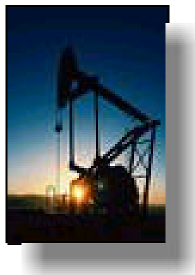
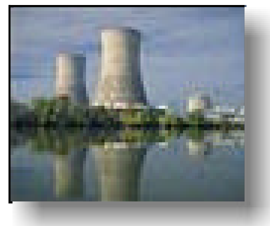
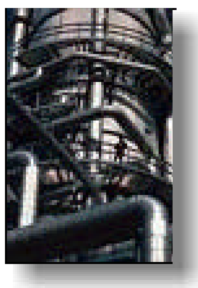
ELECTRIC UTILITY RESTRUCTURING LEGISLATIVE OVERSIGHT COMMITTEE







REPORT TO THE 77TH LEGISLATURE
NOVEMBER 2000

Electric Utility Restructuring Legislative Oversight Committee

REPORT TO THE 77TH LEGISLATURE

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**ELECTRIC UTILITY RESTRUCTURING
LEGISLATIVE OVERSIGHT COMMITTEE**

November 15, 2000

The Honorable George W. Bush, Governor
The Honorable Rick Perry, Lieutenant Governor
The Honorable James E. "Pete" Laney, Speaker of the House of Representatives

Gentlemen:

The Electric Utility Restructuring Legislative Oversight Committee hereby submits this interim report for consideration by the 77th Legislature pursuant to Section 39.907, Public Utility Regulatory Act.

This report tracks the progress of electric utility restructuring legislation implementation and summarizes major issues addressed during the Committee's interim hearings.

Respectfully submitted,

SIGNED	SIGNED
Rep. Steven Wolens, Co-Chairman	Sen. David Sibley, Co-Chairman
SIGNED	SIGNED
Rep. Kim Brimer	Sen. David Cain
SIGNED	SIGNED
Rep. David Counts	Sen. Frank Madla
SIGNED	SIGNED
Rep. Debra Danburg	Sen. Jane Nelson
SIGNED	SIGNED
Rep. Sylvester Turner	Sen. John Whitmire

PREFACE

The Electric Utility Restructuring Legislative Oversight Committee issues this report in accordance with Section 39.907 of the Public Utility Regulatory Act (Title II, Texas Utilities Code) as amended by Senate Bill 7, 76th Legislature.

The committee is charged with monitoring the effectiveness of electric utility restructuring and required to report on the committee's activities conducted during the interim, including meetings with the Public Utility Commission of Texas and information received about rules relating to electric utility restructuring. The committee is further required to analyze any problems caused by electric utility restructuring and recommend any legislative action necessary to address those problems or to further retail competition within the electric power industry.

Four public hearings were held featuring invited and public testimony from consumers and consumer advocates, state and federal agencies, the independent system operator, representatives of the electric power industry, community-based organizations and others. A summary of testimony presented to the committee at these hearings is included at the end of this report in Appendices D through G.

There have been many changes in global, national and local energy and power markets since the enactment of SB 7. The committee recognizes that the release of this report coincides with rising public concerns about increasing energy costs in Texas and volatile electricity prices elsewhere in the country. The committee has attempted to address many of these contemporary questions herein.

The committee extends its appreciation to all parties participating in the electric utility restructuring process, including the witnesses who offered testimony at committee hearings. The committee particularly wishes to thank the dedicated commissioners and staff of the Public Utility Commission of Texas for their tireless work on this complex issue to ensure that Texas' restructuring effort yields a fair market providing reliable, affordable electricity for all Texas customers. The committee also wishes to thank Mark Bruce and all committee staff for their contributions to this report.

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Executive Summary

The Electric Utility Restructuring Legislative Oversight Committee was established pursuant to Senate Bill 7, 76th Legislature, to study the effects of that bill on the state's electricity markets, transmission system and consumers of electricity. The committee conducted four public hearings during the 1999-2000 interim to accept invited and public testimony. The committee issues this report pursuant to Section 39.907, Public Utility Regulatory Act (PURA).

This oversight report includes an overview of implementation progress, analysis of Texas' system reliability and examination of developments in the Texas marketplace, including fuel price spikes, environmental issues, consumer protections and school funding impacts. Where illustrative, comparisons between the emerging market structure in Texas and other market models are presented.

Implementation Overview

Primary responsibility and authority for implementing customer choice, mandated by Senate Bill 7 and relevant provisions of Senate Bill 86, 76th Legislature, rests with the Public Utility Commission of Texas (PUC). Although several important rulemakings remain, the PUC has made great strides toward putting the foundation of the restructured market in place. Rules requiring utility business separation plans, codes of conduct, certification and registration of market participants and open access transmission service terms have been implemented. New programs promoting energy efficiency, renewable energy generation and customer education are being established. The PUC has engaged in restructuring activity at all levels, through workshops with industry participants and consumer representatives, market seminars and training sessions and regular updates at each of this committee's interim hearings. The PUC has also established a new Market Oversight Division to monitor and evaluate wholesale and retail market functions.

The majority of the technical issues of market restructuring have been decided by the Electric Reliability Council of Texas (ERCOT), a non-profit corporation serving as the Independent System Operator (ISO) of the Texas Interconnection, a power region covering approximately 85 percent of Texas. ERCOT's responsibilities include supervising the collective transmission facilities, systemwide transmission planning, nondiscriminatory coordination of market transactions, and network reliability. To facilitate the implementation process, the ISO contracted with Andersen Consulting, a firm with electric utility restructuring experience in other markets. ERCOT is in the process of expanding its infrastructure and staffing to comply with SB 7 and oversee retail access in the electric market. All restructuring efforts at the ISO are scheduled for implementation by the start of the retail competition pilot project on June 1, 2001. Andersen Consulting and ERCOT staff report implementation activity is proceeding close to schedule.[1]

Another state agency involved in electric power market restructuring is the General Land Office (GLO), which has begun converting state in-kind royalties to electricity and selling the power at discounted prices to itself and public schools in Texas. As of October 18, 2000, the GLO reported more than $350,000 in retail electric sales, providing almost $60,000 in savings to public schools.[2] The Land Commissioner has executed 46 contracts with public retail customers and 164 contracts are in progress as of the filing of this report. The vast majority of these contracts are with public school districts.

As required by SB 7, the Texas Natural Resource Conservation Commission (TNRCC) has established emissions caps affecting electric generating facilities (EGFs) previously exempted from air quality regulations, or "grandfathered facilities."[3] Some EGFs, both grandfathered and permitted, will be required to make further emissions reductions than those mandated by SB 7 under the TNRCC's State Implementation Plans (SIPs) for areas of Texas that are in violation of National Ambient Air Quality Standards (NAAQS) set by the U.S. Environmental Protection Agency (EPA). The Dallas SIP is currently under EPA review. The Houston/Galveston SIP is currently under development at the TNRCC.

[1]ERCOT Director Sam Jones, comments on the status of implementation activities, ERCOT Market Readiness Series No. 4, Sept. 25, 2000, Austin.

[2]Interview with Deputy Land Commissioner J. David Hall, Oct. 20, 2000.

[3]PURA §39.264.

Electric System Reliability

Because electricity cannot be stored, it must be made, delivered and used in real-time. This unique characteristic provides many challenges to keeping the system in balance so that the strength of electric current remains steady. Ensuring electric grid reliability requires three key components: adequate generation of electric power, sufficient transmission systems to move power from generators to end users and an operating and monitoring system to make the minute-to-minute adjustments necessary to keep the grid balanced.

Deservedly or not, San Diego became synonymous with deregulation in mainstream public discussion during Summer 2000. Residential electric bills skyrocketed from the previous year, and some businesses chose to close their doors in the face of unpredictable and seemingly uncontrollable power costs.[4] Rolling brownouts and regular service interruptions plagued San Francisco and Silicon Valley in an unusually hot May and June.[5] While state and federal agencies investigate charges of market abuses, system operators have already started planning for Summer 2001.[6]

Significant debate exists on the full range of causes behind California's restructuring problems, but the diagnosis is clear: the California system is not working.[7] As California's problems surfaced during the course of this committee's interim hearings, the committee sought answers to the question,"Could similar problems occur in Texas?"

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[4]Craig D. Rose, "Average SDG&E Bill Is Going Up 16 Percent More; Rate-Wracked Consumers Caught In Surging Crisis," *San Diego Union-Tribune*, July 11, 2000, p. A1. San Diegans paid 13.8 cents per kilowatt hour, compared with 3.6 cents the previous year.

[5]Fred Bayles, "California Readies For Blackouts," *USA Today.com*, Web site visited Aug. 2, 2000.

[6]On August 2, 2000, California PUC President Loretta Lynch and Electricity Oversight Board Chairman Michael Kahn submitted a report requested by Governor Gray Davis addressing problems in California's electricity market. In the document, *California's Electricity Options and Challenges: Report to Governor Gray Davis*, the authors recommended that the attorney general participate in a broadened market abuse investigation. On August 23, 2000, the Federal Energy Regulatory Commission (FERC) also announced plans to investigate market problems. It issued its report on November 1, 2000.

[7]Michael Kahn and Loretta Lynch, *California's Electricity Options and Challenges: Report to Governor Gray Davis*, Aug. 2, 2000, p. 3. Authors state, "California is experiencing major problems with electricity supply and pricing caused by policies and procedures adopted over the past ten years ... These serious, but thus far isolated examples represent a precursor of what lies ahead for California's economy over the next 30 months."

The heart of California's problem lies in its lack of sufficient electric generation capacity to meet rising demand.[8] California's expensive and cumbersome siting process led to a near halt in new construction for most of the 1990s. Most of the new capacity currently planned and under construction in California will not be available by next summer.[9] In the meantime, demand for electricity continues to rise, creating scarcity in that market.

Electricity demand in Texas has also steadily increased in the 1990s, yet significant increases in generation capacity have been added to the system. Since the deregulation of wholesale power generation in Texas in 1995,[10] 22 new power plants totaling almost 5,700 megawatts (MW) of capacity have come on line,[11] compared to the 672 MW of new capacity added in California during the same period.[12] Since 1997, ERCOT has received more than 110 requests for generation interconnection.[13] Since the institution of market-based independent power production, siting new facilities in Texas can be accomplished in 24 to 36 months, compared to five to seven years in California.

Directly comparing the margin of reserve capacity against peak demand in each state illustrates the differences in generation system reliability. During Summer 2000, California's reserve margin dipped below 5 percent, whereas Texas enjoyed a greater than 12 percent reserve margin average.[14] As new generation currently under development is connected to the grid, ERCOT reserve margins are expected to increase to 30 percent by Summer 2001 and 2002.[15]

[8]Kahn and Lynch, p. 38.

[9]Ibid., p. 37.

[10]Senate Bill 373, 74th Legislature.

[11]PUC Chairman Pat Wood, testimony before the Electric Utility Restructuring Legislative Oversight Committee, August 22, 2000 (See Appendix F for summary).

[12]Kahn and Lynch, p. 36.

[13]Electric Reliability Council of Texas, *Existing and Potential Electric System Constraints and Needs Within ERCOT*, Oct. 1, 2000, p. 17.

[14]Kahn and Lynch, pp. 21, 35; Chairman Wood, August 22, 2000.

[15]Public Utility Commission of Texas, *Draft Scope of Competition Report*, Project No. 22258, August 17, 2000, p. 42.

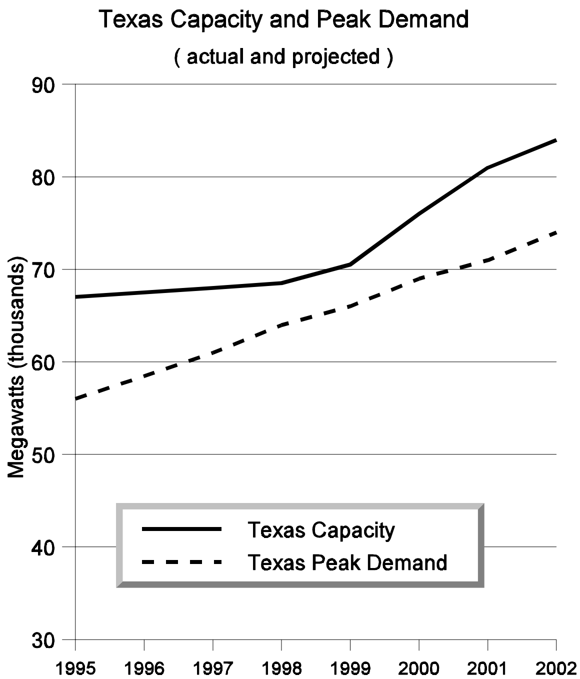

Fig. ES.1 source: Public Utility Commission of Texas

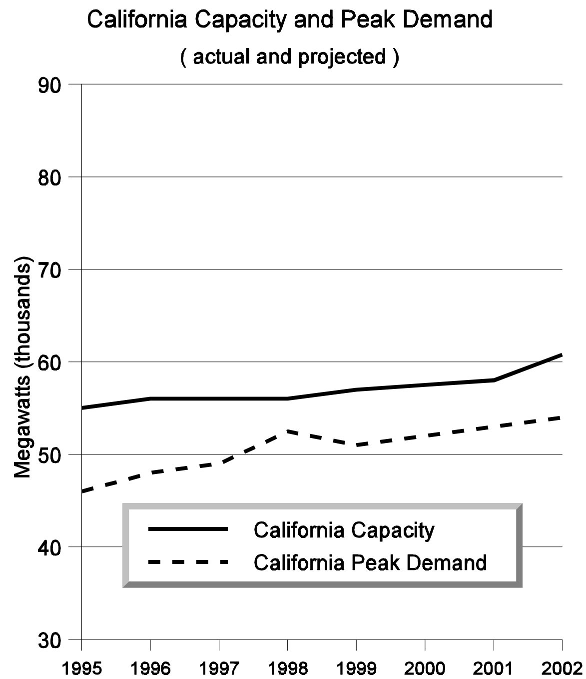

Fig. ES.2 source: California ISO

Most observers agree generation capacity in Texas will be adequate to meet demand for the next several years. However, the state's transmission system is in need of expansion to relieve existing bottlenecks and to distribute the power to be provided by new generation facilities. From 1994 to 2000, total load in ERCOT has grown 14,018 MW, or 32 percent, while very few bulk transmission additions have been made.[16]

Current constraints in the transmission system include moving electricity from power-rich areas of the state such as the Houston Ship Channel to power-hungry regions like the Dallas/Fort Worth Metroplex and moving power East to West in TXU's service territory. Seven major transmission projects are currently under development to resolve these problems, with completion anticipated in 2002 and 2003. Estimated spending on transmission-related improvements in the next three years

[16]Electric Reliability Council of Texas, p. 12.

is $543 million.[17] Seven additional projects have been reviewed and endorsed by ERCOT and await action by the PUC. ERCOT is currently evaluating 21 additional projects.[18]

Siting high-voltage transmission lines requires approximately the same amount of time as siting new power plants. Uncontested transmission projects might be constructed as quickly as one year, but most projects typically take 24 to 36 months. The siting process for high-voltage lines will likely lengthen in the future as transmission corridors are located in suburban and urban areas. Advances in micro-turbine design, fuel cell technology and other self-serve power options, collectively known as distributed generation, hold the promise of limited relief for the state's transmission network in the future. To facilitate increased introduction of distributed generation in Texas, standardized emissions permits and interconnection terms are under development at the TNRCC and PUC.

As previously noted, ERCOT is in the process of expanding its staff and technical infrastructure to meet the needs of the emerging market. ERCOT began monitoring the Texas Interconnection in the early 1970s and assumed security functions in 1983. Preparations to perform the additional functions required of an independent system operator began in 1995. The ERCOT ISO operates a control facility located in Taylor. A 45,000 square-foot back-up center in Austin is nearing the construction phase. If, for any reason, the Taylor facility were to experience a loss of power or other disabling event, operations control would switch to the Austin facility.

The Texas electric grid weathered several challenges during Summer 2000: wildfires, thunderstorms, drought, blistering heat and historic high electric demand. Despite these conditions, load interruptions were ordered less frequently than in 1998 and 1999, due in part to additions in generation capacity and cool temperatures in June. ERCOT directed some interruptible load shed five days in May, one day in July and two days in September. Unplanned energy transactions were also curtailed during Summer 2000, primarily due to North/South transmission constraints, although the number and volume of curtailments occurred at lower levels than the previous summer.[19] In other words, firm, uninterruptible load was reliably served through the year 2000 peak demand season.

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[17]Chairman Wood, August 22, 2000.

[18]Electric Reliability Council of Texas, pp. 4-5.

[19]Interviews with ERCOT Director of Coordination and Reports Larry Grimm, Oct. 12, 2000 and ERCOT Director of Technical Operations Kent Saathoff, Oct. 23, 2000.

However, for successful market restructuring to occur, greater liquidity in unplanned energy transfers must be developed to allow retail electric providers (REPs) access to the most economical generation sources.

Market Structure

Rapid electrification of major urban areas in the United States occurred soon after Thomas Edison demonstrated that a series of electric lights could be powered from a generator in an adjacent building in 1882. The industry was very competitive from the outset, with dozens of firms competing for business in the same parts of American cities. As the use of electricity grew in the early 1900s, a dominant view emerged that electricity could best be provided by one large firm serving a single area, rather than multiple independent power producers. Proponents of this view claimed electric utilities were “natural monopolies,” with each utility in a given area achieving significant cost savings through owning and planning its own generation, transmission and distribution systems. Since the 1970s, several changes in the industry have contributed to the decline of this theory in contemporary economics, including technological advances in power conversion and generation, advances in automated computer systems and new management models and practices.[20]

In Texas, electric utilities have assumed both public and private forms. Although one answers to an elected body such as a city council or cooperative board and the other to investors, both models share many consistencies, namely their vertically integrated structure coupled with the exclusive right to provide retail electric service in a given territory. Under this system, planning for additional generation capacity and transmission and distribution network upgrades is a very centralized process, with regulated rate structures designed to pay for those systems over their life of service.

The enactment of the Energy Policy Act of 1992 (P.L. 102-486) created opportunities nationwide for non-utility power generators to enter the wholesale electricity market. Texas began wholesale restructuring in 1995, by requiring transmission owners to provide non-discriminatory access to the electric grid and requiring utilities to consider power purchases from independent power producers

[20] A good source for introductory reading on the foundations of the electric utility restructuring debate is Peter Fox-Penner’s *Electric Utility Restructuring: A Guide to the Competitive Era*, Public Utility Reports, Inc., Vienna, Va, 1997.

as a low-cost alternative to ratepayer-financed new plant construction. Non-utility generation has significantly increased in Texas as a result of these rules. Competitive energy services have also flourished in the state with demand-side management programs, energy efficiency audits and specialized time-of-use metering and billing functions. These unregulated market activities continue to grow in number and scope as the market evolves. This restructured competitive market places the risks and rewards of marketplace activity with investors rather than the captive ratepayer base.

Enacted in 1999, SB 7 directed utilities to separate business activities into three components: a competitive power generation company, a competitive retail electric provider and a regulated transmission and distribution service provider.[21] SB 7 did not require utilities to divest generation assets, leaving intact the ability to call on native generation to meet demand, a key distinction from the California model. However, the legislation did cap the total amount of generation any one firm can own in a power region at no more than 20 percent to mitigate potential market power abuse.[22] Additionally, codes of conduct adopted by the PUC restrict utilities from subsidizing competitive activities with revenues from regulated activities, and utilities are required to treat their affiliated companies and competitors equally in the marketplace.

The codes of conduct are especially important in the Texas market because bilateral contracts will be the predominant form of marketplace activity, another key distinction from the California model. In the Texas market structure, pricing information will remain privileged data between parties, as opposed to the California model, where prices are openly set in a centralized power exchange (PX). The California PX model has shown significant disadvantages since its implementation. The PX takes hourly bids from generators and then pays all generators the highest price set that hour. Buyers in the exchange, therefore, will pay the highest price for every kilowatt-hour of power at any given hour of the day, even if one or more generators is willing to sell electricity at a lower price.

The Texas bilateral market structure, on the other hand, will allow electric service providers to use long-term bilateral power contracts to hedge risk in the marketplace by seeking primary and secondary generation sources at the lowest prices available in the market. Again, a primary reason why this approach is feasible in Texas is the adequacy of generation capacity. A possible constraint

[21]PURA §39.051(b).

[22]PURA §39.156(b).

on the effectiveness of this approach, however, is the lack of liquidity in unplanned energy transfer capability during the peak demand season due to transmission system congestion.

As noted above, primary rulemaking and enforcement authority regarding electric utility industry restructuring is granted to the PUC. A new Market Oversight Division was created by the PUC to monitor several aspects of competition at all market levels: generation, wholesale and retail. Additionally, the PUC is granted authority to delay competition before January 1, 2002, if it determines a power region is unable to offer fair competition and reliable service to all retail customer classes.[23]

Stranded Costs

As utilities unbundle business activities into regulated and unregulated components, the issue of stranded costs arises from the fact that some facilities and contracts produced in the regulated environment prove to be uneconomical in a competitive market. The 76th Legislature decided these excess costs over market (ECOM), or stranded costs, should be reimbursed to the utilities through a non-bypassable charge on all customer bills until the costs are recovered. Another key difference between the California and Texas models is the treatment of stranded costs. San Diego Gas and Electric customers were exposed to wholesale market volatility when the utility paid off its stranded costs, which lifted the rate freeze under California's restructuring law. Under the Texas model, there is no correlation between stranded cost recovery and the lifting of the mandated 6 percent rate reduction and retail price cap, known as the price to beat. Furthermore, whereas California's other two major investor-owned utilities expect to complete stranded cost recovery and lift the rate freeze in their territories by 2002, stranded costs in Texas may be recovered over a much longer period of time, minimizing impact on the developing market.

In 1998, the PUC reported possible ECOM for Texas utilities at $4.39 billion.[24] The most recent ECOM estimates come from the utilities themselves, in their "unbundling filings" submitted in

[23]PURA §39.103.

[24]Public Utility Commission of Texas, *Report to the Texas Senate Interim Committee on Electric Utility Restructuring: Potentially Strandable Investment (ECOM)*, 1998.

March 2000. Orders have been issued by the PUC allowing securitization of $764 million in regulatory assets and transaction costs for Central Power and Light and $740 million for Reliant Energy HL&P. The PUC's securitization order of $363 million for TXU is under court challenge.

As the restructuring process continues, stranded costs in Texas are significantly impacted by a variety of market factors, particularly the price of natural gas, which has more than doubled in the past year. Natural gas is the fuel of choice for independent power producers because natural gas facilities are generally smaller and less expensive to build than other forms of generation. Natural gas is also a relatively inexpensive and abundant fuel source. However, recent increases in natural gas prices have translated into higher fuel charges on consumer electric bills in 2000.

Stranded costs should be lower because coal and nuclear plants — which comprise the bulk of stranded assets — have become more competitive with natural gas power generation, thereby increasing their market value. ECOM discussions will continue for the next four years. The PUC has not yet determined what costs related to emission reductions may be included in recovery proceedings. Additionally, TXU's pending request for recovery of nuclear plant costs could add as much as $941 million to total stranded costs.[25] A commission order on stranded costs is expected in Summer 2001, and the ECOM "true-up" will occur in 2004, at which time real data from a mandated 5 percent generation capacity auction and the first two years of market competition will be used to settle the issue.[26]

Rising Energy Costs

Quantifying the effects of higher natural gas prices on the Texas electric power industry is difficult at best. The recent increase in natural gas prices, if the trend continues, may provide the benefit of reducing stranded costs. Such a reduction could lower the non-bypassable charge on customer bills used as a repayment mechanism. However, this reduction in the "price floor" of the retail electricity

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[25]TXU petitioned the PUC to securitize $1.65 billion in regulatory assets. The PUC concluded that only $363 million of TXU's regulatory assets met the criteria for securitization. TXU has appealed the decision to the courts. *Docket No. 21527 - Application of TXU Electric Company for a Financing Order to Securitize Regulatory Assets and Other Qualified Costs.*

[26]PURA §39.307.

price structure could be offset by increases in fuel costs for competitors.

Texans will see an increase in the retail price of electricity over the next few years, completely independent of market restructuring efforts if natural gas prices continue to increase. This issue is further compounded by the industry trend to rely on natural gas for generating fuel. All new generation capacity slated to come online in the next two to three years in Texas will be fueled by natural gas, with the notable exception of several new "wind farms" proposed in West Texas and other small renewable sources.

There is some question as to how much impact new gas-fired generation facilities will have on the total demand for natural gas. Although several new facilities have been announced or are under construction, new efficiencies in gas turbine technology allow more electricity to be produced from less fuel. However, rising electric demand means these plants will be running more often, and it is simply too early to tell what the net effect on total gas consumption will be. One noticeable impact of electric generating facilities on the gas market has been decreased levels of gas put into storage for the traditional peak winter season. Low gas production, coupled with all-time high summer electric demand largely fulfilled by gas-fired generators, has resulted in significantly decreased storage rates in 2000.[27]

Industry estimates vary considerably on the question of where natural gas prices will settle in coming months. Overall, exploration and drilling activity has declined since 1998, when prices remained low for most of the year. Approximately one third of all natural gas produced in the United States comes from Texas, yet Texas production has experienced an average annual decline of 2 percent per year since natural gas production peaked in 1972.[28] Many industry analysts predict shortfalls in natural gas availability during Winter 2000 as a result of production and storage declines.[29]

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[27]Texas Railroad Commissioner Charles Matthews, testimony before the Electric Utility Restructuring Legislative Oversight Committee, Sept. 26, 2000 (See Appendix G for summary).

[28]Ibid.

[29]"Panel: Consumers Face 'Perfect Storm' Of Energy Problems," *Oil & Gas Journal Online*, Oct. 24, 2000.

Environmental Issues

The amount of pollution caused by EGFs in Texas will decline substantially under provisions of SB 7. Key reductions will be made in sulfur dioxide (SO2) and in nitrogen oxides (NOx), a pollutant that contributes to the formation of ground-level ozone, a widely-recognized health hazard. EGFs in Texas previously exempted from permitting requirements — so-called "grandfathered facilities" — were required under SB 7 to apply for an emissions permit from the TNRCC no later than September 1, 2000, or cease plant operation by May 1, 2003.[30] Total annual emissions from grandfathered facilities will decrease by 112,000 tons, or 12 percent, as a result of SB 7.[31] As of the filing of this report, 76 grandfathered EGFs had requested emissions permits.

The emissions cap and trade program established by the TNRCC also allows non-grandfathered facilities to implement pollution reduction measures and participate in the buying and selling of credits. This mechanism facilitates allocation of monetary resources where the greatest pollution reductions can be achieved for the least cost.

A common concern of the PUC, ISO administrators and industry participants is that EPA requirements to reduce ozone-forming emissions further in certain metropolitan areas may present challenges to maintaining overall reliability of the electric grid in Texas, particularly in the Dallas/Fort Worth area. The reliability challenges stem from two sources. First, some plants must be shut down in order to retrofit equipment with updated emissions control technology. This can generally be scheduled and accomplished during the off-peak season. However a high degree of coordination will be required to ensure sufficient capacity remains online to serve load. Second, some plants may be uneconomical to retrofit with improved emissions control devices and therefore are candidates for closure. Those same plants may also be integral parts of maintaining grid reliability by stabilizing voltage in a critical geographic area.

Industry response to the renewable energy mandate of SB 7 has thus far exceeded the goals of the bill. The PUC has established a renewable energy credits trading program, which allows all Texas

[30]PURA §39.904.

[31]TNRCC Executive Director Jeff Saitas, testimony before the Electric Utility Restructuring Legislative Oversight Committee, Nov. 30, 1999 (see Appendix D for summary).

customers to participate in renewable energy development by requiring all REPs to own a proportional share of credits in the Texas market. Since 1999, almost 700 MW of new capacity from wind projects alone have been announced by traditional utilities and "green power" firms alike. This amount is roughly one third of the total new capacity required by 2009 under SB 7.

