Short-Term Integrated Forecasting System

1993 Model Documentation Report

May 1993

Energy Information Administration
Office of Energy Markets and End Use
U.S. Department of Energy
Washington, DC 20585

Contacts

The *Short-Term Integrated Forecasting System: 1993 Model Documentation Report* is prepared by the Energy Information Administration (EIA), Office of Energy Markets and End Use (EMEU). General questions concerning the content of the report may be addressed to W. Calvin Kilgore (202-586-1617), Director of EMEU; Arthur Andersen (202-586-1441), Director of the Energy Markets and Contingency Information Division; or Derriel Cato (202-586-6574), Chief of the Short Term Forecasting and Contingency Branch.

Detailed questions may be addressed to David Costello (202/586-1468) or the following analysts:

World Oil Prices/International Petroleum	Michael Grillot (202-586-6577)
Macroeconomic	Kay A. Smith (202-586-1455)
Energy Product Prices	Neil Gamson (202-586-2418)
Petroleum Demands	Michael Morris (202-586-1199)
Petroleum Supply	Tancred Lidderdale (202-586-7321)
Natural Gas	Evelyn Amerchih (202-586-8760)
Coal	Elias Johnson (202-586-7277)
Electricity	Evelyn Amerchih (202-586-2867)

Preface

The Short-Term Integrated Forecasting System (STIFS) was developed by the Office of Energy Markets and End Use and its predecessors within the Energy Information Administration (EIA). STIFS is the integrated system for the development of supply and demand forecasts that are published quarterly in the *Short-Term Energy Outlook (Outlook).*

This report is written for persons who want to know how integrated short-term forecasts are produced by EIA. The demand and price forecasts for petroleum, electricity, coal, and natural gas are described in the third chapter of this report. This report has been written to comply with the requirements specified in EIA Order EI 5910-.3B, "Guidelines and Procedures for Model Documentation," effective October 1, 1985. The requirement for a corresponding model archival package is met by the creation of the CN6777.PRJ.STIFS0193 archive tape, which contains all the files needed to replicate the forecasts published in the First Quarter 1993 *Outlook.* Instructions for loading and executing these files are contained in the last file (38) on the archive tape, CN6777.PRJ.STIFS0193.INSTALL.MANUAL.

An electronic copy of the model may be obtained from the National Technical Information Service (NTIS) at the address below:

National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, Virginia
(703) 487-4807

The version of STIFS documented here was used by DOE to create the forecasts for the First Quarter 1993 *Outlook.*

Contents

Tables

Figures

1. Introduction to the Short-Term Integrated Forecasting System

The purpose of this report is to define the Short-Term Integrated Forecasting System (STIFS) and describe its basic properties. The Energy Information Administration (EIA) of the U.S. Energy Department (DOE) developed the STIFS model to generate short-term (up to 8 quarters), monthly forecasts of U.S. supplies, demands, imports, exports, stocks, and prices of various forms of energy. The models that constitute STIFS generate forecasts for a wide range of possible scenarios, including the following ones done routinely on a quarterly basis:

- A base (mid) world oil price and medium economic growth.
- A low world oil price and high economic growth.
- A high world oil price and low economic growth.

All three of these cases assume normal weather scenarios. However, to determine the resulting change in petroleum demand due to changes in the weather, the weather assumptions are varied yielding petroleum demand sensitivities.

This report is written for persons who want to know how short-term energy markets forecasts are produced by EIA. The report is intended as a reference document for model analysts, users, and the public.

This report documents the First Quarter 1993, version of STIFS and has been written to comply with the requirements specified in Public Law 94-385, section 57.b.2, Energy Conservation and Production Act and EIA Standard 91-01-03, Model Documentation.

Model Summary

In January, April, July, and October of each year, quarterly forecasts of short-term supply, demand, and prices are revised for publication in the *Short-Term Energy Outlook (Outlook)*, DOE/EIA-0202, prepared by EIA's Office of Energy Markets and End Use (EMEU). Within EMEU, the Energy Markets and Contingency Information Division is responsible for the preparation of the quarterly prices, supply, and disposition tables published in the *Outlook.* The **SAS** programming language is used for model estimation and simulation.[1] The tables published in the *Outlook* are first compiled from **SAS** generated output tables that are then downloaded from the IBM mainframe computer to personal computer word processing program files.

Inputs to STIFS consist of historical data and forecasts that relate to production, demand, imports, exports, and stocks of both primary and end-use energy sources. Historical data comes mainly from the Integrated Modelling Data System (IMDS), an in-house EIA electronic database. The IMDS data are compiled primarily from data regularly reported in the following EIA publications:

Monthly Energy Review, DOE/EIA-0035
Petroleum Supply Monthly, DOE/EIA/0109
Quarterly Coal Report, DOE/EIA-0121

[1] See SAS Institute Inc., *SAS/ETS User's Guide, Version 6, First Edition*, (Cary, NC, 1988).

Electric Power Monthly, DOE/EIA-0226
Natural Gas Monthly, DOE/EIA-0130
Petroleum Marketing Monthly, DOE/EIA-0380

STIFS also utilizes as inputs, several satellite supply models that are maintained and operated within EIA, but outside of EMEU. These are:

Fuel	**Source**
Coal Supply	Office of Coal, Nuclear, Electric and Alternate Fuels
Crude Oil Production	Office of Oil and Gas
Natural Gas Productive Capacity	Office of Oil and Gas
Nuclear Power	Office of Coal, Nuclear, Electric and Alternate Fuels
Hydroelectric Power	Office of Coal, Nuclear, Electric and Alternate Fuels
Electricity Imports	Office of Coal, Nuclear, Electric and Alternate Fuels
Purchases of Electricity by Electric Utilities from Nonutility Producers	Office of Coal, Nuclear, Electric and Alternate Fuels

Forecasts of end-use energy demands, primary energy production, refinery inputs, refinery outputs, net imports, stocks and prices are generated by:

- Econometric techniques
- Time-series forecasting techniques
- Simulation Rules-of-Thumb
- Data analysis by EIA analysts
- Market-clearing assumptions

From alternative model structures, the criteria for choosing particular specifications of the equations estimated econometrically is primarily the adjusted R-square criteria. Parallel to this is the "alternative" R-square criteria which is described in Appendix G of this report. Also recent forecast performance is an important but second order criterium. Finally analysts' judgement about the sensibleness of the equation's properties is taken into account.

With STIFS, the user can simulate a variety of energy-market conditions that affect the projections of energy supply, demand, and prices by altering certain assumptions. For example, a severe winter weather scenario might be simulated by specifying very low temperatures for the next winter. An oil import disruption scenario can be simulated by specifying a future low level of petroleum imports and/or high world oil prices. Types of scenarios that can be simulated by STIFS include:

- Macroeconomic scenarios, characterized by differences in aggregate output, income and prices

- Oil price scenarios, characterized by exogenous shifts in world oil prices due to varying world oil market conditions

- Weather scenarios, characterized by abnormally high or low levels for heating or cooling degree-days

- Constrained imports scenarios, characterized, for example, by different levels of petroleum (and natural gas) imports

- Constrained production capacity scenarios, characterized by different levels of natural gas productive capacity

- Stock-level scenarios, characterized by alternative forecasts of petroleum and coal stock (and natural gas storage) patterns

- Electric utility supply interruption scenarios that are characterized, for example, by increased or reduced supplies of nuclear or hydroelectric power

However, considerable analyst intervention is necessary, at times, to obtain meaningful results relating to scenarios.

Model Contact

Questions concerning the STIFS model may be addressed to:

Dave Costello, EI-621
Energy Information Administration
U.S. Department of Energy
1000 Independence Avenue
Washington, DC 20585
(202)-586-1468

Archive Package

The requirement for a corresponding model archive package is met by EIA Standard 91-01-4, Model Archival, which provides the creation of CN6777.PRJ.STIFS0193 archive tape. This tape contains all the files needed to replicate the forecasts published in the First Quarter 1993 *Outlook*. Instructions for loading and executing these files are contained in the last file (38) on the archive tape CN6777.PRJ.STIFS0193.INSTALL.MANUAL. The archival contact for the STIFS model is:

Elias Johnson, EI-621
Energy Information Administration
U.S. Department of Energy
1000 Independence Avenue
Washington, DC 20585
(202) 586-7277

An electronic copy of the model may be obtained from the National Technical Information Service (NTIS) at the address below:

National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22161
(703) 487-4807

Report Organization

Chapter 1 of this report is the Introduction with a brief model summary and reference to the available archive package.

Chapter 2 of this report is the Model Overview. This section presents the general process flow of STIFS, showing its purpose and scope. This also includes the level of aggregation and a description of the interrelationship between the various models of STIFS.

Chapter 3 of the report presents a detailed technical description of all individual models that compose STIFS. Included in this section are the theoretical and mathematical structures of the models.

Appendix A of this report presents the regression results summary statistics for the equations estimated in STIFS.

Appendix B includes data definitions, sources, and units for all the variables modeled in STIFS.

Appendix C provides an alphabetical listing of all STIFS variables with a cross reference to the archive model file name and line number for all endogenous variables.

Appendix D of the report presents a system abstract of STIFS, describing the model in whole, providing a detailed list of archive tapes, and referencing reviews and manuals.

Appendix E reviews the sources of energy variable forecasts which are exogenous to the STIFS model and briefly summarizes the methodology behind the generation of those forecasts.

Appendix F provides a list of references of source data used in the STIFS model.

Appendix G presents the "alternate" R-square statistic used to judge the "measure of fit" of the regression equations which may be more accurate than the traditional R-square for time series analysis.

Appendix H describes the new Refining Petroleum Supply Model (RPSM) which is currently being tested and will soon be incorporated into STIFS, replacing the current petroleum products supply model.

2. Model Overview

Introduction

The Short-Term Integrated Forecasting System (STIFS) is a set of interlinked submodels which provide a model of the domestic energy market of the United States. These submodels can generally be classified as belonging to one of the following six groups:

- Refined petroleum products demand
- Refined petroleum products supply
- Electricity supply and demand
- Natural gas supply and demand
- Coal demand
- Petroleum and other energy prices

Figure 1 gives a broad indication of the structural links that exist between various portions of the STIFS model. The groups described here are identified as separate entities for convenience of exposition, but it should be noted that in estimation, STIFS generally handles the separate equations one at a time, often with varying periods of estimation for different variables. Nevertheless, numerous simultaneities exist in the model, and the model solution algorithm provides a dynamic simultaneous model solution.

The STIFS model runs on monthly data aggregated to the national or total industry level. It is designed to provide short-term forecasts (up to eight quarters) of the supplies, demands, imports, exports, stocks and prices of any of eight major products: motor gasoline, distillate fuel oil, residual fuel oil, jet fuel, liquefied petroleum gases, other petroleum products, natural gas, electricity, and coal. STIFS can also simulate the effect on any of these variables of changes in one or more of the input variables. Changes in macroeconomic conditions, weather conditions, energy tax policy, energy regulations or world oil price are some of the scenarios that are commonly simulated using STIFS.

STIFS has external links to several models maintained by outside offices or organizations. These external models provide forecasts of exogenous variables for use by STIFS in generating its own forecasts and simulations (refer to Appendix E for a more complete description of these outside models). Macroeconomic forecasts come from the DRI/McGraw-Hill quarterly model of the U.S. Economy.[2] The Office of Oil and Gas, Reserves and Production Branch, provides projections of domestic crude oil production. The Energy Markets and Contingency Information Division of the EIA supplies exogenous forecasts of the price of imported oil, using the Oil Market Simulation model. The Office of Coal, Nuclear, Electric and Alternate Fuels of the EIA provides coal production forecasts from the Short-Term Coal Analysis System, nuclear power forecasts from the Short-Term Nuclear Annual Power Production Simulation, and hydroelectric power forecasts from information obtained from a sample of utilities.

[2] Macroeconomic projections in the First Quarter 1993 *Outlook* are based on DRI/McGraw-Hill Forecast CONTROL 1292. The DRI/McGraw-Hill model is run by the EIA's Office of Integrated Analysis and Forecasting, incorporating key oil price and other energy-related assumptions employed in the corresponding STIFS model runs.

Model Development History

The first *Short-Term Energy Outlook* was published in November 1979 by the Energy Information Administration.[3] The current version of the STIFS model represents an evolution from the original 1979 model. A heuristic approach to model development has led to changes in forecasting equations and procedures that have been periodically documented by the EIA in *Model Documentation Reports* and *Short-Term Energy Outlook Annual Supplements* (see Appendix D, Model Abstract, Bibliography, for references).

The model documented in this report represents the third generation of the STIFS model. This generation differs from earlier generations in that it implements a more integrated environment in which the coefficients of models can be more easily combined into a dynamic simultaneous framework. This is accomplished by means of the *MODEL* procedure in **SAS** Version 6.06.

General Modeling Approach and Basic Assumptions

STIFS is a collection of single equations designed to forecast short-run variations in key aggregate energy quantity and price concepts which are routinely reported by the Energy Information Administration and other government and non-government sources of energy data. The energy concepts covered follow rather closely the coverage provided for domestic energy demand, supply and prices in EIA's *Monthly Energy Review*. STIFS provides monthly domestic energy market demand and supply balances for each major energy source, and provides sectoral detail on energy demand where such data is available on a monthly basis. A comprehensive accounting of energy flows by detailed economic sector (i.e. residential, commercial, industrial, transportation, and electric utilities) is not attempted, although significant sectoral energy demand detail is provided for energy products other than petroleum. The discussion that follows provides a general view of the rationale behind the structure of the STIFS equations. Discussion of the particular estimating equations used is provided in Chapter 3.

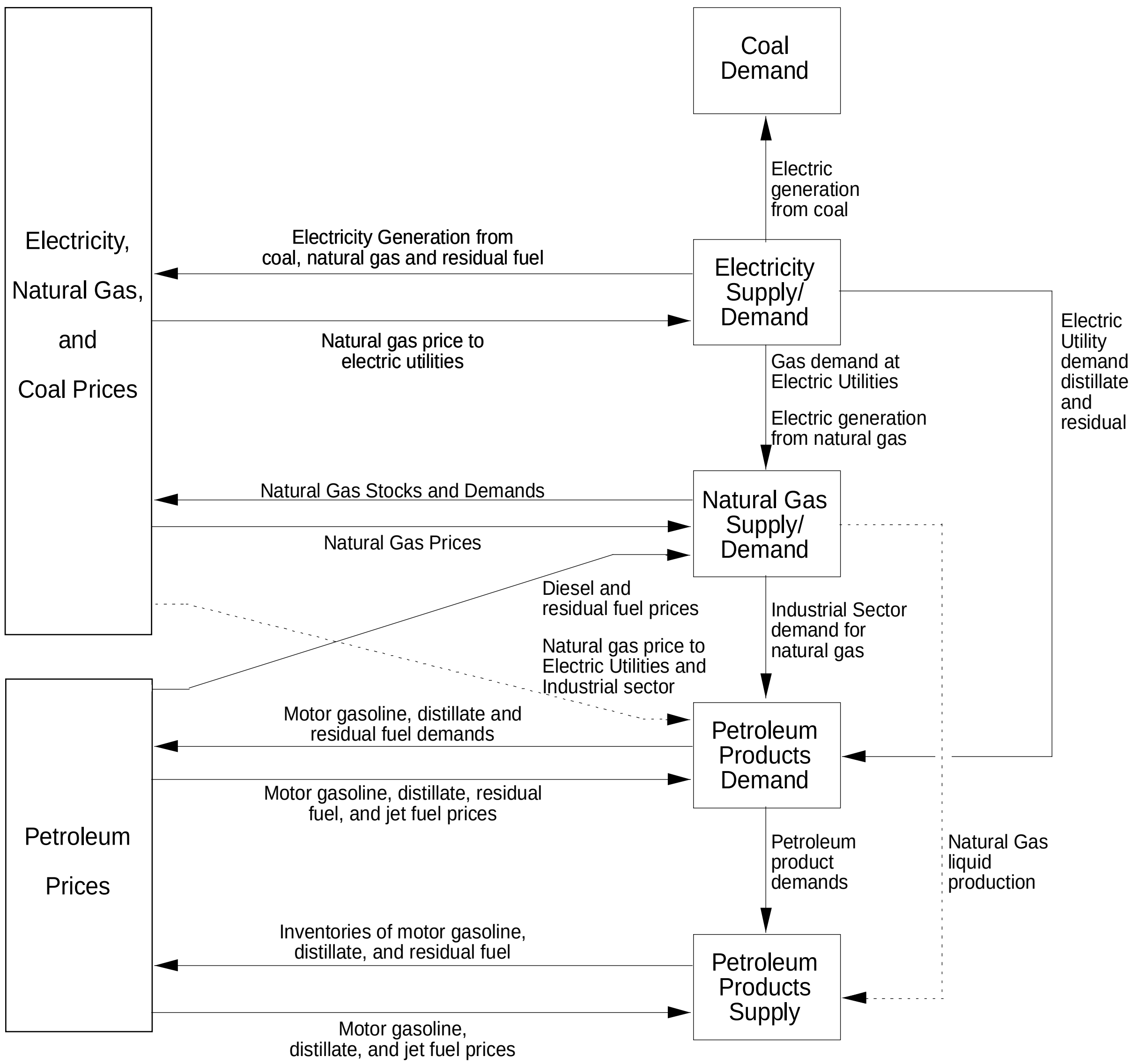
STIFS focuses primarily on capturing short-run energy demand fluctuations, with the assumption that, in general, supply will flow to meet demand from available domestic sources or from imports, with relatively little feedback through prices to demand. In fact, as currently structured, STIFS takes some key energy supply variables (such as U.S. crude oil production) as exogenous inputs determined by other EIA models, so that to some extent STIFS performs more of an accounting function than an equilibration function.

In STIFS, aggregate demand for energy is the derived demand for energy products resulting from the collective demand for energy services (such as heating, cooling, lighting, personal travel, etc.) or the derived demand for energy inputs by industry in manufacturing or other industrial or commercial activities. It is generally assumed that relatively simple equations, amenable to linear estimation techniques, can be used to represent monthly energy demand according to the following general form:

$$D_{ij} = f_{ij}(P_{ij}, Y, W, Z, e_{ij})$$

[3] Energy Information Administration, *Short-Term Energy Outlook - October 1979*, DOE/EIA-0202/1 (Washington, DC, November 1979).

Figure 1. Energy Sector Linkages in STIFS



where:

D_{ij} = average daily demand for energy product i in sector j (where available)
P_{ij} = real (or relative) price of product i in sector j
Y = measure of income or output
W = vector of weather variables (i.e. heating and/or cooling degree-days)
Z = vector of other noneconomic variables, such as dummy variables for strikes and other unusual occurrences, time trends, etc.
e_{ij} = a random disturbance term, possibly emanating from an autoregressive process, but otherwise assumed to be independently and identically normally distributed.

Whether all of the above factors appear in any particular equation depends upon the energy sector involved, or the type of energy product involved (e.g. heating fuel or feedstock, motor fuel or miscellaneous industrial material input).

As noted above, STIFS generally works on the assumption that domestic energy production is demand driven. This is particularly true for electricity and coal, less so for petroleum and natural gas which tend to be constrained by capacity limitations in the short run. Domestic energy sources are assumed to be utilized most heavily at first, with foreign sources assumed to be the residual source of energy supply once domestic capacity limits are reached. The last point is a broad characterization, however. Since it is observed that significant energy product imports exist across a broad range of domestic energy market conditions, some imports are expected for each product regardless of the U.S. market situation. By convention, STIFS treats electricity and coal imports as strictly exogenous, with the forecasts for these items being done by other EIA models not integrated directly into the STIFS system (see Appendix E). In general, however, imports are expected to be significantly more important once domestic capacity constraints (such as refinery capacity) are approached. As noted below, the implications of these assumptions for domestic energy prices are complex.

The following general formulation indicates how STIFS determines the demand and supply balances regularly reported in the *Short-Term Energy Outlook*:

$$Q_i = D_i + X_i - M_i - (K_{i,-1} - K_i) + B_i$$

where:

Q_i = domestic production of product i
D_i = domestic demand for product i (all sectors)
X_i = exports of product i
M_i = imports of product i
$(K_{i,-1} - K_i)$ = inventory change of product i (where applicable)
B_i = statistical discrepancy or unaccounted-for supply

A more formal microeconomic approach to energy supply and demand determination has not been implemented for several reasons: 1) data on supply are not defined the same way as data on demand and therefore no market equilibration (in a strict sense) can be done; 2) standard microeconomic theory generally abstracts from short-term market adjustment problems that dominate short-term forecasts (i.e. standard theory may not help much); 3) data on technology, costs, etc., are not available to implement the supply curve estimates. Despite these problems, in a few sectors a more formal microeconomic approach has been tried, such as for refined product supply, which is discussed in appendix H, and in the discussion of some of the individual equations.

Petroleum Supply and Demand Overview

An important feature of the first quarter 1993 version of STIFS is that the stock withdrawal term in the basic supply/demand balance equation given above (i.e. $K_{i,-1} - K_i$) is specified exogenously for petroleum stocks, under the assumption that domestic crude oil and oil product inventories will quickly approach pre-specified "normal levels," which are usually set at about the average of recent years, but in any case well within the average inventory range for petroleum products reported in EIA's *Weekly Petroleum Status Report*. An endogenous framework for petroleum inventories currently being tested for STIFS, using dynamic duality principles in the context of a monthly U.S. refined product supply model, is given in Appendix H.

For domestic crude oil production and coal production, Q is exogenous (see the specific discussions in Chapter 3, "Mathematical Specifications," and Appendix E, "Sources of Exogenous Forecasts"). It should be noted that, while strictly speaking domestic crude oil production is exogenous to STIFS, no standard model runs of STIFS are reported without a separate run of the external model which generates the exogenous oil production forecasts using consistent oil price assumptions.

The Q's relating to petroleum refinery output are endogenous to STIFS, subject to an overall average operable refinery capacity utilization limit on distillation unit inputs of 92 percent (which is about the maximum utilization rate observed to have been maintained for a period of one month or more). Refinery output for petroleum product k is given generally by:

$$Q_{Rk} = f_{Rk}(P_R, D_{cj}, D_k, Z, e_k)$$

where:

Q_{Rk} = refinery output for petroleum product k
P_R = a vector of refiner prices for petroleum products
D_{cj} = refiner demand for oil inputs (i.e. j=1=crude, j=2=unfinished oils)
D_k = total demand for petroleum product k
Z = a vector of noneconomic variables (such as dummy variables to capture unusual events, seasonal factors, etc.)
e_k = random error term

Crude oil and other refinery oil inputs are given as:

$$D_{cj} = D_{cj}(D_p, S_p, Z, e_c)$$

subject to:

$$D_{cd} \leq C * 0.92$$

where:

D_{cd} = fraction of D_{cj} entering distillation units
D_p = total petroleum product demand
S_p = a vector of petroleum product stocks
e_c = random error term
C = total operable refinery capacity

Thus, domestic refinery runs and production are favored in the first instance over imports, up the point at which maximum refinery capacity is reached.

Three major kinds of demand and supply balances are derived for petroleum: an aggregate crude oil balance; a refinery materials balance; and a refined products demand and supply balance.

The crude oil demand and supply balance starts with the equation for refinery inputs of crude oil (D_{c1}) given above (see equation A18 in Chapter 3 below). Since the United States is far from being self-sufficient in crude oil production, except for some short-term possibilities of relying on increased stock withdrawals, incremental crude oil demand in the United States is met by imports. Thus, given domestic production, and given an exogenously specified path for petroleum inventories, crude oil imports are assumed to be directly related to increases in refinery crude oil demand (see equation A30 in Chapter 3). Once an appropriate level of net imports is determined, the B_i (unaccounted for crude oil in this case) is determined as the residual (see "Balancing Crude Oil Supply and Demand" in Chapter 3).

The refinery materials balance starts at the same place that the crude oil balance does, namely with the D_c function given above. Once crude oil and unfinished oil inputs are determined (subject to the distillation capacity constraint), liquefied petroleum gas (and other miscellaneous) refinery inputs are determined, and a total refinery input level is derived (see the "Refinery Inputs" section of Chapter 3). Since converting raw materials into finished products at refineries involves a volumetric "processing gain," a key identity for refinery operations is that the volume of refinery outputs must equal the volume of refinery inputs plus the processing gain. (The processing gain is somewhat of a misnomer because it includes an unknown amount of statistical discrepancy or unaccounted-for product as well as actual volumetric gain over input quantities due to distillation and other refinery processes, and therefore should be considered a net concept). A first pass at refinery outputs is made using econometric equations specified in the "Refinery Outputs" section of Chapter 3, with the general specification discussed above. The total of these outputs are checked against the total refinery inputs, and each component of output is scaled proportionately to enforce the refinery balance identity (see "Balancing Refinery Outputs with Refinery Inputs" in Chapter 3).

Finally, petroleum product demand and supply is determined by making net product imports a residual. The version of the supply/demand balancing identity given above in the context of petroleum products is:

$$NI_p = D_p - Q_p - (K_{p,-1} - K_p)$$

where "NI" refers to net imports and the "p" subscript refers to finished petroleum products. No discrepancy is assumed here. In fact, this product demand/supply balance identity is just a rearrangement of the identity used to actually define the variable D_p, which is also referred to in EIA data publications as "product supplied" or "disappearance from primary supply."[4] For completeness, gross exports for petroleum products are determined independently and gross imports determined by adding this into net imports. (See the "Imports and Exports" section of Chapter 3).

Electricity Supply and Demand

The basic approach to electricity demand and supply modeling in STIFS is generally consistent with the formal approach outlined above. Figure 2 presents the general flow of the logic of the electricity-related portions of STIFS.

Demands for electricity by individual sectors are determined as a function of weather, aggregate economic activity and other factors. The sum of sectoral demands is assumed to be met from domestic production of electricity (including that from electric utilities and nonutility power producers) and imports.

STIFS takes electricity imports and nonutility sources of supply as exogenous [5], and concentrates on determining electricity supplied by electric utilities in the aggregate and by fuel source. STIFS only determines some of the electric utility supply endogenously, in particular electricity supplied from fuel sources other than nuclear and hydroelectric.

---

[4]See the glossary in *Petroleum Supply Monthly*, DOE/EIA-0109, for a detailed definition of this demand concept.

[5]The source of these exogenous forecasts is EIA's Office of Coal, Nuclear, Electric and Alternate Fuels, and their derivation is described in Appendix D. It should be noted that STIFS does not identify and model electricity produced for own use by nonutility producers, and thus actually understates total electricity supply and demand somewhat. For the year 1990, nonutility electricity supplied for own use was estimated to be slightly more than 4 percent of total electric utility sales to all sectors. (See Energy Information Administration, *Annual Energy Outlook 1993*, DOE/EIA-0383(93), Table A4.

Electricity generated from nuclear and hydroelectric sources are provided exogenously by EIA's Office of Coal, Nuclear, Electric and Alternate Fuels, generally only once a quarter and usually only for a "base case" or "mid case" scenario. An implicit assumption accepted in this arrangement is that hydroelectric and nuclear power production are not sensitive to demand shifts or other electricity market variables. In general, this is a reasonable approach in that both sources of electricity are low-variable-cost base-load supply sources which are used to the maximum extent possible under existing capacity and water-level conditions. In reality, it is not likely that demand shocks have no short-run impact on these supply sources, particularly in the case of nuclear power. Nevertheless, the exogeneity assumption for nuclear and hydroelectric power is basically consistent with EIA's established view on the independence of these sources of supply from demand shifts, at least as this view is indicated in EIA's *Annual Energy Outlook*[6].

STIFS uses several estimated equations to split out the remaining sources of supply, based on assumed levels of coal generating capacity, relative oil and gas prices, and other factors, as detailed in the "Electricity Supply" section of Chapter 3.

Natural Gas Supply and Demand

For the natural gas portion of STIFS, as elsewhere, the starting point is demand, which is estimated by sector using national-level equations (see equations A58 to A64 and associated identities in Chapter 3). Total demand plus exports must be met by current domestic production, imports, and withdrawals from storage. Figure 3 depicts the flow of logic used in STIFS to derive a demand and supply balance for natural gas.

Domestic production is assumed to be strictly responsive (with a lag) to current demand shifts up to the point at which maximum domestic productive capacity is reached. The main gas production relationship, prior to imposing any capacity constraints, is given in equation A69 in chapter 3. (Seasonality in the aggregate production relationship is assumed to be important and is related to the need for domestic producers to perform routine maintenance on producing facilities during off-peak periods.)

Natural gas imports are also subject to a constraint related to the capacity to transport gas by pipeline from Canada. (Liquefied natural gas imports are not treated separately but are generally small). Maximum gas productive capacity and maximum gas import capacity are given exogenously by EIA's Office of Oil and Gas. A different productive capacity trajectory is provided to STIFS for each standard oil price scenario considered (see "Natural Gas Supply" section in Chapter 3).

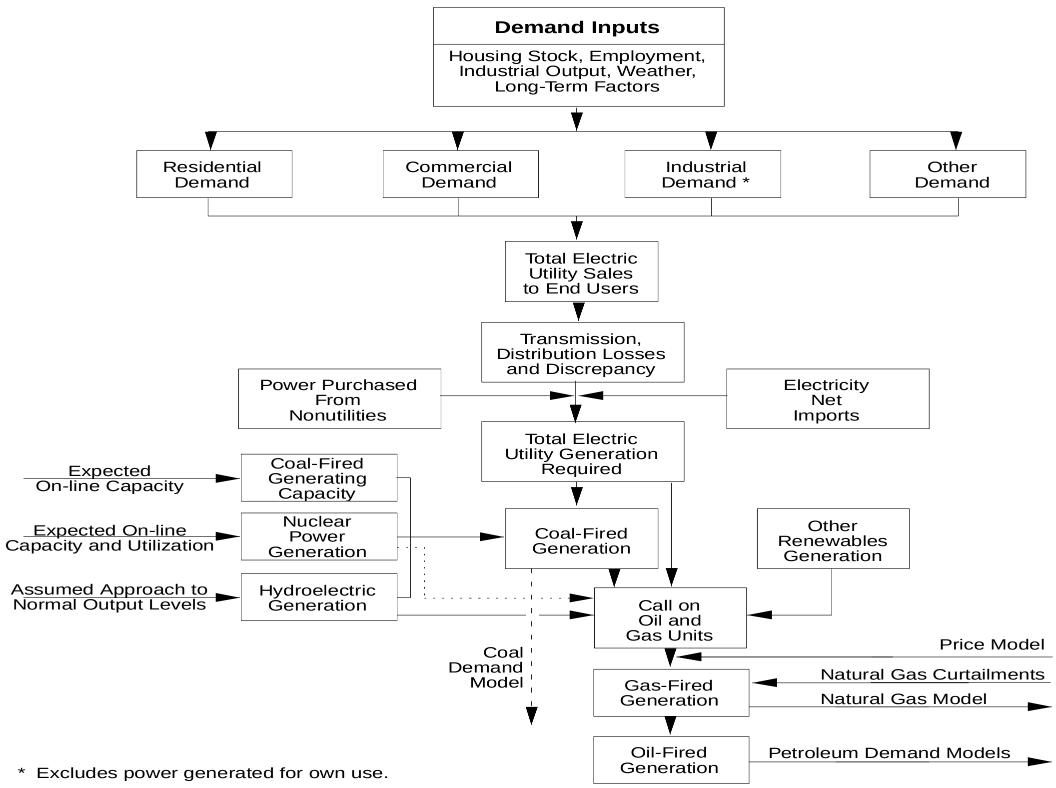
For natural gas, the B_i (i.e. unaccounted-for gas or the gas supply/demand balancing item) is assumed to be independent of other considerations and is held at some predetermined level on an annual basis, with an estimated "normal" seasonality imposed over the months. The fixed annual level is normally taken from the last historical year, and equation A66 is used to generate that level (and seasonality) with the add factor set so as to insure the prescribed annual level. This is done because, while the unaccounted for gas undoubtedly includes some significant gas losses as well as pure statistical discrepancy, not enough is known about this component of the balance to do anything but abstract from it as much as possible in the short-run forecasts.

Given a first pass at gas inventory changes (determined with normal seasonality through equation A68 in Chapter 3), supplemental gaseous fuels (equation A67), the unaccounted-for gas (equation A66), and gas exports (equation A65), the main question in STIFS for gas supply is: Is there enough domestic gas production or import capacity to meet demand? Given initial total demand estimates, STIFS calculates a required total of domestic production and imports needed to meet that demand (plus exports), given the other supply components including inventory change, supplemental fuels, and unaccounted-for gas.

---

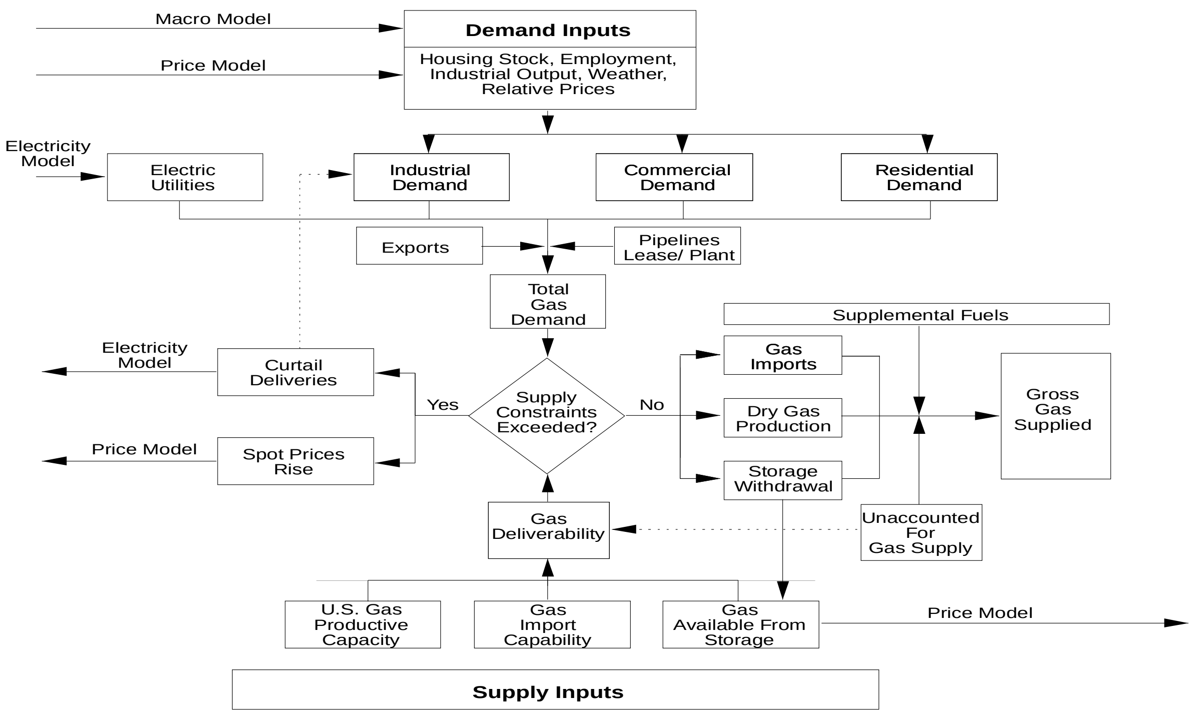
[6]Virtually none of a hypothesized 1 percent shift in electric utility output for the year 1995 between reference and high economic growth scenarios reported in the last 1993 *AEO* was met by nuclear or hydroelectric power. See Energy Information Administration, *Annual Energy Outlook 1993*, Tables A4 and B4.

Figure 2. Electricity Supply and Demand Model



* Excludes power generated for own use.

Figure 3. Natural Gas Supply and Demand Model



STIFS sets gas production equal to the initial estimates from equation A69 and the associated reseasonalization identity or to the productive capacity maximum, whichever is smaller. A similar calculation is done for imports. If either the productive capacity or import constraints are binding, total gas demand is reduced by the difference between the unconstrained and constrained levels for production plus imports and is further adjusted by a minor recalculation of gas inventory levels (see "Natural Gas Supply" in Chapter 3). The demand reduction is shared out proportionately to the industrial and electric utility sectors, under the simplifying assumption that the other sectors are comprised of firm customers only.

In general, price responses to any shortfall in supply as described above are not handled directly or automatically in STIFS. A general simulation rule generally adhered to for routine forecasts, involving iterative re-simulations of the entire STIFS model, is that ultimate gas production levels should not exceed approximately 95 percent of total productive capacity. In the re-simulations, spot gas prices are gradually dialled upward, using the add factor shown in equation A86 in Chapter 3, until demand is forced down to a level which leaves solution values for production for any month at or below 95 percent of capacity. The 95 percent rule is an arbitrary restriction on maximum production, but it is designed to keep gas production forecasts at reasonable operational levels.

Coal Supply and Demand

The specifications of the coal portion of the STIFS model is provided in the "Coal Supply and Demand" section of chapter 3. A key feature of the coal market balance in STIFS is that coal production, imports, exports and producer stocks are exogenously supplied from an external model maintained by the Office of Coal, Nuclear, Electric and Alternate Fuels (see Chapter 3 and Appendix E). Electric utility coal demand is effectively determined in the electricity portion of STIFS, leaving coal demand for three other sectors (coking coal, non-coking industrial coal, and a relatively small amount of residential and commercial coal) to be determined separately.

Coking coal demand is a derived input demand in the coke-using portion of the steel industry. Coking coal is needed to produce coke which is used in the reduction of iron ore to pig iron (which is ultimately processed into raw steel) in the sector of the steel industry using basic oxygen furnace (BOF) technology. About 63 percent of raw steel produced in the United States is from BOF furnaces. Thus, coking coal demand derives from overall demand for raw steel which is not met by non-BOF processes (principally electric arc furnaces which use electricity to reconvert scrap steel to raw product). Raw steel demand (and thus raw steel production if one ignores steel inventory changes) is assumed to be a function of major economic variables affecting the output of domestic manufacturers of products using raw steel as a main input. Of the numerous macroeconomic variables tested in this context, manufacturers inventories and real fixed investment prove to be most significant, and these are included in the raw steel production specification (see equation A74 in Chapter 3). The procedure for backing into coke production and thus (coking coal demand) from raw steel production and the formulation of other minor coal demands are provided in Chapter 3.

Since coal supply (including primary inventory change) is exogenous to STIFS, total secondary (i.e. consumer) stock change (and stock levels given initial values for the latter) are determined identically. STIFS does produce estimates of share weights for distributing total consumer stocks across sectors. The basic assumption here is that coal stocks in each sector will approach, through a partial adjustment mechanism, pre-specified desired relative stock levels (specified in terms of days of supply relative to monthly demand) from initial levels observed at the beginning of the prediction period. The inventory sharing-out routine is discussed in the "Coal Inventories" section of Chapter 3.

Data Flow

The flow of data in the STIFS model is described in Figure 4. The primary monthly data which comprise the STIFS historical database come from three sources: 1) "*IMDS*" (EIA's Integrated Modeling Data System); 2) a separate collection of input datasets, called "*MANUAL*", which consists of additional energy market data (such as highway and air travel data) not available in IMDS; and 3) a collection of macroeconomic data series called "*MACRO*", a source of many of the key economic drivers for STIFS energy demand relationships. The STIFS model combines the historical energy, weather, macroeconomic, and other data into one main historical database called "*BASE*".

Regression equations which make up the STIFS model are then estimated from this historical data (the "*ESTIMATE*" step) and the estimation results are saved to a SAS model library. The *ESTIMATE* step is usually performed at most once every quarter.

The *BASE* database is then expanded with forecasts of exogenous variables, which represent a selected scenario, the model is solved, and a forecast is thus generated. The solution algorithm is described in *SAS/ETS User's Guide*, Version 6, First Edition, under the MODEL Procedure documentation.[7] The expansion of the *BASE* dataset with the exogenous variable forecasts is done every time that a new scenario is specified, just prior to solving the model, designated in Figure 1 as the "*SIMULATE*" step. This expansion of the "*BASE*" dataset results in a complete set of data inputs for the specified scenario. The SAS "*MODEL*" procedure is used to interpret the model coefficients and lag structure (saved in the *ESTIMATE* step) to perform the model solution step. The *SIMULATE* step returns all of the historical and exogenous data forecasts, plus solution values for all of the endogenous variables in the model. These outputs are stored in a SAS library, identified by scenario, for report writing and further analysis.

The forecast range for any endogenous variable is normally from the first period after the last available history to the last period in which the forecast of all exogenous variables in the STIFS model are available in the expanded data set used as the input in the *SIMULATE* step. All of the endogenous and exogenous variables in STIFS are identified in Appendices B and C. Sources of historical and forecast data series are provided in Appendix B. Cross-references to locations in the archived STIFS model listing of the endogenous variable formulas are given in Appendix C.

The construction of the forecasted exogenous information prior to model solution in the *SIMULATE* step is done in several steps. The forecasts of macroeconomic data (such as industrial output, personal income, etc.) are derived by running the DRI / McGraw-Hill Quarterly Model of the U.S. Economy using the crude oil price assumptions employed in particular scenarios, as well as initial forecasts of end-use energy prices.[8] The resulting macroeconomic forecasts are stored in a dataset which is read into the STIFS input dataset during the *SIMULATE* step. The oil price assumptions constructed by EIA are saved in a separate dataset and are also read in during the *SIMULATE* step. Weather forecasts, in terms of future heating and cooling degree-days, are based on the simple assumption that, for any particular month, the weather variables will be equal to a long-run (30-year) average, labeled "normal", from the National Oceanographic and Atmospheric Administration. Exogenous energy supply information, such as crude oil production, is similarly saved into datasets which are inputs to the *SIMULATE* step.

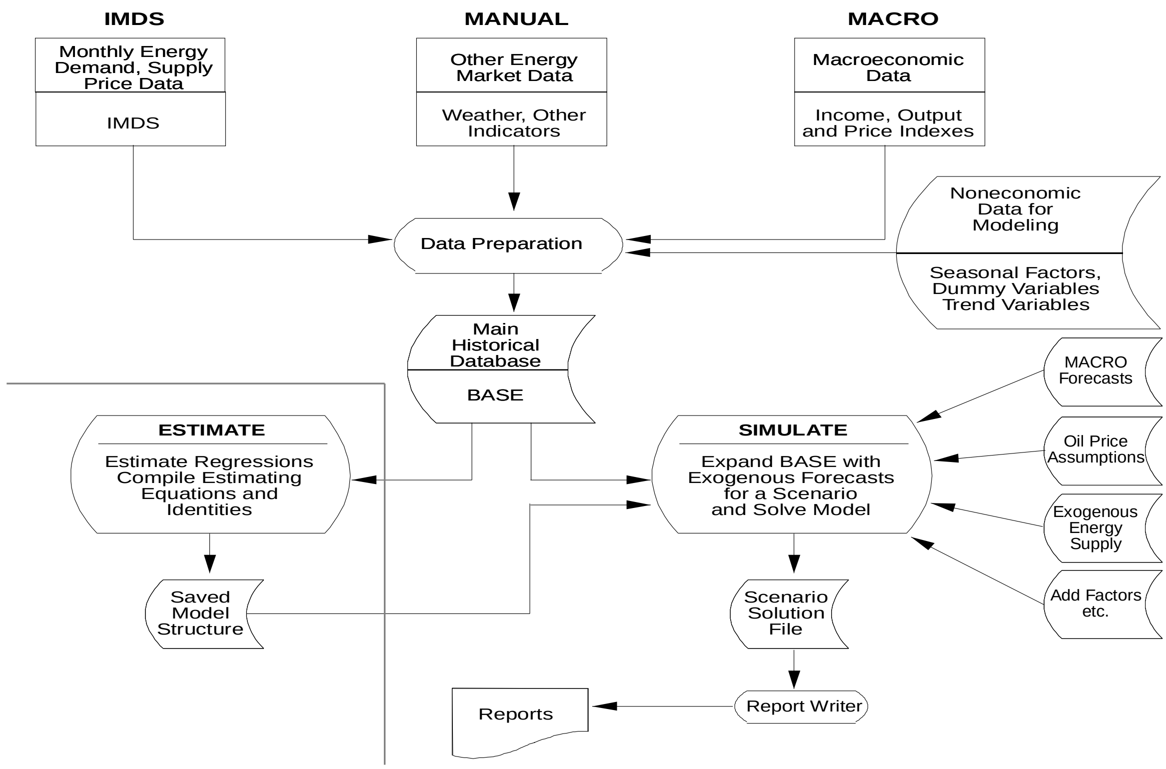
STIFS is updated quarterly in response to new data and information on new regulations and other institutional changes. The version of the model described in this report was used to produce the First Quarter 1993 *Outlook*.

---

[7] For standard STIFS forecasts, the "SOLVE" command in the SAS "PROC MODEL" routine is invoked, with "FORECAST" and "DYNAMIC" options set, and the "NEWTON" solution method specified (by default).

[8] Initial forecasts of energy end-use prices in a scenario are generated by a preliminary STIFS run under the given crude oil price assumptions and a previous set of macroeconomic forecast assumptions.

Figure 4. Short-Term Integrated Forecasting System: Data Flow



Statistical Overview

The STIFS model consists of 305 equations, of which 93 are estimated. The 93 estimated equations are linear regression equations that together form a system of interrelated equations. The selection of functional form and the estimation technique is generally done on an equation-by-equation basis. The general method of estimation is ordinary least squares. Some equations incorporate a correction for autocorrelation of the error term.

Data Overview

The historical energy data used to estimate the model come primarily from the IMDS electronic database. IMDS merges data regularly reported in several EIA publications: *Quarterly Coal Report*, *Petroleum Supply Monthly*, *Petroleum Marketing Monthly*, *Electric Power Monthly*, *Natural Gas Monthly*, and *Monthly Energy Review*. Because of data limitations there are inconsistencies in the level of disaggregation of each type of fuel. For example, electricity and natural gas demands are represented by market sector, but petroleum products are represented only as national totals or for a combination of sectors. Market-level data are available for the regulated industries (electricity and natural) gas while product-level data are available for the petroleum product markets.

These energy price and volume data are supplemented by data from outside sources; the most common are listed below.

Employment and Earnings, Bureau of Labor Statistics, U.S. Department of Labor.

Industrial Production, Board of Governors, U.S. Federal Reserve System.

Monthly Labor Review, Bureau of Labor Statistics, U.S. Department of Labor.

Monthly State, Regional, and National Heating/Cooling Degree-Days Weighted by Population, National Oceanic and Atmospheric Administration, U.S. Department of Commerce.

National Income and Product Accounts of the United States, Bureau of Economic Analysis, U.S. Department of Commerce.

Survey of Current Business, Bureau of Economic Analysis, U.S. Department of Commerce.

A variable-by-variable breakdown of data sources is provided in Appendix B.

Most of the data sources provide monthly data and are used directly. One exception is coal data, which are quarterly and must be interpolated into monthly series. In addition, the variables are transformed into a common set of units, and many are deseasonalized prior to estimation using the Census Bureau's X-11 procedure as it appears in SAS.

Forecast Accuracy

Forecasts from the STIFS model are compared with actual values in the *Short Term Energy Outlook Annual Supplement (Supplement)* for many of the variables. The *Supplement* evaluates model forecasts and presents tables showing forecast errors by fuel prices and quantities. The *Supplement* also compare EIA forecasts with relevant external forecasts. Model modifications and occasional articles on model modifications and improved forecast methodologies are also reviewed in the *Supplement*.

Model Domain and Discontinuities

The STIFS model is known to be robust within the following ranges of the exogenous variables around the First Quarter 1993 *Outlook* base case forecast:

Crude oil price	± 10%
Heating or cooling degree-days	± 20%
Gross domestic product (GDP)[9]	± 2%

Tests for discontinuities in the model results outside of the ranges specified above or associated with variations in other variables have not been conducted.

Data Quality

Information on the quality of historical data used by the STIFS model is limited to the following published analyses:

Energy Information Administration, *An Assessment of Principal Oil and Gas Data Series of the Energy Information Administration*, DOE/EIA-00491, (Washington, DC, August 1984).

Energy Information Administration, *An Assessment of the Quality of Selected EIA Data Series: Coal Data 1983 Through 1988,* DOE/EIA-0292(89), (Washington, DC, December 1991).

Energy Information Administration, *An Assessment of the Quality of Selected EIA Data Series: Electric Power Data*, DOE/EIA-0292(87), (Washington, DC, May 1989).

Energy Information Administration, *An Assessment of the Quality of Selected EIA Data Series: Petroleum Supply Data*, DOE/EIA-0292(86), (Washington, DC, August 1987).

Energy Information Administration, "Comparisons of Independent Statistics on Petroleum Supply," *Petroleum Supply Monthly March 1992*, DOE/EIA-0109(92/03), (Washington, DC, March 1992).

Energy Information Administration, "Timeliness and Accuracy of Petroleum Supply Data," *Petroleum Supply Monthly September 1992*, DOE/EIA-0109(92/09), (Washington, DC, September 1992).

[9] Indices of industrial output, personal income, inflation, and other macroeconomic variables are also adjusted to be consistent with the assumed variation in GDP.

3. Mathematical Specifications

This section summarizes the equations that appear in the STIFS model. While the method of simulating the model was revised in 1992, the STIFS model equations remain similar to those that appear in the last published model documentation for STIFS.[10] The model presentation follows the following outline:

- Refined petroleum products demand
- Refined petroleum products supply
- Electricity supply and demand
- Natural gas supply and demand
- Coal demand
- Petroleum and other energy prices

The interrelationships between prices and the different fuel sectors are shown in Figure 2 below.

Regression Equations

All equations are estimated using ordinary least-squares (OLS). Parameter estimates and other regression statistics for the model equations appear in order of presentation in Appendix A tables. Definitions and data sources for each variable are provided in Appendix B.

Regression Equation Coefficients

In all equations, the estimated parameters appear before their associated right-hand-side variable. A standard naming convention is used in most equations. The first three or four letters of the coefficients correspond to the first three or four letters of the endogenous variable, followed by an underscore, then followed by two letters from the associated exogenous variable. For example, for nonutility distillate fuel demand (equation A11):

$$DSTCPUS_t = DSTC\_01 + DSTC\_AC * DFACPUS_t$$

The coefficient DSTC_01 is the estimated equation intercept and DSTC_AC is the estimated coefficient associated with distillate demand in the transportation sector, DFACPUS.

The definitions and statistics associated with the estimated parameters are given by equation in Appendix A.

Autocorrelation Correction

When time series data are used in regression analysis, often the error term is not independent through time. If the error term is autocorrelated, the efficiency of ordinary least-squares parameter estimates is adversely affected and standard error estimates are biased. The Durbin-Watson statistic is used to test for the presence of first-order autocorrelation in OLS residuals and is reported in the regression results in Appendix A. For equations in which a lagged dependent variable is present, the Durbin *h* statistic is reported.

---

[10] Energy Information Administration, *Short-Term Integrated Forecasting System: 1990 Model Documentation Report,* DOE/EIA-M041.

Autocorrelation correction involves estimating the parameters of a linear model whose error term is assumed to be an autoregressive process of a given order *p*, denoted AR(*p*). The model for an autoregressive process is of the form:

$$y_t = a + b_0 x_t + u_t$$

where, $u_t = \epsilon_t - \alpha_1 u_{t-1} - ... - \alpha_p u_{t-p}$
ϵ_t = normally and independently distributed white noise disturbance

The autoregression coefficients, α_i, are designated in the Appendix A estimation results as the name of the endogenous variable followed by "_L*p*", where *p* refers to the specified order (usually 1 in this version of *STIFS*). For example, the nonutility distillate fuel demand (equation A11) is estimated with a first-order autoregressive error term:

$$DSTCPUS_t = DSTC\_01 + DSTC\_AC * DFACPUS_t + u_t$$

where

$$u_t = \epsilon_t - DSTCPUS\_L1 * u_{t-1}$$

Distributed Lag Terms

Some equations explain the current values of endogenous variables as functions of past values of exogenous variables using a polynomial distributed lag structure (also called an Almon lag model). For a regression equation in which the coefficient on the exogenous variable, x_t, is a polynomial distributed lag structure of the form:

$$y_t = a + b_0 x_t + b_1 x_{t-1} + b_2 x_{t-2} + ... b_k x_{t-k}$$

where $b_i = \Sigma_j \alpha_j i^j$ j = 0 to n, n = degree of polynomial used
i = 0 to k, k = number of lags

The polynomial distributed lag is identified in the text as:

distlag(exogenous, degree=j, lags=i)

For example, the log of air travel capacity (equation A6) involves a distributed lag on the log of the aircraft utilization rate (LDRZM):

$$LDRTM_t = ...+ distlag(LDRZM, degree = 2, lags = 2) +...$$

The estimated coefficients. α_j, are reported in the Appendix A estimation results as the name of the endogenous variable followed by "*k_j*", where *k* refers to the distributed lag term (usually equal to 1 where no equation contains more than one distributed lag term) and *j* refers to the degree of the polynomial (j = 0 to n).

$$LDRTM_t = ...+ b_0 LDRZM_t + b_1 LDRZM_{t-1} + b_2 LDRZM_{t-2} + ...$$

where, $b_0 = LDRZM1\_1 + LDRZM1\_2$
$b_1 = LDRZM1\_0 + LDRZM1\_1 + LDRZM1\_2$
$b_2 = LDRZM1\_0 + 2 * LDRZM1\_1 + 4 * LDRZM1\_2$

"Add" Factors

Forecasts can be corrected by using additive and multiplicative factors which are included in some of the regression equations. These factors are exogenously specified variables whose values are either added to a specified forecast series or multiplied by the forecast series. These factors allow the analyst to incorporate expected changes in supply, demand, or prices due to new taxes, environmental regulations, other changes in government policy, or some other expected change in market dynamics. In addition, add factors can be used to generate simulations in which target values for endogenous variables can be achieved (for special analysis purposes) with exogenizing that portion of the model.

Additive and multiplicative factors are designated in regression equations as the first four or five letters of the dependent variable's names followed by "AD" pr "MU", respectively (see Appendix B for a list of additive and multiplicative factors names). The default value for add factors is 0 when no change to a forecast is desired. The default value for multiplicative factors is 1.

An example of these forecast correction factors is in the seasonally adjusted wholesale motor gasoline price (equation A77):

MGWHUUSA = (MGWHP_01 +...+ MGWHUAD) * MGWHUMU

In this example the add factor, MGWHUAD, may be used to account for the expected additional costs of blending oxygenates with motor gasoline during the forecast period winter months to comply with the Clean Air Act Amendments of 1990. The multiplicative factor, MGWHUUMU, could be used to account for new fees which are based on a percentage of the product's market price.

Deseasonalized Variables

Several regression equations are estimated using seasonally-adjusted data. If the variable ends in an "A", such as *MGUCUUSA*, then the data for *MGUCUUS* has been deseasonalized using seasonal factors (in this case, *MGUCUUSS*) from the U.S. Census X-11 multiplicative seasonal adjustment routine. To obtain non-seasonally adjusted projections, the forecasts developed from seasonally-adjusted equations are the reseasonalized using the Census X-11 seasonal adjustment factors. A list of seasonally-adjusted variables and their corresponding seasonal adjustment factors are provided in Appendix B.

Nonutility Petroleum Products Demand

Overview

In the STIFS model, nonutility petroleum products consist of the following: motor gasoline, jet fuel, nonutility distillate fuel oil, nonutility residual fuel oil, liquefied petroleum gases (LPG's), and the other (minor) petroleum products. The major determinants of demand for these products are transportation activity, economic activity, and weather. Utility demand for distillate and residual fuel oil is derived through simulation of the electricity model (see Electricity Supply and Demand section).

Detailed statistical information for each of the estimating equations is provided in Appendix A, tables A1 to A17. Data descriptions are summarized in Appendix B.

Motor Gasoline Demand

Two components comprise seasonally-adjusted motor gasoline demand. They are: (seasonally-adjusted) fleet fuel efficiency (MPGA) and highway travel activity (MVVMPUSA). Both series are deseasonalized prior to estimation to ensure greater forecast accuracy. These estimating relationships are presented below:

MPGA = (MEFF_01 + MEFF_T * TIME + MEFF_D02 * D8412 + MEFF_D03 * D8302 (A1)
+ MEFF_D04 * DRVP89 + MEFF_D05 * DRVP90
+ distlag (MGUCUUSA / CICPIUS, degree=1, lags=1)
+ MPGAAD) * MPGAMU

MVVMPUSA = (MVMT_01 + MVMT_YT * YD87OUS * TIME (A2)
+ MVMT_D01 * D8501 + MVMT_D02 * D89ON
+ distlag (MGUCUUSA / (MPGA * CICPIUS), degree=1, lags=1)
+ MVVMPAD) * MVVMPMU

The price terms, MGUCUUSA / CICPIUS and MGUUUUSA / (MPGA / CICPIUS), which represent (seasonally-adjusted) retail motor gasoline price per gallon and fuel cost per mile, respectively, are defined by one-month-long polynomial distributed lags with a polynomial degree of one. The dummy variables, D8412, D8302, and D8501 refer to months of unusually severe weather that affected motor gasoline demand. The dummy variable, DRVP89, refers to the implementation of new RVP standards during the summer months of 1989. DRVP90 pertains to RVP regulations which apply during the summer months of 1990 and following years. D89ON is an adjustment factor that reflects a one-time shift in the level of travel activity brought about by changes in reporting methodology beginning in 1989.

