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

VOLUME I

SUMMARY OF RESULTS AND RECOMMENDATIONS

FEBRUARY 1989

THE PUBLIC UTILITY COMMISSION OF TEXAS

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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.

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CHAPTER ONE

SUMMARY AND INTRODUCTION

1.1 SUMMARY OF RESULTS

Whether one accepts the load forecasts and capacity resource plans prepared by the utilities in Texas (as reported in Volume II) or the independent load projections and recommended resource plans developed by the Electric Division staff of the Public Utility Commission of Texas (PUCT), as reported in this volume, Texas will have sufficient electrical generating capacity to meet its growing energy needs over the next ten years. While the resource plans currently being pursued by the Texas utilities are likely to result in a reliable power system, the PUCT staff recognizes a number of additional actions that could be taken to improve system efficiency and electrical energy costs, and to maintain or improve system reliability.

1.1.1 The Demand for Electricity in Texas

Based on results derived from the staff Econometric Electricity Demand Forecasting System, statewide peak demand is expected to grow at an annual rate of 2.8 percent over the next ten years, reaching 61,521 MW by 1997. This compares to the utility-projected 2.3-percent annual growth rate, resulting in a 58,551 MW peak demand for 1997. These are both base case projections presented prior to adjustments for demand-side management programs. (interruptible load, conservation, load management, and promotional programs).

These projected growth rates in demand contrast with the rapid increases in statewide peak demand experienced historically in Texas. From 1950 to 1970, peak demand in Texas increased at a high but relatively stable 10-percent annual rate. From 1975 to 1985, a period of rapid increases in energy prices, annual peak demand growth in Texas slowed to a rate of approximately 5 percent. In recent years, peak demand has declined in many areas of the State, with little change statewide.

The load projections developed by the Commission staff and the utilities assume a gradual recovery from the present recession in Texas. Industrial diversification efforts within the State, a rebounding energy industry, and population growth rates in excess of national rates are expected to contribute to stronger electricity demand. While the State's economic performance is expected to improve, it is unlikely that Texas will again, in the foreseeable future, achieve the economic growth experienced in the 1970s and early 1980s.

Also expected to contribute to electricity demand growth are higher saturations of electrical equipment in the residential sector, particularly electric heating equipment, air conditioning, and electric cooking appliances. The impact of higher saturations of electricity consuming equipment will be somewhat offset by greater equipment energy efficiencies attributable to technical progress, utility-sponsored conservation programs, and federal appliance standards.

In the later years of the forecast horizon, electricity prices are expected to become more favorable relative to natural gas costs. Electric prices are expected to increase at modest rates over the next ten years, based on the projections presented in Chapter Two. Little change is expected in electric rates in real dollar terms for most regions of the State.

While statewide economic growth and favorable electric rates are expected to contribute to growth in electricity demand, a number of factors will serve to constrain that growth. As a reaction to likely rate increases by utilities with investments in nuclear projects, a number of large industrial energy consumers along the Gulf Coast and in the City of Austin are pursuing self-generation or cogeneration projects to reduce their dependence on utility-supplied power. Also, as discussed below, the impact of the National Appliance Energy Conservation Act of 1987 and utility-sponsored conservation programs will likely affect the demand for electricity placed on utility systems.

For inclusion in this report, the Commission staff has updated its independent peak electricity demand forecasts for twelve of the State's largest utilities:

1. Texas Utilities Electric Company (TU Electric)
2. Houston Lighting and Power Company (HL&P)
3. Gulf States Utilities Company (GSU)
4. Central Power and Light Company (CPL)
5. City Public Service Board of San Antonio (CPS)
6. Southwestern Public Service Company (SPS)
7. Southwestern Electric Power Company (SWEPCO)

8. Lower Colorado River Authority	(LCRA)
9. City of Austin	(COA)
10. West Texas Utilities Company	(WTU)
11. El Paso Electric Company	(EPE)
12. Texas-New Mexico Power Company	(TNP)

In order to provide a comparison of peak demand projections prepared by the Commission staff and utilities between the 1986 report and this report, the 1995 forecast was selected. Except for WTU, the other 10 major utilities (i.e., not including TNP) reduced their peak demand projections between the 1985 and 1987 filings. Staff also reduced its 1995 peak demand projections for all major electric utilities with the exception of CPS. However, on average, the utilities reduced their 1995 peak demand forecast by 14 percent while reduction in the staff's forecast was 11.4 percent. A utility specific forecast revision is provided in Chapter Three.

TU Electric. The Econometric Electricity Demand Forecasting system projects a peak demand of 23,582 MW for the TU Electric system in 1997. Peak load and energy sales are forecast to increase at annual rates of 3.52 percent and 3.53 percent, respectively, from 1987 to 1997. These projections are similar to those prepared by the staff and presented in the Commission's 1986 biennial forecast report. The staff projections for TU Electric are largely in agreement with the utility filing.

HL&P. Since release of the 1986 forecast report, both the company and the staff have drastically lowered demand forecasts for the HL&P system. Under the staff projections, the State's second largest electric utility is expected to experience a 1.3-percent annual increase in unadjusted peak load through 1997, with electricity sales growing at a 1.4-percent rate. HL&P's "restated"[1] forecast also shows a 1-percent annual increase in unadjusted peak demand over the forecast period. The difference between the staff and the utility projections may largely be traced to projections of energy sales to the residential class. While HL&P projects no increase in residential sector energy consumption in its service area, the staff is forecasting an annual growth rate of over 1.5 percent through the ten-year forecast horizon. Both the Company and staff projections indicate that completion of the Robertson generating units by Texas-New Mexico Power Company (HL&P's largest customer) and increased self-generation activity among local industrial energy consumers will reduce or constrain wholesale and industrial sector sales and demand.

GSU. GSU has experienced generally declining peak demand since 1980. Staff projections indicate slow but consistent growth in peak load and sales over the next ten years at an annual rate of around 0.5 percent to a Texas peak of 2,417 MW in 1997. Demand growth is expected to be stronger in the Company's non-Texas service area. GSU anticipates a 1997 peak demand of about 50 MW less than the PUCT projection. Recent decreases in electricity demand may be traced to a depressed service area economy and volatility in the Company's rates. The current staff projection is slightly lower than the peak demand presented in the 1986 report.

CPL. While electricity sales to the residential and commercial customer classes are projected to remain strong, many of CPL's large industrial customers have turned, or are planning to turn, to self-generation and/or reducing their reliance on the utility. Self-generation is a response to anticipated higher rates attributable to the company's involvement in the South Texas Nuclear Project and presently depressed natural gas prices. Staff projects an annual growth rate of 3.2 percent in peak demand over the next 10 years. The separate projections prepared by CPL and the PUCT staff are within 4 percent of each other throughout the forecast horizon.

CPS. A strong 3.3-percent annual growth rate in peak load is forecast for the CPS system. Having already collected a large percentage of the construction costs associated with its share of the South Texas Nuclear Project from its ratepayers, CPS should be able to constrain future rate increases. Population growth and favorable rates will contribute to relatively high levels of electricity consumption growth, particularly in the residential and commercial sectors.

SPS. Serving the Texas Panhandle region, SPS is forecast to have an annual growth rate in peak demand of around 2 percent over the next ten years. The staff projections are slightly higher than the forecasts prepared by the utility and in close agreement with the 1986 staff projections.

SWEPCO. SWEPCO, serving northeast Texas and portions of Louisiana and Arkansas, is forecasting an annual peak demand growth of around 2 percent through 1997. Peak demand will approach 3,870 MW by 1997 on a total-system basis, and 2,073 MW on a Texas-system basis. Demand growth is expected to be much stronger in the Texas than in the non-Texas service area. This projection is a reduction from the staff 1986 demand forecast.

LCRA. Operating in Central Texas, LCRA's peak demand and sales are forecast to increase at annual rates of 3.7 percent and 3.8 percent, respectively, over the forecast horizon. Among major generating utilities in Texas, LCRA is expected to experience the second highest rate of demand growth. This updated load forecast is significantly lower than the staff 1986 projections due to continued economic stagnation in Central Texas and a less optimistic short-term economic outlook for the service area.

COA. COA is forecast to have the highest growth rate in electricity demand for the major utilities in Texas, with peak load expected to rise from 1,408 MW in 1987 to about 2,200 MW in 1997. Projected annual growth in peak demand and total sales are 4.6 percent and 4.2 percent, respectively.

WTU. The staff projects a 3.1 percent annual growth rate for WTU peak demand over the next ten years. While the Company forecasts higher growth in the near term, WTU and staff results are very similar for the mid-1990s.

EPE. Historically, the staff projections have been considerably more pessimistic than the forecasts prepared by EPE for that utility's service area. Once again, staff forecasts show lower rates of growth than those forecast by the Company. However, the differences between EPE and staff projections are smaller than they have been in the past. A 2.8-percent annual growth rate in peak demand is projected by the staff.

TNP. Included in this report is the first independent demand forecast for the Texas portion of the TNP system. The staff projection of Texas system sales and peak demand for TNP are 5,481 GWH and 1,187 MW, respectively, for 1997. The forecast annual growth rates for energy and peak demand are 1.9 percent and 2.0 percent, respectively.

In general, the Commission staff has achieved a higher degree of accuracy in projecting future electricity demand than the Texas utilities over the past few years. However, a considerable degree of uncertainty in both the staff's and the industry's ten-year load projections must be acknowledged. Based on statistical results attained by the staff, **plus or minus 5 percent** may be applied to the staff's projections to recognize this uncertainty.

At the present time, a key uncertainty in demand growth involves future self-generation activity. Even without the availability of firm capacity payments to cogenerators, many firms involved in the chemical, petrochemical, and petroleum refining industries have found it more economical to self-generate with cogeneration technologies than to continue to purchase from their utility supplier. For example, staff analysis indicates that roughly 400 MW of industrial load could drop off the HL&P system if staff projections of HL&P industrial prices are realized. At industrial retail electricity rates between 5 and 6 cents per KWH, the loss of industrial load to self-generation activity is highly uncertain but potentially could affect a very large portion of a utility's large-industrial load.

It should be noted that these demand projections are intended as a planning tool and not necessarily as a prediction. These projections indicate what future demand is likely to be, assuming the status quo or continuation of recent trends in demand-side management, rate design, and technological progress. If action is taken to change these factors (possibly as a Commission or utility reaction to the projected demand), then these projections might not materialize.

1.1.2 Electrical Energy Resources

To meet the State's growing electrical energy needs, a variety of supply-side and demand-side resources will be relied upon, including:

1. The construction of additional generating capacity
2. Non-utility generation (cogeneration and small power production)
3. Demand-side management (including conservation and load management programs, and strategic rate design)
4. Purchased power from other utilities
5. Efficiency improvements in generation, transmission, and distribution systems

The Commission staff has reviewed and generally supports the target reserve margins that the State's major generating utilities have established for planning purposes. These reserve margins reflect the utility's capacity needs, in excess of expected peak demand, that each utility requires to maintain reliability. The Electric Reliability Council of Texas (ERCOT) requires its member-utilities to maintain minimum 15-percent reserve margin targets. Some ERCOT utilities are using higher targets which may be justified due to larger baseload capacity units, increased dependence on non-utility generation, and uncertain performance of nuclear units during their first few years of operation.[2] The Western States Coordinating Council (WSCC) and the Southwest Power Pool (SPP), two adjoining reliability councils which also serve in parts of Texas, have established different methodologies for calculating reliability standards for their member utilities.

Staff analysis indicates that target reserve margins adopted by HL&P for planning purposes could be reduced from 1991 through 1997 without impairing reliability. Staff suggests reducing the 20 percent target established by the Company to 18 percent. During this period, the Company's reliance upon non-utility generation is likely to be reduced as a percentage of its peak demand, and the South Texas Nuclear Project will have achieved greater maturity and reliability. If demand increases more rapidly than currently expected, promotional programs could be curtailed or additional capacity could be secured from cogenerators.

Given the staff demand forecasts and target reserve margins, potential resources were compared on the basis of cost and reliability. The analysis indicates that there may be opportunities for delaying planned capacity additions through greater purchased power transactions and slightly greater reliance upon both demand-side management techniques and firm capacity available from cogenerators, relative to the reliance upon those resources presently planned by the utilities in the State.

Industrial cogeneration presently supplies, and will continue to supply, a significant part of the total electric energy needs in Texas. Cogeneration has developed very rapidly in the past few years. However, its growth now seems to be slowing and its continued development will depend on the economic vitality of the chemical, petrochemical, and petroleum refining industries in Texas; the relative prices of electricity and natural gas; the levels of standby charges; and, most importantly, the need for additional capacity in the State. The need for additional generating capacity by the utility industry affects cogenerator capacity payments from the utilities for the available cogenerating capability.

Of the 5,273 MW of cogeneration capacity presently operational in Texas, approximately 51 percent is currently under contract to provide firm capacity to the State's utilities. The remaining cogeneration capacity provides non-firm or firm energy or satisfies on-site energy requirements. An additional 580 MW of cogeneration is presently under construction in the State. Upon completion of the South Texas and Comanche Peak nuclear projects, the involved utilities plan to reduce (as a percentage of peak demand) their reliance on cogeneration to provide firm capacity.

In recent years, a number of utilities anticipating excess capacity in the near term have reduced their conservation program efforts and initiated aggressive new promotional programs to encourage electrical energy use. The staff is concerned that such a strategy might not be in the long-run best interests of the utilities' customers and may conflict with other policy objectives.

Two forecasts of demand-side program impacts were prepared: an adjustment based on utilities' current demand-side program impacts, and an independent assessment of conservation savings which will be lost if utilities do not act now. Staff-recommended demand-side adjustments are a blending of these two. In the case of three utilities --the City of Austin, the Lower Colorado River Authority, and TU Electric-- staff has essentially adopted the reported demand-side resource plans. For the remaining large generating utilities, the reported programs were amended to include certain low-cost activities which will benefit the service area. In many cases, these changes are very small. As a result, statewide peak demand is projected to be 4.5 percent lower in 1997 than it would be without demand-side management programs. This is equivalent to a 2,798 MW reduction in projected peak demand in 1997.

Aside from interruptible rate programs, strategic rate design has not been extensively used in Texas as a resource planning tool. Rate design could effectively be used as a means of encouraging more economically efficient consumer and utility behavior, and thereby serve as a means of deferring or reducing the need for additional generating capacity. Further research, including pilot programs and experiments, is necessary before specific recommendations on this topic can be formulated.

Based on the analysis of resource options available to the electric power industry, some opportunity to defer utility-planned capacity additions is apparent. Capacity additions recommended for deferral include Malakoff 1 (HL&P), Calaveras 6 (CPS), EPE's combustion turbine addition in 1996, and the COA combined-cycle addition in 1997. Additionally, staff proposes delays in commercial operating dates of the TNP One Units 3 and 4 (TNP) and Calaveras 5 (CPS) generating units over the forecast period. Finally, due to significant demand growth within the TU Electric service area, staff is proposing an earlier commercial operation date for Forest Grove 1. Also, TU Electric may have to rely on additional purchased power or other sources to meet its target reserve margin in 1997.

HL&P's Malakoff 1, presently scheduled for completion in 1996, could be deferred beyond that date as a result of the lower reserve margin target used in the staff analysis, reduced promotional efforts, and addition of some low-cost conservation programs. The Company has deferred construction of this unit a number of times in the past.

The staff demand projections for COA and EPE are lower than those prepared by the utilities; thus utility planned capacity additions could be deferred.

For the purposes of this report, the Commission staff does not recommend any changes to the utility-proposed on-line dates for South Texas Unit 2 (HL&P, CPL, CPS, and COA); Comanche Peak Units 1 and 2 (TU Electric and two minority owners); the combustion turbines presently being constructed by TU Electric; and TNP One Units 1 and 2 (TNP). However, the PUCT staff will continue to monitor the construction costs associated with these projects and the need for this capacity. A change in the status of these projects may be warranted if present circumstances change.

Completion of the South Texas and Comanche Peak nuclear projects and other baseload capacity additions will have a considerable impact on natural gas markets. In 1975, about 90 percent of the electricity generated by utilities in Texas was fueled with natural gas. In 1987, this percentage declined to 45 percent. The addition of 4,800 MW of nuclear capacity in Texas is expected to displace 250 to 330 billion cubic feet of natural gas fuel use per year. In the near term this reduction in demand is likely to contribute to continued surplus deliverability and price stability. In the long-term, however, persistently lower prices may limit exploration and drilling activity, thereby reducing the ratio of reserves to production and increasing the risk of price escalation. However, such future price escalation would be constrained by the prices of competing energy sources.

1.1.3 Electric Rates in Texas

For most regions of Texas, electric rates are below national averages and are expected to remain below national averages for the foreseeable future. Due to rising fuel prices, general inflation, and capacity requirements, electric rates in Texas doubled between 1976 and 1985 in nominal terms. However, electricity prices have stabilized and, in many cases, decreased since 1985.

Considerable variation may be seen in the rates charged by the electric utilities in Texas. CPL, CPS, and SWEPCO presently charge the lowest residential rates at the 1,000 KWH per month consumption level, while EPE's residential rates are the highest.[3] LCRA, a utility which primarily provides wholesale power to cooperatives and municipally-owned utilities in the Central Texas region, charges among the lowest rates in the State.

Independent "base case" projections of future average electricity prices were prepared for nine of the larger utilities in the State. **It should be emphasized that thee projections contained herein were prepared for planning purposes and do not reflect any official policy positions or predictions by the Commission.** These forecasts were based on a variety of assumptions regarding future regulatory treatment of capacity additions, capacity expansion plans, the State's economic climate, fuel prices, electricity sales levels, federal tax policy, generating unit performance, rate design, and accounting practices. The accuracy of these projections is fully dependent upon the extent to which the assumptions regarding these highly uncertain factors are realized.

For most areas of the State, future electricity price increases are expected to be at or below the anticipated rate of general inflation. Utility construction programs are winding down, and, consequently, large new capacity additions to utility rate bases will become less frequent. Successful utility diversification efforts and continued low fuel prices will constrain utility fuel costs, at least in the near term.

Between 1987 and 1997, the State's highest electric rate increases are expected for HL&P and GSU. Both have been involved in nuclear power plant construction projects. Residential average prices are forecast to increase at approximate annual rates of 3.4 percent and 4.1 percent, respectively, for the two utilities, with average industrial prices increasing at approximate rates of 5.3 percent and 4.4 percent, respectively. These rates only slightly exceed expected rates of inflation. The highest annual growth in industrial rates is expected for the HL&P service area.

Relatively low rates of growth in electric prices are projected for SPS, EPE, and CPS. SPS and EPE presently charge rates above the statewide average. For these three utilities, annual increases in residential and industrial average prices should remain under 3 percent for the next ten years.

1.1.4 Potential Problems Ahead and Key Uncertainties

While the outlook for the Texas electric power industry is generally favorable, a number of planning-related issues deserve prompt attention from the utility industry and regulators. A variety of other topics will require further study.

As noted in the final report from the PUCT's Bulk Power Transmission Study,[4] transmission constraints in some areas of the State may prevent the economical transmission of power. Without expansion of the transmission system, future power transfers could create reliability problems. Of particular concern is the status of the transmission network in the City of Austin, which does not meet ERCOT minimum standards, and along the Houston-to-Dallas corridor where several large projects have been delayed.

Near-term price increases by some utilities in Texas, particularly those involved in nuclear power projects, are of concern. Increased industrial rates, coupled with continued low natural gas prices, may result in loss of industrial customers with the capability to self-generate. Higher rates for captive residential and small commercial users who do not have a practical or economic alternative to the utility-supplied power leads to a "death spiral" as fixed costs are allocated to a decreasing customer base. This is a particular concern for the consumers along the Gulf Coast, where a concentration of industries capable of self-generation exists.

Environmental, public health, and energy security concerns may have a significant impact on the provision of electric power in Texas. Nuclear waste disposal, acid rain concerns, and global warming problems have yet to be fully addressed by the federal government. Real or imagined health concerns regarding high voltage transmission lines and nuclear power could affect system reliability. Efforts to reduce the nation's dependence upon foreign crude oil may result in higher electric rates and increased interest in conservation.

The Federal Energy Regulatory Commission's (FERC) recent initiatives toward restructuring and deregulating the nation's electric power industry introduces an additional element of uncertainty. The PUCT is concerned that, if enacted, the FERC proposals could have a detrimental effect on system reliability and an uncertain impact on costs and prices.

Movement toward a more competitive market for power will bring both new opportunities and new problems. Greater competition is entering the State's market for power in many forms. For example, cooperatives and municipal distribution utilities are showing increasing interest in shopping around for power from various utilities and cogenerators to secure power on the most attractive terms. Ultimate power consumers (the Capitol complex in Austin, for example) are also attempting to secure power from alternative sources that can supply electricity less expensively than their traditional providers. Utilities burdened with high fixed costs (often due to past planning mistakes or investment in nuclear power plants) may be at a competitive disadvantage and find it difficult to recover their allowed revenue requirement under present pricing practices.

Complacency with respect to utility planning during this phase of excess generating capacity and high reliability may jeopardize an economical and reliable electric power system for the future.

1.2 OBJECTIVES OF THIS REPORT

The Public Utility Regulatory Act, as amended through September 1, 1987, mandates the development by the Commission of a long-term statewide electrical energy forecast, to be sent to the Governor biennially. This is the third such report which the staff has prepared and recommended that the Public Utility Commission of Texas adopt.

Similar to the 1984 and 1986 reports, this report is designed to satisfy a number of objectives and summarize research findings in a number of related areas. The material presented in this report includes:

1. Staff prepared peak demand and sales forecasts for most of the larger generating electric utilities in Texas
2. Detailed resource planning recommendations designed to insure that the future electrical energy needs of the State are met in a reliable and economical manner
3. Staff analyses of fuel markets, cogeneration activity, and demand-side management impact and savings
4. A review of current utility-developed load forecasts and the capacity expansion plans presently being pursued by the State's utilities
5. Independent staff projections of future electricity prices
6. A summary of results from a variety of special projects

Together, this information is designed to provide a comprehensive and accurate outlook for the State's electric power industry and insight into key planning issues.

In comparison to earlier reports, this report provides a more comprehensive evaluation of supply-side resources, including cogeneration and utility-owned generating capacity. The status of the State's transmission network is granted considerably more attention in this report. The staff's evaluation of the likely impact of various demand-side management strategies (including conservation, load management, and promotional programs) has been significantly enhanced through greater reliance on the PUCT's end-use modeling system.

As in previous reports, and recognizing that circumstances are always changing, the Commission staff maintains that neither this report nor other forecasting or planning-related documents preclude the use of any available information in evidentiary proceedings. Load forecasts and resource plans will always require periodic adjustment and revision in light of new information. The staff remains committed to providing the most accurate and current information that our resource constraints will permit.

1.3 SUMMARY OF METHODOLOGY

The staff is presently involved in a number of complementary projects designed to promote an enhanced understanding of the State's electric power industry, to assist in identifying future potential problems and opportunities, and to provide policymakers with information and recommendations. This report provides a synthesis of the findings from these research projects and routine activities.

As required by the Public Utility Regulatory Act, most of the State's generating utilities filed Load and Capacity Resource Forecasts with the PUCT in December 1987. Utility Energy Efficiency Plans, required by the PUCT's Substantive Rules, were also filed at the Commission by the regulated Texas utilities in December 1987. Together, these filings document the industry's current projections and resource strategies. The utility filings, summarized in Volume II of this report, provide the basis for much of the staff's independent analysis.

To forecast the future demand for electricity, two forecasting systems are used. The Econometric Electricity Demand Forecasting System remains the primary forecasting tool and is utilized to obtain the projections presented in this volume. The End-Use Modeling System provides a validity check on the results obtained through the econometric models, contributes more detailed projections of energy consumption at the appliance or equipment end-use level, and is used to estimate the impact of demand-side management strategies. Both econometric and end-use forecasting systems have been significantly enhanced and refined since the release of the 1986 report.

On-going programs designed to monitor powerplant operations, generation and transmission construction projects, and cogeneration activity form the basis for much of the analysis of supply-side resource options presented in this volume.

The results derived from a number of special studies have also contributed to the development of this document. Recent special studies have included: the Bulk Power Transmission Study which assessed the operation and configuration of the transmission network in Texas, on-going research into State-Space and Bayesian statistical and forecasting techniques,[5] studies of the technical and economic relationships between utilities and cogenerators,[6] an inquiry into the economic efficiency achieved by the major electric utilities in Texas,[7] and a study designed to analyze utility error in load forecasting,[8] and studies of industrial sector energy use.[9] The reader is encouraged to reference the final reports from these studies if further information on these topics is desired.

1.4 ORGANIZATION OF REPORT

The first volume of this three-volume report presents the results from the staff's independent analysis of future electrical load and capacity resources in Texas. Volume II describes the forecasts and capacity expansion plans developed by the State's utilities. Volume III provides detailed technical documentation on the models developed by the staff to forecast demand growth.

Chapter Two of Volume I discusses various determinants of electricity demand and resources in Texas. Included in this chapter is an outlook for the State's economy, a discussion of trends in electricity consumption, a presentation of historical and projected information on electricity prices in Texas, and an outlook for fuel markets.

