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EXECUTIVE SUMMARY

Most of the discussions regarding the restructuring of the Texas electricity market have focused on further deregulation of the power generation market. While 1995 legislation created the wholesale generation market, utility-owned generation is still subject to some regulation that arguably creates inefficiencies within that portion of the market. Proponents believe further deregulation of the generation market will entice new market participants and encourage all generation owners to operate power plants more efficiently to be competitive. In addition, the creation of a deregulated retail market (retail wheeling) could enable consumers to negotiate lower rates with suppliers and therefore take advantage of the efficiencies gained from competition.

In the model most often discussed during the Committee's hearings, customers would purchase their energy from *retail electric providers* (REPs). This service would include the costs of fuel and production of electricity. Ideally, a customer would be able to compare the prices of a number of REPs and choose the provider with the best energy services at the most affordable prices. A customer could negotiate a specific energy package based on a certain contract period, a minimum or maximum amount of usage, or any variety of other unique bargaining provisions.

REPs would deliver their power services over the transmission and distribution networks of existing utilities, which could bill for their services either through the REP or directly to the consumer. The transmission and distribution systems comprise the wires over which electricity travels from power plants to end-users. For the discussion purposes of this report, the wires companies of existing utilities are referred to as electric distribution companies (EDCs).

Most policymakers believe EDCs should continue to be regulated as natural monopolies. It would be highly uneconomical for competitors to duplicate these systems in a competitive environment. Continuing regulation of the delivery network monopoly would protect the public interest while assuring reliable and quality service.

However, a fully integrated company (one that controls generation, transmission, distribution and retail supply) could have a competitive advantage over REPs because of its exclusive control of the wires necessary to deliver power. In recognition of this possible abuse of market power, most advocates of restructuring recommend the unbundling of these systems in one of two ways. *Functional unbundling* would permit the separation of generation and transmission/distribution assets into affiliate companies of the utility. However, it would be necessary for a utility with a generation affiliate to grant open and nondiscriminatory access to its transmission/distribution network by power providers so they can deliver energy to retail customers on a competitive basis. *Structural unbundling* would require that utilities sell all of their generation assets and remain strictly independent of the generation and retail supply market (full divestiture).

Customers would continue to pay regulated rates for the delivery of power but would participate in an open market for energy needs. The arrangement can be compared to a customer's ability to choose long distance providers while maintaining service with his local service provider (though deregulation of the telephone market is now providing choice for local services as well). The following sections broadly discuss the restructuring issues associated with the model outlined above and direct the reader to chapters providing greater detail. Please note that Chapter One of this report introduces important electricity concepts necessary to understanding the restructuring sections of this report.

CREATING A NEW MARKET STRUCTURE

The most difficult challenge in restructuring the electricity market is ensuring that all of the market participants can benefit from the changes, including all types of customers, new competitors and existing industry players. Most importantly, customers cannot obtain lower prices and better services without having a sufficient number of providers to choose from. Any market changes must send a signal to possible competitors that the structure is conducive to fair competition. Likewise, any continuing regulation of existing market players must not be so onerous as to prohibit their ability to compete fairly.

Some of the important issues to be considered in this structure include provisions for the certification of REPs and other market participants, and methods for introducing choice to Texas consumers. Consideration should be given to how customers select their REPs, what kinds of information are exchanged between REPs and the regulated EDCs providing delivery of electricity, how services are metered and billed, and how disputes between customers, REPs and EDCs are settled. Texas must also consider whether it should encourage the development of the retail electric market by introducing or encouraging pool structures, spot markets or power auctions.

It is also vitally important that all customers remain served by at least one provider in a competitive world. Texas can look to other states that have created providers of last resort for guidance on this issue. In addition, Texas should consider providing the ability for consumers to aggregate on some level to leverage their buying power in a new market. Aggregation can be particularly beneficial for residential customers who use less energy and may be captive to a single provider.

Chapter Six discusses these market issues more thoroughly.

STRANDED INVESTMENTS

A critical issue for existing utilities is whether they will be able to recover the costs of older and more expensive power plants that may not be competitive in a restructured environment. because newer technologies permit the construction of cheaper generation. Utilities argue that they made many of their past investment decisions under regulation and based on a guarantee of customers for a very long period of time. The debt for these plants was amortized over the lifetime of the asset and is built into current regulated rates. If utilities are not allowed to recover these costs before entering competition, it is possible that the older, higher cost plants will not generate enough profits in a competitive market to pay off existing debt, thereby "stranding" those investments.

The debate surrounding the stranded cost issue focuses on several major issues. Should the state recognize stranded costs and guarantee their recovery in a competitive market? If so, how should these costs be quantified, how much should be recovered, which customers should pay for recovery and how should these payments be made?

Chapter Seven discusses these issues in greater detail.

MARKET POWER

Another important issue is whether a deregulated marketplace will contain market players with market power that may be counterproductive to competition. Market power can exist in several forms, including the ability to maintain market prices significantly above marginal costs for long periods of time, the ability to reduce marginal costs by using cross subsidies from regulated assets, the ability to discourage competition through control over distribution facilities and the ability to retain the energy business of captive customers of a regulated monopoly.

Market power is a difficult issue because it can be largely subjective and requires flexible policy goals. Chapter Eight defines three different types of market power (vertical, horizontal and incumbent) and provides an explanation of the most controversial aspects of market power: When does it exist? How is it measured? And most importantly, how can market power be mitigated without constraining the marketplace and discouraging competition?

CONSUMER ISSUES

Adequate consumer protections and information are important in assuring both a smooth transition to a competitive marketplace and enduring benefits for all types of consumers. The deregulation of the local and long distance telephone markets has provided policymakers with a wealth of information regarding possible obstacles and problems for consumers. This experience highlights the need for some regulation that addresses different issues including the designation of a provider of last resort, marketing guidelines to prevent the unauthorized switching of providers, unauthorized billing, fraudulent advertising and unfair disconnection practices.

In addition, due consideration should be given to the need for low-income programs. A more thorough discussion of consumer issues is addressed in Chapter Ten.

ENVIRONMENTAL ISSUES

Less than one percent of all energy produced in Texas is produced from renewable resources such as light, heat, water, biomass and methane gas. The technologies available to produce electricity from these renewable resources is still expensive to use. There is concern that a competitive market would provide further disincentives to produce such power until the price of renewable power is more competitive with that of other fuels.

Chapter Eleven discusses the emissions problems associated with nonrenewable energy sources as well as possible incentives that could be included in a restructuring plan to encourage the development of renewable energy. The chapter also discusses energy efficiency programs and the growing preference for "green energy" among consumers.

System Reliability

Restructuring may create some additional dangers in the reliability of the overall system. The management of physical transactions on the grid becomes more difficult as the number of market players increases. Also, the separation of transmission/distribution from generation may create difficulties since the company that delivers electricity would no longer be in charge of dispatching generation units to meet load requirements. More parties would be involved in assuring that the correct amount of generation is available to meet customer demand at any given time.

Fortunately, Texas can build on the progress towards maintained system reliability made by changes implementing the wholesale market. The 1995 changes to the Public Utility Regulatory Act (PURA) enabled the Texas grid, ERCOT, to establish an independent system operator (ISO) to assure nondiscriminatory access to the transmission system. Chapter Nine discusses ERCOT and the ISO in greater detail and explains possible changes needed to assure continued reliability in a restructured environment.

Tax Implications

Any restructuring plan should take into consideration tax consequences for state and local governments. Some of the taxes and fees likely affected include the sales tax, property tax, state franchise tax, state utility taxes and municipal franchise fees. Many of the effects are derived from the reevaluation of previously regulated assets and the overall change in industry structures. Chapter Twelve discusses tax implications in more detail and directs the reader to a special report produced by the Texas Comptroller.

CONCLUSION

Texas is at an important junction for a decision regarding electric utility restructuring. Electricity is perhaps one of the most important resources to the residents and businesses of the state. The ability to supply inexpensive and abundant power to all Texans is crucial to the quality of life and sustained economic development. Restructuring the generation, transmission and distribution of this valuable commodity should only be undertaken with the utmost caution.

Competition for electric power has the potential to benefit all Texans, but only if initiated with very careful consideration. All parties that would be affected by restructuring have presented well-reasoned concerns to the Committee. Many believe that some form of restructuring is inevitable. The inevitability lies in the concern that the federal government will restructure the market in the near future as it did with the local service telecommunications market. Most parties would prefer that Texas enact a plan tailored to its unique needs rather than accept blanket federal legislation that may not best serve Texans. Because Texas contains an interconnection grids entirely within its borders, it is well-positioned to make many restructuring decisions that would normally be made by a federal regulatory entity.

Some Texans are already seeing the benefits of restructuring in wholesale competition. Increased competition on the wholesale level has encouraged more efficient management of power generation, which in turn has helped reduce the rates charged to end-users. The challenge will be to build on this success by bringing competition to a level where customers can directly participate without sacrificing reliability. Additionally, any deregulation plan must ensure that some customers do not benefit to the detriment of others.

Regulation will still be present in some form to provide continued service quality and fair competition. The ERCOT ISO's role will increase in a newly restructured environment as it assumes the responsibility of managing and administrating power coming on and off of the grid. Consumer protections plans would have to be initiated to prohibit unscrupulous business practices. Codes of conduct between affiliated regulated and non-regulated companies would need to be considered to prevent unfair advantages in the marketplace.

Investor owned utilities, municipally owned utilities, and co-ops each have unique circumstances, but all have the same goal of delivering inexpensive and reliable power to their customers. Realizing this goal will mean probable compromises when it comes to their competing interests, but any plan put forward should not favor one group at the expense of another.

Finally, and perhaps most importantly, policymakers must recognize how important reliable electric service is to Texas. No restructuring should take place until assurances are obtained regarding continued service levels to which Texans are accustomed. Restructuring must offer Texans better service at competitive prices while ensuring fair participation by all market players.

The Committee submits this final report without specific legislative recommendations. Instead, the Committee hopes that this report, summarizing the major issues involved, can serve as an educational tool for policymakers in evaluating any restructuring plan proposed for Texas. The complexity of this issue necessitates a serious dedication to learning restructuring issues by all interested parties.

CHAPTER ONE

INTRODUCTION

OVERVIEW OF ELECTRICITY SYSTEMS

A basic understanding of the generation, transmission, and distribution of electricity is necessary in order to begin a discussion of deregulation of the electric utility market. *Generation* is the physical production of electric power. Electricity is produced by large generators powered by burning fossil fuels such as coal or natural gas, running water such as a river controlled by a dam, renewable sources 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 that contains a metal coil which spins within a magnetic field, creating a current of electricity.

Electricity is transported to consumers by use of *transmission* and *distribution systems.* Transmitting electricity involves sending it through high voltage wires and power lines so it can travel over great distances. Distribution moves the power from the network of transmission wires over to low voltage facilities and wires to customers. Electrical current flows similarly to water in a stream. Volts measure the strength of the flow. A volt is a unit of electrical force that measures the rate at which power is moving. Low voltage is like a slow and quiet stream, while high voltage is more like a waterfall. High voltage electricity is "stepped down" by a transformer to a lower intensity, where it can be distributed to customers. By the time electricity reaches a customer's home, it is more of a trickle than the raging river it was at the power plant. *See Figure 1.*

Current technology does not allow electric power to be stored in large quantities. This means that the power plant must have enough generating capacity to meet the peak needs of its customers at any given moment, 24 hours a day, seven days a week, even if some of that

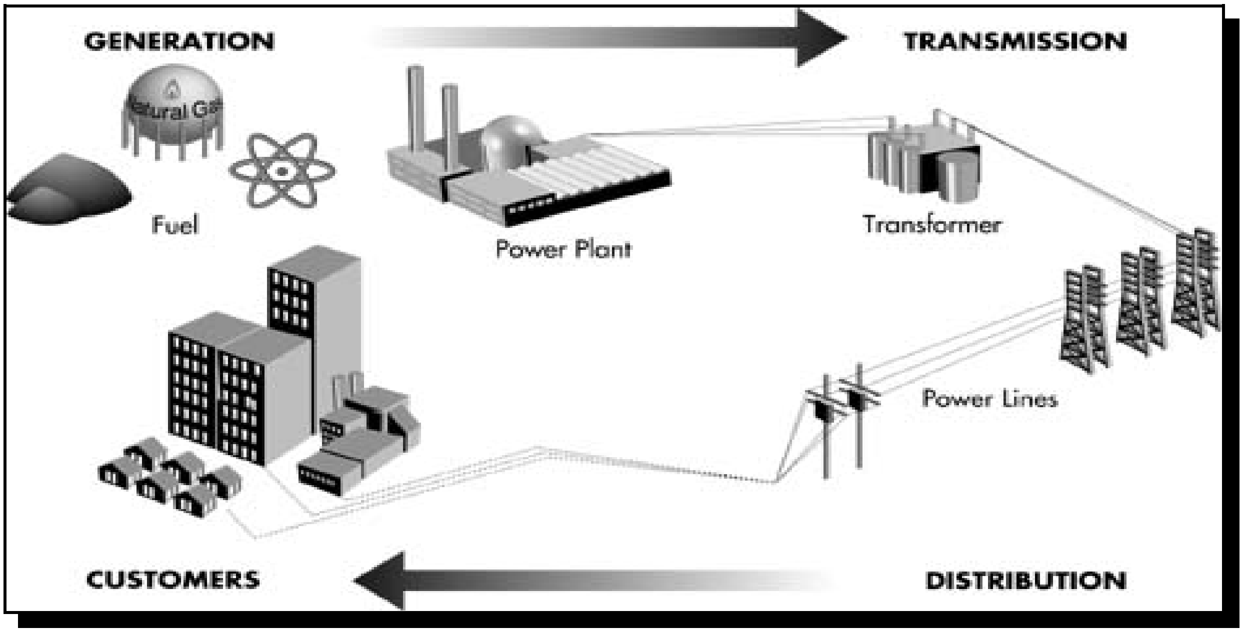

Figure 1 - Typical Flow of Electricity
Source: Alliance for Competitive Electricity

production capability sits idle until needed.[1] Generators can be started or stopped as needed to keep the flow of power continuous. As more power is demanded, more generators can be started. As demand lessens, generators are turned off to decrease costs of operation.

The average consumer is typically billed for kilowatt hours used. The watt is the basic unit of electric power, which measures the rate of work. A watt hour is an electric energy unit of measure equal to one watt of power supplied to or taken from an electric circuit steadily for one hour. A kilowatt is one thousand watts; a kilowatt hour is one thousand watt hours. To put these measurements in more familiar terms, one kilowatt hour is enough energy to light ten 100-watt light bulbs for one hour or run an average air conditioner for 15 minutes.

A megawatt is one thousand kilowatts, or one million watts. A megawatt hour is one thousand kilowatt hours, or one million watt hours. The output of power plants is typically measured in megawatts. Utilities serving large amounts of customers operate several power plants in order to generate enough megawatts to serve their operating areas. One megawatt is enough energy to power about 500 households.[2] As an example, Houston Lighting and Power calculates that an average home in Houston uses approximately 1,200 kilowatt hours a month.[3]

MARKET PARTICIPANTS

The Texas retail market is composed of three different forms of organizations that supply power directly to Texas customers: 1) Investor Owned Utilities (IOUs), 2) Municipally Owned Utilities (MOUs), and 3) Electric Cooperatives (Co-ops).

Investor owned utilities are typically owned by private investors and are operated on a for-profit basis, with publicly traded shares of stock. They serve territories granted to them by the states in which they operate. There are 10 IOUs operating in Texas, seven of which generate more than 85 percent of the state's electricity and service more than 75 percent of the state's electricity customers.[4] Examples of IOUs include Texas Utilities Electric and Houston Lighting and Power. *See Figure 2.*

Municipally owned utilities function as public works. Approximately 75 Texas cities and municipalities own and operate their electric utility systems rather than contracting with a private sector company.[5] They are publicly owned as branches of the municipal government. Typically, electric rates and utility policies are set by city councils and citizen boards and are not subject to direct regulation by the Public Utility Commission of Texas (PUC).[6] Examples are Austin Energy (City of Austin) and City Public Service Board (City of San Antonio).

Electric cooperatives are owned by the customers they serve. Member-consumers elect directors to govern the co-op organization, which operates as a non-profit entity to provide service to all members. The vast majority of co-ops are located in rural areas. Co-ops were originally formed to provide electricity to areas that were still without power which was widely available in urban areas. In 1936, the Congress passed the Rural Electrification Act which included the creation of the Rural Electric Agency (REA). The REA was designed to function as a lending agency for building electric generation, transmission, and distribution systems in rural areas not served by IOUs or MOUs.[7]

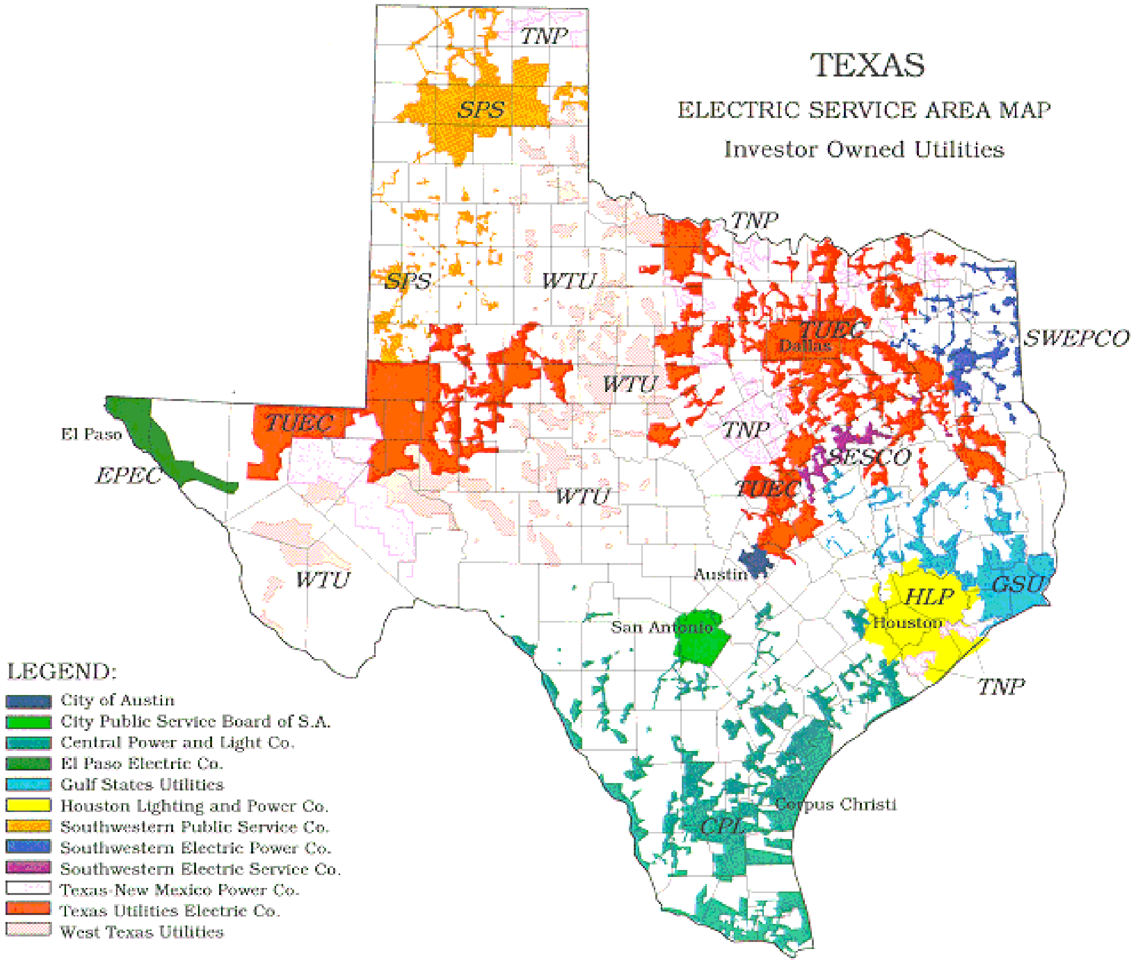

Figure 2 - Texas Electric Service Area Map
Source: Public Utility Commission of Texas

Today, more than 1,000 consumer-owned electric co-ops in 46 states provide service to 30 million members.[8] Texas co-ops serve a population of nearly 3 million customers[9] and are located in 245 of 254 counties in the state.[10] There are 11 generation and transmission co-ops and 74 distribution co-ops in Texas.[11] Examples include Bluebonnet Electric Cooperative and Victoria Electric Cooperative.