Customer Protection

Coming changes in provision of electric service coupled with recent developments in telecommunications services and mass marketing techniques spurred the 76th Legislature to adopt an extensive list of customer safeguards. Among other things, SB 86 entitles all buyers of telecommunications and retail electric service to:

- protection from fraudulent, unfair, misleading, deceptive or anticompetitive practices, including protection from being billed for services that were not authorized or provided;
- protection from discrimination on the basis of race, color, sex, nationality, religion, marital status, income level, source of income or geographic location;
- impartial and prompt resolution of disputes with a certified telecommunications utility, a retail electric provider or an electric utility;
- privacy of customer consumption and credit information; and
- bills presented in a clear, readable format and easy-to-understand language.[32]

The first step to protecting consumers from anticompetitive behavior is to promote understanding of coming changes in the marketplace. To this end, the PUC adopted a two-stage approach to inform consumers of market changes and rights and protections afforded them by law. In the first phase, High Point/Franklin, a communications firm with experience in other market restructuring efforts, was selected by the PUC to develop a customer education plan. High Point/Franklin surveyed more

[32] PURA §17.004(a).

than 40 opinion leaders and policy makers statewide, conducted eight focus groups in six Texas cities and performed telephone surveys of 1,100 residential and 400 business customers of investor-owned utilities (IOUs). The education plan adopted by the PUC on July 18, 2000, was developed from the results of the survey, High Point/Franklin's experience in other markets and input from PUC staff, consumer advocates and industry representatives.

Key points of the customer education plan include integrated communications strategies, such as paid advertising, public relations efforts, printed materials, a toll-free call center, an electric competition Web site and specific tools designed to measure the overall effectiveness of each strategy. The plan also emphasizes communication through community-based organizations, which will form the primary channel to reach traditionally under-served populations such as low-income and non-English-speaking customers. On October 19, 2000, the PUC selected marketing firm Burson-Marsteller to implement the customer education plan.

Analysis of restructuring efforts in the telecommunications industry can provide some insight into possible pitfalls along the path of electric utility restructuring. Among the research findings of High Point/Franklin's interactions with both residential and commercial customers is the conclusion that Texas customers clearly framed their view of electric choice within their experience with long distance telephone service competition.[33] Anticompetitive practices such as slamming (changing service providers without customer authorization) and cramming (hiding unauthorized charges on customer bills) were commonly cited. Additional concerns were raised about the expected level of telemarketing activity associated with retail electric competition.

To prevent the slamming practices associated with long distance competition, ERCOT will function as the customer switching information center in Texas, and it will notify each customer by postcard whenever a switch request is received. The customer can verify the request by doing nothing, or nullify the request by returning the card. The PUC anticipates adopting a rule against cramming, along with related specific provisions addressing the content of customer bills, in coming months. Other rules addressing the customer safeguards established by SB 7 and SB 86 are expected to be adopted by the PUC in December 2000. Municipally-owned utilities and electric cooperatives are also required to adopt similar rules for customers within their certificated areas.

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[33]High Point/Franklin, *Electric Competition in Texas: Customer Education Plan*, July 24, 2000, p. 13.

In much the same way monopoly utilities currently provide electric service to any requestor within their service territories, a provider of last resort (POLR) will be established to fulfill this function in the restructured marketplace.[34] Protections similar to those existing today have been established for both consumers and the REP serving as POLR. Customers who fail to pay for electric service can be disconnected except during extreme weather emergencies.

The POLR in each area of the state will be selected by the PUC through a bidding process. Large service territories, such as Reliant Energy HL&P, will likely be divided into several smaller POLR territories. If the bidding process is not successful, (e.g., the PUC does not receive enough bids for all POLR territories), the PUC can designate a REP to serve as POLR. The generally held perception is that POLR rates will be nominally higher than the market rate to allow the POLR to hedge risk against an unknown quantity and type of customer. Because customers who "choose not to choose" in areas of the state open to competition on January 1, 2002, will default to the affiliate REP of the incumbent utility, it is not expected that the POLR will be extensively utilized for the first few years of market development.

To further aid consumers in the restructured electric utility market, the System Benefit Fund (SBF) was created to fund four different programs: electric rate reductions for low-income customers, a targeted low-income weatherization program administered by the Texas Department of Housing and Community Affairs (TDHCA), appropriations for customer education programs of the PUC and administrative costs of the Office of Public Utility Counsel (OPC), and a mechanism to compensate the state and school districts for losses in property values of utilities' assets directly caused by restructuring. The source of revenues for the fund is a fee charged to customers based on the kilowatt-hours of electric energy used. Through fiscal year 2001, the SBF is expected to collect more than $90 million to fund early customer education efforts and payments to school districts. The PUC has worked with the Texas Department of Human Services to develop an automatic enrollment system for low-income customers to receive rate reductions. The PUC is expected to finalize rules relating to SBF administration in December 2000.

Thus far, the Texas Comptroller of Public Accounts has certified the property value losses directly attributable to restructuring of the electric utility industry at $6.29 billion. The Texas Education

[34] PURA §39.106

Agency (TEA) has certified that $65.12 million in Chapter 41 recapture dollars will be lost due to restructuring implementation. These losses to public school funding will be repaid through the SBF. The PUC will issue an order in December 2000 directing the IOUs to pay into the SBF their share of the amount determined by TEA.

Findings

The committee believes maintaining a reliable, affordable supply of electricity for all Texans is an essential component in our state's continued economic prosperity. The committee has observed the implementation process in action for more than a year and finds the provisions of SB 7 supply an adequate framework for electric utility restructuring in Texas.

Chapter One:
IMPLEMENTATION OVERVIEW

As expected, electric utility restructuring in Texas has proven to be a major undertaking requiring the combined efforts of several state agencies, industry participants and consumer organizations. Most regulatory implementation and market oversight functions were charged to the Public Utility Commission of Texas (PUC) and the Electric Reliability Council of Texas (ERCOT), a non-profit corporation serving as the Independent System Operator (ISO).

The task of creating a retail market structure in the electric power industry is nearing completion. The basic "rules of the road" are in place, business separation plans have been filed, registration of players in the new market has begun and the technical systems needed to meet restructuring requirements have entered the testing phase. The retail competition pilot project is expected to commence June 1, 2001, as established by PURA §39.104(b). Retail competition will begin for most of the state on January 1, 2002, as scheduled.

Implementation Strategies

Several implementation strategies have been exercised to meet the time frames set by SB 7.[1] An often-used approach in the development of both the regulatory structure and market mechanics employed collaborative, consensus-based processes involving branches of state and local government, market participants and consumer interest groups. For example, affected participants discussed implementation time lines, strategies, rules and procedures during a series of workshops hosted by the PUC. These deliberations served to delegate the work load to the appropriate levels. In many cases this process led to compromises generally accepted among affected stakeholders.[2]

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[1]SB 7 established specific deadlines for certain restructuring activities, including adoption of rules (e.g., PURA §39.101(a)), filings and actions by market participants (e.g., PURA §30.051) and updates to state leaders (e.g., PURA §§ 39.907(g), 31.003(a), and 39.902(b)).

[2]PUC Chairman Pat Wood, testimony before the Electric Utility Restructuring Legislative Oversight Committee, Nov. 30, 1999 (see Appendix D for summary).

On other implementation projects, the PUC staff issued a “straw man” rule and invited comment from interested parties. This approach also solicited a high level of communication among affected stakeholders. In other cases, traditional administrative rulemaking procedures were used. During most phases of the implementation process, public participation opportunities have existed either directly through public hearings or through interest group participation and monitoring activities.

During the restructuring period, particular attention has been focused on learning from the successes and problems of other states’ deregulation efforts. Consulting firms with experience in other market restructuring efforts were utilized by the PUC, ERCOT and electric utilities, among others. Additionally, several industry participants in the Texas market have gained experience in other restructured markets, such as California and Pennsylvania, and have brought those lessons to bear on this state’s restructuring efforts. Testimony regarding restructuring efforts in other markets was also presented to the committee.

Direct communication through seminars and training courses has also been extensively utilized. ERCOT has conducted several seminars known as the Market Readiness Series (MRS). The fourth in this series, held in Austin on September 25 and 26, 2000, drew more than 500 participants. ERCOT will conduct five more MRS seminars before the retail competition pilot project begins on June 1, 2001. ERCOT will also conduct seminar-style training classes on technical issues for market participants prior to the pilot project start date. Market players in the non-ERCOT areas of Texas have held similar functions immediately following the ERCOT seminar, in addition to participating in the ERCOT MRS seminars. These meetings have resulted in high levels of communication between industry participants, allowing shared questions and answers on every aspect of the new market from technical issues to understanding the new rules for the electric power industry.

Though not an implementation strategy, some issues related to the electric power industry and market restructuring have been or will be decided in the judicial system. Some specific cases are discussed in this report.

Public Utility Commission of Texas

In addition to continued regulation of the electric utility industry during the restructuring process, the PUC is also charged with developing most of the rules necessary to implement SB 7. Many of these rules are examined in detail in subsequent chapters of this report. A summary of completed rulemaking projects to date includes:

Code of Conduct for Electric Utilities and Affiliates: Adopted November 11, 1999, to implement PURA §39.157. This rule establishes safeguards to govern the interaction between utilities and their affiliates to prevent market power abuses and cross-subsidization between regulated and unregulated activities.

Cost Unbundling and Separation of Business Activities: Adopted December 16, 1999, to implement PURA §§ 39.051 and 39.201. This rule provides for the separation of each investor-owned utility (IOU) into a competitive power generation company (PGC), a competitive retail electric provider (REP) and a regulated transmission and distribution utility. The rule requires separation of competitive energy services from regulated utility activities and sets standards for determining transmission and distribution utility non-bypassable delivery charges, stranded cost estimation, System Benefit Fund assessment and nuclear decommissioning charges.

Certification of REPs: Adopted July 12, 2000, this is one of two rules that implement PURA Chapter 39, Subchapter H. The rule sets qualifying standards for certification as a REP.

Registration of PGCs and Aggregators: Adopted May 31, 2000, this is the other of two rules that implement PURA Chapter 39, Subchapter H. The rule sets qualifying standards for registration and operation of PGCs and aggregators.

Market Power Mitigation Plans: Adopted August 10, 2000, to implement PURA §§ 39.155 - 39.157. The rule establishes a methodology for calculating generation market share and requires reports from the owners of generation facilities.

Retail Competition Pilot Project: Adopted August 10, 2000, to implement PURA §39.104. This rule establishes the terms for the pilot project, which is scheduled to begin June 1, 2001.

Renewable Energy Mandate: Adopted December 16, 1999, to implement PURA §39.904. This rule defines the requirements for the purchase of renewable energy by competitive retailers and establishes a renewable energy credits trading program.

Public Retail Customers: Adopted September 23, 1999, to implement PURA Chapter 35, Subchapter D. This rule facilitates the sale of power by the General Land Office to public retail customers.

Energy Efficiency Programs: Adopted February 24, 2000, to implement PURA §39.905. This rule implements the statutory goal for energy efficiency. Utilities are required to fund market-based standard-offer programs and limited market transformation programs to reduce statewide energy consumption by at least ten percent of each utility's annual growth in demand by 2004.

Electric Reliability Standards: Adopted December 1, 1999, to implement PURA §38.005. This rule establishes reliability standards for electric utilities.

Distributed Generation: Adopted November 18, 1999, to implement PURA §39.101. These rules ensure electric customers have access to on-site distributed generation. The rules prescribe terms and conditions for the connection of small power generation equipment and establish technical requirements to promote safe and reliable operation of distributed generation.

ISO Funding: Adopted September 9, 1999, to implement PURA §39.151. The rule permits ERCOT to charge a fee for the use of the transmission system to cover the additional funding required to develop the staff and computer systems needed for it to carry out ISO functions.

Natural Gas Generating Capacity: Adopted December 1, 1999, to implement PURA §39.9044. This rules establishes a natural gas credit trading program to meet the legislative goal that 50 percent of generation capacity installed in Texas after January 1, 2000, use natural gas as a primary fuel source. The natural gas credit trading program will not be implemented until the proportion of new generation capacity in Texas fired by natural gas falls below 55 percent.

Terms and Conditions for Transmission Service: Adopted December 1, 1999, to implement PURA §35.004. This rule sets a "postage stamp" method of ERCOT transmission pricing.

Provider of Last Resort (POLR): Adopted October 4, 2000 to implement PURA § 39.106. This rule establishes the POLR terms of service and sets procedures for selecting POLRs for different geographic areas.

Environmental Cleanup Costs: The methodology used to calculate environmental cleanup costs to be included in stranded cost recovery under PURA §39.263 has been adopted by the PUC. The rule requires a cost-benefit analysis of pollution control versus plant retirement. Consideration of likely future environmental regulations and their potential financial impacts is required. A final order on recoverable environmental cleanup costs will be issued during the 2004 true-up proceedings.

Several rules to implement retail electric choice remain to be set by the PUC. A summary of major projects remaining includes:

Customer Protections: Anticipated adoption in December 2000 to implement PURA §§ 17.001 and 39.101. The currently proposed rule includes requirements for metering and billing, protections against slamming and cramming, telephone solicitation rules, terms for access to consumer information and other safeguards mandated by SB 86 and SB 7. A more detailed examination of customer safeguards is included in Chapter 5.

Capacity Auction: This rule will set the terms and conditions for the generation capacity auctions required by PURA §39.153. Adoption is scheduled for December 2000.

System Benefit Fund (SBF): This rule will describe how the SBF will be administered and establish guidelines for the low-income programs to be supported by the SBF as mandated by PURA §39.903. Adoption is scheduled for December 2000.

Code of Conduct for Municipal Utilities and Cooperatives: This rule will establish standards to prevent market power abuses and cross-subsidization between regulated and competitive activities of municipal utilities and cooperatives, which are not subject to the code of conduct that has been adopted for IOUs. Adoption is scheduled for February 2001.

Terms and Conditions for Transmission and Distribution: This rule will establish the terms and conditions under which wires companies will provide service to retail electric providers. Adoption is scheduled for November 2000.

Additionally, the PUC is scheduled to review and approve the market protocols developed by ERCOT by March 2001. The protocols will set the rules and procedures for market participant interaction with the ISO.

Electric Reliability Council of Texas

ERCOT's primary function in the restructured marketplace is to serve as the ISO of the electric transmission grid. Additionally, ERCOT will maintain customer registration and switching information to protect consumers from slamming. To cover ISO operations and facilitate transition activities, a fee of 15 cents per megawatt-hour is levied against all energy transactions. Estimated revenue from transactions fees in 2000 is $40 million.[3]

Most restructuring activity deadlines in ERCOT are set for June 1, 2001, the retail competition pilot project start date. At the end of September 2000, ERCOT reported restructuring operations were about one week behind schedule.[4] Although it may be necessary to delay the pilot project if technical systems are not ready, the ISO anticipates meeting the June 1 target date.[5]

To accomplish restructuring objectives, ERCOT is engaged in hiring additional staff, constructing additional facilities and computer systems and drafting new market rules, called protocols. The ERCOT protocols will be reviewed by the PUC in early 2001. Additionally, some organizational restructuring was required for ERCOT to meet the ISO criteria established in SB 7. This activity is complete. A new board of directors will assume office in December 2000. Updates to hardware and software needed by ERCOT and market participants in the restructured market have entered the development and testing phases.[6] All ERCOT systems will undergo a "live test" phase in April 2001. This test, known as the mock market, will last approximately 60 days and will examine system performance under a variety of theoretical scenarios. Participants in the retail competition pilot

[3] Interview with ERCOT Director of Coordination and Reports Larry Grimm, Oct. 12, 2000.

[4] ERCOT Director Sam Jones, remarks at ERCOT Market Readiness Series No. 4, Sept. 25, 2000, Austin.

[5] Interview with ERCOT Director of Technical Operations Kent Saathoff, Oct. 23, 2000.

[6] Larry Grimm, Oct 12, 2000.

project will also test new systems during the April mock market.

A more thorough description of ISO duties and ERCOT's preparations to assume that role is provided in Chapter 4, which also includes a review of transmission coordination in the non-ERCOT areas of Texas.

Other State Agencies

Texas Natural Resource Conservation Commission (TNRCC): SB 7 directed the TNRCC to develop a cap and trade program for emissions from electric generating facilities (EGFs).[7] The program requires EGFs previously exempted from the requirements of the Texas Clean Air Act (TCAA), or "grandfathered facilities," to apply for an emissions permit by September 1, 2000. These facilities must obtain a permit or cease operating by May 1, 2003. For facilities receiving permits under this rule, emissions of nitrogen oxides are capped at 50 percent below 1997 levels. Coal-fired EGFs must reduce emissions of sulfur dioxide by 25 percent below 1997 levels. The rule allows EGFs already permitted under the TCAA to voluntarily reduce emissions for the purpose of obtaining credits for sale under the program. Of the 130 grandfathered EGFs in Texas, 76 applied for permits under the new rule. The TNRCC is considering an additional rule that would allow other industries to participate in the cap and trade program. The stated purpose of the rule is to allow companies flexibility to determine the best mix of using control technologies to reduce their own emissions and/or the purchase or trading of surplus allowances from other facilities. This rule is scheduled for adoption in December 2000.

General Land Office (GLO): SB 7 included a provision authorizing the GLO to negotiate and execute contracts for the conversion of state in-kind royalties to other forms of energy and sell the converted energy to public retail customers.[8] SB 7 defines the state in-kind royalties which may be used as oil or gas produced on state mineral lands, university mineral lands or the first three miles of federal waters adjacent to the state boundaries. The GLO has developed and implemented the Texas State Power Program to execute this authority.

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[7] PURA §39.264.

[8] PURA Chapter 35, Subchapter D.

The provisions of SB 7 limit power sales to public retail customers, which are defined as public school districts, state colleges and universities, state agencies and political subdivisions of the state. GLO sales are capped at no more than 2.5 percent of the total retail load in a service territory. The GLO is prohibited from selling electricity to public retail customers served by electric cooperatives or municipal power agencies (MPAs) unless the cooperative or MPA member utility has decided to opt in to competition.

The GLO will not build or own any electric facilities or generate electricity. A contracted agent or energy service provider (ESP) and the incumbent utility will conduct all electric and utility-related business. The GLO will supply gas to the ESP and contract for service with customers. It will execute contracts with electric power providers that assist the GLO with all aspects of converting royalties, retail marketing, sales, billing, metering and ancillary services.

The State Power Program is structured to include a Gas Sales Agreement specifying oil and liquids to be converted at value, an Electric Service Agreement (ESSA) and a Retail Sales Contract with customers. Under the Gas Sales Agreement, the GLO will provide gas to the ESP for an industry standard indexed price at volumes determined in the ESSA. Under the ESSA, the GLO will provide gas or oil volumes necessary to generate the number of kilowatts contracted with customers. The ESP will provide electricity for a fixed price and set volumes and delivery points for gas and oil. The Retail Sales Contract with each customer will follow standard market utility provider contracts.

As mentioned above, the PUC enacted the rule granting GLO access to retail electric sales September 23, 1999. As of October 2000, the GLO reported more than $350,000 in retail electric sales, providing almost $60,000 in savings to public schools. The GLO has executed 46 contracts with public retail customers, and 164 contracts are in progress at the filing of this report. The vast majority of these contracts are with public school districts.

Earnings from royalty conversions are placed in the Permanent School Fund. Earnings from retail electric sales are placed in the Available School Fund.

Legislative Oversight

The Electric Utility Restructuring Legislative Oversight Committee conducted four public hearings in three Texas cities during the 1999-2000 interim. The hearings featured invited and public testimony from consumers and consumer advocates, state and federal agencies, the independent system operator, representatives of the electric power industry, community-based organizations and others. A summary of testimony presented to the committee at these hearings is included at the end of this report in Appendices D through G.

In addition to briefings regarding implementation activities, the committee received testimony related to various changes in energy markets both in Texas and elsewhere. The price spikes and reliability problems experienced in California received particular attention in the committee's investigation into market restructuring issues. Other issues figuring prominently in the committee's public discussions include air quality data and environmental regulatory impacts on the electric power industry, planning and reliability of the bulk power grid and energy price pressures. Each of these topics are addressed in succeeding chapters.

Chapter Two:
ELECTRIC SYSTEM RELIABILITY

Maintaining an adequate, affordable supply of electricity for all customer classes is a fundamental security issue. One of the most critical aspects of the restructuring process is to avoid compromising reliability of the bulk electric system in Texas. The process of planning, building and maintaining electric systems in Texas and the United States has undergone significant changes during the 1990s. In many ways, these changes have enhanced system reliability by channeling new development into the bulk power system infrastructure. In other ways, system planning has been complicated by the redistribution of some reliability functions and responsibilities. This chapter provides an overview of how electric systems work, current and anticipated generation capacity in Texas, challenges to electricity transmission across the state and other factors which complicate system reliability during the restructuring transition period.

Overview of Electric Systems

Basic knowledge of how electric systems work is essential to understanding the changes taking place in the Texas electricity market. Electricity is somewhat unique as a commodity in that it cannot be readily stored in significant quantities. Therefore, it must be made, distributed and consumed in real time. Ensuring electric system reliability requires three key components: adequate generation of electric power, sufficient transmission systems to move the power from generators to end users and an operating and monitoring system to make the minute-to-minute adjustments necessary to keep the grid balanced between available supply and demand at all times.

Generation refers to the physical production of electric power. Electricity is produced by generating units powered by burning fossil fuels such as coal or natural gas, running water such as a river controlled by a dam, renewable resources such as solar and wind energy, or by nuclear fission. These fuel sources serve as a catalyst which heats water to create steam. This steam is used to turn a turbine containing a metal coil which spins within a magnetic field, creating a current of electricity. The electricity is transported to consumers by use of transmission and distribution systems. Transmitting electricity involves sending it through high-voltage power lines, usually over long distances. Lower-

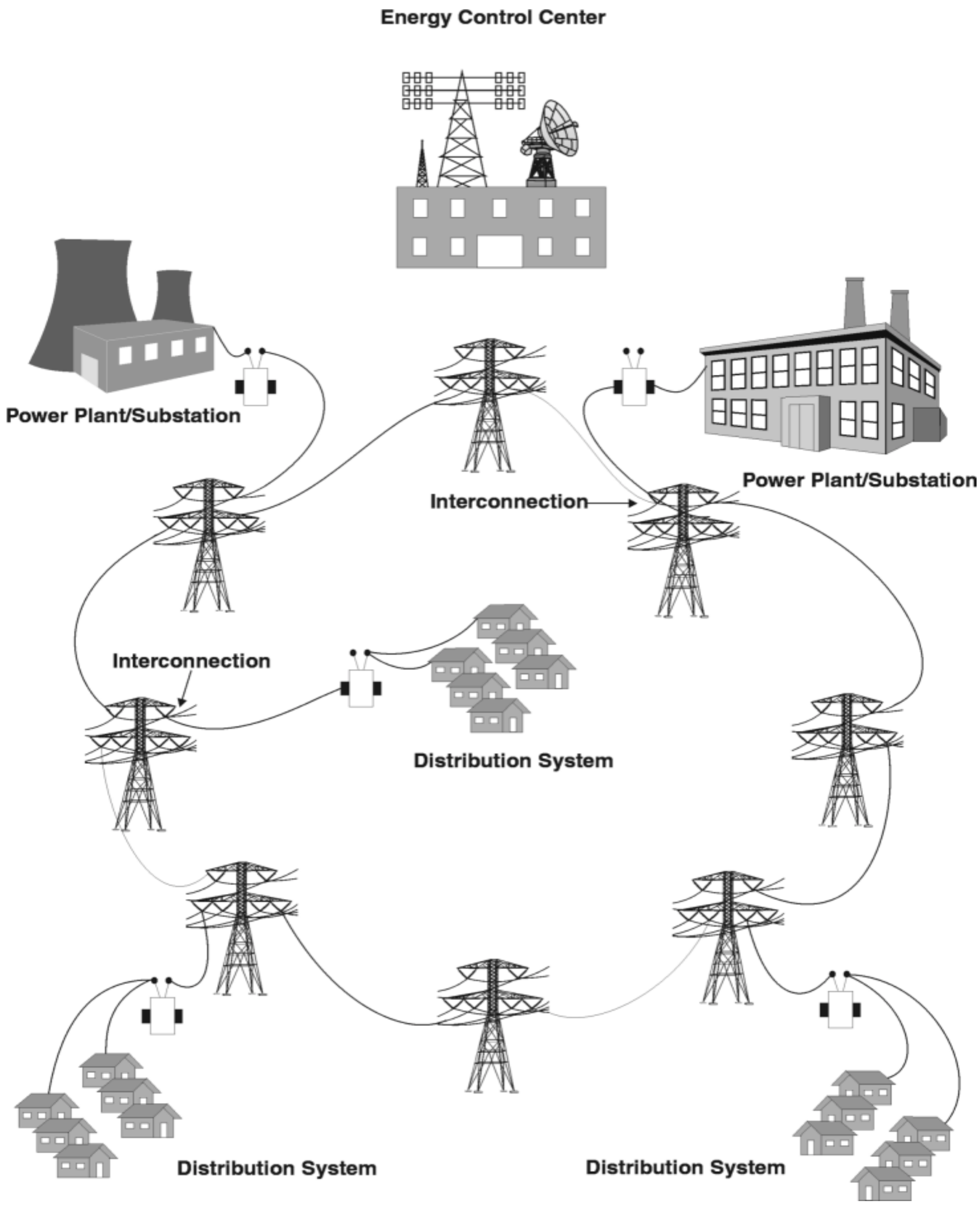

Fig. 2.1 **A Simple Electric System**

voltage distribution networks move the power from the transmission system to end users *(see Figure 2.1).* A defining feature of the bulk power system is the degree of interdependence between its various parts. The need for coordinated system operation stems from more than a simple energy balance. Because the system uses alternating current, every generating plant must be in precise synchronization in order to keep the network at the same frequency and maintain voltage. This is complicated by a phenomenon known as reactive losses, which are tiny amounts of energy stored in transmission lines as power is moved over great distances. Reactive losses generally have the effect of lowering voltage at one end of the transmission line, which can harm electronic equipment plugged into the system.

An energy control center is needed to apply the proper amount of reactive power from various points in the grid by remote control. The challenge of keeping a power system in supply-demand balance, synchronized and voltage-supported is made difficult by the fact that the electric transmission system generally does not allow power to be directed down a specific path from one generator to one consumer. The transmission system is more like a large water pool into which electricity flows from all generators. All users take from this pool, and the system is adjusted so that the total water flowing into the pool equals the total water being withdrawn by all users at every moment.[1]

Of the 48 contiguous states, Texas is in the unique position of controlling most of the power grid within the state's borders. Most other states lie within either the Eastern or Western Interconnections and fall under the guidelines of the Federal Energy Regulatory Commission (FERC). The Texas Interconnection, monitored by the Electric Reliability Council of Texas (ERCOT) covers all but four portions of the state: El Paso, the Northwest Panhandle and parts of Northeast and Southeast Texas. The principal regulatory body for the 84 percent of Texas located within ERCOT boundaries is the Public Utility Commission of Texas (PUC).