Economic activity is a key determinant of electricity demand growth and future resource requirements. While the State's recent severe economic recession is now considered to be over, some sectors of the economy and regions of the State have not yet completely rebounded. Among regional forecasters, there appears to be some disagreement over the future of the State's economy. Detailed information on the basic economic and demographic assumptions underlying the staff demand projections is provided in Volume III of this report.

Electricity prices, another important determinant of electricity demand, are also analyzed in Chapter Two. Historical trends in electricity prices are analyzed and the staff projections are presented.

With completion of new nuclear, lignite, and coal-fueled powerplant projects, the Texas electric power industry's diminishing dependence upon natural gas is discussed. An outlook for fuels markets is presented in the final section of Chapter Two.

Chapter Three reports the independent electricity demand projections for twelve large generating electric utilities in Texas. In general, these projections are consistent with the forecasts prepared by the State's utilities. The methodology employed to develop these projections is described in much greater detail in Volume III of this report. In any long-term forecasting effort, there is considerable uncertainty; thus the final section of Chapter Three reviews the accuracy of the utilities' past demand forecasting efforts.

Chapter Four highlights a key uncertainty in current utility and staff forecasts of the future demand to be served by the utility industry -- industrial self-generation. CPL, HL&P, GSU, and COA have recently lost, or may in the near future lose, a significant share of their large industrial load to self-generation. The extent to which this will occur in the future will largely depend upon future retail electric rates, standby charges, and fuel costs. This chapter is based on the preliminary results of on-going research by PUCT staff and is included to promote discussion among interested parties. **Due to their preliminary nature, the findings in this chapter are not reflected in the staff-recommended resource plans presented in Chapter Six.**

Chapter Five describes demand-side resources, including federal appliance standards, conservation and load management programs, and pricing strategies. Included are descriptions of the philosophies, methodologies, and techniques evolving in the staff approach to demand-side issues. Utility resource planners are particularly encouraged to review the information in this chapter. Chapter Six considers supply-side resources, including the construction of new generating units, purchased power, cogeneration, and efficiency improvements.

Finally, Chapter Seven of this volume summarizes the results and findings from the staff's analysis and provides policy recommendations and topics for further research.

Chapter One Notes:

1 HL&P's "official" forecast (Volume II, Chapter Three) is significantly lower than the company's "restated" forecast. The company's official forecast is already adjusted for plant siting, self-generation, and appliance efficiency impacts. The commission staff treats these adjustments differently. Therefore, HL&P's restated forecast provides a meaningful comparison with staff projections.

2 A paradox may be seen in this argument. One may question whether reliance upon a relatively unreliable generation source is justified, if it forces the utility to increase its capacity needs to compensate for the lower degree of reliability.

3 It should be noted, however, that average electricity consumption per residential customer is significantly lower in El Paso than in other regions of Texas due to climate and appliance holdings. Thus, such comparisons of electric rates at a fixed consumption level may not provide useful comparisons of actual bills received by ratepayers.

4 Public Utility Commission of Texas. **Bulk Power Transmission Study**, Austin, May 1988.

5 Ramgopal, Paul and George Mentrup, **Probability Theory and Confidence Intervals: Examples in the Regulatory Setting**, PUCT Discussion Paper, 1988; Paul Ramgopal, **On the Theory and Applications of State-Space Models**, PUCT Discussion Paper, 1987; Paul Ramgopal and George Mentrup, **Bayesian Analysis of a Linear Model of Total Electricity Sales**, PUCT Discussion Paper, October 1988.

6 Younghan Kwun, **Joint Optimal Supply Planning of Industrial Cogeneration and Conventional Electricity Systems**, PUCT Discussion Paper, August 1986.

7 Younghan Kwun, **Productivity and Regulation of Electric Utilities: An Empirical Study**, PUCT Discussion Paper, August 1987.

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CHAPTER TWO

ECONOMIC OUTLOOK AND IMPACTS ON ELECTRIC ENERGY IN TEXAS

Faced daily with headlines reporting record numbers of bank failures and mergers, bankruptcies, and real estate vacancies, many Texans find themselves asking some very important questions like:

> Will this recession ever end?
> Will the oil industry ever bounce back?
> What kind of standard of living can I expect in the future?
> What will the job situation be like in my field?

This analysis is intended to address these and other questions which are of major concern to most of the citizens of Texas in these seemingly troubled times. In addition, electric energy consumption and factors such as population, income, electricity prices, and fuel prices which can influence electricity consumption are analyzed in this Chapter.

2.1 THE TEXAS ECONOMY

According to most economists, the recession is indeed over. In fact, many indicators of the Texas economy have been exhibiting modest growth over the past several quarters. Unfortunately, this growth has been overshadowed by the ill-fated financial and real estate sectors. The important thing to remember is that the difficulties being experienced by these industries did not develop overnight. They are the result of decisions made during the oil boom. Banks were making real estate loans and contractors were building houses, apartment complexes, and office buildings to accommodate all the people and businesses that this economy was attracting. Then came the oil glut.

In early 1986, oil prices fell drastically. Many people lost their jobs as exploration was abandoned and refineries were closed. Not only were people and businesses no longer coming to Texas, but many of those that were here were leaving. The aftermath was a record amount of vacant real estate all across the State and, of course, no one to pay for it. This began a chain reaction. Builders, developers, and investors could neither sell to non-existent buyers nor collect rent from non-existent renters; therefore they could not repay the banks that had loaned the money. As a consequence, banks suffered record losses and many were forced into mergers or even failure. It is this, the reverberations of the oil glut, that we are seeing at present.

In spite of bank failures in excess of 100, the financial sector was expected to bottom out towards the end of 1988 and begin an expansionary phase. Growth will initially be sluggish as banks and other lending institutions remain leery of real estate and small business loans; but as time progresses and banks become more optimistic, growth is expected to gain momentum.

The prognosis for the construction industry is not quite as optimistic as that for the financial sector. It is likely to be several years before the excess real estate can be absorbed to a point that will allow any significant amount of new construction. In the long run, the construction industry is expected to demonstrate some growth. However, it is doubtful that we will again witness the degree of construction activity seen in the 1970s and early 1980s.

From the turn of this century until the early 1980s, the petroleum industry was the driving force behind the prosperous Texas economy. Recent events, however, have taught Texans the painful lesson that it is not only short-sighted but foolhardy to rely too heavily on one industry. Today's oil market is extremely unpredictable, with prices being highly sensitive to the actions of almost any OPEC nation. Oil prices are expected to continue to be very erratic, ranging anywhere from $10 to $20 per barrel over the next few years. As of October 25, 1988, the West Texas Intermediate Crude spot market price was $13.25 per barrel. While Texas maintains a significant presence in world petroleum production, the overall State economy is not and will not be as dependent on the health of this industry as it once was. Yet the industry is expected to demonstrate modest expansion. The number of rotary rigs in the State is projected to grow to and level off at approximately 500 toward the end of this century.

The current recovery taking place in Texas is due primarily to a conscious effort to diversify the economy. Modest growth is being seen over a broad base of industries. Among the industries demonstrating the strongest expansion are services, agriculture, retail trade, and manufacturing. In addition, the devaluation of the dollar has greatly enhanced those businesses that deal with exports. Over the next decade, services and high-tech industries are expected to lead the way to a more stable and prosperous economy.

Population and real personal income are projected to show relatively healthy growth over the next decade. Unemployment is expected to decline during this same time frame. According to most analysts, growth in real personal income will exceed that of population, resulting in an overall higher standard of living for the average Texan. Combined with an older, more educated work force, the labor market should tighten. The people of Texas will reap the benefits in the form of higher overall wages and lower unemployment.

The future of Texas looks bright. Expansion has been occurring over a wide range of industries. This somewhat modest growth may not be headline material, but it has been sustained over several quarters and promises to continue and to increase in strength through the end of this century. In fact, many economists are predicting that Texas will outperform the nation as a whole in several areas.

2.1.1 Macroeconomic Factors Affecting Electricity Demand

One factor affecting demand for electricity is population. Real per capita income also plays an important role in determining trends of future electricity consumption. If personal income is growing at a faster pace than population, the average person expects to enjoy an overall higher standard of living. A higher standard of living generally translates into an increase in comfort and convenience, which in many instances leads directly to an increase in electricity consumption. Finally, shifts in non-agricultural employment have implications with respect to electricity consumption within the commercial and industrial sectors. If employment is on the rise, it is assumed that the commercial and industrial sectors are experiencing growth. This growth may take the form of increased production or the entry of new businesses, both of which imply a rise in the demand for electricity.

Economic and demographic variables such as population, personal income, and nonagricultural employment are utilized in the econometric and end-use models by the Commission staff to forecast electricity demand. The staff of the PUCT analyzes a number of different forecasts in order to derive its vision of future trends in electricity demand. These projections (or combination thereof) are then used in the staff models to form its forecast of future electricity consumption. The staff models and the projections used as inputs are discussed in detail in Volume III of this report.

Sources for the projections considered by the PUCT staff include the Baylor University Forecasting Service, produced under the supervision of Dr. M. Ray Perryman, Data Resources, Inc. (DRI), Wharton Econometric Forecasting Associates (WEFA), and the Texas Comptroller of Public Accounts. Tables containing the specific forecasts made by the above sources for the period from 1987 through 1997 are provided for comparison purposes. These tables illustrate the differences among the different forecasting sources. It should be noted that while the actual projections are important, the more meaningful comparisons are drawn between the expected growth rates of the indicators.

As shown in Table 2.1.1, DRI is projecting the lowest annual growth rate in population for Texas through 1997. DRI's projections of non-agricultural employment are also lower than other sources (see Table 2.1.2). However, they expect the highest annual growth rates in personal income for Texas over the next ten years (Table 2.1.3). The Commission staff has used a more optimistic view of the future of Texas population and employment than those projected by DRI. See Volume III for more detail on inputs to staff models.

2.2 ELECTRIC ENERGY

It is commonly accepted that the current state of modernization and technological progress could not be achieved without the advantages provided by the use of electric energy. Factors other than the macroeconomic ones discussed above have important influences on future electric energy consumption. For a historical perspective on electric energy in Texas, this section consists of a discussion of electric energy consumption. Other fuel prices and electricity prices are two variables analyzed in later sections of this Chapter.

2.2.1 Electricity Consumption

Electricity consumption can be analyzed by looking at two variables. The first one is per capita electricity consumption, which is defined as total electricity consumption divided by total population for each electric utility's service area. The annual growth in this variable reflects the change in electricity consumption by all classes. The second variable is average annual residential electricity consumption, which is defined as total electricity consumption by residential class divided by the number of residential customers for each electric utility's service area. The annual growth in this variable only reflects the change

TABLE 2.1.1

Projections of Population for The State of Texas

Year	Baylor (1)	DRI (2)	Wharton (3)	Texas Comptroller (4)
1987	16,785,000	16,800,000	16,961,400	16,881,770
1988	17,006,000	16,800,000	17,229,000	17,096,200
1989	17,266,000	16,900,000	17,503,400	17,406,290
1990	17,550,000	17,000,000	17,759,600	17,754,300
1991	17,829,000	17,200,000	18,013,200	18,077,370
1992	18,103,000	17,400,000	18,289,600	18,362,430
1993	18,371,000	17,600,000	18,577,200	18,620,810
1994	18,632,000	17,800,000	18,868,800	18,864,230
1995	18,887,000	18,000,000	19,182,700	19,101,420
1996	19,134,000	18,200,000	19,514,800	19,331,420
1997	19,375,000	18,400,000	19,866,000	19,549,300
Annual Growth Rate	1.45%	0.91%	1.59%	1.48%

Sources:

(1) Texas Economic Forecast: Baylor University Forecasting Service; July 1987.

(2) Texas State Package: Data Resources, Inc.; Spring 1988.

(3) Regional Forecast Long-Term State Tables: Wharton Econometric Forecasting Associates; Spring 1988.

(4) Comptroller of Public Accounts for the State of Texas; November 1987.

TABLE 2.1.2

Projections of Non-Agricultural Employment for The State of Texas

Year	Baylor (1)	DRI (2)	Wharton (3)	Texas Comptroller (4)
1987	6,796,500	6,508,600	6,507,400	6,529,140
1988	6,829,600	6,633,000	6,570,900	6,655,230
1989	6,924,600	6,775,100	6,674,900	6,834,810
1990	7,052,800	6,928,200	6,807,800	7,041,750
1991	7,202,400	7,058,900	6,921,900	7,245,100
1992	7,370,300	7,163,400	7,087,400	7,412,750
1993	7,549,300	7,264,200	7,279,100	7,551,280
1994	7,738,100	7,365,000	7,464,400	7,689,970
1995	7,931,900	7,465,800	7,662,400	7,845,580
1996	8,129,200	7,565,100	7,853,200	8,007,080
1997	8,330,600	7,644,600	8,045,700	8,159,010
Annual Growth Rate	2.06%	1.62%	2.14%	2.25%

Sources:

(1) Texas Economic Forecast: Baylor University Forecasting Service; July 1987.

(2) Texas State Package: Data Resources, Inc.; Spring 1988.

(3) Regional Forecast Long-Term State Tables: Wharton Econometric Forecasting Associates; Spring 1988.

(4) Comptroller of Public Accounts for the State of Texas; November 1987.

TABLE 2.1.3

Projections of Personal Income for The State of Texas

(Millions of dollars)

Year	Baylor		DRI		Wharton		Texas Comptroller		
	Nominal Personal Income	Real Personal Income*	Nominal Personal Income	Real Personal Income*	Nominal Personal Income	Real Personal Income*	Nominal Personal Income	Real Personal Income*	Consumer Price Index**
1987	231,223	73,850	232,800	74,353	231,000	73,778	238,544	76,188	3.131
1988	244,684	75,450	246,700	76,072	243,000	74,931	254,317	78,420	3.243
1989	261,870	77,316	263,500	77,798	258,400	76,292	273,141	80,644	3.387
1990	280,634	79,613	284,600	80,738	276,500	78,440	292,881	83,087	3.525
1991	301,274	82,134	304,900	83,124	294,500	80,289	320,885	87,482	3.668
1992	323,913	84,750	328,600	85,976	315,700	82,601	343,680	89,922	3.822
1993	348,772	87,609	355,000	89,174	339,500	85,280	368,375	92,533	3.981
1994	375,458	90,211	383,900	92,239	366,400	88,035	395,772	95,092	4.162
1995	404,100	92,684	415,900	95,390	395,800	90,780	425,611	97,617	4.360
1996	434,835	95,067	450,400	98,470	428,200	93,616	458,968	100,343	4.574
1997	467,808	97,521	486,900	101,501	463,100	96,540	496,010	103,400	4.797
Annual Growth Rate	7.30%	2.82%	7.66%	3.16%	7.20%	2.73%	7.60%	3.10%	

* Real values are in 1967 dollars.

** The Consumer Price Index from WEFA is used to calculate Real Personal Income for all above four forecasts.

Sources: Texas Economic Forecast: Baylor University Forecasting Service; July 1987.

Texas State Package: Data Resources, Inc.; Spring 1988.

Regional Forecast Long-Term State Tables: Wharton Econometric Forecasting Associates; Spring 1988.

Real Estate & Construction Tables: Wharton Econometric Forecasting Associates; 1987.

Comptroller of Public Accounts for the State of Texas; November 1987.

in electricity consumption per residential customer. Given the significant impacts of conservation programs within the residential sector, one may expect lower annual growth rates in average residential electricity consumption than in per capita electricity consumption.

As shown in Table 2.2.1, the change in per capita electricity consumption between 1977 and 1987 varies significantly among Texas utilities' service areas. Areas served by HL&P and GSU experienced significant decreases in per capita electricity consumption between 1977 and 1987. The areas served by these two utilities probably felt the impact of the decrease in oil prices more than any other areas in the State. The areas served by CPL and EPE were also affected by the changes in economic conditions. In contrast, the area served by COA experienced the highest annual growth in per capita electricity consumption. The area served by LCRA ranked second in growth in per capita consumption. Most of the areas served by COA and LCRA are within Central Texas, which had significant economic growth between 1977 and 1987.

The projection from 1987 to 1997 in Table 2.2.1 shows that all areas served by the 11 utilities will experience an increase in per capita electricity consumption during the next ten years. EPE and CPL are expected to recover faster than the areas served by HL&P and GSU. The latter two utilities are projected to experience only a slight increase in their service areas' per capita electricity consumption.

In Table 2.2.2, average annual residential electricity consumption and annual growth rates are presented. CPS experienced the highest annual growth in average residential consumption between 1978 and 1987, and this trend is expected to continue over the next ten years. In contrast, average annual residential electricity consumption within the HL&P service area declined drastically between 1978 and 1987, and is expected to decline further over the next ten years.

Overall, a comparison between Tables 2.2.1 and 2.2.2 reveals that, on average, annual residential electricity consumption increased more slowly than annual per capita electricity consumption in Texas. A similar trend is expected over the forecast period. Furthermore, projected values in both Tables are not adjusted for appliance standards and utility-sponsored programs. Such programs typically result in lower electric energy consumption.

TABLE 2.2.1

Annual Per Capita Electricity Consumption

Electric Utility	1977 (KWH/Person)	1987 (KWH/Person)	Ten-Year Change 1977-87 (Percent)	Annual Change 1977-87 (Percent)	1997 (KWH/Person)	Ten-Year Change 1987-97 (Percent)	Annual Change 1987-97 (Percent)
TU	12,009	14,382	19.8	1.8	16,873	17.3	1.6
HL&P	17,908	15,997	-10.7	-1.1	16,641	0.3	0.4
GSU	15,683	13,562	-13.5	-1.4	13,956	2.9	0.3
CPL	7,714	7,724	0.1	0.0	9,365	21.2	1.9
CPS	6,562	8,472	29.1	2.6	10,756	27.0	2.4
SPS	15,053	19,104	26.9	2.4	21,823	14.2	1.3
SWEPCO	8,429	10,623	26.0	2.3	12,145	14.3	1.3
LCRA	7,447	9,835	32.1	2.8	11,361	15.5	1.5
COA	8,307	11,482	38.2	3.3	13,527	17.8	1.7
WTU	9,763	11,415	16.9	1.6	13,893	21.7	2.0
EPE	5,437	5,571	2.5	0.2	6,133	10.1	1.0

Note: Self-generation of electricity is not included in derivation of per capita electricity consumption.

TABLE 2.2.2

Average Annual Residential Electricity Consumption

(MWH Per Customer)

YEAR	TU	HL&P	GSU	CPL	CPS	SPS	SWEPCO	LCRA	WTU	EPE
1978	15.09	14.73	13.01	9.31	8.90	7.38	10.69	12.26	8.42	6.15
1979	13.89	13.52	12.37	9.21	8.61	7.18	9.99	12.50	8.25	6.07
1980	14.95	14.22	13.17	9.90	9.69	7.60	11.32	10.52	9.00	6.06
1981	13.41	13.59	12.79	9.92	9.33	7.15	10.58	10.07	8.72	5.85
1982	13.74	13.50	13.02	10.11	9.77	7.33	10.90	10.89	9.11	5.87
1983	13.30	11.76	12.10	9.49	9.20	7.49	10.46	10.46	8.95	5.84
1984	13.98	12.62	13.00	10.01	9.70	7.52	10.79	11.31	9.22	5.75
1985	14.05	13.00	12.80	10.32	10.01	7.66	11.14	11.41	9.18	5.74
1986	13.67	12.69	12.73	10.34	10.12	7.58	11.06	11.57	9.11	5.72
1987	14.04	12.94	12.46	10.37	10.14	7.33	11.31	11.91	9.16	5.87
1988	14.34	12.87	12.54	10.20	10.55	7.50	11.14	11.89	9.27	5.68
1989	14.67	12.92	12.55	10.18	10.54	7.45	11.06	11.86	9.29	5.60
1990	14.73	12.95	12.50	10.19	10.65	7.50	11.10	11.95	9.32	5.54
1991	14.67	12.31	12.50	10.20	10.79	7.60	11.27	11.97	9.42	5.50
1992	14.73	11.56	12.59	10.35	11.01	7.70	11.48	12.00	9.58	5.42
1993	14.78	11.00	12.73	10.66	11.19	7.79	11.75	12.05	9.79	5.37
1994	14.99	10.75	13.00	11.02	11.39	7.89	12.11	12.14	10.06	5.44
1995	15.18	10.93	13.37	11.38	11.59	8.00	12.56	12.23	10.38	5.62
1996	15.24	11.61	13.93	11.74	11.80	8.08	12.95	12.33	10.69	5.83
1997	15.45	12.62	14.14	12.13	12.02	8.17	13.28	12.44	10.95	6.01
Annual Growth (Percent)										
1978-87	-0.80	-1.43	-0.48	1.21	1.46	-0.08	0.63	-0.32	0.90	-0.52
1987-97	0.96	-0.25	1.27	1.58	1.72	1.09	1.62	0.44	1.80	0.24
1978-97	0.12	-0.81	0.44	1.40	1.59	0.54	1.15	0.08	1.39	-0.12

Note: Actual historical values from 1978-87 are not weather adjusted.

Projected data from fourth quarter of 1987.

The projected values are not adjusted for the effects of appliance standards or other conservation activities.

Data for COA and TNP are not available since the staff has not projected sales by class on a systemwide basis for these two utilities.

2.2.2 Trends in Electricity Prices

During the period from 1976 to 1985, electricity prices in Texas steadily increased to where the 1985 average price for residential, commercial, and industrial classes was twice what it was in 1975. This growth can largely be attributed to the addition of generating capacity and the increase in fuel prices. Additional generating capacity was required to meet the needs of a growing economy in Texas. Since 1985, fuel prices have stabilized. Electricity prices have likewise stabilized and in some cases have actually decreased in the last three years. Tables 2.2.3, 2.2.4, and 2.2.5 show the historical prices for the residential, commercial, and industrial classes from 1975 through 1986 for ten major electric utilities in the State. The average prices are calculated by dividing total class revenues by total class energy for each utility, so the values do not represent actual rates. For comparative purposes, the United States average values are also shown in the tables.

The data in the tables show that the average price for the industrial class experienced the greatest percentage increase of 139 percent, with commercial and residential classes showing a slightly lower percentage increase (110 percent) for the period from 1976 to 1984. For 1985 and 1986, all three classes experienced a decline in average prices due primarily to lower fuel prices.

In all three classes, EPE had the highest electricity prices as the Company relied on natural gas and the Palo Verde Nuclear Project for most of its power. SPS was also charging higher than the average prices of other utilities to the industrial and residential classes.

Another way to look at the residential price is to determine the monthly residential bill for usage of 1,000 KWH. The average residential consumption in Texas is above 1,000 KWH and the annual consumption will vary from month to month during a typical year. In addition, electricity consumption will also vary according to the climate, income, and stock of appliances in the service area. However, this is an effort to provide a second comparison in contrast to using the total revenue divided by the total energy approach. In Table 2.2.6, the average residential prices based on 1,000 KWH usage are provided in current dollars. Table 2.2.7 shows the same prices in 1976 dollars.

When comparing the residential price per 1,000 KWH and the average residential prices, there appears to be no major differences in the relative ranking of the utilities. EPE, HL&P, SPS, and GSU have higher than average residential prices in both tables.

TABLE 2.2.3

Average Residential Electricity Prices*

(Cents per KWH)

Utility	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
TU	2.62	3.02	3.29	3.53	3.87	4.37	5.19	5.82	6.44	6.77	6.82	6.10
HL&P	2.39	2.84	3.08	3.33	4.06	4.92	6.16	7.61	8.16	8.10	8.33	7.23
GSU[1]	2.71	3.02	3.39	3.65	4.09	4.68	5.82	6.83	7.68	7.85	9.44	7.22
CPL	3.96	4.45	4.77	4.84	4.99	5.68	6.22	7.04	7.47	7.50	6.90	6.61
CPS	3.78	4.19	4.58	4.40	4.53	4.97	5.39	6.62	6.94	7.40	7.68	6.87
SPS[1]	3.38	3.91	4.30	4.55	5.20	5.70	6.45	7.17	7.72	7.54	7.15	7.36
SWEPCO[1]	2.52	2.95	3.32	3.46	3.46	3.69	4.15	5.32	6.62	7.63	6.74	6.58
WTU	3.39	3.78	3.97	4.13	4.32	4.50	5.36	6.62	7.31	7.45	7.70	6.94
EPE[1]	3.54	3.92	4.01	4.95	5.84	6.72	8.52	8.96	10.20	10.43	9.96	9.84
COA[2]	--	4.71	4.69	4.68	4.62	4.97	5.11	5.41	5.88	6.59	5.89	5.88
U.S.A.[3]	--	--	4.05	4.31	4.64	5.36	6.20	6.86	7.18	7.54	7.79	7.80

* Total revenue divided by total energy.

1 Texas only.

2 Rate based on 1,000 KWH usage.

3 Source: U.S. Department of Energy, **Electric Power Monthly**, Energy Information Administration, Washington, DC, June 1988.

Note: Values are for comparison purposes only. Actual rates will vary according to usage and tariff provisions.

LCRA is not included because retail sales is a minor portion of its total sales.

