wages and other prices don't fall, higher energy prices raise the overall price level. The most striking examples were in 1974 and 1979-80: Sharply higher energy prices brought general inflation, not the deflation in wages and other prices predicted by a neoclassical model. With a higher overall price level and unresponsive monetary policy, it was simply inevitable that real output and employment had to decline.

I think there is pretty substantial agreement among a reasonably wide class of macroeconomists on that basic mechanism. Different macroeconomists have different stories to tell about exactly why it is that the economy functions in that way, but there is good agreement that price shocks for important inputs like energy bring on recessions.

Price rigidity is not an unfamiliar issue to macroeconomics. It has been at center stage in the field since Keynes. And, although the word Keynesian is associated with almost a splinter group in the profession today, in the sense of emphasis on fiscal measures to offset recessions, the thoughts of Keynes on price rigidity are dominant. Many of us are Keynesians in the sense of worrying seriously about price and wage rigidity, even though we are very much anti-Keynesian in our recommendations about economic policy.

Once price rigidity enters a model, many more things become important that weren't important in the full-employment model. The money stock and financial markets become central. In full-employment, neoclassical energy-macro models, money and finance are correctly viewed as footnotes. But once the models venture into disequilibrium and price rigidity, the money stock takes on an important role and deserves much more attention. I am not making a structural criticism of the models on their own grounds. Rather, I am pointing out what a large change will occur when the models are opened up to serious consideration of the recession that an energy price increase brings.

I don't have a strong message about how to proceed at this point, simply because there isn't a professional consensus on why price and wage rigidity is a feature of the economy and how we might go about building models of it. Some macroeconomists today would stick to the idea of a Phillips curve. In some respects it's a discredited idea, yet no empirical regularity has been demonstrated that can replace the Phillips curve as a statement about how the wage and price process operates. There is, of course, the highly developed rational expectations school which says that the Phillips curve is a generalization from particular experience and may not hold in the future if the economic situation changes in other respects. At a minimum, the school has undermined any faith in the idea that a simple Phillips curve is an unchanging feature of the economy. I am a very careful reader about rational expectations and a participant in debates on the subject, but I have not seen anything emerge from the school that would commend itself to be plugged into a model that would deal with the issues that we would want to deal with. Thousands of pages have been published on the subject in professional journals, yet we haven't come to a good answer.

Another issue that matters a lot for the energy-economy interaction model is productivity. Again, productivity has been a colossal disappointment in the past decade. In the postwar era through 1973, productivity grew at quite a satisfactory pace. Since 1973, and especially through the two major oil price increases, productivty has been a disaster. Surely, the price increases had something to do with the disaster. But no simple theory of productivity growth explains the relation. Productivity is a feature of the production function, and, again, factor prices don't shift production functions. We have only just begun to sort out this central issue, but it will be hard to get sensible results from models until we do. If productivity growth has been cut from almost 3 percent per year to below one percent and that situation is going to remain for the next decade or two, that's a much more important fact than almost anything that can come out of a full-employment intersectoral model of the type that has been under discussion in energy work to date. There has been some work on this topic--Dale Jorgenson has been a leader in the area. I don't think we've reached a clear conclusion at this stage but it certainly is an issue that we ought to be thinking about very hard.

Now let me talk about energy policy. First, there is a whole set of policy questions that can be dealt with quite outside of any model of the type that's under construction in the Energy Department. If energy prices are set fundamentally in world energy markets and we do have a U.S. energy market that is small relative to the world market, then we can make a very simple assumption: Policy does not affect price.

For many policies, for example, for anything that has to do with the details of U.S. oil production, we can just take the price as given. Then there are virtually none of the interactions that create all the difficulties in these models. We can price out synthetic fuels, it seems to me, and reach the conclusion that nobody in their right mind would have anything to do with synthetic fuels, without having to do any of the kind of research or build the kind of model we are talking about here. Policy analysis can have a life of its own quite apart from the construction of elaborate models.

On the other hand, some issues require the general equilibrium approach. Natural gas deregulation is an example. Detailed work is required to assure the President when he signs the bill for total cold-turkey deregulation that there won't be a macroeconomic disaster. I'm certainly not persuaded that the models we have built to date are of much value on an issue like natural gas deregulation.

It's important to recognize the intellectual force behind the simple free-market proposition that all we have to do in energy policy is to let free markets do their job. That force is overwhelming compared to anything that is associated with research or modeling acitivty. The appeal of free-market principles in the Carter administration and, perhaps a little less, in the Reagan administration, is very, very strong. The head of steam that free-market policies have today is, I think, a continuing one and will dominate whatever one gets out of models that are under construction in the Energy Department.

Now let me talk a bit about macro modeling issues. In the first place, I think we are on pretty firm ground in talking about the full-employment production side of an analysis of the economy. The work of Hudson and Jorgenson, in its many manifestations today, is widely respected and used by economists and by energy modelers. It's disappointing that even at this date, it doesn't seem to be a part of the EIA's model, but it certainly could be.

The thing that is new, which I read with great interest in the material for this meeting, is that the wage-price rigidity issue seems to be entering the discussion for the first time. But, it has entered at a very primitive level. The remarks in Section 5, the paper on energy-macro interactions, is pretty naive by professional standards. The movement of energy economists into macroeconomics is the mirror image of something that first happened nine years ago, namely the invasion of energy economics by macroeconomists. We suddenly discovered that energy existed and made equally naive statements about energy. Herbert Stein has been quoted as saying that all you have to know to be an energy economist is that there are 42 gallons in a barrel, that Kaddafi is a man, and Qatar is a place.

There is somewhat the same flavor in the energy economists' discussions of what it takes to understand wage and price rigidity. Some of the brightest macroeconomists, Keynes and since, have struggled hard with the issue. It's going to take more than the relatively small amount of attention than it has received so far from energy economists to make progress.

The most highly developed thinking on macro energy issues within a framework of wage and price rigidity is in the quarterly econometric models, which now reside almost entirely in the commercial sector. DRI, Chase, Wharton, and so on, are the only places where energy and price-wage rigidity and the possibility of fluctuating unemployment and departure from neoclassical full employment are taken seriously and put to work. I don't personally have much faith in what comes out of their calculations, but I have a lot of respect for the amount of work that went into the effort. The fact that the effort has been going on for decades and has only reached this stage illustrates how tought the issues are.

Let me mention just briefly that I have done a little work in these ares with Knut Mork, written up in two papers in the Energy Journal. I don't think this research really provides a practical alternative to the EIA models and the quarterly econometric models, but it does illustrate another way to go about thinking about the issue of departures from full employment. What we found was that a whole set of issues beyond the obvious one of wage-price rigidity mattered. The interest elasticity of money demand is central because of the importance of money demand in a disequilibrium model. Short-run fluctuations in productivity are another issue of first-order importance. So are investment lags. The role of the rest of the world, beyond just trade in oil, is critical. Consumption decisions of households matter a great deal, and there is a serious question whether the full neoclassical treatment of consumption is right, or whether we need to recognize some practical limitations on consumption and saving.

I want to close by asking: How will the President be advised on the macro effects of energy? Are we moving in the direction of having a model in the EIA which is sufficiently respected by economists elsewhere to let the model have a central role in policy advice? I would guess not. I think that back-of-the-envelope economics will continue to dominate policy advice. Even though I believe very strongly in the notion of modeling based on serious research, for the moment, I am more comfortable about the destiny of the nation to think that it's the back of the envelope types who still have the President's attention. We are very, very far from having any kind of an energy model in the area of macro interactions that has a real claim to providing usable answers on the central issues of what happens when world energy prices change or energy policy changes.

DISCUSSION

DR. JORGENSON:

Well, let me be slightly unfair to Bob Hall by caricaturing his remarks. First of all, his point is that energy cannot effect the real GNP, at least not to the first order. So it is a great mystery as to what is going on. That is a point that was actually first popularized by Ed Denison and it goes something like this: Energy cancels out in the GNP accounts since it is produced by oil refineries and electric generating plants, but it is used up by other producers who produce automobiles and other things that are delivered to final demand. Since energy essentially disappears when you look at the GNP -- deliveries to the GNP are four percent of the total value added -- it must cancel out.