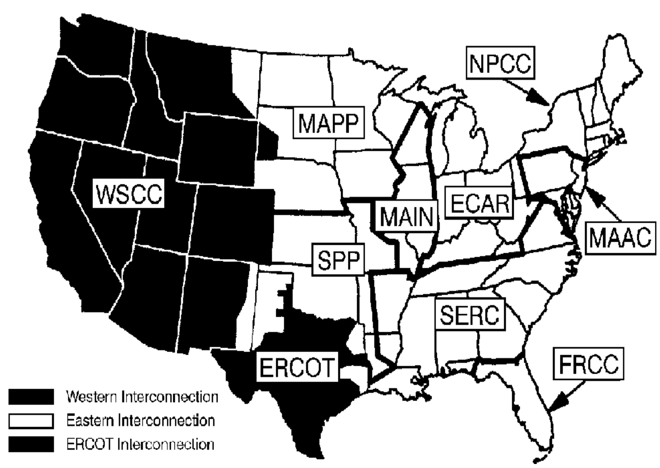

Fig. 2.2 **Major U.S. Interconnected Electric Systems**

Energy control center functions within the ERCOT boundaries will be performed by the ERCOT Independent System Operator (ISO). ERCOT will also perform some statewide functions, including maintaining

[1]Peter Fox-Penner, *Electric Utility Restructuring: A Guide to the Competitive Era*, Public Utility Reports, Inc., Vienna, Va., 1997, pp. 25-26.

market participant and customer registration databases. In the non-ERCOT areas of Texas, energy control center functions will likely be performed by regional transmission organizations (RTOs) pursuant to FERC Order 2000. A more complete discussion of ISO implementation and control center functions can be found in Chapter 4.

Generation

Construction of additional generation capacity in Texas slowed during the early 1990s as utilities and independent power producers watched the development of wholesale market restructuring in the state. In 1995, the 74th Legislature passed SB 373, which required open access to utility transmission systems, paving the way for non-utility power producers to operate in Texas. Industry response to wholesale market restructuring has been positive. Twenty-two new power plants have added more than 5,700 megawatts (MW) of capacity. Approximately 15 more generation facilities are under construction.[2] The total available capacity above peak electric demand, or reserve margin, is widening in Texas after dipping below the recommended 15 percent from 1998 to Summer 2000. PUC staff predict reserve margins in ERCOT will approach 30 percent by Summer 2001 and 2002.[3]

Figure 2.3 provides details of many of the new generation capacity announced or under development in ERCOT as of October 2000. Because generation interconnection requests are considered proprietary information, this is a partial list reflecting only those projects approved for disclosure.[4] In some cases, market conditions may cause a power producer to alter plans or abandon a project. It is unlikely every project on the list will be developed in the anticipated time frame. Figure 2.4 summarizes power generation market activity since SB 373 implementation.[5]

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[2]PUC Chairman Pat Wood, testimony before the Electric Utility Restructuring Oversight Committee, August 22, 2000 (see Appendix F for summary).

[3]Public Utility Commission of Texas, *Draft Scope of Competition Report*, Project No. 22258, August 17, 2000, p. 42.

[4]Electric Reliability Council of Texas, “New Generation Projects Under Development in ERCOT,” Web site information retrieved Oct. 9, 2000.

[5]Public Utility Commission of Texas, *Update on Activities in the ERCOT Wholesale Electricity Market*, April-June, 2000, Project No. 19616, p. 13.

Fig. 2.3 **Announced New Generation Capacity in ERCOT**

In Service	Capacity (MW)		Location (County)	Owner
		Natural Gas		
June 2001	500		Bastrop	Calpine
May 2001	479	summer, 539 winter	Bexar	CPS-San Antonio
June 2002	306	summer, 357 winter	Bosque	Southern Company Energy
January 2002	800		Chambers	Calpine
June 2001	75		Collin	City of Garland
1st Quarter 2004	385		Duval	CCNG
July 2001	1,000		Ector	Texas Independent Energy
June 2000	1,000		Ellis	American National Power
September 2001	350		Ellis	Tractebel Power
June 2002	600		Fort Bend	Avista
May 2002	1,050		Freestone	Entergy Power Group
June 2000	830	summer, 910 winter	Grimes	Tenaska Power
December 2000	1,000		Guadalupe	Texas Independent Energy
June 2002	820		Guadalupe	Constellation Power
June 2000	545		Harris	Calpine
May 2001-Feb. 2002	830		Harris	Calpine
April 2002	770		Harris	Reliant Energy
June 2002	1,650		Harris	American National Power
May 2003	578		Harris	Sempra Energy
May 2003-May 2004	535	Phase 1, 535 Phase II	Harris	Energy Generation Corp.
June 2001	1,650	summer, 1,500 winter	Hays	American National Power
June 1999	514		Hidalgo	Frontera Generating
May 2000	510		Hidalgo	Duke Energy
February 2001	514		Hidalgo	Calpine
March 2002	750		Hood	AES
3rd Quarter 2002	1,500		Kaufman	Cosiba-Forney Power
July 2000	1,000		Lamar	FPL Energy
May 2003	578		Montgomery	Sempra Energy
April 2002	530		Nueces	Skygen Energy
May 2001	186		Travis	Austin Energy
July 2002	510		Wise	KN Power
June 2003	800		Wise	Tractebel Power
		Wind		
April 2001	175		Culberson	Orion Energy
July 2001	250		Ector & Winkler	York Research
Dec. 2000-Oct. 2001	150		Pecos	Enron Wind Corp.
January 2001	125		Pecos	Orion Energy
September 2001	100		Pecos	Cielo Power Market
Dec. 2001-Dec. 2002	400		Sweetwater	Enron Wind Corp.
Nov. 2000-Nov. 2001	300		Upton	Cielo Power Market

Source: Electric Reliability Council of Texas

Fig. 2.4 **New Generation Since SB 373**

Year in Service	All of Texas (MW)	ERCOT (MW)
Completed		
1996	341	341
1998	570	570
1999	1,277	897
2000	3,202	3,004
Total Completed	5,390	4,812
Under Construction		
2000	2,963	2,920
2001	7,646	6,776
2002	3,208	3,208
Total Under Construction	13,817	12,904

Year in Service	All of Texas (MW)	ERCOT (MW)
Announced		
2000	4	4
2001	376	284
2002	5,236	4,006
2003	6,411	6,411
2004	885	885
Indefinite	4,217	4,217
Total Announced	17,129	15,807
Total New Generation	36,336	33,523

Source: Electric Reliability Council of Texas

Adequate capacity is only one part of the equation. Access to a diverse source of generation fuels is an important factor to consider when estimating risk associated with a number of potential market scenarios. Figure 2.5 shows the installed capacity by fuel source for the 13 largest Texas utilities in 1998. Since 1998, almost all new capacity in Texas has been gas-fired non-utility generation facilities. Sustained higher natural gas prices have caused some in government and industry to speculate whether the Texas generation market is becoming too heavily dependent on natural gas as a fuel source.[6] A detailed look at recent activity in the natural gas market is included in Chapter 3.

Resource diversity can be an important risk management strategy, but several other considerations also factor into resource development decisions. Natural gas is favored in areas with air quality concerns because of its low emissions. As previously noted, however, if high natural gas prices are sustained, other fuel sources become more attractive in the marketplace. SB 7 required at least 50 percent of all new capacity installed in Texas to be fueled by natural gas.[7] The PUC has adopted a rule to implement this mandate. SB 7 also required additional investment in renewable resources, more than tripling the state's total renewable capacity by 2009.[8] A complete discussion of renewable

[6]Frank McCamant, testimony before the Electric Utility Restructuring Legislative Oversight Committee, Nov. 30, 1999 (see Appendix D for summary).

[7]PURA §39.9044.

[8]PURA §39.904.

Fig. 2.5 **Installed Capacity in Texas by Fuel Type and Owner**

Owner	Gas	Coal	Lignite	Nuclear	Hydro	Wind	PV	Total
TXU	12,995	-	5,825	2,300	-	-	-	21,120
RHLP	9,335	2,415	1,520	770	-	-	-	14,040
CPS	2,425	1,385	-	700	-	-	-	4,510
CPL	3,116	684	-	630	6	-	-	4,436
SPS	1,624	1,588	-	-	-	-	-	3,212
EGS	2,268	269	-	281	-	-	-	2,818
AE	1,450	570	-	400	-	-	0.3	2,420
SWEPCO	938	971	443	-	-	-	-	2,352
LCRA	1,040	1,024	-	-	273	-	-	2,337
WTU	1,025	370	-	-	-	1	-	1,396
EPE	607	82	-	466	-	-	-	1,155
BEPC	687	-	-	-	-	-	-	687
TNMP	-	-	301	-	-	-	-	301
Total ERCOT	33,222	7,293	8,037	4,800	435	1	0.3	53,788
Total Texas	38,918	10,258	8,597	5,547	662	1	0.3	64,011

Source: Public Utility Commission of Texas
(The total capacity shown for ERCOT and Texas includes other utilities and merchant power plants not listed individually.)

energy resources is included in Chapter 7.

Transmission

Ensuring system reliability depends not only on how much power is produced, but also how it is transported around the state. Electricity must be available both *when* and *where* consumers need it. Texas suffers from transmission constraints that restrict the flow of electricity at critical times during the day, especially during the peak summer season.[9] These transmission constraints have two primary effects. First, load centers dependent on imported power, such as the Dallas/Fort Worth (D/FW) Metroplex, could experience a supply shortage during peak use hours, even though sufficient generation capacity exists elsewhere in the system. Second, constrained transmission systems decrease liquidity in the marketplace, limiting the volume, type and timing of energy transactions between buyers and sellers.

[9]Electric Reliability Council of Texas, *Existing and Potential Electric System Constraints and Needs Within ERCOT*, Oct. 1, 2000, p. 10.

Prior to restructuring, new generation facilities and transmission lines were often planned together. In a restructured market, the PUC will no longer have significant advance knowledge where new generation facilities requiring connection to the grid will be located. This fact complicates system planning. Because transmission utilities will continue to be regulated monopolies after the transition to a competitive market, several important decisions will still fall to the PUC through formal proceedings in much the same way it has been done in the past.

To mitigate potential market power abuse, transmission utilities are required to provide non-discriminatory access to their lines. The utility cannot deny an interconnection request in its service territory. Utilities recover the cost of lines through a "wires charge" set by the PUC. Construction of transmission facilities to connect a new generator may not always be in the public interest. For example, the cost or impact of a new line may outweigh the benefits of the electric power it would connect to the grid. In this instance, the PUC may deny the utility a certificate of convenience and necessity for the line, thus absolving the utility of its interconnection responsibility and effectively canceling the proposed generation project. Part of the ERCOT ISO's responsibilities include reviewing proposed transmission projects and making recommendations to the PUC.

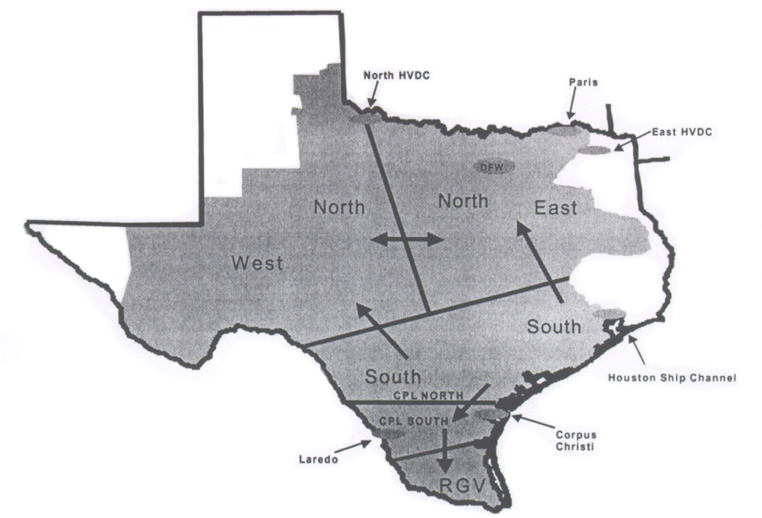

Fig. 2.6 **Major Transmission Constraints in ERCOT**

Currently in Texas, transmission systems are primarily constrained in the flow of power from South to North and to and from West Texas *(see Figure 2.6)*. The West Texas constraints have a particular impact on much of the state's new renewable energy projects, which are primarily wind facilities located in that area. Keeping the "green" megawatts flowing on the grid is important to obtaining the overall energy mix mandated by SB 7.

The most significant transmission challenge in Texas is importing power to the four-county D/FW Metroplex. Approximately 65 percent of the Metroplex's electric demand is served by power imported into the region over the ERCOT transmission grid. Peak demand in the Dallas area is approximately 15,000 MW. Current installed capacity is 5,900 MW. Population growth and increased demand will require utilities to import even more power in the near future. Population in the D/FW area grew 2.3 percent between 1996 and 1999. Electric load in the D/FW area has grown at about 2.9 percent annually and is expected to continue growing at approximately 3.4 percent per year. Projected growth in population and electric demand, existing air quality regulations and the lack of suitable sites for power plant construction near the load center point to the need for substantial additions in transmission capacity in and around the Metroplex.[10]

However, considering economics and good utility practice, ERCOT does not believe that sufficient transmission facilities can be installed to completely remove the need for new generation in the D/FW area. ERCOT believes a combination of new voltage support projects, strategic additions to the transmission system and an appropriate level of generation in the area is the only way future reliability needs for the D/FW area can be met. In addition, the existing transmission system is inadequate to handle significant increases in new generation at existing generation sites.[11]

Some relief for the Dallas area is scheduled to come online before the Summer 2001 peak demand season: a 75 MW power plant planned by the City of Garland and a new 345-kilovolt transmission line known as the Limestone Watermill Double Circuit. Other solutions under consideration by the PUC, ERCOT and D/FW transmission service providers include demand-side management, energy efficiency programs, distributed generation and price-responsive demand mechanisms. Lessons learned in the D/FW area from implementation of these non-traditional approaches to transmission constraints could be applied to other transmission-constrained areas of the state as well.

Seven transmission projects are currently under construction in the state, and seven more are in the review stage at the PUC. Projected spending on new transmission facilities in Texas is $543 million

[10]Public Utility Commission of Texas, "Meeting the DFW Reliability Challenge: Background Paper," October 2000, p. 3.

[11]Electric Reliability Council of Texas, *Existing and Potential Electric System Constraints and Needs Within ERCOT*, Oct. 1, 2000, p. 40.

through 2003.[12]

Independent System Operator

The final physical link in ensuring system reliability rests with the ISO. As noted, this role will be performed by ERCOT. The ISO performs several key functions in the real-time market: monitoring voltage levels on the grid, making the minute-to-minute adjustments required to keep the system in balance, ordering power interruptions in an emergency and shopping for additional power to import to the grid when a shortage occurs. A full report of ERCOT ISO preparations and transmission system operations in the non-ERCOT areas of Texas is provided in Chapter 4, along with a review of transmission system operations in the non-ERCOT areas of Texas.

Complicating Factors

Under normal conditions, reliable delivery of electric service to Texas consumers faces many challenges. During 2000, drought conditions threatened some West Texas power plants because large cooling ponds required for operation began to dry up.[13] Wildfires across the state destroyed miles of transmission and distribution lines, sporadically severing service to customers.[14] Thousands of Gulf Coast customers lost power for a few days after thunderstorms knocked down transmission and distribution lines in July.[15] These challenges exist with or without market restructuring efforts.

A final important factor complicating overall system reliability is the impact of mandated emissions reductions on electric generating facilities. As noted above, Texas is heavily dependent on a variety

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[12]PUC Chairman Pat Wood, testimony before the Electric Utility Restructuring Oversight Committee, August 22, 2000 (see Appendix F for summary).

[13]Scott Parks, "Drought Hindering Electricity Production," *Dallas Morning News*, August 26, 2000, p. 2B.

[14]Associated Press news service, August 31, 2000.

[15]Jeannie Wiggins, "2,000 Customers Still Without Power Monday," Port Arthur News, July 25, 2000, p. 1A.

of fossil fuels for power production. Many of these fuels emit pollutants with wide-ranging environmental impacts during the combustion process. Meeting the needs of a growing population with escalating electricity demands while maintaining clean air standards will likely be the toughest challenge for the industry in the next several years. A more detailed discussion of air quality concerns and impacts is provided in Chapter 6.

Although Texas is experiencing a boom of power plant construction now, some observers wonder how the market will react when installed electric power capacity significantly exceeds demand. PUC Chairman Wood said he expects new plant construction to level off in a few years, but he anticipates power generators will resume new plant construction when needed, "as long as the correct market signals are getting sent."[16] An analysis of industry response to Texas market signals is presented in the following chapter.

[16]Chairman Wood, August 22, 2000.

Chapter Three:
MARKET TRANSITION

This chapter reviews the major market restructuring requirements of Senate Bill 7 and the activities of the PUC, electric utilities and others to implement them. Lessons learned from other states' restructuring efforts are noted where appropriate, and particular attention is paid to the developing retail electricity price structure.

This chapter also examines emerging issues in Texas and national energy markets, with particular focus on recent developments in the natural gas industry and their impact on electric utility restructuring in Texas.

SB 7 Requirements and Implementation

SB 7 established a number of deadlines for state agencies and market participants to perform certain restructuring activities from 1999 through 2009. All statutory deadlines have been met to date, and implementation of retail electric competition is on schedule. The retail competition pilot project is scheduled to begin on June 1, 2001, and full competition in eligible areas of the state should commence on January 1, 2002.

SB 7 required the state's vertically-integrated investor-owned electric utilities (IOUs) to separate their businesses activities into three components:

a competitive power generation company (PGC);

a competitive retail electric provider (REP); and

a regulated transmission and distribution utility (T&D).[1]

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[1]PURA §39.051.

This business separation, known as unbundling, may be accomplished through the creation of separate affiliated companies owned by a common holding company or through the sale of assets to a third party. As required by SB 7, utilities have filed business separation plans for review and approval by the PUC. Final orders on the separation plans are expected in March 2001.

Through this process, some utilities may be left with costs incurred under the regulatory structure which may not be economical in the competitive environment. These excess costs over market (ECOM), or stranded costs, primarily represent investments in nuclear power. When the 76th Legislature passed SB 7 in 1999, total ECOM was estimated at $4.39 billion.[2] Recent changes in market conditions have led to several revisions of this estimate. It is now generally expected that stranded costs will be much lower than previously estimated. The impact of stranded costs on the retail electricity price structure is examined below.

A code of conduct for IOUs was adopted by the PUC in November 1999 to prevent affiliated wires companies from subsidizing unregulated market enterprises with revenues from regulated activities and from giving the unregulated company and advantage in the marketplace. This code of conduct requires T&Ds to grant access and privileges to all market participants similar to those granted to their affiliated companies. A similar code of conduct for municipal-owned utilities (MOUs) and electric cooperatives (Coops) is scheduled for PUC adoption in February 2001.

SB 7 froze IOU retail base rates at September 1, 1999, levels and maintains this rate freeze until January 1, 2002, when retail competition begins.[3] At that time, residential and small commercial customers will receive a 6 percent rate reduction. This discounted rate will be known as the price to beat. In each IOU service territory in the state, the affiliated REP of the incumbent utility cannot offer rates different from the price to beat for three years (January 1, 2005, for most of the state) or until it loses 40 percent of its retail customer base, whichever occurs first.[4]

The price to beat mechanism will establish a rate under which new competitors may enter the market

[2]Public Utility Commission of Texas, *Report to the Texas Senate Interim Committee on Electric Utility Restructuring: Potentially Strandable Investment (ECOM)*, 1998.

[3]PURA §39.052.

[4]PURA §39.202.

and prevent the affiliated REP of the incumbent utility from exercising undue market influence and undercutting competition. The affiliated REP must offer the price to beat to all small customers requesting it until January 1, 2007, providing customers a five-year window of protection against any unforseen market forces which may create price volatility.

SB 7 also mandated that each power region of the state create and maintain an independent organization to monitor the transmission network and settle wholesale energy transactions. This organization is commonly known as the Independent System Operator (ISO). Transactions between wholesale power buyers and sellers will be settled through the ISO. The ISO will not function as a power pool, however, and will not set prices or match buyers with sellers. Wholesale contract terms and conditions will be established through bilateral contracts between buyers and sellers.

The ISO role will be fulfilled by a restructured ERCOT organization within the ERCOT power region. The PUC conditionally certified the ERCOT ISO in April 2000, and ERCOT requested final certification in November 2000. ISO functions in the non-ERCOT areas of Texas will likely be performed by a regional transmission organization (RTO) within the Southwest Power Pool reliability council and a privately-owned transmission company in the Entergy service territory. A more complete look at ISO functions is included in Chapter 4.

Retail Price Structure

Composition of the retail price structure is an important feature of the restructured electricity market. The price structure must cover all costs of market transition, power generation, customer assistance programs and transmission system administration while leaving enough room for each entity in the electricity delivery process to generate return on investment.

Figure 3.1 illustrates the retail electricity price structure in the competitive market. The horizontal time line at the top of the diagram shows the price ceiling imposed by the 1999 rate freeze and price to beat beginning in 2002. In addition to the price ceiling imposed by the price to beat, the retail price structure also has a floor composed of non-bypassable charges which will be included on all customer bills. These charges include the Competition Transition Charge (CTC), System Benefit Fund (SBF), and transmission and distribution (T&D) fees. The PUC will set the non-bypassable

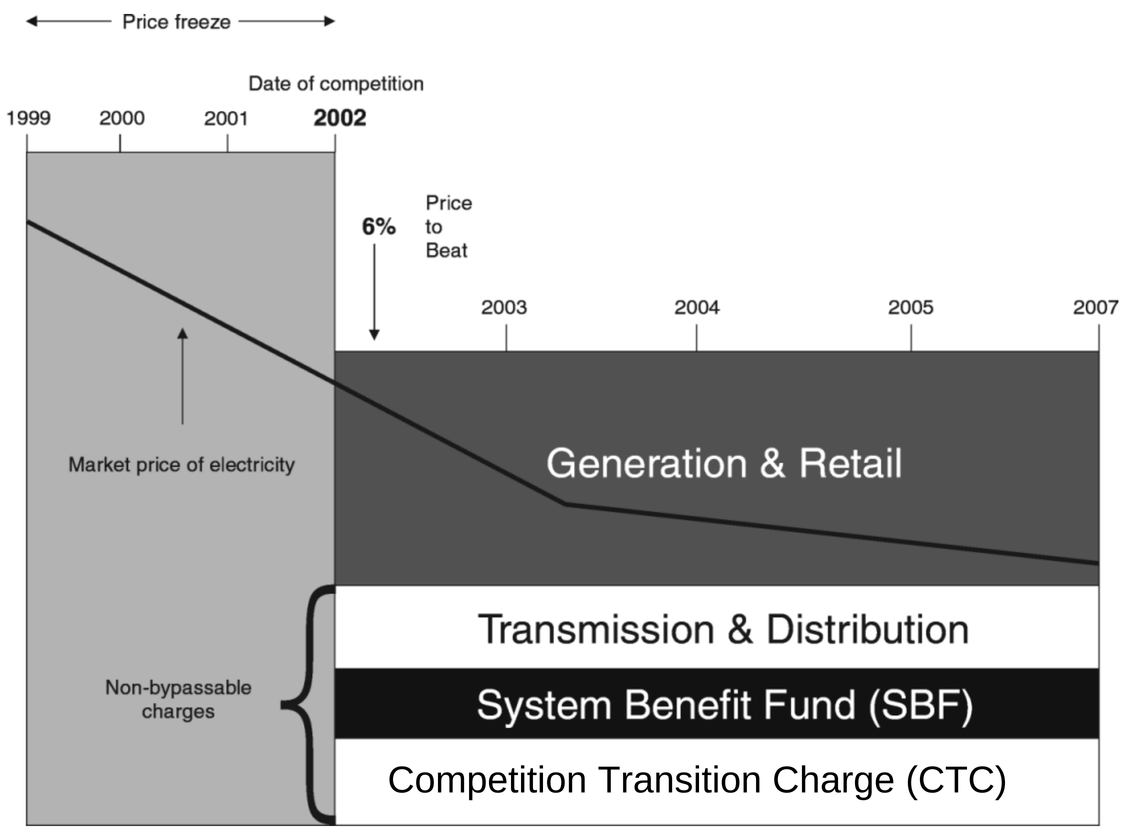


Fig. 3.1 **Texas Retail Price Structure and Time line**

charges in 2001.

T&D fees will be set during each utility's transmission cost of service proceedings as part of the business separation filings. The T&D portion of customer bills will pay for necessary expansion of the transmission system, ISO administration of the transmission system and a return on investment for T&D utilities. Even after competition begins, the PUC will continue to regulate T&D utilities and set their rates.

The SBF will be collected to fund rate reductions and energy efficiency programs for low-income customers, fund customer education programs and reimburse school districts for property value losses suffered as a direct result of electric utility restructuring. The customer education and low-income assistance programs funded by the SBF are examined in greater detail in Chapter 5. As required by SB 7, the Texas Comptroller of Public Accounts certified the property value losses directly attributable to restructuring of the electric utility industry at $6.29 billion. On October 31, 2000 the Texas Education Agency (TEA) certified that $65.12 million in Chapter 41 recapture dollars would be lost due to restructuring implementation.[5] These losses to public school funding will be repaid through the SBF. The PUC will issue an order in December 2000 directing investor-owned utilities to pay into the SBF their share of the amount, as determined by TEA.

The CTC is the mechanism through which utilities may recover stranded costs over time. The PUC will issue orders in the unbundling cases in 2001 and set the CTC at that time. Under SB 7, utilities also have the option to securitize certain regulatory assets. Securitization is a transaction that permits a utility to receive a lump sum payment for stranded costs from investors in lieu of collecting such costs through its regulated cost of service. The lump sum payment is financed through the issuance of debt securities to third party investors. From the investors' point of view, these debts exhibit less risk than the utility's common stock and therefore carry a lower interest rate than the utility's overall rate of return, which includes a return on common equity. The utility's customers pay the principle and interest on the securitized debt by a charge in their electric rates, but the stranded costs are paid at a lower rate of return and without federal income tax expense.

Orders have been issued by the PUC allowing securitization of $764 million in regulatory assets and transaction costs for Central Power and Light and $740 million for Reliant Energy HL&P. The commission's securitization order of $363 million for TXU is under court challenge.[6]

As the restructuring process continues, stranded costs in Texas are significantly impacted by a variety of market factors, particularly the price of natural gas, which has more than doubled in the past year. Natural gas is the fuel of choice for independent power producers because natural gas facilities are generally smaller and less expensive to build than other forms of generation and natural gas has historically been a relatively inexpensive and abundant fuel source. However, recent increases in natural gas prices have translated into increased fuel charges on consumer electric bills in 2000.

[5]Refers to Title II, Texas Education Code. Chapter 41 provides for determining an equalized wealth level of the state's public school districts.

[6]TXU petitioned the PUC to securitize $1.65 billion in regulatory assets. The PUC concluded that only $363 million of TXU's regulatory assets met the criteria for securitization. TXU has appealed the decision to the courts. *Docket No. 21527 - Application of TXU Electric Company for a Financing Order to Securitize Regulatory Assets and Other Qualified Costs.*

These price increases are occurring under the regulated structure and would be a factor even without electric utility restructuring. Although the generation portion of customer bills will likely increase due to higher prices for natural gas, these price increases may also benefit consumers by significantly lowering some utilities' anticipated level of stranded investment.

In the face of sustained higher natural gas prices, electricity generated from existing coal and nuclear plants has become more cost-competitive, leading some market observers to predict that some utilities may experience the opposite condition of stranded costs. In this scenario, the market value of certain generation assets wuld actually exceed the net book value of the assets. Because SB 7 provided for the application of excess revenues toward ECOM mitigation during the transition period, it is possible overmitigation of stranded costs may occur. Since overrecovery of stranded costs is expressly prohibited by SB 7, the PUC is currently evaluating how and when any overpayments would be returned to ratepayers. These ECOM discussions will continue for the next four years. The PUC has not yet determined what costs related to emission reductions may be included in recovery proceedings. A commission order on stranded costs is expected in Spring 2001, and an ECOM "true-up" will occur in 2004, at which time real data from a mandated capacity auction and the first two years of market competition will be used to settle the issue.

