LONG-TERM ELECTRIC PEAK DEMAND AND CAPACITY RESOURCE FORECAST FOR TEXAS, 1992

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ABSTRACT

More than adequate electrical generating capacity exists to meet demand in the short term in Texas. This offers high reliability, but also imposes the cost of plant investments. Despite these near-term capacity surpluses, a number of resource planning issues deserve prompt attention:

1. Alleviate transmission bottlenecks.
2. Moderate near-term rate increases to prevent widespread self-generation or bypass.
3. Scrutinize promotional activities.
4. Examine end-use energy efficiency programs.
5. Research solar and wind technologies.
6. Consider dispersed resources to defer investments in transmission and distribution system upgrades.

The **Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas 1992** is designed to provide information and recommendations to policy makers and others interested in the present and future status of the Texas electric power industry. Volume I of this two-volume report provides staff-recommended electricity demand projections for 13 of the state's largest generating utilities and a capacity resource plan for Texas. The economic outlook for Texas, fuel markets, cogeneration activity, demand-side management program impacts, environmental issues, and strategic rate design are highlighted. Substantial emphasis is placed on alternative power sources (particularly purchases from qualifying facilities) and energy efficiency to reduce the rate of growth of peak demand. The current report recognizes the end of the late 1980s economic recession in Texas, yet emphasizes efficiency improvements as the key to reliable and low-cost electrical services, environmental integrity, and increased economic growth.

Volume II summarizes the electricity demand forecasts, energy efficiency plans, and capacity resource plans developed by generating electric utilities and filed at the Commission in December 1991 (or later amended). The technical appendices provide a description of the staff's econometric electricity demand forecasting and resource planning system used to develop the load forecast contained in Volume I, and are available upon request.

LONG-TERM ELECTRIC PEAK DEMAND AND CAPACITY RESOURCE FORECAST FOR TEXAS 1992
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<u>CHAPTER ONE</u>

SUMMARY AND INTRODUCTION

Summary of Results

Sufficient electric energy resources are available in Texas to meet the state's energy needs through 2001. The proposed 1992 Statewide Electrical Energy Plan developed by the Electric Division staff of the Public Utility Commission of Texas (PUCT or the Commission) and presented in this volume as well as the separate electric load forecasts and capacity resource plans developed by the utilities in Texas (summarized in Volume II) indicate a reliable electric system for the next decade. Although the utility and staff forecasts are similar, the PUCT staff resource plan includes several proposals to improve system efficiency and reliability and reduce electrical energy costs.

Objectives of this Report

The Texas Public Utility Regulatory Act mandates the development of a biennial long-term statewide electrical energy forecast by the PUCT, which includes an analysis of utility resource plans.

This is the fifth energy plan which the PUCT staff has prepared and recommended for adoption. As in the 1984 through 1990 reports, this **Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas 1992** report is designed to satisfy a number of objectives. The materials presented in this report include:

1. Staff-prepared peak demand and sales forecasts for most of the 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. 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 as well as insight into key planning issues.

Statewide Planning Goals

Electric utilities in Texas should assure the maintenance of a reliable electrical system capable of operating at the lowest reasonable cost to consumers, while also considering public policy concerns. This section addresses two levels of goals: (1) the regulatory goals which will ensure that the utilities' resource planning processes are in the public interest; and (2) the resource planning goals for Texas which will guide individual utility plans.

Regulatory Planning Goals The Commission implements a regulatory process to protect the public interest through comprehensive planning and licensing, to assure that long-term plans are in the public interest. The adoption of a statewide electrical energy plan is an important part of that process.

The regulatory process should ensure that several basic conditions are maintained throughout the planning process. These conditions are stated here as Commission goals. The Commission will ensure that:

1. Relevant forecasting and resource planning data are provided periodically to the public and the Commission.
2. The public has the opportunity to participate in the development of the utilities' strategic planning goals.
3. Non-utility parties have the opportunity to participate in Commission workshops and proceedings related to resource planning.
4. The forecasting and planning methods employed by electric utilities fairly assess all reasonable resource alternatives, both demand-side and supply-side.
5. Regulatory impediments to the use of all economical resource alternatives are eliminated.

6. Utilities are provided the opportunity to make a reasonable profit on investments in all economical resource alternatives.
7. A reliable transmission system is maintained that enhances competition.
8. Competition among the suppliers of alternative generating resources and among the suppliers of end-use energy services is facilitated by regulators.
9. Utilities implement resource plans compatible with the statewide electrical energy plan.
10. Utilities operate existing facilities and implement programs efficiently to reduce the cost of electric services to the consumer.

Many of these goals are addressed in the current rules and practices of the Commission. Others are in the developmental phase as the PUCT staff prepares new rules on integrated resource planning.

Statewide Goals Texas is in the beginning stages of developing statewide goals for electric resource planning. Current practice, with few exceptions, has been for the staff to rely on the explicit or implicit planning goals of the utilities in the preparation of the statewide electrical energy plan. As often noted in previous reports, the utilities' goals have been primarily to meet future electrical needs through the acquisition of generating capacity. While some utilities have added capacity from qualifying cogenerators and others have embraced load management programs, most utilities have set forth objectives to minimize rates and risk through their own construction programs.

The staff's approach has resulted in the recommended deferral of some power plant additions in each report and an explicit demand-side management goal in the 1986 report. In that report, staff recommended that utilities achieve a savings of 12 percent of projected peak demand through conservation and load management programs. It is premature for the staff to recommend a comprehensive set of resource planning goals for Texas at this time. The primary focus of recent staff efforts has been in the development of an improved regulatory process that encompasses integrated resource planning.

The comprehensive development of statewide electrical energy planning goals in the future should be based on:

- the resource plans of individual utilities
- legislative mandates (i.e., PURA)
- the electricity-related planning goals of other government agencies

- the policy objectives and issues identified by the Commissioners

The staff is aware of the need for explicit resource planning goals for the State of Texas, which will be developed during the next biennial planning cycle.

Organization of Report

Article III, Section 16(b) of the Texas Public Utility Regulatory Act requires the Public Utility Commission of Texas to prepare a biennial long-term statewide electrical energy forecast. This staff report was prepared by the Electric Division and consists of two volumes and supporting technical appendices:

1. Volume I contains the staff's independent long-term peak demand forecast and capacity resource plan for Texas.
2. Volume II is a summary of the generating utilities' December 31, 1991 load and capacity resource forecast filings (as amended in 1992).
3. The Technical Appendices provide supporting documentation on the staff's forecasting and planning models.

Chapter Two of this volume 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 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 economic recession is now almost over, some sectors of the economy and regions of the state remain sluggish. Among regional forecasters, there is some disagreement over the future of the state's economy. The Texas electric power industry's generation mix is also discussed in Chapter Two.

Chapter Three reports the staff's independent electricity demand projections for the 13 largest generating electric utilities in Texas. In general, these projections are consistent with the forecasts prepared by the utilities.

Chapter Four highlights four special topics: strategic rate design as a resource option, compliance strategy for the 1990 Amendments to the Clean Air Act, target reserve margin, and the potential for increased power transactions. As utility resource planners have recently shown interest in using rate design as a planning tool, this chapter discusses both the rate design resource option and a summary of the pricing options under consideration in Texas. The passage of the 1990 amendments to the Clean Air Act may have far-reaching consequences for the state's generating utilities. Chapter Four summarizes how the utilities (e.g., which plants) in Texas are affected and what strategies are planned for compliance with the Act. The last two topics, target reserve margins and power transactions, are two important factors affecting the need for additional capacity, and hence the cost of electricity. The utilities were asked to submit reports of their studies on these two topics in the 1991 Load and Capacity Resource Forecast filing. The utility studies are summarized in Chapter Four.

Chapter Five describes the demand-side resources that will influence electricity consumption, including the federal appliance standards and conservation and load management programs. Descriptions of the utilities' energy efficiency goals and demand-side management programs are provided.

Chapter Six considers the supply-side resources, including the construction of new generating units, purchased power, cogeneration, and efficiency improvements. A recommended capacity resource plan is presented for each major service area, ERCOT, and for the state.

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

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 potential problems and opportunities, and to provide policy makers 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 1991. Utility Energy Efficiency Plans, required by the PUCT's Substantive Rules, were also filed by the utilities in December 1991. Together, these filings documented the industry's current projections and resource strategies. The utility filings, summarized in Volume II of this report, provide the basis for 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 sales projections presented in this volume. The end-use modeling system provides a validity check on the results obtained through the econometric models and contributes more detailed projections of energy consumption at the appliance or equipment end-use level. An end-use model is also used to derive peak demand forecasts from sales forecasts and estimate the impact of the federal appliance standards. Both econometric and end-use forecasting systems have been significantly enhanced and refined since the 1990 report.

Current resource planning and production costing projects, under contract with the Center for Energy Studies (CES) at The University of Texas at Austin, as well as staff models are used in the statewide electrical energy plan. In addition, ongoing programs designed to monitor power plant operations, generation and transmission construction projects, cogeneration activity, and the results of several staff-sponsored studies form the basis for much of the analysis of supply-side resource options presented in this volume.

Words of Caution

This report represents a 1992 work product of the PUCT staff. As an aid to understanding the relative positions of the staff and the major generating electric utilities, comparisons are made throughout this report with the data filed by regulated utilities in December 1991.[1] The December 1991 forecasts and capacity resource plans typically represent the most up-to-date utility data available. TU Electric and HL&P have provided the staff with updated forecasts and resource plans which were prepared during 1992. This information is referenced in many places to allow a comparison of these utilities' more recent projections with the staff findings.

It should be noted that the projections contained in this report are intended as a planning tool to indicate what the future demand and electricity sales are likely to be, assuming a

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1 On February 15, 1992, utilities were required to update their December filing with actual 1991 figures. Commission staff identifies and corrects problems with historic data on an ongoing basis.

continuation of recent trends in the many factors that influence electricity use. The PUCT staff maintains that neither this report nor any other forecasting or planning-related document preclude the use of the most up-to-date information available when called for in a regulatory proceeding. The staff remains committed to providing the most accurate and current information that staffing constraints will permit.

The Commission acknowledges that this plan is a staff product. Adoption of this report as the Statewide Electrical Energy Plan or as the electric forecast required in PURA in Section 16(f) does not constitute an adoption of facts or policies contained in this report for the purpose of conclusively determining the outcome of any issue in a contested proceeding or case before the Commission. The Commission agrees with the staff that the most up-to-date information available should be used in proceedings before the Commission.

The Demand for Electricity in Texas

Based on the staff's Econometric Electricity Demand Forecasting System, statewide peak demand is expected to grow at an annual rate of 2.4 percent over the next ten years, reaching 60,486 MW by the year 2001. The projected growth rate is substantially lower than the statewide peak demand experienced historically in Texas. From 1950 to 1970, peak demand in Texas increased at a relatively consistent 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 some areas of the state, with little change statewide. However, improvements in the Texas economy indicate load growth in all of the utilities' service areas.

The load projections developed by the staff assume a gradual recovery from the recession experienced in Texas during the last few years. Industrial diversification efforts within the state, a rebounding construction industry, and above-average population growth rates contribute to stronger electricity demand. While the state's economic performance is expected to improve, it is unlikely that Texas will repeat the high growth rates of the 1970s and early 1980s in the next decade.

Higher saturations of electrical equipment in the residential sector, particularly electric heating equipment, air conditioning, and electric cooking appliances are also expected to contribute to electricity demand growth. The impact of higher saturations of electrical equipment will be partially offset by greater equipment efficiencies from technological progress, utility-sponsored energy efficiency programs, and higher appliance standards (established in the National Appliance Energy Conservation Act of 1987 and the Energy Policy Act of 1992).

The following list provides the acronym and electric reliability council for the 13 largest utilities in Texas. Utilities in Texas are members of either the Electric Reliability Council of Texas (ERCOT), the Western Systems Coordinating Council (WSCC), or Southwest Power Pool (SPP).

Company	Acronym	Council
Texas Utilities Electric Company	TU Electric	ERCOT
Houston Lighting and Power Company	HL&P	ERCOT
Gulf States Utilities Company	GSU	SPP
Central Power and Light Company	CPL	ERCOT
City Public Service of San Antonio	CPS	ERCOT
Southwestern Public Service Company	SPS	SPP
Southwestern Electric Power Company	SWEPCO	SPP
Lower Colorado River Authority	LCRA	ERCOT
City of Austin Electric Utility	COA	ERCOT
West Texas Utilities Company	WTU	ERCOT
El Paso Electric Company	EPE	WSCC
Texas-New Mexico Power Company	TNP	ERCOT
Brazos Electric Power Cooperative	BEPC	ERCOT

To compare the peak demand projections contained in the 1990 report and this report, staff selected the forecast year 1999. For the major utilities in Texas, except GSU, SPS, and SWEPCO, staff's current peak demand projections are lower. The staff's forecast of 1999 peak demand as a whole for Texas is 2.3 percent (1,342 MW) higher than the 1999 peak projected in the 1990 load forecast report. Chapter Three includes the staff-proposed demand forecast for each utility.

TU Electric. The staff projects a peak demand of 21,317 MW for the TU Electric system in the year 2001. From 1991 to 2001, peak load and energy sales are forecast to increase at annual rates of 2.4 percent and 2.6 percent, respectively. Both the utility and the staff have lowered their demand forecasts for the TU Electric system since the 1990 forecast report.

HL&P. The company and the staff demand forecasts for the HL&P system are lower in this report than in the 1990 forecast report. Staff projects a 2.1 percent annual increase in peak load through the year 2001, with electricity sales growing at a 1.9 percent rate. HL&P's forecast shows a 1.8 percent annual increase in peak demand over the forecast period. Both forecasts indicate that the completed Robertson generating units (TNP One) of Texas-New Mexico Power Company (HL&P's largest wholesale customer) and increased self-generation activity among industrial energy consumers will limit wholesale and industrial sector growth. The staff forecasts 13,475 MW for 2001, while HL&P forecasts 13,031 MW.

GSU. GSU has generally experienced slow peak demand growth since 1980. A depressed economy in the GSU service area in the late 1980s caused a decrease in demand growth. Staff projections indicate slow but consistent growth in peak load and sales over the next ten years as the economy recovers. With an annual rate of growth of 1.5 percent and an expected Texas peak of 2,545 MW in 2001, GSU is the slowest-growing major utility in Texas. The company's non-Texas service area should experience slightly stronger growth rates. The current staff projection in annual demand growth is higher than the peak demand presented in the 1990 report, but is lower than GSU's current forecast for 1996-2001. The staff projects a 2,499 MW peak demand for GSU's Texas service area for 1999, whereas the previous forecast projected 2,431 MW for the same year. GSU's Texas forecast for 2001 is 2,603 MW.

CPL. Staff projects an annual growth rate of 2.0 percent in peak demand reaching 3,828 MW in the year 2001. This is lower than the staff forecast two years ago. In this forecast, CPL's projections are higher except for the years 1997 and 1998.

CPS. A strong 3.4 percent annual growth rate in peak load is forecast for the CPS system. Population growth and favorable rates will contribute to relatively high levels of growth, particularly in the residential and commercial sectors. Staff projects a peak demand of 3,918 MW in 2001, lower than CPS's projection of 4,046 MW for 2001.

SPS. Providing service in the Texas Panhandle region, SPS is forecast to have an annual growth rate in peak demand of 1.7 percent over the next ten years. The staff projections, very similar to the forecast prepared by the utility, include peak demand of 2,689 MW for the Texas service area in 2001. Both staff and the company have increased demand projections over their 1990 estimates.

SWEPCO. SWEPCO serves northeast Texas as well as portions of Louisiana and Arkansas. The Texas peak demand growth rate is expected to be 3.5 percent annually. The average annual growth rate of 3.5 percent is lower in this forecast than the 3.7 percent forecast in 1990.

LCRA. Peak demand and sales are expected to increase at annual rates of 1.9 percent and 2.7 percent, respectively. A less-optimistic (when compared to the 1990 projection) economic outlook for this central Texas service area influenced the lower projections in this report. The staff demand forecast for the year 2001 is 1,933 MW, while LCRA's projection is 1,891 MW.

COA. The summer peak load for the City of Austin is expected to rise from 1,457 MW in 1991 to about 1,877 MW in the year 2001. Projected annual growth in peak demand and total sales are 2.6 percent and 2.7 percent, respectively.

WTU. The staff projects a 2.6 percent annual growth rate for peak demand over the next ten years. This growth rate is higher than the rate projected in 1990.

EPE. In past reports, the staff projections have been considerably more pessimistic than the utility's forecasts. The current staff forecast, however, shows slightly higher rates of growth than EPE's forecast. In addition, the differences in the forecasts are smaller than they have been in the past. A 2.3 percent annual growth rate in Texas peak demand is projected by the staff, resulting in demand of 954 MW in 2001. The current staff projection is lower than the 1990 projection.

TNP. With annual growth rates for peak demand of 2.0 percent, the staff projection of Texas system peak demand in 2001 is 1,207 MW. The staff forecast is slightly higher than the utility's forecast.

BEPC. The staff projects that BEPC will have the highest growth rate in electricity demand over the next ten years among the major generating utilities in Texas. According to this projection, peak demand will increase at an annual rate of 4.1 percent, reaching 1,277 MW in the year 2001. The current projection is lower than the staff's 1990 projection because of the less optimistic economic outlook in BEPC's service area and Texas as a whole.

Figure 1.1 provides the actual peak demand for 1991 and staff-projected peak demand for 2001 for the major generating utilities in Texas.

Forecast Uncertainty

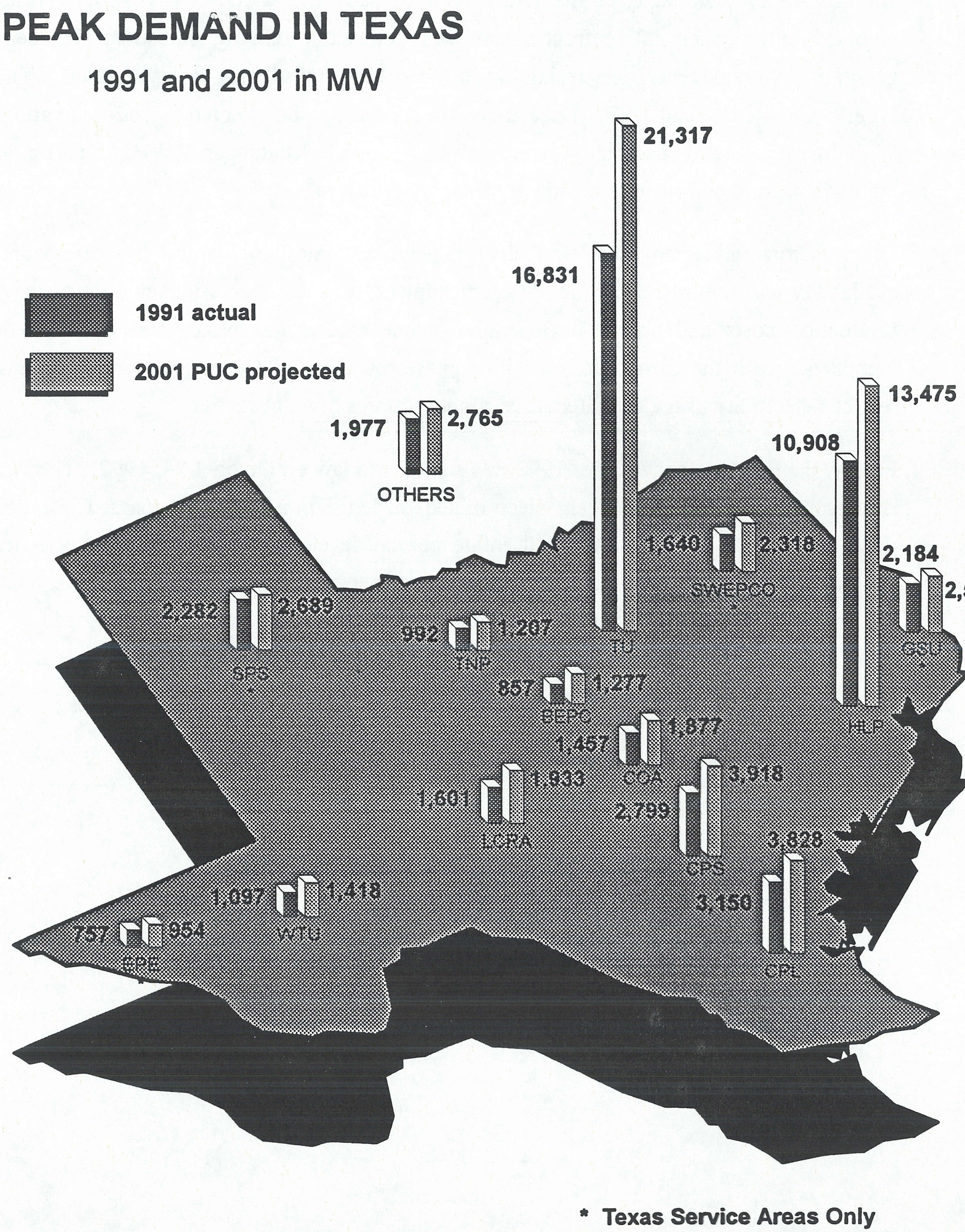
A considerable degree of uncertainty exists in any long-term forecast. In particular, there are several factors mentioned below that may add to the uncertainty in the current projections.

One source of uncertainty is the future level of self-generation activity. Many firms involved in the chemical, petrochemical, and petroleum refining industries find self-generation with cogeneration technologies more economical than utility service. The HL&P, GSU, CPL, and TNP service areas will continue to be affected by self-generation. With industrial retail electricity rates between 5 and 6 cents per KWH, the loss of industrial load to self-generation activity is highly probable.

Other factors influencing the variability of electricity sales are natural gas prices and availability and the impact of the 1990 amendments to the Clean Air Act on electricity production costs and pricing. Generally, higher natural gas prices and the cost of compliance with the Clean Air Act will increase the costs of utility production, making reduced electricity usage and alternative supply sources more attractive.

Finally, the Energy Policy Act of 1992 was signed into law on October 24, 1992. The Act is considered the most significant piece of federal legislation on energy passed in many years. In particular, this Act will influence the level of competition in electricity generation and will encourage more reliance on energy conservation and renewable resources. The full impact of this Act on the electric industry is yet to be determined.

FIGURE 1.1



PEAK DEMAND IN TEXAS
1991 and 2001 in MW
1991 actual
2001 PUC projected
1,977
2,765
OTHERS
16,831
21,317
TU
10,908
13,475
HLP
1,640
2,318
SWEPCO
*
2,184
2,545
GSU
*
2,282
2,689
SPS
*
992
1,207
TNP
857
1,277
BEPC
1,457
1,877
COA
1,601
1,933
LCRA
2,799
3,918
CPS
3,150
3,828
CPL
1,097
1,418
WTU
757
954
EPE
*
* Texas Service Areas Only

Electrical Energy Resources

In the development of resource plans, electric utilities must achieve a balance between cost and reliability. A highly reliable system can usually be achieved through greater investments in generation, transmission, and distribution systems. In the staff demand forecasts and target reserve margins, potential resources were compared on the basis of cost and reliability.

Target Reserve Margins Electric utilities select a level of system reliability which will satisfy the needs of their customers at a reasonable cost. They do this by selecting "target" reserve margins. Target reserve margins of a utility reflect the utility capacity needs, in excess of expected peak demand, required to maintain adequate reliability.

The PUCT staff generally supports the target reserve margins that the state's major generating utilities have established for planning purposes. ERCOT requires its member utilities to maintain a minimum 15 percent target reserve margin. Some ERCOT utilities use higher targets because of larger base load capacity units, increased dependence on non-utility generation, or uncertain performance of nuclear units during the initial years of operation. WSCC and SPP, two adjoining reliability councils that also serve parts of Texas, have established different methodologies for calculating reliability standards for their member utilities.

Staff analysis indicates that CPL and EPE target reserve margins could be reduced throughout the planning period without impairing reliability. Commission staff recommends reducing target reserve margins to about 15 percent and 20 percent, respectively, for these two utilities.

Alternative Resources Traditionally, the construction of electrical generating capacity has been the most economical means of meeting growth in demand. Electric utilities are now analyzing a variety of supply-side and demand-side options to meet the state's growing electrical energy needs. These include:

1. Construction of additional generating capacity.
2. Purchases from non-utility generators (qualifying cogenerators and small power producers).

3. Demand-side management (including conservation or energy efficiency programs, load management programs, and strategic rate design).
4. Purchases of power from other utilities.
5. Efficiency improvements in the existing generation, transmission, and distribution systems.
6. Reliance on alternative renewable resources.

Having developed and analyzed the resource plans for the utilities in Texas, the staff concludes that current utility plans can be improved by increased emphasis on purchased power transactions, demand-side management, and firm capacity purchases from cogenerators. Thus, opportunities exist for deferring planned capacity additions.

Cogeneration Cogeneration has developed very rapidly during the past few years. However, growth seems to be slowing. 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 the need for additional electric generating capacity in the state.

In Texas, 3,206 MW of cogeneration, approximately 45 percent of the 7,360 MW of cogeneration capacity operational in Texas, was under contract to provide firm capacity to utilities in 1991. The remaining cogeneration capacity provides energy on a non-firm basis, or satisfies on-site energy requirements. An additional 557 MW of cogeneration was under construction in 1991. With the commercial operation of nuclear units in Texas, the utilities involved -- TU Electric with Comanche Peak Steam Electric Station (CPSES) Unit 1 completed and Unit 2 which has an expected commercial operation of Summer 1993 and HL&P, the major partner in the completed South Texas Nuclear Project (STNP) Units 1 and 2 -- plan to reduce reliance on cogeneration during the forecast period.

In contrast, the staff's cogeneration forecasts are significantly higher. Staff expects the level of cogeneration to increase over the next 10 to 15 years, anticipating nearly all expiring firm cogeneration contracts to be renegotiated by HL&P, TU Electric, and TNP. Furthermore, the staff sees potential for other utilities to rely on more cogeneration to meet resource needs.

The staff projects 4,621 MW of cogeneration in the Texas resource mix by 2001 and 5,972 MW by 2006. These figures represent an annual growth of 3.7 percent and 4.2

percent, respectively, over the actual 1991 level of 3,206 MW. Given the potential impact of the Energy Policy Act of 1992, the staff cogeneration projections are moderate.

Demand-Side Management (DSM) During the second half of the 1980s, many utilities reduced their conservation program efforts and initiated aggressive promotional programs to encourage electrical energy use. Staff maintains that many promotional strategies are not in the long-term interest of utility customers and may conflict with other policy objectives.

The discussion of demand-side management and adjustments to the "raw" econometric forecasts are presented in Chapter Five. Total adjustments to peak demand are the sum of exogenous factors (primarily the gains from federal appliance efficiency legislation) and demand-side management (including conservation and load management programs and interruptible loads). The statewide peak demand is projected to be 6.7 percent lower in 2001 than it would be without the staff's demand-side management adjustments. This is equivalent to a 4,341 MW reduction in projected peak demand by the year 2001. Excluding active DSM programs (i.e., interruptible loads and other direct load control activities), staff projects a peak-demand reduction of 1,806 MW resulting from utility-sponsored passive DSM programs. In addition, exogenous factors will reduce peak demand by 289 MW in the year 2001.

Renewable Resources Prior to 1993, renewable resources had not received much attention from the electric utility industry in Texas. Consequently, while renewable resources, primarily hydroelectric power, account for 9 to 10 percent of domestic energy supplies in the United States, their share in Texas is about 1 percent. In 1991, Texas relied on 660 MW of renewable resources, of which 642 MW was hydroelectric power. Lubbock Power & Light is currently the only utility relying on renewable resources for future additions to capacity (10 MW fueled by municipal waste) over the next ten years. The PUCT staff has not yet thoroughly investigated the potential for alternative energy sources. As a result, the current Statewide Electrical Energy Plan does not include renewable resources beyond the level reported by utilities. Alternative resources will be addressed by staff in future planning activities.

Three utilities announced in early 1993 demonstration projects to evaluate renewable resources or high-efficiency equipment. Central and Southwest is undertaking a five-year program involving solar dish and photovoltaic units and a small wind farm in West Texas.

LCRA is planning small-scale solar distributed resource projects including installation of solar phototvoltaic units on-site at some existing substations, residential solar installations, and possibly some remote powering for water pumps. TU Electric announced a visitor-education "Energy Park" in the Dallas-Fort Worth area with the first phase to be a Renewable Energy and Emerging Technology Center examining technologies such as solar, wind, fuel cells, and electric and gas-powered vehicles, and testing high-efficiency lighting and HVAC equipment.