Fuel efficiency and highway travel activity define deseasonalized motor gasoline demand (MGTCPUSA) by the following identity:

MGTCPUSA = MVVMPUSA / MPGA / 42

These components are reseasonalized by their respective seasonal factors, MVVMPUSS and MPGS, to derive forecasts of motor gasoline demand, as depicted in the following relationship:

MGTCPUS = (MVVMPUSA * MVVMPUSS) / (MPGA * MPGS) / 42

The unleaded share of motor gasoline demand (MUTCSUS) is estimated using the following equation:

MUTCSUS = 1 / (1 + exp (MSH_01 + MSH_T * TIME + MSH_D01 * D88ON)) (A3)

Jet Fuel

As with motor gasoline, jet fuel demand is derived with the use of seasonally-adjusted data. For modeling purposes, kerosene jet fuel and naphtha jet fuel are regarded as one product in anticipation of the phasing out of naphtha jet fuel use in the military during the next few years. The identity that defines (deseasonalized) jet fuel demand (JFTCPUSA), consists of three components: aircraft utilization (RMZZPUSA), load factor (LFSA), and fuel efficiency (EFFSA). Each of these is modeled separately. The identity is defined as follows:

JFTCPUSA = RMZZPUSA / LFSA / EFFSA

Aircraft utilization requires yield projections as an explanatory variable. The (deseasonalized) inflation-adjusted yield (AARYFUSA), average ticket price divided by number of passenger miles, is estimated in logarithmic form (LDRYLD). It is a function of the inflation-adjusted wholesale price of kerosene jet fuel (JKTCUUSA / WPCPIUS).

LDRYLD = YLD0 + YLD1 * log (JKTCUUSA / WPCPIUS) + YLD2 * TIME + AARYFAD (A4)

The aircraft utilization rate (RMZZPUSA), revenue ton miles per day, is also modeled as a logarithmic function. The major explanatory variables are disposable income (YD87OUS) and yield.

LDRZM = RZM0 + RZM1 * log (YD87OUS * TIME) + RZM2 * D91 (A5)
+ distlag (LDRYLD, degree=2, lags=2) + RMZZPAD

The relationship shows that air travel activity responds to changes in ticket prices over a period of two months with a polynomial degree of 2. The projections are then retransformed for insertion into the jet fuel demand identity above:

RMZZPUSA = exp (LDRZM)

Air travel capacity (RMZTPUSA), available revenue ton miles per day, is also transformed into a logarithmic series (LDTRM) for modeling purposes to form the following equation:

LDRTM = RTM0 + RTM1 * D8082 + RTM2 * TIME (A6)
+ distlag (LDRZM, degree = 2, lags = 6) + RMZTPAD

The equation shows that airline capacity responds to shifts in utilization over a period of six months. That projection is then "delogged" to form RMZTPUSA and used as the denominator to define the (seasonally-adjusted) load factor (LFSA).

RMZTPUSA = exp (LDRTM)

LFSA = RMZZPUSA / RMZTPUSA

Load factor projections are inserted into the demand identity and also used as an explanatory variable in the equation for aircraft efficiency (EFFSA):

EFFSA = (EFF0 + EFF1 * LFSA + EFF2 * TIME + EFF3 * D8912 + EFFSAD) * EFFSMU (A7)

The deseasonalized demand projection for jet fuel (JFTCPUSA) is then reseasonalized:

JFTCPUS = JFTCPUSA * JFTCPUSS

Nonutility Distillate Fuel Oil

This product is modeled as three separate sectoral linear equations. The sectors are: (1) transportation; (2) residential and commercial; and (3) industrial and other nonutility consumers. Transportation demand (DFACPUS) is a function of manufacturing output (ZOMNIUS):

$$\begin{aligned} DFACPUS = (&DFAC\_01 + DFAC\_JQ * ZOMNIUS + DFAC\_06 * FEB + DFAC\_07 * MAR \\ &+ DFAC\_08 * APR + DFAC\_09 * MAY + DFAC\_10 * JUN + DFAC\_11 * JUL \\ &+ DFAC\_12 * AUG + DFAC\_13 * SEP + DFAC\_14 * OCT + DFAC\_15 * NOV \\ &+ DFAC\_16 * DEC + DFACPAD) * DFACPMU \end{aligned} \tag{A8}$$

Residential and commercial demand (DFHCPUS) is a function of the previous month's demand and the current month's population-weighted heating-degree-days deviation from normal in the Northeast (ZWHDDNO) adjusted for the number of days in each month (ZSAJQUS)

$$\begin{aligned} DFHCPUS = (&DFHC\_01 + DFHC\_R1 * DFHCPUS_{-1} + DFHC\_W * (ZWHDDNO / ZSAJQUS) \\ &+ DFHC\_06 * FEB + DFHC\_07 * MAR + DFHC\_08 * APR + DFHC\_09 * MAY \\ &+ DFHC\_10 * JUN + DFHC\_11 * JUL + DFHC\_12 * AUG + DFHC\_13 * SEP \\ &+ DFHC\_14 * OCT + DFHC\_15 * NOV + DFHC\_16 * DEC + DFHCPAD) * DFHCPMU \end{aligned} \tag{A9}$$

Industrial and other demand (DFICPUS) is modeled as a function of total industrial production (ZOTOIUS), a relative price term of wholesale distillate heating oil to industrial natural gas, and an adjustment factor (NGINPUSX - NGINPUS) that defines curtailments of natural gas deliveries to the industrial sector during peak periods (see Natural Gas Supply and Demand section). The factor (0.362*1.030 / 5.825) is the share (0.362) of total estimated switchable gas capacity in the industrial manufacturing sector (converted to million barrels per day) thought to be dedicated primarily to distillate fuel as an alternate fuel.[11] Thus, any reduction in industrial gas demand due to gas supply constraints are assumed to be made up by other fuels, with 36.2 percent (by Btu content) coming from distillate fuel oil.

$$\begin{aligned} DFICPUS = (&DFIC\_01 + (0.362*1.030 / 5.825) * (NGINPUSX-NGINPUS) \\ &+ DFIC\_JQ * ZOTOIUS + DFIC\_P * ((D2WHUUS*DFTCZUS) / (NGICUUS*NGNUKUS)) \\ &+ DFIC\_W * (ZWHDDUS / ZSAJQUS) * (OCT+NOV+DEC+JAN+FEB+MAR+APR) \\ &+ DFIC\_06 * FEB + DFIC\_07 * MAR + DFIC\_08 * APR + DFIC\_09 * MAY \\ &+ DFIC\_10 * JUN + DFIC\_11 * JUL + DFIC\_12 * AUG + DFIC\_13 * SEP \\ &+ DFIC\_14 * OCT + DFIC\_15 * NOV + DFIC\_16 * DEC + DFICPAD) * DFICPMU \end{aligned} \tag{A10}$$

Total nonutility demand (DFNUPUS) is the sum of the three sectoral demands:

$$DFNUPUS = DFACPUS + DFHCPUS + DFICPUS$$

Demand for No. 2 diesel fuel through company-owned outlets (DSTCPUS) is also estimated for reporting purposes only:

$$DSTCPUS = DSTC\_01 + DSTC\_AC * DFACPUS \tag{A11}$$

Nonutility Residual Fuel Oil

Nonutility heavy fuel oil demand (RFNUPUS) is modeled as a linear function of the index of industrial production (ZOMNIUS), heating degree-days (ZWHDPUS), the relative price of retail residual fuel oil (RFTCUUS*RFTCZPUS) to industrial natural gas (NGICUUS / NGNUKUS), a winter dummy variable (DUMWTR) defined as one for October through March and zero elsewhere, and the proxy for curtailments of natural gas deliveries (NGINPUSX - NGINPUS). The factor (0.321*1.030 / 6.287) is the share (0.321) of total

[11] The shares of alternate fuels for switchable natural gas capacity are taken from the Energy Information Administration, *Manufacturing Energy Consumption Survey: Fuel Switching, 1985*, DOE / EIA-0515(88), Table 4.

estimated switchable gas capacity in the industrial manufacturing sector (converted to million barrels per day) thought to be dedicated primarily to residual fuel as an alternate fuel. Thus, any reduction in industrial gas demand due to gas supply constraints are assumed to be made up by other fuels, with 32.1 percent (by Btu content) coming from residual fuel oil.

$$\begin{aligned} RFNUPUS = {} & RFNU\_01 + RFNU\_JQ * ZOMNIUS + RFNU\_W * ZWHDPUS \\ & + RFNU\_P * ((RFTCUUS*RFTCZUS) / (NGICUUS*NGNUKUS)) \\ & + RFNU\_D2 * DUMWTR + (0.321*1.03 / 6.287) * (NGINPUSX-NGINPUS) \\ & + RFNU\_W1 * HDDX85 + RFNU\_T * TIMEX85 + RFNU\_T1 * PRE85XT \\ & + RFNU\_D1 * POST85 + RFNU\_D3 * D8809 \end{aligned} \tag{A12}$$

Liquefied Petroleum Gases (LPG's)

Demand for liquefied petroleum gases (LGTCPUS) is disaggregated into demand for ethane (ETTCPUS) and LPG's heavier than ethane (LXTCPUS):

$$LGTCPUS = ETTCPUS + LXTCPUS$$

The deseasonalized demand for ethane (ETTCPUSA) is estimated using the following linear equation:

$$\begin{aligned} ETTCPUSA = {} & (ETH0 + ETH1 * (D2WHUUSA / NGEUDUSA) + ETH2 * D8184 \\ & + ETH3 * TD8184 + ETH4 * D8990 + ETH5*TD8990) * ETTCPMU \end{aligned} \tag{A13}$$

The relative price of wholesale distillate to the price for natural gas to electric utilities (D2WHUUSA / NGEUDUSA) is the principal driver in the equation. The absence of a proxy explanatory variable for economic growth such as petrochemical or industrial demand reflects the lack of upward trend in demand for this product. The ethane equation is reseasonalized after the initial demand estimation:

$$ETTCPUS = ETTCPUSA * ETTCPUSS$$

Demand for LPG's excluding ethane (LXTCPUS) is a linear function of the previous month's demand, day-weighted heating degree-days' deviations from normal (ZWHDPUS-ZWHNPUS) / ZSAJQUS, the index of chemical production (ZO28IUS), and an adjustment factor (NGINPUSX-NGINPUS) that defines interruptions of natural gas deliveries to industrial customers. The factor (0.273*1.030 / 3.836) is the share (0.273) of total estimated switchable gas capacity in the industrial manufacturing sector (converted to million barrels per day) thought to be dedicated primarily to LPG's as an alternate fuel. Thus, any reduction in industrial gas demand due to gas supply constraints are assumed to be made up by other fuels, with 27.3 percent (by Btu content) coming from liquefied petroleum gas.

$$\begin{aligned} LXTCPUSA = {} & (LXT0 + LXT2 * LXTCPUSA_{-1} + LXT1 * (ZWHDPUS-ZWHNPUS) / ZSAJQUS \\ & + LXT3 * ZO28IUS + (0.273*1.03 / 3.836) * (NGINPUSX-NGINPUS) \\ & + LXT4 * D9001 + LXTCPAD) * LXTCPMU \end{aligned} \tag{A14}$$

Subsequent reseasonalization yields the non-seasonally adjusted demand for this product group, as shown below:

$$LXTCPUS = LXTCPUSA * LXTCPUSS$$

Although propane (PRTCPUS) is part of the LPG product group (LXTCPUS), the STIFS model includes a separate estimating equation for propane. This variable is used in the estimation of propane retail sales volume in the petroleum supply portion of the STIFS model (see equation A47). Because propane constitutes the bulk of the LXTCPUS group, LXTCPUS is the principal explanatory variable in the equation:

$$PRTCPUS = PRTC\_01 + PRTC\_Q * LXTCPUS + PRTC\_06 * JAN + PRTC\_07 * FEB \tag{A15}$$

+ PRTC_08 * MAR + PRTC_09 * APR + PRTC_10 * MAY + PRTC_11 * JUN
+ PRTC_12 * JUL + PRTC_13 * AUG + PRTC_14 * SEP + PRTC_15 * OCT
+ PRTC_16 * NOV

Other Petroleum Products

This group of products, sometimes referred to as "minor" petroleum products, is comprised of oil-based petrochemical feedstocks, and miscellaneous products.

Petrochemical Feedstocks

The oil-based petrochemical feedstocks (FETCPUS) category consists of naphtha and other oils > 400 degrees. The deseasonalized series (FETCPUSA) is modeled in logarithmic form:

LSFET = FET0 + FET1 * log (ZO28IUS) + FET2 * log (WP57IUS / WPCPIUS) + FETCPAD (A16)

The equation shows that petrochemical feedstocks are a logarithmic function of petrochemical activity and the producer price index of petroleum products adjusted by the producer price index for all goods. The following equations summarize the delogging and reseasonalization steps to generate the forecast for this product group:

FETCPUSA = exp(LSFET)
FETCPUS = FETCPUSA * FETCPUSS

Miscellaneous Products

The miscellaneous products category (MITCPUS) consists of nine products: aviation gasoline, kerosene, special naphthas, lubricants, waxes, petroleum coke, asphalt and road oil, refinery gas, and other products defined as miscellaneous products in the *Petroleum Supply Monthly*. As with petrochemical feedstocks, the category is deseasonalized and restated in logarithmic form for estimation purposes:

LSMIS = MIS0 + distlag (log(WP57IUS / WPCPIUS, degree=2, lags=6) (A17)
+ MIS1 * log (ZOMNIUS) + MIS2 * D8301 + MIS3 * D8412
+ MIS4 * D8611 + MIS5 * D8912 + MITCPAD

The industrial production index (ZOMNIUS) and a 6-month distributed lag for the inflation adjusted producer price index for petroleum products (WP57IUS / WPCPIUS) are the main determinants for this category. The corresponding delogging and reseasonalization steps are summarized below:

MITCPUSA = exp (LSMIS)
MITCPUS = MITCPUSA * MITCPUSS

In addition to the categories explicitly modeled in the STIFS demand model, the other petroleum products group includes two components which are not modeled with conventional behavioral equations. These components are (a) crude oil directly consumed and pentanes plus, and (b) unfinished oils and motor gasoline blending components. Crude oil directly consumed (COTCPUS) is assumed to be a constant 20 thousand barrels per day throughout the forecast interval. Pentanes plus (PPTCPUS), unfinished oils (UOTCPUS), and motor gasoline blending components (MBTCPUS) are assumed to be proportions of miscellaneous products (MITCPUS) based on actual demand for the last 12 months of the estimation interval. These relationships are defined below:

COTCPUS = 0.020
PPTCPUS = 0.099773 * MITCPUS
UOTCPUS = - 0.10271 * MITCPUS
MBTCPUS = 0.020938 * MITCPUS

Petroleum Products Supply

Overview

The driving forces in the STIFS refined crude oil product supply model are estimated refinery inputs and refined product demands. Estimated refinery outputs of individual products yield share weights with which to disaggregate total refinery inputs. Net product imports then bear the burden of balancing refined product supply and demand by individual product.

Inputs to refineries include crude oil, unfinished oils, liquefied petroleum gases, pentanes plus, aviation gasoline blending components, and "other" petroleum inputs. Refinery capacity presents a constraint on refinery inputs of crude oil and unfinished oils. The most recently reported operable refining capacity is carried through the forecast period unless a change in capacity is exogenously specified by the analyst. If projected refinery inputs exceed a specified operating factor (e.g., 92 percent of operable capacity), crude and unfinished oils are proportionately scaled downwards so that the constraint is satisfied.

Six categories of refinery outputs - motor gasoline, jet fuel, distillate fuel, residual fuel, and liquefied petroleum gases (LPGs), and "other" petroleum products - are represented individually in the model. The sixth category, other petroleum products, consists of petrochemical feedstocks, petroleum coke, waxes, lubricants, etc. Total refinery output is adjusted to equal total refinery inputs plus a refinery volumetric processing gain. Each refinery output is proportionately scaled upwards or downwards so that a refinery material balance holds.

The sources of crude oil supply to refineries include domestic production, net imports, inventory change, and imbalances between imports for the Strategic Petroleum Reserve (SPR) and the SPR fill rate (or withdrawal from the SPR for sales). Forecasts of domestic crude oil production are supplied by the EIA Office of Oil and Gas, Reserves and Natural Gas Division (refer to Appendix E for a description of the domestic crude oil production estimation method). Forecasts of the SPR balance are supplied by the EIA Office of Technical Management, Strategic Petroleum Reserve. Crude oil demand is represented by inputs to oil refineries, crude oil used directly as fuel, and losses. Imbalances between crude oil supply and demand are carried by an "unaccounted for" crude oil term.

Refinery Inputs and Outputs

Refinery Inputs

Inputs to refineries include crude oil, unfinished oils, liquefied petroleum gases, pentanes plus, aviation gasoline blending components, and "other" petroleum inputs.

Refinery input of crude oil (CORIPUS) is estimated as a linear function of a distributed lag of total petroleum demand (PATCPUS), one-month lags of motor gasoline stocks (MGPSPUS) and distillate stocks (DFPSPUS), and monthly dummy variables. The lagged relationship with demand is motivated by the notion that refiners will not adjust refinery runs immediately in response to short-run demand shifts, but will do so gradually, particularly so long as adequate primary product inventories (MGPSPUS and DFPSPUS) are available.

$$\begin{aligned} \text{CORIPUSJ} = {} & \text{COR\_B0} + \text{distlag (PATCPUS, degree=3, lags=6)} \\ & + \text{COR\_MGPS} * \text{MGPSPUS}_{-1} + \text{COR\_DFPS} * \text{DFPSPUS}_{-1} \\ & + \text{CORI\_E1} * \text{JAN} + \text{CORI\_E2} * \text{FEB} + \text{CORI\_E3} * \text{MAR} + \text{CORI\_E4} * \text{APR} \\ & + \text{CORI\_E5} * \text{MAY} + \text{CORI\_E6} * \text{JUN} + \text{CORI\_E7} * \text{JUL} + \text{CORI\_E8} * \text{AUG} \\ & + \text{CORI\_E9} * \text{SEP} + \text{CORI\_E10} * \text{OCT} + \text{CORI\_E11} * \text{NOV} + \text{CORIPAD} \end{aligned} \tag{A18}$$

Refinery input of unfinished oils (UORIPUS) is estimated as a function of total petroleum product demand (PATCPUS) and monthly dummy variables:

$$UORIPUSJ = UORI\_B0 + UORI\_PA * PATCPUS + UORI\_D1 * D90ON + UORI\_E1 * JAN + UORI\_E2 * FEB + UORI\_E3 * MAR + UORI\_E4 * APR + UORI\_E5 * MAY + UORI\_E6 * JUN + UORI\_E7 * JUL + UORI\_E8 * AUG + UORI\_E9 * SEP + UORI\_E10 * OCT + UORI\_E11 * NOV + UORIPAD \quad (A19)$$

Total input to primary crude distillation (CODIPUS) is estimated from refinery inputs of crude oil and unfinished oils.

$$CODIPUSJ = CODI\_CO * CORIPUSJ + CODI\_UO * UORIPUSJ \quad (A20)$$

Total inputs to primary crude distillation are restricted to be less than or equal to 92% of total refinery atmospheric distillation capacity (ORCAPUS). The utilization rate is seen as the maximum monthly operable refinery utilization rate. The most recently reported operable refinery distillation capacity is carried through the forecast period unless a change in capacity is exogenously specified by the analyst. If this restriction is violated, crude oil and unfinished oil inputs to refineries are proportionately adjusted downwards.

$$CODIPUS = \min(CODIPUSJ, ORCAPUS * .920)$$

$$CORIPUS = CORIPUSJ * CODIPUS \ / \ CODIPUSJ$$
$$UORIPUS = UORIPUSJ * CODIPUS \ / \ CODIPUSJ$$

Refinery inputs are then deseasonalized using seasonal factors estimated using the Census X-11 multiplicative seasonal adjustment routine for use as independent variables in other estimating equations:

$$CORIPUSA = CORIPUS \ / \ CORIPUSS$$
$$UORIPUSA = UORIPUS \ / \ UORIPUSS$$

Refinery utilization rate (ORUTCUS) is defined as total inputs to crude distillation units divided by operable refinery atmospheric distillation capacity:

$$ORUTCUS = CODIPUS \ / \ ORCAPUS$$

Linear regression equations are also estimated for refinery inputs of liquefied petroleum gases (LGRIPUSA), pentanes plus (PPRIPUSA), and "other" petroleum inputs (PSRIPUS).[12] A volume ratio of the annual averages of each refinery input to total annual average gasoline production (DUMYRLG, DUMYRPP, and DUMYRPS, respectively) is included as an explanatory variable in each of the three regressions. Thus, they are the same for all months within a year, but differ from year to year. The values of the DUMYxxx variables for the last full year of the estimation period are retained as the values for the forecast period (and the final year of the estimation period if it does not cover a full twelve months).

$$LGRIPUSA = LGRI\_B0 + LGRI\_MG * MGTCPUSA + LGRI\_DL * DUMYRLG \quad (A21)$$

$$LGRIPUS = LGRIPUSA * LGRIPUSS$$

$$PPRIPUSA = PPRI\_B0 + PPRI\_MG * MGTCPUSA + PPRI\_DP * DUMYRPP \quad (A22)$$

$$PPRIPUS = PPRIPUSA * PPRIPUSS$$

$$PSRIPUS = PSRI\_DP * DUMYRPS + PSRI\_E2 * FEB + PSRI\_E3 * MAR + PSRI\_E4 * APR + PSRI\_E9 * SEP + PSRI\_E10 * OCT + PSRIPAD \quad (A23)$$

[12] Inputs of "other" petroleum products, PSRIPUS, is not seasonally adjusted because the series contains some negative values (January, 1989 and February, 1990) which cannot estimated using the Census X-11 method (without some adjustment to the series such as rescaling). This inconsistency is small and is assumed to insignificantly affect the results.

Refinery inputs of aviation gasoline blending components (ABRIPUS) is constrained to equal 0:

ABRIPUS = 0

Aggregate measures of refinery inputs are calculated for crude oil and unfinished oils (CURIPUS), other refinery inputs (MBOLPUS), and total refinery inputs (PARIPUS) by the following identities:

CURIPUS = CORIPUS + UORIPUS
MBOLPUS = LGRIPUS + PPRIPUS + PSRIPUS
PARIPUS = CORIPUS + UORIPUS + LGRIPUS + PPRIPUS + PSRIPUS + ABRIPUS

Refinery Outputs

Six categories of refinery outputs are estimated: (1) motor gasoline; (2) distillate fuel oil; (3) jet fuel; (4) residual fuel; (5) liquefied petroleum gases (LPGs); and (6) "other". The sixth category, other petroleum products, consists of petrochemical feedstocks, petroleum coke, waxes, lubricants, still gas, asphalt and road oil, special naphthas, kerosene, finished aviation gasoline, and miscellaneous products.

All refinery output series are deseasonalized using the Census X-11 multiplicative seasonal adjustment routine. The independent variables in the refinery output regression equations are specified on the basis of whether the product (dependent variable) is a substitute or complement to other products. All variables, for example, are treated as complements in production when the level of refinery inputs is changed, i.e., all dependent variables are positive functions of the level of refinery inputs.

The motor gasoline output (MGROPUSA) and distillate output (DFROPUSA) regressions also treat these two products as substitutes in production from a fixed supply of refinery inputs (both variables are a function of the motor gasoline-distillate wholesale price ratio).

MGROPUSA = MGRO_B0 + MGRO_PR * MGWHUUSA / D2WHUUSA + MGROPAD (A24)
+ MGRO_CO * (CORIPUSA + PSRIPUS + UORIPUSA + LGRIPUSA + PPRIPUSA)

DFROPUSA = DFRO_B0 + DFRO_PR * MGWHUUSA / D2WHUUSA (A25)
+ DFRO_CO * (CORIPUSA + PSRIPUS + UORIPUSA)

Jet fuel output (JFROPUSA) is assumed to be a substitute in production of both gasoline and distillate (though statistical significance does not hold for the reciprocal relationship in the gasoline and distillate equations).

JFROPUSA = (JFRO_B0 + JFRO_CO * (CORIPUSA + PSRIPUS + UORIPUSA) (A26)
+ JFRO_P1 * MGWHUUSA / JKTCUUSA + JFRO_P2 * D2WHUUSA / JKTCUUSA
+ JFRO_D1 * D90ON + JFROPAD) * JFROPMU

Residual fuel oil output (RFROPUSA) is not significantly associated with relative petroleum product prices.

RFROPUSA = RFRO_B0 + RFRO_CO * (CORIPUSA + PSRIPUS + UORIPUSA) (A27)

Refinery output of LPGs (LGROPUSA) is found to be in part a byproduct to the production of gasoline.

LGROPUSA = LGRO_B0 + LGRO_CO * (CORIPUSA + PSRIPUS + UORIPUSA) (A28)
+ LGRO_MG * MGROPUSA

The refinery output of "other" petroleum products (PSROPUSA) presents problems in modeling because of the variety of products carried under its umbrella. For simplicity, refinery output of other petroleum products is posited to be a function of its own demand, in addition to being directly related to primary refinery inputs.

PSROPUSA = PSRO_B0 + PSRO_CO * (CORIPUSA + PSRIPUS + UORIPUSA) (A29)
+ PSRO_TC * PSTCPUSA

Balancing Refinery Outputs With Refinery Inputs

Refinery outputs are scaled upwards or downwards based on total refinery inputs and refinery volume processing gain. A volume ratio of the average annual refinery processing gain (PAGLPUS) to average annual refinery inputs of crude oil and unfinished oils (CORIPUS + UORIPUS) is calculated. The value of the refinery processing gain fraction, DUMYZWPG, for the last full year of the estimation period is retained for the forecast period. Total estimated refinery input plus processing gain is then multiplied by calculated refinery output shares for corrected refinery output volumes.

PAGLPUS = DUMYZWPG * (CORIPUS + UORIPUS)

PAROPUSX = MGROPUSA * MGROPUSS + DFROPUSA * DFROPUSS
+ JFROPUSA * JFROPUSS + LGROPUSA * LGROPUSS
+ PSROPUSA * PSROPUSS + RFROPUSA * RFROPUSS

PAROBAL = (PARIPUS + PAGLPUS) / PAROPUSX

MGROPUS = MGROPUSA * MGROPUSS * PAROBAL
DFROPUS = DFROPUSA * DFROPUSS * PAROBAL
JFROPUS = JFROPUSA * JFROPUSS * PAROBAL
LGROPUS = LGROPUSA * LGROPUSS * PAROBAL
PSROPUS = PSROPUSA * PSROPUSS * PAROBAL
RFROPUS = RFROPUSA * RFROPUSS * PAROBAL

Individual corrected refinery outputs are then summed to arrive at total refinery output:

PAROPUS = MGROPUS + DFROPUS + JFROPUS + LGROPUS + PSROPUS + RFROPUS

Crude Oil Supply and Net Crude Oil Imports

The sources of crude oil supply to U.S. refineries include domestic production, net imports, inventory change, and imbalances between imports for the Strategic Petroleum Reserve (SPR) and the SPR fill rate. Crude oil demand is represented by inputs to oil refineries, crude oil used directly as fuel, and crude oil losses. Imbalances between crude oil supply and demand are carried by an "unaccounted for" crude oil term.

Total domestic crude oil production (COPRPUS) is calculated from exogenously specified production in the lower-48 states (PAPRP48) and Alaska (PAPRPAK) by the identity:

COPRPUS = PAPRP48 + PAPRPAK

Net imports of crude oil other than for the Strategic Petroleum Reserve (CONXPUS) are estimated based on the levels of domestic crude oil production and refinery inputs of crude oil. Crude oil net imports reported in the *Petroleum Supply Monthly* are adjusted to include imbalances between imports for the SPR (COCQPUS) and the SPR fill rate (COQMPUS).

CONXPUS = COCQPUS - COQMPUS + CONX_RI * CORIPUS + CONX_PR * COPRPUS (A30)

Total crude oil net imports including the SPR (CONIPUS) are defined by the following identity:

CONIPUS = CONXPUS + COQMPUS

Crude oil gross exports (COEXPUS) are estimated as a constant with seasonal dummies and a dummy variable to capture a shift in crude exports beginning in 1990:

COEXPUS = COEX_B0 + COEX_D1 * D90ON (A31)
+ COEX_E1 * JAN + COEX_E2 * FEB + COEX_E3 * MAR + COEX_E4 * APR
+ COEX_E5 * MAY + COEX_E6 * JUN + COEX_E7 * JUL + COEX_E8 * AUG
+ COEX_E9 * SEP + COEX_E10 * OCT + COEX_E11 * NOV

Total crude oil gross imports (COIMPUS) are then defined by the identity:

COIMPUS = CONXPUS + COEXPUS + COQMPUS

The Strategic Petroleum Reserve (SPR) fill rate (COCQPUS) and SPR supply from domestic crude oil (CODQPUS) are exogenously specified.

For simulations, imports of crude for the SPR (COQMPUS) are set equal to the SPR fill rate (if positive) less purchases of domestic crude for the SPR.

CODQPUSX = CODQPUS
COQMPUS = COCQPUS - CODQPUSX

The level of crude inventory excluding the SPR (COSXPUS) is exogenously specified in the model. The SPR inventory level (COSQPUS) is projected using the identity:

COSQPUS = COSQPUS_{-1} + COCQPUS * ZSAJQUS

Crude oil losses (COLOPUS) have historically been very small (less than 5,000 barrels per day since 1981 and less than 500 barrels per day since 1986). Strictly for the purpose of generating a plausible simulation mechanism for this variable, crude oil loss is estimated as a constant with seasonal variation:

COLOPUS = COLO_B0 + COLO_E1 * JAN + COLO_E2 * FEB + COLO_E3 * MAR (A32)
+ COLO_E4 * APR + COLO_E5 * MAY + COLO_E6 * JUN + COLO_E7 * JUL
+ COLO_E8 * AUG + COLO_E9 * SEP + COLO_E10 * OCT + COLO_E11 * NOV

Crude oil product supplied (COTCPUS), which primarily represents crude oil used directly as fuel, is set at a fixed value of 20,000 barrels per day in the Miscellaneous Petroleum Demands Model:

COTCPUS = 0.020

Balancing Crude Oil Supply and Demand

A balance between crude oil supply and demand is attained by the identity for unaccounted for crude oil (COUNPUS):

COUNPUS = COPRPUS + CONXPUS + COQMPUS - COCQPUS - COLOPUS
- COTCPUS - CORIPUS - (COSXPUS - COSXPUS_{-1}) / ZSAJQUS

Field Production

Three other refinery inputs are also domestically produced: LPG's, pentanes plus, and other hydrocarbons/alcohols. LPG's and pentanes plus are recovered as liquids from natural gas production. Other hydrocarbons/alcohols represent several sources of refinery inputs such as methyl tertiary butyl ether (MTBE) produced by petrochemical plants.

Field production of LPGs (LGFPPUS) and pentanes plus (PPFPPUS) are calculated as NGL plant liquid production (NLPRPUS) times the LPG or pentane plus fraction of total NGL liquid production. The LPG and pentane plus fractions of NGL plant liquid production (PRNLSUS and PPNLSUS, respectively) are exogenously specified.

$$LGFPPUS = NLPRPUS * PRNLSUS$$
$$PPFPPUS = NLPRPUS * PPNLSUS$$

NGL plant liquid production (NLPRPUS) is estimated from the difference in thermal content between wet and dry natural gas (see Natural Gas section for estimation of wet and dry natural gas production).

$$NLPRPUS = NLPR\_B0 + NLPR\_01 * (NGMPPUS * NAPRKUS - NGPRPUS * NGPRKUS) \qquad (A33)$$

An estimating equation for field production of other hydrocarbons/alcohol (OHRIPUS) is included in the model. However, projections from this equation are overridden by an exogenously specified forecast developed off-line to accommodate MTBE blending under the new winter oxygenated gasoline program:

$$OHRIPUS = OHRIPAD + (MGTCPUS + 10/ZSAJQUS) / 100$$

No field production of motor gasoline (MGFPPUS), distillate fuel (DFFPPUS), jet fuel (JFFPPUS), residual fuel (RFFPPUS), and unfinished oils and gasoline blending components (PSFPPUS) has been reported since December, 1988. In the model, field production of each of these streams is exogenously constrained to zero.

Inventories

Inventories of most raw materials and refined products for the forecast period are exogenously specified. Total raw material plus refined product inventory (PASXPUS) is specified by the following identity:

$$\begin{aligned} PASXPUS = {} & COSXPUS + UOPSPUS + PPPSPUS + MGPSPUS + JFPSPUS \\ & + DFPSPUS + RFPSPUS + LGPSPUS + PSPSPUS + MBPSPUS \end{aligned}$$

Inventory of pentanes plus (PPPSPUS) is estimated as a fixed stock with seasonal variation:

$$\begin{aligned} PPPSPUS = {} & PPPS\_B0 + PPPS\_E1 * JAN + PPPS\_E2 * FEB + PPPS\_E3 * MAR \qquad (A34) \\ & + PPPS\_E4 * APR + PPPS\_E5 * MAY + PPPS\_E6 * JUN + PPPS\_E7 * JUL \\ & + PPPS\_E8 * AUG + PPPS\_E9 * SEP + PPPS\_E10 * OCT + PPPS\_E11 * NOV \end{aligned}$$

The inventory of propane (PRPSPUS) is estimated as a function of the total inventory of LPGs (LGPSPUS):

$$PRPSPUS = PRPS\_LG * LGPSPUS \qquad (A35)$$

Imports and Exports

The STIFS model estimates gross exports, calculates net imports by means of a material balance around refinery output, inventory change and product demand, and then derives gross imports as the sum of net imports and gross exports.

	Gross Imports		Gross Exports		Net Imports
Pentanes plus	PPIMPUS	-	PPEXPUS	=	PPNIPUS
Unfinished oils	n/a		n/a		UONIPUS
Motor gasoline	MGIMPUS	-	MGEXPUS	=	MGNIPUS
Distillate fuel oil	DFIMPUS	-	DFEXPUS	=	DFNIPUS
Residual fuel oil	RFIMPUS	-	RFEXPUS	=	RFNIPUS
Jet fuel	JFIMPUS	-	JFEXPUS	=	JFNIPUS
LPGs	LGIMPUS	-	LGEXPUS	=	LGNIPUS
"Other" petroleum products	PSIMPUS	-	PSEXPUS	=	PSNIPUS

Refined product gross exports are modeled as constants with seasonal variation. Gross exports of motor gasoline (MGEXPUS) and distillate fuel oil (DFEXPUS) include a dummy variable for all months from January 1990 on to capture the recent increase in exports of these two products. Gross exports of jet fuel (JFEXPUS) include dummy variables which represent the Desert Shield and Desert Storm months. Gross exports of other petroleum products (PSEXPUS) includes the inverse of time (1/TIME) and as independent variable.

$$\begin{aligned} MGEXPUS = {} & MGEX\_B0 + MGEX\_E1 * JAN + MGEX\_E2 * FEB + MGEX\_E3 * MAR \\ & + MGEX\_E4 * APR + MGEX\_E5 * MAY + MGEX\_E6 * JUN \\ & + MGEX\_E7 * JUL + MGEX\_E8 * AUG + MGEX\_E9 * SEP \\ & + MGEX\_E10 * OCT + MGEX\_E11 * NOV + MGEX\_D1 * D9009ON \end{aligned} \tag{A36}$$

$$\begin{aligned} DFEXPUS = {} & DFEX\_B0 + DFEX\_E1 * JAN + DFEX\_E2 * FEB + DFEX\_E3 * MAR \\ & + DFEX\_E4 * APR + DFEX\_E5 * MAY + DFEX\_E6 * JUN \\ & + DFEX\_E7 * JUL + DFEX\_E8 * AUG + DFEX\_E9 * SEP \\ & + DFEX\_E10 * OCT + DFEX\_E11 * NOV + DFEX\_D1 * D9009ON \end{aligned} \tag{A37}$$

$$\begin{aligned} RFEXPUS = {} & RFEX\_B0 + RFEX\_E1 * JAN + RFEX\_E2 * FEB + RFEX\_E3 * MAR \\ & + RFEX\_E4 * APR + RFEX\_E5 * MAY + RFEX\_E6 * JUN \\ & + RFEX\_E7 * JUL + RFEX\_E8 * AUG + RFEX\_E9 * SEP \\ & + RFEX\_E10 * OCT + RFEX\_E11 * NOV \end{aligned} \tag{A38}$$

$$\begin{aligned} JFEXPUS = {} & JFEX\_B0 + JFEX\_E1 * JAN + JFEX\_E2 * FEB + JFEX\_E3 * MAR \\ & + JFEX\_E4 * APR + JFEX\_E5 * MAY + JFEX\_E6 * JUN \\ & + JFEX\_E7 * JUL + JFEX\_E8 * AUG + JFEX\_E9 * SEP \\ & + JFEX\_E10 * OCT + JFEX\_E11 * NOV \\ & + JFEX\_D1 * DSHIELD + JFEX\_D2 * DSTORM \end{aligned} \tag{A39}$$

$$\begin{aligned} LGEXPUS = {} & LGEX\_B0 + LGEX\_E1 * JAN + LGEX\_E2 * FEB + LGEX\_E3 * MAR \\ & + LGEX\_E4 * APR + LGEX\_E5 * MAY + LGEX\_E6 * JUN \\ & + LGEX\_E7 * JUL + LGEX\_E8 * AUG + LGEX\_E9 * SEP \\ & + LGEX\_E10 * OCT + LGEX\_E11 * NOV \end{aligned} \tag{A40}$$

$$\begin{aligned} PSEXPUS = {} & PSEX\_B0 + PSEX\_E1 * JAN + PSEX\_E2 * FEB + PSEX\_E3 * MAR \\ & + PSEX\_E4 * APR + PSEX\_E5 * MAY + PSEX\_E6 * JUN \\ & + PSEX\_E7 * JUL + PSEX\_E8 * AUG + PSEX\_E9 * SEP \\ & + PSEX\_E10 * OCT + PSEX\_E11 * NOV + PSEX\_ET * 1 \,/\, TIME \end{aligned} \tag{A41}$$

$$\begin{aligned} PPEXPUS = {} & PPEX\_B0 + PPEX\_E1 * JAN + PPEX\_E2 * FEB + PPEX\_E3 * MAR \\ & + PPEX\_E4 * APR + PPEX\_E5 * MAY + PPEX\_E6 * JUN \end{aligned} \tag{A42}$$

$$+ PPEX\_E7 * JUL + PPEX\_E8 * AUG + PPEX\_E9 * SEP + PPEX\_E10 * OCT + PPEX\_E11 * NOV + PPEX\_D1 * D89$$

Net imports of LPGs (LGNIPUS), pentanes plus (PPNIPUS), and unfinished oils (UONIPUS) are balanced around demand, inventory change, refinery inputs, refinery outputs (except unfinished oils), and field production (except unfinished oils). In the LPG import balance (LGNIPUS), demand is separated into LPGs excluding ethane (LXTCPUS) and ethane (ETTCPUS).

$$LGNIPUS = LXTCPUS + ETTCPUS + (LGPSPUS - LGPSPUS_{-1}) / ZSAJQUS + LGRIPUS - LGROPUS - LGFPPUS$$

$$PPNIPUS = PPTCPUS + (PPPSPUS - PPPSPUS_{-1}) / ZSAJQUS + PPRIPUS - PPROPUS - PPFPPUS$$

$$UONIPUS = UOTCPUS + (UOPSPUS - UOPSPUS_{-1}) / ZSAJQUS + UORIPUS$$

Net imports of refined products are derived using a material balance identity around product demand, inventory change, refinery output, and field production:

$$MGNIPUS = MGTCPUS + (MGPSPUS - MGPSPUS_{-1}) / ZSAJQUS - MGROPUS - MGFPPUS$$

$$DFNIPUS = DFTCPUS + (DFPSPUS - DFPSPUS_{-1}) / ZSAJQUS - DFROPUS - DFFPPUS$$

$$RFNIPUS = RFTCPUS + (RFPSPUS - RFPSPUS_{-1}) / ZSAJQUS - RFROPUS - RFFPPUS$$

$$JFNIPUS = JFTCPUS + (JFPSPUS - JFPSPUS_{-1}) / ZSAJQUS - JFROPUS - JFFPPUS$$

Net imports of "other" petroleum liquids (PSNIPUS) includes miscellaneous petroleum products, petrochemical feedstocks, and motor and aviation gasoline blending components.

$$PSNIPUS = PSTCPUS - COTCPUS - PPTCPUS + MBTCPUS + ABTCPUS + (PSPSPUS - PSPSPUS_{-1}) / ZSAJQUS + (MBPSPUS - MBPSPUS_{-1}) / ZSAJQUS + PSRIPUS - PSROPUS - PSFPPUS - OHRIPUS$$

Where,

$$PSTCPUS - COTCPUS - PPTCPUS = AVTCPUS + KSTCPUS + LUTCPUS + ARTCPUS + SGTCPUS + FETCPUS$$

Two aggregate measures of imports are calculated using identities: gross imports of crude oil plus net imports of unfinished oils (RAIMPUS) and net imports of refined finished and unfinished products (PANIPUS):

$$RAIMPUS = CONXPUS + COEXPUS + UONIPUS$$

$$PANIPUS = MGNIPUS + DFNIPUS + RFNIPUS + JFNIPUS + LGNIPUS + PPNIPUS + UONIPUS + PSNIPUS$$

Average Quarterly and Annual Price Weights

Volumes of motor gasoline and distillate sales for resale (MGWHPUS and D2WHPUS, respectively) and residual fuel, jet fuel, and propane product sales to end users (RFESPUS, JKESPUS, and PRESPUS, respectively) are estimated and used to volume weight monthly product prices to arrive at average quarterly and annual prices:

$$MGWHPUS = MGWH\_TC * MGTCPUS \qquad (A43)$$

D2WHPUS = D2WH_B0 + D2WH_TC * DFTCPUS (A44)

RFESPUS = RFES_B0 + RFES_TC * RFTCPUS + RFES_D1 * D90ON (A45)

JKESPUS = JKES_TC * JFTCPUS (A46)

PRESPUS = PRES_B0 + PRES_TC * PRTCPUS + PRES_D1 * D90ON (A47)

These quantity weights are carried in the STIFS forecast and used to derive weighted average prices not because they are of particular interest themselves, but because they are used as quantity weights to calculate average quarterly or annual prices in EIA historical data publications, such as the *Monthly Energy Review*. Extending these weights into the forecast period ensures compatability of average price calculations across time and between EIA publications.

Electricity Supply and Demand

Overview

The STIFS model determines monthly aggregate U.S. electricity demand by four major sectors and provides a national-level supply balance. Electricity supply is determined in terms of electric utility net electricity generation (that is, electric power actually transmitted to the transportation grid by electric utility-owned power plants) by fuel type (coal, petroleum, natural gas, nuclear power, hydroelectric and other renewables, including wind and solar, wood and waste, and geothermal), net imports of electricity from Canada and Mexico, purchases of electricity by electric utilities from nonutilities (including cogeneration facilities and independent power producers), and a catchall category representing the total of transportation and distribution losses of electricity and other items, including any pure statistical discrepancy between electricity supply and electricity demand.

The electricity module of STIFS is structured so as to be highly recursive in the following sense. Demand by sector is determined, leading to a calculation of aggregate electricity demand. Working backward from total demand, a certain level of transmission and distribution losses is calculated. Demand plus transmission and distribution losses equals total electricity gross supply. Contributions from nun-utility power producers (NUPPs) and imports are subtracted from total supply. This yields a net electricity generation total for domestic electric utilities. Total generation and a number of exogenous factors determine most of the categories of electricity production by fuel source, except that relative prices help determine the portions of electricity generation contributed by petroleum and natural gas units.

Electricity Demand

Electricity demand is measured in terms of monthly sales divided by the number of days in the month. For electricity demand, reported monthly sales are not strictly related to consumption in the month that they are reported. This is because reported sales are on a billing-cycle rather than calendar-month basis. A reported month's electricity sales actually represents consumption by customers for part of the current month and part of the previous month. The simple assumption is made that the average of the current month's reported sales rate and the proceeding month's reported sales rate is a better estimate of the current month's actual demand rate than either the current month's or the proceeding month's reported sales rate taken by themselves. For all sectors this average is used in constructing estimating equations.

Total electricity demand is calculated for four broad sectors: (1) residential; (2) commercial; (3) industrial; and (4) "other"[13]. The main determinants of electricity demand in the STIFS estimating equations are: household growth (residential sector); changes in commercial employment (commercial); growth in manufacturing output (industrial) or in real GDP (other); weather (residential and commercial); general seasonal factors (commercial, industrial, and other); and trends in demand intensity (residential, commercial, and other). Trends in the intensity of electricity use in the aggregate sectors are the net result of several (possibly counteracting) factors, such as cumulative efficiency changes, demographic shifts (for example from geographical areas with typically high electricity intensities to areas with low ones, or vice versa), increased penetration of electricity-using equipment (such as computers, electronic appliances, etc.), and so on. STIFS does not account for the separate components of these long-run trend factors, but only provides a quantification of the net result.

The principal determinants of short-term demand variations in the residential sector (ESRCPUS) are weather factors, although a significant trend in consumption per household persists in raising demand from year to year. For weather, non-zero parameter values for heating degree-days (ZWHDPUS) or cooling degree-days (ZWCDPUS) are allowed only during the season in which particular weather impacts are meaningful for the

[13] "Other" is public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

aggregate data.[14] In addition, growth in the total number of households in the United States adds proportionately to electricity demand, other things being equal.

$$\begin{aligned} ESRCPUSQ = {} & (ESRC\_01 + ESRC\_05 * TIME \\ & + (ESRC\_03 * ZWHDPUS * (OCT + NOV + DEC + JAN + FEB + MAR + APR) \\ & + ESRC\_04 * ZWCDPUS * (MAY + JUN + JUL + AUG + SEP)) / ZSAJQUS \\ & + ESRCPAD) * ESRCPMU \end{aligned} \tag{A48}$$

Where,

ESRCPUSQ = Residential electricity sales, billion kilowatt hours per million homes per day
TIME = Integer valued time trend variable
ZSAJQUS = Number of days in each month

While weather also measurably affects demand in the commercial sector (ESCMPUS), this factor is less important than strong, persistent trends in the intensity of electricity use due to the continued introduction of electronic equipment such as microcomputers into the work place. For a given level of expected electricity use per commercial employee per day, average daily consumption of electricity in the commercial sector is expected to increase (or decrease) proportionately with employment, leading to a somewhat more cyclical short-run pattern of underlying demand (that is, demand corrected for noneconomic factors such as weather) than is to be expected in the residential sector.

$$\begin{aligned} ESCMPUSQ = {} & (ESCM\_01 + ESCM\_02 * TIME \\ & + (ESCM\_04 * ZWHDPUS * (OCT + NOV + DEC + JAN + FEB + MAR + APR) \\ & + ESCM\_05 * ZWCDPUS * (MAY + JUN + JUL + AUG + SEP)) / ZSAJQUS \\ & + ESCM\_06 * JAN + ESCM\_07 * FEB + ESCM\_08 * MAR + ESCM\_09 * APR \\ & + ESCM\_10 * MAY + ESCM\_11 * JUN + ESCM\_12 * JUL + ESCM\_13 * AUG \\ & + ESCM\_14 * SEP + ESCM\_15 * OCT + ESCM\_16 * NOV + ESCMPAD) * ESCMPMU \end{aligned} \tag{A49}$$

Where,

ESCMPUSQ = Commercial electricity sales, billion kilowatt hours per million commercial employees per day

Of the major electricity demand sectors, industrial demand (ESICPUS) is undoubtedly the most cyclical, being so dependent upon movements in the level of industrial output (ZOMNIUS). Seasonal shifts in industrial demand are apparent, although typical measurements of weather variability generally do not serve particularly well as indicators of industrial electricity use.

$$\begin{aligned} ESICPUSB = {} & \exp (ESIC\_01 + ESIC\_Q * \log (ZOMNIUS) + ESIC\_17 * DUM8083 \\ & + ESIC\_06 * JAN + ESIC\_07 * FEB + ESIC\_08 * MAR + ESIC\_09 * APR \\ & + ESIC\_10 * MAY + ESIC\_11 * JUN + ESIC\_12 * JUL + ESIC\_13 * AUG \\ & + ESIC\_14 * SEP + ESIC\_15 * OCT + ESIC\_16 * NOV) * ESICPMU + ESICPAD \end{aligned} \tag{A50}$$

Where,

ESICPUSB = Industrial electricity sales, billion kilowatt hours per day
DUM8083 = Intercept dummy variable for all months, 1980 through 1983

For the "other" electricity demand category (ESOTPUS), the simple assumption that, other things being equal, demand growth will be proportional to growth in the overall economy (in terms of real GNP) provides a good basis for estimating short-run demand changes. Even in this sector, a trend in the intensity of electricity use (in terms of demand per dollar of GNP) is evident, as is regular seasonal variation. The latter effect may be

[14] Thus, heating degree-days affects residential demand only from October through April. This technique is designed to improve the credibility of the separate estimates of heating and cooling degree-day effects on electricity demand, which might otherwise be confounded due to a close (negative) correlation between aggregate measured cooling and heating degree-days.

partly related to weather factors, but may also be due to a combination of other non-economic factors such as variations in the amount of daytime hours (which affects the extent of use of municipal lighting, for example).

$$ESOTPUSQ = (ESOT\_01 + ESOT\_02 * TIME + ESOT\_D1 * D90ON + ESOT\_06 * JAN + ESOT\_07 * FEB + ESOT\_08 * MAR + ESOT\_09 * APR + ESOT\_10 * MAY + ESOT\_11 * JUN + ESOT\_12 * JUL + ESOT\_13 * AUG + ESOT\_14 * SEP + ESOT\_15 * OCT + ESOT\_16 * NOV + ESOTPAD) * ESOTPMU \quad (A51)$$

Where,

ESOTPUSQ = Other electricity sales, billion kilowatt hours per million dollars GNP per day
D90ON = Intercept dummy variable for all months, 1990 on

Identities for retransforming estimated adjusted electricity demand values into daily consumption rates:

ESRCPUSB = ESRCPUSQ * KQHMPUS
ESCMPUSB = ESCMPUSQ * EMCMPUS
ESOTPUSB = ESOTPUSQ * GNPQXUS

Where,

KQHMPUS = Housing stock, millions
EMCMPUS = Commercial sector employment, millions
GNPQXUS = Real gross national product

Total electricity demand adjusted for billing cycle lags (ESTCPUSB) is then determined by the identity:

ESTCPUSB = ESRCPUSB + ESCMPUSB + ESICPUSB + ESOTPUSB

Identities for retransforming estimated adjusted daily demand values into daily as-reported consumption rates (in billion kilowatt hours per day):

$ESRCPUS = (ESRCPUSB + ESRCPUSB_{-1}) / 2$
$ESCMPUS = (ESCMPUSB + ESCMPUSB_{-1}) / 2$
$ESICPUS = (ESICPUSB + ESICPUSB_{-1}) / 2$
$ESOTPUS = (ESOTPUSB + ESOTPUSB_{-1}) / 2$

ESTCPUS = ESRCPUS + ESCMPUS + ESICPUS + ESOTPUS

Electricity Supply

The supply of electricity as presented in STIFS refers to electricity produced or purchased and delivered to customers by regulated electric utilities. Excluded are any amounts of electricity supplied to customers directly from cogeneration facilities or from independent power producers. Thus, in STIFS, electricity supply (and demand) is understated by however much electricity is demanded by users who either generate their own electricity or purchase electricity directly from nonutility power producers (NUPPs). The main components of electricity supply are: net imports of electricity; purchases of electricity by electric utilities from NUPPs; and generation of electricity by electric utilities. Electric utility power generation is further broken down into components by power source (that is, by fuel category). Generation from coal, petroleum, natural gas, nuclear power, hydroelectric power and geothermal and other renewable power sources is covered.

Purchases of electricity from both nonutilities and net imports are taken as exogenous. A detailed description of the methodology for determining these variables for use in STIFS is provided in Appendix E.

Modeling the Canadian electricity market is outside of the scope of STIFS and, therefore, imports are taken as exogenous. A major factor in the availability of electricity imports from Canada is the condition of watersheds affecting Canadian hydroelectric output. The exogenous information on imports is constructed to take account of most-likely outcomes for such key Canadian supply factors. Special scenarios which include variations in assumed electricity imports can be used to investigate the significance of greater or lesser availability of Canadian supply.

In the short run, nonutility supply is determined largely by available capacity because additional nonutility supply (capacity) entails building new units which take a number of years to complete. The capacity information used to determine supply in the *Outlook* is obtained using the EIA Form 867, *Annual Nonutility Power Producer Report*, which reports existing and planned nonutility units. The utilization of this capacity (to calculate nonutility sales to utilities and generation for own-use) are determined based on history. However, the utilization of these units can be varied to reflect different scenarios.

Net electricity generation from nuclear power plants and from hydroelectric facilities is exogenous. Detailed analysis of short-term hydroelectric and nuclear power availability is done regularly for routine STIFS runs, but the results are generally assumed to be insensitive to any alternative scenarios considered in simulations of STIFS. For nuclear power, under normal circumstances, only unforseen downtime would alter expectations about generation patterns, since these plants provide almost exclusively baseload rather than incremental or peaking power capacity. A similar argument applies to hydroelectric power, except that the unknown factor is the relative abundance (or lack) of rainfall and snowpack to feed watershed levels. STIFS does not attempt to directly incorporate rainfall data. However, the forecasts from the current year are based on information from a sample of utilities representing eight geographic regions that use precipitation and reservoir level data. The assumption of normal precipitation is the basis for exogenous hydroelectric power projections for the second year of the forecast. Special scenarios which alter these exogenous assumptions can of course be created to check for the significance of altering nuclear and hydroelectric power availability. A more detailed description of the hydroelectric and nuclear power assumptions in STIFS is provided in Appendix E.

In the electricity model, the demand side is linked to the supply side by exploiting observed regularities in the difference between total electricity demand adjusted for billing-cycle lags (ESTCPUSB) and total electricity supply, as defined by the sum of the three main supply components mentioned above (ELNIPUS + ELNSPUS + ELEOPUS). This difference (TDLOPUSB) includes any transmission and distribution loss of electrical energy, errors related to the imperfect knowledge about the true nature of the billing-cycle problem, and other discrepancies related to the independent measurement of electricity supply and demand. It is assumed that, other things being equal, TDLOPUSB will be proportional to ESTCPUSB. More specifically, the ratio of the two variables (labeled TDLOFUSB) is modeled as being constant except for some regular seasonal variation. Once TDLOFUSB and TDLOPUSB are calculated, total electricity generated by electric utilities (ELEOPUS) can be determined.

$$\begin{aligned} \text{TDLOFUSB} = {} & \text{PTND\_01} + \text{PTND\_17} * \text{D89ON} \\ & + \text{PTND\_06} * \text{JAN} + \text{PTND\_07} * \text{FEB} + \text{PTND\_08} * \text{MAR} + \text{PTND\_09} * \text{APR} \\ & + \text{PTND\_10} * \text{MAY} + \text{PTND\_11} * \text{JUN} + \text{PTND\_12} * \text{JUL} + \text{PTND\_13} * \text{AUG} \\ & + \text{PTND\_14} * \text{SEP} + \text{PTND\_15} * \text{OCT} + \text{PTND\_16} * \text{NOV} \end{aligned} \tag{A52}$$

$$\text{TDLOPUSB} = -\ \text{TDLOFUSB} * \text{ESTCPUSB}$$

$$\text{TDLOPUS} = (\text{TDLOPUSB} + \text{TDLOPUSB}_{-1})\ /\ 2$$

$$\text{ELEOPUS} = \text{ESTCPUSB} + \text{TDLOPUSB} - \text{ELNIPUS} - \text{ELNSPUS}$$

Where,

D89ON = Intercept dummy variable for all months, 1989 on

Given exogenous estimates for nuclear and hydroelectric power as well as functionally independent estimates for renewable sources of supply other than hydropower, the requirements for generation from fossil fuel sources can be determined.