In addition to the non-bypassable charges, costs associated with power generation and REP overhead form the remaining components of the retail price floor. The difference between the floor and the ceiling in the retail price structure is known as "headroom." One lesson drawn from other market restructuring efforts is that for retail competition to flourish, new market entrants must have the headroom available to offer consumers sufficient savings to encourage REP switching while still maintaining ability to generate profits.

As previously mentioned, the prospect for sustained higher natural gas prices will almost certainly add costs to the generation portion of customer bills. Some Texas market observers claim higher gas prices must be offset by CTC reductions to maintain a workable competitive structure. "The high prices for generation erode the headroom for competition. If consumers and competitors do not receive the benefit of these high generation prices through reduced stranded cost charges, there will be little room for competitors to enter the market."[7]

[7]Testimony of Janee Briesemeister before the Electric Utility Restructuring Legislative Oversight Committee, Sept. 26, 2000 (see Appendix G for summary).

Prospects for sufficient headroom in the Texas retail electricity price structure are good. As discussed in Chapter 4, system administration costs are lower in Texas than other markets. Texas has a comfortable reserve margin of power capacity over peak demand creating downward pressures on generation prices. Finally, stranded costs are expected to be lower than previous estimates, possibly resulting in a low CTC, creating still more headroom for competition.

Natural Gas Price Impacts

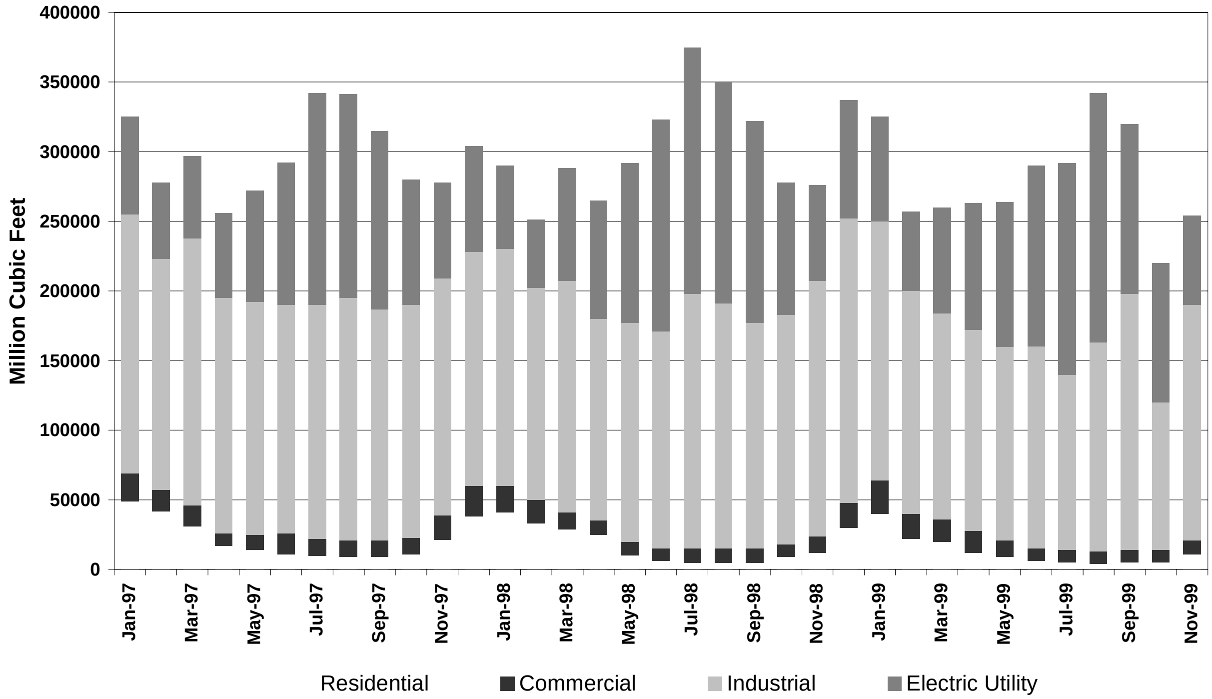
The variable with the greatest potential impact on electric power market restructuring efforts may be the recent increase in natural gas prices. The effects of higher gas prices touch every sector of the Texas economy either directly or indirectly. Quantifying the net effect of higher gas prices on economic activity is a complex task. However, some knowledge of the challenges to reliable delivery of affordable natural gas is essential to understand the fundamental forces reshaping the Texas electric power market.

Oil and gas production have long been staples of Texas economic activity. But increasing diversification of the state's economy has altered the significance of petroleum product price changes. As University of North Texas Center for Economic Development and Research professors Bernard Weinstein and Terry Clower noted in a July 2000 study:

> "For Texas, higher gas prices bring both good news and bad news. Because Texas ranks number one among the lower 48 states for on-shore production, higher prices generate added jobs, income and severance tax revenues ... Because more than 60 percent of the electric utility capacity in Texas uses natural gas, the cost of power generation has risen rapidly over the past six months. Each $1 increase per MCF (thousand cubic feet) boosts fuel costs to utilities and non-utility generators by about $1.46 billion. However, as has been the case for many years, these costs are passed on to households through 'fuel adjustment' and affect consumers differently depending on each utility system's configuration ... In sum, although rising natural gas prices are a boon to gas drilling, production and distribution companies and their employees, the resulting higher costs to Texas industries and households more than offset any gains."[8]

[8]Bernard L. Weinstein and Terry L. Clower, "The Impact of Higher Natural Gas Prices on the Texas Economy," University of North Texas Center for Economic Development and Research, July 2000, pp. iii-iv.

Fig 3.2 **Gas Consumption in Texas by Class**



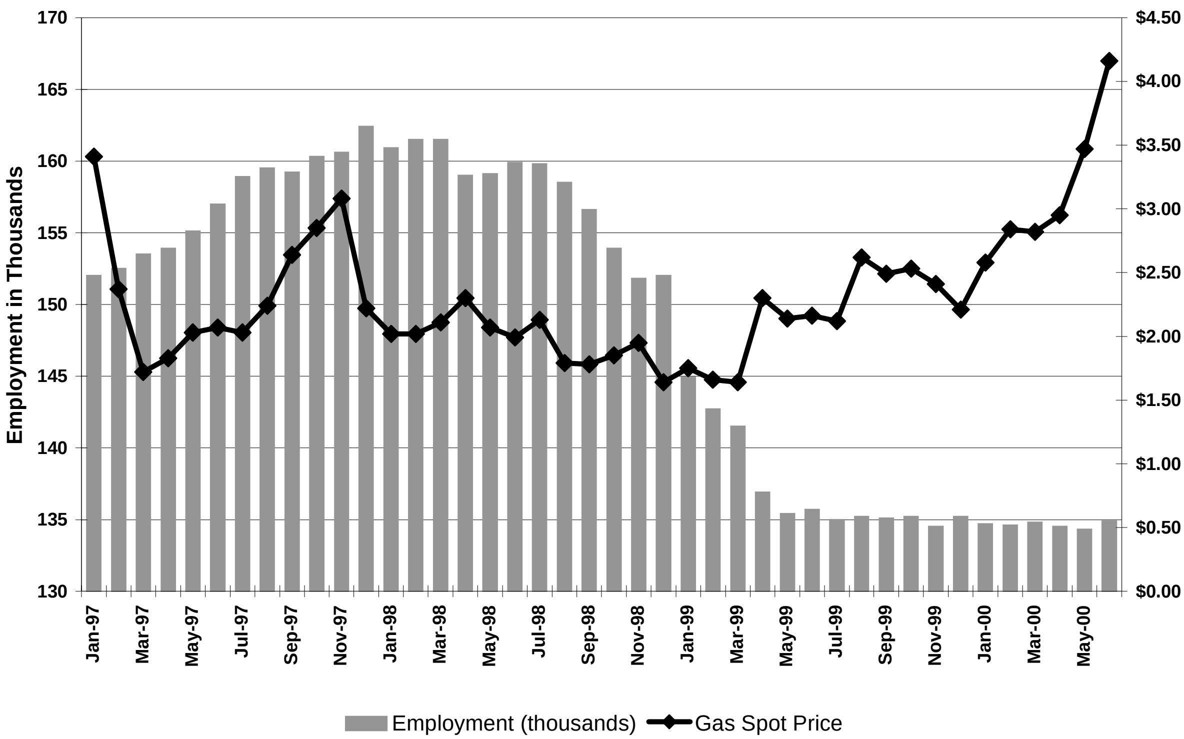
Source: Texas Railroad Commission

Many observers predict near-term natural gas prices to remain well above 1998 and 1999 levels, citing the combination of production declines and soaring demand largely driven by electric power generation.

Figure 3.2 illustrates the recent impact of gas-fired generator additions in Texas. Commercial and residential gas consumption continues to follow the traditional pattern — minimal demand in summer months and increased demand in winter months — and industrial consumption does not exhibit a significant seasonal differential. Electric generating facilities now account for almost half of all summertime natural gas demand.[9] Thus, the season during which gas has traditionally been injected into storage for the winter heating period is now the peak demand period in Texas.

[9]Weinstein and Clower, p. 11.

Fig. 3.3 **Texas Oil & Gas Employment and Natural Gas Price**



Source: Texas Railroad Commission

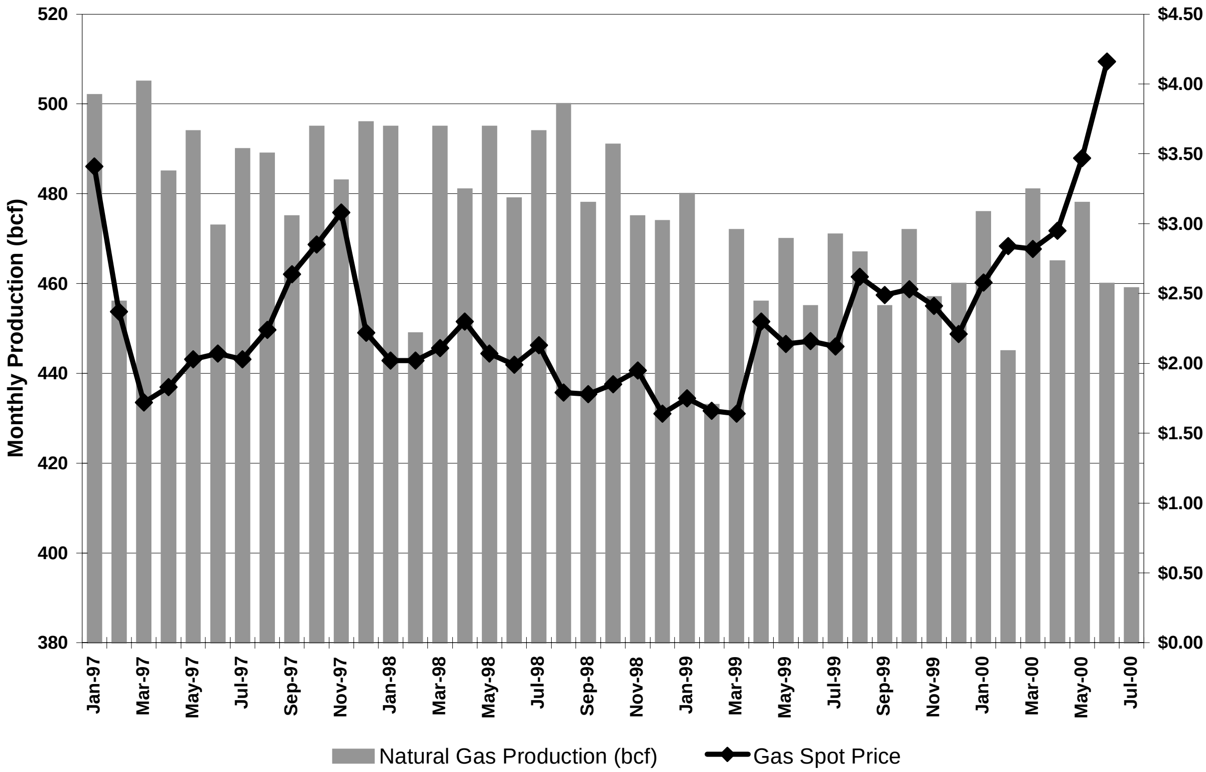
Some market watchers predict a long recovery period for gas storage inventories before the onset of lower prices. Following the market downturn in early 1998, Texas lost 18,000 oil and gas industry jobs, and exploration activities were reduced.[10] Higher prices in 2000 have yet to spur a significant increase in oil and gas employment, a critical factor in capturing necessary supply *(see Figure 3.3)*.

Lower production, a lack of skilled labor, higher demand and the absence of a traditional storage injection period will likely lead to sustained tight supplies and higher prices.[11] Tight supplies and higher prices for natural gas over the next year or more will have significant impacts on electric utility restructuring. Irrespective of restructuring efforts, electricity prices for most Texans will likely

[10]Texas Railroad Commissioner Charles Matthews, testimony before the Electric Utility Restructuring Legislative Oversight Committee, Sept. 26, 2000 (see Appendix G for summary).

[11]Chip Cummins and Alexei Barrionuevo, "Stuck In The Mud: Spike In Demand Has Natural Gas Producers Struggling to Catch Up," *The Wall Street Journal*, Oct. 11, 2000, p. A1.

Fig 3.4 **Texas Natural Gas Production and Price**



Source: Texas Railroad Commission

increase if natural gas prices are sustained at higher levels. As previously noted, in addition to the 60 percent of current Texas generation capacity dependent on natural gas, most new generators in Texas will use natural gas as well. Demand from electric generating facilities not only stretches available gas supplies, but also the gas industry infrastructure as well. Adequate pipeline capacity and firm delivery prospects are potential hurdles to new EGF siting.[12] Some power producers have turned to other fuel sources as gas prices climbed throughout the year. City Public Service, the municipal utility of the City of San Antonio, in discussions about future alternatives, mentioned it had not ruled out a new coal-powered facility using advanced clean coal technology.[13]

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[12]Jimmy Glotfelty, testimony before the Electric Utility Restructuring Oversight Committee, July 10, 2000 (see Appendix E for summary).

[13]Ann de Rouffignac, "City Public Service Mulls Building New Coal Plant," *Oil and Gas Journal Online*, Oct. 11, 2000.

Market Snapshot

The Texas electric power market has undergone significant changes since the passage of SB 7 in May 1999. Some utilities have been purchased or merged with other companies while others are busy separating business activities into regulated and unregulated components. Traditional utilities are engaging in new business ventures such as telecommunications services and energy trading. New participants, from generation to retail, have entered the Texas electricity market.

A major new Texas market participant is American Electric Power (AEP), an Ohio-based company now serving customers in Texas, Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Virginia and West Virginia. In the Texas market, AEP now operates in the former service territories of Cental Power and Light, Southwest Electric Power Company and West Texas Utilities. In other merger activity, Southwest Public Service Company merged with Public Service Company of Colorado to form New Century Energies, which in turn merged with Northern States Power Company to form Xcel Energy. Based in Minnesota, Xcel Energy serves customers in 12 Western states, including the Texas Panhandle.

The pending merger between Entergy, which serves customers in the non-ERCOT area of Southeast Texas, and Florida Power and Light would create the nation’s largest electric power company. Pending regulatory approval, the deal could be complete just before the start of retail competition in Texas on January 1, 2002.

At the filing of this report, TXU is the one IOU to file for REP certification at the PUC. Enron Energy Services, Enron Power Marketing and the New Power Company have also filed for REP certification at the PUC. One REP has already been certified by the PUC: TXI Power, a unit of TXI, Inc., the state’s largest concrete manufacturer. TXI intends to sell electricity to its own manufacturing facilities. However, in a September 2000 market participant survey conducted by ERCOT, 18 firms indicated intent to provide retail electric services in Texas.

The California Model

Many of the structural changes in the Texas electricity market can be more fully understood when specific features are compared to a different market structure. Widespread attention on California's recent problems has highlighted some key distinctions between the two approaches to market restructuring.

Like Texas, California required utilities to separate business activities into competitive and regulated enterprises. California's restructuring legislation also required utilities to divest generation assets and meet all power requirements through a centralized power pool managed by the California Power Exchange (PX). California's model has shown significant disadvantages since its implementation. The PX takes hourly bids from generators and then pays all generators the highest price set that hour. Buyers in the exchange, therefore, will pay the highest price for every kilowatt-hour of power at any given hour of the day, even if one or more generators is willing to sell electricity at a lower price. Texas did not structure its market in this manner. Instead, the Texas model will allow electric service providers to use long-term bilateral power contracts to hedge risk in the marketplace by seeking primary and secondary generation sources at the lowest prices available in the market. This approach is feasible in Texas because of adequate generation capacity.

The California model also mandated a rate freeze followed by a rate reduction of 10 percent, compared to the 6 percent reduction required in Texas. In California, this had the effect of lowering the available retail headroom, resulting in limited participation by new market entrants and thus less opportunity for customers to switch providers. During the rate freeze period, utilities were directed to allocate all overearnings to stranded cost mitigation. The rate freeze in each IOU service territory in California is lifted when the utility fully retires its stranded costs. San Diego Gas and Electric (SDG&E) was the first to do so, and during Summer 2000 its customers experienced the effects of a retail price structure without a cap coupled with a requirement that power be bought at the highest price through the PX pool. Price spikes are inevitable when demand exceeds supply and a utility is unable to engage in long-term contracts or call on native generation to serve its electric load. As the crisis in Southern California worsened, several wholesale power marketers offered long-term power contracts to SDG&E at rates well below peak prices, but the utility was unable to pursue any power purchases outside the PX and thus unable to shield customers from wholesale market price volatility.

Several investigations have been conducted at the state and federal level into California's electricity problems, resulting in numerous recommendations for structural changes. Although some consumer advocates and state regulators accused market participants of "gaming" the system, reports issued by the California PX, California ISO and Federal Energy Regulatory Commission (FERC) found the roots of the Golden State's problems in a flawed market design.[14] Many of the changes proposed in a FERC order issued November 1, 2000 mirror provisions of the Texas market design. FERC recommended California streamline its power plant siting procedures and enable utilities to engage in bilateral power contracts outside the confines of the PX.[15]

[14]See California Independent System Operator, *Report on California Energy Market Issues and Performance: May-June, 2000*, Aug. 10, 2000. See also Federal Energy Regulatory Commission, *Market Order Proposing Remedies for California Wholesale Electric System*, Nov. 1, 2000, Docket No. EL00-95-000, et al.

[15]Federal Energy Regulatory Commission, p. 24.

Chapter Four:
INDEPENDENT SYSTEM OPERATOR

The Independent System Operator (ISO) fulfills several key roles in the restructured electricity market. This chapter provides a more in-depth review of the various ISO functions which will be primarily fulfilled by the Electric Reliability Council of Texas (ERCOT) and a report on ISO implementation efforts. Proposed transmission operations in the non-ERCOT areas of Texas are also examined.

ERCOT Background and History

A non-profit corporation, ERCOT is one of 10 regional reliability councils in the North American Electric Reliability Council (NERC) organization, which was formed following the disastrous blackouts of 1965 along the eastern seaboard of the United States. ERCOT represents a bulk electric system located totally within the State of Texas and serves approximately 85 percent of the state's electrical load. Due to its intrastate status, the primary regulatory authority for ERCOT utilities is the Public Utility Commission of Texas (PUC). The Federal Energy Regulatory Commission (FERC) exercises limited authority over ERCOT. FERC has primary wholesale regulatory authority over the utilities and ISOs in the other nine reliability councils.

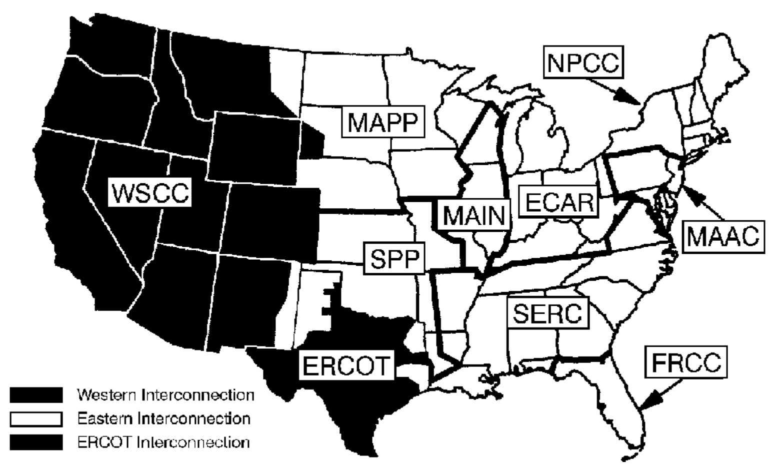

Fig. 4.1 **Major U.S. Interconnected Electric Systems**

The origins of the modern Texas electric grid can be traced back to the beginning of World War II when a number of electric utilities banded together to send excess generation to Gulf Coast area industries to aid the war effort. The group became known as the Texas Interconnected System (TIS). After the war, TIS members recognized the reliability advantages of remaining interconnected and continued to utilize and develop the system as electrical loads grew and larger generating units were installed. In the 1960s and 1970s, operating guidelines were adopted and ERCOT assumed security monitoring functions from stations located in the control centers of two utilities in North and South Texas.

During a severe cold weather event in 1981, small amounts of load were shed in ERCOT for what was thought to be a capacity shortage situation. A review of the event determined that the load had been shed unnecessarily and that better coordination was needed in the region. In 1983, two security centers replaced ERCOT's existing monitoring functions, and the operating guides were strengthened to provide for security center coordination of interconnected operations between the control areas in the region. A computerized Security and Information System (SIS) was created and operated by the two ERCOT security centers. The SIS began as a control area operator manual entry system and has since grown to include real-time telemetry with many automated security applications.

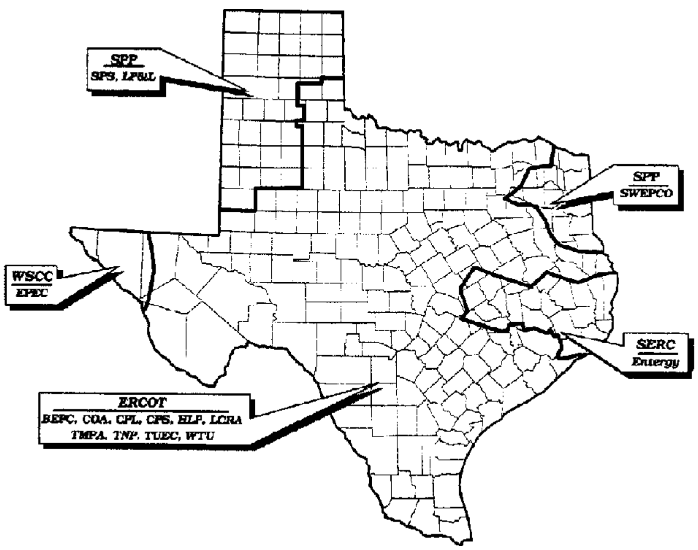

Fig. 4.2 **Texas Interconnected Electric Systems**

Following the passage of the Energy Policy Act of 1992 (P.L. 102-486), ERCOT began the process of studying the changes needed to create a central security center independent of the utilities. The federal legislation rolled back New Deal-era regulations and required utilities to open their transmission lines to all sellers of electricity, paving the way for independent power producers to sell electricity to utilities.

Three years later, the 74th Legislature passed SB 373, which opened the ERCOT wholesale market to competition. As a result of SB 373 implementation, the PUC issued revised rules in early 1996 requiring a joint industry filing for the creation of an ISO responsible for security of the bulk power system, facilitation of the use of the electric transmission system by all market participants and coordination of transmission planning in the ERCOT region.

Although the responsibilities of the ISO went beyond the broadened security coordination functions originally envisioned by ERCOT a broad-based industry task force preparing the joint industry filing decided the Texas ISO function should be fulfilled by a restructured ERCOT organization. The recommended ERCOT - ISO formation was endorsed by the PUC on August 21, 1996. The ERCOT membership approved the restructuring required in the joint filing and implementation began on September 11, 1996. The ISO operations center is now located in an independent facility in Taylor. A back-up facility is planned and will be located in Austin. Operations control would transfer to the Austin facility if the Taylor facility were unable to perform for any reason.

SB 7 Requirements and Implementation

SB 7 defined the ISO as an entity charged with supervising the collective transmission facilities of a power region, coordinating market transactions, planning systemwide transmission and ensuring network reliability.[1] To meet these goals, ERCOT's efforts have focused on two primary tracks: developing new protocols for market participants and solving the functional and technical issues of restructured market activity. The ERCOT protocols are under final development and are scheduled for review and adoption by the PUC in early 2001.

The ERCOT ISO is expanding its infrastructure and staffing to comply with SB 7 and oversee retail access in the electric market. Approximately 50 employees have been hired in the last six months. ERCOT expects to hire an additional 100 employees in the coming year. New facilities and new computer systems, including both hardware and software necessary to carry out market coordination functions, have been acquired.

To facilitate the implementation process, the ISO contracted with Andersen Consulting, a firm with

[1]PURA §39.151.

experience in other electricity market restructuring efforts. Several working groups were formed within ERCOT. System administrators, PUC staff, electric utilities, power marketers, consumer groups and other stakeholders have all been involved in ERCOT's restructuring efforts.

The ERCOT ISO is managed by a chief executive officer who is hired by and reports to the ERCOT Board of Directors. The 21-member board is composed of three members from each of the seven market groups: investor-owned utilities, municipal utilities owning generation or transmission facilities, electric cooperatives owning generation or transmission facilities, transmission-dependent utilities, independent power producers, power marketers and consumers. A new ERCOT Board of Directors will assume office in December 2000. The PUC Chairman and Public Utility Counsel are *ex-officio*, non-voting members of the ERCOT Board of Directors.

ERCOT responsibilities expanded by market restructuring include real-time system monitoring, long-term system monitoring, response to contingency situations, administration of a system-wide information system and system transmission tariffs and energy transaction scheduling. ERCOT also supervises regional transmission planning and acquisition. ERCOT will not function as a power pool and will not be responsible for energy pricing or matching buyers and sellers.

The transmission pricing methodology established by SB 7 is unique and forms the basis for many of the business practices now in place at ERCOT. Under the rule adopted by the PUC, all transmission service is considered to be either planned or unplanned. Planned service is defined as service to a specified load from designated resources. Unplanned service is between a specified load and specified resource, is 30 days or less in duration and is available subject to the availability of transmission capacity required for planned service. As noted in Chapter 1, constraints in the state's transmission system led to several curtailments of unplanned energy transfers in 2000.

In the ERCOT market protocols, which are still under development and awaiting PUC approval, transmission pricing will reflect the cost impacts of congested wires. If costs to clear commercially significant transmission exceed $20 million in any 12-month sliding window, ERCOT will institute a congestion management fee. The congestion management plan will be reviewed in 2003 if the $20 million threshold has not been reached. Final details of the congestion management plan have not been finalized, but it is likely the financial impact of congestion management fees will be borne by customers within transmission constrained zones such as the Dallas/Fort Worth area. The PUC opened a new project in October 2000 to study possible revisions to the transmission pricing rule adopted in 1999. The purpose of the possible revision is to eliminate inconsistencies between the adopted rule and the ERCOT protocols.