Deferral of Utility-Owned Capacity

Based on the analysis of resource options available, there are opportunities to defer utility-planned capacity additions. The recommended capacity deferrals beyond the year 2001 include the two 750-MW (lignite-fueled) Twin Oak Units 1 and 2 (TU Electric), and the 149-MW (lignite-fueled) TNP One Unit 3 (TNP). In addition, the PUCT staff is recommending deferral of unnamed capacity beyond the year 2001 totaling 1,242 MW (various utilities).

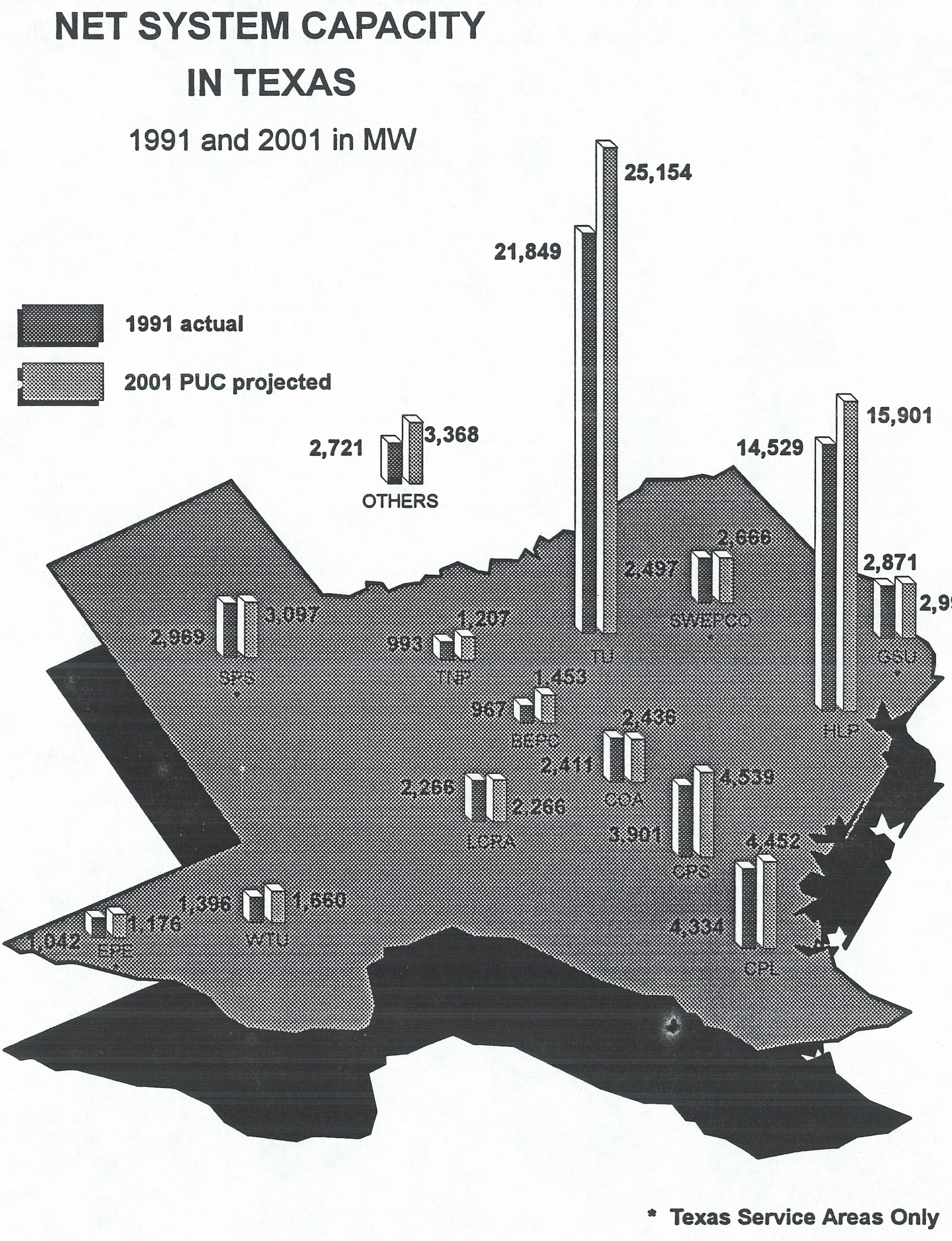
The staff also recommends that HL&P defer construction of the Malakoff Unit 1 to beyond year 2006. This lignite unit, with expected capacity of 645 MW, was last scheduled for serving system summer peak in 2005. While HL&P has a CCN for both units of Malakoff, a favorable natural gas market and negative environmental impacts of lignite-fueled units may defer construction of the Malakoff units indefinitely. Furthermore, staff recommends deferral of all coal and lignite units proposed by TU Electric, CPS, COA, and the utility companies of Central and South West Corporation (CPL, SWEPCO, WTU) planned for commercial operation early in the next century.

In total, staff recommends deferral of 2,891 MW of capacity beyond the year 2001 as compared to the utilities' December 1991 resource plans. If the forecast horizon is expanded to 2006, the staff-proposed Statewide Electrical Energy Plan includes 4,331 MW less additional capacity than the utilities' December 1991 resource plans.

For the purposes of this report, the PUCT staff does not recommend any changes to the utility-proposed on-line dates between 1992 and 1995. This includes TU Electric's Comanche Peak (CPSES) Unit 2 for 1,150 MW, HL&P's DuPont Steam Project for 158 MW, BEPC's two 104-MW combustion turbines, and some upgrades. The staff will continue to monitor the construction costs associated with these projects. A change in the status of these projects may be warranted if circumstances change. Figure 1.2 presents the actual 1991 net system capacity for the major generating utilities as well as staff-projected net system capacity for 2001.

The staff-recommended capacity additions considerably alter the amount of natural gas in the resource mix. In 1975, about 90 percent of the electricity generated by utilities in Texas was fueled with natural gas. In 1991, this percentage declined to 39 percent. Given the environmental benefits of natural gas and its availability, staff projects the share of natural gas for electricity generation by utilities to increase to about 42 percent by the

FIGURE 1.2


NET SYSTEM CAPACITY
IN TEXAS
1991 and 2001 in MW
1991 actual
2001 PUC projected
2,721
3,368
OTHERS
21,849
25,154
TU
2,497
2,666
SWEPCO
14,529
15,901
HLP
2,871
2,990
GSU
2,969
3,097
SPS
993
1,207
TNP
967
1,453
BEPC
2,411
2,436
COA
2,266
2,266
LCRA
3,901
4,539
CPS
4,334
4,452
CPL
1,042
1,176
EPE
1,396
1,660
WTU
* Texas Service Areas Only

end of 2001. This projection may not be realized if an unstable gas market emerges during the forecast horizon.

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 1975 and 1984 in nominal terms. Rates stabilized in 1985, but declined in 1986 with energy prices. Electricity prices generally stabilized in the late 1980s. As a result, the state average of electricity prices in Texas, when adjusted for inflation, has not grown since 1984. Only recently has the real (inflation-adjusted) average electricity price in Texas increased.

Rates charged by the electric utilities in Texas, however, vary considerably. COA, SPS, SWEPCO, and TU Electric charge the lowest residential rates, while EPE, GSU, and HL&P charge the highest. If commercial and industrial average electricity prices are also considered, SPS, SWEPCO and TU Electric (except for 1991) take the lead in offering low electricity prices overall. LCRA, which primarily provides wholesale power to cooperatives and municipally-owned utilities, charges some of the lowest rates in the state.

For most areas of the state, future electricity price increases are expected to grow at rates below the anticipated rate of general inflation. Utility construction programs have diminished. Also, successful utility diversification efforts and continued low fuel costs will limit the fuel component of rates, at least in the near term.

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.

As noted in the final reports of the Commission's Bulk Power Transmission Study and the Optimal State Electricity Supply in Texas Study, transmission constraints in some areas of the state may prevent the economical transmission of power. Without expansion of the transmission system, the need for power transfers could create reliability problems. The transmission system limitations may become more critical when FERC implements aspects of the Energy Policy Act of 1992 facilitating access to the transmission grid by exempt wholesale generators (EWGs).

Near-term price increases by some utilities in Texas, particularly those involved in nuclear power projects, cause concern. Increased rates, coupled with continued low natural gas prices, may result in the loss of industrial customers. Utilities burdened with high fixed costs may be at a competitive disadvantage. To cope with this fast changing environment, one should expect new and innovative approaches to be introduced by utilities over the next several years. Utilities in Texas and Wisconsin have already begun to construct cogeneration facilities to sell steam to industrial customers and provide electric power to their service areas.

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. Health concerns regarding high voltage transmission lines and nuclear power could affect system reliability. Environmental concerns may result in a different resource mix than that recommended by staff in this statewide electrical energy plan. Furthermore, efforts to reduce the nation's dependence upon foreign crude oil may result in higher electric rates and increased interest in energy conservation and reliance on alternative and domestically available resources.

The new Energy Policy Act of 1992 will likely create a competitive environment in the electricity market with new opportunities and problems. In addition to utility innovation, electricity consumers at the wholesale and retail level will review nontraditional resources in an increasingly competitive electricity market. Complacent utility planning during this period of excess capacity and greater competition may jeopardize an efficient, reliable electric power system in the future.

CHAPTER TWO

ECONOMIC OUTLOOK AND IMPACTS ON ELECTRIC ENERGY IN TEXAS

The 1988 and 1990 **Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas** indicated an end to the Texas recession. Those predictions appear to have been accurate. Although there are a few troubling signs, the Texas economy is slowly recovering from the downturn.

The Texas Economy

Two years ago, staff reported that growth in Texas was driven, not by the traditional mining and extraction (oil and gas production) sectors but, by the service sector. This continues to be the case.

However, sluggishness in the oil patch continues. As oil becomes less important to the Texas economy, the oil drilling industry will continue to contract. A number of analysts point to two major trends. One, oil and gas companies continue layoffs of workers as the nationwide recovery is not generating growth in the demand for oil and gas products. Two, oil companies are increasingly turning to fields overseas which appear to be more promising.

The manufacturing sector continues to provide little in the way of growth to the Texas economy. A partial explanation lies in the petroleum and coal sectors. Analysts predict a decline in employment in these sectors close to two percent annually through 1995. Somewhat surprising is the weakness in the computer industry. But this can, at least partially, be explained by intense competition in this sector.

Another area of manufacturing weakness is in the industrial machinery sector. Weak demand for farm and construction machinery as well as industrial machinery is to blame. The fabricated metals sector, tied to the industrial machinery sector as well as aircraft and auto industries, has suffered a reduction in employment recently.

The future of defense industries remains cloudy. Analysts suggest that layoffs in the manufacturing sector can be attributed to the aerospace and electronics industries. Some see prospects for the defense industry as grim at best. Congressional debates on military spending and research for space and high-tech projects may be ongoing, and clearly the outcome will have important impacts on the Texas economy. The early years of the forecast period will likely face economic change evolving from either the enactment of a national economic plan or other federal legislation. Hopefully, any military, defense, or research cutbacks in Texas will be countered by momentum to promote employment growth and job retraining.

As noted at the outset, the Texas economy continues to grow as a result of having diversified into sectors showing the most promise. Despite weakness in the manufacturing sector, there are some strong pockets of activity capable of yielding moderate job growth in Texas.

Some analysts note that across the U.S. there have been job losses in the trade, transportation, and financial sectors. However, these sectors and the service sector have expanded in Texas and should continue to improve over the next ten years. Even banking has shown some improvement, recording profits and a declining rate of job loss. Unlike in the rest of the country, in Texas, strong gains have been observed in the construction industry. The sector showing the strongest growth in Texas is health services.

Employment in business services began to pick up after the early 1992 declines. Employment in this sector is linked to trade and analysts see the North American Free Trade Agreement (NAFTA) reducing trade barriers between the U.S. and Mexico fortifying this sector.

A number of analysts see employment in the transportation, communications, and public utility sectors increasing. However, when this sector is disaggregated, most of the growth is predicted to come from the transportation sector, specifically from the trucking and airline industries. Communications firms are contracting. Public utility employment is expected to remain level across the U.S., although there have been significant layoffs and early retirement programs in Texas.

Consistent with the outlook of two years ago, at least in the short-term, continued recovery of the Texas economy is expected. Leading the way again will be the service, trade, and construction sectors. The manufacturing sector is expected to be somewhat sluggish.

Macroeconomic Factors Affecting Electricity Demand

The demand for electricity is a function of many variables. Among the most important, and those the staff monitor closely, are population, real per capita income, and non-agricultural employment. Most analysts agree that these variables can be powerful predictors of the demand for electricity. As an example, growth in real per capita income results in a higher standard of living and thus higher consumption of electricity.

Finally, it is hypothesized that changes in non-agricultural employment reflect changes in electricity consumption within the commercial and industrial sectors. When non-agricultural employment increases (decreases), we assume that the commercial and industrial sectors are experiencing growth (contraction). The growth (contraction) may manifest itself in either entry of new businesses (exit of existing businesses) or increased production (reduced production) or both.

The economic and demographic variables discussed above are used by the staff in a number of ways. These variables are used in the econometric, time-series, and end-use models employed by the staff to predict electricity demand. The staff relies on a number of forecasts of these variables in order to derive a final forecast of expected trends, which in turn shapes the forecast of electricity demand. The staff models and the projections used as inputs are discussed in detail in the technical appendices to this report and are available upon request.

The various sources for population, personal income, and non-agricultural employment factors 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. Forecasts of these variables for the period 1990 through 2001 are provided in Tables 2.1 through 2.3 for purposes of comparison.

Most illustrative are the differences in projections of growth provided by the various forecasting services. Noteworthy is the growth rate for the Texas population projected by WEFA in Table 2.1. They have reduced their projection of growth from 1.45 percent

TABLE 2.1

HISTORICAL VALUES AND PROJECTIONS OF POPULATION FOR THE STATE OF TEXAS

Year	Baylor (1)	DRI (2)	Wharton (3)	Texas Comptroller (4)
1981	14,846,257	14,846,257	14,846,257	14,846,257
1982	15,420,242	15,420,242	15,420,242	15,420,242
1983	15,838,005	15,838,005	15,838,005	15,838,005
1984	16,118,500	16,118,500	16,118,500	16,118,500
1985	16,415,760	16,415,760	16,415,760	16,415,760
1986	16,679,748	16,679,748	16,679,748	16,679,748
1987	16,782,494	16,782,494	16,782,494	16,782,494
1988	16,860,010	16,860,010	16,860,010	16,860,010
1989	17,013,787	17,013,787	17,013,787	17,013,787
1990	17,244,649	17,212,064	17,182,713	17,267,836
1991	17,446,480	17,472,297	17,365,158	17,567,341
1992	17,695,858	17,735,615	17,542,996	17,881,694
1993	17,947,231	18,007,920	17,700,307	18,141,097
1994	18,196,609	18,262,047	17,853,612	18,328,678
1995	18,502,845	18,494,984	18,008,920	18,495,149
1996	18,805,091	18,719,613	18,176,444	18,683,741
1997	19,103,347	18,917,775	18,348,975	18,889,606
1998	19,398,610	19,099,754	18,522,308	19,098,704
1999	19,689,884	19,269,416	18,697,242	19,303,761
2000	19,977,167	19,432,861	18,877,283	19,508,010
2001	20,259,463	19,600,169	19,063,132	19,710,643
Annual Growth Rate (1990-2001)	1.48%	1.19%	0.95%	1.21%

Sources:

(1) Texas Economic Forecast: M. Ray Perryman, Ph.D.; May 1992

(2) DRI/McGraw-Hill: Regional Information Service-Southern Focus; Third Quarter, 1991

(3) Regional Forecast Long-Term State Tables: The WEFA Group; Fall 1991

(4) Comptroller of Public Accounts for the State of Texas, Regional Economic Forecast, May 1992

TABLE 2.2

HISTORICAL VALUES AND PROJECTIONS OF NON-AGRICULTURAL EMPLOYMENT FOR THE STATE OF TEXAS

Year	Baylor (1)	DRI (2)	Wharton (3)	Texas Comptroller (4)
1981	6,179,895	6,179,895	6,179,895	6,179,895
1982	6,263,550	6,263,550	6,263,550	6,263,550
1983	6,193,569	6,193,569	6,193,569	6,193,569
1984	6,490,327	6,490,327	6,490,327	6,490,327
1985	6,662,322	6,662,322	6,662,322	6,662,322
1986	6,564,050	6,564,050	6,564,050	6,564,050
1987	6,516,415	6,516,415	6,516,415	6,516,415
1988	6,677,015	6,677,015	6,677,015	6,677,015
1989	6,839,346	6,839,346	6,839,346	6,839,346
1990	7,100,225	7,031,538	7,033,244	7,101,186
1991	7,166,719	7,127,830	7,112,844	7,168,896
1992	7,291,109	7,249,965	7,179,243	7,291,315
1993	7,453,796	7,421,613	7,310,742	7,451,839
1994	7,630,482	7,640,650	7,444,941	7,602,862
1995	7,791,569	7,827,009	7,560,840	7,734,583
1996	7,953,855	7,983,113	7,660,839	7,942,114
1997	8,116,342	8,074,193	7,739,339	8,161,348
1998	8,276,429	8,167,727	7,814,838	8,384,582
1999	8,435,016	8,278,126	7,901,237	8,602,015
2000	8,592,104	8,370,860	8,002,036	8,826,149
2001	8,747,691	8,468,072	8,110,636	9,045,383
Annual Growth Rate (1990-2001)	1.92%	1.70%	1.30%	2.22%

Sources:

(1) Texas Economic Forecast: M. Ray Perryman, Ph.D.; May 1992

(2) DRI/McGraw-Hill: Regional Information Service-Southern Focus; Third Quarter, 1991

(3) Regional Forecast Long-Term State Tables: The WEFA Group; Fall 1991

(4) Comptroller of Public Accounts for the State of Texas, Regional Economic Forecast, May 1992

TABLE 2.3

HISTORICAL VALUES AND PROJECTIONS OF PERSONAL INCOME ($1,000,000) FOR THE STATE OF TEXAS

	Baylor		DRI		Wharton		Texas Comptroller		
Year	Nominal Personal Income	Real Personal Income	Nominal Personal Income	Real Personal Income	Nominal Personal Income	Real Personal Income	Nominal Personal Income	Real Personal Income	Deflator
1981	164,222	234,905	164,222	234,905	164,222	234,905	164,222	234,905	0.699
1982	179,679	241,848	179,679	241,848	179,679	241,848	179,679	241,848	0.743
1983	188,884	246,274	188,884	246,274	188,884	246,274	188,884	246,274	0.767
1984	205,500	255,723	205,500	255,723	205,500	255,723	205,500	255,723	0.804
1985	220,714	266,683	220,714	266,683	220,714	266,683	220,714	266,683	0.828
1986	224,969	269,284	224,969	269,284	224,969	269,284	224,969	269,284	0.835
1987	230,467	270,803	230,467	270,803	230,467	270,803	230,467	270,803	0.851
1988	245,645	280,521	245,645	280,521	245,645	280,521	245,645	280,521	0.876
1989	263,613	288,760	263,613	288,760	263,613	288,760	263,613	288,760	0.913
1990	285,147	297,102	284,903	296,848	284,961	296,908	285,114	297,068	0.960
1991	300,942	300,942	297,263	297,263	297,863	297,863	300,815	300,815	1.000
1992	318,976	308,060	317,637	306,767	313,567	302,836	321,416	310,416	1.035
1993	341,246	316,179	340,608	315,588	336,972	312,219	346,117	320,693	1.079
1994	364,526	324,391	364,160	324,065	363,977	323,903	371,118	330,258	1.124
1995	391,354	335,705	388,884	333,587	392,083	336,331	383,419	328,899	1.166
1996	419,553	346,506	415,701	343,324	415,688	343,314	412,120	340,367	1.211
1997	449,726	356,569	443,381	351,538	439,193	348,218	444,222	352,205	1.261
1998	482,453	366,629	472,594	359,137	464,599	353,061	477,624	362,959	1.316
1999	516,499	376,190	503,959	367,057	493,605	359,515	512,525	373,296	1.373
2000	552,942	385,531	536,651	374,172	526,612	367,173	550,127	383,569	1.434
2001	591,176	393,881	571,814	380,981	563,220	375,254	589,729	392,917	1.501
*	6.85%	2.60%	6.54%	2.29%	6.39%	2.15%	6.83%	2.57%	

* Annual Growth Rate (1990-2001). Real Values are in 1991 dollars.

The deflator is constructed using the Consumer Price Index from DRI/McGraw-Hill.

Sources:

(1) Texas Economic Forecast: M. Ray Perryman, Ph.D.; May 1992

(2) DRI/McGraw-Hill: Regional Information Service-Southern Focus; Third Quarter, 1991

(3) Regional Forecast Long-Term State Tables: The WEFA Group; Fall 1991

(4) Comptroller of Public Accounts for the State of Texas, Regional Economic Forecast, May 1992

annually, reported two years ago, to 0.95 percent annually in their latest forecast. The Baylor projections of annual growth in population and real personal income are the most robust while the Comptroller's forecast of annual growth of 2.2 percent in non-agricultural employment is the strongest.

Comparison of Service Area Macroeconomic Variables

The staff's projections of growth for these three variables are found in Table 2.4. Staff's forecasts can be found between the high- and low-growth projections yielded by the various services discussed previously. For example, the staff projects growth in population on an annual basis of 1.21 percent compared with Baylor's 1.48 percent and WEFA's forecast of 0.95 percent. Non-agricultural employment follows the same pattern with the staff's prediction of 1.69 percent annual growth falling between the Comptroller's strong 2.2 percent and WEFA's 1.30 percent growth. Finally, Baylor's forecast of annual growth in real personal income of 2.60 percent and WEFA's prediction of 2.15 percent growth bracket the staff's projection of 2.25 percent growth.

In a state as large as Texas, there is considerable variation in expected growth in economic and demographic variables across the various service areas. Annual growth in population ranges from a low of 1.00 percent annually in the GSU service area to 1.40 percent in the CPL service area between 1990 and 2001. GSU's service area shows the lowest rate of growth in non-agricultural employment of 1.30 percent annually compared with a relatively robust 1.95 percent growth in the CPL service area. GSU shows the slowest growth in real personal income of 1.99 percent while the HL&P service area shows annual growth of 2.57 percent during the forecast period.

Weather

Weather can be a significant determinant in the consumption of electric power. This causal relationship between weather and power usage is primarily a result of the operation of temperature-sensitive equipment such as air conditioners, heat pumps, and space heaters to satisfy a comfort-conscious society. Electric utilities and regulators alike are concerned with the tracking of weather patterns and any anomalies in these patterns for the development of sales and load forecasts.

TABLE 2.4

STAFF-PROJECTED GROWTH RATES
SERVICE AREA ECONOMIC/DEMOGRAPHIC VARIABLES
1990/2001 (Percent)

Utility Service Area	Total Population	Non-Agricultural Employment	Nominal Personal Income	Real Personal Income
TU Electric	1.06	1.54	6.35	2.12
HL&P	1.45	1.90	6.82	2.57
GSU-TX	1.00	1.40	6.22	1.99
CPL	1.29	1.95	6.59	2.35
CPS	1.50	1.65	6.20	2.15
SPS-TX	1.21	1.65	6.37	2.13
SWEPCO-TX	1.06	1.52	6.27	2.03
LCRA	1.11	1.84	6.74	2.49
COA	1.42	1.94	6.79	2.54
WTU	1.39	1.78	6.43	2.19
EPE-TX	1.37	1.80	6.76	2.50
TNP	1.11	1.75	6.32	2.09
BEPC	1.11	1.87	6.57	2.33
TEXAS				
LEVEL (1990)	17,207,100	7,030,742	283,385*	295,266*
LEVEL (2001)	19,642,349	8,457,528	566,237*	377,265*
GROWTH RATE(%)	1.21	1.69	6.49	2.25
NON-TEXAS				
EPE-NTX	1.37	1.80	6.76	2.51
GSU-NTX	0.92	1.39	6.22	1.99
SWEPCO-NTX	0.79	1.34	6.02	1.79
SPS-NTX	1.21	1.65	6.37	2.13

* Millions of dollars

Sources:

DRI/McGraw Hill: Regional Information Service-Southern Focus; Third Quarter, 1991
Texas Economic Forecast: M. Ray Perryman, Ph.D.; May, 1992
U.S. Department of Commerce, Bureau of the Census; County Population Estimates, April 1990, January 1988, August, September, December, 1987
U.S. Bureau of Economic Analysis; Local Area Personal Income, Southeast Region 1982-1989
Oklahoma Employment Security Commission; County Employment And Wage Data; November 1989
Arkansas Employment Security Commission; Labor Force Statistics; May 1989; August 1983
New Mexico Department of Labor; Non-Agricultural Wage And Salary Employment; March 1990; May 1981
Louisiana Department of Labor; Employment And Wages; October 1987; November 1986; October 1983; November 1980; August 1977
Kansas Department of Labor; Covered Employment Data; August 1990

Background The vast majority of electric utilities obtain their weather information from the National Oceanic and Atmospheric Administration (NOAA). Although several types of weather data are furnished including dry bulb temperatures, precipitation, and minutes of sunshine, the data series of choice to determine electricity consumption are heating degree days (HDDs) and Cooling degree days (CDDs). The two basic formulas follow:

HDD = BASE TEMP - [(MAX TEMP + MIN TEMP) / 2]
CDD = [(MAX TEMP + MIN TEMP) / 2] - BASE TEMP
Where :

MAX TEMP = Daily Maximum Temperature
MIN TEMP = Daily Minimum Temperature
BASE TEMP = 65°F

Normal Weather While actual degree days series are used to estimate the weather responsiveness of electricity sales, some measure of expected or normal weather is needed to weather-normalize sales and to develop forecasts. The normal monthly HDDs and CDDs presented in Tables 2.5 and 2.6 employ a base temperature of 65°F. This is the base temperature used by NOAA and is presented here for comparative purposes. Other base temperatures are chosen by the utilities depending on their understanding of the temperature sensitivity of electric equipment. For example, CPS develops CDDs using a base temperature of 72°F while still using the 65°F base for HDDs.

Normal weather values are developed by calculating the average of recorded weather data over a specified period of time. The number of years of data used to develop normal degree days are generally based upon the availability of reliable data and the possible effects of changing long-term weather conditions. A 30-year average is most common following NOAA practice.

COA and HL&P are examples of utilities that use weather data from only one weather station. However, Texas is both a large and a climatically diverse state. In situations where the weather varies dramatically throughout a utility's service area, several weather sites are employed, aggregated, and weighted. For example, TNP weights degree days by the total number of customers for each of the company's divisions, while TU Electric uses the percentage of residential single-metered customers.

The SPS service area experiences the highest total number of HDDs for the normal year while the CPL service area has the lowest. Conversely, SPS experiences the lowest total number of CDDs in a year. SPS also has the lowest number of monthly normal CDDs during the summer. While CPL experiences the highest total yearly number of CDDs, several other utilities exhibit a similar (or higher) number of CDDs as CPL during the peak cooling months of July and August. One can also note from Tables 2.5 and 2.6 that the number of CDDs experienced annually by a Texas utility, with the exception of EPE, SPS, and WTU, is greater than the number of annual HDDs experienced by the same utility.

Weather Impacts on Electricity Demand

As a result of the large impact of weather on electricity use, weather normalization and energy forecasting have become two important activities performed by the utility industry. Weather normalization is critical to the load forecasting process. Without weather normalization, actual results and any trends may be misleading. Utilities and regulatory agencies are, therefore, concerned with keeping an account of weather patterns and also estimating the effects on sales due to abnormal weather.

Demand for electricity is assumed to be influenced by: (1) economic and demographic variables; and (2) weather. The influence of weather on electricity consumption is a consequence of increased use of temperature-sensitive equipment such as air conditioners, heat pumps, and space heaters. The effects of weather on electricity demand are most evident during the extremes of winter and summer. Abnormal weather events and their effects on electricity consumption tend to cancel each other out in the long run. Therefore, the price of electricity and other economic and demographic variables (non-weather variables) are considered to be the major determinants of long-run trends in electricity demand.