The basic presupposition of Denison's analysis and implicitly of Hall's, is an assumption that Hall himself analyzes in his earlier incarnation as a neoclassical economist. That is, that production functions everywhere in the whole economy, all 20,000 of them, have to be identical up to a scalar multiple and must be, in fact, value added separable. That assumption, of course, is discarded in the multisectoral approach that I alluded to earlier.

As to whether wage-price rigidity is the key to the problem, that is, the problem of how energy affects the economy, let me simply point to some obvious facts. Since 1973, real energy prices have increased by four-fold. Therefore, the whole key to the analysis cannot be wage-price rigidity. This amounts to using weapons that were built for the Great Depression of the 1930's to solve current problems. What is really critical to energy analysis and to economic impact analysis is the change in relative prices. It is not only the price of energy relative to other prices which has changed dramatically, but it is also wage rates relative to other prices.

For example, real wages in the United States have risen until about 1973. Since that time real wages have remained stable or have fallen, so that we are now at something like 1967 levels. There is no such thing as wage-price rigidity over a period of time even as long as the one that has elapsed since 1973. There is really nothing to be learned from the macroeconomic discussion summarized by Bob Hall that is relevant to economic impacts of energy policy and world energy prices.

Let me just illustrate my conclusion by the productivity conundrum. What is it that generates productivity growth? It is not good theory, Bob tells us, to confuse substitution with technical change. Of course, I couldn't agree more. In the modeling framework that I described earlier, productivity is a function of relative prices. This makes the productivity growth rate itself a function of relative prices. As an empirical fact, higher energy prices are associated with lower productivity growth. That explains a very sizable amount of the productivity slowdown, but not by any means all of it. The point is that our explanation of the productivity slowdown runs in terms of relative prices.

Bob's second point is that there is no point in trying to build any great analytical apparatus since the President only wants to know, what is the free market answer? He doesn't want to fool around with all the details. He doesn't even want to know if the economy is going to collapse. He wants to know what the free market answer is and then we'll let free markets to their job. I don't think that any of us would disagree about that.

One of the most positive contributions of analysis that has taken place within EIA and elsewhere is toward thinking how to undo the mess that we got into when people attempted to use depression-type economics to deal with the energy problem, as they did in the great lamented days of Richard Nixon. You remember that we had a system of price controls that led to energy price controls that persisted for a very very long period of time. Now, of course, Milton Friedman would have said, I could have advised the President immediately that, all he had to do was just get rid of those controls. But, it took Jimmy Carter to start doing it and Ronald Reagan to finish the job in the case of petroleum prices.

A very important role was played, not be depression-type thinking and depression economics, but by the economics of relative prices which showed precisely what the impacts of price controls were -- unsuspected impacts like stimulating the growth of energy imports, distorting relative prices in the economy, leading to greater inefficiency, slowing productivity growth and all the rest. The calculations, in fact, preceded the Carter decision and demonstrated precisely what those economic loses were and put forward a very convincing case. This is reported in the famous EIA study, Energy Markets - Energy Policies, which was a case for free market economics.

So, the conclusion is, that indeed, the President doesn't need an economist, ever. He doesn't need a chairman of the Council of Economic Advisors. He doesn't need Bob Hall. He doesn't need me. He doesn't need any economists who are here in the group. He knows what he wants and I think that is probably true of many presidents. But, in terms of responding to what happens when energy policy changes, if you think about trying to do it with the economic tools that were appropriate for analysis of the Great Depression we are in for a real depression.

DR. TODD: Let me just take a moment to emphasize one thing that Fred mentioned in the beginning of this, but which we may have been remiss in not making clear to people; which is, that the determination of the world oil price is done in a separate system -- a system also in my division, but independent of this. This system, IFFS, assumes the world oil price to be given and worries about some of the domestic interactions issues such as the rate base and electric utilities and things of that sort.

The macroeconomic affects of petroleum supply interruption may also be poorly modelled but, at any rate, are not part of this particular modelling enterprise. This particular enterprise takes the world oil price and the results for initial macroeconomic variables from an independent interaction of a set of models including the DRI model and the OMS model spoken of earlier, and a little bit of envelopes on occasion. That then becomes the input to IFFS which is not responsible for modelling the macroeconomic effects of changes in the world oil price. So, that may escape us periodically as we go through.

IFFS: AN OVERVIEW

by

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I. Overall Structure: The IFFS model is basically a year-by-year partial equilibrium model of the domestic energy markets, designed to provide forecasts over a 5-10 year horizon. IFFS is designed to provide forecasts for the period between the Short-Term Integrated Forecasting System (STIFS) and the Midterm Energy Forecasting System (MEFS). STIFS is used for forecasts of one or two years. MEFS has been used to provide forecasts 5 years in the future, although its major use is for forecasts of 10-15 years. Therefore, substantial overlap exists between IFFS and MEFS. The first question to be asked is whether a new model like IFFS is needed? It seems to me that two arguments can be made in favor of IFFS: (1) MEFS is a quite large and to some extent an unwieldy model to use. IFFS promises to be considerably smaller and easier to operate.[1] However, the simplified structure of IFFS is gained at some cost in loss of regional detail with respect to MEFS. (2) MEFS is an optimization model designed around the solution of an integrating (transportation) model. While some dynamics, especially in the demand sectors, are included in the structure of MEFS, it really is not designed to provide yearly forecasts. IFFS is explicitly designed to provide yearly forecasts. This feature might be quite important in assessing the adjustment of energy markets to changes in regulations like the Natural Gas Policy Act (NGPA) and the Fuel Use Act (FUA). In fact, early versions of IFFS have been used in just this type of policy analysis. To the extent that year-by-year forecasts are useful for policy analysis, a strong argument can be made for a new model. Thus, the IFFS model may well have an important role in analysis of intermediate-run response to changes in energy policy. Macroeconometric models which IFFS resembles in many respects have achieved their greatest success in an intermediate range forecasting interval. Yet a possible weakness of the IFFS framework is its failure to integrate long-run effects of changes in regulations and energy markets on intermediate-run outcomes. It is not clear that a basically myopic model like IFFS will capture successfully the operation of energy markets because it ignores the role of expectations which can have an important effect on current activity. I will return to this point subsequently.

IFFS is a partial equilibrium energy market model which takes the path of the crude oil price as given and attempts to solve for the

[1] However recent developments of IFFS with respect to domestic oil and natural gas supply and integration with a macro model seem to point in the direction of a more complicated structure than the earlier structure of IFFS, c.f. Hausman (1982). Whether the computationally convenient properties of IFFS will remain when these extensions are made remains to be investigated.

equilibrium prices in each year of refined oil products, the various types of natural gas, electricity, and coal.[1] Since oil, coal, and natural gas are used to produce electricity and oil and natural gas are used to produce refined oil products and all the energy sources are substitutes for each other in certain demand sectors, it is clear that an equilibrium exists to find prices such that supply and demand are equated in all the energy markets. A simplified diagram of the interdependencies (excluding transportation) is given in Figure 1. In terms of supply, oil and natural gas often compete for the same resources, e.g., drilling rigs, and are also to some extent produced together with associated products. Overall, the model is driven by the yearly forecasts of a macro-model. Macro models have a limited capability of utilizing the output from IFFS so that a complete integration may be difficult to perform in terms of overall supply effects on the economy.

The solution procedure used for IFFS is to vary one price at a time, holding all other prices constant to find an equilibrium in the market under consideration. When an equilibrium has been found, the solution procedure moves onto the next market, taking as fixed the price in the previous market. This solution procedure corresponds to the Gauss-Seidel procedure for the solution of nonlinear equations. It is often used to solve for forecasts in macroeconometric models. An equilibrium is claimed when prices do not change in any market, i.e., demand equals supply in all markets at current prices. To date the algorithm appears to have worked well, although its performance may degrade as the model size increases.