Planned transmission service is paid for by load entities on a load ratio basis. Effective December 1, 1999, the PUC required scheduling entities to begin paying a fee of 15 cents per megawatt-hour (MWh) for all planned and unplanned energy transactions in ERCOT. Transaction fees are the primary revenue source for ERCOT and are expected to generate approximately $40 million in 2000.[2] The ERCOT ISO fee compares favorably to other system administration fees in the country. In California, for example, the ISO fee is 80 cents per MWh in addition to a 30 cent per MWh fee charged by the California Power Exchange. It is anticipated that the ERCOT ISO fee will not have a negative impact on headroom in the retail price structure.[3]

Fig. 4.3 **Intended Roles in the Market**

Qualified Scheduling Entities
American Electric Power # Automated Power Exchange # Bryan Texas Utilities # Calpine # City of San Antonio # Coral Power # Dynegy # Enron # Entergy # Garland Power and Light # Lower Colorado River Authority # Southern Company Energy Marketing # Tenaska # Texas-New Mexico Power # TXU # Xcel Energy

Non Opt-in Entities
Big Country Cooperative # Bryan Texas Utilities # Greenville Electric Utility System

Power Generation Companies
American Electric Power # Calpine # City of San Antonio # Dynegy # FPL Energy # Guadalupe-Blanco River Authority # Lower Colorado River Authority # Southern Company Energy Marketing # Texas-New Mexico Power # TXU

Retail Electric Providers
AEP Retail Operations # Calpine # Dynegy # Entergy # Exelon # New Energy Texas # Reliant # Southern Company Energy Marketing # Texas-New Mexico Power # TXU

Load Acting as Resource
Dow

Source: Electric Reliability Council of Texas. Includes only those entities that have authorized ERCOT to disclose their intended roles in the restructured market.

One concern raised before the committee concerning ERCOT activities involves the creation of a new market participant not included in SB 7: qualified scheduling entities (QSEs). QSEs will be responsible for coordinating balanced energy loads with resources and providing ancillary service bids. The QSE requirement was devised to streamline energy scheduling communications between the various market participants and the ISO. QSEs are the only market

[2]Interview with ERCOT Director of Coordination and Reports Larry Grimm, Oct. 12, 2000.

[3]PUC Chairman Pat Wood, testimony before the Electric Utility Restructuring Legislative Oversight Committee, August 22, 2000 (see Appendix F for summary).

participants requiring direct ERCOT certification. Consumer advocates expressed concern that an additional layer of costs in the wholesale market may act to squeeze available headroom in the retail price structure.[4]

As of October 2000, 26 firms have indicated intent to become certified QSEs in Texas. Additional market participants indicating intent to participate in the restructured market include 18 REPs, 17 power generation companies and 11 transmission and distribution utilities. Figure 4.3 provides the intended market roles of firms that have authorized ERCOT to disclose their intentions as of October 2000. One municipal utility or electric cooperative has indicated intent to opt-in to retail competition but has not permitted disclosure of identifying information by ERCOT. Also denying disclosure, 10 municipal utilities or electric cooperatives have indicated they do not intend to opt-in to retail competition.[5]

Non-ERCOT Areas of Texas

Although ERCOT will perform some statewide services, such as maintaining customer registration and switching information, operation of the bulk power system in Texas outside ERCOT boundaries will fall to other regional organizations in the Southwest Power Pool (SPP), the Western Systems Coordinating Council (WSCC) and the Southeastern Electric Reliability Council (SERC) *(see Figure 4.2)*.

Restructuring activity in the non-ERCOT areas of Texas must meet conditions set forth in both state and federal legislation and regulations. In 1996, FERC issued Orders 888 and 889 to provide non-discriminatory open access on the transmission system. While open access was achieved, the existing transmission system has become strained because of the resulting increases in wholesale electricity trading as well as the strong economy and state-mandated retail open access. FERC Order 2000 was issued on December 20, 1999, to encourage all transmission owners to voluntarily join regional transmission organizations (RTOs) to help address the engineering and economic inefficiencies

[4] Janee Briesemeister, testimony before the Electric Utility Restructuring Legislative Oversight Committee, Sept. 26, 2000 (see Appendix F for summary).

[5] Results compiled from ERCOT Quarterly Survey of Market participants, September 2000.

inherent in the current transmission system and to correct real or perceived discrimination by transmission owners. RTOs will perform functions similar to the ERCOT ISO, including transaction scheduling, congestion management, ancillary services, wholesale settlement and market monitoring. FERC Order 2000 establishes minimum characteristics for RTOs without establishing a particular geographic or organizational design. The order allows both ISOs and independent, privately-owned transmission companies (transcos) to apply for RTO status.

SB 7 requires Southwest Public Service Company to file a transition to competition plan with the PUC, and all utilities in non-ERCOT areas of Texas to separate competitive and regulated business activities and participate in the retail competition pilot project. Full customer choice will not be implemented in non-ERCOT areas of Texas until the PUC certifies the service area of a non-ERCOT utility as a competitive power region. Three requirements must be met to create a competitive power region: a sufficient number of interconnected utilities in the region must fall under the operational control of an ISO, transmission facilities must provide non-discriminatory open access and no market participant may own or control more than 20 percent of the electric generation capacity serving the region.[6]

Three of the four non-ERCOT areas of Texas plan to participate in the pilot project and offer full customer choice in 2002. El Paso Electric will not offer customer choice in Texas until the expiration of its rate freeze agreement with the PUC in August 2005. Although El Paso Electric is not required to unbundle its business activities until the end of the rate freeze period, the utility expects to do so in 2001, consistent with the State of New Mexico's restructuring requirements.

Southwest Public Service (SPS) in the Texas Panhandle and Southwestern Electric Power Company (SWEPCO), both members of the Southwest Power Pool regional reliability council, will participate in the retail pilot project and intend to move to full customer choice as soon as the three requirements for a competitive power region are met. For SPS, now a part of Xcel Energy in 2000, this means a significant number of power generation facilities must be sold. SWEPCO, now a unit of American Electric Power (AEP), has submitted a filing with the FERC indicating its intent to participate in the SPP RTO. SPP is seeking RTO recognition under FERC Order 2000, with a requested effective date of January 1, 2001. SPS is currently a member of the SPP but plans to join

[6]PURA §39.152.

the Midwest ISO when it begins commercial operations.

Entergy, on the other hand, has filed for FERC approval to establish a transco, or privately-owned transmission company, to manage bulk energy transfers. The Entergy transco would operate under the supervision of the SPP RTO. A FERC ruling on Entergy's proposal is anticipated in April or May 2001.

Retail Competition Pilot Project

The retail competition pilot project will allow the PUC to evaluate the ability of each power region and electric utility to offer customer choice.[7] Beginning June 1, 2001, each IOU in the state will offer customer choice to 5 percent of the customer base within its service area. In non-ERCOT areas of Texas, the pilot project may be extended by the PUC if a power region is not deemed competitive by January 1, 2002, when full customer choice begins in the ERCOT power region.

All ERCOT restructuring activities are scheduled for completion by March 31, 2001. A "mock market" will commence April 1, allowing full testing of new systems between the ISO and market participants. During March 2001, ERCOT will host a series of training seminars for employees of market participants in both the ERCOT and non-ERCOT areas of Texas so they can become familiar with the new ISO communications and settlement systems. ERCOT will begin accepting customer switch requests May 31, 2001, and anticipates "going live" with all new systems on June 1, 2001.

[7]PURA §39.104.

Chapter Five:
CUSTOMER PROTECTIONS

Protecting customers from unfair business practices and inadequate service in markets for essential commodities like electricity and telecommunications services is important not only for the individual consumers who may be adversely affected by anticompetitive behavior but also for the long-term health of the market itself.

The 76th Legislature adopted Senate Bill 86 to add new customer protection standards to the Public Utility Regulatory Act (PURA).[1] The statute provides the Public Utility Commission (PUC) authority to establish and enforce rules to protect retail customers from fraudulent, unfair, misleading, deceptive or anticompetitive practices. Specific consumer entitlements were established, including protection from fraud and discrimination, protection of choice, privacy of consumption and credit information, accuracy in billing and information presented in English, Spanish and any other language necessary.[2] Senate Bill 7 also established additional retail electric customer safeguards, including:

- the right to safe, reliable and reasonably priced electricity, including protection against service disconnections in extreme weather emergency or in cases of medical emergency or for nonpayment of unrelated services;

- bills presented in a clear format and in language readily understandable by customers;

- information about rights and opportunities in the transition to a competitive electric industry;

- access to providers of energy efficiency services, on-site distributed generation and providers of energy generated by renewable energy resources;

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[1]PURA §17.001(a).

[2]PURA §17.004(a).

sufficient information to make an informed choice of service provider;

protection from unfair, misleading or deceptive practices, including protection from being billed for services that were not authorized or provided; and

an impartial and prompt resolution of disputes with retail electric providers and transmission and distribution utilities.[3]

SB 7 also conferred authority on the PUC to oversee all providers of electric service and assess administrative and civil penalties for violations.[4]

The PUC rule implementing customer safeguards against anticompetitive practices is under development with adoption anticipated in December 2000. In addition to the protections outlined above, SB 7 also contained a number of market design features to further protect electric customers, including a campaign to raise awareness of coming changes in retail electric service, the establishment of a fund to assist low-income people and a universal service requirement.

Customer Education

SB 7 required the PUC to conduct a customer education campaign to raise awareness of coming changes in the retail electric market.[5] To implement the statute, the PUC adopted a two-stage approach to inform consumers of impending market changes and rights and protections afforded them by law. In the first phase, High Point/Franklin, a communications firm with experience in other market restructuring efforts, was selected by the PUC to develop a customer education plan. High Point/Franklin surveyed more than 40 opinion leaders and policy makers statewide, conducted eight focus groups in six Texas cities and performed telephone surveys of 1,100 residential and 400 business customers of investor-owned utilities (IOUs). The education plan adopted by the PUC on July 18, 2000, was developed from the results of the survey, High Point/Franklin's experience in

[3]PURA §§ 29.101(a) and (b).

[4]PURA §39.101(d).

[5]PURA §39.902.

other markets and input from PUC staff, consumer advocates, IOU representatives and potential retail electric providers (REPs) in the competitive Texas market.

Key points of the customer education plan include integrated communications strategies, such as paid advertising, public relations efforts, printed materials, a toll-free call center, an electric competition Web site and specific tools designed to measure the overall effectiveness of each strategy. The plan also emphasizes communication through community-based organizations, which will form the primary channel to reach traditionally under-served populations such as low-income and non-English-speaking customers. On October 19, 2000, the PUC selected marketing firm Burson-Marsteller to implement the customer education plan.

System Benefit Fund

To further aid consumers in the restructured electric utility market, the System Benefit Fund (SBF) was created to fund four different programs:

- electric rate reductions for low-income customers;
- a targeted low-income weatherization program administered by the Texas Department of Housing and Community Affairs (TDHCA);
- appropriations for customer education programs and administrative costs of the Office of Public Utility Counsel; and
- a mechanism to compensate the state and school districts for losses in property values of utilities' assets directly caused by restructuring.

The source of revenues for the fund is a fee charged to customers based on the kilowatt-hours of electricity used. Through fiscal year 2001, the SBF is expected to collect more than $90 million to fund early customer education programs and payments to school districts affected by electric utility restructuring. The PUC has worked with Texas Department of Human Services to develop an automatic enrollment system for low-income customers to receive rate reductions and weatherization benefits. As mentioned above, the customer education plan has completed the design phase and is now moving into the implementation phase. The PUC is expected to finalize rules relating to SBF administration in December 2000.

Provider of Last Resort

In much the same way monopoly utilities currently provide electric service to any requestor within their service territories, the provider of last resort (POLR) will be established to fulfill this function in the restructured marketplace. Protections similar to those existing today have been established for both consumers and the REP serving as POLR. Customers who fail to pay for electric service can be disconnected except during extreme weather emergencies.

The POLR in each area of the state will be selected by the PUC through a bidding process. Large service territories, such as Reliant Energy HL&P, will likely be divided into several smaller POLR territories. If the bidding process is not successful, (e.g., the PUC does not receive enough bids for all POLR territories) the PUC can designate a REP to serve as POLR. The generally held perception is that POLR rates will be nominally higher than the market rate to allow the POLR to hedge risk against an unknown quantity and type of customer. Because customers who “choose not to choose” in areas of the state open to competition on January 1, 2002, will default to the affiliate REP of the incumbent utility, it is not expected that the POLR will be extensively utilized for the first few years of market development.

Curbing Anticompetitive Behavior

Analysis of restructuring efforts in the telecommunications industry can provide some insight into possible pitfalls along the path of electric utility restructuring. Among the research findings of High Point/Franklin’s interactions with both residential and commercial customers is the conclusion that Texas customers clearly framed their view of electric choice within their experience with long distance telephone service competition. Anticompetitive practices such as slamming (changing service providers without customer authorization) and cramming (hiding unauthorized charges on customer bills) were commonly cited. Additional concerns were raised about the expected level of telemarketing activity associated with retail electric competition.

To prevent the slamming practices associated with long distance competition, ERCOT will function as the customer switching information center in Texas and will notify each customer by postcard whenever a switch request is received. The customer can verify the request by doing nothing, or nullify the request by returning the card. The PUC anticipates adopting a rule against cramming, along with related specific provisions addressing the content of customer bills, in coming months. Other rules addressing the customer safeguards established by SB 7 and SB 86 are expected to be adopted by the PUC in December 2000. The governing bodies of municipally-owned utilities and electric cooperatives are also required to adopt similar rules for customers within their certificated areas.

PUC Oversight

As noted above, primary rulemaking and enforcement authority regarding electric utility industry restructuring is granted to the PUC. A new Market Oversight Division was created by the PUC to address market design flaws, identify and prevent market power abuses and encourage and facilitate competition in the bulk power, ancillary services and transmission services markets.

Additionally, the PUC is granted authority to delay competition before January 1, 2002, if it determines a power region is unable to offer fair competition and reliable service to all retail customer classes.

Chapter Six:
AIR QUALITY

Air quality concerns run parallel to virtually every aspect of electric utility restructuring efforts, affecting the emerging competitive market structure on numerous levels and presenting challenges to reliability of the bulk power grid.

Air quality concerns are a driving issue in most metropolitan areas of Texas. The underlying focus is to meet regulations established by the U.S. Environmental Protection Agency (EPA) to implement the Clean Air Act of 1990 (P.L. 101-549). The Act established National Ambient Air Quality Standards (NAAQS), which designate maximum allowable concentrations of certain pollutants. The EPA has designated four Texas metropolitan areas as "non-attainment" zones for compliance with the NAAQS: Beaumont/Port Arthur, Dallas/Forth Worth, Houston/Galveston/Brazoria and El Paso. All four of these areas do not meet the EPA standard for ground-level ozone concentration. This is of particular concern to the electric power industry because many electric generating facilities (EGFs) produce high levels of nitrogen oxides (NOx), a primary component of ground-level ozone formation. El Paso is also non-compliant with carbon monoxide and particulate matter standards. Other metropolitan areas of Texas classified as "near non-attainment" are Austin, San Antonio and Tyler/Longview/Marshall.[1]

The state is required to submit a State Implementation Plan (SIP) to the EPA that enumerates a strategy to meet the NAAQS. If the state plan is not approved, the EPA is required to draft its own plan for the state. In addition to mandatory remediation measures, penalties for NAAQS non-attainment can be assessed, including the withholding of federal funds for highway construction and other potential contributors to continued non-compliance.

SB 7 Requirements and Implementation

SB 7 directly addressed the contribution of EGFs to air pollution in the state. Prior to the enactment

[1]U.S. Environmental Protection Agency, "USA Air Quality Non-Attainment Areas," July 31, 2000.

of SB 7, 192 EGFs located at 75 sites in Texas had been exempt from the emissions permitting requirements of the Texas Clean Air Act. The Texas act requires state review and permitting for new point sources of air pollution. These exempted plants, known as "grandfathered facilities," are responsible for up to 36 percent of total emissions from industrial sources in the state, according to a 1998 survey of U.S. Energy Information Administration (EIA) data.

SB 7 required the Texas Natural Resource Conservation Commission (TNRCC) to develop a mass emissions cap and trade program to distribute emissions allowances for use by EGFs.[2] One allowance represents authorization to emit one ton of NOx or sulfur dioxide (SO2) per year. The bill required grandfathered facilities to apply for a permit under the program by September 1, 2000. To secure a permit, grandfathered EGFs must reduce emissions of NOx by 50 percent and SO2 by 25 percent below 1997 levels. The bill further requires grandfathered EGFs to secure a TNRCC permit by May 1, 2003, or cease operation. Implementation of SB 7 will achieve a minimum annual reduction of 75,000 tons of NOx and 37,000 tons of SO2, representing a 12 percent reduction in total grandfathered emissions statewide.[3]

As required, the TNRCC adopted an emissions cap and trade program in December 1999. The TNRCC is currently reviewing all 76 applications submitted for the cap and trade program. No grandfathered EGF permits have yet been issued. Issuance of a permit will cap the maximum allowable emissions from each permitted facility at 1997 levels, minus the reductions in specific pollutants required by the statute. The program allows facilities to trade allowances, providing flexibility for facility owners to determine the most cost-effective means of achieving the statutory goals. As authorized by SB 7, grandfathered EGFs can also purchase allowances from permitted facilities which make voluntary emissions reductions in exchange for an equivalent number of allowances. The rule does not allow EGFs to earn allowances through reduced operations or shutdowns.

The TNRCC is considering an additional rule to expand the scope of emissions trading to include a wider array of facilities in larger geographics regions. The goal of the proposed rule is to allow

[2]PURA §39.264.

[3]TNRCC Executive Director Jeff Saitas, testimony before the Electric Utility Restructuring Legislative Oversight Committee, November 30, 1999 (see Appendix D summary).

additional point source polluters to contribute to overall emissions reductions goals through program participation. The rule is scheduled for adoption in December 2000.

Non-attainment Areas In Texas

Under the TNRCC trading program, permit holders are required to consider the impact of allowance transfers on those counties which are in non-attainment or near non-attainment. The stated goal of the program is to encourage actual reductions in non-attainment and near-non-attainment areas, rather than reductions in more distant areas with allowance transfers to facilities in trouble zones. This consideration is primarily due to the tougher standards which must be applied in non-attainment areas to meet NAAQS. Stricter emissions limits than those mandated by SB 7 will be required of EGFs in non-attainment areas of Texas. For example, generators in the Dallas area must reduce NOx emissions by 88 percent to meet the goals of the Dallas SIP as submitted to the EPA. Several corporate entities have pending legal challenges against the Dallas SIP, including airlines, cement makers, diesel engine manufacturers and waste haulers. On November 6, 2000, TXU and the TNRCC agreed to settle the utility's SIP challenge. Under terms of the agreement, total emissions reductions required of TXU by the SIP did not change. The utility gained the ability to trade emissions credits among its own facilities, providing greater flexibility in determining the most cost-effective method of achieving pollution reductions.[4]

Significant expenditures on emissions reductions in non-attainment areas of Texas is likely. The committee received testimony from TXU and Reliant that suggested environmental cleanup spending in the greater Dallas and Houston areas alone could top $812 million.

To further scientific understanding of the factors contributing to ground-level ozone formation, the TNRCC is participating in a cooperative $20 million study with public, private and academic institutions utilizing the expertise of more than 150 scientists and engineers from throughout the nation to develop better assessment tools and design more cost-effective strategies to improve air quality. The study primarily focuses on the eight-county Houston metropolitan area, but data from more than 60 monitoring stations in Texas, Louisiana, Arkansas and Oklahoma will also be analyzed to track pollution migration.

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[4]Randy Lee Loftis, "State, TXU Settle On Clean Air Plan," *Dallas Morning News*, Nov. 7, 2000, p. 23A.

Complicating Factors

Balancing the costs of various environmental damage mitigation strategies with economic effects on businesses and households proves to be a delicate task. A common concern of the PUC, Independent System Operator (ISO) administrators and industry participants is that EPA requirements to reduce ozone-forming emissions present challenges to maintaining overall reliability of the electric grid in Texas, particularly in the Dallas/Fort Worth area. The reliability challenges stem from two sources. First, some plants must be shut down in order to retrofit old equipment with updated emissions control technology. This can generally be scheduled and accomplished during the off-peak season. However, a high degree of coordination will be required to ensure sufficient capacity remains online to serve load. Second, some plants may be uneconomical to retrofit with improved emissions control devices and therefore are candidates for closure. However, those same plants may also be integral to maintaining grid reliability by stabilizing voltage in a critical geographic area.[5]

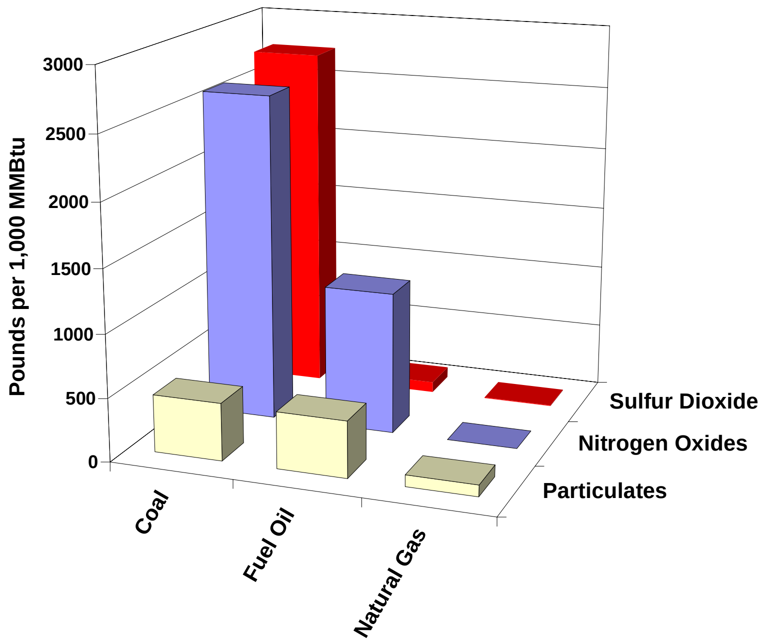
SB 7 allows utilities to include costs associated with implementation of improved emissions controls in stranded cost recovery proceedings.[6] The rule to implement this provision of the law was adopted by the PUC in August 2000. Under the rule, the PUC must determine for each candidate facility whether the public interest is better served by paying for cleanup costs or retiring the plant. Complicating the decision are further restrictions on EGFs planned by the EPA pertaining to emissions of mercury, carbon monoxide and particulate matter. In Texas, coal-fired facilities are at greatest risk from additional regulations. Although a number of mercury control technologies are under evaluation for utility boilers, most are still in the research stages, making it difficult to predict final cost-effectiveness as well as the time required to scale-up and commercialize the technologies. Because the chemical species of mercury emitted from boilers varies from plant to plant, there is no single control technology that removes all forms of mercury. There remains a wide variation in the projected end costs of control measures for utilities and the possible impact of such costs.[7] Similar

[5]TXU President Tom Baker and ERCOT ISO Director Sam Jones, testimony before the Electric Utility Restructuring Legislative Oversight Committee, July 11, 2000 (see Appendix E for summary).

[6]PURA §39.263.

[7]U.S. Environmental Protection Agency, “Mercury Study Report to Congress: Overview,” Sept. 26, 2000, p. 3.

Fig. 6.1 **Fossil Fuel Emissions**



Source: Energy Information Administration

vagaries exist in determining the appropriate level of mitigation controls related to carbon monoxide and particulate matter. The primary concern of the PUC is that Texas electric customers do not foot the bill to retrofit a facility that might be retired in a few years because of additional federal regulations. The methodology adopted by the PUC for determining the allowable level of recoverable environmental cleanup costs considers potential future federal regulations as one criterion.

Air quality is decidedly impacted by the choice of fuels used to generate electricity. One benefit of rapid deployment of new gas turbine technology by independent power producers has been a significant increase in generation capacity without resultant increases in air pollution. Figure 6.1 illustrates the environmental benefit of natural gas combustion when compared to other commonly used fossil fuels in the electricity generation process. However, recent spikes in natural gas prices may lead to the increased utilization of alternate fuel sources, including less expensive fossil fuels. City Public Service, the municipal utility of the City of San Antonio, in discussions about future alternatives, recently mentioned it had not ruled out a new coal-fired facility using advanced clean coal technology as a hedge against sustained high natural gas prices.[8] Due to initial construction expense, however, it is unlikely any more nuclear facilities will be built in Texas for some time.[9]

Advances in renewable energy technologies offer at least a partial solution to maintaining fuel diversity in the face of high natural gas prices while still maintaining overall air quality goals. Development of renewable energy resources in Texas is covered in the next chapter.

[8]Ann de Rouffignac, "City Public Service Mulls Building New Coal Plant," *Oil and Gas Journal Online*, Oct. 11, 2000.

[9]PUC Chairman Pat Wood, testimony before the Electric Utility Restructuring Legislative Oversight Committee, August 22, 2000 (see Appendix F for summary).

Chapter Seven:
RENEWABLE ENERGY

Renewable energy is derived from sources that are not depleted by human use, such as wind, solar energy and water movement. These energy forms may be converted to heat, mechanical energy and electricity in several ways. Other technologies, including geothermal and biomass conversion are only now coming into their own. A primary impediment to widespread use of renewable resources has been its high cost relative to other generating fuels. For several renewable power sources, however, the gap in cost per kilowatt-hour compared to fossil fuels is decreasing as the technology becomes more advanced and their use becomes more common. Recent increases in natural gas prices have also enhanced the attractiveness of several renewable generation technologies. Customers of Austin Energy, the City of Austin's municipal electric utility, may participate in a "green choice" program in which the standard electric fuel charge is replaced by a "green power" charge. Originally, the green power charge for average Austin residential use came to $4 more than the standard fuel charge each month. Recent increases in natural gas prices have reduced the difference to $1.37 per month.[1]

SB 7 Requirements and Implementation

Senate Bill 7 directly addressed the twin pressures of rising power demand and air quality concerns through a mandate to add 2,000 megawatts (MW) of new generation capacity from renewable resources in Texas by 2009, more than tripling renewable capacity in the state.

In 1999, approximately 880 MW of generation capacity from renewable resources existed in Texas. Some Northeast Texas electric cooperatives also had standing contracts for hydroelectric power from out of state resources which were not calculated as part of the state's total renewable energy portfolio. The Public Utility Commission of Texas (PUC) was directed to create a system by which customers statewide could participate in development of the state's renewable resources.[2]

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[1]Mary Alice Piasecki, "Generating a Powerful Role," *Austin Business Journal*, Sept. 1, 2000, p. 3.

[2]PURA §39.904.

To fulfill this requirement, the PUC established a renewable energy credit (REC) trading program for retail electric providers (REPs) in Texas. As required by the statute, the PUC also established a series of stair-stepped goals for the installation of renewable generation facilities. Power generators must add 400 MW of new capacity by 2003, an additional 450 MW by 2005, another 550 MW by 2007 and another 600 MW by 2009.

Renewable Energy Credits Program

Each REP and municipal utility or electric cooperative opting for customer choice in Texas is required to purchase a number of RECs proportional to its share of the Texas retail market. One REC represents one megawatt-hour (MWh) of renewable energy that is generated from a new resource and physically metered and verified in Texas. Each REP is not required to purchase an equivalent amount of electricity generated from renewable resources. The electricity is bought and sold in the marketplace independent of the sale of RECs. This should allow renewable generators to sell renewable power at market rates and make up the cost difference through the REC sales.

By requiring all competitive retailers (REPs and opt-in municipal utilities and electric cooperatives) to participate in the REC program, instead of mandating high-cost direct renewable energy purchases, investment dollars will likely be steered to the best location for the development of particular renewable resources. For example, an electric generator could build a wind plant in Galveston, but it would likely not produce the same amount of electricity as one atop a West Texas mesa. Rather than require REPs in the Houston area to buy renewable power, the program allows retailers to participate in renewable energy resource development where it makes sense for them to do so. The rule does not prevent a REP from purchasing both the renewable energy and the REC created from its production.