COMPOSITION OF POWER GRIDS

The United States is divided into three large grids or interconnections. A power grid is a system of interconnected generators and power lines. A power grid can be likened to a large lake with rivers of power flowing into it at some places from generators, and flowing back out of it at other places as streams as it is used by customers. The three large U.S. grids are the Western Interconnection, the Eastern Interconnection, and the Electric Reliability Council of Texas (ERCOT) Interconnection. Each grid connects to the others to a limited degree.

ERCOT is also one of the 10 regional councils that serve as members of the Northern American Electric Reliability Council (NERC). NERC was formed in 1968 to promote the reliability of the electric supply after a major blackout on the East coast in 1965. The regional councils are composed of electric industry members that actively seek to promote the reliability and efficiency of the interconnected power systems within their geographic areas. These non-profit entities develop reliability criteria and procedures while monitoring the compliance of their members. Some councils, including ERCOT, have independent system operators (ISOs) that administer the operation and use of the transmission system to assure non-discriminatory access by market participants. *See Figure 3.*

ERCOT contains approximately 84 percent of the electricity generated in Texas. Portions of East Texas are in the Eastern Interconnection and portions of West Texas are in the

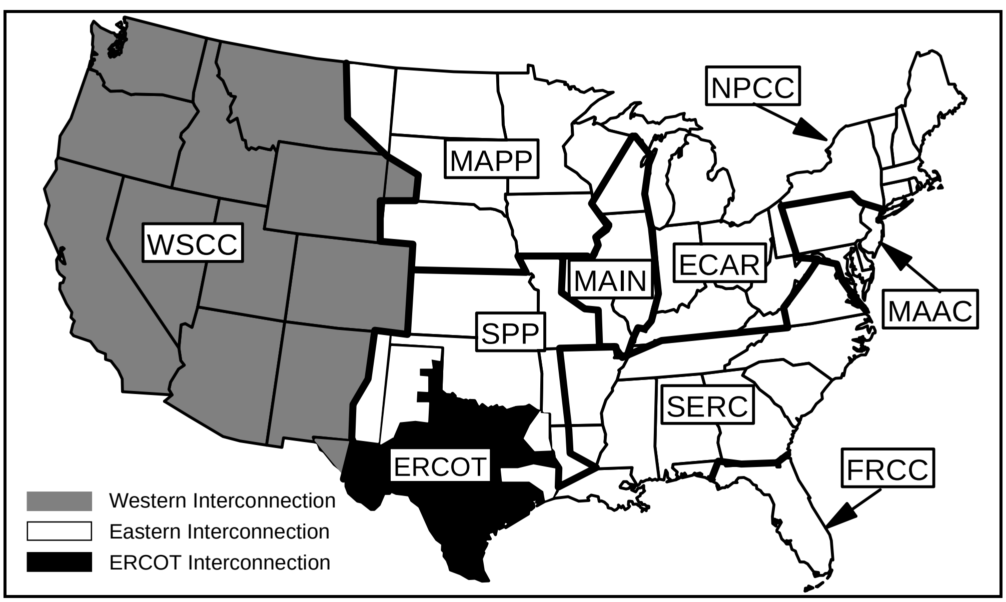

Figure 3 - U.S. Interconnected Transmission System
Source - Public Utility Commission

Western Interconnection. Texas is the only state that has operations in all three U.S. interconnections. ERCOT is unique in that it only operates in Texas, meaning that it is not subject to the Federal Energy Regulatory Commission (FERC). Instead, ERCOT falls under the jurisdiction of the Texas PUC. A more thorough explanation of ERCOT is contained in the Chapter Nine.

Several companies that operate in Texas are not located within the boundaries of ERCOT. Southwestern Electric Power Company (SWEPCO), Entergy-Texas (Entergy) and Southwestern Public Service Company (SPS) are members of the Southwest Power Pool. El Paso Electric Company (EPE) is part of the Western Systems Coordinating Council (WSCC). *See Figure 4.*

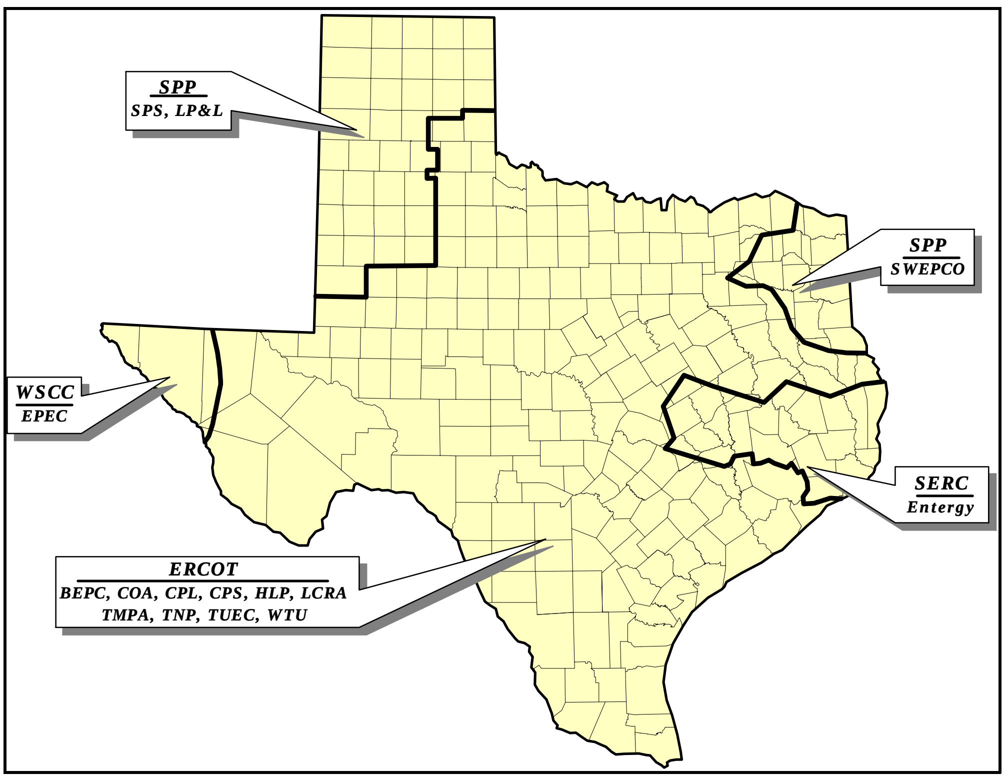

Figure 4 - Major Interconnected Transmission Systems in Texas
Source: Public Utility Commission

GENERATION CAPACITY IN TEXAS

The most recent data made available to the committee estimates that Texas utilities and non-utilities will have generated 277 million megawatt hours (MWh) of electric energy in

1998. IOUs own 71 percent of the statewide generation capacity; MOUs own 12 percent, river authorities own 3 percent, co-ops own 2 percent, and non-utility generators own the other 12 percent.[12] During 1998, the Texas electricity market had a net system capacity of 65,071 megawatts (MW) and experienced an aggregate 61,698 MW coincident peak demand.[13]

The amount of available generation capacity that exceeds the generator's firm peak demand is known as the *actual reserve margin*. ERCOT requires its members to maintain a minimum 15 percent *planning reserve margin* to ensure that the system can accommodate unanticipated outages or higher than expected peak demand.   In 1998, the actual reserve margin for the entire state was 12.3 percent while the ERCOT actual reserve margin was 11.5 percent.[14] However, if the interruptible load (the load represented by large customers who have agreed to have power turned off in peak demand times in exchange for lower rates) is not included in the calculation, the adjusted actual reserve margins for the state and ERCOT would have been 5.5 percent and 4.9 percent, respectively.[15] Actual reserve margins have been decreasing as expected demand has increased, older power plants have been retired, and as long-term requirements contracts have expired.

Power in Texas is generated from a variety of sources. The type of generation plant depends upon what area it serves. The PUC estimates that for 1998, the breakdown for installed generating power capacity by type of resource is 61 percent natural gas or oil, 15 percent coal, 14 percent lignite, 8 percent nuclear, and less than one percent for each of hydro, wind, and photovoltaic sources.[16] *See Figure 5*.

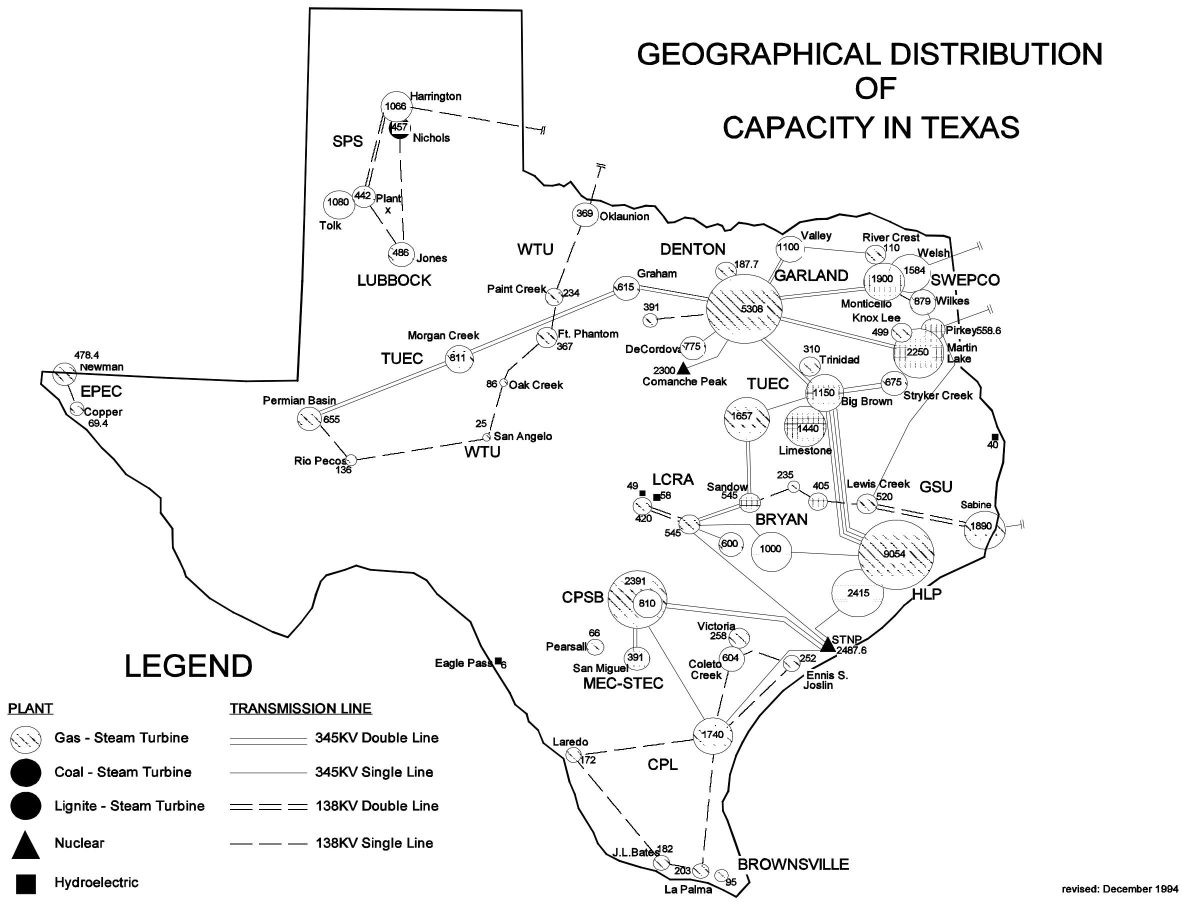

Figure 5 - Geographical Distribution of Capacity in Texas
Source: Public Utility Commission

TEXAS RATES

Electric rates in Texas are below the national average cost per kilowatt hour of power. Texas ranks 25th among states, with a statewide average of 7.76 cents per kilowatt hour (kW/h).[17] The national average is 8.36 cents per kW/h. However, with the extreme heat of Texas summers, Texas customers pay the fourth highest electric bills in the country, with an annual cost of $1063.12 for residential users.[18] The annual U.S. average is only $858.84. *See Appendix J.*

Rates within Texas vary across customer classes and different types of providers. On average, residential customers pay higher rates than commercial or industrial customers. This may be attributable to the high usage of more expensive peak power by residential customers. Industrial customers, which tend to use a constant amount of power throughout the day, typically have lower rates. Industrial rates may also be lower for those customers that are willing to take interruptible power.

These customer class rate trends hold true for most providers of electricity, though provider rates may vary according to unique factors including geographic location, extreme weather occurrences, customer density and power generation costs. For instance, distribution companies that serve rural customers may have to charge more for delivery costs because of the greater distances involved. Similarly, distribution companies in hurricane prone areas may have greater maintenance and repair expenses than other companies. Because of these unique circumstances it is difficult to make generalizations about the rates charged by different types of providers. *See Table 1.*

Table 1: Texas Average Retail Price by Customer Class by Utility Type, 1995 (¢/kWh)

Utility Type	Customer Class: Residential	Commercial	Industrial	Weighted Average
IOUs	8.04	6.81	4.73	6.60
Cooperatives	7.47	6.92	5.12	7.15
Municipals	6.92	6.66	5.69	6.42
Weighted Avg.	7.84	6.80	4.81	6.62

Source: Public Utility Commission - 1997 Scope of Competition, Vol. II, V-18. Average prices include total cost of electric services, including generation, transmission and distribution costs.

CHAPTER TWO

CURRENT MARKET STRUCTURE

FEDERAL REGULATION

One of the oldest sources of federal regulation in the electric industry is the Public Utility Holding Company Act of 1935 (PUHCA). PUHCA prohibited multistate utility holding companies from having holdings that were geographically diverse. The Act prohibited acquisition of any wholesale or retail electric business through a holding company unless that business formed part of an integrated public utility system when combined with the utility's other electric business. For example, a California utility could not own a utility in Texas, and vice versa.[19] The legislation also restricted ownership of an electric business by non-utility corporations, meaning that it acted as a two-way barrier: new companies not already in the electric utility market could not enter, and existing companies could not diversify into fields too far removed from their core business as utility providers.

Additional federal regulation is included in the Public Utility Regulatory Policies Act (PURPA).[20] PURPA requires utilities to buy electric power from private "qualifying facilities" at an avoided cost rate. This avoided cost rate is equivalent to what it would have otherwise cost the utility to generate or purchase the power itself. Most qualifying facilities are co-generators, those who generate their own power on their premises. Utilities must further provide customers who choose to generate their own power a reasonably priced back-up supply of electricity.

The most recent form of federal regulation comes from the Energy Policy Act of 1992 (EPAct).[21] The EPAct addresses a wide variety of energy issues including the creation of a new class of power generators, exempt wholesale generators (EWGs), which are exempt from the provisions of PUHCA. The Act grants the Federal Energy Regulatory Commission (FERC) the authority to order and condition access by eligible parties to the interconnected transmission grid. Essentially, these new generators can compete against electric utilities to supply electricity.[22]

Another function of EPAct is to require owners of transmission lines to allow any electric generator use of the lines to transmit power at an approved and published price.[23] This is an important step leading toward deregulation because utilities used to be able to control who had access to their distribution system of power lines. While this does not force competition, it does allow market forces to begin exerting their influence in a previously wholly controlled medium.

FERC

The Federal Energy Regulatory Commission replaced the Federal Power Commission in 1977 and was created in part to regulate interstate commerce in the wholesale sales and transmission of electricity. It also oversees various matters concerning natural gas, oil, hydroelectricity and related environmental activities. The five members governing FERC activity are appointed by the President and confirmed by the U.S. Senate.

In terms of electricity regulation, FERC approves rates for wholesale electric sales and transmission in interstate commerce. It also oversees certain financial transactions, including the issuance of stock and mergers, and collects financial reporting data by different market entities. FERC derives this authority from a variety of federal legislation, including the federal acts mentioned above

FERC has a lesser jurisdictional role in Texas because 84 percent of the electricity generated in Texas is contained within the ERCOT interconnection, which does not share boundaries with other states and has minimal ties to other grids. Therefore, interstate commerce in and out of Texas is largely limited to transactions outside of ERCOT and the very few transmissions and sales of electricity coming into and out of ERCOT. For Texas, this jurisdictional advantage means that policymakers have greater flexibility in implementing changes to the Texas electric market.