TABLE 2.2.4

Average Commercial Electricity Prices*

(Cents per KWH)

Utility	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
TU	--	--	--	3.51	3.62	3.95	4.66	5.46	5.79	5.92	5.71	5.37
HL&P	2.08	2.63	2.91	3.19	3.97	4.68	5.71	6.97	7.36	7.27	7.28	6.20
GSU[1]	2.50	2.75	3.15	3.39	3.67	4.42	5.04	5.86	6.35	6.42	7.78	6.77
CPL	3.61	4.08	4.37	4.52	4.70	5.91	6.55	7.37	7.30	7.39	6.83	6.81
CPS	3.83	4.33	4.64	4.04	4.31	4.86	5.21	6.42	6.86	7.04	7.26	6.46
SPS[1]	2.63	3.22	3.62	3.92	4.52	4.95	5.53	6.14	6.71	6.55	6.12	6.48
SWEPCO[1]	2.31	2.73	3.08	3.23	3.23	3.48	3.68	4.51	5.45	5.79	5.41	5.21
WTU	2.94	3.31	3.69	3.89	4.04	4.23	4.87	6.02	6.58	6.67	6.44	5.60
EPE	3.15	3.62	3.70	4.31	4.93	5.96	7.57	8.06	9.17	9.31	8.66	8.49
COA[2]												
U.S.A.[3]	--	--	4.09	4.36	4.68	5.48	6.29	6.86	7.02	7.33	7.47	7.41

* Total revenue divided by total energy.

1 Texas only.

2 Data not available.

3 Source: U.S. Department of Energy, **Electric Power Monthly**, Energy Information Administration, Washington, DC, June 1988

NOTE: Values are for comparison purposes only. Actual rates will vary according to load, usage, and tariff provisions.

LCRA is not included because retail sales is a minor portion of its total sales.

TABLE 2.2.5

Average Industrial Electricity Prices*

(Cents per KWH)

Utility	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
TU	1.41	1.71	1.98	2.27	2.43	2.74	3.66	4.25	4.33	4.39	4.47	3.91
HL&P	1.22	1.61	1.87	2.13	2.70	3.21	4.10	5.10	5.22	5.07	4.98	3.89
GSU[1]	1.36	1.54	1.94	2.18	2.53	2.85	3.44	3.83	3.83	3.85	4.94	3.90
CPL	1.49	1.75	1.60	1.70	1.83	2.54	2.66	3.40	3.55	3.84	3.15	3.51
CPS	2.14	2.47	2.64	2.45	2.57	3.24	3.30	4.12	4.38	4.44	4.64	4.10
SPS[1]	1.56	1.99	2.50	2.76	3.31	3.55	3.95	4.47	4.86	4.78	4.43	4.46
SWEPCO[1]	1.35	1.79	2.16	2.33	2.30	2.49	2.62	3.56	4.20	4.45	4.07	3.90
WTU	2.04	2.49	2.70	2.85	2.47	3.33	4.18	5.15	5.64	5.51	5.11	4.35
EPE[1]	2.29	2.70	2.86	3.44	3.87	4.55	5.51	6.04	6.72	6.73	6.28	6.26
COA[2]												
U.S.A.[3]	--	--	2.50	2.79	3.05	3.69	4.29	4.95	4.96	5.04	5.16	5.10

* Total revenue divided by total energy.

1 Texas only.

2 Data not available.

3 Source: U.S. Department of Energy, **Electric Power Monthly**, Energy Information Administration, Washington, DC, June 1988.

NOTE: Values are for comparison purposes only. Actual rates will vary according to load, usage, and tariff provisions.

LCRA is not included because retail sales is a minor portion of its total sales.

TABLE 2.2.6

Public Utility Commission of Texas
Average Residential Rate Survey

(current dollars per 1,000 KWH usage)

	COA	CPL	CPS	EPE	GSU	HL&P	LCRA	SPS	SWEPCO	TU	WTU	Texas Average
1976	47.06	45.76	40.20	38.25	30.09	28.75	29.53	38.10	29.31	32.40	36.45	34.37
1977	46.85	47.85	44.46	40.39	34.15	30.89	31.34	42.31	35.11	35.51	38.59	37.30
1978	46.76	49.05	42.09	49.25	37.49	33.77	37.56	46.15	36.55	37.90	40.41	39.52
1979	46.23	49.94	43.48	55.68	41.53	41.03	38.95	54.41	36.31	41.66	42.46	43.50
1980	49.72	56.14	47.78	64.89	48.09	50.52	41.55	57.85	38.86	47.64	44.27	49.81
1981	51.14	62.57	51.92	81.77	58.32	62.69	46.59	62.58	43.36	60.37	51.80	60.01
1982	54.09	71.63	63.96	86.33	67.88	78.03	51.58	69.31	50.01	66.27	64.61	69.19
1983	58.82	75.10	67.52	96.82	75.09	83.02	52.73	76.44	62.63	68.50	71.50	73.55
1984	65.85	76.12	72.41	98.37	78.14	83.46	53.09	75.33	70.38	71.52	76.29	75.95
1985	58.93	70.31	75.25	93.22	96.84	88.25	51.78	75.06	68.43	70.17	77.53	76.60
1986	58.83	67.14	67.05	92.21	76.09	81.84	44.84	74.66	64.85	65.76	69.93	71.07
1987	55.17	62.57	64.03	82.14	72.19	78.41	42.16	73.51	64.43	63.58	61.67	67.85
1988	68.54	63.25	64.39	81.90	76.26	78.71	50.90	73.51	65.95	66.96	79.56	70.49

Notes:

1) Values for TU Electric Company prior to December 1984 are calculated using a weighted average of DPL, TESCO, and TPL rates based on annual revenues 1977 - 1983.

2) The Texas Average is a weighted average based on the number of retail residential customers of each utility. Data is taken from Request 12 of the Load and Capacity Resource Forecast, December 1987 filings. The number of Texas customers was used for the multi-jurisdictional utilities.

3) 1988 data is only through October.

4) Updated October 11, 1988. Public Utility Commission of Texas - Electric Division.

TABLE 2.2.7

Public Utility Commission of Texas
Average Residential Rate Survey

(1976 dollars per 1,000 KWH usage)

	COA	CPL	CPS	EPE	GSU	HL&P	LCRA	SPS	SWEPCO	TU	WTU	Texas Average
	—	—	—	—	—	—	—	—	—	—	—	—
1976	45.58	44.32	38.93	37.08	29.13	27.86	28.61	36.91	28.36	31.38	35.29	33.29
1977	42.47	43.39	40.31	36.65	30.95	27.99	28.36	38.35	31.81	32.19	34.99	33.82
1978	39.60	41.49	35.60	41.71	31.71	28.55	31.78	39.00	30.90	32.04	34.20	33.42
1979	35.80	38.77	33.74	43.18	32.20	31.83	30.23	42.24	28.17	32.29	32.98	33.74
1980	34.87	39.37	33.56	45.42	33.75	35.42	29.17	40.59	27.24	33.39	31.03	34.93
1981	32.85	40.23	33.35	52.62	37.49	40.29	29.97	40.28	27.87	38.85	33.32	38.59
1982	32.95	43.63	38.95	52.63	41.36	47.53	31.44	42.22	30.45	40.40	39.36	42.15
1983	34.79	44.44	39.95	57.29	44.43	49.12	31.21	45.24	37.05	40.53	42.31	43.52
1984	38.17	44.13	41.97	57.02	45.28	48.37	30.78	43.67	40.79	41.45	44.22	44.02
1985	33.52	40.00	42.80	53.03	55.09	50.20	29.46	42.70	38.92	39.91	44.10	43.57
1986	33.15	37.83	37.79	51.96	42.88	46.12	25.27	42.07	36.54	37.06	39.41	40.05
1987	30.78	34.91	35.73	45.85	40.28	43.75	23.53	41.02	35.95	35.47	34.41	37.85
1988	37.56	34.66	35.29	44.89	41.80	43.15	27.90	40.30	36.14	36.69	43.60	38.63

Notes:

1) Values for TU Electric Company prior to December 1984 are calculated using a weighted average of DPL, TESCO, and TPL rates based on annual revenues 1977 - 1983.

2) 1976 values represent January prices.

3) The Texas Average is a weighted average based on the number of retail residential customers of each utility. Data is taken from Request 12 of the Load and Capacity Resource Forecast December 1987 filings. The number of Texas customers was used for the multi-jurisdictional utilities.

4) Inflation rates are based on CPI data supplied by The Bureau of Business Research, Graduate School of Business, University of Texas at Austin.

5) 1988 data is only through October.

6) Updated October 11, 1988. Public Utility Commission of Texas - Electric Division.

Also, COA, SWEPCO, and TU Electric Company have lower than average residential rates. LCRA was added to Tables 2.2.6 and 2.2.7 and shows the lowest price for 1988, as it has been since 1983.

In Table 2.2.6, the effect of inflation on the residential prices from 1976 to 1988 is apparent with a doubling of the Texas average price from $34.37 per 1,000 KWH in 1976 to $70.49 per 1,000 KWH in 1988. However, when these prices are adjusted for changes in the Consumer Price Index to reflect inflation, the real increase in Texas average prices during the same period is only $5.34 per 1,000 KWH, an increase of only 16%. When the effects of inflation are removed, a direct comparison can be made on how well a particular utility performed on residential prices.

The utilities able to decrease the real cost of electricity to residential customers from 1976 to 1988 to a level below the Texas average for 1988 include COA, CPL, CPS, and LCRA.

2.2.3 Future Trends

Using the PUCT staff's Econometric Electricity Demand Forecasting System, described in detail in Volume III, average prices of electricity to the residential, commercial, and industrial customers of nine of the utilities in the State have been projected. Average price projections are not provided for COA, LCRA, and TNP because the staff model for these utilities does not provide separate projections for the residential, commercial, and industrial classes. Average prices are defined as the total revenues collected from a class divided by total energy sales to that class.

As described further in Volume III, projections of average prices are developed through statistically estimated relationships between the utility's historical costs and prices, and projections of those costs. Costs may be divided into two components: fixed costs and variable costs (primarily fuel expenses). The fixed costs are developed through a revenue requirements model developed by the Commission staff. The results are largely dependent upon the utility's capacity expansion plan and associated costs. Variable costs are based largely on the simultaneously determined level of sales and a simple "economic merit order" dispatch model within the econometric forecasting models. Thus, variable cost projections are based on projected unit fuel prices, capacity factors, and heat rates, as well as capacity expansion plans.

The projections that follow are properly regarded as "base case" projections. Many factors, including some which are presently unknown or uncertain, will determine the rates which will actually be established in the future. Among the factors which are unpredictable at this time are regulatory decisions, technological developments, energy market conditions, and state and regional economies.

Price projections have not been prepared for the City of Austin because, during many periods in the past, prices have borne little relationship to the Electric Department's costs. In addition, no price projections are provided for LCRA which sells over 98 percent of its electricity to wholesale customers.

The residential projections are shown on Table 2.2.8. EPE, which had the highest price in 1987, is expected to fall to the second highest by 1997. GSU is projected to move from the second highest in 1987 to the highest price in 1997. The other utilities are projected to maintain about the same ranking except for TU Electric which moves from the lowest price in 1987 to the third lowest price in 1997, above CPS and SWEPCO.

The variations in commercial price projections among different utilities on Table 2.2.9 are not as dramatic as those of industrial price projections. During the period from 1987 to 1997, EPE is projected to maintain the highest price in the commercial class. HL&P is projected to have one of the largest increases in the same time period and move its relative ranking from fifth to second highest in 1997. The other utilities are projected to maintain approximately the same ranking between 1987 and 1997. SWEPCO is projected to maintain the lowest commercial price from 1987 to 1997 while SPS is projected to have the lowest growth in commercial prices between 1987 and 1997.

The industrial projections on Table 2.2.10 identify several significant changes. EPE is projected to have the highest industrial rate in 1997. HL&P is projected to have a substantial increase in its industrial prices and rise from the fourth lowest price in 1987 to the second highest in 1997. The CPS projection shows one of the lowest increases from 1987 to 1997 and the lowest price for 1997.

Comparing the staff projections to the West South Central region and national projections made by DRI (Table 2.2.11), the majority of the utilities in the staff projection will have lower prices in all three classes than the utilities in the West South Central region, if projections are realized. This statement is also true when the prices are compared to the Wharton Econometric Forecasting Associates projections, which are also shown in Table 2.2.11. This trend continues from 1988 to 1995. Those utilities

TABLE 2.2.8

Projected Average Residential Electricity Prices

(Cents per KWH)

Utility	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Annual Growth Rate (%)
TU	6.07	6.02	5.83	5.77	6.15	6.50	7.04	7.41	7.78	8.37	8.60	3.6
HL&P	7.58	7.50	7.85	9.02	9.66	10.07	10.39	10.66	10.91	11.21	11.23	3.4
GSU[1]	8.05	8.31	8.76	9.21	9.53	9.78	10.17	10.54	10.94	11.64	12.04	4.1
CPL	6.67	6.73	6.54	6.95	7.65	8.24	8.37	8.52	8.62	8.76	8.97	3.0
CPS	6.39	6.57	6.66	6.85	7.02	7.00	7.18	7.42	7.66	7.84	7.91	2.2
SPS[1]	7.58	7.34	7.24	7.32	7.42	7.51	7.68	7.97	8.11	8.47	8.73	1.4
SWEPCO[1]	6.56	7.05	7.29	7.43	7.43	7.43	7.45	7.60	7.82	8.07	8.33	2.4
WTU	6.80	7.28	7.47	7.63	7.79	8.00	8.20	8.43	8.84	9.22	9.50	3.4
EPE[1]	9.63	10.39	10.75	10.74	10.75	11.40	11.92	12.01	11.94	11.99	11.88	2.1
COA[2]												

1 Texas only.

2 Data not available.

NOTE: Projected values are for comparison purposes only. Actual rates will vary according to usage and tariff provisions.

LCRA is not included because retail sales is a minor portion of its total sales.

TABLE 2.2.9

Projected Average Commercial Electricity Prices

(Cents per KWH)

Utility	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Annual Growth Rate (%)
TU	5.45	5.40	5.27	5.21	5.51	5.77	6.20	6.49	6.78	7.23	7.39	3.1
HL&P	6.49	6.42	6.69	7.59	8.11	8.47	8.78	9.05	9.32	9.66	9.73	4.1
GSU[1]	7.17	7.33	7.75	8.06	8.24	8.37	8.59	8.80	9.03	9.45	9.69	3.1
CPL	6.72	6.79	6.58	7.03	7.80	8.45	8.60	8.77	8.99	9.05	9.29	3.3
CPS	5.98	6.11	6.16	6.35	6.55	6.51	6.71	6.97	7.24	7.45	7.56	2.4
SPS[1]	6.67	6.44	6.33	6.37	6.44	6.50	6.63	6.76	6.94	7.22	7.42	1.1
SWEPCO[1]	5.15	5.45	5.60	5.70	5.73	5.76	5.90	5.92	6.11	6.31	6.51	2.4
WTU	6.05	6.67	6.98	7.23	7.44	7.71	7.95	8.25	8.75	9.23	9.58	4.7
EPE[1]	8.11	8.72	9.01	9.04	9.12	9.75	10.34	10.55	10.59	10.66	10.78	2.9
COA[2]												

1 Texas only.

2 Data not available.

NOTE: Projected values are for comparison purposes only. Actual rates will vary according to load, usage and fuel costs.

LCRA is not included because retail sales is a minor portion of its total sales.

TABLE 2.2.10

Projected Average Industrial Electricity Prices

(Cents per KWH)

Utility	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Annual Growth Rate (%)
TU	3.99	3.96	3.83	3.79	4.04	4.28	4.64	4.86	5.13	5.53	5.68	3.6
HL&P	4.04	3.99	4.15	4.72	5.09	5.38	5.68	5.96	6.25	6.62	6.77	5.3
GSU[1]	4.18	4.32	4.50	4.74	4.94	5.09	5.33	5.56	5.80	6.21	6.45	4.4
CPL	4.06	4.21	4.06	4.43	5.22	5.84	5.89	5.76	5.60	5.45	5.31	2.7
CPS	3.79	3.87	3.90	4.03	4.17	4.14	4.27	4.45	4.63	4.78	4.86	2.5
SPS[1]	4.58	4.47	4.44	4.52	4.62	4.71	4.86	5.03	5.22	5.51	5.73	2.3
SWEPCO[1]	3.73	3.96	4.11	4.21	4.29	4.37	4.46	4.61	4.84	5.09	5.34	3.7
WTU	4.15	4.35	4.54	4.72	4.92	5.15	5.36	5.59	5.90	6.18	6.42	4.5
EPE[1]	6.06	6.50	6.71	6.70	6.71	7.07	7.36	7.41	7.36	7.33	7.31	1.9
COA[2]												

1 Texas only.

2 Data not available.

NOTE: Projected values are for comparison purposes only. Actual rates will vary according to load, usage and tariff provisions.

LCRA is not included because retail sales is a minor portion of its total sales.

TABLE 2.2.11

Projections of Average Electricity Prices

(Cents per KWH)

		1986	1987	1988	1990	1995	2000	2010
West South Central States:								
Residential	-DRI	7.01	6.99	7.45	9.01	11.06	13.83	23.29
	-WEFA	7.4	8.0	10.2	12.7			
Commercial	-DRI	6.42	6.54	6.94	7.39	8.68	11.17	20.80
	-WEFA	6.5	7.1	8.9	10.7			
Industrial	-DRI	4.50	4.30	4.48	5.03	6.40	8.75	16.10
	-WEFA	4.9	5.5	7.3	9.1			
All classes	-DRI	5.91	5.78	6.12	7.20	8.96	11.64	20.33
National Average:								
Residential	-DRI	7.44	7.60	7.98	8.64	9.83	12.41	22.49
	-WEFA	8.3	8.9	11.3	14.0			
Commercial	-DRI	7.11	7.20	7.52	8.05	9.40	12.05	21.53
	-WEFA	7.9	8.5	10.8	13.3			
Industrial	-DRI	4.99	5.08	5.27	5.70	6.96	9.16	16.48
	-WEFA	5.5	6.1	8.2	10.6			
All classes	-DRI	6.49	6.62	6.91	7.46	8.76	11.27	20.28

Sources: DRI, **Energy Review**, Spring 1988, pp. A-50 and A-51.

Wharton Econometric Forecasting Associates, **Energy Analysis Quarterly**, Winter 1988, pp. 8.66, 8.67, 8.92, 8.93.

that are projected by the PUCT to have prices above the West South Central and national average price projections prepared by DRI are shown below. The utilities that are projected by the PUCT to have prices above Wharton Econometric Forecasting Associates national and regional projections are shown in parentheses.

PUCT Price Projection Above the West South Central Average:

	Residential	Commercial	Industrial
1988	HL&P, GSU, EPE (EPE)	GSU, EPE	EPE
1990	HL&P, GSU, EPE	HL&P, GSU, EPE	EPE
1995	EPE	HL&P, GSU, CPL WTU, EPE	EPE

PUCT Price Projection Above the National Average:

	Residential	Commercial	Industrial
1988	GSU, EPE	EPE	EPE
1990	HL&P, GSU, EPE	GSU, EPE	EPE
1995	HL&P, GSU, EPE	EPE	EPE

2.3 FUEL SUPPLY

Fuel typically is an electric utility company's largest single expense. Recovery of fuel costs can account for more than 30 percent of a utility's overall revenues and, in periods of rising fuel prices, fuel cost recovery can exceed 50 percent of revenues. This section discusses historical consumption of fuel used in generation and the fuel diversification which has occurred in Texas. Historical and projected generation fuel prices are also discussed. Finally, the projected availability of different generation fuels is reviewed.

2.3.1 Fuel Consumption

Texas electric utilities' fuel requirements, including a historical summary of fuel consumption, are shown in Figure 2.3.1. By any measure, Texas utilities, as a class, are both a major generator of electricity and a major consumer of fuel used in electricity generation.

Nearly 40 percent of the natural gas consumed for electric generation nationwide is consumed by Texas utilities. Texas utilities' consumption is about 77 percent more than that of California utilities, the second largest natural gas consumer for electricity generation.

Texas utilities consume more than seven percent of the total heating value of coal used in electricity generation nationwide. For electricity generation, coal consumption by Texas utilities is second only to coal consumption of Ohio utilities.

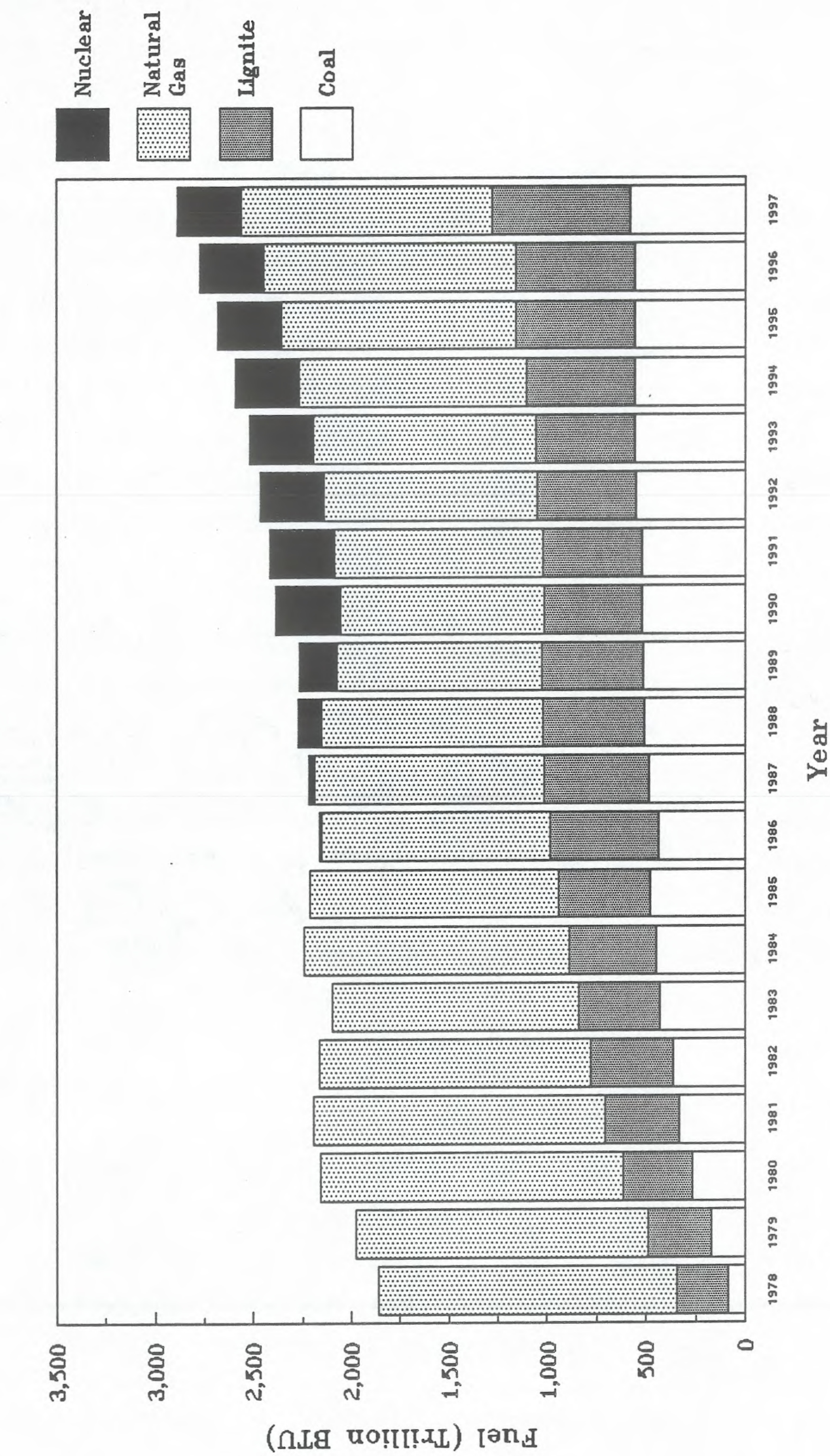
Overall, Texas accounts for approximately 13 percent of the fossil fuel heating value consumed for electricity generation nationwide and more than twice as much fossil fuel than is consumed by utilities of either of the runner-up states, Ohio and Pennsylvania.

Currently, the primary fuels used for generation in Texas are natural gas and coal. Nuclear units under construction within the State were not yet completed in 1987. GSU and EPE own interests in nuclear generating facilities which commenced operation prior to 1988; these facilities are located in Louisiana and Arizona, respectively. However, nuclear generation is projected to account for a significant 14 percent of Texas electricity requirements by 1992. This increase is due to the projected commercial operation of the South Texas Nuclear Project and Comanche Peak units.

In 1975, about 90 percent of the electricity generation was natural gas-fired. The 1988 generation mix projections include four fuels for thermal generating plants. Although still the dominant fuel, natural gas is projected to account for only 45 percent of the thermal generation serving Texas in 1988. Coal and lignite each are projected to account for about 25 percent of the remaining generation and nuclear generation will provide the remainder.

Texas utilities have undertaken fuel diversification programs that helped to protect against severe disruptions due to the unavailability of any single fuel and allowed the use of low-cost fuels. Continued fuel diversification is planned during the next ten years.

FIGURE 2.3.1
Fuel requirements for Electricity Generation
By Utilities in Texas



Note: Portions outside Texas are not included.