Some REPs will receive REC offsets under the PUC program. A REC offset represents one MWh of renewable energy from an existing facility that may be used in place of a REC to meet the renewable energy requirement imposed by the PUC. REC offsets may not be traded. REC offsets will be equal to the average annual MWh output of an existing resource. The REC offset provision precludes existing resources from deflating the value of RECs in the marketplace, which could negatively impact further renewable capacity development, while recognizing the contribution existing resources provide to the state's total energy portfolio. The offset provision received broad support from participants in the workgroup discussions. It was generally recognized that the REC offset provision will also make it easier for municipal utilities or electric cooperatives with rights to existing resources to opt in to competition.

The statewide REC program will be administered by ERCOT, which will determine the number of RECs required of each REP annually, subject to PUC approval, and will track the creation, retirement and banking of credits. ERCOT will issue a compliance report to the PUC each April. This annual report will also detail the number and type of operating renewable energy generators in the state.

Although the REC requirements will not be instituted until January 1, 2002, renewable generating facilities will be eligible to earn RECs beginning June 1, 2001. This "early banking" provision should ensure enough liquidity in the marketplace that scarcity does not artificially inflate REC prices. Liquidity of RECs will also place cost containment responsibilities on renewable energy generators. If generators hold more RECs than REPs are required to purchase, the price of RECs should fall. If both the price of RECs and wholesale energy prices are low, it will be difficult for high-cost renewable facilities to operate profitably.

Outlook for New Generation

Industry response to the renewable energy provisions of SB 7 has been encouraging. Six months after the PUC adopted the REC program, ERCOT received more than 20 renewable generation interconnection requests, representing a capacity greater than 2,800 MW.[3] Some of the projects are in competition with one another, however, so not all of them will materialize. The 2,000 MW by 2009 requirement of SB 7 will likely be met, even exceeded, in the time frame established by the bill. ERCOT estimates West Texas could ultimately host more than 8,600 MW of wind power, with around 5,400 MW available for export to other regions.

The majority of megawatts from proposed renewable generation facilities in Texas will come from

[3]Electric Reliability Council of Texas, "Presentation on Transmission in West Texas Related to Wind Projects," March 31, 2000.

"wind farms," large-scale projects located across several hundred acres of West Texas. Giant wind turbines, some hundreds of feet tall, will generate electricity by harnessing the strong West Texas winds. Although wind projects consume no fossil fuels, require no cooling ponds and release no toxic emissions, the surge in wind power development is not without problems. Transmission constraints in West Texas must be overcome to move wind-generated power to load centers in other parts of the state. Additionally, system administrators worry that wind turbines spinning in the night, when electric use is low, may create high-voltage problems on the grid.[4] Because wind turbines only produce electricity in windy conditions, incorporating wind resources into long-term energy and system reliability planning processes is likely to be challenging to the ERCOT ISO.

Other renewable projects under development, such as Reliant Energy Renewables' 12 proposed landfill gas conversion facilities, will likely become base-load generators that will be depended upon for a steady flow of power.

In addition to the REC trading program, federal tax incentives also play a role in encouraging new renewable generation capacity. The Energy Tax Act of 1978 (P.L. 95-618) created solar credits and residential and business credits for wind energy installations; it expired on December 31, 1985. However, business investment credits were extended repeatedly through the 1980s. Section 1916 of the Energy Policy Act of 1992 (P.L. 102-486) extended the 10 percent business tax credits for solar and geothermal equipment indefinitely. Also, Section 1914 of that Act created an income tax "production" credit of 1.5 cents/kwh for electricity produced by wind and closed-loop biomass systems. P.L. 106-170 expanded this credit to include poultry waste and extended it through December 31, 2001.[5]

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[4] Ibid.

[5] Congressional Research Service, "Renewable Energy: Tax Credit, Budget, and Electricity Restructuring Issues," May 12, 2000, p. 3.

Chapter Eight:
COMMITTEE FINDINGS

The committee believes maintaining a reliable, affordable supply of electricity for all Texans is an essential component in our state's continued economic prosperity. The legislative actions establishing a new structure for the generation and delivery of electric power have been the result of years of intense study and difficult compromise. The committee has observed the implementation process in action for more than a year and finds the provisions of Senate Bill 7 supply an adequate framework for electric utility restructuring in Texas.

The committee recognizes that many issues remain to be resolved before full retail competition begins on January 1, 2002. The committee has endeavored to understand the nature of problems experienced in other restructuring markets in an effort to avert similar circumstances in Texas and ensure the development of a properly functioning marketplace that provides customers with a real choice of competitive providers. Where potential problems do exist, the committee recognizes multiple approaches or solutions may be available and legislation may be one of these solutions. The issues explored in this report will be important matters for the 77th Legislature to monitor during the upcoming session.

Since the enactment of SB 7 in 1999, several key events have transpired in local, national and global energy markets which add a degree of apprehension to a process already requiring tough decisions to be made in many critical areas. Although the committee's primary focus throughout the interim has been to monitor the implementation of SB 7, well-publicized problems in California and other energy markets caused the committee to re-focus its oversight activities to be certain Texas is not headed for similar problems.

Implementation of Statutory Goals

The committee finds substantial progress has been made towards implementing the goals of SB 7. Several state agencies were assigned specific functions in the bill, with specific deadlines for completion. Target dates for action by the Comptroller of Public Accounts, Texas Education Agency, General Land Office and Texas Natural Resource Conservation Commission (TNRCC) have been met. The Public Utility Commission of Texas (PUC) has diligently completed a wide array of projects in the time frame specified by restructuring legislation. The committee expects the PUC will continue implementation activities on schedule and will maintain regular communication to ensure this occurs. The committee notes most Texas market participants have met various statutory deadlines for restructuring activities, including PUC and TNRCC filings, business separation activities and technical operations implementation. As the restructuring process continues, the committee will continue observation to ensure all market participants and implementing agencies continue to perform within the parameters intended by acts of the Legislature to provide fair competition in the Texas retail electric market.

Reliability

The committee is encouraged by the surge in announced generation facilities in Texas, although some concern exists about heavy dependence on natural gas. The more than 5,700 MW of new generation capacity added in Texas since the wholesale restructuring process began should provide a dependable power reserve margin. The committee is further encouraged by the level of cooperation between the PUC, TNRCC and Electric Reliability Council of Texas (ERCOT) to facilitate the spread of distributed generation as a partial solution to air quality concerns and transmission constraints in the state. Although new difficulties in transmission planning have surfaced since wholesale market restructuring began in 1995, the committee finds sufficient coordination between power generators, utilities, ERCOT and the PUC exists to solve potential problems.

Price Volatility

The committee does not expect the Texas retail electric market to experience the wholesale or retail price volatility experienced elsewhere in the United States during Summer 2000. Abundant generation resources, a workable market structure and the price to beat mechanism will serve to stabilize power costs and protect customers from volatility. The committee will continue to monitor activities to ensure the restructured competitive market functions properly.

Stranded Costs

The committee finds changes in energy markets have led to ongoing revisions of estimated stranded investment. SB 7 provided mechanisms for the state's investor-owned utilities to recover costs incurred under the regulatory structure which prove to be uneconomical in the competitive market. It is believed these costs will be lower than previously anticipated. In any event, this is an issue requiring continued monitoring by the committee.

Consumer Protections

The committee received substantial testimony from consumer advocates concerning a wide array of customer protection issues. The committee finds basic consumer protections from anticompetitive activities are fundamental to maintaining a vibrant, healthy market. Final review and adoption of the ERCOT market protocols and PUC rules implementing the customer safeguards established in PURA by SB 7 and SB 86 are not yet complete. The committee will continue to monitor both the remaining implementation process and market participant adherence to Legislative intent.

Air Quality

The committee finds air quality in Texas will improve under the provisions of SB 7. Annual emissions from electric generating facilities will decline by at least 112,000 tons. However, continuing to improve air quality while maintaining electric system reliability is a complex task. Any future air quality regulations at the state or federal level may have broad, significant impacts on several sectors of the Texas economy. This is an issue requiring continued monitoring by the Legislature.

Renewable Energy

The committee is encouraged by the level of activity in the renewable energy market in Texas and finds that the renewable energy mandate of SB 7 will likely be met before the statutory deadline.

Continued Oversight

The committee finds further oversight of implementation activities is necessary to ensure a workable competitive environment develops. Remaining issues requiring the committee's continued attention include diligent monitoring of ERCOT operations, regular communication with the PUC about implementation progress and ongoing analysis of market events as retail electric competition begins in Texas.

Pursuant to PURA §39.907, the committee shall continue to meet at least annually with the PUC, receive information about rules related to electric utility restructuring, review recommendations for legislation and monitor the effectiveness of electric utility restructuring. In accordance with the statute, the committee shall issue a report in November 2002.

DISSENTING OPINION OF REPRESENTATIVES SYLVESTER TURNER AND DEBRA DANBURG

Estimates of stranded costs for utilities have fallen lower and lower throughout the course of the committee's four interim hearings, primarily due to higher natural gas prices. Since the conclusion of those hearings, it has become apparent that not only may stranded costs be fully mitigated before the start of retail competition, but also some generation assets may actually possess market value above their net book value, creating a negative stranded cost for some utilities. SB 7 prohibits utilities from overrecovering stranded costs, and any excess revenues collected by the utilities must be returned to ratepayers. Though the committee report recognizes this as a possibility, it does not present the kind of discussion on this issue that I believe is appropriate.

The Office of Public Utility Counsel (OPC) has filed testimony with the Public Utility Commission (PUC) that estimates the total overrecovery of stranded costs to be over $7 billion by 2004. PUC staff have also presented estimates of overrecovery to the commissioners in public meetings that are significantly lower than OPC's estimates but still amount to at least $2 billion by 2004. This begs the question of whether utilities should be allowed to hold onto any excess collections they may already have, not to mention whether ratepayers should be asked to continue paying down stranded costs that may not even exist.

We do not know what the final stranded cost figures will be. However, I believe the Legislature must make a policy decision as to whether this issue should be addressed before the true-up proceeding in 2004. If the potential for overrecovery is as great as some suggest, then this issue should be looked at now, not just allowed to proceed until 2004. This committee's report seems to exclude the possibility that the Legislature may wish to provide the PUC further guidance on how to handle any overrecovery of stranded costs. I understand that there is very little desire to reopen SB 7, but the issue remains that Texas electricity customers may have already paid for stranded costs.

Just as recent market changes unforseen in 1999 have altered our current discussions of potentially strandable investment, it is likely that estimates of excess costs over market will continue to shift as Texas moves closer to introducing retail competition in electricity markets. It is understandable that the committee is hesitant to predict market conditions for several years into the future and determine the possible effects of multiple market factors on potentially strandable investment.

Because the definition of stranded costs in SB 7 includes only the “positive excess” of net book value over market value, the Legislature must provide further guidance to the PUC as to how it should proceed. The PUC is investigating stranded costs, and it may have sufficient tools available under current law to deal with this issue appropriately during the transition period. For example, the PUC could redirect depreciation transfers from the transmission facilities to the generation assets or end the application of excess revenues to stranded costs.

The Legislature could also provide the PUC with additional tools to ensure that ratepayers are not asked to pay too much toward stranded costs, including the establishment of a negative Competition Transition Charge (CTC) or another mechanism that would reduce the non-bypassable charges on customers’ bills to prevent overrecovery of stranded costs. Reducing non-bypassable charges means more headroom in the retail price structure, and thus more room for competition. If it would be appropriate to refund customers who have paid too much toward stranded costs, then it makes sense that we should consider applying those refunds no later than the start of competition.

In most respects, I agree with this committee’s conclusion that SB 7 provides an adequate framework for successfully introducing retail electric competition in Texas. Continued monitoring of restructuring legislation implementation is needed to be certain a workable market develops. More than just monitoring, we should examine this stranded cost issue thoroughly during the upcoming session. The Legislature should commit to making a policy decision whether it is appropriate for utilities to continue collecting money from ratepayers to apply to their stranded costs or should the PUC set a CTC that is zero or possibly negative. This is an important issue for all electricity customers in Texas.

SIGNED	SIGNED
Rep. Sylvester Turner	Rep. Debra Danburg

Appendix A:
LIST OF FIGURES

Appendix B:

COMMONLY USED ACRONYMS

AARP	American Association of Retired Persons
AE	Austin Energy
AEP	American Electric Power
AECT	Association of Electric Companies of Texas
bcf	Billion Cubic Feet
BEPC	Brazos Electric Power Cooperative
btu	British Thermal Unit
CCN	Certificate of Convenience and Necessity
Coop	Electric Cooperative
CPS	City Public Service Board of San Antonio
CPL	Central Power and Light
CTC	Competition Transition Charge
D/FW	Dallas/Fort Worth
ECOM	Excess Costs Over Market, also known as “stranded costs”
EGF	Electric Generating Facility
EGS	Entergy Gulf States
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPE	El Paso Electric
ERCOT	Electric Reliability Council of Texas
ESSA	Electric Service Agreement, a term used by the General Land Office
ESP	Electric Service Provider, a term used by the General Land Office
FERC	Federal Energy Regulatory Commission
GLO	General Land Office
ISO	Independent System Operator
IOU	Investor-Owned Utility
kwh	Kilowatt-hour
kw	Kilowatt

kv	Kilovolt
LCRA	Lower Colorado River Authority
mcf	Thousand Cubic Feet
MM	One Million
MOU	Municipal-Owned Utility
MPA	Municipal Power Agency
MRS	ERCOT's Market Readiness Series
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Council
NOx	Nitrogen Oxides
OPC	Office of Public Utility Counsel
PGC	Power Generation Company
PL	Public Law
POLR	Provider of Last Resort
PUC	Public Utility Commission of Texas
PUHCA	Public Utility Holding Company Act of 1935
PURA	Public Utility Regulatory Act, Title II, Texas Utilities Code
PURPA	Public Utilities Regulatory Policy Act of 1978
PV	Photovoltaic
PX	Power Exchange
QSE	Qualified Scheduling Entity
REC	Renewable Energy Credit
REP	Retail Electric Provider
RHLP	Reliant Energy, Houston Light and Power
RTO	Regional Transmission Organization
SB	Senate Bill
SBF	System Benefit Fund
SERC	Southeastern Electric Reliability Council
SDG&E	San Diego Gas and Electric
SIP	State Implementation Plan
SIS	Security and Information System
SO2	Sulfur Dioxide

SPP	Southwest Power Pool
SPS	Southwestern Public Service Company
SUV	Sport Utility Vehicle
SWEPCO	Southwest Electric Power Company
T&D	Transmission and Distribution Utility
TCAA	Texas Clean Air Act
TDHCA	Texas Department of Housing and Community Affairs
TEA	Texas Education Agency
TIS	Texas Interconnected System
TNMP	Texas New Mexico Power Company
TNRCC	Texas Natural Resource Conservation Commission
TREC	Texas Rural Electric Coalition
TXU	Texas Utilities
VOC	Volatile Organic Compound
WSCC	Western Systems Coordinating Council
WTU	West Texas Utilities

Appendix C:
GLOSSARY

A

aggregator: a person joining two or more customers, other than municipalities and political subdivision corporations, into a single purchasing unit to negotiate the purchase of electricity from retail electric providers. Aggregators may not sell or take title to electricity. Retail electric providers cannot be aggregators.

ancillary services: services called on to control electric system frequency by matching production and consumption. The key ancillary services are regulation and reserves. Regulation is provided by measuring the deviation of the system from the standard frequency and sending signals to generators to increase or decrease their output. Reserves are an "insurance policy" against larger events, such as the failure of a generating unit. Reserves can be provided by generating units that are able to quickly and significantly increase their output or by customers who are able to quickly and significantly decrease their consumption.

C

competition transition charge (CTC): a non-bypassable charge included on all electricity customer bills to recover stranded costs.

cogeneration: production of electricity from steam, heat or other forms of energy produced as a by-product of another process.

combined cycle: an electric generating technology in which electricity and process steam is produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

commercial information: information that can be used in the marketplace.

commonly-owned unit: a generating unit whose capacity is owned or leased and divided among two or more entities. Synonym: jointly-owned unit.

control area: an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection.

cramming: hiding unauthorized charges on customer bills.

curtailability: the right of a transmission provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide that transmission service. Transmission service is to be curtailed only in cases where system reliability is threatened or emergency conditions exist.

curtailment: a reduction in the scheduled capacity or delivery of energy.

D

demand: the rate at which electric energy is delivered to or by a system or parts of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. Demand should not be confused with load.

demand-side management: the term for all activities or programs undertaken by an electric system or its customers to influence the amount or timing of electricity use.

distributed generation: a distributed generation system involves small amounts of generation located on a utility's distribution system for the purpose of meeting local substation level peak loads and displacing the need to build additional local distribution lines.

E

Electricity Reliability Council of Texas (ERCOT): one of 10 reliability councils in the North

American Electric Reliability Council, ERCOT is a non-profit corporation which administers the bulk transmission network within its boundaries. Approximately 84 percent of Texas lies within ERCOT.

estimated costs over market (ECOM): the historic financial obligations of utilities incurred in the regulated market that become unrecoverable in a competitive market. Other phrases are also used to describe the concept, include *potentially stranded investment*, or *stranded costs*. These terms emphasize that these historic costs are not yet stranded, but may become stranded in the future. The degree to which investments are ultimately stranded will depend upon changes in the market price of electricity, the speed with which markets become competitive, tax implications of restructuring options, mitigation efforts by utilities and the actions of utilities, the Legislature and the PUC regarding electric industry restructuring.

F

fuel factor: that portion of the regulated electric utility bill which pays for fuel as an input to the electricity generation process.

functional unbundling: the process by which a utility separates business activities according to the functional role of each activity in the electricity delivery process. In Texas, and most other restructured markets, monopoly utilities are separated into a power generation company, a transmission and distribution utility and a retail electric provider.

G

generation: the process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in megawatts.

grandfathered facilities: industrial plants in existence before implementation of the Texas New Source Review permitting program and exempt from the requirements of the Texas Clean Air Act.

H

headroom: the difference between the sum of non-bypassable charges and the price to beat, usually expressed in cents per kilowatt-hour.

I

independent power producer: any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other non-utility producers, such as exempt wholesale generators that sell electricity.

independent system operator (ISO): an entity charged with supervising the collective transmission facilities of a power region, coordinating market transactions, planning systemwide transmission and ensuring network reliability..

interconnected system: a system consisting of two or more individual electric systems that normally operate in synchronism and have connecting tie lines.

Interconnection: when capitalized, any one of the five major electrical system networks in North America: Eastern, Western, ERCOT, Quebec and Alaska. When not capitalized, the facilities that connect two systems or control areas. Additionally, an interconnection refers to the facilities that connect a non-utility generator to a control area or electric system.

K

kilovolt (kv): one thousand volts; see *volt*.

kilowatt (kw): one thousand watts; see *watt*.

kilowatt-hour (kwh): one thousand watt-hours; see *watt*.

L

load: an end-use device or customer that receives power from the electrical system. Load should not be confused with demand, which is the measure of power that a load receives or requires.

load cycle: the normal pattern of demand over a specified time period associated with a device or circuit.

load shedding: the process of deliberately removing, either manually or automatically, preselected customer demand from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

load shifting: demand-side management programs designed to encourage consumers to move their use of electricity from on-peak times to off-peak times.

M

margin: the difference between net capacity resources and net internal demand. Margin is usually expressed in megawatts.

marketer: an entity that has the authority to take title to electric power generated by itself or another entity and remarket that power at market-based rates.

Megawatt (MW): one million watts; see *watt*.

Megawatt-hour (MWh): one million watt-hours; see *watt*.

P

price to beat: in the restructured Texas electricity market, the price to beat is the rate charged by the affiliated REP of an incumbent utility. The price to beat is fixed at 6 percent below the rate in effect on September 1, 1999, adjusted for changes in the fuel factor. The price to beat must be offered to all small customers through January 1, 2007.

power exchange (PX): a centralized market mechanism matching wholesale power buyers and sellers.

Q

qualified scheduling entity (QSE): a market participant that is qualified in accordance with Section 16, Registration and Certification of Market Participants, by ERCOT to submit balanced schedules and ancillary service bids and settle payments with ERCOT.

R

renewable energy: energy derived from sources that are not depleted by human use, such as wind, solar energy and water movement.

S

securitization: a transaction that permits a utility to receive a lump sum payment for stranded costs from investors in lieu of collecting such costs through its regulated cost of service. The lump sum payment is financed through the issuance of debt securities to third party investors.

slamming: the unauthorized switching of a customer's service provider.

stranded costs: see *estimated costs over market*.

T

transco: short for *transmission company*. In the restructured Texas electricity market, independent system operator functions may be carried out by privately-owned, for-profit transmission companies.

true-up: as set forth in PURA §39.262, the true-up is a process scheduled to take place in 2004 in which the PUC will make a final determination of the stranded investment incurred by each utility.

V

volt: the unit of electromotive force that will drive a current of one ampere through a resistence of one ohm. Voltage may be thought of as a "push" that moves or tends to move a current through a conductor.

W

watt: a unit for measuring power, or the rate at which work is done. In electricity, a watt is equal to the flow of one ampere at a pressure of one volt (watts = volts X amperes). A watt-hour is the amount of electrical energy used to keep a one-watt unit working for one hour.

wind farm: a facility employing the use of several devices to harness the power of wind to turn turbines and produce electricity.

wires charge: that portion of a customer's electric bill which covers costs associated with the construction, maintenance and administration of the bulk transmission system.

Appendix D:
SUMMARY OF TESTIMONY
November 30, 1999, Austin

PAT WOOD, Chairman, Public Utility Commission of Texas

Chairman Wood outlined the process and time line for Senate Bill 7 implementation, expressing confidence that implementation projects could be completed on schedule. Due to the large volume of work associated with implementing market restructuring legislation, Chairman Wood said the Public Utility Commission (PUC) has relied heavily on the use of collaborative, consensus-oriented processes. "We get members of the public and the industry, new players and old players, to come together and try to work through as many issues as they can. If we can't get consensus on the issues — and that has happened — then the PUC really decides the issue," he stated.

The chairman outlined five "big picture items" that must be completed on track for restructuring to take place in the time frame specified by the bill. First, he reminded committee members that utilities are still regulated, and the PUC must continue to regulate them effectively prior to opening the market on January 1, 2002.

Second, the "back end" systems must be prepared for opening day. "Based on the Commission's experience with Southwestern Bell and the long distance issues in the local competition market, we realized that if we have computers that don't speak to each other or if you don't have computers at all, it is going to be very difficult to deal with millions of customers and sending them accurate bills month after month," he said. By statute, the Electric Reliability Council of Texas (ERCOT) is charged with developing the new system infrastructure. ERCOT will also assume new duties: managing the settlement system, ensuring accurate bills between electricity providers and maintaining the customer registration system. Chairman Wood said, "I am comfortable with the progress ERCOT is making on these issues." Although the PUC allows ERCOT to handle its own business, Chairman Wood said a significant level of staff-to-staff communication is taking place. Ultimately, the PUC maintains an oversight function and must approve the ERCOT marketplace rules.

Third, industry standards must be developed. Chairman Wood said that PUC staff is working with industry and consumer groups to achieve consensus based on national models tailored to fit the Texas statutes.

Fourth, customer protection rules must be established. Chairman Wood said SB 7 "was very well filled out in that regard — not a lot of dotted lines to fill in. But it's still important to pull it all together." Some questions exist on how to pay for certain activities such as services needed for development and implementation of the consumer education plan, which must occur before 2002. Some anticipated difficulties concern establishing a protective framework that still allows a degree of freedom and innovation in the marketplace. For example, Chairman Wood said different consumers want different things from their utility bill. Some people may want a very detailed listing of all charges whereas others simply want a box highlighting the amount due. "We are trying to strike a fair balance that does not encourage fraudulent or misleading statements," he said.

Fifth, the PUC is still trying to work out how much interaction the transmission and distribution utilities will have with customers. In other words, "Who do you call when the wires go down?" As long distance telephone service has been restructured in the state, Chairman Wood said the PUC found it works better if there is one entity customers can go to when something goes wrong. "Otherwise you have a lot of blame-shifting behavior," he said.

Chairman Wood next addressed reliability issues, noting that a significant level of new power generation is planned or under construction in Texas. This new capacity will meet the growth in demand. In the time since SB 373, 74th Legislature, restructured wholesale electric markets, all new power plants in Texas have been built by non-utility companies, meaning the risks and rewards have been placed on the marketplace instead of retail customers. Chairman Wood envisions an industry requirement mandating a 15 percent reserve capacity margin to keep abreast of demand growth. Chairman Wood said he anticipates the market maturing in Texas by 2010, reducing the need for regulators to be involved in generation capacity monitoring.

Capacity is only the first part of the reliability equation. The question is not only can we generate enough power to meet demand, but also, is the infrastructure capable of moving the power from where it is generated to where consumers use it? As the process for siting and building power generation facilities has become more streamlined and faster, the process for siting and building additional transmission facilities has become longer and more complex. Environmental regulations and historical requirements are part of that, but the biggest single issue is landowner concerns associated with acquiring the right-of-way necessary for construction. More and more of the transmission network needs to be routed through urbanizing areas.

Seven major transmission projects are under way now, and seven more are planned. The PUC has been working to get these projects underway so certain bottlenecks in the transmission grid will be unclogged by the start of competition. The ability to move electricity from power-rich Houston to power-hungry Dallas is very important, requiring resolution of the state's South to North transmission constraint.

Chairman Wood said the power market has reacted favorably to both the new structure and the perceived need in Texas. He reported particular success in South Texas. "As a result of signals sent by the Rio Grande Valley market, we have one new completed plant, one near completion and one that will be ready by mid-01," he said. South Texas used to be a power-starved area of the country, but new generation sited in the Valley since the 1995 restructuring legislation will likely make it a power-rich region.

Some generators now want to increase ties to Mexico's power grid to sell excess power, an idea supported by Central Power and Light and the PUC. Some concerns have been expressed that tying into the Mexican grid may encourage further development of heavy-polluting plants. Chairman Wood said the efficiency of natural gas plants on the Texas side of the border decreases long-term viability of the older plants South of the border.

JEFF SAITAS, Executive Director, Texas Natural Resource Conservation Commission

Mr. Saitas provided the committee with an overview of the environmental provisions of SB 7, updated the committee on the progress of implementation and discussed emerging problems and policy issues.

The TNRCC anticipates a 75,000 ton per year reduction in nitrogen oxides (NOx) emissions and a 37,000 ton per year reduction in sulfur dioxide (SO2) emissions statewide as a result of SB 7. This represents a 12 percent reduction from the approximately 900,000 tons per year of total grandfathered contaminants released into the air. The grandfathered emissions portion of SB 7 affects 192 individual emissions sources located at 75 different sites in the state.

In some areas of the state, much more significant reductions are required to meet the eight-hour ozone standard promulgated by the U.S. Environmental Protection Agency (EPA) to fulfill the requirements of the federal Clean Air Act of 1990. To meet these standards, NOx emissions must be reduced by about 88 percent in the Dallas/Fort Worth area and 90 percent in the Houston area.

Mr. Saitas said some grandfathered facilities may have polluting equipment on site not covered by SB 7, since the legislation has been interpreted by TNRCC as dealing only with units that generate electricity. Under this interpretation, a train that transports coal would not be covered by the SB 7 permitting and reduction requirements because the train does not generate electricity. TNRCC is considering a rule that would allow companies who voluntarily seek permits for those additional facilities to use reductions beyond what is required for trading purposes.

In response to a question from Representative Danburg, Chairman Wood said any electric utility investment to clean air quality pursuant to TNRCC compliance with National Ambient Air Quality Standards is includable in stranded cost recovery at the true-up in 2004, not just those costs related to the grandfathered facilities, according to PURA §39.263.