Wind- and solar-powered electricity generation (WNEOPUS) as well as the wood and waste category (WWEOPUS) exhibit some seasonality but no discernible trend, on balance appearing to have remained about flat since 1989 or 1990.

$$\begin{aligned} WNEOPUS = {} & WNEO\_01 + WNEO\_D1 * D89ON \\ & + WNEO\_06 * JAN + WNEO\_07 * FEB + WNEO\_08 * MAR + WNEO\_09 * APR \\ & + WNEO\_10 * MAY + WNEO\_11 * JUN + WNEO\_12 * JUL + WNEO\_13 * AUG \\ & + WNEO\_14 * SEP + WNEO\_15 * OCT + WNEO\_16 * NOV \end{aligned} \tag{A53}$$

$$\begin{aligned} WWEOPUS = {} & WWEO\_01 + WWEO\_D1 * D90ON \\ & + WWEO\_06 * JAN + WWEO\_07 * FEB + WWEO\_08 * MAR + WWEO\_09 * APR \\ & + WWEO\_10 * MAY + WWEO\_11 * JUN + WWEO\_12 * JUL + WWEO\_13 * AUG \\ & + WWEO\_14 * SEP + WWEO\_15 * OCT + WWEO\_16 * NOV \end{aligned} \tag{A54}$$

Where,

D90ON = Intercept dummy variable for all months, 1990 on

Geothermal-based generation (GEEOPUS) has exhibited a significant downward trend since at least 1987, reflecting the much less favorable tax treatment afforded such projects following the Tax Reform Act of 1986.

$$GEEOPUS = \exp(GEEO\_01 + GEEO\_02 * TIME) \tag{A55}$$

In contrast to the assumptions applied to nuclear power and hydroelectric generation, the amount of coal-based power generation (CLEOPUS) is assumed to be strongly influenced by changes in the overall load on the power generating system (ELEOPUS):

$$\begin{aligned} CLEOPUS = {} & (CLEO\_01 + CLEO\_02 * ELEOPUS + CLEO\_04 * HYEOPUS \\ & + CLEO\_03 * (ELEOPUS * CLCAPUS) + CLEO\_05 * NUEOPUS \\ & + CLEO\_06 * JAN + CLEO\_07 * FEB + CLEO\_08 * MAR + CLEO\_09 * APR \\ & + CLEO\_10 * MAY + CLEO\_11 * JUN + CLEO\_12 * JUL + CLEO\_13 * AUG \\ & + CLEO\_14 * SEP + CLEO\_15 * OCT + CLEO\_16 * NOV + CLEOPAD) * CLEOPMU \end{aligned} \tag{A56}$$

Where,

CLCAPUS	=	Nameplate capacity of coal-fired generating units, total U.S.
HYEOPUS	=	Net electricity generated at hydroelectric power stations
NUEOPUS	=	Net electricity generated at nuclear power plants

The response of coal generating units to changes in overall system load is assumed to be affected by the level of capacity in place at any point in time. This effect is captured in the "CLEO_03*(ELEOPUS*CLCAPUS)" term in equation (A56). Given some level for aggregate system load (ELEOPUS), coal is affected negatively by significant changes in nuclear power and hydroelectric power availability. The extent of these negative effects will tend to vary across regions of the country, tending to limit the accuracy of the above equation when estimating the effects of highly localized changes in nuclear or hydroelectric power. STIFS, however, is linked to an offline regional electricity generation algorithm which can assist in lining up baseline estimates for coal-based generation to be more realistic than the standard aggregate predictions from the equation above.

Once coal-based generation is determined, the problem is to calculate how much of the remaining required electricity output (XGONG) is to be made up from natural gas-fired units as opposed to oil-fired units.

$$XGONG = ELEOPUS - CLEOPUS - HYEOPUS - NUEOPUS - WNEOPUS - WWEOPUS - GEEOPUS$$

The ratio of natural gas-based generation to natural gas- plus oil-based generation (NGEOSHRX) is assumed to be a function of the relative price of heavy oil and natural gas delivered to electric utilities (RFEUDUS / NGEUDUS) as well as seasonal factors relating to seasonal shifts in the peak-load patterns across regions.

$$\begin{aligned} NGEOSHRX = \; & (NGEO\_01 + NGEO\_P1 * (RFEUDUS \;/\; NGEUDUS) \\ & + NGEO\_R1 * NGEOSHR_{-1} + NGEO\_06 * JAN + NGEO\_07 * FEB \\ & + NGEO\_08 * MAR + NGEO\_09 * APR + NGEO\_10 * MAY + NGEO\_11 * JUN \\ & + NGEO\_12 * JUL + NGEO\_13 * AUG + NGEO\_14 * SEP + NGEO\_15 * OCT \\ & + NGEO\_16 * NOV + NGEOSAD) * NGEOSMU \end{aligned} \tag{A57}$$

The adjustment to changes in the relative price of natural gas is not immediate because incremental purchases of natural gas by utilities are not always possible because gas suppliers must maintain sufficient supplies for priority (particularly residential) customers during peak heating periods. Thus, a partial adjustment mechanism is assumed to describe the aggregate response toward relative price shifts, so far as oil and gas fuel choice at electric utilities is concerned.

Because of quantity constraints on certain natural gas supply variables, electric utility gas generation share (NGEOSHRX) is calculated as a temporary variable, while STIFS checks for whether or not initially calculated total natural gas demand is within assumed deliverability limits. (See the Natural Gas Model section for details on gas supply constraints.) If initially calculated natural gas demand exceeds the supply constraints, demand cutbacks may automatically be enforced (in the electric utility and industrial sectors only), unless accommodating changes in inventory patterns or higher price trajectories (or both) are instituted. The STIFS model automatically calculates final demand and supply quantities that may be equal to or less than quantities initially calculated.

Once a final (possibly truncated) level for natural gas consumed at electric utilities (NGEUPUS) is determined in the natural gas portion of the model, final natural gas-fired generation is determined and oil-based generation (PAEOPUS) falls out as a residual.

$$\begin{aligned} NGEOPUS &= NGEUPUS \;/\; NGEOKUS \\ NGEOSHR &= NGEOPUS \;/\; XGONG \\ PAEOPUS &= XGONG - NGEOPUS \end{aligned}$$

Where,

NGEOPUS	=	Net electricity generated at natural gas-fired power plants
NGEOSHR	=	Final gas-fired share of gas- plus oil-fired generation
PAEOPUS	=	Net electricity generated at petroleum-fired power plants

Components of oil-based generation (for residual fuel (RFEOPUS), distillate fuel oil (DKEOPUS), and petroleum coke (PCEOPUS)) are shared out according to average percentages of total oil-based generation.

$$\begin{aligned} RFEOPUS &= RFSHR * PAEOPUS \\ DKEOPUS &= DFSHR * PAEOPUS \\ PCEOPUS &= PCSHR * PAEOPUS \end{aligned}$$

RFSHR = total oil-based generation from residual fuel oil, given as 0.925
DFSHR = total oil-based generation from distillate fuel oil, given as 0.07
PCSHR = total oil-based generation from petroleum coke, given as 0.005

On rare occasions, the share of total oil-based generation from distillate-fired units (DFSHR) has been seen to rise sharply to levels significantly above normal average levels, which are generally quite low. When certain regions of the country are faced simultaneously with little or no excess generating capacity and high gas demand by firm customers, extraordinarily high reliance on relatively expensive peaking units may be resorted to as a short-run electricity supply option. If this happens during the winter heating season (which would be expected to be the case), significant impacts on fuel oil prices and quantities could result depending on the general supply and demand conditions in those markets. The effect of any propensity to heavily utilize distillate fuel oil for electricity generation in times of extreme peak demand can be handled through special simulations of STIFS in which DFSHR is allowed to assume extreme values.

Natural Gas Supply and Demand

Natural Gas Demand

In STIFS, natural gas demand is calculated for six sectors, including four major consumption or end-use categories as well as estimated consumption of natural gas by pipelines and natural gas consumption by gas field and natural gas plant operations. In addition, a small amount of gas exports is accounted for. Weather (particularly in the residential and commercial sectors), household formation (residential sector), commercial employment (commercial sector), natural gas prices relative to competing fuel prices, and industrial output (industrial sector) are all important factors in the short-term determination of natural gas demand. In the electric utility sector, gas demand is affected by the level of overall electricity output, which is determined primarily by various factors affecting electricity demand, as well as the availability of hydroelectric and nuclear power, excess coal generating capacity, and, to some extent, the price of gas relative to competing fuel oil. Some longer term factors, such as gradually improving energy efficiency of residential and commercial buildings and of industrial processes, ongoing penetration of high-efficiency gas appliances, and demographic trends, marginally influence the aggregate gas intensity (that is consumption per customer or per unit of output) and thus aggregate gas consumption in the short term. These longer term factors are generally captured by the inclusion of time trends in the equations for gas demand. All gas demand relationships are estimated based on monthly data, with demand data being expressed in terms of consumption per day, to correct for varying days in months.

For some of the natural gas demand categories used in STIFS (as is also true for similar categories in the electricity model), reported monthly sales are not strictly the same as demand in the month that they are reported. This is because reported sales are on a billing-cycle basis, which generally records monthly electricity sales which were actually used by customers in part of the current month and part of the previous month. In STIFS, the simple assumption is made that the average of the current month's reported sales rate and the following month's reported sales rate is a better estimate of the current month's actual demand rate than either the current month's or the following month's reported sales rate taken by themselves. For all sectors this average is used in constructing estimating equations.

Because of quantity constraints on certain natural gas supply variables (described below), temporary variables (usually identified with either an "X" or "Z" as the last character in the variable name) are calculated for some of the natural gas demand quantities until STIFS checks for whether or not initially calculated demand is within assumed deliverability limits. If initially calculated demand exceeds the supply constraints, demand cutbacks may automatically be enforced (in the electric utility and industrial sectors only), unless accommodating changes in inventory patterns or higher price trajectories (or both) are instituted. The STIFS model automatically calculates final demand and supply quantities that may be equal to or less than quantities initially calculated.

For the residential and commercial sectors, natural gas demand is calculated by first determining the number of customers in each sector (NGNRPUSA and NGNCPUSA, respectively), and then estimating natural gas consumption per customer (NGRCPUSX and NGCCPUSX for the residential and commercial sectors respectively), and, finally, multiplying use per customer times the number of customers.

The consumption-per-customer variables are modeled as a function of weather, monthly dummy variables and, in the case of commercial demand, a time variable to capture intensity trends. The only weather variable assumed to affect residential and commercial natural gas demand is heating degree-days which, for obvious reasons, has discernible effects only during the heating season. For this aggregate model, the heating season is assumed to extend from October through April, although the length of the season would obviously vary from region to region. It is assumed that, for the customer equations, changes in associated economic variables (housing stock for residential, commercial employment for the commercial sector) elicit proportional changes in the number of customers, given constant relative gas prices. In addition, relative gas prices are assumed to affect the level of customers somewhat in the short term (by changing marginally the penetration rates for natural gas or by sufficiently changing the incentives for conversion from other fuels for some proportion of the customer base). Relative prices are entered into the customer relationships with a polynomial distributed lag specification, and with an expected negative sign associated with them.

Deseasonalized number of residential gas customers:

$$\begin{aligned} NGNRPUSA = {} & \exp(NGNR\_01 + NGNR\_H * \log(KQHMPUS) \\ & + (NGNUKUS / DFTCZUS) \\ & * \mathrm{distlag}(\log((NGRCUUSA*NGNUKUS(/ (D2RCUUSA*DFTCZUS)), \mathrm{degree}=2, \mathrm{lags}=12)) \end{aligned} \tag{A58}$$

Reseasonalizing:

$$NGNRPUS = NGNRPUSA * NGNRPUSS$$

Adjusted residential natural gas demand per customer per day:

$$\begin{aligned} NGRCPUSX = {} & (NGRC\_01 \\ & + NGRC\_HD * (ZGHDPUS / ZSAJQUS) * (OCT+NOV+DEC+JAN+FEB+MAR+APR) \\ & + NGRC\_09 * MAY + NGRC\_10 * JUN + NGRC\_11 * JUL + NGRC\_12 * AUG \\ & + NGRC\_13 * SEP + NGRCPAD) * NGRCPMU \end{aligned} \tag{A59}$$

Adjusted residential gas consumption per day:

$$NGRCPUSB = NGRCPUSX * NGNRPUS$$

As-reported residential gas consumption per day:

$$NGRCPUS = 0.5 * NGRCPUSB + 0.5 * NGRCPUSB_{-1}$$

Where,

DFTCZUS	=	Thermal content of distillate fuel oil
D2RCUUSA	=	Seasonally adjusted retail heating oil price
KQHMPUS	=	Housing stocks, millions
NGNRPUS	=	Residential natural gas customers (millions)
NGNUKUS	=	Thermal content of nonutility natural gas
NGRCPUSX	=	Adjusted residential natural gas demand per customer per day
NGRCPUSB	=	Adjusted residential natural gas demand per day
NGRCPUS	=	As-reported residential natural gas demand per day
NGRCUUSA	=	Seasonally adjusted residential natural gas price
ZGHDPUS	=	Gas-weighted heating degree-days

Deseasonalized commercial gas customers:

$$\begin{aligned} NGNCPUSA = {} & \exp(NGNC\_01 + NGNC\_E * \log(EMCMPUS) \\ & + (NGNUKUS / DFTCZUS) \\ & * \mathrm{distlag}(\log((NGCCUUSA*NGNUKUS) / (D2WHUUSA*DFTCZUS)), \mathrm{degree}=2, \mathrm{lags}=12)) \end{aligned} \tag{A60}$$

Reseasonalizing:

$$NGNCPUS = NGNCPUSA * NGNCPUSS$$

Where,

EMCMPUS	=	Commercial employment, millions
NGCCUUS	=	Commercial natural gas price, not seasonally adjusted
NGNCPUS	=	Commercial gas customers (millions)
NGNCPUSA	=	NGNCPUS seasonally adjusted

Adjusted commercial natural gas demand per customer per day:

NGCCPUSX = (NGCC_01 + NGCC_P * (NGCCUUS / WPCPIUS) (A61)
+ NGCC_HD * (ZWHDPUS / ZSAJQUS) * (OCT+NOV+DEC+JAN+FEB+MAR+APR)
+ NGCC_T * TIME + NGCC_D1 * DTO87 + NGCC_D1T * DTO87 * TIME
+ NGCC_D2 * D8912 + NGCC_09 * MAY + NGCC_10 * JUN + NGCC_11 * JUL
+ NGCC_12 * AUG + NGCC_13 * SEP + NGCCPAD) * NGCCPMU

Adjusted commercial gas consumption per day:

NGCCPUSB = NGCCPUSX * NGNCPUS

As-reported commercial gas consumption per day:

NGCCPUS = 0.5 * NGCCPUSB + 0.5 * $NGCCPUSB_{-1}$

Where,

D8912	=	Dummy intercept variable for December 1989
DTO87	=	Dummy intercept variable for pre-1988 period
NGCCPUSX	=	Adjusted commercial natural gas consumption per customer per day
NGCCPUSB	=	Adjusted commercial natural gas consumption per day
NGCCPUS	=	As-reported commercial natural gas demand per day
NGCCUUS	=	Commercial natural gas price, not seasonally adjusted
NGCCUUSA	=	Seasonally adjusted commercial natural gas price
WPCPIUS	=	Producer price index, total
ZWHDPUS	=	Population weighted heating degree-days

The demand for natural gas in the industrial sector (NGINPUS) is determined by first estimating the amount of gas consumed per unit of industrial output (NGINPUSZ), and multiplying that variable by the gas consumption-weighted manufacturing production index (QSIC), which is taken as exogenous to the STIFS system. For gas consumed in the industrial sector, the measure of output is a composite index of selected 2-digit SIC manufacturing output indexes (as defined by the Federal Reserve Board), where the weights for the composite index are fixed proportions of natural gas consumption estimated for the component 2-digit SIC manufacturing sectors. Given constant relative prices for industrial natural gas relative to residual fuel oil, consumption per unit of output is modeled as having a time trend, and seasonal variation. The aggregate time trend was seen to have shifted around 1987, and slope dummies for this effect were introduced into the estimating relationship.

NGINPUSZ = (NGIN_01 + NGIN_TD * TIME * D87ON + NGIN_T * TIME (A62)
+ NGIN_P * (NGICUUSA * NGNUKUS) / (RFTCUUSA * RFTCZUS)
+ NGIN_06 * FEB + NGIN_07 * MAR + NGIN_08 * APR + NGIN_09 * MAY
+ NGIN_10 * JUN + NGIN_11 * JUL + NGIN_12 * AUG + NGIN_13 * SEP
+ NGIN_14 * OCT + NGIN_15 * NOV + NGIN_16 * DEC + NGINPAD) * NGINPMU

NGINPUSB = NGINPUSZ * QSIC

NGINPUSX = 0.5 * NGINPUSB + 0.5 * $NGINPUSB_{-1}$

Where,

NGICUUSA = Seasonally adjusted industrial natural gas price adjusted
RFTCUUSA = Seasonally adjusted residual fuel oil price
RFTCZUS = Thermal content of residual fuel oil

The method for determining natural gas demand in the electric utility sector is shown in the description of the electricity model, but the balancing of total gas demand and supply quantities is described below.

Two relatively minor categories of gas demand, gas used in oil and gas well, field, and lease operations (NGLPPUS) and pipeline fuel (NGACPUS), are assumed to be directly related to the volume of gas demand for the four major demand categories.

NGLPPUS = (NGLP_01 + NGLP_D1 * DTO87 + NGLP_D2 * D90ON (A63)
+ NGLP_DM * (NGRCPUS + NGCCPUS + NGEUPUS + NGINPUS)
+ NGLPPAD) * NGLPPMU

NGACPUS = (NGAC_01 (A64)
+ NGAC_DM * (NGRCPUS + NGCCPUS + NGEUPUS + NGINPUS)
+ NGACPAD) * NGACPMU

Initial calculations for natural gas consumption at electric utilities (NGEUPUSX) are made by converting the initial estimate for natural gas-fired generation at electric utilities (NGEOPUSX) into fuel requirements using an assumed heat rate at gas-fired power plants (NGEOKUS) and an average thermal content for natural gas delivered to electric utilities (NGEUKUS).

NGEUPUSX = NGEOPUSX * NGEOKUS / NGEUKUS

A small amount of natural gas exports (NGEXPUS) is expected, in amounts that have averaged between about 200 million and 500 million cubic feet per day since 1989.

NGEXPUS = NGEX_01 + NGEX_D * D89ON + NGEX_08 * APR + NGEX_09 * MAY (A65)

Initial calculations for total natural gas demand (NGTCPUSX) are made by adding up individual sectoral components:

NGTCPUSX = NGACPUS + NGLPPUS + NGRCPUS + NGCCPUS + NGINPUSX + NGEUPUSX

Natural Gas Supply

Domestic natural gas supply in STIFS encompasses aggregate production (including conventional dry natural gas (NGPRPUS) as well as supplemental gaseous fuels (NGSFPUS), imports (NGIMPUS) and inventory change. Inventories in this case are so-called "working gas" portions of underground storage volumes (NGWGPUS).

In STIFS, the volume of natural gas supplied at any time is subject to certain constraints on the capacity of the domestic supply system to produce and deliver gas to markets. In particular, exogenous constraints on total domestic productive capacity and on total import capability are imposed so as to prevent production and imports from exceeding maximums calculated from detailed analysis outside of the STIFS system.[15] STIFS allows for excess demand to feed through automatically to price changes that will move the system toward an

[15] EIA's *Natural Gas Productive Capacity for the Lower 48 States, 1982 Through 1993,* DOE/EIA-0542(93), is the basis for the current assumptions about aggregate natural gas productive capacity. Consultations with EIA's Reserves and Natural Gas Division resulted in the current assumptions for maximum gas import capacity.

equilibrium, but a combination of involuntary cutbacks and significantly higher spot natural gas price trajectories may be required to prevent solutions in which demand exceeds available supply.

For more than 10 years, the domestic gas market has generally been in an excess supply situation[16], but, because of the cumulative effect of low domestic exploration efforts, the current situation is one in which the probability of demand trends impinging upon total supply capacity (and thus causing sharp increases in spot and average gas prices) is significantly increased. The domestic gas industry has not experienced a situation of general natural gas supply tightness in a deregulated environment, and this makes projections for natural gas wellhead prices more uncertain than they may have been in the past. A significant amount of judgement is required to construct reasonable gas price forecasts for any given scenario, particularly in cases where upward demand shocks are considered.

An initial estimate of total natural gas volumes supplied from imports and domestic production (NGSUPX) is calculated as the difference between total initial demand plus exports (NGTCPUSX + NGEXPUS) and the sum of initial net storage withdrawals (NGNWPUSX), supplemental fuels (NGSFPUS) and an assumed discrepancy term (BALIT), which contains losses and unaccounted for gas supply and which is set at observed average seasonal levels:

$$NGSUPX = (NGTCPUSX + NGEXPUS) - (BALIT + NGNWPUSX + NGSFPUS)$$

Both the gas demand/supply discrepancy variable (BALIT) and the minor supply component known as supplemental fuels (NGSFPUS) are captured as simple seasonal variables:[17]

$$\begin{aligned} BALIT = (&NGBL\_01 + NGBL\_06 * FEB + NGBL\_07 * MAR + NGBL\_08 * APR \\ &+ NGBL\_09 * MAY + NGBL\_10 * JUN + NGBL\_11 * JUL + NGBL\_12 * AUG \\ &+ NGBL\_13 * SEP + NGBL\_14 * OCT + NGBL\_15 * NOV + NGBL\_16 * DEC \\ &+ BALITAD) * BALITMU \end{aligned} \tag{A66}$$

$$\begin{aligned} NGSFPUS = &NGSF\_01 + NGSF\_06 * FEB + NGSF\_07 * MAR + NGSF\_08 * APR \\ &+ NGSF\_09 * MAY + NGSF\_10 * JUN + NGSF\_11 * JUL + NGSF\_12 * AUG \\ &+ NGSF\_13 * SEP + NGSF\_14 * OCT + NGSF\_15 * NOV \end{aligned} \tag{A67}$$

End-of-month natural gas storage volumes follow a very regular seasonal pattern although particularly high (or low) consumption in a month may swing storage to below (or above) average seasonal levels. Initial values for natural gas storage (NGWGPUS) is calculated as a function of initial natural gas demand and seasonal factors, from which initial storage net withdrawals (NGNWPUS) are calculated:

$$\begin{aligned} NGWGPUSX = (&NGWG\_01 + NGWG\_DM * (NGTCPUSX * ZSAJQUS) \\ &+ NGWG\_06 * FEB + NGWG\_07 * MAR + NGWG\_08 * APR + NGWG\_09 * MAY \\ &+ NGWG\_10 * JUN + NGWG\_11 * JUL + NGWG\_12 * AUG + NGWG\_13 * SEP \\ &+ NGWG\_14 * OCT + NGWG\_15 * NOV + NGWG\_16 * DEC \\ &+ NGWGPAD) * NGWGPMU \end{aligned} \tag{A68}$$

$$NGNWPUSX = (NGWGPUSX_{-1} - NGWGPUSX) \ / \ ZSAJQUS$$

In the short run, natural gas production is a function of gas demand, although significant changes in

[16] Energy Information Administration, *Natural Gas Productive Capacity for the Lower 48 States, 1982 Through 1993*, DOE/EIA-0542(93), (Washington, DC, 1993).

[17] The discrepancy variable BALIT is given consideration because, based on recent historical experience, its expected value is far from zero, although it does tend to change sign over the course of the year and to have more or less consistent seasonal patterns. Setting this term at average seasonal values acknowledges a systematic component of measured supply (or demand) that is not otherwise specifically accounted for.

equilibrium, but a combination of involuntary cutbacks and significantly higher spot natural gas price trajectories may be required to prevent solutions in which demand exceeds available supply.

For more than 10 years, the domestic gas market has generally been in an excess supply situation[16], but, because of the cumulative effect of low domestic exploration efforts, the current situation is one in which the probability of demand trends impinging upon total supply capacity (and thus causing sharp increases in spot and average gas prices) is significantly increased. The domestic gas industry has not experienced a situation of general natural gas supply tightness in a deregulated environment, and this makes projections for natural gas wellhead prices more uncertain than they may have been in the past. A significant amount of judgement is required to construct reasonable gas price forecasts for any given scenario, particularly in cases where upward demand shocks are considered.

An initial estimate of total natural gas volumes supplied from imports and domestic production (NGSUPX) is calculated as the difference between total initial demand plus exports (NGTCPUSX + NGEXPUS) and the sum of initial net storage withdrawals (NGNWPUSX), supplemental fuels (NGSFPUS) and an assumed discrepancy term (BALIT), which contains losses and unaccounted for gas supply and which is set at observed average seasonal levels:

$$NGSUPX = (NGTCPUSX + NGEXPUS) - (BALIT + NGNWPUSX + NGSFPUS)$$

Both the gas demand/supply discrepancy variable (BALIT) and the minor supply component known as supplemental fuels (NGSFPUS) are captured as simple seasonal variables:[17]

$$\begin{aligned} BALIT = (&NGBL\_01 + NGBL\_06 * FEB + NGBL\_07 * MAR + NGBL\_08 * APR \\ &+ NGBL\_09 * MAY + NGBL\_10 * JUN + NGBL\_11 * JUL + NGBL\_12 * AUG \\ &+ NGBL\_13 * SEP + NGBL\_14 * OCT + NGBL\_15 * NOV + NGBL\_16 * DEC \\ &+ BALITAD) * BALITMU \end{aligned} \tag{A66}$$

$$\begin{aligned} NGSFPUS = &NGSF\_01 + NGSF\_06 * FEB + NGSF\_07 * MAR + NGSF\_08 * APR \\ &+ NGSF\_09 * MAY + NGSF\_10 * JUN + NGSF\_11 * JUL + NGSF\_12 * AUG \\ &+ NGSF\_13 * SEP + NGSF\_14 * OCT + NGSF\_15 * NOV \end{aligned} \tag{A67}$$

End-of-month natural gas storage volumes follow a very regular seasonal pattern although particularly high (or low) consumption in a month may swing storage to below (or above) average seasonal levels. Initial values for natural gas storage (NGWGPUS) is calculated as a function of initial natural gas demand and seasonal factors, from which initial storage net withdrawals (NGNWPUS) are calculated:

$$\begin{aligned} NGWGPUSX = (&NGWG\_01 + NGWG\_DM * (NGTCPUSX * ZSAJQUS) \\ &+ NGWG\_06 * FEB + NGWG\_07 * MAR + NGWG\_08 * APR + NGWG\_09 * MAY \\ &+ NGWG\_10 * JUN + NGWG\_11 * JUL + NGWG\_12 * AUG + NGWG\_13 * SEP \\ &+ NGWG\_14 * OCT + NGWG\_15 * NOV + NGWG\_16 * DEC \\ &+ NGWGPAD) * NGWGPMU \end{aligned} \tag{A68}$$

$$NGNWPUSX = (NGWGPUSX_{-1} - NGWGPUSX) \; / \; ZSAJQUS$$

In the short run, natural gas production is a function of gas demand, although significant changes in

[16] Energy Information Administration, *Natural Gas Productive Capacity for the Lower 48 States, 1982 Through 1993*, DOE/EIA-0542(93), (Washington, DC, 1993).

[17] The discrepancy variable BALIT is given consideration because, based on recent historical experience, its expected value is far from zero, although it does tend to change sign over the course of the year and to have more or less consistent seasonal patterns. Setting this term at average seasonal values acknowledges a systematic component of measured supply (or demand) that is not otherwise specifically accounted for.

demand (aside from normal seasonal variations) would induce only a partial response in terms of current production, because there is some lead time required to bring shut-in or underutilized facilities up to capacity and because productive capacity is strictly limited in the short run. On a seasonally adjusted basis, initial natural gas production (NGPRPUSZ) is assumed to be a function of seasonally adjusted demand and the lag of seasonally adjusted gas production estimates:

$$NGPRPUSZ = (NGPR\_01 + NGPR\_R1 * NGPRPUSA_{-1} + NGPR\_DM * NGTCPUSA + NGPRPAD) * NGPRPMU \quad (A69)$$

Reseasonalizing initial gas production estimates:

$$NGPRPUSX = NGPRPUSZ * NGPRPUSS$$

Final natural gas production estimates (NGPRPUS) are then calculated as the minimum of maximum dry natural gas production capacity (NGPRMX) or the proportionate share of calculated initial production plus gross imports (NGSUPX):

$$NGPRPUS = \min (NGPRMX, (NGPRPUSX \ / \ (NGPRPUSX + NGIMPUSX)) * NGSUPX)$$

Wet natural gas production (NGMPPUS) is assumed to be linearly related to dry gas production:

$$NGMPPUS = NGMP\_01 + NGMP\_PR * NGPRPUS \quad (A70)$$

Resetting deseasonalized production for the proceeding period:

$$NGPRPUSA = NGPRPUS \ / \ NGPRPUSS$$

Gross imports of gas into the United States have been rising steadily in recent years. On a seasonally adjusted basis, initial natural gas imports (NGIMPUSZ) is assumed to be a linear function of time (although estimated aggregate impacts of known pipeline capacity expansions at the U.S.-Canada border are added in forecasts as they become known, through the exogenous add factor NGIMPAD).

$$NGIMPUSZ = NGIM\_01 + NGIM\_T * TIME + NGIMPAD \quad (A71)$$

Reseasonalizing initial natural gas imports estimates:

$$NGIMPUSX = NGIMPUSZ * NGIMPUSS$$

Final estimated natural gas total imports (NGIMPUS) are then calculated as the minimum of maximum import capacity (NGIMMX) or the proportionate share of calculated initial production plus gross imports (NGSUPX).

$$NGIMPUS = \min (NGIMMX, (NGIMPUSX \ / \ (NGPRPUSX + NGIMPUSX)) * NGSUPX)$$

Natural gas net imports (NGNIPUS) are calculated as an identity:

$$NGNIPUS = NGIMPUS - NGEXPUS$$

Final natural gas storage withdrawals (NGNWPUS) are calculated as: (during the fall and winter, when withdrawals are usually positive), the minimum of initial gas storage withdrawal estimates and the total excess of initial demand estimates over final supply (other than inventory change); or (during the spring and summer, when withdrawals are usually negative), the maximum of initial gas storage withdrawal estimates and the total excess of initial demand estimates over final supply (other than inventory change).

$$NGNWPUS = \min (NGNWPUSX, (NGTCPUSX-BALIT-NGPRPUS-NGIMPUS+NGEXPUS-NGSFPUS))$$

$$* (NOV + DEC + JAN + FEB + MAR)$$
$$+ \max (NGNWPUSX, (NGTCPUSX-BALIT-NGPRPUS-NGIMPUS+NGEXPUS-NGSFPUS))$$
$$* (1 - NOV - DEC - JAN - FEB - MAR)$$

End-of-month natural gas storage levels (NGWGPUS) are then determined by the identity:

$$NGWGPUS = NGWGPUS_{-1} - NGNWPUS * ZSAJQUS$$

Final total demand estimates (NGTCPUS), which will equal initial estimates provided that maximums for imports or domestic gas production are not exceeded, is calculated by the identity:

$$NGTCPUS = NGPRPUS + NGIMPUS - NGEXPUS + NGSFPUS + NGNWPUS + BALIT$$

Reseasonalizing gas demand:

$$NGTCPUSA = NGTCPUS / NGTCPUSS$$

Final industrial and electric utility gas demands (NGINPUS and NGEUPUS, respectively) are calculated as follows:

$$NGINPUS = NGINPUSX * (1 - (NGTCPUSX - NGTCPUS) / (NGINPUSX + NGEUPUSX))$$

$$NGEUPUS = NGEUPUSX * (1 + (NGTCPUS-NGTCPUSX) / (NGEUPUSX + NGINPUSX))$$

If, as in the case of gas curtailments, final industrial and utility natural gas demand is below initial (or unconstrained) levels, then increments to alternative (petroleum-based) fuels are assumed to make up the difference in energy requirements in the respective markets. In the electric utility sector, the energy deficit is proportionately allocated to residual fuel oil, distillate fuel oil and petroleum coke (see "Electricity Demand and Supply" below). In the nonutility industrial sector, the deficit is allocated proportionately to residual fuel oil, distillate fuel oil and liquefied petroleum gases, where the proportions are based on estimates of the relative capabilities of industrial energy users to switch to these alternative fuels from natural gas (see the petroleum demand section above).[18]

[18] Energy information Administration, *Manufacturing Fuel-Switching Capability*, DOE/EIA-0515(88), (Washington, DC, September 1991).

Coal Supply and Demand

Overview

The STIFS model determines total coal consumption (CLTCPUS) as the total of demand for three major sectors: (1) electric utilities (CLEUPUS); (2) coke plants (CLKCPUS); and (3) retail and general industry (CLZCPUS).

CLTCPUS = CLEUPUS + CLKCPUS + CLZCPUS

Supply elements appearing in the coal model (domestic production, imports, exports, and producer and distributor stocks) are exogenous. Forecasts for these components are provided by the Energy Information Administration's Office of Coal, Nuclear,Electric and Alternative Fuels, Coal Division, Data Analysis and Forecasting Branch. Total production of coal is the sum of each sector's consumption, minus stock withdrawals, plus coal exports, minus coal imports.

Electric Utility Coal Demand

The model for electric utility coal demand is discussed in the section on electricity supply. To translate coal generation requirements into coal consumption at electric utilities, a simple equation is used, which does not assume strict proportionality between coal input and electricity output, but measures changes in coal consumption due to changes in electricity requirements. This equation allows for a trend and seasonality in the average net conversion rate of coal to electric power. Seasonality arises from normal geographic shifts of electricity requirements from month to month from areas with newer, more efficient plants, or with access to higher quality coal, to areas with older, less efficient plants, or with access to lower quality fuel. Also, ambient atmospheric conditions (temperature extremes) may affect conversion loss rates, and these conditions can change significantly over the course of a year. Thus, consumption of coal at electric utilities (CLEUPUS) is expressed as follows:

CLEUPUS = CLEU_01 + CLEU_02 * CLEOPUS + CLEU_17 * DS2 + CLEU_18 * TIME (A73)
+ CLEU_06 * JAN + CLEU_07 * FEB + CLEU_08 * MAR + CLEU_09 * APR
+ CLEU_10 * MAY + CLEU_11 * JUN + CLEU_12 * JUL + CLEU_13 * AUG
+ CLEU_14 * SEP + CLEU_15 * OCT + CLEU_16 * NOV

Coking Coal Demand

Coking coal is used in the manufacture of coke, which fuels blast furnaces that produce molten iron for the production of steel. Thus, coking coal demand is derived from the demand for steel. Coke is only used in steel plants that employ basic oxygen furnaces or open-hearth furnaces. Determining the domestic demand for coking coal requires estimates of how much of coke demand will be satisfied from coke production, coke stocks, and net coke imports.

Coke demand (CCTCPUS) is derived from a forecast of total steel production (RSPRPUS):

CCTCPUS = K1 * K5 * RSPRPUS

K_1 = ratio of coke consumption to total raw steel production, given as 0.436
K_5 = ratio of raw steel production at basic oxygen furnaces to total raw steel production, given as 0.629

Net imports of coke (CCNIPUS) are derived as a fraction of total coke demand:

CCNIPUS = K2 * CCTCPUS

K_2 = ratio of coke net imports to coke consumption, given as 0.0372

The change in coke stocks is derived as a fixed fraction of the change in coke demand:

$$CCSDPUS - CCSDPUS_{-1} = K_3 * (CCTCPUS - CCTCPUS_{-1})$$

K_3 = ratio of coke stock withdrawal to the change in coke consumption, given as 0.334

Total coke production is determined from the identity:

$$CCPRPUS = CCTCPUS - CCNIPUS + (CCSDPUS - CCSDPUS_{-1})$$

Demand for coking coal is then estimated from total coke demand by the following production function:

$$CLKCPUS = K4 * CCPRPUS$$

K_4 = ratio of coking coal consumption to coke production, given as 1.41;

The above relationships are combined into one reduced-form equation for coking coal demand in the STIFS model:

$$CLKCPUSX = K1 * (1-K2+K3) * K4 * K5 * RSPRPUS - RSPRPUS_{-1} * K1 * K3 * K4 * K5$$

The only remaining task for forecasting coking coal consumption is to provide an estimate of raw steel production (RSPRPUS). Seasonally adjusted raw steel production is estimated as a linear function of the change in manufacturing inventories (KRDRXUS), real fixed investment (I87RXUS), and a time trend:

$$RSPRPUSA = (RSP\_01 + RSP\_02 * KRDRXUS + RSP\_03 * I87RXUS + RSP\_04 * TIME + RSPRPAD) * RSPRPMU \qquad (A74)$$

And, reseasonalizing:

$$RSPRPUS = RSPRPUSA * RSPRPUSS$$

To ensure that the estimated value of coking coal consumption does not exceed a maximum monthly consumption capacity of 3.16667 million short tons, the following adjustment mechanism is used:

$$CLKCPUS = \min[CLKCPUSX, (3.16667 / ZSAJQUS)]$$

$$CCTCPUSX = K1 * K5 * RSPRPUS$$

$$CCSDPUS = CCTCPUSX * K3 * 3.0 * ZSAJQUS$$

$$COKEBAL = CCTCPUSX - (CCPRPUS + CCNIPUS) - (CCSDPUS - CCSDPUS_{-1}) / ZSAJQUS$$

COKEBAL = Difference between coke supply and demand

$$CCTCPUS = CCTCPUSX - COKEBAL$$

Retail and General Industry Demand

Two equations are used to forecast coal consumption in the retail and general industry sector. One forecasts the consumption of coal in the industrial sector (excluding use at coke plants and synfuel plants), and the other forecasts consumption by the residential/commercial sector. Coal used in the manufacture of synfuels (CLFCPUS) is assumed to remain constant at the first quarter 1992 level of 1.7 million tons per quarter.

Industrial sector coal consumption net of synfuels-related consumption (CLXCPUS) is modeled as a function of the coal-weighted industrial production index (ZOSIIUS) and time dummy variables:

$$\begin{aligned} CLXCPUS = (&CLXC\_01 + CLXC\_02 * DUM84 + CLXC\_03 * TREND84 \\ &+ CLXC\_04 * ZOSIIUS + CLXC\_05 * JAN + CLXC\_06 * FEB + CLXC\_07 * MAR \\ &+ CLXC\_08 * APR + CLXC\_09 * MAY + CLXC\_10 * JUN + CLXC\_11 * JUL \\ &+ CLXC\_12 * AUG + CLXC\_13 * SEP + CLXC\_14 * OCT + CLXC\_15 * NOV \\ &+ CLXCPAD) * CLXCPMU \end{aligned} \tag{A75}$$

Total industrial sector coal demand (CLYCPUS) is then determined using the identity:

$$CLYCPUS = CLFCPUS + CLXCPUS$$

Residential and commercial coal consumption (CLHCPUS) is a small and relatively stable portion of total retail and general industry coal consumption. It is modeled as follows as a function of U.S. population-weighted heating degree-days (ZWHDPUS) and time dummy variables:

$$\begin{aligned} CLHCPUS = (&CLHC\_01 + CLHC\_02 * DUM84 + CLHC\_03 * TREND84 \\ &+ CLHC\_04 * ZWHDPUS + CLHC\_05 * JAN + CLHC\_06 * FEB + CLHC\_07 * MAR \\ &+ CLHC\_08 * APR + CLHC\_09 * MAY + CLHC\_10 * JUN + CLHC\_11 * JUL \\ &+ CLHC\_12 * AUG + CLHC\_13 * SEP + CLHC\_14 * OCT + CLHC\_15 * NOV \\ &+ CLHCPAD) * CLHCPMU \end{aligned} \tag{A76}$$

Total retail and general industry coal consumption (CLZCPUS) is given by the identity:

$$CLZCPUS = CLYCPUS + CLHCPUS$$

Coal Inventories

After consumption of coal has been forecast for the various sectors, the only remaining element of total coal demand is stock withdrawals. Secondary coal stocks in each sector are estimated using partial stock adjustment equations that relate actual stocks to target stock levels. Target stock levels are derived from forecasts of consumption and exogenously specified target days-of-supply:

$$\begin{aligned} CLSESTAR &= CLDESTAR * CLEUPUS \\ CLSKSTAR &= CLDKSTAR * CLKCPUS \\ CLSOSTAR &= CLDOSTAR * CLYCPUS \end{aligned}$$

$$\begin{aligned} CLSEPUSX &= CLSEPUS_{-1} + CLSA\_E * (CLSESTAR - CLSEPUS_{-1}) \\ CLSKPUSX &= CLSKPUS_{-1} + CLSA\_K * (CLSKSTAR - CLSKPUS_{-1}) \\ CLSOPUSX &= CLSOPUS_{-1} + CLSA\_O * (CLSOSTAR - CLSOPUS_{-1}) \end{aligned}$$

$$CLSTPUSX = CLSEPUSX + CLSKPUSX + CLSOPUSX$$

CLSESTAR = Target stock levels at electric utilities
CLSKSTAR = Target stock levels at coke plants
CLSOSTAR = Target stock levels at retail and general industry sector
CLDESTAR = Target days of supply of stocks at electric utilities
CLDKSTAR = Target days of supply of stocks at coke plants
CLDOSTAR = Target days of supply of stocks at retail and general sector
CLSEPUS = Stocks at electric utilities

CLSOPUS = Stocks at retail and general industry sector
CLSKPUS = Stocks at coke plants

A recursive adjustment is utilized to calculate final secondary stocks. Indicated production (CLPRPUSX) is calculated as the sum of total consumption (CLTCPUS), exports (CLEXPUS), change in producer stocks (CLDSPUS), and the change in total secondary stocks (CLSTPUS), minus imports (CLIMPUS). The factor is calculated to be the difference between the exogenous and indicated production divided by total secondary stocks. The factor is then applied to each estimated component of secondary stocks to determine the final values.

$$\begin{aligned} CLPRPUSX = {} & CLTCPUS + (CLSDPUS - CLSDPUS_{-1}) \ / \ ZSAJQUS \\ & - (CLIMPUS - CLEXPUS) + (CLSTPUSX - CLSTPUS_{-1}) \ / \ ZSAJQUS \end{aligned}$$

$$CLSTBAL = 1 + (CLPRPUS - CLPRPUSX) * ZSAJQUS \ / \ CLSTPUSX$$

$$CLSEPUS = CLSEPUSX * CLSTBAL$$
$$CLSOPUS = CLSOPUSX * CLSTBAL$$
$$CLSKPUS = CLSKPUSX * CLSTBAL$$

Total secondary coal stocks (CLSTCPUS) then represents the sum of stocks in each sector:

$$CLSTPUS = CLSEPUS + CLSOPUS + CLSKPUS$$

Energy Prices

Overview

This section discusses the methodology for forecasting the various energy prices published in the *Outlook*. The prices are important in their own right, because they are widely used for budget planning and other purposes by local government and corporate planners. These prices are also used in the projections of energy supply and demand discussed in the previous sections.

In these equations, the dependent price variables are seasonally adjusted *prior* to being deflated by a price index. If the variable ends in "A", such as *MGUCUUSA*, then the data for *MGUCUUS*, have been deseasonalized using seasonal factors (in this case, *MGUCUUSS*) from the U.S. Census, X-11 multiplicative seasonal adjustment routine.

Petroleum Prices

Crude Oil

The price of imported crude oil (RAIMPUS) is based on the Oil Market Simulation (OMS) model of the International and Contingency Information Division. Forecasts from the model are benchmarked to the most recent available data. The price of domestic crude oil (RACPUUS) is assumed to equal the imported price for the forecast period

The composite refiner acquisition cost of crude oil (RACPUUS), a weighted average of imported and domestic crude oil costs, is therefore assumed to equal the imported cost of oil. The RACPUUS variable is not seasonally adjusted in any of the price equations because its seasonality was not statistically significant.

Motor Gasoline

The wholesale price of gasoline (MGWHUUS) is estimated as a function of the dependent variable lagged 1-month, the refiners' acquisition cost of crude oil, the wholesale price index for non-energy products (WPIINUS) as a measure of inflation, and the day's supply of motor gasoline ($MGPSPUSA_{-1}$ / MGTCPUSA). In the forecast an add factor (MGWHUAD) incorporates the additional costs of blending oxygenates with motor gasoline to comply with the Clean Air Act Amendments of 1990.

$$\begin{aligned} MGWHUUSA = {} & (MGWHP\_01 + MGWHP\_PC * RACPUUS + MGWHP\_WI * WPIINUS \\ & + MGWHP\_DS * MGPSPUSA_{-1} / MGTCPUSA + MGWHUAD) * MGWHUMU \end{aligned} \quad \text{(A77)}$$

The retail price of motor gasoline (MGUCUUSA) is estimated as a function of the dependent variable lagged 1 month, the wholesale price of motor gasoline, and the Consumer Price Index (CICPIUS) as a measure of inflation.

$$\begin{aligned} MGUCUUSA = {} & (MGUCP\_01 + MGUCP\_R1 * MGUCUUSA_{-1} \\ & + MGUCP\_WH * MGWHUUSA + MGUCP\_CI * CICPIUS \\ & + MGUCUAD) * MGUCUMU \end{aligned} \quad \text{(A78)}$$

And, reseasonalizing:

$$MGWHUUS = MGWHUUSA * MGWHUUSS$$
$$MGUCUUS = MGUCUUSA * MGUCUUSS$$

Distillate Fuel Oil

The wholesale price of distillate fuel oil (D2WHUUSA) is estimated as a function of the price of crude oil (RACPUUS) and days supply of distillate fuel oil ($DFPSPUSA_{-1}$ / DFTCPUSA):

$$D2WHUUSA = (D2WHP\_01 + D2WHP\_PC * RACPUUS + D2WHP\_DS * DFPSPUSA_{-1} / DFTCPUSA + D2WHUAD) * D2WHUMU \quad (A79)$$

Retail distillate prices (D2RCUUSA) are estimated as a function of the dependent variable lagged 1 month, the wholesale price of distillate fuel oil, and the Producer Price Index as a measure of inflation (WPCPIUS):

$$D2RCUUSA = (D2RCP\_01 + D2RCP\_R1 * D2RCUUSA_{-1} + D2RCP\_WH * D2WHUUSA + D2RCP\_WN * WPIINUS + D2RCUAD) * D2RCUMU \quad (A80)$$

And, reseasonalizing:

$$D2WHUUS = D2WHUUSA * D2WHUUSS$$
$$D2RCUUS = D2RCUUSA * D2RCUUSS$$

Diesel Fuel

The price of diesel fuel, excluding federal and state taxes (DSTCUUSA) is estimated a function of the price of crude oil (RACPUUS), days supply of distillate fuel oil ($DFPSPUSA_{-1}$ / DFTCPUSA), and the consumer price index (CICPIUS), to account for inflation. A dummy variable (D9001) captures the effect of the severe winter in January 1990. In the forecast an add factor (DSTCUAD) incorporates the additional costs of low sulfur requirements to comply with the Clean Air Act Amendments of 1990:

$$DSTCUUSA = (DSTCP\_01 + DSTCP\_PC * RACPUUS + DSTCP\_CI * CICPIUS + DSTCP\_DS * DFPSPUSA_{-1} / DFTCPUSA + DSTCP\_D1 * D9001 + DSTCUAD) * DSTCUMU \quad (A81)$$

And, reseasonalizing:

$$DSTCUUS = DSTCUUSA * DSTCUUSS$$

Federal and state taxes (DSTXUUS), are then added to the retail price. Diesel taxes, in cents per gallon, are from the table "Federal and State Motor Fuel Taxes" in Table **EN1** of the *Petroleum Marketing Monthly*, (DOE/EIA-0380). In the forecast, taxes are assumed to increase a rate of one cent per year.

$$DSRTUUS = DSTCUUS + DSTXUUS$$

Residual Fuel Oil

Retail residual fuel oil prices (RFTCUUS) are estimated as a function of the crude oil price (RACPUUS), days supply of residual fuel oil ($RFPSPUS_{-1}$ / RFTCPUS), and 11 monthly seasonal dummy variables. In the forecast, an add (negative) factor (RFTCUAD) incorporates the structural decline of the residual fuel oil market.

$$RFTCUUS = (RFTCP\_01 + RFTCP\_PC * RACPUUS + RFTCP\_RF * RFPSPUS_{-1} / RFTCPUS + RFTCP\_06 * JAN + RFTCP\_07 * FEB + RFTCP\_08 * MAR + RFTCP\_09 * APR + RFTCP\_10 * MAY + RFTCP\_11 * JUN + RFTCP\_12 * JUL + RFTCP\_14 * SEP + RFTCP\_15 * OCT + RFTCP\_16 * NOV + RFTCP\_17 * DEC + RFTCUAD) * RFTCUMU \quad (A82)$$

The deseasonalized price of residual fuel oil to electric utilities (RFEUDUSA), in dollars per million Btu, is calculated by dividing seasonally adjusted retail residual fuel price (RFTCUUSA), in dollars per barrel, by the heat content for residual fuel oil (6.287 million Btu per barrel).

$$RFTCUUSA = RFTCUUS \ / \ RFTCUUSS$$
$$RFEUDUSA = RFTCUUSA \ / \ RFTCZUS * .42 + .20$$

And, reseasonalizing:

$$RFEUDUS = RFEUDUSA * RFEUDUSS$$

Jet Fuel

The average retail price of kerosene jet fuel (JKTCUUSA) is estimated as a function of the dependent variable lagged 1 month, the price of crude oil (RACPUUS), the wholesale price index for non-energy products as a measure of inflation (WPIINUS), and a dummy variable (DUMCOLD) representing the period of December 1989 through January 1990, when cold weather caused all petroleum product prices to surge.

$$\begin{aligned} JKTCUUSA = (&JKTCP\_01 + JKTCP\_R1 * JKTCUUSA_{-1} + JKTCP\_PC * RACPUUS \\ &+ JKTCP\_WN * WPIINUS + JKTCP\_D1 * DUMCOLD + JKTCUAD) * JKTCUMU \end{aligned} \tag{A83}$$

And, reseasonalizing:

$$JKTCUUS = JKTCUUSA * JKTCUUSS$$

Propane

The average retail price of propane (PRTCUUSA) is estimated as a fuction of the dependent variable lagged 1 month, the price of a competing fuel, diesel fuel (D2RCUUSA), and the wholesale price index for non-energy products as a measure of inflation (WPIINUS):

$$\begin{aligned} PRTCUUSA = (&PRTCP\_01 + PRTCP\_R1 * PRTCUUSA_{-1} + PRTCP\_WI * WPIINUS \\ &+ PRTCP\_D2 * D2RCUUSA + PRTCUAD) * PRTCUMU \end{aligned} \tag{A84}$$

And, reseasonalizing:

$$PRTCUUS = PRTCUUSA * PRTCUUSS$$

Producer Price Index for Petroleum Products

The deseasonalized producer price index for petroleum products (WP57IUS) is estimated as a function of the refiner (wholesale) price of gasoline (MGWHUUSA), the price of diesel fuel oil (DSTCUUSA), and the price of kerosene jet fuel (JKTCUUSA):

$$\begin{aligned} WP57IUS = &WP57P\_01 + WP57P\_MG * MGWHUUSA + WP57P\_DS * DSTCUUSA \\ &+ WP57P\_JK * JKTCUUSA \end{aligned} \tag{A85}$$

Natural Gas, Electricity, and Coal Prices

Natural Gas Wellhead Price

The spot price of natural gas (NGSPUUS) is estimated as a function of a 1-month lag of natural gas underground storage (NGWGPUS), the price of residual fuel oil, a competitor fuel (RFTCUUS), and 11 monthly seasonal dummy variables:

$$\begin{aligned} NGSPUUS = (&NGSPP\_01 + NGSPP\_WG * NGWGPUS_{-1} + NGSPP\_RF * RFTCUUS \\ &+ NGSPP\_06 * JAN + NGSPP\_07 * FEB + NGSPP\_08 * MAR + NGSPP\_09 * APR \\ &+ NGSPP\_10 * MAY + NGSPP\_11 * JUN + NGSPP\_12 * JUL + NGSPP\_14 * SEP \\ &+ NGSPP\_15 * OCT + NGSPP\_16 * NOV + NGSPP\_17 * DEC \\ &+ NGSPP\_R1 * NGSPUUS_{-1} + NGSPUAD) * NGSPUMU \end{aligned} \tag{A86}$$

The wellhead price of natural gas (NGWPUUS) is estimated as a function of the spot price of natural gas (NGSPUUS), the dependent variable lagged one month, and 11 monthly seasonal dummy variables.

$$\begin{aligned} NGWPUUS = (&NGWPP\_01 + NGWPP\_R1 * NGWPUUS_{-1} + NGWPP\_SP * NGSPUUS \\ &+ NGWPP\_06 * JAN + NGWPP\_07 * FEB + NGWPP\_08 * MAR \\ &+ NGWPP\_09 * APR + NGWPP\_10 * MAY + NGWPP\_11 * JUN \\ &+ NGWPP\_12 * JUL + NGWPP\_14 * SEP + NGWPP\_15 * OCT \\ &+ NGWPP\_16 * NOV + NGWPP\_17 * DEC + NGWPUAD) * NGWPUMU \end{aligned} \tag{A87}$$

Natural Gas Price to Electric Utilities

The natural gas price to electric utilities (NGEUDUSA) is estimated as a function of the wellhead price (NGWPUUSA), the dependent variable lagged 1 month, and the price of a competing fuel, residual fuel oil to electric utilities (RFEUDUSA).

$$\begin{aligned} NGEUDUSA = &NGEUP\_01 + NGEUP\_R1 * NGEUDUSA_{-1} \\ &+ NGEUP\_WP * NGWPUUSA + NGEUP\_RF * RFEUDUSA + NGEUDAD \end{aligned} \tag{A88}$$

Where, $NGWPUUSA = NGWPUUS / NGWPUUSS$

And, reseasonalizing:

$$NGEUDUS = NGEUDUSA * NGEUDUSS$$

Residential Natural Gas Price

The price of natural gas to residential consumers (NGRCUUSA) is assumed to be a function of the wellhead price (NGWPUUSA), the dependent variable lagged 1 month, and an index of inflation (WPIINUS):

$$\begin{aligned} NGRCUUSA = (&NGRCP\_01 + NGRCP\_R1 * NGRCUUSA_{-1} + NGRCP\_WI * WPIINUS \\ &+ NGRCP\_NP * NGWPUUSA_{-1} + NGRCUAD) * NGRCUMU \end{aligned} \tag{A89}$$

And, reseasonalizing:

$$NGRCUUS = NGRCUUSA * NGRCUUSS$$

Commercial Natural Gas Price

The price of natural gas to commercial users (NGCCUUSA) is assumed to be a function of the wellhead price (NGWPUUSA), the dependent variable lagged 1 month and an index of inflation (WPIINUS):

$$NGCCUUSA = (NGCCP\_01 + NGCCP\_R1 * NGCCUUSA_{-1} + NGCCP\_WI * WPIINUS + NGCCP\_WP * NGWPUUSA + NGCCUAD) * NGCCUMU \quad (A90)$$

And, reseasonalizing:

$$NGCCUUS = NGCCUUSA * NGCCUUSS$$

Industrial Natural Gas Price

The price of natural gas to industrial users (NGICUUSA) is estimated as a function of the wellhead price (NGWPUUSA), and the dependent variable lagged 1 month:

$$NGICUUSA = (NGICP\_01 + NGICP\_R1 * NGICUUSA_{-1} + NGICP\_WP * NGWPUUSA + NGICUAD) * NGICUMU \quad (A91)$$

and, reseasonalizing:

$$NGICUUS = NGICUUSA * NGICUUSS$$

Residential Electricity Price

The residential electricity price (ESRCUUSA) is estimated as a function of the weighted price of fossil fuels and coal to electric utilities (AFUEUUS) lagged 2 months; a labor and material cost index (WPIINUS); a dummy variable for 1989 (D89) representing large increases in generation from the prior year in relatively inexpensive hydropower; a dummy variable (DUMELE) representing a slight structural shift upward in price after January 1991 caused by a decline in hydropower and increase in nuclear power; and a 12-period lag of a 6 month moving average of the prime rate (PRIMEUS) as a measure of the cost of capital (PRIMELG). PRIMELG is defined as:

$$PRIMELG = (PRIMEUS_{-12} + PRIMEUS_{-13} + PRIMEUS_{-14} + PRIMEUS_{-15} + PRIMEUS_{-16} + PRIMEUS_{-17}) / 6$$

$$AFUEUUS = (RFEUDUS * QRESD + NGEUDUS * QNGAS + CLEUDUS * QCOAL) / (QRESD + QNGAS + QCOAL)$$

Fossil fuel shares are defined as:

QRESD = RFEOPUS * RFEOKUS (Generation from heavy oil times its heat rate)
QNGAS = NGEOPUS * NGEOKUS (Generation from gas times its heat rate)
QCOAL = CLEOPUS * CLEOKUS (Generation from coal times its heat rate)

Thus:

$$ESRCUUSA = (ESRCP\_01 + ESRCP\_IN * PRIMELG + ESRCP\_WPI * WPIINUS + ESRCP\_AF * AFUEUUS_{-2} + ESRCP\_D1 * DUMELE + ESRCP\_D2 * DUM89 + ESRCUAD) * ESRCUMU \quad (A92)$$

And, reseasonalizing:

$$ESRCUUS = ESRCUUSA * ESRCUUSS$$

Utility Coal Price

The price of coal (CLEUDUSA) is estimated as a function of transportation costs in the form of diesel prices (DSTCUUS), mining productivity in tons per miner-hour (CLMRHUS), and the dependent variable lagged 1 month. CLEUDAD is added to the forecast to account for structural changes due to stockpiling in anticipation of a coal miners strike in 1993, and increased costs due to the Clean Air Act.

```
CLEUDUSA = (CLEUP_01 + CLEUP_R1 * LAG(CLEUDUSA)
        + CLEUP_MR * CLMRHUS + CLEUP_DS * DSTCUUS
        + CLEUDAD) * CLEUDMU                                  (93)
```

And, reseasonalizing:

```
CLEUDUS  = CLEUDUSA * CLEUDUSS
```

Appendix A

Regression Results

Appendix A

Regression Results

Table A1. Automobile Fleet Fuel Efficiency (Seasonally Adjusted) (MPGA)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
MPGA	9	179	20.10609	0.11232	0.33515	0.9740	0.9728	2.008

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
MEFF_01	10.913451	0.22550	48.40	0.0001	MPGA constant coef
MEFF_T	0.039101	0.0006833	57.22	0.0001	MPGA coef of TIME
MEFF_D02	0.602276	0.33512	1.80	0.0740	MPGA coef of D8412
MEFF_D03	0.907054	0.34060	2.66	0.0084	MPGA coef of D8302
MEFF_D04	0.209685	0.18798	1.12	0.2661	MPGA coef for DRVP89
MEFF_D05	0.264281	0.16242	1.63	0.1055	MGPA coef for DRVP90
MPGA1_0	0.031256	0.0094917	3.29	0.0012	PDL(MPGA1,1,1) parameter for (L)**0
MPGA1_1	-0.052575	0.01887	-2.79	0.0059	PDL(MPGA1,1,1) parameter for (L)**1
MPGA_L1	0.108952	0.07583	1.44	0.1525	MPGA 1st-order autocorrleation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 7701 TO 9208

Table A2. Vehicle Miles Traveled (Seasonally Adjusted) (MVVMPUSA)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
MVVMPUSA	7	181	707038	3906.3	62.50030	0.9923	0.9921	2.304

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
MVMT_01	4495.60	124.71350	36.05	0.0001	MVVMPUSA constant coef
MVMT_YT	0.00237522	0.0001357	17.50	0.0001	MVVMPUSA coef of YD87OUS*TIME
MVMT_D01	-126.649974	52.99484	-2.39	0.0179	MVVMPUSA coef of D8501
MVMT_D02	186.496777	42.62524	4.38	0.0001	MVVMPUSA coef of D89ON
MVVMPUS1_0	-66.734339	16.19423	-4.12	0.0001	PDL(MVVMPUS1,1,1) parameter for (L)**0
MVVMPUS1_1	50.624020	29.87466	1.69	0.0919	PDL(MVVMPUS1,1,1) parameter for (L)**1
MVVMPUSA_L1	0.659760	0.05806	11.36	0.0001	MVVMPUSA 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 7701 TO 9208

Table A3. Unleaded Motor Gasoline Demand Share (MUTCSUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
MUTCSUS	4	184	0.01989	0.0001081	0.01040	0.9978	0.9977	2.427

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
MSH_01	1.482042	0.33262	4.46	0.0001	MUTCSUS constant coef
MSH_T	-0.018193	0.0028205	-6.45	0.0001	MUTCSUS coef of TIME
MSH_D01	-0.107930	0.06865	-1.57	0.1176	MUTCSUS coef of D88ON
MUTCSUS_L1	0.966708	0.01936	49.92	0.0001	MUTCSUS 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 7701 TO 9208

Table A4. Log of Average Realized Airline Ticket Price (Seasonally Adjusted) (LDRYLD)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
LDRYLD	4	125	0.06560	0.0005248	0.02291	0.9580	0.9570	2.014

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
YLD0	2.628038	0.19932	13.18	0.0001	LDRYLD constant coef
YLD1	0.034336	0.03688	0.93	0.3536	LDRYLD coef for JKTCUUS/WPCPIUS
YLD2	-0.00270911	0.0005323	-5.09	0.0001	LDRYLD coef for TIME
LDRYLD_1	0.908366	0.03979	22.83	0.0001	LDRYLD 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8201 TO 9209

Table A5. Log of Aircraft Traffic (Seasonally Adjusted) (LDRZM)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
LDRZM	7	158	0.06261	0.0003962	0.01991	0.9942	0.9940	2.473

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
RZM0	8.538688	0.83812	10.19	0.0001	LDRZM constant coef
RZM1	0.329191	0.05460	6.03	0.0001	LDRZM coef for LOG(YD87OUS)
RZM2	-0.053697	0.01399	-3.84	0.0002	LDRZM coef for D91
LDRZM1_0	-0.173027	0.06166	-2.81	0.0056	PDL(LDRZM1,2,2) parameter for (L)**0
LDRZM1_1	0.024639	0.15152	0.16	0.8710	PDL(LDRZM1,2,2) parameter for (L)**1
LDRZM1_2	0.00565498	0.07246	0.08	0.9379	PDL(LDRZM1,2,2) parameter for (L)**2
LDRZM_L1	0.960546	0.02072	46.36	0.0001	LDRZM 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 7901 TO 9209

Table A6. Log of Aircraft Available Ton-Miles (Seasonally Adjusted) (LDRTM)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
LDRTM	7	158	0.04505	0.0002852	0.01689	0.9956	0.9954	1.973

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
RTM0	-0.374828	0.61044	-0.61	0.5401	LDRTM constant coef
RTM1	0.015634	0.0090363	1.73	0.0856	LDRTM coef for D8082
RTM2	0.00054850	0.0002765	1.98	0.0490	LDRTM coef for TIME
LDRTM1_0	0.345193	0.05960	5.79	0.0001	PDL(LDRTM1,6,2) parameter for (L)**0
LDRTM1_1	-0.214071	0.05153	-4.15	0.0001	PDL(LDRTM1,6,2) parameter for (L)**1
LDRTM1_2	0.032543	0.0082970	3.92	0.0001	PDL(LDRTM1,6,2) parameter for (L)**2
LDRTM_L1	0.569589	0.06663	8.55	0.0001	LDRTM 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 7901 TO 9209

Table A7. Average Aircraft Efficiency (Seasonally Adjusted) (EFFSA)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
EFFSA	5	160	57761908	361011.9	600.84268	0.9135	0.9113	1.955

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
EFF0	18022.53	1905.9	9.46	0.0001	EFFSA constant coef
EFF1	-832.555718	356.15523	-2.34	0.0206	EFFSA coef for LFSA
EFF2	40.897288	1.37654	29.71	0.0001	EFFSA coef for TIME
EFF3	-2310.54	581.14431	-3.98	0.0001	EFFSA coef for D8912
EFFSA_L1	0.274601	0.07668	3.58	0.0005	EFFSA 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 7901 TO 9209

Table A8. Transportation Sector Demand for Distillate Fuel Oil (DFACPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
DFACPUS	14	127	0.41497	0.0032675	0.05716	0.9216	0.9136	2.059

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
DFAC_01	0.085062	0.05425	1.57	0.1194	DFACPUS constant coef
DFAC_JQ	1.443216	0.05445	26.51	0.0001	DFACPUS coef of ZOMNIUS
DFAC_06	0.022896	0.02075	1.10	0.2719	DFACPUS coef of FEB
DFAC_07	0.085149	0.02331	3.65	0.0004	DFACPUS coef of MAR
DFAC_08	0.128498	0.02394	5.37	0.0001	DFACPUS coef of APR
DFAC_09	0.129651	0.02411	5.38	0.0001	DFACPUS coef of MAY
DFAC_10	0.183599	0.02416	7.60	0.0001	DFACPUS coef of JUN
DFAC_11	0.202598	0.02418	8.38	0.0001	DFACPUS coef of JUL
DFAC_12	0.157509	0.02418	6.52	0.0001	DFACPUS coef of AUG
DFAC_13	0.148145	0.02414	6.14	0.0001	DFACPUS coef of SEP
DFAC_14	0.131136	0.02447	5.36	0.0001	DFACPUS coef of OCT
DFAC_15	0.077396	0.02388	3.24	0.0015	DFACPUS coef of NOV
DFAC_16	0.072107	0.02134	3.38	0.0010	DFACPUS coef of DEC
DFACPUS_L1	0.262525	0.08600	3.05	0.0028	DFACPUS 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8101 TO 9209

Table A9. Residential and Commercial Sectors Demand for Distillate Fuel Oil (DFHCPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
DFHCPUS	14	102	0.42084	0.0041259	0.06423	0.8833	0.8684	2.135

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
DFHC_01	0.386574	0.06088	6.35	0.0001	DFHCPUS constant coef
DFHC_R1	0.632839	0.06059	10.44	0.0001	DFHCPUS coef of LAG(DFHCPUS)
DFHC_W	0.038001	0.0055313	6.87	0.0001	DFHCPUS coef of ZWHDDNO/ZSAJQUS
DFHC_06	-0.052871	0.02890	-1.83	0.0702	DFHCPUS coef of FEB
DFHC_07	-0.119383	0.02887	-4.14	0.0001	DFHCPUS coef of MAR
DFHC_08	-0.234286	0.02983	-7.85	0.0001	DFHCPUS coef of APR
DFHC_09	-0.227753	0.03344	-6.81	0.0001	DFHCPUS coef of MAY
DFHC_10	-0.176511	0.03655	-4.83	0.0001	DFHCPUS coef of JUN
DFHC_11	-0.198058	0.03709	-5.34	0.0001	DFHCPUS coef of JUL
DFHC_12	-0.140257	0.03760	-3.73	0.0003	DFHCPUS coef of AUG
DFHC_13	-0.137061	0.03625	-3.78	0.0003	DFHCPUS coef of SEP
DFHC_14	-0.093577	0.03555	-2.63	0.0098	DFHCPUS coef of OCT
DFHC_15	-0.053677	0.03342	-1.61	0.1113	DFHCPUS coef of NOV
DFHC_16	0.078417	0.03162	2.48	0.0148	DFHCPUS coef of DEC

Method of Estimation: OLS
RANGE of Fit: 8301 TO 9208

Table A10. Industrial Sector Demand for Distillate Fuel Oil (DFICPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
DFICPUS	15	101	1.18612	0.01174	0.10837	0.7612	0.7281	1.678

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
DFIC_01	0.700991	0.12970	5.40	0.0001	DFICPUS constant coef
DFIC_W	0.023102	0.0054685	4.22	0.0001	DFICPUS coef of ZWHDDUS(OCT...APR)
DFIC_JQ	0.173328	0.13291	1.30	0.1952	DFICPUS coef of ZOTOIUS
DFIC_P	-0.00030225	0.0005232	-0.58	0.5647	DFICPUS coef of D2WHUUS/NGICUUS
DFIC_06	-0.021018	0.04870	-0.43	0.6669	DFICPUS coef of FEB
DFIC_07	-0.053814	0.04853	-1.11	0.2701	DFICPUS coef of MAR
DFIC_08	-0.265416	0.04894	-5.42	0.0001	DFICPUS coef of APR
DFIC_09	-0.372213	0.04912	-7.58	0.0001	DFICPUS coef of MAY
DFIC_10	-0.442545	0.04910	-9.01	0.0001	DFICPUS coef of JUN
DFIC_11	-0.613190	0.04914	-12.48	0.0001	DFICPUS coef of JUL
DFIC_12	-0.445838	0.04933	-9.04	0.0001	DFICPUS coef of AUG
DFIC_13	-0.428518	0.05080	-8.44	0.0001	DFICPUS coef of SEP
DFIC_14	-0.251719	0.05113	-4.92	0.0001	DFICPUS coef of OCT
DFIC_15	-0.239508	0.05026	-4.77	0.0001	DFICPUS coef of NOV
DFIC_16	-0.169590	0.05139	-3.30	0.0013	DFICPUS coef of DEC

Method of Estimation: OLS
RANGE of Fit: 8301 TO 9208

Table A11. No. 2 Diesel Fuel Demand
(DSTCPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
DSTCPUS	3	101	0.03664	0.0003628	0.01905	0.8614	0.8587	2.334

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
DSTC_AC	0.042673	0.02347	1.82	0.0720	DSTCPUS coef of DFACPUS
DSTC_01	0.148033	0.03613	4.10	0.0001	DSTCPUS constant coef
DSTCPUS_L1	0.987297	0.01715	57.57	0.0001	DSTCPUS 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8101 TO 9208

Table A12. Non-Utility Demand for Residual Fuel Oil
(RFNUPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
RFNUPUS	11	117	1.03925	0.0088825	0.09425	0.7738	0.7544	1.989

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
RFNU_01	2.112015	0.19620	10.76	0.0001	RFNUPUS CONSTANT TERM
RFNU_JQ	-0.043909	0.29540	-0.15	0.8821	RFNUPUS coef of ZOMNIUS
RFNU_W	0.00033420	0.00006349	5.26	0.0001	RFNUPUS coef of ZWHDPUS
RFNU_W1	-0.00006261	0.00005378	-1.16	0.2466	RFNUPUS coef of HDDX85
RFNU_P	-0.00127006	0.0006400	-1.98	0.0495	RFNUPUS coef of RFTCUUS/NGICUUS
RFNU_T	-0.00130870	0.0007777	-1.68	0.0951	RFNUPUS coef of TIMEX85
RFNU_T1	-0.011308	0.0021431	-5.28	0.0001	RFNUPUS coef of PRE85XT
RFNU_D1	-1.116472	0.20157	-5.54	0.0001	RFNUPUS coef of POST85
RFNU_D2	0.040420	0.03410	1.19	0.2383	RFNUPUS coef of DUMWTR
RFNU_D3	-0.133612	0.09667	-1.38	0.1696	RFNUPUS coef of D8809
RFNUPUS_L1	-0.032826	0.09412	-0.35	0.7279	RFNUPUS 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8201 TO 9208

Table A13. Demand for Ethane (Seasonally Adjusted) (ETTCPUSA)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
ETTCPUSA	7	121	0.13163	0.0010878	0.03298	0.5842	0.5636	2.457

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
ETH0	0.427947	0.03743	11.43	0.0001	ETTCPUSA constant coef
ETH1	0.00443494	0.0015380	2.88	0.0047	ETTCPUSA coef for D2WHUUSA/NGEUDUSA
ETH2	-1.593763	0.76326	-2.09	0.0389	ETTCPUSA coef for D8184
ETH3	0.343748	0.16593	2.07	0.0404	ETTCPUSA coef for TD8104
ETH4	4.272131	4.14406	1.03	0.3046	ETTCPUSA coef for D8990
ETH5	-0.836604	0.80160	-1.04	0.2987	ETTCPUSA coef for TD8990
ETTCPUSA_L1	0.614590	0.07327	8.39	0.0001	ETTCPUSA 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8201 TO 9208

Table A14. Demand for Liquefied Petroleum Gas, Excluding Ethane (Seasonally Adjusted) (LXTCPUSA)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
LXTCPUSA	5	135	0.73221	0.0054238	0.07365	0.5191	0.5049	1.972

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
LXT0	0.294487	0.07014	4.20	0.0001	LXTCPUSA constant coef
LXT1	0.014400	0.0033117	4.35	0.0001	LXTCPUSA coef for (ZWHDPUS-ZWHNPUS)/ZSAJQUS
LXT2	0.309779	0.07533	4.11	0.0001	LXTCPUSA coef for LAG(LXTCPUSA)
LXT3	0.451470	0.07419	6.09	0.0001	LXTCPUSA coef for ZO28IUS
LXT4	-0.195578	0.07932	-2.47	0.0149	LXTCPUSA coef for D9001

Method of Estimation: OLS
RANGE of Fit: 8101 TO 9208

Table A15. Demand for Propane
(PRTCPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
PRTCPUS	14	127	0.16890	0.0013299	0.03647	0.9697	0.9666	2.215

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
PRTC_01	0.065204	0.04479	1.46	0.1479	PRTCPUS constant coef
PRTC_Q	0.797030	0.03241	24.59	0.0001	PRTCPUS coef for LXTCPUS
PRTC_06	0.020118	0.01218	1.65	0.1011	PRTCPUS coef for JAN
PRTC_07	-0.015655	0.01520	-1.03	0.3049	PRTCPUS coef for FEB
PRTC_08	-0.033033	0.01866	-1.77	0.0791	PRTCPUS coef for MAR
PRTC_09	-0.046484	0.02199	-2.11	0.0365	PRTCPUS coef for APR
PRTC_10	-0.063248	0.02377	-2.66	0.0088	PRTCPUS coef for MAY
PRTC_11	-0.071909	0.02390	-3.01	0.0032	PRTCPUS coef for JUN
PRTC_12	-0.065129	0.02262	-2.88	0.0047	PRTCPUS coef for JUL
PRTC_13	-0.027107	0.02234	-1.21	0.2272	PRTCPUS coef for AUG
PRTC_14	-0.032660	0.01904	-1.72	0.0887	PRTCPUS coef for SEP
PRTC_15	-0.020951	0.01609	-1.30	0.1953	PRTCPUS coef for OCT
PRTC_16	-0.027903	0.01282	-2.18	0.0314	PRTCPUS coef for NOV
PRTCPUS_L1	0.655914	0.06753	9.71	0.0001	PRTCPUS 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8101 TO 9209

Table A16. Log of Demand for Petrochemical Feedstocks (Seasonally Adjusted)
(LSFET)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
LSFET	4	101	0.76020	0.0075267	0.08676	0.7384	0.7307	2.280

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
FET0	-0.895572	0.04624	-19.37	0.0001	LSFET constant coef
FET1	1.338579	0.22414	5.97	0.0001	LSFET coef of LOG(ZO28IUS)
FET2	-0.154819	0.09084	-1.70	0.0914	LSFET coef of LOG(WP57IUS/WPCPIUS)
LSFET_L1	0.509675	0.08561	5.95	0.0001	LSFET 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8401 TO 9210

Table A17. Log of Demand for Miscellaneous Petroleum Products (Seasonally Adjusted) (LSMIS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
LSMIS	9	120	0.12213	0.0010178	0.03190	0.8009	0.7877	1.518

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
MIS0	0.536406	0.01160	46.25	0.0001	LSMIS constant coef
MIS1	0.290540	0.04962	5.86	0.0001	LSMIS coef of LOG(ZOMNIUS)
MIS2	-0.073873	0.03253	-2.27	0.0249	LSMIS coef of D8301
MIS3	-0.063228	0.03219	-1.96	0.0518	LSMIS coef of D8412
MIS4	-0.102823	0.03312	-3.10	0.0024	LSMIS coef of D8611
MIS5	-0.092418	0.03220	-2.87	0.0049	LSMIS coef of D8912
LSMIS1_0	0.00032431	0.02512	0.01	0.9897	PDL(LSMIS1,6,2) parameter for (L)**0
LSMIS1_1	-0.025519	0.02622	-0.97	0.3324	PDL(LSMIS1,6,2) parameter for (L)**1
LSMIS1_2	0.00471822	0.0043404	1.09	0.2792	PDL(LSMIS1,6,2) parameter for (L)**2

Method of Estimation: OLS
RANGE of Fit: 8201 TO 9209

Table A18. Refinery Inputs of Crude Oil (CORIPUSJ)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
CORIPUSJ	18	123	9.13235	0.07425	0.27248	0.8914	0.8764	1.022

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
COR_B0	2.221079	0.75055	2.96	0.0037	CORIPUSJ constant coef
COR_MGPS	-0.017220	0.0027298	-6.31	0.0001	CORIPUSJ coef for LAG(MGPSPUS)
COR_DFPS	0.00142226	0.0014186	1.00	0.3180	CORIPUSJ coef for LAG(DFPSPUS)
CORI_E1	-0.196291	0.11795	-1.66	0.0986	CORIPUSJ coef for JAN
CORI_E2	-0.263937	0.13728	-1.92	0.0568	CORIPUSJ coef for FEB
CORI_E3	-0.234513	0.14212	-1.65	0.1015	CORIPUSJ coef for MAR
CORI_E4	-0.00198652	0.14948	-0.01	0.9894	CORIPUSJ coef for APR
CORI_E5	0.502058	0.15415	3.26	0.0015	CORIPUSJ coef for MAY
CORI_E6	0.787038	0.14415	5.46	0.0001	CORIPUSJ coef for JUN
CORI_E7	0.745415	0.13364	5.58	0.0001	CORIPUSJ coef for JUL
CORI_E8	0.636981	0.12368	5.15	0.0001	CORIPUSJ coef for AUG
CORI_E9	0.482243	0.12806	3.77	0.0003	CORIPUSJ coef for SEP
CORI_E10	0.097640	0.12259	0.80	0.4273	CORIPUSJ coef for OCT
CORI_E11	0.151333	0.12374	1.22	0.2237	CORIPUSJ coef for NOV
CORIPUS1_0	0.196511	0.05197	3.78	0.0002	PDL(CORIPUS1,6,3) parameter for (L)**0
CORIPUS1_1	0.093520	0.10201	0.92	0.3610	PDL(CORIPUS1,6,3) parameter for (L)**1
CORIPUS1_2	-0.061484	0.04253	-1.45	0.1508	PDL(CORIPUS1,6,3) parameter for (L)**2
CORIPUS1_3	0.00696184	0.0046843	1.49	0.1398	PDL(CORIPUS1,6,3) parameter for (L)**3

Method of Estimation: OLS
RANGE of Fit: 8101 TO 9209

Table A19. Refinery Inputs of Unfinished Oils (UORIPUSJ)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
UORIPUSJ	14	127	2.00593	0.01579	0.12568	0.5723	0.5285	1.466

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
UORI_B0	-0.261467	0.23465	-1.11	0.2673	UORIPUSJ constant coef
UORI_PA	0.051694	0.01378	3.75	0.0003	UORIPUSJ coef for PATCPUS
UORI_D1	0.176137	0.02679	6.58	0.0001	UORIPUSJ coef for D90ON
UORI_E1	-0.264312	0.05262	-5.02	0.0001	UORIPUSJ coef for JAN
UORI_E2	-0.278543	0.05283	-5.27	0.0001	UORIPUSJ coef for FEB
UORI_E3	-0.342023	0.05313	-6.44	0.0001	UORIPUSJ coef for MAR
UORI_E4	-0.221335	0.05406	-4.09	0.0001	UORIPUSJ coef for APR
UORI_E5	-0.170216	0.05477	-3.11	0.0023	UORIPUSJ coef for MAY
UORI_E6	-0.095085	0.05324	-1.79	0.0765	UORIPUSJ coef for JUN
UORI_E7	-0.045715	0.05363	-0.85	0.3956	UORIPUSJ coef for JUL
UORI_E8	-0.121837	0.05294	-2.30	0.0230	UORIPUSJ coef for AUG
UORI_E9	-0.139038	0.05387	-2.58	0.0110	UORIPUSJ coef for SEP
UORI_E10	-0.193841	0.05424	-3.57	0.0005	UORIPUSJ coef for OCT
UORI_E11	-0.071092	0.05454	-1.30	0.1947	UORIPUSJ coef for NOV

Method of Estimation: OLS
RANGE of Fit: 8101 TO 9209

Table A20. Inputs to Primary Crude Distillation (CODIPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
CODIPUSJ	2	103	0.21932	0.0021293	0.04614	0.9956	0.9955	1.032

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
CODI_UO	0.044098	0.02734	1.61	0.1098	CODIPUSJ coef for UORIPUSJ
CODI_CO	1.011631	0.0011395	887.77	0.0001	CODIPUSJ coef for CORIPUSJ

Method of Estimation: OLS
RANGE of Fit: 8401 TO 9209

Table A21. Refinery Inputs of Liquefied Petroleum Gases (Seasonally Adjusted) (LGRIPUSA)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
LGRIPUSA	4	137	0.03758	0.0002743	0.01656	0.5539	0.5441	1.825

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
LGRI_B0	-0.023469	0.07746	-0.30	0.7624	LGRIPUSA constant coef
LGRI_MG	0.015398	0.0071971	2.14	0.0342	LGRIPUSA coef for MGTCPUSA
LGRI_DL	4.795904	1.21960	3.93	0.0001	LGRIPUSA coef for DUMYRLG
LGRIPUSA_L1	0.539792	0.07575	7.13	0.0001	LGRIPUSA 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8101 TO 9209

Table A22. Refinery Inputs of Pentanes Plus (Seasonally Adjusted) (PPRIPUSA)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
PPRIPUSA	4	137	0.01413	0.0001032	0.01016	0.7289	0.7229	1.969

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
PPRI_B0	-0.092659	0.04109	-2.26	0.0257	PPRIPUSA constant coef
PPRI_MG	0.016147	0.0044669	3.61	0.0004	PPRIPUSA coef for MGTCPUSA
PPRI_DP	5.915214	0.50796	11.65	0.0001	PPRIPUSA coef for DUMYRPP
PPRIPUSA_L1	0.349942	0.08042	4.35	0.0001	PPRIPUSA 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8101 TO 9209

Table A23. Refinery Inputs of Other Petroleum Products (PSRIPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
PSRIPUS	6	135	0.38959	0.0028859	0.05372	0.5826	0.5671	2.061

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
PSRI_DP	6.202389	0.20744	29.90	0.0001	PSRIPUS coef for DUMYRPS
PSRI_E2	-0.026790	0.01644	-1.63	0.1056	PSRIPUS coef for FEB
PSRI_E3	0.058823	0.01644	3.58	0.0005	PSRIPUS coef for MAR
PSRI_E4	0.058763	0.01644	3.57	0.0005	PSRIPUS coef for APR
PSRI_E9	-0.047853	0.01644	-2.91	0.0042	PSRIPUS coef for SEP
PSRI_E10	0.051456	0.01713	3.00	0.0032	PSRIPUS coef for OCT

Method of Estimation: OLS
RANGE of Fit: 8101 TO 9209

Table A24. Refinery Outputs of Motor Gasoline (Seasonally Adjusted) (MGROPUSA)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
MGROPUSA	4	137	1.17777	0.0085968	0.09272	0.9104	0.9084	2.027

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
MGRO_B0	1.173850	0.27992	4.19	0.0001	MGROPUSA constant coef
MGRO_CO	0.343487	0.01984	17.31	0.0001	MGROPUSA coef for refinery inputs
MGRO_PR	0.691799	0.14941	4.63	0.0001	MGROPUSA coef for MGWHUUSA/D2WHUUSA
MGROPUSA_L1	0.553346	0.07164	7.72	0.0001	MGROPUSA 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8101 TO 9209

Table A25. Refinery Outputs of Distillate Fuel Oil (Seasonally Adjusted) (DFROPUSA)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
DFROPUSA	4	137	0.67012	0.0048914	0.06994	0.8668	0.8638	1.858

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
DFRO_B0	0.299972	0.22389	1.34	0.1825	DFROPUSA constant coef
DFRO_CO	0.246359	0.01585	15.55	0.0001	DFROPUSA coef for refinery inputs
DFRO_PR	-0.731765	0.11756	-6.22	0.0001	DFROPUSA coef for MGWHUUSA/D2WHUUSA
DFROPUSA_L1	0.600399	0.07134	8.42	0.0001	DFROPUSA 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8101 TO 9209

Table A26. Refinery Outputs of Jet Fuel (Seasonally Adjusted) (JFROPUSA)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
JFROPUSA	6	135	0.30850	0.0022852	0.04780	0.9363	0.9340	2.422

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
JFRO_B0	0.464742	0.21021	2.21	0.0287	JFROPUSA constant coef
JFRO_CO	0.070705	0.01390	5.09	0.0001	JFROPUSA coef for refinery inputs
JFRO_P1	-0.175164	0.09049	-1.94	0.0550	JFROPUSA coef for MGWHUUSA/JKTCUUSA
JFRO_P2	-0.303229	0.11705	-2.59	0.0106	JFROPUSA coef for D2WHUUSA/JKTCUUSA
JFRO_D1	0.078493	0.05223	1.50	0.1353	JFROPUSA coef for D90ON
JFROPUSA_L1	0.987923	0.01283	77.02	0.0001	JFROPUSA 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8101 TO 9209

Table A27. Refinery Outputs of Residual Fuel (Seasonally Adjusted) (RFROPUSA)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
RFROPUSA	3	138	0.30381	0.0022015	0.04692	0.8862	0.8846	2.284

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
RFRO_B0	0.407629	0.19127	2.13	0.0348	RFROPUSA constant coef
RFRO_CO	0.076422	0.01313	5.82	0.0001	RFROPUSA coef for refinery inputs
RFROPUSA_L1	0.994821	0.0081139	122.61	0.0001	RFROPUSA 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8101 TO 9209

Table A28. Refinery Outputs of Liquefied Petroleum Gases (Seasonally Adjusted) (LGROPUSA)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
LGROPUSA	4	137	0.06817	0.0004976	0.02231	0.9543	0.9533	1.965

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
LGRO_B0	0.012647	0.10237	0.12	0.9019	LGROPUSA constant coef
LGRO_MG	0.013556	0.01586	0.85	0.3942	LGROPUSA coef for MGROPUSA
LGRO_CO	0.025265	0.0083635	3.02	0.0030	LGROPUSA coef for refinery inputs
LGROPUSA_L1	0.974000	0.02035	47.85	0.0001	LGROPUSA 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8101 TO 9209

Table A29. Refinery Outputs of Other Petroleum Products (Seasonally Adjusted) (PSROPUSA)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
PSROPUSA	4	137	0.37108	0.0027086	0.05204	0.8697	0.8669	2.173

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
PSRO_B0	0.093876	0.16298	0.58	0.5656	PSROPUSA constant coef
PSRO_CO	0.123611	0.01524	8.11	0.0001	PSROPUSA coef for refinery inputs
PSRO_TC	0.245614	0.05384	4.56	0.0001	PSROPUSA coef for PSTCPUSA
PSROPUSA_L1	0.664425	0.06476	10.26	0.0001	PSROPUSA 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8101 TO 9209

Table A30. Net Imports of Crude Oil Excluding SPR (CONXPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
CONXPUS	2	139	13.30569	0.09572	0.30939	0.9389	0.9385	1.831

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
CONX_RI	0.935654	0.01609	58.14	0.0001	CONXPUS coef of CORIPUS
CONX_PR	-0.917691	0.02476	-37.07	0.0001	CONXPUS coef of COPRPUS

Method of Estimation: OLS
RANGE of Fit: 8101 TO 9209

Table A31. Crude Oil Exports
(COEXPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
COEXPUS	13	116	0.34818	0.0030015	0.05479	0.3356	0.2668	1.854

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
COEX_B0	0.185690	0.01747	10.63	0.0001	COEXPUS constant coef
COEX_E1	-0.026914	0.02395	-1.12	0.2635	COEXPUS coef for JAN
COEX_E2	0.019416	0.02395	0.81	0.4192	COEXPUS coef for FEB
COEX_E3	0.017332	0.02395	0.72	0.4707	COEXPUS coef for MAR
COEX_E4	-0.024821	0.02395	-1.04	0.3022	COEXPUS coef for APR
COEX_E5	-0.00044337	0.02395	-0.02	0.9853	COEXPUS coef for MAY
COEX_E6	-0.012576	0.02395	-0.53	0.6006	COEXPUS coef for JUN
COEX_E7	-0.040674	0.02395	-1.70	0.0922	COEXPUS coef for JUL
COEX_E8	0.00114855	0.02395	0.05	0.9618	COEXPUS coef for AUG
COEX_E9	-0.040885	0.02395	-1.71	0.0905	COEXPUS coef for SEP
COEX_E10	-0.038590	0.02450	-1.58	0.1180	COEXPUS coef for OCT
COEX_E11	0.00271220	0.02450	0.11	0.9120	COEXPUS coef for NOV
COEX_D1	-0.069606	0.01108	-6.28	0.0001	COEXPUS coef for D90ON

Method of Estimation: OLS
RANGE of Fit: 8201 TO 9209

Table A32. Crude Oil Losses
(COLOPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
COLOPUS	12	58	1.22133E-6	2.10575E-8	0.0001451	0.0621	-0.1158	1.772

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
COLO_B0	0.000077419	0.0000649	1.19	0.2377	COLOPUS constant coef
COLO_E1	0.000067742	0.00008787	0.77	0.4439	COLOPUS coef for JAN
COLO_E2	-1.06468E-6	0.00008787	-0.01	0.9904	COLOPUS coef for FEB
COLO_E3	0.000051613	0.00008787	0.59	0.5592	COLOPUS coef for MAR
COLO_E4	0.000072581	0.00008787	0.83	0.4122	COLOPUS coef for APR
COLO_E5	0.000056989	0.00008787	0.65	0.5192	COLOPUS coef for MAY
COLO_E6	0.000028136	0.00008787	0.32	0.7500	COLOPUS coef for JUN
COLO_E7	0.000046237	0.00008787	0.53	0.6008	COLOPUS coef for JUL
COLO_E8	-0.00003978	0.00008787	-0.45	0.6524	COLOPUS coef for AUG
COLO_E9	0.000072581	0.00008787	0.83	0.4122	COLOPUS coef for SEP
COLO_E10	0.000019355	0.00008787	0.22	0.8264	COLOPUS coef for OCT
COLO_E11	9.247312E-6	0.00009178	0.10	0.9201	COLOPUS coef for NOV

Method of Estimation: OLS
RANGE of Fit: 8701 TO 9210

Table A33. NGL Plant Liquid Production (NLPRPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
NLPRPUS	2	139	0.46135	0.0033191	0.05761	0.2226	0.2170	0.504

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
NLPR_B0	1.061675	0.08488	12.51	0.0001	NLPRPUS constant coef
NLPR_01	0.085966	0.01363	6.31	0.0001	NLPRPUS coef for NGMPPUS - NGPRPUS

Method of Estimation: OLS
RANGE of Fit: 8101 TO 9209

Table A34. Pentanes Plus Inventory (PPPSPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
PPPSPUS	12	93	71.15176	0.76507	0.87468	0.4974	0.4379	0.437

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
PPPS_B0	7.289750	0.30925	23.57	0.0001	PPPSPUS constant coef
PPPS_E1	-0.403083	0.42502	-0.95	0.3454	PPPSPUS coef for JAN
PPPS_E2	-0.331639	0.42502	-0.78	0.4372	PPPSPUS coef for FEB
PPPS_E3	-0.252306	0.42502	-0.59	0.5542	PPPSPUS coef for MAR
PPPS_E4	0.278583	0.42502	0.66	0.5138	PPPSPUS coef for APR
PPPS_E5	0.747472	0.42502	1.76	0.0819	PPPSPUS coef for MAY
PPPS_E6	1.333917	0.42502	3.14	0.0023	PPPSPUS coef for JUN
PPPS_E7	1.782361	0.42502	4.19	0.0001	PPPSPUS coef for JUL
PPPS_E8	1.874139	0.42502	4.41	0.0001	PPPSPUS coef for AUG
PPPS_E9	1.647917	0.42502	3.88	0.0002	PPPSPUS coef for SEP
PPPS_E10	1.047750	0.43734	2.40	0.0186	PPPSPUS coef for OCT
PPPS_E11	0.432125	0.43734	0.99	0.3257	PPPSPUS coef for NOV

Method of Estimation: OLS
RANGE of Fit: 8401 TO 9209

Table A35. Propane Inventory
(PRPSPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
PRPSPUS	1	140	4083	29.16665	5.40062	0.8058	0.8058	0.100

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
PRPS_LG	0.511516	0.0043762	116.89	0.0001	PRPSPUS coef for LGPSPUS

Method of Estimation: OLS
RANGE of Fit: 8101 TO 9209

Table A36. Motor Gasoline Exports
(MGEXPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
MGEXPUS	13	116	0.04277	0.0003687	0.01920	0.6448	0.6081	0.946

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
MGEX_B0	0.024242	0.0061325	3.95	0.0001	MGEXPUS constant coef
MGEX_E1	-0.00968982	0.0083904	-1.15	0.2505	MGEXPUS coef for JAN
MGEX_E2	-0.00778434	0.0083904	-0.93	0.3555	MGEXPUS coef for FEB
MGEX_E3	0.00073448	0.0083904	0.09	0.9304	MGEXPUS coef for MAR
MGEX_E4	-0.00373067	0.0083904	-0.44	0.6574	MGEXPUS coef for APR
MGEX_E5	-0.00652193	0.0083904	-0.78	0.4386	MGEXPUS coef for MAY
MGEX_E6	0.00845645	0.0083904	1.01	0.3156	MGEXPUS coef for JUN
MGEX_E7	0.00934671	0.0083904	1.11	0.2676	MGEXPUS coef for JUL
MGEX_E8	0.00734855	0.0083904	0.88	0.3829	MGEXPUS coef for AUG
MGEX_E9	-0.00330739	0.0083958	-0.39	0.6944	MGEXPUS coef for SEP
MGEX_E10	-0.00537589	0.0085875	-0.63	0.5325	MGEXPUS coef for OCT
MGEX_E11	0.00102684	0.0085875	0.12	0.9050	MGEXPUS coef for NOV
MGEX_D1	0.060182	0.0042860	14.04	0.0001	MGEXPUS coef for D9009ON

Method of Estimation: OLS
RANGE of Fit: 8201 TO 9209

Table A37. Distillate Fuel Exports
(DFEXPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
DFEXPUS	13	116	0.21811	0.0018802	0.04336	0.6878	0.6555	1.251

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
DFEX_B0	0.112721	0.01385	8.14	0.0001	DFEXPUS constant coef
DFEX_E1	0.00062378	0.01895	0.03	0.9738	DFEXPUS coef for JAN
DFEX_E2	0.00463988	0.01895	0.24	0.8070	DFEXPUS coef for FEB
DFEX_E3	-0.046578	0.01895	-2.46	0.0154	DFEXPUS coef for MAR
DFEX_E4	-0.059747	0.01895	-3.15	0.0021	DFEXPUS coef for APR
DFEX_E5	-0.043570	0.01895	-2.30	0.0233	DFEXPUS coef for MAY
DFEX_E6	-0.061684	0.01895	-3.26	0.0015	DFEXPUS coef for JUN
DFEX_E7	-0.059309	0.01895	-3.13	0.0022	DFEXPUS coef for JUL
DFEX_E8	-0.055330	0.01895	-2.92	0.0042	DFEXPUS coef for AUG
DFEX_E9	-0.057231	0.01896	-3.02	0.0031	DFEXPUS coef for SEP
DFEX_E10	-0.050302	0.01939	-2.59	0.0107	DFEXPUS coef for OCT
DFEX_E11	-0.051886	0.01939	-2.68	0.0085	DFEXPUS coef for NOV
DFEX_D1	0.141911	0.0096784	14.66	0.0001	DFEXPUS coef for D9009ON

Method of Estimation: OLS
RANGE of Fit: 8201 TO 9209

Table A38. Residual Fuel Exports
(RFEXPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
RFEXPUS	12	117	0.36034	0.0030798	0.05550	0.1698	0.0917	1.444

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
RFEX_B0	0.241915	0.01755	13.78	0.0001	RFEXPUS constant coef
RFEX_E1	-0.020751	0.02425	-0.86	0.3939	RFEXPUS coef for JAN
RFEX_E2	-0.036974	0.02425	-1.52	0.1300	RFEXPUS coef for FEB
RFEX_E3	-0.042105	0.02425	-1.74	0.0851	RFEXPUS coef for MAR
RFEX_E4	-0.033058	0.02425	-1.36	0.1754	RFEXPUS coef for APR
RFEX_E5	-0.039609	0.02425	-1.63	0.1051	RFEXPUS coef for MAY
RFEX_E6	-0.058631	0.02425	-2.42	0.0171	RFEXPUS coef for JUN
RFEX_E7	-0.089750	0.02425	-3.70	0.0003	RFEXPUS coef for JUL
RFEX_E8	-0.044965	0.02425	-1.85	0.0662	RFEXPUS coef for AUG
RFEX_E9	-0.084978	0.02425	-3.50	0.0006	RFEXPUS coef for SEP
RFEX_E10	-0.053702	0.02482	-2.16	0.0325	RFEXPUS coef for OCT
RFEX_E11	-0.031289	0.02482	-1.26	0.2099	RFEXPUS coef for NOV

Method of Estimation: OLS
RANGE of Fit: 8201 TO 9209

Table A39. Jet Fuel Exports
(JFEXPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
JFEXPUS	14	115	0.04200	0.0003652	0.01911	0.5086	0.4530	1.277

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
JFEX_B0	0.040199	0.0061539	6.53	0.0001	JFEXPUS constant coef
JFEX_E1	-0.00996571	0.0085281	-1.17	0.2450	JFEXPUS coef for JAN
JFEX_E2	-0.013052	0.0085281	-1.53	0.1286	JFEXPUS coef for FEB
JFEX_E3	-0.024810	0.0084302	-2.94	0.0039	JFEXPUS coef for MAR
JFEX_E4	-0.026849	0.0084302	-3.18	0.0019	JFEXPUS coef for APR
JFEX_E5	-0.030912	0.0084302	-3.67	0.0004	JFEXPUS coef for MAY
JFEX_E6	-0.029966	0.0084302	-3.55	0.0006	JFEXPUS coef for JUN
JFEX_E7	-0.026794	0.0084302	-3.18	0.0019	JFEXPUS coef for JUL
JFEX_E8	-0.026725	0.0084302	-3.17	0.0020	JFEXPUS coef for AUG
JFEX_E9	-0.021786	0.0084302	-2.58	0.0110	JFEXPUS coef for SEP
JFEX_E10	-0.020128	0.0085461	-2.36	0.0202	JFEXPUS coef for OCT
JFEX_E11	-0.012427	0.0085461	-1.45	0.1486	JFEXPUS coef for NOV
JFEX_D1	0.063289	0.01163	5.44	0.0001	JFEXPUS coef for DSHIELD
JFEX_D2	0.087378	0.01417	6.17	0.0001	JFEXPUS coef for DSTORM

Method of Estimation: OLS
RANGE of Fit: 8201 TO 9209

Table A40. Liquefied Petroleum Gases Exports
(LGEXPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
LGEXPUS	12	117	0.05062	0.0004326	0.02080	0.0860	0.0001	1.226

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
LGEX_B0	0.062053	0.0065773	9.43	0.0001	LGEXPUS constant coef
LGEX_E1	-0.00645273	0.0090879	-0.71	0.4791	LGEXPUS coef for JAN
LGEX_E2	-0.010830	0.0090879	-1.19	0.2358	LGEXPUS coef for FEB
LGEX_E3	-0.00358933	0.0090879	-0.39	0.6936	LGEXPUS coef for MAR
LGEX_E4	-0.010603	0.0090879	-1.17	0.2457	LGEXPUS coef for APR
LGEX_E5	-0.017615	0.0090879	-1.94	0.0550	LGEXPUS coef for MAY
LGEX_E6	-0.015981	0.0090879	-1.76	0.0813	LGEXPUS coef for JUN
LGEX_E7	-0.018831	0.0090879	-2.07	0.0404	LGEXPUS coef for JUL
LGEX_E8	-0.017057	0.0090879	-1.88	0.0630	LGEXPUS coef for AUG
LGEX_E9	-0.016680	0.0090879	-1.84	0.0690	LGEXPUS coef for SEP
LGEX_E10	-0.019976	0.0093017	-2.15	0.0338	LGEXPUS coef for OCT
LGEX_E11	-0.013835	0.0093017	-1.49	0.1396	LGEXPUS coef for NOV

Method of Estimation: OLS
RANGE of Fit: 8201 TO 9209

Table A41. Other Petroleum Product Exports (PSEXPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
PSEXPUS	13	116	0.18296	0.0015773	0.03971	0.3786	0.3143	1.525

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
PSEX_B0	0.361744	0.01785	20.27	0.0001	PSEXPUS constant coef
PSEX_E1	-0.034113	0.01737	-1.96	0.0519	PSEXPUS coef for JAN
PSEX_E2	-0.028869	0.01736	-1.66	0.0991	PSEXPUS coef for FEB
PSEX_E3	-0.031938	0.01736	-1.84	0.0683	PSEXPUS coef for MAR
PSEX_E4	-0.012760	0.01736	-0.74	0.4637	PSEXPUS coef for APR
PSEX_E5	-0.017292	0.01735	-1.00	0.3211	PSEXPUS coef for MAY
PSEX_E6	0.022705	0.01735	1.31	0.1933	PSEXPUS coef for JUN
PSEX_E7	-0.00034853	0.01735	-0.02	0.9840	PSEXPUS coef for JUL
PSEX_E8	-0.026459	0.01735	-1.52	0.1300	PSEXPUS coef for AUG
PSEX_E9	-0.00363172	0.01735	-0.21	0.8346	PSEXPUS coef for SEP
PSEX_E10	-0.019351	0.01776	-1.09	0.2782	PSEXPUS coef for OCT
PSEX_E11	-0.00865693	0.01776	-0.49	0.6269	PSEXPUS coef for NOV
PSEX_ET	-12.330665	1.79733	-6.86	0.0001	PSEXPUS coef for 1 / TIME

Method of Estimation: OLS
RANGE of Fit: 8201 TO 9209

Table A42. Pentanes Plus Exports (PPEXPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
PPEXPUS	13	116	0.0004258	3.67048E-6	0.0019158	0.3937	0.3309	0.987

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
PPEX_B0	0.00145835	0.0006086	2.40	0.0182	PPEXPUS constant coef
PPEX_E1	-0.00007064	0.0008371	-0.08	0.9329	PPEXPUS coef for JAN
PPEX_E2	0.00046152	0.0008371	0.55	0.5825	PPEXPUS coef for FEB
PPEX_E3	0.00011255	0.0008371	0.13	0.8933	PPEXPUS coef for MAR
PPEX_E4	-0.00032310	0.0008371	-0.39	0.7002	PPEXPUS coef for APR
PPEX_E5	0.00043563	0.0008371	0.52	0.6038	PPEXPUS coef for MAY
PPEX_E6	0.00022478	0.0008371	0.27	0.7888	PPEXPUS coef for JUN
PPEX_E7	0.00045315	0.0008371	0.54	0.5893	PPEXPUS coef for JUL
PPEX_E8	-0.00028069	0.0008371	-0.34	0.7380	PPEXPUS coef for AUG
PPEX_E9	-0.00084505	0.0008371	-1.01	0.3148	PPEXPUS coef for SEP
PPEX_E10	-0.00124481	0.0008568	-1.45	0.1490	PPEXPUS coef for OCT
PPEX_E11	0.00028929	0.0008568	0.34	0.7362	PPEXPUS coef for NOV
PPEX_D1	0.00473409	0.0005808	8.15	0.0001	PPEXPUS coef for D89

Method of Estimation: OLS
RANGE of Fit: 8201 TO 9209

Table A43. Motor Gasolines Sales for Resale (MGWHPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
MGWHPUS	1	103	2.20872	0.02144	0.14644	0.7700	0.7700	0.874

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
MGWH_TC	0.865318	0.0020155	429.33	0.0001	MGWHPUS coef for MGTCPUS

Method of Estimation: OLS
RANGE of Fit: 8401 TO 9208

Table A44. Distillate Fuel Sales for Resale (D2WHPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
D2WHPUS	2	102	3.10201	0.03041	0.17439	0.5850	0.5809	0.438

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
D2WH_B0	-0.873516	0.17225	-5.07	0.0001	D2WHPUS constant coef
D2WH_TC	0.690464	0.05759	11.99	0.0001	D2WHPUS coef for DFTCPUS

Method of Estimation: OLS
RANGE of Fit: 8401 TO 9208

Table A45. Residual Fuel Sales for End Users
(RFESPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
RFESPUS	3	101	0.37615	0.0037242	0.06103	0.7500	0.7450	1.560

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
RFES_B0	0.138337	0.04125	3.35	0.0011	RFESPUS constant coef
RFES_TC	0.429419	0.03044	14.11	0.0001	RFESPUS coef for RFTCPUS
RFES_D1	-0.061409	0.01390	-4.42	0.0001	RFESPUS coef for D90ON

Method of Estimation: OLS
RANGE of Fit: 8401 TO 9208

Table A46. Jet Fuel Sales to End Users
(JKESPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
JKESPUS	1	103	0.30365	0.0029481	0.05430	0.4386	0.4386	1.051

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
JKES_TC	0.642957	0.0038373	167.55	0.0001	JKESPUS coef for JFTCPUS

Method of Estimation: OLS
RANGE of Fit: 8401 TO 9208

Table A47. Propane Sales to End Users (PRESPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
PRESPUS	3	101	0.02768	0.0002740	0.01655	0.6272	0.6198	0.694

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
PRES_B0	-0.00843848	0.0077607	-1.09	0.2795	PRESPUS constant coef
PRES_TC	0.103540	0.0083668	12.38	0.0001	PRESPUS coef for PRTCPUS
PRES_D1	-0.019046	0.0035370	-5.38	0.0001	PRESPUS coef for D90ON

Method of Estimation: OLS
RANGE of Fit: 8401 TO 9208

Table A48. Residential Sector Electricity Demand (ESRCPUSQ)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
ESRCPUSQ	5	147	0.0001235	8.40334E-7	0.0009167	0.9014	0.8987	1.864

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
ESRC_01	0.013802	0.0003862	35.74	0.0001	ESRCPUSQ constant coef
ESRC_03	0.00028442	0.00001185	24.01	0.0001	ESRCPUSQ coef for ZWHDPUS*(OCT...APR)
ESRC_04	0.00093629	0.0000329	28.46	0.0001	ESRCPUSQ coef for ZWCDPUS*(MAY...SEP)
ESRC_05	0.000024023	2.11726E-6	11.35	0.0001	ESRCPUSQ coef for TIME
ESRCPUSQ_L1	0.201749	0.09057	2.23	0.0274	ESRCPUSQ 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8001 TO 9208

Table A49. Commercial Sector Electricity Demand (ESCMPUSQ)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
ESCMPUSQ	16	136	0.0000127	9.30211E-8	0.0003050	0.9834	0.9815	1.581

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
ESCM_01	0.021469	0.0004297	49.96	0.0001	ESCMPUSQ constant coef
ESCM_02	0.000026804	2.09307E-6	12.81	0.0001	ESCMPUSQ coef for TIME
ESCM_04	0.000055167	0.0000104	5.30	0.0001	ESCMPUSQ coef for ZWHDPUS*(OCT...APR)
ESCM_05	0.00022524	0.0000415	5.43	0.0001	ESCMPUSQ coef for ZWCDPUS*(MAY...SEP)
ESCM_06	0.00101544	0.00009672	10.50	0.0001	ESCMPUSQ coef for JAN
ESCM_07	0.00030030	0.0001195	2.51	0.0132	ESCMPUSQ coef for FEB
ESCM_08	-0.00088336	0.0001565	-5.64	0.0001	ESCMPUSQ coef for MAR
ESCM_09	-0.00050996	0.0002220	-2.30	0.0232	ESCMPUSQ coef for APR
ESCM_10	0.00117786	0.0003492	3.37	0.0010	ESCMPUSQ coef for MAY
ESCM_11	0.00292676	0.0004382	6.68	0.0001	ESCMPUSQ coef for JUN
ESCM_12	0.00310136	0.0005455	5.68	0.0001	ESCMPUSQ coef for JUL
ESCM_13	0.00338908	0.0005068	6.69	0.0001	ESCMPUSQ coef for AUG
ESCM_14	0.00228882	0.0003781	6.05	0.0001	ESCMPUSQ coef for SEP
ESCM_15	0.00053172	0.0002259	2.35	0.0200	ESCMPUSQ coef for OCT
ESCM_16	-0.00018965	0.0001361	-1.39	0.1657	ESCMPUSQ coef for NOV
ESCMPUSQ_L1	0.747871	0.05668	13.20	0.0001	ESCMPUSQ 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8001 TO 9208

Table A50. Industrial Sector Electricity Demand (ESICPUSB)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
ESICPUSB	15	137	0.05945	0.0004339	0.02083	0.9888	0.9876	1.625

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
ESIC_01	0.852265	0.01769	48.17	0.0001	ESICPUSB constant coef
ESIC_06	0.042573	0.0025632	16.61	0.0001	ESICPUSB coef for JAN
ESIC_07	0.048247	0.0032806	14.71	0.0001	ESICPUSB coef for FEB
ESIC_08	0.026958	0.0037111	7.26	0.0001	ESICPUSB coef for MAR
ESIC_09	0.036269	0.0040201	9.02	0.0001	ESICPUSB coef for APR
ESIC_10	0.058187	0.0042235	13.78	0.0001	ESICPUSB coef for MAY
ESIC_11	0.069098	0.0043083	16.04	0.0001	ESICPUSB coef for JUN
ESIC_12	0.063035	0.0042655	14.78	0.0001	ESICPUSB coef for JUL
ESIC_13	0.081155	0.0041874	19.38	0.0001	ESICPUSB coef for AUG
ESIC_14	0.068227	0.0038479	17.73	0.0001	ESICPUSB coef for SEP
ESIC_15	0.046442	0.0032901	14.12	0.0001	ESICPUSB coef for OCT
ESIC_16	0.023608	0.0024336	9.70	0.0001	ESICPUSB coef for NOV
ESIC_17	0.030582	0.0095307	3.21	0.0017	ESICPUSB coef for DUM8083
ESIC_Q	0.686170	0.07748	8.86	0.0001	ESICPUSB coef for LOG(ZOMNIUS)
ESICPUSB_L1	0.964638	0.02322	41.55	0.0001	ESICPUSB 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8001 TO 9208

Table A51. Other Electricity Demand (ESOTPUSQ)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
ESOTPUSQ	15	101	1.3399E-10	1.3266E-12	1.15178E-6	0.8623	0.8432	1.184

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
ESOT_01	0.00006193	3.80935E-6	16.26	0.0001	ESOTPUSQ constant coef
ESOT_02	-5.15268E-8	2.49122E-8	-2.07	0.0412	ESOTPUSQ coef for TIME
ESOT_06	1.967579E-6	3.82475E-7	5.14	0.0001	ESOTPUSQ coef for JAN
ESOT_07	6.05589E-7	4.88612E-7	1.24	0.2181	ESOTPUSQ coef for FEB
ESOT_08	-2.06905E-6	5.56249E-7	-3.72	0.0003	ESOTPUSQ coef for MAR
ESOT_09	-2.20941E-6	5.99597E-7	-3.68	0.0004	ESOTPUSQ coef for APR
ESOT_10	-6.89277E-7	6.24409E-7	-1.10	0.2723	ESOTPUSQ coef for MAY
ESOT_11	1.488154E-6	6.33231E-7	2.35	0.0207	ESOTPUSQ coef for JUN
ESOT_12	2.149315E-6	6.26816E-7	3.43	0.0009	ESOTPUSQ coef for JUL
ESOT_13	2.384216E-6	6.04459E-7	3.94	0.0001	ESOTPUSQ coef for AUG
ESOT_14	4.438003E-7	5.60209E-7	0.79	0.4301	ESOTPUSQ coef for SEP
ESOT_15	-1.32166E-6	4.86342E-7	-2.72	0.0077	ESOTPUSQ coef for OCT
ESOT_16	-9.44651E-7	3.63946E-7	-2.60	0.0108	ESOTPUSQ coef for NOV
ESOT_D1	3.124812E-8	1.14499E-6	0.03	0.9783	ESOTPUSQ coef for D90ON
ESOTPUSQ_L1	0.885030	0.04625	19.13	0.0001	ESOTPUSQ 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8301 TO 9208

Table A52. Electricity Transmission and Distribution Loss Factor (TDLOFUSB)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
TDLOFUSB	14	138	0.01577	0.0001143	0.01069	0.8901	0.8798	1.728