I see the following problems associated with the partial equilibrium year-by-year approach adopted for the IFFS model structure:

(1) Given the severe shocks and the presence of government regulations we may not observe the energy markets in equilibrium on a year to year basis. An example may be the reported shortage of drilling rigs after a large price jump in the world oil market. Of course, a respected school of economic thought argues that we are always in equilibrium, but it suffices to point out that the reported prices of drilling rigs were unlikely to have cleared the market in the mid-1970's. Therefore, the historical data on which the model forecasts are based may well not represent an equilibrium situation. It is unclear how good a guide to a posited equilibrium future is provided. Also, (unexpected) government regulations or deregulations can have a similar effect on market equilibrium. The effect of natural gas curtailments during the shortage of a few years ago has generated a pronounced effect on current industrial use which may not be well represented in a equilibrium model.

(2) A lack of expectations in the model structure together with its myopic approach to year-by-year equilibrium lead to the absence of an intertemporal equilibrium for the model. For instance, under the current

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[1] Some general equilibrium aspects will be included when successful integration is performed with the macro model 9DGEM. But even here, apart from the energy sector, the rest of the economy is treated in a highly aggregated form.

NGPA significant price incentives exist for production of deep (107) gas due to its unregulated status and the average cost pricing of natural gas. Current drillers of non-deep gas have an incentive to shut-in their gas if they expect that the price rise in 1985 (or sooner) exceeds the rate of interest, after taxes, of investing current proceeds from production. Or producers may not sign long term contracts without provisions for price escalation. Clearly, the expectations of natural gas producers could have a significant impact on current gas supply. Similarly, on the demand side for natural gas, price expectations form an important component of conversion decisions which have led to increased consumption, especially in the Northeast. Unfortunately, the year by year solution approach does not build in these price expectations.[1] Within an equilibrium market model these expectations can be included although the model structure is complicated considerably. However, this lack of expectations and intertemporal equilibrium in the model is an important potential shortcoming.

(3) As currently constructed, equilibrium in the model is found via the price of unregulated deep gas. However, 'shortages' of natural gas are handled by the existence of supplemental gas to which the "price of crude oil effectively places a ceiling on the price of 107 gas in the model". I believe this assumption is contrary to fact because of the average cost pricing and the existence of old low price gas contracts, the price of deep gas can be much higher than the price of crude oil. In fact, I believe that the 1981 price of deep gas was about \$8-\$9 which is over 50% higher than the crude oil price.[2] It is in the best interests of the gas pipelines to 'roll-in' this expensive gas because of the nature of their contracts. It is not clear how well the model would perform if the fiction of supplemental gas were discarded. Yet even if this discrepancy were corrected, it points up an important structural defect of the model. Since the price of oil is taken as given, it is essentially the equilibrium price in the natural gas market which drives the model since electricity production represents a derived demand for all three energy sources. To simplify, we can identify three types of natural gas: old gas subject to long term contracts, new gas subject to the NGPA up through 1985, and deep gas which is unregulated. At least through 1985 equilibrium is essentially found in the deep gas market. But, we have very incomplete evidence on the quantities of gas supply in each category. Educated guesses are made at the amount of old gas under long term contracts, but little hard data exist. Yet the amount of old

[1] Quantity expectations may also be important with regard to electricity capacity expansion and transportation of coal.

[2] The current (August 1982) price of 107 gas is now reported in the Wall Street Journal, Aug. 3, 1982, to be closer to \$6 more in line with the crude oil price. These sharp fluctuations in the price of 107 gas when the price of crude oil has fluctuated about 10-15% illustrate the dangers of basing model equilibration on 107 gas and a price ceiling on "supplemental gas".

gas is a crucial determinant for prices and supplies of new gas because of average cost pricing. It seems to me to be an extremely problematical choice to base a model on a market of which our knowledge is very incomplete.

Along these same lines, up through 1985 at least, it is the price of deep gas that drives the natural gas market. But up until 1978 deep gas did not exist as a separate category. It is only the perverse consequences of government regulation that have created the inefficient path of resource development where more costly deposits are developed before existing less costly deposits. Since the historical experience can offer little guidance about exploration costs, finding rates, and other facts of deep gas production it seems unwise to place such a heavy reliance on this segment of the natural gas market which comprises less than 10% of total natural gas production.

I have identified three areas where the equilibrium structure of IFFS seem questionable: the disequilibrium nature of some of our recent experience in energy markets,[1] the lack of expectations and an intertemporal equilibrium, and excessive reliance on deep gas prices in determining the equilibrium solution. The latter two shortcomings are amenable to improvement by further development of IFFS. The disequilibrium problem would require a substantially different model structure which is well beyond the techniques of current models and data requirements. But disequilibrium is a potentially important problem which should be kept in mind especially because of its potential interaction with government regulation.

II. Supply Analysis: An attractive feature of the IFFS model is the treatment of the separate energy markets. To a large extent, the interdependence of energy supply is captured by the equilibrium conditions that prevail when a solution is reached. Yet, at the same time the markets can be studied independently, at least for small perturbations, so that model development should be possible in a segmented framework. Also, since an optimizing framework is not used as in MEFS, it seems very much easier to model the effects of government regulations such as the NGPA. Within the market setup average cost pricing is straightforward to represent. For instance the representation of the natural gas supply curve is given in Figure 2. S_1 is the marginal cost curve which would be the supply curve under deregulation if competition exists in the market. S_2 is the average cost supply curve where the quantity of old gas, Q_{old} at price P_{old}, is averaged together with the unregulated gas. Other categories of partially unregulated gas can also be included. With this type of supply curve analysis the effect of changes in government regulations can also be included. I find this

[1] Some notice is taken that natural gas consumption in a given year may not equal natural gas demand at the historical prices, i.e., quantity constraints exist. However, these quantity constraints do not seem to have been incorporated into the econometric procedures as of yet.

flexibility which exists in the model structure to be a very attractive feature of IFFS.

It is now proposed (July 1982) to abandon the time series econometric approach for the supply module used in an earlier version of IFFS, c.f. Hausman (1982), which had severe problems. Instead, a discounted cash flow (DCF) approach similar to that used in PIES-MEFS is to be adopted. I encourage this change as an improvement in model structure although the approach is subject to potential problems, Hausman (1975). While I cannot go into detail on the oil and gas supply models and since evaluation would be difficult given that they have not yet been integrated with IFFS, I would like to point out the following potential problems:

(1) The quantity constraint on rigs which determines total drilling through a merit order approach seems overly rigid. During the 1970's we saw a significant supply response of rigs to economic forces. A problem arises of how to incorporate such a supply response into the model without greatly increasing its size and complexity.

(2) The production equation has a very simple decline relationship. Has the key formula been verified empirically? A potentially serious problem exists because of uncertainty in the size of reserves, especially for natural gas.

(3) BTU parity prices are assumed for deep gas with respect to oil. As I mentioned previously, this assumption is incorrect because of average cost pricing. Arguments can be made against a BTU equilibrium on either the positive or negative side and 1985 may be too soon for the equilibrating processes to proceed very much.

(4) Only current prices are used in the drilling module for 102 gas. This assumption seems incorrect because of forthcoming deregulation.

(5) The deep (107) gas module is based on very shaky assumptions given the lack of historical data. Yet, it plays an essential role in the determination of equilibrium as I discussed previously. Sensitivity analysis with respect to the assumptions seems an important short term goal.

(6) Most importantly, a fixed level of development is assumed for 107-deep gas. Because of the crucial equilibrium role assigned to 107 gas this fixed development assumption could have a significant effect on model results. Development should depend crucially on the current oil price, expectations of the future oil price, and the tax treatment of natural gas. Recent experience in 1982 demonstrates how important thse factors can be.

Lastly, to fit the oil and gas models within IFFS, a pseudo-data approach will be used. I discuss the pseudo-data approach subsequently, but it is not clear that the approach offers a satisfactory resolution to to a diffficult modelling problem.