Mr. Saitas also addressed reliability concerns from the TNRCC's perspective. "We want to make sure that as we proceed as a state in addressing the air quality part of our business, that we do not create a situation where permitting interrupts the ability to deliver power to the people so that we have to choose … between a brownout or clean air. Clearly the path we have to follow is that we've got to do both."

SAM JONES, Director, Electric Reliability Council of Texas, Independent System Operator

Mr. Jones summarized the activities of ERCOT in preparation to assume the role of Independent System Operator in the restructured Texas market. To facilitate the implementation process, ERCOT contracted Andersen Consulting to serve as project manager. The firm has experience in retail market transition in North America as well as overseas. Thus far the consulting team has produced cash flow models, staffing and facilities needs analyses and other planning items.

ERCOT formed several task forces that began meeting soon after the end of the 76th Legislature to discuss the market structure within ERCOT. The meetings have been open to any interested participants. Some outstanding issues requiring resolution include how to pay for congestion management and how to acquire some of the ancillary services needed. The ISO director expressed hope the ERCOT committees could reach consensus on these and other issues. If not, he expects the PUC will step in and make those decisions.

Mr. Jones reported that some interruptible load in North Texas was shed during the summer of 1999 solely due to transmission constraints. Some generators in the area had been forced out of service and the North-South transmission lines were already at maximum capacity.

As the transmission system operator, ERCOT informs a utility that a certain number of megawatts of load must be shed to maintain system integrity, Mr. Jones explained. The utility then interrupts load according to its procedures. After 2002, that procedure will change somewhat as the interruptible load becomes a tool or a commodity which a retail provider would exercise for money. To illustrate his point, Mr. Jones said an entity willing to interrupt load during a time of need would say, "Okay, I'll interrupt so many megawatts for so many dollars," and the ISO could accept the offer and pay that price for load reduction.

Co-chairmen Sibley and Wolens asked how the load interruption procedure will be handled in the future. The current system configuration only requires one call to the utility in each service area, but the future market structure involves several REPs, each of which may have some interruptible customers. Mr. Jones replied that at this time it is somewhat uncertain how that situation will be handled in the future.

The ISO director acknowledged the outlook for new power generation in Texas is positive but counseled that additional transmission lines will be needed to connect many of these facilities to the grid. Discussion ensued between Senator Sibley, Representative Turner, Mr. Jones and Chairman Wood concerning transmission planning. Under the regulated monopoly structure, generation and transmission were usually planned together. The new market environment requires non-discriminatory access to the grid, which complicates protecting the public interest against unnecessarily expensive transmission projects. Mr. Jones explained that ERCOT has no authority over plant siting or connection to the grid. The ISO is involved in transmission planning, however, and reviews proposed projects.

Chairman Wood explained the PUC maintains the authority to protect the public interest in this area. Generation plants only require two permits to build: an emissions permit from the TNRCC and a permit indicating compliance with local government rules. To operate, however, generation plants need a connection to the grid. Transmission utilities cannot reject a request for interconnection outright. This rule prevents discrimination in favor of the transmission utility's affiliated generation company. However, a Certificate of Convenience and Necessity (CCN) is still required from the PUC in order for the transmission utility to recoup the cost of the line through the non-bypassable charge on customer bills applied by the transmission and distribution utility.

If the PUC determines a proposed transmission line does not serve the public interest due to environmental, health, economic or other reasons, it may reject the CCN request. Such a decision would relieve the transmission utility of the responsibility to connect the proposed plant to the grid and would likely cause the power producer to abandon the proposed project.

Air quality issues have also presented problems for ERCOT. "We've made no decision at the ISO based on any of the air quality issues because we have not traditionally been involved in anything like that," Mr. Jones said. "We've depended on the TNRCC permitting process to deal with that." Air quality issues in North Texas present particular problems. Some of the grandfathered facilities are essential to maintaining system voltage on peak days, but they may not be retrofitted because of economic reasons. There has been talk of extensive transmission upgrades running from Houston to Dallas to address that problem. However, Mr. Jones said, "We need new, good, clean generation up there." New capacity is being built outside the non-attainment area, but the local transmission system in place there will not support the load in North Dallas without most of the older generating plants in full operation. Mr. Jones said ERCOT administrators are very concerned about air quality rules having a negative impact on system reliability on the Dallas metropolitan area.

Mr. Jones said in his opinion SB 7 was a good bill and did not anticipate needing any further legislation to allow ERCOT to fulfill its mission as the ISO.

STEVE SCHAEFFER, representing the Associated Electric Companies of Texas

Mr. Schaeffer first addressed issues related to the transition period. He echoed Chairman Wood's assessment that Texas had sufficient existing and planned generation capacity to meet demand. The market has responded well to the 1995 wholesale restructuring legislation. A number of new generating facilities have come online without ratepayer subsidization, but planning for new load requirements in the restructured market is somewhat complex and will begin in earnest before competition actually begins. The impact of market restructuring on the planning process is that strategies shift from a regional focus to more of a statewide outlook. For example, when the General Land Office (GLO) begins serving entities formerly served by the utilities, it will affect individual system planning, even though it does not affect ERCOT demand or capacity totals. In Reliant's territory, 200 to 300 MW of load should be dropped from the system due to GLO's activities. Another planning factor is the retail competition pilot program, which should shave Reliant's load again by another 5 percent.

Mr. Schaeffer said planning has been problematic for the past few years, largely due to weather impacts, and 1998 was one of the hottest years ever recorded in Texas. More accurate than simple high and low temperatures is measuring the number of degree-hours existing above 70 degrees, which draws a closer approximation of air conditioner use than other models. In fact, 1998 exceeded any other year on record for the number of degree-hours above 70 degrees.

Planning margins are figured assuming average weather and no forced outages. When the weather is exceptionally hot or a plant unexpectedly ceases operations, the reserve margin is supposed to be able to handle that power emergency. "We think the system has performed well for the past few years. We have had interruptions, but interruptible customers expect interruptions," Mr. Schaeffer said. As the market changes, he expects consumer habits to change with it. As customers witness price volatility in the marketplace, they will respond more directly than they did under the regulated rate system which tends to average costs over time, he said. This may be a beneficial effect for some consumers, but one which limits opportunities for others.

As a result of changing customer habits, electric companies expect load shapes to get flatter across the state. In the context of reliability and generation capacity, that means the state will have an even greater reserve margin as customers react rationally to price signals and reduce on-peak consumption. Mr. Schaeffer stated that nearly one-third of the kilowatt-hours Reliant currently sells are associated with customers whose metering technology allows them to observe and react to time-of-use pricing for electricity. This generally applies to the large industrial and commercial users. Smaller consumers are less likely to have to respond so specifically to price fluctuations. Mr. Schaeffer theorized that retail electric providers seeking residential market share are likely to use an average-price basis.

On the issue of transmission constraints, Mr. Schaeffer said both power plant and transmission network construction would be necessary to overcome capacity limits on the grid. “If there is a significant capacity constraint for transmission, what happens is prices will go up in a region and people will build generation that will take advantage of it and prices will go back down. It’s a normal market response. That’s one thing that we can expect to see happen in the future,” he said.

If a power plant fails in a region, however, the system still needs to be able to move replacement power into the area to keep the grid up. Although it may appear that areas can be served through the generation siting process without major commitments to the transmission infrastructure, that is not the case. Adequate transmission facilities are needed as a backup for generation failures.

Although new transmission projects are in progress, there has not been significant transmission construction in the state in more than a decade. Mr. Schaeffer expects new projects to move forward, but it is becoming increasingly difficult to site transmission projects in Texas today, primarily due to landowner concerns. It is also somewhat more difficult to plan for transmission projects since generation facilities are now privately planned.

The majority of announced generation projects in Texas will utilize natural gas as fuel, but it may be erroneous to assume this will lead to an increase in the total amount of natural gas consumed by the electric utility industry. Newer plants are more efficient, producing more kilowatt-hours of electricity from less gas combustion. Mr. Schaeffer said he expects older plants will primarily serve peak load and the newer, cleaner, more efficient plants will become base load servers. He predicted that a new class of plant will also develop in the market, called mid-merit, serving load somewhere between base and peak loads. Large coal plants are a good candidate for this class. Although they are not very fuel efficient, they are relatively inexpensive to operate. Some of the older gas plants will also fall into this mid-merit category. Mr. Schaeffer said nuclear plants will likely remain base load carriers.

On the subject of air quality, Mr. Schaeffer said it would make no sense to retrofit an older plant with new emissions technology just to get the money back through stranded costs. The decision to retrofit only makes sense if the owner thinks the plant still has life left in the wholesale market. Texas will probably need many of the grandfathered plants to handle peak demand, primarily because the state still has dramatic swings between peak and off-peak consumption.

Representative Danburg voiced concern that as the heavier polluting, less efficient facilities move toward peak demand fulfillment, negative impacts on air quality would emerge. “That’s precisely when the ozone problems are at their worst,” she stated. Mr Schaeffer replied that the bill will result in fewer total emissions statewide, “but you may well have emissions that are centered in areas you wish they weren’t.”

FRANK McCAMANT, representing the Lower Colorado River Authority

Mr. McCamant offered a more conservative analysis of electric power generation capacity than previous witnesses. “And I guess on one point we’ll take a little bit of a contrarian role in terms of adequate generation reserves,” he told the committee. “We think if you look at the numbers that have come out between ERCOT and the PUC, you can make a case that generation reserves are going to be fairly tight over the next few years. That means there will be adequate generation, but should there be some disruption in terms of weather or outages, we could see ourselves in potential shortage situations.”

Mr. McCamant said reserve margins in the regulated market have been adequate, and margins in the restructured market should be also. The transition period bears close scrutiny. An important question remaining in the restructuring rulemaking is whether the state will allow market forces to determine reserve capacity or develop a mechanism to ensure reserve margins are built into the system.

Mr. McCamant also voiced concerns about the adequacy of natural gas distribution systems. He agreed with Mr. Schaefer’s earlier assessment that the total volume of gas consumed by generating facilities could remain relatively stable in the face of additional gas-fired generation construction because of greater efficiencies in combustion processes. However, he contended there will still be a peak delivery issue as electric load grows and new plants are hooked up to the natural gas pipelines. An additional technological concern is that newer plants require gas at a higher compression. Mr. McCamant said government intervention in the natural gas distribution system is unnecessary because the market will likely address those system constraints.

A related question about the use of natural gas springs from a growing dependence on it as a primary fuel source for electric power generation. Mr. McCamant told the committee, “As capacity grows and we become more and more dependent on gas capacity in the future, you begin to have to ask yourself about strategic issues of risk management. Do we really want to put all our eggs in one basket in terms of depending so heavily on gas? … Gas plants are wonderful. They are efficient. The prices are great right now. But that could change quickly depending on what happens in the fuel market.”

Mr. McCamant further stated, “On the flip side of that, you have the risk issue of environmental legislation related to coal emissions and greenhouse gases, which could also completely flip the economics of how you dispatch those plants.”

BILL BURCHETTE, representing, East Texas Cooperatives

The East Texas Cooperatives are dissatisfied with the renewable energy credit program proposed by the PUC because they cannot receive credits for hydroelectric resources currently under contract. The East Texas Cooperatives have been purchasing hydroelectric power from the federal government since the 1950s. Investor-owned utilities had the option to purchase this power then but chose not to because it was more expensive than coal-generated power. The cooperatives currently purchase 128 MW of hydro power generated in Texas and five other states through the Southwestern Power Administration, a federal agency. Mr. Burchette suggested the rule be modified to allow federal hydropower allocated to Texas to be included in the renewable energy credit program.

Appendix E:

SUMMARY OF TESTIMONY

July 11, 2000, Dallas

PAT WOOD, Chairman, Public Utility Commission of Texas

Chairman Wood said one of the toughest issues facing the PUC is developing the rule to choose between spending resources to retrofit and clean up existing fossil fuel generation facilities or retire and replace them with newer, more efficient models.

He noted the Dallas/Fort Worth Metroplex comprises roughly one fourth of the state's total electricity demand, about 15,000 MW. But with only 6,000 MW of generation capacity in the area, the majority of that power is imported from outside the four-county area. The good news is several new generation projects have been announced in surrounding counties outside the non-attainment zone. However, significant upgrades to the transmission system will be needed to move that power to customers in Dallas, Fort Worth and the mid-cities.

Chairman Wood stated that of the three issues affecting reliability — air quality, transmission and new plant construction — he was least worried about luring new power producers into the market. Since the restructuring of the wholesale market in 1995, 22 new merchant power plants have been connected to the grid statewide.

Transmission issues are the real problem, he said. It is very difficult to add new plants near the load centers in the Metroplex due to air quality problems. But it is also becoming increasingly difficult to bring power from outside the Metroplex as well because major transmission lines must be built through urbanizing areas.

JEFF SAITAS, Executive Director, Texas Natural Resources Conservation Commission

Mr. Saitas explained that the TNRCC's emissions cap and trade program will function very differently in the Dallas/Fort Worth area than other parts of the state because the number of point-source polluters is limited. Thus, the credits market will be severely constrained by an initial lack of participants. Whereas in the Houston/Galveston non-attainment area there are several industrial point-source emitters, in Dallas there are basically three: TXU, the electric generation facilities owned by the City of Garland and the electric generation facilities of the City of Denton. Mr. Saitas said there may be some smaller industrial facilities that can achieve some credits for sale through voluntary emissions reductions. An entity wanting to construct a new electric generation facility could conceivably purchase several of these smaller batches of credits to qualify the new facility.

An effective emissions cap and trade program is important to make sure that the most-cost effective emissions reductions proposals are implemented. He said the TNRCC would rely on the trading program to allow market mechanisms to make the best choices on reducing emissions, whether from 15 small business or one large industrial source.

Mr. Saitas acknowledged a certain level of apprehension from potential market participants that even if they conform to current rules and emissions standards, they have no guarantee that the rules would not be tightened later in such a way as to prohibit making a return on investment. Unfortunately, there is really no way to limit what future commissions, the Legislature or the Environmental Protection Agency (EPA) may do. Some uncertainty in the political environment is always assumed to exist.

In the Dallas area, it is particularly important to achieve a high level of emissions reduction from the electricity generating facilities because there so few other sources of nitrogen oxides (NOx). Aside from the electric utilities, Mr. Saitas said the other two major sources of NOx are automobiles and the four area airports. Federal law preempts the state from imposing limitations on airplanes as they take off and land. Therefore, the state has instead asked for a high degree of reductions from the driving public, including the purchase of more expensive fuel-efficient cars, the use of more expensive reformulated gasolines, annual emissions testing and a requirement to fix problems identified by those tests.

Mr. Saitas also noted that while Texas government has a decisive role to play in cleaning the air, there are many contributing factors over which the TNRCC has no control such as airline operations, international shipping, ports and interstate railroads. Mr. Saitas said his agency was working with the EPA to accelerate implementation of federal rules which will help Texas' efforts to clean the air in non-attainment zones, such as the introduction of reduced-sulfur diesel fuel.

BECKY WEBER, Environmental Protection Agency, Region VI, Dallas

Ms. Weber focused her testimony on the importance of emissions reductions from utilities in the Dallas/Fort Worth area. Although the State Implementation Plan (SIP) submitted by the TNRCC has been approved by the EPA, there is still some concern that the plan could later be deemed incomplete if TNRCC loses any of the court challenges to the SIP. The Dallas/Fort Worth plan lacks a "safety margin," meaning if any of the controls proposed in the SIP are rejected by the courts, then a substitute control with equivalent reductions must be included in the plan or it could be rejected by the EPA. A rejection of the plan at any point by the EPA starts the clock ticking on implementation of federal sanctions.

Mr. Saitas responded that he was confident that TNRCC would prevail in each of the pending suits. He said some controls designed for the Houston area could be inserted into the Dallas SIP if a court strikes a particular remedy from the plan. Mr. Saitas said TNRCC could keep the Dallas SIP in compliance with EPA parameters regardless of future court decisions.

TOM BAKER, President, TXU Electric & Gas

Mr. Baker said TXU's preferred option to comply with TNRCC air emissions standards in the Dallas/Fort Worth area is to retrofit existing generation units with technological modifications that achieve those standards. Mr. Baker said the cost of such modifications over the entire TXU service territory would be about $635 million. The cost of such modifications within the Dallas/Fort Worth non-attainment area would be approximately $333 million. Although those estimates represent a significant capital expenditure, Mr. Baker said the cost divides out to approximately $65 per kilowatt of capacity. He said that cost compares favorably to the $475 per kilowatt of capacity to construct new facilities.

Other alternatives mentioned by Mr. Baker included shutting down the plants, which he maintained would sacrifice reliability, and building new plants to replace existing units, an option he said is not cost-effective. A final option would be construction of an extensive new transmission network throughout the urban area, an idea sure to encounter public opposition and fail to protect system reliability.

Mr. Baker said his company has six generation plant sites for sale on the market. TXU has temporarily suspended the sale process due to uncertainty in the regulatory arena regarding TNRCC emissions standards and PUC rules governing the inclusion of environmental cleanup costs in stranded cost calculations.

Mr. Baker next addressed transmission issues, saying the siting process in metropolitan areas is very difficult, expensive and time consuming. Furthermore, such projects will only become more complicated as population density and power demands increase in the future. He commented the processes outlined in SB 7 for the ISO to participate in transmission planning have worked well.

TOMMY FORD, general contractor

Mr. Ford informed the committee that he has actively attended workshops and symposiums regarding the SIP for the Dallas area. A 40-year veteran of the construction industry, Mr. Ford said proposed SIP restrictions on morning construction activity would be harmful to his business and to the families of his employees. The loss of three morning hours cannot be made up in the afternoon due to heat-related safety concerns. Prohibitions on morning construction activity translate into a 16 percent wage reduction for his employees and up to a 25 percent reduction in his firm's business volume. Mr. Ford suggested other remedies to NOx problems exist, especially in the area of better traffic control.

JIMMY GLOTFELTY, representing Calpine Corporation

Mr. Glotfelty said Calpine was excited about participating in the Texas electric generation market, noting that the company had three generation plants in Texas when SB 7 was passed, compared to 11 now. Some problems exist, however, in the procurement of some essential components of generation facilities: natural gas, transmission access and emissions credits.

Mr. Glotfelty said Calpine has experienced difficulty establishing generation facilities in North Texas because the company could not secure a firm natural gas commitment from TXU. Mr. Baker responded that TXU offers gas contracts under curtailment standards set by the Texas Railroad Commission. Mr. Baker said TXU uses a fuel oil backup system during the winter peak gas demand months when tight gas supplies can occasionally force curtailment to electric generating facilities.

Mr. Glotfelty said uninterruptible gas service for power generators should be a policy priority, especially during summer months.

Mr. Glotfelty next addressed the lack of liquidity in the NOx trading program within the four-county Dallas/Fort Worth non-attainment area. Because TXU has not made the emissions reductions necessary to create credits, there are not enough credits available to construct generation in the Dallas area, he said. Furthermore, he stated, when these credits are created, the majority will be owned by TXU, restricting credit trading capability and hampering new generation construction.

Mr. Glotfelty suggested that the regulatory structure allow firm gas contracts in North Texas and the emissions program be expanded to allow more industries to trade credits within a larger geographic area.

RICK LEVY, representing the Texas State Association of Electrical Workers, AFL-CIO

Mr. Levy contrasted the relationship between safety, reliability and profit under the old regulatory system with current trends emerging in the restructured competitive market. "In the past, electric utilities knew that if they were reasonable in their expenditures and they ran a sound operation, they would receive a certain measure of profit. And so there was no inherent conflict between safety, reliability, and profit because it all went together. The problem is in the transition to a new economic environment . . . there has to be a trade-off between how much money is going to be spent to address reliability and how much profit there is because it is not all recoverable."

Mr. Levy stated that some utilities, such as Reliant Energy, have made strong commitments to hiring and training new workers. Others, such as TXU, have approached the transition period in a more problematic fashion. He stated that workforce reductions at large TXU generating facilities are at least partly responsible for increased power interruptions to customers in recent years. Mr. Levy said the Trading House Plant near Waco suffered a failure in May, causing the interruption of several major employers in the Tyler area. Ten years ago, that plant employed 20 mechanics to perform maintenance. "Now it's down to five and there is just no way that five mechanics can do the same level of maintenance on a facility that 20 can do," he said.

JIM MARSTON, Director, Texas Office of Environmental Defense

Mr. Marston said implementation of the provisions of SB 7 related to renewable energy generation looks very positive, so far. Addressing discussion in earlier testimony on the negative effects of regulatory uncertainty on financial markets and investors, Mr. Marston suggested the way to create certainty is for the Legislature to push for caps on mercury and carbon dioxide emissions alongside current mandated reductions in sulfur dioxide (SO2) and NOx. "If anything makes it uncertain what utilities will have to face, it's what they are going to have to do on mercury, what they are going to have to do on carbon dioxide, because the cost of those two things will likely dwarf anything that had to be done about NOx in this state. That's the real uncertainty in the market in my opinion and we need to settle that."

Environmental Defense filed joint comments with public power companies calling for the emissions cap and trade program to expand across the entire spectrum of polluters. "We think it will reduce costs for everybody," he stated.

Mr. Marston next addressed concerns about the quality of data used in the SIP model. In his organization's estimation, the numbers undercount the amount of pollution in the Dallas area and overcount the estimated pollution reductions. For example, he said the TNRCC used the national average ownership rates for sport utility vehicles (SUVs) and light trucks rather than calculating input specific to the Dallas area. "I'm sorry," he said, "but Dallas is the SUV and pickup truck capital of the country."

H said legal challenges to the process for including environmental cleanup costs in stranded cost calculations would likely lead to delays in retrofitting activity. He urged legislators to stand firm on the deadline for inclusion of the costs as outlined in SB 7. "I think there ought to be an understanding that if you file a lawsuit and you delay the time in which the permits take place, that's at your own peril. We gave them a guaranteed payment. Why they don't take our money I still don't understand. But we said if you will come forward now and make reductions that we desperately need, we'll guarantee that you get paid back. That was the deal. We'll pay you if you make the reductions early. But don't let them file suit, delay the time of those implementations or investments and then come back later and say, 'Let's move the date back because our lawsuits delayed the time for us to make those investments.'"

Appendix F:
SUMMARY OF TESTIMONY
August 22, 2000, Houston

PAT WOOD, Chairman, Public Utility Commission of Texas

Chairman Wood first drew a distinction between the Texas and California restructuring plans by noting that, although the two states began deregulating the wholesale electricity market at approximately the same time, California moved to retail competition much faster than Texas. The retail market restructuring process in Texas will span about seven years, compared with two in California.

Since the Texas wholesale power market was opened in 1995, 22 new plants representing about 5,700 MW have come on line. By comparison, California saw only 672 MW in new generation capacity during the same period. The two states are comparably sized power markets, and both have growing economies.

Chairman Wood said 15 new plants, totaling approximately 9,600 MW, are scheduled to come online by the time the retail market opens January 1, 2002. Thirty-three additional plants are in the planning stages. Chairman Wood said Texas is an attractive state for investment in new power generation because the overall economic climate is good and the siting and permitting process is relatively simple and fast compared to other states. It now takes 24 to 36 months in Texas to take a power plant from the chalkboard to operational status compared with up to seven years in California.

California's dependence on hydroelectric power also provides a constraint on its electricity supply during dry seasons. Because Texas uses so little hydroelectric power, the same concerns do not apply here. The vast majority of generating facilities in Texas use coal and natural gas, two resources in abundant supply without seasonal limitations. Chairman Wood advised the committee that Texas' power supply portfolio is inherently more stable than California's, a point generally overlooked by mainstream media.

Chairman Wood said a successful component of a workable power market is to maintain reserve margins sufficiently high that power generators cannot game the system to their advantage by charging higher spot prices for electricity when demand outstrips supply during peak usage. He said the ERCOT area of Texas has traditionally planned to maintain a conservative 15 percent or higher reserve margin. The latest round of additions to Texas-based generation capacity should place the reserve margin near 20 percent in the next few years.

There is some concern that the Texas market is becoming overbuilt and that will send signals to investors that the prospect for high profit margins in Texas is dwindling, so they will likely choose to construct new facilities in other states. Chairman Wood's question is whether the market will respond again when Texas' reserve margin falls back into the 10 to 15 percent range or if there should be some kind of requirement on power generators to maintain a reserve margin of 15 percent based on their rated output capacity. Chairman Wood indicated solutions other than a mandatory reserve margin are also being contemplated at this time by both PUC staff and ERCOT engineers.

Although the PUC has a comfortable outlook on how much power generation will be available for the Texas grid for the next few years, Chairman Wood said he is somewhat unsure of the impact competition will have on demand. Although demand has been steadily increasing at roughly 4 percent a year in the ERCOT area of Texas, and the state's strong economic climate will likely contribute to that trend, the Chairman indicated that open market experience in other locales, notably England, has led to a demonstrable reduction in demand as larger consumers of electricity modify methods and behaviors to respond to more accurate price signals from the restructured marketplace.

Chairman Wood next addressed the issue of rising natural gas prices, saying multiple effects would be felt in the restructured marketplace. Higher natural gas prices could be considered useful because they lower stranded costs. Because coal-fired and nuclear generating plants will compete with natural gas-fired plants, rising gas prices make coal and nuclear fuel more cost competitive. Increased gas prices will also have the counter-effect of universally increasing electric costs because so much of the state's base-line generation is exclusively natural gas dependent. Chairman Wood pointed out that these higher prices would be paid by consumers whether the state restructured the electricity market or not. Fuel costs are always passed on to the consumer.

One area of uncertainty caused by increasing natural gas prices is on the headroom for new competitors to enter the marketplace. The price to beat mechanism employed in SB 7 acts in two distinct ways on the marketplace. First, by discounting and then freezing rates at the start of competition, it serves as a price ceiling for consumers through 2007. Incumbent utilities would not be able to charge more than the price to beat, allowing for adjustments related to the costs of fuel. Second, the price to beat mechanism acts as a floor, by not allowing the incumbent utilities to charge less than the price to beat until they lose more than 40 percent of their residential ratepayer base or January 1, 2005, whichever occurs first. This has the effect of leaving "headroom" for new market entrants to sell power at a price less than the incumbent utilities are allowed to offer.

Chairman Wood offered two additional notes on building headroom into the Texas retail price structure. First, he noted the charges related to administration of the electric system are much higher in California than Texas. ERCOT's transaction fee is 15 cents per megawatt-hour (MWh), whereas the California ISO and Power Exchange (PX) fees add up to $1.20 MWh. A second difference between the headroom in Texas and California is the treatment of stranded costs. These costs will be collected in Texas over a period of 12 to 14 years, whereas California set a much more aggressive time line, with disastrous consequences for the retail market. The main impact of California's more rapid stranded cost repayment was to reduce the available headroom for new market entrants. He also reminded the committee that unlike in California, the threshold for removing price to beat protections in Texas does not depend on stranded cost recovery, but on market share dilution. "Their price protection disappeared altogether when the stranded costs got paid off. There's no nexus in my mind between price protection and paying off stranded costs," he said.

Chairman Wood next addressed issues related to transmission constraints in Texas. "We might have enough power statewide, but we've got to make sure that power is near where it needs to be for the customers," he said. The PUC empowered ERCOT to oversee long-range transmission planning for the whole grid, ensuring that large transmission projects affect several power plants, rather than taking them one at a time. Regional planning will be used to build transmission in advance of the need. Representative Madden voiced concerns that non-attainment issues would cause more transmission problems, and Chairman Wood agreed with that possibility. Restrictions on plant siting in the four-county D/FW Metroplex will lead to new plant construction farther away from electric load centers, leading to new transmission requirements. Representative Brimer asked if utilities in the suburban Dallas area would likely have to take property through eminent domain procedures to site necessary transmission lines through the urban residential areas. Chairman Wood said that scenario is likely.