Additional baseload capacity planned for operation during the next ten years includes the previously mentioned nuclear units, several lignite-fired units, and at least one coal-fired unit. Also, numerous gas-fired, non-baseload units are planned.

In many respects the increase in fuel diversification was a very natural occurrence. The plants which operate as base-load units and operate at the highest capacity factors should be exploiting the least expensive fuel available. Particularly in the 1970s and early 1980s, coal, lignite, and nuclear fuel were all less expensive than natural gas and oil; thus, construction of these types of plants was a natural result. Although the capital costs of coal, lignite, and nuclear plants are higher than gas- or oil-fired plants, long-term fuel economics tend to favor the overall production costs of coal and lignite plants. Additionally, the oil- and natural gas-fueled plants can be designed to be more flexible and better able to follow system load. The ability to track load coupled with a relatively higher cost of natural gas makes natural gas-fired units a good choice for cycling and peak-demand units for a generating system.

Because of a combination of existing take-or-pay contractual commitments for coal and coal transportation and the increase in Texas nuclear generation over the next four years (which will be the base of the owning utilities' base load), gas-fired generation will be reduced. This circumstance will displace a share of natural gas production that previously had been dedicated to the generation of electricity. The quantity of natural gas consumed for Texas electric generation is projected to decrease through 1990, continuing the downward trend which began in 1981. As indicated in Figure 2.3.1, gas consumed by Texas utilities for electric generation is not projected to show another year-to-year increase until 1991.

2.3.2 Trends in Fuel Prices

A slow, steady rise in average fuel prices can be expected over the next ten years. Seasonal influences and periodic swings in market psychology will tend to cause both upward and downward price "spikes" during this period. However, surplus availability and competition among fuels will act to keep fuel prices moderate relative to runaway price levels experienced during the 1970s and early 1980s.

Natural gas prices will be affected by continuing displacement of natural gas as a boiler fuel and a price ceiling imposed by residual fuel oil which is a substitute fuel currently available at low prices. Relatively high winter prices for natural gas are likely to continue for several years. During seasons other than winter, however, natural gas prices will be relatively soft.

Coal prices can be expected to rise during the next ten years. Mining costs and rail transportation costs are expected to increase, but slowly. The over-supply of western coal deliverability will continue to moderate solid fuel prices. As existing contracts expire, coal requirements will be satisfied through either spot market arrangements or market price-based, firm-commitment contracts.

Lignite prices are expected to increase at a rate roughly equal to the rate of inflation. Since lignite-fired power plants are essentially mine-mouth operations, lignite prices will vary as mining costs vary; transportation will have only a small effect on the delivered price of lignite during the next ten years.

Factors affecting the price for nuclear fuel are 1) an abundance of low cost uranium, 2) a strong secondary market for material and services, and 3) low demand due to high inventory levels, existing contract commitments, and limited growth in nuclear generation. During the next ten years, the uranium market is expected to become more efficient and competitive, although at reduced levels of production from the early 1980s. Utilities will have stabilized their nuclear materials and services inventories and will be arranging contract terms which reflect the buyer's market which will exist.

Nuclear fuel is projected to be the least expensive fuel during the next ten years. The price of nuclear fuel is projected to be less than $1 per million BTU equivalent compared to lignite at $2 to $3 per million BTU, coal at $2 to $4 per million BTU, and gas at over $5 per million BTU by 1997.

2.3.3 Fuel Price Projections

Tables 2.3.1 through 2.3.4 present the Commission staff projection of fuel prices for 1988 through 1997. The prices given in Tables 2.3.1 through 2.3.4 are projections based on the existing fuel supply contracts, projected spot fuel prices, and each utility's ability to negotiate effectively in the marketplace. Utility-furnished information related to existing contracts was analyzed, and costs for fuel to be taken through existing contracts were projected. Costs of fuel to be bought through spot market or new contracts were projected by the staff based upon fuel cost projections of nationally recognized consulting firms.

TABLE 2.3.1

Staff-Projected Average Natural Gas Prices

($/MMBTU)

Year	COA	CPS	CPL	EPE	GSU	HL&P	LCRA	SPS	SWEPCO	TU	WTU
1988	2.49	2.21	2.29	2.27	1.95	1.93	1.99	2.18	2.14	2.57	2.20
1989	2.57	2.38	2.39	2.39	2.05	2.02	2.10	2.26	2.36	2.62	2.47
1990	2.90	2.64	2.64	3.03	2.40	2.33	2.44	2.63	2.58	2.84	2.75
1991	2.89	3.02	2.77	3.24	2.70	2.58	2.77	2.84	2.80	3.01	2.99
1992	3.13	3.24	2.98	3.46	2.94	2.85	3.00	3.03	3.25	3.24	3.37
1993	3.68	3.48	3.06	4.11	3.35	3.25	3.42	3.46	3.52	3.54	3.63
1994	3.98	4.04	3.56	4.48	3.67	3.60	3.72	3.76	3.83	3.83	3.94
1995	4.32	4.37	4.03	4.89	4.00	3.98	4.06	4.10	4.47	4.16	4.45
1996	5.08	4.74	4.40	5.60	4.68	4.54	4.75	4.80	4.85	4.69	4.85
1997	5.29	5.30	4.87	5.85	4.91	4.89	4.96	5.00	5.07	4.91	5.09

TABLE 2.3.2

Staff-Projected Average Delivered Coal Prices*

($/MMBTU)

Year	COA	CPS	CPL	EPE	GSU	HL&P	LCRA	SPS	SWEPCO	WTU
1988	1.71	1.80	2.20	1.04	2.08	2.23	1.57	1.83	1.87	1.78
1989	1.80	1.91	2.29	1.10	2.21	2.31	1.66	1.92	1.98	1.88
1990	1.90	1.99	2.32	1.16	2.31	2.40	1.75	2.00	2.07	1.96
1991	2.03	2.13	2.44	1.23	2.46	2.49	1.89	2.12	2.20	2.09
1992	2.12	2.22	2.56	1.31	2.57	2.60	1.98	2.21	2.30	2.18
1993	2.25	2.35	2.69	1.40	2.73	2.73	2.10	2.34	2.44	2.31
1994	2.38	2.50	2.83	1.50	2.89	2.87	2.22	2.47	2.58	2.45
1995	2.55	2.68	2.47	1.60	3.10	3.02	2.38	2.63	2.77	2.63
1996	2.21	2.86	2.59	1.72	3.30	3.18	2.22	2.80	2.96	2.80
1997	2.37	2.83	2.72	1.84	3.54	3.36	2.39	2.99	3.17	3.00

* Railcar maintenance and handling costs are included.

TABLE 2.3.3

Staff-Projected Average Lignite Price*

($/MMBTU)

Year	TU	HL&P	SWEPCO	TNP
1988	1.11	1.76	1.18	1.29
1989	1.17	1.86	1.23	1.34
1990	1.24	1.97	1.28	1.43
1991	1.32	2.05	1.34	1.47
1992	1.41	2.12	1.41	1.55
1993	1.50	2.20	1.48	1.64
1994	1.62	2.28	1.56	1.74
1995	1.75	2.37	1.64	1.88
1996	1.82	2.47	1.74	2.01
1997	1.93	2.62	1.83	2.14

* Handling costs are included.

TABLE 2.3.4

Staff-Projected Average Nuclear Fuel Prices*

($/MMBTU)

Year	COA	CPS	CPL	EPE	GSU	HL&P	TU
1988	0.51	0.51	0.63	1.03	1.03	0.63	
1989	0.51	0.51	0.63	0.93	1.11	0.63	
1990	0.54	0.54	0.67	0.79	1.13	0.66	0.33
1991	0.56	0.56	0.69	0.71	1.08	0.73	0.46
1992	0.57	0.57	0.69	0.64	0.95	0.80	0.51
1993	0.55	0.55	0.65	0.67	0.89	0.86	0.53
1994	0.53	0.53	0.63	0.72	0.86	0.89	0.57
1995	0.54	0.54	0.62	0.76	0.85	0.91	0.61
1996	0.55	0.55	0.63	0.74	0.84	0.92	0.65
1997	0.58	0.58	0.65	0.78	0.84	0.93	0.68

* Price includes Department of Energy disposal fee.

Forecasted natural gas prices indicate that, in general, the smaller natural gas users are expected to have higher prices while the larger users are expected to have lower prices. Market presence will be a key price determinant with the larger companies, such as TU Electric, HL&P, GSU, and CPL exerting more buying leverage on the marketplace with smaller users such as EPE, SWEPCO, and WTU exerting less leverage.

Although delivered spot coal prices will be mostly dependent upon rail distance from the Powder River Basin or other coal supply areas, contract coal prices will be governed primarily by existing coal and rail transportation contracts. Many of the existing coal supply agreements were consummated in the sellers' market of the 1970s and early 1980s, and the resulting delivered costs therefore may not reflect current market conditions. A combination of long rail transportation distances and 1970s' vintage coal contracts will likely keep delivered coal costs to HL&P, WTU, SWEPCO, and GSU high over the forecast period. Interestingly, the non-investor-owned generating utilities, as a group, have been more successful in minimizing problems associated with seller's market coal contracts than the investor-owned companies. COA, CPL, CPS, and LCRA have the lowest projected coal costs for the period with the exception of EPE, which only uses coal at its partially-owned Four Corners station.

Supply of all lignite requirements for existing stations are virtually guaranteed through long-term contracts. These contracts are expected to increase at about the rate of overall inflation during the ten-year forecast period. TU Electric was the first Texas utility to develop lignite on a large scale, and its reserves are among the best in the State. SWEPCO also participated in some early lignite reserve acquisition, and the two SWEPCO properties which currently are in production are among the better lignite deposits in the Gulf Coast area. Therefore, TU Electric and SWEPCO are projected to have the most favorable long-term lignite costs.

Projected nuclear fuel costs are dependent upon the arrangements which govern each utility's nuclear fuel supply. Differences in nuclear fuel prices reflect different material and services contracts, different inventory levels and carrying costs, and different methods of financing nuclear fuel. The nuclear fuel prices converge in the later years of the forecast. This convergence reflects a stabilization of inventory levels in conjunction with supplies more closely matched with market conditions. Material and services supply contracts will expire and be replaced by contracts better suited to satisfy the needs of the mature nuclear plant.

2.3.4 Future Fuel Availability

Natural Gas. Major disruptions of natural gas supplies are not expected during the next ten years. Relatively low natural gas prices likely will reduce natural gas supply due to lack of exploratory drilling incentive. The resulting insufficient replenishment of reserves and the anticipated high level of utilization of nuclear and solid fossil fuel-fired plants will reduce the demand for natural gas as a utility boiler fuel. The availability of residual fuel oil as a substitute for natural gas will offer utilities a viable backup boiler fuel, thereby reducing the potential for a major, long-term fuel supply disruption.

Current gas supplies are adequate for projected generation requirements and prices are relatively stable. However, the long-term uncertainties associated with both price and supplies of natural gas likely will prevent utilities from planning any new baseload gas-fired generation. A recent Department of Energy study concluded that substantial quantities of natural gas that could be developed profitably at prices below $3.00 per million BTU are yet to be discovered in the U.S.

Coal. Almost all coal-fired generation units that serve Texas are fueled with sub-bituminous coal, purchased from the Powder River Basin in Wyoming, and other western U. S. bituminous and sub-bituminous coal. Presently, the Powder River Basin, as well as the U. S. coal industry in general, has excess production capacity and projected demand is not likely to employ the extra deliverability for several years. New coal supply arrangements will continue to be market price-based until the excess production capacity is eliminated sometime beyond the ten-year forecast period.

Lignite. As previously noted, the lignite required for the next ten years already is under contract, dedicated to serving an adjacent power plant. Two events could adversely affect the otherwise solid plans for lignite consumption. The first detrimental event which could affect an individual plant would be a major mining stoppage caused by a major equipment failure, mine failure, or strike. The other event which could adversely affect lignite consumption would be a change of regulations covering the burning of lignite.

Although lignite is the primary fuel planned for future capacity expansion in Texas, the low price of western coal may displace some planned lignite-fired generation for economic reasons.

Nuclear. The manner in which nuclear fuel is consumed precludes any short-term availability difficulties. The critical path for nuclear fuel is the manufacturing of the fuel bundles. Because the manufacturing process involves five distinct steps which are performed at different locations, fuel unavailability can be caused due to inadequate planning or from an unavailability of material (yellowcake, natural uranium hexafluoride, or enriched uranium hexafluoride) or services (conversion, enrichment, or fabrication).

In the current market, yellowcake is both plentiful and inexpensive. Many suppliers are available to satisfy demand for yellowcake, including several reliable foreign suppliers. Yellowcake is plentiful in the secondary market as well. The development of several high quality uranium deposits and large utility inventories of yellowcake are likely to keep uranium prices low for the next several years.

Strong competitive secondary markets also exist for natural uranium hexafluoride, conversion services, and enrichment services. The availability of enrichment services is particularly good due to the strong secondary market as well as services offered by foreign suppliers.

The area which shows the highest likelihood for disruption of supply is the fabrication service sector. Only a few suppliers offer fabrication services and any loss of service from a supplier will likely mean a disruption to the nuclear fuel supply.

CHAPTER THREE

ELECTRICITY DEMAND FORECAST

Chapter Three provides the Commission staff's recommended demand projections from 1988 to 1997, for 12 of the State's largest generating electric utilities. Following a discussion of the staff's modeling efforts developing the projections, details of the recommended projections are given and contrasted with the utility-provided forecasts of total sales and peak demand. The chapter closes with a section on historical forecast accuracy including the specific forecasts of nine utilities.

3.1 ELECTRICITY DEMAND FORECASTING PROJECTS AT THE PUCT

In the past five years, the Economic Analysis Section of the Public Utility Commission of Texas has inititated three distinct projects designed to produce accurate, flexible, and tenable independent projections of demand to be faced by the State's largest generating electric utilities. These projects are the Econometric Electricity Demand Forecasting System; the End-Use Energy Modeling and Forecasting System; and State Space, Time Series, and Bayesian Forecasting.

Econometric Electricity Demand Forecasting System. The Econometric Electricity Demand Forecasting System Project statistically estimates the behavioral relationships between electricity demand and various demand 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." The electricity sales projections are converted to peak demand using the Hourly Electric Load Model (HELM). Simultaneous equation econometric models, ranging up to 45 equations in size, have been developed for every major electric utility in the State. A database containing over 7,000 time-series variables provides input to this set of models. Numerous improvements have been made to this forecasting system since its initial results were reported in the Commission's load forecast reports in 1984 and 1986. The current structure of this modeling system is described in Volume III.

End-Use Energy Modeling and Forecasting System. The End-Use Energy Modeling and Forecasting System Project, 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 demand-side management strategies. The electricity demand projections derived from this system also provide a valuable validity check upon the staff's econometrically-developed forecasts. To date, residential and commercial sector energy consumption projections for all major utility planning regions in the State have been produced from this system. These projections are then input to the HELM, along with projections of industrial and other electric use, to yield peak demand forecasts by end-use as well as for the entire system. Also, an industrial sector end-use model has recently been acquired and implementation is underway.

State Space, Time Series, and Bayesian Forecasting. While the Econometric and End-Use Energy models are designed to provide an accurate long-range outlook for the State's electricity markets, the State Space and Time Series models help in providing shorter-term projections of peak demand. These models examine patterns in a utility's quarterly peak demand over time. Seasonal, cyclical, and trend components of historical patterns are identified, and projections are devised based on the delineation of these components. The Bayesian models created by the staff are still in a preliminary stage. These models formally incorporate pertinent prior information via a probability distribution. The current data is then used with this probability distribution to compute the predictive distribution of energy. Among the merits of this approach is the ability of these models to allow the decision-maker to validate his or her findings with the aid of Bayesian probability statements.

The staff has developed a Bayesian model to forecast total system sales for the City of Austin Electric Utility. For inclusion in this report however, the staff has not developed peak demand forecasts using the State Space, Time Series, or Bayesian models for any of the other utilities.

3.1.1 Methods Used in This Report

Pursuing three distinct forecasting methods permits the Commission staff to exploit the unique capabilities of each. End-Use models are considered superior in addressing demand-side management issues. Econometric models are typically more useful in studying electricity demand responsiveness to energy prices and the impact of weather and economic activity on energy demand. Recent studies in the statistical and econometric literature confirm the accuracy of time series models in short-term to medium-range peak demand forecasting applications. Bayesian methods are gaining popularity since the practitioners of these methods have demonstrated the superiority of this approach over the classical statistical methods. The results of each of these forecasting methods provide validity checks of the projections obtained from the alternative staff approaches, as well as of the utility-provided forecasts.

Random or unanticipated factors are difficult to incorporate into any projection. Uncertainty will be associated with any long-term projection of electricity demand. In order to account for the uncertainty in peak demand forecasts, the staff is currently developing Bayesian models of total system sales. These models are still in the preliminary stages of development. For the purposes of this report, the staff used a conventional statistical measure to deal with forecast uncertainity. The root mean square (RMS) error was calculated for the total electricity sales variable from the econometric models for each utility. The average RMS for all the utilities considered together was about five percent. The uncertainity in the projected peak demand can then be expressed by adding and subtracting five percent of the system peak demand from the staff's base case forecast of peak demand for each utility.

For this report, the Econometric Electricity Demand Forecasting System is primarily relied upon to derive the long-range peak demand projections that formed the basis for the evaluation of capacity requirements described later in this volume.

The Commission staff's projections are intended to provide a reasonable estimate of the future demand to be faced by the State's largest electricity producers, given the most updated and reliable information available at the Commission.

3.1.2 A Comparison With 1986 Forecast Report

The PUCT staff's most recent load forecast for the 12 major generating utilities in Texas indicates that the growth of peak demand in Texas will be lower than the staff forecast prepared in 1986. In 1986, the staff forecast of peak demand for 1995 for TU Electric was 22,052 MW. The most recent projection for TU Electric results in peak demand of 21,847 MW in 1995. This is a difference of about 1 percent. For the investor-owned utilities in Texas, the differences in the 1995 peak demand projections made by the staff in 1986 and 1988 range from 1 percent to 30 percent. These differences are primarily due to the recession in the Texas economy since 1986. Also, the staff's econometric models have been modified somewhat. The staff has used historical data up to the third quarter of 1987 to estimate the equations. Including data from 1986 in the estimation phase captures the downward trend in the economy.

According to the 1986 report, the staff projection of peak demand, unadjusted for demand-side management programs, for the 11 utilities (excluding TNP) in Texas was 64,512 MW by 1995. In contrast, the 11 utilities projected peak demand of 67,796 MW by 1995. In the current report, the staff projection of unadjusted peak demand by 1995 declines by 11.4 percent, yielding a peak demand forecast of about 57,130 MW in 1995. In contrast, the most recent combined peak demand forecast of the 11 utilities results in a reduction of 14 percent in 1995 peak demand; i.e., unadjusted peak is projected to be only 58,280 MW in 1995.

On a utility-specific basis, the staff's percentage reduction in its 1995 unadjusted peak demand has been smaller than reductions reported by most of the generating utilities in Texas. In the case of CPS and WTU, modifications in 1995 unadjusted peak demand by staff are in opposite directions to the modifications proposed by the utilities. A comparison of unadjusted peak demand by 1995 between the current and 1986 report results in the following modifications in 1995 unadjusted peak demand for the 11 utilities:

MODIFICATIONS IN 1995 UNADJUSTED PEAK DEMAND

CURRENT VERSUS 1986 REPORT

Forecast by:	Utility	PUCT Staff
1. TU Electric	-6.2	-0.9
2. HL&P	-28.4	-19.2
3. GSU	-11.9	-5.3
4. CPL	-22.1	-11.2
5. CPS	-4.7	+1.4
6. SPS	-17.7	-6.2
7. SWEPCO	-9.4	-9.0
8. LCRA	-28.1	-30.0
9. COA	-1.4	-3.2
10. WTU	+0.2	-7.7
11. EPE	-7.2	-6.3

3.2 PUBLIC UTILITY COMMISSION STAFF RECOMMENDED PEAK DEMAND FORECASTS

The staff-recommended demand projections for the 12 largest generating electric utilities are contrasted with utility-developed forecasts of total sales and peak demand. It should be stressed that the Commission staff projections presented in this chapter are prior to any adjustments for demand-side management programs. Several utilities, through a variety of techniques, report that the effects of their demand-side management programs are reflected in their forecasts. Thus the actual demand recorded by these utilities in the future cannot be directly compared with the projections presented here.

Independent peak demand projections have been developed by the staff for the following utilities:

1. Texas Utilities Electric Company (TU Electric)
2. Houston Lighting and Power Company (HL&P)
3. Gulf States Utilities Company (GSU)
4. Central Power and Light Company (CPL)
5. City Public Service of San Antonio (CPS)
6. Southwestern Public Service Company (SPS)
7. Southwestern Electric Power Company (SWEPCO)
8. Lower Colorado River Authority (LCRA)
9. City of Austin (COA)
10. West Texas Utilities Company (WTU)
11. El Paso Electric Company (EPE)
12. Texas-New Mexico Power Company (TNP)

In most cases, the Commission staff's projections tend to be comparable to utility-developed demand forecasts. Overall, growth in electricity demand is expected to be strongest in the Central Texas areas served by LCRA, COA, and CPS and in the TU Electric service area. For each of these utilities, annual growth in peak demand is expected to exceed 3.25 percent through 1997.

Slow electricity demand growth is expected for GSU, serving the Beaumont area and portions of Louisiana. This utility was involved in an expensive nuclear power plant construction project that resulted in higher electricity rates and downward pressure on energy demand from the utility's ratepayers. Also, relatively sluggish growth is expected for the GSU service area economy.

Future self-generation and cogeneration activity remains a key uncertainity for the demand projections developed for the utilities serving the industrial Gulf Coast: HL&P, CPL, and GSU.

3.2.1 TU Electric Company

The system peak demand faced by the State's largest electric utility is expected to exceed 23,500 MW by 1997, prior to any adjustments for demand-side management programs. This represents a 3.5 percent annual increase in peak load over the next ten years. Historically, the Company's peak demand grew at a 5.2 percent rate between 1975 and 1985. Total sales growth is projected to exceed 3.5 percent per year. Growth in electricity sales to residential ratepayers is expected to approach 3.5 percent annually, while industrial electricity consumption is expected to grow at a 2.4 percent annual rate. The differences between the Company and Commission staff projections of peak demand never exceed 3 percent over the next 10 years.

Over the next ten years, growth in TU Electric service area population and employment are expected to remain level with the statewide average, increasing at more moderate rates than experienced since 1975. Over the next ten years, population is projected to grow by 1.8 percent per year, with employment increasing at a 2.8 percent rate.

Based on projections prepared by DRI, the price of natural gas to residential, commercial, and industrial customers is expected to increase at annual rates ranging from 6.3 to 8.6 percent over the next ten years in the West South Central census region. Also, the real price of electricity is expected to rise moderately over the next ten years. Thus, it is likely that some fuel switching from natural gas to electricity among households and businesses in the TU Electric service area may be anticipated.

