Report to the 82nd Texas Legislature

Scope of Competition in Electric Markets in Texas

Public Utility Commission of Texas
January 2011

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Public Utility Commission of Texas

January 14, 2011

Honorable Members of the Eighty-Second Texas Legislature:

We are pleased to submit our 2011 Report on the Scope of Competition in Electric Markets, as required by Section 31.003 of the Public Utility Regulatory Act. This report provides an update on the status of the electric markets in Texas, as well as a summary of the Commission's activities during the last biennium relating to electric competition and other electric industry responsibilities under State law. The report concludes with a discussion of emerging issues and recommendations that the Legislature may want to consider.

Competitive electricity prices have dropped over the past two years in Texas, and today the lowest-priced residential rate offers are lower than the final regulated rates charged before the retail market opened in 2002. The three major factors influencing prices are lower natural gas prices, more wind generation displacing higher-priced generation, and increased competition in the electricity market. More retailers and more offers are available to residential customers than there were two years ago. In addition to the maturing competitive market, the Commission has overseen many infrastructure and market improvements that have enhanced the customer experiences in the Electric Reliability Council of Texas (ERCOT) region.

The State of Texas continues to be a leader in the implementation of a competitive electric market and a world leader in renewable wind energy. In a December 2010 study of restructured electricity markets, performed by Distributed Energy Financial Group, LLC, both the residential and the commercial and industrial electricity markets in Texas scored significantly higher than other states' and Canadian markets. The Commission's sequencing plan for completion of the Competitive Renewable Energy Zones (CREZ) transmission plan, the selection of the transmission utilities to build the lines, and the approval of 22 CREZ CCNs to date continues to progress us toward completion of all CREZ transmission construction by the end of 2013. Completion of the CREZ plan will enable over 18,000 MW of renewable energy to be delivered to customers in ERCOT. Advanced metering deployment, currently totaling over 2.5 million meters, with expected completion of all 6.1 million by 2015, promises to improve the operation and reliability of our transmission and distribution infrastructure, provide benefits to consumers, and reduce costs for utilities.

Following extensive market testing and training, ERCOT implemented a new wholesale market design, the Texas Nodal Market, on December 1, 2010. The project has improved the management of the ERCOT transmission network resulting in more efficient operation of generation facilities, more reliable grid operations, better future investment decisions by power generation companies, and greater integration of renewable generation.

We look forward to continued collaboration with the Legislature as we work together to secure a bright energy future for electricity customers, commerce, and industry in Texas. If you need additional information about any issues addressed in this report, please contact us.

Sincerely,

Barry T. Smitherman
Chairman

Donna L. Nelson
Commissioner

Kenneth W. Anderson, Jr.
Commissioner

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I. INTRODUCTION AND EXECUTIVE SUMMARY

During the past two years, wholesale prices in the competitive electric market in Texas have been lower than the regulated retail electricity prices in 2001, before the introduction of competition. During the same time frame, the Commission has taken a number of actions that are expected to improve retail customers' experience in buying and using electricity, and it has made substantial progress in the licensing of new transmission facilities that will facilitate a significant increase in the wind generating capacity in the State. A major wholesale market redesign for the Electric Reliability Council of Texas (ERCOT), the nodal market, was initiated on December 1, 2010, which should improve the efficiency and management of the wholesale market and congestion within the ERCOT region. By November 30, 2010, 2.5 million advanced meters had been deployed in areas that are open to retail competition, and they are providing customers new service options, shortening the time required to switch providers or initiate service, and giving customers ways to obtain information about their consumption more easily and on a timelier basis.

Wholesale and retail prices

In stark contrast to the 2007/2008 time frame, natural gas, prices during the 2009/2010 time frame were low and stable, resulting in low wholesale and retail electricity prices. The lowest competitive offers for residential service in the Texas retail electricity market are below the regulated rates that were in effect in 2001. The average 2001 rate was 10.6¢ per kilowatt-hour (kWh), the average lowest fixed rate as of December 1, 2010 was 7.6¢ per kWh, and the average lowest variable rate was 7.2¢ per kWh. In most of the service areas, rates are available at less than 8¢ per kWh. The lowest residential rates in the market today are well below the national average electric rates.

REP Certification Standards

During May and June 2008, high natural gas prices and transmission congestion drove up wholesale and retail electricity prices, putting financial stress on some of the retail electric providers (REPs), leading several of them to leave the market, and transfer their customers to Providers of Last Resort (POLR). Some REPs also failed to meet financial obligations of ERCOT or transmission and distribution utilities (TDUs). As a result, the Commission in May 2009 amended its REP certification rules to improve the credit quality and technical and managerial qualifications of REPs. For most REPs, the amended rule requires a REP to demonstrate its financial qualifications by providing the Commission a letter of credit in the amount of $500,000 and ensuring the protection of customer deposits by putting deposits in an escrow account or covering the customer deposits with a second letter of credit for 100% of the deposit amounts.