Chairman Wood updated the committee on the progress of the ERCOT ISO in implementing the customer choice provisions to eliminate problems with slamming, such as those that occurred with telephone service deregulation. He stated the ERCOT system would automatically send a customer a postcard when it is notified of a request to change service providers. If the information is incorrect, the customer simply returns the card to ERCOT and the customer is returned to his or her previous retail electric provider (REP).

Although the $12 million allocated to the customer education plan should be sufficient to complete the task, Chairman Wood emphasized that the scope and nature of the project is such that the money could be spent easily and quickly without accomplishing the goals of the program. "This is an appropriate budget, but it puts the onus on us to make sure that we spend every penny and then multiply it by 10 in free media." Chairman Wood said he expected statewide interest in electric utility restructuring to become more noticeable after the pilot program is well under way and becomes a more common topic of discussion.

Discussing technological innovations likely to play a role in how the Texas electric market is reshaped in coming years, Chairman Wood said, "The silver bullet for our state and for our economy is little bitty power." So-called micropower will likely serve commercial clients in the 100 to 1,000 kilowatt range. Such enterprises range in size from a fast-food restaurant to a large supermarket. The technology has come a long way, he said, and the economics of small-scale power generation are getting better. "I think this is probably what your successors and mine are going to be talking about ten years from now."

Chairman Wood said the PUC and TNRCC have been working very closely to make sure such innovation can thrive in the Texas market. Generally speaking, micro-generators are so small and efficient that they produce few emissions. They give a lot of power in the aggregate and they can give a very high-quality power. Many of the high-tech firms in Texas, such as silicon chip manufacturers, demand very high power quality. They depend on voltage being absolutely precise for all their instrumentation. Much of the self-generated power never gets on the transmission grid. It is consumed mostly on-site or nearby so it stays in the distribution network but is not transported long distances on the major transmission grid.

JEFF SAITAS, Executive Director, Texas Natural Resources Conservation Commission

Mr. Saitas updated the committee on the status of the State Implementation Plan (SIP) to meet Environmental Protection Agency (EPA) rules for air quality in the Houston/Galveston non-attainment area. Texas will submit its plan to EPA for approval in December 2000. The deadline to clean the air is November 15, 2007. With respect to the plan for the Houston/Galveston area, Mr. Saitas said speed limit reductions to 55 miles per hour are likely in much of the eight-county area. Other components of the plan include incentives for carpooling, local government energy efficiency efforts and expansion of Harris County's automobile inspection and maintenance program to the other seven counties in the non-attainment zone.

TNRCC has also proposed rules to ban the use of certain construction equipment during key ozone-forming hours. Mr. Saitas said construction activity is a "significant contributor" to the formation of ground-level ozone. Although industry participants informed the TNRCC that new, cleaner technologies are on the horizon, Mr. Saitas said the commission did not feel comfortable including new technology mandates in a rule because cleaner machines are not yet widely available. The construction ban is proposed to begin in 2005, and TNRCC will identify specific emissions reducing strategies in the interim. The ban will likely have a trade-off component, where high-emitting equipment — bulldozers, backhoes and other older, heavy equipment — cannot be used before a certain hour of the morning unless they are retrofitted with scrubbing technology to reduce emissions. Mr. Saitas made clear his policy preference that the ban be combined with incentives to eliminate the use of older equipment and supplant those pieces with newer, cleaner machines. This is especially important in the Houston area, where meteorological conditions reduce the effectiveness of later construction start times as an ozone-reducing strategy. During the worst parts of ozone season, lingering high pressure systems combined with coastal wind patterns simply recirculate the pollutants over the city to be warmed up and turned into ozone on the next day. "The preferred option there is that we actually move forward and find a program to actually physically and technically reduce the emissions. We don't need to be shifting them. We need to be taking them out of the air."

Other strategies mentioned by Mr. Saitas included the introduction of cleaner diesel fuels and accelerated purchases of new heavy-duty equipment and airport ground support equipment. Response from the City of Houston and Continental Airlines has been encouraging, and Mr. Saitas said an arrangement with Southwest Airlines would be completed soon.

Addressing Chairman Wood's points on micro-power, Mr. Saitas said the TNRCC is in the process of developing a standard permit for small distributed generation plants. This permit would simplify the process by pre-certifying certain classes of equipment at the manufacturer so that each piece of installed equipment does not have to be physically inspected. He added that the TNRCC would likely adopt rules to allow for check-ups to ascertain that the equipment is being maintained in such a way as to keep emissions within determined guidelines.

Mr. Saitas said there are federal issues associated with other pollutants that may have a cost impact on electric generation. Some degree of uncertainty still exists in the regulatory environment with respect to emissions standards for electric power generators, such as federally mandated reductions in mercury emissions from coal-fired plants.

JIM LESTER, representing air quality researchers at the University of Houston

Mr. Lester testified that the scientific community is "short on knowledge in terms of understanding the predictive nature of air chemistry." He said the Texas Air Quality Study 2000 currently underway in Houston is the largest study to date on the physics and chemistry of Houston air. However, he lamented that the data will not be collected, analyzed and available for incorporation into an area-wide plan until 2003, by which time a number of policies will already have been put in place in order to meet approaching policy deadlines. He termed this phenomenon the "crisis mode of management."

"Working in this crisis mode, I'm very concerned about unintended consequences of the regulations, in particular some [issues] about health problems that might arise," he said. "I worry about the safety of construction workers at night if they expand that time period. I am also concerned that we will have short-lived policies, that we'll be tweaking the thing frequently as we go along as the science comes into play."

With respect to the reliability of the air quality models used in the Houston area, Mr. Lester said, "These are the best models that we've got and we've got extremely good people working on them." However, the models fall short for the Houston area because they lack some data-specific entry point relevant to Houston's meteorology and climate. For example, small-scale sea breezes often cycle air over the city, out to the Gulf, and then back over the city and Gulf again until a strong weather front appears and moves the air out of the region. "So if you move the timing of the generation of NOx to the afternoon, it doesn't necessarily help move it out of the region. It can be with you the next day," he said.

Another point lacking in the model is in the accidental release of volatile organic compounds (VOCs), a primary ingredient in the formation of ground-level ozone in Texas, particularly in the Houston area. The high concentration of chemical plants along the coast leads to an increased risk of accidental releases of VOCs, which can preempt all the other chemical calculations made to achieve compliance with the EPA's ambient air quality standards. Population growth also represents a constraint on the model. "We're getting more people, more cars, new houses, new demands for energy. It makes it very hard to model."

Mr. Lester said he did not think the Houston area would be able to achieve compliance with the air quality standards by the 2007 deadline. The technological limits on industrial reduction were being pushed to the maximum, and it is not clear how effective such a push would be in the long term, especially given the likelihood of occasional accidental releases from Houston's heavy industrial base. Much of the possibility of meeting the eight-hour standard also rests with the weather. If a high pressure system parks over Houston on days with really high temperatures, no matter how effective the SIP, no matter what the rate of compliance, he said the city is still likely to exceed ambient air quality standards on a day like that.

Mr. Lester said he sees a lack of public involvement and education on air quality issues. "Without the regulatory hammer, in the environmental area, we have seen that public education has driven things like recycling, litter control and a variety of personal choices." There is no major effort to try to encourage people to shift from gas-powered equipment at their houses, change their driving habits or undertake any of a number of things that could reduce the emissions of NOx on a voluntary basis. Mr. Lester also said that strides are being made in the policy arena to retreat from a "command and control model" in which regulatory bodies make decisions without much public input up front. He said experience has shown that it makes more sense to involve stakeholders throughout the policy-making process.

GREGG COOKE and NED MEYER, Environmental Protection Agency

In response to Mr. Lester's critique of the urban airshed model used in the Houston area, Mr. Cooke explained it can be adjusted with new input. The cost of generating additional data will be born by the state, chamber of commerce, or other entity willing to finance such data collection. Mr. Meyer added that the only area of the country to produce major funding to update the model was California, both in the South Coast Air Quality Management District and in the San Joaquin Valley. Mr. Meyer said it would be prohibitively expensive to model an area as large as the eight-county Houston/Galveston non-attainment zone in the detail required to observe the effect of the land-sea breeze phenomenon mentioned by Mr. Lester. However, such modeling could be done just over the city proper, and then a less-expensive large-scale model would prove sufficient in the surrounding parts of the non-attainment area.

Mr. Cooke also noted that Tier 2 federal fuel standards for sulfur in gasoline take effect in 2004 and represent the biggest single reduction of NOx from mobile sources. Emissions from gasoline combustion represent 45 percent of all mobile emissions and 17 percent of total emissions. Without the adoption of cleaner burning fuels, Dallas and Houston would never make Clean Air Act standards, Mr. Cooke said. He said discussions with the TNRCC suggest they would prefer to speed up the implementation of new gasoline standards and diesel fuel standards. However, Mr. Cooke noted that industry opposition to the diesel fuel standards would likely be subject to lengthy litigation, and he predicted that a refined product may be even longer in coming to market.

ED FEITH, representing, Reliant Energy

Reliant Energy began a program to reduce NOx emissions in the Houston area in 1998. Reliant believes the plan is consistent with the requirements of SB 7, and it will be fully implemented by May 2003. Reliant's plan achieves an 88 percent reduction in NOx in the Houston area at a cost to the company of $512 million, Mr. Feith said. The draft Houston SIP requires a 93 percent reduction and other short-term limitations which present a problem for Reliant. It plans to ask TNRCC for some modifications to the draft rules to make them more workable.

Mr. Feith testified that each coal plant viewed as a candidate for environmental cleanup through the addition of retrofitted scrubber devices has different costs associated with the implementation of that technology. In the Houston area, such costs will average approximately $70 million per plant. At Reliant's lignite plant in East Texas, where the air quality standards are not as strict as those in the Houston SIP, the cost is approximately $26 million per facility.

Mr. Feith described the $512 million plan as a "no regrets" plan in which "every dollar and every project will be helpful. It will reduce NOx. It will improve air quality." Mr. Feith said achieving an additional 3 percent NOx reduction beyond Reliant's plan would cost an additional $200 million.

In response to questions from the committee, Mr. Feith said he could not reasonably estimate the threshold at which natural gas prices would make a new coal plant look attractive to investors. Such calculations are very complex and specific to the individual plant. Coal plants have certain regulatory disadvantages, longer construction times and larger physical plants that make them unattractive unless high natural gas prices appear to be a long-term norm.

STEVE KEAN, representing Enron Corporation

Mr. Kean agreed with Chairman Wood's previous testimony that California's problems are a simple issue of supply and demand. The market has responded with proposals to increase generation capacity, but California's siting process is lengthy and difficult. When San Diego experienced dramatic price spikes, 10 utilities stepped in to offer long-term contracts to stabilize their price structure, but the rules of the game in California prevented San Diego Gas & Electric from stepping outside the California Power Exchange to take advantage of those offers. "So their customers continue to face volatile prices from the wholesale market even though the market was more than willing and able to provide a solution to that problem," he said.

In Mr. Kean's opinion, the deregulated portion of California's market is working fine. It is the remaining regulations causing many of the problems faced in the summer of 2000. "Our customers, the people who signed up with us, the people who signed up, presumably, with other energy suppliers out there, they got a fixed price. It's at a lower rate than what people are paying in California today. We went out in the market and hedged that position. In other words, we bought the supply that we needed in order to serve our retail customers."

Mr. Kean also indicated that having access to a customer's metering technology would provide the information necessary to help the customer reduce peak demand or apply energy efficiencies in ways to lower the total electric bill, which should be a higher concern than simply locking in a low rate. Mr. Kean updated the committee on Enron's projects to contribute to cleaning Houston's air. Enron has subsidized Metro transportation. Enron's downtown headquarters building received an EPA

Energy Star award for energy efficiency. Enron is implementing pilot telecommuting programs for employees. The company's Bammell gas storage facility has been recently converted to use electric engines, reducing annual NOx emissions by 1,250 tons. Enron is taking advantage of SB 7 provisions calling for renewable energy capacity and is investing heavily in wind power.

Enron is also gearing up to trade emissions credits. "In emissions markets in the U.S., we are making markets in both SO2 and NOx. And the lesson there is that those programs, if they are properly constructed, do work," Mr. Kean said. "When you put market mechanisms in place, even to serve environmental objectives, they work. The dollars start to chase the absolute lowest cost solution to whatever the NOx problem is. And in that regard, I've got a couple of reservations about what we're dealing with here in the Houston/Galveston region. So far we're looking at a cap and trade program for NOx that is really limited to the eight-county area. It's been our experience that that is not a big enough area."

Mr. Kean also predicted that, although the reliability issue looks good today, at some point the Houston area is going to need new generation capacity and whoever comes into the market to supply that generation will need access to those credits. Today those credits are held by a handful of dominant market participants. Some possible solutions offered by Mr. Kean include expanding the eight-county area to include other upwind participants in the air pollution problem or setting aside allowances for new market entrants.

GEORGE BEATTY, representing the Greater Houston Partnership

Mr. Beatty noted that some counties included in the Houston/Galveston non-attainment zone do not feel they should be a part of cleaning up Houston's air, something they largely consider a Houston problem.

Whatever is done to clean the air, the Partnership is very concerned that regulations should not hinder the economic growth of the Houston area, or any of the non-attainment or near non-attainment areas in the state. Whereas with Reliant Energy, the SIP NOx reductions target about 60 EGFs, greater industrial restrictions would have an effect on more than 2,000 manufacturing facilities in the Houston area.

Mr. Beatty stated Houston businesses are willing "to do our share," but he said the federal government must do its share also by implementing Tier 2 fuel standards in a reasonable time frame. He also noted that the local community has no control over areas preempted by federal regulation, such as the Port of Houston, interstate trucking and George Bush Intercontinental Airport.

Appendix G:
SUMMARY OF TESTIMONY
September 26, 2000, Austin

CHARLES MATTHEWS, Commissioner, Railroad Commission of Texas

Commissioner Matthews addressed some of his concerns affecting the provision of natural gas to electric generation utilities and gas distribution customers. “The Texas natural gas industry must be healthy if Senate Bill 7 is going to be implemented successfully and electricity costs for Texas businesses and residential customers are to remain reasonable,” he said.

The Commissioner informed the committee that Texas produces roughly one third of all natural gas in the United States and has proven reserves of nearly 40 trillion cubic feet (tcf). Some experts predict yet another 325 tcf of reserves remain to be developed. However, he noted overall production in the state has declined by 2 percent per year since the market peaked in 1972.

Natural gas storage levels are down from previous years nationwide. The Commissioner said Texas will likely follow that trend. With high demand and prices, there is little incentive for producers to store gas. Non-utility electric generators are placing significant demands on the natural gas market. In Texas, the peak period of natural gas consumption has switched from the traditional winter months to July and August when electric generation is running at full capacity. Mr. Matthews advised the committee that new gas-fired generation in Texas will further impact the natural gas industry. Even if higher market prices lead to increased exploration and drilling activities, he expressed concern that Texas may suffer a shortage of skilled field workers.

JOHNETTE HICKS, A. R. KAMPSCHAFER, JOHNNY RAYMOND and DAVID OJEDA, JR., representing the Texas Association of Community Action Agencies

The four panelists testified as a group on issues related to the sufficiency of funding and administration of the System Benefit Fund (SBF). Member organizations of the Texas Association of Community Action Agencies currently provide energy efficiency and low-income ratepayer assistance programs with a combination of funds from the federal government (disbursed through the Texas Department of Housing and Community Affairs) and funds contributed by investor-owned utilities. When retail competition begins on January 1, 2002, the community action agencies will no longer receive funds from utilities. These funds are to be replaced by an allocation from the SBF. The panelists expressed concern that weatherization programs may not be funded at the level required to deliver services to everyone requiring assistance. Mr. Raymond said the SBF commitment for community-based weatherization programs should be $17 million. He said his organization had to turn down 426 families for weatherization assistance last year due to lack of funds.

Mr. Kampschafer said his organization spends an average of $1,500 per house in funds from utilities to supplement federal funds. Currently, only 50 percent of his organization's low-income clients are eligible for utility funds because the current rules require recipients to live in the service area of the participating utility. Mr. Kampschafer said the SBF provision for low-income rate reductions is important, but weatherization is more important in his opinion. Total energy bill reductions of 25 to 50 percent are possible by reducing energy loss.

PUC Chairman Pat Wood informed the committee that the SBF rule has been published for public comment and would likely be adopted in December. Chairman Wood said the present ambiguity in determining the funding level for each of the programs receiving SBF money stems from uncertainty in the number of payments required to school districts to offset property value reductions resulting from electric utility restructuring. If only one payment were required to offset initial reductions in property value, then the SBF fee would provide sufficient revenue for all four programs to be fully funded. If multiple annual payments to school districts are required, then other SBF programs may be limited because the fee is capped by statute. Chairman Wood said SBF funds should be available to provide the $5 million in funds the community action agencies currently receive from investor-owned utilities. It is unclear if the SBF will initially be able to support expansion of community-based energy efficiency programs at the level requested by the panelists.

ROY BAKER, representing the American Association of Retired Persons (AARP)

Mr. Baker addressed several ongoing rulemaking proceedings at the PUC. He expressed AARP's preference that uniform rules be required in term of service contracts and billing procedures to eliminate confusion in the retail marketplace. He supported granting allowing all customers the right to cancel any contract without penalty with 30 days notice. AARP survey data suggests older citizens are not likely to switch providers if they think such a decision will risk service reliability. Mr. Baker also stated opposition to the release of customer specific data to retail marketers without prior written consent of the customer.

LARRY OEFINGER, representing the Texas Rural Electric Coalition (TREC)

Mr. Oefinger informed members of the committee that, although his organization views high distribution costs as a barrier to successful competitive market restructuring, TREC will not pursue an amendment to SB 7 in the 77th Legislature on this issue. He then stated that the issue will be studied more fully by the cooperatives, with the stated goal of identifying a fair formula to implement an Equal Access Fund. At issue is the higher cost per meter to distribute electricity in rural areas because the number of customers per mile of line is low. Mr. Oefinger said he believes the issue of high distribution costs in rural areas is something the Legislature must deal with in a future session.

JOHN W. FAINTER, President, Association of Electric Companies of Texas (AECT)

Mr. Fainter opened his comments by saying that the industry is confident it will be ready for the retail choice pilot project on June 1, 2001, and full competition on January 1, 2002. “While other states, namely California, have encountered problems this summer, we believe, based on the progress we have made to date, that Texas’ model for competition in the electric industry will ensure that everyone benefits. We believe the current framework will provide consumers with competitive and affordable prices, preserve and enhance reliability and ensure fairness to all customers.”

An issue of concern for AECT regards the authority to disconnect service for non-payment. The association agrees current rules prohibiting disconnection, such as during extreme weather conditions, should continue to be enforced. However, if REPs are not able to disconnect a customer for non-payment, then losses sustained by REPs for bad debt will significantly increase.

Mr. Fainter next addressed rulemaking proceedings relating to the Provider of Last Resort (POLR). He said AECT recognizes the important function of the POLR in an evolving retail market. However, in order for the market to be truly competitive, this “universal provider” must be able to charge prices commensurate with the risk involved in serving an unknown volume and type of customer. At this time, he said, selection of the POLR for each area is expected to be achieved by auction. If the auction process does not go well and the PUC is forced to designate a POLR, it should do so at a price that reflects this non-traditional service. Mr. Fainter said it is not unrealistic to foresee a situation where a company serving as POLR might suddenly find itself with thousands of new customers at a time when the market price is high and the price to beat is insufficient to cover costs. For this reason, AECT hopes the final POLR rule will recognize this potential problem and determine that the affiliate REP cannot serve as POLR in its own territory at the price to beat.

The final issue addressed by Mr. Fainter was the rate of return on regulated wires investments. “At the heart of our concern is the erroneous notion held by some stakeholders that the regulated wires company will be a less risky business than the historic integrated utility and, therefore, can be given a lower rate of return in order to attract new capital. We submit that this will not be the case. In fact, the uncertainty of a new and largely untested market supports our contention that the new electric market structure may be more risky for the regulated wires company. Competition from self generation and the evolution of distributed generation will certainly work to undermine the stability of the wires utility.”

To attract capital into the transmission market, Mr. Fainter suggested the rate of return should be established at near-historic levels. The electric industry will continue to have high fixed operating costs and correspondingly high debt costs which must be supported by the regulated market with adequate return on capital, he said. The rate of return issue is linked to the ability of the transmission utilities to assure enough infrastructure exists to facilitate a robust competitive environment in which REPs can successfully operate.

CAROL BIEDRZYCKI, Director, Texas Ratepayer’s Organization to Save Energy

When SB 7 was debated, Texas ROSE was one of the few groups to formally oppose restructuring the retail electric market. Ms. Biedrzycki expressed concern about developments in California and other states where supply has been short and prices have risen. She offered a series of recommendations that can be implemented without reopening SB 7. “We believe it would be premature to amend SB 7 because the PUC has sufficient authority under the bill to control unpredictable problems. Most importantly, if we did change SB 7, we would not know how to change it. The bill and the market design developed by the Commission must be tested before we will know how it should be changed,” she said.

Ms. Biedrzycki said it has been difficult at times to coordinate all the activities planned by the agencies involved in SBF rulemaking procedures. She suggested maintaining the SBF as a general revenue fund is insufficient for the fund to function successfully. A general revenue account is too restrictive, dependent on biennial appropriations, and not allowed to carry over or accumulate funds. She said an amendment to HB 3084, 76th Legislature, is needed to delete the reference to the SBF in §9(b)(8) of that bill.

Ms. Biedrzycki said that all four programs supported by the SBF — the school funding loss mechanism, low-income rate reductions, low-income weatherization and customer education — should be fully funded and one should not be given preferential funding over another.

In particular, she was concerned that the low-income weatherization program may be viewed as a lower priority item in disbursement of SBF dollars. In addition to providing a safety net for low-income customers, she pointed out that many utilities are depending on savings from the weatherization program to meet the energy efficiency goals set forth in PURA §39.905. She also noted that the labor-intensive nature of the weatherization program served to provide a number of jobs for low-income people. She recommended a funding level for weatherization programs from the SBF of $17 million.

Ms. Biedrzycki said workable competition must include a market structure which convinces residential consumers to choose electric providers. “We are concerned about proposals made by the industry before the PUC that we believe will leave competition dead in its tracks for residential customers from the opening of the market. The industry is seeking changes that will confuse customers, increase their risk and inhibit competition.” Specific problems include industry proposals to force customers to sign long-term contracts and charge penalties for breaking the contract.

Ms. Biedrzycki said electric competition has been minimal in states that have restructured, especially in the residential portion of the markets. In California, only 1.8 percent of residential customers have switched. In Massachusetts, only 0.1 percent of residential customers have changed electric companies. Switching is usually concentrated in high-cost areas, she said.

"We support one set of customer protection standards. If terms of service are standard and the same as they are today, consumers can focus on price and make informed, confident decisions. When confronted with complicated contracts and a lot of fine print, most consumers will choose to do nothing. Competition could stop before it starts," she stated.

Ms. Biedrzycki said electric service providers should never be able to block a customer's switch and supported Mr. Baker's testimony that any customer should be able to cancel a contract without penalty with 30 days notice. "A customer's right to buy from another company is a powerful consumer protection. Tying customers into long-term contracts even if they are not satisfied with the service creates a captive market with no regulation," she said.

JANEE BRIESEMEISTER, representing Consumers Union

Although many of the problems experienced in California's transition to a restructured marketplace are the result of policies unique to that market, Ms. Briesemeister said there are systematic weaknesses in restructuring utility markets that have not been adequately addressed anywhere in the country. These include transmission systems to support a competitive market, increased corporate merger activity which reduces competition, the inability of small consumers to react to changes in price due to lack of information and inflexible demand, and the uniqueness of electricity as a commodity, such as its inability to be stored or substituted and the long lead time required for construction of facilities.

Ms. Briesemeister suggested market power remains a concern in the Texas generation market. The requirement that no generating company may own more than 20 percent of generation capacity is a feature unique in Texas law, designed to address market power concerns. However, market power can manifest itself in numerous other ways. For example, in California no generator is close to owning 20 percent of the market, yet several agencies are examining possible market power abuses there. Consumers Union welcomes the PUC's increased emphasis on monitoring these developments through the creation of a Market Oversight Division.

Consumers Union and others have been frustrated by the level of activity taking place outside the PUC at ERCOT and the difficulty in participating effectively at ERCOT. A lack of accountability of the ISO was one of the criticisms of the California market model included in a recent report prepared for Governor Gray Davis. Until a few months ago, Ms. Briesemeister said, ERCOT board meetings were closed to the press and the public.

Ms. Briesemeister also stated she was disturbed that the issue of reserve margins remains open in the ERCOT protocols. One side in the debate would have ERCOT set a reserve margin, others would let the market handle the reserve issue. ERCOT has traditionally required a reserve margin, a critical feature when unplanned outages occur. Reserves come into play when electricity is needed most and the opportunity to exercise abusive market power is greatest. "We do not endorse letting the market determine how reserves are handled," she said. "Obviously, there is a cost to acquiring a reserve margin, but there is also a cost to having no reserves."

Ms. Briesemeister raised concerns about the creation of Qualified Scheduling Entities (QSEs) through the ERCOT implementation process. These entities are not included or even contemplated in SB 7, she said. These entities have been created by ERCOT, not the PUC. Their role is to schedule power for competitive retailers. There has been some discussion that some entities intending to become QSEs do not intend to serve retailers serving residential customers, which creates another barrier to REPs wanting to serve residential customers. We recommend the PUC require QSEs to serve all types of loads. Because QSEs will charge for their service, additional cost will be added for market participants. The QSEs' fee schedules should be reviewed and approved by the PUC. Also, QSEs can be generators or affiliates of generators. The potential for anti-competitive conduct due to the affiliate relationship between a retailer and a wires company is precisely what the Code of Conduct in SB 7 addressed. The PUC should adopt a similar code of conduct for QSEs.

Ms. Briesemeister said stranded costs are the biggest issue affecting headroom for competition. The debate over stranded costs has shifted dramatically in just the past few weeks. Instead of debating how high the stranded costs are, customer groups and utilities are now arguing over how much of the already collected stranded costs the utilities should return to their customers, due in large part to the impact of high natural gas prices on the market. Consumers have already made a significant down payment on stranded costs through securitization, accelerated depreciation and the shifting of costs from generation assets to the transmission and distribution system. A top priority for Consumers Union will be to make sure consumers get the benefits of high gas prices reflected in low stranded costs. Where there is over-recovery, consumers must benefit. Otherwise, the high prices for generation will erode headroom for competition. If consumers and competitors do not receive the benefit of these high generation prices through reduced stranded cost charges, there will be little room for competitors to enter the market.

Ms. Briesemeister said the use of minimum term contracts with penalties for switching providers discourages consumers from shopping around. “We fear contracts could contain anti-consumer provisions in fine print or lock consumers into bad deals as the market opens, depriving them of benefits as competition develops,” she said. The potential benefit of a contract is the guarantee of stable prices. However, Ms. Briesemeister said current proposals on the table are all one way in that they involve penalties for consumers who break the contract, but none for the REP. The REP could change the terms and conditions of the contract, or exit the market, with notice to the customer only. Yet the customer could not exit the contact without incurring a financial penalty. “Large corporations hire attorneys to read contracts and negotiate deals for telephone and electric service. But consumers should not have to hire a lawyer to read a contract prior to purchasing electric service from a new competitor. It is the PUC’s job to make it easy for consumers to shop based on price and service by adopting a standard set of customer protections equivalent to those enjoyed today. If contracts are permitted they should be standardized, reviewed by the PUC and there should be equivalent penalties for both parties for breaking the deal.”