STATE REGULATION

While the FERC regulates interstate transmission and wholesale electric sales, the states reserve the right to regulate retail sales. The Texas Legislature established the Public Utility

Commission (PUC) in 1975 with the enactment of the Public Utility Regulatory Act (PURA). The PUC assumed regulation over electric and telephone utilities from traditional municipal regulation. “The mission of the PUC is to assure the availability of safe, reliable, high quality services that meet the needs of all Texans at just and reasonable rates. To accomplish this mission, the PUC shall regulate electric and telecommunications utilities as required while facilitating competition, operation of the free market, and customer choice.”[24]

All public utilities that sell power in Texas are required to apply for a certificate of convenience and necessity (CCN) from the PUC before they can sell power to retail customers.[25] This includes IOUs and co-ops. MOUs are subject to control by their local municipal governments, although many defer to the PUC for ongoing rate regulation.[26]

Changes made to PURA in 1995 allow electric co-op members to vote to deregulate the rates of the co-op without a review by the PUC on a reasonableness standard.[27] Co-op members are protected from arbitrary rates set by the board in that members may petition the PUC to review rates set by the board of directors of the co-op.

Most utilities in Texas have supplied power by acting as the sole agent for their customers, including generating, transmitting and distributing the power, and finally acting as customer service provider after the power is delivered.[28] The PUC terms utilities that provide all these services as “fully vertically integrated.”[29] Most co-ops do not fall into this category, as only 11 co-ops generate and transmit power, while 74 co-ops only distribute power to customers.

Utilities file tariffs, or rate schedules, with the PUC which list the prices for electricity that the utility will charge its customers. Typically, utilities undergo rate case proceedings where rates are set based on the cost of service provided plus a reasonable rate of return. These rates are applied to different customer classes using variables that allocate costs based on load patterns, policy considerations, historical precedent and other principles designed to ensure fair and reasonable rates. Charges on a customer’s bill will include a fixed monthly charge for connection and other services, a variable charge for energy usage base on kWh used, and a variable demand charge for certain non-residential customers which is based on kW demand.

The PUC also has considerable authority over the operations of utilities to assure that decisions are made in the public interest. Sections 34.021-34.022 of PURA require each utility to develop a plan to provide electricity at the lowest reasonable cost by using integrated resource planning (IRP). IRP is defined as a public planning process and framework to provide reliable power at the lowest reasonable system cost.[30] In determining the lowest reasonable system cost, the PUC considers direct costs, effects on various types of customers of fuel costs and fuel mix, and the cost of compliance with environmental regulations. Utilities file IRP plans with the PUC every three years that include a 10 year forecast of demand and the utilities' ability to meet it.

IRP plans must follow guidelines of the PUC and must include 1) an objective for providing reliable service at the lowest cost, taking into account customer bills, rates, future fuel costs, and appropriateness and reliability; 2) public participation from the customers served by the utility; and 3) competitive bidding using an all-source resource solicitation, meaning that the utility must integrate and consider all options for both power supply, including constructing new plants or buying power on the wholesale market, as well as power demand from customers.[31]

While regulation has resulted in a reliable electric system for customers, recent trends in both federal and state regulations have worked to bring about more competition in the generation market.

WHOLESALE COMPETITION IN TEXAS

Texas moved to a deregulated wholesale market in 1995 with the passage of SB 373 amending PURA. The amendments declares that "[t]he development of a competitive wholesale electric market that allows for increased participation by electric utilities and certain nonutilities is in the public interest".[32] The wholesale market allows power producers and marketers to compete against each other in supplying electricity to utilities that then distribute it to retail customers.

This change in PURA allowed non-regulated electric generators, known as *exempt wholesale generators* (EWGs), to sell power to regulated utilities. EWGs are independent of utilities and do not own any transmission or distribution systems other than to connect to the grid. Fair wholesale competition is assured by requiring nondiscriminatory access to the transmission grid for newly created EWGs.[33] Under PURA, utilities owning the network of wires that bring power to customers must give access to EWGs to deliver wholesale power.

The law also allows *power marketers* to buy and sell electricity on the wholesale market without owning generation or transmission/distribution systems. The PUC has registered 85 power marketers and 12 exempt wholesale generators in Texas as of November 3,1998.[34]

ELECTRICITY RATES

In a vertically integrated utility, the total cost of generating, transmitting, and distributing electricity is borne by the utility and recouped directly through cost-based rates charged to customers. As an example, the largest percentage of costs for a utility come from generation, which typically accounts for 72 percent of the cost of a kilowatt-hour (kWh). Transmission of the power may require 7 percent of costs, and distribution can account for the remaining 21 percent.[35] *Figure 6* uses a sample figure of 5.94 cents for one kWh of power. The actual costs for each utility may differ based on a variety of utility-specific factors.

Under the present system, electric providers serve all customers in their service areas with a few exceptions. Generally, electric customers come in five categories: 1) residential, which consists of homeowners and tenants; 2) commercial, including small businesses, small industrial plants, retail stores, and office buildings; 3) industrial, which includes large manufacturing plants and accounts for the great bulk of sales in some areas of the state; 4) municipal, which uses power for city facilities and services such as street lights, but also for resale to end user customers; and 5) other public utilities such as co-ops, other wholesalers, or retailers.

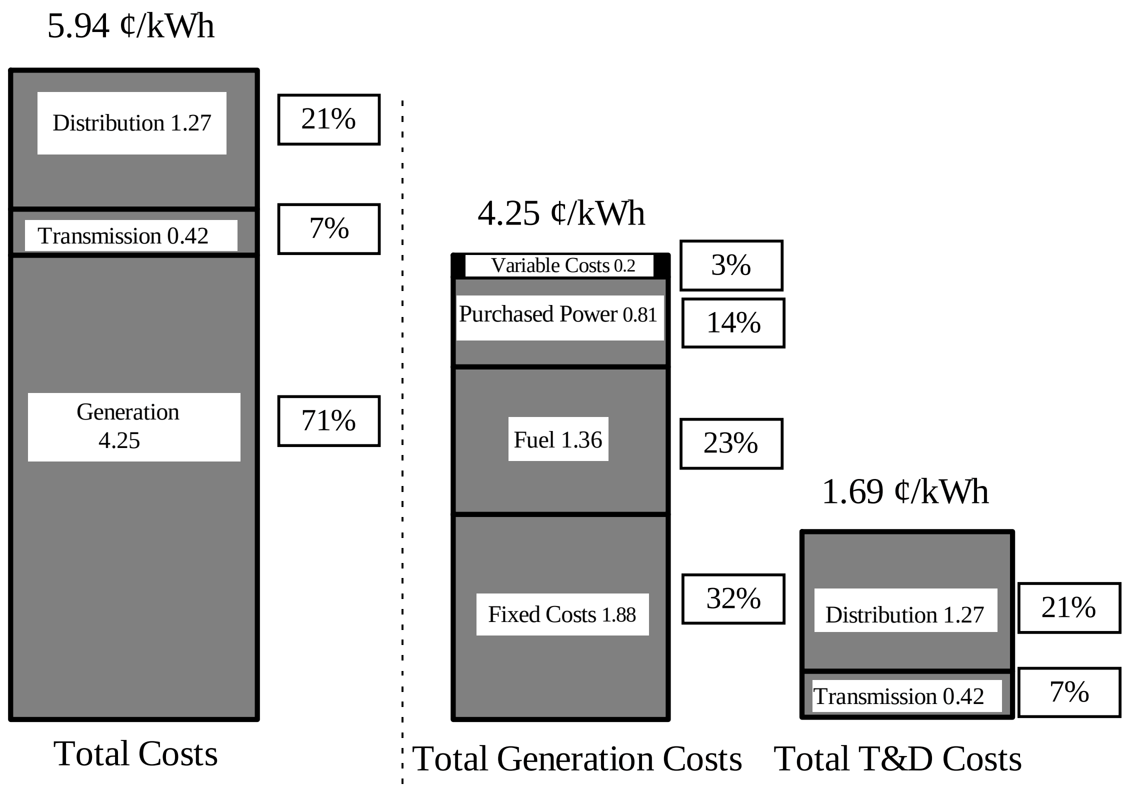

Figure 6 - Illustration of Integrated Components of Utility Costs in Texas
Source: Public Utility Commission

Each type of customer is charged a different rate, according to the cost of delivering the power and the way that customer uses the power. *Residential* customers' usage fluctuates, with the highest usage during the daytime, particularly when the heat of the summer months makes air conditioners work harder. Demand lessens at night when temperatures cool and electrical appliances are not in use. The same holds true for *commercial* customers which use more power when employees are at work during the day. Large industrial plants that manufacture other goods have different demands. Manufacturing has a steady need for large amounts of electricity, 24 hours a day, seven days a week. *Industrial* users typically have the lowest rates of all customers since their demand is constant and easy to forecast. The more consistent load patterns of industrial users means that the lower price of off-peak power is averaged into their rates, thereby decreasing industrial rates overall relative to residential rates.

Industrial customers can also receive lower rates from some utilities by agreeing to become interruptible customers, meaning that the utilities can interrupt or temporarily cut off the flow of electricity at peak demand times. The most common example is during the hottest part of summer when electric demand is at its highest. In order to continue to provide service to customers who pay higher rates for guaranteed power, a utility may temporarily halt the flow of power to an interruptible customer until demand lessens or additional power is made available by increased generation output from the utility or another wholesale provider.

SELF AND CO-GENERATION

Large industrial customers currently have the additional option of generating their electricity with their own facilities. Self-generators install their own production facilities to meet their energy needs. This is increasingly becoming a viable option for industrial users as the costs of small production facilities has become more competitive with utility pricing. Self-generation is also becoming more available for smaller industrial customers as low-capacity generating units have also become possible and more affordable.

For some companies, electricity may be a by-product of a manufacturing process that produces some form of thermal energy like steam or heat. These co-generators, such as chemical or petrochemical companies, can use the resulting steam to turn a turbine that generates electricity. Many of these operations are location along the Texas Gulf Coast.

Co-generators and self generators may sell excess power into the wholesale generation market. Under PURPA, co-generators can also serve as *qualifying facilities* (QFs) because they are not primarily engaged in the business of electricity sales. Under some circumstances, utilities are required to purchase available power from QFs that they would otherwise be obligated to generate to meet demand. A utility is required to pay an avoided cost rate for electricity purchased from QFs.

GENERATION MANAGEMENT

Power is delivered to customers over the power grid from generating stations. However, not all generators are operating at the same time. A typical utility company will have three types of generating plants:

Base load plants run at all times during the year except for maintenance. They typically have the lowest costs to operate and produce the largest amounts of power when compared to other types of generators. They can be powered by coal, lignite, or nuclear fission.

Intermediate load plants can be started in the morning hours to meet the increased demand during the day. They typically have higher operating costs than the base loads but are not always run on a continuous basis. They are typically fueled by natural gas.

Peak load plants are used primarily during the highest level of demand, which is approximately only 1 percent of the year. The units are typically less expensive to build than the other types but have higher operating costs. They are often fueled by natural gas.

A utility typically dispatches generation in order of the least cost generation to the highest cost generation until it meets the load requirements during any given time period. A utility may have contracts with other generation providers to supplement its load when demand is high, or may have agreements with industrial customers to temporarily shut off their power supply in exchange for charging a lower rate. Utilities carefully plan how they will meet load requirements using any number of techniques designed to maximize profits. Generation construction is planned based on the amount of power a utility predicts its customers will need in the future, plus a planning reserve margin.

CHAPTER THREE

THE PUSH FOR RESTRUCTURING

AN IMPETUS FOR CHANGE

Regulation of the electric industry was previously deemed necessary by both federal and state government in order to ensure economic growth and prosperity. As an essential element of commerce, governments took the position that electricity was too important a commodity to leave open to market forces. Electric companies operated in what comes closer to the definition of a natural monopoly than nearly any other industry. It was not efficient for competitors to duplicate transmission and distribution systems in order to provide an alternative to customers, and building generation was expensive and not viable without a delivery system.

Regulation was enacted to prevent electric utilities from overcharging customers, providing poor service, providing no service at all, or for any manner of practices that are possible in a monopoly. However, other industries that have been traditionally regulated as monopolies have been deregulated over the last few years. The most notable and recent examples have been the airline, telephone and rail industries.

A nationwide campaign for electric deregulation has been gathering momentum. At present, nearly every state has either already instituted some form of deregulation, is in the process of enacting legislation, or is considering it through legislative studies. The reasons for this push for deregulation are complex and intertwined, but can be broken down into a few general categories.

First, large energy producing corporations are looking for new markets for expansion. Electricity production is a natural extension for companies that produce a number of energy products, including petroleum and natural gas. Some companies are already competing in the telecommunications business by providing phone and Internet services.

Second, the successful deregulation of other industries has provided customers with different levels of choice and increased services they previously did not have. Proponents of electric restructuring would like an opportunity to see what innovations, such as different rates for different demand times, might occur in a deregulated market.

Third, a large factor in the push for deregulation has been a change in technology. Without getting into scientific jargon, newer power plants using a technology called combined cycle generation can be constructed for less money, burn fuel more efficiently, and produce more electricity than older plants.

Fourth, the Federal government has been considering action that would open the electric market to competition. The Executive Branch has developed a detailed plan for electric restructuring and many electric restructuring bills have been filed in Congress. While no action has yet occurred, it is believed by many that the issue will be one of major importance during the 106th Congress.

Lastly, and perhaps the most simplistic reason, is that many Americans like some kind of choice in selecting a service of any kind. The idea of allowing consumers to choose has a traditional resonance with both policymakers and voters alike.

RESTRUCTURING IN OTHER STATES

Texas has the benefit of studying the effects of electric deregulation in other markets before deciding whether to proceed with its own plan. Results have been somewhat mixed in the few state markets where deregulation is now in place. For example, California approved deregulation of its electric market in 1996 and allowed customers to choose their own electric providers beginning in early 1998. Even with the option to choose in place, customers have been slow to embrace it.

California electric rates are among the highest in the country by any measure. In August 1998, 1,000 kilowatt hours of electricity cost the average residential consumer in San Francisco $114.71, but the same amount of power in Austin was only $77.40.[36] Even with California's high rates, to date, less than 68,000 residential customers, less than 1 percent of the market, have elected to switch to new providers.[37] *See Appendix H* for a more thorough comparison of electric rates.

The California plan has been met with criticism from consumer advocates in its handling of stranded cost recovery. Stranded costs represent the money spent by utilities under regulation that may not be able recoverable in a competitive system.   Under California's deregulation plan, utilities were allowed to recover the great bulk of stranded costs, approximately $28 billion by some of the highest estimates, by assessing a competitive transmission charge (CTC) to pay down $10 billion in bonds issued by the three major California IOUs.[38] While customers can choose a new provider, their total bills are not necessarily lower because of the additional charges.[39] Consumer advocates argue that the California utilities were allowed to recover too much. Stranded costs are more fully discussed in a Chapter Seven.

Dissatisfied Californians placed Proposition 9 on the November 1998 ballot to undo some of the electric restructuring policies. Its purpose was to mandate a 20 percent rate cut and to prohibit electric companies from using customer revenue to pay down the cost of the bonds. Critics of Proposition 9 argued that if utilities were not allowed to recover through transition charges, taxpayers as a whole, beyond the customers of the IOUs and including those not currently liable for the bonds, could be saddled with the debt.[40] Proposition 9 was overwhelmingly defeated on the ballot.

Pennsylvania enacted the Pennsylvania Electricity Generation Customer Choice and Competition Act in 1996 which allows customers to choose their electric generation supplier. A key factor in determining the need to restructure the electric industry in Pennsylvania was the cost of electricity for its citizens. Pennsylvania's average electric rates are 15 percent higher than the national average. Rates for industrial customers, commercial customers and residential customers are 11th, 12th and 13th highest (respectively) in the nation.[41]

Under the Pennsylvania plan, transmission and distribution aspects of electric service remain regulated. Pennsylvania customers have a choice of generation providers while the company delivering power and providing customer service remains the same (their current utility). Customers remaining with their present utilities are guaranteed rate reductions, while those going to other providers can choose the lowest price offered to them and figure their final rate using a formula calculated by the Pennsylvania PUC.[42] Competition is being phased in over a two-year period with two-thirds of the state's electric customers able to participate as of January 2, 1999. The second phase begins in January 2000 and will include the remaining one-third of electric customers. Customers began enrolling in the Electric Choice Program in June 1998 when all Pennsylvania citizens received a postage-paid enrollment response package. As of August 1998, 1.75 million customers, or one-third of Pennsylvania's customer base, had signed up to participate. While California has few customers participating in switching providers, the Pennsylvania Electric Choice Program public opinion research indicates 95 percent of the citizens of that state are aware that they can or may soon be able to choose their electric supplier.[43] The "Electrichoice" program is generally viewed as highly successful in proceeding to a deregulated market.

Pennsylvania decided to allow recovery of some stranded costs through a charge on customer bills. This charge is a non-bypassable surcharge that customers are already paying on their monthly bills. The length of time utilities are allowed to collect the surcharge is limited and varies from company to company based on individual restructuring plans undertaken by each company. Generally speaking the surcharges will last about nine years.

In 1997 the eight major electric utilities in Pennsylvania began pilot programs which have provided Pennsylvania with a useful guide in developing its Electric Choice Program. While open to all electric customers, only five percent of customers from each rate class were selected by lottery drawing to participate in the pilot program which guaranteed a 10 percent savings. Response to the pilot programs was overwhelming as nearly 1 million customers signed up for 250,000 spots.

Texas is fortunate to be able to draw on the experience of states such as Pennsylvania and California. Indeed, there are many lessons already learned and pitfalls identified for future reference.