III. Energy Transformation Activities: In the last section I considered the supply models for three primary sources of energy - coal, oil, and natural gas. In this section the two major energy transformation activities are investigated - oil refining and electricity supply. Here, activity analysis type of models which depend on cost minimization through linear or non-linear programming techniques have been used. These activitv models are usually constructed on a microeconomic or even plant-level basis. They offer a detailed description of the technology and the possibility of substitution in inputs and outputs. The models are in actual use in both operations and planning activities by industry. Their engineering detail can provide a considerably more accurate representation of the process under study than can econometric models which must depend on price and quantity variation observed in the time series data. Yet, the amount of engineering detail can make the use of the models unwieldy in the context of a larger equilibrium or optimization model. Thus, often simplifications of the activity model are made in their actual use, e.g., the model of electricity generation in PIES as described by Hausman (1975). The IFFS modellers have taken an interesting approach to the conflicting properties of the activity models - accurate technological detail together with reasonably quick execution. I will attempt to assess the likely success of this approach.

The approach taken in PIES, MEMM, and MFS to model the oil refining process has been to use an approximation to a larger optimization model through a mixture of the extreme points generated by the larger model. However, it was found that an excessive number of extreme points were required to represent the solution space adequately. An alternative approach of a mixture of a set of extreme points and historical data has been unable to model the changes in product mix adequately. This problem may be especially important if coal is substituted for residual oil in boiler use. The expected product mix may be quite different from recent historical experience.

The IFFS model takes the pseudo-data approach to the problem originally advocated by Adams and Griffin (1972). The pseudo-data approach uses the activity analysis optimization model to solve for costs and factor demands for a large number of output price points. The approach there was a statistical cost function summarize the input-output and elasticity relationships which is estimated by econometric techniques. Since the data generation process is not constrained by limited historical variability on price, inputs, and outputs, in general an accurate fit of the econometric model can be obtained. Griffin has used the pseudo data approach to model electricity generation (1977) and petrochemicals (1978) in addition to the original Adams-Griffin model of refineries.

The particular econometric specification used in IFFS is basically a log linear (Cobb-Douglas) approach to the technology. The equations take the form

(3.1.a)

$$\log(\text{price of gasoline}) = \alpha_1 \log(\text{price or crude}) + \beta_1(\text{gas quality}) + \gamma_1(\text{quality of resid}) + \delta_1(\text{percentage of gas}).$$

(3.1.b)

$$\log(\text{price of other product}) = \alpha_2 \log(\text{price of crude}) + \beta_2(\text{product demand}) + \delta_2(\text{price of gasoline})$$

These equations can be assumed to arise from a (restricted) profit function or a cost function where output prices arise from marginal cost relationships. Three possible improvements might be made in the IFFS pseudo-data approach: (1) A more general approach than the simple Cobb-Douglas should be tried. Griffin has tended to use flexible function forms such as the translog in his recent work. While the Cobb-Douglas representation is easier to use within IFFS, its unitary elasticity assumptions may be unreliable for the refining industry. In fact, the implied separability assumptions of the Cobb-Douglas function are likely to be invalid. Instead a joint cost function approach of the form C(y;Pc;Png) where y is the vector of outputs, Pc is the price of crude, and Png is the price of natural gas should be taken. The form of C should permit jointness of production, e.g., the translog.[1] The joint product nature of the refining process seems especially important with respect to the question of output substitution. (2) The question of cost markups to determine prices is not considered adequately. Currently, IFFS assumes a constant markup in real terms. Especially in gasoline the markups seem to have varied considerably over the last decade. At the current time a variation in gasoline prices among retail stations of 10% is not uncommon. The markup relationship in wholesale prices should be included in the price equations. (3) Little or no research into the effect of industry capacity utilization has been done. Currently, capacity utilization in the refinery industry is below 70%. A vintage effect might be important here which neither the activity analysis model nor econometric equation is taking account of.

A more substantive question exists about the overall validity of the pseudo data approach. Maddala and Roberts (1980) have recently cast considerable doubt on the accuracy of the approach although Griffin (1980) does not accept their critique. In a simple example Maddala and Robèrts claim that even though the statistical fit of the econometric equation may be excellent, i.e., very high R's, that they found the elasticity estimate to vary significantly with the functional form and to

[1] Caves, Christensen and Swanson (1980) and Caves, Christensen and Trethewey (1981) use translog forms to model the joint product case.

not give accurate estimates of the true underlying elasticities. Nor did they find that the translog model offered a significant improvement over a Cobb-Douglas model. Furthermore, the change in factor demands was not captured accurately by the pseudo-data cost function. Griffin, in his reply, critized the simple model of Maddala and Roberts and the extreme points at which they evaluated the elasticities. My evaluation of the controversy is that the pseudo-data approach has not been validated adequately to date. However, an improvement I would suggest that merits investigation is not to attempt to fit the same translog or Cobb-Douglas function over the entire price and quantity space. The reason that econometric cost functions work adequately on historical data is that the limited variation in the data can be suitably approximated by a first or second order approximation. Investigators who use pseudo data are unconstrained by historical data and therefore use a wide variation to improve the fit of the equation. I believe this procedure is usually a mistake because the econometric functions cannot approximate the actual technological relationship over a wide range of variation. Instead, I would attempt to choose a limited number of points and to generate pseudo-data around them. I would then fit separate econometric functions at each point. For use in IFFS interpolations among the points could be made. The required number of estimates and the optimal spacing of the reference points would need to be determined with further research. I feel the current pseudo-data aproach of "distilling the complex process analysis representation into a single equation", Griffin (1977), is beyond the approximation capabilities of the econometric equations. However, the use of more than one set of estimates may well improve the accuracy of the econometric representation.

I have significantly less expertise with respect to electricity generation models. Therefore my remarks here will be relatively brief. A simplification of utility planning models such as WASP and OGP is used in a static and deterministic framework. The documentation here was not adequate for me to assess how well the approach was carried out. The model works on a year by year basis with an exponential smoothing of future prices for capacity planning in the manner of the Baughman-Joskow model. This approach has the shortcoming of the omission of considerations of <u>intertemporal equilibrium</u>. That is, at the quantities being planned for, the prices may need to be higher than the smoothed forecasts. Thus the expectations can be incorrect within the context of the planning model. Financial and regulatory issues are handled by the National Utility Financial Statement (NUFS). NUFS does seem to include the important factors which will affect utility performance in the future. The main shortcoming of NUFS which I can see is its failure to represent adequately the interaction of the tax treatment of utilities with the cost of capital as generated by financial markets. For instance the altered tax treatment of electric utilities in the 1981 tax legislation is meant to decrease the cost of capital for electric utilities. The cost of capital is now one of the major factors in capacity expansion plans. Furthermore, this output needs to be integrated with the planning models. Currently, expansion plans which have already begun are being cancelled due to the high cost of capital. This aspect of planning, regulation, and the tax treatment of utilities should be represented better in IFFS.

A deterministic merit order dispatch is used to generate the derived demand curves by fuel type. A certainly equivalent approach is used instead of a probabilistic approach which may bias downward the predicted operation of peaking capacity and consequently oil and gas demand. A further source of uncertainty is the amount of conversion to coal use by base load plants from current oil consumption. My general impression here is that the deterministic approach may well be adequate, especially if some adjustments were made for peaking operation in line with the historical experience. However, greater uncertainty due to conversion to coal and possible adoption of Time of Use (TOU) pricing and the continued effects of a fall in the demand growth rate need to be studied. Further data gathering efforts in these areas might be quite helpful in decreasing this current uncertainty.

