LONG-TERM ELECTRIC PEAK DEMAND AND CAPACITY RESOURCE FORECAST FOR TEXAS 1988

VOLUME III

PUCT STAFF ECONOMETRIC ELECTRICITY DEMAND FORECASTING SYSTEM

FEBRUARY 1989

THE PUBLIC UTILITY COMMISSION OF TEXAS

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Note: Partial funding for some of the research described in this three-volume report was secured from the U.S. Department of Energy through the 1988 State Energy Conservation Program.

ABSTRACT

Although electric utilities in Texas have entered a period of significant excess generating capacity, a number of planning issues deserve prompt attention. These issues include the future role of cogeneration in Texas, alleviating potential transmission bottlenecks in some areas of the State, the short-term and long-term implications associated with abandoning conservation programs in favor of promotional strategies, the appropriate degree of operating and planning coordination among the State's utilities, better utilization of the transmission system, and the potential for rate design to serve as a resource planning tool.

This report is designed to provide information and recommendations to policymakers and others interested in the present and future status of the Texas electric power industry. The first volume of this three volume report of the Commission staff's **Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas, 1988** provides recommended electricity demand projections for twelve of the State's largest electric utilities and an independent recommended capacity resource plan for Texas. Fuel markets, cogeneration activity, and the potential loss of industrial loads are discussed along with a number of topics of special interest.

The second volume summarizes the electricity demand forecasts, energy efficiency plans, and capacity resource plans developed by Texas generating electric utilities and filed at the Commission in December 1987. The third volume provides a technical description of the staff's Econometric Electricity Demand Forecasting system and other models used by the staff to develop the recommended load forecast presented in this volume.

The 1984 and 1986 reports focused on two central themes: 1) the development of load forecasting methodologies, data, and models; and 2) capacity expansion through the construction of utility-owned generating units. The central theme of this 1988 report, in view of the lingering effects of the Texas recession, is how to achieve greater efficiency in the use of the State's electrical resources. Within this framework, substantially more emphasis is directed toward demand-side management approaches, alternative power and energy sources, and system economics. The information presented here attempts to capture the underlying philosophy, as well as the techniques, which are used to address these important issues and provide a focus on anticipated problems and opportunities.

It should be emphasized that the projections contained herein were prepared for planning purposes and do not reflect any official policy positions or predictions by the Commission.

CONTENTS

CHAPTER ONE

ELECTRICITY DEMAND FORECASTING PROJECTS AT THE COMMISSION

In the past five years, the Electric Division (formerly the Economic Research Division) of the Public Utility Commission has initiated three distinct projects designed to produce accurate, flexible, and tenable independent projections of the demand for electricity to be faced by the State's larger generating electric utilities. These projects are:

1. The Econometric Electricity Demand Forecasting System
2. The End-Use Energy Modeling and Forecasting System
3. The Time-Series and Bayesian Forecasting Systems

The Econometric Electricity Demand Forecasting System seeks to statistically estimate the behavioral relationships among the demand for electricity and its various determinants such as weather, population, employment, personal income, electricity prices, prices of alternative energy sources, and industrial production. Future electricity consumption is projected based on these historical relationships and forecasts of these demand determinants or "explanatory variables." These energy projections are made at the customer-class level and then converted to demand and aggregated to a system peak through the use of the Hourly Electric Load Model (HELM). Simultaneous equation econometric models, ranging up to 45 equations in size, have been developed for every major generating electric utility in the State. A database containing over 7,000 time-series variables provides data input to this set of models. Numerous improvements have been made to this forecasting system since its results were reported in the Commission's **Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas, 1986.**

The End-Use Energy Modeling and Forecasting System, initiated in the spring of 1985, examines the end-uses of energy consumption in Texas. These end-uses include air conditioning, space-heating, refrigeration, dishwashing, lighting, irrigation, and industrial processes. Changes in the stock of energy-intensive equipment, appliance efficiencies, equipment usage patterns, and the determinants of these factors (demographic patterns, technology, laws and regulations, relative fuel prices, climatological factors, etc.) are given explicit attention. The End-Use Modeling System provides a means to explore a variety of conservation and load management strategies. The electricity demand projections derived from this system also provide a valuable validity-check upon the staff's econometric forecasts. To date, residential sector and commercial sector energy consumption for all major utility planning regions in the State have been produced from this system. These results are obtained from the Residential End-Use Energy Planning System (REEPS) and the Commercial Sector End-Use Energy Demand Forecasting Model (COMMEND) . End-use models for the industrial sector are being implemented presently. Current results from the End-Use Modeling System are not presented in this report. However, their results have been used in the staff's conservation and demand-side management analysis. Also, these end-use results are reported in a recent staff report, **End-Use Modeling Project: 1987 Demand Forecast and Report**, August 1987.

While the Econometric Electricity Demand Forecasting System and the End-Use Energy Modeling and Forecasting System are designed to provide an accurate long-range outlook for the State's electricity markets, the Time-Series and Bayesian Forecasting Systems provide alternative statistical methods for producing short-term and long-term forecasts. Time-series methods investigated by the staff include Kalman filter models, ARIMA models, and transfer function models. ARIMA models of quarterly peak demand were presented and discussed in Volume III of the staff's 1986 forecast. No new results from the Time-Series System are reported in this edition of the forecast.

The Bayesian Forecasting System is based on an approach which formally incorporates information found outside the sample period into the modeling process. For purposes of this report, the load forecast for the City of Austin is based on results from a Bayesian linear regression model.

The pursuit of several distinct forecasting approaches permits the Commission staff to exploit the unique capabilities of each. End-use models are considered by some to be superior in addressing conservation and load management issues. Econometric models are typically more useful in studying electricity demand's responsiveness to energy prices, and the impact of weather and economic activity on energy demand. Recent studies sponsored by Battelle Laboratories and the Electric Power Research Institute confirm the accuracy of time-series methods in short- and medium-range peak demand forecasting applications. Bayesian methods are becoming more and more prevalent in applied statistical work. The results from each of these forecasting systems provide a useful frame of reference when analyzing forecast results from other methods and sources. This volume will provide a general description of the staff's Econometric Electricity Demand Forecasting System and the Bayesian linear regression model.

CHAPTER TWO

ECONOMETRIC FORECASTING SYSTEM

2.1 OVERVIEW

Simultaneous equation econometric models have been established to produce electricity sales projections for each of the larger generating electric utilities in Texas. Each forecasting model contains a set of equations representing the relationships among a utility's costs, prices and sales, and how economic demographic, and climatological factors affect electricity sales.

Each of the forecasting models contain four submodels, which interact to produce forecasts of sales, prices, fuel costs, and number of customers:

1. The Electricity Sales Submodel
2. The Electricity Price Submodel
3. The Utility Cost Submodel
4. The Customer Submodel

The relationship between these four submodels is graphically depicted in Figure 2.1.1.

The Electricity Sales Submodel consists of a set of statistically-estimated equations describing the relationship among electricity sales to various customer classes and a set of economic, demographic, and climatological variables--including population, number of customers, employment, real personal income, cooling degree-days, heating degree-days, the price of natural gas, interest rates, and electricity prices. Projections of electricity prices (average) are obtained from the Electricity Prices Submodel, while customer projections are provided by the Customer Submodel.

The average electricity prices faced by various customer classes are determined by the Electricity Prices Submodel. Within this submodel, electricity prices are premised to be determined primarily by the utility's current average fuel costs, and the utility's averaged fixed costs over a historical period. Here, fixed costs are treated as a catch-all for any significant utility costs that are not incorporated elsewhere within the submodels. These costs include depreciation expense, return on ratebase, nuclear decommissioning costs

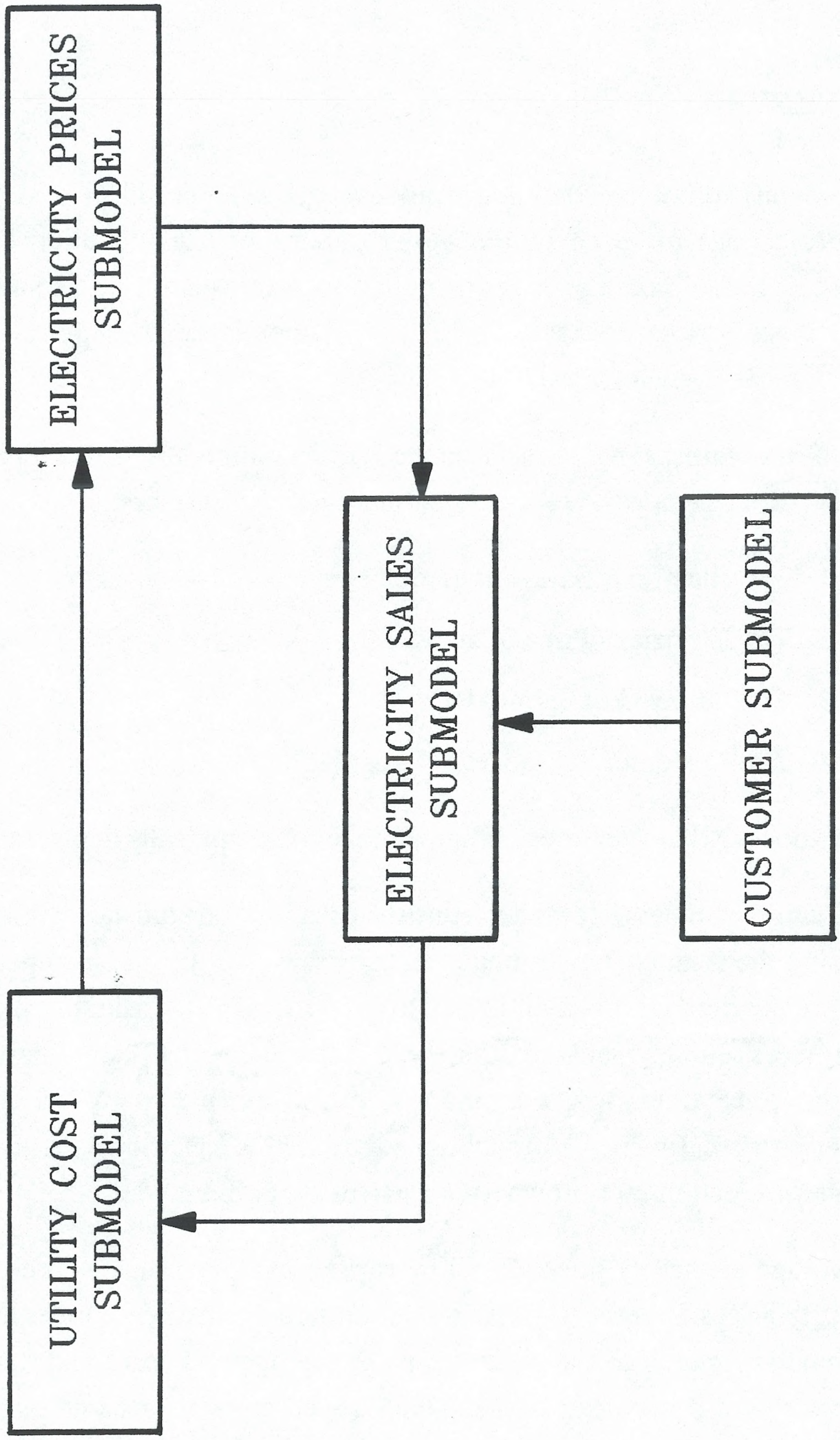

FIGURE 2.1.1
Submodel Interaction

(where appropriate), taxes, and operations and maintenance (O&M) expense. Most of these costs are determined by the utility's assets or ratebase, and are "fixed" in the sense that they do not fluctuate with generation or sales levels. The major exception is O&M which has a variable component. Each utility's O&M projections, as presented in their forecast filings, are incorporated into the staff's fixed cost calculations for the Utility Cost Submodel.

The Utility Cost Submodel has two distinct components: a fuel cost model and a fixed cost model. The utility's fuel expenses are simulated using a simple "economic merit order" model, based on the premise that a utility satisfies the demand for electricity at any given point in time with the generating units having the lowest fuel costs. Generating capacity by fuel type, average fuel prices, heat rates, capacity factors, loss factors, and electricity sales are inputs to the fuel model. Sales estimates are obtained from the Electricity Sales Submodel. Forecasts of a utility's asset base are based on current capacity expansion plans and construction cost estimates, among other factors. Debt service coverage is the primary determinant of fixed costs for a publicly-owned utility.

A utility's customers are projected based on anticipated population and growth, as well as historical customer growth patterns. As in the other three submodels, statistical techniques are extensively relied upon in the Customer Submodel.

Each of the statistically-determined relationships in each submodel (except the Customer Submodel) are estimated using the two-stage-least squares estimation procedure to reduce simultaneous equation bias. Once each coefficient has been estimated, all the submodels (except the Customer Submodel) are solved simultaneously through an iterative procedure to yield a projection of electricity sales, by customer class, for a given utility.

The Hourly Electric Load Model (HELM) converts the projections of electricity sales into peak demand forecasts. The following subsections will describe the structure of each of these submodels in greater detail.

2.2 ELECTRICITY SALES SUBMODEL

The Electricity Sales Submodel projects energy sales by customer class based on a set of economic, demographic, and climatological factors and the outputs from the Customer Submodel and the Electricity Price Submodel. Because the determinants of electricity consumption differ for various customer groups, electricity sales to different customer classes are modeled separately. As many as seven different customer groups are treated independently in this submodel:

1. Residential
2. Commercial
3. Industrial
4. Irrigation
5. Cotton Gin
6. Other Retail
7. Wholesale

For utilities without significant sales to irrigators or cotton gins, such sales were included in the industrial or commercial classes. The Electricity Sale Submodels for each of the utilities under study are tailored to some extent to account for the unique record-keeping practices and customer mix of a particular utility.

Equation specification and variable selection are based on a number of criteria, including compatibility with economic theory and previous studies, statistical results, data availability, and simulation behavior. The equation used to determine sales to residential ratepayers typically takes the following specification:

$$RS_t = b_0 + b_1 (HDD_t \bullet RC_t) + b_2 (CDD_t \bullet RC_t) + b_3 (PI_t / CPI_t) + b_4 [(RAP_t / CPI_t) \bullet RC_t] + b_5 [(PNGR_{t-4} / CPI_{t-4}) \bullet RC_t] + e_t$$

where:

RS	=	Sales to Residential Customers (MWH)
RC	=	Number of Residential Customers
HDD	=	Heating Degree-Days
CDD	=	Cooling Degree-Days
PI	=	Nominal Personal Income (millions of dollars)
CPI	=	Texas Consumer Price Index
RAP	=	Average Price of Electricity to Residential Ratepayers (dollars per KWH)
PNGR	=	Price of Natural Gas to Residential Customers (cents per therm)

t	=	Time period (calendar quarter)
$b_0...b_5$	=	Coefficients to be Estimated
e_t	=	Error term

Most of the variables on the right side of the equation are multiplied by the number of residential customers to acknowledge that the energy impact of each of the demand determinants varies in relation to the size of the customer class. Heating degree-days and cooling degree-days variables are used to measure the impact of weather on electricity sales. Real personal income is normally positively related to electricity sales. As incomes increase, consumers often utilize and purchase more electricity-intensive equipment. The real price of electricity is used to capture price elasticity effects in the model. Increases in the real price of electricity tend to discourage usage. The real price of natural gas to residential customers represents the cost of alternative energy sources. As natural gas becomes more expensive relative to electricity, electricity usage may be encouraged. The four quarter lag on this variable acknowledges the long-run nature of this response.

The equation used to determine electricity sales to commercial customers follows a similar specification:

$$CS_t = b_0 + b_1 (HDD_t \bullet CC_t) + b_2 (CDD_t \bullet CC_t) + b_3 (EMPLOY_t) + b_4 [(CAP_t / CPI_t) \bullet CC_t] + b_5 [(CAP_{t-4} / PNGC_{t-4}) \bullet CC_t] + e_t$$

where:

CS	=	Sales to Commercial customers (MWH)
CC	=	Number of Commercial Customers
HDD	=	Heating Degree-Days
CDD	=	Cooling Degree-Days
EMPLOY	=	Service Area Employment (thousands)
CPI	=	Texas Consumer Price Index
CAP	=	Average Price of Electricity to Commercial Ratepayers (dollars per KWH)
PNGC	=	Price of Natural Gas to Commercial Customers (cents per therm)
t	=	Time Period (calendar quarter)
$b_0...b_5$	=	Coefficients to be Estimated
e_t	=	Error term

Specification of the equation used to determine sales to industrial customers varies among models depending on each utility's industrial mix and other factors. For example, "rotary rigs running in Texas" is sometimes used as a variable if a utility's service area's industrial base is tightly linked to the oil and gas industry. The following specification is somewhat exemplary:

$$IS_t = b_0 + b_1 (CDD_t) + b_2 (IAP_t / CPI_t) + b_3 (EMPLOY_t) + b_4 (IAP_{t-4} / PNGI_{t-4}) + e_t$$

where:

IS	=	Sales of Electricity to Industrial Customers (MWH)
CDD	=	Cooling Degree-Days
CPI	=	Texas Consumer Price Index
EMPLOY	=	Service Area Employment (thousands)
IAP	=	Average Electricity Price to Industrial Ratepayers (dollars per KWH)
PNGI	=	Price of Natural Gas to Industrial Customers (cents per therm)
t	=	Time Period (calendar quarter)
$b_0 ... b_4$	=	Coefficients to be Estimated
e_t	=	Error term

Other retail sales are primarily electricity sales for street and highway lighting or municipal purposes. Variables such as population, cooling degree-days, heating degree-days, electricity prices, and natural gas prices are used in their determination. Sales to wholesale customers are modeled using a similar set of explanatory variables.

2.3 ELECTRICITY PRICES SUBMODEL

The main purpose of this submodel is to provide average electricity price projections to the Electricity Sales Submodel. Average electricity prices are here defined as the revenue collected from a particular class divided by the electricity sold to that class in a given quarter. Separate equations are used to model the average prices faced by each class of customers. Each of the price equations takes the following general form:

$$AP_t = b_0 + b_1 (AFC_t) + b_2 (AQT_t) + e_t$$

where:

AP_t	=	Average Price of Electricity to a Particular Customer Class
AFC_t	=	Four-Quarter Moving Average of Fixed Costs Divided by the Four-Quarter Moving Average of Total Sales
AQT_t	=	Average Fuel Cost (Total Fuel Expense divided by Total Sales)
t	=	Time Period (calendar quarter)
$b_0 ... b_3$	=	Coefficients to be estimated
e_t	=	Error term

Under this specification, the average price of electricity to a particular customer class is primarily determined by the utility's average fixed costs and average fuel costs. Rates are assumed to be based partially on a utility's fixed costs divided by total sales over a historical "test year" period. Note that with regard to the 1986 forecast, this equation has been changed in that dummy variables to indicate the change from "automatic fuel adjustment clauses" to fixed fuel factors have been deleted. It was concluded that forecasting performance was not enhanced by such variables.

2.4 UTILITY COST SUBMODEL

The Utility Cost Submodel provides forecasts of a utility's fuel expenses and fixed costs to the Electricity Prices Submodel, which in turn provides price projections to the Electricity Sales Submodel. The determination of fuel expenses and fixed costs have been modified somewhat from earlier forecasts.

The projection of costs within the sales forecasting model seeks to avoid forecasting bias common when variable costs are determined exogenously. A projection of a utility's generation or fuel cost must, at least in part be based either on a forecast or assumptions concerning future sales or generation. Similarly, a projection of cost, fed through price variables, is at least implicit in an electricity sales forecast. Should a marked inconsistency occur between the implicit sales forecast, upon which projected costs and prices are based, and the econometric sales forecasts, which use the projected prices as input, a forecasting bias would be introduced.

Fuel expenses were simulated through a simple economic merit order model. Based on the premise that a utility satisfies the demand for electricity at any given time with the units having the lowest fuel cost, the logic of this submodel may be represented as:

Generation Requirements by Fuel Type

NGR = (TOTGEN) - [(CHY)(FHY)(2190) + (CNU)(FNU)(2190) + (CLI)(FLI)(2190) + (CCO)(FCO)(2190)]
for NGR > 0

NGR = 0 for NGR < 0

COR = (TOTGEN) - NGR -[(CHY)(FHY)(2190) + (CNU)(FNU)(2190) + (CLI)(FLI)(2190)]

LIGR = (TOTGEN) - NGR - COR - [(CNU)(FNU)(2190) + (CHY)(FHY)(2190)]

NUR = (TOTGEN) - NGR - COR - LIGR - [(CHY)(FHY)(2190)]

HYR = (TOTGEN) - NGR - COR - LIGR - NUR

Fuel Costs

NGC = (NGR)(HRNG)(PNG)

COC = (COR)(HRCO)(PCO)

LIGC = (LIGR)(HRLIG)(PLIG)

NUC = (NURC)(HRNU)(PNU)

where:

NGR	=	Generation Requirements from Natural Gas-fired Units
COR	=	Generation Requirements from Coal-fired Units
LIGR	=	Generation Requirements from Lignite-fired Units
NUR	=	Generation Requirements from Nuclear Units
HYR	=	Generation Requirements from Hydro Units
NGC	=	Total Natural Gas Fuel Cost
COC	=	Total Coal Fuel Costs
LIGC	=	Total Lignite Fuel Costs
NUC	=	Total Nuclear Fuel Costs
TOTGEN	=	Total Sales Plus Losses
CHY	=	Hydroelectric Generation Capacity
CNU	=	Nuclear Generation Capacity

CLI	=	Lignite Generation Capacity
CCO	=	Coal Generation Capacity
FHY	=	Capacity Factor for Hydroelectric Units (= .15)
FNU	=	Capacity Factor for Nuclear Units (= .70)
FLI	=	Capacity Factor for Lignite Units (= .70)
FCO	=	Capacity Factor for Coal Units (= .70)
2190	=	Number of Hours in a Calendar Quarter
PNG	=	Unit Price of Natural Gas
PCO	=	Unit Price of Coal
PLIG	=	Unit Price of Lignite
PNU	=	Unit Price of Nuclear Fuel
HRNG	=	Heat Rate--Natural Gas
HRCO	=	Heat Rate--Coal
HRLIG	=	Heat Rate--Lignite
HRNU	=	Heat Rate--Nuclear

NOTE: All time subscripts have been dropped, since no lags and leads are present. Also, the actual programming statements in the computer code are somewhat different than the statements given above; however, the logic is similar.

Generation requirements by fuel type are determined by total generation requirements and capacity factors. Total generation requirements are estimated by adjusting total sales for line loss and company use. In the models, generation from natural gas-fired units is used to meet the generation requirements that cannot be satisfied by the available hydroelectric, nuclear, lignite, or coal fired capacity, since natural gas is the most expensive fuel. Generation from coal-fired units meets the needs that cannot be satisfied by lower-cost baseload units and that have not been met by generation from natural gas units. This calculation is continued down to hydroelectric facilities. This results in what might be described as a "top-down" approach to estimating the generation requirements met by each unit type. By explicitly incorporating capacity considerations, fuel cost savings resulting from new baseload units coming on-line can be reflected in the model. Data Resources Inc.'s (DRI) Energy Model includes a very similar means of calculating fuel costs of generating electricity on a regional level. (U.S. Energy Model Documentation, Data Resources, Inc., 1984)

The total cost for each fuel type is calculated by multiplying generation requirements associated with each fuel type by heat rates and average fuel costs. While utility-specific data are used to represent average fuel costs, heat rates are based on statewide averages. In cases where a utility does not have and does not intend to construct capacity of a given type, the equations associated with that capacity type are excluded from the submodel.

The cost of the fuel necessary to meet generation requirements is the sum of the costs associated with each fuel type:

$$TF = NGC + COC + LIGC + NUC$$

where:

TF	=	Total Cost of Fuel Necessary to Meet Generation Needs
NGC	=	Total Natural Gas Fuel Cost
COC	=	Total Coal Fuel Costs
LIGC	=	Total Lignite Fuel Costs
NUC	=	Total Nuclear Fuel Costs

However, the actual available data concerning each utility's fuel costs are based on fuel purchases. A "mismatch" commonly occurs between each utility's fuels purchased and fuels actually used in any given time period. This discrepancy may be further increased by power exchanges and purchases among utilities, the assumption of choice of a constant ratio between sales and generation requirements, and inventory costing method. A simple stochastic equation was used to correct for this mismatch:

$$CFP_t = b_0 + b_1 TF_t + e_t$$

where:

CFP	=	Cost of Fuels Purchased
TF	=	Total Cost of Fuel Necessary to Meet Generation Needs
t	=	Time Period (calendar quarter)
b_0, b_1	=	Coefficients to be Estimated
e_t	=	error term

Two models were used to determine utility fixed costs. For publicly-owned utilities, fixed costs are based on debt service coverage. Historic fixed costs are derived from annual reports. The quarterly amount of fixed charges is estimated by multiplying the expected debt service coverage ratio times the projected total debt service amount, then subtracting projected interest income. Since utility projections of debt service coverage sometimes move erratically, the fixed cost projections are smoothed in some cases.

Fixed costs for an investor-owned utility are defined as the sum of depreciation expense, return requirements, projected nuclear decommissioning cost, federal income tax, other revenue related taxes, and O&M expense.

Quarterly historical data on total plant, accumulated depreciation, net plant, depreciation expense, and interest expense were obtained from Securities and Exchange Commission Forms 10Q and 10K. A small amount of these data were unavailable; interpolations are utilized in these situations. Allowed rate of return, weighted cost of debt factors, and ratebase amounts are taken from Final Orders issued by the Public Utility Commission of Texas (PUCT).

In order to forecast each of the fixed cost categories it is first necessary to project a utility's total plant. Total plant is the sum of four categories of assets:

$$TOTP = PP + TP + DP + GP$$

where:

TOTP	=	Total Plant in Service
PP	=	Production Plant in Service
TP	=	Transmission Plant in Service
DP	=	Distribution Plant in Service
GP	=	General Plant in Service

Future production plant in service is estimated by adding the estimated construction costs of various generating plant construction projects to this series at the expected on-line dates of the units. In some cases, production plant impacts are "smoothed" over time.

Future values of transmission plant, distribution plant, and general plant are projected using regression techniques. The following specification is used:

$$(P_t - P_{t-1}) / CI_t = b_1 \ln(POP_t) + e_t$$

where:

P	=	Transmission, Distribution, or General Plant
CI	=	Cost Index
POP	=	Service Area Population
t	=	Time Period
b_1	=	Coefficient to be Estimated
e_t	=	Error Term

Changes in plant-in-service are first calculated and deflated by the appropriate Handy-Whitman cost index. The resulting real changes in plant in service are then regressed on the natural logarithm of service area population.

Once projections of total plant are developed, depreciation expense is calculated by multiplying Total Plant by a depreciation rate:

$$DE = dr \bullet TOTP$$

where:

DE	=	Depreciation Expense
dr	=	Depreciation Rate (1975-1985)
TOTP	=	Total Plant in Service

Accumulated depreciation and net plant may then be calculated:

$$AD_t = AD_{t-1} + DE_t$$

$$NP_t = TOTP_t - AD_t$$

where:

AD	=	Accumulated Depreciation
DE	=	Depreciation Expense
NP	=	Net Plant
TOTP	=	Total Plant in Service
t	=	Time Period

In the projected period, ratebase is composed of a component estimated from net plant plus estimated construction work in progress (CWIP) allowed in ratebase. The net plant component is estimated by dividing the projected net plant by the historic average ratio of net plant to ratebase. This factor implicitly includes other components of allowed ratebase as a function of net plant. In general it its assumed that no CWIP will be allowed in the ratebase for future construction projects.

For HL&P, no CWIP associated with the South Texas Project is assumed to be allowed in ratebase per the Commissions Final Order in Docket No. 5779 and HL&P's filing in Docket No. 6765.

Symbolically, ratebase is estimated as:

$$RB = (NP / NPRBF)$$

where:

RB	=	Ratebase
NP	=	Net Plant
NPRBF	=	Nondepreciable Ratebase Factor

Federal income taxes permitted by the regulatory authority are determined by the taxable component of return, multiplied by the tax factor. In order to calculate the taxable component of return, interest expense is calculated and subtracted from the return requirement. These calculations are summarized as follows:

$$IE = w \bullet RB$$

$$RR = ror \bullet RB$$

$$FIT = tf \bullet (RR - IE)$$

where:

IE	=	Interest Expense
RB	=	Ratebase
RR	=	Return Requirement
FIT	=	Federal Income Tax
w	=	Weighted Cost of Debt
ror	=	Regulatory Authority's Allowed Rate of Return
tf	=	Federal Income Tax Factor

The rate of return and weighted cost of debt from actual rate cases are used for the historical period. The allowed weighted cost of debt and rate of return from each utility's most recent rate case are assumed constant in the forecast period.

Initially, other revenue-related taxes are calculated at the rate allowed in each utility's most recent rate case. The resulting fixed cost revenue requirement is then compared with the revenue requirement from the most recent rate case, less fuel and purchased power. If the difference is substantial, other revenue-related taxes are used as a "calibration variable" to bring the model's forecast (as of the period of the last rate case) into line with allowed fixed costs.

Total fixed costs are then calculated as the sum of depreciation expense, return requirement, O&M expense, federal income tax, nuclear decommissioning costs, and other revenue-related taxes.

$$FC = DE + RR + FIT + DC + ORRT$$

where:

FC	=	Fixed Costs
DE	=	Depreciation Expense
RR	=	Return Requirement
FIT	=	Federal Income Tax
DC	=	Nuclear Decommissioning Costs
ORRT	=	Other Revenue-Related Taxes

For those utilities whose service area extends beyond Texas, the fixed costs were first calculated on a total system basis. A Texas allocator was then applied to obtain the portion of fixed costs associated with the Texas system.

2.5 CUSTOMER SUBMODEL

The Electricity Sales Submodel relies, in part, upon a projection of number of residential and commercial customers in the development of an electricity sales projection. These customer projections are provided by the Customer Submodel. These models are run on a personal computer using a multiple regression program.

Each Customer Submodel contains two statistically-estimated equations: one to determine number of residential customers and one for commercial customers. The exact specification of these equations vary among models in order to satisfy statistical criteria. An example specification is:

$$RC_t = a_0 + a_1 (POP_t) + (\text{AR Process of Error Term})$$

$$CC_t = b_0 + b_1 (RC_t) + b_2 (CC_{t-4}) + (\text{AR Process of Error Term})$$

where:

RC	=	Number of Residential Customers
CC	=	Number of Commercial Customers
POP	=	Service Area Population
t	=	Time Period (calendar quarter)
AR Process	=	Auto-Regressive Correction)
$a_0 ... a_1$	=	Coefficients to be estimated
$b_0 ... b_2$	=	Coefficients to be estimated

Residential customers are primarily determined by population. The number of commercial customers is related to the number of Residential Customers. Consequently, commercial customers are modeled primarily as a function of residential customers, commercial customer lagged, and an auto-regressive structure on the error term.

2.6 SUMMARY OF MODELING STRUCTURE

Econometric Electric Demand Forecasting System of the PUCT staff consists of a set of mathematical equations and submodels designed to accurately explain and project the energy demand faced by an electric utility in Texas. A wide range of economic, engineering, financial and accounting concepts are integral to this modeling structure. The modeling method was designed by the PUCT staff to acknowledge the impact of economic, demographic, and climatological factors on electricity consumption.

Within this modeling system, electricity prices have an influence on the quantity of electricity consumed. The relationship between the price of electricity to a particular class and a utility's fixed costs and fuel expenses is estimated statistically.

A utility's fixed costs are determined by a utility's assets (primarily total plant in service), allowed rates of return, depreciation rates, tax factors, weighted cost of debt, and a set of accounting and economic relationships.

Fuel costs are calculated through "economic merit order" logic, based on the assumption that a utility meets a given load level with the combination of generating units having the lowest fuel cost. Fuel prices, capacity factors, heat rates, capacity by fuel type, loss factors, and total sales are among the inputs into this calculation.

The numbers of residential and commercial customers, two other important determinants of energy sales, are projected on the basis of population and lagged number of customers.

Each of the four submodels in this system interact to produce a projection of electricity sales for a given utility. The next chapter will discuss the database used in this forecasting system.