TABLE 3.2.1

Comparison of Utility-Provided and PUCT Staff Peak Demand Forecast

TU Electric

(MW)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	16,680	16,680	0	0.00
1988	17,378	17,069	(309)	-1.78
1989	17,877	17,839	(38)	-0.21
1990	18,405	18,535	130	0.71
1991	18,989	19,001	12	0.06
1992	19,599	19,665	66	0.34
1993	20,207	20,286	79	0.39
1994	20,841	21,029	188	0.90
1995	21,501	21,847	346	1.61
1996	22,187	22,593	406	1.83
1997	22,916	23,582	666	2.91
Annual Growth Rate	3.23%	3.52%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.2

Comparison of Utility-Provided and PUCT Staff Electric Energy Sales Forecast

TU Electric

(MWH)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	77,665,792	75,689,612	(1,976,180)	-2.54
1988	80,051,011	77,202,935	(2,848,076)	-3.56
1989	82,305,821	80,806,862	(1,498,959)	-1.82
1990	84,792,634	84,014,801	(777,833)	-0.92
1991	87,571,976	86,113,218	(1,458,758)	-1.67
1992	90,134,640	89,125,305	(1,009,335)	-1.12
1993	93,094,297	92,043,646	(1,050,651)	-1.13
1994	95,982,260	95,442,256	(540,004)	-0.56
1995	98,982,179	99,183,929	201,750	0.20
1996	102,100,476	102,629,814	529,338	0.52
1997	105,374,798	107,108,835	1,734,037	1.65
Annual Growth Rate	3.10%	3.53%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.3

PUCT Staff Forecast of Electric Energy Sales By Class

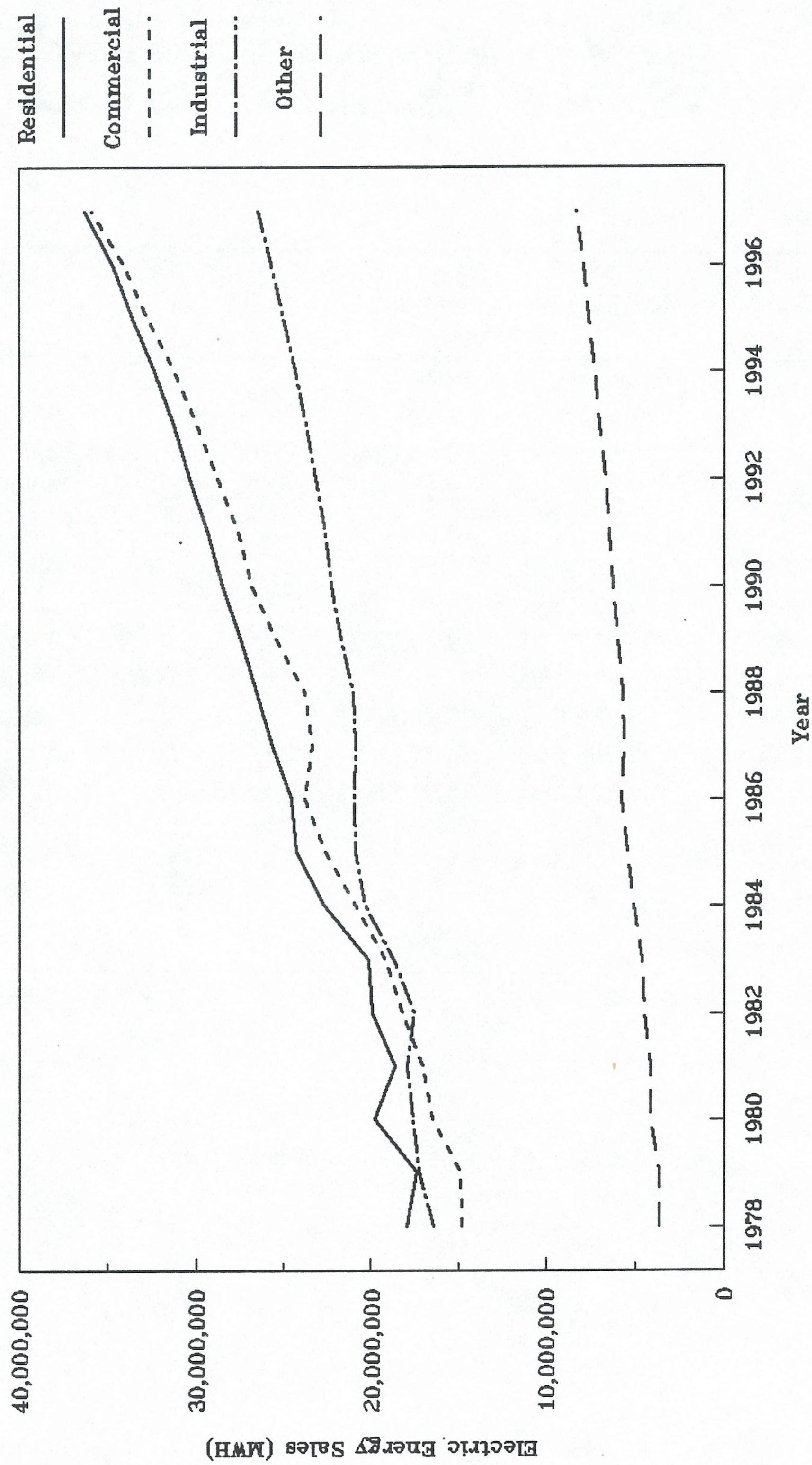
TU Electric

(MWH)

Year	Residential	Commercial	Industrial	Other	Total
1987	25,669,060	23,423,380	20,961,390	5,635,782	75,689,612
1988	26,576,220	23,858,240	21,058,530	5,709,945	77,202,935
1989	27,520,350	25,515,820	21,740,300	6,030,392	80,806,862
1990	28,549,040	26,867,700	22,304,290	6,293,771	84,014,801
1991	29,385,650	27,605,740	22,656,670	6,465,158	86,113,218
1992	30,421,660	28,781,520	23,198,130	6,723,995	89,125,305
1993	31,277,090	29,968,860	23,785,390	7,012,306	92,043,646
1994	32,417,420	31,297,820	24,411,330	7,315,686	95,442,256
1995	33,653,890	32,780,500	25,101,470	7,648,069	99,183,929
1996	34,766,640	34,151,860	25,751,680	7,959,634	102,629,814
1997	36,324,560	35,915,540	26,536,050	8,332,685	107,108,835
Annual Growth Rate	3.53%	4.37%	2.39%	3.99%	3.53%

Note: Projected data from the fourth quarter of 1987.

FIGURE 3.2.1
Staff-Projected Electric Energy Sales by Class
TU Electric



3.2.2 Houston Lighting and Power Company

HL&P is expected to experience an annual growth rate in peak demand of 1.3 percent over the next ten years, before adjustments for self-generation and demand-side mangement programs, including interruptible load. This represents a slowdown from the 4 percent growth rate experienced by the Company between 1975 and 1985. Sales of electricity are projected to grow at a rate of 1.4 percent per year through the next decade.

Slower economic growth in the HL&P service area and higher rates attributable to the Company's involvement in the South Texas Nuclear Project are expected to slow the growth in demand for electricity in the service area. Growth in industrial sales is expected to be lower than the growth in residential and commercial sales.

Other sales by HL&P are made primarily to Texas-New Mexico Power Company for resale. Since TNP is expected to start its own generation in 1991, the HL&P load declines in the early 1990s to reflect the loss of load to the TNP internal generation.

HL&P's "official forecast" (Volume II, Chapter Three) is significantly lower than "Utility Projection" shown in table 3.2.4 and 3.2.5. The company's official forecast is already adjusted for plant siting, self-generation, and appliance efficiency impacts. Therefore, HL&P's "restated" forecast is used for comparison with commission staff projections.

Differences between the Commission staff projections and HL&P projections for the entire range of the forecast stay within 4 percent. This difference may be attributable to differences in the input assumptions, such as population, employment, and personal income annual growth rate, made by the staff and the utility in developing their respective demand forecasting models. Cogeneration and self-generation activities remain extremely difficult to predict.

3.2.3 Gulf States Utilities Company

The slow growth rate in electricity demand projected for the GSU service area is largely attributable to continued stagnation in the service area economy and the expected rate impact from the River Bend Nuclear Project. Although GSU is offering incentive rates to its industrial customers, with the Company's electric rates among the highest in the State and further increases possible, some of the utility's industrial customers may opt for self-generation. For the near-term, the Commission staff expects a very slow rate of

TABLE 3.2.4

Comparison of Utility-Provided and PUCT Staff Peak Demand Forecast

HL&P

(MW)

Year	Utility* Projection	Staff Projection	Raw Difference	Percentage Difference
1987	11,318	11,438	120	1.06
1988	11,457	11,601	144	1.26
1989	11,416	11,773	357	3.13
1990	11,398	11,789	391	3.43
1991	11,487	11,610	123	1.07
1992	11,638	11,477	(161)	-1.38
1993	11,811	11,442	(369)	-3.12
1994	11,954	11,529	(425)	-3.56
1995	12,114	11,807	(307)	-2.53
1996	12,333	12,317	(16)	-0.13
1997	12,491	12,994	503	4.03
Annual Growth Rate	0.99%	1.28%		

Note: Projected data from the fourth quarter of 1987.

* HL&P's "official" forecast is lower as it includes adjustments for plant siting, self-generation, and appliance efficiency impacts. The "Utility Projection" here is expressed on a comparable basis with the staff's projections.

TABLE 3.2.5

Comparison of Utility-Provided and PUCT Staff Electric Energy Sales Forecast

HL&P

(MWH)

Year	Utility* Projection	Staff Projection	Raw Difference	Percentage Difference
1987	54,077,000	53,746,020	(330,980)	-0.61
1988	56,484,000	54,624,480	(1,859,520)	-3.29
1989	58,047,000	55,384,610	(2,662,390)	-4.59
1990	58,965,000	55,784,340	(3,180,660)	-5.39
1991	60,370,000	55,376,750	(4,993,250)	-8.27
1992	61,637,000	55,172,640	(6,464,360)	-10.49
1993	62,897,000	55,348,900	(7,548,100)	-12.00
1994	64,160,000	55,930,720	(8,229,280)	-12.83
1995	65,430,000	57,138,430	(8,291,570)	-12.67
1996	66,694,000	59,107,520	(7,586,480)	-11.38
1997	67,781,000	61,613,600	(6,167,400)	-9.10
Annual Growth Rate	2.28%	1.38%		

Note: Projected data from the fourth quarter of 1987.

* HL&P's "official" forecast is lower as it includes adjustments for plant siting, self-generation, and appliance efficiency impacts. The "Utility Projection" here is expressed on a comparable basis with the staff's projections.

TABLE 3.2.6

PUCT Staff Forecast of Electric Energy Sales By Class

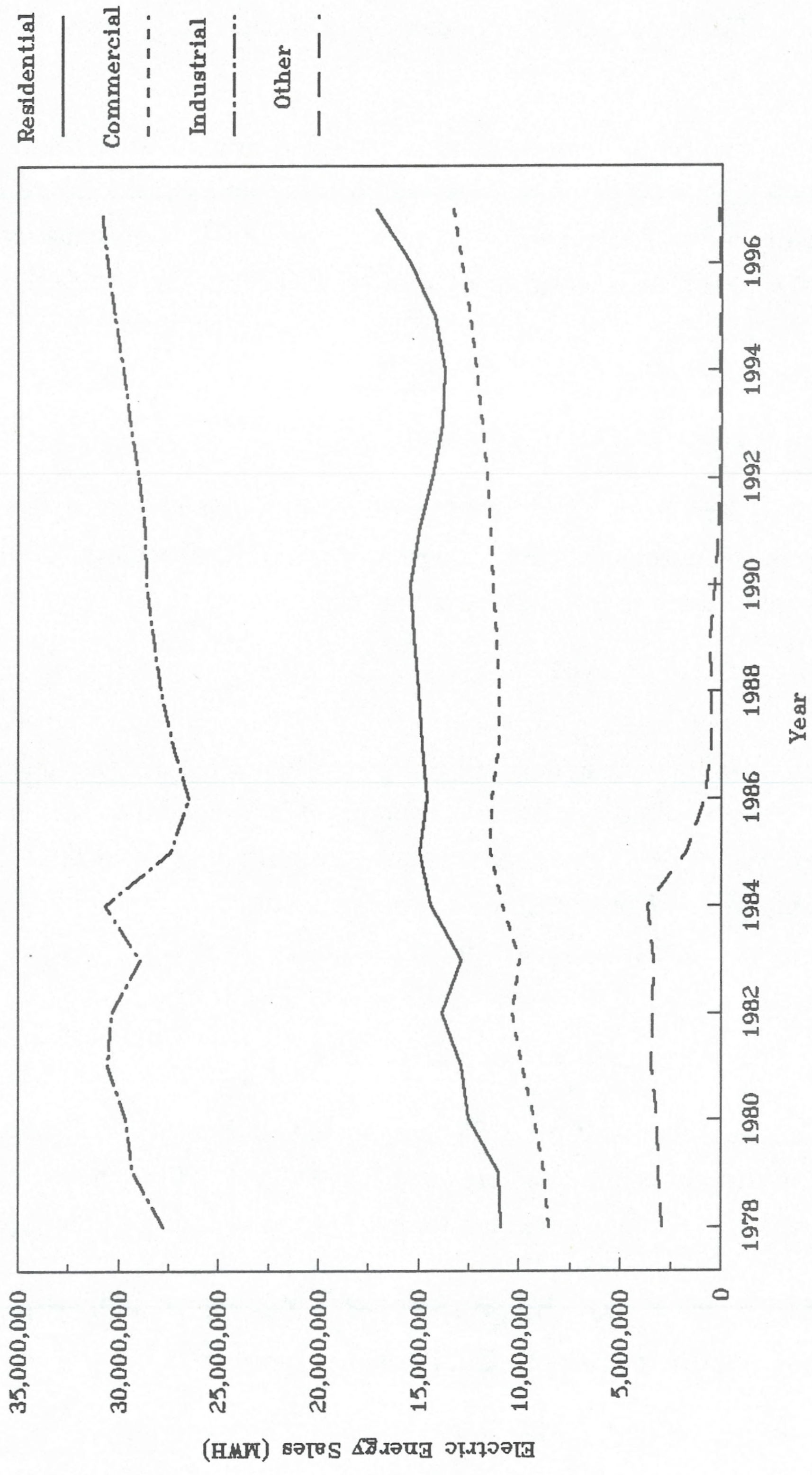
HL&P

(MWH)

Year	Residential	Commercial	Industrial	Other	Total
1987	14,863,110	11,044,560	27,287,570	550,780	53,746,020
1988	15,049,610	11,064,090	27,935,440	575,340	54,624,480
1989	15,298,050	11,201,840	28,259,860	624,860	55,384,610
1990	15,499,540	11,329,430	28,618,060	337,310	55,784,340
1991	15,052,700	11,462,770	28,710,670	150,610	55,376,750
1992	14,394,540	11,643,560	29,003,580	130,960	55,172,640
1993	13,914,800	11,883,560	29,415,460	135,080	55,348,900
1994	13,794,150	12,182,080	29,815,280	139,210	55,930,720
1995	14,259,350	12,534,130	30,201,580	143,370	57,138,430
1996	15,461,860	12,927,340	30,570,830	147,490	59,107,520
1997	17,189,540	13,381,630	30,890,780	151,650	61,613,600
Annual Growth Rate	1.46%	1.94%	1.25%	-12.10%	1.38%

Note: **Projected data from the fourth quarter of 1987.**

FIGURE 3.2.2
Staff-Projected Electric Energy Sales by Class
HL&P



growth in the system peak demand for GSU. Depreciation of the costly River Bend Plant and some improvement in the service area economy by the early 1990s enhance the prospects for some increase in peak demand and energy sales through the forecast horizon.

On a total system basis, peak demand is projected to grow at an annual rate of about 1 percent over the next ten years. Total sales for the same period are expected to increase at a rate of under 1 percent. The rate of growth in Louisiana is expected to be significantly higher than the rate of growth in Texas. In fact, little or no growth is expected in the Texas portion of the GSU service area within the next 10 years.

3.2.4 Central Power and Light Company

Peak demand for CPL is expected to increase at an annual rate of 3.2 percent over the next ten years. Continued strong growth is expected in all sectors. The rate of growth in electricity sales over the forecast horizon is projected to be 3.5 percent. The differences between the staff and utility projections of peak demand after 1988 are less than 4 percent.

Population growth over the next ten years is expected to be lower than that experienced since 1975. Residential electricity consumption is projected to increase by 3.6 percent per year through 1997. Commercial sector consumption is projected to grow at a slower, 2.5 percent, rate. The industrial sector, in contrast to the 1986 PUCT forecast, is expected to grow at a healthy rate of 3.6 percent over the next ten years.

3.2.5 City Public Service Board of San Antonio

The system peak demand for CPS is expected to exceed 3,600 MW in 1997. Peak demand and total system sales are expected to grow at an annual rates of 3.3 and 3 percent, respectively, in the next ten years. Throughout most of the forecast horizon, the PUCT staff's forecast for the CPS planning region is lower than the projections prepared by the Board. The growth rates are fairly strong for all classes that constitute total system sales relative to most other utilities in Texas.

The outlook for the CPS service area economy is quite optimistic. In spite of the recent recession in the Texas economy, the key determinants of electricity demand, such as

TABLE 3.2.7

Comparison of Utility-Provided and PUCT Staff Peak Demand Forecast

GSU -- Total System

(MW)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	4,991	4,937	(54)	-1.08
1988	5,046	5,027	(19)	-0.38
1989	5,048	5,062	14	0.28
1990	5,090	5,071	(19)	-0.37
1991	5,137	5,084	(53)	-1.03
1992	5,175	5,118	(57)	-1.10
1993	5,232	5,166	(66)	-1.26
1994	5,285	5,223	(62)	-1.17
1995	5,361	5,302	(59)	-1.10
1996	5,413	5,396	(17)	-0.31
1997	5,484	5,435	(49)	-0.89
Annual Growth Rate	0.95%	0.97%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.8

Comparison of Utility-Provided and PUCT Staff Electric Energy Sales Forecast

GSU -- Total System

(MWH)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	26,602,270	26,549,680	(52,590)	-0.20
1988	27,080,066	27,129,310	49,244	0.18
1989	27,211,661	27,415,440	203,779	0.75
1990	27,565,711	27,548,460	(17,251)	-0.06
1991	27,840,962	27,648,700	(192,262)	-0.69
1992	28,052,469	27,831,650	(220,819)	-0.79
1993	28,328,910	28,060,910	(268,000)	-0.95
1994	28,616,733	28,278,100	(338,633)	-1.18
1995	29,000,005	28,566,510	(433,495)	-1.49
1996	29,258,473	28,815,140	(443,333)	-1.52
1997	29,577,500	28,886,300	(691,200)	-2.34
Annual Growth Rate	1.07%	0.85%		

Note: Projected data from the fourth quarter of 1987.

The Staff's Total Sales projections include Wholesale sales and Miscellaneous sales. These enter the model exogenously.

The breakdown of Total Sales into Texas and Non-Texas portions do not include Wholesale and Miscellaneous sales.

TABLE 3.2.9

Comparison of Utility-Provided and PUCT Staff Peak Demand Forecast

GSU -- Texas Only

(MW)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	2,302	2,302	0	0.00
1988	2,344	2,346	2	0.09
1989	2,340	2,335	(5)	-0.21
1990	2,353	2,312	(41)	-1.74
1991	2,375	2,292	(83)	-3.49
1992	2,401	2,285	(116)	-4.83
1993	2,426	2,291	(135)	-5.56
1994	2,444	2,310	(134)	-5.48
1995	2,487	2,350	(137)	-5.51
1996	2,506	2,382	(124)	-4.95
1997	2,531	2,417	(114)	-4.50
Annual Growth Rate	0.95%	0.49%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.10

PUCT Staff Forecast of Electric Energy Sales By Class

GSU -- Texas Only

(MWH)

Year	Residential	Commercial	Industrial	Other	Total
1987	2,978,050	1,982,061	6,075,402	131,717	11,167,230
1988	2,952,016	1,986,754	6,132,126	132,174	11,203,070
1989	2,898,363	1,988,547	6,158,767	132,243	11,177,920
1990	2,848,159	1,988,433	6,173,790	132,408	11,142,790
1991	2,809,870	1,986,884	6,162,830	132,756	11,092,340
1992	2,810,267	1,985,327	6,161,515	133,191	11,090,300
1993	2,832,657	1,983,843	6,159,577	133,483	11,109,560
1994	2,911,708	1,983,787	6,142,878	133,767	11,172,140
1995	3,047,018	1,986,518	6,135,688	134,056	11,303,280
1996	3,190,369	1,991,277	6,104,083	134,111	11,419,840
1997	3,329,495	1,996,514	6,077,242	134,449	11,537,700
Annual Growth Rate	1.12%	0.07%	0.00%	0.21%	0.33%

Note: Projected data from the fourth quarter of 1987.
Total Sales data exclude Miscellaneous and Wholesale sales.

TABLE 3.2.11

PUCT Staff Forecast of Electric Energy Sales By Class

GSU -- Non-Texas

(MWH)

Year	Residential	Commercial	Industrial	Other	Total
1987	3,053,144	2,692,012	6,061,689	130,345	11,937,190
1988	3,078,430	2,706,985	6,304,676	130,639	12,220,730
1989	3,121,072	2,739,067	6,517,837	131,554	12,509,530
1990	3,144,855	2,770,792	6,668,316	132,897	12,716,860
1991	3,190,541	2,796,952	6,767,100	134,697	12,889,290
1992	3,251,317	2,829,995	6,885,462	136,846	13,103,620
1993	3,316,864	2,863,431	6,993,133	139,262	13,312,690
1994	3,386,267	2,903,460	7,054,294	141,849	13,485,870
1995	3,453,175	2,942,564	7,112,053	143,978	13,651,770
1996	3,623,953	2,994,630	7,071,858	147,169	13,837,610
1997	3,633,255	3,022,134	7,019,003	150,448	13,824,840
Annual Growth Rate	1.75%	1.16%	1.48%	1.44%	1.48%

Note: Projected data from the fourth quarter of 1987.
Total Sales data exclude Miscellaneous and Wholesale sales.

TABLE 3.2.12

PUCT Staff Forecast of Electric Energy Sales By Class

GSU -- Total System

(MWH)

Year	Residential	Commercial	Industrial	Other	Total
1987	6,031,194	4,674,073	12,137,091	3,707,322	26,549,680
1988	6,030,446	4,693,739	12,436,802	3,968,323	27,129,310
1989	6,019,435	4,727,614	12,676,604	3,991,787	27,415,440
1990	5,993,014	4,759,225	12,842,106	3,954,115	27,548,460
1991	6,000,411	4,783,836	12,929,930	3,934,523	27,648,700
1992	6,061,584	4,815,322	13,046,977	3,907,767	27,831,650
1993	6,149,521	4,847,274	13,152,710	3,911,405	28,060,910
1994	6,297,975	4,887,247	13,197,172	3,895,706	28,278,100
1995	6,500,193	4,929,082	13,247,741	3,889,494	28,566,510
1996	6,814,322	4,985,907	13,175,941	3,838,970	28,815,140
1997	6,962,750	5,018,648	13,096,245	3,808,657	28,886,300
Annual Growth Rate	1.45%	0.71%	0.76%	0.27%	0.85%

Note: Projected data from the fourth quarter of 1987.
Other Sales data include Miscellaneous and Wholesale sales.

FIGURE 3.2.3
Staff-Projected Electric Energy Sales by Class
GSU

TABLE 3.2.13

Comparison of Utility-Provided and PUCT Staff Peak Demand Forecast

CPL

(MW)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	2,804	2,636	(168)	-5.99
1988	2,725	2,815	90	3.30
1989	2,762	2,859	97	3.51
1990	2,867	2,916	49	1.71
1991	2,948	2,944	(4)	-0.14
1992	3,029	2,982	(47)	-1.55
1993	3,123	3,063	(60)	-1.92
1994	3,219	3,187	(32)	-0.99
1995	3,317	3,327	10	0.30
1996	3,419	3,467	48	1.40
1997	3,512	3,618	106	3.02
Annual Growth Rate	2.28%	3.22%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.14

Comparison of Utility-Provided and PUCT Staff Electric Energy Sales Forecast

CPL

(MWH)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	13,952,581	13,341,300	(611,281)	-4.38
1988	14,314,150	14,633,210	319,060	2.23
1989	14,892,923	14,881,760	(11,163)	-0.07
1990	15,510,898	15,212,720	(298,178)	-1.92
1991	15,821,852	15,350,040	(471,812)	-2.98
1992	16,168,524	15,474,750	(693,774)	-4.29
1993	16,517,819	15,819,390	(698,429)	-4.23
1994	16,939,559	16,440,940	(498,619)	-2.94
1995	17,372,026	17,188,960	(183,066)	-1.05
1996	17,825,133	17,953,260	128,127	0.72
1997	18,240,241	18,737,420	497,179	2.73
Annual Growth Rate	2.72%	3.45%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.15

PUCT Staff Forecast of Electric Energy Sales By Class

CPL

(MWH)

Year	Residential	Commercial	Industrial	Other	Total
1987	4,422,942	3,801,360	4,175,916	941,082	13,341,300
1988	4,619,703	3,862,079	4,909,735	1,241,693	14,633,210
1989	4,685,221	3,955,363	4,966,569	1,274,607	14,881,760
1990	4,764,047	4,039,324	5,122,120	1,287,229	15,212,720
1991	4,844,384	4,088,805	5,093,994	1,322,857	15,350,040
1992	4,986,863	4,162,798	4,957,757	1,367,332	15,474,750
1993	5,212,823	4,304,838	4,896,680	1,405,049	15,819,390
1994	5,470,599	4,441,750	5,074,560	1,454,031	16,440,940
1995	5,749,805	4,579,666	5,354,694	1,504,795	17,188,960
1996	6,031,232	4,716,786	5,642,556	1,562,686	17,953,260
1997	6,314,224	4,876,695	5,942,393	1,604,108	18,737,420
Annual Growth Rate	3.62%	2.52%	3.59%	5.48%	3.45%

Note: Projected data from the fourth quarter of 1987.
Other sales include Wholesale sales.