IV. Demand: The information provided on demand models is not extensive. As I understand matters, the log linear representation of demand used in the MEFS demand system is being used in IFFS. These demand equations are in turn based on the engineering approach of the Oak Ridge models: (1) the Hirst-Carney model for residential demand, (2) the Jackson model for commercial demand, (3) the Oak Ridge industrial model (ORIM) for industrial demand. Lastly, the Sweeney model is used for transportation demand. I have some familiarity with all of the demand models except ORIM. However, an in-depth review of the models is beyond the scope of this paper since each demand model is a proper subject subject for an individual review. To the best of my knowledge the Hirst-Carney model has undergone such a review by Freedman, Rothenberg, and Sutch (1980), and McFadden (1981). I do not know of intensive reviews of the other three models although they may well exist. Certainly the Hirst-Carney model has certain questionable features, e.g., Hausman and Joskow (1981), and I would not be surprised if review of the other models did not lead to an improvement in their structure after a careful analysis was undertaken.

I do have four points about the structure of the demand model which may merit further examination. (1) the log linear approximation to a demand curve at a vector of prices typically takes the form for fuel i

$$q_{it}-b_i q_{i,t-1} - \sum_{i\neq j} a_{ij} \log p_{jt} = a_i \log p_{it} \tag{4.1}$$

where q is quantity, p is price and the a's and b's are estimated coefficients. However, within the operation of an individual fuel model the terms $b_i q_{i,t-1} - \sum a_{ij} \log p_{jt}$ are put into a constant term when price is is varied to find the equilibrium price. It is my understanding, which may be inaccurate, that this constant term is not changed across iterations of IFFS when an equilibrium is searched for. If my described procedure is correct, serious errors may result. Since b_i is often estimated to be near one then $q_{it} \approx b_i q_{i,t-1}$ and the equilibrium is reached via equality of $-\sum a_{ij} \log p_{jt}$ to $a_i \log p_{it}$. But if the correct prices are not used in the p_{jt} the supposed equilibrium solution may be quite inaccurate. (2) No expectations occur in the demand models. In the Northeast knowledge that natural gas prices may sharply rise in 1985 has certainly affected conversions from oil for home heating. It would take a substantial revision of the demand methodology to include expectations in the model, but such revision may be called for. Similary, it is not clear how accurate the lagged endogenous demand curve representation will be if a sharp rise in natural gas prices does occur in 1985. In intertemporal models, it is usually the role of expectations to smooth out response variables. But since expectations are not included in IFFS, it is possible to have a large jump in quantities of natural gas which is probably not a realistic forecast of what we expect to occur. (3) Industrial demand currently comprises about 40% of natural gas use of which manufacturing consumes 80%. Therefore, the particular macroeconomic forecasts used may be extremely important since the forecasts are used to drive the demand model. IFFS model runs under different macro forecast assumption should be useful to ascertain the sensitivity of the models results to this factor. I would not be surprised if the IFFS results are sensitive to the macroeconomic assumptions which would emphasize the importance of the macro forecasts in results derived from the model.

V. Results: The IFFS model was run for eight years, 1980-1988, without any change in federal regulatory policy assumed beyond existing legislation. Other model assumptions were: (1) The base supply-base demand case of ARC81 is used in all cases. (2) For the baseline run the price of oil is set exogeneously at 31.20 for 1981 (in 1979 dollars) and the average world oil price from the ARC81 report is used for subsequent years. (3) For the 'high price'run the oil price is set at 10% higher for all years. The oil price is 34.32 for 1981. (4) For the 'low price' run the oil price is set at 10% lower than the base case. The oil price is 28.08 for 1981. The three model runs correspond to a change in the oil price of plus or minus 10%. They should be able to give a reasonable idea about the price and demand and supply elasticities of the model. Since natural gas and petroleum prices and quantities are the central part of the IFFS equilibrium process, I will mainly consider them in discussing the results.

First, we consider petroleum products. Since the price of crude oil is set exogeneously to IFFS here we are basically looking at the interaction of the refinery model and the demand models in terms of the output. In Table 1 I present the results for the baseline run for 5 years; 1980, 1981, and 1983, 1985, and 1988. For comparison purposes I include actual U.S. prices (in 1979 dollars) as reported in the Monthly Energy Review, Dec. 1981. Note that the IFFS results have both the wholesale and retail price of distillate decreasing by about 8.1 over the first four year period while the wholesale and retail price of gasoline are forecast to increase by about 5.3% over the period 1980-1983. The divergence in price paths is somewhat puzzling. Furthermore, from 1985-88 the exogenously set world oil price increases by 19.3% while the wholesale gasoline price decreases by 4.9%. The relationship of the products price with the crude price seems to merit further investigation. Overall, IFFS results do seem to have the price differentials among the various petroleum products approximately correct. Gasoline price seems to be the only remaining problem.

I now turn to the high price and low price oil runs for comparison purposes in Table 2. The price pattern is quite similar to the baseline run. Distillate prices fall by about 6% over the five year period 1981-1985 while gasoline prices rise by about 5%. Again, the latter finding seems quite surprising.

I now consider the IFFS model results with respect to the natural gas price in Table 3. Since the Monthly Energy Review only reports an average delivered price and average wellhead price for natural gas, comparison to the actual prices is quite difficult. Information on current deep gas (unregulated) prices would be very helpful. Prices are given in 1979 dollars per MMBTU.

An anomaly in the table is the low price of deep gas in 1981 which cannot rise above a ceiling set by the IFFS program. It is not clear to me how well the program would work if this ceiling were removed. Subsequently, the price of deep gas falls sharply in 1983 and thereafter remains at the basic price of unallocated gas. It is not clear why this path would occur prior to deregulation in 1985. Also the decline in the price of delivered natural gas between 1981 and 1983 and 1981 and 1985 seems puzzling. Given the vintage contract structure of 102 gas, this outcome seems very unlikely if not impossible.

With respect to the possibility of a 'BTU equilibirum' after deregulation, the results have the price of natural gas at the wellhead significantly below the crude oil price in 1985 and 1988 by about 75%. Given significant delivery costs for natural gas, we expect this result. Residential gas remains cheaper than distillate by about 50%. The price for industrial gas is about 33% lower than the high sulphur residual price. Lastly, for electric utilities the price difference is 37% in 1985, but it falls to 17% in 1988. Therefore, at all margins gas is still a bargain after 1985 although some convergence of prices certainly occurs. But to my way of thinking, natural gas remains too cheap relative to oil in the model during the entire period up through 1988.

I next consider prices of natural gas in the high oil price and low oil price cases. Results are presented in Table 4. Again the deep gas prices are set at the ceiling imposed by the IFFS program in 1981 but then decline to the unallocated gas price. The delivered price of gas continues to take a surprising fall of about 33% between 1981 and 1983. I do not see what set of events could create this decline in price. Since old gas contracts are being replaced by higher priced new contracts, I would expect a price rise over the 1981-85 period. Lastly, almost no price response in natural gas occurs over the base, high, and low oil scenarios even though the oil price varies by 20%. The level of price response in natural gas to changes in the oil price certainly bears further investigation.

The last table that I present considers quantities consumed in 1981 to 1985 under the three price scenarios. These results are presented in Table 5 to give some notion of overall price elasticities. The change in consumption seem surprisingly small. For instance, total consumption does not vary at all in 1983 despite a 20% difference in the oil price. Since the delivered natural gas price does not vary over the period, it seems that the natural gas model is 'uncoupled' from the oil model at the expected level of demands. Further rises in the price of oil need to be considered to find at what point the natural gas market is affected by changes in oil prices. At least for changes of ± 10%, no effect is forthcoming. Lastly, in the industrial sector which might be expected to be the most price sensitive sector, consumption differs by only 0.3% in 1983 and 0.6% in 1985 with respect to the high and low oil price case from the base case. This result might well call for further investigation.