CHAPTER THREE

DATABASE DEVELOPMENT

3.1 INTRODUCTION

To provide data input for the Public Utility Commission of Texas' (PUCT) forecasting models, a computerized database containing over 7,000 data files is maintained by the PUCT staff. This chapter will discuss the data used in this project, its sources, and any transformations performed before the information was used in the forecasting models.

Three of the most imposing problems typically facing electric demand forecasting efforts are:

1. Matching county, SMSA, or state-level data to a utility's geographical service area
2. Transforming data of dissimilar frequencies (annual, quarterly, and monthly, being the most common) to a comparable frequency
3. Developing reasonable projections of the factors affecting future electricity demand

Electric utility service areas rarely correspond to political boundaries. Thus, it is often necessary to proportion and aggregate county-level data in order to derive some estimate of a service area's economic-demographic profile. The next section of this chapter describes how the state is divided into "utility planning regions" for the purposes of this study. Each region is designed to roughly correspond to the service area of a generating electric utility and the nongenerating distribution utilities to which it normally sells power. These regions provide a basis for estimating service area population, personal income, and employment and for developing an economic/demographic profile of the utility's operating environment.

This chapter also lists the sources of the historical data used in this study, as well as the transformations used to develop quarterly time-series. Most of the utility operating data are obtained from the utilities' responses to data requests by the PUCT. Historical economic and demographic data are obtained from a number of state and federal government agencies, as well as Data Resources, Inc.

Finally, in order to forecast the demand for electricity using an econometric approach, it is necessary to obtain projections or make reasonable assumptions regarding the future of the factors assumed to influence electricity demand. The final section of this chapter discusses these exogenous variable projections.

3.2 METHODOLOGY OF AGGREGATING COUNTY-LEVEL ECONOMIC DEMOGRAPHIC DATA

Since utility service areas rarely correspond to any political boundaries, it is necessary to develop a means of proportioning and aggregating county-level economic and demographic data to the "utility planning region" level. Each utility planning region was designed to correspond to the service area of a generating utility and the service areas of any nongenerating distribution utility to which the generator normally sells power. A spring 1985 staff study was the basis for the utility planning region delineation used here.

The basic methodology for deriving the service area divisions is fairly straightforward, but the actual application of these methods is very tedious and time consuming. The first step in the process is to develop a set of maps to illustrate what portion of each county in Texas is served by a particular utility. The initial maps, which are provided by the PUCT engineering staff, indicate which regions are served by each utility, including cooperatives. Then the determination is made as to which generating utilities supply power to the nongenerating utilities and the electric cooperatives through reference to the **Directory of Electric Utilities**, (McGraw-Hill, 1983-1984 edition). The 17 cooperatives that purchase electricity from more than one utility were then contacted by telephone to determine the portion of each county in their service area that is served by a specific generating utility. In most cases, this information is easily derived based on the cooperatives' transmission network. The original maps are then altered to pictorially represent the "utility planning regions" of the major generating utilities in the state. Once the physical determination of which utilities supplied power to specific regions of each county is made, the task is then to indicate the proportion of the population in each county that is contained in a given service area.

The counties are separated into subdivisions defined by the **1980 Census of Housing: General Housing Characteristics**, Part 45 Texas, and these subdivisions were translated to the maps. The census provides housing and population information for each of the subdivisions, including single- and multiple-dwelling units. Using local highway maps and the population of cities within each subdivision as reference, the percentage of each subdivision that is served by a particular utility is determined.

3.3 SOURCES OF HISTORICAL DATA

The data used in this study were obtained from a variety of sources. This subsection reviews data sources and concepts.

Weather Data

Source: U.S. Department of Commerce, National Oceanic and Atmospheric Administration.

Series: Heating Degree Days, Cooling Degree Days, and Precipitation(for rural areas).

Weather Stations:

Texas:	Amarillo	Houston	Abilene
	Lubbock	Austin	Midland
	Brownsville	Port Arthur	Corpus Christi
	San Angelo	Dallas	San Antonio
	Del Rio	Victoria	El Paso
	Waco	Galveston	Wichita Falls
Louisiana:	Shreveport	Lake Charles	Baton Rouge
Arkansas:	Fort Smith		

Population

Source: Based on annual county-level data from Data Resources, Inc., and the U.S. Bureau of Economic Analysis.

Series: Total Population for Texas Counties and Parts of Oklahoma, New Mexico, Louisiana, and Arkansas.

Units: Thousands.

Aggregation to Utility Planning Region-Level:
See Section 3.2.

Transformation to Quarterly:
Annual population estimates were assumed to be the 3rd quarter values of a quarterly series. Linear interpolation was performed to obtain 1st, 2nd, and 4th quarter values.

Personal Income

Source: Based on annual county-level data from Data Resources, Inc.

Series: Total Personal Income by Place of Residence for all counties in Texas and parts of Oklahoma, New Mexico, Louisiana, and Arkansas. (Millions of current dollars.)

Aggregation to Utility Planning Region-Level:
See Section 3.2.

Transformation to Quarterly:
Linear Interpolation.

Employment

Source: Based on annual county-level data from Data Resources, Inc.

Series: Total Non-agricultural Employment Wage and Salary Employment (employment excluding proprietors) in thousands.

Aggregation to Utility Planning Region-Level:
See Section 3.2

Transformation to Quarterly:
Linear Interpolation.

Consumer Price Index

Source: Wharton Econometric Forecasting Associates

Series: Texas CPI.

Price of Natural Gas to Residential, Commercial, and Industrial Consumers

Source: Data Resources, Inc. Energy Database.

Series: Average Price of Natural Gas to Residential and Industrial Consumers--West-South-Central census region. (Cents per therm.)

Fuel Costs

Source: Calculated from U.S. Department of Energy data which was based on FERC Forms 423.

Series: Average fuel cost by utility by fuel type (natural gas, fuel oil, bituminous coal, sub-bituminous coal, lignite, etc.). (Dollars per MMBTU.)

Total fuel cost by utility by fuel type:
Thousands of dollars

Capacity Data

Source: Ten-year load forecasts submitted by the state's generating electric utilities, annual reports to stockholders, and other sources.

Series: Utility-specific MW capacity by fuel type.

Financial Data

Source: Forms 10Q and 10K to the Securities and Exchange Commission. Final Orders of the PUCT.

Series: Depreciation Expense
Plant in Service
Accumulated Depreciation
Allowed Rate of Return
Weighted Cost of Debt

Operating Data

Source: Utility responses to PUCT requests for data. Additional data were obtained from FERC Forms 1, the DOE's statistics of Publicly-Owned Utilities and statistics of Privately-Owned Utilities, and Annual Reports to Stockholders.

Series: The data received varied among utilities. Generally the information included total electric expenses (or operating expenses) and sales and revenues by rate class (residential, commercial, industrial, and other).

3.4 SOURCES OF PROJECTIONS FOR EXOGENOUS VARIABLES

A key step in developing the capability to project future electricity demand is deriving reasonable forecasts of the factors believed to influence the demand for electricity. This subsection describes the forecasts of exogenous variables used in this study.

Weather Data

"Normal" weather was calculated by simply averaging quarterly historical values. "Normal heating degree days" was based on a 21-year average, while "normal cooling degree days" and "precipitation" were calculated from a 15-year sample. These were the largest samples for which data were readily available.

Population, Employment, and Personal Income

The projections of these economic data are obtained by examining projections from the major forecasting services such as DRI, Inc., Wharton Econometric Forecasting Associates (WEFA), and The Baylor Economic Forecasting Service. A "consensus" projection is established for each utility. The following table summarizes the growth rates (in percentage terms) for these variables between 1987 and 1997:

Utility	Population	Employment	Nominal Income
TU	1.764	2.429	7.455
HLP	1.246	1.44	7.776
GSU	- 0.35	0.539	5.713
CPL	1.204	1.774	7.029
CPS	1.519	1.877	6.974
SPS	0.688	1.473	6.536
SWEPCO	1.392	1.831	6.897
LCRA	2.621	3.116	8.225
COA	2.612	nu	nu
WTU	1.092	1.72	6.803
EPE	1.456	1.822	6.791
TNP	nu	nu	nu
BEPC	nu	nu	nu
OTHERS	nu	nu	nu

nu = "not used"

Consumer Price Index

The projected Texas CPI is based on the WEFA Spring 1988 Forecast. The average inflation rate projected over the 1988-1997 period is 4.2 percent.

Price of Natural Gas to Residential, Commercial, and Industrial Consumers

The price projections for natural gas are based on the Fall 1987 DRI Long-term Energy Model Forecast for the West-South-Central Census Region. The average annual growth rates for the forecast period for residential, commercial, and industrial are 6.3, 8.7, and 7.5 percent, respectively.

Fuel Costs

Projected fuel costs by fuel type for each utility serving Texas are calculated by the Fuel Section of the Electric Division of the PUCT. These long-term projections take into account projected spot market price, existing contracts, and a number of other factors. These projected fuel costs are found in Volume I, Chapter Two of this report.

Capacity Expansion Data

Capacity expansion data are based on information provided by the Engineering Section of the Electric Division at the PUCT and augmented with information taken from the ten-year load forecasts filed by the State's generating electric utilities, December 1987. The data reflect Staff-proposed modifications to the utility-proposed capacity expansion plans as described in Volume I, Chapter Six.

Financial Data

Financial data are projected via the fixed cost model described in Chapter Two of this volume. The capacity expansion data drives these projections.

Operating Data

Sales, revenues, and fuel costs, are projected within the econometric models. That is, they are endogenous to the models.

CHAPTER FOUR

MODELING AND FORECASTING PROCEDURES

Software used for the models, database, and many of the data transformation programs are mainly written in TROLL, a mainframe statistical software package developed at M.I.T. The Statistical Analysis System (SAS) is used for some graphics and additional programming applications, while a personal computer spreadsheet package is used in the development of fixed cost projections. Most computations are performed on an IBM 3081 mainframe computer at the University of Texas at Austin.

4.1 SALES MODEL ESTIMATION PROCEDURE

The appropriate choice of estimation technique for a simultaneous equation model is a frequent topic of debate. From a theoretical perspective, two-stage-least-squares, three-stage-least-squares, or full-information-maximum-likelihood techniques are favored for their minimization of simultaneous equation bias. Practitioners often find ordinary least squares to be more robust, especially in small samples where full information estimators lose their desirable properties. Both ordinary least squares and two-stage-least-squares are applied to the models. Since the estimation results do not differ significantly with respect to the choice of estimator, the more theoretically appealing method, two-stage-least-squares (TSLS), is used in producing the final results. In TROLL, two-stage-least-squares is treated as an instrumental variables technique. The modeler is required to choose the instruments used in estimation. In most cases, all of the "important" predetermined (exogenous and lagged endogenous) variables involved in the stochastic equations are selected as instruments. In some of the larger models, dummies and other variables of lesser importance are excluded to enable the instrument set to satisfy the constraint that the number of instruments not exceed the number of observations.

A common problem encountered in dealing with time-series data (especially when some data are interpolated) is the presence of autocorrelation. In the presence of autocorrelation, parameter estimates are not minimum-variance and are not consistent. As a result, a modified TSLS procedure is used when appropriate. This method uses the algorithm developed by Fair (1970) to correct for autocorrelation in simultaneous equation systems.

Simulation is performed using Newton's solution algorithm. All models are simulated in-sample as well as forecasted. In-sample simulations are graphed and summary statistics are printed to assist in detecting problems with identities and potential sources of model instability, such as inappropriate functional forms.

The forecasting model, as well as the estimation method, for the City of Austin (COA) is different from what was just described. The COA model is a single-equation model of total system sales. This more aggregated modeling procedure is used for COA due to data availability problems. The estimation and forecasting method is not the usual single equation estimation method (ordinary least squares or "OLS"). The estimation method for the COA model is a Bayesian estimation and projection. In Bayesian statistics model parameters (such as weather sensitivity of electric demand) are viewed as random quantities with a probability distribution, rather than being viewed as fixed but unknown constants. The Bayesian approach consists of three stages:

1. The formulation of a prior distribution for the model's parameters.
2. The formulation of the likelihood function which generates the observed data (e.g., KWH sales).
3. The derivation of the posterior (parameter) distribution and predictive distribution.

The prior distribution is a vehicle for quantifying one's beliefs about some phenomena before viewing the current data. The current data are viewed through the likelihood function. The prior distribution and likelihood function are combined to produce the posterior distribution of the parameters. The details of this approach are found in Zellner (1971).

The COA model has the following form:

$$TOTSCOA_t = a_0 + a_1 (CDD_t) + a_2 (HDD_t) + a_3 (POP_t) + e_t$$

where:

TOTSCOA	=	Total System Sales in MWH
CDD	=	Cooling Degree-Days
HDD	=	Heating Degree-Days
POP	=	Service Area Population
t	=	Time Period (calendar quarter)
$a_0 ... a_3$	=	Coefficients to be Estimated
e	=	Error Term

Using data from 1974 (first quarter) through 1977 (fourth quarter), a prior distribution for the parameters and variance of TOTSCOA is formulated. This prior distribution is computed by using OLS estimates of the above equation. The (joint) prior distribution for the coefficients and the unknown variance is assumed to be of the Normal-Gamma form. The data for 1978 (first quarter), through 1987 (third quarter), (i.e., the estimation period) are assumed to be generated from a Normal distribution. Combining the prior distribution and the likelihood function yields the posterior distribution. Also, the predictive distribution for TOTSCOA is generated. The expected value of this latter distribution is the staff's official point forecast for total sales for COA. The program for this procedure is written in SAS-IML and resides on an IBM 3081.

4.2 CONVERSION TO PEAK DEMAND PROJECTIONS

The electricity sales projections produced by the Econometric Modeling System described previously are converted into forecasts of peak demand using the Hourly Electric Load Model (HELM). HELM, which was developed by ICF, Inc. for the Electric Power Research Institute (EPRI), is a structural model which applies hourly load shapes to class sales forecasts to obtain hourly demand projections. The hourly demands are then summed across classes and added to hourly losses in order to produce hourly demand for the entire system. Peak demand is extracted from this system hourly demand forecast.

Generation requirements are also calculated in HELM by adding total system losses to the total sales projections. The system losses are obtained by applying loss factors to the class sales projections and summing across classes. Class loss factors used in this step are derived from the results of utility-sponsored loss studies presented in recent rate cases before the Commission and information contained in the utility load forecast filings.

The 1988 load forecast represents the first application of HELM for deriving the PUCT official peak demand forecast. This approach is a significant improvement over previous efforts whereby constant load factors were applied to class sales forecasts. The use of HELM also allows more flexibility in load forecasting because various factors such as alternative weather scenarios, load management programs, and changes in customer mix and consumption patterns can be explicitly modeled.

CHAPTER FIVE

SUMMARY OF ECONOMETRIC FORECASTING SYSTEM METHODOLOGY

The staff of the Public Utility Commission of Texas is presently pursing three distinct projects designed to provide policy-makers , the State's power industry, and the public with accurate independent estimates of the future electricity demand to be faced by each of the State's major generating electric utilities. These projects are:

1. The Econometric Electricity Demand Forecasting System
2. The End-Use Energy Modeling and Forecasting System
3. The Time-Series and Bayesian Forecasting Project

These projects have been extensively integrated with a number of other ongoing strategic planning activities at the Commission.

To provide peak demand estimates for this report the Commission Staff is relying primarily upon the Econometric Electricity Demand Forecasting System. This forecasting system consists of simultaneous equation systems that provide sales and price projections at the customer-class level of detail. Separate models are developed for each major generating utility in the State. Each model seeks to statistically estimate the behavioral relationships among electricity demand and various demand determinants such as weather, population, employment, personal income, electricity prices, prices of alternative energy sources, and industrial production. Each forecasting model actually consists of four submodels:

1. Electricity Sales Submodel
2. Electricity Prices Submodel
3. Utility Cost Submodel
4. Customer Submodel

These submodels are solved simultaneously to yield a projection of a utility's total electricity sales. The database input to this forecasting system is developed from a variety of government, university, and private sources. Projections of demand determinants (employment, population, energy prices, etc.) are developed in-house or obtained from other reputable forecasting sources such as Wharton-Econometric

Forecasting Associates, the University of Texas Bureau of Business Research, the Texas Department of Health, Data Resources, Inc., Texas Comptrollers Office, and the Baylor Forecasting Service.

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APPENDIX

ECONOMETRIC MODELS: STATISTICAL EQUATION ESTIMATION

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A.1 TEXAS UTILITIES ELECTRIC COMPANY

Model -- TU Electric

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SYMBOL DECLARATIONS

ENDOGENOUS:
   AFCTUEC  - AVERAGE FIXED COSTS:DOLLARS PER MWH
   AQTTUEC  - AVERAGE FUEL COSTS:DOLLARS PER MWH
   CAPINST  - INSTRUMENT FOR COAPTUEC
   COAPTUEC - COMMERCIAL AVERAGE PRICE:000'S OF $ PER MWH
   COSTUEC  - COMMERCIAL SALES:MWH
   IAPINST  - INSTRUMENT FOR IAPTUEC
   IAPTUEC  - INDUSTRIAL AVERAGE PRICE:000'S OF $ PER MWH
   ISTUEC   - INDUSTRIAL SALES:MWH
   LIGRCOND - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   LIGTUEC0 - TOTAL COAL COST:DOLLARS
   LIGTUEC1 - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   LIGTUEC2 - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NGCTUEC  - TOTAL NATURAL GAS COST:DOLLARS
   NGRCOND  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NUCCOMP  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NUCTUEC0 - TOTAL NUCLEAR FUEL COST:DOLLARS
   NUCTUEC1 - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NUCTUEC2 - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NURCOND  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   QTTUEC   - TOTAL FUEL EXPENSE ESTIMATE:DOLLARS
   RAPINST  - INSTRUMENT FOR RAPTUEC
   RAPTUEC  - RESIDENTIAL AVERAGE PRICE:000'S OF $ PER MWH
   RSTUEC   - RESIDENTIAL SALES:MWH
   TFTUEC   - TOTAL FUEL EXPENSE REQUIREMENTS:DOLLARS
   TOTSTUEC - TOTAL SYSTEM SALES:MWH
   WAPINST  - INSTRUMENT FOR WAPTUEC
   WAPTUEC  - WHOLESALE AVERAGE PRICE:000'S OF $ PER MWH
   WSTUEC   - WHOLESALE SALES:MWH

EXOGENOUS:
   CCDDINST - INSTRUMENT FOR COMMERCIAL COOLING DEGREE DAYS
   CCTUEC   - COMMERCIAL CUSTOMERS:NUMBER OF CUSTOMERS
   CDDTUEC  - COOLING DEGREE DAYS:NUMBER OF DAYS
   CHDDINST - INSTRUMENT FOR COMMERCIAL HEATING DEGREE DAYS
   FCTUEC   - FOUR-QUARTER SUM OF COSTS:THOUSANDS OF DOLLARS
   HDDTUEC  - HEATING DEGREE DAYS:NUMBER OF DAYS
   PIINST   - INSTRUMENT FOR PERSONAL INCOME (BILLIONS OF DOLLARS)
   QATUECLI - AVERAGE PRICE OF LIGNITE:DOLLARS PER MMBTU
   QATUECNG - AVERAGE PRICE OF NATURAL GAS:DOLLARS PER MMBTU
   QATUECNU - AVERAGE PRICE OF NUCLEAR FUEL:DOLLARS PER MMBTU
   QCTUECLI - LIGNITE CAPACITY:MW
   QCTUECNU - NUCLEAR CAPACITY:MW
   RCDDINST - INSTRUMENT FOR RESIDENTIAL COOLING DEGREE DAYS
   RCTUEC   - RESIDENTIAL CUSTOMERS:NUMBER OF CUSTOMERS
   RHDDINST - INSTRUMENT FOR RESIDENTIAL HEATING DEGREE DAYS
   TEXCPI   - TEXAS CONSUMER PRICE INDEX
   TUNAG    - NON-AGRICULTURAL EMPLOYMENT:THOUSANDS OF PERSONS

COEFFICIENT:
   A0  A1  A2  A3  A4  B0  B1  B2  D0  D1  D2  D3  D4  E0  E1  E2  F0  F1  F2  F3  G0  G1  G2  M0
M1  N0  N1  N2  N3  N4  O0  O1  O2

EQUATIONS
     1:        RSTUEC = A0+A1*RHDDINST+A2*RCDDINST+A3*RAPINST+A4*PIINST
     2:        COSTUEC = D0+D1*CHDDINST+D2*CCDDINST+D3*TUNAG+D4*CAPINST
     3:        ISTUEC = F0+F1*CDDTUEC+F2*IAPINST+F3*TUNAG
     4:        WSTUEC = N0+N1*HDDTUEC+N2*CDDTUEC+N3*TUNAG+N4*WAPINST

       RESIDENTIAL AVERAGE PRICE:
     5:        RAPTUEC = B0+B1*AQTTUEC+B2*AFCTUEC
```

```
     COMMERCIAL/OTHER AVERAGE PRICE:
  6:        COAPTUEC = E0+E1*AQTTUEC+E2*AFCTUEC

     INDUSTRIAL AVERAGE PRICE:
  7:        IAPTUEC = G0+G1*AQTTUEC+G2*AFCTUEC

     WHOLESALE AVERAGE PRICE:
  8:        WAPTUEC = O0+O1*AQTTUEC+O2*AFCTUEC
  9:        RAPINST = RAPTUEC/TEXCPI*RCTUEC
 10:        CAPINST = COAPTUEC/TEXCPI*CCTUEC
 11:        IAPINST = IAPTUEC/TEXCPI
 12:        WAPINST = WAPTUEC/TEXCPI

     TOTAL SYSTEM SALES:
 13:        TOTSTUEC = RSTUEC+COSTUEC+ISTUEC+WSTUEC
 14:        NUCCOMP = RSTUEC*1.0614+COSTUEC*1.0593+ISTUEC*1.0434
                           +WSTUEC*1.0259-0.7*2190*QCTUECNU
 15:        NURCOND = IF NUCCOMP GT 0 THEN NUCCOMP ELSE
                           RSTUEC*1.0614+COSTUEC*1.0593+ISTUEC*1.0434+WSTUEC*1.0259
 16:        LIGRCOND = IF NURCOND EQ NUCCOMP THEN NUCCOMP-QCTUECLI*2190*0.7 ELSE 0
 17:        NGRCOND = IF LIGRCOND GT 0 THEN LIGRCOND ELSE 0
 18:        NUCTUEC1 = QCTUECNU*2190*0.7*0.0105*QATUECNU
 19:        NUCTUEC2 = (RSTUEC*1.0614+COSTUEC*1.0593+ISTUEC*1.0434+WSTUEC*1.0259)*0.0105*QATUECNU
 20:        NUCTUEC0 = IF NURCOND EQ NUCCOMP THEN NUCTUEC1 ELSE NUCTUEC2
 21:        LIGTUEC1 = QCTUECLI*2190*0.7*0.0112*QATUECLI
 22:        LIGTUEC2 = NUCCOMP*0.0112*QATUECLI
 23:        LIGTUEC0 = IF NUCCOMP-QCTUECLI*2190*0.7 GT 0 THEN LIGTUEC1 ELSE LIGTUEC2
 24:        NGCTUEC = NGRCOND*0.0105*QATUECNG
 25:        TFTUEC = NGCTUEC+LIGTUEC0+NUCTUEC0
 26:        QTTUEC = M0+M1*TFTUEC
 27:        AQTTUEC = QTTUEC/TOTSTUEC
 28:        AFCTUEC = FCTUEC/(TOTSTUEC+TOTSTUEC(-1)+TOTSTUEC(-2)+TOTSTUEC(-3))
```

Results -- TU Electric

TWO-STAGE LEAST SQUARES

MODEL NAME: TUEC88

```
   1 :  RSTUEC = A0+A1*RHDDINST+A2*RCDDINST+A3*RAPINST+A4*PIINST

NOB = 39                 NOVAR = 5                 NCOEF = 5                NOINST = 8
RANGE:  1978 1  TO  1987 3
RSQ =           0.953636 CRSQ =          0.948181  F(4/34) =       174.832  PROB>F =
0.
SER =       361728.      SSR =       4.448814E+12  DW(0) =         2.21946  COND =
67.9202
MAX:HAT =        NA      RSTUDENT =        NA      DFFITS =          NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
A0	-1.583027E+06	674120.	-2.34829	0.024815
A1	0.001777	0.000142	12.5278	0.
A2	0.002665	0.000123	21.6006	0.
A3	-0.049215	0.031461	-1.56431	0.127007
A4	741022.	280263.	2.64402	0.012306

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: TUEC88

2 : COSTUEC = D0+D1*CHDDINST+D2*CCDDINST+D3*TUNAG+D4*CAPINST

```
NOB = 38                NOVAR = 6                NCOEF = 6                NOINST = 6
RANGE:  1978 1  TO  1987 3
RSQ =          0.958927 CRSQ =          0.952509 F(4/32) =        149.419   PROB>F =
0.
SER =       230655.     SSR =       1.702449E+12 DW(0) =          1.80708   COND =
130.958
MAX:HAT =        NA     RSTUDENT =       NA      DFFITS =         NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
D0	-4.458918E+06	739514.	-6.02952	0.
D1	0.002497	0.000538	4.63814	0.
D2	0.006927	0.000485	14.286	0.
D3	4705.96	581.355	8.0948	0.
D4	-0.534894	0.22462	-2.38133	0.023369
AR1.0002	0.42	0.162893	2.57838	0.014732

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: TUEC88

3 : ISTUEC = F0+F1*CDDTUEC+F2*IAPINST+F3*TUNAG

```
NOB = 38                NOVAR = 5                NCOEF = 5                NOINST = 5
RANGE:  1978 1  TO  1987 3
RSQ =          0.894141 CRSQ =          0.88131  F(3/33) =        69.6839   PROB>F =
0.
SER =       158336.     SSR =       8.273243E+11 DW(0) =          1.89332   COND =
134.227
MAX:HAT =        NA     RSTUDENT =       NA      DFFITS =         NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
F0	621153.	459034.	1.35317	0.185198
F1	202.055	40.2895	5.01508	0.
F2	-48294.8	24336.7	-1.98445	0.055573
F3	2166.53	192.773	11.2388	0.
AR1.0003	0.3	0.165503	1.81266	0.078991