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
PTND_01	-0.105341	0.0033526	-31.42	0.0001	TDLOFUSB constant coef
PTND_06	0.047373	0.0036775	12.88	0.0001	TDLOFUSB coef for JAN
PTND_07	0.049912	0.0042603	11.72	0.0001	TDLOFUSB coef for FEB
PTND_08	0.027454	0.0044527	6.17	0.0001	TDLOFUSB coef for MAR
PTND_09	0.00927466	0.0045201	2.05	0.0421	TDLOFUSB coef for APR
PTND_10	-0.021740	0.0045433	-4.79	0.0001	TDLOFUSB coef for MAY
PTND_11	-0.024649	0.0045489	-5.42	0.0001	TDLOFUSB coef for JUN
PTND_12	-0.011481	0.0045434	-2.53	0.0126	TDLOFUSB coef for JUL
PTND_13	0.044561	0.0045204	9.86	0.0001	TDLOFUSB coef for AUG
PTND_14	0.062820	0.0045235	13.89	0.0001	TDLOFUSB coef for SEP
PTND_15	0.022242	0.0043296	5.14	0.0001	TDLOFUSB coef for OCT
PTND_16	-0.00316783	0.0037121	-0.85	0.3949	TDLOFUSB coef for NOV
PTND_17	0.00656653	0.0029409	2.23	0.0272	TDLOFUSB coef for D89ON
TDLOFUSB_L1	0.362595	0.07948	4.56	0.0001	TDLOFUSB 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8001 TO 9208

Table A53. Electricity Generation from Wind, Solar and Other
(WNEOPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
WNEOPUS	14	103	1.44329E-8	1.4013E-10	0.00001184	0.7494	0.7178	1.978

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
WNEO_01	0.000014926	6.28124E-6	2.38	0.0193	WNEOPUS constant coef
WNEO_06	4.646068E-6	4.21359E-6	1.10	0.2728	WNEOPUS coef for JAN
WNEO_07	6.480238E-6	5.38454E-6	1.20	0.2315	WNEOPUS coef for FEB
WNEO_08	0.000012021	6.06884E-6	1.98	0.0503	WNEOPUS coef for MAR
WNEO_09	0.000018191	6.47984E-6	2.81	0.0060	WNEOPUS coef for APR
WNEO_10	0.000025969	6.70357E-6	3.87	0.0002	WNEOPUS coef for MAY
WNEO_11	0.000029144	6.77842E-6	4.30	0.0001	WNEOPUS coef for JUN
WNEO_12	0.000024934	6.71594E-6	3.71	0.0003	WNEOPUS coef for JUL
WNEO_13	0.000024087	6.50572E-6	3.70	0.0003	WNEOPUS coef for AUG
WNEO_14	0.000022191	6.1108E-6	3.63	0.0004	WNEOPUS coef for SEP
WNEO_15	0.000014318	5.43244E-6	2.64	0.0097	WNEOPUS coef for OCT
WNEO_16	5.445503E-6	4.17064E-6	1.31	0.1946	WNEOPUS coef for NOV
WNEO_D1	-0.00001901	7.38996E-6	-2.57	0.0115	WNEOPUS coef for D89ON
WNEOPUS_L1	0.741699	0.06639	11.17	0.0001	WNEOPUS 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8301 TO 9209

Table A54. Electricity Generation from Wood and Waste
(WWEOPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
WWEOPUS	14	78	0.0000141	1.80371E-7	0.0004247	0.8587	0.8352	2.205

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
WWEO_01	0.00515065	0.0006922	7.44	0.0001	WWEOPUS constant coef
WWEO_06	0.000048461	0.0001674	0.29	0.7730	WWEOPUS coef for JAN
WWEO_07	-0.00014673	0.0002121	-0.69	0.4910	WWEOPUS coef for FEB
WWEO_08	-0.00039416	0.0002414	-1.63	0.1065	WWEOPUS coef for MAR
WWEO_09	-0.00068007	0.0002606	-2.61	0.0109	WWEOPUS coef for APR
WWEO_10	-0.00087442	0.0002718	-3.22	0.0019	WWEOPUS coef for MAY
WWEO_11	-0.00039805	0.0002760	-1.44	0.1533	WWEOPUS coef for JUN
WWEO_12	-0.00020331	0.0002735	-0.74	0.4595	WWEOPUS coef for JUL
WWEO_13	0.00035360	0.0002640	1.34	0.1843	WWEOPUS coef for AUG
WWEO_14	0.00022440	0.0002444	0.92	0.3613	WWEOPUS coef for SEP
WWEO_15	-0.00014814	0.0002116	-0.70	0.4860	WWEOPUS coef for OCT
WWEO_16	-0.00001117	0.0001578	-0.07	0.9437	WWEOPUS coef for NOV
WWEO_D1	-0.00037092	0.0004716	-0.79	0.4340	WWEOPUS coef for D90ON
WWEOPUS_L1	0.927973	0.04295	21.61	0.0001	WWEOPUS 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8501 TO 9208

Table A55. Electricity Generation from Geothermal Energy (GEEOPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
GEEOPUS	3	66	0.0000777	1.17665E-6	0.0010847	0.8730	0.8692	1.995

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
GEEO_01	-2.718693	0.07726	-35.19	0.0001	GEEOPUS constant coef
GEEO_02	-0.00537853	0.0004396	-12.23	0.0001	GEEOPUS coef for TIME
GEEOPUS_L1	0.426347	0.11121	3.83	0.0003	GEEOPUS 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8701 TO 9209

Table A56. Electricity Generation from Coal (CLEOPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
CLEOPUS	17	135	0.27551	0.0020408	0.04518	0.9927	0.9918	2.075

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
CLEO_01	0.798567	0.16229	4.92	0.0001	CLEOPUS constant coef
CLEO_02	0.165628	0.05548	2.99	0.0034	CLEOPUS coef for ELEOPUS
CLEO_03	0.061833	0.0061293	10.09	0.0001	CLEOPUS coef for (ELEOPUS*CLCAPUS)
CLEO_04	-0.682669	0.07826	-8.72	0.0001	CLEOPUS coef for HYEOPUS
CLEO_05	-0.543132	0.05243	-10.36	0.0001	CLEOPUS coef for NUEOPUS
CLEO_06	0.048160	0.01535	3.14	0.0021	CLEOPUS coef for JAN
CLEO_07	0.034473	0.01875	1.84	0.0681	CLEOPUS coef for FEB
CLEO_08	-0.089189	0.02167	-4.12	0.0001	CLEOPUS coef for MAR
CLEO_09	-0.157027	0.02590	-6.06	0.0001	CLEOPUS coef for APR
CLEO_10	-0.176883	0.02577	-6.86	0.0001	CLEOPUS coef for MAY
CLEO_11	-0.153111	0.02349	-6.52	0.0001	CLEOPUS coef for JUN
CLEO_12	-0.163606	0.02649	-6.18	0.0001	CLEOPUS coef for JUL
CLEO_13	-0.172075	0.02651	-6.49	0.0001	CLEOPUS coef for AUG
CLEO_14	-0.163559	0.02352	-6.95	0.0001	CLEOPUS coef for SEP
CLEO_15	-0.165470	0.02622	-6.31	0.0001	CLEOPUS coef for OCT
CLEO_16	-0.081833	0.01876	-4.36	0.0001	CLEOPUS coef for NOV
CLEOPUS_L1	0.705302	0.06432	10.97	0.0001	CLEOPUS 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8001 TO 9208

Table A57. Ratio of Electricity Generation from Natural Gas to Generation from Gas Plus Oil (NGEOSHRX)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
NGEOSHRX	14	78	0.10688	0.0013702	0.03702	0.8392	0.8124	2.116

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
NGEO_01	0.011728	0.04658	0.25	0.8019	NGEOSHRX constant coef
NGEO_P1	0.062007	0.02305	2.69	0.0087	NGEOSHRX coef for RFEUDUS/NGEUDUS
NGEO_R1	0.739093	0.06583	11.23	0.0001	NGEOSHRX coef for LAG(NGEOSHR)
NGEO_06	0.055020	0.01971	2.79	0.0066	NGEOSHRX coef for JAN
NGEO_07	0.087589	0.01987	4.41	0.0001	NGEOSHRX coef for FEB
NGEO_08	0.127091	0.01958	6.49	0.0001	NGEOSHRX coef for MAR
NGEO_09	0.147347	0.01917	7.69	0.0001	NGEOSHRX coef for APR
NGEO_10	0.120175	0.01946	6.18	0.0001	NGEOSHRX coef for MAY
NGEO_11	0.089223	0.01977	4.51	0.0001	NGEOSHRX coef for JUN
NGEO_12	0.111138	0.01947	5.71	0.0001	NGEOSHRX coef for JUL
NGEO_13	0.107829	0.01955	5.51	0.0001	NGEOSHRX coef for AUG
NGEO_14	0.118418	0.02010	5.89	0.0001	NGEOSHRX coef for SEP
NGEO_15	0.094360	0.02036	4.63	0.0001	NGEOSHRX coef for OCT
NGEO_16	0.038012	0.02025	1.88	0.0642	NGEOSHRX coef for NOV

Method of Estimation: OLS
RANGE of Fit: 8501 TO 9208

Table A58. Number of Residential Natural Gas Customers (Seasonally Adjusted) (NGNRPUSA)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
NGNRPUSA	5	82	2.30109	0.02806	0.16752	0.9902	0.9897	0.183

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
NGNR_01	-1.692000	0.06344	-26.67	0.0001	NGNRPUSA constant coef
NGNR_H	1.148041	0.01324	86.73	0.0001	NGNRPUSA HOUSING STOCK ELAST
NGNRPUS1_0	-0.010489	0.0019724	-5.32	0.0001	PDL(NGNRPUS1,12,2) parameter for (L)**0
NGNRPUS1_1	0.00381644	0.0009055	4.21	0.0001	PDL(NGNRPUS1,12,2) parameter for (L)**1
NGNRPUS1_2	-0.00034208	0.00007436	-4.60	0.0001	PDL(NGNRPUS1,12,2) parameter for (L)**2

Method of Estimation: OLS
RANGE of Fit: 8410 TO 9112

Table A59. Residential Sector Demand for Natural Gas (NGRCPUSX)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
NGRCPUSX	8	91	0.04236	0.0004654	0.02157	0.9835	0.9822	2.015

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
NGRC_01	0.063539	0.0068817	9.23	0.0001	NGRCPUSX constant coef
NGRC_HD	0.015026	0.0003104	48.41	0.0001	NGRCPUSX coef for (ZGHDPUS/ZSAJQUS)*(OCT...APR)
NGRC_09	0.071440	0.01118	6.39	0.0001	NGRCPUSX coef for MAY
NGRC_10	0.034342	0.01033	3.32	0.0013	NGRCPUSX coef for JUN
NGRC_11	0.019499	0.01094	1.78	0.0779	NGRCPUSX coef for JUL
NGRC_12	0.022426	0.01021	2.20	0.0307	NGRCPUSX coef for AUG
NGRC_13	0.053996	0.01148	4.70	0.0001	NGRCPUSX coef for SEP
NGRCPUSX_L1	-0.366845	0.10031	-3.66	0.0004	NGRCPUSX 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8310 TO 9112

Table A60. Number of Commercial Natural Gas Customers (Seasonally Adjusted) (NGNCPUSA)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
NGNCPUSA	5	82	0.09411	0.0011477	0.03388	0.9662	0.9645	0.071

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
NGNC_01	-1.873470	0.07318	-25.60	0.0001	NGNCPUSA constant coef
NGNC_E	0.723596	0.01568	46.13	0.0001	NGNCPUSA EMPLOYMENT ELAST
NGNCPUS1_0	-0.00534717	0.0029915	-1.79	0.0776	PDL(NGNCPUS1,12,2) parameter for (L)**0
NGNCPUS1_1	0.00195566	0.0013502	1.45	0.1513	PDL(NGNCPUS1,12,2) parameter for (L)**1
NGNCPUS1_2	-0.00021276	0.0001105	-1.93	0.0576	PDL(NGNCPUS1,12,2) parameter for (L)**2

Method of Estimation: OLS
RANGE of Fit: 8410 TO 9112

Table A61. Commercial Sector Natural Gas Demand
(NGCCPUSX)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
NGCCPUSX	13	86	0.97508	0.01134	0.10648	0.9863	0.9844	2.016

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
NGCC_01	1.933890	0.39948	4.84	0.0001	NGCCPUSX constant coef
NGCC_HD	0.082942	0.0015734	52.72	0.0001	NGCCPUSX coef for (ZGHDPUS/ZSAJQUS)*(OCT...APR)
NGCC_T	-0.00031015	0.0009387	-0.33	0.7419	NGCCPUSX coef for TIME
NGCC_D1	1.336370	0.23189	5.76	0.0001	NGCCPUSX coef for DTO87
NGCC_D1T	-0.00854982	0.0013809	-6.19	0.0001	NGCCPUSX coef for DTO87*TIME
NGCC_D2	-0.360727	0.10444	-3.45	0.0009	NGCCPUSX coef for D8912
NGCC_09	0.400119	0.05630	7.11	0.0001	NGCCPUSX coef for MAY
NGCC_10	0.241026	0.05115	4.71	0.0001	NGCCPUSX coef for JUN
NGCC_11	0.182006	0.05533	3.29	0.0015	NGCCPUSX coef for JUL
NGCC_12	0.200046	0.05094	3.93	0.0002	NGCCPUSX coef for AUG
NGCC_13	0.363872	0.05773	6.30	0.0001	NGCCPUSX coef for SEP
NGCC_P	-0.290507	0.06791	-4.28	0.0001	NGCCPUSX coef for NGCCUUS/WPCPIUS
NGCCPUSX_L1	-0.409291	0.10213	-4.01	0.0001	NGCCPUSX 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8310 TO 9112

Table A62. Industrial Sector Demand for Natural Gas
(NGINPUSZ)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
NGINPUSZ	15	88	76.10310	0.86481	0.92995	0.7825	0.7479	0.325

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
NGIN_01	17.716343	1.01596	17.44	0.0001	NGINPUSZ constant coef
NGIN_P	-263.349374	44.22600	-5.95	0.0001	NGINPUSZ coef for NGICUUSA/RFTCUUSA
NGIN_06	-0.757463	0.43843	-1.73	0.0876	NGINPUSZ coef for FEB
NGIN_07	-1.785405	0.43856	-4.07	0.0001	NGINPUSZ coef for MAR
NGIN_08	-2.788405	0.43920	-6.35	0.0001	NGINPUSZ coef for APR
NGIN_09	-3.611610	0.43903	-8.23	0.0001	NGINPUSZ coef for MAY
NGIN_10	-4.020918	0.43936	-9.15	0.0001	NGINPUSZ coef for JUN
NGIN_11	-4.260845	0.43909	-9.70	0.0001	NGINPUSZ coef for JUL
NGIN_12	-4.113402	0.45249	-9.09	0.0001	NGINPUSZ coef for AUG
NGIN_13	-3.621456	0.45248	-8.00	0.0001	NGINPUSZ coef for SEP
NGIN_14	-2.720156	0.45236	-6.01	0.0001	NGINPUSZ coef for OCT
NGIN_15	-1.691391	0.45222	-3.74	0.0003	NGINPUSZ coef for NOV
NGIN_16	-0.724660	0.45228	-1.60	0.1127	NGINPUSZ coef for DEC
NGIN_TD	-0.00627742	0.0026046	-2.41	0.0180	NGINPUSZ coef for TIME*D87ON
NGIN_T	0.038135	0.0078811	4.84	0.0001	NGINPUSZ coef for TIME

Method of Estimation: OLS
RANGE of Fit: 8401 TO 9207

Table A63. Demand for Natural Gas in Oil and Gas Well, Field, and Lease Operations (NGLPPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
NGLPPUS	5	94	0.83622	0.0088959	0.09432	0.9065	0.9026	2.036

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
NGLP_01	2.159651	0.14422	14.97	0.0001	NGLPPUS constant coef
NGLP_D1	0.283512	0.09903	2.86	0.0052	NGLPPUS coef for DTO87
NGLP_D2	0.500551	0.09186	5.45	0.0001	NGLPPUS coef for D90ON
NGLP_DM	0.012333	0.0013409	9.20	0.0001	NGLPPUS coef for natural gas consumption
NGLPPUS_L1	0.917825	0.04159	22.07	0.0001	NGLPPUS 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8310 TO 9112

Table A64. Demand for Natural Gas by Pipelines (NGACPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
NGACPUS	3	137	1.62731	0.01188	0.10899	0.9042	0.9028	1.387

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
NGAC_01	0.630397	0.09022	6.99	0.0001	NGACPUS constant coef
NGAC_DM	0.022667	0.0013339	16.99	0.0001	NGACPUS coef for natural gas consumption
NGACPUS_L1	0.858398	0.04496	19.09	0.0001	NGACPUS 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8101 TO 9208

Table A65. Natural Gas Exports
(NGEXPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
NGEXPUS	5	135	0.49375	0.0036574	0.06048	0.7651	0.7582	2.506

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
NGEX_01	0.211302	0.03256	6.49	0.0001	NGEXPUS constant coef
NGEX_D	0.092117	0.04688	1.97	0.0515	NGEXPUS coef for D89ON
NGEX_08	-0.029778	0.01563	-1.91	0.0589	NGEXPUS coef for APR
NGEX_09	-0.058520	0.01563	-3.75	0.0003	NGEXPUS coef for MAY
NGEXPUS_L1	0.810520	0.05890	13.76	0.0001	NGEXPUS 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8101 TO 9208

Table A66. Natural Gas Demand/Supply Discrepancy
(BALIT)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
BALIT	13	127	578.95922	4.55873	2.13512	0.5328	0.4887	2.129

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
NGBL_01	-1.095183	0.62831	-1.74	0.0837	BALIT constant coef
NGBL_06	3.229813	0.79422	4.07	0.0001	BALIT coef for FEB
NGBL_07	2.026299	0.87091	2.33	0.0216	BALIT coef for MAR
NGBL_08	3.045318	0.88565	3.44	0.0008	BALIT coef for APR
NGBL_09	1.407647	0.88861	1.58	0.1157	BALIT coef for MAY
NGBL_10	0.540095	0.88921	0.61	0.5447	BALIT coef for JUN
NGBL_11	-0.016171	0.88931	-0.02	0.9855	BALIT coef for JUL
NGBL_12	-0.162262	0.88922	-0.18	0.8555	BALIT coef for AUG
NGBL_13	-0.607454	0.90785	-0.67	0.5046	BALIT coef for SEP
NGBL_14	-2.627362	0.90573	-2.90	0.0044	BALIT coef for OCT
NGBL_15	-3.806299	0.89132	-4.27	0.0001	BALIT coef for NOV
NGBL_16	-2.746278	0.81567	-3.37	0.0010	BALIT coef for DEC
BALIT_L1	0.202806	0.08688	2.33	0.0211	BALIT 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8101 TO 9208

Table A67. Supplemental Gaseous Fuels Produced (NGSFPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
NGSFPUS	12	91	0.08574	0.0009422	0.03069	0.7236	0.6901	2.051

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
NGSF_01	0.375676	0.01150	32.68	0.0001	NGSFPUS constant coef
NGSF_06	-0.020253	0.01121	-1.81	0.0741	NGSFPUS coef for FEB
NGSF_07	-0.053320	0.01398	-3.81	0.0002	NGSFPUS coef for MAR
NGSF_08	-0.078671	0.01530	-5.14	0.0001	NGSFPUS coef for APR
NGSF_09	-0.109310	0.01596	-6.85	0.0001	NGSFPUS coef for MAY
NGSF_10	-0.114691	0.01625	-7.06	0.0001	NGSFPUS coef for JUN
NGSF_11	-0.101169	0.01627	-6.22	0.0001	NGSFPUS coef for JUL
NGSF_12	-0.099535	0.01637	-6.08	0.0001	NGSFPUS coef for AUG
NGSF_13	-0.117878	0.01584	-7.44	0.0001	NGSFPUS coef for SEP
NGSF_14	-0.075954	0.01455	-5.22	0.0001	NGSFPUS coef for OCT
NGSF_15	-0.054893	0.01175	-4.67	0.0001	NGSFPUS coef for NOV
NGSFPUS_L1	0.596065	0.08342	7.15	0.0001	NGSFPUS 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8401 TO 9207

Table A68. Natural Gas Working Inventory (NGWGPUSX)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
NGWGPUSX	14	126	438413	3479.5	58.98700	0.9891	0.9879	1.890

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
NGWG_01	3414.50	145.63340	23.45	0.0001	NGWGPUSX constant coef
NGWG_DM	-0.535143	0.06328	-8.46	0.0001	NGWGPUSX coef for NGTCPUSX*ZSAJQUS
NGWG_06	-472.242380	23.20252	-20.35	0.0001	NGWGPUSX coef for FEB
NGWG_07	-715.951464	32.83194	-21.81	0.0001	NGWGPUSX coef for MAR
NGWG_08	-812.879746	50.48437	-16.10	0.0001	NGWGPUSX coef for APR
NGWG_09	-686.901496	64.17178	-10.70	0.0001	NGWGPUSX coef for MAY
NGWG_10	-473.750420	71.46336	-6.63	0.0001	NGWGPUSX coef for JUN
NGWG_11	-189.050316	70.38827	-2.69	0.0082	NGWGPUSX coef for JUL
NGWG_12	78.910920	69.76104	1.13	0.2601	NGWGPUSX coef for AUG
NGWG_13	295.818823	72.43054	4.08	0.0001	NGWGPUSX coef for SEP
NGWG_14	500.027100	62.76266	7.97	0.0001	NGWGPUSX coef for OCT
NGWG_15	519.716698	49.23787	10.56	0.0001	NGWGPUSX coef for NOV
NGWG_16	370.864842	23.54442	15.75	0.0001	NGWGPUSX coef for DEC
NGWGPUSX_L1	0.900961	0.03849	23.41	0.0001	NGWGPUSX 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8101 TO 9208

Table A69. Dry Natural Gas Production (Seasonally Adjusted)
(NGPRPUSZ)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
NGPRPUSZ	3	137	93.60898	0.68328	0.82661	0.9054	0.9040	2.088

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
NGPR_01	2.927244	1.22764	2.38	0.0185	NGPRPUSZ constant coef
NGPR_R1	0.750382	0.03640	20.62	0.0001	NGPRPUSZ coef for LAG(NGNRPUSA)
NGPR_DM	0.178572	0.02723	6.56	0.0001	NGPRPUSZ coef for NGTCPUSA

Method of Estimation: OLS
RANGE of Fit: 8101 TO 9208

Table A70. Wet Natural Gas Production
(NGMPPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
NGMPPUS	3	137	0.35821	0.0026147	0.05113	0.9998	0.9998	2.171

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
NGMP_01	0.194582	0.13944	1.40	0.1651	NGMPPUS constant coef
NGMP_PR	1.043027	0.0028279	368.83	0.0001	NGMPPUS coef for NGPRPUS
NGMPPUS_L1	0.909137	0.03034	29.97	0.0001	NGMPPUS 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8101 TO 9208

Table A71. Natural Gas Gross Imports
(NGIMPUSZ)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
NGIMPUSZ	3	78	3.44808	0.04421	0.21025	0.9689	0.9681	1.982

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
NGIM_01	-4.637019	0.54811	-8.46	0.0001	NGIMPUSZ constant coef
NGIM_T	0.048822	0.0031428	15.53	0.0001	NGIMPUSZ coef for TIME*D88ON
NGIMPUSZ_L1	0.710359	0.08415	8.44	0.0001	NGIMPUSZ 1st-order autocorrelation coef

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8601 TO 9209

Table A72. Withdrawals from Natural Gas Underground Storage
(NGWSPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
NGWSPUS	13	127	564.78180	4.44710	2.10882	0.9004	0.8910	2.137

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
NGWS_01	18.211078	0.64478	28.24	0.0001	NGWSPUS constant coef
NGWS_D	-1.089959	0.36427	-2.99	0.0033	NGWSPUS coef for DTO87
NGWS_06	-3.086147	0.86092	-3.58	0.0005	NGWSPUS coef for FEB
NGWS_07	-8.494624	0.86092	-9.87	0.0001	NGWSPUS coef for MAR
NGWS_08	-13.914158	0.86092	-16.16	0.0001	NGWSPUS coef for APR
NGWS_09	-16.376344	0.86092	-19.02	0.0001	NGWSPUS coef for MAY
NGWS_10	-16.619713	0.86092	-19.30	0.0001	NGWSPUS coef for JUN
NGWS_11	-16.448925	0.86092	-19.11	0.0001	NGWSPUS coef for JUL
NGWS_12	-16.225806	0.86092	-18.85	0.0001	NGWSPUS coef for AUG
NGWS_13	-16.456862	0.88048	-18.69	0.0001	NGWSPUS coef for SEP
NGWS_14	-15.288729	0.88048	-17.36	0.0001	NGWSPUS coef for OCT
NGWS_15	-11.002316	0.88048	-12.50	0.0001	NGWSPUS coef for NOV
NGWS_16	-2.643568	0.88048	-3.00	0.0032	NGWSPUS coef for DEC

Method of Estimation: OLS
RANGE of Fit: 8101 TO 9208

Appendix B

Data Definitions and Sources

Appendix B

Data Definitions and Sources

Nearly 600 variables are used in the STIFS model for estimation, simulation, and report writing. Most of these variables follow the following naming convention:

Characters	MG	TC	P	US	A
Positions	1 and 2	3 and 4	5	6 and 7	8
Identity	Type of Energy	Energy Activity or consumption end-use sector	Type of data	Geographic area or special equation factor	Data treatment

In this example, MGTCPUSA is the identifying code for motor gasoline total consumption in physical units in the United States which is deseasonalized.

The type of energy categories, which is represented by the first two letters of the variable name, are:

AB = aviation gasoline blending components
CC = coal coke
CL = coal
CO = crude oil, including lease condensate
CP = crude oil and pentanes plus
CU = crude oil and unfinished oils
DF = distillate fuel, including diesel fuel and heating oil
DS = diesel fuel
D2 = heating oil
EL = electricity
ES = electricity sales
ET = ethane
FE = petrochemical feedstocks
GE = geothermal energy
HY = hydroelectric power
JF = jet fuel
JK = jet fuel, kerosene-type
LG = liquefied petroleum gases
LX = liquefied petroleum gases, excluding ethane
MB = motor gasoline blending components
MG = finished motor gasoline
MI = miscellaneous petroleum products
ML = leaded motor gasoline
MU = unleaded motor gasoline
NA = natural gas, including natural gas liquids

NG = natural gas
NL = natural gas liquids
NU = nuclear power
OH = other hydrocarbons/alcohol
PA = all petroleum products
PC = petroleum coke
PP = pentanes plus
PR = propane
PS = other petroleum products
RF = residual fuel
RS = raw steel
UO = unfinished oils
WN = wind, photovoltaic, and solar thermal energy

Energy activity or consumption end-use sectors, identified by characters three and four of each variable name, are:

AC = transportation sector consumption
CA = capacity
CC = commercial sector consumption
CM = commercial sector consumption
EO = electricity production
ES = sales to end-users
EU = electricity sector consumption
EX = gross export
FC = synfuels consumption
FP = field production
HC = residential/commerical sector consumption
IC = industrial sector consumption
IM = gross import
KC = coke oven consumption
LO = losses
NI = net import
NS = nonutility supply
PR = production
PS = petroleum product stocks
RC = residential sector consumption
RI = refinery input
RO = refinery output
RT = retail sales
TC = total consumption of all sectors
TX = Federal, state, and local taxes
UN = unaccounted for
WH = wholesale sales

The fifth character of the variable names in STIFS identifies the type of data by using one of the following letters:

D = price per million Btu
K = factor for converting data from kilowatthours to Btu
M = data in alternative physical units
P = data in standardized physical units
S = share or ratio expressed as a fraction
U = price per standardized physical unit
Z = factor for converting data from barrels to Btu

The physical units for data series in the STIFS model, represented by a "P" in the fifth character, include some of the following: coal data are in thousand short tons, petroleum data are in thousand barrels, natural gas data are in million cubic feet, and electricity data are in billion kilowatthours. Conversion factors, represented by a "K" in the fifth character, are applied to the physical unit data to convert the data to British thermal units, a common unit for all forms of energy.

The two characters in positions 6 and 7 represent a geographic identification or denote special additive or multiplicative factors used in estimating equations. The codes used in the STIFS model are:

AD = "Add" factor
AK = Alaska
MU = "Multiply" factor
48 = The contiguous 48 states and the District of Columbia
US = United States

Data treatment:

A = deseasonalized data series
S = seasonal factors derived from Census X-11 method
B,Q,X,Z = temporary variables

Exogenous Variables

Add Factors

Variable	Units	ADD Factor For
AARYFAD	LDPM	LDRYLD
BALITAD	BCFD	BALIT
CLEOPAD	BKWD	CLEOPUS
CLEUDAD	DMMB	CLEUDUSA
CLHCPAD	MMTD	CLHCPUS
CLKCPAD	MMTD	CLKCPUSX
CLXCPAD	MMTD	CLXCPUS
CORIPAD	MMBD	CORIPUS
DFACPAD	MMBD	DFACPUS
DFHCPAD	MMBD	DFHCPUS
DFICPAD	MMBD	DFICPUS
DSTCUAD	CPG	DSTCUUSA
D2RCUAD	CPG	D2RCUUSA
D2WHUAD	CPG	D2WHUUSA
EFFSAD	HTMB	EFF
ESCMPAD	BKWD	ESCMPUSQ
ESICPAD	BKWD	ESICPUSB
ESOTPAD	BKWD	ESOTPUSQ
ESRCPAD	BKWD	ESRCPUSQ
ESRCUAD	CKWH	ESRCUUSA
FETCPAD	LMMBD	LSFET
JFROPAD	MMBD	JFROPUS
JKTCUAD	MMBD	JKTCUUSA
LXTCPAD	MMBD	LXTCPUSA
MGROPAD	MMBD	MGROPUSA
MGUCUAD	CPG	MGUCUUSA
MGWHUAD	CPG	MGWHUUSA
MITCPAD	MMBD	MITCPUS
MPGAAD	MPG	MPGA
MVVMPAD	MM	MVVMPUSA
NGACPAD	BCFD	NGACPUS
NGCCPAD	BCFD	NGCCPUSX
NGCCUAD	BCFD	NGCCUUSA
NGEOSAD	BKWD	NGEOSHRX
NGEUDAD	DMMB	NGEUDUSA
NGICUAD	DMCF	NGICUUSA
NGIMPAD	BCFD	NGIMPUSZ
NGINPAD	BCFD	NGINPUSZ
NGLPPAD	BCFD	NGLPPUS
NGPRPAD	BCFD	NGPRPUSZ
NGRCPAD	BCFD	NGRCPUSX
NGRCUAD	DMCF	NGRCUUSA
NGSPUAD	DMMB	NGSPUUS
NGWGPAD	BCF	NGWGPUSX
NGWPUAD	DMCF	NGWPUUS
OHRIPAD	MMBD	OHRIPUS
PRTCUAD	CPG	PRTCUUSA
PSRIPAD	MMBD	PSRIPUS
RFTCUAD	CPG	RFTCUUS
RMZTPAD	LRTMD	LDRTM
RMZZPAD	LRTMD	LDRZM
RSPRPAD	MMTD	RSPRPUSA
UORIPAD	MMBD	UORIPUSJ

Units Key

BCFD	=	Billion cubic feet per day
BCF	=	Billion cubic feet
BKWD	=	Billion kilowatthours per day
CKWH	=	Cents per kilowatthour
CPG	=	Cents per gallon
DMCF	=	Dollars per million cubic feet
DMMB	=	Dollars per million Btu
LDPM	=	Log dollars per passenger mile
LMMBD	=	Log million barrels per day
LRTMD	=	Log revenue ton miles per day
MMB	=	Million barrels
MMBD	=	Million barrels per day

Multiplicative Factors

Variable	Multiplicative Factor For
BALITMU	BALIT
CLEOPMU	CLEOPUS
CLEUDMU	CLEUDUSA
CLHCPMU	CLHCPUS
CLXCPMU	CLXCPUS
DFACPMU	DFACPUS
DFHCPMU	DFHCPUS
DFICPMU	DFICPUS
DSTCUMU	DSTCUUSA
D2RCUMU	D2RCUUSA
D2WHUMU	D2WHUUSA
EFFSMU	EFF
ESCMPMU	ESCMPUSQ
ESICPMU	ESICPUSB
ESOTPMU	ESOTPUSQ
ESRCPMU	ESRCPUSQ
ESRCUMU	ESRCUUSA
ETTCPMU	ETTCPUSA
JFROPMU	JFROPUS
JKTCUMU	JKTCUUSA
LXTCPMU	LXTCPUSA
MGUCUMU	MGUCUUSA
MGWHUMU	MGWHUUSA
MITCPMU	MITCPUS
MPGAMU	MPGA
MVVMPMU	MVVMPUSA
NGACPMU	NGACPUS
NGCCPMU	NGCCPUSX
NGCCUMU	NGCCUUSA
NGEOSMU	NGEOSHRX
NGICUMU	NGICUUSA
NGINPMU	NGINPUSZ
NGLPPMU	NGLPPUS
NGPRPMU	NGPRPUSZ
NGRCPMU	NGRCPUSX
NGRCUMU	NGRCUUSA
NGSPUMU	NGSPUUS
NGWGPMU	NGWGPUSX
NGWPUMU	NGWPUUS
PRTCUMU	PRTCUUSA
RFTCUMU	RFTCUUS
RSPRPMU	RSPRPUSA

Seasonal Factors

Variable	Seasonal Factors For
AARYFUSS	AARYFUS
CLEUDUSS	CLEUDUS
CORIPUSS	CORIPUS
DFPSPUSS	DFPSPUS
DFROPUSS	DFROPUS
DFTCPUSS	DFTCPUS
DSRTUUSS	DSRTUUS
DSTCUUSS	DSTCUUS
D2RCUUSS	D2RCUUS
D2WHUUSS	D2WHUUS
ESRCUUSS	ESRCUUS
ETTCPUSS	ETTCPUS
FETCPUSS	FETCPUS
JFROPUSS	JFROPUS
JFTCPUSS	JFTCPUS
JKTCUUSS	JKTCUUS
LGRIPUSS	LGRIPUS
LGROPUSS	LGROPUS
LGTCPUSS	LGTCPUS
LXTCPUSS	LXTCPUS
MGPSPUSS	MGPSPUS
MGROPUSS	MGROPUS
MGTCPUSS	MGTCPUS
MGUCUUSS	MGUCUUS
MGWHUUSS	MGWHUUS
MITCPUSS	MITCPUS
MLTCPUSS	MLTCPUS
MUTCPUSS	MUTCPUS
MVVMPUSS	MVVMPUS
NGCCUUSS	NGCCUUS
NGEUDUSS	NGEUDUS
NGICUUSS	NGICUUS
NGIMPUSS	NGIMPUS
NGNCPUSS	NGNCPUS
NGNRPUSS	NGNRPUS
NGPRPUSS	NGPRPUS
NGRCUUSS	NGRCUUS
NGSPUUSS	NGSPUUS
NGTCPUSS	NGTCPUS
NGWGPUSS	NGWGPUS
NGWPUUSS	NGWPUUS
ORUTCUSS	ORUTCUS
PATCPUSS	PATCPUS
PPRIPUSS	PPRIPUS
PRTCUUSS	PRTCUUS
PSROPUSS	PSROPUS
PSTCPUSS	PSTCPUS
RACPUUSS	RACPUUS
RFEUDUSS	RFEUDUS
RFPSPUSS	RFPSPUS
RFROPUSS	RFROPUS
RFTCPUSS	RFTCPUS
RFTCUUSS	RFTCUUS
RMZTPUSS	RMZTPUS
RMZZPUSS	RMZZPUS
RSPRPUSS	RSPRPUS
UORIPUSS	UORIPUS

Source: Derived from Census X-11 multiplicative seasonal adjustment routine.

Dummy, Integer, Date, and Time Variables

Variable	Type	Definition
APR	DUMM	1 for April
AUG	DUMM	1 for August
DATE	DATE	Numeric year/month
DATEX	DATE	Starting date for equation estimation
DAYSMO	INTS	Number of days in the month
DEC	DUMM	1 for December
DRVP89	DUMM	DATE greater than 8903 and less than 8908
DRVP90	DUMM	DATE greater than 9003 and less than 9008
DS2	DUMM	DATE greater than or equal to 8104 and less than or equal to 8106
DSHIELD	DUMM	DATE greater than or equal to 9010 and less than or equal to 9012
DSTORM	DUMM	DATE equal to 9101 or 9102
DTO87	DUMM	DATE less than or equal to 8712
DUM84	DUMM	DATE greater than 8401
DUM89	DUMM	DATE greater than 8910 and less than 9001
DUM8083	DUMM	YEAR greater than 1979 and less than 1984
DUMCOLD	DUMM	DATE equal to 8912 or 9001
DUMELE	DUMM	DATE greater than 9102
DUMIRAN	DUMM	DATE greater than 7904 and less than 9010
DUMWTR	DUMM	YEAR greater than 1980 and MO equal to 1, 2, 3, 4, 11, OR 12
D87ON	DUMM	DATE greater than 8703
D88ON	DUMM	YEAR greater than 1987
D89ON	DUMM	YEAR greater than 1988
D90ON	DUMM	YEAR greater than 1989
D9009ON	DUMM	DATE greater than 9009
D81	DUMM	YEAR equal to 1981
D89	DUMM	YEAR equal to 1989
D91	DUMM	DATE equal to 9102 or 9103
D8002	DUMM	DATE equal to 8002
D8082	DUMM	DATE greater than 7912 and less than 8301
D8184	DUMM	DATE greater than 8012 and less than 8404
D8301	DUMM	DATE equal to 8301
D8302	DUMM	DATE equal to 8302
D8412	DUMM	DATE equal to 8412
D8501	DUMM	DATE equal to 8501
D8611	DUMM	DATE equal to 8611
D8809	DUMM	DATE equal to 8809
D8912	DUMM	DATE equal to 8912
D8990	DUMM	DATE greater than 8902 and less than 9002
D9001	DUMM	DATE equal to 9001
FEB	DUMM	1 for February
JAN	DUMM	1 for January
JUL	DUMM	1 for July
JUN	DUMM	1 for June
MAR	DUMM	1 for March
MAY	DUMM	1 for May
MO	INTS	2-digit month of observation
NOV	DUMM	1 for November
OCT	DUMM	1 for October
POST85	DUMM	DATE greater than or equal to 8501
PRE85XT	DUMM	Slope dummy, (1 - POST85) * TIME
SEP	DUMM	1 for September
TD8184	DUMM	Slope dummy, Log(TIME) * D8184
TD8990	DUMM	Slope dummy, Log(TIME) * D8990
TDTO87	DUMM	Slope dummy, integers where DATE less than or equal to 8712
TIMEX85	DUMM	Slope dummy, integers, where DATE greater than 8412
TIME	INTS	Integers 1 - n, where n = number of observations
TREND	INTS	Temporary variable for time
TREND84	DUMM	Slope dummy, integers, where DATE greater than 8312
YEAR	INTS	2-digit Year of observation—example: 89 = 1989
ZSAJQUS	INTS	Number of days in a month

Type Key:
DATE = Numeric year/month - example: 8901 = January 1989
DUMM = Dummy variable, 1 where specified, 0 otherwise
INTS = Positive integer

Heat Rates and Thermal Contents

Variable	Units	Definition
CLEOKUS	MBtuK	Heat rate for coal
CLEUKUS	MMBtuT	Thermal content of coal at electric utilities
DFEOKUS	MBtuK	Heat rate for distillate fuel oil
DFTCZUS	MMBtuB	Thermal content of distillate fuel oil
ELEOKUS	MBtuK	Heat rate for electricity consumption
FFEOKUS	MBtuK	Heat rate for hydropower generation
NAPRKUS	MMBtuCF	Thermal content of wet natural gas production
NGEOKUS	CFK	Heat rate for natural gas
NGNUKUS	MMBtuCF	Thermal content of nonutility natural gas
NGPRKUS	MMBtuCF	Thermal content of dry natural gas production
NUEOKUS	MBtuK	Heat rate for nuclear power
PCEOKUS	MBtuK	Heat rate for petroleum coke
PCTCZUS	MMBtuB	Thermal content of petroleum coke
QCOAL	TBtuD	Heat generation from coal
QNGAS	TBtuD	Heat generation from natural gas
QRESD	TBtuD	Heat generation from residual fuel oil
RFEOKUS	MBtuK	Heat rate for residual fuel oil
RFTCZUS	MMBtuB	Thermal content of residual fuel oil

Units Key:
CFK = Cubic feet per kilowatt hour
MMBtuB = Millions of Btu's (British Thermal Units) per barrel.
MMBtuT = Millions of Btu's per short ton.
MBtuK = Thousands of Btu's per kilowatt hour.
MBtuCF = Thousands of Btu's per cubic foot.

Source: Energy Information Administration, *Monthly Energy Review*, EIA/DOE-0035.

Weather Variables

Variable	Units	Definition	Source History	Source Forecast
DZWCD	CDD	Deviation from normal for CDD's	NOA	ROT
DZWHD	HDD	Deviation from normal for HDD's	NOA	ROT
DZWHDN	HDD	DZWHD for fall/winter months only	NOA	ROT
DZWHDP	HDD	DZWHD for spring/summer months only	NOA	ROT
D_MATL	HDD	HDD's deviation from normal, Mid-Atlantic Region	NOA	ROT
D_NENG	HDD	HDD deviation from normal, New-England Region	NOA	ROT
HDDX85	HDD	HDD's after 8501, 0 otherwise	NOA	ROT
W_MATL	FRAC	Mid-Atlantic region, population weighted	CEN	ROT
W_NE	FRAC	North East (W_MATL + W_NENG), population wtd.	CEN	ROT
W_NENG	FRAC	New England, population weighted	CEN	ROT
ZGHDPUS	HDD	Natural gas weighted HDD's	NOA	ROT
ZGHNPUS	HDD	Normal natural gas-weighted HDD's	NOA	ROT
ZWCDPUS	CDD	Average population weighted CDD's	NOA	ROT
ZWCNPUS	CDD	Average 'Normal' population weighted CDD's	NOA	ROT
ZWHDDNO	HDD	Northern (NE & MA) deviations from normal	NOA	ROT
ZWHDDUS	HDD	Deviations from normal HDD, U.S.	NOA	ROT
ZWHDPMA	HDD	Mid-Atlantic population weighted HDD's	NOA	ROT
ZWHDPNE	HDD	New England population weighted HDD's	NOA	ROT
ZWHDPNO	HDD	Northeast (NE & MA) HDD's	NOA	ROT
ZWHDPUS	HDD	Average population weighted HDD's	NOA	ROT
ZWHNPMA	HDD	Normal HDD's for the Mid-Atlantic	NOA	ROT
ZWHNPNE	HDD	Normal HDD's for New England	NOA	ROT
ZWHNPNO	HDD	Northeast (NE & MA) normal HDD's	NOA	ROT
ZWHNPUS	HDD	Average 'Normal' population weighted HDD's	NOA	ROT

Units Key:
CDD = Cooling degree-days.
HDD = Heating degree-days.
FRAC = Fraction.

Source Key:
CEN = U.S. Department of Commerce, Bureau of the Census, "Estimates of the Population of the United States."
NOA = National Oceanic and Atmospheric Administration, *Monthly State, Regional, and National Heating/Cooling Degree-Days Weighted by Population*.
ROT = "Rule of Thumb." For CDD's and HDD's, the forecasts assume a 30-year normal (1951-1981). The population weights are assumed to remain constant.

Exogenous Macro Variables

			Source	
Variable	**Units**	**Definition**	History	Forecast
CICPIUS	INDX	Consumer price index, Urban	BLS	DRI
EMCMPUS	MM	Commercial employment	BLS	DRI
EMNFPUS	MM	Non-farm employment	BLS	DRI
EMPIPUS	MM	Manufacturing employment	BLS	DRI
EMPMPUS	MM	Mining employment	BLS	DRI
FEERIUS	INDX	Real exchange rate	MGT	DRI
GDPDIUS	INDX	Gross domestic product implicit price deflator	BEA	DRI
GNPDIUS	INDX	Gross national product implicit price deflator (PGNP)	BEA	DRI
GDPQXUS	BIL$	Real gross domestic product, 1987 dollars	BEA	DRI
GNPQXUS	BIL$	Real gross national product, 1987 dollars	BEA	DRI
I87RXUS	BIL$	Private domestic fixed investment, 1987 dollars	BEA	DRI
KQHMPUS	MM	Housing stocks	CEN	DRI
KQH1PUS	MM	Single family dwelling housing stocks	CEN	DRI
KRDRXUS	BIL$	Change in manufacturing inventories	BEA	DRI
PRIMELG	PCT	12 month lag of 6-month moving average of PRIMEUS	STF	STF
PRIMEUS	PCT	Prime Rate	FRB	DRI
QSIC	INDX	Natural gas-weighted industrial production index	STF	STF
WPCPIUS	INDX	Producer price index 1984 = 1.00	BLS	DRI
WPIINUS	INDX	Producer price index, less energy and food	BLS	DRI
WP57IUS	INDX	Producer price index, petroleum products	BLS	STF
YD87OUS	BIL$	Real disposable personal income, 1987 dollars	BEA	DRI
ZOCBIUS	INDX	Industrial production index: basic chemicals	FRB	DRI
ZOISIUS	INDX	Industrial production index: iron and steel	FRB	DRI
ZOMNIUS	INDX	Industrial production index: manufacturing	FRB	DRI
ZOSIIUS	INDX	Coal weighted production index	STF	DRI
ZOTOIUS	INDX	Industrial production index: total	FRB	DRI
ZO20IUS	INDX	Industrial production index: food	FRB	DRI
ZO26IUS	INDX	Industrial production index: paper	FRB	DRI
ZO28IUS	INDX	Industrial production index: chem	FRB	DRI
ZO29IUS	INDX	Industrial production index: petroleum refineries	FRB	DRI
ZO32IUS	INDX	Industrial production index: stone, clay and glass	FRB	DRI
ZO33IUS	INDX	Industrial production index: total	FRB	DRI

Units Key:
BIL$ = Billion Dollars.
FRAC = Fraction.
INDX = Index.
MM = Million.
PCT = Percent.

Source Key:
BEA = Bureau of Economic Analysis, *National Income and Product Accounts of the U.S.*
BLS = Bureau of Labor Statistics: Price Indices from the *Monthly Labor Review*. Employment data are from the survey: *Employment and Earnings*.
CEN = U.S. Bureau of the Census, *Census of Housing, Housing Completions*.
DRI = DRI/McGraw-Hill Forecast CONTROL1292.
FRB = Federal Reserve System, *Statistical Release G 17*.
MGT = Morgan Guarantee Trust, New York, N.Y.
STF = Short-Term Integrated Forecasting System (January, 1993) calculation

Exogenous Energy Variables

Variable	Units	Definition	Source	
			History	Forecast
CLDESTAR	DAYS	Target days supply of coal stocks at electric utilities	CAL	ROT
CLDKSTAR	DAYS	Target days supply of coal stocks at coke plants	CAL	ROT
CLDOSTAR	DAYS	Target days supply of coal stocks at other industrial users	CAL	ROT
CLMRHUS	TNHR	Coal miner productivity in tons/hour	CP9	RO1
COCQPUS	MMBD	Total strategic petroleum reserve fill rate	PSM	SPO
CODQPUS	MMBD	Strategic Petroleum Reserve fill rate from domestic sources	PSM	SPO
COPRPUS	MMBD	Total U.S. crude oil production	PSM	O&G
COQMPUS	MMBD	Strategic petroleum reserve imports	PSM	SPO
ELNIPUS	BKWD	Net imports of electricity	EPM	OCE
ELNSPUS	BKWD	Non-utility supply of electricity	759	OCE
HYEOENC	BKWD	Hydroelectric generation, East North Central region	759	OCE
HYEOESC	BKWD	Hydroelectric generation, East South Central region	759	OCE
HYEOMTN	BKWD	Hydroelectric generation, Mountain region	759	OCE
HYEOPAC	BKWD	Hydroelectric generation, Pacific region	759	OCE
HYEOPMA	BKWD	Hydroelectric generation, Mid-Atlantic region	759	OCE
HYEOPNE	BKWD	Hydroelectric generation, New England region	759	OCE
HYEOPSA	BKWD	Hydroelectric generation, South Atlantic region	759	OCE
HYEOPUS	BKWD	Hydroelectric generation, Total U.S.	EPM	OCE
HYEOWNC	BKWD	Hydroelectric generation, West North Central region	759	OCE
HYEOWSC	BKWD	Hydroelectric generation, West South Central region	759	OCE
NGIMMX	BCFD	Natural gas import capacity	CAL	RO2
NUEOENC	BKWD	Electricity generation by nuclear power, East North Central region	759	SNP
NUEOESC	BKWD	Electricity generation by nuclear power, East South Central region	759	SNP
NUEOMTN	BKWD	Electricity generation by nuclear power, Mountain region	759	SNP
NUEOPAC	BKWD	Electricity generation by nuclear power, Pacific region	759	SNP
NUEOPMA	BKWD	Electricity generation by nuclear power, Mid-Atlantic region	759	SNP
NUEOPNE	BKWD	Electricity generation by nuclear power, New England region	759	SNP
NUEOPSA	BKWD	Electricity generation by nuclear power, South Atlantic region	759	SNP
NUEOPUS	BKWD	Electricity generation by nuclear power, total U.S.	EPM	SNP
NUEOWNC	BKWD	Electricity generation by nuclear power, West North Central region	759	SNP
NUEOWSC	BKWD	Electricity generation by nuclear power, West South Central region	759	SNP
ORCAPUS	MMBD	Monthly U.S. operable refinery capacity	PSM	ROT
PAPRP48	MMBD	Crude oil production, Lower 48 States	PSM	O&G
PAPRPAK	MMBD	Crude oil production, Alaska	PSM	O&G
PAPRPUS	MMBD	Domestic crude oil production	PSM	O&G

Exogenous Energy Variables (Continued)

Variable	Units	Definition	Source History	Source Forecast
RACPUUS	DPB	Refiner acquisition cost for crude oil (composite)	PMM	OMS
RACPUUSA	DPB	RACPUUS seasonally adjusted	STF	STF
RAIMUUS	DPB	Imported crude oil refiner acquisition cost	PMM	OMS
RAIMUUSA	DPB	RAIMUUS seasonally adjusted	STF	STF

Units Key:
BCFD = Billion cubic feet per day.
BKWD = Billion kilowatthours per day.
DAYS = Number of days.
DPB = Dollars per barrel.
FRAC = Fraction.
MMB = Million barrels.
MMBD = Million barrels per day.
TNHR = Short tons per hour.

Source Key:
CP9 = Energy Information Administration, *Coal Production 1991*, DOE/EIA-0118(91).
EPM = Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226.
OCE = Office of Coal, Nuclear, Electricity, & Alternate Fuels OCE provides exogenous forecasts of hydroelectric generation, based on forecasts of selected utilities.
O&G = Office of Oil and Gas (EIA).
OMS = Oil Market Simulation model. The composite RAC is assumed to equal the imported RAC in the forecast.
PMM = Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380.
PSM = Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109.
PSA = Energy Information Administration, *Petroleum Supply Annual*, DOE/EIA-0340.
ROT = "Rule of Thumb." In the forecast, these variables with the exception of the "target" variables are assumed to remain constant, equal to the last available historical data. The "target" variables are set at the observed historical minimum.
RO1 = Based on the implied assumption in the *Annual Energy Outlook 1993*, DOE/EIA-0383 that productivity remains unchanged in their forecast, and on historical data, productivity is assumed to increase by 0.7 percent per year in the forecast.
RO2 = Import capacity is assumed to increase by 6 percent per year in the forecast, based on data from Energy Information Administration, *Natural Gas Productive Capacity for the Lower 48 States,* DOE/EIA-0542(92).
SNP = Short-Term Nuclear Annual Power Production Simulation (SNAPPS) model, Office of Coal, Nuclear, Electricity, & Alternate Fuels, (EIA).
SPO = Office of Strategic Petroleum Reserve.
STF = Short-Term Integrated Forecasting System (January, 1993) calculation
759 = Form EIA-759, "Monthly Power Plant Report."

Endogenous Variables

Petroleum Products Demand

Variable	Units	Definition	Source History	Source Forecast
AARYFUS	CPPM	Average realized airline ticket price	FAA	STF
AARYFUSA	CPPM	AARYFUS seasonally adjusted	—	—
ABTCPUS	MMBD	Reclassified aviation gasoline blending components	PSM	STF
COTCPUS	MMBD	Demand for unprocessed crude oil	PSM	ROT
CPM	CPG	Real price per mile travelled for motor gasoline	CAL	STF
CPMSA	CPG	CPM seasonally adjusted	—	—
CPTCPUS	MMBD	Demand for crude oil and pentanes plus	PSM	STF
DFACPUS	MMBD	Demand for diesel fuel - transportation sector	PPM	STF
DFHCPUS	MMBD	Demand for distillate fuel oil - residential and commercial sectors	PMM	STF
DFICPUS	MMBD	Demand for distillate fuel oil - industrial sector	PMM	STF
DFNUPUS	MMBD	Non-utility demand for distillate fuel: DFTCPUS - DFEPPUS	CAL	STF
DFTCPUS	MMBD	Demand for distillate fuel oil	PSM	STF
DFTCPUSA	MMBD	DFTCPUS seasonally adjusted	—	—
DSTCPUS	MMBD	Demand for No. 2 diesel fuel oil	PMM	STF
D2RCPUS	MMBD	Demand for No. 2 heating oil, residential	PMM	STF
ETTCPUS	MMBD	Demand for ethane	PSM	STF
ETTCPUSA	MMBD	ETTCPUS seasonally adjusted	—	—
EFF	HTMB	Average aircraft efficiency RMZTPUS / JFTCPUS	CAL	STF
EFFSA	HTMB	EFF seasonally adjusted	—	—
FETCPUS	MMBD	Demand for petrochemical feedstocks	PSM	STF
FETCPUSA	MMBD	FETCPUS seasonally adjusted	—	—
JFTCPUS	MMBD	Demand for jet fuel	PSM	STF
JFTCPUSA	MMBD	JFTCPUS seasonally adjusted	—	—
LDRYLD	LDPM	Log(AARYFUSA)	—	—
LDRZM	LRTMD	Log(RMZZPUSA)	—	—
LDRTM	LRTMD	Log(RMZTPUSA)	—	—
LF	FRAC	Revenue ton miles/available ton-miles: RMZZPUS/RMZTPUS	CAL	STF
LFSA	FRAC	LF seasonal adjusted	—	—
LGTCPUS	MMBD	Demand for liquefied petroleum gas	PSM	STF
LGTCPUSA	MMBD	LGTCPUS seasonally adjusted	—	—
LSFET	LMMBD	Log(FETCPUSA)	—	—
LSMIS	LMMBD	Log(MITCPUSA)	—	—
LXTCPUS	MMBD	Demand for liquefied petroleum gas, excluding ethane	PSM	STF
LXTCPUSA	MMBD	LXTCPUS seasonally adjusted	—	—
MBTCPUS	MMBD	Demand for motor gasoline blending components	PSM	STF
MGDAYSP	DAYS	Motor gasoline days' supply	CAL	STF
MGTCPUS	MMBD	Demand for finished motor gasoline	PSM	STF
MGTCPUSA	MMBD	MGTCPUS seasonally adjusted	—	—
MITCPUS	MMBD	Demand for miscellaneous petroleum products	PSM	STF
MITCPUSA	MMBD	MITCPUS seasonally adjusted components	—	—
MLTCPUS	MMBD	Demand for leaded gasoline	PSM	STF
MLTCPUSA	MMBD	MLTCPUS seasonally adjusted	—	—
MOGP	CPG	Real seasonalized price of motor gasoline	CAL	STF
MOGPSA	CPG	Real deseasonalized price of motor gasoline	CAL	STF
MPG	MPG	Automobile fleet fuel efficiency, MGTCPUS / MVVMPUS	CAL	STF
MPGA	MPG	MPG seasonally adjusted	—	—
MUTCPUS	MMBD	Demand for unleaded motor gasoline	PSM	STF
MUTCPUSA	MMBD	MUTCPUS seasonally adjusted	—	—
MUTCSUS	%	Unleaded motor gasoline demand share	PSM	STF
MVVMPUS	MM	Vehicle miles travelled	FHA	STF
MVVMPUSA	MM	MVVMPUS seasonally adjusted	—	—
PPTCPUS	MMBD	Demand for pentanes plus	PSM	STF
PRTCPUS	MMBD	Demand for propane	PSM	STF

Petroleum Products Demand (Continued)

Variable	Units	Definition	Source: History	Source: Forecast
PSTCPUS	MMBD	Demand for "other" petroleum products	PSM	STF
PSTCPUSA	MMBD	PSTCPUS seasonally adjusted	—	—
RFNUPUS	MMBD	Non-utility demand for residual fuel oil	CAL	STF
RFTCPUS	MMBD	Demand for residual fuel oil	PSM	STF
RFTCPUSA	MMBD	RFTCPUS seasonally adjusted	—	—
RMZTPUS	MTMD	Air travel capacity	FAA	STF
RMZTPUSA	MTMD	RMZTPUS seasonally adjusted	—	—
RMZZPUS	MTMD	Aircraft utilization rate	FAA	STF
RMZZPUSA	MTMD	RMZZPUS seasonally adjusted	—	—
UOTCPUS	MMBD	Reclassified unfinished oils	PSM	STF

Units Key:
- CPG = Cents per gallon.
- CPPM = Cents per passenger mile.
- DAYS = Number of days.
- FRAC = Fraction.
- HTMB = Hundred ton-miles per barrel.
- MM = Million.
- MMBD = Million barrels per day.
- MPG = Miles per gallon.
- MTMD = Million ton miles per day.
- % = Percent.