Activity on the Federal Level

Executive Branch

The Clinton Administration announced its proposal for competition and consumer choice in the electric industry in March 1998. The plan provides customer choice by 2003 but contains an opt out provision for states not wanting to go to a competitive environment. The plan also includes the following: support for stranded cost recovery; mandatory standards for service reliability; ISO control of transmission facilities; disclosure requirements for services offered by utilities to customers; establishment of a renewable portfolio standard to guarantee at least 5.5 percent of generation comes from renewable energy sources by 2010; economic incentives to cut energy wasted in fossil fuel generation; establishment of a public benefits fund for low-income assistance, energy-efficiency programs, research and development and renewable technologies; provisions for reduction of nitrogen oxide; and provisions to address market power.[44]

Legislative Branch

Over the last two years there has been a considerable amount of activity involving the electric industry in Congress. The 105th Congress introduced many bills to address retail competition in the electric industry. However, efforts to pass restructuring legislation by the end of the session stalled due to time constraints. Rep. Bliley, chairman of the House Commerce Committee, concurred with House Energy and Power Subcommittee Chairman Rep. Schaefer in his decision not to mark up any electric deregulation legislation in 1998. Several members have expressed support for making electric utility restructuring a priority during the 106th Congress. The following is a list of electric restructuring bills introduced during the 105th Congress:

1. Transition to Electric Competition Act of 1997 (Introduced in the Senate, S.1401 by Sen. Bumpers)
2. Electric Consumers Protection Act of 1997 (Introduced in the Senate, S.237 by Sen. Bumpers)
3. Electric Power Competition and Consumer Choice Act of 1997 (Introduced in the House, H.R.1960 by Rep. Markey)
4. Electric Consumers' Power to Choose Act of 1997 (Introduced in the House, H.R.655 by Rep. Schaefer)
5. Transition to Competition in the Electric Industry Act (Introduced in the Senate, S.2381 by Sen. Mack)
6. Electric Utility Restructuring Empowerment and Competitiveness Act of 1997 (Introduced in the Senate, S.722 by Sen. Thomas)
7. Consumers Electric Power Act of 1997 (Introduced in the House, H.R.1230 by Rep. DeLay)

8. The Power Bill (Introduced in the House, H.R.4715 by Rep. Burr)
9. Federal Power Act Amendments of 1997 (Introduced in the Senate, S.1276 by Sen. Bingaman)
10. Comprehensive Electricity Competition Act (Introduced in the Senate, S.2287 by Sen Murkowski)
11. Electricity Consumer, Worker and Environmental Protection Act (Introduced in the House, H.R. 4798 by Rep. Kucinich)

CHANGING ATTITUDES IN TEXAS

The current state of the electric industry allows wholesale competition between suppliers, but no direct retail competition for end users of electricity. The most recent report on the industry[45] has shown that wholesale competition has resulted in lower rates among those providers that have negotiated new contracts for supplying them with power. By allowing entities such as co-ops and other power wholesalers to select a provider based on service and price, power providers were placed in competition with each other for the first time. This structure led to rate reductions in a manner that most businesses engaged in competitive bidding have been accustomed, with the contract being awarded to the lowest bidder.

Proponents of retail competition would like to bring this same structure to the end user retail market, with residences and other small businesses selecting the provider that will deliver reliable power at the lowest cost. Potential advantages are reduced electric rates, choices for buyers, better service response, and a more attractive environment for attracting and retaining businesses. Under one scheme, retail competition would operate by “unbundling” the different areas of electric service. Customers would be able to negotiate with a different provider for each of the major areas of electric utilities: generation, transmission, and distribution. Proponents argue that the current regulated monopolies are mired in inefficiency in trying to offer all areas of service instead of specializing. If service is unbundled, providers can serve customers more efficiently by outsourcing or subcontracting with other entities.

Opponents of a deregulated system are concerned that smaller customers, especially residential users, will actually pay higher rates. They believe that large customers will be able to leverage even lower rates, which may leave smaller customers to make up the difference in lost utility revenue. Proponents argue that large customers are already bypassing the system because they are able to self generate or are paying utility near-cost rates. They argue that restructuring will give residential users the opportunity to band together to attain similar bargaining positions.

Co-ops are concerned that REPs may not be interested in serving low-volume rural customers. They argue that co-ops were originally formed because utilities did not have an incentive to serve these distant customers. Co-ops and other current providers are also concerned because their existing power purchase contracts were negotiated based on an expected load that may not exist if larger customers are picked off by competitors. They worry that they will not be able to recover the costs of the contracts in the wholesale market, and many co-ops aren't necessarily interested in competing outside their service territories since they are not profit driven.

Environmental concerns are also a factor, with the possibility that the cheapest electricity will be produced by older, coal-fired plants that have exemptions from emission standards. In addition, power producers may have little incentive to build renewable power in an unregulated market because of the current higher costs associated with renewable technologies.

Other potential pitfalls of a deregulated system would be similar to those experienced in the telecommunications industry, such as the unauthorized switching of providers (slamming), additional unauthorized charges on customers' bills (cramming), and unfair marketing tactics. There is also the potential that low-income customers may have difficulty in obtaining service, and the PUC may not have the authority to prohibit disconnections during dangerously hot months.

Most importantly, deregulation could jeopardize the safety and reliability of the current system without adequate safeguards. Moving to retail transactions may be problematic for system operators, particularly if service quality standards are not enforced and adhered to by all market players.

Changing attitudes in Texas can also be seen at the PUC. The lower costs associated with wholesale competition and movement toward electric restructuring has presented unique opportunities for the PUC as it reviewed rates. The following section describes regulatory activities that have occurred regarding utility rates and potentially strandable costs.

TRANSITION PLANS

Since the close of the 1997 legislative session, the PUC has addressed rate cases in a manner that recognizes the possibility of retail competition. The PUC has recognized that several factors have contributed to declining costs which present an opportunity for rate reductions. Efficient generating technologies and wholesale competition are among the many factors involved.

In light of this new environment, Texas Utilities Electric Company (TUEC), Houston Lighting and Power (HL&P) and Texas New Mexico Power (TNMP) have all come to settlement agreements on rate cases. These rate cases, or "transition plans" as they have come to be known, were negotiated between the utility, the PUC and numerous interested parties. While the individual agreements vary, the primary benefits of the agreements are rate reductions for retail customers ranging from 1 to 4 percent during 1998 and 1999 and accelerated recovery of assets that are potentially unrecoverable in a competitive market (potentially strandable costs).[46]

HL&P and TUEC

While the HL&P and TUEC transition plans are separate cases, they are similar in outcome. HL&P residential customers received rate reductions of 4 percent in 1998 and 2 percent in 1999. Small commercial customer rates were cut by 2 percent in 1998.[47] TUEC residential customers received rate reductions of 4 percent in 1998 and 1.4 percent in 1999. Small commercial customer base rates were reduced by 2 percent in 1998 and all other TUEC customers were granted rate reductions of 1 percent in 1998.[48]

Under the HL&P and TUEC agreements, all expenses that would have been credited to the depreciation reserves for transmission, distribution and general property will instead be redirected toward production property (generation facilities). Both agreements also contain a mechanism to allow earnings in excess of a predetermined cap to be applied as additional production depreciation.

Another provision of both agreements includes utility support for future legislation that would introduce retail competition. If an electric restructuring bill is passed that implements retail customer choice later than December 31, 2001 then it is up to the discretion of the PUC as to whether redirection of depreciation will continue in 1999. However, if retail competition occurs on or before December 31, 2001, then the redirection of depreciation would continue as agreed.

TNMP

The TNMP agreement departs from the HL&P and TUEC agreements in three key ways. First, depreciation of generation is accelerated as opposed to redirection of transmission and distribution depreciation. Second, earnings above a set earning cap are applied 50 percent to additional generation depreciation and 50 percent to customer rate reductions. Third, TNMP has volunteered to implement retail choice for its customers by January 1, 2003. HL&P and TUEC have only promised to support certain retail competition legislation in 1999. According to the final order, base rates of TNMP residential customers were reduced by 3 percent in January 1998, and will be again in January 2000 and in January 2001. Commercial customers received reductions of 1 percent over the same timeline.[49]

RATE CASES

CP&L and Entergy Gulf States

Central Power and Light and Entergy Gulf States underwent rate cases that more closely resembled classic rate case scenarios. The CP&L case originated from a request by the utility for an 8 percent base rate increase. The CP&L rate case was decided by the PUC in October 1997 and resulted in a $100 million cumulative reduction for retail customers over three years.[50] The PUC accelerated the depreciation on the estimated cost over market (ECOM) portion of CP&L's nuclear investment which included a reduction of the return on equity for that portion of invested capital.

The PUC issued its final order in the Entergy Gulf States case in October 1998. This case was extremely complex and very contested. The general outcome of the case was a net base rate decrease of approximately $69 million per year from June 1, 1996, to May 31, 1999.[51] The final outcome of the Entergy Gulf States case resulted in an accelerated amortization schedule for regulatory assets and significant refunds and rate reductions for its retail customers.

DISCUSSION OF COMMITTEE'S WORK

After receiving the charge from Lt. Governor Bullock, the Committee conducted an organizational meeting to explore general restructuring issues and to propose a schedule of hearings for more thorough study. The Committee conducted five more hearings throughout the state, each focusing on certain elements of discussion: market issues (Amarillo), environmental issues (Austin), MOU and cooperative issues (Grapevine), stranded costs (Victoria), and system reliability (College Station). Consumer issues were addressed at each of the meetings as they related to the specific issues being studied.

Each meeting began with one or more invited panels of experts designed to present information in a question and answer format with discussion amongst all of the panelists and the Committee members. Public testimony was then held to encourage constituents and individual parties to articulate their concerns and opinions.

The following chapters discuss in more detail the issues associated with restructuring. Most of the information is based on public testimony received at the Committee's hearings and represents the differing views of a wide variety of participants. The purpose of this report is to provide an informative summary of the many issues raised by policymakers and interested parties.

CHAPTER FOUR

ELECTRIC COOPERATIVES

Electric cooperatives (co-ops) were created in areas that were not served or were underserved by utilities. Citizens in these areas, typically rural, joined together to form a member-owned utility to provide power and other services directly to its members. Co-ops are owned by the customers they serve and are usually governed by a board of directors chosen by the cooperative members. There are 74 distribution co-ops and 11 generation and transmission co-ops in Texas.

Electric co-ops bear a higher cost of distributing power to customers than utilities serving urban areas. Customers of co-ops are spread out over a wider area, meaning that more resources such as wires and poles must be used to reach all users. On average, there are five customers per mile of distribution line in Texas. Because of the sparsity of rural populations, co-ops must bear the burden of higher costs and capital investments with fewer customers to share in these costs.

Co-ops provide service to approximately three million Texans in all but two counties. The primary concerns expressed by co-ops regarding electric restructuring are ensuring that rates do not increase and maintaining reliability. Co-ops fear that the small number of customers in rural areas combined with the low usage requirements by residential customers means that there may not be enough profits to encourage new providers to serve these areas. In addition, co-ops have general reliability concerns about restructuring and specific concerns that other providers may have difficulties locating customers for meter-reading or may not be able to provide assistance during power outages.

Most co-ops currently serve an aggregation function for their members which has given them the purchasing power to negotiate better rates with generation providers. This has resulted in the purchase of long-term contracts which were negotiated based on load forecasting under a regulated environment. Co-ops may face excess supplies over demand if their membership is able to choose alternative suppliers. Many believe this would represent a "stranded investment" in much the same way regulated utilities consider some of their contracts potentially strandable. In addition, it may be difficult for co-ops to compete for new customers given that they are not profit driven and are usually not interested in serving customers outside of their geographic areas. While co-ops could sell this excess power on the wholesale market, any losses incurred would have to be borne by their remaining members.

The most commonly proposed solution to prevent cooperative losses is to allow co-ops to join competition at their own pace rather than having the state impose choice on co-op members. This would give co-ops more time to plan for competition while allowing them to continue to serve the aggregation function for their members. A co-op could join competition by either a vote of the membership or a vote of the board of directors. Another proposed solution may be to allow limited choice for co-op members to guarantee that a co-op has at least as much load as it is committed to under contracts for power.

The co-ops have organized an industry restructuring task force to consider ways to make restructuring work for their customers. Based on the deliberation of this task force, the co-ops have taken a position that restructuring must benefit all its consumers before they can support it. Due to previous experience with deregulated industries in rural areas, co-ops want to ensure that service for its customers will improve. An example of the impacts of a deregulated industry in rural areas that is commonly used is that of the airline industry. Many feel that with the deregulation of airline service came a decline in the number of airlines and flights serving rural airports. Co-ops are wary of deregulation without assurances that service in rural areas would improve and grow.

Co-ops are quick to point out that they will support electric restructuring if it provides a better way to provide electric service. They are suggesting a model that recognizes the unique circumstances of cooperative utilities.

CHAPTER FIVE

PUBLIC POWER

Municipally owned utilities (MOUs) serve 15 percent of the retail electric customers in Texas. The 75 cities with MOUs in Texas are often represented by the Texas Public Power Association (TPPA).

Subject to only limited regulation by the PUC, MOUs are primarily governed at the local level. TPPA believes that the current system of allowing local control for MOUs has been successful and should be kept in place. The TPPA advocates maintaining local control of MOUs because of the adequate safeguards provided by locally elected public officials who manage a system publicly owned by the people it serves.[52]

Local control translates into the ability of city councils or citizen boards to participate in, examine and make decisions regarding different aspects of the utility. This may include planning, ratesetting, power supply, resources, service quality, etc. MOUs also advocate local control to determine when a municipality is ready to open its systems to competition. By providing electric services as a municipality, cities are able to derive efficiencies which help provide other public services for their citizens.

Some cities depend on the sale of electric power to finance city expenditures such as emergency services, parks and recreation, and transportation. In a competitive environment, municipalities served by an MOU would run the risk of losing customers to private companies thereby reducing a city's source of operating capital. This scenario could lead to an increased burden on those customers who choose not to leave the city utility, as well as possible property or other tax increases to make up the difference in lost revenue. Some cities, such as Garland, have undertaken the process of making its general fund less reliant on utility revenues as a major funding source.

TPPA has stressed the importance of treating customers fairly. This means ensuring that all customers of an MOU benefit from any type of electric restructuring. A fundamental issue to treating customers fairly and ensuring quality service is reliability. TPPA has a longstanding policy that “reliable electric service must be assured in any competitive market.”

Along with fair treatment of all customers, both large and small, the TPPA seeks to preserve the financial integrity of those entities that own their local electric providers. Public debt for construction of power facilities is secured by electric revenues. If cities are unable to pay for already issued bonds, financial ratings for city debt could fall, making it more difficult for cities to obtain future financing at favorable rates. TPPA has stated that estimates as to the amount of potentially strandable investments are probably in excess of $1 billion.

An important issue faced by MOUs is the treatment of tax exempt financing in the future. MOUs have historically been able to issue tax exempt public debt to finance facilities. According to temporary rules released in early 1998 by the Internal Revenue Service (IRS) addressing Federal Tax Code private-use restrictions, MOUs are provided some latitude as the move toward competitive power markets continues. In certain instances, MOUs will be able to participate in competitive environments without jeopardizing the tax exempt status of financing for up to three years.[53] The rules also set certain limits on the issuance of new tax exempt bonds by MOUs to finance additional electric utility facilities to compete in a restructured market.

Some MOUs financed their utility investments in combination with other public improvements (i.e. combined debt to fund local electric and water utilities). This means that it would be difficult to isolate these tax exempt bonds in order to comply with public use rules when moving to a competitive market.

CHAPTER SIX

MARKET STRUCTURE

Developing a market structure for a deregulated generation market that includes retail wheeling involves many important issues. Ideally, a restructured market would include a number of market participants working to provide electricity at competitive prices. Generation owners would meet market demand for electricity through the operation of power plants efficiently managed to minimize production costs. These owners could sell their energy to power marketers, aggregators, other generation companies, *retail electric providers* (REPs or suppliers) and even directly to some consumers. A generation owner could also have an REP affiliate which becomes the point of contact with customers.

All commodity sellers need access to transportation mechanisms to deliver their product to consumers. In the case of electric power, that transportation mechanism includes a network of transmission and distribution lines that deliver power from generation plants to the end-user. This network seldom includes more than one set of transmission and/or distribution lines in any given geographic area because these areas have typically been singly-certificated under regulation and because it would be very expensive to duplicate the necessary infrastructure. For this reason, it is commonly recommended that the transmission and distribution systems continue to be regulated as monopolies. For the purposes of discussion in this report, these entities are referred to as *electric distribution companies* (EDCs). They might also be affiliated with generation producers or REPs, depending on the structure established by policyholders.

Each power provider will have to estimate and purchase the amount of power its wholesale and retail customers will need on a continuous basis. The many transactions by different market players will have to be scheduled and managed to make sure there is enough aggregate power on the grid on a real time basis to meet demand. Customer usage will have to be accurately measured by reliable metering services so that the actual amounts used can be reconciled with the amounts scheduled. This reconciliation would then have to be sorted out in a settlement process among the market participants, each of whom may have miscalculated load requirements.

Meanwhile, REPs and *aggregators* will be vying to win customers by actively marketing services and proposing different pricing mechanisms. An aggregator is an entity that increases the purchasing power of customers by bringing them together to buy electricity in bulk. The aggregator may charge an administrative fee for it's services, but by and large is not assuming risk in the electricity market. A customer that chooses a new provider must be assured of a smooth transition to the new provider without service interruptions or delays. The new providers must be able to access metering information to accurately estimate the load factors of its customers in order to be successful in the marketplace.

Adequate consideration must be given to a variety of issues to ensure that market structures are conducive to the process outlined above. Some of these issues include methods for addressing the unbundling of services, nondiscriminatory transmission/distribution access, metering and billing, interconnection, selection of providers, market development and the introduction of competition.

UNBUNDLING

The market structure most often discussed at the Committee's hearings involved the unbundling of the generation, transmission and distribution systems of vertically integrated companies. Some form of unbundling is necessary to assure open and nondiscriminatory access to the delivery infrastructure by non-utility generation owners and power providers.

Unbundling would involve the separation of the functional units of a vertically integrated utility into separate, affiliated companies (functional unbundling) or into completely independent companies (structural unbundling). Unbundling would separate generation assets from transmission/distribution assets, and may even separate other functions such as billing and metering services. Functional unbundling is a preferable alternative for IOUs because the sale of assets by utilities under structural unbundling can carry heavy federal income tax consequences. Utilities also believe they should be able to continue owning their assets as long as independence can be assured. Transferring assets to an affiliate helps minimize any possible tax burden while instituting some level of independence between the affiliates.

Functional unbundling is more difficult for regulators because it necessitates oversight of the interactions between affiliate companies. Attention should be given to how an EDC treats its generation affiliate or REP affiliate to assure that preferential treatment is not given over other competitors. In addition, there is a legitimate concern that cross subsidies could exist between the regulated utility and the generation or REP affiliate. For example, a generation affiliate might be able to use office space and equipment owned by the EDC, which would pass those costs through to ratepayers. This could result in lower overall costs for the generation company which would give it a competitive edge in the market.

Another concern about affiliates depends on whether the EDC has direct access to the consumer and how it might use that relationship to influence the customer's decision to use its affiliated REC. There is also concern that an EDC would be able to provide competitive information to affiliates regarding future energy needs of its customers, such as the need for energy related services.

The PUC may be more prepared for these issues as it has been wrestling with similar issues in the deregulation of the local telephone market. It proposed affiliate rules earlier this year which, while never adopted, were a good starting point for discussions.

NONDISCRIMINATORY TRANSMISSION/DISTRIBUTION PRICING AND ACCESS

Without question all of the participants in the Committee process agreed that nondiscriminatory pricing and access to the delivery network is essential in creating a truly competitive environment. This process has already begun in Texas with the deregulation of the wholesale market in 1995. Because of the uniqueness of ERCOT, the Texas PUC has been able to promulgate transmission access rules and pricing mechanisms for the Texas wholesale market (FERC regulates this in other grids). Texas would need to establish similar guidelines for distribution access and pricing.