VI. Conclusion: Overall, I like the potential represented by the IFFS model. It models the actual working of energy markets on a year-by-year basis. Thus, its results can be compared to the actual situation in energy markets. This feature is its best attribute and makes it much more favorable than models like PIES, MEFS, and LEAP. The potential also exists for a much more successful integration with a macromodel than has occurred previously, c.f. the proposed integration with the 9DGEM discussed in Kydes, et al. (1982). I strongly feel that more emphasis should be placed on models that can be compared to real data. This argument is developed in Hausman (1981). IFFS has the potential for policy analysis and forecasts well beyond other existing EIA models. It closely resembles in its solution framework and architecture many econometric models. Thus, I feel that the overall concept is sound. However, as I have pointed out significant improvements still need to be made in IFFS. My most important concern is data on natural gas categories in the supply module. For the IFFS model to predict successfully events up to 1985 (or when deregulation occurs) and after, better data seem necessary. At the current time the natural gas market model shows little responsiveness to events in the oil market. I doubt this result is plausible. Better data on gas contracts might help alleviate the problem since increasing amounts of deregulated natural gas which enter the market will reflect, at least partly, the effects of higher or lower oil prices.

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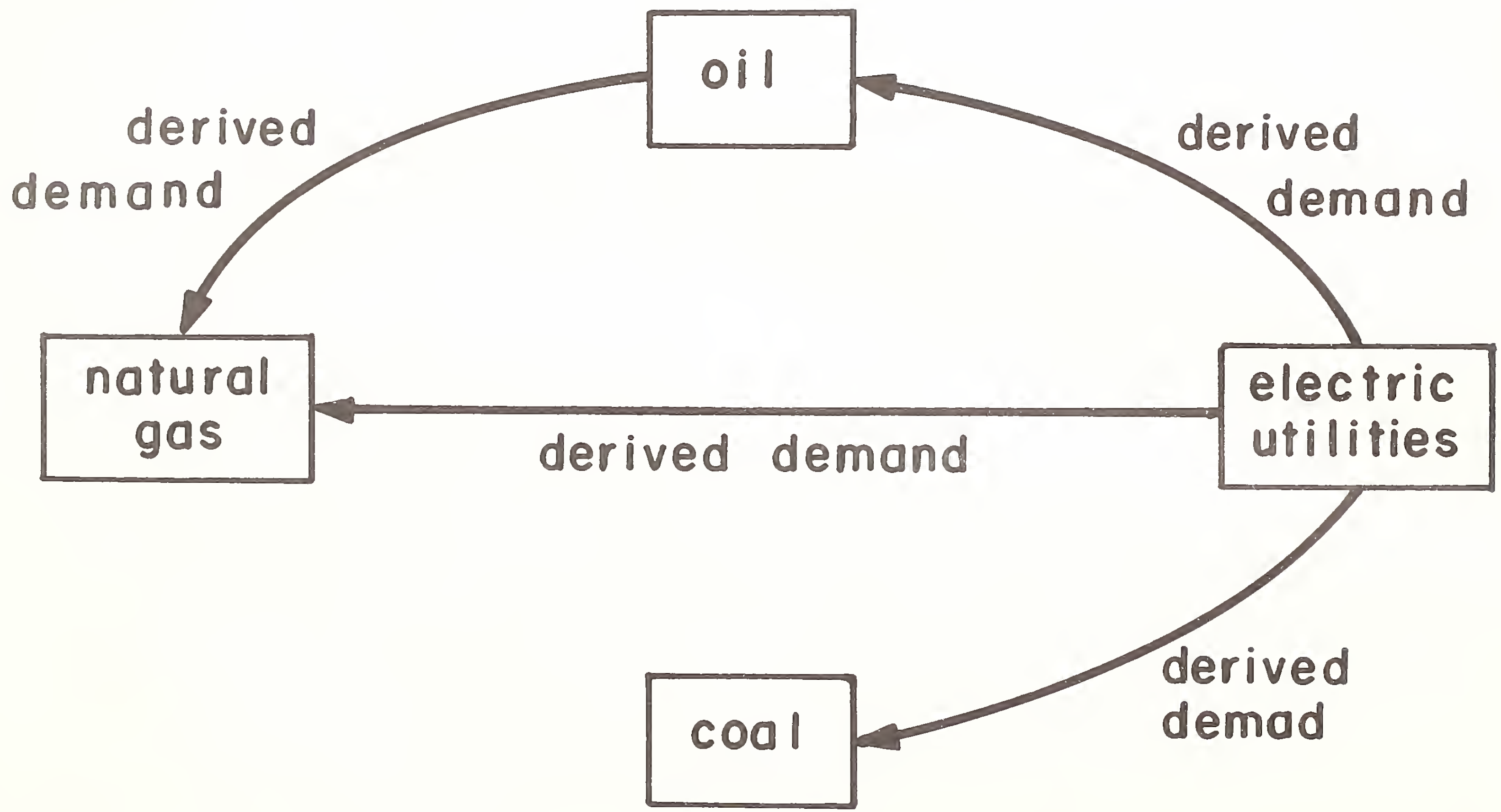
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FIGURE 1