Source Key:
- CAL = Calculated.
- FAA = Department of Transportation, Federal Aviation Administration, Form 41, Schedule T1.
- FHA = Federal Highway Administration, *Traffic Volume Trends*.
- PMM = Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380.
- PSM = Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109.
- ROT = "Rule of Thumb." In the forecast, these variables are assumed to remain constant, equal to the last historical data.
- STF = Short-Term Integrated Forecasting System (First Quarter 1993) calculation.

Petroleum Products Supply

Variable	Units	Definition	Source History	Source Forecast
ABRIPUS	MMBD	Refinery inputs, aviation gasoline blending components	PSM	STF
CODIPUS	MMBD	Gross inputs to crude distillation units	PSM	STF
CODIPUSJ	MMBD	Temporary variable for CODIPUS	—	—
COEXPUS	MMBD	Exports of crude oil	PSM	STF
COIMPUS	MMBD	Gross imports of crude oil (including SPR)	PSM	STF
COLOPUS	MMBD	Crude oil losses	PSM	STF
CONIPUS	MMBD	Net imports of crude oil (including SPR)	PSM	STF
CONXPUS	MMBD	Net imports of crude oil (excluding SPR)	PSM	STF
CORIPUS	MMBD	Refinery inputs of crude oil	PSM	STF
CORIPUSA	MMBD	CORIPUS seasonally adjusted	—	—
CORIPUSJ	MMBD	Temporary variable for CORIPUS	—	—
COSQPUS	MMB	Strategic petroleum reserve level	PSM	STF
COSQPUS1	MMB	One-period lag of COSQPUS	PSM	STF
COSXPUS	MMB	Stocks of crude oil	PSM	STF
COUNPUS	MMBD	Unaccounted crude oil	PSM	STF
CURIPUS	MMBD	Refinery inputs of crude and unfinished oils	PSM	STF
D2WHPUS	MMBD	Demand for no. 2 heating oil (wholesale)	PMM	STF
DFEXPUS	MMBD	Exports of distillate fuel oil	PSM	STF
DFFPPUS	MMBD	Field production of distillate fuel oil	PSM	STF
DFIMPUS	MMBD	Gross imports of distillate fuel oil	PSM	STF
DFNIPUS	MMBD	Net imports of distillate fuel oil	PSM	STF
DFPSPUS	MMB	Stocks of distillate fuel oil	PSM	STF
DFPSPUSA	MMB	DFPSPUS seasonally adjusted	—	—
DFROPUS	MMBD	Refinery output of distillate fuel oil	PSM	STF
DFROPUSA	MMBD	DFROPUS seasonally adjusted	—	—
DUMYRLG	FRAC	Annual ratio of LGRIPUS/MGROPUS	STF	ROT
DUMYRPP	FRAC	Annual ratio of PPRIPUS/MGROPUS	STF	ROT
DUMYRPS	FRAC	Annual ratio of PSRIPUS/MGROPUS	STF	ROT
JFEXPUS	MMBD	Exports of jet fuel	PSM	STF
JFFPPUS	MMBD	Field production of jet fuel	PSM	STF
JFIMPUS	MMBD	Gross imports of jet fuel	PSM	STF
JFNIPUS	MMBD	Net imports of jet fuel	PSM	STF
JFPSPUS	MMB	Stocks of jet fuel	PSM	STF
JFROPUS	MMBD	Refinery output of jet fuel	PSM	STF
JFROPUSA	MMBD	JFROPUS seasonally adjusted	—	—
JKESPUS	MMBD	Kerosene jet fuel sales to end-users	PMM	STF
LGEXPUS	MMBD	Exports of LPG's	PSM	STF
LGFPPUS	MMBD	Field production of LPG's	PSM	STF
LGIMPUS	MMBD	Gross imports of LPG's	PSM	STF
LGNIPUS	MMBD	Net imports of LPG's	PSM	STF
LGPSPUS	MMB	Stocks of LPG's	PSM	STF
LGRIPANN	MMB	Annual monthly average of refinery inputs of LPGs	PSA	ROT
LGRIPUS	MMBD	Refinery inputs of LPG's	PSM	STF
LGRIPUSA	MMBD	LGRIPUS seasonally adjusted	—	—
LGROPUS	MMBD	Refinery output of LPG's	PSM	STF
LGROPUSA	MMBD	LGROPUS seasonally adjusted	—	—
MBOLPUS	MMBD	Other refinery inputs	PSM	STF
MBPSPUS	MMB	Stocks of motor gasoline blending components	PSM	STF
MGEXPUS	MMBD	Exports of motor gasoline	PSM	STF
MGFPPUS	MMBD	Field production of finished motor gasoline	PSM	STF
MGIMPUS	MMBD	Gross imports of motor gasoline	PSM	STF
MGNIPUS	MMBD	Net imports of motor gasoline	PSM	STF
MGPSPUS	MMB	Stocks of motor gasoline	PSM	STF
MGPSPUSA	MMB	MGPSPUS seasonally adjusted	—	—
MGROPANN	MMB	Annual monthly average of refinery output of motor gasoline	PSA	ROT

Petroleum Products Supply (Continued)

Variable	Units	Definition	Source History	Source Forecast
MGROPUS	MMBD	Refinery output of motor gasoline	PSM	STF
MGROPUSA	MMBD	MGROPUS seasonally adjusted	—	—
MGWHPUS	MMBD	Wholesale volume: motor gasoline	PMM	STF
NLPRPUS	MMBD	Natural gas plant liquid production	PSM	STF
OHRIPUS	MMBD	Other hydrocarbons and alcohol field production	PSM	STF
ORUTCUS	FRAC	Refinery utilization rate, CODIPUS / ORCAPUS	—	—
ORUTCUSA	FRAC	ORUTCUS seasonally adjusted	—	—
PAGLPUS	MMBD	Refinery processing gain	PSM	STF
PANIPUS	MMBD	Net imports of petroleum products	PSM	STF
PARIPUS	MMBD	Total refinery inputs	PSM	STF
PAROBAL	MMBD	Refinery output balancing item	CAL	ROT
PAROPUS	MMBD	Total refinery output	PSM	STF
PAROPUSX	MMBD	Temporary variable for PAROPUS	—	—
PASXPUS	MMB	Total petroleum stocks (excluding SPR)SM	STF	
PATCPUS	MMBD	Total petroleum product demand	PSM	STF
PATCPUSA	MMBD	PATCPUS seasonally adjusted	—	—
PPEXPUS	MMBD	Exports of pentanes plus	PSM	STF
PPFPPUS	MMBD	Field production of pentanes plus	PSM	STF
PPIMPUS	MMBD	Gross imports of pentanes plus	PSM	STF
PPNIPUS	MMBD	Net imports of pentanes plus	PSM	STF
PPNLSUS	FRAC	Pentanes plus fraction of NGPL's	CAL	ROT
PPPSPUS	MMB	Stocks of pentanes plus	PSM	STF
PPRIPANN	MMB	Annual refiner inputs of PPRIPUS	PSA	ROT
PPRIPUS	MMBD	Refinery inputs of pentanes plus	PSM	STF
PPRIPUSA	MMBD	PPRIPUS seasonally adjusted	—	—
PRESPUS	MMBD	Retail volumes of propane	PMM	STF
PRNLSUS	FRAC	LPG fraction of NGPL's	CAL	ROT
PRPSPUS	MMB	Stocks of propane	PSM	STF
PSEXPUS	MMBD	Exports of "other" petroleum products	PSM	STF
PSFPPUS	MMBD	Field production of "other" petroleum	PSM	STF
PSIMPUS	MMBD	Gross imports of "other" petroleum products	PSM	STF
PSNIPUS	MMBD	Net imports of "other" petroleum products	PSM	STF
PSPSPUS	MMB	Stocks of "other" petroleum products	PSM	STF
PSRIPANN	MMB	Annual refinery inputs of "other" petroleum	PSA	ROT
PSRIPUS	MMBD	Refinery inputs of "other" petroleum products	PSM	STF
PSROPUS	MMBD	Refinery output of "other" petroleum products	PSM	STF
PSROPUSA	MMBD	PSROPUS seasonally adjusted	—	—
RACPPUS	MMBD	Refiner volume of crude oil RACPPUS = CODIPUS	CAL	STF
RAIMPUS	MMBD	Gross imports crude oil plus unfinished oils	CAL	ROT
RFESPUS	MMBD	Residual fuel oil sale to end-users	PMM	STF
RFEXPUS	MMBD	Exports of residual fuel oil	PSM	STF
RFFPPUS	MMBD	Field production of residual fuel oil	PSM	STF
RFIMPUS	MMBD	Gross imports of residual fuel oil	PSM	STF
RFNIPUS	MMBD	Net imports of residual fuel oil	PSM	STF
RFPSPUS	MMB	Stocks of residual fuel oil	PSM	STF
RFROPUS	MMBD	Refinery output of residual fuel oil	PSM	STF
RFROPUSA	MMBD	RFROPUS seasonally adjusted	—	—

Petroleum Products Supply (Continued)

Variable	Units	Definition	Source History	Source Forecast
UONIPUS	MMBD	Net Import of unfinished oils	PSM	STF
UOPSPUS	MMB	Stocks of unfinished oils	PSM	STF
UORIPUS	MMBD	Refinery inputs of unfinished oils	PSM	STF
UORIPUSA	MMBD	UORIPUS seasonally adjusted	—	—
UORIPUSJ	MMBD	Temporary variable for UORIPUS	—	—
ZWPGIUS	FRAC	Refinery processing gain fraction	PSM	STF

Units Key:
FRAC = Fraction.
MMB = Million barrels.
MMBD = Million barrels per day.

Source Key:
CAL = Calculated.
PMM = Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380.
PSM = Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109.
ROT = "Rule of Thumb." In the forecast, these variables are assumed to remain constant, equal to the last available historical data.
STF = Short-Term Integrated Forecasting System (First Quarter 1993), calculation.

Electricity Supply and Demand

			Source	
Variable	**Units**	**Definition**	History	Forecast
CLCAPUS	BKWD	Coal-electricity generation capacity	860	ROT
CLEOPUS	BKWD	Electricity generation by coal	EPM	STF
DFEPPUS	MMBD	Shipments of distillate fuel oil to electric utilities	EPM	STF
DKEOPUS	BKWD	Electricity generation by distillate fuel oil	EPM	STF
DKEUPUS	MMBD	Demand for distillate fuel at electric utilities	EPM	STF
DKSEPUS	MMB	Stocks of distillate fuel at electric utilities	EPM	STF
ELEOPUS	BKWD	Total utility electricity generation	EPM	STF
ESCMPUSQ	FRAC	Ratio: commercial electricity demand to commercial employment	CAL	STF
ESCMPUS	BKWD	Commercial electricity demand	EPM	STF
ESCMPUSB	BKWD	ESCMPUS seasonally adjusted 2-month moving average	—	—
ESICPUS	BKWD	Industrial electricity demand	EPM	STF
ESICPUSB	BKWD	ESICPUS 2-month moving average	—	—
ESOTPUS	BKWD	Other electricity demand	EPM	STF
ESOTPUSB	BKWD	ESOTPUS 2-month moving average	—	—
ESOTPUSQ	FRAC	Ratio: ESOTPUSB/GNPQXUS	CAL	STF
ESRCPUS	BKWD	Residential electricity demand	EPM	STF
ESRCPUSB	BKWD	ESRCPUS 2-month moving average	—	—
ESRCPUSQ	FRAC	Residential electricity demand to housing stocks	CAL	STF
ESTCPUS	BKWD	Total electricity demand	EPM	STF
ESTCPUSB	BKWD	ESTCPUS 2-month moving avg.	—	—
ETOTSUP	BKWD	Total electricity supply (utility + nonutility + imports)	EPM	STF
GEEOPUS	BKWD	Electricity generation by geothermal power	759	STF
NGEOPUS	BKWD	Electricity generation by natural gas	EPM	STF
NGEOSHR	FRAC	Share of gas generation to oil and gas generation	CAL	STF
NGEOSHRX	FRAC	Temporary variable for NGEOSHR	—	—
NGEUPUS	BCFD	Demand for natural gas at electric utilities	NGM	STF
NGEUPUSX	BCFD	Temporary variable for NGEUPUS	—	—
PAEOPUS	BKWD	Electricity generation by petroleum	EPM	STF
PCEOPUS	BKWD	Electricity generation by petroleum coke	759	STF
PCEUPUS	MMBD	Demand for petroleum coke at electric utilities	759	STF
PCSEPUS	MMB	Petroleum coke stocks at electric utilities	759	STF
RFEOPUS	BKWD	Electricity generation by residual fuel oil	EPM	STF
RFEPPUS	MMBD	Shipments of residual fuel oil to electric utilities	EPM	STF
RFEUPUS	MMBD	Demand for residual oil to produce electricity	EPM	STF
RFSEPUS	MMB	Stocks of residual oil at electric utilities	EPM	STF
TDLOPUS	BKWD	Transmission and distribution losses	CAL	STF

Electricity Supply and Demand (Continued)

			Source	
Variable	**Units**	**Definition**	History	Forecast
TDLOFUSB	FRAC	TDLOPUS/ESTCPUS	CAL	STF
TDLOPUSB	BKWD	TDLOPUS 2-month moving average	—	—
WNEOPUS	BKWD	Electricity generation by wind, solar and other	759	STF
WWEOPUS	BKWD	Electricity generation by wood and waste	759	STF
XGONG	BKWD	Oil and natural gas generation at electric utilities	EPM	STF
XTCLEL	MMT	Shipments of coal to electric utilities	EPM	STF
XTDSEL	MMB	Shipments of distillate fuel to electric utilities	EPM	STF
XTRSEL	MMB	Shipments of residual fuel to electric utilities	EPM	STF

Units Key:
BCFD = Billion cubic feet per day.
BKWD = Billion kilowatthours per day.
FRAC = Fraction.
MM = Millions
MMB = Million barrels.
MMT = Million tons.
MMTD = Million tons per day.

Source Key:
CAL = Calculated.
EPM = Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226.
NGM = Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130.
STF = Short-Term Integrated Forecasting System (January, 1993) calculation.
759 = Form EIA-759, "Monthly Power Plant Report."
860 = Form EIA-850, "Annual Electric Generator Report."

Natural Gas Supply and Demand

Variable	Units	Definition	Source: History	Source: Forecast
BALIT	BCFD	Natural gas balancing item	NGM	STF
NGACPUS	BCFD	Demand for natural gas, pipeline use	NGM	STF
NGCCPUS	BCFD	Demand for natural gas, commercial sector	NGM	STF
NGCCPUSB	BCFD	NGCCPUS 2-month moving average	—	—
NGCCPUSX	FRAC	Ratio of NGCCPUSB/NGCCPUS	CAL	STF
NGEUPUS	BCFD	Demand for natural gas, electric utilities	NGM	STF
NGEUPUSX	BCFD	Temporary variable for NGEUPUS	—	—
NGEXPUS	BCFD	Exports of natural gas	NGM	STF
NGICPUS	BCFD	Natural gas demand, industrial sector	NGM	STF
NGIMPUS	BCFD	Total imports of natural gas	NGM	STF
NGIMPUSA	BCFD	NGIMPUS seasonally adjusted	—	—
NGIMPUSX	BCFD	Temporary variable for NGIMPUS	—	—
NGIMPUSZ	BCFD	Temporary variable for NGIMPUSA	—	—
NGINPUS	BCFD	NGICPUS plus NGLPPUS	NGM	STF
NGINPUSB	BCFD	NGINPUSA 2-month moving average	—	—
NGINPUSX	BCFD	NGINPUS 2-month moving average	—	—
NGINPUSZ	FRAC	Ratio: NGINPUSB/QSIC (gas weighted industrial production index)	CAL	STF
NGLPPUS	BCFD	Demand for natural gas (lease & plant)	NGM	STF
NGMPPUS	BCFD	Production of wet marketed natural gas	NGM	STF
NGNCPUS	MM	Number of commercial natural gas customers	AGA	STF
NGNCPUSA	MM	NGNCPUS seasonally adjusted	—	—
NGNIPUS	BCFD	Net imports of natural gas	NGM	STF
NGNRPUS	MM	Number of residential natural gas customers	AGA	STF
NGNRPUSA	MM	NGNRPUS seasonally adjusted	—	—
NGNWPUS	BCFD	Net withdrawals of natural gas from underground storage	NGM	STF
NGNWPUSX	BCFD	Temporary variable for NGNWPUS	—	—
NGPRMX	FRAC	Natural gas productive capacity	GPC	CAL
NGPRPUS	BCFD	Dry natural gas production	NGM	STF
NGPRPUSA	BCFD	NGPRPUS seasonally adjusted	—	—
NGPRPUSX	BCFD	Reseasonalized NGPRPUSA	—	—
NGPRPUSZ	BFCD	Temporary term for NGPRPUSA	—	—
NGRCPUS	BCFD	Demand for natural gas, residential sector	NGM	STF
NGRCPUSB	BCFD	NGRCPUS 2-month moving average	—	—
NGRCPUSX	BCFD	Temporary term for NGRCPUSB	—	—
NGSFPUS	BCFD	Supplemental gaseous fuels produced	NGM	STF
NGSIPUS	BCFD	Injections of natural gas to underground storage	NGM	STF
NGSUPX	BCFD	Total primary natural gas supply	NGM	STF
NGTCPUS	BCFD	Demand for dry natural gas	NGM	STF
NGTCPUSA	BCFD	NGTCPUS seasonally adjusted	—	—
NGTCPUSX	BCFD	Temporary variable for NGTCPUS	—	—
NGWGPUS	BCF	Stocks working natural gas in underground storage	NGM	STF
NGWGPUSA	BCF	NGWGPUS seasonally adjusted	—	—

Natural Gas Supply and Demand (Continued)

Variable	Units	Definition	Source: History	Source: Forecast
NGWGPUSX	BCF	Temporary variable for NGWGPUS	—	—
NGWSPUS	BCFD	Withdrawals from natural gas underground storage	NGM	STF
NXSCPUS	BCFD	Net withdrawals of natural gas from underground storage	NGM	STF

Units Key:
BCF = Billion cubic feet.
BCFD = Billion cubic feet per day.
FRAC = Fraction.
MM = Million.

Source Key:
AGA = American Gas Association, *Gas Stats*.
CAL = Calculated.
GPC = Energy Information Administration, *Natural Gas Productive Capacity for the Lower 48 States*, DOE/EIA-0542(92).
NGM = Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130.
STF = Short-Term Integrated Forecasting System (First Quarter 1993) calculation.

Coal Demand

Variable	Units	Definition	Source: History	Source: Forecast
CCNIPUS	MMTD	Net imports of coal coke	QCR	STF
CCPRPUS	MMTD	Production of oven and beehive coke	QCR	STF
CCSDPUS	MMT	Coal coke producer stocks	QCR	STF
CCTCPUS	MMTD	Demand for coal coke	QCR	STF
CCTCPUSX	MMTD	Temporary variable for CCTCPUS	-	-
CLEUPUS	MMTD	Demand for coal to produce electricity	QCR	STF
CLEXPUS	MMTD	Exports of coal	QCR	SCL
CLFCPUS	MMTD	Demand for synfuels coal	QCR	ROT
CLHCPUS	MMTD	Demand for coal: residential and commercial	QCR	STF
CLIMPUS	MMTD	Imports of coal	QCR	SCL
CLKCPUS	MMTD	Monthly U.S. coal shipments to coke ovens	QCR	STF
CLKCPUSX	MMTD	Temporary variable for CLKCPUS	—	—
CLPRPUS	MMTD	Total coal production	QCR	SCL
CLPRPUSX	MMTD	Temporary variable for CLPRPUS	—	—
CLSDPUS	MMT	Stocks of coal at producers and distributors	QCR	SCL
CLSEPUS	MMT	Stocks of coal at electric utilities	QCR	STF
CLSEPUSX	MMT	Temporary variable for CLSEPUS	—	—
CLSESTAR	MMT	Target stocks for CLEUPUS	STF	ROT
CLSKPUS	MMT	Stocks of coal at coke plants	QCR	STF
CLSKPUSX	MMT	Temporary variable for CLSKPUS	—	—
CLSKSTAR	MMT	Target stocks for CLSKPUS	STF	ROT
CLSOPUS	MMT	Stocks of coal at retail and general industry	QCR	STF
CLSOPUSX	MMT	Temporary variable for CLSOPUS	—	—
CLSOSTAR	MMT	Target stocks for CLYCPUS	STF	ROT
CLSTBAL	MMTD	Balancing item for coal supply	QCR	STF
CLSTPUS	MMT	Total secondary coal stocks	QCR	STF
CLSTPUSX	MMT	Temporary variable for CLSTPUS	—	—
CLTCPUS	MMTD	Total coal demand	QCR	STF
CLXCPUS	MMTD	Coal demand by synfuels and other industrial users	QCR	STF
CLYCPUS	MMTD	Demand for coal by other industrial users	QCR	STF
CLZCPUS	MMTD	Demand for coal by retail and general industry	QCR	STF
COKEBAL	MMTD	Temporary measure of coke supply-demand imbalance	-	STF
K1	FRAC	Coal coke demand to steel production	STF	ROT
K2	FRAC	Net imports of coal to coal coke demand	STF	ROT
K3	FRAC	Coal coke producer stocks to coal coke demand	STF	ROT
K4	FRAC	Shipments of coal to coke ovens/production of oven & beehive coke	STF	ROT
K5	FRAC	Electric arc raw steel production/total raw steel production	STF	ROT
RSELPUS	MMTD	Raw steel production - electric arc	I&S	STF
RSPRPUS	MMTD	Raw steel production - total	I&S	STF
RSPRPUSA	MMTD	RSPRPUS seasonally adjusted	—	—

Units Key:
FRAC = Fraction.
MMT = Million tons.
MMTD = Million tons per day.

Source Key:
I&S = American Iron and Steel Institute, *Raw Steel and Pig Iron Production* (monthly).
QCR = Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0121.
ROT = "Rule of Thumb." In the forecast, these variables with the exception of the "target" variables are assumed to remain constant, equal to the last available historical data. The "target" variables are set at the observed historical minimum.
SCL = Short-Term Coal Analysis System (SCOAL) model, Office of Coal, Nuclear, Electric & Alternate Fuels.
STF = Short-Term Integrated Forecasting System (January, 1993) calculation.

Petroleum and Non-Petroleum Prices

Variable	Units	Definition	Source: History	Source: Forecast
AFUEUUS	DMMB	Weighted price fossil fuel to electric utilities	CAL	STF
CLEUDUS	DMMB	Cost of coal to electric utilities	EPM	STF
CLEUDUSA	DMMB	CLEUDUS seasonally adjusted	—	—
DSRTUUS	CPG	Retail price of diesel fuel oil	PMM	STF
DSRTUUSA	CPG	DSRTUUS seasonally adjusted	—	—
DSTCUUS	CPG	No.2 diesel fuel prices	PMM	STF
DSTCUUSA	CPG	DSTCUUS seasonally adjusted	—	—
DSTXUUS	CPG	No. 2 diesel fuel taxes	PMM	STF
D2RCUUS	CPG	No. 2 heating oil, residential price	PMM	STF
D2RCUUSA	CPG	D2RCUUS seasonally adjusted	—	—
D2WHUUS	CPG	No. 2 heating oil wholesale price	PMM	STF
D2WHUUSA	CPG	D2WHUUS seasonally adjusted	—	—
ESRCUUS	CKWH	Residential electricity price	EPM	STF
ESRCUUSA	CKWH	ESRCUUS seasonally adjusted	—	—
EXDFDS	DAYS	Excess days' supply of distillate fuel oil	CAL	STF
JKTCUUS	CPG	Price of kerosene based jet fuel	PMM	STF
JKTCUUSA	CPG	JKTCUUS seasonally adjusted	—	—
MGUCUUS	CPG	Motor gasoline, all grades and all services, retail price	BLS	STF
MGUCUUSA	CPG	MGUCUUS seasonally adjusted	—	—
MGWHUUS	CPG	Wholesale price of motor gasoline	PMM	STF
MGWHUUSA	CPG	MGWHUUS seasonally adjusted	—	—
NGCCUUS	DMCF	Price of natural gas, commercial sector	NGM	STF
NGCCUUSA	DMCF	NGCCUUS seasonally adjusted	-	-
NGEUDUS	DMMB	Cost of natural gas to electric utilities	EPM	STF
NGEUDUSA	DMMB	NGEUDUS seasonally adjusted	—	—
NGICUUS	DMCF	Price of natural gas, industrial sector	NGM	STF
NGICUUSA	DMCF	NGICUUS seasonally adjusted	—	—
NGRCUUS	DMCF	Residential natural gas price	NGM	STF
NGRCUUSA	DMCF	NGRCUUS seasonally adjusted	—	—
NGSPUUS	DMMB	Spot natural gas wellhead price	NGW	STF
NGSPUUSA	DMMB	NGSPUUS seasonally adjusted	—	—
NGWPUUS	DMCF	Natural gas wellhead price	NGM	STF
NGWPUUSA	DMCF	NGWPUUS seasonally adjusted	—	—
PRTCUUS	CPG	Retail price of propane	PMM	STF
PRTCUUSA	CPG	PRTCUUS seasonally adjusted	—	—
RFEUDUS	DMMB	Cost of residual fuel oil to electric utilities	EPM	STF
RFEUDUSA	DMMB	RFEUDUS seasonally adjusted	—	—
RFTCUUS	CPG	No.6 residual fuel oil retail price	PMM	STF
RFTCUUSA	CPG	RFTCUUS seasonally adjusted	—	—

Units Key:
- BCFD = Billion cubic feet per day.
- BKWD = Billion kilowatthours per day.
- CKWH = Cents per kilowatthour.
- CPG = Cents per gallon.
- DAYS = Number of days.
- DMCF = Dollars per million cubic feet.
- DMMB = Dollars per million Btu's.

Source Key:
- BLS = Bureau of Labor Statistics, *Monthly Labor Review.*
- CAL = Calculated.
- EPM = Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226.
- NGM = Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130.
- NGW = Natural Gas Week, Washington D.C.
- PMM = Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380.
- ROT = "Rule of Thumb." Diesel fuel taxes are assumed to increase at a rate of one cent per year.
- STF = Short-Term Integrated Forecasting System (First Quarter 1993) calculation.

Appendix C

Alphabetical Variable Listing and Cross Reference

Appendix C

Alphabetical Variable Listing and Cross Reference

This appendix provides an alphabetical listing of all variables used in the STIFS model.

A cross reference to the variable categories used in Appendix B is provided. Variable category code corresponding to Appendix B is:

Add	= Add factor
CL	= Coal supply or demand
Dumm	= Dummy, integer, date, or time variable
EL	= Electricity supply or demand
Heat	= Heat rate or thermal content
Mult	= Multiplicative factor
NG	= Natural gas supply or demand
PD	= Petroleum product demand
PR	= Petroleum or non-petroleum price
PS	= Petroleum product supply
Seas	= Seasonal factor
Wthr	= Weather variable
XE	= Exogenous energy variable
XM	= Exogenous macro variable

A cross reference is also provided to the archive file name and file line number for all endogenous variables in the STIFS model. Endogenous variables include the 93 estimated variables listed in Appendix A, and 212 variables calculated by identities in STIFS. The archive file name codes are:

CLMOD	= CN6777.PRJ.STIF0193.SIMULATE.SAS(CLMOD)
D2MOD	= CN6777.PRJ.STIF0193.SIMULATE.SAS(D2MOD)
ELMOD	= CN6777.PRJ.STIF0193.SIMULATE.SAS(ELMOD)
JFMOD	= CN6777.PRJ.STIF0193.SIMULATE.SAS(JFMOD)
LPMOD	= CN6777.PRJ.STIF0193.SIMULATE.SAS(LPMOD)
MGMOD	= CN6777.PRJ.STIF0193.SIMULATE.SAS(MGMOD)
MIMOD	= CN6777.PRJ.STIF0193.SIMULATE.SAS(MIMOD)
NGMOD	= CN6777.PRJ.STIF0193.SIMULATE.SAS(NGMOD)
POMOD	= CN6777.PRJ.STIF0193.SIMULATE.SAS(POMOD)
PPMOD	= CN6777.PRJ.STIF0193.SIMULATE.SAS(PPMOD)
RFMOD	= CN6777.PRJ.STIF0193.SIMULATE.SAS(RFMOD)
SUMOD	= CN6777.PRJ.STIF0193.SIMULATE.SAS(SUMOD)

Variable	Category	Definition	Archive File Name	File Line Number
AARYFAD	Add	Add factor for LDRYLD		
AARYFUS	PD	Average realized airline ticket price	JFMOD	50
AARYFUSA	PD	AARYFUS seasonally adjusted	JFMOD	46
AARYFUSS	Seas	Seasonal factor for AARYFUS		
ABRIPUS	PS	Refinery inputs, aviation gasoline blending components	SUMOD	400
ABTCPUS	PD	Reclassified aviation gasoline blending components	MIMOD	33
AFUEUUS	PR	Weighted price fossil fuel to electric utilities	POMOD	55
APR	Dumm	1 for April		
AUG	Dumm	1 for August		
BALIT	NG	Natural gas balancing item	NGMOD	188
BALITAD	Add	Add factor for BALIT		
BALITMU	Mult	Multiplicative factor for BALIT		
CCNIPUS	CL	Net imports of coal coke	CLMOD	79
CCPRPUS	CL	Production of oven and beehive coke	CLMOD	75
CCSDPUS	CL	Coal coke producer stocks	CLMOD	77
CCTCPUS	CL	Demand for coal coke	CLMOD	84
CCTCPUSX	CL	Temporary variable for CCTCPUS	CLMOD	73
CICPIUS	XM	Consumer price index, Urban		
CLCAPUS	EL	Coal-electricity generation capacity		
CLDESTAR	XE	Target days supply of coal stocks at electric utilities		
CLDKSTAR	XE	Target days supply of coal stocks at coke plants		
CLDOSTAR	XE	Target days supply of coal stocks at other industrial users		
CLEOKUS	Heat	Heat rate for coal		
CLEOPAD	Add	Add factor for CLEOPUS		
CLEOPMU	Mult	Multiplicative factor for CLEOPUS		
CLEOPUS	EL	Electricity generation by coal	ELMOD	117
CLEUDAD	Add	Add factor for CLEUDUSA		
CLEUDMU	Mult	Multiplicative factor for CLEUDUSA		
CLEUDUS	PR	Cost of coal to electric utilities	POMOD	101
CLEUDUSA	PR	CLEUDUS seasonally adjusted	POMOD	5
CLEUDUSS	Seas	Seasonal factor for CLEUDUS		
CLEUKUS	Heat	Thermal content of coal at electric utilities	ELMOD	252
CLEUPUS	CL	Demand for coal to produce electricity	ELMOD	142
CLEXPUS	CL	Exports of coal		
CLFCPUS	CL	Demand for synfuels coal		
CLHCPAD	Add	Add factor for CLHCPUS		
CLHCPMU	Mult	Multiplicative factor for CLHCPUS		
CLHCPUS	CL	Demand for coal: residential and commercial	CLMOD	14
CLIMPUS	CL	Imports of coal		
CLKCPAD	Add	Add factor for CLKCPUSX		
CLKCPUS	CL	Monthly U.S. coal shipments to coke ovens	CLMOD	71
CLKCPUSX	CL	Temporary variable for CLKCPUS	CLMOD	68
CLMRHUS	XE	Coal miner productivity in tons/hour		
CLPRPUS	CL	Total coal production		
CLPRPUSX	CL	Temporary variable for CLPRPUS	CLMOD	106
CLSDPUS	CL	Stocks of coal at producers and distributors		
CLSEPUS	CL	Stocks of coal at electric utilities	CLMOD	113
CLSEPUSX	CL	Temporary variable for CLSEPUS	CLMOD	98
CLSESTAR	CL	Target stocks for CLEUPUS	CLMOD	92
CLSKPUS	CL	Stocks of coal at coke plants	CLMOD	115
CLSKPUSX	CL	Temporary variable for CLSKPUS	CLMOD	102
CLSKSTAR	CL	Target stocks for CLSKPUS	CLMOD	96
CLSOPUS	CL	Stocks of coal at retail and general industry	CLMOD	114

Variable	Category	Definition	Archive File Name	File Line Number
CLSOPUSX	CL	Temporary variable for CLSOPUS	CLMOD	100
CLSOSTAR	CL	Target stocks for CLYCPUS	CLMOD	94
CLSTBAL	CL	Balancing item for coal supply	CLMOD	111
CLSTPUS	CL	Total secondary coal stocks	CLMOD	117
CLSTPUSX	CL	Temporary variable for CLSTPUS	CLMOD	104
CLTCPUS	CL	Total coal demand	CLMOD	90
CLXCPAD	Add	Add factor for CLXCPUS		
CLXCPMU	Mult	Multiplicative factor for CLXCPUS		
CLXCPUS	CL	Coal demand by synfuels and other industrial users	CLMOD	39
CLYCPUS	CL	Demand for coal by other industrial users	CLMOD	86
CLZCPUS	CL	Demand for coal by retail and general industry	CLMOD	88
COCQPUS	XE	Total strategic petroleum reserve fill rate		
CODIPUS	PS	Gross inputs to crude distillation units	SUMOD	57
CODIPUSJ	PS	Temporary variable for CODIPUS	SUMOD	52
CODQPUS	XE	Strategic Petroleum Reserve fill rate from domestic sources		
CODQPUSX	PS	Temporary variable for CODQPUS	SUMOD	400
COEXPUS	PS	Exports of crude oil	SUMOD	175
COIMPUS	PS	Gross imports of crude oil (including SPR)	SUMOD	432
COKEBAL	CL	Temporary measure of coke supply-demand imbalance	CLMOD	81
COLOPUS	PS	Crude oil losses	SUMOD	350
CONIPUS	PS	Net imports of crude oil (including SPR)	SUMOD	433
CONXPUS	PS	Net imports of crude oil (excluding SPR)	SUMOD	167
COPRPUS	XE	Total U.S. crude oil production	SUMOD	165
COQMPUS	XE	Strategic petroleum reserve imports	SUMOD	401
CORIPAD	Add	Add factor for CORIPUS		
CORIPUS	PS	Refinery inputs of crude oil	SUMOD	58
CORIPUSA	PS	CORIPUS seasonally adjusted	SUMOD	61
CORIPUSJ	PS	Temporary variable for CORIPUS	SUMOD	5
CORIPUSS	Seas	Seasonal factor for CORIPUS		
COSQPUS	PS	Strategic petroleum reserve level	SUMOD	403
COSQPUS1	PS	One-period lag of COSQPUS	SUMOD	402
COSXPUS	PS	Stocks of crude oil		
COTCPUS	PD	Demand for unprocessed crude oil	MIMOD	37
COUNPUS	PS	Unaccounted crude oil	SUMOD	446
CPM	PD	Real price per mile travelled for motor gasoline	MGMOD	54
CPMSA	PD	CPM seasonally adjusted	MGMOD	53
CPTCPUS	PD	Demand for crude oil and pentanes plus	MIMOD	38
CURIPUS	PS	Refinery inputs of crude and unfinished oils	SUMOD	429
DATE	Dumm	Numeric year/month		
DATEX	Dumm	Starting date for equation estimation		
DAYSMO	Dumm	Number of days in the month		
DEC	Dumm	1 for December		
DFACPUS	PD	Demand for diesel fuel - transportation sector	D2MOD	5
DFACPAD	Add	Add factor for DFACPUS		
DFACPMU	Mult	Multiplicative factor for DFACPUS		
DFEOKUS	Heat	Heat rate for distillate fuel oil		
DFEPPUS	EL	Shipments of distillate fuel oil to electric utilities	ELMOD	246
DFEXPUS	PS	Exports of distillate fuel oil	SUMOD	215
DFFPPUS	PS	Field production of distillate fuel oil		
DFHCPUS	PD	Demand for distillate fuel oil - residential and commercial	D2MOD	32
DFHCPAD	Add	Add factor for DFHCPUS		
DFHCPMU	Mult	Multiplicative factor for DFHCPUS		
DFICPUS	PD	Demand for distillate fuel oil - industrial sector	D2MOD	61

Variable	Category	Definition	Archive File Name	File Line Number
DFICPAD	Add	Add factor for DFICPUS		
DFICPMU	Mult	Multiplicative factor for DFICPUS		
DFIMPUS	PS	Gross imports of distillate fuel oil	SUMOD	435
DFNIPUS	PS	Net imports of distillate fuel oil	SUMOD	411
DFNUPUS	PD	Non-utility demand for distillate fuel: DFTCPUS - DFEPPUS	D2MOD	93
DFPSPUS	PS	Stocks of distillate fuel oil		
DFPSPUSA	PS	DFPSPUS seasonally adjusted	PPMOD	92
DFPSPUSS	Seas	Seasonal factor for DFPSPUS		
DFROPUS	PS	Refinery output of distillate fuel oil	SUMOD	155
DFROPUSA	PS	DFROPUS seasonally adjusted	SUMOD	100
DFROPUSS	Seas	Seasonal factor for DFROPUS		
DFTCPUS	PD	Demand for distillate fuel oil	D2MOD	95
DFTCPUSA	PD	DFTCPUS seasonally adjusted	D2MOD	96
DFTCPUSS	Seas	Seasonal factor for DFTCPUS		
DFTCZUS	Heat	Thermal content of distillate fuel oil		
DKEOPUS	EL	Electricity generation by distillate fuel oil	ELMOD	239
DKEUPUS	EL	Demand for distillate fuel at electric utilities	ELMOD	243
DKSEPUS	EL	Stocks of distillate fuel at electric utilities		
DRVP89	Dumm	DATE greater than 8903 and less than 8908		
DRVP90	Dumm	DATE greater than 9003 and less than 9008		
DSHIELD	Dumm	DATE greater than 9009 and less than 9101		
DSRTUUS	PR	Retail price of diesel fuel oil	PPMOD	87
DSRTUUSA	PR	DSRTUUS seasonally adjusted	PPMOD	66
DSRTUUSS	Seas	Seasonal factor for DSRTUUS		
DSTCPUS	PD	Demand for No. 2 diesel fuel oil	D2MOD	99
DSTCUAD	Add	Add factor for DSTCUUSA		
DSTCUMU	Mult	Multiplicative factor for DSTCUUSA		
DSTCUUS	PR	No.2 diesel fuel prices	PPMOD	86
DSTCUUSA	PR	DSTCUUS seasonally adjusted	PPMOD	54
DSTCUUSS	Seas	Seasonal factor for DSTCUUS		
DSTORM	Dumm	DATE equal to 9101 or 9102		
DSTXUUS	CPG	No. 2 diesel fuel taxes		
DS2	Dumm	DATE greater than 8103 and less than 8107		
DTO87	Dumm	DATE less than or equal to 8712		
DUM84	Dumm	DATE greater than 8401		
DUM89	Dumm	DATE greater than 8910 and less than 9001		
DUM8083	Dumm	YEAR greater than 1979 and less than 1984		
DUMCOLD	Dumm	DATE equal to 8912 or 9001		
DUMELE	Dumm	DATE greater than 9102		
DUMIRAN	Dumm	DATE greater than 7904 and less than 9010		
DUMWTR	Dumm	YEAR greater than 1980 and MO equal to 1, 2, 3, 4, 11, OR 12		
DUMYRLG	PS	Annual ratio of LGRIPUS/MGROPUS		
DUMYRPP	PS	Annual ratio of PPRIPUS/MGROPUS		
DUMYRPS	PS	Annual ratio of PSRIPUS/MGROPUS		
DZWCD	Wthr	Deviation from normal for CDD's		
DZWHD	Wthr	Deviation from normal for HDD's		
DZWHDN	Wthr	DZWHD for fall/winter months only		
DZWHDP	Wthr	DZWHD for spring/summer months only		
D2RCPUS	PD	Demand for No. 2 heating oil, residential	D2MOD	98
D2RCUAD	Add	Add factor for D2RCUUSA		
D2RCUMU	Mult	Multiplicative factor for D2RCUUSA		
D2RCUUS	PR	No. 2 heating oil, residential price	PPMOD	83
D2RCUUSA	PR	D2RCUUS seasonally adjusted	PPMOD	25

Variable	Category	Definition	Archive File Name	File Line Number
D2RCUUSS	Seas	Seasonal factor for D2RCUUS		
D2WHPUS	PS	Demand for no. 2 heating oil (wholesale)	SUMOD	375
D2WHUAD	Add	Add factor for D2WHUUSA		
D2WHUMU	Mult	Multiplicative factor for D2WHUUSA		
D2WHUUS	PR	No. 2 heating oil wholesale price	PPMOD	82
D2WHUUSA	PR	D2WHUUS seasonally adjusted	PPMOD	17
D2WHUUSS	Seas	Seasonal factor for D2WHUUS		
D87ON	Dumm	DATE greater than 8703		
D88ON	Dumm	YEAR greater than 1987		
D89ON	Dumm	YEAR greater than 1988		
D90ON	Dumm	YEAR greater than 1989		
D9009ON	Dumm	DATE greater than 9009		
D81	Dumm	YEAR equal to 1981		
D89	Dumm	YEAR equal to 1989		
D91	Dumm	DATE equal to 9102 or 9103		
D8002	Dumm	DATE equal to 8002		
D8082	Dumm	DATE greater than 7912 and less than 8301		
D8184	Dumm	DATE greater than 8012 and less than 8404		
D8301	Dumm	DATE equal to 8301		
D8302	Dumm	DATE equal to 8302		
D8412	Dumm	DATE equal to 8412		
D8501	Dumm	DATE equal to 8501		
D8611	Dumm	DATE equal to 8611		
D8809	Dumm	DATE equal to 8809		
D8912	Dumm	DATE equal to 8912		
D8990	Dumm	DATE greater than 8902 and less than 9002		
D9001	Dumm	DATE equal to 9001		
D_MATL	Wthr	HDD's deviation from normal, Mid-Atlantic Region		
D_NENG	Wthr	HDD deviation from normal, New-England Region		
EFF	PD	Average aircraft efficiency RMZTPUS / JFTCPUS	JFMOD	54
EFFSA	PD	EFF seasonally adjusted	JFMOD	32
EFFSAD	Add	Add factor for EFF		
EFFSMU	Mult	Multiplicative factor for EFF		
ELEOPUS	EL	Total utility electricity generation	ELMOD	207
ELEOKUS	Heat	BKWD/quad electricity consumption		
ELNIPUS	XE	Net imports of electricity		
ELNSPUS	XE	Non-utility supply of electricity		
EMCMPUS	XM	Commercial employment		
EMNFPUS	XM	Non-farm employment		
EMPIPUS	XM	Manufacturing employment		
EMPMPUS	XM	Mining employment		
ESCMPAD	Add	Add factor for ESCMPUSQ		
ESCMPMU	Mult	Multiplicative factor for ESCMPUSQ		
ESCMPUS	EL	Commercial electricity demand	ELMOD	89
ESCMPUSB	EL	ESCMPUS seasonally adjusted 2-month moving average	ELMOD	84
ESCMPUSQ	EL	Ratio: commercial electric demand/commercial employment	ELMOD	15
ESICPAD	Add	Add factor for ESICPUSB		
ESICPMU	Mult	Multiplicative factor for ESICPUSB		
ESICPUS	EL	Industrial electricity demand	ELMOD	90
ESICPUSB	EL	ESICPUS 2-month moving average	ELMOD	39
ESOTPAD	Add	Add factor for ESOTPUSQ		
ESOTPMU	Mult	Multiplicative factor for ESOTPUSQ		
ESOTPUS	EL	Other electricity demand	ELMOD	91

Variable	Category	Definition	Archive File Name	File Line Number
ESOTPUSB	EL	ESOTPUS 2-month moving average	ELMOD	85
ESOTPUSQ	EL	Ratio: ESOTPUSB/GNPQXUS	ELMOD	62
ESRCPAD	Add	Add factor for ESRCPUSQ		
ESRCPMU	Mult	Multiplicative factor for ESRCPUSQ		
ESRCPUS	EL	Residential electricity demand	ELMOD	88
ESRCPUSB	EL	ESRCPUS 2-month moving average	ELMOD	83
ESRCPUSQ	EL	Residential electricity demand to housing stocks	ELMOD	5
ESRCUAD	Add	Add factor for ESRCUUSA		
ESRCUMU	Mult	Multiplicative factor for ESRCUUSA		
ESRCUUS	PR	Residential electricity price	POMOD	105
ESRCUUSA	PR	ESRCUUS seasonally adjusted	POMOD	58
ESRCUUSS	Seas	Seasonal factor for ESRCUUS		
ESTCPUS	EL	Total electricity demand	ELMOD	92
ESTCPUSB	EL	ESTCPUS 2-month moving avg.	ELMOD	86
ETOTSUP	EL	Total electricity supply (utility + nonutility + imports)	ELMOD	208
ETTCPMU	Mult	Multiplicative factor for ETTCPUSA		
ETTCPUS	PD	Demand for ethane	LPMOD	32
ETTCPUSA	PD	ETTCPUS seasonally adjusted	LPMOD	19
ETTCPUSS	Seas	Seasonal factor for ETTCPUS		
EXDFDS	PR	Excess days' supply of distillate fuel oil		
FEB	Dumm	1 for February		
FEERIUS	XM	Real exchange rate		
FETCPAD	Add	Add factor for LSFET		
FETCPUS	PD	Demand for petrochemical feedstocks	MIMOD	32
FETCPUSA	PD	FETCPUS seasonally adjusted	MIMOD	28
FETCPUSS	Seas	Seasonal factor for FETCPUS		
FFEOKUS	Heat	Heat rate for hydropower generation		
GDPDIUS	XM	Gross domestic product implicit price deflator		
GDPQXUS	XM	Real gross domestic product, 1987 dollars		
GEEOPUS	EL	Electricity generation by geothermal power	ELMOD	201
GNPDIUS	XM	Gross national product implicit price deflator (PGNP)		
GNPQXUS	XM	Real gross national product, 1987 dollars		
HDDX85	Wthr	HDD's after 8501, 0 otherwise		
HYEOENC	XE	Hydroelectric generation, East North Central region		
HYEOESC	XE	Hydroelectric generation, East South Central region		
HYEOMTN	XE	Hydroelectric generation, Mountain region		
HYEOPAC	XE	Hydroelectric generation, Pacific region		
HYEOPMA	XE	Hydroelectric generation, Mid-Atlantic region		
HYEOPNE	XE	Hydroelectric generation, New England region		
HYEOPSA	XE	Hydroelectric generation, South Atlantic region		
HYEOPUS	XE	Hydroelectric generation, Total U.S.		
HYEOWNC	XE	Hydroelectric generation, West North Central region		
HYEOWSC	XE	Hydroelectric generation, West South Central region		
I87RXUS	XM	Private domestic fixed investment, 1987 dollars		
JAN	Dumm	1 for January		
JFEXPUS	PS	Exports of jet fuel	SUMOD	253
JFFPPUS	PS	Field production of jet fuel		
JFIMPUS	PS	Gross imports of jet fuel	SUMOD	436
JFNIPUS	PS	Net imports of jet fuel	SUMOD	413
JFPSPUS	PS	Stocks of jet fuel		
JFROPAD	Add	Add factor for JFROPUS		
JFROPMU	Mult	Multiplicative factor for JFROPUS		
JFROPUS	PS	Refinery output of jet fuel	SUMOD	156

Variable	Category	Definition	Archive File Name	File Line Number
JFROPUSA	PS	JFROPUS seasonally adjusted	SUMOD	107
JFROPUSS	Seas	Seasonal factor for JFROPUS		
JFTCPUS	PD	Demand for jet fuel	JFMOD	55
JFTCPUSA	PD	JFTCPUS seasonally adjusted	JFMOD	42
JFTCPUSS	Seas	Seasonal factor for JFTCPUS		
JKESPUS	PS	Kerosene jet fuel sales to end-users	SUMOD	387
JKTCUAD	Add	Add factor for JKTCUUSA		
JKTCUMU	Mult	Multiplicative factor for JKTCUUSA		
JKTCUUS	PR	Price of kerosene based jet fuel	PPMOD	81
JKTCUUSA	PR	JKTCUUS seasonally adjusted	PPMOD	5
JKTCUUSS	Seas	Seasonal factor for JKTCUUS		
JUL	Dumm	1 for July		
JUN	Dumm	1 for June		
KQHMPUS	XM	Housing stocks		
KQH1PUS	XM	Single family dwelling housing stocks		
KRDRXUS	XM	Change in manufacturing inventories		
K1	CL	Coal coke demand to steel production		
K2	CL	Net imports of coal to coal coke demand		
K3	CL	Coal coke producer stocks to coal coke demand		
K4	CL	Shipments of coal to coke ovens/prod of oven & beehive coke		
K5	CL	Electric arc raw steel production/total raw steel production		
LDRTM	PD	Log(RMZTPUSA)	JFMOD	23
LDRYLD	PD	Log(AARYFUSA)	JFMOD	6
LDRZM	PD	Log(RMZZPUSA)	JFMOD	15
LF	PD	Revenue ton miles/available ton-miles: RMZZPUS/RMZTPUS	JFMOD	53
LFSA	PD	LF seasonal adjusted	JFMOD	31
LGEXPUS	PS	Exports of LPG's	SUMOD	274
LGFPPUS	PS	Field production of LPG's	SUMOD	424
LGIMPUS	PS	Gross imports of LPG's	SUMOD	437
LGNIPUS	PS	Net imports of LPG's	SUMOD	414
LGPSPUS	PS	Stocks of LPG's		
LGRIPANN	PS	Annual monthly average of refinery inputs of LPGs		
LGRIPUS	PS	Refinery inputs of LPG's	SUMOD	70
LGRIPUSA	PS	LGRIPUS seasonally adjusted	SUMOD	63
LGRIPUSS	Seas	Seasonal factor for LGRIPUS		
LGROPUS	PS	Refinery output of LPG's	SUMOD	157
LGROPUSA	PS	LGROPUS seasonally adjusted	SUMOD	119
LGROPUSS	Seas	Seasonal factor for LGROPUS		
LGTCPUS	PD	Demand for liquefied petroleum gas	LPMOD	34
LGTCPUSA	PD	LGTCPUS seasonally adjusted	LPMOD	35
LGTCPUSS	Seas	Seasonal factor for LGTCPUS		
LSFET	PD	Log(FETCPUSA)	MIMOD	22
LSMIS	PD	Log(MITCPUSA)	MIMOD	5
LXTCPAD	Add	Add factor for LXTCPUSA		
LXTCPMU	Mult	Multiplicative factor for LXTCPUSA		
LXTCPUS	PD	Demand for liquefied petroleum gas, excluding ethane	LPMOD	17
LXTCPUSA	PD	LXTCPUS seasonally adjusted	LPMOD	5
LXTCPUSS	Seas	Seasonal factor for LXTCPUS		
MAR	Dumm	1 for March		
MAY	Dumm	1 for May		
MBOLPUS	PS	Other refinery inputs	SUMOD	428
MBPSPUS	PS	Stocks of motor gasoline blending components		
MBTCPUS	PD	Demand for motor gasoline blending components	MIMOD	34

Variable	Category	Definition	Archive File Name	File Line Number
MGDAYSP	PD	Motor gasoline days' supply	MGMOD	55
MGEXPUS	PS	Exports of motor gasoline	SUMOD	195
MGFPPUS	PS	Field production of finished motor gasoline		
MGIMPUS	PS	Gross imports of motor gasoline	SUMOD	438
MGNIPUS	PS	Net imports of motor gasoline	SUMOD	410
MGPSPUS	PS	Stocks of motor gasoline		
MGPSPUSA	PS	MGPSPUS seasonally adjusted	MGMOD	48
MGPSPUSS	Seas	Seasonal factor for MGPSPUS		
MGROPAD	Add	Add factor for MGROPUSA		
MGROPANN	PS	Annual monthly average of refinery output of motor gasoline		
MGROPUS	PS	Refinery output of motor gasoline	SUMOD	154
MGROPUSA	PS	MGROPUS seasonally adjusted	SUMOD	92
MGROPUSS	Seas	Seasonal factor for MGROPUS		
MGTCPUS	PD	Demand for finished motor gasoline	MGMOD	50
MGTCPUSA	PD	MGTCPUS seasonally adjusted	MGMOD	49
MGTCPUSS	Seas	Seasonal factor for MGTCPUS		
MGUCUAD	Add	Add factor for MGUCUUSA		
MGUCUMU	Mult	Multiplicative factor for MGUCUUSA		
MGUCUUS	PR	Motor gasoline, all grades and all services, retail price	PPMOD	85
MGUCUUSA	PR	MGUCUUS seasonally adjusted	PPMOD	44
MGUCUUSS	Seas	Seasonal factor for MGUCUUS		
MGWHPUS	PS	Wholesale volume: motor gasoline	SUMOD	390
MGWHUAD	Add	Add factor for MGWHUUSA		
MGWHUMU	Mult	Multiplicative factor for MGWHUUSA		
MGWHUUS	PR	Wholesale price of motor gasoline	PPMOD	84
MGWHUUSA	PR	MGWHUUS seasonally adjusted	PPMOD	34
MGWHUUSS	Seas	Seasonal factor for MGWHUUS		
MITCPAD	Add	Add factor for MITCPUS		
MITCPMU	Mult	Multiplicative factor for MITCPUS		
MITCPUS	PD	Demand for miscellaneous petroleum products	MIMOD	20
MITCPUSA	PD	MITCPUS seasonally adjusted components	MIMOD	29
MITCPUSS	Seas	Seasonal factor for MITCPUS		
MLTCPUS	PD	Demand for leaded gasoline	MGMOD	58
MLTCPUSA	PD	MLTCPUS seasonally adjusted	MGMOD	59
MLTCPUSS	Seas	Seasonal factor for MLTCPUS		
MO	Dumm	2-digit month of observation		
MOGP	PD	Real seasonalized price of motor gasoline	MGMOD	52
MOGPSA	PD	Real deseasonalized price of motor gasoline	MGMOD	51
MPG	PD	Automobile fleet fuel efficiency, MGTCPUS / MVVMPUS	MGMOD	46
MPGA	PD	MPG seasonally adjusted	MGMOD	5
MPGAAD	Add	Add factor for MPGA		
MPGAMU	Mult	Multiplicative factor for MPGA		
MUTCPUS	PD	Demand for unleaded motor gasoline	MGMOD	59
MUTCPUSA	PD	MUTCPUS seasonally adjusted	MGMOD	57
MUTCPUSS	Seas	Seasonal factor for MUTCPUS		
MUTCSUS	PD	Unleaded motor gasoline demand share	MGMOD	32
MVVMPAD	Add	Add factor for MVVMPUSA		
MVVMPMU	Mult	Multiplicative factor for MVVMPUSA		
MVVMPUS	PD	Vehicle miles travelled	MGMOD	47
MVVMPUSA	PD	MVVMPUS seasonally adjusted	MGMOD	21
MVVMPUSS	Seas	Seasonal factor for MVVMPUS		
NAPRKUS	Heat	Thermal content of wet natural gas production		
NGACPAD	Add	Add factor for NGACPUS		