ERCOT has already established an ISO to independently manage portions of the grid. With further deregulation, it may be necessary to give more technical capabilities to the ISO to guarantee system reliability and open access for competitors. An increase in the number of participants and transactions in a retail market could be confusing if not properly managed by an independent party. The ISO or another independent party would have to assure that generation meets load requirements. This entity would have to be given the authority to buy power if contracts do not match load. System dispatching functions are currently handled by utility control areas which also make certain transmission planning and repair decisions. The ERCOT ISO could take over these functions from utilities to guarantee reliability and open access.

An important issue in this debate is whether to increase the independence of the ISO by including consumer representation and possibly other market participants on the ERCOT board. The inclusion of residential, commercial and industrial consumer representatives would assure that customers' interests are represented in all decisions impacting the marketplace. Also, the PUC or ERCOT must develop a method for allocating the costs of the ISO so that all market players are assessed fairly.

The non-ERCOT areas pose a more difficult challenge in assuring nondiscriminatory access. The FERC has jurisdictional control over transmission issues in these areas. Furthermore, these areas are part of larger grids which encompass other states, requiring their cooperation to establish an independent system operator.

Many participants in the Committee process believe that a market test should be established to determine whether non-ERCOT areas are subject to competition. This market test would include requirements for nondiscriminatory access and pricing which could be satisfied with an adequate independent system operator, regional transmission organization (RTO), or complete structural unbundling which would separate transmission/distribution systems from generation owners. Any Texas legislation would have to recognize these issues and set up the appropriate alternatives.

It is imperative that systems issues be worked out before the date of actual competition. California had to delay the start of competition for several months because its ISO and power exchange were not ready. Texas can learn from these experiences and may be able to anticipate problems and properly estimate its ability to open the market.

METERING AND BILLING

Metering

Metering data is used both to bill customers for energy usage and to accurately forecast load requirements in order to maintain the reliability of the electric system. The ability to accurately estimate future load requirements is an essential element in efficiently managing an energy portfolio of generation capacity and financial contracts. In a competitive market, both the wires company and power marketers will need metering information. The question is, who should have control of the information?

Currently, the utility serving the customer owns or controls the equipment used to transmit and meter the amount of power being used. In a vertically integrated company, the metered information is used to bill the customer directly for energy usage and is used to maintain the reliability of the system. Utilities use this information to form hypothetical load shapes, which are used to estimate the correct amount of electricity needed to be produced by the company's generation plants or provided by power purchased on the wholesale market.

Metering services can be unbundled and made competitive, similar to the structure in California. Depending on the structure of a new environment, several market participants may need the metering information. The marketplace, through an independent entity, will have to settle up the differences between how much actual power is used and how much was produced or purchased by all of the different market participants at a given point in time. Some utilities have also argued that control of the meter is necessary to maintain contact with the customer and handle system outage problems or other network related problems.

REPs and power marketers need metering information so they can more accurately estimate the load requirements of their customers. Many power marketers believe the metering function should be competitive so suppliers can use whatever kind of meter best fits each individual customer. They argue that technology innovations enable them to offer customers discounts and packages based on time of day use. They also argue that this information should remain proprietary to the customer's exclusive energy provider.

Careful consideration should be given to the possible benefits of improved metering technology. Advanced technology is already available and can be used to provide more accurate usage measurements. Cellular technology allows the electronic transmission of metering information as often as needed to enable real-time pricing of electricity. Real-time pricing allows customers to pay less for off-peak hours rather than paying for averaged rates. In addition, the enhanced information available through new metering technology could improve the ability of marketers to accurately forecast the load requirements of their customers, thereby maximizing profits and lowering prices. Another important benefit of cellular meter-reading includes the automatic detection of electric outages. This, too, can lead to improved service for customers.

Metering services could be broken down into several components, one or all of which could be considered competitive. Metering services include installation, maintenance, reading and transmittal of metering information. It is important to the market as a whole that the metering information be accurate and independently verified in some manner for the settlement process. Usage disputes between all of the market participants, including customers, are bound to occur.

Billing

Another important component of restructuring includes the billing of customers and other market participants. If unbundling occurs, a decision must be made as to how all of these services should be billed. Should the customer get billed by the providers of each service, or should services be billed through one provider? It is also important to remember that billing of services will occur among the market participants. The ISO or the entity handling system dispatch will need to bill power marketers for energy used by their customers that was not provided by the marketer (if the marketer underestimates load) and will need to pay marketers for any power that was used by other customers.

Policymakers should weigh the benefits and costs of billing policies for all market participants. First of all, it may not be cost effective to require that each market participant have its own billing function. Ultimately, these costs would be borne by the customer. For example, the customers of MOUs typically get one bill for distribution, energy, fuel, gas, sewage services and even garbage disposal. The efficiency gained by one billing mechanism should be considered.

Second, multiple bills may be confusing for customers, especially if bills are not adequately explained. Customers would need a clear understanding of each service in order to justify each bill. Third, it should be remembered that a bill is the point of contact between providers and customers. This is especially important for competitive services. A customer should be able to easily identify who is providing what services, especially if problems with a service occur. Billing should provide adequate information to customers about how to resolve service and billing complaints.

Billing can also be a competitive service. Billing can be provided by independent companies that have experience in developing billing systems. Some retail suppliers may use the distribution company to bill for their services, or vice versa. In this case, it may be important for there to be nondiscriminatory pricing for billing services if provided by a regulated entity. There is also a concern that a regulated entity may use its billing ability to direct business to its energy affiliate.

INTERCONNECTION REQUIREMENTS

The ability for market participants to interconnect with each other for physical and financial transactions is critical in nurturing a competitive environment. For example, once a customer chooses a new retail electric provider, this information must be communicated to the party responsible for metering as soon as possible. Otherwise, the former provider of electricity will continue to be liable for that customer's use of energy. In addition, the new provider must have quick access to information about the customer, including service location and load history. Some suppliers argue that they should have access to personal customer information maintained by the distribution company.

The development of computer systems designed to process thousands of transactions is a long and tedious process. The computer systems of each retail electric provider must be able to communicate directly with the ISO, power suppliers and marketers, the distribution company, the meter operator, billing systems and any other participant maintaining necessary information. Any discrepancies in the name, type, size or location of data fields can seriously affect exchanges of information and delay the provision of services.

Fortunately, the Texas experience with deregulation of local telephone markets is providing considerable information on the complexities of electronic data interface (EDI) systems. The PUC has been overseeing the development of EDI systems between telephone competitors and is probably best prepared to oversee such development under a restructured electricity market. However, policymakers considering restructuring should give adequate consideration to the conflicts involved in EDI development and the time it takes to resolve them. Policymakers may also want to provide guidance to regulators about the confidentiality and proprietary nature of certain kinds of information.

SELECTION OF PROVIDERS

An important transition issue concerns how current customers of a vertically integrated utility choose their REP. With functional unbundling, the question arises whether these customers would automatically be considered customers of the energy affiliate without affirmative changes to new providers by customers. If so, it can be considered an incumbency advantage since it is expensive for new providers to market to and gain customers. One way to mitigate this advantage would be to require the affiliate provider of customers that did not make affirmative choices to charge a regulated rate. Another would be for the state or another entity to aggregate these customers and solicit competitive contracts to serve their loads.

The state could institute the selection of new providers (instead of transferring the customer to the utility affiliate) in a variety of ways. Providers could be assigned through a lottery system which randomly selects voluntary REPs for customers who have not made a choice. Alternatively, the PUC could provide each utility with a list of providers that the utility would use to assign providers to customers on a rotational basis. Another approach would be to have the state or the utility be the aggregator for all of the customers that have not chosen by putting out bids to the market for power on a competitive basis.

With structural unbundling, a decision would have to be made as to which companies would provide electricity on the first day the market opens since the utility would not have an affiliate REP to be the default provider. Again, customers could be randomly assigned or provided power through aggregation.

More importantly, the state would have to make a policy decision as to who would serve customers that are unable to find an REP to serve them. Some customers may be refused service for having bad credit histories or for not having payed a bill to their current provider. There is also some concern that low energy usage or remote customers would have trouble obtaining services because they are more difficult to serve. Decisions must be made as to whether a provider of last resort should be designated that cannot refuse service. The state may also want to mandate how much this provider can charge. In addition, careful consideration should be given to disconnection practices as the lack of electricity can be potentially hazardous for customers during very hot or cold weather.

DEVELOPMENT OF MARKETS

The market mechanism used to bring buyers and sellers of energy together for wholesale and retail transactions is another important consideration in the restructuring debate. It should be noted that these financial transactions are not always directly linked to the physical movement of power. Electricity travels by displacement, so that electrons from generating plants in a particular area, depending on transmission constraints, are co-mingled and used in aggregate by all of the customers in that area. The coordination of physical transactions is discussed in the chapter on system reliability and is mentioned in this chapter in the sections on transmission access and interconnection. This section discusses the market procedures for conducting financial transactions.

In general, financial transactions can be accomplished either through direct bilateral contracts between buyers and sellers, through some sort of centralized pool structure or a combination of both. Each would allow wholesale and retail transactions, though retail transactions under a pool structure would probably only be feasible for large end-users.

A bilateral contract model allows two parties to contract directly with each other for a variety of products and services. Utilities, generators, marketers, brokers, suppliers, aggregators and customers would contract with each other in a number of different combinations and under uniquely negotiated terms. This model would allow market participants to tailor contracts to the specific needs of buyers and sellers alike. However, one of the disadvantages to this type of model, if used exclusively, is that it would be difficult for policymakers to obtain the data necessary to monitor the market for abuses and abnormalities. While a highly competitive market may not need this sort of oversight, this data may be more important in the early stages of competition where fewer competitors and larger market shares among them may increase the potential for market power abuses.

A pool structure, sometimes referred to as a “poolco,” creates a central mechanism for matching supply bids with demand bids in the marketplace. In general, a pool operator establishes the market price based on the highest cost of power bid for the supply necessary to meet demand during a predetermined block of time (i.e., on the half hour, hour, day, etc.). The pool operator would set the market price and would either order the dispatch of the power needed for that block of time (if also controlling the grid) or communicate that information directly to the grid operator(s). The pool operator would also process the financial transactions between buyers and sellers.

A pool structure may emerge naturally as a short-term wholesale market or be encouraged or created by policymakers. As stated earlier, a pool structure can be combined with a bilateral contract model. If a pool is developed officially, policymakers would need to determine whether the pool is voluntary or if sellers and buyers are required to funnel a certain amount of their business through the pool. For instance, policymakers may require that generators sell a certain amount, or all, of their capacity into the pool. These decisions are ultimately dependent on the structure and market policymakers are attempting to foster. The unique design of a pool structure may encourage or discourage the entry of new competitors, could improve or worsen market power problems, or have any variety of consequences for the market depending on how it is structured.

Some critics of pool structures have argued that a pool which is established to be the sole coordinator of all power sales cannot exist in practice because contracts for differences will emerge between market players. This type of contract allows a buyer and seller to negotiate energy prices contingent on either party making side payments to account for the difference between the negotiated price and the market price. Contracts for differences have emerged in the restructured British electric system where almost all generated power must be bid into the central pool. Essentially, contracts for differences allow buyers and sellers to hedge the market by speculating on the market price and agreeing to pay or receive the difference from the actual market price. This contract can almost be described as insurance for both parties and is similar to a futures contract.

The market mechanisms used in creating a restructured electricity market should be designed with the goals of encouraging competition and efficiency for the benefit of all participants. While residential customers would likely engage in direct contracts with only suppliers or aggregators, they will ultimately also be affected by the design of a wholesale market.

INTRODUCTION OF COMPETITION

Some states and countries have either created pilot projects, phased-in choice for customers over a period of time, or both. Moving to a retail market is a significant step that requires a lot of planning and cooperation among a multitude of participants. Pilot projects and phase-in programs allow the testing of systems on a smaller scale before the introduction of competition to the entire market.

Pennsylvania used a pilot project and a phase-in program to study market procedures and to assess customer reaction to the new environment. These smaller steps enabled the state to make changes to its procedures before the restructuring program was rolled out on a larger scale. A pilot or phase-in program can occur by selecting a specific geographic area for early competition or by permitting a certain number of each customer class to participate in advance. Pennsylvania implement a pilot program by choosing a subset of each customer class. Britain's phase-in program introduced competition in stages, starting with the largest users first.

It should be noted that while these programs can offer significant advantages, they also require a great deal of effort and may pose unanticipated problems. Pennsylvania found that some industrial and commercial customers were concerned that the ability of a competitor, for example a company in the manufacturing sector, to negotiate lower electricity prices as a member of a pilot program. Pennsylvania had to take this issue into consideration when choosing which customers would be able to participate in its phase-in program.

Fortunately, Texas has the advantage of being able to learn from the experiences of other jurisdictions like Pennsylvania, California and Great Britain. Texas policymakers can evaluate the lessons learned in these other areas and make a determination whether pilot and phase-in programs would be beneficial for its customers.

CHAPTER SEVEN

STRANDED INVESTMENTS

Moving to a deregulated electricity market cannot proceed without addressing the issue of whether to allow the recovery of *stranded costs* of utilities, and if so, to find an acceptable and accurate form of measuring them. Under previous years of regulation, many utilities constructed plants based on older, less efficient technologies. In the 1970s and early 1980s, when it appeared that fossil fuel prices would continue to increase in price, expensive nuclear power plants were constructed to provide an alternative form of energy that did not depend on foreign suppliers. These older plants now generate power that costs more to produce (if you include remaining capital costs) when compared to newer and less expensive plants using modern generating technology. Other types of plants may be in a similar predicament because the generation industry is mostly a declining cost business.

In a regulated electricity market, utilities charge rates that guarantee a return on their investments to retire costs of constructing power plants and transmission/distribution infrastructure. Regulation guarantees that utilities can slowly pay off the debt of these older and more expensive plants over the life of the asset. However, in a competitive and less regulated market, newer and more efficient power plants may be able to set a market price for electricity below what the older plants can minimally charge. The older, higher cost plants may not generate enough revenue to cover debt service, thus “stranding” the investments made in them.

Additionally, utilities entered into long-term contracts to buy and sell fuel or power at a time when prices for the fuels of natural gas and coal were more expensive. These long term commitments may result in costs that are higher than the market value of the contracts. Some parties also argue that older plants must be retrofitted or upgraded to comply with current environmental standards and will not be competitive with newer, cleaner plants. Stranded assets may also include regulatory assets which, for example, include the offset of initial construction costs that were guaranteed by regulators to be recovered in the future. These costs are typically carried as assets on the utility's balance sheet, but are not recoverable in a competitive environment since the assets have no actual value.

Each utility has different amounts of potentially stranded costs, while others have negative stranded costs and some have none. There are different reasons behind the stranded investments of each company. Some have large amounts of nuclear generation while others have uneconomical long-term contracts with power providers. Some companies even claim stranded costs for their fossil units due to retrofitting costs for environmental purposes. It is also important to remember that other market participants, such as co-ops and municipally owned utilities, may have stranded costs which would be borne by their members instead of a typical shareholder.

Recovery of stranded costs is one of the most divisive areas in the discussion of whether to deregulate the market. Large IOUs are seeking to recover costs of plants that were constructed because previous legislation on both the federal and state levels mandated alternative energy sources. Their position is that past investments were made in a heavily regulated environment that found those investments to be reasonable and prudent. They argue that some of their past investments were disallowed by regulators at the time and that those costs were not included in past rates and will not be included in stranded costs.

The obligation to serve means that utilities have a regulatory pact obligating them to make certain investments for their customers. They believe their shareholders are entitled to recover these investments made in good faith. In fact, their position is that anything less than 100 percent stranded cost recovery would constitute an illegal taking of property by the state. This constitutional argument could be set forth in a court proceeding if a utility does not agree with policymakers on the amount of stranded cost recovery.

Some consumer groups oppose any stranded cost recovery, or support less than 100 percent recovery. They argue that IOUs should be responsible for poor investment decisions or at least share in the responsibility with consumers. And several interest groups argue that allowing utilities to recoup these costs, especially if the amount is overestimated,

will give them a competitive and unfair advantage in the new marketplace. Opponents believe that IOUs should bear the costs of deregulation as was done by other industries that were restructured.

Addressing stranded costs is difficult for other reasons beyond the policy question of whether they should be recovered. There are controversies surrounding how stranded costs should be determined, how they should be recovered and who should be responsible for assuming those costs from the IOUs.

QUANTIFICATION

Different approaches exist for determining the amount of investment that could potentially be stranded. Both *market-based* and *administrative* methods compare the value of plants in a regulated versus a deregulated market. Policymakers must also decide whether they will determine these costs before or after the start of competition.

Market-Based Methods

In this method, the actual market price received by a utility from a sale is used to calculate the value of the plant or other asset for stranded cost recovery. Proponents of this method argue that the best way to determine a plant's value is to let a free and independent purchaser arrive at a purchase price with the seller in an arm's length transaction. Each party would negotiate a price based on its best interests.

IOUs argue they should not be required to sell their assets to gain entry into a competitive market. They believe an administrative method with proper true-ups in the future can be just as reliable as a market-based method without the sale of assets. In addition, the sale of assets can have significant income tax consequences for the seller.

Some market-based alternatives do not require complete divestiture of generation assets. For instance, a utility could transfer an asset to a separate holding company and then sell stock based on those assets. Policymakers would have to decide how much of the stock should be sold and what selling price should be used to calculate the value of the assets (because of variable stock prices). Many utilities are more willing to use this approach than full divestiture because it allows them to continue to own part of the asset.

A possible disadvantage to using a market evaluation is that there is not an opportunity for a true-up in the future. A market-based evaluation based on investor decisions does not necessarily set the best price for an asset. Investors are placing a value on the asset based on their estimates of how the market will perform for the life of the asset, as much as 20 or 30 years into the future depending on the asset. They could be making estimates that turn out to be largely inaccurate. This poses a risk for the investor and for whoever ultimately pays the stranded costs. An administrative mechanism may also make inaccurate guesses but allows for a reconciliation at least sometime in the future while the stranded costs are still being paid.

In addition, a market evaluation of nuclear assets is difficult because of the amount of risk involved. The Nuclear Regulatory Commission continues to regulate nuclear facilities for safety, nuclear waste disposal and decommissioning methods. Estimating the costs associated with compliance of such regulations is difficult. It is also difficult to transfer ownership of this type of an asset.