Geography

Developing models of weather's influence on electricity sales is a particular challenge for Texas electric utilities due to the assortment of conditions which influence weather variables. Second only to California, Texas has the most variety in physical setting, temperature, and annual rainfall. Altitudes in Texas range from sea level to over 8,700 feet. Average annual temperatures range from a high of over 70°F to a low of less than 55°F. Average annual rainfall ranges from more than 70 inches to less than 10 inches. In addition, differences in the types of soils and vegetation, annual sunshine, and humidity provide a variety of environmental

TABLE 2.5

AVERAGE NORMAL MONTHLY HEATING DEGREE DAYS

Month	TUE	HL&P	GSU	CPL	CPS	SPS	SWEPCO	LCRA	COA	WTU	EPE	TNP	BEPC
Jan	655	442	447	299	479	856	583	500	500	723	645	269	683
Feb	563	314	418	193	320	662	444	345	345	521	465	424	542
Mar	374	175	270	70	150	511	316	183	183	351	318	226	258
Apr	175	32	129	14	38	212	75	40	40	104	93	96	120
May	38	0	40	0	1	58	0	3	3	12	0	19	15
Jun	3	0	6	0	0	2	0	0	0	0	0	2	1
Jul	0	0	0	0	0	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	1	0	0	0
Sep	2	0	1	0	2	19	0	1	1	9	0	1	5
Oct	30	36	27	12	34	184	69	34	34	103	96	30	49
Nov	166	201	113	102	199	536	285	210	210	397	408	179	243
Dec	443	349	282	252	403	771	512	410	410	632	639	393	515
Total	2,449	1,549	1733	942	1,626	3,811	2284	1,726	1,726	2,853	2,664	1,639	2,431

Source:

Except for the HDDs of CPL, CPS, and LCRA, these data have been provided by the utilities in response to an informal Commission staff request in 1992. Because the degree day data provided by CPL, CPS, and LCRA were not developed using a 65 degree base, CPL and CPS numbers in this table are taken from the staff's data base for comparison purposes. COA degree days are used as proxy for LCRA.

NOTES:

TU: 1) Degree days data are weighted by each weather site's respective percentage of total Residential single metered customers.
2) HDDs based upon historical data from 1962-1991.

HL&P: 1) HDD data are for Intercontinental Airport, 1969-1991

SPS: 1) Weighted average based on Texas data.

COA: 1) HDD data are monthly average for Austin Municipal Airport, 1956-1991.

WTU: 1) Total system degree days weighted by number of customers per district.

EPE: 1) Data are for El Paso International Airport, 1962-1991.

TNP: 1) HDDs were derived from each of TNP's Texas Divisions based on billing cycles and are weighted by customer count per Division.

BEPC: 1) Based upon wholesale billing period.

TABLE 2.6

AVERAGE NORMAL MONTHLY COOLING DEGREE DAYS

Month	TUE	HL&P	GSU	CPL	CPS	SPS	SWEPCO	LCRA	COA	WTU	EPE	TNP	BEPC
Jan	1	20	26	33	7	0	0	7	7	0	0	1	1
Feb	2	20	19	47	16	0	8	16	16	0	0	6	3
Mar	14	51	47	138	70	7	31	62	62	34	11	26	24
Apr	59	143	110	260	169	29	105	159	159	112	51	93	81
May	165	307	220	430	346	136	253	307	307	272	218	251	216
Jun	371	468	385	537	509	347	444	474	474	508	474	426	460
Jul	584	561	489	602	603	447	574	577	577	626	543	547	605
Aug	593	546	496	616	611	389	570	590	590	590	474	565	633
Sep	511	402	480	484	432	185	363	419	419	356	273	450	456
Oct	233	181	322	296	212	34	140	205	205	122	52	206	174
Nov	66	54	156	135	62	0	12	55	55	12	0	49	39
Dec	13	8	70	52	14	0	0	11	11	0	0	12	3
Total	2,612	2,761	2,820	3,630	3,051	1,574	2,500	2,882	2,882	2,632	2,096	2,632	2,695

Source:

Except for the CDDs of CPL, CPS, and LCRA, these data have been provided by the utilities in response to an informal Commission staff request in 1992. Because the degree day data provided by CPL, CPS, and LCRA were not developed using a 65 degree base, CPL and CPS numbers in this table are taken from the staff's data base for comparison purposes. COA degree days are used as proxy for LCRA.

NOTES:

TU: 1) Degree days data are weighted by each weather site's respective percentage of total Residential single metered customers.
2) CDDs based upon historical data from 1962-1991.

HL&P: 1) CDD data are for Intercontinental Airport, 1969-1991

SPS: 1) Weighted average based on Texas data.

COA: 1) CDD data are monthly average for Austin Municipal Airport, 1956-1991.

WTU: 1) Total system degree days weighted by number of customers per district.

EPE: 1) Data are for El Paso International Airport, 1962-1991.

TNP: 1) CDDs were derived from each of TNP's Texas Divisions based on billing cycles and are weighted by customer count per Division.

BEPC: 1) Based upon wholesale billing period.

conditions. A utility in Texas can have several varying climate zones within its widespread service territory.

Heating Degree Days. HDDs serve as an index of the amount of heat required to maintain a comfortable indoor temperature level during the winter months. HDDs clearly reflect climatic conditions. For example, the Chicago area has a total of 6,100 annual normal HDDs while the HL&P service area has only 1,549. In Texas, where heating is relatively less important than in the northern and western United States, the range is from 3,811 per year for SPS to 942 per year for CPL.

The estimated coefficients obtained for HDDs and CDDs from regression equations reflect the effects of weather on the consumption of electricity. These coefficients are affected by factors such as relative humidity, appliance saturation, personal income, and availability of alternative energy sources. For example, everything else remaining the same, a lower level of appliance saturation would imply less responsiveness of sales to weather and hence smaller degree-day coefficients. As an illustration, one can look at the regression coefficients for the customer-weighted HDDs in the residential sales equations for HL&P and EPE in the staff's last forecast. The coefficients are 0.0007 and 0.0003, respectively. Because of EPE's low electric heat appliance saturation and lower personal income, EPE has a lower coefficient estimate than HL&P.

Cooling Degree Days. CDDs serve as an index of air conditioning requirements during the summer months. The greater the number of CDDs, the more energy is needed to maintain indoor temperatures at a comfortable level.

The electric utilities in Texas are summer peaking. Air conditioning is a primary contributor to peak load. On a statewide basis, cooling requirements comprise nearly 80% of residential and 50% of commercial peak demand. In addition, the peak demands for the residential and commercial classes often occur at the same time during the afternoon in the late summer months.

The summer weather in Texas causes high electricity demand. That the magnitude of the impact varies across utility service areas is evident upon comparison of the estimated regression coefficients for residential CDDs. Again, the results from the previous staff load forecast show the estimated regression coefficient for residential CDDs for HL&P to be 0.0008, while the same coefficient for EPE is only 0.0004. The service area of HL&P is characterized by long and extremely humid summers requiring the use of electricityintensive refrigerated air conditioning. By contrast, EPE's service area, in the high desert, has sunny but dry summers punctuated by brief but often heavy thunderstorms. Customers in this climate are able to use evaporative cooling, which is less energy-intensive than refrigerated air conditioning. Furthermore, HL&P currently has the highest saturation of refrigerated air conditioning statewide while EPE has the lowest.

Shoulder Months. Although the demand for electricity is clearly influenced by weather conditions, the extent of this influence changes throughout the year. Months with relatively more mild weather are called "shoulder months" and vary among the utility service areas. In Texas, the months of March, April, October, and November are typically the shoulder months. Although the weather in these months may be abnormal, the demand for electricity in these months is usually significantly less than demand during the winter and summer seasons.

Summary

The demand for electricity is determined by several variables including weather. HDDs and CDDs serve as separate indices for heating and cooling requirements. Weather normalization is considered to be a critical part of the load forecasting process. However, while the effect of weather is important, its maximum influence is during summer and winter. In the long term, the effects of abnormal weather events on electricity consumption tend to cancel out over time and are eclipsed by the influence of long-term trends in price and economic activity.

Electric Energy

Electricity has qualities that make it an especially attractive form of energy. It has a well-defined engineering structure while being both clean and flexible in terms of its end uses. Technological advances have created new opportunities for electric power use. In the past, these advances were generally associated with a similar increase in the consumption of electricity. While a continued increase in the use and application of electric energy is expected, future electricity consumption is expected to be partially offset by increases in efficiency brought about by programs such as the National Appliance Energy Conservation Act of 1987.

Electricity Consumption

Electricity consumption data may be analyzed by studying: (1) per capita electricity consumption (Table 2.7); and (2) average annual residential electricity consumption (Table 2.8). Per capita electricity consumption is defined as total electricity consumption divided by total population of the utility's service area. The annual growth in this variable reflects the change in electricity consumption over all customer classes. The 10-year change reflects the compounded growth rate in per capita electricity consumption.

Average annual residential electricity consumption is defined as total electricity consumption for the residential class divided by the number of residential customers. The growth rates in this variable reflect only the change in electricity consumption per residential customer. Growth rates in average residential electricity consumption tend to be lower than in per capita consumption. Per capita electricity consumption includes both commercial and industrial customers. While these customers may be smaller in number, they tend to be larger consumers of electricity and are more sensitive to changes in economic conditions. In addition, conservation programs are anticipated to have an especially significant impact on residential electricity consumption in the future.

As shown in Table 2.7, the changes in per capita electricity consumption between 1981 and 1991 vary a great deal among Texas electric utilities. Per capita electricity consumption in the areas served by HL&P and TNP experienced a reduction while GSU and CPL experienced only moderate increases. These four service areas were impacted more than other areas of the state by the decrease in oil prices and the ensuing Texas economic recession. A contributing factor was the loss of industrial load that occurred from self-generation. Several service areas, led by COA and CPS, showed significant economic growth between 1981 and 1991. These service areas were less affected by the economic recession and loss of industrial load over the last few years.

The projections from 1991 to 2001 in Table 2.7 show an increase in per capita electricity consumption for 10 of the 11 utilities providing data. HL&P is the only utility expected to show a reduction, albeit by a very small magnitude, during the forecast period. Table 2.8 presents average annual residential electricity consumption and annual growth rates. CPS experienced the highest annual growth in average residential consumption over the years 1981 through 1991. This growth rate is expected to slow down considerably in the next ten years but still CPS is expected to remain one of the faster growing utilities (relative to other Texas utilities) in terms of average residential electricity consumption. HL&P exhibited the smallest increase in average residential consumption over the 1981 through 1991 period and is expected to show a reduction over the next decade.

TABLE 2.7

ANNUAL PER CAPITA ELECTRICITY CONSUMPTION (KWH)

Electric Utility	1981	1991	Ten-Year Change 1981-1991 (Percent)	Annual Change 1981-1991 (Percent)	2001	Ten-Year Change 1991-2001 (Percent)	Annual Change 1991-2001 (Percent)
TU	13,031	14,955	14.76%	1.39%	16,840	12.60%	1.19%
HL&P	17,370	15,876	-8.60%	-0.90%	15,855	-0.13%	-0.01%
GSU	16,621	17,458	5.04%	0.49%	18,216	4.34%	0.43%
CPL	8,772	9,139	4.18%	0.41%	9,769	6.89%	0.67%
CPS	7,759	9,911	27.74%	2.48%	12,650	27.64%	2.47%
SPS	NA	17,100	NA	NA	NA	NA	NA
SWEPCO	14,579	18,155	24.53%	2.22%	22,315	22.91%	2.08%
LCRA	NA	NA	NA	NA	NA	NA	NA
COA	6,340	8,194	29.24%	2.60%	9,598	17.13%	1.59%
WTU	8,270	10,084	21.93%	2.00%	10,856	7.66%	0.74%
EPE	5,607	6,193	10.45%	1.00%	6,630	7.06%	0.68%
TNP	11,573	10,540	-8.93%	-0.93%	10,811	2.57%	0.25%
BEPC	6,020	8,016	33.16%	2.90%	9,294	15.94%	1.49%

SOURCE: These data were provided by the utilities in response to an informal Commission staff request in 1992.

NOTES

GSU: Total Texas retail sales divided by Texas service area population. Service area is based on the Beaumont, Port Arthur, metropolitan areas and the sum of five counties north of Houston.

SWEPCO: Calculated by dividing total Texas KWH sold by estimated population served by SWEPCO in Texas.

COA: City of Austin Electric Utility system sales divided by Austin MSA population.

WTU: The population values used are BEA estimates of the counties served and forecast based on those values. The sales values are 1981 actuals, 1991 estimates and 2001 forecast of on-system sales.

EPE: Total Texas retail sales divided by El Paso MSA population.

BEPC: Based upon number of residential meters and 1983 and 1988 per capita survey information.

TABLE 2.8

AVERAGE ANNUAL RESIDENTIAL ELECTRICITY CONSUMPTION (MWH Per Customer)

Year	TU	HL&P	GSU	CPL	CPS	SPS	SWEPCO	COA	WTU	EPE	TNP
1981	13.41	13.59	12.79	9.92	9.33	7.40	10.59	9.27	8.72	5.62	11.37
1982	13.74	13.50	13.02	10.11	9.77	7.60	10.91	10.00	9.11	5.66	11.50
1983	13.30	11.76	12.10	9.49	9.20	7.79	10.45	9.41	8.95	5.63	10.69
1984	14.05	12.62	13.00	10.01	9.70	7.85	10.81	10.12	9.22	5.54	11.49
1985	14.11	12.96	12.80	10.32	10.01	8.00	11.14	10.32	9.18	5.54	11.68
1986	13.70	12.68	12.73	10.34	10.12	7.92	11.09	9.99	9.11	5.54	11.81
1987	14.05	12.81	12.82	10.37	10.19	8.12	11.30	9.73	9.33	5.69	12.01
1988	14.42	13.16	13.03	10.92	10.86	8.33	11.43	9.91	9.51	5.87	12.47
1989	14.62	13.27	13.23	11.46	11.42	8.50	11.28	10.17	9.72	6.00	12.70
1990	14.90	13.85	13.80	11.45	11.35	8.55	11.88	10.30	9.56	5.97	13.12
1991	14.91	13.79	13.79	11.49	11.57	8.59	12.00	10.06	9.71	5.94	13.06
1992	14.07	13.39	13.39	11.14	11.72	NA	12.01	10.10	9.37	5.98	13.13
1993	15.65	13.29	13.51	11.52	11.93	NA	12.13	10.07	10.46	5.97	13.21
1994	15.35	13.26	13.61	11.70	12.09	NA	12.22	10.06	10.69	6.02	13.29
1995	15.73	13.24	13.67	11.82	12.19	NA	12.30	10.05	10.77	6.10	13.38
1996	15.84	13.08	13.74	11.90	12.25	NA	12.38	10.06	10.81	6.18	13.48
1997	16.03	12.98	13.84	11.99	12.31	NA	12.42	10.05	10.82	6.25	13.56
1998	16.22	12.90	13.89	12.09	12.38	NA	12.49	10.06	10.83	6.31	13.64
1999	16.45	12.75	13.94	12.17	12.45	NA	12.55	10.07	10.83	6.36	13.72
2000	16.69	12.70	13.97	12.20	12.52	NA	12.62	10.11	10.84	6.42	13.82
2001	16.92	12.69	13.95	12.25	12.60	NA	12.70	10.10	10.85	6.42	13.94
Annual Growth (Percent)											
81-91	1.07%	0.15%	0.76%	1.48%	2.18%	1.50%	1.26%	0.82%	1.08%	0.56%	1.40%
91-01	1.27%	-0.83%	0.12%	0.64%	0.86%	NA	0.57%	0.04%	1.12%	0.78%	0.65%
81-01	1.17%	-0.34%	0.44%	1.06%	1.51%	NA	0.91%	0.43%	1.10%	0.67%	1.02%

SOURCE: These data were provided by the utilities in response to an informal Commission staff request in 1992.

NOTES:
LCRA is not included because retail sales constitute a minor portion of its total sales.
BEPC is not included because it is a wholesale supplier.

HL&P: Projected values are adjusted for the effects of appliance standards and other conservation activities.

GSU: Historical and projected data are total system. Projected values are adjusted for the effects of appliance standards and other conservation activities. Projected data is derived by dividing the total annual residential sales (MWH) by the average number of residential customers.

COA: Historical values from 1981 to 1990 are not weather adjusted. Projected data from 1991-2001.

EPE: Projected values are adjusted for effects of conservation activities.

EPE, which currently has the lowest residential electricity consumption rate in the state, is anticipated to show a significant increase in the next ten years, but still remain the lowest in this category. Similarly, TU Electric, the utility having the highest average residential electricity consumption in Texas currently, is expected to remain the highest by growing the fastest in the next ten years. Overall, a comparison between Tables 2.7 and 2.8 reveals that, on average, annual average residential electricity consumption increased more slowly than annual per capita electricity consumption in Texas. A similar trend is expected over the next decade.

Trends in Electricity Prices Tables 2.9, 2.10, and 2.11 show the historical prices for residential, commercial, and industrial classes, respectively, from 1975 through 1991 for 11 major utilities in the state. The average prices are calculated by dividing each utility's total class revenues by total class sales. These values, therefore, represent average electricity prices rather than actual rates. During the period from 1975 to 1984, electricity prices in Texas steadily increased to the point where the 1984 price for residential, commercial, and industrial classes was twice that of the 1975 price. This increase can largely be attributed to generating capacity additions and increases in fuel prices. In the 1984-1985 period, fuel prices, and hence electricity prices, began to stabilize, but only temporarily. The Texas economic recession began to clearly manifest itself in 1986. With the price of natural gas taking a nose dive, average electricity prices went down too, as reflected in Tables 2.9 through 2.11. In one case the average price fell by as much as 25 percent in one year. From 1987 through the end of the 80s, prices generally stabilized. However, different regions in Texas and, therefore, different utilities, have recovered from the economic downturn to varying extents and in some cases prices have continued to decrease. More recently, plant additions to various utilities' resource bases have resulted in increases in electricity prices.

One can also look at Tables 2.9 through 2.11 to study how utilities are ranked in terms of electricity prices. EPE has the highest prices in all three customer classes for many years in the 1980s and the beginning of the 1990s. Indeed, EPE is the only utility whose prices went above ten cents per KWH for residential rates. This is a result of EPE's reliance upon natural gas and the Palo Verde nuclear generating station for most of its power. At the other end of the spectrum, SWEPCO had the lowest average commercial price. COA, SWEPCO, and TU Electric are among the electric utilities who have been offering low residential prices. The lowest average industrial prices in Texas over the 1980s were consistently offered by SWEPCO and TU Electric with GSU often among the "lowest-priced" group followed closely by SPS for most years. Since the beginning of the 1990s, SPS has had the lowest average residential and industrial prices among the major Texas utilities. Combining average residential, commercial, and industrial electricity prices for the last few years in Texas, SPS, SWEPCO, and TU Electric still rank lowest, although for lower residential and commercial rates in 1991, TU Electric is replaced by other utilities.

Another method for examining residential prices is to determine the annual average residential rate for 1,000 KWH of usage. In Table 2.12, the average residential rates based on 1,000 KWH are expressed in current (or nominal) terms. Table 2.13 presents the same prices in real terms (1991 dollars), using a Texas Consumer Price Index (CPI) as the deflator. The Texas average in both tables is a weighted average, based upon the number of residential customers for each utility.

Electricity prices for 1,000 KWH will vary according to the design of the rates. In addition, actual annual consumption will vary from month to month during a typical year dependent upon such factors as climate, income, electricity prices, and the stock of appliances within the service territory.

While a direct comparison between Tables 2.12 and 2.13 with price per KWH (Table 2.9) may not be appropriate due to differing rate designs, many utilities exhibit similar relative rankings. EPE, GSU, and HL&P have the highest average residential prices in both sets of tables, while COA, SWEPCO and TU Electric are among the lowest. Care should be taken when looking at 10-year averages. Current conditions may be masked. For example, SPS over the 10-year period exhibits a high average rate; but recently, their rates are among the lowest.

In Table 2.12, the effect of inflation on weighted average Texas residential prices between 1977 and 1991 is quite evident. Nominal electricity prices for 1,000 KWH more than doubled from $37.09 to $78.55. However, when the effects of inflation are removed, as in Table 2.13, a direct comparison may be made as to how a particular utility's prices evolved during changing economic conditions. When electricity prices are adjusted for changes in the Consumer Price Index, we see that although the prices, even in real terms, sky rocketed in 1981 and 1982, they came down in the 1986-1987 recession period. As a result, the current average Texas residential bill is not really any higher than the bill in 1977 when adjusted for inflation. Several utilities have reduced the real bill for electricity

TABLE 2.9

AVERAGE RESIDENTIAL ELECTRICITY PRICES

(Cents per KWH)

Electric Utility	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
TU	2.57	3.04	3.32	3.57	3.87	4.42	5.59	6.21	6.48	6.81	6.89	6.22	6.24	6.37	6.42	6.60	7.17
HL&P	2.38	2.83	3.09	3.36	4.09	5.00	6.29	7.76	8.25	8.14	8.30	7.32	7.34	7.53	7.97	8.30	8.63
GSU (1)	2.69	3.02	3.39	3.68	4.09	4.67	5.86	6.84	7.74	7.89	9.49	7.11	7.07	7.41	7.54	7.69	8.19
CPL	3.96	4.44	4.76	4.84	4.99	5.69	6.25	7.09	7.47	7.49	6.88	6.02	6.18	5.97	5.93	6.90	7.96
CPS	3.79	4.22	4.60	4.39	4.52	4.99	5.50	6.75	7.00	7.52	7.61	6.92	6.58	6.54	6.59	6.55	6.45
SPS (1)	3.28	3.85	4.21	4.44	4.77	5.70	6.42	7.16	7.67	7.50	7.15	7.32	7.27	6.92	6.71	6.18	6.22
SWEPCO (1)	2.51	2.94	3.32	3.46	3.47	3.71	4.21	5.37	6.63	7.13	6.79	6.63	6.51	6.73	6.65	6.60	6.62
COA	3.08	4.38	3.27	5.50	4.81	5.26	5.41	5.79	6.17	6.64	6.07	6.16	5.68	6.89	6.55	6.96	6.52
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	6.43	7.81	8.30	8.12	7.79
EPE (1)	3.54	3.92	3.99	4.93	5.85	6.73	8.51	8.92	10.18	10.43	9.90	9.83	8.65	8.72	8.96	9.14	9.45
TNP	2.65	3.06	3.42	3.60	4.05	4.74	6.26	7.49	7.93	7.96	8.12	6.89	7.23	7.23	7.27	7.52	8.73
U.S.A.	NA	NA	4.09	4.36	4.64	5.36	6.20	6.86	7.18	7.54	7.79	7.41	7.41	7.49	7.64	7.80	8.10

SOURCE:

These data were provided by the utilities in response to an informal Commission staff request in 1992.

Data on U.S.A. is from U.S. Department of Energy, Electric Power Monthly, Energy Information Administration, December 1991, page 73.

NOTES:

LCRA is not included because retail sales constitute a minor portion of total sales.
BEPC is not included because it is a wholesale supplier.

(1) Texas Only.

SPS: 1975-1979 is total company, while 1980 to the present is Texas only.

WTU: Total residential revenue divided by total residential energy.

TABLE 2.10

AVERAGE COMMERCIAL ELECTRICITY PRICES

(Cents per KWH)

Electric Utility	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
TU	2.28	2.68	3.04	3.35	3.68	4.02	5.06	5.53	5.75	5.93	5.94	5.30	5.23	5.38	5.42	5.39	6.07
HL&P	2.08	2.63	2.91	3.20	3.97	4.68	5.73	6.98	7.36	7.21	7.23	6.18	6.17	6.38	6.70	6.88	7.06
GSU (1)	2.48	2.76	3.16	3.39	3.67	4.14	5.04	5.88	6.35	6.42	7.77	6.72	7.04	7.19	7.13	7.25	7.45
CPL	3.62	4.08	4.37	4.52	4.69	5.93	6.57	7.39	7.62	7.73	7.09	6.81	6.45	6.26	6.22	7.10	8.15
CPS	3.83	4.32	4.60	4.40	4.51	4.84	5.24	6.51	6.86	7.08	7.27	6.45	6.15	5.99	6.09	6.05	5.98
SPS (1)	2.55	3.16	3.56	3.80	4.11	4.96	5.85	6.36	6.88	6.90	6.53	6.86	7.02	6.58	6.31	5.48	5.47
SWEPCO (1)	2.31	2.73	3.08	3.23	3.23	3.48	3.68	4.53	5.44	5.78	5.39	5.19	5.11	5.33	5.28	5.16	5.23
COA	2.45	3.70	2.92	4.69	5.03	5.46	5.83	6.52	6.85	6.18	6.79	7.28	5.87	6.70	6.28	6.47	6.22
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	5.16	6.03	6.45	6.15	5.88
EPE (1)	3.15	3.62	3.69	4.27	4.89	5.94	7.53	7.99	9.12	9.25	8.61	8.44	7.35	7.34	7.67	7.96	8.41
TNP	2.60	3.06	3.43	3.70	4.10	4.67	6.03	7.17	7.33	7.30	7.44	6.08	6.52	6.54	6.58	6.76	7.90
U.S.A.	NA	NA	4.09	4.36	4.68	5.48	6.29	6.86	7.02	7.33	7.47	7.13	7.01	7.07	7.21	7.30	7.20

SOURCE:

These data were provided by the utilities in response to an informal Commission staff request in 1992.

Data on U.S.A. is from U.S. Department of Energy, Electric Power Monthly, Energy Information Administration, December 1991, page 73.

NOTES:

LCRA is not included because retail sales constitute a minor portion of total sales.
BEPC is not included because it is a wholesale supplier.

(1) Texas Only.

SPS: 1975-1979 is total company, while 1980 to the present is Texas only.

WTU: Total commercial revenue divided by total commercial energy.

EPE: Includes commercial and small industrial revenues/sales.

TABLE 2.11

AVERAGE INDUSTRIAL ELECTRICITY PRICES

(Cents per KWH)

Electric Utility	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
TU	1.41	1.71	1.98	2.27	2.43	2.75	3.67	4.25	4.32	4.39	4.47	3.92	3.74	3.82	3.86	3.71	4.00
HL&P	1.23	1.61	1.87	2.13	2.70	3.21	4.11	5.16	5.22	5.06	4.94	3.91	3.62	3.75	3.87	4.03	4.11
GSU (1)	1.31	1.54	1.94	2.18	2.53	2.85	3.42	3.84	3.83	3.84	4.93	3.89	4.06	3.93	3.97	3.98	4.02
CPL	2.49	3.00	3.14	3.27	3.40	4.24	4.82	5.63	5.87	5.92	5.59	5.03	4.98	4.38	4.16	4.12	4.07
CPS	2.71	3.07	3.27	3.04	3.17	3.74	4.12	5.20	5.60	5.89	6.04	5.21	4.95	4.75	4.73	4.66	4.52
SPS (1)	1.49	1.90	2.44	2.67	3.00	3.47	3.85	4.39	4.81	4.74	4.38	4.48	4.43	4.30	3.99	3.57	3.49
SWEPCO (1)	1.35	1.79	2.16	2.33	2.30	2.49	2.64	3.48	4.22	4.45	4.07	3.94	3.72	3.93	3.91	3.80	3.88
COA	NA	NA	NA	3.94	4.29	4.82	5.27	6.19	6.55	7.27	6.34	6.76	5.14	5.52	4.74	4.83	4.75
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	3.90	4.45	4.92	4.66	4.42
EPE (1)	2.29	2.70	2.86	3.43	3.87	4.52	5.51	6.05	6.71	6.73	6.27	6.26	5.32	5.07	5.24	5.39	5.27
TNP	1.25	1.65	2.01	2.28	2.84	3.38	4.00	4.97	5.13	5.20	5.35	4.13	4.65	4.54	4.54	4.54	5.02
U.S.A.	NA	NA	2.50	2.79	3.05	3.69	4.29	4.95	4.96	5.04	5.16	4.90	4.72	4.62	4.72	4.80	4.90

SOURCE:

These data were provided by the utilities in response to an informal Commission staff request in 1992.

Data on U.S.A. is from U.S. Department of Energy, Electric Power Monthly, Energy Information Administration, December 1991, page 73.

NOTES:

LCRA is not included because retail sales constitute a minor portion of total sales.
BEPC is not included because it is a wholesale supplier.

(1) Texas Only.

CPL: CPL includes large and small industrial classes and excludes cotton gin and large and small irrigation.

SPS: 1975-1979 is total company, while 1980 to the present is Texas only.

WTU: Total industrial revenue divided by total industrial energy.

EPE: Includes all large commercial and industrial revenues/sales.