TWO-STAGE LEAST SQUARES

MODEL NAME: TUEC88

4 : WSTUEC = N0+N1*HDDTUEC+N2*CDDTUEC+N3*TUNAG+N4*WAPINST

```
NOB = 39                NOVAR = 5                NCOEF = 5                NOINST = 8
RANGE:  1978 1  TO  1987 3
RSQ =          0.944908 CRSQ =          0.938427 F(4/34) =        145.788   PROB>F =
0.
SER =       70589.5     SSR =       1.694180E+11 DW(0) =          2.32289   COND =
32.6017
MAX:HAT =        NA     RSTUDENT =       NA      DFFITS =         NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
N0	-1.316611E+06	153862.	-8.55709	0.
N1	328.049	37.6487	8.71342	0.
N2	547.112	36.2821	15.0794	0.
N3	1041.52	58.8276	17.7046	0.
N4	-20968.1	7861.1	-2.66732	0.011624

TWO-STAGE LEAST SQUARES

MODEL NAME: TUEC88

5 : RAPTUEC = B0+B1*AQTTUEC+B2*AFCTUEC

NOB = 39 NOVAR = 3 NCOEF = 3 NOINST = 13
RANGE: 1978 1 TO 1987 3
RSQ = 0.894643 CRSQ = 0.88879 F(2/36) = 152.848 PROB>F =
0.
SER = 4.22081 SSR = 641.349 DW(0) = 1.94432 COND =
26.6216
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
B0	4.79636	4.81878	0.995348	0.326211
B1	1687.68	248.915	6.78014	0.
B2	0.689787	0.3436	2.00753	0.052245

TWO-STAGE LEAST SQUARES

MODEL NAME: TUEC88

6 : COAPTUEC = E0+E1*AQTTUEC+E2*AFCTUEC

NOB = 39 NOVAR = 3 NCOEF = 3 NOINST = 13
RANGE: 1978 1 TO 1987 3
RSQ = 0.930272 CRSQ = 0.926398 F(2/36) = 240.145 PROB>F =
0.
SER = 2.62557 SSR = 248.17 DW(0) = 2.0891 COND =
26.6216
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
E0	9.55141	2.99753	3.18642	0.002974
E1	1231.45	154.838	7.95314	0.
E2	0.646763	0.213737	3.02597	0.004556

TWO-STAGE LEAST SQUARES

MODEL NAME: TUEC88

7 : IAPTUEC = G0+G1*AQTTUEC+G2*AFCTUEC

NOB = 39 NOVAR = 3 NCOEF = 3 NOINST = 13
RANGE: 1978 1 TO 1987 3
RSQ = 0.914894 CRSQ = 0.910166 F(2/36) = 193.5 PROB>F =
0.
SER = 2.51616 SSR = 227.918 DW(0) = 2.25673 COND =
26.6216
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
G0	3.13629	2.87263	1.09178	0.282181
G1	1146.52	148.386	7.7266	0.
G2	0.427391	0.204831	2.08655	0.044073

TWO-STAGE LEAST SQUARES

MODEL NAME: TUEC88

8 : WAPTUEC = O0+O1*AQTTUEC+O2*AFCTUEC

NOB = 39 NOVAR = 3 NCOEF = 3 NOINST = 13
RANGE: 1978 1 TO 1987 3
RSQ = 0.898708 CRSQ = 0.89308 F(2/36) = 159.704 PROB>F =
0.
SER = 2.77899 SSR = 278.02 DW(0) = 1.96038 COND =
26.6216
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
O0	4.51435	3.17269	1.42288	0.16338
O1	1239.14	163.886	7.561	0.
O2	0.301089	0.226227	1.33091	0.191585

TWO-STAGE LEAST SQUARES

MODEL NAME: TUEC88

26 : QTTUEC = M0+M1*TFTUEC

NOB = 39 NOVAR = 2 NCOEF = 2 NOINST = 5
RANGE: 1978 1 TO 1987 3
RSQ = 0.943433 CRSQ = 0.941904 F(1/37) = 617.091 PROB>F =
0.
SER = 32755.5 SSR = 3.969815E+10 DW(0) = 2.23857 COND =
5.42521
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
M0	19974.1	14711.2	1.35774	0.182768
M1	0.939224	0.04254	22.0784	0.

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A.2 HOUSTON LIGHTING & POWER COMPANY

Model -- HL&P

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SYMBOL DECLARATIONS

ENDOGENOUS:
   AFCHLP    - AVERAGE FIXED COSTS:DOLLARS PER MWH
   AQTHLP    - AVERAGE FUEL COSTS:DOLLARS PER MWH
   CAPHLP    - COMMERCIAL AVERAGE PRICE:000'S OF $ PER MWH
   CAPINST   - INSTRUMENT FOR CAPHLP
   COCHLP0   - TOTAL COAL COST:DOLLARS
   COCHLP1   - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   COCHLP2   - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   CORCOND   - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   CSHLP     - COMMERCIAL SALES:MWH
   GENHLP    - GENERATION REQUIREMENTS:MWH
   IAPHLP    - INDUSTRIAL AVERAGE PRICE:000'S OF $ PER MWH
   IAPINST   - INSTRUMENT FOR IAPHLP
   ISHLP     - INDUSTRIAL SALES:MWH
   LIGCHLP0  - TOTAL LIGNITE COST:DOLLARS
   LIGCHLP1  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   LIGCHLP2  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   LIGRCOND  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NGCHLP    - TOTAL NATURAL GAS COST:DOLLARS
   NGRHLP    - NATURAL GAS REQUIREMENTS
   NUCHLP0   - TOTAL NUCLEAR FUEL COST:DOLLARS
   NUCHLP1   - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NUCHLP2   - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NURCOMP   - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NURCOND   - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   QTHLP     - TOTAL FUEL EXPENSE ESTIMATE:DOLLARS
   RAPHLP    - RESIDENTIAL AVERAGE PRICE:000'S OF $ PER MWH
   RAPINST   - INSTRUMENT FOR RAPHLP
   RSHLP     - RESIDENTIAL SALES:MWH
   TFHLP     - TOTAL FUEL EXPENSE REQUIREMENTS:DOLLARS
   TOTSHLP   - TOTAL SYSTEM SALES:MWH

EXOGENOUS:
   CCDDINST  - INSTRUMENT FOR COMMERCIAL COOLING DEGREE DAYS
   CCHLP     - COMMERCIAL CUSTOMERS:NUMBER OF PERSONS
   CDDHOUST  - COOLING DEGREE DAYS:NUMBER OF DAYS
   CHDDINST  - INSTRUMENT FOR COMMERCIAL HEATING DEGREE DAYS
   CORHLP    - COAL CAPACITY REQUIREMENTS:MW
   DUMMY     - RECESSION DUMMY FOR THE INDUSTRIAL SALES CLASS
   FCHLP     - FOUR-QUARTER SUM OF COSTS:THOUSANDS OF DOLLARS
   HLPNAG    - NONAGRICULTURAL EMPLOYMENT:THOUSANDS OF PERSONS
   LIGRHLP   - LIGNITE CAPACITY REQUIREMENTS:MW
   NURHLP    - NUCLEAR CAPACITY REQUIREMENTS:MW
   OSHLP     - COMMERCIAL SALES:MWH
   PIINST    - INSTRUMENT FOR PERSONAL INCOME (BILLIONS OF DOLLARS)
   PNGIND    - PRICE OF NATURAL GAS TO INDUSTRIAL CUSTOMERS:CENTS PER THERM
   PNGRES    - PRICE OF NATURAL GAS TO RESIDENTIAL CUSTOMERS:CENTS PER THERM
   QAHLPCO   - AVERAGE PRICE OF COAL:DOLLARS PER MMBTU
   QAHLPLI   - AVERAGE PRICE OF LIGNITE:DOLLARS PER MMBTU
   QAHLPNG   - AVERAGE PRICE OF NATURAL GAS:DOLLARS PER MMBTU
   QAHLPNU   - AVERAGE PRICE OF NUCLEAR FUEL:DOLLARS PER MMBTU
   RCDDINST  - INSTRUMENT FOR RESIDENTIAL COOLING DEGREE DAYS
   RCHLP     - RESIDENTIAL CUSTOMERS:NUMBER OF PERSONS
   RHDDINST  - INSTRUMENT FOR RESIDENTIAL HEATING DEGREE DAYS
   TEXCPI    - TEXAS CONSUMER PRICE INDEX

COEFFICIENT:
   A0  A1  A2  A3  A5  A6  B0  B1  B2  D0  D1  D2  D3  D4  D5  E0  E1  E2  F0  F1  F2  F3  F4  F5
I0  I1  I2  Y0  Y1

EQUATIONS
     1:        RSHLP = A0+A1*PIINST+A2*RCDDINST+A3*RHDDINST+A5*RAPINST+A6*RSHLP(-4)
```

```
  2:     CSHLP = D0+D1*CAPINST+D2*CHDDINST+D3*CCDDINST+D4*HLPNAG+D5*CSHLP(-4)
  3:     ISHLP = F0+F1*IAPINST+F2*ISHLP(-1)+F3*CDDHOUST+F4*HLPNAG+F5*DUMMY
  4:     RAPHLP = B0+B1*AQTHLP+B2*AFCHLP
  5:     CAPHLP = E0+E1*AQTHLP+E2*AFCHLP
  6:     IAPHLP = I0+I1*AQTHLP+I2*AFCHLP
  7:     RAPINST = RAPHLP(-4)/PNGRES(-4)*RCHLP
  8:     IAPINST = IAPHLP(-4)/PNGIND(-4)
  9:     CAPINST = CAPHLP(-1)/TEXCPI(-1)*CCHLP

   TOTAL SALES:
 10:     TOTSHLP = OSHLP+RSHLP+CSHLP+ISHLP

   COST EQUATIONS:
 11:     GENHLP = 1.0724*RSHLP+1.0724*CSHLP+1.0134*ISHLP+1.0724*OSHLP
 12:     NURCOMP = GENHLP-NURHLP
 13:     NURCOND = IF NURCOMP LE 0 THEN GENHLP ELSE NURCOMP
 14:     LIGRCOND = IF NURCOND EQ NURCOMP THEN LIGRHLP*2190*0.7-NURCOMP ELSE 0
 15:     CORCOND = IF LIGRCOND LT 0 THEN CORHLP+LIGRCOND ELSE 0
 16:     NGRHLP = IF CORCOND LT 0 THEN (-1)*CORCOND ELSE 0
 17:     NGCHLP = NGRHLP*0.0105*QAHLPNG
 18:     NUCHLP0 = IF NURCOND EQ NURCOMP THEN NUCHLP2 ELSE NUCHLP1
 19:     NUCHLP1 = GENHLP*QAHLPNU*0.0105
 20:     NUCHLP2 = NURHLP*QAHLPNU*0.0105
 21:     LIGCHLP0 = IF LIGRCOND LT 0 THEN LIGCHLP2 ELSE LIGCHLP1
 22:     LIGCHLP1 = IF LIGRCOND GT 0 THEN NURCOMP*0.0112*QAHLPLI ELSE 0
 23:     LIGCHLP2 = LIGRHLP*0.0112*QAHLPLI*0.7*2190
 24:     COCHLP0 = IF CORCOND LT 0 THEN COCHLP2 ELSE COCHLP1
 25:     COCHLP1 = IF CORCOND GT 0 THEN LIGRCOND*0.0102*QAHLPCO ELSE 0
 26:     COCHLP2 = CORHLP*0.0102*QAHLPCO
 27:     TFHLP = NGCHLP+NUCHLP0+LIGCHLP0+COCHLP0
 28:     QTHLP = Y0+Y1*TFHLP

   AVERAGE COST EQUATIONS:
 29:     AQTHLP = QTHLP/TOTSHLP
 30:     AFCHLP = FCHLP/(TOTSHLP+TOTSHLP(-1)+TOTSHLP(-2)+TOTSHLP(-3))
```

Results -- HL&P

TWO-STAGE LEAST SQUARES   HILDRETH-LU PROCEDURE

MODEL NAME: HLP88

```
   1 :  RSHLP = A0+A1*PIINST+A2*RCDDINST+A3*RHDDINST+A5*RAPINST+A6*RSHLP(-4)

NOB = 38                NOVAR = 7              NCOEF = 7           NOINST = 10
RANGE:  1978 1  TO  1987 3
RSQ =          0.966863 CRSQ =        0.960449 F(5/31) =    150.752   PROB>F =
0.
SER =     209363.       SSR =     1.358823E+12 DW(0) =       1.79314  COND =
97.5733
MAX:HAT =        NA     RSTUDENT =        NA   DFFITS =        NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
A0	-725102.	824878.	-0.879041	0.386142
A1	459159.	263427.	1.74302	0.091242
A2	0.000695	0.000201	3.46052	0.001593
A3	0.000533	0.000205	2.59667	0.014266
A5	-682.18	276.162	-2.47022	0.019209
A6	0.788266	0.070702	11.1491	0.
AR1.0001	0.34	0.169183	2.00965	0.053241

TWO-STAGE LEAST SQUARES

MODEL NAME: HLP88

4 : RAPHLP = B0+B1*AQTHLP+B2*AFCHLP

NOB = 39 NOVAR = 3 NCOEF = 3 NOINST = 5
RANGE: 1978 1 TO 1987 3
RSQ = 0.891608 CRSQ = 0.885586 F(2/36) = 148.064 PROB>F = 0.
SER = 0.0063 SSR = 0.001429 DW(0) = 2.20191 COND = 9.88993
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
B0	-0.011834	0.004677	-2.53054	0.015903
B1	1.50865	0.172722	8.73455	0.
B2	0.001868	0.000151	12.3958	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: HLP88

5 : CAPHLP = E0+E1*AQTHLP+E2*AFCHLP

NOB = 39 NOVAR = 3 NCOEF = 3 NOINST = 5
RANGE: 1978 1 TO 1987 3
RSQ = 0.88025 CRSQ = 0.873597 F(2/36) = 132.313 PROB>F = 0.
SER = 0.005378 SSR = 0.001041 DW(0) = 2.33343 COND = 9.88993
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
E0	-0.005489	0.003992	-1.37503	0.177621
E1	1.46903	0.147444	9.96332	0.
E2	0.00134	0.000129	10.4201	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: HLP88

6 : IAPHLP = I0+I1*AQTHLP+I2*AFCHLP

NOB = 39 NOVAR = 3 NCOEF = 3 NOINST = 5
RANGE: 1978 1 TO 1987 3
RSQ = 0.84305 CRSQ = 0.83433 F(2/36) = 96.686 PROB>F = 0.
SER = 0.004732 SSR = 0.000806 DW(0) = 2.31547 COND = 9.88993
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
I0	-0.00837	0.003512	-2.38287	0.022579
I1	1.41945	0.129724	10.9421	0.
I2	0.000681	0.000113	6.01685	0.

```
TWO-STAGE LEAST SQUARES  HILDRETH-LU PROCEDURE

MODEL NAME:  HLP88

   2 :  CSHLP = D0+D1*CAPINST+D2*CHDDINST+D3*CCDDINST+D4*HLPNAG+D5*CSHLP(-4)

NOB = 38                    NOVAR = 7                    NCOEF = 7                    NOINST = 10
RANGE:  1978 1   TO   1987 3
RSQ =              0.966312 CRSQ =             0.959792  F(5/31) =        148.202     PROB>F =
0.
SER =        76240.6        SSR =          1.801919E+11  DW(0) =              1.43689  COND =
107.809
MAX:HAT =          NA       RSTUDENT =          NA       DFFITS =            NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
D0	-905356.	639790.	-1.41508	0.167012
D1	-83.6968	50.2048	-1.66711	0.105566
D2	0.000809	0.000412	1.96281	0.058696
D3	0.001008	0.000441	2.28302	0.029442
D4	993.259	438.032	2.26755	0.030477
D5	0.849229	0.085281	9.95797	0.
AR1.0002	0.58	0.128685	4.50714	0.

```
TWO-STAGE LEAST SQUARES

MODEL NAME:  HLP88

   3 :  ISHLP = F0+F1*IAPINST+F2*ISHLP(-1)+F3*CDDHOUST+F4*HLPNAG+F5*DUMMY

NOB = 39                    NOVAR = 6                    NCOEF = 6                    NOINST = 12
RANGE:  1978 1   TO   1987 3
RSQ =              0.688451 CRSQ =             0.641247  F(5/33) =        14.5845     PROB>F =
0.
SER =        323477.        SSR =          3.453040E+12  DW(0) =              2.29028  COND =
88.3106
MAX:HAT =          NA       RSTUDENT =          NA       DFFITS =            NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
F0	2.081651E+06	983200.	2.11722	0.041864
F1	-3.171679E+08	5.133084E+08	-0.617889	0.540889
F2	0.385545	0.128263	3.0059	0.00503
F3	360.554	102.553	3.51577	0.001298
F4	1804.91	1224.27	1.47427	0.149885
F5	-715446.	195289.	-3.66352	0.

```
TWO-STAGE LEAST SQUARES  HILDRETH-LU PROCEDURE

MODEL NAME:  HLP88

  28 :  QTHLP = Y0+Y1*TFHLP

NOB = 38                    NOVAR = 3                    NCOEF = 3                    NOINST = 5
RANGE:  1978 1   TO   1987 3
RSQ =              0.922547 CRSQ =             0.918121  F(1/35) =        208.442     PROB>F =
0.
SER =        30091.9        SSR =          3.169336E+10  DW(0) =              1.85419  COND =
24.1079
MAX:HAT =          NA       RSTUDENT =          NA       DFFITS =            NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
Y0	34693.4	23985.9	1.44641	0.156959
Y1	0.822549	0.062757	13.1068	0.
AR1.0028	0.32	0.160545	1.99321	0.054079

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A.3 GULF STATES UTILITIES COMPANY

Model -- GSU

SYMBOL DECLARATIONS

ENDOGENOUS:

```
   AFCGSU   - AVERAGE FIXED COSTS:DOLLARS PER MWH
   AQTGSU   - AVERAGE FUEL COSTS:DOLLARS PER MWH
   CAPNGSU  - COMMERCIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
   CAPNINST - INSTRUMENT FOR CAPNGSU
   CAPTGSU  - COMMERCIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
   CAPTINST - INSTRUMENT FOR CAPTGSU
   COCGSU0  - TOTAL COAL COST:DOLLARS
   COCGSU1  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   COCGSU2  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   CORCOND  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   CSGSU    - COMMERCIAL SALES:MWH
   CSNGSU   - COMMERCIAL SALES (NON-TEXAS):MWH
   CSTGSU   - COMMERCIAL SALES (TEXAS):MWH
   GENGSU   - TOTAL GENERATION REQUIREMENTS:MWH
   IAPNGSU  - INDUSTRIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
   IAPNINST - INSTRUMENT FOR IAPNGSU
   IAPTGSU  - INDUSTRIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
   IAPTINST - INSTRUMENT FOR IAPTGSU
   ISGSU    - INDUSTRIAL SALES:MWH
   ISNGSU   - INDUSTRIAL SALES (NON-TEXAS):MWH
   ISTGSU   - INDUSTRIAL SALES (TEXAS):MWH
   NGCGSU   - TOTAL NATURAL GAS COST:DOLLARS
   NGRCOND  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NTSALES  - TOTAL NON-TEXAS SYSTEM SALES:MWH
   NUCCOMP  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NUCGSU0  - TOTAL NUCLEAR FUEL COST:DOLLARS
   NUCGSU1  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NUCGSU2  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NURCOND  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   OAPTGSU  - OTHER AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
   OAPTINST - INSTRUMENT FOR OAPTGSU
   OSGSU    - OTHER SALES:MWH
   OSNGSU   - OTHER SALES (NON-TEXAS):MWH
   OSTGSU   - OTHER SALES (TEXAS):MWH
   QTGSU    - TOTAL FUEL EXPENSE ESTIMATE:DOLLARS
   RAPNGSU  - RESIDENTIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
   RAPNINST - INSTRUMENT FOR RAPNGSU
   RAPTGSU  - RESIDENTIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
   RAPTINST - INSTRUMENT FOR RAPTGSU
   RSGSU    - RESIDENTIAL SALES:MWH
   RSNGSU   - RESIDENTIAL SALES (NON-TEXAS):MWH
   RSTGSU   - RESIDENTIAL SALES (TEXAS):MWH
   TFGSU    - TOTAL FUEL EXPENSE REQUIREMENTS:DOLLARS
   TOTSGSU  - TOTAL SYSTEM SALES:MWH
   TSALES   - TOTAL TEXAS SYSTEM SALES:MWH
```

EXOGENOUS:

```
   CAPDUM   - COMMERCIAL AVERAGE PRICE DUMMY
   CCNGSU   - COMMERCIAL CUSTOMERS (NON-TEXAS):NUMBER OF CUSTOMERS
   CCTGSU   - COMMERCIAL CUSTOMERS (TEXAS):NUMBER OF CUSTOMERS
   CDDLAKEC - (LAKE CHARLES) COOLING DEGREE DAYS:NUMBER OF DAYS
   CDDPORTA - (PORT ARTHUR) COOLING DEGREE DAYS:NUMBER OF DAYS
   CNCDDINS - INSTRUMENT FOR (NON-TEXAS) COMMERCIAL COOLING DEGREE DAYS
   CNHDDINS - INSTRUMENT FOR (NON-TEXAS) COMMERCIAL HEATING DEGREE DAYS
   CTCDDINS - INSTRUMENT FOR (TEXAS) COMMERCIAL COOLING DEGREE DAYS
   CTHDDINS - INSTRUMENT FOR (TEXAS) COMMERCIAL HEATING DEGREE DAYS
   FCGSU    - FOUR-QUARTER SUM OF COSTS:THOUSANDS OF DOLLARS
   GSUNNAG  - NONAGRICULTURAL EMPLOYMENT (NON-TEXAS):THOUSANDS OF PERSONS
   GSUNPOP  - SERVICE AREA POPULATION (NON-TEXAS):THOUSANDS OF PERSONS
   GSUTPOP  - SERVICE AREA POPULATION (TEXAS):THOUSANDS OF PERSONS
   HDDLAKEC - (LAKE CHARLES) HEATING DEGREE DAYS:NUMBER OF DAYS
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   HDDPORTA - (PORT ARTHUR) HEATING DEGREE DAYS:NUMBER OF DAYS
   MISSGSU  - MISCELLANEOUS SALES:MWH
   NPIINST  - INSTRUMENT FOR (NON-TEXAS) PERSONAL INCOME (BILLIONS OF DOLLARS)
   PNGCOM   - PRICE OF NATURAL GAS TO COMMERCIAL CUSTOMERS:CENTS PER THERM
   PNGRES   - PRICE OF NATURAL GAS TO RESIDENTIAL CUSTOMERS:CENTS PER THERM
   QAGSUCO  - AVERAGE PRICE OF COAL:DOLLARS PER MMBTU
   QAGSUNG  - AVERAGE PRICE OF NATURAL GAS:DOLLARS PER MMBTU
   QAGSUNU  - AVERAGE PRICE OF NUCLEAR FUEL:DOLLARS PER MMBTU
   QCGSUCO  - COAL CAPACITY:MW
   QCGSUNU  - NUCLEAR CAPACITY:MW
   RCNGSU   - RESIDENTIAL CUSTOMERS (NON-TEXAS):NUMBER OF CUSTOMERS
   RCTGSU   - RESIDENTIAL CUSTOMERS (TEXAS):NUMBER OF CUSTOMERS
   RNCDDINS - INSTRUMENT FOR (NON-TEXAS) RESIDENTIAL COOLING DEGREE DAYS
   RNHDDINS - INSTRUMENT FOR (NON-TEXAS) RESIDENTIAL HEATING DEGREE DAYS
   RTCDDINS - INSTRUMENT FOR (TEXAS) RESIDENTIAL COOLING DEGREE DAYS
   RTHDDINS - INSTRUMENT FOR (TEXAS) RESIDENTIAL HEATING DEGREE DAYS
   TEXCPI   - TEXAS CONSUMER PRICE INDEX
   TPIINST  - INSTRUMENT FOR (TEXAS) PERSONAL INCOME (BILLIONS OF DOLLARS)
   WSGSU    - WHOLESALE SALES:MWH

COEFFICIENT:
   A0  A1  A2  A3  A4  A5  B0  B1  B2  D0  D1  D2  D4  D5  E0  E1  E2  F0  F1  F2  F3  F4  G0  G1
G2  H0  H1  H2  H3  I0  I1  I2  K0  K1  K2  K3  K4  K5  L0  L1  L2  M0  M1  M2  M3  M4  M5  N0  N1
N2  O0  O1  O3  O4  P0  P1  P2  Q0  Q1  Q2  Q3  Q5  U0  U1

EQUATIONS
     1:      RSTGSU = A0+A1*RTHDDINS+A2*RTCDDINS+A3*TPIINST+A4*RSTGSU(-4)+A5*RAPTINST
     2:      CSTGSU = D0+D1*CTHDDINS+D2*CTCDDINS+D4*CAPTINST+D5*CSTGSU(-4)
     3:      ISTGSU = F0+F1*IAPTINST+F2*GSUTPOP(-4)+F3*ISTGSU(-1)+F4*CDDPORTA
     4:      OSTGSU = H0+H1*CDDPORTA+H2*HDDPORTA+H3*OAPTINST
     5:      RSNGSU = K0+K1*NPIINST(-4)+K2*RNHDDINS+K3*RNCDDINS+K4*RAPNINST+K5*RSNGSU(-1)
     6:      CSNGSU = M0+M1*CAPNINST*CAPDUM+M2*GSUNNAG+M3*CNCDDINS+M4*CNHDDINS+M5*CSNGSU(-1)
     7:      ISNGSU = O0+O1*IAPNINST+O3*CDDLAKEC+O4*ISNGSU(-1)
     8:      OSNGSU = Q0+Q1*OSNGSU(-4)+Q2*GSUNPOP+Q3*CDDLAKEC+Q5*HDDLAKEC
     9:      RAPTGSU = B0+B1*AQTGSU+B2*AFCGSU
    10:      CAPTGSU = E0+E1*AQTGSU+E2*AFCGSU
    11:      IAPTGSU = G0+G1*AQTGSU+G2*AFCGSU
    12:      OAPTGSU = I0+I1*AQTGSU+I2*AFCGSU
    13:      RAPNGSU = L0+L1*AQTGSU+L2*AFCGSU
    14:      CAPNGSU = N0+N1*AQTGSU+N2*AFCGSU
    15:      IAPNGSU = P0+P1*AQTGSU+P2*AFCGSU
    16:      RAPTINST = RAPTGSU/PNGRES*RCTGSU
    17:      CAPTINST = CAPTGSU/PNGCOM*CCTGSU
    18:      IAPTINST = IAPTGSU(-1)/TEXCPI(-1)
    19:      OAPTINST = OAPTGSU/TEXCPI
    20:      RAPNINST = RAPNGSU(-4)/TEXCPI(-4)*RCNGSU
    21:      CAPNINST = CAPNGSU(-2)/PNGCOM(-2)*CCNGSU
    22:      IAPNINST = IAPNGSU/TEXCPI

      TOTAL SYSTEM SALES:
    23:      TOTSGSU = WSGSU+RSGSU+CSGSU+OSGSU+ISGSU+MISSGSU

      SALES EQUATIONS:
    24:      RSNGSU = RSGSU-RSTGSU
    25:      CSNGSU = CSGSU-CSTGSU
    26:      ISNGSU = ISGSU-ISTGSU
    27:      OSNGSU = OSGSU-OSTGSU

      COST EQUATIONS:
    28:      GENGSU = 1.1073*RSTGSU+1.1073*CSTGSU+1.027*ISTGSU+1.1073*OSTGSU
                           +1.0855*RSNGSU+1.1073*CSNGSU+1.0278*ISNGSU+1.1073*OSNGSU
                           +1.0778*WSGSU+1.1073*MISSGSU
    29:      NUCCOMP = GENGSU-0.7*2190*QCGSUNU
    30:      NURCOND = IF NUCCOMP GT 0 THEN NUCCOMP ELSE GENGSU
    31:      CORCOND = IF NURCOND EQ NUCCOMP THEN NUCCOMP-QCGSUCO*2190*0.7 ELSE 0
    32:      NGRCOND = IF CORCOND GT 0 THEN CORCOND ELSE 0
    33:      NUCGSU1 = QCGSUNU*2190*0.7*0.0105*QAGSUNU
    34:      NUCGSU2 = GENGSU*0.0105*QAGSUNU
    35:      NUCGSU0 = IF NURCOND EQ NUCCOMP THEN NUCGSU1 ELSE NUCGSU2
    36:      COCGSU1 = QCGSUCO*2190*0.7*0.0102*QAGSUCO
    37:      COCGSU2 = NUCCOMP*0.0102*QAGSUCO
    38:      COCGSU0 = IF NUCCOMP-QCGSUCO*2190*0.7 GT 0 THEN COCGSU1 ELSE COCGSU2
```

```
39:      NGCGSU = NGRCOND*0.0105*QAGSUNG
40:      TFGSU = NGCGSU+COCGSU0+NUCGSU0
41:      QTGSU = U0+U1*TFGSU
42:      AQTGSU = QTGSU/TOTSGSU
43:      AFCGSU = FCGSU/(TOTSGSU+TOTSGSU(-1)+TOTSGSU(-2)+TOTSGSU(-3))

   SALES EQUATIONS:
44:      NTSALES = RSNGSU+CSNGSU+ISNGSU+OSNGSU
45:      TSALES = RSTGSU+CSTGSU+ISTGSU+OSTGSU
```

Results -- GSU

TWO-STAGE LEAST SQUARES

MODEL NAME: GSU88

1 : RSTGSU = A0+A1*RTHDDINS+A2*RTCDDINS+A3*TPIINST+A4*RSTGSU(-4)+A5*RAPTINST

```
NOB = 39                 NOVAR = 6                NCOEF = 6                NOINST = 9
RANGE:  1978 1  TO  1987 3
RSQ =          0.957211  CRSQ =          0.950728  F(5/33) =       147.646  PROB>F =
0.
SER =        41301.      SSR =       5.629058E+10  DW(0) =         1.75191  COND =
60.2167
MAX:HAT =       NA       RSTUDENT =        NA      DFFITS =          NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
A0	-158219.	115822.	-1.36605	0.181162
A1	0.001228	0.00024	5.11255	0.
A2	0.00127	0.000218	5.81775	0.
A3	402924.	163285.	2.46762	0.018959
A4	0.521261	0.084221	6.18919	0.
A5	-444.957	222.753	-1.99754	0.054066

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: GSU88

2 : CSTGSU = D0+D1*CTHDDINS+D2*CTCDDINS+D4*CAPTINST+D5*CSTGSU(-4)

```
NOB = 38                 NOVAR = 6                NCOEF = 6                NOINST = 8
RANGE:  1978 1  TO  1987 3
RSQ =          0.959538  CRSQ =          0.953215  F(4/32) =       151.772  PROB>F =
0.
SER =        16435.7     SSR =       8.644276E+09  DW(0) =         2.16332  COND =
18.8227
MAX:HAT =       NA       RSTUDENT =        NA      DFFITS =          NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
D0	146154.	76660.9	1.9065	0.065599
D1	0.001284	0.000523	2.4578	0.01958
D2	0.00201	0.000609	3.29916	0.002385
D4	-206.617	1682.12	-0.122831	0.903009
D5	0.616964	0.106869	5.77307	0.
AR1.0002	0.76	0.120689	6.29719	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: GSU88

3 : ISTGSU = F0+F1*IAPTINST+F2*GSUTPOP(-4)+F3*ISTGSU(-1)+F4*CDDPORTA

NOB = 39 NOVAR = 5 NCOEF = 5 NOINST = 8
RANGE: 1978 1 TO 1987 3
RSQ = 0.393435 CRSQ = 0.322075 F(4/34) = 5.51335 PROB>F = 0.001566
SER = 54927.2 SSR = 1.025779E+11 DW(0) = 1.64197 COND = 68.2451
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
F0	593272.	209025.	2.83828	0.007597
F1	-1.704920E+07	1.095808E+07	-1.55586	0.129002
F2	306.707	233.483	1.31362	0.197771
F3	0.580759	0.138065	4.20642	0.
F4	36.0025	15.0048	2.39939	0.022049

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: GSU88

4 : OSTGSU = H0+H1*CDDPORTA+H2*HDDPORTA+H3*OAPTINST

NOB = 38 NOVAR = 5 NCOEF = 5 NOINST = 7
RANGE: 1978 1 TO 1987 3
RSQ = 0.928168 CRSQ = 0.919461 F(3/33) = 106.601 PROB>F = 0.
SER = 836.424 SSR = 2.308694E+07 DW(0) = 2.38161 COND = 7.3638
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
H0	34509.7	4535.57	7.60867	0.
H1	2.45049	0.423056	5.79237	0.
H2	2.56981	0.51254	5.01387	0.
H3	-162309.	149873.	-1.08298	0.286669
AR1.0004	0.92	0.026101	35.2475	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: GSU88

5 : RSNGSU = K0+K1*NPIINST(-4)+K2*RNHDDINS+K3*RNCDDINS+K4*RAPNINST+K5*RSNGSU(-1)

NOB = 39 NOVAR = 6 NCOEF = 6 NOINST = 9
RANGE: 1978 1 TO 1987 3
RSQ = 0.910501 CRSQ = 0.89694 F(5/33) = 67.1437 PROB>F = 0.
SER = 72715.2 SSR = 1.744878E+11 DW(0) = 2.38277 COND = 53.1366
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
K0	-216939.	154498.	-1.40415	0.169617
K1	253240.	215956.	1.17264	0.249335
K2	0.001917	0.000276	6.95224	0.
K3	0.002849	0.00022	12.9783	0.
K4	-16.7649	24.325	-0.689202	0.495514
K5	0.199333	0.06811	2.92663	0.006161

TWO-STAGE LEAST SQUARES

MODEL NAME: GSU88

6 : CSNGSU = M0+M1*CAPNINST*CAPDUM+M2*GSUNNAG+M3*CNCDDINS+M4*CNHDDINS+M5*CSNGSU(-1)

NOB = 39 NOVAR = 6 NCOEF = 6 NOINST = 10
RANGE: 1978 1 TO 1987 3
RSQ = 0.93567 CRSQ = 0.925923 F(5/33) = 95.9964 PROB>F = 0.
SER = 28036.5 SSR = 2.593955E+10 DW(0) = 1.94734 COND = 71.3537
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
M0	-39927.4	104977.	-0.380344	0.706127
M1	-196.396	645.503	-0.304252	0.762846
M2	502.489	238.351	2.10819	0.042692
M3	0.007894	0.000565	13.982	0.
M4	0.004418	0.000786	5.62165	0.
M5	0.417109	0.051836	8.04665	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: GSU88

7 : ISNGSU = O0+O1*IAPNINST+O3*CDDLAKEC+O4*ISNGSU(-1)

NOB = 39 NOVAR = 4 NCOEF = 4 NOINST = 7
RANGE: 1978 1 TO 1987 3
RSQ = 0.890356 CRSQ = 0.880958 F(3/35) = 94.7382 PROB>F = 0.
SER = 106642. SSR = 3.980398E+11 DW(0) = 1.6668 COND = 31.4186
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
O0	549881.	228084.	2.41087	0.021301
O1	-3.230901E+07	1.139072E+07	-2.83643	0.007535
O3	86.1751	30.9128	2.78768	0.008523
O4	0.90315	0.062537	14.4419	0.