Variable	Category	Definition	Archive File Name	File Line Number
NGACPMU	Mult	Multiplicative factor for NGACPUS		
NGACPUS	NG	Demand for natural gas, pipeline use	NGMOD	113
NGCCPAD	Add	Add factor for NGCCPUSX		
NGCCPMU	Mult	Multiplicative factor for NGCCPUSX		
NGCCPUS	NG	Demand for natural gas, commercial sector	NGMOD	68
NGCCPUSB	NG	NGCCPUS 2-month moving average	NGMOD	67
NGCCPUSX	NG	Ratio of NGCCPUSB/NGCCPUS	NGMOD	47
NGCCUAD	Add	Add factor for NGCCUUSA		
NGCCUMU	Mult	Multiplicative factor for NGCCUUSA		
NGCCUUS	PR	Price of natural gas, commercial sector	POMOD	108
NGCCUUSA	PR	NGCCUUS seasonally adjusted	POMOD	90
NGCCUUSS	Seas	Seasonal factor for NGCCUUS		
NGEOKUS	Heat	Heat rate for natural gas		
NGEOPUS	EL	Electricity generation by natural gas	ELMOD	235
NGEOSAD	Add	Add factor for NGEOSHRX		
NGEOSHR	EL	Share of gas generation to oil and gas generation	ELMOD	236
NGEOSHRX	EL	Temporary variable for NGEOSHR	ELMOD	211
NGEOSMU	Mult	Multiplicative factor for NGEOSHRX		
NGEUDAD	Add	Add factor for NGEUDUSA		
NGEUDUS	PR	Cost of natural gas to electric utilities	POMOD	104
NGEUDUSA	PR	NGEUDUS seasonally adjusted	POMOD	40
NGEUDUSS	Seas	Seasonal factor for NGEUDUS		
NGEUPUS	EL	Demand for natural gas at electric utilities	ELMOD	234
NGEUPUSX	EL	Temporary variable for NGEUPUS	ELMOD	233
NGEXPUS	NG	Exports of natural gas	NGMOD	123
NGICPUS	NG	Natural gas demand, industrial sector	NGMOD	119
NGICUAD	Add	Add factor for NGICUUSA		
NGICUMU	Mult	Multiplicative factor for NGICUUSA		
NGICUUS	PR	Price of natural gas, industrial sector	POMOD	107
NGICUUSA	PR	NGICUUS seasonally adjusted	POMOD	82
NGICUUSS	Seas	Seasonal factor for NGICUUS		
NGIMMX	XE	Natural gas import capacity		
NGIMPAD	Add	Add factor for NGIMPUSZ		
NGIMPUS	NG	Total imports of natural gas	NGMOD	238
NGIMPUSA	NG	NGIMPUS seasonally adjusted	NGMOD	239
NGIMPUSS	Seas	Seasonal factor for NGIMPUS		
NGIMPUSX	NG	Temporary variable for NGIMPUS	NGMOD	237
NGIMPUSZ	NG	Temporary variable for NGIMPUSA	NGMOD	232
NGINPAD	Add	Add factor for NGINPUSZ		
NGINPMU	Mult	Multiplicative factor for NGINPUSZ		
NGINPUS	NG	NGICPUS plus NGLPPUS	NGMOD	254
NGINPUSB	NG	NGINPUSA 2-month moving average	NGMOD	96
NGINPUSX	NG	NGINPUS 2-month moving average	NGMOD	97
NGINPUSZ	NG	Ratio: NGINPUSB/QSIC (gas weighted ind. prod. index)	NGMOD	72
NGLPPAD	Add	Add factor for NGLPPUS		
NGLPPMU	Mult	Multiplicative factor for NGLPPUS		
NGLPPUS	NG	Demand for natural gas (lease & plant)	NGMOD	101
NGMPPUS	NG	Production of wet marketed natural gas	NGMOD	244
NGNCPUS	NG	Number of commercial natural gas customers	NGMOD	44
NGNCPUSA	NG	NGNCPUS seasonally adjusted	NGMOD	37
NGNCPUSS	Seas	Seasonal factor for NGNCPUS		
NGNIPUS	NG	Net imports of natural gas	NGMOD	241
NGNRPUS	NG	Number of residential natural gas customers	NGMOD	16

Variable	Category	Definition	Archive File Name	File Line Number
NGNRPUSA	NG	NGNRPUS seasonally adjusted	NGMOD	9
NGNRPUSS	Seas	Seasonal factor for NGNRPUS		
NGNUKUS	Heat	Thermal content of nonutility natural gas		
NGNWPUS	NG	Net withdrawals of natural gas from underground storage	NGMOD	178
NGNWPUSX	NG	Temporary variable for NGNWPUS	NGMOD	177
NGPRKUS	Heat	Thermal content of dry natural gas production		
NGPRMX	NG	Natural gas productive capacity		
NGPRPAD	Add	Add factor for NGPRPUSZ		
NGPRPMU	Mult	Multiplicative factor for NGPRPUSZ		
NGPRPUS	NG	Dry natural gas production	NGMOD	229
NGPRPUSA	NG	NGPRPUS seasonally adjusted	NGMOD	230
NGPRPUSX	NG	Reseasonalized NGPRPUSA	NGMOD	228
NGPRPUSZ	NG	Temporary term for NGPRPUSA	NGMOD	221
NGPRPUSS	Seas	Seasonal factor for NGPRPUS		
NGRCPAD	Add	Add factor for NGRCPUSX		
NGRCPMU	Mult	Multiplicative factor for NGRCPUSX		
NGRCPUS	NG	Demand for natural gas, residential sector	NGMOD	33
NGRCPUSB	NG	NGRCPUS 2-month moving average	NGMOD	32
NGRCPUSX	NG	Temporary term for NGRCPUSB	NGMOD	19
NGRCUAD	Add	Add factor for NGRCUUSA		
NGRCUMU	Mult	Multiplicative factor for NGRCUUSA		
NGRCUUS	PR	Residential natural gas price	POMOD	106
NGRCUUSA	PR	NGRCUUS seasonally adjusted	POMOD	72
NGRCUUSS	Seas	Seasonal factor for NGRCUUS		
NGSFPUS	NG	Supplemental gaseous fuels produced	NGMOD	205
NGSIPUS	NG	Injections of natural gas to underground storage	NGMOD	184
NGSPUAD	Add	Add factor for NGSPUUS		
NGSPUMU	Mult	Multiplicative factor for NGSPUUS		
NGSPUUS	PR	Spot natural gas wellhead price	POMOD	15
NGSPUUSA	PR	NGSPUUS seasonally adjusted	POMOD	102
NGSPUUSS	Seas	Seasonal factor for NGSPUUS		
NGSUPX	NG	Total primary natural gas supply	NGMOD	138
NGTCPUS	NG	Demand for dry natural gas	NGMOD	252
NGTCPUSA	NG	NGTCPUS seasonally adjusted	NGMOD	253
NGTCPUSS	Seas	Seasonal factor for NGTCPUS		
NGTCPUSX	NG	Temporary variable for NGTCPUS	NGMOD	120
NGWGPAD	Add	Add factor for NGWGPUSX		
NGWGPMU	Mult	Multiplicative factor for NGWGPUSX		
NGWGPUS	NG	Stocks working natural gas in underground storage	NGMOD	183
NGWGPUSA	NG	NGWGPUS seasonally adjusted		
NGWGPUSS	Seas	Seasonal factor for NGWGPUS		
NGWGPUSX	NG	Temporary variable for NGWGPUS	NGMOD	141
NGWPUAD	Add	Add factor for NGWPUUS		
NGWPUMU	Mult	Multiplicative factor for NGWPUUS		
NGWPUUS	PR	Natural gas wellhead price	POMOD	27
NGWPUUSA	PR	NGWPUUS seasonally adjusted	POMOD	103
NGWPUUSS	Seas	Seasonal factor for NGWPUUS		
NGWSPUS	NG	Withdrawals from natural gas underground storage	NGMOD	158
NLPRPUS	PS	Natural gas plant liquid production	SUMOD	370
NOV	Dumm	1 for November		
NUEOENC	XE	Electricity generation by nuclear power, East North Central region		
NUEOESC	XE	Electricity generation by nuclear power, East South Central region		
NUEOKUS	Heat	Heat rate for nuclear power		

Variable	Category	Definition	Archive File Name	File Line Number
NUEOMTN	XE	Electricity generation by nuclear power, Mountain region		
NUEOPAC	XE	Electricity generation by nuclear power, Pacific region		
NUEOPMA	XE	Electricity generation by nuclear power, Mid-Atlantic region		
NUEOPNE	XE	Electricity generation by nuclear power, New England region		
NUEOPSA	XE	Electricity generation by nuclear power, South Atlantic region		
NUEOPUS	XE	Electricity generation by nuclear power, total U.S.		
NUEOWNC	XE	Electricity generation by nuclear power, West North Central region		
NUEOWSC	XE	Electricity generation by nuclear power, West South Central region		
NXSCPUS	NG	Net withdrawals of natural gas from underground storage	NGMOD	185
OCT	Dumm	1 for October		
OHRIPAD	Add	Add factor for OHRIPUS		
OHRIPUS	PS	Other hydrocarbons and alcohol field production	SUMOD	445
ORCAPUS	XE	Monthly U.S. operable refinery capacity		
ORUTCUS	PS	Refinery utilization rate, CODIPUS / ORCAPUS	SUMOD	443
ORUTCUSA	PS	ORUTCUS seasonally adjusted	SUMOD	444
ORUTCUSS	Seas	Seasonal factor for ORUTCUS		
PAEOPUS	EL	Electricity generation by petroleum	ELMOD	237
PAGLPUS	PS	Refinery processing gain	SUMOD	144
PANIPUS	PS	Net imports of petroleum products	SUMOD	430
PAPRP48	XE	Crude oil production, Lower 48 States		
PAPRPAK	XE	Crude oil production, Alaska		
PAPRPUS	XE	Domestic crude oil production		
PARIPUS	PS	Total refinery inputs	SUMOD	142
PAROBAL	PS	Refinery output balancing item	SUMOD	152
PAROPUS	PS	Total refinery output	SUMOD	161
PAROPUSX	PS	Temporary variable for PAROPUS	SUMOD	145
PASXPUS	PS	Total petroleum stocks (excluding SPR)	SUMOD	441
PATCPUS	PS	Total petroleum product demand	SUMOD	453
PATCPUSA	PS	PATCPUS seasonally adjusted	SUMOD	455
PATCPUSS	Seas	Seasonal factor for PATCPUS		
PCEOKUS	Heat	Heat rate for petroleum coke		
PCEOPUS	EL	Electricity generation by petroleum coke	ELMOD	240
PCEUPUS	EL	Demand for petroleum coke at electric utilities	ELMOD	244
PCSEPUS	EL	Petroleum coke stocks at electric utilities		
PCTCZUS	Heat	Thermal content of petroleum coke		
POST85	Dumm	DATE greater than or equal to 8501		
PPEXPUS	PS	Exports of pentanes plus	SUMOD	312
PPFPPUS	PS	Field production of pentanes plus	SUMOD	425
PPIMPUS	PS	Gross imports of pentanes plus	SUMOD	440
PPNIPUS	PS	Net imports of pentanes plus	SUMOD	419
PPNLSUS	PS	Pentanes plus fraction of NGPL's		
PPPSPUS	PS	Stocks of pentanes plus	SUMOD	332
PPRIPANN	PS	Annual refiner inputs of PPRIPUS		
PPRIPUS	PS	Refinery inputs of pentanes plus	SUMOD	79
PPRIPUSA	PS	PPRIPUS seasonally adjusted	SUMOD	72
PPRIPUSS	Seas	Seasonal factor for PPRIPUS		
PPTCPUS	PD	Demand for pentanes plus	MIMOD	36
PRESPUS	PS	Retail volumes of propane	SUMOD	393
PRE85XT	Dumm	Slope dummy, (1 - POST85) * TIME		
PRIMELG	XM	12 month lag of 6-month moving average of PRIMEUS	POMOD	50
PRIMEUS	XM	Prime Rate		
PRNLSUS	PS	LPG fraction of NGPL's		
PRPSPUS	PS	Stocks of propane	SUMOD	405

Variable	Category	Definition	Archive File Name	File Line Number
PRTCPUS	PD	Demand for propane	LPMOD	37
PRTCUAD	Add	Add factor for PRTCUUSA		
PRTCUMU	Mult	Multiplicative factor for PRTCUUSA		
PRTCUUS	PR	Retail price of propane	PPMOD	111
PRTCUUSA	PR	PRTCUUS seasonally adjusted	PPMOD	102
PRTCUUSS	Seas	Seasonal factor for PRTCUUS		
PSEXPUS	PS	Exports of "other" petroleum products	SUMOD	292
PSFPPUS	PS	Field production of "other" petroleum		
PSIMPUS	PS	Gross imports of "other" petroleum products	SUMOD	439
PSNIPUS	PS	Net imports of "other" petroleum products	SUMOD	416
PSPSPUS	PS	Stocks of "other" petroleum products		
PSRIPAD	Add	Add factor for PSRIPUS		
PSRIPANN	PS	Annual refinery inputs of "other" petroleum		
PSRIPUS	PS	Refinery inputs of "other" petroleum products	SUMOD	81
PSROPUS	PS	Refinery output of "other" petroleum products	SUMOD	158
PSROPUSA	PS	PSROPUS seasonally adjusted	SUMOD	126
PSROPUSS	Seas	Seasonal factor for PSROPUS		
PSTCPUS	PD	Demand for "other" petroleum products	MIMOD	39
PSTCPUSA	PD	PSTCPUS seasonally adjusted	MIMOD	40
PSTCPUSS	Seas	Seasonal factor for PSTCPUS		
QCOAL	Heat	Heat generated by coal	POMOD	54
QNGAS	Heat	Heat generated by natural gas	POMOD	53
QRESD	Heat	Heat generagted by residual fuel oil	POMOD	52
QSIC	XM	Natural gas-weighted industrial production index		
RACPPUS	PS	Refiner volume of crude oil RACPPUS = CODIPUS	SUMOD	426
RACPUUS	XE	Refiner acquisition cost for crude oil (composite)		
RACPUUSA	XE	RACPUUS seasonally adjusted	PPMOD	93
RACPUUSS	Seas	Seasonal factor for RACPUUS		
RAIMPUS	PS	Gross imports crude oil plus unfinished oils	SUMOD	434
RAIMUUS	XE	Imported crude oil refiner acquisition cost		
RAIMUUSA	XE	RAIMUUS seasonally adjusted		
RFEOKUS	Heat	Heat rate for residual fuel oil		
RFEOPUS	EL	Electricity generation by residual fuel oil	ELMOD	238
RFEPPUS	EL	Shipments of residual fuel oil to electric utilities	ELMOD	247
RFESPUS	PS	Residual fuel oil sale to end-users	SUMOD	380
RFEUDUS	PR	Cost of residual fuel oil to electric utilities	PPMOD	90
RFEUDUSA	PR	RFEUDUS seasonally adjusted	PPMOD	89
RFEUDUSS	Seas	Seasonal factor for RFEUDUS		
RFEUPUS	EL	Demand for residual oil to produce electricity	ELMOD	242
RFEXPUS	PS	Exports of residual fuel oil	SUMOD	235
RFFPPUS	PS	Field production of residual fuel oil		
RFIMPUS	PS	Gross imports of residual fuel oil	SUMOD	173
RFNIPUS	PS	Net imports of residual fuel oil	SUMOD	412
RFNUPUS	PD	Non-utility demand for residual fuel oil	RFMOD	5
RFPSPUS	PS	Stocks of residual fuel oil		
RFPSPUSS	Seas	Seasonal factor for RFPSPUS		
RFROPUS	PS	Refinery output of residual fuel oil	SUMOD	159
RFROPUSA	PS	RFROPUS seasonally adjusted	SUMOD	133
RFROPUSS	Seas	Seasonal factor for RFROPUS		
RFSEPUS	EL	Stocks of residual oil at electric utilities		
RFTCPUS	PD	Demand for residual fuel oil	RFMOD	26
RFTCPUSA	PD	RFTCPUS seasonally adjusted	RFMOD	28
RFTCPUSS	Seas	Seasonal factor for RFTCPUS		

Variable	Category	Definition	Archive File Name	File Line Number
RFTCUAD	Add	Add factor for RFTCUUS		
RFTCUMU	Mult	Multiplicative factor for RFTCUUS		
RFTCUUS	PR	No.6 residual fuel oil retail price	PPMOD	68
RFTCUUSA	PR	RFTCUUS seasonally adjusted	PPMOD	88
RFTCUUSS	Seas	Seasonal factor for RFTCUUS		
RFTCZUS	Heat	Thermal content of residual fuel oil		
RSELPUS	CL	Raw steel production - electric arc	CLMOD	66
RSPRPUS	CL	Raw steel production - total	CLMOD	64
RSPRPUSA	CL	RSPRPUS seasonally adjusted	CLMOD	4
RMZTPAD	Add	Add factor for LDRTM		
RMZTPUS	PD	Air travel capacity	JFMOD	52
RMZTPUSA	PD	RMZTPUS seasonally adjusted	JFMOD	48
RMZTPUSS	Seas	Seasonal factor for RMZTPUS		
RMZZPAD	Add	Add factor for LDRZM		
RMZZPUS	PD	Aircraft utilization rate	JFMOD	51
RMZZPUSA	PD	RMZZPUS seasonally adjusted	JFMOD	47
RMZZPUSS	Seas	Seasonal factor for RMZZPUS		
RSPRPAD	Add	Add factor for RSPRPUSA		
RSPRPMU	Mult	Multiplicative factor for RSPRPUSA		
RSPRPUSS	Seas	Seasonal factor for RSPRPUS		
SEP	Dumm	1 for September		
TDLOFUSB	EL	TDLOPUS/ESTCPUS	ELMOD	95
TDLOPUS	EL	Transmission and distribution losses	ELMOD	115
TDLOPUSB	EL	TDLOPUS 2-month moving average	ELMOD	114
TD8184	Dumm	Slope dummy, Log(TIME) * D8184		
TD8990	Dumm	Slope dummy, Log(TIME) * D8990		
TDTO87	Dumm	Slope dummy, integers where DATE less than 8801		
TIME	Dumm	Integers 1 - n, where n = number of observations		
TIMEX85	Dumm	Slope dummy, integers, where DATE greater than 8412		
TREND	Dumm	Temporary variable for time		
TREND84	Dumm	Slope dummy, integers, where DATE greater than 8312		
UONIPUS	PS	Net imports of unfinished oils	SUMOD	420
UOPSPUS	PS	Stocks of unfinished oils		
UORIPAD	Add	Add factor for UORIPUSJ		
UORIPUS	PS	Refinery inputs of unfinished oils	SUMOD	59
UORIPUSA	PS	UORIPUS seasonally adjusted	SUMOD	62
UORIPUSJ	PS	Temporary variable for UORIPUS	SUMOD	29
UORIPUSS	Seas	Seasonal factor for UORIPUS		
UOTCPUS	PD	Reclassified unfinished oils	MIMOD	35
WNEOPUS	EL	Electricity generation by wind, solar and other	ELMOD	165
WPCPIUS	XM	Producer price index 1984 = 1.00		
WPIINUS	XM	Producer price index, less energy and food		
WP57IUS	XM	Producer price index, petroleum products	PPMOD	94
WWEOPUS	EL	Electricity generation by wood and waste	ELMOD	183
W_MATL	Wthr	Mid-Atlantic region, population weighted		
W_NE	Wthr	North East (W_MATL + W_NENG), population wtd.		
W_NENG	Wthr	New England, population weighted		
XGONG	EL	Oil and natural gas generation at electric utilities	ELMOD	209
XTCLEL	EL	Shipments of coal to electric utilities	ELMOD	250
XTDSEL	EL	Shipments of distillate fuel to electric utilities	ELMOD	248
XTRSEL	EL	Shipments of residual fuel to electric utilities	ELMOD	249
YD87OUS	XM	Real disposable personal income, 1987 dollars		
YEAR	Dumm	2-digit Year of observation—example: 89 = 1989		

Variable	Category	Definition	Archive File Name	File Line Number
ZGHDPUS	Wthr	Natural gas weighted HDD’s		
ZGHNPUS	Wthr	Normal natural gas-weighted HDD’s		
ZOCBIUS	XM	Industrial production index: basic chemicals		
ZOISIUS	XM	Industrial production index: iron and steel		
ZOMNIUS	XM	Industrial production index: manufacturing		
ZOSIIUS	XM	Coal weighted production index		
ZOTOIUS	XM	Industrial production index: total		
ZO20IUS	XM	Industrial production index: food		
ZO26IUS	XM	Industrial production index: paper		
ZO28IUS	XM	Industrial production index: chem		
ZO29IUS	XM	Industrial production index: petroleum refineries		
ZO32IUS	XM	Industrial production index: stone, clay and glass		
ZO33IUS	XM	Industrial production index: total		
ZSAJQUS	Dumm	Number of days in a month		
ZWCDPUS	Wthr	Average population weighted CDD’s		
ZWCNPUS	Wthr	Average ’Normal’ population weighted CDD’s		
ZWHDDNO	Wthr	Northern (NE & MA) deviations from normal		
ZWHDDUS	Wthr	Deviations from normal HDD, U.S.		
ZWHDPMA	Wthr	Mid-Atlantic population weighted HDD’s		
ZWHDPNE	Wthr	New England population weighted HDD’s		
ZWHDPNO	Wthr	Northeast (NE & MA) HDD’s		
ZWHDPUS	Wthr	Average population weighted HDD’s		
ZWHNPMA	Wthr	Normal HDD’s for the Mid-Atlantic		
ZWHNPNE	Wthr	Normal HDD’s for New England		
ZWHNPNO	Wthr	Northeast (NE & MA) normal HDD’s		
ZWHNPUS	Wthr	Average ’Normal’ population weighted HDD’s		
ZWPGIUS	PS	Refinery processing gain fraction		

Appendix D

Short-Term Integrated Forecasting System (STIFS) Model Abstract

Appendix D

Short-Term Integrated Forecasting System (STIFS) Model Abstract

A. Model Name: Short-Term Integrated Forecasting System

B. Acronym: STIFS

C. Description: The STIFS model is used for producing the forecasts in the *Short-Term Energy Outlook (Outlook).* It provides a national monthly data base and accounting framework for energy supply, demand, stocks, and conversion processes (refineries and electric utilities). The model balances historical data and forecasts the entire energy network for up to two years in the future, based on prices, income, and weather. It also reflects the effects on prices likely to result from inventories, world oil prices, and inflation rates.

D. Model's Purpose: STIFS generates short-term (up to 8 quarters), monthly and quarterly forecasts of U.S. supplies, demands, imports, exports, and stocks of all fuels for up to two years into the future.

E. Model Updated: October 1992

F. Part of Another Model: No

G. Model Interface: STIFS utilizes forecasts of several satellite models maintained by the Energy Information Administration:
- Crude oil price - Oil Market Simulation (OMS) model
- Electricity supply from nuclear power - Short-Term Nuclear Annual Power Simulation (SNAPPS) model
- Coal supply - Short-Term Coal Analysis System (SCOAL)

H. Official Model Representative:
Sponsoring Agency: Energy Information Administration
Office: Energy Markets and End Use
Division: Energy Markets and Contingency Information Division
Branch: Short-Term Forecasting and Contingency Branch, EI-621
Model Contact: David Costello
Telephone: (202) 586-1468

I. Documentation References:

Decision Analysis Corporation of Virginia, *Second Quarter STIFS III Update and Evaluation Draft Model Evaluation Report*, July 16, 1992

Decision Analysis Corporation of Virginia, *Short-Term Integrated Forecasting System III: Model Documentation*, December 31, 1991

J. Archive Media and Installation Manual:

Model archived: First Quarter 1993 *Outlook*
Model archival tape: CN6777.PRJ.STIFS0193
Model installation manual: CN6777.PRJ.STIFS0193.INSTALL.MANUAL
Archival contact:

Elias Johnson, EI-621
Energy Information Administration
U.S. Department of Energy
1000 Independence Avenue
Washington, DC 20585
(202) 586-7277

K. Energy System Described by Model:

U.S. energy production, consumption, imports, exports, stocks, and prices. All major fuels: oil, gas, coal, and electricity on a national basis.

L. Coverage:

Geographic: National

Time Unit/Frequency: Monthly. Published results show only quarterly statistics plus forecasts for up to two years.

Product(s): Motor gasoline, distillate fuel oil, residual fuel oil, jet fuel, liquefied petroleum gases, other petroleum products, natural gas, coal, electricity, nuclear energy, hydroelectricity, and gross and net energy consumption.

Economic Sector(s): Total U.S. with explicit treatment given to electric utility and nonutility consumption, imports, and exports.

M. Modeling Features:

Model Structure: Accounting and algorithmic to balance supply and demand

Modeling Technique: Includes accounting, algorithmic, econometric, and time-trending techniques

Special Features: None

N. Input Data - Non-DOE:

U.S. Department of Transportation, Federal Highway Administration, Highway Statistics Division, *Traffic Volume Trends* (monthly)

- Vehicle miles traveled

Form 41 Data Base, collected by I.P. Sharp for U.S. Department of Transportation

- Revenue ton-miles
- Aircraft yield
- Aircraft load factor
- Available ton-miles
- Average aircraft efficiency

U.S. Department of Labor, Bureau of Labor Statistics, Consumer Price Index -- Detailed Report

- Retail price of motor gasoline

U.S. Department of Labor, Bureau of Labor Statistics, *Monthly Labor Review*

- Consumer price index

U.S. Department of Labor, Bureau of Labor Statistics, *Employment and Earnings*

- Employment

U.S. Department of Labor, Bureau of Labor Statistics, *Producer Price Index* (monthly)

- Producer price index
- Producer price index for petroleum products

Data Resources Inc., U.S. Central Data Base

- Consumer price index projections
- Disposable personal income projections
- Employment, projections
- Industrial production, index, projections
- Chemical production index, projections
- Change in manufacturing inventories, projections
- Raw steel production, projections
- AA bond rating for utilities, projections

Data Resources Inc.

- Real exchange rate plus projections
- AA bond rating for utilities plus projections

U.S. Department of Commerce, Bureau of Economic Analysis, *National Income and Product Accounts of the United States*

- Gross national product
- Gross domestic product
- Disposable personal income
- Gross national product implicit price deflator
- Gross domestic product implicit price deflator
- Gross private domestic fixed investment
- Change in manufacturing inventories

U.S. Department of Commerce, National Oceanic and Atmospheric Administration, *Monthly State, Regional and National Heating/Cooling Degree-Days Weighted by Population*

- New England heating degree-days
- Mid Atlantic heating degree-days
- Population-weighted heating and cooling degree-days

U.S. Federal Reserve System, Board of Governors, *Statistical Release G 17*

- Industrial production index

U.S. Federal Reserve System, Board of Governors, *Federal Reserve Bulletin*

- Bank prime loan rate

American Gas Association, *Quarterly Report of Gas Industry Operations*

- Number of customers, residential and commercial

American Iron and Steel Institute, *Raw Steel and Pig Iron Production Reports*, AIS-7 (monthly reports)

- Raw steel production

Merrill Lynch Bond Pricing Survey

- AA bond rating for utilities

O. Input Data - DOE: **Publications and Forms**:

Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035, (Washington, DC, most recent and 2 previous months' data)

- Retail prices--motor gasoline, distillate and residual fuel oil
- Product supplied--total motor gasoline, no.2 fuel oil (industrial sector), nonutility distillate and residual fuel oil
- Price of natural gas--for industrial users and to electric utilities
- Electricity generation--total, nuclear, hydroelectric, petroleum, natural gas, coal)
- Price of residual fuel to electric utilities
- Natural gas delivered--to residential and commercial consumers
- Natural gas demand for lease and plant fuel
- Natural gas used by pipelines
- Coal consumption--at electric utilities and by industrial users
- Price of imported crude oil
- Domestic and composite refiner acquisition cost of crude oil
- Natural gas wellhead prices
- Residential and commercial natural gas prices
- Price of coal to electric utilities

Energy Information Administration, *Weekly Petroleum Status Report*, DOE/EIA-0208, (Washington, DC)

- Retail price of motor gasoline

Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380, (Washington, DC, most recent and 2 previous months' data)

- Product supplied--No.2 diesel fuel, No.2 fuel oil (industrial sector)
- Price of diesel fuel oil
- Wholesale prices--heating oil, motor gasoline
- Average retail price for kerosene jet fuel

Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109, (Washington, DC, most recent and 2 previous months' data)

- Product supplied--liquefied petroleum gases (excluding ethane), jet fuel (kerosene-type, naphtha-type, total), petrochemical feedstocks, miscellaneous products, crude oil and pentanes plus
- Demand for ethane

Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226, (Washington, DC, most recent and 2 previous months' data)

- Electricity sales
- Electricity generation
- Net imports of electricity
- Consumption of fuels at electric utilities
- Residential electricity price

Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130, (Washington, DC, most recent and 2 previous months' data)

- Natural gas consumption

Energy Information Administration, *Coke and Coal Chemicals*, DOE/EIA-0120, (Washington, DC, most recent and 2 previous months' data)

- Coke production and consumption, and end-of-month coke stocks (December 1977 through December 1980)

Energy Information Administration, *Coke Plant Report*, DOE/EIA-0121, (Washington, DC, most recent and 2 previous months' data)

- Coke production and consumption, and end-of-month coke stocks (January 1981 through December 1981)

Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0121, (Washington, DC, most recent and 2 previous months' data)

- Coke production and consumption, and end-of-month coke stocks
- Net coke imports
- Coking coal demand
- Coal consumption--by industrial users, residential and commercial and total retail and general industry
- Coal production
- Net imports of coal
- Coal exports

Energy Information Administration, Form EIA-860, "Annual Electric Generator Report"

- Coal-fired generating capacity

Energy Information Administration, Form FERC-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants"

- Prices to electric utilities--natural gas, residual fuel, coal

Models and Other:

Energy Information Administration, Economics and Statistics Division, Integrated Modeling Data System

- Residential and commercial demand for distillate
- Electricity generation--wind, wood and waste, geothermal
- Transmission and distribution losses
- Natural gas delivered

Energy Information Administration, internal documents

- Coal consumption by industrial users
- Synfuels-related consumption of coal

P. Output Data: Projections of production, stocks, net imports, and demands for the following major products: motor gasoline, distillate fuel oil, residual fuel oil, jet fuel, liquefied petroleum products, other petroleum products, electricity, natural gas, and coal.

Q. Computing Environment:

Hardware Used: IBM 3084
Operating System: OS/MVS2
Language/Software Used: SAS, Version 6.07
Memory Requirement: 2000K
Storage Requirement: 2000 Tracks
Estimated Run Time: 150 CPU seconds for each simulation

R. Independent Reviews:

Maddala, G.S., "Independent Expert Review of the EIA Short-Term Integrated Forecasting System (STIFS)," University of Florida, Gainesville, FL, May 23, 1991.

Kundra, Inderjit, "Model Quality Audit Short-Term Integrated Forecasting System," Energy Information Administration, Office of Statistical Standards, Washington, DC, July 21, 1992.

Mount, Timothy, "Independent Expert Review of the EIA Short-Term Integrated Forecasting System," Cornell University, Ithaca, NY, May 1991.

Trost, Robert P., "Replication of STIFS and Sensitivity Analysis of STIFS," Energy Information Administration, Office of Statistical Standards, Washington, DC, January 1992.

Trost, Robert P., "A Brief Critique of STIM," Energy Information Administration, Office of Statistical Standards, Washington, DC, May 1992.

Price Forecasting in DOE's Short-Term Integrated Forecasting System. Sitzer, S., Paxson, D., and Gamson,N., Energy Economics, Policy, and Management, Winter 1982

Assessment of the Compliance of Short-Term Integrated Forecasting System (STIFS) Methodology and Model Descriptions with EIA Documentation Standards

Edmonds, James A., "Assessment of the Short-Term Integrated Forecasting System Methodology and Model Descriptions," June 13, 1980.

Kneiser, Thomas J., "Short-Term Integrated Forecasting System (STIFS) Data Base Documentation," December 11, 1980.

S. Status of Evaluation Efforts: Comparisons of forecast to reported values for major projections are published annually in the *Short-Term Energy Outlook Annual Supplement*, DOE/EIA-0202.

T. Bibliography:

Decision Analysis Corporation of Virginia, *Second Quarter STIFS III Update and Evaluation Draft Model Evaluation Report*, July 16, 1992

Decision Analysis Corporation of Virginia, *Short-Term Integrated Forecasting System III: Model Documentation*, December 31, 1991

Decision Analysis Corporation of Virginia, *Unified Demand and Price Analysis Subsystem*, December 1989.

Energy Information Administration, *Model Documentation: Short-Term Integrated Forecasting System Demand Model*, March 1983, DOE/EIA-0391

Energy Information Administration, *Model Documentation: Short-Term Integrated Forecasting System Demand Model*, May 1984, DOE/EIA-0391(84)

Energy Information Administration, *Model Documentation Report: Short-Term Integrated Forecasting System Demand Model 1985*, July 1985, DOE/EIA-M009

Energy Information Administration, *Model Documentation Report: Short-Term Integrated Forecasting System*, June 1986, DOE/EIA-M017

Energy Information Administration, *Short-Term Integrated Forecasting System: 1988 Model Documentation Report*, 1988, DOE/EIA-M030

Energy Information Administration, *Short-Term Integrated Forecasting System: 1990 Model Documentation Report*, 1990, DOE/EIA-M041

Energy Information Administration, *Short-Term Energy Outlook, Methodology*, "An Alternative Integrating Procedure for STIFS," July 1985, DOE/EIA-0202(85/2Q)/2, pp. 77-86.

Kilkeary, Scott, and Associates, Inc., *Short-Term Integrated Forecasting System: Data Base Description*, September 1981

Kilkeary, Scott, and Associates, Inc., *Short-Term Integrated Forecasting System: Model Description*, May 1986

Kilkeary, Scott, and Associates, Inc., *Short-Term Integrated Forecasting System: Model Summary*, May 1986

Kilkeary, Scott, and Associates, Inc., *Short-Term Integrated Forecasting System: Software Description*, May 1986

Kilkeary, Scott, and Associates, Inc., *Short-Term Integrated Forecasting System Operations Manual*, May 1986

Logistics Management Institute, *Short-Term Integrated Forecasting System (STIFS) Methodology and Model Descriptions*, September 1981

MIL Corp., *Short-Term Integrated Forecast System Price Model: User's Manual*, September 1983.

Appendix E

Sources of Exogenous Forecasts

Appendix E

Sources of Exogenous Forecasts

Macroeconomic Variables

The forecasts of exogenous economic variables like gross national product, real disposable personal income, and industrial production indexes, are taken from the DRI/McGraw Hill macroeconomic model. The DRI/McGraw-Hill model is run by EIA's Office of Integrated Analysis and Forecasting, incorporating key oil price and other energy-related assumptions employed in the corresponding STIFS model runs.

U.S. Crude Oil Production

Domestic crude oil production forecasts are prepared by EIA's Office of Oil and Gas, Reserves and Production Branch. Crude oil production estimates for the United States are the sum of the estimates for the lower 48 States and Alaska. Quarterly estimates are done separately for the lower 48 States and Alaska based on the three world oil price cases (low, mid, and high). Crude oil estimates for the various components involved in the oil forecast process are combined in a systematic manner to obtain the results required (Figure E1).

Alaskan Crude Oil Production

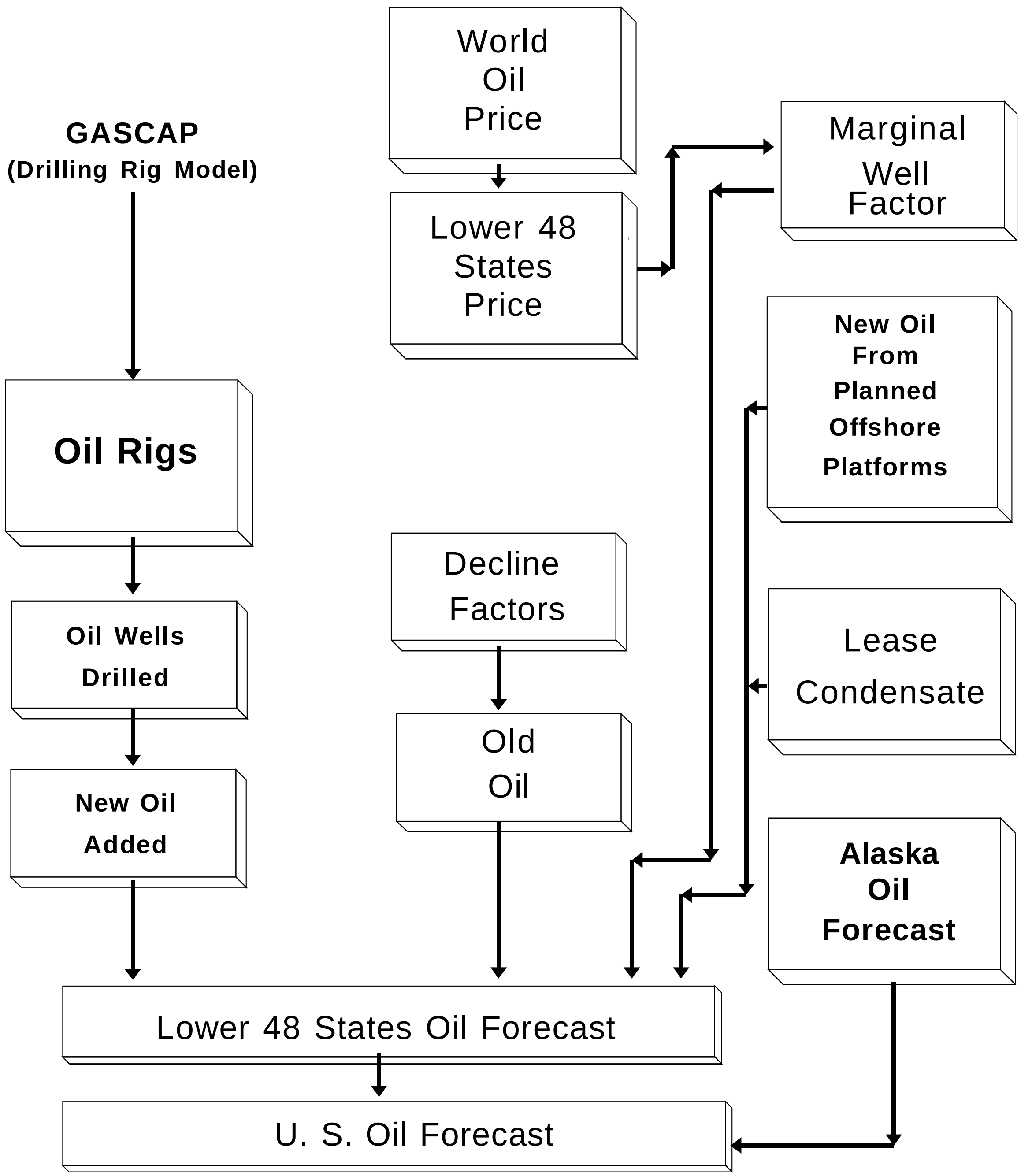
Crude oil production estimates for Alaska consist of individual estimates for the North Slope fields and an estimate for south Alaska fields together. Each quarter, operators of the North Slope fields provide information pertaining to their latest oil production forecasts for the currently active fields and also, if applicable, for new fields that are scheduled to come on production during the forecast period. For example, an operator of the giant Prudhoe Bay field in the North Slope provides a forecast that takes into account new field developments and response from waterfloods, enhanced recovery projects, well stimulations, and recompletions. Furthermore, the forecast is adjusted for downtime due to shutdowns for scheduled maintenance, etc. The expected decline rates for this giant field are varied to account for the difference in the three price cases and also for the uncertainty of the estimates. Monthly estimates of oil production are developed for the remainder of the fields from the operator's information. These are added to the estimates for the giant Prudhoe Bay field to obtain the North Slope totals for the forecast period.

Crude oil production estimates for south Alaska are extrapolated from a least squares fit of the monthly data to an exponential function. The set of data points selected for the fit usually represent the most recent trend. Adjustments to results are made in case interruptions to production are expected during the forecast period. The monthly estimates for the North Slope are further added to the monthly estimates for south Alaska and summarized by quarters to obtain the quarterly estimates for Alaska for the three price cases.

Lower 48 States Crude Oil Production

Estimates of crude oil production (excluding lease condensate) for the lower 48 States are made taking into account such factors as the price of oil, decline rate of old oil, the impact on production from marginal wells, and new oil added by drilling. In addition, new oil expected from the offshore fields

Figure E1. U.S. Oil Forecast Process



scheduled to be placed on production during the forecast period is included in the forecast. Estimates of lease condensate production are also included. Monthly estimates of lease condensate production are based on historical production patterns.

The price of oil for the lower 48 States is estimated for the three price cases by assuming that it will change in the same proportion as the world oil price. Thus, a price path for each of the price cases is established. Crude oil production estimates are prepared for each of the three price cases. An old oil base rate is estimated at the beginning of each forecast year. This oil base rate is declined on a monthly basis based on assumed decline rates for each of the three cases to obtain the old oil estimates.

The impact on production from marginal wells depends on how the crude oil price varies during the forecast period. As the price drops, marginal wells that are no longer economical to operate at the lower price levels are shut-in. Conversely, as the price increases, some marginal wells that were uneconomical to operate at the lower price levels and as a result were shut-in previously are placed anew on production if they become economical to operate at the higher price levels. The loss or gain in production is estimated from a tabulation of the percentage of the lower 48 States production that becomes uneconomical at various price levels. The price levels in the tabulation range from $8 to $25 per barrel and the price interval is $2 except where a $1 interval was used. The data for the tabulation are based on the estimated operating cost data developed for the lower 48 States, individual field data and a range of crude oil prices. The gain in production from marginal wells (increased prices) is derived taking into account that a minimum increase in price of $2 per barrel has to occur before any oil is added back into the production stream. The $2 per barrel of oil price increase is used because it is assumed that it will take capital expenditures to return a well to production and this increase will allow such capital expenditures to be realized in 3 to 6 months. The source of cost data is the report titled *Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations, 1985* by the Energy Information Administration (EIA), and the source for the individual field data is Dwight's Energydata, Inc.

The new oil added depends on the number of new oil wells drilled each year. The number of new oil wells drilled is obtained from an estimate of the number of rigs drilling for oil. Models formulated to predict the number of drilling rigs and the percentage of rigs drilling for gas for the EIA report *Natural Gas Productive Capacity for the Lower 48 States 1982 through 1993* are used to generate monthly estimates of the rigs drilling for oil. These are converted to monthly oil wells drilled based on historical monthly ratios of the number of oil wells drilled to the number of rigs drilling for oil. From the monthly oil wells drilled, the new oil added per month is estimated based on a set contribution per new oil well. A description of the drilling rig and percentage gas rigs models follows.

A model was formulated to predict the number of drilling rigs from oil and gas income. The model generates monthly rig counts from January 1984 through history and into the immediate future (2 to 3 years). In addition to oil and gas incomes, a term to account for seasonality is included in the model.

Oil income is used as a daily rate each month and is calculated by multiplying the lower-48 daily oil production by the world oil price. Gas income is calculated in the same manner. Lower-48 daily gas production is multiplied by the U.S. average gas price to obtain the gas income. Prices are adjusted to constant dollars using the gross domestic product (GDP) deflator. Both income streams are exponentially smoothed prior to being used in the model.

The model formulation is as follows:

$$Rigs_i = Sn * b * \left[(SOI_i)^d + a * \left(\left(\frac{\sum_{i-24}^{i-12} GI}{12} \right) * \left(\frac{SGI_i}{SGI_{i-12}} \right) \right)^d \right] \tag{E1}$$

where	Rigs	=	the total number of rigs drilling for oil and gas
	SOI	=	smoothed oil income
	SGI	=	smoothed gas income
	GI	=	gas income
	Sn	=	seasonality factor (equation E4)
	i	=	current month
	a,b,d	=	constants

Oil income and gas income are exponentially smoothed using the following equation:

$$SI_i = I_i * \alpha + SI_{i-1} * (1 - \alpha) \tag{E2}$$

where	SI	=	smoothed income
	I	=	income
	α	=	exponential smoothing coefficient
	i	=	current month
	α_{SGI}	=	constant exponential smoothing coefficient for smoothed gas income.

The exponential smoothing coefficient for oil income is determined by the following equation:

$$\alpha_{SOI_i} = \frac{2}{2 + [h * \exp^{\left(c * \left((SOI6_i - SOI6_{i-2}) - |SOI6_i - SOI6_{i-2}|\right)\right)}]} \tag{E3}$$

where	c,h	=	constants
	SOI6	=	smoothed oil income with a constant exponential smoothing coefficient of 0.2857 (equivalent to a 6 month smoothing)
	i	=	current month.

A seasonality factor was calculated for each month in the following manner:

$$
\begin{aligned}
&Sn_{i=1} = f \quad \textit{for January}\\
&Sn_{i=2} = f + \frac{l}{2^{i-1}} \quad \textit{for February}\\
&Sn_{i=3} = f + \frac{l}{2^{i-2}} + \frac{l}{2^{i-1}} \quad \textit{for March}\\
&Sn_{i=4} = f + \frac{l}{2^{i-3}} + \frac{l}{2^{i-2}} + \frac{l}{2^{i-1}} \quad \textit{for April}\\
&Sn_{i=5,11} = Sn_{i=4} + j*(i-4) \quad \textit{for May thru November}\\
&Sn_{i=12} = Sn_{i=11} + \frac{j}{3} \quad \textit{for December}
\end{aligned}
\qquad \text{(E4)}
$$

where Sn = the 12 different seasonality factors for January through December
i = 1 through 12 for the corresponding months January through December
f,j,l = constants

The Solver routines contained in a personal computer spreadsheet file are used to determine simultaneously the values for all the parameters in equations E1 through E4. To define the parameter values, Solver is required to minimize the sum of the squares of the differences between the actual and estimated number of drilling rigs. Equation E1 was given a condition that the number of rigs drilling for gas determined by the gas income term had to be at least 25 percent of the total rigs determined by equation E1 each month.

To normalize or benchmark the model data to the actual data, all parameters are fixed except for the multiplier *b*. Solver is run again but only over the last 12 months. The new "benchmarked" value for *b* is determined. Benchmarked model data are used for the forecast period.

Oil and gas production for the current forecast period are taken from the previous *Short-Term Energy Outlook* (*Outlook*) oil forecast, while the prices are those projected for the current *Outlook* forecast period. The mid case gas production forecast from the previous *Outlook* gas forecast is decreased by 4 percent for the low case gas production forecast and is increased by 4 percent for the high case gas production forecast.

A model was formulated to determine the percentage of rigs drilling for gas. The model uses oil and gas income and a special factor to handle coalbed methane and tight gas sand drilling. Historical data start in January 1984 through the latest month for which a rig count is available. Monthly percentages are determined from monthly income values for the time period January 1984 through the end of the forecast period.

Oil income is used as a daily rate each month and is calculated by multiplying the lower-48 daily oil production by the world oil price. Gas income is calculated in the same manner. Lower-48 daily gas production is multiplied by the U.S. average gas price to obtain the gas income. Prices are adjusted to constant dollars using the GDP deflator. Both income streams are exponentially smoothed prior to being used in the model.

The percent gas rigs model is as follows:

$$GRR_i = \left[a + e*(SOI_{i-1}) + \left(\left(d*(SGI_{i-1}) + f*\left(\frac{GI3_{i-1} - GI3_{i-13}}{GI3_{i-13}} \right) \right) *(1+b) \right) \right] *100 \tag{E5}$$

where	GRR	=	gas rig ratio as a percent
	SOI	=	smoothed oil income
	SGI	=	smoothed gas income
	GI3	=	3-month running average of gas income
	α_{SGI}	=	constant exponential smoothing coefficient for gas income
	α_{SOI}	=	constant exponential smoothing coefficient for oil income
	b	=	constant coalbed methane and tight gas sand drilling factor (1+*b*)
	a,d,e,f	=	constants
	i	=	current month.

The Solver routines contained in the spreadsheet are used to determine simultaneously values for all the parameters in equation E5. To define the parameter values, Solver is required to minimize the sum of the squares of the differences between the actual and estimated gas rig ratios. All parameters are determined for the time period from January 1984 through the latest month for which a rig count is available.

Because of increasing tax credits, coalbed methane and tight gas sand drilling started to become a significant portion of gas well drilling in 1988. The coalbed methane and tight gas sand drilling factor (1+*b*) is first applied in January 1988 at 1/24 its full value. The factor grows linearly until it reaches its full value in December 1989 (24 months). The factor remains at full value until January 1993 when it is reduced by half. It remains at half value for the rest of the forecast period.

The model data are normalized or benchmarked to the actual data. The model data are spliced to the actual data at the latest month for which a rig count is known. The splicing ratio is applied to the model data for the forecast period. Benchmarked model data are used for the forecast period.

Oil and gas production for the current forecast period are taken from the previous *Outlook* oil forecast, while the prices are those projected for the current forecast period. Three scenarios are used to forecast the percent gas rigs: a mid case, a low case, and a high case. The mid case gas production forecast from the previous *Outlook* gas forecast is decreased by 4 percent for the low case gas production forecast and is increased by 4 percent for the high case gas production forecast.

Crude oil estimates for each of the components (old oil, new oil, condensate, marginal wells, and new offshore fields if applicable) are added and summarized by quarter to obtain the estimates for all three price cases. In addition, crude oil production estimates for the low and high price cases contain an uncertainty component as well as a component due to price impacts. The uncertainty component was introduced in order to have the low and high cases generally cover the likely range of crude oil production estimates during the forecast period. The two basic types of uncertainties applicable to the low and high price cases are those associated with the current production level and those associated with the timing of expected events such as the onset of production from a relatively large field. The uncertainty portion (associated with the current production level) for the estimates results by varying the low and high price case oil production estimates (plus for the high case and minus for the low case) by an amount equal to 1 percent of the latest known quarterly rate of oil production and declining that amount throughout the forecast period.

Crude Oil Prices

The Oil Market Simulation (OMS) model is used by EIA's Energy Markets and Contingency Information Division to help determine the price of imported crude oil by benchmarking the forecasts to the most recent available data. The domestic crude oil price for the forecast period is assumed to be equal to the imported oil price. The composite refiner acquisition cost of crude oil, a weighted average of imported and domestic crude oil costs, is assumed to be equal to the cost of imported crude oil.

Electricity Supply

Forecasts for nuclear and hydroelectric generation and coal production, coal imports, and coal exports are generated independent of the STIFS model by the EIA Office of Coal, Nuclear, Electric, and Alternate Fuels.

Nuclear Power Electricity Generation

The Short-Term Nuclear Annual Power Simulation (SNAPPS) model produces forecasts of electricity generation by U.S. commercial nuclear power plants. The SNAPPS model is sponsored and maintained by the Analysis and Systems Division (ASD), Office of Coal Nuclear, Electric and Alternate Fuels, Energy Information Administration (EIA), U.S. Department of Energy (DOE).

SNAPPS is a relatively simple, straightforward accounting model programmed in FORTRAN; it does not contain any stochastic features. The model consists of code that provides accounting for each nuclear reactor's generation over the projection period. It does this by developing reactor activity schedules, determining if the reactor is generating power or is shutdown for an extended period. Individual reactor monthly generation is computed using the central equation in SNAPPS:

$$\text{NUEOPUS} = \text{CAPACITY} * \text{CAPACITY FACTOR} * \text{TIME}$$

NUEOPUS is the individual reactor monthly generation. CAPACITY is the net summer capability value for the reactor from Form EIA-860, "Annual Electricity Generator Report." CAPACITY FACTOR is the ratio of the kilowatthours the reactor is expectd to generate during a month to the total number of kilowatthours of generation in a month. For the near term, about six months, the values are calculated in a preprocessor that estimates system-wide monthly capacity factors by applying time-series techniques to historical data. For the remainder of the projection period, SNAPPS uses estimates of average, full-cycle capacity factors based on reactor type (BWR or PWR) and fuel cycle (1st, 2nd, or equilibrium). The SNAPPS system adjusts the full cycle capacity factors for seasonality (monthly perturbations) and longer-term trends (annual adjustments) to obtain monthly capacity factors. The TIME variable is the number of hours in the month.

SNAPPS calculates each reactor's electricity generation for each month in the forecast period. The resulting reactor generation values are then cumulated into monthly, annual and regional totals.

The SNAPPS system establishes a decision hierarchy for calculating electricity generation as follows:

- For months for which it is available, SNAPPS uses historical electricity generation, by reactor, month, and year. The data are obtained by direct access to the generation data reported on the Form EIA-759.

- When historical data are not available, SNAPPS employs system-wide monthly capacity factors. These values are developed from information on expected refueling outages or major maintenance outages of each reactor gathered from sources at the Nuclear Regulatory Commission (NRC), trade press and direct utility contacts.

- If neither historical data nor information to support monthly capacity factors are available, SNAPPS uses generic capacity factors categorized by reactor type and cycle. These values are derived from an analysis of historical nuclear capacity factors.

The estimates of operable dates for new units are based on utility schedules, NRC licensing schedules, information from the industry press, and historical construction schedule dates.

Hydroelectric Generation

Hydroelectric generation is forecast exogenously. For each month during the current water year, which ends September 30, or a nine-month period from presently available data if longer, hydroelectric generation projections are based upon information obtained from a sample of utilities representing eight U.S. geographic regions. Generation in each region is projected to change by the same percentage as generation for the sample. That is, estimations for each of the forecast months are determined by calculating a monthly ratio of each utility's projected generation to its actual generation in the past year. This ratio is applied to the region's generation for the previous year to arrive at a projected value for the corresponding month of the current year. The regional projections are aggregated to obtain a national projection for generation. The results achieved by this approach are assessed based on historically observed month-to-month patterns or other factors, such as precipitation, weather, demand, or market conditions.

Hydroelectric generation in the succeeding years is assumed to be normal. Normal generation is calculated for conventional and pumped storage units by using capacity information from the Form EIA-860, "Annual Electric Generator Report," and historical monthly capacity factors averaged over ten years.

Region	State
1	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont, New Jersey, Delaware, District of Columbia, New York, Pennsylvania.
2	Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, W. Virginia, Tennessee, Alaska, Hawaii
3	California
4	Nevada, Utah, Arizona, Colorado, New Mexico
5	Washington, Oregon, Idaho
6	Minnesota, Iowa, Kansas, Oklahoma, Texas, Wisconsin, Illinois, Missouri, Arkansas, Louisiana, Michigan, Ohio, Indiana
7	Montana, Wyoming
8	North Dakota, South Dakota, Nebraska

Net Electricity Imports

International electricity trade projections are based on existing firm and interruptible contracts of U.S. and Canadian utilities that import or export electricity. Firm power contracts are identified from publications prepared by the Department of Energy's Office of Fuels Programs and the Canadian National Energy Board, as well as resource plans of U.S. and Canadian utilities. Current water and economic conditions in both the United States and Canada and discussions with U.S. and Canadian utilities are used in conjunction with terms specified in existing contracts to estimate interruptible trade and exchanges of electricity.

Electric Utility Power Purchases from Nonutilities

Utility purchases from nonutilities include all receipts of electricity by utilities from generators that are not utilities. Nonutilities include firms which generate electricity for sale to utilities and/or for their own consumption. They include independent power producers, cogenerators, and small power producers. Many are "qualifying facilities" (QF) under the Public Utility Regulatory Policies Act of 1978 (PURPA, P.L. 95-617), which requires utilities to purchase the power that QFs generate.

The Energy Information Administration (EIA) estimates utility purchases from nonutilities in a year to be the total sales to utilities in the prior year as reported on the Form EIA-861, "Annual Electric Utility Report," or estimated by EIA, plus the estimated sales from planned capacity additions for the forecast year as reported on the Form EIA-867, "Annual Nonutility Power Producer Report." A small percentage increase is also added to account for increases in output over time. Quarterly estimates are based on the previous year's distribution of utility purchases from nonutilities as reported by the Edison Electric Institute.

Coal Production, Imports, and Exports

Forecasts for coal production, coal imports, and coal exports are also generated independent of the STIFS model by the EIA Office of Coal, Nuclear, Electric and Alternate Fuels. The short-term quarterly projections of coal production, imports, and exports for 6 to 8 quarters are made by using the Short-Term Coal Analysis System (SCOAL).

Total Coal Production

Total U.S. coal production is derived as the sum of two separate estimates, one for anthracite and the other for bituminous coal and lignite. The equations for estimating coal production are given below.