Administrative Methods

An administrative method uses models, forecasting and other analyses to arrive at a value before sale. Those in favor of this method assert that it will take many more factors into consideration, such as regulatory assets that may not be calculated under a market evaluation method. There are basically two different approaches for administratively estimating stranded costs. The top-down approach values the entire utility as one unit to measure, then averages the costs of all plants and assets that produce power.[54] The bottom-up method uses the value of each plant individually to calculate a utility's total investments.

The top-down approach is the simplest method because less information is required to evaluate a unit as a whole. The major drawback is an increased risk that the estimate will have a greater variance from actual stranded costs because of the assumptions made to simplify the estimate. A bottom-up approach critically evaluates each asset and liability separately to estimate market and book costs. The evaluation requires large amounts of information and is more work-intensive.

Administrative methods by their nature require policymakers to make educated guesses and assumptions about the future of the market. For this reason, administrative methods pose a risk for both utilities and the customers that must pay the stranded costs.

PUC Administrative Model

The Texas Public Utility Commission (PUC) has developed a model called ECOM, or Estimated Costs Over Market, to evaluate the stranded costs of each utility. This model is a top-down/bottom-up hybrid that values different groups of assets (coal plants, gas plants, etc.) for determining costs rather than valuing each unit separately or the set as a whole. The ECOM model determines generation-related cost-of-service revenues under regulation and compares this figure to a forecast of likely revenues in a competitive environment. The ECOM model also computes a discounted net present value that accounts for the time value of money to arrive at a final estimate.

In forecasting future cost-of-service revenues, the ECOM model includes amounts for returns on capital and federal income taxes as if rate regulation would continue for the life of the asset. The estimate can be further reduced if the rates used for financing stranded cost recovery are lower than rates for returns on and of capital. The resulting costs of debt service should be considered when evaluating different cost recovery methods.

At the Committee's request, the PUC updated it's ECOM estimates in anticipation of the Committee's hearing on stranded costs in May 1998. The numbers showed that stranded costs in Texas have been decreasing over the past few years as a result of decreasing costs overall. In addition, these numbers will continue to decline as many utilities have agreed to dedicate surplus earnings to pay off stranded costs while decreasing base rates (through transition plans in lieu of rate cases).

RECOVERY MECHANISMS

In its report to the 75th Legislature, the PUC identified five major recovery mechanisms for stranded costs: 1) access charges, which are imposed on customers and tied to continued transmission and distribution, regardless of who the generator of the power is; 2) exit fees, which are assessed on customers who depart from their existing provider under regulation and sign up with a new generator; 3) revaluing assets, which is an administrative remedy that writes down the book value of the utilities' generation assets while writing up the book value of transmission and distribution assets; 4) adjusting depreciation, which accelerates depreciation on generation assets and decelerates it on transmission and distribution assets; and 5) rate freezes, which lock rates at the current levels and mandate that any additional earnings from efficiency gains or decreases in fuel prices pay down the debt.[55]

Utilities are currently recovering their costs of facilities through state or local approved rates. The rates charged by utilities are on set schedules for utilities to recover costs at a guaranteed rate of return over the life of the assets. The mechanisms used for recovery of stranded costs can actually result in lessening the total amount of stranded costs since the recovery period is faster than what would have occurred during regulation. A faster recovery can actually save money since the debt is paid off in a shorter amount of time, not unlike the savings realized from paying a mortgage over 15 years instead of 30 years.

In considering any cost recovery method, it is important to consider the effects such methods may have on the marketplace and different classes of consumers. Most parties agree that a recovery method must be predictable and competitively neutral. Restructuring can include a combination of methods designed to pay off stranded investments while encouraging the marketplace to grow. This report includes an explanation of securitization as a recovery method because it has the potential to reduce the amount of stranded costs.

Depreciation and Reevaluation of Assets

There are essentially two depreciation methods to help pay down stranded costs. The simplest method is to accelerate the amounts of depreciation on generation assets, thereby reducing the book values of generation. This reduction helps to minimize the difference between market values and book values, which make up stranded costs (if the book value of an asset is greater than what can be received in the market). This depreciation would have allocated costs over a longer period of time during regulation. However, acceleration of depreciation has the net effect of increasing costs for ratepayers in the short-term. This can be offset by decelerating the depreciation of transmission and distribution assets (which would remain regulated). This deceleration would reduce current rates but increase them in out years for the regulated transmission/distribution system only.

Another depreciation mechanism is to allow the transfer of depreciation from transmission/distribution assets to generation assets, also known as redirection or reevaluation. In this scenario, depreciation amounts are actually transferred from transmission/distribution assets to generation assets. The result is that transmission/distribution assets will have higher book values while generation assets will have lower book values. Some parties argue that this method can also shift the burden of these costs to residential and commercial consumers over the long term since they are less likely to leave the distribution systems.

In either case, Texas has an advantage in the ERCOT areas because the Texas PUC has regulatory authority over transmission and distribution rates in those areas, whereas its jurisdictional control is limited to distribution rates in non-ERCOT areas. This is important because the FERC has objected to some transmission depreciation fixes in other states. In fact, the Texas PUC has been able to approve depreciation changes in the transition plans adopted earlier this year.

Rate Adjustments

The use of rate adjustments during a transition period can help lower stranded costs and/or provide rate relief to consumers. Since this is a declining cost industry, efficiencies gained can be dedicated to stranded cost recovery during a transition period. In fact, the transition plans and rate cases adopted by the Texas PUC impose rate reductions for consumers while dedicating excess earnings to stranded cost recovery.

Texas can consider rate reductions or freezes, but it is important to note that rate adjustments alone cannot provide significant reductions in the short term. When combined with depreciation adjustments, they can help offset stranded costs without rate shock for consumers.

Access Charges

Access charges, also known as competitive transition charges (CTC), are typically applied through the transmission/distribution system. The charge may be billed through the REP or through the EDC. An access charge designed to recover stranded costs is convenient because it can allow for adjustments over time based on final determinations of stranded costs.

An important issue when authorizing access charges is the determination of which customers are to pay them and how they are applied. For instance, should the customers of one utility pay the stranded costs of another utility, or of another MOU? Most parties in the Texas debate have argued that stranded costs should be recovered from the customers which were served by the utility seeking those costs. They feel that past decisions under a fully regulated environment were made on the behalf of those customers and that it is not fair for those costs to be allocated to customers that were not a part of those decisions.

The application of access charges can have different effects on different types of consumers. For instance, an access charge levied through distribution would potentially not apply to large customers that are directly connected to the transmission system or that may choose to generate their own power in the future. Some have suggested applying exit fees to customers that choose to generate their own power, since they would not be paying access charges levied through the wires company.

Access fees can be based on the amount of generation used, a flat fee or a combination of both. Charges that are too heavily based on generation could have the effect of overburdening commercial and industrial customers. Again, it might also encourage these customers to bypass the system and to generate their own power.

No matter how an access fee is levied, due consideration should be given to how much each customer class should be responsible for the fees. Some parties advocate levying the fees based on current cost allocation methods used under regulation, while others suggest revisiting those methods to ensure customer classes are treated fairly. Residential consumer advocates argue that current cost allocation assigns more production costs to residential consumers because the costs are based on peak power costs, which residential customers use more. They add that stranded costs for baseload plants that are always running (such as nuclear) should not be allocated using peak usage. Once the responsibility for these costs are determined, decisions can be made on how best to structure the fees to reflect those decisions.

The way access charges are levied can have huge consequences for the competitive marketplace. California has a floating competitive transition charge that makes it difficult for new entrants to compete during the transition period. California’s access charges are linked to the pool price of generation and can vary greatly. The unpredictability of the access charges combined with a relatively short recovery period has distorted generation prices in California, making it difficult for competitors to formulate long-term contracts with consumers. At least one large marketer, Enron, has abandoned the California market because of the stranded cost recovery mechanism. However, one advantage of the California system is that the aggressive recovery will lead to a shorter transition period for consumers. California will not have to wait long for robust competition.

Securitization

Securitization is a process by which assets and their associated stream of income are packaged in a transaction that results in the sale of securities, commonly called "asset-backed securities."[56] Essentially, it is the refinancing of debt that allows a utility to recover some or all of its stranded costs up front. Security bonds are sold to finance the old debt in a new form. The bonds would be paid off over time from a revenue stream created to pay off stranded costs, such as access charges.

An advantage to this method of recovery is that it allows utilities to start over with a new balance sheet, freeing them to compete without the existing debt. Critics argue that a large infusion of capital up front after these bonds are offered, rather than a gradual recovery, will allow existing utilities to enjoy a competitive advantage.[57]

The advantage of securitization is that the cost of debt financing can be lower than the built-in costs of utility financing which are usually included in the stranded cost estimate. Utility financing is not just based on debt financing, but also based on the equity of shareholders. Utility rates include payments to shareholders for returns on and returns of equity, plus payments to bondholders for debt financing. The difference between securitization rates and utility financing rates can actually be used to reduce the total amount of stranded costs. However, the amount of the reduction will be dependent on the amount and length of the revenue stream used to pay off the bonds. It is difficult to quantify how much savings can be generated without information about these important drivers.

A potential disadvantage to securitization is that once issued, the bonds are irrevocable. Utilities will have recovered their stranded costs upfront and a true-up mechanism may be difficult to implement at this point. Meanwhile, consumers will be paying for the transition costs that are guaranteeing the bonds. Some consumer advocates have suggested that securitization should not be used or that it should not be used to finance 100 percent of the amount of stranded costs. Policymakers should weigh these concerns in combination with the potential benefits of securitization for consumers.

CHAPTER EIGHT

MARKET POWER

A central concern regarding competition in any market is whether one or more market participants may be able to control market prices, supply, market information or service quality in a manner that is ultimately detrimental for customers and competitors alike. Market power, as this issue is commonly referred to, is controversial because it is not easily defined and there is little agreement on when the exercise of market power may result in detrimental or illegal activity.

The market power issue in the context of electric utility restructuring is particularly challenging because its significance is entirely dependent on the structure of new markets for a variety of services. In the case of Texas, the debate has focused on opening competition in the generation market, allowing retail wheeling of electricity and keeping transmission/distribution functions regulated. The interaction between components of the various markets involved will dictate how much or how little potential there is for market power abuses.

This chapter discusses how market power can be used, the different types of market power that may exist in a restructured electric market, how it can be measured, whether it is detrimental and how it can be mitigated if it is deemed potentially detrimental.

UNDERSTANDING MARKET POWER

Market power exists in any competitive market where a market participant has an advantage over other competitors. However, it is when market participants use their advantages to unfairly reduce competition in a market or to bar the entry of new players that it becomes detrimental to consumers and the marketplace.

For example, the fact that an efficient producer can charge lower prices and gain substantial market share is not necessarily detrimental to the marketplace – consumers could benefit from the lower prices. However, what happens if this player leverages its greater market share to artificially lower prices and drive out its competition? This exercise of market power would later enable the participant to raise its prices substantially above a competitive price while sending new entrants the signal that it is not worthwhile to compete in this market.

Assume that one company owns or controls 80 percent of a market. Does the large market share constitute market power? Probably. That company could engage in activities to weed out its competitors and keep new entrants from participating. But what if that company just sells a really great product at a really low price? Market power in and of itself is an important element of competition that does not have to be harmful.

The greatest concern in Texas is that existing utilities which own large portions of generation in their relevant markets may be able to substantially raise or lower electricity prices while discouraging competition. It is also feared that existing utilities may be able to leverage their regulated wires companies to discourage or bar competitors in their service territories. Regulated entities may indeed have some advantages in a competitive market that should be considered. However, at what point does market power mitigation stifle competition? Overly burdensome market regulations may discourage new participants, which could stifle competition.

Policymakers involved in electric utility restructuring must consider the potential for market abuse both during the initial stages of competition and when competition has matured. The mitigation of market power for existing utilities does not necessarily prevent new entrants from obtaining and abusing market power in the future. Policymakers must consider short-term and long-term market goals to ensure robust competition.

The following sections explain the different kinds of market power that can exist and how they specifically affect the different sections of the electric market.

TYPES OF MARKET POWER

Horizontal market power occurs when a generation provider has the ability to sell energy at prices exceeding competitive prices for an extended period of time. This can occur if a generation owner controls a large portion of the generation within a particular market and if transmission constraints prevent the importation of power from other areas. Companies with market power can maintain artificially high prices or can lower prices to decrease profit margins for weaker competitors.

Utilities argue that competition will prevent generation owners from being able to exercise market power since any price increases would send a signal to competitors that profit margins are high in that market. They argue that newer technologies enable competitors to build generation more rapidly than ever before and that the addition of new market participants is the most critical component of having a successful marketplace.

There is additional concern about horizontal market power in Texas because of limited generation capacity and the presence of transmission constraints. An improvement in either of these two areas would act to mitigate horizontal market power.

Vertical market power is possible when a generation provider is also the owner or controller of the only electric delivery network available. The company can limit the use of the network by competitors, thereby increasing its ability to sell power to captive wire customers. For this reason, most parties agree that generation should be unbundled and separated from the transmission/distribution system to assure nondiscriminatory access to the delivery system.

Another form of vertical market power is the ability of a generation owner to spread costs from the generation company to the regulated distribution entity, thereby reducing marginal costs for generation production. Known as *cross subsidies*, this ability to reduce generation costs is only available to vertically integrated companies.

Incumbent market power is only possible when an existing utility is able to retain contact with its regulated customers when providing competitive services. A utility could refer customers of its regulated company to an affiliate that provides competitive products such as power or energy services. For example, a distribution company may be the first to know that an industrial customer is going to expand and have additional energy-related needs. The transfer of this information to an affiliate may be anticompetitive.

A formerly regulated utility may also be able to leverage advantages gained from prior regulation. This would include the use of a brand name known by captive customers under regulation. This prior relationship with customers can be advantageous if the brand name was generally considered reputable. Other advantages include access to information about customer loads, credit information and employees trained under regulation.

The most significant form of incumbent advantage may lie in the ability of utilities to retain the customers they had in the regulated market who have not chosen a new provider. This is significant because it is costly to gain new customers. Also, the utility may hold an advantage if it retains exclusive control over billing of customers.

MEASURING MARKET POWER

The definition of market power has two very basic elements. First, the relevant product must be identified. For instance, is the product at issue power generation, metering services or energy services such as efficiency consulting? Perhaps it is the distribution network. Owning 100 percent of a distribution network that is regulated as a monopoly is very different from owning a large portion of an unregulated generation market. The potential for abuse in the market of each product can vary and may also affect the competitiveness of other products.

Second, the relevant market must be identified. A market can be defined as a geographical area or an area of economic activity in which buyers and sellers come together and the forces of supply and demand affect prices. The geographic market could be different for each product. For distribution it would most likely be the certificated service territory. For metering, there could be a market for the actual supply of meters and yet another market for meter-read information. The market for some of these services could even be national. It depends on the number of competitors available, their hold over the market, and the difficulty for new entry.

The market for power generation is usually a geographic area within an interconnection or grid, unless a significant amount of capacity can flow between grids. ERCOT can be considered a market by itself since it has limited direct current ties to other grids. However, some parties believe that regional markets exist within ERCOT due to transmission constraints in and out of certain areas. These constraints lessen the possibility for the physical flow of competitive power from other areas.

Once the relevant product and markets are determined, policymakers can attempt to measure the presence of market power. They must then evaluate whether the mitigation of market power is necessary to develop a competitive market.

Herfindahl-Hirschman Index

Horizontal market power is commonly discussed in terms of market share within a particular market. A commonly used approach to measure horizontal market power is the Herfindahl-Hirschman Index (HHI). The HHI was developed in the 1940s to measure the market concentration of various industries. It was adopted in 1982 by the U.S. Justice Department as a tool to analyze mergers. The HHI is based on the economic theory that the risk of collusion among market players increases as the amount of market shares held increases.

HHI is the sum of the squares of the market shares of all of the firms in a particular market. It is usually calculated based on the percentage of market share though it is sometimes expressed in decimal terms (resulting in an HHI range of 0 to 1). For example, a particular market may have four players with each firm holding 25% of the market. The HHI would be computed as follows:

$$HHI = 25^2 + 25^2 + 25^2 + 25^2 = 2{,}500$$

Another example, showing lesser market concentration, might include 10 firms each having 10 percent of the market:

$$HHI = 10^2 + 10^2 + 10^2 + 10^2 + 10^2 + 10^2 + 10^2 + 10^2 + 10^2 + 10^2 = 1{,}000$$

The higher the HHI, the higher the market concentration and the higher the risk of abuses of market power among one or more firms. Theoretically, the HHI of a monopoly market would be 10,000 since one player controls 100 percent of the market. On the low end, 100 players each owning 1 percent of the market would produce an HHI of 100.

What is an acceptable HHI? That all depends on the commodity and the market. HHI is really a quantification of the concentration of a market which emphasizes players that have greater market shares. It does not necessarily indicate whether a company can control the market price, although a very high HHI would lead one to believe that it likely could. Also, its significance is dependent on whether the market is properly defined and on the basis chosen for defining market share.

For example, to calculate HHI within a specific generation market in Texas, it could be based on any number of measures including total generation capacity or the amount of generation capacity available for sale. In other words, if a generation company has half of its output committed to a 20-year term contract made under regulation, would it be reasonable to deduct that capacity from the calculation of market share if it cannot sell that energy into the competitive market? Similarly, is market concentration as important during off-peak seasons when capacity needs are low as it is during peak when demand is up?

The market concentration within different types of generation may be more critical than the concentration in the generation market as a whole. The generation market consists of base load, intermediate load and peak load plants. The costs of each of these types of power can vary significantly and, generally speaking, power from the plants which produce the cheapest overall power will be dispatched first. Typically, a base load plant is always in operation, and generators will add intermediate and peak load plants as demand increases. The ability to manipulate market prices depends on the ability to control prices for the incremental loads of power needed to meet demand. In other words, the companies that own the type of power that would be needed where the demand and supply curves meet are the companies that may be able to exercise the most control over price. Since base load plants generally have to be run all of the time to be efficient, they would not necessarily set the price unless demand is low.

Another key question is whether co-generation power should be included in the calculation of capacity for a particular market, particularly if the co-generation owner sells part of its power back into the market. Utilities argue that these capacities should be considered since they represent viable competitive alternatives.

FERC

It is also helpful to study how the Federal Energy Regulatory Commission (FERC) addresses market power issues in reviewing energy-related mergers. FERC takes into consideration three important factors when considering mergers: 1) the effect of a merger on competition; 2) the effect on rates; and 3) the effect on regulation.[58] FERC reviews pending mergers with the goals of ensuring that mergers are consistent with the public interest and that the reviews of such mergers provide market participants with greater regulatory certainty and expeditious regulatory action.