HILDRETH-LU PROCEDURE

MODEL NAME: GSU88

8 : OSNGSU = Q0+Q1*OSNGSU(-4)+Q2*GSUNPOP+Q3*CDDLAKEC+Q5*HDDLAKEC

NOB = 38 NOVAR = 6 NCOEF = 6 RANGE: 1978 1 TO 1987 3

```
RSQ =             0.888584 CRSQ =          0.871175  F(4/32) =        51.0423    PROB>F =
0.
SER =          1042.65     SSR =       3.478778E+07  DW(0) =          2.00447    COND =
92.3547
MAX:HAT =         0.232055 RSTUDENT =      2.99723   DFFITS =         0.95112
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
Q0	-10735.1	6712.1	-1.59937	0.119566
Q1	0.611574	0.128107	4.77393	0.
Q2	19.5053	8.1176	2.40284	0.02224
Q3	0.798272	0.567434	1.40681	0.169122
Q5	1.24138	0.759497	1.63447	0.11196
AR1.0008	0.3	0.169261	1.77241	0.085848

TWO-STAGE LEAST SQUARES

MODEL NAME: GSU88

9 : RAPTGSU = B0+B1*AQTGSU+B2*AFCGSU

```
NOB = 39                   NOVAR = 3                    NCOEF = 3                   NOINST = 5
RANGE:  1978 1  TO  1987 3
RSQ =             0.734438 CRSQ =          0.719685  F(2/36) =        49.7808    PROB>F =
0.
SER =             0.009925 SSR =           0.003546  DW(0) =          0.798671   COND =
19.1476
MAX:HAT =         NA       RSTUDENT =      NA        DFFITS =         NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
B0	-0.008422	0.010172	-0.827954	0.413152
B1	3.75712	0.977524	3.8435	0.
B2	0.002162	0.000717	3.01402	0.004701

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: GSU88

10 : CAPTGSU = E0+E1*AQTGSU+E2*AFCGSU

```
NOB = 38                   NOVAR = 4                    NCOEF = 4                   NOINST = 5
RANGE:  1978 1  TO  1987 3
RSQ =             0.858362 CRSQ =          0.845865  F(2/34) =        68.6831    PROB>F =
0.
SER =             0.005711 SSR =           0.001109  DW(0) =          1.68627    COND =
22.084
MAX:HAT =         NA       RSTUDENT =      NA        DFFITS =         NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
E0	0.00247	0.007985	0.309318	0.758968
E1	2.3681	0.751048	3.15306	0.003368
E2	0.002328	0.000556	4.18619	0.
AR1.0010	0.28	0.15873	1.764	0.086716

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: GSU88

11 : IAPTGSU = G0+G1*AQTGSU+G2*AFCGSU

NOB = 38 NOVAR = 4 NCOEF = 4 NOINST = 5
RANGE: 1978 1 TO 1987 3
RSQ = 0.792909 CRSQ = 0.774636 F(2/34) = 43.3931 PROB>F = 0.
SER = 0.003989 SSR = 0.000541 DW(0) = 1.62038 COND = 23.8243
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
G0	-0.000924	0.004959	-0.186287	0.853327
G1	2.14574	0.467998	4.58494	0.
G2	0.000639	0.000344	1.85675	0.072028
AR1.0011	0.18	0.162115	1.11032	0.274652

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: GSU88

12 : OAPTGSU = I0+I1*AQTGSU+I2*AFCGSU

NOB = 38 NOVAR = 4 NCOEF = 4 NOINST = 5
RANGE: 1978 1 TO 1987 3
RSQ = 0.834566 CRSQ = 0.819969 F(2/34) = 57.1733 PROB>F = 0.
SER = 0.007489 SSR = 0.001907 DW(0) = 1.76836 COND = 22.084
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
I0	-0.000791	0.010472	-0.075533	0.940234
I1	2.55391	0.985011	2.59277	0.013937
I2	0.003016	0.000729	4.13554	0.
AR1.0012	0.28	0.158858	1.76258	0.08696

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: GSU88

13 : RAPNGSU = L0+L1*AQTGSU+L2*AFCGSU

NOB = 38 NOVAR = 4 NCOEF = 4 NOINST = 5
RANGE: 1978 1 TO 1987 3
RSQ = 0.920496 CRSQ = 0.913481 F(2/34) = 131.218 PROB>F = 0.
SER = 0.003976 SSR = 0.000537 DW(0) = 2.26658 COND = 13.6038
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
L0	0.009829	0.008613	1.14116	0.261779
L1	1.72291	0.753761	2.28575	0.028625
L2	0.002394	0.000663	3.60793	0.
AR1.0013	0.64	0.143264	4.46727	0.

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: GSU88

14 : CAPNGSU = N0+N1*AQTGSU+N2*AFCGSU

NOB = 38 NOVAR = 4 NCOEF = 4 NOINST = 5
RANGE: 1978 1 TO 1987 3
RSQ = 0.892643 CRSQ = 0.88317 F(2/34) = 94.2334 PROB>F = 0.
SER = 0.00418 SSR = 0.000594 DW(0) = 1.67607 COND = 20.4621
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
N0	0.002058	0.00645	0.319034	0.751653
N1	2.16971	0.60391	3.59277	0.001022
N2	0.001835	0.000452	4.05942	0.
AR1.0014	0.36	0.15055	2.39123	0.022471

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: GSU88

15 : IAPNGSU = P0+P1*AQTGSU+P2*AFCGSU

NOB = 38 NOVAR = 4 NCOEF = 4 NOINST = 5
RANGE: 1978 1 TO 1987 3
RSQ = 0.910774 CRSQ = 0.902901 F(2/34) = 115.685 PROB>F = 0.
SER = 0.002964 SSR = 0.000299 DW(0) = 1.75305 COND = 20.8862
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
P0	-0.006065	0.004461	-1.35963	0.182897
P1	2.19551	0.418214	5.24971	0.
P2	0.001023	0.000312	3.28035	0.002399
AR1.0015	0.34	0.153465	2.21549	0.033526

TWO-STAGE LEAST SQUARES

MODEL NAME: GSU88

41 : QTGSU = U0+U1*TFGSU

NOB = 39 NOVAR = 2 NCOEF = 2 NOINST = 7
RANGE: 1978 1 TO 1987 3
RSQ = 0.657726 CRSQ = 0.648476 F(1/37) = 71.1006 PROB>F = 0.
SER = 14851.4 SSR = 8.160891E+09 DW(0) = 1.82944 COND = 5.78535
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
U0	57160.6	7084.69	8.06819	0.
U1	0.394773	0.054724	7.21384	0.

A.4 CENTRAL POWER AND LIGHT COMPANY

Model -- CPL

```
SYMBOL DECLARATIONS

ENDOGENOUS:
   AFCCPL   - AVERAGE FIXED COSTS:DOLLARS PER MWH
   AQTCPL   - AVERAGE FUEL COSTS:DOLLARS PER MWH
   CAPCPL   - COMMERCIAL AVERAGE PRICE:000'S OF $ PER MWH
   CAPINST  - INSTRUMENT FOR CAPCPL
   COCCPL0  - TOTAL COAL COST:DOLLARS
   COCCPL1  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   COCCPL2  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   CORCOND  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   CSCPL    - COMMERCIAL SALES:MWH
   GENCPL   - GENERATION REQUIREMENTS:MWH
   IAPCPL   - INDUSTRIAL AVERAGE PRICE:000'S OF $ PER MWH
   IAPINST  - INSTRUMENT FOR IAPCPL
   ISCPL    - INDUSTRIAL SALES:MWH
   NGCCPL   - TOTAL NATURAL GAS COST:DOLLARS
   NGRCOND  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NUCCOMP  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NUCCPL0  - TOTAL NUCLEAR FUEL COST:DOLLARS
   NUCCPL1  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NUCCPL2  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NURCOND  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   QTCPL    - TOTAL FUEL EXPENSE ESTIMATE:DOLLARS
   RAPCPL   - RESIDENTIAL AVERAGE PRICE:000'S OF $ PER MWH
   RAPINST  - INSTRUMENT FOR RAPCPL
   RSCPL    - RESIDENTIAL SALES:MWH
   TFCPL    - TOTAL FUEL EXPENSE REQUIREMENTS:DOLLARS
   TOTSCPL  - TOTAL SYSTEM SALES:MWH

EXOGENOUS:
   CCCPL    - COMMERCIAL CUSTOMERS:NUMBER OF CUSTOMERS
   CCDDCPL  - INSTRUMENT FOR COMMERCIAL COOLING DEGREE DAYS
   CDDCPL   - COOLING DEGREE DAYS:NUMBER OF DAYS
   CPLPOP   - POPULATION DATA:THOUSANDS OF PERSONS
   FCCPL    - FOUR-QUARTER SUM OF COSTS:THOUSANDS OF DOLLARS
   IRDUM    - DUMMY FOR INDUSTRIAL REVENUES
   OSCPL    - OTHER SALES:MWH
   PIINST   - INSTRUMENT FOR PERSONAL INCOME (BILLIONS OF DOLLARS)
   PNGCOM   - PRICE OF NATURAL GAS TO COMMERCIAL CUSTOMERS:CENTS PER THERM
   PNGIND   - PRICE OF NATURAL GAS TO INDUSTRIAL CUSTOMERS:CENTS PER THERM
   PNGRES   - PRICE OF NATURAL GAS TO RESIDENTIAL CUSTOMERS:CENTS PER THERM
   QACPLCO  - AVERAGE PRICE OF COAL:DOLLARS PER MMBTU
   QACPLNG  - AVERAGE PRICE OF NATURAL GAS:DOLLARS PER MMBTU
   QACPLNU  - AVERAGE PRICE OF NUCLEAR FUEL:DOLLARS PER MMBTU
   QCCPLCO  - COAL CAPACITY:MW
   QCCPLNU  - NUCLEAR CAPACITY:MW
   RCCPL    - RESIDENTIAL CUSTOMERS:NUMBER OF CUSTOMERS
   RCDDCPL  - INSTRUMENT FOR RESIDENTIAL COOLING DEGREE DAYS
   RHDDCPL  - INSTRUMENT FOR RESIDENTIAL HEATING DEGREE DAYS
   WSCPL    - WHOLESALE SALES:MWH

COEFFICIENT:
   A0  A1  A2  A3  A4  B0  B1  B2  B3  B5  C0  C1  C2  C3  C4  C5  E0  E1  E2  F0  F1  F2  G0  G1
G2  I0  I1

EQUATIONS
     1:        RSCPL = A0+A1*RCDDCPL+A2*RHDDCPL+A3*RAPINST+A4*PIINST
     2:        CSCPL = B0+B1*CCDDCPL+B2*CAPINST+B5*CPLPOP+B3*CSCPL(-1)
     3:        ISCPL = C0+C1*ISCPL(-1)+C2*CPLPOP+C3*IAPINST+C4*CDDCPL+C5*IRDUM
     4:        RAPCPL = E0+E1*AFCCPL+E2*AQTCPL
     5:        CAPCPL = F0+F1*AFCCPL+F2*AQTCPL
     6:        IAPCPL = G0+G1*AFCCPL+G2*AQTCPL
     7:        QTCPL = I0+I1*TFCPL
```

```
 8:   RAPINST = RAPCPL/PNGRES*RCCPL
 9:   CAPINST = CAPCPL(-1)/PNGCOM(-1)*CCCPL
10:   IAPINST = IAPCPL(-4)/PNGIND(-4)
11:   TOTSCPL = RSCPL+CSCPL+ISCPL+WSCPL+OSCPL
12:   GENCPL = RSCPL*1.1081+CSCPL*1.1071+ISCPL*1.0406+WSCPL*1.0371+OSCPL*1.1081
13:   NUCCOMP = GENCPL-0.7*2190*QCCPLNU
14:   NURCOND = IF NUCCOMP GT 0 THEN NUCCOMP ELSE GENCPL
15:   CORCOND = IF NURCOND EQ NUCCOMP THEN NUCCOMP-0.7*2190*QCCPLCO ELSE 0
16:   NGRCOND = IF CORCOND GT 0 THEN CORCOND ELSE 0
17:   NUCCPL1 = QCCPLNU*2190*0.7*0.0105*QACPLNU
18:   NUCCPL2 = GENCPL*0.0105*QACPLNU
19:   NUCCPL0 = IF NURCOND EQ NUCCOMP THEN NUCCPL1 ELSE NUCCPL2
20:   COCCPL1 = QCCPLCO*2190*0.7*0.0102*QACPLCO
21:   COCCPL2 = NUCCOMP*0.0102*QACPLCO
22:   COCCPL0 = IF NUCCOMP-QCCPLCO*2190*0.7 GT 0 THEN COCCPL1 ELSE COCCPL2
23:   NGCCPL = NGRCOND*0.0105*QACPLNG
24:   TFCPL = NGCCPL+COCCPL0+NUCCPL0
25:   AQTCPL = QTCPL/TOTSCPL
26:   AFCCPL = FCCPL/(TOTSCPL+TOTSCPL(-1)+TOTSCPL(-2)+TOTSCPL(-3))
```

Results -- CPL

```
TWO-STAGE LEAST SQUARES

MODEL NAME:  CPL88

   1 :  RSCPL = A0+A1*RCDDCPL+A2*RHDDCPL+A3*RAPINST+A4*PIINST

NOB = 40                 NOVAR = 5                NCOEF = 5              NOINST = 8
RANGE:  1978 1  TO  1987 4
RSQ =          0.839422  CRSQ =         0.82107   F(4/35) =       45.7406    PROB>F =
0.
SER =       111616.      SSR =      4.360341E+11  DW(0) =         2.27823    COND =
226.208
MAX:HAT =       NA       RSTUDENT =       NA      DFFITS =        NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
A0	-516841.	1.605746E+06	-0.321869	0.749466
A1	0.001576	0.000206	7.66383	0.
A2	0.002243	0.000473	4.74114	0.
A3	-0.411752	1.62479	-0.253418	0.801428
A4	786649.	493217.	1.59494	0.119718

```
TWO-STAGE LEAST SQUARES

MODEL NAME:  CPL88

   2 :  CSCPL = B0+B1*CCDDCPL+B2*CAPINST+B5*CPLPOP+B3*CSCPL(-1)

NOB = 40                 NOVAR = 5                NCOEF = 5              NOINST = 7
RANGE:  1978 1  TO  1987 4
RSQ =          0.951161  CRSQ =         0.94558   F(4/35) =       170.411    PROB>F =
0.
SER =        37221.7     SSR =      4.849084E+10  DW(0) =         2.45359    COND =
110.801
MAX:HAT =       NA       RSTUDENT =       NA      DFFITS =        NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
B0	-97685.5	251360.	-0.388627	0.699906
B1	0.00305	0.000186	16.3683	0.
B2	-1.36755	1.39233	-0.982197	0.332744
B3	0.482132	0.083823	5.75181	0.
B5	314.083	85.6905	3.66533	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: CPL88

3 : ISCPL = C0+C1*ISCPL(-1)+C2*CPLPOP+C3*IAPINST+C4*CDDCPL+C5*IRDUM

NOB = 40 NOVAR = 6 NCOEF = 6 NOINST = 9
RANGE: 1978 1 TO 1987 4
RSQ = 0.561486 CRSQ = 0.496998 F(5/34) = 8.70691 PROB>F = 0.
SER = 88092.2 SSR = 2.638479E+11 DW(0) = 1.81383 COND = 66.3523
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
C0	147417.	245308.	0.600947	0.551861
C1	0.356873	0.171495	2.08095	0.045042
C2	408.224	202.584	2.01509	0.051857
C3	-196790.	199077.	-0.988514	0.329884
C4	50.99	23.1613	2.20151	0.034586
C5	191357.	71490.1	2.67669	0.01136

TWO-STAGE LEAST SQUARES

MODEL NAME: CPL88

4 : RAPCPL = E0+E1*AFCCPL+E2*AQTCPL

NOB = 40 NOVAR = 3 NCOEF = 3 NOINST = 5
RANGE: 1978 1 TO 1987 4
RSQ = 0.909189 CRSQ = 0.904281 F(2/37) = 185.22 PROB>F = 0.
SER = 2.97338 SSR = 327.116 DW(0) = 1.66991 COND = 10.8867
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
E0	18.1491	2.41357	7.51963	0.
E1	0.916996	0.078052	11.7485	0.
E2	712.121	66.9199	10.6414	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: CPL88

5 : CAPCPL = F0+F1*AFCCPL+F2*AQTCPL

NOB = 40 NOVAR = 3 NCOEF = 3 NOINST = 5
RANGE: 1978 1 TO 1987 4
RSQ = 0.866647 CRSQ = 0.859439 F(2/37) = 120.23 PROB>F = 0.

SER = 4.02005 SSR = 597.95 DW(0) = 1.67435 COND =
10.8867
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
F0	13.5629	3.26318	4.15633	0.
F1	1.00284	0.105528	9.50306	0.
F2	802.625	90.4767	8.87107	0.

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: CPL88

6 : IAPCPL = G0+G1*AFCCPL+G2*AQTCPL

NOB = 39 NOVAR = 4 NCOEF = 4 NOINST = 5
RANGE: 1978 1 TO 1987 4
RSQ = 0.894042 CRSQ = 0.88496 F(2/35) = 98.4399 PROB>F =
0.
SER = 3.03845 SSR = 323.127 DW(0) = 1.38516 COND =
15.8602
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
G0	-1.22539	6.97441	-0.175698	0.861544
G1	1.21008	0.189418	6.3884	0.
G2	84.2618	165.553	0.508973	0.613965
AR1.0006	0.6	0.128554	4.6673	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: CPL88

7 : QTCPL = I0+I1*TFCPL

NOB = 40 NOVAR = 2 NCOEF = 2 NOINST = 5
RANGE: 1978 1 TO 1987 4
RSQ = 0.869439 CRSQ = 0.866003 F(1/38) = 253.052 PROB>F =
0.
SER = 11596.8 SSR = 5.110460E+09 DW(0) = 2.05374 COND =
8.72252
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
I0	-6792.01	8101.98	-0.838315	0.407096
I1	1.18856	0.083733	14.1946	0.

A.5 CITY PUBLIC SERVICE BOARD OF SAN ANTONIO

Model -- CPS

```
SYMBOL DECLARATIONS

ENDOGENOUS:
   AFCSA    - AVERAGE FIXED COSTS:DOLLARS PER MWH
   AQTSA    - AVERAGE FUEL COSTS:DOLLARS PER MWH
   CAPINST  - INSTRUMENT FOR CAPSA
   CAPSA    - COMMERCIAL AVERAGE PRICE:000'S OF $ PER MWH
   COCSA0   - TOTAL COAL COST:DOLLARS
   COCSA1   - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   COCSA2   - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   CORCOND  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   CSSA     - COMMERCIAL SALES:MWH
   IAPINST  - INSTRUMENT FOR IAPSA
   IAPSA    - INDUSTRIAL AVERAGE PRICE:000'S OF $ PER MWH
   ISSA     - INDUSTRIAL SALES:MWH
   NGCSA    - TOTAL NATURAL GAS COST:DOLLARS
   NGRCOND  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NUCCOMP  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NUCSA0   - TOTAL NUCLEAR COST:DOLLARS
   NUCSA1   - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NUCSA2   - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NURCOND  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   QTSA     - TOTAL FUEL EXPENSE ESTIMATE:DOLLARS
   RAPINST  - INSTRUMENT FOR RAPSA
   RAPSA    - RESIDENTIAL AVERAGE PRICE:000'S OF $ PER MWH
   RSSA     - RESIDENTIAL SALES:MWH
   TFSA     - TOTAL FUEL EXPENSE REQUIREMENTS:DOLLARS
   TOTSSA   - TOTAL SYSTEM SALES:MWH

EXOGENOUS:
   CCDDSAN  - INSTRUMENT FOR COMMERCIAL COOLING DEGREE DAYS
   CDDSANAN - COOLING DEGREE DAYS:NUMBER OF DAYS
   CHDDSAN  - INSTRUMENT FOR COMMERCIAL HEATING DEGREE DAYS
   FCSA     - FOUR-QUARTER SUM OF COSTS:THOUSANDS OF DOLLARS
   OSSA     - OTHER SALES:MWH
   PIINST   - INSTRUMENT FOR PERSONAL INCOME (BILLIONS OF DOLLARS)
   QASACO   - AVERAGE PRICE OF COAL:DOLLARS PER MMBTU
   QASANG   - AVERAGE PRICE OF NATURAL GAS:DOLLARS PER MMBTU
   QASANU   - AVERAGE PRICE OF NUCLEAR FUEL:DOLLARS PER MMBTU
   QCSACO   - COAL CAPACITY:MW
   QCSANU   - NUCLEAR CAPACITY:MW
   RCDDSAN  - INSTRUMENT FOR RESIDENTIAL COOLING DEGREE DAYS
   RCSA     - RESIDENTIAL CUSTOMERS:NUMBER OF CUSTOMERS
   RHDDSAN  - INSTRUMENT FOR RESIDENTIAL HEATING DEGREE DAYS
   SAPOP    - SERVICE AREA POPULATION:THOUSANDS OF PERSONS
   TEXCPI   - TEXAS CONSUMER PRICE INDEX

COEFFICIENT:
   A0  A1  A2  A3  A4  B0  B1  B2  B3  B4  D0  D1  D2  E0  E1  E2  G0  G1  H0  H1  H2  H3  H5  I0
I1  I2

EQUATIONS
     1:        RSSA = A0+A1*RHDDSAN+A2*RCDDSAN+A3*PIINST+A4*RAPINST
     2:        CSSA = B0+B1*CHDDSAN+B2*CCDDSAN+B3*SAPOP+B4*CSSA(-1)
     3:        ISSA = H0+H1*SAPOP+H2*IAPINST+H3*CDDSANAN+H5*ISSA(-4)
     4:        RAPSA = D0+D1*AQTSA+D2*AFCSA
     5:        CAPSA = E0+E1*AQTSA+E2*AFCSA
     6:        IAPSA = I0+I1*AQTSA+I2*AFCSA
     7:        QTSA = G0+G1*TFSA
     8:        RAPINST = RAPSA/TEXCPI*RCSA
     9:        CAPINST = CAPSA/TEXCPI
    10:        IAPINST = IAPSA/(-2)/TEXCPI(-2)
    11:        TOTSSA = RSSA+CSSA+OSSA+ISSA
    12:        NUCCOMP = TOTSSA*1.06-0.65*2190*QCSANU
```

```
13:     NURCOND = IF NUCCOMP GT 0 THEN NUCCOMP ELSE TOTSSA*1.06
14:     CORCOND = IF NURCOND EQ NUCCOMP THEN NUCCOMP-QCSACO*2190*0.7 ELSE 0
15:     NGRCOND = IF CORCOND GT 0 THEN CORCOND ELSE 0
16:     NUCSA1 = QCSANU*2190*0.65*0.0105*QASANU
17:     NUCSA2 = TOTSSA*1.06*0.0105*QASANU
18:     NUCSA0 = IF NURCOND EQ NUCCOMP THEN NUCSA1 ELSE NUCSA2
19:     COCSA1 = QCSACO*2190*0.7*0.0102*QASACO
20:     COCSA2 = NUCCOMP*0.0102*QASACO
21:     COCSA0 = IF NUCCOMP-QCSACO*2190*0.7 GT 0 THEN COCSA1 ELSE COCSA2
22:     NGCSA = NGRCOND*0.0105*QASANG
23:     TFSA = NGCSA+COCSA0+NUCSA0
24:     AQTSA = QTSA/TOTSSA
25:     AFCSA = FCSA/(TOTSSA+TOTSSA(-1)+TOTSSA(-2)+TOTSSA(-3))
```

Results -- CPS

TWO-STAGE LEAST SQUARES

MODEL NAME: SA88

1 : RSSA = A0+A1*RHDDSAN+A2*RCDDSAN+A3*PIINST+A4*RAPINST

```
NOB = 39                 NOVAR = 5                NCOEF = 5             NOINST = 8
RANGE:  1978 1  TO  1987 3
RSQ =        0.945396 CRSQ =         0.938972 F(4/34) =       147.165   PROB>F =
0.
SER =        78866.4    SSR =      2.114767E+11 DW(0) =         2.01264  COND =
49.9995
MAX:HAT =        NA     RSTUDENT =       NA     DFFITS =          NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
A0	-537936.	114267.	-4.7077	0.
A1	0.001188	0.000194	6.13585	0.
A2	0.001849	0.000132	13.9693	0.
A3	925625.	229258.	4.03748	0.
A4	-38.1923	23.8586	-1.60078	0.118679

ORDINARY LEAST SQUARES

MODEL NAME: SA88

2 : CSSA = B0+B1*CHDDSAN+B2*CCDDSAN+B3*SAPOP+B4*CSSA(-1)

```
NOB = 39                 NOVAR = 5                NCOEF = 5             RANGE:  1978 1
TO  1987 3
RSQ =        0.973394 CRSQ =         0.970264 F(4/34) =       310.983   PROB>F =
0.
SER =        19997.4    SSR =      1.359647E+10 DW(0) =         2.2089   COND =
71.1007
MAX:HAT =    0.247577 RSTUDENT =     -2.38331   DFFITS =       -1.36711
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
B0	-575875.	68465.6	-8.41116	0.
B1	0.002045	0.00044	4.65209	0.
B2	0.003792	0.00029	13.0758	0.
B3	700.438	81.0565	8.64136	0.
B4	0.177188	0.052719	3.36099	0.001931

TWO-STAGE LEAST SQUARES   HILDRETH-LU PROCEDURE

MODEL NAME: SA88

3 :   ISSA = H0+H1*SAPOP+H2*IAPINST+H3*CDDSANAN+H5*ISSA(-4)

NOB = 38   NOVAR = 6   NCOEF = 6   NOINST = 7
RANGE: 1978 1 TO 1987 3
RSQ = 0.917431   CRSQ = 0.904529   F(4/32) = 71.1106   PROB>F =
0.
SER = 35848.8   SSR = 4.112443E+10   DW(0) = 1.81796   COND =
307.507
MAX:HAT = NA   RSTUDENT = NA   DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
H0	9221.84	180370.	0.051127	0.959542
H1	332.854	253.171	1.31474	0.197941
H2	-4.314031E+06	1.179364E+07	-0.365793	0.716927
H3	49.2976	20.7609	2.37454	0.023735
H5	0.610208	0.187048	3.26231	0.002629
AR1.0003	0.46	0.147841	3.11145	0.0039

TWO-STAGE LEAST SQUARES

MODEL NAME: SA88

4 :   RAPSA = D0+D1*AQTSA+D2*AFCSA

NOB = 39   NOVAR = 3   NCOEF = 3   NOINST = 5
RANGE: 1978 1 TO 1987 3
RSQ = 0.967237   CRSQ = 0.965417   F(2/36) = 531.408   PROB>F =
0.
SER = 0.002261   SSR = 0.000184   DW(0) = 2.06428   COND =
11.0909
MAX:HAT = NA   RSTUDENT = NA   DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
D0	0.008766	0.001746	5.02193	0.
D1	0.73015	0.073977	9.86996	0.
D2	0.00025	1.222968E-05	20.4681	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: SA88

5 :   CAPSA = E0+E1*AQTSA+E2*AFCSA

NOB = 39   NOVAR = 3   NCOEF = 3   NOINST = 5
RANGE: 1978 1 TO 1987 3
RSQ = 0.960542   CRSQ = 0.958349   F(2/36) = 438.177   PROB>F =
0.
SER = 0.002423   SSR = 0.000211   DW(0) = 2.09571   COND =
11.0909
MAX:HAT = NA   RSTUDENT = NA   DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
E0	0.006359	0.001871	3.3989	0.001667
E1	0.872581	0.079286	11.0055	0.
E2	0.000222	1.310740E-05	16.9052	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: SA88

6 : IAPSA = I0+I1*AQTSA+I2*AFCSA

NOB = 39 NOVAR = 3 NCOEF = 3 NOINST = 5
RANGE: 1978 1 TO 1987 3
RSQ = 0.910007 CRSQ = 0.905007 F(2/36) = 182.016 PROB>F =
0.
SER = 0.002531 SSR = 0.000231 DW(0) = 2.19406 COND =
11.0909
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
I0	0.00218	0.001954	1.1159	0.271858
I1	0.596858	0.082809	7.20765	0.
I2	0.000146	1.368974E-05	10.6905	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: SA88

7 : QTSA = G0+G1*TFSA

NOB = 39 NOVAR = 2 NCOEF = 2 NOINST = 5
RANGE: 1978 1 TO 1987 3
RSQ = 0.947546 CRSQ = 0.946128 F(1/37) = 668.381 PROB>F =
0.
SER = 5134.16 SSR = 9.753073E+08 DW(0) = 2.37529 COND =
6.55498
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
G0	1946.51	2757.21	0.705969	0.484629
G1	0.971658	0.048412	20.0708	0.

A.6 SOUTHWESTERN PUBLIC SERVICE COMPANY

Model -- SPS

```
SYMBOL DECLARATIONS

ENDOGENOUS:
   AFCSPS   - AVERAGE FIXED COSTS:DOLLARS PER MWH
   AQTSPS   - AVERAGE FUEL COSTS:DOLLARS PER MWH
   CAPNINST - INSTRUMENT FOR CAPNSPS
   CAPNSPS  - COMMERCIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
   CAPTINST - INSTRUMENT FOR CAPTSPS
   CAPTSPS  - COMMERCIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
   COCCOMP  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   COCSPS0  - TOTAL COAL COST:DOLLARS
   COCSPS1  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   CSNSPS   - COMMERCIAL SALES (NON-TEXAS):MWH
   CSSPS    - COMMERCIAL SALES:MWH
   CSTSPS   - COMMERCIAL SALES (TEXAS):MWH
   IAPNINST - INSTRUMENT FOR IAPNSPS
   IAPNSPS  - INDUSTRIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
   IAPTINST - INSTRUMENT FOR IAPTSPS
   IAPTSPS  - INDUSTRIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
   ISNSPS   - INDUSTRIAL SALES (NON-TEXAS):MWH
   ISSPS    - INDUSTRIAL SALES:MWH
   NGCSPS   - TOTAL NATURAL GAS COST:DOLLARS
   NGRSPS   - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NISTSPS  - INDUSTRIAL SALES (TEXAS):MWH
   QTSPS    - TOTAL FUEL EXPENSE ESTIMATE:DOLLARS
   RAPNINST - INSTRUMENT FOR RAPNSPS
   RAPNSPS  - RESIDENTIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
   RAPTINST - INSTRUMENT FOR RAPTSPS
   RAPTSPS  - RESIDENTIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
   RSNSPS   - RESIDENTIAL SALES (NON-TEXAS):MWH
   RSSPS    - RESIDENTIAL SALES:MWH
   RSTSPS   - RESIDENTIAL SALES (TEXAS):MWH
   TFSPS    - TOTAL FUEL EXPENSE REQUIREMENTS:DOLLARS
   TOTSSPS  - TOTAL SYSTEM SALES:MWH

EXOGENOUS:
   CCNSPS   - COMMERCIAL CUSTOMERS (NON-TEXAS):NUMBER OF CUSTOMERS
   CCTSPS   - COMMERCIAL CUSTOMERS (TEXAS):NUMBER OF CUSTOMERS
   CNCDDINS - INSTRUMENT FOR (NON-TEXAS) COMMERCIAL COOLING DEGREE DAYS
   CNHDDINS - INSTRUMENT FOR (NON-TEXAS) COMMERCIAL HEATING DEGREE DAYS
   CTCDDINS - INSTRUMENT FOR (TEXAS) COMMERCIAL COOLING DEGREE DAYS
   CTHDDINS - INSTRUMENT FOR (TEXAS) COMMERCIAL HEATING DEGREE DAYS
   CUSTDUM  - COMMERCIAL CUSTOMERS DUMMY
   FCSPS    - FOUR-QUARTER SUM OF COSTS:THOUSANDS OF DOLLARS
   ISNDUM   - INDUSTRIAL REVENUE DUMMY
   MISSPS   - MISCELLANEOUS SALES:MWH
   PIINST   - INSTRUMENT FOR PERSONAL INCOME (BILLIONS OF DOLLARS)
   PNGCOM   - PRICE OF NATURAL GAS TO COMMERCIAL CUSTOMERS:CENTS PER THERM
   PNGRES   - PRICE OF NATURAL GAS TO RESIDENTIAL CUSTOMERS:CENTS PER THERM
   QASPSCO  - AVERAGE PRICE OF COAL:DOLLARS PER MMBTU
   QASPSNG  - AVERAGE PRICE OF NATURAL GAS:DOLLARS PER MMBTU
   QCSPSCO  - COAL CAPACITY:MW
   RCNSPS   - RESIDENTIAL CUSTOMERS (NON-TEXAS):NUMBER OF CUSTOMERS
   RCTSPS   - RESIDENTIAL CUSTOMERS (TEXAS):NUMBER OF CUSTOMERS
   RNCDDINS - INSTRUMENT FOR (NON-TEXAS) RESIDENTIAL COOLING DEGREE DAYS
   RNHDDINS - INSTRUMENT FOR (NON-TEXAS) RESIDENTIAL HEATING DEGREE DAYS
   RTCDDINS - INSTRUMENT FOR (TEXAS) RESIDENTIAL COOLING DEGREE DAYS
   RTHDDINS - INSTRUMENT FOR (TEXAS) RESIDENTIAL HEATING DEGREE DAYS
   SPSPOP   - SERVICE AREA POPULATION :THOUSANDS OF PERSONS
   TEXCPI   - TEXAS CONSUMER PRICE INDEX

COEFFICIENT:
   A0  A1  A2  A3  A4  B0  B1  B2  D0  D1  D2  D3  D4  D5  E0  E1  E2  F0  F2  F3  G0  G1  G2  J0
J2  J3  J4  J5  K0  K1  K2  L0  L1  L2  L3  L4  M0  M1  M2  N0  N1  N2  N3  O0  O1  O2  W0  W1
```

```
EQUATIONS
     1:        RSTSPS = A0+A1*RAPTINST+A2*RTCDDINS+A3*RTHDDINS+A4*PIINST
     2:        CSTSPS = D0+D2*CTHDDINS+D3*CTCDDINS+D4*CAPTINST+D5*SPSPOP+D1*CSTSPS(-1)
     3:        NISTSPS = F0+F2*IAPTINST+F3*SPSPOP
     4:        RSNSPS = J0+J2*RNCDDINS+J3*RNHDDINS+J4*RAPNINST*CUSTDUM+J5*RSNSPS(-4)
     5:        CSNSPS = L0+L1*CNHDDINS+L2*CNCDDINS+L3*CUSTDUM*CAPNINST+L4*CSNSPS(-4)
     6:        ISNSPS = N0+N1*ISNSPS(-4)+N2*IAPNINST*ISNDUM+N3*SPSPOP
     7:        RAPTSPS = B0+B1*AQTSPS+B2*AFCSPS
     8:        CAPTSPS = E0+E1*AQTSPS+E2*AFCSPS
     9:        IAPTSPS = G0+G1*AQTSPS+G2*AFCSPS
    10:        RAPNSPS = K0+K1*AQTSPS+K2*AFCSPS
    11:        CAPNSPS = M0+M1*AQTSPS+M2*AFCSPS
    12:        IAPNSPS = O0+O1*AQTSPS+O2*AFCSPS
    13:        RAPTINST = RAPTSPS/TEXCPI*RCTSPS
    14:        CAPTINST = CAPTSPS(-2)/TEXCPI(-2)*CCTSPS
    15:        IAPTINST = IAPTSPS/TEXCPI
    16:        RAPNINST = RAPNSPS(-4)/PNGRES(-4)*RCNSPS
    17:        CAPNINST = CAPNSPS(-2)/PNGCOM(-2)*CCNSPS
    18:        IAPNINST = IAPNSPS(-2)/TEXCPI(-2)

   TOTAL COMPANY SALES:
    19:        TOTSSPS = RSSPS+CSSPS+ISSPS+MISSPS
    20:        COCCOMP = RSSPS*1.0789+CSSPS*1.0787+ISSPS*1.0399+MISSPS*1.0464-QCSPSCO*0.7*2190
    21:        NGRSPS = IF COCCOMP GT 0 THEN COCCOMP ELSE 0
    22:        NGCSPS = NGRSPS*QASPSNG*0.0105
    23:        COCSPS1 = QCSPSCO*0.0102*QASPSCO*0.7*2190
    24:        COCSPS0 = IF COCCOMP GT 0 THEN COCSPS1 ELSE (RSSPS*1.0789+CSSPS*1.0787+ISSPS*1.0399
                                +MISSPS*1.0464)*0.0102*QASPSCO
    25:        TFSPS = NGCSPS+COCSPS0
    26:        QTSPS = W0+W1*TFSPS

   AVERAGE COST EQUATIONS:
    27:        AQTSPS = QTSPS/TOTSSPS

   SALES EQUATIONS:
    28:        RSSPS = RSTSPS+RSNSPS
    29:        CSSPS = CSTSPS+CSNSPS
    30:        ISSPS = NISTSPS+ISNSPS

   AVERAGE FIXED COST EQUATIONS:
    31:        AFCSPS = FCSPS/(TOTSSPS+TOTSSPS(-1)+TOTSSPS(-2)+TOTSSPS(-3))
```

Results -- SPS

```
TWO-STAGE LEAST SQUARES

MODEL NAME:  SPS88

   1 :  RSTSPS = A0+A1*RAPTINST+A2*RTCDDINS+A3*RTHDDINS+A4*PIINST

NOB = 39                    NOVAR = 5                NCOEF = 5                NOINST = 8
RANGE:  1978 1  TO  1987 3
RSQ =              0.928459 CRSQ =           0.920043 F(4/34) =      110.314   PROB>F =
0.
SER =          20303.4      SSR =        1.401573E+10 DW(0) =          1.73616  COND =
77.9455
MAX:HAT =          NA       RSTUDENT =          NA    DFFITS =          NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
A0	-313346.	82927.4	-3.77856	0.
A1	-4.66441	13.2512	-0.351999	0.727011
A2	0.001489	8.009002E-05	18.5912	0.
A3	0.000557	4.409450E-05	12.6241	0.
A4	624804.	131980.	4.73409	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: SPS88

2 : CSTSPS = D0+D2*CTHDDINS+D3*CTCDDINS+D4*CAPTINST+D5*SPSPOP+D1*CSTSPS(-1)

NOB = 39 NOVAR = 6 NCOEF = 6 NOINST = 9
RANGE: 1978 1 TO 1987 3
RSQ = 0.950805 CRSQ = 0.943351 F(5/33) = 127.561 PROB>F =
0.
SER = 13486.1 SSR = 6.001893E+09 DW(0) = 2.06388 COND =
171.468
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
D0	-397236.	92880.8	-4.27683	0.
D1	0.467717	0.057922	8.07494	0.
D2	0.001221	0.000162	7.5265	0.
D3	0.005213	0.000307	16.9576	0.
D4	-74.9199	69.235	-1.08211	0.287048
D5	755.676	181.289	4.16834	0.