TABLE 2.12

AVERAGE RESIDENTIAL RATES

(Nominal dollars per 1,000 KWH usage)

Year	TU	HL&P	GSU	CPL	CPS	SPS	SWEPCO	COA	WTU	EPE	TNP	Texas Avg.
1977	35.51	30.89	34.15	47.61	44.46	39.03	35.11	46.85	38.59	40.39	34.12	37.09
1978	37.90	33.76	37.49	48.42	42.09	44.62	36.55	46.76	40.41	49.25	36.07	39.38
1979	41.66	41.03	41.53	49.87	43.48	51.18	36.31	46.23	42.46	55.68	40.44	43.37
1980	47.64	50.51	48.09	56.86	47.78	55.76	38.86	49.72	44.27	64.89	48.19	49.88
1981	60.37	62.69	58.32	62.53	51.92	62.58	43.36	51.14	51.80	81.77	62.43	60.13
1982	66.27	78.03	67.89	71.63	63.96	69.31	50.01	54.09	64.61	86.33	74.75	69.55
1983	68.50	83.02	75.09	75.10	67.52	76.44	62.63	58.82	71.50	96.82	77.92	73.96
1984	71.52	83.46	78.14	76.12	72.41	75.33	70.38	65.85	76.29	98.37	79.16	76.31
1985	70.17	88.25	96.84	70.31	75.25	75.06	68.43	58.93	77.53	93.22	81.62	77.05
1986	65.76	81.84	76.09	67.14	67.05	74.66	64.85	58.83	69.93	92.21	68.14	71.20
1987	63.58	78.41	72.19	62.57	64.03	73.51	64.43	55.17	61.67	82.14	62.50	67.83
1988	65.94	78.71	76.31	62.57	63.81	73.51	64.00	66.61	78.42	82.08	70.45	70.12
1989	66.52	81.94	77.83	62.83	64.23	68.82	65.08	63.46	80.71	86.46	72.97	71.20
1990	67.78	85.70	79.40	73.15	63.72	65.87	65.10	66.05	82.77	88.47	75.57	73.70
1991	74.14	89.17	84.50	86.28	62.87	64.60	70.55	65.19	80.31	90.42	87.56	78.55
10-yr Avg.	68.02	82.85	78.43	70.77	66.48	71.71	64.55	61.30	74.37	89.65	75.06	72.95

NOTES:

Source: PUC Bill Survey

1) LCRA and BEPC are excluded since these utilities do not directly sell to residential customers.

2) The Texas average is a weighted average based on the number of residential customers.
The number of Texas customers is used for multi-jursidictional utilities.
The Texas number of customers was taken from the Public Utility Commission of Texas "Load and Capacity Resource Forecast Filing, 1991, Request 3.01".

TABLE 2.13

AVERAGE RESIDENTIAL RATES

(Real 1991 dollars per 1,000 KWH usage)

Year	TU	HL&P	GSU	CPL	CPS	SPS	SWEPCO	COA	WTU	EPE	TNP	Texas Avg.
1977	78.10	67.94	75.11	104.72	97.79	85.85	77.22	103.05	84.88	88.84	75.05	81.57
1978	77.05	68.63	76.22	98.44	85.57	90.71	74.30	95.06	82.15	100.12	73.33	80.07
1979	75.56	74.42	75.32	90.45	78.86	92.83	65.86	83.85	77.01	100.99	73.35	78.66
1980	75.69	80.25	76.40	90.34	75.91	88.59	61.74	78.99	70.33	103.09	76.56	79.25
1981	86.35	89.67	83.42	89.44	74.27	89.52	62.02	73.15	74.10	116.96	89.30	86.00
1982	89.20	105.02	91.37	96.41	86.09	93.29	67.32	72.81	86.96	116.19	100.61	93.61
1983	89.31	108.24	97.90	97.92	88.03	99.67	81.66	76.69	93.23	126.24	101.59	96.44
1984	89.00	103.86	97.24	94.72	90.11	93.74	87.58	81.94	94.94	122.41	98.51	94.96
1985	84.79	106.63	117.01	84.95	90.92	90.69	82.68	71.21	93.67	112.63	98.62	93.10
1986	78.71	97.95	91.08	80.36	80.26	89.37	77.62	70.41	83.71	110.38	81.56	85.22
1987	74.71	92.13	84.83	73.52	75.23	86.38	75.71	64.83	72.47	96.52	73.43	79.70
1988	75.30	89.88	87.14	71.45	72.87	83.95	73.09	76.07	89.55	93.73	80.45	80.07
1989	72.86	89.76	85.26	68.82	70.35	75.38	71.28	69.52	88.40	94.71	79.93	77.99
1990	70.62	89.29	82.72	76.21	66.39	68.63	67.83	68.81	86.24	92.18	78.73	76.79
1991	74.14	89.17	84.50	86.28	62.87	64.60	70.55	65.19	80.31	90.42	87.56	78.55
10-yr Avg.	79.86	97.19	91.90	83.07	78.31	84.57	75.53	71.75	86.95	105.54	88.10	85.64

NOTES

1) See Table 2.12 in this Report.

2) The inflation rate used is obtained from DRI/McGraw-Hill (Fall 1991).

to residential customers to levels below both the Texas weighted average and the 1977 bills in real terms, including COA, CPS, SPS, SWEPCO, and TU Electric.

Fuel Supply

Fuel is typically an electric utility company's largest single expense. Fuel costs can account for more than 30 percent of a utility's overall revenues and, in periods of high fuel prices, fuel costs 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 fuel prices are also discussed. Finally, the projected availability of different fuels is reviewed.

Fuel Consumption Texas electric utilities' generation by fuel type, including a historical summary of fuel consumption, is shown in Figure 2.1. By any measure, utilities in Texas, as a class, are both major generators of electricity and major consumers of fuel used in electricity generation.

In 1975, about 90 percent of the electric generation in Texas was natural gas-fired. The 1991 generation mix included four fuels for thermal generating plants. Natural gas accounted for a total of 47 percent, 10 percent of which is from cogeneration. Coal and lignite together accounted for about 44 percent of generation, and nuclear generation provided about 10 percent.[1]

Nearly 38 percent of the natural gas consumed for electric generation nationwide is consumed by utilities in Texas. Consumption of natural gas by Texas utilities is more than twice that of California utilities, the second-largest natural gas consumer for electricity generation.

Texas utilities consume more than 8 percent of the total heating value of coal used in electricity generation nationwide. For electricity generation, coal consumption by Texas utilities ranks first. It is followed by Ohio and Pennsylvania in second and third place, respectively.

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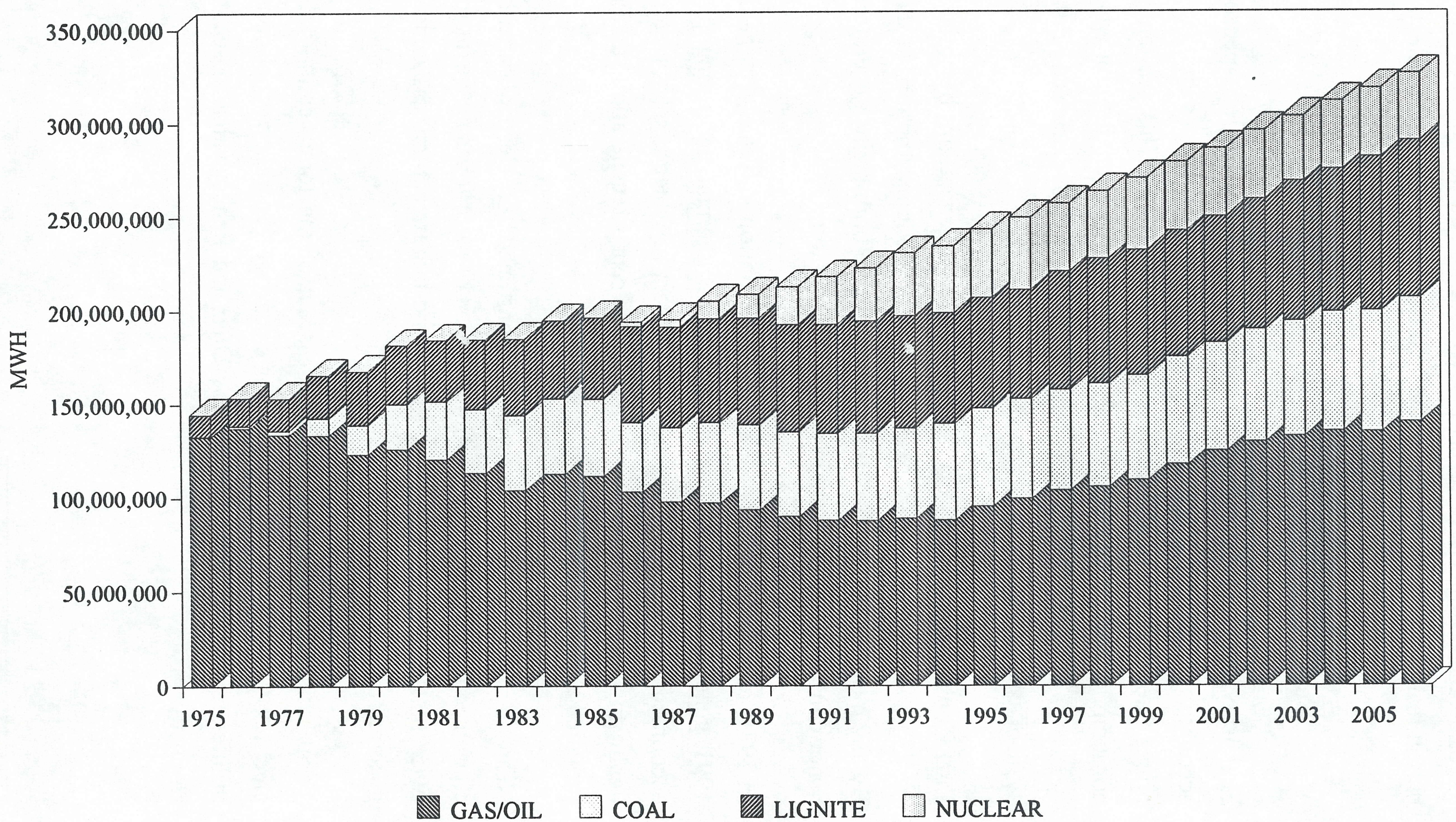
1 1991 PUCT Fuel Efficiency Report

FIGURE 2.1
ELECTRICITY GENERATION BY FUEL TYPE



Note: Only Texas-supplied generation included. Hydro and other alternative sources were less than 1 percent.

Overall, Texas accounts for approximately 12 percent of the fossil fuel heating value consumed for electricity generation nationwide. This is equal to the combined fossil fuel heating values of Ohio and Pennsylvania, the runner-up states.

Although the primary fuels used for generation in Texas are natural gas and coal, nuclear generation accounted for a significant 10 percent of Texas electricity requirements in 1991. Seven Texas utilities own nuclear generation: CPL, HL&P, CPS, and COA (South Texas Project Units 1 and 2); GSU (partial ownership of River Bend); TU Electric (100% ownership of Comanche Peak Units 1 and 2); and EPE (partial ownership of Palo Verde Units 1, 2, and 3). All units are on commercial status except Comanche Peak Unit 2.

Fuel Diversification Texas utilities have undertaken fuel diversification programs to protect against severe disruptions. Continued fuel diversification is planned during the next ten years. This includes Unit 2 of Comanche Peak Steam Generating Station nuclear plant, 4 lignite-fired units, 2 coal-fired units, and over 25 natural gas-fired units.

Fuel diversification mitigates the risk associated with the supply and price of any one fuel. The plants which operate as base-load units and at the highest capacity factors should be exploiting the least expensive fuel available. In the 1970s and early 1980s, coal-, lignite-, and nuclear-fueled plants were operated as base load. Though the capital costs for these plants are higher than gas- or oil-fired plants, long-term fuel economics tend to favor the overall production costs. The ability to track load coupled with the higher cost of natural gas make natural gas-fired units a better choice as cycling and peaking units in a generating system.

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 are affected by the price of residual fuel oil, a substitute fuel. Occasionally, world events may cause oil prices to soar, which may in turn allow natural gas prices to increase during peak consumption periods. During the remainder of the year, however, natural gas prices should be relatively soft due to supply surplus.

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. Because lignite-fired power plants are typically 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 because of 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 a buyer's market.

Nuclear fuel is projected to be the least expensive fuel during the next ten years for the electric utilities in Texas. By the year 2000, the average price of nuclear fuel is projected to be approximately $0.61 per million BTU compared to lignite at $1.73 per million BTU, coal at $2.14 per million BTU, and gas at $2.72 per million BTU.

Fuel Price Projections

Tables 2.14 through 2.17 present the Commission staff projections of fuel prices for 1990 through 2000. The prices given in these tables are projections based on existing fuel supply contracts, projected spot fuel prices, and each utility's ability to negotiate effectively in the marketplace. Existing fuel contracts were analyzed, and costs for fuel to be taken were projected. Costs of fuel to be purchased in the spot market were projected by staff based upon historical fuel costs, projected fuel availability, and projected gas supply trends.

About one-half of the natural gas supply in Texas is acquired through firm contracts while the other half is purchased on the spot market. By the year 2000, the mix should reflect a

TABLE 2.14

STAFF-PROJECTED AVERAGE NATURAL GAS PRICES

($/MMBTU)

Year	COA	CPS	CPL	EPE	GSU	HL&P	LCRA	SPS	SWEPCO	TU	WTU	BEPC
1991	1.85	1.68	2.03	1.84	1.69	1.62	1.51	1.58	2.46	2.48	1.84	1.68
1992	1.81	1.75	1.73	1.90	1.76	1.68	1.63	1.66	1.93	2.42	1.65	1.75
1993	1.88	1.82	1.87	1.95	1.85	1.75	1.71	1.73	2.10	2.51	1.78	1.82
1994	1.97	1.89	2.05	2.02	1.93	1.82	1.79	1.80	2.30	2.61	1.98	1.89
1995	2.05	1.97	2.19	2.14	2.01	1.90	1.86	1.88	2.46	2.72	2.12	1.97
1996	2.16	2.05	2.30	2.27	2.13	2.00	1.95	1.97	2.59	2.83	2.24	2.05
1997	2.27	2.14	2.43	2.40	2.22	2.13	2.03	2.06	2.71	2.96	2.35	2.14
1998	2.40	2.24	2.53	2.55	2.34	2.24	2.13	2.17	2.85	3.09	2.48	2.24
1999	2.53	2.34	2.67	2.70	2.45	2.36	2.23	2.28	3.01	3.23	2.62	2.34
2000	2.67	2.46	2.86	2.88	2.59	2.50	2.35	2.40	3.22	3.39	2.82	2.46
2001	2.81	2.59	3.07	3.03	2.73	2.63	2.47	2.53	3.47	3.57	3.04	2.59
2002	2.96	2.73	3.30	3.19	2.87	2.78	2.61	2.66	3.73	3.76	3.28	2.73
2003	3.12	2.88	3.53	3.36	3.02	2.93	2.75	2.81	3.99	3.96	3.52	2.88
2004	3.28	3.03	3.76	3.53	3.18	3.09	2.89	2.96	4.26	4.17	3.76	3.03
2005	3.45	3.19	3.99	3.72	3.35	3.26	3.05	3.13	4.52	4.39	4.00	3.19
2006	3.63	3.36	4.24	3.91	3.52	3.44	3.21	3.30	4.80	4.63	4.26	3.36

1991 - Actual.

TABLE 2.15

STAFF-PROJECTED AVERAGE COAL PRICES

($/MMBTU)

Year	COA	CPS	CPL	EPE	GSU	HL&P	LCRA	SPS	SWEPCO	TU	WTU
1991	1.45	0.90	1.82	1.15	1.91	2.38	1.34	1.73	1.80	---	1.55
1992	1.41	1.52	1.99	1.20	1.75	2.38	1.43	1.78	1.73	---	1.82
1993	1.46	1.57	2.04	1.23	1.80	2.44	1.47	1.83	1.77	---	1.86
1994	1.50	1.62	2.10	1.27	1.85	2.49	1.52	1.88	1.81	---	1.91
1995	1.55	1.67	2.06	1.30	1.90	2.55	1.57	1.93	1.85	---	1.96
1996	1.61	1.73	2.12	1.34	1.93	2.63	1.62	1.99	1.90	---	2.01
1997	1.66	1.79	2.18	1.38	1.99	2.71	1.67	2.05	1.96	---	2.07
1998	1.72	1.86	2.25	1.43	2.05	2.80	1.73	2.11	2.01	---	2.13
1999	1.79	1.93	2.32	1.47	2.12	2.90	1.80	2.19	2.07	---	2.19
2000	1.85	2.00	2.25	1.53	2.20	3.00	1.86	2.27	2.15	---	2.27
2001	1.93	2.08	2.35	1.59	2.29	3.13	1.94	2.36	2.24	---	2.37
2002	2.01	2.16	2.45	1.65	2.38	3.27	2.02	2.45	2.35	1.84	2.48
2003	2.08	2.24	2.57	1.72	2.48	2.82	2.09	2.55	2.23	1.91	2.60
2004	2.16	2.33	2.68	1.79	2.58	2.95	2.17	2.65	2.44	2.10	2.68
2005	2.25	2.42	2.81	1.86	2.69	3.08	2.26	2.76	2.55	2.19	2.80
2006	2.33	2.51	2.94	1.93	2.75	3.22	2.34	2.87	2.62	2.29	2.93

1991 - Actual.

TABLE 2.16

STAFF-PROJECTED AVERAGE LIGNITE PRICES

($/MMBTU)

Year	TU	HL&P	SWEPCO	TNP	SMEC (*)	CPL	CPS	WTU
1991	0.98	1.69	1.37	1.40	0.92	---	---	---
1992	1.01	1.74	1.40	1.56	0.95	---	---	---
1993	1.04	1.78	1.44	1.62	0.98	---	---	---
1994	1.07	1.83	1.48	1.69	1.00	---	---	---
1995	1.10	1.88	1.52	1.76	1.03	---	---	---
1996	1.13	1.94	1.56	1.83	1.06	---	---	---
1997	1.17	2.00	1.61	1.92	1.09	---	---	---
1998	1.18	2.06	1.66	2.00	1.13	---	---	---
1999	1.22	2.13	1.72	2.10	1.17	---	---	---
2000	1.26	2.21	1.78	2.20	1.21	---	---	---
2001	1.31	2.30	1.86	2.31	1.26	---	---	---
2002	1.37	2.39	2.00	2.43	1.31	---	---	---
2003	1.42	2.49	2.09	2.55	1.36	2.26	---	2.24
2004	1.48	2.59	2.17	2.68	1.42	2.35	---	2.34
2005	1.54	3.06	2.26	2.82	1.47	2.44	1.28	2.45
2006	1.60	3.38	2.35	2.96	1.53	2.54	1.33	2.57

1991 - Actual.
* - San Miguel Electric Cooperative.

TABLE 2.17

STAFF-PROJECTED AVERAGE NUCLEAR FUEL PRICES

($/MMBTU)

Year	COA	CPS	CPL	EPE	GSU	HL&P	TU
1991	0.47	0.63	0.65	0.76	1.15	0.65	0.24
1992	0.49	0.52	0.61	0.59	1.15	0.57	0.38
1993	0.50	0.57	0.63	0.58	0.98	0.63	0.57
1994	0.50	0.55	0.61	0.56	0.92	0.58	0.67
1995	0.48	0.53	0.60	0.54	0.86	0.57	0.68
1996	0.47	0.53	0.61	0.54	0.80	0.55	0.61
1997	0.46	0.54	0.62	0.56	0.82	0.54	0.53
1998	0.46	0.52	0.62	0.56	0.80	0.54	0.48
1999	0.48	0.54	0.65	0.57	0.83	0.54	0.48
2000	0.54	0.57	0.68	0.50	0.92	0.58	0.51
2001	0.61	0.59	0.71	0.56	0.93	0.60	0.53
2002	0.56	0.62	0.74	0.57	1.00	0.63	0.55
2003	0.57	0.63	0.75	0.59	1.08	0.64	0.56
2004	0.56	0.66	0.78	0.63	1.09	0.65	0.58
2005	0.56	0.69	0.82	0.65	1.15	0.70	0.59
2006	0.61	0.71	0.85	0.68	1.25	0.72	0.62

1991 - Actual.

greater reliance on firm contracts. However, future firm supply contracts will be market-responsive. Prices will be tied to a market representative index, or the contracts will contain periodic re-openers so that either buyer or seller can make adjustments for unforeseen market events. Larger consumers such as HL&P and GSU can be expected to exert more buying leverage in the marketplace, relative to smaller users such as SPS and EPE.

Although delivered spot coal prices will be mostly dependent upon coal supply/demand factors and 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 mid-1970s to early 1980s, and the resulting delivered costs 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. 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, CPS, and LCRA generally have lower projected coal costs for the period than the investor-owned companies.

Supply of all lignite requirements for existing power stations are virtually guaranteed through long-term contracts. The prices under these contracts are expected to increase at about the rate of overall inflation during the 10-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.

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.

Future Fuel Availability

Natural Gas. Major disruptions of natural gas supplies are not expected during the next ten years. Price increases and the resulting increase in exploration activity during the late 1970s and early 1980s has created a natural gas oversupply, the gas "bubble," which persists today. The effect of natural gas oversupply is depressed prices, so that reserve additions have not been replacing production. Eventually, supply and demand will come back into balance, and gas prices will rise. Increased prices will again generate increased exploration activity but at the same time curtail demand. Consequently, although there may be periods of sharply rising prices driven by tightening supply, these periods will be followed by falling prices as reduced demand meets increased supply.

Current gas supplies are adequate for projected generation requirements and prices are relatively stable. Further, the increased efficiencies of new advance combined cycle gas turbines may result in greater reliance on natural gas for base load service. This is in addition to expected intermediate and peaking duty since the new combined cycles are flexible enough to perform those functions as well. Although natural gas-fired units are projected to be the predominant choice by Texas utilities for peaking and intermediate use, the long-term uncertainties associated with both price and supplies of natural gas likely will prevent utilities from planning any new base load gas-fired generation.

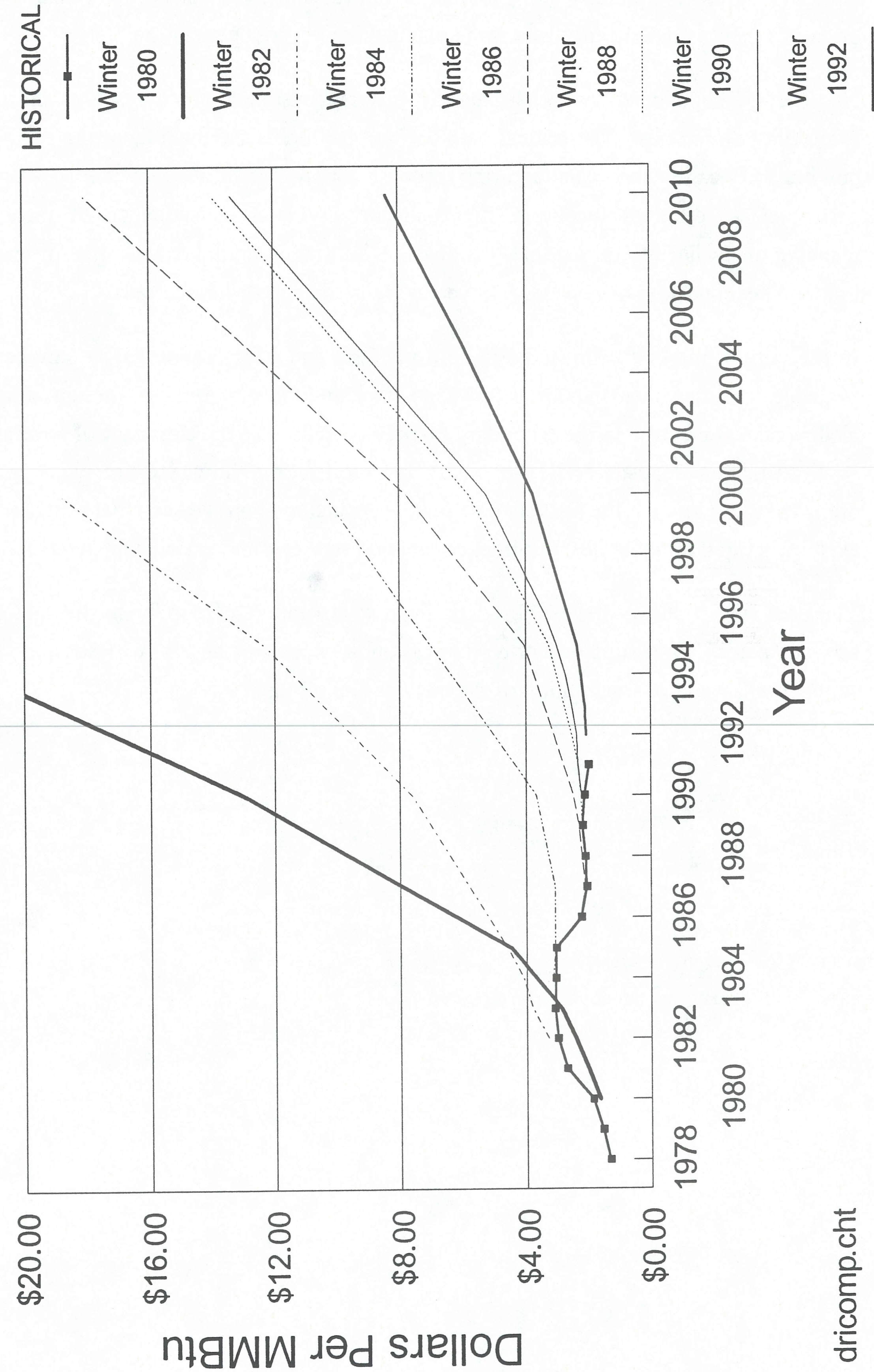
An example of the uncertainty in predicting price and supply can be viewed in Figure 2.2. This figure compares the annual forecasts of the price of natural gas to electric utilities in the U.S. West South Central Region. These forecasts are those of DRI/McGraw-Hill, a large energy forecasting group. One can see that DRI's forecasted trends have resulted in the actual prices for natural gas being significantly overestimated. In reality, the market has not allowed the price of natural gas to escalate at the rates that have been predicted.

Coal. Almost all coal-fired generating 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 subbituminous coal. Presently, the Powder River Basin, as well as the U. S. coal industry in general, has excess production capacity; but 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 near the end of the 10-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 firm plans for lignite consumption. The first event would be a major mining stoppage caused by a major equipment failure, mine failure, or strike; the other event, a change in regulations covering the burning of lignite.

FIGURE 2.2

Price of Natural Gas to Electric Utilities



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

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 is a consequence of inadequate planning, 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 area which shows the highest risk from a disruption of supply is the fabrication service sector. Few suppliers offer fabrication services and any loss of service from a supplier will result in a disruption of the nuclear fuel supply.

<u>CHAPTER THREE</u>

ELECTRICITY DEMAND FORECAST

This chapter provides the staff's recommended demand projections from 1992 through 2006 for 13 of the state's largest generating electric utilities. Following a discussion of the PUCT staff's modeling efforts, details of staff-recommended projections are compared with utility forecasts of total sales and peak demand.

Electricity Demand Forecasting Projects at the PUCT

Over the past nine years, the Economic Analysis Section of the Public Utility Commission of Texas has initiated three distinct projects designed to produce accurate, flexible, and tenable independent projections of demand for the largest generating electric utilities in Texas. These projects are: the Econometric Electricity Demand Forecasting System; the End-Use Energy Modeling and Forecasting System; and the State Space, Time Series, and Bayesian Forecasting.[1]

Methods Used in This Report

The **Econometric Electricity Demand Forecasting System** project statistically estimates the relationships between electricity demand and various demand determinants or "explanatory variables." These demand determinants include weather, population, personal income, electricity prices, and prices of alternative energy sources. Simultaneous-equation econometric models have been developed for the major electric utilities in the state. Future electricity consumption is projected based on the historical relationships and forecasts of the demand determinants. The electricity sales projections are converted to peak demand using the Hourly Electric Load Model (HELM). Numerous improvements have been made to this forecasting system since its inception in 1984.

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1 Partial funding for the Commission's End-Use Modeling Project was secured through the Governor's Energy Office and the State Energy Conservation Program.

For this report, the Econometric Electricity Demand Forecasting System is primarily relied upon to derive the long-term peak demand projections used to evaluate capacity requirements described later in this volume. The current structure of this modeling system is described in the technical appendix to this report and is available upon request.

The **End-Use Energy Modeling and Forecasting System** Project, initiated in the Spring of 1985, examines the final uses of energy in Texas. These end-uses include: air conditioning, space heating, refrigeration, lighting, irrigation, and industrial processes. Changes in the stock of energy-intensive equipment, appliance efficiencies, usage patterns, and the determinants of these factors (demographic patterns, technology, laws, regulations, fuel prices, etc.) are addressed. End-use models provide a means of estimating the technical and economic potential of a variety of conservation and load management strategies. In addition, the forecasts derived from end-use modeling systems provide a validity check on the results obtained from econometric forecasting models. Funding for the third and final phase of this project was completed in June 1990. Currently, HELM is the only end-use model actively used by staff.

While the Econometric and End-use Energy models are designed to provide an accurate long-range outlook for the state's electricity service areas, the **State Space and Time Series** models are employed to provide short-term projections of peak demand. These models examine patterns in a given utility's quarterly peak demand over time. Seasonal, cyclical, and trend components of historical patterns are identified, and projections are developed based on the delineation of these components.