FIGURE 3.2.4
Staff-Projected Electric Energy Sales by Class
CPL

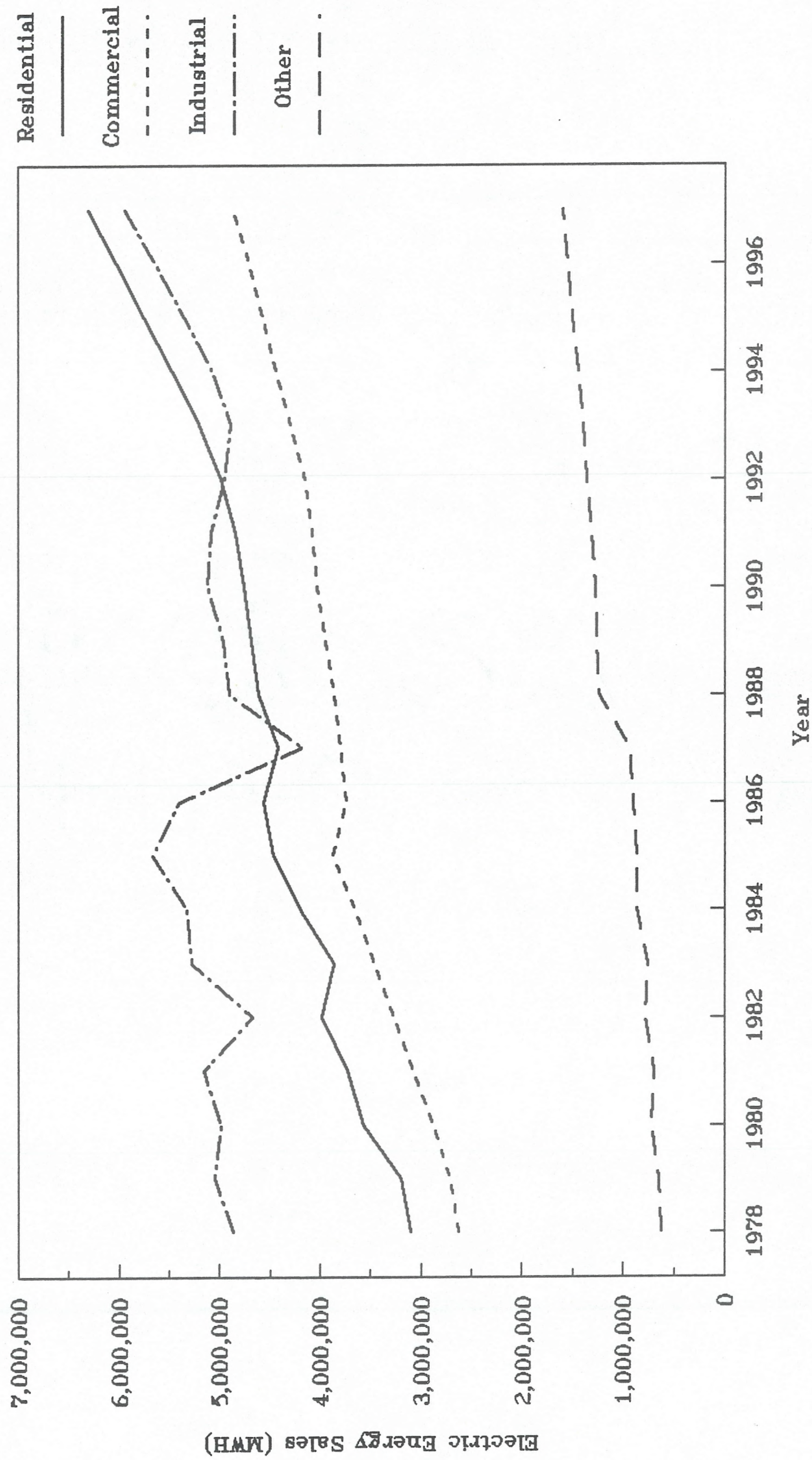


TABLE 3.2.16

Comparison of Utility-Provided and PUCT Staff Peak Demand Forecast

CPS

(MW)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	2,564	2,652	88	3.43
1988	2,651	2,755	104	3.92
1989	2,782	2,822	40	1.44
1990	2,890	2,893	3	0.10
1991	3,017	2,977	(40)	-1.33
1992	3,140	3,082	(58)	-1.85
1993	3,275	3,184	(91)	-2.78
1994	3,402	3,290	(112)	-3.29
1995	3,515	3,404	(111)	-3.16
1996	3,623	3,521	(102)	-2.82
1997	3,755	3,651	(104)	-2.77
Annual Growth Rate	3.89%	3.25%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.17

Comparison of Utility-Provided and PUCT Staff Electric Energy Sales Forecast

CPS

(MWH)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	10,385,840	11,470,000	1,084,160	10.44
1988	11,002,518	11,883,000	880,482	8.00
1989	11,584,597	12,159,000	574,403	4.96
1990	12,109,069	12,446,000	336,931	2.78
1991	12,717,315	12,771,000	53,685	0.42
1992	13,349,350	13,170,000	(179,350)	-1.34
1993	13,963,746	13,563,000	(400,746)	-2.87
1994	14,592,274	13,972,000	(620,274)	-4.25
1995	15,161,067	14,408,000	(753,067)	-4.97
1996	15,759,087	14,859,000	(900,087)	-5.71
1997	16,383,248	15,352,000	(1,031,248)	-6.29
Annual Growth Rate	4.66%	2.96%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.18

PUCT Staff Forecast of Electric Energy Sales By Class

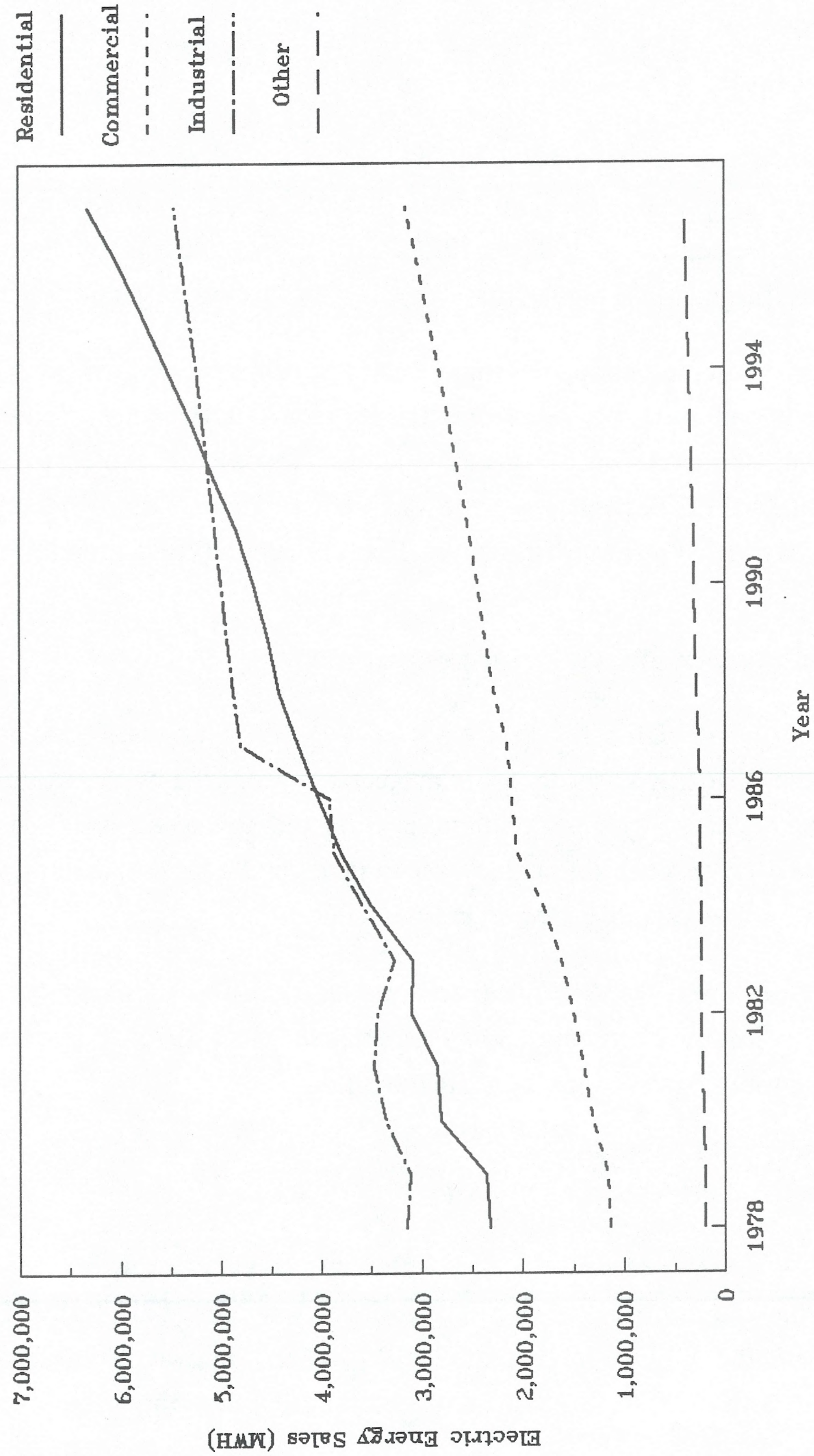
CPS

(MWH)

Year	Residential	Commercial	Industrial	Other	Total
1987	4,227,072	2,166,883	4,814,402	261,643	11,470,000
1988	4,420,206	2,291,190	4,886,256	285,348	11,883,000
1989	4,531,225	2,381,715	4,949,978	296,082	12,159,000
1990	4,674,224	2,456,526	5,007,177	308,073	12,446,000
1991	4,847,031	2,540,118	5,064,359	319,492	12,771,000
1992	5,078,889	2,636,629	5,121,798	332,684	13,170,000
1993	5,299,554	2,734,421	5,183,187	345,838	13,563,000
1994	5,530,822	2,832,936	5,248,176	360,066	13,972,000
1995	5,779,666	2,936,005	5,316,465	375,864	14,408,000
1996	6,035,321	3,045,226	5,387,318	391,135	14,859,000
1997	6,325,098	3,159,528	5,459,706	407,668	15,352,000
Annual Growth Rate	4.11%	3.84%	1.27%	4.53%	2.96%

Note: Projected data from the fourth quarter of 1987.

FIGURE 3.2.5
Staff-Projected Electric Energy Sales by Class
CPS



population and personal income, are expected to be slightly higher than the statewide growth rates.

3.2.6 Southwestern Public Service Company

The total system peak demand for SPS is expected to exceed 3,500 MW in 1997, including interruptible load. The annual growth rate for total system sales is forecast to exceed 2.2 percent from 1987 to 1997. Throughout most of the forecast horizon, the PUCT staff projection is higher than the Company's own projections.

Residential and commercial electricity sales are projected to grow at a fairly robust rate. For these two classes, the Texas portion of the SPS service area will experience higher growth than the non-Texas portion. Industrial sales are projected to increase at an annual rate of 1.6 percent over the next ten years in Texas. Overall, total sales is expected to grow at a slower rate in the Texas portion of the Company's service area.

3.2.7 Southwestern Electric Power Company

Throughout most of the forecast horizon, the PUCT staff forecast for the SWEPCO service area is slightly lower than the projections prepared by the Company. The system peak demand faced by the Company is expected to exceed 3,800 MW in 1997. This represents a 1.6 percent annual increase in peak load over the next ten years. Total sales growth are projected to be 1.9 percent per year.

Over the next ten years, service area population and employment are expected to increase at more moderate rates than experienced since 1975. These factors will serve to reduce the rate of growth in electricity demand.

3.2.8 Lower Colorado River Authority

The LCRA is expected to have one of the State's higher growth rates in peak demand, with a projected annual growth rate of 3.7 percent. The PUCT staff forecast is slightly higher than the utility forecast until 1991, when the two forecasts begin to diverge somewhat, with the staff forecast then becoming less than the utility's.

High rates of population growth in Central Texas contribute to strong increases in electricity sales to LCRA's residential, commercial, and wholesale customer groups.

TABLE 3.2.19

Comparison of Utility-Provided and PUCT Staff Peak Demand Forecast

SPS -- Total System

(MW)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	2,827	2,843	16	0.57
1988	2,900	2,940	40	1.38
1989	2,945	3,000	55	1.87
1990	2,989	3,062	73	2.44
1991	3,035	3,126	91	3.00
1992	3,087	3,197	110	3.56
1993	3,154	3,266	112	3.55
1994	3,222	3,337	115	3.57
1995	3,292	3,408	116	3.52
1996	3,362	3,477	115	3.42
1997	3,428	3,546	118	3.44
Annual Growth Rate	1.95%	2.23%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.20

Comparison of Utility-Provided and PUCT Staff Electric Energy Sales Forecast

SPS -- Total System

(MWH)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	14,509,927	14,397,000	(112,927)	-0.78
1988	14,886,393	14,880,000	(6,393)	-0.04
1989	15,110,367	15,199,000	88,633	0.59
1990	15,337,830	15,514,000	176,170	1.15
1991	15,568,791	15,830,000	261,209	1.68
1992	15,834,829	16,179,000	344,171	2.17
1993	16,171,830	16,521,000	349,170	2.16
1994	16,516,239	16,865,000	348,761	2.11
1995	16,868,228	17,212,000	343,772	2.04
1996	17,227,934	17,550,000	322,066	1.87
1997	17,560,464	17,892,000	331,536	1.89
Annual Growth Rate	1.93%	2.20%		

Note: Projected data from the fourth quarter of 1987.
Total sales data do not include Miscellaneous sales.

TABLE 3.2.21

Comparison of Utility-Provided and PUCT Staff Peak Demand Forecast

SPS -- Texas Only

(MW)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	2,105	2,096	(9)	-0.43
1988	2,160	2,178	18	0.83
1989	2,192	2,222	30	1.37
1990	2,225	2,267	42	1.89
1991	2,261	2,314	53	2.34
1992	2,299	2,363	64	2.78
1993	2,348	2,412	64	2.73
1994	2,400	2,462	62	2.58
1995	2,451	2,511	60	2.45
1996	2,503	2,557	54	2.16
1997	2,552	2,603	51	2.00
Annual Growth Rate	1.94%	2.19%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.22

PUCT Staff Forecast of Electric Energy Sales By Class

SPS -- Texas Only

(MWH)

Year	Residential	Commercial	Industrial	Total
1987	1,517,207	1,767,685	5,027,570	8,312,462
1988	1,590,042	1,824,942	5,141,380	8,556,364
1989	1,603,289	1,898,356	5,253,439	8,755,084
1990	1,641,151	1,960,681	5,342,196	8,944,028
1991	1,697,957	2,011,454	5,424,041	9,133,452
1992	1,753,566	2,058,985	5,508,091	9,320,642
1993	1,809,297	2,106,218	5,586,042	9,501,557
1994	1,867,332	2,150,290	5,663,570	9,681,192
1995	1,923,999	2,194,047	5,739,107	9,857,153
1996	1,970,920	2,235,719	5,809,891	10,016,530
1997	2,019,090	2,277,394	5,888,886	10,185,370
Annual Growth Rate	2.90%	2.57%	1.59%	2.05%

Note: Projected data from the fourth quarter of 1987.
Total Sales data do not include Miscellaneous sales.

TABLE 3.2.23

PUCT Staff Forecast of Electric Energy Sales By Class

SPS -- Non-Texas

(MWH)

Year	Residential	Commercial	Industrial	Total
1987	580,008	595,353	1,090,853	2,266,214
1988	584,693	598,359	1,134,184	2,317,236
1989	593,371	603,634	1,185,471	2,382,476
1990	604,986	610,077	1,238,449	2,453,512
1991	614,826	616,610	1,291,303	2,522,739
1992	623,724	623,187	1,344,064	2,590,975
1993	633,808	630,128	1,396,924	2,660,860
1994	645,179	637,491	1,449,780	2,732,450
1995	660,259	645,823	1,502,786	2,808,868
1996	679,624	655,220	1,555,935	2,890,779
1997	699,921	665,145	1,609,307	2,974,373
Annual Growth Rate	1.90%	1.11%	3.97%	2.76%

Note: Projected data from the fourth quarter of 1987.
Total Sales data do not include Miscellaneous sales.

TABLE 3.2.24

PUCT Staff Forecast of Electric Energy Sales By Class

SPS -- Total System

(MWH)

Year	Residential	Commercial	Industrial	Other	Total
1987	2,097,216	2,363,038	6,118,423	3,818,323	14,397,000
1988	2,174,735	2,423,301	6,275,564	4,006,400	14,880,000
1989	2,196,660	2,501,990	6,438,910	4,061,440	15,199,000
1990	2,246,137	2,570,758	6,580,645	4,116,460	15,514,000
1991	2,312,783	2,628,064	6,715,344	4,173,809	15,830,000
1992	2,377,290	2,682,172	6,852,155	4,267,383	16,179,000
1993	2,443,105	2,736,346	6,982,966	4,358,583	16,521,000
1994	2,512,511	2,787,781	7,113,350	4,451,358	16,865,000
1995	2,584,258	2,839,870	7,241,893	4,545,979	17,212,000
1996	2,650,544	2,890,939	7,365,826	4,642,691	17,550,000
1997	2,719,011	2,942,539	7,498,193	4,732,257	17,892,000
Annual Growth Rate	2.63%	2.22%	2.05%	2.17%	2.20%

Note: Projected data from the fourth quarter of 1987.

FIGURE 3.2.6
Staff-Projected Electric Energy Sales by Class
SPS

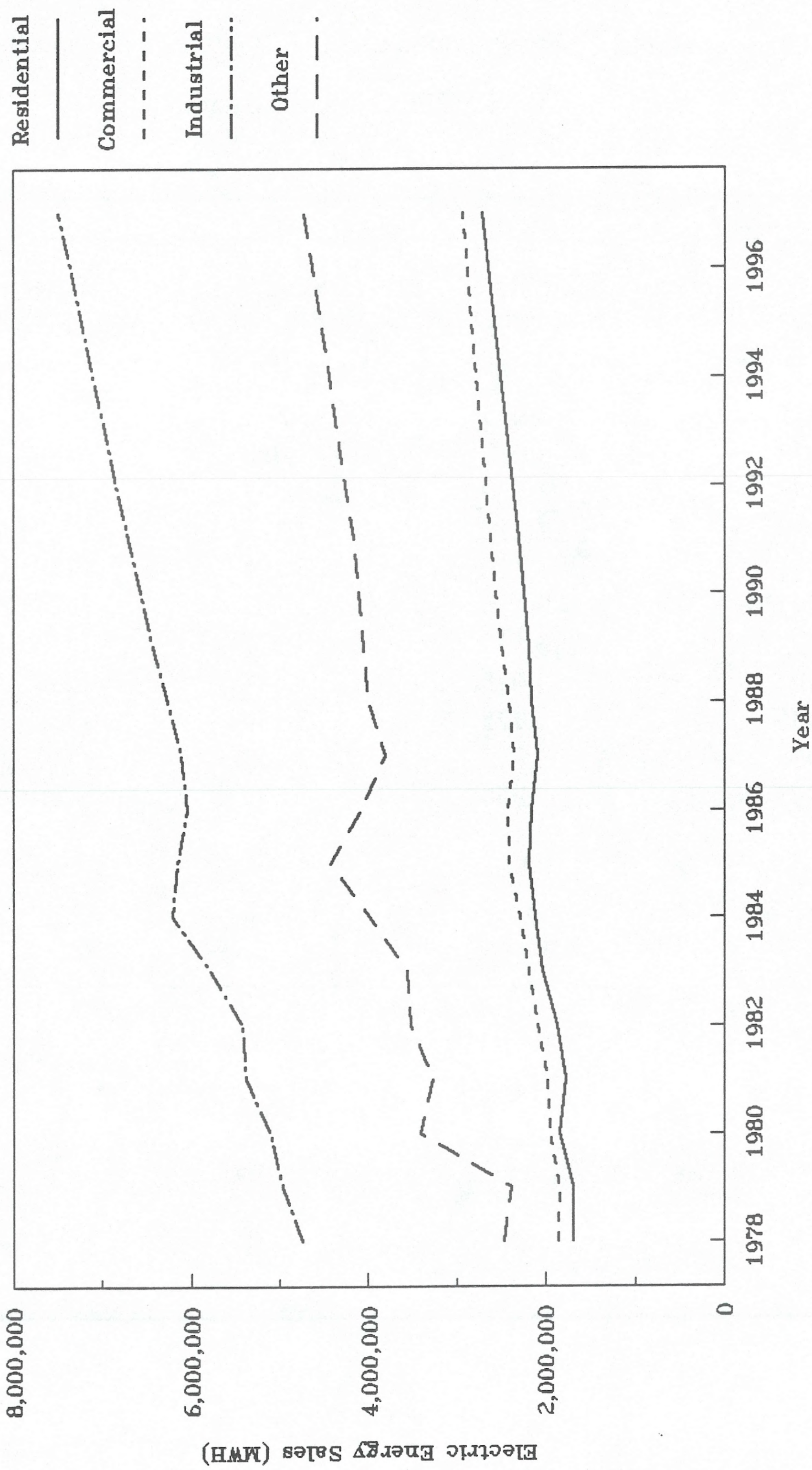


TABLE 3.2.25

Comparison of Utility-Provided and PUCT Staff Peak Demand Forecast

SWEPCO -- Total System

(MW)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	3,085	3,301	216	7.00
1988	3,030	3,038	8	0.26
1989	3,120	3,067	(53)	-1.70
1990	3,210	3,121	(89)	-2.77
1991	3,310	3,194	(116)	-3.50
1992	3,410	3,283	(127)	-3.72
1993	3,510	3,377	(133)	-3.79
1994	3,615	3,486	(129)	-3.57
1995	3,725	3,614	(111)	-2.98
1996	3,835	3,742	(93)	-2.43
1997	3,950	3,870	(80)	-2.03
Annual Growth Rate	2.50%	1.60%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.26

Comparison of Utility-Provided and PUCT Staff Electric Energy Sales Forecast

SWEPCO -- Total System

(MWH)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	13,998,231	14,822,200	823,969	5.89
1988	13,766,000	13,779,580	13,580	0.10
1989	14,084,000	13,967,500	(116,500)	-0.83
1990	14,439,000	14,262,960	(176,040)	-1.22
1991	14,843,000	14,637,930	(205,070)	-1.38
1992	15,286,000	15,081,770	(204,230)	-1.34
1993	15,740,000	15,551,210	(188,790)	-1.20
1994	16,210,000	16,073,640	(136,360)	-0.84
1995	16,693,000	16,663,980	(29,020)	-0.17
1996	17,192,000	17,264,880	72,880	0.42
1997	17,704,000	17,877,420	173,420	0.98
Annual Growth Rate	2.38%	1.89%		

Note: Projected data from the fourth quarter of 1987.
Total Sales projections include Wholesale sales.

TABLE 3.2.27

Comparison of Utility-Provided and PUCT Staff Peak Demand Forecast

SWEPCO -- Texas Only

(MW)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	1,542	1,539	(3)	-0.19
1988	1,515	1,570	55	3.63
1989	1,560	1,595	35	2.24
1990	1,605	1,635	30	1.87
1991	1,655	1,683	28	1.69
1992	1,705	1,735	30	1.76
1993	1,755	1,792	37	2.11
1994	1,808	1,856	48	2.65
1995	1,863	1,929	66	3.54
1996	1,918	2,002	84	4.38
1997	1,973	2,073	100	5.07
Annual Growth Rate	2.50%	3.02%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.28

PUCT Staff Forecast of Electric Energy Sales By Class

SWEPCO -- Texas Only

(MWH)

Year	Residential	Commercial	Industrial	Other	Total
1987	1,408,742	1,093,722	2,900,355	150,654	5,553,473
1988	1,402,721	1,078,163	3,001,867	152,650	5,635,401
1989	1,414,166	1,059,045	3,122,839	155,696	5,751,746
1990	1,442,767	1,065,689	3,252,335	158,833	5,919,624
1991	1,494,498	1,066,758	3,387,066	162,087	6,110,409
1992	1,555,576	1,069,563	3,522,366	165,365	6,312,870
1993	1,624,624	1,079,738	3,659,215	168,656	6,532,233
1994	1,709,545	1,093,897	3,797,475	171,952	6,772,869
1995	1,809,877	1,121,157	3,934,617	175,275	7,040,926
1996	1,899,766	1,164,100	4,068,559	178,610	7,311,035
1997	1,974,813	1,208,196	4,208,891	182,108	7,574,008
Annual Growth Rate	3.44%	1.00%	3.79%	1.91%	3.15%

Note: Projected data from the fourth quarter of 1987.
Total Sales projections include Wholesale sales.

TABLE 3.2.29

PUCT Staff Forecast of Electric Energy Sales By Class

SWEPCO -- Non-Texas

(MWH)

Year	Residential	Commercial	Industrial	Other	Total
1987	2,145,325	1,631,505	2,119,805	207,574	6,104,209
1988	2,102,433	1,642,781	2,090,642	205,326	6,041,182
1989	2,077,341	1,677,742	2,099,892	203,784	6,058,759
1990	2,071,891	1,706,280	2,143,782	202,386	6,124,339
1991	2,093,017	1,727,766	2,218,976	202,765	6,242,524
1992	2,125,680	1,766,452	2,319,771	204,994	6,416,897
1993	2,157,650	1,802,567	2,434,482	204,280	6,598,979
1994	2,209,579	1,842,879	2,552,341	204,969	6,809,768
1995	2,281,803	1,897,488	2,672,754	206,008	7,058,053
1996	2,348,557	1,961,273	2,796,678	207,345	7,313,853
1997	2,412,994	2,031,094	2,933,419	208,915	7,586,422
Annual Growth Rate	1.18%	2.21%	3.30%	0.06%	2.20%

Note: Projected data from the fourth quarter of 1987.
Total Sales projections include Wholesale sales.