Expedited connection and switching

Historically, when a residential customer decided to switch to a different REP, the switch was not accomplished until after the customer's meter was read. Because meters were read on a monthly basis and the processing of a switch request could take a week or more, a customer that decided to switch REPs might have to wait for more than a month for the switch to be processed. If the switch was to a lower rate, the customer would continue to be charged the original higher rate until the switch was accomplished. To shorten the switching process for retail customers, the Commission changed the process for selection of a REP. The new process requires TDUs to process meter reads for customers who are switching REPs within four business days of receiving a request. It also requires REPs to request switches consistent with the customer's requested switch date. These process revisions now permit customers to switch providers in about five to seven days.

Enforcement

The Commission has created an Oversight and Enforcement Division (O&E) to promote improved compliance with PURA and other applicable laws. O&E recently has emphasized the Commission's customer protection rules by conducting audits of retail electric providers to evaluate their compliance with these rules. In addition, REPs were required to file information not later than 2010 to demonstrate that they meet the new certification standards that the Commission adopted in 2009. Commission staff has evaluated this information, and proceedings have been initiated to decertify REPs that did not meet the standards or were not in operation.

Texas Nodal Market

ERCOT, which operates the grid that serves 85% of the electric load in Texas, implemented a new wholesale market design, the Texas Nodal Market, in December 2010. The new market design required ERCOT to develop a complex system of software and hardware, and required market participants to develop the systems to make bids in the new market and respond to instructions and other communications from ERCOT. The nodal market will improve the management of transmission congestion and provide better information about where it would be desirable to build new generation facilities, resulting in more efficient operation of generation facilities, more reliable grid operations, and better investment decisions by power generation companies. The nodal market opened without incident on December 1, 2010.

CREZ Transmission Plan

In October 2008, the Commission designated five areas in West Texas and the Panhandle as competitive renewable energy zones (CREZs) and identified major transmission improvements necessary to deliver over 18,456 MW of renewable resources to customers in other parts of the state. This level of renewable capacity is roughly two times the current renewable capacity in Texas. In December 2008, the Commission held a hearing to select the entities to build the CREZ facilities. Many Texas transmission providers and other foreign and domestic companies submitted applications to build and operate the CREZ facilities. In May 2009, the Commission designated the transmission providers that would construct the CREZ transmission facilities and assigned them specific facilities to construct. Many of the new CREZ transmission facilities require the Commission issuance of certificates of convenience and necessity (CNNs) prior to construction and the Commission adopted a schedule for the filing of the CREZ CCNs.

Commission actions as of the end of 2010 included, the approval of 16 CREZ CCNs, the denial of one CCN, and requested an update of the CREZ Transmission Optimization (CTO) study to permit a more cost effective transmission solution for the Kendall to Newton segment. Some of these facilities involve transmission lines that span one hundred miles or more and large numbers of landowners and local officials have participated in the CCN cases. The CREZ schedule calls for the completion of all CREZ transmission construction by the end of 2013.

Advanced Metering Deployment

Texas legislation enacted in 2005 encouraged the adoption of advanced meters, recognizing that "new metering and meter information technologies have the potential to increase the reliability of the regional electrical network, encourage dynamic pricing and demand response, make better use of transmission and generation assets, and provide more choices for consumers." The Commission adopted a rule in May 2007 that established a framework for TDUs to deploy advanced meters. The three largest TDUs in ERCOT have received Commission approval of plans for the deployment of smart meters and have begun deployment in their service territories. By November 30, 2010, 2.5 million advanced meters had been deployed, and by the end of 2013 approximately 6.1 million smart meters will be installed in ERCOT.

TDUs, REPs and ERCOT are beginning to provide tools that will permit customers to realize the benefits of advanced meters. In early 2010 the TDUs launched Smart Meter Texas, an online tool for customers and REPs to access 15-minute consumption data from smart meters. ERCOT began to use 15-minute consumption data for wholesale settlement in December of 2010, and approximately 1.6 million meters are being settled on a 15-minute basis. REPs are also beginning to offer products that take advantage of the 15-minute smart-meter data, including prepaid services that permit customers to avoid paying a deposit for electric service and to pay for electricity in smaller increments. REPs have initiated pilot programs with customer information devices, programmable thermostats, smart appliances and other technologies that will allow customers to use the information from smart meters to manage their consumption better.