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: SPS88

3 : NISTSPS = F0+F2*IAPTINST+F3*SPSPOP

NOB = 38 NOVAR = 4 NCOEF = 4 NOINST = 5
RANGE: 1978 1 TO 1987 3
RSQ = 0.888708 CRSQ = 0.878888 F(2/34) = 90.5006 PROB>F =
0.
SER = 26503. SSR = 2.388196E+10 DW(0) = 1.85569 COND =
30.44
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
F0	-1.096512E+06	289134.	-3.79241	0.
F2	-1.078935E+07	6.916899E+06	-1.55985	0.128055
F3	3288.02	334.993	9.81519	0.
AR1.0003	0.34	0.153987	2.20798	0.034092

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: SPS88

4 : RSNSPS = J0+J2*RNCDDINS+J3*RNHDDINS+J4*RAPNINST*CUSTDUM+J5*RSNSPS(-4)

NOB = 38 NOVAR = 6 NCOEF = 6 NOINST = 9
RANGE: 1978 1 TO 1987 3
RSQ = 0.970977 CRSQ = 0.966442 F(4/32) = 214.114 PROB>F =
0.
SER = 5718.06 SSR = 1.046278E+09 DW(0) = 2.0655 COND =
13.273
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
J0	58826.1	10602.2	5.54849	0.
J2	0.000655	7.702992E-05	8.50009	0.
J3	0.000333	3.804229E-05	8.76643	0.
J4	-145.752	43.2705	-3.36838	0.001984
J5	0.377269	0.075162	5.01942	0.
AR1.0004	0.88	0.063859	13.7803	0.

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: SPS88

5 : CSNSPS = L0+L1*CNHDDINS+L2*CNCDDINS+L3*CUSTDUM*CAPNINST+L4*CSNSPS(-4)

NOB = 38 NOVAR = 6 NCOEF = 6 NOINST = 9
RANGE: 1978 1 TO 1987 3
RSQ = 0.975259 CRSQ = 0.971393 F(4/32) = 252.28 PROB>F =
0.
SER = 5296.64 SSR = 8.977421E+08 DW(0) = 1.95935 COND =
11.8715
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
L0	62111.6	14399.1	4.31358	0.
L1	0.00073	0.000132	5.54367	0.
L2	0.002575	0.000379	6.80191	0.
L3	-175.267	219.561	-0.798261	0.430603
L4	0.444207	0.085778	5.17854	0.
AR1.0005	0.92	0.050951	18.0565	0.

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: SPS88

6 : ISNSPS = N0+N1*ISNSPS(-4)+N2*IAPNINST*ISNDUM+N3*SPSPOP

NOB = 38 NOVAR = 5 NCOEF = 5 NOINST = 7
RANGE: 1978 1 TO 1987 3
RSQ = 0.921832 CRSQ = 0.912357 F(3/33) = 97.2915 PROB>F =
0.
SER = 17973.4 SSR = 1.066046E+10 DW(0) = 1.10616 COND =
17.6381
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
N0	-929486.	730480.	-1.27243	0.212113
N1	0.355575	0.142719	2.49144	0.017926
N2	-822125.	752210.	-1.09295	0.282332
N3	1466.25	983.24	1.49125	0.145395
AR1.0006	0.8	0.09283	8.61786	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: SPS88

7 : RAPTSPS = B0+B1*AQTSPS+B2*AFCSPS

NOB = 39 NOVAR = 3 NCOEF = 3 NOINST = 5

```
RANGE:  1978 1  TO  1987 3
RSQ =             0.828002 CRSQ =         0.818447  F(2/36) =      86.6523    PROB>F =
0.
SER =             0.004824 SSR =          0.000838  DW(0) =        2.12823    COND =
13.0152
MAX:HAT =         NA       RSTUDENT =     NA        DFFITS =       NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
B0	0.004871	0.004612	1.0562	0.297912
B1	0.966535	0.189284	5.10628	0.
B2	0.002576	0.000312	8.25846	0.

```
TWO-STAGE LEAST SQUARES

MODEL NAME:  SPS88

   8 :  CAPTSPS = E0+E1*AQTSPS+E2*AFCSPS

NOB = 39                  NOVAR = 3                NCOEF = 3               NOINST = 5
RANGE:  1978 1  TO  1987 3
RSQ =             0.851996 CRSQ =         0.843773  F(2/36) =      103.618    PROB>F =
0.
SER =             0.003896 SSR =          0.000546  DW(0) =        2.37492    COND =
13.0152
MAX:HAT =         NA       RSTUDENT =     NA        DFFITS =       NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
E0	0.003682	0.003725	0.988675	0.329421
E1	0.763955	0.152859	4.99776	0.
E2	0.002387	0.000252	9.47572	0.

```
TWO-STAGE LEAST SQUARES

MODEL NAME:  SPS88

   9 :  IAPTSPS = G0+G1*AQTSPS+G2*AFCSPS

NOB = 39                  NOVAR = 3                NCOEF = 3               NOINST = 5
RANGE:  1978 1  TO  1987 3
RSQ =             0.797149 CRSQ =         0.78588   F(2/36) =      70.7353    PROB>F =
0.
SER =             0.003345 SSR =          0.000403  DW(0) =        2.57059    COND =
13.0152
MAX:HAT =         NA       RSTUDENT =     NA        DFFITS =       NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
G0	0.002009	0.003198	0.62833	0.533754
G1	0.747944	0.131249	5.69867	0.
G2	0.001434	0.000216	6.63229	0.

```
TWO-STAGE LEAST SQUARES  HILDRETH-LU PROCEDURE

MODEL NAME:  SPS88

  10 :  RAPNSPS = K0+K1*AQTSPS+K2*AFCSPS

NOB = 38                  NOVAR = 4                NCOEF = 4               NOINST = 5
```

RANGE: 1978 1 TO 1987 3
RSQ = 0.90847 CRSQ = 0.900393 F(2/34) = 112.487 PROB>F =
0.
SER = 0.003071 SSR = 0.000321 DW(0) = 2.03827 COND =
16.0753
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
K0	0.012637	0.011409	1.10758	0.275817
K1	0.603812	0.243091	2.48389	0.018084
K2	0.002353	0.000626	3.75564	0.
AR1.0010	0.74	0.161192	4.59081	0.

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: SPS88

11 : CAPNSPS = M0+M1*AQTSPS+M2*AFCSPS

NOB = 38 NOVAR = 4 NCOEF = 4 NOINST = 5
RANGE: 1978 1 TO 1987 3
RSQ = 0.965681 CRSQ = 0.962653 F(2/34) = 318.903 PROB>F =
0.
SER = 0.001946 SSR = 0.000129 DW(0) = 2.45366 COND =
11.4745
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
M0	0.016747	0.011431	1.46507	0.152089
M1	0.397497	0.155907	2.54957	0.015465
M2	0.002041	0.00061	3.34517	0.002015
AR1.0011	0.88	0.081378	10.8137	0.

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: SPS88

12 : IAPNSPS = O0+O1*AQTSPS+O2*AFCSPS

NOB = 38 NOVAR = 4 NCOEF = 4 NOINST = 5
RANGE: 1978 1 TO 1987 3
RSQ = 0.924526 CRSQ = 0.917866 F(2/34) = 138.828 PROB>F =
0.
SER = 0.002218 SSR = 0.000167 DW(0) = 2.47301 COND =
12.1265
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
O0	0.016212	0.01215	1.33425	0.190989
O1	0.28084	0.17893	1.56955	0.12578
O2	0.001416	0.000657	2.15654	0.038202
AR1.0012	0.86	0.092032	9.34457	0.

```
TWO-STAGE LEAST SQUARES

MODEL NAME:  SPS88

  26 :  QTSPS = W0+W1*TFSPS

NOB = 39                    NOVAR = 2                   NCOEF = 2                   NOINST = 5
RANGE:  1978 1  TO  1987 3
RSQ =            0.757926 CRSQ =            0.751384  F(1/37) =        115.846      PROB>F =
0.
SER =        11541.6       SSR =        4.928692E+09  DW(0) =            2.30456    COND =
9.13945
MAX:HAT =        NA        RSTUDENT =        NA       DFFITS =         NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
W0	-13809.2	8546.56	-1.61576	0.114642
W1	1.22788	0.11228	10.9358	0.

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A.7 SOUTHWESTERN ELECTRIC POWER COMPANY

Model -- SWEPCO

SYMBOL DECLARATIONS

```
ENDOGENOUS:
   AFCSWEP  - AVERAGE FIXED COSTS:DOLLARS PER MWH
   AQTSWEP  - AVERAGE FUEL COSTS:DOLLARS PER MWH
   CAPNINST - INSTRUMENT FOR CAPNSWEP
   CAPNSWEP - COMMERCIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
   CAPTINST - INSTRUMENT FOR CAPTSWEP
   CAPTSWEP - COMMERCIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
   COCSWEP0 - TOTAL COAL COST:DOLLARS
   COCSWEP1 - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   COCSWEP2 - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   CORCOND  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   CSNSWEP  - COMMERCIAL SALES (NON-TEXAS):MWH
   CSSWEP   - COMMERCIAL SALES:MWH
   CSTSWEP  - COMMERCIAL SALES (TEXAS):MWH
   IAPNINST - INSTRUMENT FOR IAPNSWEP
   IAPNSWEP - INDUSTRIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
   IAPTINST - INSTRUMENT FOR IAPTSWEP
   IAPTSWEP - INDUSTRIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
   ISNSWEP  - INDUSTRIAL SALES (NON-TEXAS):MWH
   ISSWEP   - INDUSTRIAL SALES:MWH
   ISTSWEP  - INDUSTRIAL SALES (TEXAS):MWH
   LICSWEP0 - TOTAL NUCLEAR FUEL COST:DOLLARS
   LICSWEP1 - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   LICSWEP2 - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   LIGCCOMP - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   LIGRCOND - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NGCSWEP  - TOTAL NATURAL GAS COST:DOLLARS
   NGRCOND  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   OAPNINST - INSTRUMENT FOR OAPNSWEP
   OAPNSWEP - OTHER AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
   OAPTINST - INSTRUMENT FOR OAPTSWEP
   OAPTSWEP - OTHER AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
   OSNSWEP  - OTHER SALES (NON-TEXAS):MWH
   OSSWEP   - OTHER SALES:MWH
   OSTSWEP  - OTHER SALES (TEXAS):MWH
   QTSWEP   - TOTAL FUEL EXPENSE ESTIMATE:DOLLARS
   RAPNINST - INSTRUMENT FOR RAPNSWEP
   RAPNSWEP - RESIDENTIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
   RAPTINST - INSTRUMENT FOR RAPTSWEP
   RAPTSWEP - RESIDENTIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
   RSNSWEP  - RESIDENTIAL SALES (NON-TEXAS):MWH
   RSSWEP   - RESIDENTIAL SALES:MWH
   RSTSWEP  - RESIDENTIAL SALES (TEXAS):MWH
   TFSWEP   - TOTAL FUEL EXPENSE REQUIREMENTS:DOLLARS
   TOTSSWEP - TOTAL SYSTEM SALES:MWH

EXOGENOUS:
   CCNSWEP  - COMMERCIAL CUSTOMERS (NON-TEXAS):NUMBER OF CUSTOMERS
   CCTSWEP  - COMMERCIAL CUSTOMERS (TEXAS):NUMBER OF CUSTOMERS
   CDDSWEP  - COOLING DEGREE DAYS:NUMBER OF DAYS
   CNCDDINS - INSTRUMENT FOR (NON-TEXAS) COMMERCIAL COOLING DEGREE DAYS
   CNHDDINS - INSTRUMENT FOR (NON-TEXAS) COMMERCIAL HEATING DEGREE DAYS
   CTCDDINS - INSTRUMENT FOR (TEXAS) COMMERCIAL COOLING DEGREE DAYS
   CTHDDINS - INSTRUMENT FOR (TEXAS) COMMERCIAL HEATING DEGREE DAYS
   FCSWEP   - FOUR-QUARTER SUM OF COSTS:THOUSANDS OF DOLLARS
   HDDSWEP  - HEATING DEGREE DAYS:NUMBER OF DAYS
   NPIINST  - INSTRUMENT FOR (NON-TEXAS) PERSONAL INCOME (BILLIONS OF DOLLARS)
   OAPNDUM  - OTHER (NON-TEXAS) AVERAGE PRICE DUMMY
   PNGCOM   - PRICE OF NATURAL GAS TO COMMERCIAL CUSTOMERS:CENTS PER THERM
   PNGIND   - PRICE OF NATURAL GAS TO INDUSTRIAL CUSTOMERS:CENTS PER THERM
   PNGRES   - PRICE OF NATURAL GAS TO RESIDENTIAL CUSTOMERS:CENTS PER THERM
   QASWEPCO - AVERAGE PRICE OF COAL:DOLLARS PER MMBTU
```

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   QASWEPLI - AVERAGE PRICE OF LIGNITE:DOLLARS PER MMBTU
   QASWEPNG - AVERAGE PRICE OF NATURAL GAS:DOLLARS PER MMBTU
   QCSWEPCO - COAL CAPACITY:MW
   QCSWEPLI - LIGNITE CAPACITY:MW
   RCNSWEP  - RESIDENTIAL CUSTOMERS (NON-TEXAS):NUMBER OF CUSTOMERS
   RCTSWEP  - RESIDENTIAL CUSTOMERS (TEXAS):NUMBER OF CUSTOMERS
   RNCDDINS - INSTRUMENT FOR (NON-TEXAS) RESIDENTIAL COOLING DEGREE DAYS
   RNHDDINS - INSTRUMENT FOR (NON-TEXAS) RESIDENTIAL HEATING DEGREE DAYS
   RTCDDINS - INSTRUMENT FOR (TEXAS) RESIDENTIAL COOLING DEGREE DAYS
   RTHDDINS - INSTRUMENT FOR (TEXAS) RESIDENTIAL HEATING DEGREE DAYS
   SWENNAG  - NONAGRICULTURAL EMPLOYMENT (NON-TEXAS):THOUSANDS OF PERSONS
   SWENPOP  - SERVICE AREA POPULATION (NON-TEXAS):THOUSANDS OF PERSONS
   SWETPOP  - SERVICE AREA POPULATION (TEXAS):THOUSANDS OF PERSONS
   TEXCPI   - TEXAS CONSUMER PRICE INDEX
   TPIINST  - INSTRUMENT FOR (TEXAS) PERSONAL INCOME (BILLIONS OF DOLLARS)
   WSSWEP   - WHOLESALE SALES:MWH

COEFFICIENT:
   A0  A1  A2  A3  A5  B0  B1  B2  C0  C1  D0  D1  D2  D4  D5  E0  E1  E2  F0  F1  F2  F3  G0  G1
G2  H0  H1  H2  H3  H4  H5  I0  I1  I2  J0  J1  J2  J3  J4  J5  K0  K1  K2  L0  L1  L2  L3  L4  L5
M0  M1  M2  N0  N1  N2  N3  O0  O1  O2  P0  P1  P2  P3  P4  P5  Q0  Q1  Q2  Q3

EQUATIONS
     1:       RSTSWEP = A0+A1*RTHDDINS+A2*RTCDDINS+A3*RAPTINST+A5*TPIINST
     2:       CSTSWEP = D0+D1*CTHDDINS+D2*CTCDDINS+D4*CAPTINST+D5*CSTSWEP(-1)
     3:       ISTSWEP = F0+F1*ISTSWEP(-1)+F2*IAPTINST+F3*SWETPOP
     4:       OSTSWEP = H0+H1*OSTSWEP(-1)+H2*OAPTINST+H3*CDDSWEP+H4*SWETPOP+H5*HDDSWEP
     5:       RSNSWEP = J0+J1*RNCDDINS+J2*RNHDDINS+J3*NPIINST+J4*RSNSWEP(-1)+J5*RAPNINST
     6:       CSNSWEP = L0+L1*CNCDDINS+L2*CNHDDINS+L3*SWENNAG+L4*CAPNINST+L5*CSNSWEP(-1)
     7:       ISNSWEP = N0+N1*ISNSWEP(-4)+N2*IAPNINST+N3*SWENNAG
     8:       OSNSWEP = P0+P1*OSNSWEP(-1)+P2*OAPNINST+P3*CDDSWEP+P4*HDDSWEP+P5*SWENPOP
     9:       RAPTSWEP = B0+B1*AQTSWEP+B2*AFCSWEP
    10:       CAPTSWEP = E0+E1*AQTSWEP+E2*AFCSWEP
    11:       IAPTSWEP = G0+G1*AQTSWEP+G2*AFCSWEP
    12:       OAPTSWEP = I0+I1*AQTSWEP+I2*AFCSWEP
    13:       RAPNSWEP = K0+K1*AQTSWEP+K2*AFCSWEP
    14:       CAPNSWEP = M0+M1*AQTSWEP+M2*AFCSWEP
    15:       IAPNSWEP = O0+O1*AQTSWEP+O2*AFCSWEP
    16:       OAPNSWEP = Q0+Q1*AQTSWEP+Q2*AFCSWEP+Q3*OAPNDUM
    17:       RAPTINST = RAPTSWEP/PNGRES*RCTSWEP
    18:       CAPTINST = CAPTSWEP(-2)/PNGCOM(-2)*CCTSWEP
    19:       IAPTINST = IAPTSWEP(-4)/TEXCPI(-4)
    20:       OAPTINST = OAPTSWEP/PNGIND
    21:       RAPNINST = RAPNSWEP/PNGRES*RCNSWEP
    22:       CAPNINST = CAPNSWEP/PNGCOM*CCNSWEP
    23:       IAPNINST = IAPNSWEP/PNGIND
    24:       OAPNINST = OAPNSWEP/PNGIND
    25:       TOTSSWEP = RSSWEP+CSSWEP+ISSWEP+OSSWEP+WSSWEP
    26:       RSSWEP = RSNSWEP+RSTSWEP
    27:       CSSWEP = CSNSWEP+CSTSWEP
    28:       ISSWEP = ISNSWEP+ISTSWEP
    29:       OSSWEP = OSNSWEP+OSTSWEP
    30:       LIGCCOMP = RSSWEP*1.0867+CSSWEP*1.0862+ISSWEP*1.0478+OSSWEP*1.0867+WSSWEP*1.0259
                           -0.7*2190*QCSWEPLI
    31:       LIGRCOND = IF LIGCCOMP GT 0 THEN LIGCCOMP ELSE RSSWEP*1.0867
                           +CSSWEP*1.0862+ISSWEP*1.0478+OSSWEP*1.0867+WSSWEP*1.0259
    32:       CORCOND = IF LIGRCOND EQ LIGCCOMP THEN LIGCCOMP-QCSWEPCO*2190*0.7 ELSE 0
    33:       NGRCOND = IF CORCOND GT 0 THEN CORCOND ELSE 0
    34:       LICSWEP1 = QCSWEPLI*2190*0.7*0.0112*QASWEPLI
    35:       LICSWEP2 = (RSSWEP*1.0867+CSSWEP*1.0862+ISSWEP*1.0478
                           +OSSWEP*1.0867+WSSWEP*1.0259)*0.0112*QASWEPLI
    36:       LICSWEP0 = IF LIGRCOND EQ LIGCCOMP THEN LICSWEP1 ELSE LICSWEP2
    37:       COCSWEP1 = QCSWEPCO*2190*0.7*0.0102*QASWEPCO
    38:       COCSWEP2 = LIGCCOMP*0.0102*QASWEPCO
    39:       COCSWEP0 = IF LIGCCOMP-QCSWEPCO*2190*0.7 GT 0 THEN COCSWEP1 ELSE COCSWEP2
    40:       NGCSWEP = NGRCOND*0.0105*QASWEPNG
    41:       TFSWEP = NGCSWEP+LICSWEP0+COCSWEP0
    42:       QTSWEP = C0+C1*TFSWEP
    43:       AQTSWEP = QTSWEP/TOTSSWEP
    44:       AFCSWEP = FCSWEP/(TOTSSWEP+TOTSSWEP(-1)+TOTSSWEP(-2)+TOTSSWEP(-3))
```

Results -- SWEPCO

TWO-STAGE LEAST SQUARES

MODEL NAME: SWEPCO88

1 : RSTSWEP = A0+A1*RTHDDINS+A2*RTCDDINS+A3*RAPTINST+A5*TPIINST

NOB = 39 NOVAR = 5 NCOEF = 5 NOINST = 8
RANGE: 1978 1 TO 1987 3
RSQ = 0.939186 CRSQ = 0.932031 F(4/34) = 131.27 PROB>F = 0.
SER = 24931.8 SSR = 2.113430E+10 DW(0) = 1.9954 COND = 37.8558
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
A0	-143397.	58404.1	-2.45525	0.019348
A1	0.000962	0.000101	9.53731	0.
A2	0.002245	0.000119	18.8816	0.
A3	-728.738	291.263	-2.50199	0.017324
A5	774743.	131103.	5.90942	0.

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: SWEPCO88

2 : CSTSWEP = D0+D1*CTHDDINS+D2*CTCDDINS+D4*CAPTINST+D5*CSTSWEP(-1)

NOB = 38 NOVAR = 6 NCOEF = 6 NOINST = 9
RANGE: 1978 1 TO 1987 3
RSQ = 0.98067 CRSQ = 0.97765 F(4/32) = 324.697 PROB>F = 0.
SER = 7415.38 SSR = 1.759612E+09 DW(0) = 2.62795 COND = 10.1442
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
D0	177913.	28475.4	6.24797	0.
D1	0.001286	0.000159	8.0671	0.
D2	0.004977	0.000199	25.0346	0.
D4	-2545.95	928.741	-2.74129	0.009931
D5	0.287772	0.027859	10.3294	0.
AR1.0002	0.92	0.043435	21.181	0.

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: SWEPCO88

3 : ISTSWEP = F0+F1*ISTSWEP(-1)+F2*IAPTINST+F3*SWETPOP

NOB = 38 NOVAR = 5 NCOEF = 5 NOINST = 8
RANGE: 1978 1 TO 1987 3
RSQ = 0.893998 CRSQ = 0.88115 F(3/33) = 69.579 PROB>F = 0.
SER = 34477.6 SSR = 3.922719E+10 DW(0) = 1.65823 COND = 52.3115
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
F0	-752054.	308472.	-2.438	0.02032
F1	0.453125	0.176733	2.56389	0.015091
F2	-3.408001E+06	4.867994E+06	-0.700083	0.488782
F3	2495.42	846.941	2.94639	0.005859
AR1.0003	0.34	0.162004	2.09871	0.043576

TWO-STAGE LEAST SQUARES

MODEL NAME: SWEPCO88

4 : OSTSWEP = H0+H1*OSTSWEP(-1)+H2*OAPTINST+H3*CDDSWEP+H4*SWETPOP+H5*HDDSWEP

NOB = 39 NOVAR = 6 NCOEF = 6 NOINST = 11
RANGE: 1978 1 TO 1987 3
RSQ = 0.913369 CRSQ = 0.900243 F(5/33) = 69.5851 PROB>F =
0.
SER = 1134.2 SSR = 4.245144E+07 DW(0) = 1.6784 COND =
97.1254
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
H0	-14894.6	4832.59	-3.08211	0.00413
H1	0.329953	0.073188	4.50827	0.
H2	-104902.	555706.	-0.188773	0.851427
H3	6.37814	0.656451	9.71609	0.
H4	74.1074	13.9709	5.30441	0.
H5	2.06132	0.501825	4.10765	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: SWEPCO88

5 : RSNSWEP = J0+J1*RNCDDINS+J2*RNHDDINS+J3*NPIINST+J4*RSNSWEP(-1)+J5*RAPNINST

NOB = 39 NOVAR = 6 NCOEF = 6 NOINST = 11
RANGE: 1978 1 TO 1987 3
RSQ = 0.964072 CRSQ = 0.958628 F(5/33) = 177.099 PROB>F =
0.
SER = 32003.5 SSR = 3.379939E+10 DW(0) = 2.37773 COND =
59.5742
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
J0	-281047.	86705.9	-3.24139	0.002718
J1	0.002363	0.000108	21.7812	0.
J2	0.000908	8.215198E-05	11.0531	0.
J3	496197.	136585.	3.63288	0.
J4	0.120746	0.044715	2.70033	0.010844
J5	-311.654	270.004	-1.15425	0.256686

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: SWEPCO88

6 : CSNSWEP = L0+L1*CNCDDINS+L2*CNHDDINS+L3*SWENNAG+L4*CAPNINST+L5*CSNSWEP(-1)

NOB = 38 NOVAR = 7 NCOEF = 7 NOINST = 10

RANGE: 1978 1 TO 1987 3
RSQ = 0.97294 CRSQ = 0.967702 F(5/31) = 185.766 PROB>F = 0.
SER = 12166.7 SSR = 4.588921E+09 DW(0) = 2.25876 COND = 40.6561
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
L0	-536100.	120378.	-4.45349	0.
L1	0.006343	0.00026	24.3798	0.
L2	0.00184	0.000223	8.2473	0.
L3	2.17247	0.409124	5.31005	0.
L4	-905.281	1624.74	-0.557186	0.581401
L5	0.221495	0.044476	4.98009	0.
AR1.0006	0.52	0.152796	3.40323	0.001855

TWO-STAGE LEAST SQUARES

MODEL NAME: SWEPCO88

7 : ISNSWEP = N0+N1*ISNSWEP(-4)+N2*IAPNINST+N3*SWENNAG

NOB = 39 NOVAR = 4 NCOEF = 4 NOINST = 9
RANGE: 1978 1 TO 1987 3
RSQ = 0.703874 CRSQ = 0.678492 F(3/35) = 27.731 PROB>F = 0.
SER = 32811.2 SSR = 3.768010E+10 DW(0) = 1.88769 COND = 98.6055
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
N0	-281083.	165608.	-1.69728	0.09852
N1	0.754935	0.147818	5.10721	0.
N2	-3.939859E+07	1.930306E+07	-2.04105	0.048843
N3	1.39361	0.604739	2.30448	0.027247

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: SWEPCO88

8 : OSNSWEP = P0+P1*OSNSWEP(-1)+P2*OAPNINST+P3*CDDSWEP+P4*HDDSWEP+P5*SWENPOP

NOB = 38 NOVAR = 7 NCOEF = 7 NOINST = 10
RANGE: 1978 1 TO 1987 3
RSQ = 0.965498 CRSQ = 0.95882 F(5/31) = 144.584 PROB>F = 0.
SER = 1177.52 SSR = 4.298301E+07 DW(0) = 1.59546 COND = 58.5486
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
P0	-97575.9	12459.3	-7.83159	0.
P1	0.077465	0.06813	1.13703	0.264239
P2	-296697.	324776.	-0.913544	0.368007
P3	6.92719	0.585456	11.8321	0.
P4	2.11434	0.463337	4.56328	0.
P5	152.605	16.1289	9.46159	0.
AR1.0008	0.26	0.163615	1.5891	0.122186

TWO-STAGE LEAST SQUARES

MODEL NAME: SWEPCO88

9 : RAPTSWEP = B0+B1*AQTSWEP+B2*AFCSWEP

NOB = 39 NOVAR = 3 NCOEF = 3 NOINST = 7
RANGE: 1978 1 TO 1987 3
RSQ = 0.877593 CRSQ = 0.870792 F(2/36) = 129.05 PROB>F = 0.
SER = 0.006077 SSR = 0.00133 DW(0) = 1.74538 COND = 22.1294
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
B0	-0.002477	0.003788	-0.653976	0.517283
B1	1.04048	0.50253	2.07048	0.045637
B2	0.001879	0.000438	4.29351	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: SWEPCO88

10 : CAPTSWEP = E0+E1*AQTSWEP+E2*AFCSWEP

NOB = 39 NOVAR = 3 NCOEF = 3 NOINST = 7
RANGE: 1978 1 TO 1987 3
RSQ = 0.898653 CRSQ = 0.893022 F(2/36) = 159.607 PROB>F = 0.
SER = 0.003352 SSR = 0.000404 DW(0) = 2.25786 COND = 22.1294
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
E0	0.00944	0.00209	4.51761	0.
E1	0.817288	0.277182	2.94856	0.005577
E2	0.001058	0.000241	4.38231	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: SWEPCO88

11 : IAPTSWEP = G0+G1*AQTSWEP+G2*AFCSWEP

NOB = 39 NOVAR = 3 NCOEF = 3 NOINST = 7
RANGE: 1978 1 TO 1987 3
RSQ = 0.870403 CRSQ = 0.863203 F(2/36) = 120.892 PROB>F = 0.
SER = 0.003233 SSR = 0.000376 DW(0) = 1.88766 COND = 22.1294
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
G0	0.004348	0.002016	2.15739	0.037725
G1	0.976855	0.267368	3.65359	0.
G2	0.000636	0.000233	2.73004	0.009739

TWO-STAGE LEAST SQUARES

MODEL NAME: SWEPCO88

12 : OAPTSWEP = I0+I1*AQTSWEP+I2*AFCSWEP

NOB = 39 NOVAR = 3 NCOEF = 3 NOINST = 7
RANGE: 1978 1 TO 1987 3
RSQ = 0.960266 CRSQ = 0.958058 F(2/36) = 435.01 PROB>F = 0.
SER = 0.002861 SSR = 0.000295 DW(0) = 2.5213 COND = 22.1294
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
I0	-0.003653	0.001783	-2.0489	0.047815
I1	0.645981	0.236539	2.73096	0.009717
I2	0.001898	0.000206	9.21588	0.

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: SWEPCO88

13 : RAPNSWEP = K0+K1*AQTSWEP+K2*AFCSWEP

NOB = 38 NOVAR = 4 NCOEF = 4 NOINST = 7
RANGE: 1978 1 TO 1987 3
RSQ = 0.894802 CRSQ = 0.88552 F(2/34) = 96.4004 PROB>F = 0.
SER = 0.004833 SSR = 0.000794 DW(0) = 1.92211 COND = 50.1775
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
K0	5.573727E-05	0.004045	0.013779	0.989087
K1	0.348951	0.529737	0.658725	0.514509
K2	0.002126	0.00045	4.72565	0.
AR1.0013	0.24	0.163518	1.46773	0.151369

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: SWEPCO88

14 : CAPNSWEP = M0+M1*AQTSWEP+M2*AFCSWEP

NOB = 38 NOVAR = 4 NCOEF = 4 NOINST = 7
RANGE: 1978 1 TO 1987 3
RSQ = 0.935512 CRSQ = 0.929821 F(2/34) = 164.409 PROB>F = 0.
SER = 0.003202 SSR = 0.000348 DW(0) = 1.78251 COND = 43.0125
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
M0	0.000682	0.003414	0.19965	0.842944
M1	0.510698	0.436339	1.17041	0.249972
M2	0.001652	0.000368	4.49016	0.
AR1.0014	0.4	0.148677	2.6904	0.010984

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: SWEPCO88

15 : IAPNSWEP = O0+O1*AQTSWEP+O2*AFCSWEP

NOB = 38 NOVAR = 4 NCOEF = 4 NOINST = 7
RANGE: 1978 1 TO 1987 3
RSQ = 0.798238 CRSQ = 0.780435 F(2/34) = 44.8385 PROB>F = 0.
SER = 0.00541 SSR = 0.000995 DW(0) = 1.73906 COND = 50.8994
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
O0	-0.001885	0.00441	-0.427567	0.671662
O1	0.697765	0.577994	1.20722	0.235679
O2	0.001265	0.000491	2.57519	0.014541
AR1.0015	0.22	0.162845	1.35097	0.185626

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: SWEPCO88

16 : OAPNSWEP = Q0+Q1*AQTSWEP+Q2*AFCSWEP+Q3*OAPNDUM

NOB = 38 NOVAR = 5 NCOEF = 5 NOINST = 8
RANGE: 1978 1 TO 1987 3
RSQ = 0.873883 CRSQ = 0.858596 F(3/33) = 57.1653 PROB>F = 0.
SER = 0.015748 SSR = 0.008184 DW(0) = 1.89579 COND = 31.8731
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
Q0	-0.015152	0.029132	-0.520108	0.60646
Q1	0.589517	2.65856	0.221743	0.82588
Q2	0.006073	0.002573	2.36036	0.02432
Q3	-0.095062	0.012245	-7.76357	0.
AR1.0016	0.6	0.113866	5.26935	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: SWEPCO88

42 : QTSWEP = C0+C1*TFSWEP

NOB = 39 NOVAR = 2 NCOEF = 2 NOINST = 7
RANGE: 1978 1 TO 1987 3
RSQ = 0.833459 CRSQ = 0.828958 F(1/37) = 185.168 PROB>F = 0.

SER = 10531.3 SSR = 4.103571E+09 DW(0) = 1.61805 COND =
5.93571
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
C0	-562.598	5146.89	-0.109308	0.913549
C1	0.949269	0.076319	12.4381	0.

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A.8 LOWER COLORADO RIVER AUTHORITY

Model -- LCRA

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SYMBOL DECLARATIONS

ENDOGENOUS:
   AFCLCRA  - AVERAGE FIXED COSTS:DOLLARS PER MWH
   AQTLCRA  - AVERAGE FUEL COSTS:DOLLARS PER MWH
   CAPINST  - INSTRUMENT FOR CAPLCRA
   COCLCRA  - TOTAL COAL COST:DOLLARS
   CSLCRA   - COMMERCIAL SALES (ADJUSTED):MWH
   CSLCRA1  - COMMERCIAL SALES:MWH
   HYRCOMP  - CONDITIONAL VARIABLE LEADING TO THE IF ARGUMENT
   IAPINST  - INSTRUMENT FOR IAPLCRA
   IRSLCRA  - IRRIGATION SALES (ADJUSTED):MWH
   IRSLCRA1 - IRRIGATION SALES:MWH
   ISLCRA   - INDUSTRIAL SALES (ADJUSTED):MWH
   ISLCRA1  - INDUSTRIAL SALES:MWH
   NGCLCRA  - TOTAL NATURAL GAS COST:DOLLARS
   NGRLCRA  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   OAPINST  - INSTRUMENT FOR OAPLCRA
   OSLCRA   - MISCELLANEOUS SALES (ADJUSTED):MWH
   OSLCRA1  - MISCELLANEOUS SALES:MWH
   QTLCRA   - TOTAL FUEL EXPENSE ESTIMATE:DOLLARS
   RAPINST  - INSTRUMENT FOR RAPLCRA
   RSLCRA   - RESIDENTIAL SALES (ADJUSTED):MWH
   RSLCRA1  - RESIDENTIAL SALES:MWH
   TFLCRA   - TOTAL FUEL EXPENSE REQUIREMENTS:DOLLARS
   TOTSLCRA - TOTAL SYSTEM SALES:MWH
   WAPLCRA  - WHOLESALE AVERAGE PRICE :000'S OF $ PER MWH

EXOGENOUS:
   CCDDINST - INSTRUMENT FOR COMMERCIAL COOLING DEGREE DAYS
   CCLCRA   - COMMERCIAL CUSTOMERS:NUMBER OF CUSTOMERS
   CDDAUSTI - COOLING DEGREE DAYS:NUMBER OF DAYS
   CORLCRA  - GENERATION REQUIREMENTS - COAL
   FCLCRA   - FOUR-QUARTER SUM OF COSTS:THOUSANDS OF DOLLARS
   HDDAUSTI - HEATING DEGREE DAYS:NUMBER OF DAYS
   LCRACPI  - CONSUMER PRICE INDEX
   LCRANAG  - SERVICE AREA NONAGRICULTURAL EMPLOYMENT:THOUSANDS OF PERSONS
   PIINST   - INSTRUMENT FOR PERSONAL INCOME (BILLIONS OF DOLLARS)
   PNGCOM   - PRICE OF NATURAL GAS TO COMMERCIAL CUSTOMERS:CENTS PER THERM
   PNGIND   - PRICE OF NATURAL GAS TO INDUSTRIAL CUSTOMERS:CENTS PER THERM
   QALCRANG - AVERAGE PRICE OF NATURAL GAS:DOLLARS PER MMBTU
   QALCRASU - AVERAGE PRICE OF COAL:DOLLARS PER MMBTU
   QCLCRAHY - HYDRO CAPACITY:MW
   RCDDINST - INSTRUMENT FOR RESIDENTIAL COOLING DEGREE DAYS
   RCLCRA   - RESIDENTIAL CUSTOMERS:NUMBER OF CUSTOMERS
   RHDDINST - INSTRUMENT FOR RESIDENTIAL HEATING DEGREE DAYS

COEFFICIENT:
   A0  A1  A2  A3  A4  A5  B0  B1  B2  B3  C0  C1  C2  C3  C4  F0  F1  F2  F3  H0  H1  H2  H3  H4
I1  I2  M0  M1

EQUATIONS
     1:       RSLCRA1 = A0+A1*RSLCRA1(-4)+A2*RCDDINST+A3*RHDDINST+A4*PIINST+A5*RAPINST
     2:       CSLCRA1 = C0+C1*CSLCRA1(-4)+C2*CCDDINST+C3*CAPINST+C4*LCRANAG
     3:       ISLCRA1 = F0+F1*IAPINST+F2*CDDAUSTI+F3*LCRANAG
     4:       IRSLCRA1 = I1*IRSLCRA1(-1)+I2*CDDAUSTI
     5:       OSLCRA1 = H0+H1*HDDAUSTI+H2*CDDAUSTI+H3*OAPINST+H4*OSLCRA1(-1)
     6:       RSLCRA = RSLCRA1/0.944
     7:       CSLCRA = CSLCRA1/0.944
     8:       ISLCRA = ISLCRA1/0.944
     9:       IRSLCRA = IRSLCRA1/0.944
    10:       OSLCRA = OSLCRA1/0.944
    11:       TOTSLCRA = RSLCRA+CSLCRA+ISLCRA+OSLCRA+IRSLCRA
    12:       WAPLCRA = B0+B1*AQTLCRA+B2*AFCLCRA+B3*AQTLCRA(-2)
```

```
13:        RAPINST = WAPLCRA/LCRACPI*RCLCRA
14:        CAPINST = WAPLCRA/PNGCOM*CCLCRA
15:        IAPINST = WAPLCRA/PNGIND
16:        OAPINST = WAPLCRA/LCRACPI
17:        HYRCOMP = TOTSLCRA/0.95-QCLCRAHY*2190*0.15
18:        QTLCRA = M0+M1*TFLCRA
19:        NGRLCRA = IF HYRCOMP-CORLCRA GT 0 THEN HYRCOMP-CORLCRA ELSE 0
20:        NGCLCRA = IF NGRLCRA GT 0 THEN NGRLCRA*0.0105*QALCRANG ELSE 0
21:        COCLCRA = IF HYRCOMP-CORLCRA GT 0 THEN CORLCRA*0.0102*QALCRASU
                                 ELSE HYRCOMP*0.0102*QALCRASU
22:        TFLCRA = NGCLCRA+COCLCRA

   AVERAGE COST EQUATIONS :
23:        AQTLCRA = QTLCRA/TOTSLCRA
24:        AFCLCRA = FCLCRA/(TOTSLCRA+TOTSLCRA(-1)+TOTSLCRA(-2)+TOTSLCRA(-3))
```