Anthracite Production

Although anthracite accounts for a very small portion of total U.S. coal production (about 3 percent in 1992), it is separately estimated from bituminous coal and lignite production. The equation for anthracite production is estimated as a function of a one-period lag of the dependent variable, a time trend, and seasonal dummy variables. The structural specification is:

$$LACP_t = B_1DQ_1 + B_2DQ_2 + B_3DQ_3 + B_4DQ_4 + B_5TIME_t + B_6LACP_{t-1} \qquad \text{(E6)}$$

where:

$LACP_t$	= Anthracite coal production in thousand short tons
DQ_1	= Quarterly dummy variable = 1 in selected quarter i, 0 otherwise; i = 1,2,3,4
TIME	= Time variable that has an increasing value of 1 per quarter, starting with the first quarter of 1973 equal to 1
B_1, ... B_6	= Regression coefficients

Bituminous Coal and Lignite Production

Bituminous coal and lignite account for almost all of the coal produced in the United States (97 percent in 1992). Bituminous coal and lignite production is estimated as a function of a one-period lag of coal production, relative prices of coal to oil, seasonal dummy variables, and relevant coal strike dummy variables.

$$LCPTOT_t = B_1DQ_1 + B_2DQ_2 + B_3DQ_3 + B_4DQ_4 + B_5LCPTOT_{t-1} + B_6LPRTO_t + B_7STRIKE3 + B_8PS3 + B_9D824 + B_{10}D833 + B_{11}NS843 + B_{12}NS844 \quad (E7)$$

where:

$LCPTOT_t$	= Bituminous coal and lignite production in thousand short tons
DQ_1	= Quarterly dummy variable = 1 in selected quarter i, 0 otherwise; i = 1,2,3,4
LPRTO	= The ratio of the delivered price of coal to the delivered price of oil for electric utilities in cents per million Btu.
STRIKE3	= A dummy variable that has a value of 1 in the second quarter of 1981 and a value of 0 otherwise
PS3	= A dummy variable that has a value of 1 in the third quarter of 1981 and a value of 0 otherwise, representing post strike period
D824	= A dummy variable that has a value of 1 in the fourth quarter of 1982 and a value of 0 otherwise
D833	= A dummy variable that has a value of 1 in the third quarter of 1983 and a value of 0 otherwise
NS843	= A dummy variable for the pre-strike buildup in production in the third quarter of 1984 in anticipation of a UMWA strike that has a value of 1 in that quarter and a value of 0 otherwise
NS844	= A dummy variable for the non-strike slowdown in production in the fourth quarter of 1984 (when a contract was signed without a strike) that has a value of 1 in that quarter and a value of 0 otherwise
B_1,... B_{12}	= Regression coefficients

Total U.S. coal production is calculated as $LACP_t + LCPTOT_t$

Coal Imports

Coal imports into the United States are a small percentage of domestic coal consumption (about 0.4 percent in 1992) but have been increasing during the past few years. U.S. coal imports are estimated in SCOAL as a function of a one-period lag of coal imports, seasonal dummy variables, and relevant strike dummy variables.

The estimating equation for U.S. coal imports used within SCOAL is as follows:

$$LCIM_t = B_1DQ_1 + B_2DQ_2 + B_3DQ_3 + B_4DQ_4 + B_5LCIM_{t-1} + B_6D893 + B_7CCAL \quad (E8)$$

where:

$LCIM_t$	= U.S. Coal imports in thousand short tons
DQ_1	= Quarterly dummy variable = 1 in selected quarter i, 0 otherwise; i = 1,2,3,4
D893	= A dummy variable for coal strike in the third quarter of 1989, with a value of 1 in that quarter and 0 otherwise
CCAL	= Model calibration dummy variable that has a value of 1 in the third quarter of 1992 and a value of 0 otherwise
B_1, ... B_7	= Regression coefficients

Coal Exports

U.S. metallurgical and steam coal exports are estimated separately in order to take into account their different characteristics. Estimates of total coal exports are then derived as the sum of the two separate estimates.

Steam Coal Exports

Steam coal exports accounted for 42 percent of total U.S. coal exports in 1992. The model estimates steam coal exports separately to Canada, the Far East, and the rest of the world. The results from these three equations are then summed to obtain total U.S. steam coal exports.

The equation for steam coal exports to Canada is an ordinary least squares equation specified as a seasonal model, with dummy variable for low hydroelectric generation whenever it has occurred. The structural specification is:

$$LCSCEXP_t = B_1DQ_1 + B_2DQ_2 + B_3DQ_3 + B_4DQ_4 + B_5OHYDRO \qquad (E9)$$

where:

$LCSCEXP_t$	= Steam coal exports to Canada in thousand short tons
DQ_1	= Quarterly dummy variable = 1 in selected quarter i, 0 otherwise; i = 1,2,3,4
OHYDRO	= Dummy variable that has a value of 1 in the first quarter of 1987 and 1989 when low hydropower was available and a value of 0 otherwise
B_1, ... B_5	= Regression coefficients

Steam coal exports to the Far East are estimated as a function of seasonal dummy variables, the ratio of U.S. coal export price to the Far East (F.A.S.) to Indonesian crude oil price (F.O.B.), and a dummy variable representing the drop in crude oil price in 1986 through 1988.

$$LFSCEXP_t = B_1LFIPRICE + B_2DQ_1 + B_3DQ_2 + B_4DQ_3 + B_5DQ_4 + B_6COPD + B_7CCAL \qquad (E10)$$

where:

$LFSCEXP_t$	= Steam coal exports to the Far East in thousand short tons
DQ_1	= Quarterly dummy variable = 1 in selected quarter i, 0 otherwise; i = 1,2,3,4
LFIPRICE	= Price ratio of the F.A.S. price of steam coal exports per million Btu to the F.O.B. price of crude oil per million Btu.
COPD	= Dummy variable for crude oil price drop that has a value of 1 in the quarters of 1986 through 1988 and a value of 0 otherwise
CCAL	= Model calibration dummy variable that has a value of 1 in the third quarter of 1992 and a value of 0 otherwise
B_1, ... B_7	= Regression coefficients

Steam coal exports to the rest of the world are estimated as a function of the ratio of U.S. coal export price to other countries (F.A.S.) to Saudi Arabian crude oil price (F.O.B.) and disruptions in foreign countries such as Iraq.

$$LOSCEXP_t = B_1LOSPRICE_t + B_2PD + B_3COL + {}_4DIRAQ + B_5CCAL1 \qquad (E11)$$

where:

$LOSCEXP_t$	= Steam coal exports to the rest of the world in thousand short tons
$LOSPRICE_t$	= Price ratio of the F.A.S. price of steam coal exports per million Btu to the F.O.B. price of crude oil per million Btu.

PD = Dummy variable for labor problems in Poland and Australia that has a value of 1 in the first quarter of 1981 through the second quarter of 1982, a value of 0.5 in the third and fourth quarter of 1982, and a value of 0 otherwise

COL = A dummy variable for rapidly increasing exports from Colombia that has a value of 0 through 1984, 0.5 for 1985, and 1 for the rest of the estimation period.

DIRAQ = Dummy variable representing Iraq's invasion of Kuwait with a value of 1 in the third quarter 1990, a value of 0.75 in the fourth quarter 1990 and a value of 0 otherwise

CCAL1 = Model calibration dummy variable that has a value of 1 in the third quarter of 1992 and a value of 0 otherwise

$B_1, \ldots B_5$ = Regression coefficients

Metallurgical Coal Exports

Metallurgical coal exports accounted for about 58 percent of total U.S. coal exports in 1992. Like steam coal exports, the model divides the metallurgical coal exports sector into the same three regions: Canada, the Far East, and the rest of the world. Total U.S. metallurgical coal exports are derived as the sum of the three regional estimates.

The equation for metallurgical coal exports to Canada is estimated as a function of seasonal variation, a strike period dummy variable, representing a UMWA strike that occurred in the second quarter of 1981, and a dummy variable for the first quarter 1985 when coal exports to Canada were zero. The structural specification is:

$$LMCEXC_t = B_1DQ_1 + B_2DQ_2 + B_3DQ_3 + B_4DQ_4 + B_5D851 + B_6STRIKE3 \qquad (E12)$$

where:

$LMCEXC_t$ = Metallurgical coal exports to Canada in thousand short tons

DQ_1 = Quarterly dummy variable = 1 in selected quarter i, 0 otherwise; i = 1,2,3,4

D851 = Dummy variable for zero coal exports to Canada in the first quarter of 1985, with a value of 1 in that quarter and 0 otherwise

STRIKE3 = A dummy variable for UMWA strike that has a value of 1 in the second quarter of 1981 and a value of 0 otherwise

$B_1, \ldots B_6$ = Regression coefficients

Metallurgical coal exports to the Far East are estimated as a function of seasonal dummy variables and relevant dummy variables representing labor problems in Australia, the main supplier of coal to the Far East.

$$LMCEXA_t = B_1DQ_1 + B_2DQ_2 + B_3DQ_3 + B_4DQ_4 + B_5PD80 + B_6PD81 + B_7CCAL1 \qquad (E13)$$

where:

$LMCEXA_t$ = Metallurgical coal exports to the Far East in thousand short tons

DQ_1 = Quarterly dummy variable = 1 in selected quarter i, 0 otherwise; i = 1,2,3,4

PD80 = Dummy variable for Australian labor problems that has a value of 1 in the second through fourth quarters of 1980 and a value of 0 otherwise

PD81 = Dummy variable for Australian labor problems that has a value of 1 in the third quarter of 1981 through the first quarter of 1982 and a value of 0 otherwise

CCAL1 = Model calibration dummy variable that has a value of 1 in the third quarter of 1992 and a value of 0 otherwise

$B_1, \ldots B_7$ = Regression coefficients

Metallurgical coal exports to the rest of the world are estimated, using a least squares equation, as a function of French and Italian pig iron production and a coal strike dummy variable for Poland.

$$LMCEXRW_t = B_1STRIKE3 + B_2LEUIRN_t + B_3PDON + B_4CCAL \quad \text{(E14)}$$

where:

$LMCEXRW_t$	= Metallurgical coal exports to the rest of the world in thousand short tons
STRIKE3	= Dummy variable for UMWA strike that has a value of 1 in the second quarter of 1981 and a value of 0 otherwise
$LEUIRN_t$	= Combined estimate of the French and Italian pig iron production in thousands of metric tons per quarter
PDON	= Dummy variable for disruption in the Polish coal supplies that has a value of 1 in the second quarter of 1982, a value of 0.5 in the third quarter of 1982 through the second quarter of 1983, and a value of 0 otherwise
CCAL	= Model calibration dummy variable that has a value of 1 in the third quarter of 1992 and a value of 0 otherwise
B_1, ... B_4	= Regression coefficients

Appendix F

References

Appendix F

References

1. American Iron and Steel Institute, *Annual Statistical Report*, 1984, Washington, DC, June 1985.

2. American Iron and Steel Institute, *Raw Steel and Pig Iron Production Reports* (AIS-7), Washington, DC, monthly reports.

3. DRI/McGraw-Hill, U.S. Central Data Base, Washington, DC.

4. U.S. Department of Commerce, National Oceanic and Atmospheric Administration, *Monthly State, Regional, and National Heating/Cooling Degree-Days Weighted by Population*, National Climatic Center, Asheville, North Carolina, monthly issues.

5. U.S. Department of Commerce, Bureau of Economic Analysis, *National Income and Product Accounts of the United States*, Washington, DC, monthly issues.

6. U.S. Department of Commerce, *Report FT-410, Commodity by Country*, Schedule E and Schedule B, Washington, DC, monthly issues.

7. U.S. Department of Commerce, *Report FT-546, Commodity by Country*, Schedule B, Washington, DC, monthly issues.

8. U.S. Department of Energy, Energy Information Administration, Form EIA-860, *Annual Electric Generator Report*.

9. U.S. Department of Energy, Energy Information Administration, *Coke and Coal Chemicals*, Washington, DC, monthly issues, December 1977 through December 1980.

10. U.S. Department of Energy, Energy Information Administration, *Coke Plant Report*, Washington, DC, quarterly issues, January 1981 through December 1981.

11. U.S. Department of Energy, Energy Information Administration, *Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations*, DOE/EIA-0185, Washington, DC.

12. U.S. Department of Energy, Economic Regulatory Administration, *Electricity Transactions Across International Borders--1984*, DOE/RG-0066, Washington, DC, October 1985.

13. U.S. Department of Energy, Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226, monthly issues.

14. U.S. Department of Energy, Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035, Washington, DC, monthly issues.

15. U.S. Department of Energy, Energy Information Administration, from Federal Energy Regulatory Commission Form 423, *Monthly Report of Cost and Quality of Fuels for Electric Plants*, monthly reports.

16. U.S. Department of Energy, Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130, monthly issues.

17. U.S. Department of Energy, Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380, monthly issues.

18. U.S. Department of Energy, Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109, monthly issues.

19. U.S. Department of Energy, Energy Information Administration, *Quarterly Coal Report*, Washington, DC, quarterly issues.

20. U.S. Department of Energy, Energy Information Administration, *Short-Term Energy Outlook, Annual Supplement*, DOE/EIA-0202, Washington, DC, annual issues.

21. U.S. Department of Energy, Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202, Washington, DC, quarterly issues.

22. U.S. Department of Energy, Energy Information Administration, *Weekly Petroleum Status Report*, DOE/EIA-0208, weekly issues.

23. U.S. Department of Labor, Bureau of Labor Statistics, *Monthly Labor Review*, Washington, DC, monthly issues.

24. U.S. Department of Labor, Bureau of Labor Statistics, *Consumer Prices--Energy and Food*, Washington, DC, monthly press release, Table 3.

25. U.S. Department of Labor, Bureau of Labor Statistics, *Employment and Earnings*, Washington, DC, monthly issues.

26. U.S. Department of Labor, Bureau of Labor Statistics, *Producer Price Index*, Washington, DC, monthly issues.

27. U.S. Department of Transportation, Federal Highway Administration, Highway Statistics Division, *Traffic Volume Trends*, Washington, DC, monthly issues.

28. U.S. Federal Reserve System, Board of Governors, *Statistical Release G 17*, Washington, DC, monthly issues.

Appendix G

Alternative R-squared Measures

Appendix G

Alternative R-squared Measures

The standard measure of how well a model fits the data is R-squared. It is usually interpreted as the proportion of the variation in Y, the dependent variable, that is explained by the X's, the independent, or explanatory, variables. However, using this measure to evaluate time series regressions can be misleading. This is most clearly seen by using an alternative interpretation in which R-squared is viewed as a comparison of two models, the proposed explanatory model and a benchmark model which assumes that Y is a constant.

The problem arises from the fact that time series commonly have a trend or seasonal variation. In such cases it is easy to see that the choice of a constant Y as a benchmark is a poor one and will tend to provide the analyst with an inflated notion of the quality of the explanatory model. Any variable which has a trend of its own will correlate with the trend of the dependent variable and appear to explain some of it's variation. It is irrelevant whether or not there is any theoretical connection between the two. For example, a completely artificial variable generated by a random walk with drift will 'explain' some of the variation in any trending series. Thus, to adequately measure the quality of an explanatory time series model, a better choice for the benchmark model is needed; one that will pick up some of the trend and seasonal components. In the STIFS model the benchmarking takes one of two forms. When the dependent variable has been deseasonalized, the benchmark model sets Y equal to lagged-Y plus an estimated constant term. Otherwise, Y is set equal to lagged-Y plus estimated seasonal dummy variables (i.e., a constant term and eleven monthly dummy variables, or no constant and twelve monthly dummies).

The alternative R-squared value can be calculated either directly from the definition of the R-squared measure, or from the normal R-squared measures reported in all statistical software packages. Using the definition, the alternative R-squared is one minus the ratio of the sums-of-squared errors for the explanatory and benchmark models,

$$R^2(\text{alt}) = 1 - \frac{SSE(X)}{SSE(B)}$$

where X refers to the explanatory model and B refers to the benchmark model. If $R^2(X)$ is the reported normal R-squared from the explanatory model regression and $R^2(B)$ is the normal R-squared for the benchmark model, then the alternative R-squared can also be represented as

$$R^2(\text{alt}) = \frac{R^2(X) - R^2(B)}{1 - R^2(B)}$$

If the alternative R-squared measure is negative, it means the benchmark model outperformed the explanatory model. For purposes of forecasting one may want to substitute the benchmark forecasts while the explanatory model is being examined for possible improvements. The table below presents the alternative R-square values for the equations in STIFSIII, along with an F-statistic as a crude indicator of the reliability of the result. The higher the F-value, the more likely it is that the alternative R-square has the correct sign (in practice, an F-value greater than 1.3 usually can be considered a reliable result).

As indicated in the table below, 17 of the 93 equations in STIFSIII have a negative alternative R-square value (about half have since been revised to correct this problem). Of those, 11 have an F-statistic greater than 1.3, indicating that the problem cannot be attributed to an unfortunately bad sample. However, there is one further caution to be noted. If the benchmark model does very well, the alternative R-square will make the problem look much worse than it is. For example, the equation for NGNRPUSA has an alternative R-square of -7.91, with an F-statistic of 9.36; it looks like a terrible fit. However, the R-square for the explanatory equation is .99. It is probably not worth expending much effort in trying to improve an equation that has so little room for improvement.

Alternative R-squared Measures for the STIFSIII System

Variable	Alt(R^2)	F	Variable	Alt(R^2)	F
RSPRPUSA	.0636	1.04	ESRCUUSA	.2309	1.20
CLHCPUS	.3657	1.53	NGCCUUSA	.2860	1.33
CLXCPUS	.2574	1.31	NGEUDUSA	.4922	1.89
DSTCPUS	-.8309	-1.67	NGWPUUS	.5942	2.39
DFHCPUS	.4288	1.72	NGRCUUSA	.2996	1.35
DFICPUS	.5354	2.09	NGSPUUS	.3698	1.48
DFACPUS	.3880	1.61	MGUCUUSA	.8153	5.31
CLEOPUS	.9126	10.98	JKTCUUSA	.6926	3.14
ESCMPUSQ	.3759	1.55	WP57IUS	.8090	5.77
ESICPUSB	.2911	1.38	DSTCUUSA	.8420	6.01
ESRCPUSQ	-.8125	-1.73	D2RCUUSA	.7915	4.66
TDLOFUSB	.1883	1.22	D2WHUUSA	.6518	2.79
ESOTPUSQ	-.0783	-1.11	MGWHUUSA	.6809	3.01
CLEUPUS	.9756	40.50	RFTCUUS	.6457	2.72
WNEOPUS	.1069	1.10	PRTCUUSA	.1494	1.14
NGEOSHRX	.1821	1.19	RFNUPUS	.5493	2.24
WWEOPUS	.0427	1.02	CONXPUS	.2353	1.41
GEEOPUS	-.6137	-1.40	CORIPUSJ	.2085	1.21
EFFSA	.4214	1.69	NLPRPUS	-1.6909	-2.50
LDRYLD	.0519	1.03	PRPSPUS	-3.8309	-4.44
LDRZM	.0937	1.07	D2WHPUS	-.9098	-1.72
LDRTM	.3333	1.44	JKESPUS	-2.0070	-2.68
PRTCPUS	.8612	7.10	MGWHPUS	.4367	1.99
LXTCPUSA	.4858	1.89	PRESPUS	-1.1562	-1.96
ETTCPUSA	.2107	1.21	RFESPUS	.1683	1.32
MPGA	.5229	2.00	DFROPUSA	.6268	2.62
MUTCSUS	-.2222	-1.21	JFROPUSA	.2810	1.34
MVVMPUSA	.2667	1.33	MGROPUSA	.6700	2.96
LSMIS	.4649	1.75	RFROPUSA	.2025	1.24
LSFET	.2502	1.30	LGROPUSA	.0439	1.02
NGACPUS	.0771	1.16	LGRIPUSA	.1901	1.21
NGMPPUS	.9979	514.50	PPRIPUSA	.3685	1.55
NGPRPUSZ	.2784	1.37	PSRIPUS	.5027	2.11
BALIT	.3976	1.65	PSROPUSA	.5562	2.21
NGEXPUS	-.0459	-0.99	UORIPUSJ	.2872	1.38
NGWGPUSX	.4011	1.64	COEXPUS	.4709	1.87
NGWSPUS	.5477	2.19	DFEXPUS	.2062	1.25
NGIMPUSZ	.1313	1.12	JFEXPUS	.3401	1.49
NGCCPUSX	-.0538	-1.06	LGEXPUS	.1917	1.24
NGLPPUS	.2667	1.48	MGEXPUS	-.0392	-1.05
NGRCPUSX	-.3306	-1.27	PPEXPUS	.0772	1.07
NGINPUSZ	-.3951	-1.44	PSEXPUS	.3442	1.51
NGSFPUS	.2916	1.41	RFEXPUS	.3195	1.47
NGNCPUSA	-36.5556	-39.44	COLOPUS	.4771	1.91
NGNRPUSA	-7.9091	-9.36	CODIPUSJ	.9720	39.09
NGICUUSA	.1869	1.20	PPPSPUS	.0394	1.04
CLEUDUSA	.1512	1.13			

Appendix H

Refined Product Supply Model

Appendix H

Refined Product Supply Model

Introduction

This appendix describes a theoretically consistent model of short-run petroleum product markets that is being tested for use in STIFS forecasting and policy analysis of monthly developments in oil markets.[1] The model is designed to predict refinery inputs, inventories and prices in wholesale petroleum product markets.

One of the key features of petroleum refining is joint production. Therefore, a multiproduct formulation is adopted. Five product aggregates are examined: gasoline, distillate, residual fuel, jet fuel, and other petroleum products.

The economic model is derived assuming firms minimize variable costs subject to stocks of quasi-fixed factors. The conditional cost minimization problem can be modeled in a variety of ways. For instance, Ramey (1989, 1991), Pindyck (1991) and Considine (1992) specify a dynamic optimization problem and estimate Euler equations. This approach permits considerable flexibility in specifying expectations. One disadvantage, however, is that solving for fixed factors is very difficult if there are curvature violations. Consequently, this study derives partial adjustment equations for stocks using the dynamic duality methods developed by Epstein and Denny (1983). This raises the odds of successful model simulation but does so at the cost of assuming static expectations.

The Theoretical Framework section derives the key behavioral equations in the model. In the Model Formulation section, the estimating equations and parameter restrictions are derived. In the Econometric Results section, the econometric results of model estimation are presented.

Theoretical Framework

Many researchers have exploited the duality between cost and production functions to derive output supply and input demand functions consistent with either cost minimization or profit maximization. Following the early work by Lucas (1967) and Treadway (1971) on the flexible accelerator model, McLaren and Cooper (1980) and Epstein and Denny (1983) have extended the dual approach to dynamic problems.

A dynamic problem often embodies the distinction between the short-run when some factors of production are fixed and the long-run when all factors can adjust to their equilibrium levels. Adjustment costs are often claimed as the reason for this dichotomy. These costs are not generally observed and so are often expressed as the reduction in output resulting from diverting resources within the firm to change quasi-fixed factors of production.

[1] Considine, Timothy J., "Refined Product Supply Module for EIA's Short-Term Integrated Forecasting System Version III (STIFS-III)," (The Washington Consulting Group, Inc.: Washington, DC, September 28, 1992). Prepared for Energy Information Administration under contract No. DE-AC01-89-E121033, task assignment number 92073.

In petroleum refining, there may be significant costs associated with changing capacity levels. In addition, adjusting inventories may may be costly due to logistical difficulties in transport and scheduling. Consequently, consider the following short-run restricted cost function for a petroleum product firm:

$$C(w, y, x, \dot{x}) = \text{minimize } w \cdot z \tag{H1}$$

C(.) = cost function
w = refiner acquisition cost of crude oil and petroleum liquids
y = vector of refinery production
x = vector of quasi-fixed factors
$\dot{x}$ = vector of changes in levels of quasi-fixed factors
z = vector of variable inputs

The vector of variable inputs, z, is the choice variable in the cost minimization problem and is subject to a production transformation function:

$$F(y, z, x, \dot{x}) = 0 \tag{H2}$$

Note that $F_x > 0$, $F_z > 0$, and $F_{\dot{x}} < 0$, in which the last derivative reflects internal adjustment costs.

The refinery production vector, y, is linked to sales and product inventory change by the identity:

$$s = y - \dot{x} \tag{H3}$$

s = vector of refinery product sales

Assume that the firm attempts to minimize the present discounted value of future costs over an infinite horizon by adjusting input purchases and net accumulations of quasi-fixed factors. In this case, given initial states for the quasi-fixed factors, x_0, the discounted value function, J, is:

$$J(w, y, v, x) = \min \int_0^\infty \exp(-r\ t)\ [C(w, y, x, \dot{x}) + v'\ x]\ dt \tag{H4}$$

v = vector of rental costs for quasi-fixed factors
r = discount factor (assumed fixed)

subject to equation (H3) and positive starting values for the quasi-fixed factors.

The discounted value function is assumed to be real, non-negative, twice continuously differentiable, non-decreasing and concave in w and v and decreasing in x (Epstein and Denny, 1983). Under these conditions, the Hamilton-Jacobi-Bellman expression (Kamien and Schwartz, 1991), often referred to as the dynamic programming equation, is as follows:

$$J(w, y, v, x) = \min \int_0^\infty \exp(-r\ t)\ [C(w, y, x, \dot{x}) + v'\ x + \dot{x}'\ J_x]\ dt \tag{H5}$$

This equation simply states that the discounted long-run shadow cost is equal to the sum of total variable costs, total rental costs of the quasi-fixed factors, v'x, and the implicit value of additional fixed factors, $\dot{x}'\ J_x$ (Stefanou, 1989).

This restatement of the objective function can be used to derive a set of first-order conditions for the dynamic problem. Consider one such first-order condition involving the rate of change in quasi-fixed factors, $\dot{x}$:

$$C_{\dot{x}} = - J_x \tag{H6}$$

which states that the marginal adjustment costs of the quasi-fixed factors must equal their respective shadow values. Also, consider the first-order condition with respect to the level of quasi-fixed factors, x:

$$v' = - (C_x + J_{xx}) \tag{H7}$$

which implies that rental values should reflect the shadow value and net capital gains from stock holding. If we differentiate (H5) with respect to the rental costs for quasi-fixed factors, v, we obtain:

$$r\,J_v = x + \dot{x}^*\,J_{xv} + (C_{\dot{x}} + J_x)\,\frac{\partial \dot{x}^*}{\partial v} + (v' + C_x + J_{xx})\,\frac{\partial x^*}{\partial v} \tag{H8}$$

Using (H6) and (H7), and solving (H8) for $\dot{x}^*$ we obtain the following expression for optimal net investment in quasi-fixed factors:

$$\dot{x}^* = \frac{r\,J_v - x}{J_{xv}} \tag{H9}$$

The demands for the variable inputs can be obtained by differentiating (H5) with respect to w and using Shephard's lemma ($z^* = \partial C/\partial w$) to obtain:

$$z^* = r\,J_w - \dot{x}'\,J_{xw} \tag{H10}$$

If the production targets are consistent with long-run profit maximization under perfect competition, then the firm solves the following problem:

$$\max \int_0^\infty \exp(-r\,t)\,[p'\,y - r\,J]\,dt \tag{H11}$$

The first order condition for (H11) with respect to refinery production, y, (assuming $d\dot{x} = 0$ in long-run equilibrium) is:

$$p = r\,J_y \tag{H12}$$

which states that output prices should equal long-run marginal shadow cost of production (Stefanou, 1989).

Model Formulation

Most empirical applications of dynamic dual models utilize a second-order linear quadratic approximation (Epstein and Denny, 1983; and Stefanou, 1992a,b). An alternative approach is to use a translog or generalized Leontief approximation. Both such forms, however, must be modified to accommodate the linear adjustment mechanism in (H9) (see Taylor and Monson, 1985; and Luh and Stefanou, 1991). To avoid potential convergence problems with these mixed functional forms, a quadratic approximation of the value function will be used below. Typically a normalized quadratic formulation is used so that linear homogeneity in prices can be imposed on the cost function. Mahmud *et al* (1986), however, finds that parameter estimates from normalized models vary depending upon the selection of the numeriare.

Furthermore, as noted above data on refining costs are incomplete. Accordingly, an unrestricted model that is not homogeneous in factor prices is used.

The quadratic value function then takes the following form:

$$J = \begin{bmatrix} a_w' & a_v' & a_x' & a_y' \end{bmatrix} \begin{bmatrix} w \\ v \\ x \\ y \end{bmatrix} + \frac{1}{2} \begin{bmatrix} w' v' x' y' \end{bmatrix} \begin{bmatrix} g_w & g_v & g_x & g_y \\ g_v' & B & M^{-1} & C \\ g_x' & M^{-1} & D & T \\ g_y' & C' & T' & G \end{bmatrix} \begin{bmatrix} w \\ v \\ x \\ y \end{bmatrix}$$

$$+ u' \begin{bmatrix} f_w' & f_v' & f_x' & f_y' \end{bmatrix} \begin{bmatrix} w \\ v \\ x \\ y \end{bmatrix} + \begin{bmatrix} e_w' & e_v' & e_x' & e_y' \end{bmatrix} \begin{bmatrix} w \\ v \\ x \\ y \end{bmatrix} \qquad \text{(H13)}$$

where the variables are defined as follows:

w = 2x1 vector of real prices for the refiners acquisition cost of crude oil and for liquefied petroleum gases,

y = 5x1 vector of refinery production of gasoline, distillate, residual fuel, jet fuel and kerosene, and other petroleum products,

x = 8x1 vector of seven inventory categories including crude oil and liquids, unfinished oils, and the five products, and crude distillation capacity,

v = 8x1 vector of rental prices for the quasi-fixed factors, and

u = 2x1 vector of heating and cooling degree-days.

The parameter vectors and matrices are defined as follows:

a_v', a_x'	are 1x8
a_w'	is 1x2
a_y'	is 1x5
g_y, f_y'	are 2x5
g_w, f_w'	are 2x2
g_v, g_x, f_v', f_x'	are 2x8
B, M, D	are 8x8
C, T	are 8x5
G	is 5x5

The *e* vectors are random error terms that reflect errors in dynamic optimization described by McElroy (1987).

In light of the linear adjustment mechanism in the quasi-fixed factor investment equation (H9) above, the estimating equations for the quasi-fixed factors can be derived by taking three derivatives of the quadratic value function given in equation (H13). First, take the derivative of J with respect to v, which is

$$J_v = a_v + g_v' \, w + B \, v + M^{-1} \, x + C \, y + f_v \, u + e_v \tag{H14}$$

Next, take the derivative of J with respect to x to obtain:

$$J_x = a_x + g_x' \, w + M^{-1} \, v + D \, x + T \, y + f_x \, u + e_x \tag{H15}$$

Third, take the derivative of (H15) with respect to v to get the adjustment coefficients:

$$J_{xv} = M^{-1} \tag{H16}$$

Now substituting (H14) and (H16) into (H9), the general form for the quasi-fixed factor investment equations follow:

$$\dot{x}^* = r \, M \, (a_v + g_v' \, w + B \, v + C \, y + f_v \, u) + (r \, I - M) \, x + r \, M \, e_v \tag{H17}$$

Note that if the error terms are serially correlated, they must move at the rate of adjustment M.

Epstein and Denny (1983) show that the nonlinear structural form given by (H17) can be expressed as a linear reduced form model. To derive the reduced form for estimation rewrite (H17) as follows:

$$\dot{x}^* = (r \, I - M) \, (x - \bar{x}) \tag{H18}$$

where,

$$\bar{x} = - \, r \, (I - M)^{-1} \, r \, M \, (a_v + g_v' \, w + B \, v + C \, y + f_v \, u + e_v) \tag{H19}$$

Using the discrete approximation $(x - x_{-1})$ for x^* and $(x_{-1} - \bar{x})$ for $(x - \bar{x})$ in (H18) and rearranging, the following partial adjustment equations for the quasi-fixed factors are obtained:

$$x = r \, M \, [a_v + g_v'w + Bv + Cy + f_vu] + [(1+r) \, I - M] \, x_{-1} + r \, M \, e_v \tag{H20}$$

The terms in the first set of brackets on the right-hand side of (H19) constitute the target or long-run equilibrium level of stocks. These targets depend upon crude oil cost shocks, rental values, final product sales, and sales shocks represented by u. Given that the adjustment coefficients, M, are identified, the model can be estimated in reduced form from which the structural parameters can be derived (see, Epstein and Denny, 1983). The demands for the variable inputs are obtained by taking the derivative of J and J_x with respect to w and substituting into (H10):

$$z^* = r\,(a_w + g_w'w + g_v v + g_x x + g_y y + f_w u) - g_x(x - x_{-1}) + r\,e_w \tag{H21}$$

The second to the last term on the right of (H21) represents the extent of disequilibrium in short-run input demands.

The supply functions consistent with long-run profit maximization are derived by simply taking the derivative of J with respect to y and using (H12):

$$p = r\,(a_s + g_s'\,w + C'\,v + T'\,x + G\,y + f_s\,u) + r\,e_s \tag{H22}$$

So wholesale product prices are a function of crude oil prices, rental prices, ending stocks of inventories, refining capacity, sales shocks, and refinery production. The degree of jointness in production is captured by the parameters, G.

Equations (H20)-(H22) constitute the core of the supply model. The input demand and supply functions are linear in their parameters. The investment equations are nonlinear. The model, however, contains a set of cross equation restrictions, namely those involving the parameter matrix C in (H20) and (H22). Hence, the unrestricted model cannot be estimated in reduced form.

Fortunately, there are a number of parameter restrictions that directly follow from the simple fact that stocks of capacity and inventories can be either built up or drawn down. Up to this point, gross investment is implicitly assumed to be positive. Obviously, this is not true for petroleum product inventories. Allowing for stock reductions implies certain simplifying parameter restrictions. Epstein and Denny (1983) show that marginal adjustment costs should be negative when disinvestment occurs, or $C_{\dot{x}} < 0$ should be imposed for $\dot{x} < 0$.

Given the quadratic cost function dual to J defined in (H13), these requirements can be satisfied by imposing an additively separable structure on adjustment costs, which implies the following restrictions on the dual cost function:

$$C_{\dot{x}\dot{x}} = 0, \qquad i \neq j \tag{H23}$$

$$C_{\dot{x}j} = 0 \text{ for } \qquad j = w, x, y, u \tag{H24}$$

$$C_{\dot{x}} = 0 \text{ when } \quad \dot{x} = 0 \tag{H25}$$

The parameter restrictions implied by these constraints can be derived by substituting (H15) into (H6) to get a parametric expression for marginal adjustment costs:

$$C_{\dot{x}} = -\,[a_x + g_x'w + M^{-1}v + D\,x + T\,y + f_x\,u + e_x] \tag{H26}$$

Since (H26) must be evaluated at equilibrium, solve (H17) for v and substitute into (H26) to obtain:

$$\begin{aligned} C_{\dot{x}} = {} & [M^{-1}B^{-1}a_v - a_x] + [M^{-1}B^{-1}g_v - g_x]\,w + \{M^{-1}B^{-1}[M^{-1} - r^{-1}I] - D\}\,x \\ & + [M^{-1}B^{-1}f_v - f_x]\,u + [M^{-1}B^{-1}C - T]\,y - r^{-1}M^{-1}B^{-1}M^{-1}\dot{x} \end{aligned} \tag{H27}$$

Condition (H23) can be imposed by making M and B diagonal, which greatly simplifies the model. The monotonicity conditions imply that the first five terms in parentheses on the right-hand side of (H27) must equal zero, which implies the following parameter restrictions:

$$a_x = M^{-1}\,B^{-1}\,a_v \tag{H28}$$

$$g_x' = M^{-1}\,B^{-1}\,g_v' \tag{H29}$$

$$D = M^{-1} B^{-1} [M^{-1} - r^{-1} I] \tag{H30}$$

$$f_x = M^{-1} B^{-1} f_v \tag{H31}$$

$$C = M\ B\ T \tag{H32}$$

Notice that the first three constraints given by (H28)-(H30) involve parameters that do not appear in the structural equations, (H20)-(H22). Consequently, some additional identifying relationship is needed to impose these constraints. Two approaches are available.

First, the value function given by (H5) can be solved for cost and, therefore, could be estimated with the above constraints imposed. The model would be highly nonlinear in the parameters and could, therefore, be difficult to estimate much less simulate. Nevertheless, this approach deserves further research.

Another approach is to specify an equilibrium arbitrage relationship between user costs and the marginal benefits of stocks along the lines explored by Pindyck (1991). An essential ingredient in this approach is futures prices (a rational price expectations formulation could be adopted but would fundamentally change our model). While heating oil futures have been traded since 1978, this market was fairly thin during the early 1980's. Furthermore, trading in crude oil and gasoline futures did not begin until the mid-1980's. Incorporating futures prices into the user cost terms would truncate our sample and force us to aggregate products under the smaller degrees of freedom.

Accordingly, a compromise is proposed. The key aspect of additively separable adjustment costs (H23) will be preserved by imposing the diagonality of M and B. As a result, the monotonicity conditions are simplified and can be tested by imposing the parameter restriction implicit in equation (H32). The remaining parameters for marginal adjustment costs could be computed using equations (H28)-(H31).

In addition, constraints were placed on the C matrix to further facilitate a test for the monotonicity conditions. The following specific form for C is used:

$$C = \begin{bmatrix} C_{11} & C_{12} & C_{13} & C_{14} & 0 \\ C_{21} & C_{22} & C_{23} & C_{24} & 0 \\ C_{31} & 0 & 0 & 0 & 0 \\ 0 & C_{42} & 0 & 0 & 0 \\ 0 & 0 & C_{53} & 0 & 0 \\ 0 & 0 & 0 & C_{64} & 0 \\ 0 & 0 & 0 & 0 & 0 \\ C_{81} & C_{82} & C_{83} & C_{84} & 0 \end{bmatrix} \tag{H33}$$

So refinery capacity, crude oil and work-in-process inventories are affected by refinery production levels for all products except other petroleum products, which were eliminated to reduce convergence problems that arise from the absence of a supply equation for other products. Similarly, wholesale product prices are affected by rental costs for capital, crude oil, and work-in-progress inventories and their respective own product rental cost. Furthermore, given that the matrices B and M are diagonal, the montonicity condition (H32) implies that the T matrix, which measures the effects of month-end stocks on wholesale prices, must take the same form as C. Finally, the demand for variable inputs are assumed to be unaffected by user costs for quasi-fixed factors.

Given these assumptions, the base model can be described in summation notation as follows:

$$x_{it} = r \left[a^{*}_{vi} + \sum_{j=1}^{2} g^{*}_{vij} \, w_{jt} + b^{*}_{ii} \, v_{t} + \sum_{j=1}^{4} c^{*}_{ij} \, y_{jt} + f_{ih} \, u_{ht} + f_{ic} \, u_{ct} \right]$$

$$+ \left(1 + r - m_{ii} \right) x_{it-1} + e^{*}_{it} \,, \qquad i = 1,2,8 \qquad \text{(H34)}$$

$$x_{it} = r \left[a^{*}_{vi} + \sum_{j=1}^{2} g^{*}_{vij} \, w_{jt} + b^{*}_{ii} \, v_{t} + c^{*}_{ii-2} \, y_{i-2t} + f_{ih} \, u_{ht} + f_{ic} \, u_{ct} \right]$$

$$+ \left(1 + r - m_{ii} \right) x_{it-1} + e^{*}_{it} \,, \qquad i = 3,..,7 \qquad \text{(H35)}$$

$$z_{it} = r \left[a_{wi} + \sum_{j=1}^{2} g_{vij} \, w_{jt} + \sum_{j=1}^{8} g_{xij} \, x_{jt} + \sum_{j=1}^{5} g_{yij} \, y_{jt} + f_{zih} \, u_{ht} + f_{zic} \, u_{ct} \right]$$

$$- \sum_{j=1}^{8} g_{xij} \left(x_{jt} - x_{jt-1} \right) + e^{*}_{wt} \,, \qquad i = 1,2 \qquad \text{(H36)}$$

$$P_{it} = r \left[a_{yi} + \sum_{j=1}^{2} g_{yji} \, w_{jt} + \sum_{j=1}^{2} \left(\frac{c^{*}_{ji}}{m_{jj}} \right) v_{jt} \right.$$

$$+ \left(\frac{c^{*}_{i-2,i}}{m_{i-2,i-2}} \right) v_{it} + \left(\frac{c^{*}_{8i}}{m_{88}} \right) v_{8t} + \sum_{j=1}^{2} t_{ji} \, x_{jt} + t_{i-2} \, x_{it}$$

$$\left. + \sum_{j=1}^{5} g_{ij} \, y_{jt} + f_{ih} \, u_{ht} + f_{ic} \, u_{ct} + e^{*}_{yit} \right], \qquad i = 1,..,4 \qquad \text{(H37)}$$

Note that the investment equations are estimated in reduced form so that $c_{ij}^* = m_{ii}\, c_{ij}$. The monotonicity conditions then can be tested by imposing a set of constraints consistent with (H32). Notice that this model is nonlinear in the parameters due to the cross equation constraints involving C. The restrictions, however, are fairly simple given the diagonal structure of M and B.

Econometric Results

The models are estimated with instrumental variables to correct for simultaneous equations bias. The supply model given by equations (H34) to (H37) is estimated as a system with nonlinear three stage least squares (3SLS).

The instrumental variables are seasonally unadjusted and have been carefully selected so that they are exogenous to the model. They include housing starts, the M1 measure of the money supply, manufacturing labor hours, consumer prices net of energy, the Standard and Poor 500 stock price index, industrial production, heating and cooling degree-days, long-term bond rates, and 30-day rates on certificates of deposit. Lagged values of these variables also are used as instruments. In addition, three regime shift variables for OPEC unity are included as instruments. The first regime represents "Desert Storm" from January to February 1991. The second period is from August to December 1990, known as "Desert Shield." The third variable accounts for the crude oil price war from February to November 1986. A set of monthly dummy variables also are used as instruments to account for fixed seasonal effects.

The first step in the analysis is to test the monotonicity conditions. The value of the objective function for the unrestricted model is 522. Imposing the monotonicity conditions and using the covariance matrix of the equations errors from the unrestricted model results in an objective value of 695. This implies a Chi-squared test statistic is 346, which far exceeds the critical value of 32 for 16 degrees of freedom at the one percent significance level. Hence, the monotonicity conditions given by (H32) cannot be accepted.

The summary fit statistics for the nonmonotonic refinery supply model are presented in Table H1. Three measures of goodness of fit are presented. First, the correlations between predicted and actual values for wholesale prices and refinery inputs are very high. The correlation coefficients for the inventory equations are lower but also indicate a reasonably good fit. The very low values for the bias and regression values for the mean squared error decompositions indicate no systematic linear bias in the inventory, capacity, and wholesale price equations. Finally, the Theil statistics, which are equal to one for the naive model, are extremely small suggesting that the model could provide accurate forecasts.

The explanatory variables in the inventory equations can be classified into three categories: cost factors including refinery input prices and rental values, production levels, and sales shocks represented by the weather variables. All seven user cost terms in the inventory equations are correctly signed with statistically significant effects at the 1 percent level for gasoline and residual fuel oil stocks (see Table H2). Inventories of crude oil and gasoline are estimated to significantly increase with higher petroleum liquid input prices. So cost shocks play a limited role in explaining petroleum inventories.

The evidence on the role of production levels also is mixed. Inventories of crude oil generally increase in response to higher refinery production with significant effects for residual and jet fuel. Of the remaining production coefficients only jet fuel stocks significantly decline with higher production of that fuel (see Table H2). Hence, refinery production levels are important for crude oil inventories but considerably less so for work-in-process and final product inventories.

The sales shock variables are substantial and statistically significant. The response of inventories to weather varies by product and by season. For instance, the estimated parameter for cooling degree-days in the crude oil stock equation is more than 10 times greater than the corresponding heating degree-day coefficient, which is consistent with the well-known spring drawdown of crude oil inventories. Gasoline stocks increase more than twice as much during the summer driving season and than during the winter. Distillate fuel oil stocks drop with colder weather and rise during the summer.

Table H1. Correlations Between Predicted and Actual Values, Mean Squared Error Decompositions, and Theil's U_1 Statistics

		Mean Squared Error Decomposition			
	Correlation	Bias	Regression	Distrube	Theil's U_1
Inventories					
Crude Oil	0.782	0.000	0.030	0.970	0.0254
Work-in-Process	0.881	0.000	0.003	0.996	0.0289
Gasoline	0.745	0.000	0.007	0.993	0.0354
Distillate	0.923	0.000	0.001	0.999	0.0628
Residual	0.852	0.000	0.022	0.978	0.0651
Jet Fuel	0.860	0.001	0.037	0.963	0.0423
Other	0.955	0.001	0.001	0.998	0.0263
Refinery Capacity	0.989	0.000	0.002	0.997	0.0053
Refinery Inputs					
Crude Oil	0.982	0.000	0.011	0.989	0.0120
Liquids	0.773	0.000	0.182	0.818	0.1172
Wholesale Prices					
Gasoline	0.993	0.004	0.000	0.996	0.0228
Distillates	0.996	0.000	0.003	0.997	0.0223
Residual	0.995	0.006	0.006	0.987	0.0308
Jet Fuel	0.996	0.000	0.021	0.979	0.0229

The estimated rates of adjustment are substantially faster than the very slow adjustment rates criticized by Blinder (1981). For example, 24 percent of the total adjustment of crude oil stocks occurs within one month. The adjustment rate for gasoline is even quicker with more than 40 percent of the adjustment occurring within one month. Other petroleum product inventories are the next fastest to adjust. Jet fuel and residual fuel oil inventories respond more slowly with 13 and 16 percent of their respective adjustments occurring during the first month. Nevertheless, these rates of adjustment are plausible and suggest that petroleum stocks on average take about 4 to 5 months to adjust to equilibrium levels. The adjustment coefficients for distillate fuels and refining capacity are negative, but are insignificant.

All four of the short-run marginal cost schedules conform with the conventional notion of an upward sloping supply curve (see Table H3).

Wholesale prices for gasoline and distillate fuel rise about 5 percent for each 10 percent increase in production levels (see Table H4). The corresponding elasticities for residual fuels and jet fuel fall around 0.20. The multi-product nature of petroleum refining is reflected by the estimated complementarity between gasoline, distillate, and residual fuel oil production. Complementarity is also found between other petroleum products and distillate, residual, and jet fuels.

As expected, refinery input prices are highly significant in explaining the variation in wholesale product prices. The relation for residual fuel is nearly one to one. In contrast, roughly two-thirds of monthly charges in input costs show up in gasoline and distillate prices.

Table H2. Parameter Estimates for Inventory and Capacity Equations

Parameter	Estimate	"t" Ratio	Parameter	Estimate	"t" Ratio
	Intercepts			**Production**	
AV1	20151.4600	4.91	C11	22.5103	1.68
AV2	5241.6400	2.68	C12	22.1356	1.93
AV3	5849.0700	3.63	C13	38.4538	2.91
AV4	-215.6000	-0.20	C14	47.9390	3.39
AV5	1092.4100	1.50	C21	-6.4906	-0.69
AV6	1011.7 800	1.83	C22	-3.3696	-0.79
AV7	8118.0300	8.85	C23	-1.8365	-0.47
AV8	146.4400	1.56	C24	-1.7434	-0.43
			C31	-9.4800	-0.83
	Cost Shocks		C42	2.9676	1.14
			C53	-7.7773	-0.91
GV11	6.4758	0.96	C64	-14.6483	-1.93
GV21	8.3100	1.49	C81	2.5242	0.27
GV31	4.0958	0.84	C82	-8.2970	-0.75
GV41	-7.5906	-1.14	C83	-21.0075	-0.90
GV51	0.3617	0.09	C84	-3.6612	-0.25
GV61	-2.4811	-1.22			
GV71	-5.1649	-1.69		**Weather Shocks**	
GV81	-0.0832	-0.60			
GV12	37.7182	-2.12	FX1H	-23.8674	-1.49
GV22	13.2782	-1.21	FX2H	-10.1552	-1.14
GV32	37.2468	2.98	FX3H	34.5419	2.69
GV42	8.6995	0.59	FX4H	-72.5042	-4.38
GV52	0.4069	0.06	FX5H	-26.1365	-3.60
GV62	1.5724	0.47	FX6H	-11.3690	-3.34
GV72	-14.6076	-1.82	FX7H	-57.6726	-7.08
GV82	-0.4050	-1.78	FX8H	0.0391	0.18
B11	-15.4774	-0.37	FX1C	-126.7427	-2.86
B22	-35.0205	-1.67	FX2C	-37.8781	-1.55
B33	-76.0246	-2.81	FX3C	77.2130	2.18
B44	-32.0922	-1.19	FX4C	63.3434	1.49
B55	-21.0507	-1.59	FX5C	-57.5488	-3.48
B66	-3.3430	-0.50	FX6C	-17.2534	-1.79
B77	-28.8808	-1.53	FX7C	12.3614	0.54
B88	183.9253	0.47	FX8C	-0.4167	-0.78
	Adjustment Rates				
M11	0.2400	3.58			
M22	0.2039	3.38			
M33	0.4143	5.50			
M44	-0.0382	-0.87			
M55	0.1262	1.84			
M66	0.1654	2.33			
M77	0.2848	9.50			
M88	-0.0024	-0.76			

Table H3. Parameter Estimates for Refinery Input and Wholesale Price Equations

Parameter	Estimate	"t" Ratio	Parameter	Estimate	"t" Ratio
Refinery Inputs			**Production/Cost**		
AW1	-84.4507	-1.50	GY11	122.9210	14.15
AW2	10.7316	0.21	GY12	116.2641	14.21
GW11	0.1302	0.68	GY13	95.0065	11.26
GW12	-0.0312	-0.21	GY14	97.0767	10.96
GW22	0.4134	2.41	GY15	86.6514	4.37
GX11	-0.0060	-2.36	GY21	-1.6020	-0.21
GX12	-0.0294	-6.05	GY22	27.9383	3.74
GX13	0.0060	1.47	GY23	19.8601	2.57
GX14	0.0133	3.31	GY24	14.7416	1.94
GX15	-0.0190	-2.08	GY25	1.8548	0.11
GX16	0.0187	1.75			
GX17	-0.0032	-0.96	**Stock Levels**		
GX18	0.7115	3.21			
GX21	0.0054	2.47	T11	11.6494	2.92
GX22	0.0229	5.43	T12	-0.9309	-0.28
GX23	-0.0006	-0.18	T13	0.7131	0.22
GX24	-0.0111	-3.22	T14	-1.0932	-0.33
GX25	0.0155	1.99	T21	19.9916	2.73
GX26	-0.0129	-1.39	T22	9.3626	1.49
GX27	0.0011	0.39	T23	-1.8478	-0.28
GX28	-0.5002	-2.61	T24	2.8999	0.44
			T31	-0.003526	-0.00
Production Interactions			T42	3.0627	1.43
			T53	11.1375	1.53
G11	514.9138	3.25	T64	-22.1494	-1.57
G12	-130.2202	-0.91	T81	92.3024	0.26
G13	-159.6592	-1.00	T82	-172.1820	-0.59
G14	58.7433	0.36	T83	-735.2236	-2.43
G15	309.2931	0.58	T84	-529.6054	-1.68
G22	1134.2000	4.63			
G23	191.0698	0.83	**Weather Shocks**		
G24	164.8320	0.81			
G25	-1035.0400	-2.32	FZ1H	-0.5282	-0.86
G33	831.9899	1.67	FZ1C	3.3971	3.06
G34	11.7143	0.03	FZ2H	0.1674	0.32
G35	-296.9526	-0.65	FZ2C	-2.2480	-2.38
G44	1208.5100	2.54	FY1H	-6.4311	-0.93
G45	-837.6373	-1.80	FY2H	-12.9192	-2.30
			FY3H	-3.1945	-0.54
			FY4H	-11.5267	-1.92
			FY1C	4.6940	0.37
			FY2C	-4.2961	-0.38
			FY3C	24.6643	2.10
			FY4C	5.1942	0.46

Table H4. Short-Run Marginal Cost Elasticities

Explanatory Variables	Short-Run Marginal Costs			
	Gasoline	Distillate Fuels	Residual Fuel Oil	Jet Fuel
Input Prices				
Crude Oil	0.5831	0.6217	0.8564	0.4710
Propane	-0.0142	0.1494	0.3353	0.1336
Production Levels				
Gasoline	0.4997	-0.1424	-0.2944	0.0583
Distillate	-0.0533	0.5241	0.1488	0.0691
Residual	-0.0221	0.0299	0.2193	0.0017
Jet Fuel	0.0118	0.0375	0.0045	0.2496
Other	0.1146	-0.4323	-0.2091	-0.3174
Inventories				
Crude Oil	0.4989	-0.0449	0.0580	-0.0479
Work-in-Process	0.3762	0.1986	-0.0661	0.0558
Gasoline	-0.0001			
Distillate		0.0654		
Residual			0.1394	
Jet Fuel				-0.1458
Refining Capacity	0.1915	-0.4027	-2.8985	-1.1237
Degree Days				
Heating	-0.0207	-0.0468	-0.0195	-0.0379
Cooling	0.0003	-0.0003	0.0026	0.0003

Only three inventory-price relations were found statistically significant. Wholesale gasoline and distillate prices rise with higher levels of crude oil inventories. Only jet fuel prices decline with higher own-stock levels and that estimate is only marginally significant. Surprisingly, residual fuel oil prices are positively related to residual fuel inventories. Three of the four prices are inversely related to refiner capacity but only the elasticities for residual fuel are significant. Finally, while some of the weather effects on product prices are significant, most are small. Overall, the results suggest that refinery wholesale price movements are affected largely by input costs and production levels.

The short-run input demand elasticities are presented in Table H5. Crude oil and petroleum liquids are estimated to be complements although the parameter estimates are insignificant. Furthermore, the own price effects for crude oil also are insignificant. Refinery product output levels are an important determinant of crude oil and liquids consumption. In addition, inventory levels are also generally significant (see Table H3). In summary, while own and cross price effects are negligible, production and inventories are significant factors in determining refinery consumption of crude oil and petroleum liquids.

The summary fit statistics for the net import equations are presented in Table H1. Given the extreme volatility of these series, the correlations between predicted and actual values are reasonably good falling between 0.6 and 0.8. Although the mean squared error decompositions suggest no systematic bias in the forecasts, the relatively high Theil statistics are somewhat troubling. Nevertheless, the models are substantially better than the naive forecasting model.

Table H5. Short-Run Input Demand Elasticities

Explanatory Variables	Crude Oil	Liquids
Input Prices		
Crude Oil	0.0029	-0.0001
Propane	-0.0012	0.0029
Production Levels		
Gasoline	0.5572	-0.0012
Distillate	0.2227	0.0092
Residual	0.0616	0.0022
Jet Fuel	0.0916	0.0024
Other	0.1499	0.0005
Inventories		
Crude Oil	-0.0012	0.0002
Work-in-Process		
Gasoline	0.0007	-0.0001
Distillate	0.0019	-0.0002
Residual	-0.0006	0.0000
Jet Fuel	0.0006	0.0000
Refining Capacity	0.0069	-0.0008
Degree Days		
Heating	-0.0079	0.0025
Cooling	0.0008	-0.0006

References

Considine, T.J. (1992) "A Short-Run Model of Petroleum Product Supply, "*The Energy Journal*, Vol. 13, No. 2, pp. 61-91.

Epstein, L.G. and M.G.S. Denny (1983) "The Multivariate Accelerator Model: Its Empirical Restrictions and an Application to U.S. Manufacturing," *Econometrica*, vol. 51, 647-674.

Kamien, Morton I, and N.L. Schwartz (1991) *Dynamic Optimization: The Calculus of Variations and Optimal Control in Economics and Management*, (Amsterdam: North Holland).

Lucas, R. (1967) "Optimal Investment Policy and the Flexible Accelerator," *International Economic Review*, 78-85.

McElroy, M. (1987) "Additive General Error Models of Production, Cost, and Derived Demand or Share Systems," *Journal of Political Economy*, vol. 95, 737-5 7.

Mahmud, S.F., A.L. Robb, and W.M. Scarth, (1986) "On Estimating Dynamic Factor Demands," *Journal of Applied Econometrics*.

McLaren, K. and R. Cooper (1980) "Intertemporal Duality: Application to the Theory of the Firm," *Econometrica*, vol. 48, 1755-1762.

Pindyck, Robert S. (1991) "Inventories and the Short-Run Dynamics of Commodity Prices," M.I.T., mimeo.

Ramey, Valerie A., (1989) "Inventories as Factors of Production and Economic Fluctuations," *American Economic Review*, 79, 338-354.

Ramey, Valerie A., (1991) "Nonconvex Costs and the Behavior of Inventories," *Journal of Political Economy*, Vol. 99, 306-334.

Stefanou, S.E. (1989) "Returns to Scale in the Long-Run: The Dynamic Theory of Cost," *Southern Economic Journal*, vol. 55, 570-579.

Stefanou, S.E. (1992a) "Dynamic Measures of Scope and Scale Economies: An Application to German Agriculture," *American Journal of Agricultural Economics*, (forthcoming).

Stefanou, S.E. (1992b) "Dynamic Structure of Production Under a Quota: The Case of Milk Production in the Federal Republic of Germany," European Review of Agricultural Economics, (forthcoming).

Taylor, Timothy G. and M.J. Monson (1985) "Dynamic Factor Demands for Aggregate Southeastern United States Agriculture," *Southern Journal of Agricultural Economics*, December, 1-9.

Treadway, A. (1971) "The Rational Multivariate Flexible Accelerator," *Econometrica*, vol. 39, 845-856.