Pursuing three distinct forecasting methods permits the PUCT staff to exploit the unique capabilities of each. Econometric models are typically more useful in the study of the responsiveness of electricity demand to energy prices and the impact of weather and economic activity on energy demand. End-use models are considered superior in estimating conservation and load management program impacts. Recent studies in the statistical and econometric literature affirm the accuracy and applicability of time series models in short- to medium-range peak demand forecasting applications. The results of each of these forecasting methods provide validity checks of the projections developed from alternative staff approaches, as well as the projections of the utility-provided forecasts.

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

Public Utility Commission Staff-Recommended Peak Demand Forecasts

The staff-recommended demand projections for the 13 largest generating electric utilities are contrasted with utility-developed forecasts of total sales and peak demand. The projections of peak demand and sales presented here are net of all adjustments that reflect the effects of demand-side resources. Three types of demand-side impacts are estimated and used to adjust the "raw" peak demand and sales forecasts:

1. Exogenous factors;
2. Active demand-side management; and
3. Passive demand-side management.

Exogenous factor adjustments include the effects of laws and customer actions beyond the control of the utility. Active and passive demand-side management (DSM) adjustments include the effects of programs not reflected in the "raw" econometric forecasts. (See Chapter Five for a detailed discussion of these adjustments.)

Independent peak demand and sales projections have been developed by the staff for the following utilities (refer to Tables 3.1 through 3.49):

Utility Name	Acronym
Texas Utilities Electric Company	TU Electric
Houston Lighting and Power Company	HL&P
Gulf States Utilities Company	GSU
Central Power and Light Company	CPL
City Public Service of San Antonio	CPS
Southwestern Public Service Company	SPS
Southwestern Electric Power Company	SWEPCO
Lower Colorado River Authority	LCRA
City of Austin	COA
West Texas Utilities Company	WTU
El Paso Electric Company	EPE
Texas-New Mexico Power Company	TNP
Brazos Electric Power Cooperative	BEPC

Note that peak demand and sales figures are projections from 1992 to 2006.

The statewide coincident peak demand forecast is presented in Table 6.19. The corresponding statewide sales forecast is presented in Appendix B, Table B.1.

TU Electric Company The system peak demand faced by the largest electric utility in Texas is expected to reach 21,317 MW by the year 2001. This represents a 2.4 percent annual increase in peak load over the next ten years. The utility's peak demand grew at a much faster rate between the years 1975 and 1985, propelled by an increase in oil prices and employment in the region. In 1986, a precipitous drop in oil prices was a leading cause of the contraction of the economy in TU Electric's service area. The region's economy is expected to recover and remain stable through the end of the century with population and labor growth rates of approximately 1.1 and 1.5 percent, respectively.

Total system sales are projected to grow 2.6 percent annually over the next decade. Industrial sales are forecasted to grow at 3.0 percent, followed by residential sales at 2.5 percent and commercial sales at 2.2 percent.

Houston Lighting and Power Company HL&P is expected to experience annual growth in peak demand of 2.1 percent over the next decade, after adjustments for self-generation and demand-side management programs. Total adjusted system sales are projected to grow at an average annual rate of 1.9 percent through the year 2001. Residential sales are forecasted to grow at an annual rate of 1.7 percent and commercial sales are forecasted to grow at 3.9 percent. Growth in industrial sales is expected to be 1.3 percent (lower than the residential and commercial sectors).

The Houston area was especially affected by the state's economic downturn. Between 1976 and 1986, the region sustained two economic booms and recessions. In particular, the 1986 collapse in oil prices resulted in unemployment levels above 10 percent. However, in the last few years the HL&P service area has made a strong recovery with growth in the trade and petrochemical sectors. Non-agricultural employment is anticipated to increase at an annual rate of 1.9 percent through 2001, one of the strongest employment outlooks in the state.

Other sales by HL&P are made primarily to Texas-New Mexico Power Company for resale. A reduction in load in this category is expected because of the commercial operation of the second unit of TNP One.

TABLE 3.1
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
TEXAS UTILITIES ELECTRIC COMPANY

Year	Staff Adjusted(MW)	TU Electric Adjusted(MW)	Difference (MW)	Difference (%)
1991	16,831	16,831	0	0.00%
1992	17,304	17,953	-649	-3.62%
1993	17,643	18,237	-594	-3.26%
1994	18,003	18,224	-221	-1.21%
1995	18,548	18,695	-147	-0.79%
1996	19,095	19,086	9	0.05%
1997	19,575	19,523	52	0.26%
1998	19,969	19,979	-10	-0.05%
1999	20,421	20,472	-51	-0.25%
2000	20,895	21,006	-111	-0.53%
2001	21,317	21,535	-218	-1.01%
2002	21,800	22,116	-316	-1.43%
2003	22,252	22,698	-446	-1.97%
2004	22,728	23,269	-541	-2.33%
2005	23,198	23,848	-650	-2.72%
2006	23,617	24,418	-801	-3.28%
Average Annual Growth				
1991-2001	2.39%	2.50%		
1991-2006	2.28%	2.51%		

TABLE 3.2
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
TEXAS UTILITIES ELECTRIC COMPANY

Year	Staff Adjusted(MWH)	TU Electric Adjusted(MWH)	Difference (MWH)	Difference (%)
1991	82,289,134	82,289,134	0	0.00%
1992	83,164,198	84,206,710	-1,042,512	-1.24%
1993	85,158,652	86,460,842	-1,302,190	-1.51%
1994	87,126,601	87,166,133	-39,532	-0.05%
1995	90,010,694	89,970,765	39,929	0.04%
1996	92,980,265	92,489,922	490,343	0.53%
1997	95,695,844	95,151,409	544,435	0.57%
1998	98,141,684	98,148,445	-6,761	-0.01%
1999	100,739,848	101,124,187	-384,339	-0.38%
2000	103,526,218	104,338,997	-812,779	-0.78%
2001	106,106,369	107,590,211	-1,483,842	-1.38%
2002	108,889,359	111,020,705	-2,131,346	-1.92%
2003	111,700,816	114,628,084	-2,927,268	-2.55%
2004	114,508,884	118,038,860	-3,529,976	-2.99%
2005	117,304,225	121,351,778	-4,047,553	-3.34%
2006	120,031,350	124,766,162	-4,734,812	-3.79%
Average Annual Growth				
1991-2001	2.57%	2.72%		
1991-2006	2.55%	2.81%		

TABLE 3.3
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
TEXAS UTILITIES ELECTRIC COMPANY

Year	Residential Adjusted(MWH)	Commercial (*) Adjusted(MWH)	Industrial Adjusted(MWH)	All Other (MWH)	Total (MWH)
1991	28,430,644	27,651,124	21,975,850	4,231,515	82,289,133
1992	28,775,064	27,875,313	22,110,260	4,403,561	83,164,198
1993	29,525,915	28,495,935	22,768,422	4,368,380	85,158,652
1994	30,305,944	29,348,098	23,116,442	4,356,117	87,126,601
1995	31,255,342	30,567,569	23,632,454	4,555,329	90,010,694
1996	32,248,736	31,604,322	24,374,128	4,753,079	92,980,265
1997	33,192,329	32,413,340	25,151,100	4,939,075	95,695,844
1998	33,961,129	32,807,804	26,238,218	5,134,533	98,141,684
1999	34,847,273	33,327,425	27,231,738	5,333,412	100,739,848
2000	35,714,590	33,869,192	28,400,280	5,542,156	103,526,218
2001	36,493,452	34,243,484	29,624,706	5,744,727	106,106,369
2002	37,288,130	34,730,420	30,779,354	6,091,455	108,889,359
2003	38,000,031	35,130,181	32,314,972	6,255,632	111,700,816
2004	38,798,405	35,578,387	33,712.500	6,419,592	114,508,884
2005	39,602,750	36,049,523	35,086,320	6,565,632	117,304,225
2006	40,313,074	36,405,702	36,602,500	6,710,074	120,031,350
Average Annual Growth					
1991-2001	2.53%	2.16%	3.03%	3.10%	2.57%
1991-2006	2.36%	1.85%	3.46%	3.12%	2.55%

(*) - Commercial sales include street lighting and municipal sales.

FIGURE 3.1
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
TEXAS UTILITIES ELECTRIC COMPANY

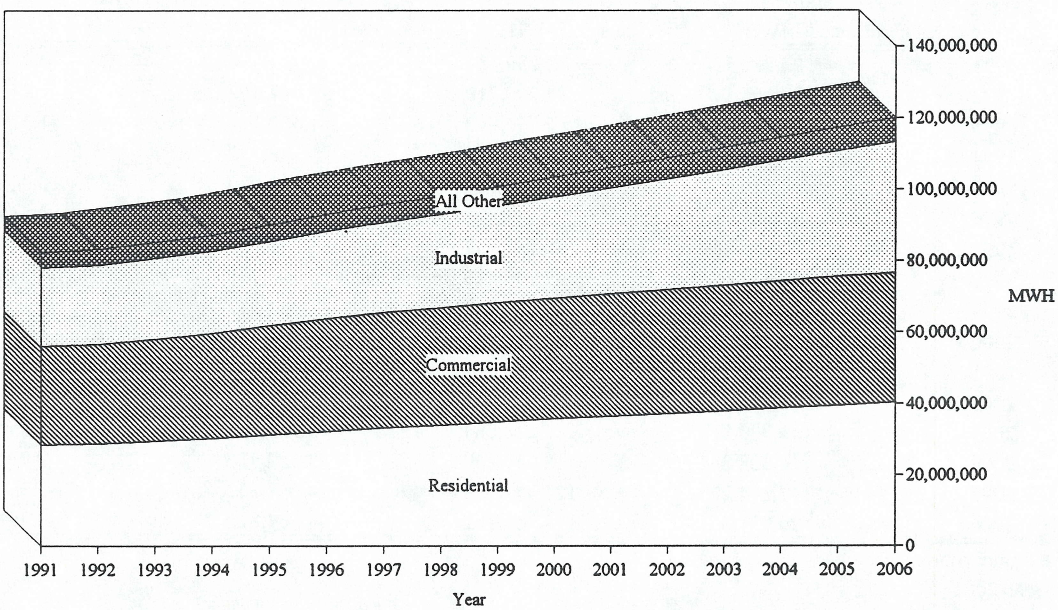


TABLE 3.4
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
HOUSTON LIGHTING AND POWER COMPANY

Year	Staff Adjusted(MW)	HL&P Adjusted(MW)	Difference (MW)	Difference (%)
1991	10,908	10,908	0	0.00%
1992	11,193	11,468	-275	-2.40%
1993	11,311	11,635	-324	-2.78%
1994	11,848	11,743	105	0.89%
1995	12,075	12,040	35	0.29%
1996	12,270	12,153	117	0.96%
1997	12,471	12,272	199	1.62%
1998	12,712	12,449	263	2.11%
1999	12,949	12,591	358	2.85%
2000	13,210	12,812	398	3.11%
2001	13,475	13,031	444	3.41%
2002	13,775	13,269	506	3.81%
2003	14,081	13,498	583	4.32%
2004	14,372	13,707	665	4.85%
2005	14,596	13,914	682	4.90%
2006	14,882	14,093	789	5.60%
Average Annual Growth				
1991-2001	2.14%	1.79%		
1991-2006	2.09%	1.72%		

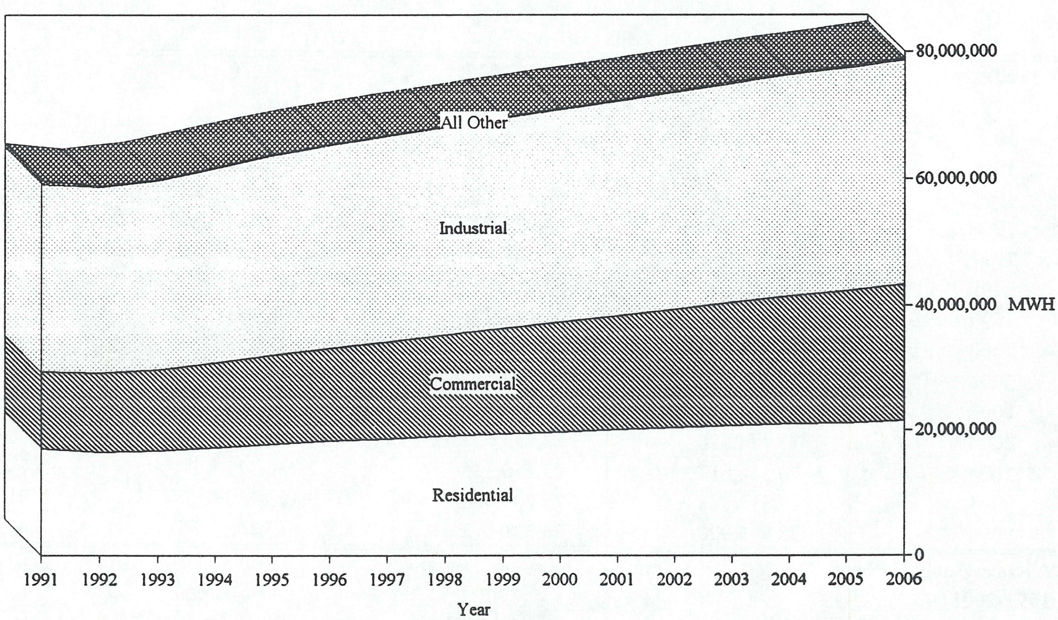
TABLE 3.5
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
HOUSTON LIGHTING AND POWER COMPANY

Year	Staff Adjusted(MWH)	HL&P Adjusted(MWH)	Difference (MWH)	Difference (%)
1991	59,652,217	59,652,217	0	0.00%
1992	58,843,825	59,020,706	-176,881	-0.30%
1993	59,831,789	60,936,206	-1,104,417	-1.81%
1994	61,798,427	60,950,226	848,201	1.39%
1995	63,774,781	61,837,056	1,937,725	3.13%
1996	65,433,570	62,994,092	2,439,478	3.87%
1997	66,819,068	63,804,748	3,014,320	4.72%
1998	68,262,892	65,012,800	3,250,092	5.00%
1999	69,656,698	66,177,975	3,478,723	5.26%
2000	70,963,914	67,630,543	3,333,371	4.93%
2001	72,321,678	69,102,677	3,219,001	4.66%
2002	73,727,399	70,700,683	3,026,716	4.28%
2003	75,174,626	72,283,601	2,891,025	4.00%
2004	76,536,617	73,756,395	2,780,222	3.77%
2005	77,614,948	75,201,698	2,413,250	3.21%
2006	78,946,920	76,331,512	2,615,408	3.43%
Average Annual Growth				
1991-2001	1.94%	1.48%		
1991-2006	1.89%	1.66%		

TABLE 3.6
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
HOUSTON LIGHTING AND POWER COMPANY

Year	Residential Adjusted(MWH)	Commercial Adjusted(MWH)	Industrial Adjusted(MWH)	All Other (MWH)	Total (MWH)
1991	16,978,936	12,501,612	29,555,238	616,431	59,652,217
1992	16,436,305	12,772,200	29,429,658	205,662	58,843,825
1993	16,587,707	13,189,988	29,848,221	205,873	59,831,789
1994	17,164,964	13,685,559	30,744,050	203,854	61,798,427
1995	17,756,611	14,283,679	31,536,453	198,038	63,774,781
1996	18,206,385	14,950,175	32,080,985	196,024	65,433,570
1997	18,596,384	15,617,623	32,409,836	195,226	66,819,068
1998	19,003,049	16,284,496	32,779,373	195,974	68,262,892
1999	19,375,365	16,965,162	33,118,189	197,981	69,656,698
2000	19,694,169	17,653,434	33,409,633	206,678	70,963,914
2001	20,022,099	18,336,706	33,748,915	213,959	72,321,678
2002	20,350,221	19,035,336	34,119,879	221,963	73,727,399
2003	20,684,465	19,738,206	34,519,859	232,097	75,174,626
2004	20,984,975	20,447,518	34,857,331	246,794	76,536,617
2005	21,118,869	21,156,728	35,073,235	266,117	77,614,948
2006	21,431,599	21,836,856	35,392,811	285,654	78,946,920
Average Annual Growth					
1991-2001	1.66%	3.90%	1.34%	-10.04%	1.94%
1991-2006	1.56%	3.79%	1.21%	-5.00%	1.89%

FIGURE 3.2
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
HOUSTON LIGHTING AND POWER COMPANY



Gulf States Utilities Company Peak demand in the GSU Texas service area is expected to reach approximately 2,545 MW by the year 2001. GSU's total system peak demand is projected to reach nearly 5,760 MW over the forecast period by the same year. This translates into annual growth rates of 1.54 and 1.58 percent, respectively. The growth rate for the Texas service area is the smallest among the 13 major utilities.

This relatively low growth reflects the depressed state of the service area economies. GSU serves an area extending 350 miles westward from Baton Rouge, Louisiana to a point about 50 miles east of Austin, Texas. This area was particularly hard hit by the drop in oil prices in 1986. Future recovery, even if moderate, will fail to bolster the demand for electricity.

Total GSU sales in Texas are expected to grow at an annual rate of 1.0 percent while total system sales are projected to grow at a rate of 1.2 percent. In Texas, commercial sales growth will be the most robust at 2.1 percent followed by industrial and residential sales at 1.4 and 0.9 percent, respectively.

Central Power and Light Company CPL, according to the staff's forecast, will experience peak demand of 3,828 MW by the year 2001. Average annual growth in peak demand from 1991 through the year 2001 is expected to be 2.0 percent which is slightly lower than the 2.1 percent growth forecast by CPL.

Total sales are expected to climb from 16,195,805 MWH in 1991 to 20,465,446 MWH by the year 2001. This yields an average annual growth rate of 2.4 percent. Commercial sales are projected to grow at a rate of approximately 2.8 percent per year through the year 2001, followed by industrial sales growing at an average annual rate of 2.4 percent. Growth in residential sales is expected to lag behind with a rate of 2.3 percent.

The three largest cities served by CPL are Corpus Christi, Laredo, and McAllen. Analysts predict relatively strong economic performance in these cities. Corpus Christi will benefit from the completion of several developments, while Laredo and McAllen are expected to benefit from the increasing strength of the maquiladora program.

TABLE 3.7
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
GULF STATES UTILITIES COMPANY - TEXAS

Year	Staff Adjusted(MW)	GSU Adjusted(MW)	Difference (MW)	Difference (%)
1991	2,184	2,184	0	0.00%
1992	2,205	2,205	0	0.00%
1993	2,408	2,374	34	1.43%
1994	2,378	2,392	-14	-0.59%
1995	2,409	2,406	3	0.12%
1996	2,443	2,450	-7	-0.29%
1997	2,447	2,458	-11	-0.45%
1998	2,473	2,503	-30	-1.20%
1999	2,499	2,542	-43	-1.69%
2000	2,522	2,571	-49	-1.91%
2001	2,545	2,603	-58	-2.23%
2002	2,568	2,560	8	0.31%
2003	2,590	2,605	-15	-0.58%
2004	2,612	2,603	9	0.35%
2005	2,634	2,600	34	1.31%
2006	2,654	2,624	30	1.14%
Average Annual Growth				
1991-2001	1.54%	1.77%		
1991-2006	1.31%	1.23%		

TABLE 3.8
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
GULF STATES UTILITIES COMPANY - TEXAS

Year	Staff Adjusted(MWH)	GSU Adjusted(MWH)	Difference (MWH)	Difference (%)
1991	12,853,599	12,853,599	0	0.00%
1992	12,253,199	12,468,435	-215,236	-1.73%
1993	13,336,194	13,592,940	-256,746	-1.89%
1994	13,199,628	13,485,665	-286,037	-2.12%
1995	13,392,860	13,342,875	49,985	0.37%
1996	13,583,488	13,598,814	-15,326	-0.11%
1997	13,603,642	13,610,850	-7,208	-0.05%
1998	13,751,158	13,834,718	-83,560	-0.60%
1999	13,889,183	13,977,554	-88,371	-0.63%
2000	14,011,493	14,199,322	-187,829	-1.32%
2001	14,131,316	14,210,839	-79,523	-0.56%
2002	14,252,477	14,051,566	200,911	1.43%
2003	14,369,220	14,049,741	319,479	2.27%
2004	14,484,865	14,058,961	425,904	3.03%
2005	14,599,249	14,060,256	538,993	3.83%
2006	14,710,034	14,070,111	639,923	4.55%
Average Annual Growth				
1991-2001	0.95%	1.01%		
1991-2006	0.90%	0.60%		

TABLE 3.9
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
GULF STATES UTILITIES COMPANY - TEXAS

Year	Residential Adjusted(MWH)	Commercial Adjusted(MWH)	Industrial Adjusted(MWH)	All Other (MWH)	Total (MWH)
1991	3,474,330	2,297,789	6,122,571	958,909	12,853,599
1992	3,462,380	2,285,879	6,061,443	443,498	12,253,199
1993	3,494,033	2,380,969	6,899,467	561,726	13,336,194
1994	3,528,884	2,464,347	6,639,518	566,880	13,199,628
1995	3,566,496	2,541,708	6,712,645	572,012	13,392,860
1996	3,605,269	2,608,856	6,792,235	577,129	13,583,488
1997	3,643,805	2,667,116	6,858,861	433,862	13,603,642
1998	3,681,878	2,715,838	6,916,104	437,338	13,751,158
1999	3,721,974	2,756,717	6,969,687	440,805	13,889,183
2000	3,759,959	2,791,695	7,015,573	444,267	14,011,493
2001	3,797,283	2,823,692	7,062,612	447,729	14,131,316
2002	3,834,107	2,855,488	7,112,338	450,545	14,252,477
2003	3,869,188	2,887,452	7,159,223	453,358	14,369,220
2004	3,903,207	2,919,560	7,205,927	456,171	14,484,865
2005	3,936,083	2,951,832	7,252,347	458,987	14,599,249
2006	3,967,409	2,984,282	7,296,533	461,810	14,710,034
Average Annual Growth					
1991-2001	0.89%	2.08%	1.44%	-7.33%	0.95%
1991-2006	0.89%	1.76%	1.18%	-4.75%	0.90%

FIGURE 3.3
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
GULF STATES UTILITIES COMPANY - TEXAS

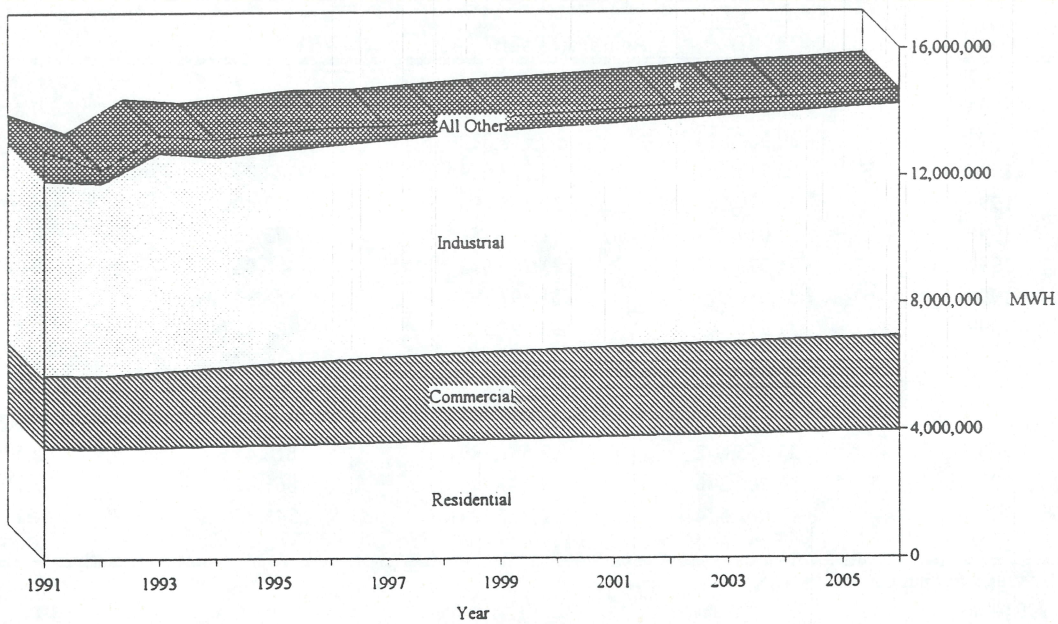


TABLE 3.10
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
GULF STATES UTILITIES COMPANY - TOTAL

Year	Staff Adjusted(MW)	GSU Adjusted(MW)	Difference (MW)	Difference (%)
1991	4,922	4,922	0	0.00%
1992	5,032	5,042	-11	-0.21%
1993	5,378	5,298	80	1.51%
1994	5,449	5,390	59	1.09%
1995	5,404	5,426	-22	-0.41%
1996	5,483	5,496	-13	-0.24%
1997	5,529	5,525	4	0.07%
1998	5,594	5,606	-12	-0.21%
1999	5,655	5,714	-59	-1.03%
2000	5,715	5,770	-55	-0.95%
2001	5,760	5,829	-69	-1.18%
2002	5,827	5,845	-18	-0.31%
2003	5,892	5,830	62	1.06%
2004	5,956	5,887	69	1.17%
2005	6,021	5,927	94	1.59%
2006	6,087	5,940	147	2.47%
Average Annual Growth				
1991-2001	1.58%	1.71%		
1991-2006	1.43%	1.26%		

TABLE 3.11
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
GULF STATES UTILITIES COMPANY - TOTAL

Year	Staff Adjusted(MWH)	GSU Adjusted(MWH)	Difference (MWH)	Difference (%)
1991	29,069,347	29,069,347	0	0.00%
1992	28,392,045	28,623,812	-231,767	-0.81%
1993	30,303,812	30,612,312	-308,500	-1.01%
1994	30,745,721	31,133,629	-387,908	-1.25%
1995	30,570,887	30,618,696	-47,809	-0.16%
1996	31,014,025	31,087,181	-73,156	-0.24%
1997	31,273,772	31,360,633	-86,861	-0.28%
1998	31,639,072	31,797,197	-158,125	-0.50%
1999	31,975,366	32,097,523	-122,157	-0.38%
2000	32,301,586	32,417,457	-115,871	-0.36%
2001	32,633,894	32,714,515	-80,621	-0.25%
2002	33,000,806	32,462,933	537,873	1.66%
2003	33,355,642	32,537,189	818,453	2.52%
2004	33,706,346	32,644,929	1,061,417	3.25%
2005	34,062,574	32,717,224	1,345,350	4.11%
2006	34,426,634	32,852,507	1,574,127	4.79%
Average Annual Growth				
1991-2001	1.16%	1.19%		
1991-2006	1.13%	0.82%		

TABLE 3.12
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
GULF STATES UTILITIES COMPANY - TOTAL

Year	Residential Adjusted(MWH)	Commercial Adjusted(MWH)	Industrial Adjusted(MWH)	All Other (MWH)	Total (MWH)
1991	6,924,648	5,460,326	13,629,341	1,016,660	29,069,347
1992	6,863,549	5,502,472	13,642,529	1,043,791	28,392,045
1993	6,933,518	5,637,870	15,174,290	1,057,662	30,303,812
1994	7,000,968	5,756,262	15,366,863	1,073,908	30,745,721
1995	7,120,369	5,865,682	14,903,875	1,090,324	30,570,888
1996	7,241,139	5,995,916	15,036,658	1,110,990	31,014,025
1997	7,312,685	6,119,670	15,200,342	1,132,973	31,273,771
1998	7,387,731	6,234,271	15,321,858	1,154,118	31,639,073
1999	7,475,283	6,340,702	15,417,582	1,174,381	31,975,366
2000	7,568,187	6,441,225	15,505,742	1,195,357	32,301,586
2001	7,659,807	6,538,610	15,598,472	1,217,473	32,633,894
2002	7,743,661	6,634,955	15,733,601	1,242,052	33,000,806
2003	7,816,537	6,731,162	15,866,742	1,267,087	33,355,639
2004	7,883,520	6,827,404	16,000,565	1,293,638	33,706,349
2005	7,954,485	6,923,521	16,134,975	1,320,053	34,062,574
2006	8,033,631	7,019,544	16,268,032	1,345,850	34,426,636
Average Annual Growth					
1991-2001	1.01%	1.82%	1.36%	1.82%	1.16%
1991-2006	1.00%	1.69%	1.19%	1.89%	1.13%