In determining whether a proposed merger is in the public interest, FERC seeks to identify the geographic and product markets affected by a merger and to use the Department of Justice and Federal Trade Commission merger guidelines as the analytical framework in its analysis of competition. As discussed earlier in this chapter, the definition of markets and products is a critical part of this process. The FERC makes these determinations based on a deliberative process inclusive of the merging companies and other interested parties. Once these decisions are made, FERC recognizes the following competitive screen analysis to identify three ranges of market concentration:

> (1) an unconcentrated post-merger market -- if the post-merger HHI is below 1,000 , regardless of the change in HHI, the merger is unlikely to have adverse competitive effects;
>
> (2) a moderately concentrated post-merger market -- if the post merger HHI ranges from 1,000 to 1,800 and the change in HHI is greater than 100, the merger potentially raises significant competitive concerns; and
>
> (3) a highly concentrated post-merger market -- if the post-merger HHI exceeds 1,800 and the change in the HHI exceeds 50, the merger potentially raises significant competitive concerns; if the change in HHI exceeds 100, it is presumed that the merger is likely to create or enhance market power.

The screen provides a starting point for FERC and all interested parties to begin an evaluation process. FERC uses this analysis to identify mergers that are unlikely to raise competitive concerns in order to expedite their approval process (typically those falling under the first HHI range). For mergers that do raise some concerns, FERC will implement a more thorough evaluation process that seeks to build consensus among parties. FERC encourages the merging companies to submit proposed market power mitigation measures to expedite the approval process.

FERC has evaluated a number of mergers since adoption of the Merger Policy Statement in 1996. In April of 1998, FERC opened another docket to revise its merger process given the many changes in the electric industry market. In its Notice of Proposed Rulemaking, FERC proposed codifying the 1996 policy, streamlining filing requirements for mergers that do not raise competitive concerns and providing for more descriptive filing requirements for merger analysis.[59] FERC is also seeking input on the use of a proposed computer simulation model to assess market power. To date, the FERC has not acted on the proposed rulemakings.

FERC’s process for evaluating energy mergers is worth studying as Texas evaluates potential market power issues in electric utility restructuring.

Modeling Programs

A number of modeling programs are available to simulate the operation of markets in a competitive environment. These programs, which are often proprietary, use a variety of data inputs to simulate probable market prices and the likely efficient management of generation assets to maximize profits. Similar to administrative calculations of stranded costs, such models make predictions about future costs and market prices that may be inaccurate. However, they can be useful in isolating potential market power dangers and therefore also assist in proposing mitigation efforts.

METHODS TO MITIGATE MARKET POWER

Potential solutions that have been put forward depend on the type of market power being addressed. As discussed previously in this report, functional or structural unbundling can be used to address vertical market power issues. Incumbent power must be addressed in market structure issues that include open and nondiscriminatory access to the transmission system, methods for the selection of providers and codes of conduct between affiliated companies. These issues have been addressed in the chapter on market structure.

For mitigation of horizontal market power, mitigation proposals have included divestiture of all or a portion of generation assets, temporary freezes or caps on retail power rates for existing utilities, caps on wholesale generation prices, and wholesale market requirements and restrictions on utilities to avoid anticompetitive price spikes and to ensure available capacity for new competitors. Mitigation efforts could include other proposals depending on the specific market dangers being addressed. In any case, policymakers should attempt to be flexible so that the marketplace is not strangled by unforeseen consequences of market structures and market power solutions.

CHAPTER NINE

SYSTEM RELIABILITY

Continued reliability of the electric distribution system is critical for a deregulated market to survive. Texans are accustomed to having immediate and dependable access to power. Any uncertainty in the reliability of a resource as important as electric power could lead to a decrease in the quality of life for residents, discouragement of future business from coming to Texas, and a risk of existing business leaving the state altogether.

The reliability of the electric system is already a concern in Texas due to decreasing actual reserve margins of electric power. As of this writing, ERCOT and the utilities it partners with are working on a strategy to increase generation efficiency, lower consumption through conservation, and promote better cooperation and coordination among members. Texas capacity constraints outside of ERCOT are a lesser concern because of the availability of power within the other two interconnections.

Restructuring poses additional system reliability concerns for two very important reasons. First, the increase in the number of market participants will make it more difficult to ensure that adequate generation capacity exists to meet load requirements. Second, any necessary changes to the mechanisms which manage physical transactions can have consequences for the overall reliability of the system if not implemented correctly. This is significant to the extent that any changes are made in the way the system is managed to balance supply and demand functions. Any changes that affect the variables involved in maintaining the bulk electric supply can have serious repercussions resulting in system outages. Moving transmission responsibilities from utilities to an ISO or a regional transmission organization is a major undertaking that will take a great deal of planning and testing to be accurate. This process becomes more difficult because we really do not know how many more physical transactions will occur as a result of retail wheeling.

System reliability issues are referenced throughout this report as they have arisen in conjunction with other issues. For example, the chapter on market structure explains in detail the reliability issues associated with the development of new market structures. This chapter attempts to highlight reliability issues in general but is by no means an exhaustive list of all reliability concerns.

CAPACITY CONCERNS

Capacity issues are often discussed in terms of planned and actual reserve margins. *Planning reserve margin* is the available capacity in excess of the projected peak firm demand for a given year in the future. Firm demand is the projected peak system demand for the utility less interruptible loads. For example, if an ERCOT utility's peak firm demand is projected to be 10,000 MW, then it will plan accordingly to meet that peak demand, plus the required reserve margin of 15 percent (as required by ERCOT guidelines). The utility will either plan to have generation (existing or new capacity) or purchase power contracts to meet the target available capacity of 11,500 MW. The reserve margin will accommodate either additional demand due to load growth or a shortage of capacity due to inclement weather or other unexpected problems.

In 1998, the *actual reserve margin* within ERCOT fell to 11.5 percent, or 4.9 percent if interruptible loads are excluded. The actual reserve margin within non-ERCOT areas was 14.9 percent, or 8.7 percent if interruptible loads are excluded. For ERCOT, the difference between actual reserve margins and the 15 percent planned reserve margin was largely caused by higher than expected peak demand from the unusually hot summer. However, by having the 15 percent reserve requirement in place, the system was able to absorb the increased demand caused by the unexpected weather conditions.

The concerns over available capacity under restructuring are not much different from concerns under regulation, but they are exacerbated because deregulation does not guarantee that all market players will plan prudently for tomorrow’s unanticipated outcomes. Under current regulation, the PUC oversees planning and guarantees a certain rate of return for prudent investments in capacity construction. In fact, the PUC has initiated a project (No. 19827) as a proactive measure to ensure adequate capacity to meet the projected peak firm demands in 1999 and 2000. This project involves projecting each utility's system peak demand for the next two years, projecting the amount of interruptible load, and projecting the net system capacity available to meet the demand. To the extent a shortage is projected for a utility (less than the planning reserve margin), the PUC is requiring the utility to submit an action plan describing how it plans to fill the gap. The action plan can consist of supply side resources (i.e., generation capacity and purchase power contracts) or demand side resources (i.e., interruptible loads, time of use rates, etc). The action plans should be finalized and approved by the PUC in early 1999 in anticipation of the 1999 summer peak

While some form of regulation would continue, serious questions remain about the ability of the state to order capacity construction for a deregulated generation market. However, markets do send participants signals about consumption needs, especially for a measurable commodity like electricity. Market players will likely build capacity if it is believed that the demand will exist and that other market players will not be able to exercise market power.

PHYSICAL TRANSACTIONS

The move from a wholesale to a retail electric market may substantially increase the number of physical transactions on the grid. For this reason it is more difficult to anticipate how much generation should be available for a given time period. In addition, the changes in grid management resulting from the need for an independent system operator will necessitate a great deal of planning. Systems will have to be thoroughly tested before they are on line and the operator will have to coordinate activities with market players to implement the complicated procedures necessary to maintain reliability.

One of the most important goals of reliability planning is to assure that all market participants are adequately prepared to initiate transactions. Whoever is responsible for system dispatch must be able to remove a participant that consistently provides unreliable information or that cannot perform necessary functions. Participants that do not observe operational rules disadvantage their customers and their competitors.

The chapter on market structure discusses the issues relating to interconnection requirements.

TRANSMISSION AND DISTRIBUTION

Specific reliability concerns regarding the delivery network under restructuring may be less significant since transmission/distribution will continue to be regulated. However, the separation of transmission/distribution from generation and from retail providers presents interesting dilemmas. For instance, any power outages due to low service standards of a distribution company will nonetheless affect retail providers since their customers will not be using the energy they provide. In addition, a utility customer may not know whether to contact the distribution company or retail electric provider during system outages.

Policymakers must consider whether additional steps need to be taken to improve the reliability of the delivery network, particularly since all market participants will be dependent on distribution/transmission for transmitting their power needs. Some parties have suggested that distribution companies should be encouraged to improve and maintain service standards by enacting performance-based regulation (PBR). PBR uses rate structures to provide economic incentives to companies that meet or exceed performance standards established by a regulatory body. Similarly, companies who continually fail to meet performance targets would face financial penalties. As an alternative to cost-of-service regulation, PBR would make distribution companies accountable to both wholesale and retail customers.

ERCOT

The Electric Reliability Council of Texas (ERCOT) is a non-profit corporation whose mission is to ensure reliability in the planning and operation of the system of electricity generation and transmission. It is a voluntary organization supported by dues and fees collected from its six kinds of member market groups, including nine cooperatives and river authorities; six MOUs; four IOUs; four IPPs; 26 power marketers; and nine transmission dependent utilities. The board of directors is composed of three members from each of the six market groups.

ERCOT was formed in 1970 to comply with the national standards set forth by the North American Electric Reliability Council (NERC). Its goal was to operate control centers, which later evolved into security centers, that monitor the flow of electricity on the interconnected grid. Since these security centers were operated by the utilities, they were not completely independent. When the Texas Legislature amended the state Public Utility Regulatory Act (PURA) and deregulated the wholesale electric market in 1995, the PUC revised its rules to create an organization independent of the utilities, but within ERCOT, to function in a competitive environment. This led to the creation of an independent system operator (ISO) within ERCOT in 1996.

The ISO within ERCOT has three primary responsibilities: 1) security operations of the bulk electric system in ERCOT; 2) facilitation of the efficient use of the electric transmission system by all market participants; and 3) coordination of future transmission planning. The chief policymaking body in ERCOT is the Technical Advisory Committee (TAC), which reports to the ERCOT board of directors. The ERCOT ISO is managed by the ISO Director, who also reports to the board.

The ERCOT ISO is comprised of three major groups: 1) the Security Center Group, which has responsibility over the bulk electric system, including directing emergency operations during contingencies; 2) the Transmission Market Operations Group, which has responsibility for administration of the ERCOT OASIS, energy transaction scheduling, and energy and loss accounting; and 3) the Technical Support Group, which has responsibility for the development and maintenance of the ERCOT OASIS as well as all of the computer and telecommunications systems in the ISO facility. An OASIS is an Open-Access Same-Time Information System, which is an electronic posting system for transmission access data that allows all transmission customers to view the data simultaneously.

Aside from all of the technical changes needed for system management, policymakers must consider necessary changes to the ERCOT board. While the board has been successful in the past, its membership will need to represent additional participants in the marketplace. In particular, it will be important to provide customer representation which includes all customer classes.

Texas is fortunate that it already has an independent system operator up and running as a result of wholesale competition. While the necessary changes to accommodate retail competition would be significant, the progress made by the PUC and the ISO participants will serve as an excellent starting point for further change.

NON-ERCOT AREAS

Reliability issues in these areas are more difficult from a policy perspective because so many of the physical transactions comprise interstate commerce. While policymakers can require that certain reliability goals are met, it is difficult to directly manage this process since it cooperation with FERC and other state jurisdictions is necessary. However, FERC has been encouraging the development of independent system operators or regional transmission organizations in areas where retail competition has occurred. Texas can develop policies which take into account these unique areas and can work with the affected market participants to improve reliability.

CHAPTER TEN

CONSUMER PROTECTIONS

The most important goal in restructuring the electric market in Texas will be to protect consumers from any pitfalls that may occur along the way. Electricity is a critical resource upon which the economic health and sustainability of a robust business climate depends. Many analysts have compared the structure of the electric utility market to that of the telecommunications market before the divestiture of AT&T. Restructuring the telecommunications market did not occur overnight, and no one expects it to happen overnight for the electric industry.

Discussions about consumer protections involve several issues that have been a problem in the restructured competitive telecommunications market. Issues such as slamming, cramming, customer education, and low-income assistance are all part of a restructured electricity market. The ability for consumers to aggregate demand and energy efficiency programs are some of the additional issues that are of concern for consumers. While this report includes references to consumer issues throughout, the following sections attempt to describe some of the more important protections needed for consumers.

AGGREGATION

One of the reasons that large industrial customers are encouraging a competitive market is their greater demand for and higher usage of electricity. These customers may be able to negotiate better prices because of the volume of power they use. An energy supplier may be able to charge lower prices when it can better predict the demand of power by its customers. Small business and residential users pay a proportionally large percentage of the company or family budget to utilities, but use only a fraction of the power used by a large industrial customer. The solution for this discrepancy may be achieved by something called "load aggregation."

Load aggregation may be accomplished by many small businesses or residential areas banding together to negotiate, as a whole, for a lower price of electricity. Aggregating customer demand allows small entities such as residences and small businesses to use their collective bargaining power to negotiate lower rates and better energy packages. Traditionally, users were aggregated by a utility's geographic service area. This may still be done in a restructured market, but there may be more options for aggregation.

For example, some users may wish to select an alternative form of generation, perhaps energy derived from a natural resource such as wind, water, or solar generation. These users may band together in an organization to negotiate a price from the generator for its members. While the purchased "green" power flows onto the power grid where it becomes indistinguishable from power generated by other sources, purchasing a particular type of power does affect the overall fuel source mix of the grid. Thus, the company generating renewable energy is paid by those customers who chose that particular option and may in fact build more capacity based on the demand for that particular energy.

Load aggregation can work for any form of organization, whether it is by geography, such as a city or co-op; type of power generated, such as renewables; or membership in a service or other membership-based organization such as Kiwanis, Rotary, etc. Aggregation gives bargaining power to users who may not otherwise be able to negotiate favorable prices.

CONSUMER EDUCATION

In order for a competitive market to function, customers need adequate information to distinguish the benefits of one service over another. However, in the case of electric restructuring, consumers will also need to be educated on how restructuring will take place.

Recognizing that consumers will need education about utility changes, many states that have already implemented electric restructuring have pursued the goal of an educated consumer through education programs developed jointly by regulators, consumers and market participants. Pennsylvania and California in particular have initiated aggressive education programs with differing results.

PENNSYLVANIA

The Pennsylvania Public Utility Commission approved a $15.5 million budget for its "Consumer Education on Electric Choice" campaign. The funding comes from customer utility bills at a rate of approximately five dollars per customer. The plan involves raising awareness of competition over a four year period through advertising and public outreach efforts such as television, radio and print ads, grassroots education and outreach, and a toll-free hotline for answering consumer questions about electric choice. Several advertising and public relations agencies were retained to conduct the state's outreach efforts.

Agencies participating in Pennsylvania's advertising and public relations efforts were selected through a bid process conducted by the Pennsylvania Electric Association (PEA). The PEA is administering the program under the oversight of the PUC and a specially formed PUC Council on Electricity Choice. The PUC and Council on Electricity Choice ensure that the program is meeting the desired objectives for education.

One of the major components of the public education program is a strong grassroots outreach effort to reach diverse audiences. The "Consumer Education on Electric Choice" campaign focuses on four core messages: Pennsylvania consumers will be among the first in the nation to have a choice of which power company supplies their power; consumers will receive the same protections and quality of service regardless of whether they participate in the Electric Choice Program; the more people know about electric choice the more they stand to benefit; and electric generation suppliers offering service in Pennsylvania must be licensed by the PUC.[60] Efforts are geared toward contacting retiree and senior citizen clubs and organizations, public libraries and places of worship, PTAs, and professional associations. The program also targets hard-to-reach communities, such as low-income residents, minorities, and Spanish-speaking consumers. Research is also being conducted to evaluate and monitor program effectiveness. A recent press release indicates a 95 percent rate of awareness among Pennsylvania residents regarding their ability to select an alternative electric provider.[61]

CALIFORNIA

The California Public Utility Commission (CPUC) budgeted $89,94,580 for its various educational efforts. The California legislation required the development and implementation of a Customer Education Plan (CEP) subject to Commission approval. The three largest IOUs, Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric filed a joint statewide proposal with the Commission that included mass media, direct mail, media relations, a customer call center, collateral and fulfillment, and a community-based organization (CBO) effort. The resulting CEP was approved by the Commission and was implemented from September 1, 1997 through May 31, 1998. The CEP budget portion was $73,494,580.

The Commission also complemented the CEP with two additional programs. It created an advisory board, the Electric Education Trust (EET), to continue the education of consumers beyond the CEP efforts. The EET uses community-based organizations to reach areas where traditional educational efforts are not feasible, where direct access participation remains low or where the level of reported consumer abuse is high. An Outreach Program developed by the Commission included additional outreach, a CPUC consumer-friendly web-page, official CPUC bill inserts and a Speakers' Bureau.

The California Public Utilities Commission reports that through August 31, 1998, approximately 95,000 residential, small business, commercial, industrial and agricultural customers chose to participate in California's "Direct Access" program. This represents approximately 1 percent of the state's electric customers, but only 8.6 percent of California's electric load.[61]

MARKETING PROTECTIONS

Besides creating a knowledgeable consumer, protecting the consumer remains an important job for government organizations in a successful move to a restructured market. Once the telecommunications market was opened up to competition, many companies stepped in to inform customers of their new freedom to select a new carrier. However, along with legitimate telecommunications companies, many fraudulent startups intent on taking advantage of customer confusion entered the market. The Texas PUC stepped in with consumer protection strategies that are revised as the market continues to grow.

"Slamming" is the practice of having a utility provider switched without proper authorization. This practice became a major concern especially in the long distance market as competitors battled to gain market share. As competition becomes fierce, companies look for ways to reach out to large portions of the public. Unscrupulous companies or marketing companies hired to solicit new business feel pressure to bring in customers which may result in slamming. The 75th Texas Legislature passed legislation that provided certain acceptable ways for companies to obtain authorization from customers to switch their service. The PUC also has authority to levy administrative penalties for companies found to be in violation. In worse case scenarios the PUC may "suspend, restrict, or revoke the registration or certificate of the telecommunications utility" that is found to be repeatedly and recklessly guilty of slamming.

"Cramming" occurs when additional fees for unrequested services appear on a customer's bill. The PUC has developed rules to address the problem of slamming and legislation has also been introduced for consideration during the 76th Legislature. Both of these practices could easily migrate into a competitive electric industry if not addressed properly.