TABLE 3.2.30

PUCT Staff Forecast of Electric Energy Sales By Class

SWEPCO -- Total System

(MWH)

Year	Residential	Commercial	Industrial	Other	Total
1987	3,554,067	2,725,227	5,020,160	3,522,746	14,822,200
1988	3,505,154	2,720,944	5,092,509	2,460,973	13,779,580
1989	3,491,507	2,736,787	5,222,731	2,516,475	13,967,500
1990	3,514,658	2,771,969	5,396,117	2,580,216	14,262,960
1991	3,587,515	2,794,524	5,606,042	2,649,849	14,637,930
1992	3,681,256	2,836,015	5,842,137	2,722,362	15,081,770
1993	3,782,274	2,882,305	6,093,697	2,792,934	15,551,210
1994	3,919,124	2,936,776	6,349,816	2,867,924	16,073,640
1995	4,091,680	3,018,645	6,607,371	2,946,284	16,663,980
1996	4,248,323	3,125,373	6,865,237	3,025,947	17,264,880
1997	4,387,807	3,239,290	7,142,310	3,108,013	17,877,420
Annual Growth Rate	2.13%	1.74%	3.59%	-1.24%	1.89%

Note: Projected data from the fourth quarter of 1987.
Total Sales Projections include Wholesale sales.

FIGURE 3.2.7
Staff-Projected Electric Energy Sales by Class
SWEPCO

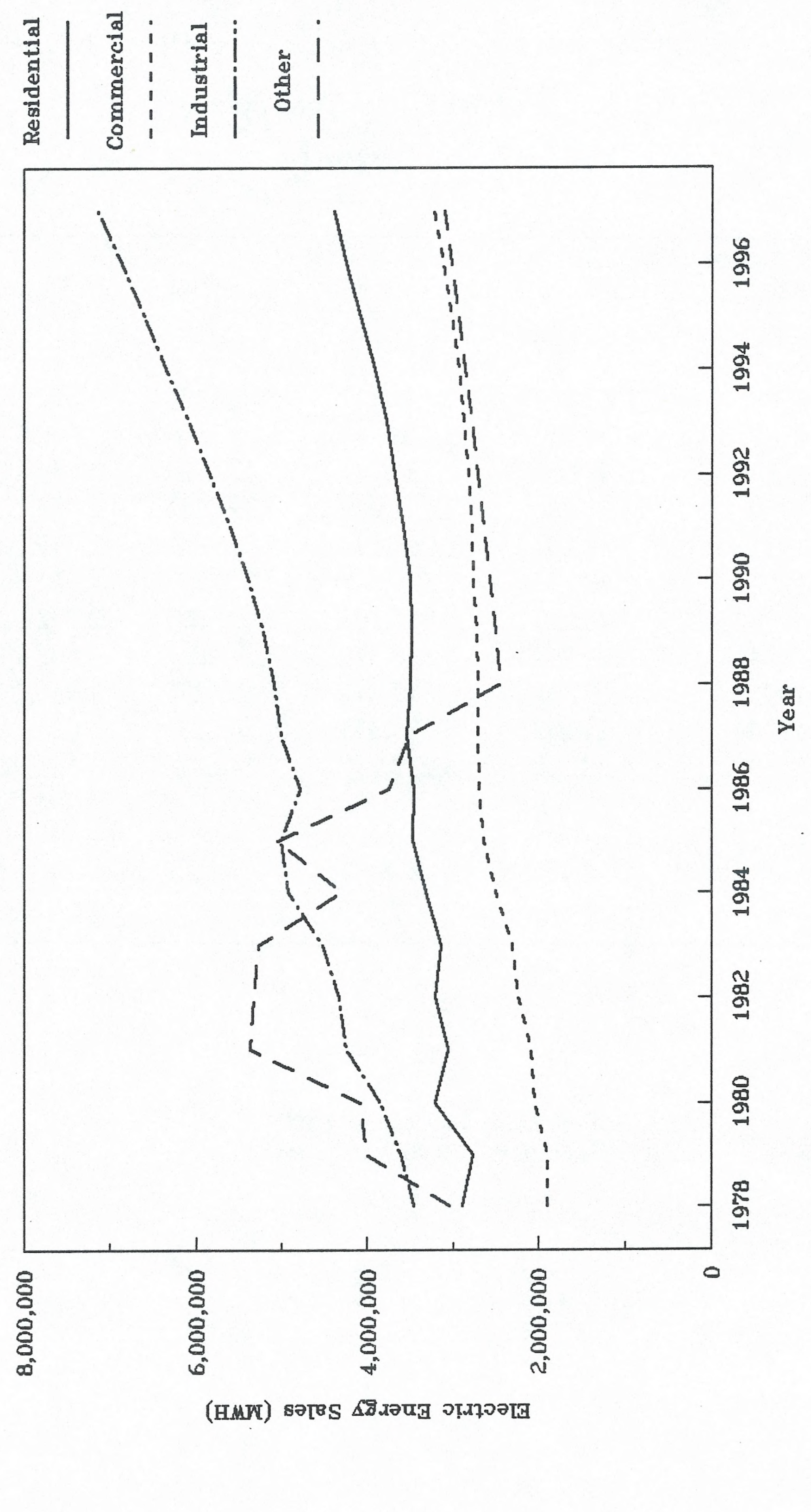


TABLE 3.2.31

Comparison of Utility-Provided and PUCT Staff Peak Demand Forecast

LCRA

(MW)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	1,514	1,574	60	3.96
1988	1,532	1,587	55	3.59
1989	1,592	1,646	54	3.39
1990	1,656	1,700	44	2.66
1991	1,733	1,744	11	0.63
1992	1,816	1,798	(18)	-0.99
1993	1,914	1,862	(52)	-2.72
1994	2,013	1,938	(75)	-3.73
1995	2,116	2,031	(85)	-4.02
1996	2,230	2,138	(92)	-4.13
1997	2,360	2,262	(98)	-4.15
Annual Growth Rate	4.54%	3.69%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.32

Comparison of Utility-Provided and PUCT Staff Electric Energy Sales Forecast

LCRA

(MWH)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	6,900,035	6,844,000	(56,035)	-0.81
1988	7,119,000	6,974,000	(145,000)	-2.04
1989	7,405,000	7,157,000	(248,000)	-3.35
1990	7,730,000	7,388,000	(342,000)	-4.42
1991	8,115,000	7,577,000	(538,000)	-6.63
1992	8,551,000	7,817,000	(734,000)	-8.58
1993	9,025,000	8,107,000	(918,000)	-10.17
1994	9,522,000	8,453,000	(1,069,000)	-11.23
1995	10,044,000	8,883,000	(1,161,000)	-11.56
1996	10,645,000	9,388,000	(1,257,000)	-11.81
1997	11,283,000	9,964,000	(1,319,000)	-11.69
Annual Growth Rate	5.04%	3.83%		

Note: Projected data from the fourth quarter of 1987.

Lower electricity rates relative to natural gas prices further support increasing electricity consumption in Central Texas.

3.2.9 City of Austin Electric Utility

A relatively optimistic demographic outlook for the Austin area supports a projected 4.6 percent annual increase in peak demand through 1997. COA predicts an even higher 5.8 percent growth rate in peak demand through the forecast horizon.

The staff developed a Bayesian model for the COA system. Data constraints prevented the staff from developing an econometric model for this utility. The single-equation Bayesian model of total system sales for COA is modeled as a function of service area population, heating degree days, and cooling degree days.

The COA electric rates are not closely related to the costs of providing electric power; hence future electricity prices are difficult to predict. Though the staff has not projected electric prices for COA customers, the staff anticipates favorable electric rates relative to natural gas prices. This may encourage fuel switching and the construction of more all-electric homes.

3.2.10 West Texas Utilities Company

The demand forecast developed by the Commission staff for the WTU planning region is lower than the projection developed by the Company throughout the forecast horizon. Peak demand is projected to increase at an annual rate of 3.2 percent over the next ten years, exceeding 1,500 MW by 1997. The largest difference in peak demand forecast between the staff projection and the Company projection is less than 6 percent in 1990.

Growth in electricity sales to residential and commercial customers is fairly robust, while industrial sales grow at a lower rate through the forecast period.

3.2.11 El Paso Electric Company

The electricity demand forecast developed by the PUCT staff for the EPE planning region is lower than that filed by the utility. While EPE projects a system peak of 1,147 MW in 1997, the staff expects peak demand to reach only 1,064 MW in that year.

TABLE 3.2.33

Comparison of Utility-Provided and PUCT Staff Peak Demand Forecast

COA

(MW)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	1,408	1,408	0	0.00
1988	1,571	1,549	(22)	-1.37
1989	1,637	1,615	(22)	-1.37
1990	1,720	1,678	(42)	-2.46
1991	1,815	1,740	(75)	-4.11
1992	1,916	1,807	(109)	-5.71
1993	2,028	1,879	(149)	-7.34
1994	2,140	1,951	(189)	-8.84
1995	2,249	2,031	(218)	-9.71
1996	2,355	2,112	(243)	-10.32
1997	2,462	2,197	(265)	-10.78
Annual Growth Rate	5.75%	4.55%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.34

Comparison of Utility-Provided and PUCT Staff Electric Energy Sales Forecast

COA

(MWH)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	5,761,024	5,761,024	0	0.00
1988	6,174,886	6,090,190	(84,696)	-1.37
1989	6,433,621	6,345,586	(88,035)	-1.37
1990	6,762,269	6,596,162	(166,107)	-2.46
1991	7,145,526	6,851,558	(293,968)	-4.11
1992	7,552,558	7,121,410	(431,148)	-5.71
1993	7,997,683	7,410,537	(587,146)	-7.34
1994	8,441,492	7,694,845	(746,647)	-8.84
1995	8,869,088	8,008,066	(861,022)	-9.71
1996	9,295,228	8,335,743	(959,485)	-10.32
1997	9,721,368	8,673,058	(1,048,310)	-10.78
Annual Growth Rate	5.37%	4.18%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.35

PUCT Staff Forecast of Electric Energy Sales By Class

COA

(MWH)

Year	Residential	Commercial	Industrial	Other	Total
1987	2,288,239	2,859,767	461,410	151,608	5,761,024
1988	2,413,979	2,963,191	552,091	160,929	6,090,190
1989	2,524,452	3,075,507	578,398	167,229	6,345,586
1990	2,618,412	3,208,502	597,329	171,919	6,596,162
1991	2,701,636	3,353,540	619,961	176,421	6,851,558
1992	2,794,513	3,504,480	641,358	181,059	7,121,410
1993	2,903,826	3,664,066	657,359	185,286	7,410,537
1994	3,011,854	3,821,310	672,388	189,293	7,694,845
1995	3,137,846	3,983,903	692,107	194,210	8,008,066
1996	3,252,541	4,170,818	712,930	199,453	8,335,743
1997	3,376,931	4,355,680	735,614	204,832	8,673,058
Annual Growth Rate	5.16%	3.97%	4.70%	3.10%	4.18%

Note: Projected data from the fourth quarter of 1987.

FIGURE 3.2.8
Staff-Projected Electric Energy Sales by Class
COA

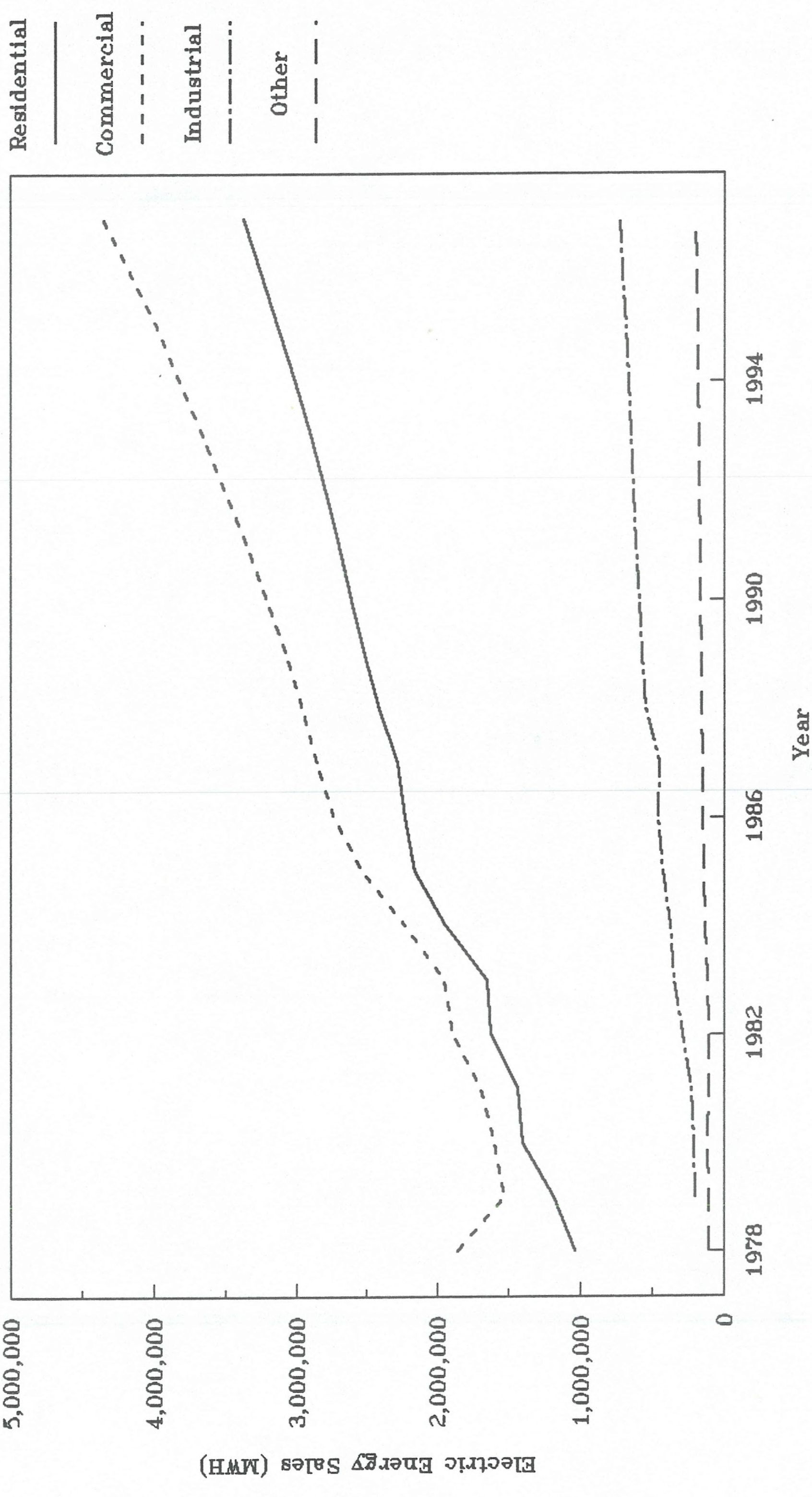


TABLE 3.2.36

Comparison of Utility-Provided and PUCT Staff Peak Demand Forecast

WTU

(MW)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	1,096	1,109	13	1.19
1988	1,165	1,129	(36)	-3.09
1989	1,221	1,157	(64)	-5.24
1990	1,261	1,191	(70)	-5.55
1991	1,303	1,231	(72)	-5.53
1992	1,345	1,272	(73)	-5.43
1993	1,385	1,316	(69)	-4.98
1994	1,428	1,362	(66)	-4.62
1995	1,470	1,411	(59)	-4.01
1996	1,511	1,460	(51)	-3.38
1997	1,554	1,513	(41)	-2.64
Annual Growth Rate	3.55%	3.16%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.37

Comparison of Utility-Provided and PUCT Staff Electric Energy Sales Forecast

WTU

(MWH)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	5,405,021	5,188,004	(217,017)	-4.02
1988	5,339,855	5,243,803	(96,052)	-1.80
1989	5,495,266	5,375,210	(120,056)	-2.18
1990	5,688,461	5,540,726	(147,735)	-2.60
1991	5,892,247	5,732,612	(159,635)	-2.71
1992	6,093,160	5,932,649	(160,511)	-2.63
1993	6,291,804	6,140,328	(151,476)	-2.41
1994	6,488,836	6,361,798	(127,038)	-1.96
1995	6,686,346	6,583,578	(102,768)	-1.54
1996	6,887,406	6,804,589	(82,817)	-1.20
1997	7,091,218	7,042,263	(48,955)	-0.69
Annual Growth Rate	2.75%	3.10%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.38

PUCT Staff Forecast of Electric Energy Sales By Class

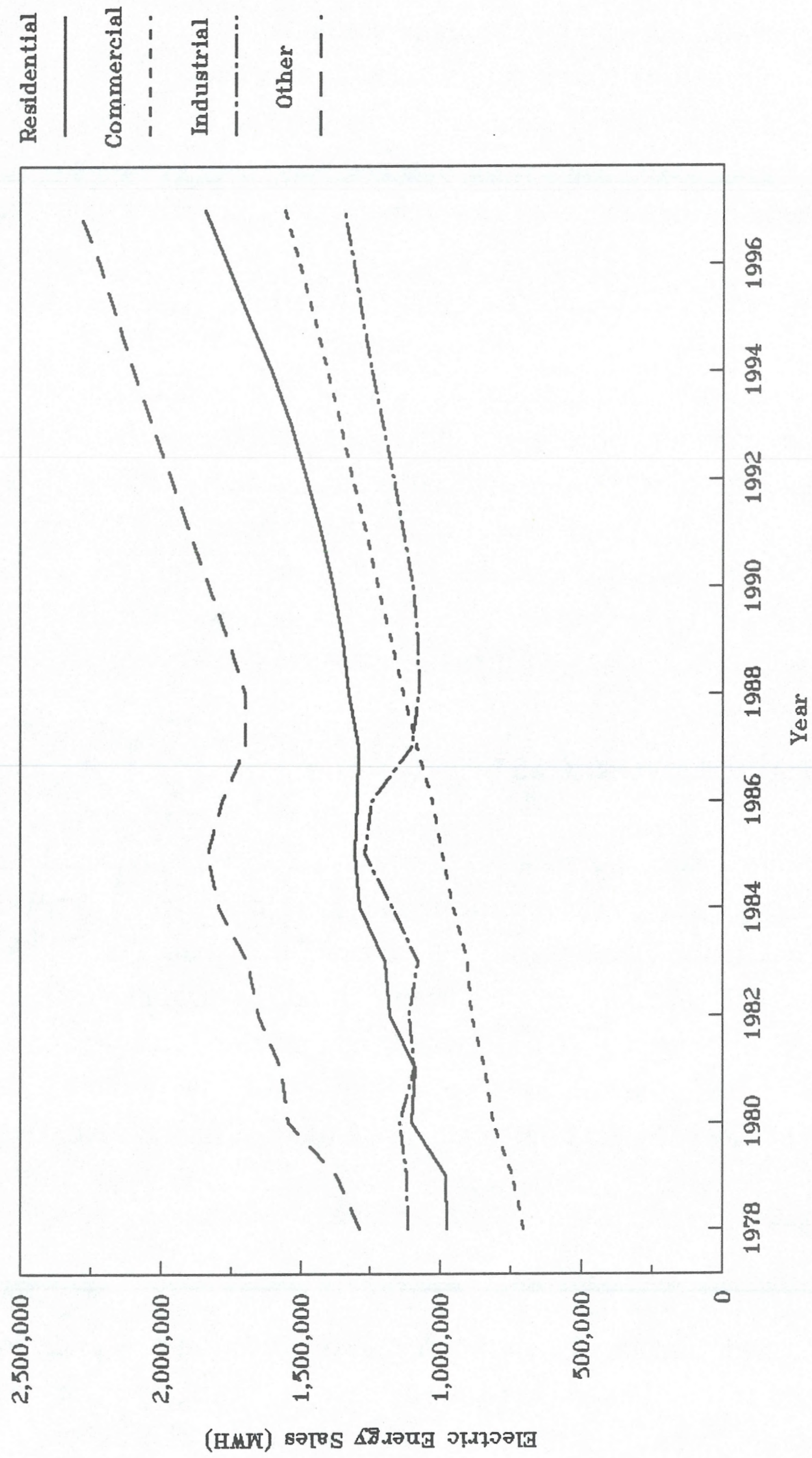
WTU

(MWH)

Year	Residential	Commercial	Industrial	Other	Total
1987	1,296,321	1,086,471	1,105,882	1,699,330	5,188,004
1988	1,328,361	1,137,127	1,079,049	1,699,266	5,243,803
1989	1,351,613	1,179,371	1,081,761	1,762,465	5,375,210
1990	1,383,556	1,223,582	1,101,911	1,831,677	5,540,726
1991	1,428,461	1,270,239	1,133,799	1,900,113	5,732,612
1992	1,479,653	1,316,192	1,171,899	1,964,905	5,932,649
1993	1,537,340	1,361,638	1,209,881	2,031,469	6,140,328
1994	1,606,825	1,407,871	1,247,268	2,099,834	6,361,798
1995	1,686,436	1,456,193	1,282,509	2,158,440	6,583,578
1996	1,766,732	1,506,179	1,314,347	2,217,331	6,804,589
1997	1,843,631	1,558,985	1,348,134	2,291,513	7,042,263
Annual Growth Rate	3.58%	3.68%	2.00%	3.03%	3.10%

Note: Projected data from the fourth quarter of 1987.

FIGURE 3.2.9
Staff-Projected Electric Energy Sales by Class
WTU



Total peak demand is projected to grow at a rate of 2.8 percent over the 10-year forecast period, while electric consumption is expected to grow at a rate of 2.7 percent.

The real price of electricity for the major customer classes is expected to remain flat or decline over the entire forecast period. This is partly due to the rate moderation scheme adopted in calculating the Company's total fixed costs. The "smoothing-out" effect of the costs of the Palo Verde Nuclear units as and when they are allowed into the rate base explains the fairly smooth rate of growth in the nominal price of electricity.

3.2.12 Texas-New Mexico Power Company

This is the first time that the staff has developed a model to predict energy sales for TNP. The staff developed a set of single-equation models for the residential and commercial classes for each of TNP's operating divisions in Texas. The staff does not have a model for TNP's non-Texas service area; therefore TNP's projections are used whenever a staff forecast is not available. The total system peak is expected to grow at an annual rate of 1.7 percent while total sales in the Texas portion of TNP's service area are expected to grow at an annual rate of 1.9 percent.

3.3 HISTORICAL FORECAST ACCURACY

An inquiry into historical forecast accuracy provides at least a partial explanation of why Texas presently has excess electrical generating capacity. The PUCT's **Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas, 1986** included a brief description of the accuracy that had been achieved by eight major electric utilities in the long-term peak load projections that they had prepared since 1974. In recent nuclear power plant prudence inquiries before the PUCT, in testimony before the Texas Legislature's House Select Committee on a Statewide Energy Plan, and in other forums, increasing interest in forecast accuracy has emerged. The need for further analysis has become evident.