FIGURE 3.4
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
GULF STATES UTILITIES COMPANY - TOTAL

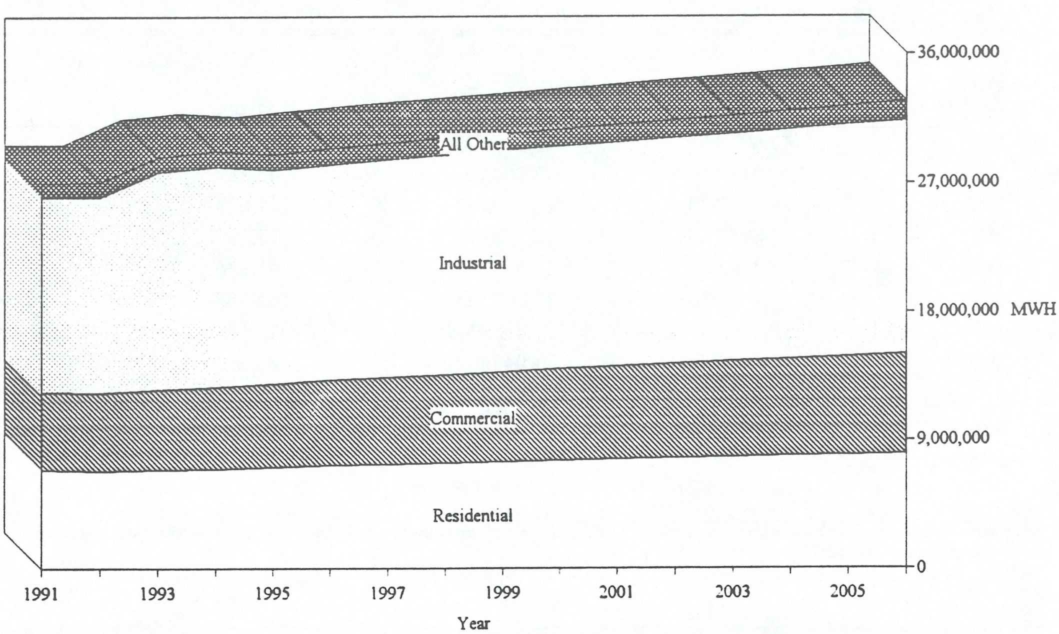


TABLE 3.13
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
CENTRAL POWER AND LIGHT COMPANY

Year	Staff Adjusted(MW)	CPL Adjusted(MW)	Difference (MW)	Difference (%)
1991	3,150	3,150	0	0.00%
1992	3,155	3,219	-64	-1.99%
1993	3,219	3,303	-84	-2.55%
1994	3,334	3,379	-45	-1.33%
1995	3,373	3,403	-30	-0.89%
1996	3,468	3,475	-7	-0.20%
1997	3,545	3,543	2	0.05%
1998	3,621	3,621	0	0.00%
1999	3,699	3,705	-6	-0.17%
2000	3,766	3,786	-20	-0.54%
2001	3,828	3,879	-51	-1.33%
2002	3,899	3,976	-77	-1.94%
2003	3,954	4,072	-118	-2.89%
2004	3,986	4,170	-184	-4.41%
2005	4,031	4,267	-236	-5.52%
2006	4,066	4,361	-295	-6.77%
Average Annual Growth				
1991-2001	1.97%	2.10%		
1991-2006	1.72%	2.19%		

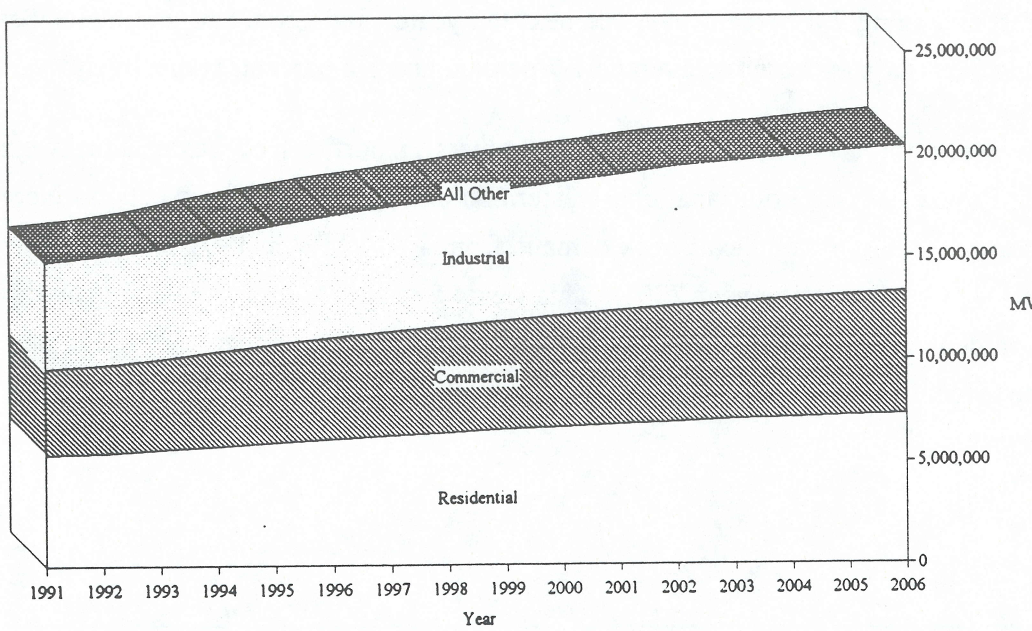
TABLE 3.14
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
CENTRAL POWER AND LIGHT COMPANY

Year	Staff Adjusted(MWH)	CPL Adjusted(MWH)	Difference (MWH)	Difference (%)
1991	16,195,805	16,195,805	0	0.00%
1992	16,651,017	16,629,955	21,062	0.13%
1993	17,054,586	17,331,965	-277,379	-1.60%
1994	17,691,165	17,817,753	-126,588	-0.71%
1995	17,945,592	17,900,205	45,387	0.25%
1996	18,461,688	18,350,615	111,073	0.61%
1997	18,875,100	18,797,165	77,935	0.41%
1998	19,308,921	19,350,757	-41,836	-0.22%
1999	19,743,036	19,908,918	-165,882	-0.83%
2000	20,116,189	20,438,592	-322,403	-1.58%
2001	20,465,446	21,045,818	-580,372	-2.76%
2002	20,888,670	21,610,265	-721,595	-3.34%
2003	21,150,964	22,209,006	-1,058,042	-4.76%
2004	21,405,747	22,790,347	-1,384,600	-6.08%
2005	21,689,936	23,365,964	-1,676,028	-7.17%
2006	21,934,746	23,897,807	-1,963,061	-8.21%
Average Annual Growth				
1991-2001	2.37%	2.65%		
1991-2006	2.04%	2.63%		

TABLE 3.15
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
CENTRAL POWER AND LIGHT COMPANY

Year	Residential Adjusted(MWH)	Commercial Adjusted(MWH)	Industrial Adjusted(MWH)	All Other (MWH)	Total (MWH)
1991	5,476,156	4,213,752	5,223,298	0	16,195,805
1992	5,554,185	4,282,065	5,349,465	0	16,651,017
1993	5,681,835	4,430,579	5,435,921	0	17,054,587
1994	5,867,260	4,616,458	5,660,091	0	17,691,165
1995	6,042,446	4,796,956	5,842,812	0	17,945,593
1996	6,214,351	4,956,619	5,994,547	0	18,461,687
1997	6,365,592	5,083,924	6,106,813	0	18,875,101
1998	6,497,609	5,199,516	6,266,765	0	19,308,921
1999	6,633,865	5,320,442	6,417,577	0	19,743,037
2000	6,758,994	5,433,620	6,530,274	0	20,116,188
2001	6,868,532	5,542,361	6,638,072	0	20,465,447
2002	6,974,039	5,656,535	6,814,542	0	20,888,671
2003	7,084,306	5,731,258	6,876,980	0	21,150,965
2004	7,163,065	5,816,461	6,946,117	0	21,405,748
2005	7,247,146	5,903,488	7,038,649	0	21,689,936
2006	7,324,781	5,994,639	7,094,985	0	21,934,746
Average Annual Growth					
1991-2001	2.29%	2.78%	2.43%	0.00%	2.37%
1991-2006	1.96%	2.38%	2.06%	0.00%	2.04%

FIGURE 3.5
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
CENTRAL POWER AND LIGHT COMPANY



City Public Service of San Antonio

San Antonio, served by CPS, has exhibited a recovery equal to, if not greater than, any of the major markets in Texas. Its recovery has been fueled by growth in the service sector as well as in tourism. The recovery is expected to continue and is reflected in the staff's peak demand and sales forecast.

The staff predicts that peak demand will reach 3,918 MW by the year 2001. This translates into an average annual growth rate over the 10-year forecast period of 3.4 percent. CPS predicts a growth of 3.8 percent over the same time period.

Total sales are also projected to grow at a relatively strong rate of 3.5 percent per year. Leading the way is industrial sales at 4.8 percent per year followed by commercial sales at 3.3 percent over the 10-year forecast period. Residential sales are projected to grow at a rate of 2.3 percent through the year 2001.

Southwestern Public Service Company

Total system peak demand is expected to increase from 3,079 MW in 1991 to 3,573 MW by the year 2001. This yields an average annual increase of 1.5 percent. Peak demand in the SPS Texas service area will grow from 2,282 MW in 1991 to 2,689 MW by the year 2001. Annual growth averages 1.7 percent over the 10-year forecast period. This is relatively sluggish growth compared to the growth rates in other service areas in Texas.

Total sales are forecasted to increase at an annual rate of 1.9 percent while sales in Texas are projected to grow at a rate of 2.3 percent. In Texas, residential sales growth will be strongest, averaging 2.8 percent over the next ten years. Industrial and commercial sales growth in Texas are expected to average 1.7 percent and 1.2 percent, respectively.

Southwestern Electric Power Company

SWEPCO serves customers in portions of Texas, northwestern Louisiana, and western Arkansas. The staff projects an increase of Texas peak demand from 1,640 MW in 1991 to 2,318 MW by the year 2001. This yields a relatively robust annual growth rate of 3.5 percent. Total system peak is expected to grow at an annual rate of 2.8 percent over the forecast period.

TABLE 3.16
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
CITY PUBLIC SERVICE OF SAN ANTONIO

Year	Staff Adjusted(MW)	CPS Adjusted(MW)	Difference (MW)	Difference (%)
1991	2,799	2,799	0	0.00%
1992	2,865	2,904	-39	-1.36%
1993	2,954	3,020	-66	-2.20%
1994	3,061	3,145	-84	-2.68%
1995	3,176	3,276	-100	-3.05%
1996	3,291	3,391	-100	-2.95%
1997	3,411	3,527	-116	-3.30%
1998	3,533	3,658	-125	-3.42%
1999	3,660	3,788	-128	-3.39%
2000	3,792	3,911	-119	-3.05%
2001	3,918	4,046	-128	-3.17%
2002	4,037	4,167	-130	-3.12%
2003	4,162	4,296	-134	-3.12%
2004	4,290	4,417	-127	-2.87%
2005	4,424	4,574	-150	-3.28%
2006	4,624	4,713	-89	-1.88%
Average Annual Growth				
1991-2001	3.42%	3.75%		
1991-2006	3.40%	3.53%		

TABLE 3.17
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
CITY PUBLIC SERVICE OF SAN ANTONIO

Year	Staff Adjusted(MWH)	CPS Adjusted(MWH)	Difference (MWH)	Difference (%)
1991	12,017,832	12,017,832	0	0.00%
1992	12,440,090	12,461,964	-21,874	-0.18%
1993	12,839,501	12,990,109	-150,608	-1.16%
1994	13,312,428	13,593,850	-281,422	-2.07%
1995	13,818,405	14,227,114	-408,709	-2.87%
1996	14,328,000	14,846,496	-518,496	-3.49%
1997	14,849,067	15,476,055	-626,988	-4.05%
1998	15,386,701	16,128,792	-742,091	-4.60%
1999	15,934,760	16,784,793	-850,033	-5.06%
2000	16,506,115	17,461,918	-955,803	-5.47%
2001	17,052,579	18,105,543	-1,052,964	-5.82%
2002	17,567,195	18,736,378	-1,169,183	-6.24%
2003	18,107,887	19,408,072	-1,300,185	-6.70%
2004	18,663,855	20,102,147	-1,438,292	-7.15%
2005	19,242,441	20,856,873	-1,614,432	-7.74%
2006	20,108,655	21,893,012	-1,784,357	-8.15%
Average Annual Growth				
1991-2001	3.56%	4.18%		
1991-2006	3.49%	4.08%		

TABLE 3.18
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
CITY PUBLIC SERVICE OF SAN ANTONIO

Year	Residential Adjusted(MWH)	Commercial Adjusted(MWH)	Industrial Adjusted(MWH)	All Other (MWH)	Total (MWH)
1991	4,823,812	2,333,529	4,558,897	0	12,017,832
1992	4,902,904	2,435,790	4,779,601	0	12,440,090
1993	4,973,117	2,519,828	5,011,136	0	12,839,501
1994	5,066,620	2,616,823	5,279,262	0	13,312,428
1995	5,181,681	2,706,690	5,565,291	0	13,818,405
1996	5,312,920	2,796,677	5,837,890	0	14,328,000
1997	5,456,237	2,880,453	6,115,299	0	14,849,067
1998	5,607,406	2,963,031	6,401,784	0	15,386,701
1999	5,767,512	3,044,559	6,689,910	0	15,934,760
2000	5,928,462	3,130,404	6,995,242	0	16,506,116
2001	6,087,159	3,213,228	7,279,966	0	17,052,580
2002	6,240,604	3,284,978	7,548,119	0	17,567,195
2003	6,390,657	3,360,968	7,840,404	0	18,107,887
2004	6,540,080	3,441,460	8,142,915	0	18,663,854
2005	6,689,259	3,521,934	8,467,085	0	19,242,441
2006	6,836,407	3,600,659	9,081,359	0	20,108,655
Average Annual Growth					
1991-2001	2.35%	3.25%	4.79%	0.00%	3.56%
1991-2006	2.35%	2.93%	4.70%	0.00%	3.49%

FIGURE 3.6
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
CITY PUBLIC SERVICE OF SAN ANTONIO

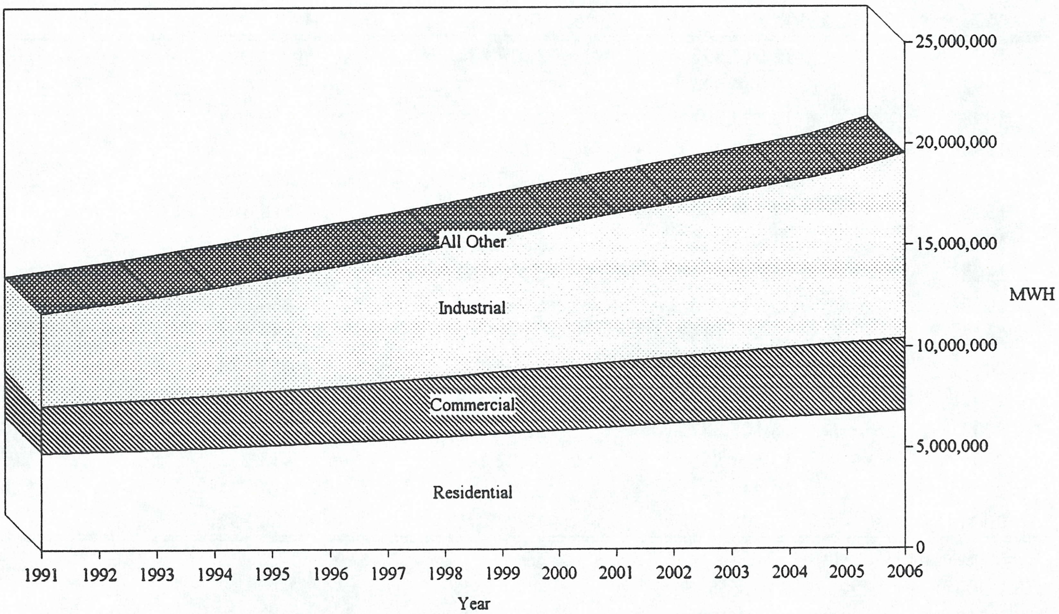


TABLE 3.19
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
SOUTHWESTERN PUBLIC SERVICE COMPANY - TEXAS

Year	Staff Adjusted(MW)	SPS* Adjusted(MW)	Difference (MW)	Difference (%)
1991	2,282	2,282	0	0.00%
1992	2,213	2,253	-40	-1.77%
1993	2,295	2,299	-4	-0.18%
1994	2,359	2,335	24	1.04%
1995	2,397	2,374	23	0.97%
1996	2,494	2,464	30	1.20%
1997	2,532	2,507	25	1.01%
1998	2,571	2,547	24	0.94%
1999	2,610	2,592	18	0.71%
2000	2,650	2,627	23	0.86%
2001	2,689	2,674	15	0.56%
2002	2,728	2,713	15	0.56%
2003	2,767	2,752	15	0.55%
2004	2,806	2,792	14	0.51%
2005	2,846	2,833	13	0.44%
2006	2,885	2,874	11	0.38%
Average Annual Growth				
1991-2001	1.65%	1.60%		
1991-2006	1.58%	1.55%		

TABLE 3.20
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
SOUTHWESTERN PUBLIC SERVICE COMPANY - TEXAS

Year	Staff Adjusted(MWH)	SPS* Adjusted(MWH)	Difference (MWH)	Difference (%)
1991	11,848,660	11,848,660	0	0.00%
1992	11,985,637	11,817,637	168,000	1.42%
1993	12,460,180	12,240,630	219,550	1.79%
1994	12,838,219	12,580,222	257,997	2.05%
1995	13,073,546	12,788,267	285,279	2.23%
1996	13,626,948	13,212,557	414,391	3.14%
1997	13,871,930	13,433,639	438,291	3.26%
1998	14,116,742	13,657,532	459,210	3.36%
1999	14,362,991	13,885,184	477,807	3.44%
2000	14,609,775	14,116,684	493,091	3.49%
2001	14,858,007	14,352,056	505,951	3.53%
2002	15,068,817	14,423,817	645,000	4.47%
2003	15,278,997	14,495,936	783,061	5.40%
2004	15,489,423	14,568,416	921,007	6.32%
2005	15,700,179	14,641,258	1,058,921	7.23%
2006	15,911,979	14,714,464	1,197,515	8.14%
Average Annual Growth				
1991-2001	2.29%	1.94%		
1991-2006	1.99%	1.45%		

* - SPS did not provide MW forecast beyond 2001, and MWH forecast beyond 1995.
Hence, staff extrapolated these numbers.

TABLE 3.21
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
SOUTHWESTERN PUBLIC SERVICE COMPANY - TEXAS

Year	Residential Adjusted(MWH)	Commercial Adjusted(MWH)	Industrial Adjusted(MWH)	All Other (MWH)	Total (MWH)
1991	1,749,385	1,352,892	6,042,022	2,704,361	11,848,660
1992	1,796,503	1,390,288	6,190,779	2,608,067	11,985,637
1993	1,856,163	1,407,888	6,311,977	2,884,152	12,460,180
1994	1,914,866	1,424,711	6,424,743	3,073,899	12,838,219
1995	1,972,213	1,439,585	6,533,010	3,128,739	13,073,546
1996	2,028,714	1,453,718	6,642,403	3,502,113	13,626,948
1997	2,085,296	1,467,348	6,751,382	3,567,905	13,871,930
1998	2,141,690	1,480,448	6,859,643	3,634,961	14,116,742
1999	2,199,026	1,493,117	6,967,541	3,703,307	14,362,991
2000	2,256,627	1,505,514	7,074,666	3,772,968	14,609,775
2001	2,314,820	1,517,709	7,181,508	3,843,970	14,858,006
2002	2,335,156	1,529,592	7,287,733	3,916,337	15,068,817
2003	2,354,593	1,541,084	7,393,222	3,990,098	15,278,997
2004	2,373,316	1,552,288	7,498,540	4,065,280	15,489,424
2005	2,391,438	1,563,258	7,603,574	4,141,910	15,700,179
2006	2,409,168	1,574,121	7,708,674	4,220,016	15,911,979
Average Annual Growth					
1991-2001	2.84%	1.16%	1.74%	3.58%	2.29%
1991-2006	2.16%	1.01%	1.64%	3.01%	1.99%

FIGURE 3.7
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
SOUTHWESTERN PUBLIC SERVICE COMPANY - TEXAS

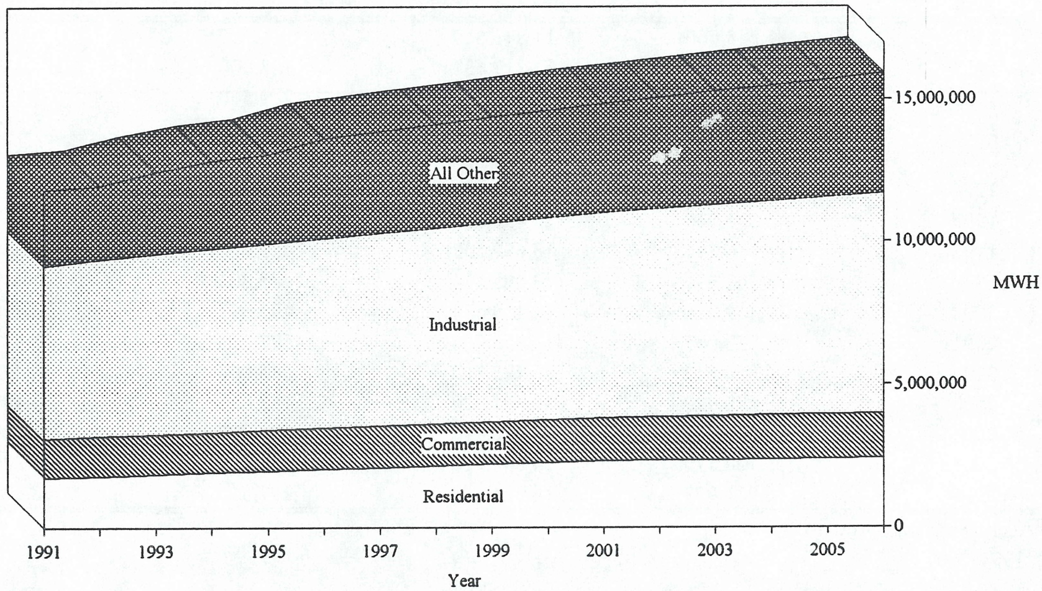


TABLE 3.22
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
SOUTHWESTERN PUBLIC SERVICE COMPANY - TOTAL

Year	Staff Adjusted(MW)	SPS* Adjusted(MW)	Difference (MW)	Difference (%)
1991	3,079	3,079	0	0.00%
1992	3,021	3,036	-15	-0.50%
1993	3,113	3,079	34	1.10%
1994	3,188	3,130	58	1.84%
1995	3,234	3,182	52	1.64%
1996	3,342	3,288	54	1.65%
1997	3,387	3,344	43	1.28%
1998	3,433	3,400	33	0.96%
1999	3,480	3,457	23	0.66%
2000	3,527	3,514	13	0.36%
2001	3,573	3,574	-1	-0.02%
2002	3,620	3,625	-5	-0.14%
2003	3,666	3,676	-10	-0.28%
2004	3,712	3,729	-17	-0.46%
2005	3,758	3,782	-24	-0.64%
2006	3,804	3,836	-32	-0.83%
Average Annual Growth				
1991-2001	1.50%	1.50%		
1991-2006	1.42%	1.48%		

TABLE 3.23
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
SOUTHWESTERN PUBLIC SERVICE COMPANY - TOTAL

Year	Staff Adjusted(MWH)	SPS* Adjusted(MWH)	Difference (MWH)	Difference (%)
1991	16,020,011	16,020,011	0	0.00%
1992	16,130,854	15,942,653	188,201	1.18%
1993	16,658,213	16,433,511	224,702	1.37%
1994	17,093,055	16,842,368	250,687	1.49%
1995	17,379,043	17,120,700	258,343	1.51%
1996	17,991,269	17,688,732	302,537	1.71%
1997	18,265,639	17,984,713	280,926	1.56%
1998	18,546,440	18,284,456	261,984	1.43%
1999	18,832,835	18,589,233	243,602	1.31%
2000	19,118,148	18,899,161	218,987	1.16%
2001	19,404,483	19,214,273	190,210	0.99%
2002	19,652,340	19,310,344	341,996	1.77%
2003	19,898,243	19,406,896	491,347	2.53%
2004	20,143,986	19,503,931	640,055	3.28%
2005	20,389,683	19,601,450	788,233	4.02%
2006	20,636,650	19,699,457	937,193	4.76%
Average Annual Growth				
1991-2001	1.94%	1.83%		
1991-2006	1.70%	1.39%		

* - SPS did not provide MW forecast beyond 2001, and MWH forecast beyond 1995.
Hence, staff extrapolated these numbers.

TABLE 3.24
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
SOUTHWESTERN PUBLIC SERVICE COMPANY - TOTAL

Year	Residential Adjusted(MWH)	Commercial Adjusted(MWH)	Industrial Adjusted(MWH)	All Other (MWH)	Total (MWH)
1991	2,432,921	1,831,955	7,563,277	4,191,858	16,020,011
1992	2,479,234	1,871,889	7,691,780	4,087,951	16,130,854
1993	2,547,767	1,893,570	7,842,604	4,374,273	16,658,213
1994	2,614,023	1,914,102	7,989,306	4,575,623	17,093,055
1995	2,677,666	1,932,188	8,128,965	4,640,224	17,379,044
1996	2,740,379	1,949,726	8,278,541	5,022,623	17,991,269
1997	2,803,252	1,966,790	8,398,444	5,097,153	18,265,639
1998	2,865,717	1,983,277	8,525,070	5,172,377	18,546,441
1999	2,929,309	1,999,316	8,655,658	5,248,554	18,832,836
2000	2,992,982	2,015,055	8,784,473	5,325,639	19,118,148
2001	3,057,181	2,030,608	8,912,870	5,403,823	19,404,482
2002	3,083,269	2,045,764	9,040,297	5,483,010	19,652,340
2003	3,108,159	2,060,442	9,166,481	5,563,160	19,898,243
2004	3,132,197	2,074,812	9,292,472	5,644,506	20,143,987
2005	3,155,522	2,088,928	9,418,127	5,727,105	20,389,683
2006	3,178,452	2,102,960	9,544,107	5,811,132	20,636,651
Average Annual Growth					
1991-2001	2.31%	1.03%	1.66%	2.57%	1.94%
1991-2006	1.80%	0.92%	1.56%	2.20%	1.70%

FIGURE 3.8
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
SOUTHWESTERN PUBLIC SERVICE COMPANY - TOTAL

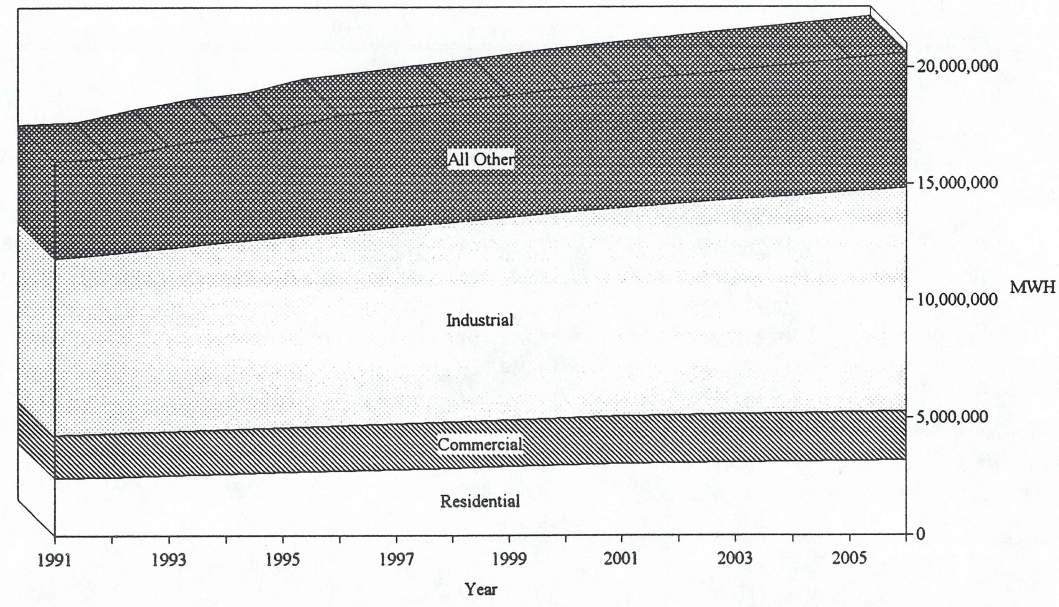


TABLE 3.25
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
SOUTHWESTERN ELECTRIC POWER COMPANY - TEXAS

Year	Staff Adjusted(MW)	SWEPCO* Adjusted(MW)	Difference (MW)	Difference
1991	1,640	1,640	0	0.00%
1992	1,707	1,711	-4	-0.22%
1993	1,766	1,834	-68	-3.69%
1994	1,881	1,865	16	0.85%
1995	1,973	1,937	36	1.88%
1996	2,025	1,968	57	2.89%
1997	2,117	2,038	79	3.86%
1998	2,162	2,069	93	4.52%
1999	2,210	2,100	110	5.24%
2000	2,277	2,155	122	5.65%
2001	2,318	2,184	134	6.15%
2002	2,365	2,220	145	6.54%
2003	2,412	2,253	159	7.04%
2004	2,452	2,287	165	7.23%
2005	2,493	2,325	168	7.24%
2006	2,534	2,366	168	7.11%
Average Annual Growth				
1991-2001	3.52%	2.91%		
1991-2006	2.94%	2.47%		

TABLE 3.26
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
SOUTHWESTERN ELECTRIC POWER COMPANY - TEXAS

Year	Staff Adjusted(MWH)	SWEPCO* Adjusted(MWH)	Difference (MWH)	Difference
1991	6,811,049	6,811,049	0	0.00%
1992	6,981,347	6,989,556	-8,209	-0.12%
1993	7,414,527	7,493,056	-78,529	-1.05%
1994	7,826,268	7,945,883	-119,615	-1.51%
1995	8,489,855	8,533,994	-44,139	-0.52%
1996	8,687,983	8,667,429	20,554	0.24%
1997	9,041,859	8,970,716	71,143	0.79%
1998	9,207,389	9,094,591	112,798	1.24%
1999	9,373,514	9,222,666	150,848	1.64%
2000	9,620,126	9,446,032	174,094	1.84%
2001	9,757,916	9,563,642	194,274	2.03%
2002	9,919,765	9,700,344	219,421	2.26%
2003	10,079,473	9,839,585	239,888	2.44%
2004	10,209,415	9,993,946	215,469	2.16%
2005	10,334,591	10,139,850	194,741	1.92%
2006	10,462,964	10,295,489	167,475	1.63%
Average Annual Growth				
1991-2001	3.66%	3.45%		
1991-2006	2.90%	2.79%		

* - Staff excluded certain NTEC MW and MWH requirements serviced through the SWEPCO system.