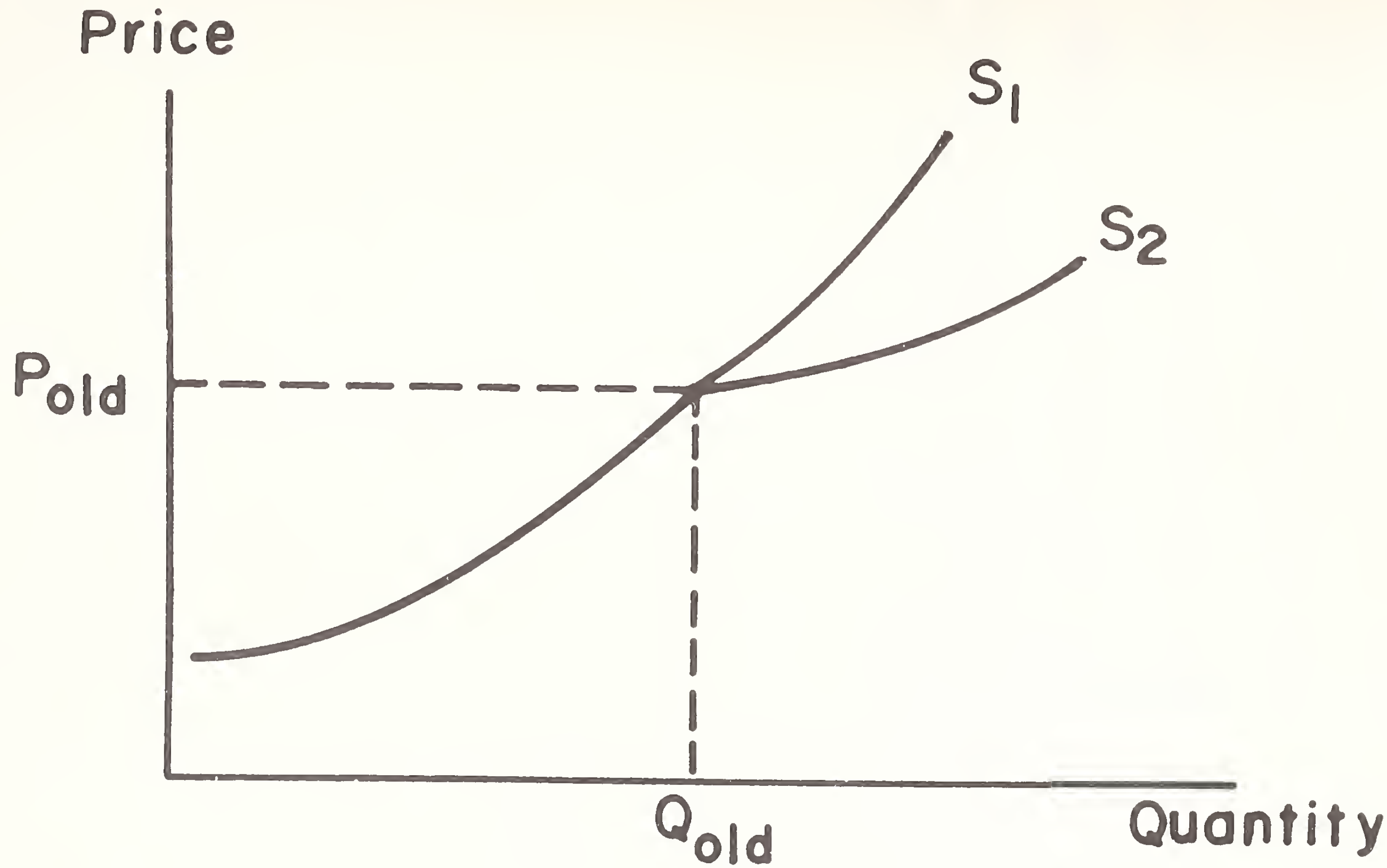

FIGURE 2

TABLE 1

Oil Product Prices

		IFFS80	IFFS81	IFFS83	IFFS85	IFFS88	MER1980[1]	MER1981[2]
1.	Crude-baseline	$31.10	$31.20	$29.37	$30.28	$36.71	$25.52	$30.33
2.	No. 2 heating oil (wholesale)	36.16	36.60	33.35	34.46	41.51	31.39	37.70
3.	Gasoline (wholesale)	36.82	36.67	38.81	38.58	36.75	--	--
4.	No. 2 Heating Oil, residential (retail)	41.12	41.56	38.32	39.44	46.51	37.34	44.42
5.	Gasoline (retail)	49.85	49.70	51.84	51.60	49.77	46.62	49.67

[1] Average 1980 price from December 1981 issue of Monthly Energy Review changed to 1979 basis.
[2] July 1981 price from December 1981 issue of Monthly Energy Review changed to 1979 basis.

TABLE 2

Oil Product Prices with High and Low Crude Prices Assumed

		High80	High81	High83	High85	Low80	Low81	Low83	Low85
1.	Crude	35.21	34.32	32.30	33.31	27.99	28.08	26.43	27.26
2.	No. 2 (wholesale)	39.72	40.20	36.58	37.86	32.60	32.99	30.02	31.05
3.	Gasoline (wholesale)	39.75	39.58	42.08	41.56	33.89	33.76	35.93	35.61
4.	No. 2 (retail)	44.68	45.16	41.55	42.85	37.56	37.95	34.99	36.03
5.	Gasoline (retail)	52.78	52.60	55.11	54.59	46.91	46.79	48.96	48.64

TABLE 3

Natural Gas Results
(Region 6)

	Category	IFFS81	IFFS83	IFFS85	IFFS88	MER80	MER81
1.	Ave. Wellhead Price Allocated Gas	1.19	1.34	1.42	1.91	--	--
2.	Unallocated Gas	3.84	1.46	1.78	3.23	--	--
3.	Deep Gas (107)	5.87	1.46	1.78	3.23	--	--
4.	Ave. Wellhead Price	1.41	1.37	1.81	2.95	1.36	1.59
5.	Residential Price (natural)	4.45	3.29	3.68	4.87	3.56	4.02
6.	Elec. Utility Price (national)	3.22	2.50	2.93	4.16	1.95	2.61

TABLE 4

Natural Gas Prices with High and Low Crude Prices Assumed
(Region 6)

	Category	High81	High83	High85	Low81	Low83	Low85
1.	Allocated Gas	1.19	1.34	1.83	1.19	1.34	1.83
2.	Unallocated Gas	4.07	1.50	1.81	3.59	1.41	1.81
3.	Deep Gas (107	6.39	1.50	1.81	5.31	1.41	1.81
4.	Ave. Wellhead Price	1.42	1.38	1.82	1.39	1.36	1.82
5.	Residential Price	4.59	3.29	3.68	4.29	3.28	3.71
6.	Elec. Utility Price	3.33	2.51	2.94	3.04	2.50	2.98

Table 5

Quantity of Natural Gas Consumed in 1981 and 1983 (quads of BTU's

	Category	Base81	Base83	Base85	High81	High83	High85	Low81	Low83	Low85
1.	Total	17.84	18.14	18.82	17.81	18.13	18.91	17.79	18.07	18.75
2.	Residential	4.44	4.57	4.70	4.41	4.59	4.69	4.49	4.53	4.59
3.	Elec. Utility	3.99	3.57	3.57	4.03	3.56	3.64	3.85	3.47	3.52
4.	Industrial	6.07	6.12	6.50	6.07	6.13	6.52	6.07	6.11	6.48

DISCUSSION

JULIE ZALKIND: This is not really a question, but, it seems like I ought to explain a little bit about the missing demand models being brought up. First, I want to say that we are not using the Hirst-Jackson model or other models that have been used in the past. But, we have rejected these models and started a new effort, in part because there are new data sources to exploit from EIA surveys. We also have fewer resources. We also seem to need to know less about demand technologies with fewer demand initiatives. So we can live with smaller models. These will be used in the next annual report cycle.

DR. TODD: I will pass the remaining time to Fred for the future agenda.

DR. MURPHY: Before going on to the future agenda, Jerry raised several issues that I would like to make a few comments about. His main points were, to begin with, the need to represent disequilibrium, the problems with myopia, and the problems with 107 gas. These are the ones that I will address at this point. It is a question of how long you have to wait before an equilibrium occurs in the market or in what you define as an equilibrium. An economic equilibrium is not a static, unchanging entity. We have tried to represent the adjustment processes in the market place, such as the expansion of the drilling industry. Dick O'Neill, who just left, cannot address your question about the rig shortages. In natural gas the curtailments that we have had in the past are compensated for by taking our curtailment survey information and adjusting demand levels.

We currently do not feel that natural gas curtailments are a significant factor except for industries that may be discouraged from buying natural gas boilers. Currently there seems to be a natural gas surplus. The question of disequilibria in gas markets will be addressed again when I talk about the role of 107 gas.

The myopia issue is a terribly important issue. The problem of expectations is significant. The question of people's expectations about 102 gas prices is important. However, how do you model the response of actors in an industry to an event about which you have no experience? I am open for suggestions, I do not know how to deal with that. One of the possibilities is survey data on intentions.

In the electric utilities environment, it's an overstatement to say that the planning component is myopic. Let me start out by saying that, if you have a demand growth rate that is sufficiently high, even in the face of moderate fuel price growth rates, the myopic solution is identical to the intertemporal optimal planning solution. How do you adjust for it when you get into a situation where demand growth slows and fuel price growth accelerates? We have adjusted for this by trying to include some compensating factors, mapping the equivalent of full, multi-period, linear programming solution into the static problem by adjustments in fuel prices.

One of the key points Jerry makes is the way we essentially capped the 107 price, in solving for the natural gas market equilibrium. Earlier this morning, I eluded to the problem of determining shortage levels. When we were doing work with an earlier version of the natural gas market module (a model that was used to produce a report called <u>The Analysis of the Economic Effects of Deregulation of Natural Gas</u>), we found that when we solved for market equilibrium without capping the 107 gas price, 107 gas prices reached around \$25 to \$30 in 1984.

We felt that printing something like that would not be a realistic result. It is ridiculous to presume that so small a component of natural gas supply will swing the market so thoroughly. We chose to cap the 107 gas price and measure potential shortages rather than presume a market equilibrium. Either, FERC would take some administration action to adjust the NGPA, or there would be a lot of law suits by consumers. We chose the crude oil price as the cap because that is close to the natural gas liquids price, because there is a lot of injection of gas liquids to make up for seasonalities in natural gas demand, and because it was a convenient and very obvious point to cap the gas price for measuring the potential for shortages. Shortages could also be met by increasing imports of natural gas from Canada or Mexico or by utilization of the synthetic gas plants that produce natural gas from gas liquids and naphtha.

This is why we made that modelling decision as we did. Again, it is because there is no easy solution to representing market clearing with the potential for serious shortages. We needed a gas price for measuring where that potential existed. We chose the crude oil price for the ceiling on the 107 gas price.

Why pseudo-data? Again, because we want a model with quick turn-around. If you can get a model to turn around within a half hour, then you can get a lot of debugging done when you are trying to do scenario implementation. It's not the computer time in terms of the dollars that we are worried about here. The machine exists and has surplus capacity with the cutbacks in DOE activities. So, in some ways, it is a free good. But we consider the run time important. Pseudo-data is a device to keep the run time in control, as the means of facilitating the analysis and not having to have our staff here working all hours of the night and working every weekend to produce a forecast, a problem in the past.