Results -- LCRA

TWO-STAGE LEAST SQUARES

MODEL NAME: LCRA88

1 : RSLCRA1 = A0+A1*RSLCRA1(-4)+A2*RCDDINST+A3*RHDDINST+A4*PIINST+A5*RAPINST

```
NOB = 39                   NOVAR = 6                   NCOEF = 6                   NOINST = 10
RANGE:  1978 1  TO  1987 3
RSQ =           0.924612  CRSQ =          0.913189   F(5/33) =       80.9467      PROB>F =
0.
SER =        50764.2      SSR =       8.504109E+10   DW(0) =          1.77055      COND =
32.3176
MAX:HAT =         NA      RSTUDENT =        NA       DFFITS =         NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
A0	-45550.9	86897.4	-0.524191	0.603649
A1	0.799946	0.09915	8.06801	0.
A2	0.000309	0.000158	1.94904	0.059834
A3	0.000323	0.000197	1.64322	0.109832
A4	236361.	151253.	1.56269	0.127666
A5	-9.849331E-05	0.008498	-0.011591	0.990822

TWO-STAGE LEAST SQUARES

MODEL NAME: LCRA88

2 : CSLCRA1 = C0+C1*CSLCRA1(-4)+C2*CCDDINST+C3*CAPINST+C4*LCRANAG

```
NOB = 39                   NOVAR = 5                   NCOEF = 5                   NOINST = 9
RANGE:  1978 1  TO  1987 3
RSQ =           0.983778  CRSQ =          0.98187    F(4/34) =       515.484      PROB>F =
0.
SER =        16286.9      SSR =       9.018929E+09   DW(0) =          1.60257      COND =
72.4544
MAX:HAT =         NA      RSTUDENT =        NA       DFFITS =         NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
C0	-109189.	69597.6	-1.56886	0.125942
C1	0.418705	0.09013	4.64555	0.
C2	0.001583	0.000262	6.04442	0.
C3	-3.54875	1.62209	-2.18776	0.035658
C4	13249.3	2120.97	6.24682	0.

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: LCRA88

3 : ISLCRA1 = F0+F1*IAPINST+F2*CDDAUSTI+F3*LCRANAG

NOB = 37 NOVAR = 5 NCOEF = 5 NOINST = 7
RANGE: 1978 2 TO 1987 3
RSQ = 0.816537 CRSQ = 0.793605 F(3/32) = 35.6056 PROB>F =
0.
SER = 9278.37 SSR = 2.754824E+09 DW(0) = 1.56043 COND =
131.044
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
F0	-3881.93	208494.	-0.018619	0.985261
F1	-20678.8	70793.6	-0.2921	0.772095
F2	9.29991	2.67909	3.47129	0.001505
F3	4776.78	3007.81	1.58812	0.122091
AR1.0003	0.08	0.176284	0.453813	0.653027

ORDINARY LEAST SQUARES

MODEL NAME: LCRA88

4 : IRSLCRA1 = I1*IRSLCRA1(-1)+I2*CDDAUSTI

NOB = 39 NOVAR = 2 NCOEF = 2 RANGE: 1978 1
TO 1987 3
RSQ = 0.885552 CRSQ = 0.882459 F(2/37) = NA PROB>F =
NA
SER = 1251.85 SSR = 5.798387E+07 DW(0) = 2.14681 COND =
1.52551
MAX:HAT = 0.214527 RSTUDENT = 3.29527 DFFITS = 1.03533

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
I1	0.187557	0.061116	3.06888	0.004008
I2	3.03725	0.216417	14.0343	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: LCRA88

5 : OSLCRA1 = H0+H1*HDDAUSTI+H2*CDDAUSTI+H3*OAPINST+H4*OSLCRA1(-1)

NOB = 39 NOVAR = 5 NCOEF = 5 NOINST = 9
RANGE: 1978 1 TO 1987 3
RSQ = 0.874117 CRSQ = 0.859307 F(4/34) = 59.023 PROB>F =
0.
SER = 1730.87 SSR = 1.018615E+08 DW(0) = 1.62265 COND =
57.1406
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
H0	16889.8	6557.2	2.57576	0.014521
H1	6.00867	1.25418	4.7909	0.
H2	6.45238	0.914748	7.05372	0.
H3	-319.46	84.6123	-3.77558	0.
H4	0.620233	0.10697	5.79817	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: LCRA88

12 : WAPLCRA = B0+B1*AQTLCRA+B2*AFCLCRA+B3*AQTLCRA(-2)

NOB = 39 NOVAR = 4 NCOEF = 4 NOINST = 7
RANGE: 1978 1 TO 1987 3
RSQ = 0.731098 CRSQ = 0.708049 F(3/35) = 31.7197 PROB>F =
0.
SER = 2.77115 SSR = 268.775 DW(0) = 1.86725 COND =
19.9906
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
B0	10.2093	3.16092	3.22985	0.002694
B1	524.771	133.775	3.92279	0.
B2	0.692646	0.24382	2.84081	0.007452
B3	242.116	111.893	2.16381	0.037388

TWO-STAGE LEAST SQUARES

MODEL NAME: LCRA88

18 : QTLCRA = M0+M1*TFLCRA

NOB = 39 NOVAR = 2 NCOEF = 2 NOINST = 7
RANGE: 1978 1 TO 1987 3
RSQ = 0.73846 CRSQ = 0.731391 F(1/37) = 104.47 PROB>F =
0.
SER = 5016.43 SSR = 9.310884E+08 DW(0) = 2.1846 COND =
7.12832
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
M0	7397.35	2919.33	2.53392	0.015645
M1	0.756881	0.082427	9.18242	0.

A.9 WEST TEXAS UTILITIES COMPANY

Model -- WTU

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SYMBOL DECLARATIONS

ENDOGENOUS:
   AFCWTU   - AVERAGE FIXED COSTS:DOLLARS PER MWH
   AQTWTU   - AVERAGE FUEL COSTS:DOLLARS PER MWH
   CAPINST  - INSTRUMENT FOR CAPWTU
   CAPWTU   - COMMERCIAL AVERAGE PRICE:000'S OF $ PER MWH
   COCCOMP  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   COCWTU0  - TOTAL COAL COST:DOLLARS
   COCWTU1  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   CSWTU    - COMMERCIAL SALES:MWH
   IAPINST  - INSTRUMENT FOR IAPWTU
   IAPWTU   - INDUSTRIAL AVERAGE PRICE:000'S OF $ PER MWH
   ISWTU    - INDUSTRIAL SALES:MWH
   NGCWTU   - TOTAL NATURAL GAS COST:DOLLARS
   NGRWTU   - NATURAL GAS REQUIREMENT:MW
   OAPINST  - INSTRUMENT FOR OAPWTU
   OAPWTU   - OTHER AVERAGE PRICE:000'S OF $ PER MWH
   OSWTU    - OTHER SALES:MWH
   QTWTU    - TOTAL FUEL EXPENSE ESTIMATE:DOLLARS
   RAPINST  - INSTRUMENT FOR RAPWTU
   RAPWTU   - RESIDENTIAL AVERAGE PRICE:000'S OF $ PER MWH
   RSWTU    - RESIDENTIAL SALES:MWH
   TFWTU    - TOTAL FUEL EXPENSE REQUIREMENTS:DOLLARS
   TOTSWTU  - TOTAL SYSTEM SALES:MWH
   WAPINST  - INSTRUMENT FOR WAPWTU
   WAPWTU   - WHOLESALE AVERAGE PRICE:000'S OF $ PER MWH
   WSWTU    - WHOLESALE SALES:MWH

EXOGENOUS:
   CCDDWTU  - INSTRUMENT FOR COMMERCIAL COOLING DEGREE DAYS
   CCWTU    - COMMERCIAL CUSTOMERS:NUMBER OF CUSTOMERS
   CDDWTU   - COOLING DEGREE DAYS:NUMBER OF DAYS
   CGSWTU   - COTTONGIN SALES:MWH
   CHDDWTU  - INSTRUMENT FOR COMMERCIAL HEATING DEGREE DAYS
   FCWTU    - FOUR-QUARTER SUM OF COSTS:THOUSANDS OF DOLLARS
   PIINST   - INSTRUMENT FOR PERSONAL INCOME (BILLIONS OF DOLLARS)
   PNGCOM   - PRICE OF NATURAL GAS TO COMMERCIAL CUSTOMERS:CENTS PER THERM
   PNGIND   - PRICE OF NATURAL GAS TO INDUSTRIAL CUSTOMERS:CENTS PER THERM
   PNGRES   - PRICE OF NATURAL GAS TO RESIDENTIAL CUSTOMERS:CENTS PER THERM
   QAWTUCO  - AVERAGE PRICE OF COAL:DOLLARS PER MMBTU
   QAWTUNG  - AVERAGE PRICE OF NATURAL GAS:DOLLARS PER MMBTU
   QCWTUCO  - COAL CAPACITY:MW
   RCDDWTU  - INSTRUMENT FOR RESIDENTIAL COOLING DEGREE DAYS
   RCWTU    - RESIDENTIAL CUSTOMERS:NUMBER OF CUSTOMERS
   RHDDWTU  - INSTRUMENT FOR RESIDENTIAL HEATING DEGREE DAYS
   TEXCPI   - TEXAS CONSUMER PRICE INDEX
   WTUNAG   - NONAGRICULTURAL EMPLOYMENT:THOUSANDS OF PERSONS
   WTUPOP   - SERVICE AREA POPULATION:THOUSANDS OF PERSONS

COEFFICIENT:
   A0  A1  A2  A3  A4  A5  B0  B1  B2  B3  B4  B5  C0  C1  C2  C3  D0  D1  D2  D3  D4  E0  E1  E2
E3  H0  H1  H2  I0  I1  I2  J0  J1  J2  K0  K2  K3  L0  L1  L2  M0  M1

EQUATIONS
     1:        RSWTU = A0+A1*RHDDWTU+A2*RCDDWTU+A3*PIINST+A4*RSWTU(-4)+A5*RAPINST
     2:        CSWTU = B0+B1*CHDDWTU+B2*CCDDWTU+B3*WTUNAG+B4*CSWTU(-1)+B5*CAPINST
     3:        ISWTU = C0+C1*ISWTU(-1)+C2*WTUNAG+C3*IAPINST
     4:        OSWTU = D0+D1*OSWTU(-1)+D2*CDDWTU+D3*WTUPOP+D4*OAPINST
     5:        WSWTU = E0+E1*WAPINST+E2*WTUNAG+E3*WSWTU(-1)
     6:        TOTSWTU = RSWTU+CSWTU+ISWTU+OSWTU+WSWTU+CGSWTU
     7:        RAPWTU = H0+H1*AFCWTU+H2*AQTWTU
     8:        CAPWTU = I0+I1*AFCWTU+I2*AQTWTU
     9:        IAPWTU = J0+J1*AFCWTU+J2*AQTWTU
```

```
10:    OAPWTU = K0+K3*AFCWTU+K2*AQTWTU
11:    WAPWTU = L0+L1*AFCWTU+L2*AQTWTU
12:    RAPINST = RAPWTU/PNGRES*RCWTU
13:    CAPINST = CAPWTU(-1)/PNGCOM(-1)*CCWTU
14:    IAPINST = IAPWTU(-2)/PNGIND(-2)
15:    OAPINST = OAPWTU/TEXCPI
16:    WAPINST = WAPWTU(-1)/TEXCPI(-1)
17:    COCCOMP = RSWTU*1.10498+CSWTU*1.09975+ISWTU*1.06977+OSWTU*1.09002+WSWTU*1.04894
                      -QCWTUCO*0.7*2190
18:    NGRWTU = IF COCCOMP GT 0 THEN COCCOMP ELSE 0
19:    NGCWTU = NGRWTU*0.0105*QAWTUNG
20:    COCWTU1 = QCWTUCO*0.7*2190*0.0102*QAWTUCO
21:    COCWTU0 = IF COCCOMP GT 0 THEN COCWTU1 ELSE (RSWTU*1.10498+CSWTU*1.09975
                      +ISWTU*1.06977+OSWTU*1.09002+WSWTU*1.04894)
                      * 0.0102*QAWTUCO
22:    TFWTU = NGCWTU+COCWTU0
23:    QTWTU = M0+M1*TFWTU
24:    AQTWTU = QTWTU/TOTSWTU
25:    AFCWTU = FCWTU/(TOTSWTU+TOTSWTU(-1)+TOTSWTU(-2)+TOTSWTU(-3))
```

Results -- WTU

TWO-STAGE LEAST SQUARES   HILDRETH-LU PROCEDURE

MODEL NAME: WTU88

7 : RAPWTU = H0+H1*AFCWTU+H2*AQTWTU

```
NOB = 38                 NOVAR = 4                NCOEF = 4              NOINST = 7
RANGE:  1978 1   TO   1987 3
RSQ =          0.878144  CRSQ =         0.867393  F(2/34) =     81.673   PROB>F =
0.
SER =          0.004951  SSR =          0.000834  DW(0) =       2.45164  COND =
11.2839
MAX:HAT =      NA        RSTUDENT =     NA        DFFITS =      NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
H0	0.010153	0.020482	0.495717	0.623283
H1	0.00124	0.000694	1.78586	0.083044
H2	1.03162	0.32256	3.19822	0.002988
AR1.0007	0.84	0.106198	7.90975	0.

TWO-STAGE LEAST SQUARES   HILDRETH-LU PROCEDURE

MODEL NAME: WTU88

9 : IAPWTU = J0+J1*AFCWTU+J2*AQTWTU

```
NOB = 38                 NOVAR = 4                NCOEF = 4              NOINST = 7
RANGE:  1978 1   TO   1987 3
RSQ =          0.882893  CRSQ =         0.87256   F(2/34) =     85.4442  PROB>F =
0.
SER =          0.003506  SSR =          0.000418  DW(0) =       2.31077  COND =
8.13123
MAX:HAT =      NA        RSTUDENT =     NA        DFFITS =      NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
J0	0.040997	0.028003	1.46401	0.152375
J1	-0.0003	0.000842	-0.35573	0.72424
J2	0.662592	0.222946	2.97199	0.005402
AR1.0009	0.94	0.047266	19.8875	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: WTU88

10 : OAPWTU = K0+K3*AFCWTU+K2*AQTWTU

NOB = 39 NOVAR = 3 NCOEF = 3 NOINST = 7
RANGE: 1978 1 TO 1987 3
RSQ = 0.813194 CRSQ = 0.802816 F(2/36) = 78.3565 PROB>F =
0.
SER = 0.0051 SSR = 0.000936 DW(0) = 0.600726 COND =
13.3862
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
K0	-0.016361	0.005197	-3.14798	0.003297
K2	1.18777	0.157244	7.55371	0.
K3	0.001647	0.000144	11.4361	0.

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: WTU88

11 : WAPWTU = L0+L1*AFCWTU+L2*AQTWTU

NOB = 38 NOVAR = 4 NCOEF = 4 NOINST = 6
RANGE: 1978 1 TO 1987 3
RSQ = 0.77021 CRSQ = 0.749934 F(2/34) = 37.987 PROB>F =
0.
SER = 0.004516 SSR = 0.000693 DW(0) = 1.80177 COND =
15.7809
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
L0	-0.017984	0.007572	-2.37498	0.023333
L1	0.001005	0.0002	5.03528	0.
L2	1.41285	0.217983	6.48147	0.
AR1.0011	0.36	0.159361	2.25902	0.030408

TWO-STAGE LEAST SQUARES

MODEL NAME: WTU88

8 : CAPWTU = I0+I1*AFCWTU+I2*AQTWTU

NOB = 39 NOVAR = 3 NCOEF = 3 NOINST = 7
RANGE: 1978 1 TO 1987 3
RSQ = 0.743987 CRSQ = 0.729764 F(2/36) = 52.3089 PROB>F =
0.
SER = 0.005582 SSR = 0.001122 DW(0) = 0.650685 COND =
13.3862

MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
I0	-0.005061	0.005689	-0.889699	0.379535
I1	0.001341	0.000158	8.5037	0.
I2	1.29837	0.172114	7.54368	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: WTU88

1 : RSWTU = A0+A1*RHDDWTU+A2*RCDDWTU+A3*PIINST+A4*RSWTU(-4)+A5*RAPINST

NOB = 39 NOVAR = 6 NCOEF = 6 NOINST = 11
RANGE: 1978 1 TO 1987 3
RSQ = 0.974233 CRSQ = 0.970328 F(5/33) = 249.538 PROB>F =
0.
SER = 12944.4 SSR = 5.529424E+09 DW(0) = 2.04602 COND =
77.6842
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
A0	-140045.	49620.1	-2.82235	0.008015
A1	0.000657	9.544291E-05	6.88035	0.
A2	0.000971	0.000135	7.17463	0.
A3	486783.	116663.	4.17257	0.
A4	0.411381	0.085636	4.80384	0.
A5	-216.238	148.703	-1.45416	0.155348

TWO-STAGE LEAST SQUARES

MODEL NAME: WTU88

2 : CSWTU = B0+B1*CHDDWTU+B2*CCDDWTU+B3*WTUNAG+B4*CSWTU(-1)+B5*CAPINST

NOB = 39 NOVAR = 6 NCOEF = 6 NOINST = 9
RANGE: 1978 1 TO 1987 3
RSQ = 0.916781 CRSQ = 0.904172 F(5/33) = 72.7084 PROB>F =
0.
SER = 13341.7 SSR = 5.874037E+09 DW(0) = 1.56669 COND =
85.0122
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
B0	-174871.	51340.7	-3.40609	0.001749
B1	0.001938	0.000332	5.84296	0.
B2	0.004303	0.00034	12.6616	0.
B3	1534.75	425.523	3.60673	0.001012
B4	0.474605	0.063457	7.47915	0.
B5	-61.4626	46.4403	-1.32348	0.194773

ORDINARY LEAST SQUARES

MODEL NAME: WTU88

3 : ISWTU = C0+C1*ISWTU(-1)+C2*WTUNAG+C3*IAPINST

NOB = 39 NOVAR = 4 NCOEF = 4 RANGE: 1978 1
TO 1987 3
RSQ = 0.656173 CRSQ = 0.626702 F(3/35) = 22.2652 PROB>F =
0.
SER = 10958.4 SSR = 4.203026E+09 DW(0) = 2.0441 COND =
67.9156
MAX:HAT = 0.503867 RSTUDENT = 2.40291 DFFITS = 1.59589

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
C0	6693.45	48634.5	0.137627	0.891324
C1	0.777757	0.097592	7.96949	0.
C2	480.718	266.513	1.80373	0.079887
C3	-9.183280E+06	1.222205E+07	-0.75137	0.457453

TWO-STAGE LEAST SQUARES

MODEL NAME: WTU88

4 : OSWTU = D0+D1*OSWTU(-1)+D2*CDDWTU+D3*WTUPOP+D4*OAPINST

NOB = 39 NOVAR = 5 NCOEF = 5 NOINST = 8
RANGE: 1978 1 TO 1987 3
RSQ = 0.930746 CRSQ = 0.922598 F(4/34) = 114.236 PROB>F =
0.
SER = 3952.17 SSR = 5.310684E+08 DW(0) = 1.74637 COND =
93.6283
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
D0	-77512.6	16542.3	-4.68572	0.
D1	0.400347	0.057996	6.90296	0.
D2	19.7776	1.0776	18.3534	0.
D3	316.188	51.4205	6.14907	0.
D4	-897142.	420613.	-2.13294	0.040232

ORDINARY LEAST SQUARES

MODEL NAME: WTU88

5 : WSWTU = E0+E1*WAPINST+E2*WTUNAG+E3*WSWTU(-1)

NOB = 39 NOVAR = 4 NCOEF = 4 RANGE: 1978 1
TO 1987 3
RSQ = 0.564617 CRSQ = 0.527299 F(3/35) = 15.1297 PROB>F =
0.
SER = 31985.2 SSR = 3.580687E+10 DW(0) = 2.18134 COND =
85.7609
MAX:HAT = 0.241408 RSTUDENT = 2.23473 DFFITS = 0.741967

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
E0	-303057.	134286.	-2.2568	0.030368
E1	-4.242793E+06	2.743920E+06	-1.54625	0.131039
E2	3862.45	1164.28	3.31747	0.002127
E3	0.298612	0.159334	1.87413	0.06928

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: WTU88

23 : QTWTU = M0+M1*TFWTU

```
NOB = 38                  NOVAR = 3                 NCOEF = 3                 NOINST = 7
RANGE:  1978 1  TO  1987 3
RSQ =          0.889394 CRSQ =           0.883073  F(1/35) =        140.719   PROB>F =
0.
SER =        3153.09    SSR =        3.479683E+08 DW(0) =           2.16139   COND =
14.4615
MAX:HAT =         NA    RSTUDENT =        NA      DFFITS =          NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
M0	-3731.57	3916.1	-0.95288	0.347185
M1	0.996765	0.104662	9.52363	0.
AR1.0023	0.68	0.104674	6.49639	0.