TABLE 3.27
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
SOUTHWESTERN ELECTRIC POWER COMPANY - TEXAS

Year	Residential Adjusted(MWH)	Commercial Adjusted(MWH)	Industrial Adjusted(MWH)	All Other (MWH)	Total (MWH)
1,991	1,560,113	1,241,693	3,403,078	606,165	6,811,049
1,992	1,546,392	1,227,286	3,407,027	800,641	6,981,347
1,993	1,582,801	1,242,321	3,410,981	1,178,424	7,414,527
1,994	1,622,287	1,261,591	3,414,940	1,527,450	7,826,268
1,995	1,664,453	1,277,658	3,531,432	2,016,313	8,489,855
1,996	1,707,868	1,298,463	3,642,488	2,039,164	8,687,983
1,997	1,742,932	1,322,860	3,743,014	2,233,053	9,041,859
1,998	1,774,811	1,350,396	3,827,519	2,254,664	9,207,389
1,999	1,809,604	1,383,834	3,902,740	2,277,336	9,373,514
2,000	1,840,323	1,417,941	3,974,344	2,387,519	9,620,126
2,001	1,869,297	1,453,521	4,046,751	2,388,347	9,757,916
2,002	1,899,907	1,489,941	4,120,771	2,409,146	9,919,765
2,003	1,932,012	1,521,616	4,194,116	2,431,728	10,079,473
2,004	1,964,016	1,535,447	4,249,825	2,460,126	10,209,415
2,005	1,995,298	1,549,477	4,309,820	2,479,997	10,334,591
2,006	2,024,599	1,557,109	4,372,673	2,508,584	10,462,964
Average Annual Growth					
1991-2001	1.82%	1.59%	1.75%	14.70%	3.66%
1991-2006	1.75%	1.52%	1.69%	9.93%	2.90%

FIGURE 3.9
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
SOUTHWESTERN ELECTRIC POWER COMPANY - TEXAS

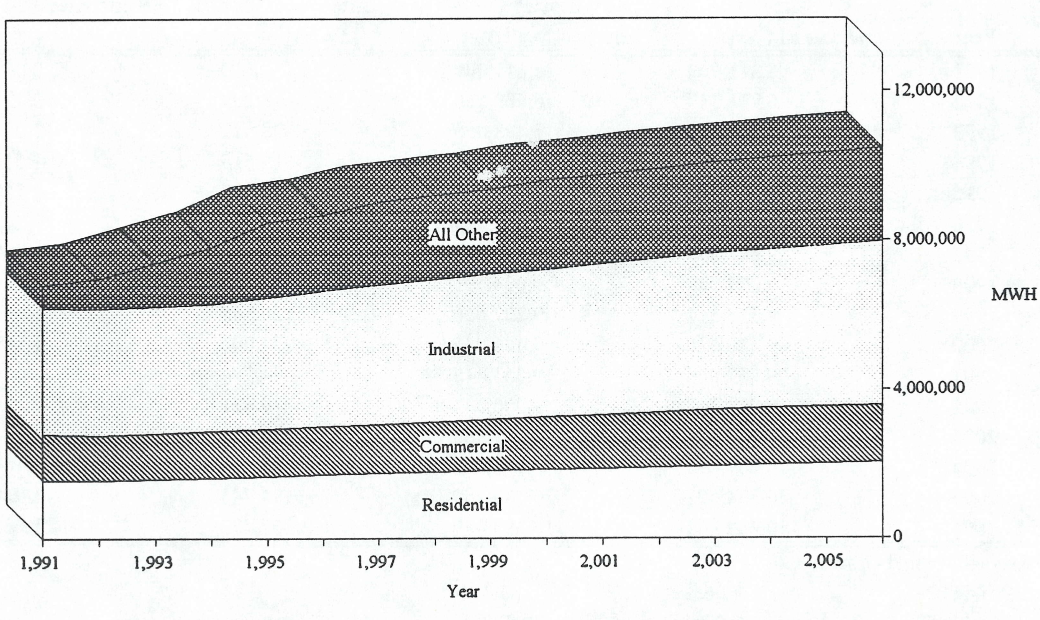


TABLE 3.28
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
SOUTHWESTERN ELECTRIC POWER COMPANY - TOTAL

Year	Staff Adjusted(MW)	SWEPCO* Adjusted(MW)	Difference (MW)	Difference
1991	2,915	2,915	0	0.00%
1992	3,046	3,122	-76	-2.45%
1993	3,137	3,277	-140	-4.26%
1994	3,287	3,337	-50	-1.50%
1995	3,420	3,442	-22	-0.63%
1996	3,500	3,497	3	0.08%
1997	3,617	3,597	20	0.56%
1998	3,688	3,652	36	1.00%
1999	3,765	3,707	58	1.57%
2000	3,861	3,792	69	1.81%
2001	3,930	3,847	83	2.17%
2002	4,005	3,912	93	2.39%
2003	4,081	3,972	109	2.73%
2004	4,151	4,032	119	2.94%
2005	4,221	4,102	119	2.90%
2006	4,291	4,177	114	2.72%
Average Annual Growth				
1991-2001	2.81%	2.61%		
1991-2006	2.43%	2.25%		

TABLE 3.29
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
SOUTHWESTERN ELECTRIC POWER COMPANY - TOTAL

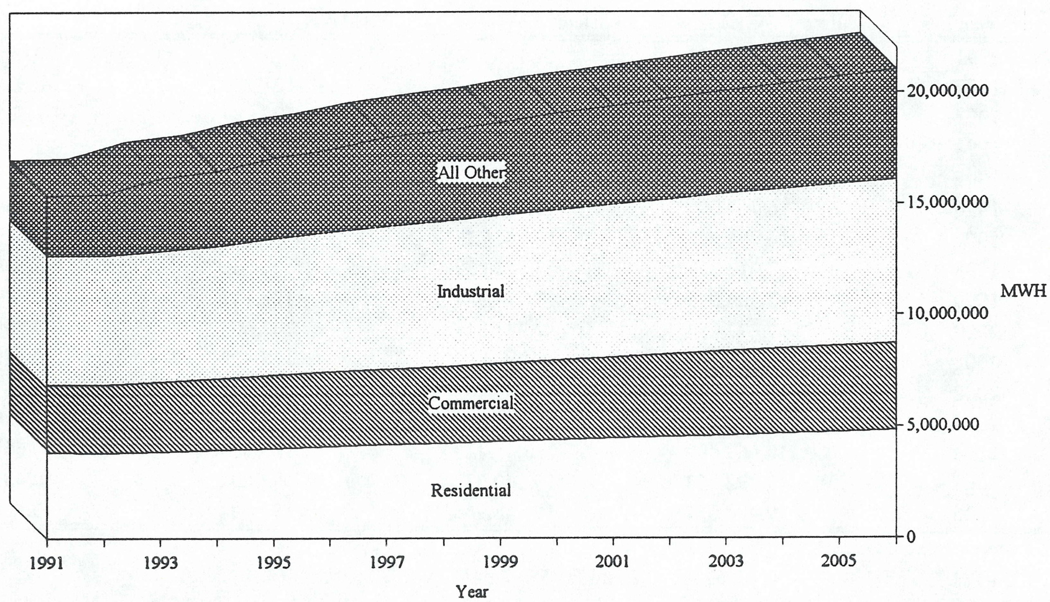
Year	Staff Adjusted(MWH)	SWEPCO* Adjusted(MWH)	Difference (MWH)	Difference
1991	14,007,092	14,007,092	0	0.00%
1992	14,094,765	14,226,654	-131,889	-0.93%
1993	14,692,090	14,889,674	-197,584	-1.33%
1994	15,287,275	15,469,582	-182,307	-1.18%
1995	16,145,980	16,180,413	-34,433	-0.21%
1996	16,467,006	16,445,037	21,969	0.13%
1997	16,934,322	16,877,228	57,094	0.34%
1998	17,213,821	17,123,285	90,536	0.53%
1999	17,506,095	17,377,948	128,147	0.74%
2000	17,877,954	17,735,347	142,607	0.80%
2001	18,140,179	17,991,877	148,302	0.82%
2002	18,426,134	18,265,262	160,872	0.88%
2003	18,711,619	18,542,658	168,961	0.91%
2004	18,969,090	18,845,410	123,680	0.66%
2005	19,222,822	19,140,820	82,002	0.43%
2006	19,480,057	19,448,965	31,092	0.16%
Average Annual Growth				
1991-2001	2.62%	2.54%		
1991-2006	2.22%	2.21%		

*** - Staff excluded certain NTEC MW and MWH requirements serviced through the SWEPCO system.**

TABLE 3.30
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
SOUTHWESTERN ELECTRIC POWER COMPANY - TOTAL

Year	Residential Adjusted(MWH)	Commercial Adjusted(MWH)	Industrial Adjusted(MWH)	All Other (MWH)	Total (MWH)
1991	3,840,944	3,056,299	5,779,059	2,675,117	14,007,092
1992	3,814,137	3,061,509	5,797,099	2,761,274	14,094,765
1993	3,876,528	3,129,467	5,868,297	3,305,457	14,692,090
1994	3,949,451	3,206,655	5,946,745	3,375,661	15,287,275
1995	4,034,332	3,281,812	6,138,465	3,635,403	16,145,980
1996	4,118,260	3,328,438	6,287,402	3,725,961	16,467,006
1997	4,192,147	3,375,702	6,420,473	3,996,148	16,934,322
1998	4,260,570	3,426,921	6,538,907	4,091,539	17,213,821
1999	4,334,944	3,492,248	6,648,406	4,189,372	17,506,095
2000	4,403,961	3,558,565	6,754,638	4,371,313	17,877,954
2001	4,469,262	3,626,657	6,862,026	4,452,257	18,140,179
2002	4,536,596	3,695,923	6,971,386	4,548,620	18,426,134
2003	4,606,646	3,760,778	7,080,431	4,646,497	18,711,619
2004	4,677,150	3,808,127	7,172,205	4,748,152	18,969,090
2005	4,746,775	3,856,013	7,268,633	4,849,155	19,222,822
2006	4,813,195	3,897,821	7,368,294	4,956,435	19,480,057
Average Annual Growth					
1991-2001	1.53%	1.73%	1.73%	5.23%	2.62%
1991-2006	1.52%	1.63%	1.63%	4.20%	2.22%

FIGURE 3.10
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
SOUTHWESTERN ELECTRIC POWER COMPANY - TOTAL



Total sales in the Texas service area are expected to grow at an annual rate of 3.7 percent. Residential growth is forecasted to be the strongest at 1.8 percent per year followed by industrial sales at 1.8 percent and commercial sales at 1.6 percent. The largest growth is in other sales which results from the additional loads of several cooperatives, including Tex-La Electric Cooperative and Rayburn Country Electric cooperative.

Lower Colorado River Authority Staff estimates that peak demand in the LCRA service area will grow at an average annual rate of 1.9 percent. LCRA's projection is 1.7 percent through the forecast period.

Staff predicts that the total system sales in LCRA's service area will grow at an average annual rate of 2.7 percent through the year 2001.

City of Austin Electric Utility Although the Austin area economy has little direct dependence on the oil industry, it nevertheless felt the impact of the Texas downturn. The construction sector was particularly hard hit during the late 1980s as a result of overbuilding and a speculative real estate market. The Austin economy is expected to improve, especially in the long-run, relying on a well-educated labor force and concentration of high-tech industries.

The staff projects a robust average annual growth in peak demand of 2.6 percent through the year 2001. The City's expectations are somewhat more optimistic. It expects the system peak to grow at an average annual rate of 2.9 percent.

Total system sales are forecasted to grow at an average annual rate of 2.7 percent. Industrial sales are expected to show an increase of 3.1 percent through the forecast period while residential and commercial sales are projected to grow at 2.3 percent and 2.9 percent, respectively.

West Texas Utilities Company Staff forecasts that peak demand will increase at an average annual rate of 2.6 percent in the next decade. WTU projects slower growth of 2.3 percent over the same period.

TABLE 3.31
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
LOWER COLORADO RIVER AUTHORITY

Year	Staff Adjusted(MW)	LCRA Adjusted(MW)	Difference (MW)	Difference (%)
1991	1,601	1,601	0	0.00%
1992	1,580	1,571	9	0.56%
1993	1,613	1,599	14	0.89%
1994	1,654	1,705	-51	-2.99%
1995	1,698	1,734	-36	-2.10%
1996	1,739	1,765	-26	-1.45%
1997	1,783	1,794	-11	-0.62%
1998	1,822	1,824	-2	-0.11%
1999	1,864	1,844	20	1.09%
2000	1,895	1,863	32	1.70%
2001	1,933	1,891	42	2.25%
2002	1,970	1,919	51	2.66%
2003	2,007	1,949	58	2.98%
2004	2,046	1,980	66	3.31%
2005	2,085	2,013	72	3.58%
2006	2,124	2,046	78	3.82%
Average Annual Growth				
1991-2001	1.90%	1.68%		
1991-2006	1.90%	1.65%		

TABLE 3.32
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
LOWER COLORADO RIVER AUTHORITY

Year	Staff Adjusted(MWH)	LCRA Adjusted(MWH)	Difference Other (MWH)	Difference (%)
1991	7,448,589	7,448,589	0	0.00%
1992	7,778,546	7,713,911	64,635	0.84%
1993	7,957,151	7,895,437	61,714	0.78%
1994	8,162,758	8,064,798	97,960	1.21%
1995	8,376,164	8,235,096	141,068	1.71%
1996	8,603,392	8,412,879	190,513	2.26%
1997	8,844,689	8,584,112	260,577	3.04%
1998	9,085,438	8,761,895	323,543	3.69%
1999	9,316,110	8,907,864	408,246	4.58%
2000	9,521,331	9,025,762	495,569	5.49%
2001	9,705,673	9,146,468	559,205	6.11%
2002	9,879,739	9,279,337	600,402	6.47%
2003	10,055,262	9,421,563	633,699	6.73%
2004	10,237,932	9,570,340	667,592	6.98%
2005	10,425,203	9,729,409	695,794	7.15%
2006	10,611,009	9,917,494	693,515	6.99%
Average Annual Growth				
1991-2001	2.68%	2.07%		
1991-2006	2.39%	1.93%		

TABLE 3.33
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
CITY OF AUSTIN ELECTRIC UTILITY

Year	Staff Adjusted(MW)	COA Adjusted(MW)	Difference (MW)	Difference (%)
1991	1,457	1,457	0	0.00%
1992	1,564	1,576	-12	-0.73%
1993	1,611	1,601	10	0.63%
1994	1,636	1,628	8	0.49%
1995	1,667	1,657	10	0.61%
1996	1,703	1,684	19	1.11%
1997	1,744	1,691	53	3.15%
1998	1,783	1,749	34	1.93%
1999	1,816	1,804	12	0.69%
2000	1,847	1,867	-20	-1.07%
2001	1,877	1,933	-56	-2.87%
2002	1,910	2,001	-91	-4.53%
2003	1,944	2,073	-129	-6.21%
2004	1,976	2,152	-176	-8.19%
2005	2,015	2,232	-217	-9.73%
2006	2,050	2,320	-270	-11.64%
Average Annual Growth				
1991-2001	2.57%	2.87%		
1991-2006	2.30%	3.15%		

TABLE 3.34
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
CITY OF AUSTIN ELECTRIC UTILITY

Year	Staff Adjusted(MWH)	COA Adjusted(MWH)	Difference (MWH)	Difference (%)
1991	6,540,257	6,540,257	0	0.00%
1992	6,821,449	6,773,172	48,277	0.71%
1993	7,030,398	6,910,559	119,839	1.73%
1994	7,184,927	7,072,662	112,265	1.59%
1995	7,337,653	7,239,062	98,591	1.36%
1996	7,535,069	7,431,560	103,509	1.39%
1997	7,755,390	7,629,181	126,209	1.65%
1998	7,966,316	7,922,774	43,542	0.55%
1999	8,157,474	8,221,779	-64,305	-0.78%
2000	8,339,966	8,571,078	-231,112	-2.70%
2001	8,508,417	8,896,290	-387,873	-4.36%
2002	8,686,983	9,260,394	-573,411	-6.19%
2003	8,869,875	9,647,195	-777,320	-8.06%
2004	9,051,484	10,079,694	-1,028,210	-10.20%
2005	9,241,438	10,477,999	-1,236,561	-11.80%
2006	9,419,691	10,936,600	-1,516,909	-13.87%
Average Annual Growth				
1991-2001	2.67%	3.12%		
1991-2006	2.46%	3.49%		

TABLE 3.35
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
CITY OF AUSTIN ELECTRIC UTILITY

Year	Residential Adjusted(MWH)	Commercial Adjusted(MWH)	Industrial Adjusted(MWH)	All Other (MWH)	Total (MWH)
1991	2,445,090	3,148,035	769,945	177,188	6,540,257
1992	2,588,029	3,287,849	763,062	182,510	6,821,449
1993	2,655,580	3,390,474	796,001	188,343	7,030,398
1994	2,693,861	3,473,045	824,541	193,481	7,184,927
1995	2,721,903	3,562,190	854,313	199,247	7,337,652
1996	2,764,069	3,677,525	888,482	204,993	7,535,068
1997	2,833,209	3,791,382	921,138	209,662	7,755,390
1998	2,900,141	3,899,166	952,976	214,033	7,966,316
1999	2,955,970	3,999,156	984,310	218,038	8,157,475
2000	3,009,547	4,093,989	1,015,097	221,332	8,339,965
2001	3,060,318	4,179,006	1,044,020	225,073	8,508,416
2002	3,109,237	4,273,796	1,075,226	228,723	8,686,982
2003	3,159,754	4,369,924	1,107,979	232,220	8,869,875
2004	3,209,506	4,464,729	1,140,954	236,296	9,051,484
2005	3,262,393	4,564,262	1,174,840	239,943	9,241,438
2006	3,316,367	4,652,249	1,207,291	243,785	9,419,691
Average Annual Growth					
1991-2001	2.27%	2.87%	3.09%	2.42%	2.67%
1991-2006	2.05%	2.64%	3.04%	2.15%	2.46%

FIGURE 3.11
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
CITY OF AUSTIN ELECTRIC UTILITY

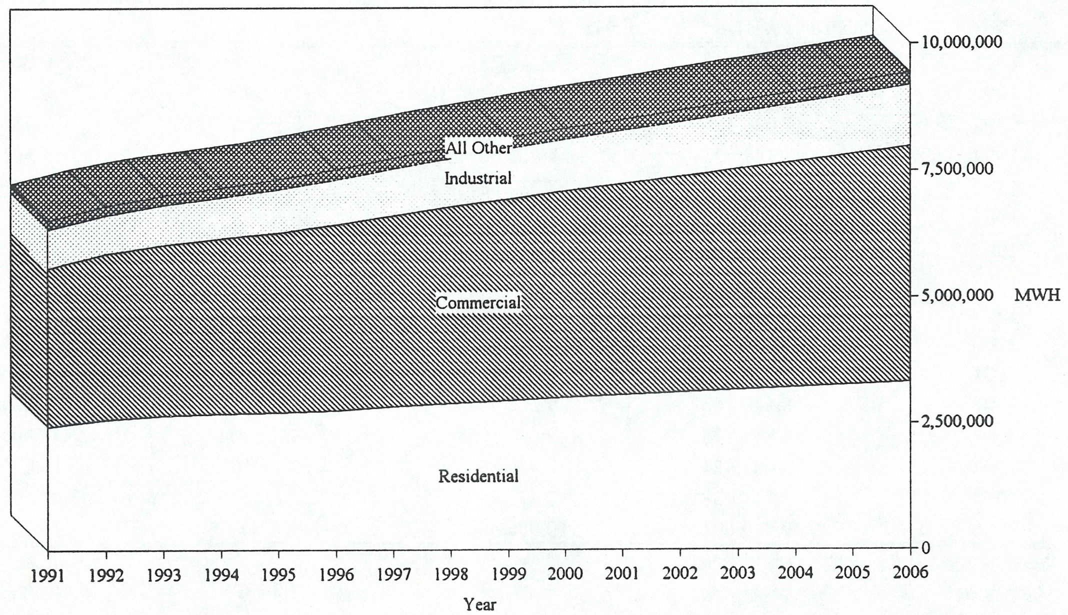


TABLE 3.36
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
WEST TEXAS UTILITIES COMPANY

Year	Staff Adjusted(MW)	WTU Adjusted(MW)	Difference (MW)	Difference (%)
1991	1,097	1,097	0	0.00%
1992	1,129	1,221	-92	-7.55%
1993	1,233	1,218	15	1.26%
1994	1,208	1,204	4	0.37%
1995	1,218	1,227	-9	-0.71%
1996	1,250	1,252	-2	-0.19%
1997	1,283	1,276	7	0.51%
1998	1,316	1,300	16	1.26%
1999	1,351	1,323	28	2.14%
2000	1,386	1,346	40	2.96%
2001	1,418	1,373	45	3.28%
2002	1,443	1,402	41	2.95%
2003	1,467	1,432	35	2.46%
2004	1,491	1,461	30	2.03%
2005	1,528	1,490	38	2.57%
2006	1,565	1,520	45	2.99%
Average Annual Growth				
1991-2001	2.60%	2.27%		
1991-2006	2.40%	2.20%		

TABLE 3.37
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
WEST TEXAS UTILITIES COMPANY

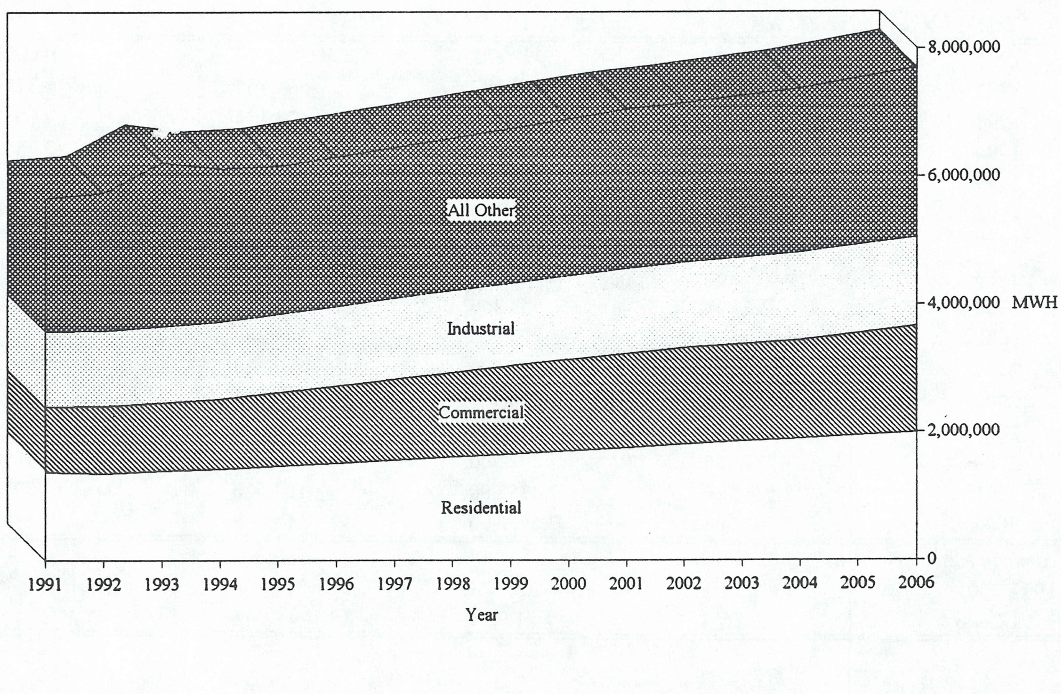
Year	Staff Adjusted(MWH)	WTU Adjusted(MWH)	Difference (MWH)	Difference (%)
1991	5,671,825	5,671,852	-27	0.00%
1992	5,742,965	6,407,700	-664,735	-10.37%
1993	6,233,906	6,407,100	-173,194	-2.70%
1994	6,126,514	6,301,700	-175,186	-2.78%
1995	6,173,054	6,302,400	-129,347	-2.05%
1996	6,311,803	6,386,300	-74,497	-1.17%
1997	6,455,179	6,482,200	-27,021	-0.42%
1998	6,602,486	6,584,300	18,186	0.28%
1999	6,753,201	6,688,400	64,801	0.97%
2000	6,903,130	6,799,900	103,230	1.52%
2001	7,045,123	6,924,600	120,523	1.74%
2002	7,150,113	7,018,100	132,013	1.88%
2003	7,262,450	7,153,700	108,750	1.52%
2004	7,373,954	7,292,200	81,754	1.12%
2005	7,538,726	7,435,200	103,526	1.39%
2006	7,702,568	7,582,900	119,668	1.58%
Average Annual Growth				
1991-2001	2.19%	2.02%		
1991-2006	2.06%	1.95%		

TABLE 3.38
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
WEST TEXAS UTILITIES COMPANY

Year	Residential Adjusted(MWH)	Commercial Adjusted(MWH)	Industrial (*) Adjusted(MWH)	All Other (MWH)	Total (MWH)
1991	1,367,003	1,035,791	1,176,103	2,092,928	5,671,825
1992	1,352,705	1,054,116	1,182,875	2,153,270	5,742,965
1993	1,386,501	1,073,337	1,201,068	2,573,000	6,233,906
1994	1,423,149	1,093,412	1,217,554	2,392,400	6,126,514
1995	1,465,232	1,150,731	1,233,290	2,323,800	6,173,054
1996	1,510,637	1,210,619	1,251,747	2,338,800	6,311,803
1997	1,557,375	1,267,993	1,268,812	2,361,000	6,455,179
1998	1,604,289	1,326,250	1,283,748	2,388,200	6,602,486
1999	1,652,565	1,383,454	1,298,283	2,418,900	6,753,201
2000	1,700,541	1,437,618	1,312,271	2,452,700	6,903,130
2001	1,747,742	1,482,536	1,325,346	2,489,500	7,045,123
2002	1,795,023	1,527,673	1,338,117	2,489,300	7,150,113
2003	1,842,927	1,539,101	1,352,021	2,528,400	7,262,450
2004	1,891,410	1,547,488	1,366,556	2,568,500	7,373,954
2005	1,940,255	1,607,589	1,381,283	2,609,600	7,538,726
2006	1,988,986	1,666,547	1,395,234	2,651,800	7,702,568
Average Annual Growth					
1991-2001	2.49%	3.65%	1.20%	1.75%	2.19%
1991-2006	2.53%	3.22%	1.15%	1.59%	2.06%

(*) - Industrial sales figures include cotton gin and irrigation sales.

FIGURE 3.12
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
WEST TEXAS UTILITIES COMPANY



Commercial sales are expected to exhibit the strongest growth at 3.7 percent while both residential and industrial sales are anticipated to grow at slower rates of 2.5 and 1.2 percent, respectively. Total system sales are forecasted to grow at a steady average annual rate of 2.2 percent through the forecast period.