There are a few other questions that have been raised, such as the cost of capital in electric utilities. We view that as significant and we have a capital supply curve in the planning module. It was not discussed beyond a passing sentence in the documentation, because it still needs a lot of work on the basic theory and on its implementation.

I have given some responses to the questions you raised. I agree with you that one of the key problems we face is the size of the model. It is hard to keep pressure on people to go with something simpler than something more complex. I keep trying to emphasize the statement of Mies van der Rohe: "less is more." With any individual sector, you should be able to pick out no more than, say, five to ten key variables that you really need to capture.

However, the model exists within an organization, and we have to respond to competing pressures for the individual analyses that people wish to make. One of the ongoing issues that EIA is going to have to face is how to keep the downward pressure on size and complexity, while, at the same time, achieving a realistic balance. In terms of what has gone on today, the whole discussion has been on the trade-off between size and realism and there is no good answer to these issues. They involve a lot of personal judgments and are not scientific.

Let me just quickly give an overview of the development status. Again, we have working versions of all components except for coal. The reason why coal lags is not because anyone has been negligent, but because of the limited resources we have had to schedule some pieces to follow along after others. Coal started last and that is why it is not finished yet.

The electricity market module, is, we feel, in reasonably complete form. We do not see adding on any more structure. If anything, we see shrinking some of the structure in electric utilities to simplify its operation. Our main goal in electric utilities is to continue the data development task, automating a lot of the data that feeds into the model right off the EIA collection forms, and simplying the task to maintain the model over the future. We are devoting a fair amount of time to resolving inconsistencies in the data that exist, so that we can have a good starting point based on historical experience.

In the oil market module, which is primarily refineries, we are re-estimating some of the equations in the model with EIA data. We very quickly got some Oil and Gas Journal data and used that to get something working. Jerry raised the issue of the Cobb-Douglas form with the pseudo-data. We have been testing variants. We have tried the equivalent of a two-term Taylor series, adding more terms to that model. We did not talk about it today because the results have not been as good as we expected. We are going to re-estimate the capacity expansion equations using EIA data.

In the gas market module, I was as surprised as Jerry to see those results. The reason why they are there and have not been prettied up at all is because those are the first runs with the new oil and gas supply pieces, versus the one we were using as a place holder. We have not done any studying of what really happened.

The fall in the 102 price is, I think, is an unrealistic phenomenon and we might have to build something in the module to deal with that because the contract structure with take-or-pay provisions can lead to strong results. The fluctuations in 107 price are something that I would expect because 107 gas is the tail wagging the dog in a sense. Extreme price movements have a certain amount of realism because of the market-out clauses allowing pipelines to break contracts.

We are also doing some work in reducing the complexity of the supply models. One of the important components is the PROLOG model that Dick O'Neill described, a linear program with about 150 to 200 rows. We are working on using something other than linear programming that would reproduce the linear programming solution and reduce it down to three constraints plus a linking Lagrange multiplier. We are trying to achieve some simplicity and regain some more control.

In the coal market module, I really will not say any more about it, except that today you have seen the development task that is ahead of us.

MR. TOM ____: Fred, you said that you are using Oil and Gas Journal data for some purposes. Were they better than EIA?

DR. MURPHY: We do not consider it to be better than EIA data. It was just easily accessible, and we took it because it was on the shelf and we knew where it was.

MR. ______: (inaudible, too far from microphone)

DR. MURPHY: The reason for going with EIA data is that we want to be compatible with our own internal data systems. I am not making any quality judgment, I am just making an organizational statement. Any other questions? Thank you all. I know I am exhausted and I am sure you are.

DR. TODD: I just wanted to say one final thing in closing, which was, that we are very greatful for the effort that the outside participants put into the critiques that they presented today.

The quality of the presentations that were given today have, in all cases, been useful to us. Thank you all for coming today.

SYMPOSIUM ON THE

DEPARTMENT OF ENERGY'S

INTERMEDIATE FUTURE FORECASTING SYSTEM

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Sponsored by
The Energy Information Administration, Department of Energy
and
The Operations Research Division, National Bureau of Standards

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Thursday, August 19, 1982

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Forrestal Building Auditorium
1000 Independence Ave., S.W.
Washington, D. C.

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PROGRAM

9:00 a.m. - 9:15 a.m.:

Welcome.. Saul I. Gass, U. MD/NBS, Symposium Chairman

Wray Smith, Director, Energy Markets and End Use/DOE

9:15 a.m. - 9:45 a.m.:
An Introduction to the New Integrated Forecasting System.................. Frederic H. Murphy, EIA/DOE

9:45 a.m. - 10:30 a.m.:
System Overview -- A Critique.................... William W. Hogan, Harvard University

10:30 a.m. - 10:45 a.m.:
Software Design.................................. Susan H. Shaw, EIA/DOE

10:45 a.m. - 11:00 a.m.:
Introduction to the Oil and Gas Supply Subsystem.................................. Richard P. O'Neill, EIA/DOE

11:00 a.m. - 11:30 a.m.:
Oil and Natural Gas Supply Subsystem -- A Critique........................ David Nissen, EXXON; William R. Finger, EXXON USA

11:30 a.m. - 11:45 a.m.:
Introduction to the Refineries Subsystem.........John Conti
EIA/DOE

11:45 a.m. - 12:15 p.m.:
Refineries Subsystem -- A Critique -- ....Neil J. Cleary
Standard Oil of Indiana

12:15 p.m. - 12:30 p.m.: Discussion and Questions

12:30 p.m. - 1:45 p.m.: Lunch

1:45 p.m. - 2:00 p.m.:
Introduction to the Electric Utilities Subsystem.....................................Reginald C. Sanders
EIA/DOE

2:00 p.m. - 2:30 p.m.:
Electric Utilities Subsystem -- A Critique......Lewis J. Rubin
EPRI

2:30 p.m. - 2.45 p.m.:
Introduction to the Coal Subsystem.............Mary J. Hutzler
EIA/DOE

2:45 p.m. - 3:15 p.m.:
Coal Subsystem -- A Critique...................Michael Elliot-Jones
Chase Econometrics

3:15 p.m. - 3:30 p.m.:
Introduction to the Energy Economy Component.....................................Dale Jorgenson
Harvard University

3:30 p.m. - 4:00 p.m.:
Energy Economy Interactions -- A Critique.......Robert Hall
Stanford University

4:00 p.m. - 4:30 p.m.:
Summation.......................................Jerry A. Hausman
M.I.T.

4:30 p.m. - 5:00 p.m.: Panel Discussion and Questions

5:00 p.m. - 5:30 p.m.:
System Use and Future Developments.............Frederic H. Murphy
EIA/DOE

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Saul I. Gass, Frederic H. Murphy and Susan H. Shaw, editors

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11. ABSTRACT (*A 200-word or less factual summary of most significant information. If document includes a significant bibliography or literature survey, mention it here*)

The Symposium on the Department of Energy's Intermediate Future Forecasting System IFFS was held in Washington, D.C. on August 19, 1982. It was funded by the Energy Information Administration of The Department of Energy (DOE) and organized by the Operations Research Division of the National Bureau of Standards. The purposes of the Symposium were (1) to present to the energy community details of DOE's new energy market model IFFS and (2) to have an open forum in which IFFS and its major elements could be reviewed and critiqued by external experts. DOE speakers discussed the total system, its software design, and the modeling aspects of oil and gas supply, refineries, electric utilities, coal, and the energy economy. Invited experts critiqued each of these topics and offered suggestions for modifications and improvement. This volume documents the Proceedings (papers and discussion) of the Symposium.

12. KEY WORDS (*Six to twelve entries; alphabetical order; capitalize only proper names; and separate key words by semicolons*)

coal; electric utilities; energy economy; energy models; energy markets; forecasting; natural gas; oil; policy analysis

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