A.10 EL PASO ELECTRIC COMPANY

Model -- EPE

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SYMBOL DECLARATIONS

ENDOGENOUS:
   AFCEPEC  - AVERAGE FIXED COSTS:DOLLARS PER MWH
   AQT      - AVERAGE FUEL COSTS:DOLLARS PER MWH
   CAPNEPEC - COMMERCIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
   CAPNINST - INSTRUMENT FOR CAPNEPEC
   CAPTEPEC - COMMERCIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
   CAPTINST - INSTRUMENT FOR CAPTEPEC
   COCEPEC0 - TOTAL COAL COST:DOLLARS
   COCEPEC1 - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   COCEPEC2 - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   CORCOND  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   CSEPEC   - COMMERCIAL SALES:MWH
   CSNEPEC  - COMMERCIAL SALES (NON-TEXAS):MWH
   CSTEPEC  - COMMERCIAL SALES (TEXAS):MWH
   FUELCOST - TOTAL FUEL COST:DOLLARS
   IAPTEPEC - INDUSTRIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
   IAPTINST - INSTRUMENT FOR IAPTEPEC
   ISEPEC   - INDUSTRIAL SALES:MWH
   NGCEPEC  - TOTAL NATURAL GAS COST:DOLLARS
   NGRCOND  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NUCCOMP  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NUCEPEC0 - TOTAL NUCLEAR FUEL COST:DOLLARS
   NUCEPEC2 - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   NURCOND  - CONDITIONAL VARIABLE IN THE IF ARGUMENT
   OAPNEPEC - OTHER AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
   OAPNINST - INSTRUMENT FOR OAPNEPEC
   OAPTEPEC - OTHER AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
   OAPTINST - INSTRUMENT FOR OAPTEPEC
   OSEPEC   - OTHER SALES:MWH
   OSNEPEC  - OTHER SALES (NON-TEXAS):MWH
   OSTEPEC  - OTHER SALES (TEXAS):MWH
   QTEPEC   - TOTAL FUEL EXPENSE ESTIMATE:DOLLARS
   RAPNEPEC - RESIDENTIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
   RAPNINST - INSTRUMENT FOR RAPNEPEC
   RAPTEPEC - RESIDENTIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
   RAPTINST - INSTRUMENT FOR RAPTEPEC
   RSEPEC   - RESIDENTIAL SALES:MWH
   RSNEPEC  - RESIDENTIAL SALES (NON-TEXAS):MWH
   RSTEPEC  - RESIDENTIAL SALES (TEXAS):MWH
   TCILB    - BASIC INDUSTRIAL SALES (TEXAS):MWH
   TFEPEC   - TOTAL FUEL EXPENSE REQUIREMENTS:DOLLARS
   TOTGENEP - TOTAL GENERATION REQUIREMENTS:MWH
   TOTSEPEC - TOTAL SYSTEM SALES:MWH
   TOTSNEPE - TOTAL NON-TEXAS SALES
   TOTSTEPE - TOTAL TEXAS SALES

EXOGENOUS:
   ANPP     - NUCLEAR UNIT STARTING POWER:MWH
   CCNEPEC  - COMMERCIAL CUSTOMERS (NON-TEXAS):NUMBER OF CUSTOMERS
   CCTEPEC  - COMMERCIAL CUSTOMERS (TEXAS):NUMBER OF CUSTOMERS
   CDDELPAS - COOLING DEGREE DAYS:NUMBER OF DAYS
   COMPUSE  - COMPANY USE:MWH
   CONSALES - CONTRACTUAL SALES:MWH
   EPENNAG  - NONAGRICULTURAL EMPLOYMENT (NON-TEXAS):THOUSANDS OF PERSONS
   EPENPOP  - SERVICE AREA POPULATION (NON-TEXAS):THOUSANDS OF PERSONS
   EPETNAG  - NONAGRICULTURAL EMPLOYMENT (TEXAS):THOUSANDS OF PERSONS
   EPETPOP  - SERVICE AREA POPULATION (TEXAS):THOUSANDS OF PERSONS
   FCEPEC   - FOUR-QUARTER SUM OF COSTS:THOUSANDS OF DOLLARS
   ISNEPEC  - INDUSTRIAL SALES (NON-TEXAS):MWH
   LISTEPEC - LARGE INDUSTRIAL SALES (TEXAS):MWH
   LTO      - LOSSES TO OTHERS:MWH
   NCCDD    - INSTRUMENT FOR (NON-TEXAS) COMMERCIAL COOLING DEGREE DAYS
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NRCDD    - INSTRUMENT FOR (NON-TEXAS) RESIDENTIAL COOLING DEGREE DAYS
NRHDD    - INSTRUMENT FOR (NON-TEXAS) RESIDENTIAL HEATING DEGREE DAYS
PNGCOM   - PRICE OF NATURAL GAS TO COMMERCIAL CUSTOMERS:CENTS PER THERM
PNGIND   - PRICE OF NATURAL GAS TO INDUSTRIAL CUSTOMERS:CENTS PER THERM
PNGRES   - PRICE OF NATURAL GAS TO RESIDENTIAL CUSTOMERS:CENTS PER THERM
PPOWCOST - PURCHASED POWER COST:DOLLARS
PPOWER   - PURCHASED POWER:MWH
PUMPSALE - SALES FROM GENERATING PUMPS:MWH
QAEPECCO - AVERAGE PRICE OF COAL:DOLLARS PER MMBTU
QAEPECNG - AVERAGE PRICE OF NATURAL GAS:DOLLARS PER MMBTU
QAEPECNU - AVERAGE PRICE OF NUCLEAR FUEL:DOLLARS PER MMBTU
QCEPECCO - COAL CAPACITY:MW
QCEPECNU - NUCLEAR CAPACITY:MW
RCNEPEC  - RESIDENTIAL CUSTOMERS (NON-TEXAS):NUMBER OF CUSTOMERS
RCTEPEC  - RESIDENTIAL CUSTOMERS (TEXAS):NUMBER OF CUSTOMERS
RGSALES  - RIO GRANDE SALES:MWH
TCCDD    - INSTRUMENT FOR (TEXAS) COMMERCIAL COOLING DEGREE DAYS
TEXCPI   - TEXAS CONSUMER PRICE INDEX
TOTLOSS  - LOSSES FROM EXPANDED SYSTEM:MWH
TPIINST  - INSTRUMENT FOR (TEXAS) PERSONAL INCOME (BILLIONS OF DOLLARS)
TRCDD    - INSTRUMENT FOR (TEXAS) RESIDENTIAL COOLING DEGREE DAYS
TRHDD    - INSTRUMENT FOR (TEXAS) RESIDENTIAL HEATING DEGREE DAYS

COEFFICIENT:
   A0  A1  A2  A3  A4  A5  B0  B1  B2  D0  D1  D2  D3  E0  E1  E2  F0  F1  F2  F3  F4  G0  G1  G2
H0  H1  H2  H3  H4  I0  I1  I2  L0  L1  L2  M0  M1  M2  M3  M4  N0  N1  N2  Q0  Q1  Q2  Q3  Q4  R0
R1  R2  U0  U1  U2  U3  U4  U5  Z0  Z1

EQUATIONS

     1:        RSTEPEC = A0+A1*RAPTINST+A2*TRHDD+A3*TRCDD+A4*TPIINST+A5*RSTEPEC(-4)
     2:        CSTEPEC = D0+D1*CAPTINST+D2*EPETNAG+D3*TCCDD
     3:        TCILB = F0+F1*IAPTINST+F2*EPETNAG+F3*CDDELPAS+F4*TCILB(-1)
     4:        OSTEPEC = H0+H1*OAPTINST+H2*EPETPOP+H3*CDDELPAS+H4*OSTEPEC(-4)
     5:        RSNEPEC = U0+U1*NRHDD+U2*NRCDD+U3*RAPNINST+U4*EPENPOP+U5*RSNEPEC(-4)
     6:        CSNEPEC = M0+M1*NCCDD+M2*CAPNINST+M3*EPENNAG+M4*CSNEPEC(-4)
     7:        OSNEPEC = Q0+Q1*EPENPOP+Q2*OAPNINST+Q3*CDDELPAS+Q4*OSNEPEC(-4)
     8:        RAPTEPEC = B0+B1*AQT+B2*AFCEPEC
     9:        CAPTEPEC = E0+E1*AQT+E2*AFCEPEC
    10:        IAPTEPEC = G0+G1*AQT+G2*AFCEPEC
    11:        OAPTEPEC = I0+I1*AQT+I2*AFCEPEC
    12:        RAPNEPEC = L0+L1*AQT+L2*AFCEPEC
    13:        OAPNEPEC = R0+R1*AQT+R2*AFCEPEC
    14:        CAPNEPEC = N0+N1*AQT+N2*AFCEPEC
    15:        RAPTINST = RAPTEPEC/PNGRES*RCTEPEC
    16:        CAPTINST = CAPTEPEC/PNGCOM*CCTEPEC
    17:        IAPTINST = IAPTEPEC(-4)/PNGIND(-4)
    18:        OAPTINST = OAPTEPEC(-1)/PNGCOM(-1)
    19:        RAPNINST = RAPNEPEC/TEXCPI*RCNEPEC
    20:        CAPNINST = CAPNEPEC/PNGCOM*CCNEPEC
    21:        OAPNINST = OAPNEPEC/PNGCOM
    22:        TOTSEPEC = RSEPEC+CSEPEC+ISEPEC+OSEPEC

      SALES IDENTITIES:
    23:        RSNEPEC = RSEPEC-RSTEPEC
    24:        CSNEPEC = CSEPEC-CSTEPEC
    25:        ISEPEC = TCILB+LISTEPEC+ISNEPEC
    26:        OSNEPEC = OSEPEC-OSTEPEC
    27:        TOTGENEP = RSEPEC*1.154+CSEPEC*1.1513+ISEPEC*1.096
                          +OSEPEC*1.0991+CONSALES+COMPUSE+LTO+ANPP+PUMPSALE
                          +RGSALES+TOTLOSS-PPOWER
    28:        NUCCOMP = TOTGENEP-0.7*2190*QCEPECNU
    29:        NURCOND = IF NUCCOMP GT 0 THEN NUCCOMP ELSE TOTGENEP
    30:        CORCOND = IF NURCOND EQ NUCCOMP THEN NUCCOMP-QCEPECCO*2190*0.7 ELSE 0
    31:        NGRCOND = IF CORCOND GT 0 THEN CORCOND ELSE 0
    32:        NUCEPEC2 = TOTGENEP*0.0085*QAEPECNU
    33:        NUCEPECO = IF NURCOND EQ NUCCOMP THEN QCEPECNU*2190*0.7*0.0085*QAEPECNU
                          ELSE NUCEPEC2
    34:        COCEPEC1 = QCEPECCO*0.7*2190*QAEPECCO*0.0099
    35:        COCEPEC2 = NUCCOMP*0.0099*QAEPECCO
    36:        COCEPECO = IF NUCCOMP-QCEPECCO*2190*0.7 GT 0 THEN COCEPEC1 ELSE COCEPEC2
    37:        NGCEPEC = NGRCOND*0.0105*QAEPECNG
```

```
38:        TFEPEC = NGCEPEC+COCEPECO+NUCEPECO
39:        QTEPEC = Z0+Z1*TFEPEC
40:        FUELCOST = QTEPEC+PPOWCOST

   TOTAL SALES EQUATIONS:
41:        TOTSTEPE = RSTEPEC+CSTEPEC+TCILB+LISTEPEC+OSTEPEC
42:        TOTSNEPE = RSNEPEC+CSNEPEC+ISNEPEC+OSNEPEC

   AVERAGE COST EQUATIONS:
43:        AQT = (FUELCOST+FUELCOST(-1)+FUELCOST(-2)+FUELCOST(-3))/(TOTSEPEC
                               +TOTSEPEC(-1)+TOTSEPEC(-2)+TOTSEPEC(-3))
44:        AFCEPEC = FCEPEC/(TOTSEPEC+TOTSEPEC(-1)+TOTSEPEC(-2)+TOTSEPEC(-3))
```

Results -- EPE

TWO-STAGE LEAST SQUARES

MODEL NAME: EPEC88

1 : RSTEPEC = A0+A1*RAPTINST+A2*TRHDD+A3*TRCDD+A4*TPIINST+A5*RSTEPEC(-4)

```
NOB = 39                 NOVAR = 6                NCOEF = 6                 NOINST = 12
RANGE:  1978 1  TO  1987 3
RSQ =          0.983444  CRSQ =         0.980936  F(5/33) =       392.047   PROB>F =
0.
SER =          4135.29   SSR =      5.643203E+08  DW(0) =         2.41809   COND =
76.5022
MAX:HAT =      NA        RSTUDENT =     NA        DFFITS =        NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
A0	29922.3	13993.9	2.13823	0.039994
A1	-175.883	62.6213	-2.80868	0.008294
A2	0.000208	3.042001E-05	6.82289	0.
A3	0.000318	4.623363E-05	6.88218	0.
A4	167536.	29701.6	5.64063	0.
A5	0.542266	0.068219	7.94885	0.

TWO-STAGE LEAST SQUARES

MODEL NAME: EPEC88

2 : CSTEPEC = D0+D1*CAPTINST+D2*EPETNAG+D3*TCCDD

```
NOB = 39                 NOVAR = 4                NCOEF = 4                 NOINST = 10
RANGE:  1978 1  TO  1987 3
RSQ =          0.94114   CRSQ =         0.936095  F(3/35) =       186.545   PROB>F =
0.
SER =          10465.3   SSR =      3.833265E+09  DW(0) =         1.84038   COND =
49.6244
MAX:HAT =      NA        RSTUDENT =     NA        DFFITS =        NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
D0	-85083.6	34475.5	-2.46794	0.018622
D1	-2727.5	1206.01	-2.2616	0.03004
D2	2120.12	151.036	14.0372	0.
D3	0.003539	0.000297	11.9166	0.

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: EPEC88

3 : TCILB = F0+F1*IAPTINST+F2*EPETNAG+F3*CDDELPAS+F4*TCILB(-1)

NOB = 38 NOVAR = 6 NCOEF = 6 NOINST = 9
RANGE: 1978 1 TO 1987 3
RSQ = 0.746494 CRSQ = 0.706883 F(4/32) = 18.8459 PROB>F =
0.
SER = 4172.48 SSR = 5.571064E+08 DW(0) = 2.02739 COND =
51.3755
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
F0	41075.3	15960.	2.57364	0.0149
F1	-1.382274E+07	5.201914E+06	-2.65724	0.012189
F2	224.748	113.742	1.97595	0.056835
F3	9.90825	1.24865	7.93515	0.
F4	0.184758	0.12032	1.53555	0.134478
AR1.0003	0.24	0.170186	1.41022	0.16812

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: EPEC88

4 : OSTEPEC = H0+H1*OAPTINST+H2*EPETPOP+H3*CDDELPAS+H4*OSTEPEC(-4)

NOB = 38 NOVAR = 6 NCOEF = 6 NOINST = 5
RANGE: 1978 1 TO 1987 3
RSQ = 0.959136 CRSQ = 0.952751 F(4/32) = 150.217 PROB>F =
0.
SER = 3107.35 SSR = 3.089807E+08 DW(0) = 1.83435 COND =
80.7455
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
H0	13908.2	14460.8	0.961789	0.343367
H1	-6.373873E+06	3.521171E+06	-1.81016	0.079672
H2	139.018	28.2366	4.92333	0.
H3	15.1377	2.761	5.48269	0.
H4	0.309282	0.124274	2.48872	0.018214
AR1.0004	0.06	0.187638	0.319765	0.751225

TWO-STAGE LEAST SQUARES

MODEL NAME: EPEC88

5 : RSNEPEC = U0+U1*NRHDD+U2*NRCDD+U3*RAPNINST+U4*EPENPOP+U5*RSNEPEC(-4)

NOB = 39 NOVAR = 6 NCOEF = 6 NOINST = 12
RANGE: 1978 1 TO 1987 3
RSQ = 0.964027 CRSQ = 0.958577 F(5/33) = 176.873 PROB>F =
0.
SER = 1390.8 SSR = 6.383299E+07 DW(0) = 2.32437 COND =
115.163
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
U0	-2394.98	3939.53	-0.607934	0.547393
U1	0.00033	4.571036E-05	7.21652	0.
U2	0.000366	5.347189E-05	6.84929	0.
U3	-10.1742	4.08858	-2.48843	0.018053
U4	349.198	87.8296	3.97586	0.
U5	0.324299	0.100777	3.21798	0.002892

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: EPEC88

6 : CSNEPEC = M0+M1*NCCDD+M2*CAPNINST+M3*EPENNAG+M4*CSNEPEC(-4)

NOB = 38 NOVAR = 6 NCOEF = 6 NOINST = 11
RANGE: 1978 1 TO 1987 3
RSQ = 0.928088 CRSQ = 0.916851 F(4/32) = 82.5972 PROB>F =
0.
SER = 2700.4 SSR = 2.333494E+08 DW(0) = 1.695 COND =
53.0666
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
M0	29008.3	11561.8	2.50897	0.017367
M1	0.001803	0.000428	4.209	0.
M2	-3313.26	1273.43	-2.60184	0.013929
M3	944.298	271.039	3.484	0.001454
M4	0.240302	0.162814	1.47593	0.149736
AR1.0006	0.42	0.154491	2.71861	0.010499

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: EPEC88

7 : OSNEPEC = Q0+Q1*EPENPOP+Q2*OAPNINST+Q3*CDDELPAS+Q4*OSNEPEC(-4)

NOB = 38 NOVAR = 6 NCOEF = 6 NOINST = 5
RANGE: 1978 1 TO 1987 3
RSQ = 0.943657 CRSQ = 0.934854 F(4/32) = 107.191 PROB>F =
0.
SER = 2291.1 SSR = 1.679728E+08 DW(0) = 2.04788 COND =
50.2532
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
Q0	6014.76	9627.92	0.624721	0.536584
Q1	413.535	81.2518	5.08954	0.
Q2	-3.755739E+06	2.656969E+06	-1.41354	0.167151
Q3	7.06402	1.45735	4.84716	0.
Q4	0.252824	0.146624	1.7243	0.094303
AR1.0007	0.28	0.163233	1.71534	0.095952

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: EPEC88

8 : RAPTEPEC = B0+B1*AQT+B2*AFCEPEC

```
NOB = 38                  NOVAR = 4                 NCOEF = 4                 NOINST = 8
RANGE:  1978 1  TO  1987 3
RSQ =             0.947453 CRSQ =           0.942816 F(2/34) =        204.345   PROB>F =
0.
SER =             0.004423 SSR =            0.000665 DW(0) =          2.26909   COND =
16.4805
MAX:HAT =         NA       RSTUDENT =       NA       DFFITS =         NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
B0	0.036076	0.027761	1.29952	0.202508
B1	0.719617	0.486651	1.47871	0.148423
B2	0.001166	0.000606	1.925	0.062628
AR1.0008	0.88	0.10065	8.74316	0.

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: EPEC88

9 : CAPTEPEC = E0+E1*AQT+E2*AFCEPEC

```
NOB = 38                  NOVAR = 4                 NCOEF = 4                 NOINST = 7
RANGE:  1978 1  TO  1987 3
RSQ =             0.883881 CRSQ =           0.873635 F(2/34) =        86.2674   PROB>F =
0.
SER =             0.006081 SSR =            0.001257 DW(0) =          1.71169   COND =
21.5433
MAX:HAT =         NA       RSTUDENT =       NA       DFFITS =         NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
E0	0.018604	0.011511	1.61623	0.115287
E1	1.05537	0.337138	3.13038	0.003575
E2	0.001058	0.000305	3.47186	0.001427
AR1.0009	0.64	0.143567	4.45784	0.

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: EPEC88

10 : IAPTEPEC = G0+G1*AQT+G2*AFCEPEC

```
NOB = 38                  NOVAR = 4                 NCOEF = 4                 NOINST = 8
RANGE:  1978 1  TO  1987 3
RSQ =             0.93361  CRSQ =           0.927752 F(2/34) =        159.376   PROB>F =
0.
SER =             0.003031 SSR =            0.000312 DW(0) =          1.85849   COND =
9.69769
MAX:HAT =         NA       RSTUDENT =       NA       DFFITS =         NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
G0	0.026695	0.021496	1.2419	0.222773
G1	0.390272	0.303239	1.28701	0.206784
G2	0.000665	0.000482	1.37999	0.176598
AR1.0010	0.9	0.094981	9.47558	0.

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: EPEC88

11 : OAPTEPEC = I0+I1*AQT+I2*AFCEPEC

```
NOB = 38                    NOVAR = 4                 NCOEF = 4                NOINST = 8
RANGE:  1978 1  TO  1987 3
RSQ =            0.933788 CRSQ =          0.927945  F(2/34) =      159.833    PROB>F =
0.
SER =            0.004007 SSR =           0.000546  DW(0) =         2.18401   COND =
11.8204
MAX:HAT =        NA       RSTUDENT =      NA        DFFITS =        NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
I0	0.001108	0.038518	0.028766	0.977219
I1	0.757114	0.535745	1.4132	0.166688
I2	0.001362	0.000788	1.72906	0.092871
AR1.0011	0.92	0.08851	10.3944	0.

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: EPEC88

12 : RAPNEPEC = L0+L1*AQT+L2*AFCEPEC

```
NOB = 38                    NOVAR = 4                 NCOEF = 4                NOINST = 11
RANGE:  1978 1  TO  1987 3
RSQ =            0.950277 CRSQ =          0.94589   F(2/34) =      216.596    PROB>F =
0.
SER =            0.004934 SSR =           0.000828  DW(0) =         1.44816   COND =
39.5887
MAX:HAT =        NA       RSTUDENT =      NA        DFFITS =        NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
L0	0.004464	0.006865	0.650207	0.519928
L1	1.11339	0.259779	4.28593	0.
L2	0.001846	0.000296	6.23208	0.
AR1.0012	0.52	0.117251	4.43495	0.

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: EPEC88

13 : OAPNEPEC = R0+R1*AQT+R2*AFCEPEC

```
NOB = 38                    NOVAR = 4                 NCOEF = 4                NOINST = 8
RANGE:  1978 1  TO  1987 3
RSQ =            0.903097 CRSQ =          0.894547  F(2/34) =      105.622    PROB>F =
0.
SER =            0.003235 SSR =           0.000356  DW(0) =         1.9967    COND =
28.7268
MAX:HAT =        NA       RSTUDENT =      NA        DFFITS =        NA
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
R0	0.018826	0.008707	2.16231	0.03772
R1	0.688579	0.247299	2.78439	0.008699
R2	0.000645	0.000202	3.18564	0.00309
AR1.0013	0.72	0.120971	5.95182	0.

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: EPEC88

14 : CAPNEPEC = N0+N1*AQT+N2*AFCEPEC

NOB = 38 NOVAR = 4 NCOEF = 4 NOINST = 6
RANGE: 1978 1 TO 1987 3
RSQ = 0.86081 CRSQ = 0.848529 F(2/34) = 70.0902 PROB>F = 0.
SER = 0.005106 SSR = 0.000886 DW(0) = 1.9261 COND = 32.8485
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
N0	0.026755	0.005057	5.29099	0.
N1	0.709476	0.178616	3.97206	0.
N2	0.000962	0.000152	6.34962	0.
AR1.0014	0.34	0.162187	2.09635	0.043567

TWO-STAGE LEAST SQUARES HILDRETH-LU PROCEDURE

MODEL NAME: EPEC88

39 : QTEPEC = Z0+Z1*TFEPEC

NOB = 38 NOVAR = 3 NCOEF = 3 NOINST = 5
RANGE: 1978 1 TO 1987 3
RSQ = 0.762636 CRSQ = 0.749073 F(1/35) = 56.2266 PROB>F = 0.
SER = 3632.78 SSR = 4.618993E+08 DW(0) = 1.84501 COND = 22.7326
MAX:HAT = NA RSTUDENT = NA DFFITS = NA

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
Z0	-45.3448	5766.29	-0.007864	0.99377
Z1	0.801349	0.265237	3.02126	0.004682
AR1.0039	0.52	0.143433	3.62538	0.

A.11 TEXAS-NEW MEXICO POWER COMPANY

Model -- TNP

SYMBOL DECLARATIONS

```
ENDOGENOUS:
   CANGCOM  - COMMERCIAL CUSTOMERS (ANGLETON) (NUMBER OF CUSTOMERS)
   CANGRES  - RESIDENTIAL CUSTOMERS (ANGLETON) (NUMBER OF CUSTOMERS)
   CCLICOM  - COMMERCIAL CUSTOMERS (CLIFTON) (NUMBER OF CUSTOMERS)
   CCLIRES  - RESIDENTIAL CUSTOMERS (CLIFTON) (NUMBER OF CUSTOMERS)
   CLEWCOM  - COMMERCIAL CUSTOMERS (LEWISVILLE) (NUMBER OF CUSTOMERS)
   CLEWRES  - RESIDENTIAL CUSTOMERS (LEWISVILLE) (NUMBER OF CUSTOMERS)
   COLNCOM  - COMMERCIAL CUSTOMERS (OLNEY) (NUMBER OF CUSTOMERS)
   COLNRES  - RESIDENTIAL CUSTOMERS (OLNEY) (NUMBER OF CUSTOMERS)
   CPETCOM  - COMMERCIAL CUSTOMERS (PETROLIA) (NUMBER OF CUSTOMERS)
   CPETRES  - RESIDENTIAL CUSTOMERS (PETROLIA) (NUMBER OF CUSTOMERS)
   CSTNP    - COMMERCIAL SALES (TEXAS ONLY) (MWH)
   CTEXCOM  - COMMERCIAL CUSTOMERS (TEXAS CITY) (NUMBER OF CUSTOMERS)
   CTEXRES  - RESIDENTIAL CUSTOMERS (TEXAS CITY) (NUMBER OF CUSTOMERS)
   CWHICOM  - COMMERCIAL CUSTOMERS (WHITEWRIGHT) (NUMBER OF CUSTOMERS)
   CWHIRES  - RESIDENTIAL CUSTOMERS (WHITEWRIGHT) (NUMBER OF CUSTOMERS)
   RSTNP    - RESIDENTIAL SALES (TEXAS ONLY) (MWH)
   SANGCOM  - COMMERCIAL SALES (ANGLETON) (MWH)
   SANGRES  - RESIDENTIAL SALES (ANGLETON) (MWH)
   SCLICOM  - COMMERCIAL SALES (CLIFTON) (MWH)
   SCLIRES  - RESIDENTIAL SALES (CLIFTON) (MWH)
   SFORCOM  - COMMERCIAL SALES (FORT STOCKTON) (MWH)
   SFORRES  - RESIDENTIAL SALES (FORT STOCKTON) (MWH)
   SLEWCOM  - COMMERCIAL SALES (LEWISVILLE) (MWH)
   SLEWRES  - RESIDENTIAL SALES (LEWISVILLE) (MWH)
   SOLNCOM  - COMMERCIAL SALES (OLNEY) (MWH)
   SOLNRES  - RESIDENTIAL SALES (OLNEY) (MWH)
   SPANCOM  - COMMERCIAL SALES (PANHANDLE) (MWH)
   SPANRES  - RESIDENTIAL SALES (PANHANDLE) (MWH)
   SPECCOM  - COMMERCIAL SALES (PECOS) (MWH)
   SPECRES  - RESIDENTIAL SALES (PECOS) (MWH)
   SPETCOM  - COMMERCIAL SALES (PETROLIA) (MWH)
   SPETRES  - RESIDENTIAL SALES (PETROLIA) (MWH)
   STEXCOM  - COMMERCIAL SALES (TEXAS CITY) (MWH)
   STEXRES  - RESIDENTIAL SALES (TEXAS CITY) (MWH)
   SWHICOM  - COMMERCIAL SALES (WHITEWRIGHT) (MWH)
   SWHIRES  - RESIDENTIAL SALES (WHITEWRIGHT) (MWH)
   TOTSCD   - TOTAL SALES CENTRAL DIVISION (MWH)
   TOTSNED  - TOTAL SALES NORTH-EAST DIVISION (MWH)
   TOTSPD   - TOTAL SALES PANHANDLE DIVISION (MWH)
   TOTSSED  - TOTAL SALES SOUTH-EAST DIVISION (MWH)
   TOTSTNP  - SUM OF TOTSSED,TOTSNED,TOTSCD,TOTSWD,AND TOTSPD.(MWH)
   TOTSWD   - TOTAL SALES WESTERN DIVISION (MWH)

EXOGENOUS:
   CDDANG   - COOLING DEGREE DAYS (ANGLETON) NUMBER OF DAYS
   CDDCLI   - COOLING DEGREE DAYS (CLIFTON) NUMBER OF DAYS
   CDDFOR   - COOLING DEGREE DAYS (FORT STOCKTON) NUMBER OF DAYS
   CDDLEW   - COOLING DEGREE DAYS (LEWISVILLE) NUMBER OF DAYS
   CDDOLN   - COOLING DEGREE DAYS (OLNEY) NUMBER OF DAYS
   CDDPAN   - COOLING DEGREE DAYS (PANHANDLE) NUMBER OF DAYS
   CDDPEC   - COOLING DEGREE DAYS (PECOS) NUMBER OF DAYS
   CDDPET   - COOLING DEGREE DAYS (PETROLIA) NUMBER OF DAYS
   CDDTEX   - COOLING DEGREE DAYS (TEXAS CITY) NUMBER OF DAYS
   CDDWHI   - COOLING DEGREE DAYS (WHITEWRIGHT) NUMBER OF DAYS
   CFORCOM  - COMMERCIAL CUSTOMERS (FORT STOCKTON) (NUMBER OF CUSTOMERS)
   CFORRES  - RESIDENTIAL CUSTOMERS (FORT STOCKTON) (NUMBER OF CUSTOMERS)
   CPANCOM  - COMMERCIAL CUSTOMERS (PANHANDLE) (NUMBER OF CUSTOMERS)
   CPANRES  - RESIDENTIAL CUSTOMERS (PANHANDLE) (NUMBER OF CUSTOMERS)
   CPECCOM  - COMMERCIAL CUSTOMERS (PECOS) (NUMBER OF CUSTOMERS)
   CPECRES  - RESIDENTIAL CUSTOMERS (PECOS) (NUMBER OF CUSTOMERS)
   HDDANG   - HEATING DEGREE DAYS (ANGLETON) NUMBER OF DAYS
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   HDDCLI   - HEATING DEGREE DAYS (CLIFTON) NUMBER OF DAYS
   HDDFOR   - HEATING DEGREE DAYS (FORT STOCKTON) NUMBER OF DAYS
   HDDLEW   - HEATING DEGREE DAYS (LEWISVILLE) NUMBER OF DAYS
   HDDOLN   - HEATING DEGREE DAYS (OLNEY) NUMBER OF DAYS
   HDDPAN   - HEATING DEGREE DAYS (PANHANDLE) NUMBER OF DAYS
   HDDPEC   - HEATING DEGREE DAYS (PECOS) NUMBER OF DAYS
   HDDPET   - HEATING DEGREE DAYS (PETROLIA) NUMBER OF DAYS
   HDDTEX   - HEATING DEGREE DAYS (TEXAS CITY) NUMBER OF DAYS
   HDDWHI   - HEATING DEGREE DAYS (WHITEWRIGHT) NUMBER OF DAYS
   HLPMPOP  - HLP MONTHLY POPULATION (THOUSANDS)
   NENAG    - NORTHEAST DIVISION NON-AGRICULTURAL EMPLOYMENT (THOUSANDS)
   NEPI     - NORTHEAST DIVISION PERSONAL INCOME (THOUSANDS OF $)
   PNAG     - PANHANDLE DIVISION NON-AGRICULTURAL EMPLOYMENT (THOUSANDS)
   PPI      - PANHANDLE DIVISION PERSONAL INCOME (THOUSANDS OF $)
   SEPI     - SOUTHEAST DIVISION PERSONAL INCOME (THOUSANDS OF $)
   TEXCPI   - TEXAS CONSUMER PRICE INDEX
   TREND    - TREND VARIABLE
   TUMPOP   - TU ELECTRIC POPULATION (THOUSANDS)
   WNAG     - WESTERNT DIVISION NON-AGRICULTURAL EMPLOYMENT (THOUSANDS)
   WPI      - WESTERN DIVISION PERSONAL INCOME (THOUSANDS OF $)