El Paso Electric Company Staff estimates a peak demand of 954 MW for Texas by the year 2001. This translates into an average annual growth of 2.3 percent for the next ten years. Texas commercial sales are forecasted to grow at an annual rate of 2.9 percent while residential sales are expected to grow 2.5 percent. Growth in electricity sales to industrial customers are expected to be the slowest at an average annual rate of 1.2 percent. Total adjusted system sales in Texas are projected to increase 2.2 percent per year.

Texas-New Mexico Power Company The adjusted peak demand forecast developed by staff for TNP's Texas Operating Divisions is slightly higher than the projections developed by the company for next ten years. Staff projects adjusted peak demand to grow at a 2.0 percent average annual rate over the next decade while TNP projects a 1.7 percent growth rate.

Total adjusted system sales are projected to grow at a 1.7 percent average annual growth rate. Residential and commercial sales are expected to grow at 2.7 and 2.4 percent, respectively. There is hardly any growth in the industrial sector. Industrial sales are forecasted to grow at an average rate of 0.1 percent per annum through the 10-year forecast horizon. Staff did not propose adjustments to commercial or industrial sales.

Brazos Electric Power Cooperative Growth in both peak demand and sales is expected to be strong due, in large part, to the effects of Baylor University in Waco and Texas A & M University in College Station. Staff forecasts a strong average annual growth in peak demand of 4.1 percent through the year 2001. This compares with BEPC's forecast of 3.6 percent average annual growth. The Commission staff also projects strong sales growth of 3.5 percent (annual average) for BEPC.

TABLE 3.39
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
EL PASO ELECTRIC COMPANY - TEXAS

Year	Staff Adjusted(MW)	EPE Adjusted(MW)	Difference (MW)	Difference (%)
1991	757	757	0	0.00%
1992	789	794	-5	-0.63%
1993	803	804	-1	-0.12%
1994	820	819	1	0.12%
1995	837	836	1	0.12%
1996	856	848	8	0.94%
1997	875	873	2	0.23%
1998	894	893	1	0.11%
1999	915	914	1	0.11%
2000	934	935	-1	-0.11%
2001	954	960	-6	-0.63%
2002	974	978	-4	-0.41%
2003	994	1,002	-8	-0.80%
2004	1,013	1,019	-6	-0.59%
2005	1,034	1,046	-12	-1.15%
2006	1,055	1,069	-14	-1.31%
Average Annual Growth				
1991-2001	2.34%	2.40%		
1991-2006	2.24%	2.33%		

TABLE 3.40
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
EL PASO ELECTRIC COMPANY - TEXAS

Year	Staff Adjusted(MWH)	EPE Adjusted(MWH)	Difference (MWH)	Difference (%)
1991	3,762,675	3,762,675	0	0.00%
1992	3,841,248	3,915,072	-73,824	-1.89%
1993	3,918,853	3,931,975	-13,122	-0.33%
1994	4,003,726	4,008,435	-4,709	-0.12%
1995	4,095,561	4,102.720	-7,159	-0.17%
1996	4,194,551	4,173.339	21,212	0.51%
1997	4,290,278	4,266.344	23,934	0.56%
1998	4,390,127	4,369.465	20,662	0.47%
1999	4,491,276	4,476.786	14,490	0.32%
2000	4,590,568	4,584.311	6,257	0.14%
2001	4,690,971	4,693.340	-2,369	-0.05%
2002	4,791,742	4,798.545	-6,803	-0.14%
2003	4,891,234	4,905,277	-14,043	-0.29%
2004	4,991,799	5,009.397	-17,598	-0.35%
2005	5,093,954	5,119,791	-25,837	-0.50%
2006	5,196,495	5,235.141	-38,647	-0.74%
Average Annual Growth				
1991-2001	2.23%	2.23%		
1991-2006	2.18%	2.23%		

TABLE 3.41
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
EL PASO ELECTRIC COMPANY - TEXAS

Year	Residential Adjusted(MWH)	Commercial Adjusted(MWH)	Industrial Adjusted(MWH)	All Other (MWH)	Total (MWH)
1,991	1,032,163	1,240,158	832,671	657,683	3,762,675
1,992	1,042,872	1,316,369	810,587	671,420	3,841,248
1,993	1,077,221	1,337,333	821,841	682,458	3,918,853
1,994	1,110,242	1,365,879	832,426	695,180	4,003,726
1,995	1,143,897	1,399,012	844,474	708,178	4,095,561
1,996	1,177,356	1,438,104	858,650	720,441	4,194,551
1,997	1,209,182	1,475,142	872,101	733,854	4,290,278
1,998	1,238,962	1,517,455	887,384	746,327	4,390,127
1,999	1,267,968	1,561,975	903,387	757,947	4,491,276
2,000	1,295,212	1,605,757	919,265	770,334	4,590,568
2,001	1,320,661	1,651,003	935,455	783,853	4,690,971
2,002	1,345,673	1,695,225	951,464	799,380	4,791,742
2,003	1,370,727	1,738,136	967,049	815,323	4,891,234
2,004	1,395,789	1,780,732	982,647	832,632	4,991,799
2,005	1,420,476	1,825,072	998,594	849,813	5,093,954
2,006	1,444,174	1,870,625	1,015,051	866,646	5,196,495
Average Annual Growth					
1991-2001	2.50%	2.90%	1.17%	1.77%	2.23%
1991-2006	2.26%	2.78%	1.33%	1.86%	2.18%

FIGURE 3.13
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
EL PASO ELECTRIC COMPANY - TEXAS

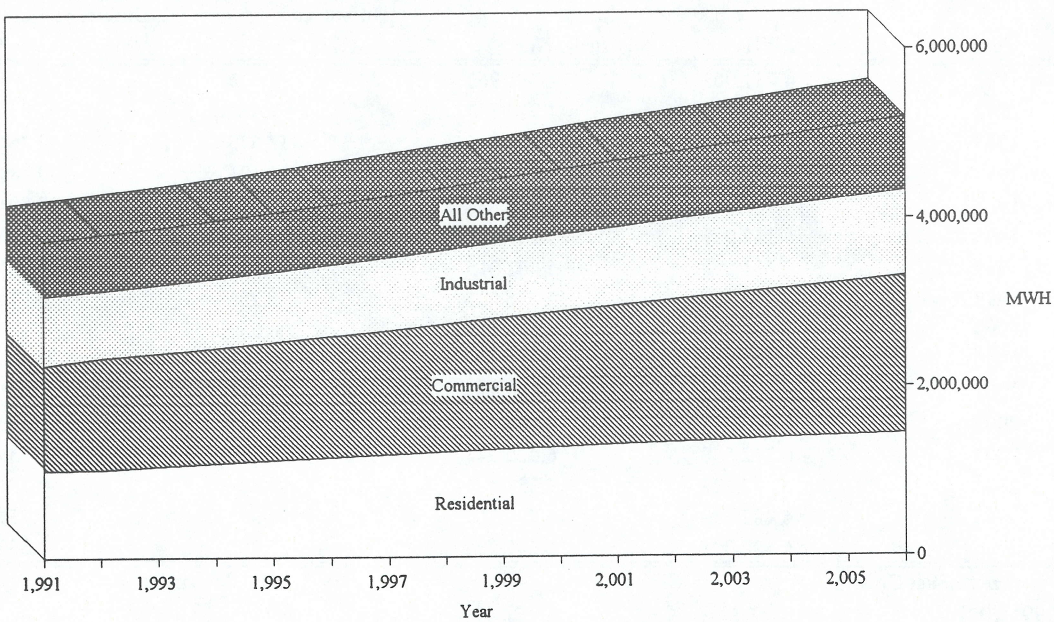


TABLE 3.42
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
EL PASO ELECTRIC COMPANY - TOTAL

Year	Staff Adjusted(MW)	EPE Adjusted(MW)	Difference (MW)	Difference (%)
1991	936	936	0	0.00%
1992	990	990	0	0.00%
1993	1,011	1,007	4	0.40%
1994	1,034	1,029	5	0.49%
1995	1,057	1,051	6	0.57%
1996	1,083	1,069	14	1.31%
1997	1,109	1,102	7	0.64%
1998	1,135	1,129	6	0.53%
1999	1,163	1,156	7	0.61%
2000	1,189	1,182	7	0.59%
2001	1,216	1,213	3	0.25%
2002	1,243	1,238	5	0.40%
2003	1,270	1,268	2	0.16%
2004	1,296	1,291	5	0.39%
2005	1,325	1,324	1	0.08%
2006	1,352	1,354	-2	-0.15%
Average Annual Growth				
1991-2001	2.65%	2.63%		
1991-2006	2.48%	2.49%		

Note: EPEC's avoided unit is a 80-MW natural gas simple cycle CCCT in 2000.

TABLE 3.43
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
EL PASO ELECTRIC COMPANY - TOTAL

Year	Staff Adjusted(MWH)	EPE Adjusted(MWH)	Difference (MWH)	Difference (%)
1991	4,711,963	4,711,963	0	0.00%
1992	4,810,882	4,910.343	-99,461	-2.03%
1993	4,917,426	4,955,105	-37,679	-0.76%
1994	5,030,711	5,055.112	-24,401	-0.48%
1995	5,151,111	5,176.858	-25,747	-0.50%
1996	5,282,929	5,277,895	5,034	0.10%
1997	5,411,990	5,402,013	9,977	0.18%
1998	5,545,277	5,536,021	9,256	0.17%
1999	5,679,849	5,673,783	6,066	0.11%
2000	5,812,256	5,811,542	714	0.01%
2001	5,945,148	5,950.225	-5,077	-0.09%
2002	6,079,375	6,085,422	-6,047	-0.10%
2003	6,212,558	6,220.944	-8,386	-0.13%
2004	6,347,222	6,358.508	-11,286	-0.18%
2005	6,483,599	6,499,590	-15,991	-0.25%
2006	6,620,001	6.645.706	-25,705	-0.39%
Average Annual Growth				
1991-2001	2.35%	2.36%		
1991-2006	2.29%	2.32%		

TABLE 3.44
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
EL PASO ELECTRIC COMPANY - TOTAL

Year	Residential Adjusted(MWH)	Commercial Adjusted(MWH)	Industrial Adjusted(MWH)	Other (MWH)	Total (MWH)
1991	1,342,831	1,487,540	864,932	1,016,660	4,711,963
1992	1,354,319	1,569,408	843,363	1,043,791	4,810,882
1993	1,400,038	1,604,485	855,241	1,057,662	4,917,426
1994	1,444,595	1,645,638	866,571	1,073,908	5,030,711
1995	1,491,181	1,690,223	879,382	1,090,324	5,151,111
1996	1,538,718	1,738,881	894,340	1,110,990	5,282,929
1997	1,584,980	1,785,450	908,586	1,132,973	5,411,990
1998	1,629,111	1,837,350	924,698	1,154,118	5,545,277
1999	1,672,504	1,891,410	941,555	1,174,381	5,679,849
2000	1,713,945	1,944,645	958,310	1,195,357	5,812,256
2001	1,753,015	1,999,256	975,404	1,217,473	5,945,148
2002	1,791,667	2,053,256	992,400	1,242,052	6,079,375
2003	1,830,521	2,105,913	1,009,038	1,267,087	6,212,558
2004	1,869,619	2,158,326	1,025,640	1,293,638	6,347,222
2005	1,908,394	2,212,488	1,042,665	1,320,053	6,483,599
2006	1,945,933	2,267,993	1,060,226	1,345,850	6,620,001
Average Annual Growth					
1991-2001	2.70%	3.00%	1.21%	1.82%	2.35%
1991-2006	2.50%	2.85%	1.37%	1.89%	2.29%

FIGURE 3.14
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
EL PASO ELECTRIC COMPANY - TOTAL

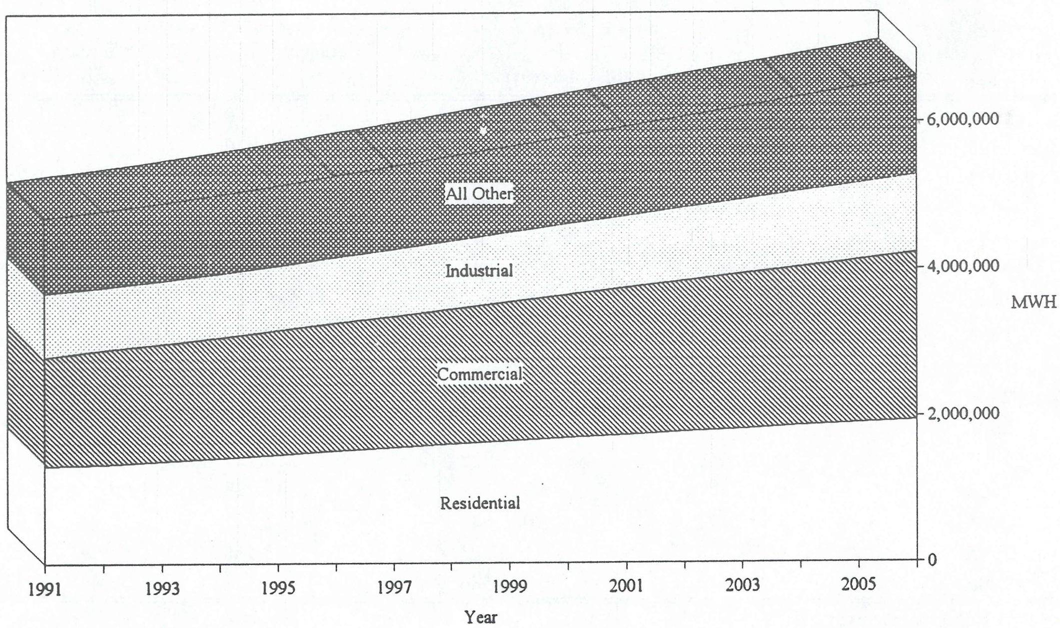


TABLE 3.45
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
TEXAS - NEW MEXICO POWER COMPANY

Year	Staff Adjusted(MW)	TNP Adjusted(MW)	Difference (MW)	Difference (%)
1991	992	992	0	0.00%
1992	1,021	1,005	16	1.61%
1993	1,032	1,001	31	3.12%
1994	1,050	1,021	29	2.81%
1995	1,082	1,042	40	3.85%
1996	1,114	1,066	48	4.53%
1997	1,136	1,089	47	4.32%
1998	1,157	1,112	45	4.00%
1999	1,175	1,133	42	3.74%
2000	1,191	1,155	36	3.13%
2001	1,207	1,179	28	2.35%
2002	1,222	1,203	19	1.58%
2003	1,234	1,227	7	0.59%
2004	1,251	1,252	-1	-0.05%
2005	1,267	1,278	-11	-0.90%
2006	1,277	1,305	-28	-2.18%
Average Annual Growth				
1991-2001	1.98%	1.74%		
1991-2006	1.70%	1.85%		

Note: TNP's avoided unit is a 152-MW lignite-fired, circulating fluidized bed steam plant in 2001.

TABLE 3.46
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
TEXAS - NEW MEXICO POWER COMPANY

Year	Staff Adjusted(MWH)	TNP Adjusted(MWH)	Difference (MWH)	Difference (%)
1991	5,001,115	5,001,115	0	0.00%
1992	4,952,287	4,928,417	23,870	0.48%
1993	5,020,166	4,885,809	134,357	2.75%
1994	5,118,684	4,971,674	147,010	2.96%
1995	5,290,435	5,067,072	223,363	4.41%
1996	5,455,916	5,180,335	275,581	5.32%
1997	5,575,963	5,287,059	288,904	5.46%
1998	5,685,278	5,392,402	292,876	5.43%
1999	5,783,722	5,491,195	292,527	5.33%
2000	5,867,245	5,594,875	272,370	4.87%
2001	5,942,391	5,702,881	239,510	4.20%
2002	6,016,652	5,813,925	202,727	3.49%
2003	6,075,344	5,928,111	147,233	2.48%
2004	6,158,472	6,045,541	112,931	1.87%
2005	6,231,789	6,166,321	65,468	1.06%
2006	6,280,044	6,290,564	-10,520	-0.17%
Average Annual Growth				
1991-2001	1.74%	1.32%		
1991-2006	1.53%	1.54%		

TABLE 3.47
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
TEXAS - NEW MEXICO POWER COMPANY

Year	Residential Adjusted(MWH)	Commercial Adjusted(MWH)	Industrial Adjusted(MWH)	All Other (MWH)	Total (MWH)
1991	1,837,969	1,318,957	1,746,773	97,416	5,001,115
1992	1,862,214	1,333,121	1,655,228	101,725	4,952,287
1993	1,885,542	1,347,437	1,683,287	103,900	5,020,166
1994	1,908,559	1,400,477	1,703,590	106,057	5,118,684
1995	1,996,132	1,454,736	1,731,438	108,129	5,290,435
1996	2,090,730	1,507,795	1,747,401	109,990	5,455,916
1997	2,162,172	1,545,542	1,756,675	111,575	5,575,963
1998	2,227,528	1,581,623	1,763,143	112,985	5,685,278
1999	2,289,195	1,613,504	1,766,777	114,246	5,783,722
2000	2,341,708	1,642,800	1,767,284	115,453	5,867,245
2001	2,387,724	1,670,134	1,767,860	116,673	5,942,391
2002	2,432,138	1,697,112	1,769,499	117,903	6,016,652
2003	2,464,736	1,718,537	1,772,929	119,144	6,075,344
2004	2,512,673	1,748,443	1,776,961	120,395	6,158,472
2005	2,563,582	1,778,432	1,768,119	121,657	6,231,789
2006	2,596,133	1,800,380	1,760,601	122,930	6,280,044
Average Annual Growth					
1991-2001	2.65%	2.39%	0.12%	1.82%	1.74%
1991-2006	2.33%	2.10%	0.05%	1.56%	1.53%

FIGURE 3.15
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
TEXAS - NEW MEXICO POWER COMPANY

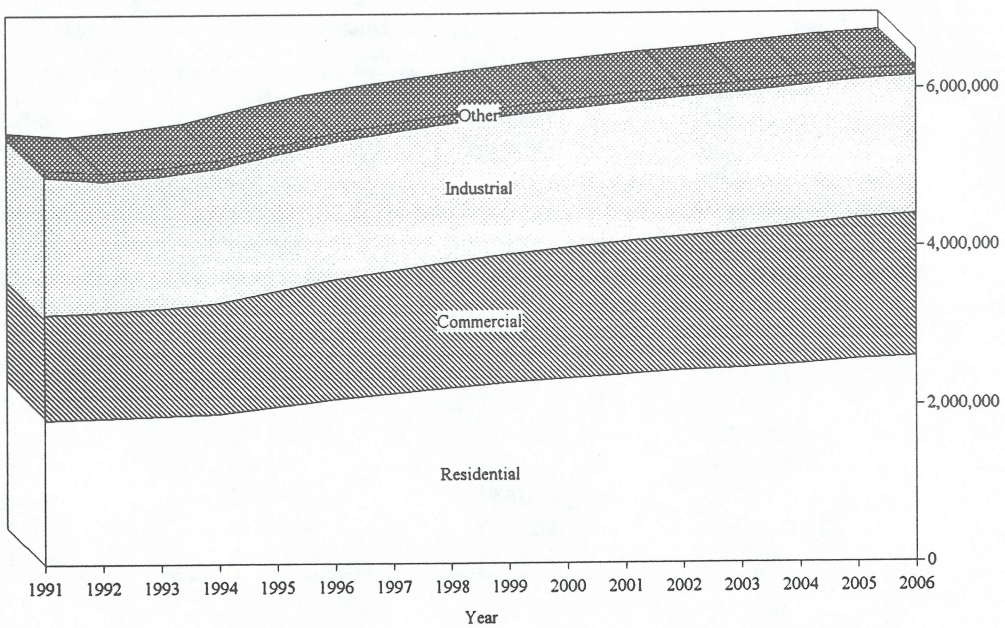


TABLE 3.48
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
BRAZOS ELECTRIC POWER COOPERATIVE, INC.

Year	Staff Adjusted(MW)	BEPC Adjusted(MW)	Difference (MW)	Difference (%)
1991	857	857	0	0.00%
1992	943	899	44	4.87%
1993	976	1,004	-28	-2.75%
1994	1,015	1,036	-21	-2.01%
1995	1,055	1,065	-10	-0.90%
1996	1,097	1,087	10	0.96%
1997	1,135	1,109	26	2.32%
1998	1,171	1,132	39	3.46%
1999	1,207	1,144	63	5.51%
2000	1,242	1,176	66	5.60%
2001	1,277	1,215	62	5.11%
2002	1,312	1,256	56	4.47%
2003	1,347	1,295	52	4.05%
2004	1,383	1,335	48	3.62%
2005	1,419	1,376	43	3.13%
2006	1,454	1,416	38	2.71%
Average Annual Growth (%)				
1991-2001	4.07%	3.55%		
1991-2006	3.59%	3.40%		

Note: The forecasts in Tables 3.48 and 3.49 are for the demand served by BEPC's own generation and transmission system.

TABLE 3.49
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
BRAZOS ELECTRIC POWER COOPERATIVE, INC.

Year	Staff Adjusted(MWH)	BEPC Adjusted(MWH)	Difference (MWH)	Difference (%)
1991	3,746,263	3,746,263	0	0.00%
1992	3,866,652	3,896,787	-30,135	-0.77%
1993	4,011,480	4,151,604	-140,124	-3.38%
1994	4,174,620	4,314,829	-140,209	-3.25%
1995	4,350,113	4,482,814	-132,701	-2.96%
1996	4,529,707	4,655,717	-126,010	-2.71%
1997	4,695,616	4,836,383	-140,767	-2.91%
1998	4,853,751	5,028,191	-174,440	-3.47%
1999	5,007,266	5,188,352	-181,086	-3.49%
2000	5,156,775	5,355,606	-198,831	-3.71%
2001	5,307,352	5,525,483	-218,131	-3.95%
2002	5,458,091	5,696,761	-238,670	-4.19%
2003	5,609,638	5,867,106	-257,468	-4.39%
2004	5,763,585	6,036,912	-273,327	-4.53%
2005	5,917,687	6,209,677	-291,990	-4.70%
2006	6,069,700	6,382,384	-312,684	-4.90%
Average Annual Growth (%)				
1991-2001	3.54%	3.96%		
1991-2006	3.27%	3.62%		

CHAPTER FOUR

SPECIAL TOPICS IN THE ELECTRIC INDUSTRY

The increasing complexity of the electric utility industry requires utilities to focus on certain key planning issues. The staff has requested utilities to undertake or update studies on aspects of strategic rate design, the Clean Air Act, increased electrical power transactions, and target reserve margins.

Increasingly, rate design is viewed as an important resource planning tool. Rate design, including the rate structure and level of charges as well as terms and conditions of various tariffs influences consumption patterns. Because consumption patterns directly affect generation requirements, rate design can be used to shape planning strategies. The 1990 amendments to the Clean Air Act have profound consequences for generating utilities. The amendments may impact operation and construction decisions. The staff has advocated increasing awareness of the potential for increased power transactions among utilities and with qualifying facilities. The studies involve analyses of technical feasibility, institutional constraints, costs, and benefits of increased transactions. Finally, continuous monitoring of reserve margins is advocated by the staff. Because the reserve margin impacts reliability and the need for additional capacity, the staff recommends that the major electric generating utilities address the issue of the optimal reserve margin for their systems.

Strategic Rate Design as a Resource Option

The structure, level of charges, and terms and conditions of rates can significantly impact the quantity of electricity consumed as well as the time patterns of electricity consumption; rate design, can be considered a resource planning tool. Because it affects consumption patterns which, in turn, influence supply options and requirements for a power supplier, it can be used as a resource option in the context of active demand-side management (interruptible rates), passive demand-side management (time of use rates), or installed capacity (payments to QFs).

Rate Design Approaches

A variety of rate design strategies have been developed by utilities in pursuit of such diverse objectives as economic efficiency, fairness, conservation, promotion of use, subsidization, predation, low-income assistance, cogeneration promotion or discouragement, and competition. Electricity supply costs vary temporally and geographically. Rate designs of varying complexity can be used to track these cost variations and pursue these objectives. Some examples of rate designs are:

1. Blocked KWH rates
2. Seasonally differentiated rates
3. Marginal cost-based rates (including time-of-use rates)
4. Real-time or spot-market pricing
5. Priority pricing

Table 4.1 summarizes special tariffs offered by the major utilities in Texas, while Table 4.2 provides residential rate design.

Blocked KWH rates are rates that vary among different "blocks" of KWH consumption. Blocked rate structures are usually only a crude approximation of cost variations, since these rates are fixed over time.

Seasonally differentiated rates imply that a different rate is charged for KWH consumption or KW demand during different seasons of the year. The price signal sent to consumers is more precise than would be received through a blocked rate because some time-variation in costs is recognized. Many utilities in Texas combine the use of seasonally differentiated and blocked rates in their residential rate design. As shown in Table 4.2, some blocks of consumption during the off-peak season of the year are priced at a rate less than that charged for summer consumption. Seasonally and block-differentiated rates are relatively inexpensive to implement as there is no need for additional metering equipment beyond the existing watt-hour meter.

Time-of-day (TOD) rates tend to send more precise price signals to consumers than non-time-differentiated approaches. During periods when the utility's operating and capacity costs tend to be higher (for example, summer afternoons), electricity is priced at a premium. Electricity purchased during off-peak, low-cost periods is available at lower prices. Such pricing strategies provide incentives for consumers to shift consumption from periods of the day where the utility's operating costs are high and capacity constraints are approached, to

TABLE 4.1

SPECIAL TARIFF AVAILABILITY AMONG MAJOR UTILITIES IN TEXAS (AS OF OCTOBER 1992)

Tariff	TU	HL&P	GSU	CPL	CPS	SPS	SWP	LCRA	COA	WTU	EPE	TNP	BEPC
Instantaneously Interruptible	✓	✓	✓	✓	✓	✓	✓			✓			✓
Notification interruptible		✓	✓	✓		✓	✓	✓		✓	✓	✓	
Time-of-day structure	✓	✓	✓		✓		✓		✓	✓	✓	✓	
Real-time pricing tariffs		✓	✓	✓									
Seasonal rate structures	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Load retention tariffs			✓	✓					✓		✓		
Economic development		✓	✓	✓				✓	✓	✓	✓		
Special block structures	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	
Customer or facility charges	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Combinations of the above		✓	✓	✓			✓	✓		✓		✓	
Value of service pricing		✓	✓										

periods where base load plants are the marginal generating units. TOD pricing does, however, involve more metering and administrative costs than the seasonal- and blocked-rate strategies.

A natural extension of traditional marginal cost pricing, such as seasonally differentiated rates and TOD pricing, is **real-time or spot-market pricing.** While seasonally differentiated rates and TOD pricing provide the consumer with a simple schedule of prices based on average patterns in utility costs, real-time pricing provides for a much more exact relationship between costs and prices. Hourly price quotes might be announced to the consumer a day in advance via cable television or other electronic avenues. Prices are based upon the utility's expected operating costs for the following day given weather forecasts, anticipated operating unit availability, and other factors. Curtailment premiums would be expected to encourage consumption abatement during periods of insufficient generating or transmission capacity.

A well-designed, real-time pricing program is likely to have the same general impact on consumption behavior and resource requirements as a traditional TOD program. However, since a better relationship between costs and prices is maintained, the potential benefits can be much greater. Although achieving greater economic efficiency, real-time pricing may sacrifice the predictability of prices that consumers are accustomed to under the alternatives discussed above. Also, the costs of demand metering and communications devices tend to reduce the efficiency gains.

Priority pricing, a rate design strategy that is related to real-time pricing, is also designed to promote economic efficiency. Under priority pricing, electric service would be unbundled into a number of priority or reliability classes. The price of service taken under each of the priority classes would be related to the cost of providing the associated level of reliability. In the event of a capacity shortage, customers' load increments would be interrupted based on the customers' selections. Common interruptible rates, where the customer selects a lower level of reliability in return for a price discount, provide a limited example of priority pricing. Large scale implementations of priority pricing have not yet been attempted. There is concern that the "obligation to serve" doctrine might be violated under such practice.

Strategic Rate Design in Texas

This section discusses specific rate design programs which have been used in Texas to affect future utility generating resource requirements.

Interruptible rates. Under an interruptible rate tariff, the customer receives power at a lower price but at a lower level of service reliability. For the utility, interruptible service may provide a means of reducing capacity requirements or stabilizing system frequency. Many large utilities in Texas offer interruptible rate tariffs. Moreover, the PUCT's Substantive Rule 23.66(j) requires utilities to offer interruptible service to a requesting qualifying facility. During peak demand periods, service to interruptible customers may be curtailed. Thus, there is usually little, if any, need for the utility to construct generating capacity to meet the needs of interruptible customers.