CERTIFICATION OF MARKET PARTICIPANTS

An important component to guaranteeing a high standard of electric service involves certification, or licensing, of market participants. Certification fosters a statewide code of conduct that consumers can rely on. Certification might entail bonding requirements or another means of ensuring financial integrity and require certain standards of customer service. The certification process not only makes electric providers accountable in a competitive market but also provides the PUC with recourse in case a company falters on its obligations.

Pennsylvania has developed licensing requirements for electricity suppliers. These requirements set forth that a supplier must: be bonded or otherwise financially secure; comply with Pennsylvania PUC technical and financial guidelines; agree to uphold consumer protection laws and standards of reliability; and support consumer education requirements.[62]

Other considerations pertaining to certification are whether a provider should be certified for a limited geographic area or market, whether utilities currently serving an area should require recertification, whether transfers of certificates will be allowed, and under what circumstances the PUC will be allowed to revoke a certificate. Certification is an issue that will be very important in laying a foundation of consumer protection and should be given close consideration by policymakers.

Low-Income Programs

All Texans need to have access to affordable electric power. Unfortunately for some, electric power is a luxury which must sometimes compete for money spent on other necessary household expenses. Currently, Texas and local communities offer a small level of assistance to low-income families for paying their electric utility bills. Expansion of low-income programs will likely be necessary in a restructured environment.

Low-income programs are currently supported primarily through federal assistance, administered through the Texas Department of Housing and Community Affairs (TDHCA). On a national level, federal funding has been decreasing. Since 1995, federal appropriations for low-income assistance in Texas have decreased by over 30 percent, from $44.0 million to $31.8 million in the 1998 program year.[63] TDHCA estimates federal funding levels in 1998 will benefit approximately eight percent of eligible households in the state.[64] Low-income households pay, on average, $709 per year for electricity, while the average annual expenditure for other households is $1,174.[65] Other funds to assist low-income families come from community donations, where utility customers can choose to voluntarily contribute to a fund by adding an amount to their monthly bill.

Some common ground has emerged in reviewing steps taken by other states that have enacted restructuring legislation. First, and foremost, is a safety net provision ensuring that a basic package of service is always available to customers. It can be coordinated by local community service organizations that administer state and federal aid to ensure that it reaches all residents in an area that may need assistance.

Other states have funded the safety net with a system benefits charge (SBC), meaning all customers pay a small "universal service" charge on their bills. Second, a default provider is available to provide service if the customer does not choose a new provider. Third, prohibitions of redlining (discussed below) have been enacted. Fourth, utilities provide information and rebates for energy efficiency devices and weatherization precautions. Fifth, fees for using the transmission wires or distribution system can include a portion for rate-assistance. Sixth, housing standards incorporating better energy efficiency into new construction and renovation of low income housing.

PROVIDER OF LAST RESORT

Under the present electric system, utilities have monopolies over certain territories. They must provide service to all customers living in that area, regardless of their income levels. Some consumer groups have concerns that low-income households with histories of late payments will be unattractive in a competitive electric market. These customers may be unable to get electric service if utilities are released from their "must carry" obligations.

Consumer advocates have expressed interest in designating a utility as a "provider of last resort" to provide power to those customers unable to obtain power from other utilities. A provider of last resort would offer basic service to customers judged too unattractive by other providers, possibly at a regulated rate. However, policymakers must determine whether this default provider can disconnect a customer who simply does not pay his bills. There is legitimate concern that the costs of continued service would ultimately be borne by other rate payers.

CHAPTER ELEVEN

ENVIRONMENTAL ISSUES

The bulk of electric power generated in Texas is produced by burning fossil fuels. However, Texas has great potential for producing more energy from renewable resources such as light and heat from solar and photovoltaic; hydroelectric from running water; wind over mountain ranges and plains; geothermal from the heat of the earth; biomass from wood and plant matter; and methane gas from landfills. Currently, these renewable energy sources account for less than one percent of all energy produced in Texas.[66]

In October 1998, the PUC gave approval to a plan allowing utilities to offer customers power generated from renewable resources. The rule allows utilities to set a price that covers the cost of acquiring the energy plus marketing and administrative expenditures. If the resources cost more than the utilities' existing generation mix, customers who select the renewable resource option would pay the difference in addition to their usual rate.

While restructuring may provide some opportunities in increasing the level of renewable resources, there is a concern that renewables may not be competitive in an open marketplace because of the higher costs associated with producing "green power." Policymakers must consider the effects of restructuring on air quality in Texas. Consideration should be given to whether affirmative steps to increase the number of renewable resources and energy efficiency programs should be taken.

AIR QUALITY

While much research is being done to advance the cause of renewables, some older plants continue to produce power with emissions levels above those standards set by state and federal law. The TNRCC has established the Clean Air Responsibility Enterprise (CARE) Advisory Committee in order to develop a voluntary emissions program. Older plants have been either grandfathered, exempted, or permitted at regulated levels.

Emissions monitored by the TNRCC are broken down into five main categories: nitrogen oxides (NOx), nonmethane organic compounds (NMOC), sulfur dioxide (SO2), carbon monoxide (CO), and particulate matter.[67] Two pollutants, NOx and NMOC, are chiefly responsible for the formation of ground level ozone, which is hazardous to breathe. Some older units emit these pollutants and are a leading cause of why four areas of Texas exceed the federal standards for ozone.

In a restructured market, there is concern that some grandfathered or exempt plants will emit pollutants at higher levels than present. Concerns have been raised regarding the selection of providers that produce the cheapest electricity because they are grandfathered out of new and expensive clean air standards. This may result in increased harmful emissions levels if customers choose their providers based on price alone.

OPTIONS TO INCREASE RENEWABLE RESOURCES

Renewable resources are increasingly becoming attractive to electric providers because of the heightened environmental protection standards on other plants. Older plants burning fossil fuels produce large amounts of emissions that are monitored by the Texas Natural Resource Conservation Commission (TNRCC). Plants must also comply with federal regulation and standards such as the Clean Air Act. An additional reason for the attractiveness of renewable energy is that it is becoming less expensive to produce. Companies have concluded that some customers place a value on power generated from renewable sources and are willing to pay extra for it. In addition, certain Texas provisions encourage companies to enter agreements with third parties to develop renewable power sources.

The restructuring of the electric industry may present a variety of opportunities for fostering renewable energy and energy efficiency in Texas. Generally speaking, methods range from pure market-based mechanisms to mandated quotas for renewable energy production. The Committee asked the Texas Energy Coordination Council (TECC) to prepare a study describing alternative market-based methods of providing renewable energy and energy efficiency programs. This study was completed and submitted to the Committee in July 1998 and can be accessed electronically on the TECC website at http://tecc.ces.utexas.edu/.

The TECC study identifies several methods for encouraging the use and development of renewable resources. These include pure market-based methods such as green pricing, market stimulation methods such as tax credits, and regulatory market stimulation methods such as a renewables portfolio standard.

Pure Market-Based Methods

Pure market-based methods are driven by consumer desire for renewable energy and energy efficiency. These methods include, but are not limited to the following:

Net Metering- the displacement of utility-supplied power by power produced by the consumer (usually from a renewable source). Any power that a consumer produces by their own means (solar, photovoltaic, etc.) offsets their demand for power off the grid. This method is simple in that there is little need for regulatory intervention.

Green Pricing- customers pay more for energy produced by renewable sources. This concept is appealing because it is driven by the simple theory of supply and demand. A disadvantage is that there is no way to separate “green” electricity from any other form of electricity generation.

Real-Time Pricing- customer prices for electricity are based on the cost of electricity at the exact time that the power is demanded. This option gives customers more control over how much they are paying for electricity because they are able to match high electricity usage times to low-cost power times (using power at off peak times).

Energy Efficient Mortgages- lenders agree to lend more money for energy efficiency homes without requiring the borrower to have additional income to qualify for the loan. Homeowners save money on electric bills because they use less electricity which reduces the amount of demand for generation, thereby reducing pollution.

Market Stimulation Methods

Another means of spurring renewable energy production and energy efficiency programs is through market stimulation methods. These methods involve non-voluntary contributions which infuse money into renewable energy and energy efficiency programs to foster development.

The most widely discussed method a systems benefit charge (SBC) which is applied across the board to all customers. Proceeds from the SBC are directed toward energy efficiency, renewable energy and low-income programs that might suffer from insufficient funding in a competitive market. Another market stimulation method is the use of tax credits to award consumers for the use of renewable energy sources.

Regulatory Market Stimulation Methods

Regulatory market stimulation methods include set asides and portfolio standards for renewable energy and energy efficiency programs. Set asides mandate that a utility must integrate a certain amount of renewable energy into its power mix. Portfolio standards set forth a certain portion of generation that must be derived from renewable resources over a given time. A portfolio may apply to a single utility or to all generation produced in a state.

All of these methods should be considered as options for fostering the expansion of renewable energy sources in Texas. Due to the fundamental policy differences between the three methods, there are threshold questions that must be answered before choosing one method over another or choosing not to use one altogether. Should the State impose the use of renewable power on all citizens or should consumer demand drive its development?

ENERGY EFFICIENCY PROGRAMS

While Texas consumers pay electric rates that are below the national average for a kilowatt hour of power, they still pay the fourth highest average annual electric bills due to the large amount of energy used by Texans. This is mostly attributable to the use of air conditioning during hot summer months. One kilowatt hour of electricity runs the average residential air conditioner for fifteen minutes. One way to lower the large electric bills that consumers face is through the use of energy efficiency programs.

Energy efficiency plans are also called conservation or *demand-side management* (DSM) programs. Their goal is to reduce electric consumption without adversely affecting a customer's lifestyle or business practices. Some examples of DSM initiatives include energy audits of homes and businesses; distribution of information about new technologies; cash incentives, loans and rebates to purchase or upgrade to newer and more energy efficient appliances; and improved pricing options that offer different rates at different times of the day when demand changes.

Because DSM programs often reduce sales of electricity through decreased usage, some consumer advocates believe that utilities have not pursued efficiency alternatives as aggressively as they could have. Notwithstanding, when less electricity is generated, power plants produce less pollution.

CHAPTER TWELVE

TAX IMPLICATIONS

Electric utility restructuring may hold significant consequences for state and local taxes based upon aspects of the industry. The Comptroller of Public Accounts has reviewed the various state and local fees and taxes that are either paid or collected by electric utilities and estimated the possible impact restructuring may have upon these revenue sources. The following summary highlights the findings of the Comptroller's office.

STATE AND LOCAL SALES TAX

Sales tax collections related to the electric utility industry are predominately derived from non-residential purchases of electricity. In Fiscal Year 1997, state sales tax collections from these purchases totaled $226.1 million. While the state does not tax the residential use of electricity, certain local governments may. Local sales tax collections in FY 1997 from purchases of electricity totaled $112.3 million.

In addition to the tax levied on the purchase of electricity, electric utilities also pay sales tax on the purchases of certain taxable items such as wires and poles. Amounts received for FY 1997 through these collections totaled $41.5 million in state sales tax revenue and $7.3 million in local sales tax revenue.

The Comptroller of Public Accounts has identified four issues that may have possible sales tax implications. These issues are price fluctuations, entry and exit in the Texas generation market, the common-carrier exemption, and nexus.

Price Fluctuations

Significant fluctuations, especially significant drops, in the price of electricity could initially affect the sales tax base. At particular risk from fluctuations are local governments that tax the residential use of electricity since residential customers consume 45 percent of the value of all electric power in Texas.

Entry and Exit in the Generation Market

As the current Texas utility system is relatively closed, short-term implications of entry and exit into the market would be minor. Since sales tax exemptions currently exist for purchases of equipment used to generate electricity, sales tax revenue in this regard would essentially be affected only by the reduction of other purchases by utilities that are struggling or ceasing operation.

In the long run, the sales tax revenue fluctuations could become more drastic as the Texas market becomes more accessible to out of state competition and Texas businesses prove relatively more or less successful against the competition.

The Common Carrier Exemption

The total charge for electricity, meaning the amount the utility charges for the electricity and the amount it charges for transporting the electricity to the consumer, is subject to state and local sales taxes. Under the state's sales tax law, transportation charges that are not connected to the sale of a taxable item are not taxed. When a third party delivers a taxable item to a purchaser, there is no sales tax due on the transportation charge.

If under restructuring generation, transmission, and distribution are performed by different entities (with each billing for its services), only the charge for the generation of the electricity would be subject to the sales tax. The Energy Information Administration estimates that 74 percent of the current cost of electricity is derived from generation. This means that approximately 26 percent of the current sales tax based on electricity purchases could become non-taxed after restructuring. This loss equates to a $70 million per year reduction in state tax revenue and a $35 million per year reduction in local tax revenue.

Nexus

Nexus describes the degree of business activity that must be present before a taxing jurisdiction has the right to impose a tax on a corporation. Determining an entity's business presence can be a complicated procedure based on various types of activity such as owning property in the state, being the general partner in a Texas limited partnership, or providing services in the state.

Restructuring could have significant sales tax implications in regards to taxing nexus for out of state electricity suppliers. If such a supplier were to use third party distribution and transmission companies, the supplier would have no nexus in the state and thus would not be required to collect sales tax from consumers. The consumer would be required to remit the tax to the state, but as in the mail-order industry, enforcement of this would be difficult and the result would probably be a revenue loss to the state.

LOCAL PROPERTY TAXES

Like other businesses throughout the state, utilities are subject to the local property tax. The Comptroller reports that the estimated total taxable value of electric utilities in Texas for 1996 was $25 billion. The estimated tax levy on this value was $540 million, with $317 million of that amount levied by school districts.

Utilities are generally appraised by one of three methods: cost, income, or sales. The cost method in its simplest form is original cost minus depreciation. The income method is net operating income divided by a capitalization rate that is derived through analysis of expected yields. The sales method is based on actual sales or a surrogate measure such as stock trades.

Restructuring holds two significant implications for the property tax system. These implications are in regard to utility valuation and stranded costs.

Valuation

The current methods used to determine a utility company's value reflect the regulated nature of the industry. In certain methods, entire companies are valuated rather than individual plants and valuations are based on long-term income streams projected from current circumstances. These methods could become obsolete if, after restructuring, more stand-alone plants exist, and the economic switch occurs from the plants with the lowest marginal cost determining electric prices to the plants with the most efficient technology doing so. As the market changes, the valuation methods would also need to adjust to reflect the nature of the industry.

Moreover, due to the significant property value of electric utilities throughout the state and the funding impact this value has on the public school system, all current appraisal information would need to remain available to the Comptroller to ensure the state's ability to equitably fund school districts. Lack of adequate information could jeopardize the reliability of the Comptroller's Property Value study which directly impacts school district funding.

Stranded Costs and Potential Losses in Value

Stranded costs are historic financial obligations that would become unrecoverable to a company if the market were to become competitive. The most common types of stranded costs include nuclear power plants and power-purchase contracts.

Since the nuclear plants are also of significant property wealth, much of the stranded investment would be expected to occur in property wealthy school districts. Property value declines could in turn reduce the wealthy school district's recapture payments to the state. As these recapture payments drop, the remaining financial education burden falls on the state.

State Franchise Tax

Electric utilities and holding companies in Texas pay a state franchise tax based on .25 percent of taxable capital or 4.5 percent of earned surplus. In recent years, most utilities have paid their franchise tax burden based on the earned surplus calculation of liability. For FY 1997, the franchise tax generated $85.9 million.

Price Effects

The franchise tax could be affected by declines in the gross revenues of utilities caused most likely by falling electric prices. The manner in which utilities adjust their cost structure to this possible scenario will determine any negative effects on the state's franchise tax.

Gas, Electric and Water Utility Tax (GEW)

The Gas, Electric, and Water Utility Tax, GEW, applies to a person who owns or operates a gas, electric light, electric power, or water works for local sales and distribution. The tax rate varies from .581 percent to 1.997 percent of a utility's gross receipts depending on the size of the city served. GEW taxpayers are limited to investor-owned utilities as cooperative utilities and utilities owned by municipalities are exempt from the tax.

In FY 1997, the GEW produced $202 million in tax revenue with 88 percent of the revenue derived from electric companies and 12 percent from gas companies. This revenue stream was projected to remain steady at approximately $200 million per each year of the 1998-1999 biennium.

Under restructuring, the current GEW may no longer be an appropriate mechanism by which to tax utilities due to problems associated with the GEW tax base and nexus.

GEW Tax Base

The current GEW tax statute considers a "utility" a vertically-integrated company that performs the total process of generation through distribution. If, in a restructured electric market, utilities were to separate into individual entities performing generation, transmission, and distribution, ambiguity would occur with this definition. Unbundling of the industry would leave no vertically integrated companies, and thus leave no "utility companies" as defined by the GEW tax statute. The entire tax base would then be eliminated.

Nexus

If the statutory definitions are corrected to cure any problems associated with the GEW tax base, problems may still arise with the emergence of out of state power marketers. These marketers would be able to sell to entities within the state but have no business nexus for tax purposes and thus avoid the GEW tax altogether.

PUBLIC UTILITY GROSS RECEIPTS TAX

The Public Utility Tax is a 1/6 of 1 percent levy on the gross receipts of utilities. The tax was implemented to offset the regulatory costs of the PUC and it generates approximately $37 million per year that is deposited in general revenue.

Like the GEW tax, the Public Utility Tax would also have significant issues associated with its tax base and tax payer nexus after restructuring.

Tax Base

The public utility tax is based on functions regulated by the PUC. If, under restructuring, the generation of electricity is no longer regulated by the PUC, this portion of the tax base would be lost. This situation could lead to $19 million loss of tax revenue.

Nexus

Like the GEW tax, the issue of business nexus in the state could become a significant issue for the Public Utility Tax. Out of state power marketers or out of state businesses created by in state generation entities to sell the electricity could avoid the tax altogether.

MUNICIPAL FRANCHISE FEES

Incorporated cities may charge utilities reasonable fees for the use of city streets or public right-of-ways in the course of the utility's business. This fee is limited to either two percent of the gross receipts of a utility or an amount directly negotiated between the city and the utility. In practice, most cities work out a negotiated fee which constitutes approximately four percent of the utility's gross receipts.

The revenue derived from franchise fees is approximately $370 million per year statewide. Restructuring could have significant implications to the base of these fees.

Fee Base

If utilities unbundle after restructuring, the generation portion of the franchise fee base may be eliminated to allow even competition. This action would leave the transmission and distribution services as the only basis for levying franchise fees. If current law were to remain, the loss from exempting generation could result in a 74 percent reduction in the franchise fee base.

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