COEFFICIENT:
   AA0  AA1  A0  A1  A2  A3  BB0  BB1  B0  B1  B2  CC0  CC1  C0  C1  C2  C3  DD0  DD1  D0  D1  D2
EE0  EE1  E0  E1  E2  E3  FF0
   FF1  F0  F1  F2  GG0  GG1  G0  G1  G2  G3  H0  H1  H2  H3  I0  I1  I2  I3  J0  J1  J2  J3  KK0
KK1  K0  K1  K2  K3  LL0  LL1  L0
   L1  L2  L3  MM0  MM1  M0  M1  M2  M3  NN0  NN1  N0  N1  N2  N3  OO0  OO1  O0  O1  O2  PP0  PP1
P0  P1  P3  QQ0  QQ1  Q0  Q1  Q2
   Q3  R0  R1  R2  S0  S1  S2  S3  T0  T1  T2  T3

EQUATIONS
     1:       SANGRES = A0+A1*CDDANG*CANGRES+A2*HDDANG*CANGRES+A3*SEPI/TEXCPI
     2:       SANGCOM = B0+B1*CDDANG*CANGCOM+B2*TREND
     3:       STEXRES = C0+C1*HDDTEX*CTEXRES+C2*CDDTEX*CTEXRES+C3*SEPI/TEXCPI
     4:       STEXCOM = D0+D1*CDDTEX*CTEXCOM+D2*TREND
     5:       SCLIRES = E0+E1*CDDCLI*CCLIRES+E2*HDDCLI*CCLIRES+E3*NEPI/TEXCPI
     6:       SCLICOM = F0+F1*CDDCLI*CCLICOM+F2*NENAG
     7:       SOLNRES = G0+G1*HDDOLN*COLNRES+G2*CDDOLN*COLNRES+G3*NEPI/TEXCPI
     8:       SOLNCOM = H0+H1*HDDOLN*COLNCOM+H2*CDDOLN*COLNCOM+H3*NENAG
     9:       SLEWRES = I0+I1*HDDLEW*CLEWRES+I2*CDDLEW*CLEWRES+I3*NEPI/TEXCPI
    10:       SLEWCOM = J0+J1*HDDLEW*CLEWCOM+J2*CDDLEW*CLEWCOM+J3*NENAG
    11:       SPETRES = K0+K1*HDDPET*CPETRES+K2*CDDPET*CPETRES+K3*NEPI/TEXCPI
    12:       SPETCOM = L0+L1*HDDPET*CPETCOM+L2*CDDPET*CPETCOM+L3*NENAG
    13:       SWHIRES = M0+M1*HDDWHI*CWHIRES+M2*CDDWHI*CWHIRES+M3*NEPI/TEXCPI
    14:       SWHICOM = N0+N1*HDDWHI*CWHICOM+N2*CDDWHI*CWHICOM+N3*NENAG
    15:       SFORRES = O0+O1*HDDFOR*CFORRES+O2*CDDFOR*CFORRES
    16:       SFORCOM = P0+P1*CDDFOR*CFORCOM+P3*WNAG
    17:       SPECRES = Q0+Q1*HDDPEC*CPECRES+Q2*CDDPEC*CPECRES+Q3*WPI/TEXCPI
    18:       SPECCOM = R0+R1*CDDPEC*CPECCOM+R2*WNAG
    19:       SPANRES = S0+S1*CDDPAN*CPANRES+S2*HDDPAN*CPANRES+S3*PPI/TEXCPI
    20:       SPANCOM = T0+T1*CDDPAN*CPANCOM+T2*HDDPAN*CPANCOM+T3*PNAG
    21:       CANGRES = AA0+AA1*HLPMPOP
    22:       CTEXRES = BB0+BB1*TREND
    23:       CCLIRES = CC0+CC1*TUMPOP
    24:       COLNRES = DD0+DD1*TUMPOP
    25:       CPETRES = EE0+EE1*TUMPOP
    26:       CLEWRES = FF0+FF1*TUMPOP
    27:       CWHIRES = GG0+GG1*TUMPOP
    28:       CANGCOM = KK0+KK1*TREND
    29:       CTEXCOM = LL0+LL1*CTEXRES
    30:       CCLICOM = MM0+MM1*TUMPOP
    31:       COLNCOM = NN0+NN1*COLNRES
    32:       CPETCOM = OO0+OO1*TUMPOP
    33:       CLEWCOM = PP0+PP1*CLEWRES
    34:       CWHICOM = QQ0+QQ1*TUMPOP
    35:       TOTSSED = (SANGRES+STEXRES+SANGCOM+STEXCOM)/1000
    36:       TOTSCD = (SCLIRES+SOLNRES+SCLICOM+SOLNCOM)/1000
    37:       TOTSNED = (SPETRES+SLEWRES+SWHIRES+SPETCOM+SLEWCOM+SWHICOM)/1000
    38:       TOTSWD = (SFORRES+SPECRES+SFORCOM+SPECCOM)/1000
    39:       TOTSPD = (SPANRES+SPANCOM)/1000
    40:       TOTSTNP = TOTSSED+TOTSNED+TOTSCD+TOTSWD+TOTSPD
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```
41:      RSTNP = (SANGRES+SCLIRES+SLEWRES+SOLNRES+SPETRES+STEXRES
                  +SWHIRES+SFORRES+SPANRES+SPECRES)/1000
42:      CSTNP = (SANGCOM+SCLICOM+SLEWCOM+SOLNCOM+SPETCOM+STEXCOM+SWHICOM
                  +SFORCOM+SPANCOM+SPECCOM)/1000
```

Results -- TNP

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

1 : SANGRES = A0+A1*CDDANG*CANGRES+A2*HDDANG*CANGRES+A3*SEPI/TEXCPI

```
NOB = 88                NOVAR = 5               NCOEF = 5               RANGE:  1980 1
TO  1987 5
RSQ =          0.936957 CRSQ =         0.933919 F(3/83) =      308.391  PROB>F =
0.
SER =      1.313001E+06 SSR =      1.430897E+14 DW(0) =         2.1247  COND =
63.5123
MAX:HAT =      0.202379 RSTUDENT =      2.89933 DFFITS =      0.950893
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
A0	3.872273E+06	5.567207E+06	0.69555	0.488653
A1	3.44701	0.122332	28.1774	0.
A2	1.01305	0.08306	12.1966	0.
A3	5.259806E+06	4.047455E+06	1.29953	0.197359
AR1.0001	0.32	0.103716	3.08535	0.002762

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

2 : SANGCOM = B0+B1*CDDANG*CANGCOM+B2*TREND

```
NOB = 88                NOVAR = 4               NCOEF = 4               RANGE:  1980 1
TO  1987 5
RSQ =          0.876246 CRSQ =         0.871826 F(2/84) =      198.256  PROB>F =
0.
SER =      585845.      SSR =      2.882997E+13 DW(0) =        2.14987  COND =
4.51228
MAX:HAT =      0.103058 RSTUDENT =      3.24937 DFFITS =     -0.588537
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
B0	6.701276E+06	198754.	33.7164	0.
B1	4.93845	0.296738	16.6425	0.
B2	29053.5	3492.9	8.31787	0.
AR1.0002	0.3	0.10771	2.78526	0.006609

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

3 : STEXRES = C0+C1*HDDTEX*CTEXRES+C2*CDDTEX*CTEXRES+C3*SEPI/TEXCPI

```
NOB = 88                NOVAR = 5               NCOEF = 5               RANGE:  1980 1
TO  1987 5
RSQ =          0.938215 CRSQ =         0.935237 F(3/83) =       315.09  PROB>F =
0.
```

SER = 4.205682E+06 SSR = 1.468084E+15 DW(0) = 2.26742 COND =
63.7109
MAX:HAT = 0.20613 RSTUDENT = 2.72147 DFFITS = 0.935548

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
C0	7.981454E+06	1.733709E+07	0.460369	0.646455
C1	1.0171	0.09565	10.6335	0.
C2	3.97075	0.141156	28.1303	0.
C3	1.647291E+07	1.260861E+07	1.30648	0.194998
AR1.0003	0.3	0.10659	2.81452	0.006099

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

5 : SCLIRES = E0+E1*CDDCLI*CCLIRES+E2*HDDCLI*CCLIRES+E3*NEPI/TEXCPI

NOB = 88 NOVAR = 5 NCOEF = 5 RANGE: 1980 1
TO 1987 5
RSQ = 0.932517 CRSQ = 0.929264 F(3/83) = 286.733 PROB>F =
0.
SER = 849975. SSR = 5.996395E+13 DW(0) = 2.00337 COND =
26.408
MAX:HAT = 0.204442 RSTUDENT = -3.03986 DFFITS = -1.0804

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
E0	-891954.	1.461846E+06	-0.610156	0.543426
E1	2.27132	0.080258	28.3002	0.
E2	0.526799	0.039108	13.4704	0.
E3	3.505243E+06	733731.	4.77729	0.
AR1.0005	0.3	0.104133	2.88094	0.005044

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

6 : SCLICOM = F0+F1*CDDCLI*CCLICOM+F2*NENAG

NOB = 88 NOVAR = 4 NCOEF = 4 RANGE: 1980 1
TO 1987 5
RSQ = 0.938023 CRSQ = 0.935809 F(2/84) = 423.779 PROB>F =
0.
SER = 491407. SSR = 2.028438E+13 DW(0) = 2.20835 COND =
32.4334
MAX:HAT = 0.091929 RSTUDENT = -2.86674 DFFITS = -0.457738

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
F0	-7.585722E+06	1.090883E+06	-6.95374	0.
F1	4.97171	0.202835	24.511	0.
F2	18738.	1475.19	12.7021	0.
AR1.0006	0.3	0.106881	2.80687	0.006217

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

8 : SOLNCOM = H0+H1*HDDOLN*COLNCOM+H2*CDDOLN*COLNCOM+H3*NENAG

NOB = 88 NOVAR = 5 NCOEF = 5 RANGE: 1980 1
TO 1987 5
RSQ = 0.861987 CRSQ = 0.855336 F(3/83) = 129.598 PROB>F =
0.
SER = 188682. SSR = 2.954865E+12 DW(0) = 2.34861 COND =
33.3284
MAX:HAT = 0.208412 RSTUDENT = -2.54494 DFFITS = -0.54082

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
H0	-2.335890E+06	616483.	-3.78906	0.
H1	0.261757	0.098093	2.66846	0.009162
H2	2.36652	0.209641	11.2884	0.
H3	6204.79	831.154	7.46527	0.
AR1.0008	0.52	0.094394	5.5088	0.

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

9 : SLEWRES = I0+I1*HDDLEW*CLEWRES+I2*CDDLEW*CLEWRES+I3*NEPI/TEXCPI

NOB = 88 NOVAR = 5 NCOEF = 5 RANGE: 1980 1
TO 1987 5
RSQ = 0.945571 CRSQ = 0.942948 F(3/83) = 360.48 PROB>F =
0.
SER = 1.192236E+06 SSR = 1.179786E+14 DW(0) = 2.10248 COND =
26.1642
MAX:HAT = 0.191068 RSTUDENT = -3.16969 DFFITS = -1.14835

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
I0	-8.517222E+06	2.304629E+06	-3.6957	0.
I1	1.12397	0.062103	18.0985	0.
I2	3.11701	0.117765	26.4681	0.
I3	8.065119E+06	1.182430E+06	6.8208	0.
AR1.0009	0.38	0.100984	3.76297	0.

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

10 : SLEWCOM = J0+J1*HDDLEW*CLEWCOM+J2*CDDLEW*CLEWCOM+J3*NENAG

NOB = 88 NOVAR = 5 NCOEF = 5 RANGE: 1980 1
TO 1987 5
RSQ = 0.946748 CRSQ = 0.944182 F(3/83) = 368.907 PROB>F =
0.
SER = 664741. SSR = 3.667614E+13 DW(0) = 2.05161 COND =
35.052
MAX:HAT = 0.186838 RSTUDENT = 3.38675 DFFITS = -0.712113

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
J0	-2.064706E+07	1.601147E+06	-12.8952	0.
J1	0.747007	0.266639	2.80157	0.006327
J2	8.28958	0.520183	15.9359	0.
J3	38756.5	2212.23	17.5192	0.
AR1.0010	0.34	0.103382	3.28878	0.001477

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

12 : SPETCOM = L0+L1*HDDPET*CPETCOM+L2*CDDPET*CPETCOM+L3*NENAG

NOB = 88 NOVAR = 5 NCOEF = 5 RANGE: 1980 1
TO 1987 5
RSQ = 0.654608 CRSQ = 0.637962 F(3/83) = 39.3266 PROB>F =
0.
SER = 23338.7 SSR = 4.520987E+10 DW(0) = 1.99912 COND =
34.1584
MAX:HAT = 0.176327 RSTUDENT = 5.8737 DFFITS = 1.39221

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
L0	-17035.7	53509.7	-0.318368	0.751006
L1	0.448992	0.083592	5.37122	0.
L2	1.50483	0.155704	9.66466	0.
L3	282.681	72.2288	3.91369	0.
AR1.0012	0.32	0.101537	3.15155	0.00226

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

13 : SWHIRES = M0+M1*HDDWHI*CWHIRES+M2*CDDWHI*CWHIRES+M3*NEPI/TEXCPI

NOB = 88 NOVAR = 5 NCOEF = 5 RANGE: 1980 1
TO 1987 5
RSQ = 0.956737 CRSQ = 0.954652 F(3/83) = 458.872 PROB>F =
0.
SER = 705866. SSR = 4.135453E+13 DW(0) = 2.22207 COND =
26.369
MAX:HAT = 0.163826 RSTUDENT = -2.87923 DFFITS = 0.687117

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
M0	-3.824177E+06	1.217604E+06	-3.14074	0.002335
M1	0.552692	0.033658	16.4207	0.
M2	2.15384	0.060485	35.6092	0.
M3	4.880113E+06	609555.	8.00602	0.
AR1.0013	0.3	0.107531	2.78988	0.006539

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

14 : SWHICOM = N0+N1*HDDWHI*CWHICOM+N2*CDDWHI*CWHICOM+N3*NENAG

NOB = 88 NOVAR = 5 NCOEF = 5 RANGE: 1980 1
TO 1987 5
RSQ = 0.908244 CRSQ = 0.903822 F(3/83) = 205.393 PROB>F =
0.
SER = 350070. SSR = 1.017157E+13 DW(0) = 2.16426 COND =
34.2112
MAX:HAT = 0.163712 RSTUDENT = 2.86623 DFFITS = -0.760233

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
N0	-5.435082E+06	777518.	-6.9903	0.
N1	0.464491	0.081186	5.72129	0.
N2	2.60095	0.147998	17.5742	0.
N3	14044.9	1052.96	13.3385	0.
AR1.0014	0.3	0.109581	2.7377	0.007568

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

17 : SPECRES = Q0+Q1*HDDPEC*CPECRES+Q2*CDDPEC*CPECRES+Q3*WPI/TEXCPI

NOB = 88 NOVAR = 5 NCOEF = 5 RANGE: 1980 1
TO 1987 5
RSQ = 0.933736 CRSQ = 0.930543 F(3/83) = 292.392 PROB>F =
0.
SER = 292481. SSR = 7.100242E+12 DW(0) = 2.30324 COND =
57.3024
MAX:HAT = 0.157369 RSTUDENT = -2.52295 DFFITS = -0.569694

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
Q0	1.149483E+06	1.063927E+06	1.08041	0.283087
Q1	0.435806	0.031572	13.8035	0.
Q2	1.5689	0.057032	27.5089	0.
Q3	9.797299E+06	6.930404E+06	1.41367	0.161199
AR1.0017	0.3	0.108513	2.76463	0.00702

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

18 : SPECCOM = R0+R1*CDDPEC*CPECCOM+R2*WNAG

NOB = 88 NOVAR = 4 NCOEF = 4 RANGE: 1980 1
TO 1987 5
RSQ = 0.826506 CRSQ = 0.82031 F(2/84) = 133.389 PROB>F =
0.
SER = 1.038927E+06 SSR = 9.066708E+13 DW(0) = 1.96539 COND =
92.6538
MAX:HAT = 0.112757 RSTUDENT = -3.45627 DFFITS = -0.600334

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
R0	1.929246E+06	9.610626E+06	0.200741	0.841386
R1	6.66961	0.550235	12.1214	0.
R2	125316.	188376.	0.665247	0.507715
AR1.0018	0.52	0.092699	5.60953	0.

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

20 : SPANCOM = T0+T1*CDDPAN*CPANCOM+T2*HDDPAN*CPANCOM+T3*PNAG

NOB = 88 NOVAR = 5 NCOEF = 5 RANGE: 1980 1
TO 1987 5
RSQ = 0.835769 CRSQ = 0.827855 F(3/83) = 105.597 PROB>F =
0.

SER = 312976. SSR = 8.130203E+12 DW(0) = 2.06242 COND =
151.523
MAX:HAT = 0.161018 RSTUDENT = 4.76542 DFFITS = 0.981857

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
T0	-4.899910E+06	3.030872E+06	-1.61667	0.109745
T1	5.06816	0.324993	15.5947	0.
T2	0.387498	0.098031	3.95282	0.
T3	89479.4	33214.1	2.69402	0.008541
AR1.0020	0.3	0.104771	2.8634	0.005305

ORDINARY LEAST SQUARES

MODEL NAME: TNP88

4 : STEXCOM = D0+D1*CDDTEX*CTEXCOM+D2*TREND

NOB = 89 NOVAR = 3 NCOEF = 3 RANGE: 1980 1
TO 1987 5
RSQ = 0.887213 CRSQ = 0.88459 F(2/86) = 338.249 PROB>F =
0.
SER = 1.658727E+06 SSR = 2.366183E+14 DW(0) = 1.83774 COND =
4.45601
MAX:HAT = 0.096768 RSTUDENT = 2.18973 DFFITS = -0.588629

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
D0	2.367302E+07	389905.	60.7149	0.
D1	7.8164	0.328476	23.796	0.
D2	73919.4	6844.51	10.7998	0.

ORDINARY LEAST SQUARES

MODEL NAME: TNP88

7 : SOLNRES = G0+G1*HDDOLN*COLNRES+G2*CDDOLN*COLNRES+G3*NEPI/TEXCPI

NOB = 89 NOVAR = 4 NCOEF = 4 RANGE: 1980 1
TO 1987 5
RSQ = 0.937752 CRSQ = 0.935555 F(3/85) = 426.839 PROB>F =
0.
SER = 254184. SSR = 5.491810E+12 DW(0) = 1.86414 COND =
27.472
MAX:HAT = 0.17715 RSTUDENT = -3.20299 DFFITS = 0.821958

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
G0	-299431.	316877.	-0.944944	0.347366
G1	0.451579	0.036732	12.2938	0.
G2	2.47206	0.074105	33.3589	0.
G3	1.007457E+06	154256.	6.53105	0.

ORDINARY LEAST SQUARES

MODEL NAME: TNP88

11 : SPETRES = K0+K1*HDDPET*CPETRES+K2*CDDPET*CPETRES+K3*NEPI/TEXCPI

NOB = 89 NOVAR = 4 NCOEF = 4 RANGE: 1980 1
TO 1987 5
RSQ = 0.855847 CRSQ = 0.850759 F(3/85) = 168.217 PROB>F =
0.
SER = 65112.5 SSR = 3.603692E+11 DW(0) = 1.92411 COND =
26.6433
MAX:HAT = 0.138786 RSTUDENT = 4.97622 DFFITS = 1.1254

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
K0	185962.	78424.4	2.37122	0.01999
K1	0.653959	0.059884	10.9204	0.
K2	2.33485	0.105185	22.1975	0.
K3	47025.3	38831.4	1.21101	0.229246

ORDINARY LEAST SQUARES

MODEL NAME: TNP88

15 : SFORRES = O0+O1*HDDFOR*CFORRES+O2*CDDFOR*CFORRES

NOB = 89 NOVAR = 3 NCOEF = 3 RANGE: 1980 1
TO 1987 5
RSQ = 0.924263 CRSQ = 0.922501 F(2/86) = 524.752 PROB>F =
0.
SER = 179687. SSR = 2.776719E+12 DW(0) = 1.93512 COND =
6.00099
MAX:HAT = 0.12653 RSTUDENT = -2.5818 DFFITS = -0.42276

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
O0	1.551321E+06	58711.3	26.4229	0.
O1	0.456944	0.030758	14.8562	0.
O2	1.63709	0.055602	29.4432	0.

ORDINARY LEAST SQUARES

MODEL NAME: TNP88

16 : SFORCOM = P0+P1*CDDFOR*CFORCOM+P3*WNAG

NOB = 89 NOVAR = 3 NCOEF = 3 RANGE: 1980 1
TO 1987 5
RSQ = 0.867346 CRSQ = 0.864261 F(2/86) = 281.151 PROB>F =
0.
SER = 358279. SSR = 1.103928E+13 DW(0) = 1.7696 COND =
91.5475
MAX:HAT = 0.096682 RSTUDENT = 2.87442 DFFITS = -0.738901

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
P0	2.072526E+06	1.527924E+06	1.35643	0.178512
P1	5.94028	0.252935	23.4854	0.
P3	30699.7	30016.8	1.02275	0.309294

ORDINARY LEAST SQUARES

MODEL NAME: TNP88

19 : SPANRES = S0+S1*CDDPAN*CPANRES+S2*HDDPAN*CPANRES+S3*PPI/TEXCPI

```
NOB = 89                 NOVAR = 4                NCOEF = 4                RANGE:  1980 1
TO  1987 5
RSQ =           0.94815  CRSQ =          0.94632  F(3/85) =      518.113   PROB>F =
0.
SER =       284692.      SSR =      6.889222E+12  DW(0) =           2.12911  COND =
63.7489
MAX:HAT =      0.140469  RSTUDENT =      3.00145  DFFITS =        -0.664844
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
S0	-1.014320E+06	802924.	-1.26328	0.209942
S1	2.57768	0.073625	35.0107	0.
S2	0.265588	0.021758	12.2065	0.
S3	1.420804E+07	3.070691E+06	4.62698	0.

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

21 : CANGRES = AA0+AA1*HLPMPOP

```
NOB = 88                 NOVAR = 3                NCOEF = 3                RANGE:  1980 1
TO  1987 5
RSQ =          0.976805  CRSQ =         0.976259  F(1/85) =      1789.79   PROB>F =
0.
SER =           135.213  SSR =      1.554014E+06  DW(0) =           1.90116  COND =
55.6612
MAX:HAT =      0.111182  RSTUDENT =     -9.50184  DFFITS =         -1.02312
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
AA0	-707.561	3989.32	-0.177364	0.859645
AA1	5.33513	1.23002	4.33743	0.
AR1.0021	0.9	0.048446	18.5775	0.

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

22 : CTEXRES = BB0+BB1*TREND

```
NOB = 88                 NOVAR = 3                NCOEF = 3                RANGE:  1980 1
TO  1987 5
RSQ =          0.979943  CRSQ =         0.979471  F(1/85) =      2076.49   PROB>F =
0.
SER =           445.986  SSR =      1.690677E+07  DW(0) =           2.14122  COND =
4.51264
MAX:HAT =      0.044688  RSTUDENT =     -11.0383  DFFITS =         -2.21898
```

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
BB0	40407.9	1118.82	36.1165	0.
BB1	101.929	18.607	5.478	0.
AR1.0022	0.9	0.047733	18.855	0.

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

23 : CCLIRES = CC0+CC1*TUMPOP

NOB = 88 NOVAR = 3 NCOEF = 3 RANGE: 1980 1
TO 1987 5
RSQ = 0.996571 CRSQ = 0.99649 F(1/85) = 12351.7 PROB>F =
0.
SER = 38.8093 SSR = 128024. DW(0) = 1.80563 COND =
34.9638
MAX:HAT = 0.051222 RSTUDENT = 2.84114 DFFITS = 0.506

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
CC0	3298.85	514.008	6.4179	0.
CC1	2.26263	0.103183	21.9285	0.
AR1.0023	0.86	0.046648	18.4358	0.

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

24 : COLNRES = DD0+DD1*TUMPOP

NOB = 88 NOVAR = 3 NCOEF = 3 RANGE: 1980 1
TO 1987 5
RSQ = 0.973792 CRSQ = 0.973176 F(1/85) = 1579.16 PROB>F =
0.
SER = 24.754 SSR = 52084.5 DW(0) = 2.19805 COND =
39.7829
MAX:HAT = 0.065082 RSTUDENT = 13.0661 DFFITS = 1.43845

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
DD0	3641.25	1305.4	2.78937	0.006517
DD1	0.100266	0.252378	0.397287	0.692152
AR1.0024	0.96	0.017924	53.5603	0.

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

25 : CPETRES = EE0+EE1*TUMPOP

NOB = 88 NOVAR = 3 NCOEF = 3 RANGE: 1980 1
TO 1987 5
RSQ = 0.892784 CRSQ = 0.890261 F(1/85) = 353.895 PROB>F =
0.
SER = 3.56664 SSR = 1081.28 DW(0) = 2.03364 COND =
33.7288
MAX:HAT = 0.04807 RSTUDENT = -3.8811 DFFITS = -0.758256

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
EE0	462.564	17.7226	26.1002	0.
EE1	0.032719	0.003591	9.11096	0.
AR1.0025	0.64	0.085107	7.51997	0.

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

26 : CLEWRES = FF0+FF1*TUMPOP

NOB = 88 NOVAR = 3 NCOEF = 3 RANGE: 1980 1
TO 1987 5
RSQ = 0.991895 CRSQ = 0.991705 F(1/85) = 5201.39 PROB>F =
0.
SER = 276.625 SSR = 6.504328E+06 DW(0) = 2.26125 COND =
36.4692
MAX:HAT = 0.055273 RSTUDENT = -8.83767 DFFITS = -1.4233

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
FF0	-43792.9	6687.19	-6.54877	0.
FF1	11.2951	1.32716	8.51072	0.
AR1.0026	0.92	0.035223	26.1195	0.

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

27 : CWHIRES = GG0+GG1*TUMPOP

NOB = 88 NOVAR = 3 NCOEF = 3 RANGE: 1980 1
TO 1987 5
RSQ = 0.985704 CRSQ = 0.985368 F(1/85) = 2930.39 PROB>F =
0.
SER = 85.2516 SSR = 617766. DW(0) = 2.46855 COND =
34.2289
MAX:HAT = 0.049328 RSTUDENT = -5.73833 DFFITS = -0.67404

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
GG0	1578.99	703.448	2.24464	0.027388
GG1	2.38644	0.142	16.8059	0.
AR1.0027	0.78	0.064644	12.066	0.

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

28 : CANGCOM = KK0+KK1*TREND

NOB = 88 NOVAR = 3 NCOEF = 3 RANGE: 1980 1
TO 1987 5
RSQ = 0.989519 CRSQ = 0.989272 F(1/85) = 4012.41 PROB>F =
0.
SER = 18.9597 SSR = 30554.8 DW(0) = 2.15015 COND =
3.94466
MAX:HAT = 0.044688 RSTUDENT = -6.03918 DFFITS = -0.886419

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
KK0	2238.56	10.0422	222.915	0.
KK1	7.10721	0.188337	37.7366	0.
AR1.0028	0.58	0.088975	6.51867	0.

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

29 : CTEXCOM = LL0+LL1*CTEXRES

NOB = 88 NOVAR = 3 NCOEF = 3 RANGE: 1980 1
TO 1987 5
RSQ = 0.974953 CRSQ = 0.974364 F(1/85) = 1654.33 PROB>F =
0.
SER = 52.4786 SSR = 234090. DW(0) = 2.24209 COND =
12.2113
MAX:HAT = 0.438279 RSTUDENT = -6.55877 DFFITS = 1.38335

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
LL0	2348.71	569.751	4.12234	0.
LL1	0.064104	0.012056	5.31711	0.
AR1.0029	0.94	0.031565	29.7799	0.

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

30 : CCLICOM = MM0+MM1*TUMPOP

NOB = 88 NOVAR = 3 NCOEF = 3 RANGE: 1980 1
TO 1987 5
RSQ = 0.99703 CRSQ = 0.99696 F(1/85) = 14266. PROB>F =
0.
SER = 12.367 SSR = 13000. DW(0) = 1.90373 COND =
37.6161
MAX:HAT = 0.058521 RSTUDENT = -4.53839 DFFITS = -0.733398

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
MM0	-1749.21	411.132	-4.25463	0.
MM1	0.929321	0.08088	11.4901	0.
AR1.0030	0.94	0.015285	61.4988	0.

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

31 : COLNCOM = NN0+NN1*COLNRES

NOB = 88 NOVAR = 3 NCOEF = 3 RANGE: 1980 1
TO 1987 5
RSQ = 0.995794 CRSQ = 0.995695 F(1/85) = 10063. PROB>F =
0.
SER = 7.76594 SSR = 5126.34 DW(0) = 2.08113 COND =
7.1157
MAX:HAT = 0.674803 RSTUDENT = -3.39497 DFFITS = -1.8386

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
NN0	1291.52	149.301	8.6504	0.
NN1	0.03455	0.033705	1.02508	0.308232
AR1.0031	0.98	0.003778	259.384	0.

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

32 : CPETCOM = OO0+OO1*TUMPOP

NOB = 88 NOVAR = 3 NCOEF = 3 RANGE: 1980 1
TO 1987 5
RSQ = 0.94265 CRSQ = 0.941301 F(1/85) = 698.565 PROB>F =
0.
SER = 2.42781 SSR = 501.013 DW(0) = 2.10573 COND =
34.3575
MAX:HAT = 0.049656 RSTUDENT = -3.35061 DFFITS = -0.505256

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
OO0	39.1722	22.1189	1.77099	0.080148
OO1	0.02745	0.004461	6.15379	0.
AR1.0032	0.8	0.059904	13.3547	0.

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

33 : CLEWCOM = PP0+PP1*CLEWRES

NOB = 88 NOVAR = 3 NCOEF = 3 RANGE: 1980 1
TO 1987 5
RSQ = 0.983373 CRSQ = 0.982982 F(1/85) = 2513.63 PROB>F =
0.
SER = 60.8835 SSR = 315079. DW(0) = 2.28101 COND =
7.89003
MAX:HAT = 0.056296 RSTUDENT = -11.1975 DFFITS = -1.90951

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
PP0	-266.079	51.7271	-5.14389	0.
PP1	0.151449	0.004216	35.9187	0.
AR1.0033	0.5	0.095663	5.22669	0.

HILDRETH-LU PROCEDURE

MODEL NAME: TNP88

34 : CWHICOM = QQ0+QQ1*TUMPOP

NOB = 88 NOVAR = 3 NCOEF = 3 RANGE: 1980 1
TO 1987 5
RSQ = 0.990764 CRSQ = 0.990547 F(1/85) = 4559.11 PROB>F =
0.
SER = 23.5687 SSR = 47216. DW(0) = 2.63412 COND =
35.3
MAX:HAT = 0.052106 RSTUDENT = -5.64729 DFFITS = -0.657549

COEF	ESTIMATE	STER	TSTAT	PROB>|T|
QQ0	-1502.98	367.677	-4.08779	0.
QQ1	0.862047	0.07362	11.7094	0.
AR1.0034	0.88	0.056223	15.6519	0.

A.12 CITY OF AUSTIN

Model -- COA

Symbol Declaration

TOTSCOA - TOTAL SYSTEM SALES IN MWH

CDD - COOLING DEGREE DAYS

HDD - HEATING DEGREE DAYS

POP - SERVICE AREA POPULATION

Coefficients:

a_0 a_1 a_2 a_3

Equation:

$$TOTSCOA_t = a_0 + a_1 (CDD_t) + a_2 (HDD_t) + a_3 (POP_t)$$

Mean of the Marginal Posterior Distribution of the Coefficients:

a0 = -1,412,605.01
a1 = 467.06
a2 = 344.94
a3 = 4,818.78.

Precision of the Marginal Posterior Distibution of the Coefficients:

a0: 6.6869×10^{-9}
a1: 0.0068
a2: 0.0027
a3: 0.0011