In general, forecasting models cannot predict random or completely unanticipated events and their impact on electricity markets. Before the volatility in energy markets experienced in the 1970s, electricity demand in Texas, and the nation as a whole, followed fairly predictable trends. Accurate projections of peak load and sales could be achieved using fairly simple techniques. However, in the past fifteen years, the

TABLE 3.2.39

Comparison of Utility-Provided and PUCT Staff Peak Demand Forecast

EPE -- Total System

(MW)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	829	808	(21)	-2.53
1988	864	809	(55)	-6.37
1989	896	819	(77)	-8.59
1990	928	836	(92)	-9.91
1991	963	853	(110)	-11.42
1992	987	864	(123)	-12.46
1993	1,021	877	(144)	-14.10
1994	1,052	908	(144)	-13.69
1995	1,082	959	(123)	-11.37
1996	1,114	1,015	(99)	-8.89
1997	1,147	1,064	(83)	-7.24
Annual Growth Rate	3.30%	2.79%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.40

Comparison of Utility-Provided and PUCT Staff Electric Energy Sales Forecast

EPE -- Total System

(MWH)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	4,002,423	3,881,219	(121,204)	-3.03
1988	4,073,062	3,904,937	(168,125)	-4.13
1989	4,279,239	3,952,941	(326,298)	-7.63
1990	4,424,513	4,029,770	(394,743)	-8.92
1991	4,600,728	4,119,290	(481,438)	-10.46
1992	4,728,847	4,177,123	(551,724)	-11.67
1993	4,887,345	4,246,616	(640,729)	-13.11
1994	5,034,967	4,388,064	(646,903)	-12.85
1995	5,183,164	4,615,149	(568,015)	-10.96
1996	5,330,980	4,867,078	(463,902)	-8.70
1997	5,491,259	5,085,673	(405,586)	-7.39
Annual Growth Rate	3.21%	2.74%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.41

Comparison of Utility-Provided and PUCT Staff Peak Demand Forecast

EPE -- Texas Only

(MW)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	658	638	(20)	-3.04
1988	684	637	(47)	-6.87
1989	706	643	(63)	-8.92
1990	731	655	(76)	-10.40
1991	755	668	(87)	-11.52
1992	774	678	(96)	-12.40
1993	800	691	(109)	-13.63
1994	825	717	(108)	-13.09
1995	848	759	(89)	-10.50
1996	873	804	(69)	-7.90
1997	894	844	(50)	-5.59
Annual Growth Rate	3.11%	2.84%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.42

Comparison of Utility-Provided and PUCT Staff Electric Energy Sales Forecast

EPE -- Texas Only

(MWH)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	3,137,757	3,051,000	(86,757)	-2.76
1988	3,214,913	3,054,000	(160,913)	-5.01
1989	3,337,114	3,072,000	(265,114)	-7.94
1990	3,441,495	3,123,000	(318,495)	-9.25
1991	3,564,304	3,179,000	(385,304)	-10.81
1992	3,657,387	3,231,000	(426,387)	-11.66
1993	3,779,670	3,296,000	(483,670)	-12.80
1994	3,893,857	3,415,000	(478,857)	-12.30
1995	4,007,830	3,601,000	(406,830)	-10.15
1996	4,118,756	3,802,000	(316,756)	-7.69
1997	4,242,678	3,977,000	(265,678)	-6.26
Annual Growth Rate	3.06%	2.69%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.43

PUCT Staff Forecast of Electric Energy Sales By Class

EPE -- Texas Only

(MWH)

Year	Residential	Commercial	Industrial	Other	Total
1987	896,678	1,047,339	578,969	528,014	3,051,000
1988	896,551	1,033,828	588,544	535,077	3,054,000
1989	894,110	1,046,332	592,996	538,562	3,072,000
1990	899,760	1,075,710	602,149	545,381	3,123,000
1991	910,160	1,093,706	622,865	552,269	3,179,000
1992	917,268	1,109,698	646,392	557,642	3,231,000
1993	929,466	1,134,539	670,829	561,166	3,296,000
1994	966,741	1,184,789	693,749	569,721	3,415,000
1995	1,030,799	1,265,701	721,755	582,745	3,601,000
1996	1,104,868	1,348,395	749,224	599,513	3,802,000
1997	1,176,678	1,419,735	764,851	615,736	3,977,000
Annual Growth Rate	2.75%	3.09%	2.82%	1.55%	2.69%

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.44

PUCT Staff Forecast of Electric Energy Sales By Class

EPE -- Non-Texas

(MWH)

Year	Residential	Commercial	Industrial	Other	Total
1987	269,123	226,403	26,676	308,017	830,219
1988	272,910	218,793	44,342	314,892	850,937
1989	278,951	214,908	66,343	320,739	880,941
1990	288,246	215,229	76,562	326,733	906,770
1991	297,979	213,243	96,724	332,344	940,290
1992	302,798	204,491	101,581	337,253	946,123
1993	307,342	197,398	103,431	342,445	950,616
1994	315,601	202,780	105,434	349,249	973,064
1995	326,706	222,201	107,410	357,832	1,014,149
1996	339,212	249,043	109,540	367,283	1,065,078
1997	352,059	270,938	109,540	376,136	1,108,673
Annual Growth Rate	2.72%	1.81%	5.17%	2.02%	2.93%

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.45

PUCT Staff Forecast of Electric Energy Sales By Class

EPE -- Total System

(MWH)

Year	Residential	Commercial	Industrial	Other	Total
1987	1,165,801	1,273,742	605,645	836,031	3,881,219
1988	1,169,461	1,252,621	632,886	849,969	3,904,937
1989	1,173,061	1,261,240	659,339	859,301	3,952,941
1990	1,188,006	1,290,939	678,711	872,114	4,029,770
1991	1,208,139	1,306,949	719,589	884,613	4,119,290
1992	1,220,066	1,314,189	747,973	894,895	4,177,123
1993	1,236,808	1,331,937	774,260	903,611	4,246,616
1994	1,282,342	1,387,569	799,183	918,970	4,388,064
1995	1,357,505	1,487,902	829,165	940,577	4,615,149
1996	1,444,080	1,597,438	858,764	966,796	4,867,078
1997	1,528,737	1,690,673	874,391	991,872	5,085,673
Annual Growth Rate	2.75%	2.87%	3.74%	1.72%	2.74%

Note: Projected data from the fourth quarter of 1987.

FIGURE 3.2.10
Staff-Projected Electric Energy Sales by Class
EPE

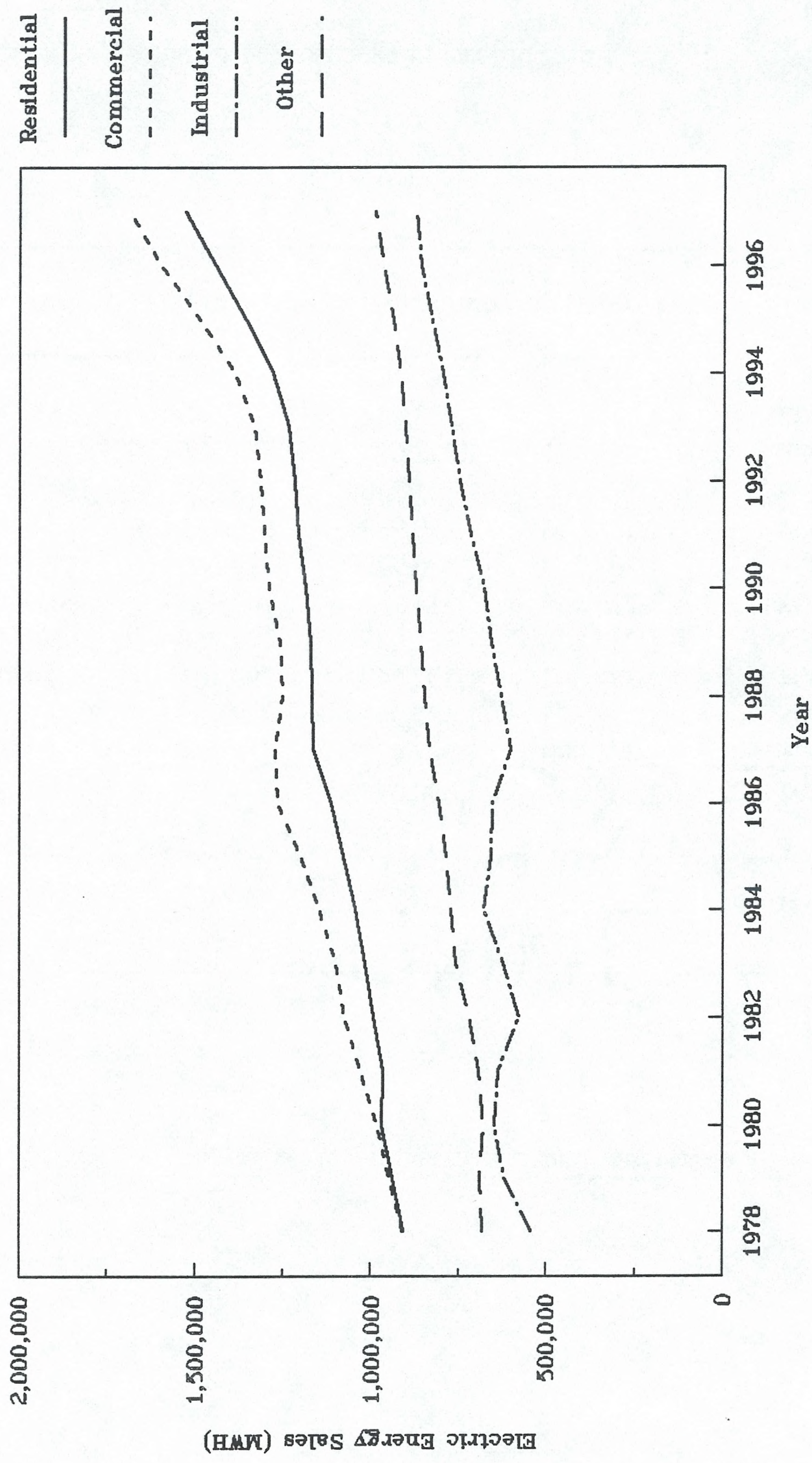


TABLE 3.2.46

Comparison of Utility-Provided and PUCT Staff Peak Demand Forecast

TNP -- Total System

(MW)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	1,094	1,128	34	3.11
1988	1,130	1,127	(3)	-0.27
1989	1,159	1,160	1	0.09
1990	1,188	1,178	(10)	-0.84
1991	1,218	1,176	(42)	-3.45
1992	1,255	1,198	(57)	-4.54
1993	1,288	1,225	(63)	-4.89
1994	1,321	1,252	(69)	-5.22
1995	1,356	1,281	(75)	-5.53
1996	1,393	1,310	(83)	-5.96
1997	1,431	1,338	(93)	-6.50
Annual Growth Rate	2.72%	1.72%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.47

Comparison of Utility-Provided and PUCT Staff Electric Energy Sales Forecast

TNP -- Total System

(MWH)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	6,059,390	5,877,993	(181,397)	-2.99
1988	6,174,435	5,911,287	(263,148)	-4.26
1989	6,457,882	6,160,483	(297,399)	-4.61
1990	6,577,608	6,253,741	(323,867)	-4.92
1991	6,500,046	6,154,258	(345,788)	-5.32
1992	6,618,135	6,252,482	(365,653)	-5.53
1993	6,761,639	6,381,412	(380,227)	-5.62
1994	6,907,293	6,512,704	(394,589)	-5.71
1995	7,058,029	6,648,652	(409,377)	-5.80
1996	7,214,885	6,784,674	(430,211)	-5.96
1997	7,377,190	6,920,980	(456,210)	-6.18
Annual Growth Rate	1.99%	1.65%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.48

Comparison of Utility-Provided and PUCT Staff Peak Demand Forecast

TNP -- Texas Only

(MW)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	965	979	14	1.45
1988	991	967	(24)	-2.42
1989	1,014	982	(32)	-3.16
1990	1,041	998	(43)	-4.13
1991	1,069	1,021	(48)	-4.49
1992	1,103	1,043	(60)	-5.44
1993	1,134	1,069	(65)	-5.73
1994	1,165	1,096	(69)	-5.92
1995	1,198	1,127	(71)	-5.93
1996	1,232	1,157	(75)	-6.09
1997	1,268	1,187	(81)	-6.39
Annual Growth Rate	2.77%	1.95%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.49

Comparison of Utility-Provided and PUCT Staff Electric Energy Sales Forecast

TNP -- Texas Only

(MWH)

Year	Utility Projection	Staff Projection	Raw Difference	Percentage Difference
1987	4,723,482	4,542,000	(181,482)	-3.84
1988	4,748,429	4,485,000	(263,429)	-5.55
1989	4,871,992	4,575,000	(296,992)	-6.10
1990	4,976,734	4,653,000	(323,734)	-6.50
1991	5,109,183	4,763,000	(346,183)	-6.78
1992	5,229,571	4,864,000	(365,571)	-6.99
1993	5,362,801	4,983,000	(379,801)	-7.08
1994	5,498,896	5,104,000	(394,896)	-7.18
1995	5,639,677	5,230,000	(409,677)	-7.26
1996	5,785,301	5,355,000	(430,301)	-7.44
1997	5,937,066	5,481,000	(456,066)	-7.68
Annual Growth Rate	2.31%	1.90%		

Note: Projected data from the fourth quarter of 1987.

TABLE 3.2.50

PUCT Staff Forecast of Electric Energy Sales By Class

TNP -- Texas Only

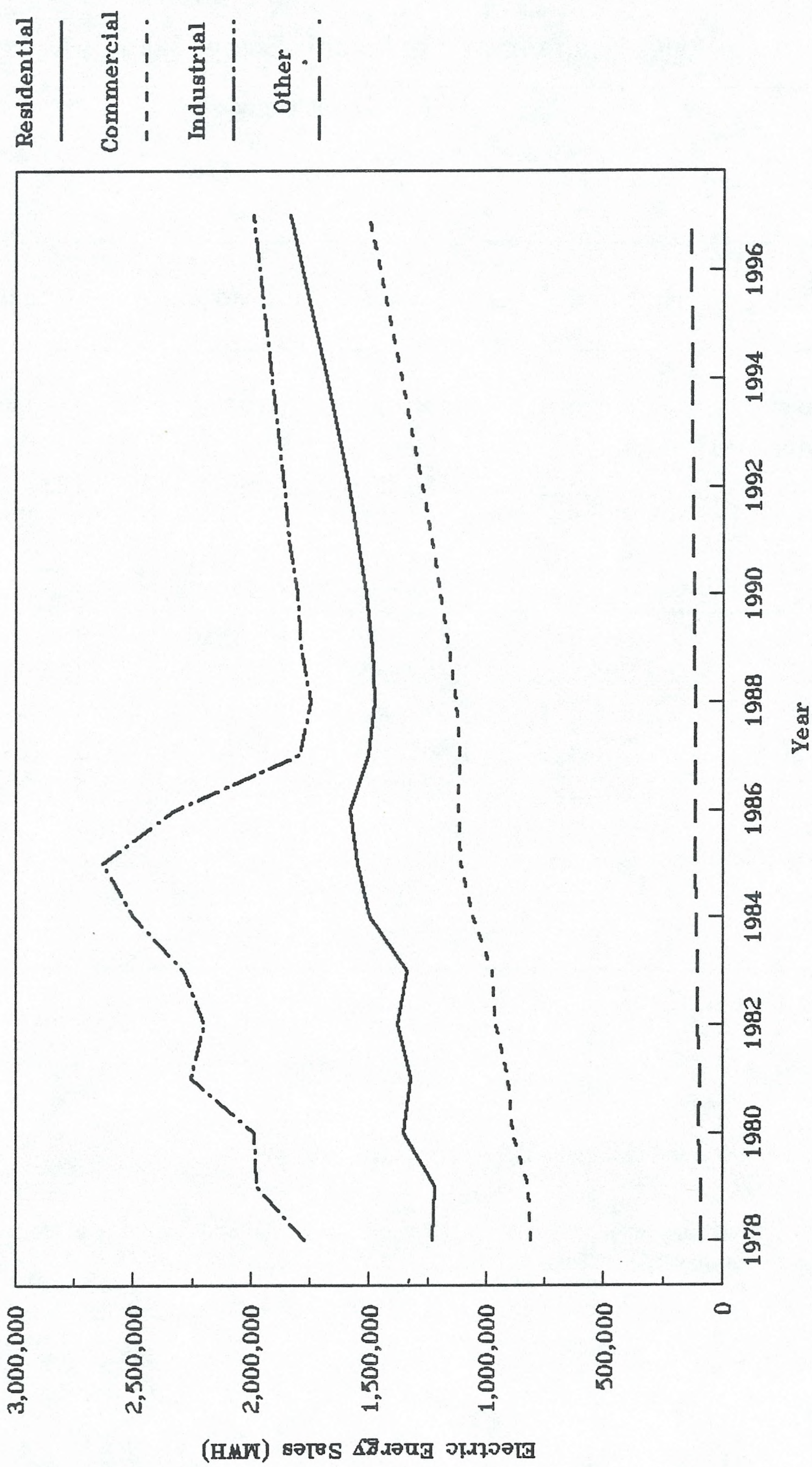
(MWH)

Year	Residential	Commercial	Industrial	Other	Total
1987	1,507,001	1,120,783	1,795,693	118,523	4,542,000
1988	1,482,771	1,132,690	1,750,314	119,225	4,485,000
1989	1,493,521	1,168,176	1,790,894	122,409	4,575,000
1990	1,517,899	1,203,917	1,806,364	124,820	4,653,000
1991	1,552,636	1,238,616	1,845,039	126,709	4,763,000
1992	1,591,256	1,279,707	1,863,433	129,604	4,864,000
1993	1,635,583	1,324,543	1,890,505	132,369	4,983,000
1994	1,685,118	1,368,685	1,916,135	134,062	5,104,000
1995	1,736,671	1,415,066	1,941,764	136,499	5,230,000
1996	1,786,870	1,461,593	1,967,393	139,144	5,355,000
1997	1,837,291	1,508,867	1,993,022	141,820	5,481,000
Annual Growth Rate	2.00%	3.02%	1.05%	1.81%	1.90%

Note: Projected data from the fourth quarter of 1987.

Staff has projected sales only for the residential and commercial classes for TNP's service area in Texas.

FIGURE 3.2.11
Staff-Projected Electric Energy Sales by Class
TNP (Texas Only)



development of accurate electricity demand projections has become a considerably greater challenge.

A number of factors have contributed to the forecasting errors that have been experienced by the State's utilities. Like electric utilities across the nation, the utilities in Texas did not fully anticipate the energy market shocks of the 1970s and their impact on electricity demand. Volatility in energy markets and the economy in general since 1974 was not widely anticipated by economists and business analysts before the mid-1970s. Projections prepared before then typically assumed that past trends in energy markets would continue. The real price of energy was expected to continue to decline or remain flat, and per capita energy consumption was expected to continue to increase. But the Arab Oil Embargo, the actions of OPEC, and related events in the 1970s had a devastating impact on energy markets and the economy in general. As a result, energy consumption began to grow at much slower rates. In Texas, however, the slowdown in demand growth from energy price increases was tempered by unparalleled economic growth lasting into the mid-1980s.

3.3.1 Forecast Accuracy by Utilities

In a recent study by the Environmental Action Foundation, the accuracy of the demand projections prepared by 106 American electric utilities between 1975 and 1985 was compared. As indicated in Tables 3.3.1 and 3.3.2, the utilities in Texas, in general, achieved a slightly higher degree of forecasting accuracy than non-Texas utilities during this time period. Of particular interest is the experience of El Paso Electric Company, whose projections were exceptionally accurate one year into the future, but turning out relatively poor in the longer run. It should be noted that such rankings are highly dependent upon the time frame chosen and the forecast horizon selected for study. Therefore, some utilities may question the validity of such rankings.

A detailed analysis of forecast accuracy has been prepared for eight investor-owned utility companies in Texas and one State-chartered river authority:

1. Texas Utilities Electric Company
2. Houston Lighting and Power Company
3. Gulf States Utilities Company
4. Central Power and Light Company

Table 3.3.1

Accuracy of Demand Forecasts Four Years Into The Future*

Utility	Average Absolute Percentage Error	National** Ranking
Central Power and Light Company	12.1%	42
Dallas Power and Light (TU Electric)	15.1%	67
El Paso Electric Company	15.6%	72
Gulf States Utilities Company	14.4%	60
Houston Lighting and Power Company	4.3%	4
Southwestern Electric Power	9.8%	21
Southwestern Public Service	9.7%	19
Texas Electric Service (TU Electric)	11.9%	41
Texas Power and Light (TU Electric)	15.6%	73
West Texas Utilities Company	4.0%	3

* Based on data from 1975 to 1985.

** Based on a national sample of 106 companies.

Source: Alan Nogee, **Gambling for Gigabucks: Excess Capacity in the Electric Utility Industry**, Environmental Action Foundation, Washington, D.C., December 1986.

Table 3.3.2

Accuracy of Demand Forecasts One Year Into The Future*

Utility	Average Absolute Percentage Error	National** Ranking
Central Power and Light Company	2.9%	14
Dallas Power and Light (TU Electric)	5.5%	68
El Paso Electric Company	1.5%	1
Gulf States Utilities Company	6.0%	79
Houston Lighting and Power Company	3.1%	16
Southwestern Electric Power	4.1%	42
Southwestern Public Service	6.7%	89
Texas Electric Service (TU Electric)	4.8%	57
Texas Power and Light (TU Electric)	3.8%	34
West Texas Utilities Company	3.8%	35

* Based on data from 1975 to 1985.

** Based on a national sample of 106 companies.

Source: Alan Nogee, **Gambling for Gigabucks: Excess Capacity in the Electric Utility Industry**, Environmental Action Foundation, Washington, D.C., December 1986.

5. Southwestern Public Service Company
6. Southwestern Electric Power Company
7. Lower Colorado River Authority
8. West Texas Utilities Company
9. El Paso Electric Company

Tables 3.3.3 through 3.3.11 report the peak demand projections developed by each utility since 1974 and the percentage errors from the peak load projections experienced. The projections are contrasted to actual peak demand data in Figures 3.3-1 through 3.3-9.

3.3.2 Sources of Forecasting Error

An examination of the peak demand projections developed by this sample of nine large utilities indicates there has been considerable forecasting error among the utilities in Texas in the past. The PUCT staff sought to statistically identify and quantify the sources of error in the peak demand projections prepared by nine of the State's largest electric utilities.[1] Five of the utilities analyzed have had a history of consistently over-projecting peak demand. Peak demand projections prepared by TU Electric in 1974 and 1975 over-projected actual 1984 peak demand by over 50 percent, or 7,715 MW. The SWEPCO 1975 and 1976 projections were in error by over 40 percent for 1984. Forecasts prepared by HL&P and SPS have also tended to be high in the past.

Until 1982, the projections developed by GSU were relatively accurate. However, utility system planners apparently did not anticipate the economic downturn in the GSU service area and the impact of recent price increases on electricity demand. Projections developed since 1978 have been overly optimistic.

The projections presented here for LCRA are actually the simple average of their high-case and low-case scenarios. Forecasts issued before 1978 over-estimated actual demand. Since 1978, accuracy seems to have improved, with under-projections more common.

It is interesting to note that the second smallest utility in this sample, WTU, has prepared the most accurate projections. Since 1976, none of the Company's projections have been in error by more than 10 percent. WTU uses relatively simple techniques and

TABLE 3.3.3
Utility-Projected Peak Demand
TU Electric

Forecast Year	Year Forecast Issued 1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Peak Demand* (MW)													
1976	**10,002**												
1977	11,531	**10,525**											
1978	12,354	11,602	**11,232**										
1979	13,213	12,328	11,851	**10,880**									
1980	14,127	13,086	12,459	12,351	**12,591**								
1981	15,091	14,214	13,487	13,374	13,422	**12,970**							
1982	16,124	15,043	14,170	14,051	14,136	13,735	**13,204**						
1983	17,206	15,917	14,895	14,770	14,864	14,365	14,260	**14,029**					
1984	18,361	16,833	15,662	15,531	15,622	15,035	14,900	14,260	**15,189**				
1985	19,580	17,800	16,475	16,337	16,448	15,755	15,590	14,845	14,800	**15,769**			
1986		18,813	17,336	17,191	17,308	16,485	16,300	15,445	15,400	15,820	**16,407**		
1987			18,250	18,098	18,224	17,250	17,040	16,055	16,100	16,285	16,567	**16,567**	
1988				19,048	19,180	18,050	17,805	16,735	16,700	16,860	17,055	17,057	**17,460**
Difference From Actual** (Percent)													
1976	**10,002**												
1977	9.56	**10,525**											
1978	9.99	3.29	**11,232**										
1979	21.44	13.31	8.92	**10,880**									
1980	12.20	3.93	-1.05	-1.91	**12,591**								
1981	16.35	9.59	3.99	3.11	3.48	**12,970**							
1982	22.11	13.93	7.32	6.41	7.06	4.02	**13,204**						
1983	22.65	13.46	6.17	5.28	5.95	2.40	1.65	**14,029**					
1984	20.88	10.82	3.11	2.25	2.85	-1.01	-1.90	-6.12	**15,189**				
1985	24.17	12.88	4.48	3.60	4.31	-0.09	-1.14	-5.86	-6.14	**15,769**			
1986		14.66	5.66	4.78	5.49	0.48	-0.65	-5.86	-6.14	-3.58	**16,407**		
1987			10.16	9.24	10.00	4.12	2.86	-3.09	-2.82	-1.70	0.00	**16,567**	
1988				9.10	9.85	3.38	1.98	-4.15	-4.35	-3.44	-2.32	-2.31	**17,460**

* Actual demands are shown in bold.
** (Forecast - Actual) / Actual

Source: Data provided by TU Electric.

TABLE 3.3.4
Utility-Projected Peak Demand
HL&P

Forecast Year	Year Forecast Issued 1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Peak Demand* (MW)													
1976	**8,019**												
1977	8,709	**8,445**											
1978	9,218	9,206	**9,114**										
1979	9,603	9,747	9,686	**9,336**									
1980	9,950	10,387	10,322	10,150	**10,266**								
1981	10,400	10,943	10,780	10,550	10,455	**10,540**							
1982	11,000	11,425	11,291	10,900	10,914	10,971	**10,594**						
1983	11,450	11,700	11,800	11,325	11,142	11,517	11,348	**10,676**					
1984	12,300	12,150	12,275	11,925	11,314	12,052	11,947	11,689	**10,851**				
1985	12,700	12,675	12,925	12,425	11,802	12,494	12,228	12,091	11,501	**10,618**			
1986		13,225	13,500	12,900	12,096	12,900	12,656	12,430	11,906	10,712	**10,556**		
1987		13,775	14,075	13,325	12,486	13,275	13,084	12,863	12,291	10,771	9,834	**10,302**	
1988			14,725	13,775	12,926	13,675	13,635	13,205	12,702	11,190	9,899	10,515	**10,422**
Difference From Actual** (Percent)													
1976	**8,019**												
1977	3.13	**8,445**											
1978	1.14	1.01	**9,114**										
1979	2.86	4.40	3.75	**9,336**									
1980	-3.08	1.18	0.55	-1.13	**10,266**								
1981	-1.33	3.82	2.28	0.09	-0.81	**10,540**							
1982	3.83	7.84	6.58	2.89	3.02	3.56	**10,594**						
1983	7.25	9.59	10.53	6.08	4.36	7.88	6.29	**10,676**					
1984	13.35	11.97	13.12	9.90	4.27	11.07	10.10	7.72	**10,851**				
1985	19.61	19.37	21.73	17.02	11.15	17.67	15.16	13.87	8.32	**10,618**			
1986		25.28	27.89	22.21	14.59	22.21	19.89	17.75	12.79	1.48	**10,556**		
1987		33.71	36.62	29.34	21.20	28.86	27.00	24.86	19.31	4.55	-4.54	**10,302**	
1988			41.29	32.17	24.03	31.21	30.83	26.70	21.88	7.37	-5.02	0.89	**10,422**

* Actual demands are shown in bold.
** (Forecast - Actual) / Actual

Source: Data provided by HL&P.