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II. SUMMARY OF COMMISSION ACTIVITIES FROM 2009 TO 2011 TO REFLECT CHANGES IN THE SCOPE OF COMPETITION IN THE ELECTRIC INDUSTRY

The Commission develops and modifies rules, policies, and procedures for the competitive electric market in Texas, consistent with law and in response to changes in the industry. The Commission also maintains oversight for programs that were enacted to promote energy efficiency and renewable energy. Certain areas of Texas remain subject to Commission rate regulation, and the Commission continues to set rates and supervise the investor-owned utilities in these areas.

A. Rulemaking Activities

During 2009 and 2010, the Commission modified existing rules to facilitate the successful operation of the competitive market and in particular to improve the experience of retail customers in buying and using electricity.

1. Major Retail Market Rulemakings

a. REP Certification

The Commission in 2009 amended the REP certification requirements to provide better protection for customers against REP insolvency.[1] The new rule requires that REPs meet higher standards for capitalization and risk management expertise. It also requires additional security of $500,000 to protect customer deposits in the event of a REP default. The Commission adopted stronger technical and managerial standards for REPs, and the rule now forbids a person who had control of a REP that transferred its customers to a Provider of Last Resort (POLR) from owning or controlling a REP.

The Commission amended its certification rule again in 2010 to allow it to draw on a REP's letter of credit in the event of a REP certificate revocation.[2] It also defined a REP's failure to remove a switch-hold (requires a customer to pay the deferred balance owed to a REP under a payment plan before switching providers) in a prescribed timeline as a significant violation of the rules and created a new REP certification for the purpose of allowing third-party ownership of distributed generation facilities on the business premises of large customers.

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[1] *Rulemaking Relating to Certification of Retail Electric Providers*, Project No. 35767, Order Adopting the Repeal of § 25.107 and New § 25.107 (May 1, 2009).

[2] *Rulemaking to Amend P.U.C. SUBST. R. 25.107 Regarding Certification of Retail Electric Providers (REPs)*, Project No. 37685, Order Adopting Amendment to § 25.107 (November 3, 2010).

b. REP Disclosure of Information

To provide better information to customers shopping for retail electricity service, the Commission amended its customer disclosure requirements to require REPs to clearly identify a service contract as providing fixed, variable, or indexed service and to prescribe definitions for each.[3] In addition, REPs must send notice of the expiration of fixed-price contracts and must notify each customer of the terms of service that will apply if they do not select another REP or service plan at the end of the contract term. The Commission also modified the Electricity Facts Label, provides a clear "apples to apples" comparison between products, to highlight specific items, such as the type of pricing in the contract and termination penalties that a customer may be charged.

c. Transition to POLR

The Commission amended its POLR rule to better protect customers if they are transferred to a POLR provider.[4] These revisions included a requirement that REPs entering the market post a $500,000 letter of credit that may be used to pay the deposits of low-income customers if they are transferred to the POLR. Incentives were added for REPs to volunteer to serve as POLRs at market-based rates. The Commission lowered the approved rates for POLR service (from 130% to 120% of wholesale energy costs), gave more time for residential customers to pay a deposit to a POLR, added additional deposit assistance for low-income customers that are transferred to a POLR, and strengthened the notice to be provided by ERCOT when a customer is transferred to POLR. The voluntary POLR provisions and lower regulated POLR price should lead to lower prices for most customers transferred to a POLR.

d. Disconnection of Service and Deferred Payment Plans

Several rules were amended to expand eligibility requirements for deferred payment plans and level or average payment plans and to provide additional protections for low-income customers and customers with medical conditions.[5] The amendments were designed to assist certain eligible low-income customers and customers with medical conditions, to avoid disconnection because of failure to timely pay high bills that result from extreme hot or cold weather. The amendments balance the increased risk associated with the expanded eligibility by allowing REPs, under certain circumstances, to require a customer to pay the deferred balance the customer owes to the REP under a payment plan before switching providers. REPs are required, prior to the customer's agreement to the payment plan, to explain fully to the customer, using a prescribed script, that the customer is required to pay the deferred balance before switching REPs. This ability to prevent a switch is referred to as a switch-hold, and implementing it should help mitigate the non-payment issues associated with the expansion of the requirement to offer

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[3] *Rulemaking Relating to Retail Electric Provider Disclosures to Customers*, Project No. 35768, Order Adopting Repeal of § 25.475, New § 25.475, and Amendment of § 25.476 (February 24, 2009).

[4] *Rulemaking Relating to Providers of Last Resort*, Project No. 35769, Order Adopting Amendment of § 25.43 (May 15, 2009).

[5] *Rulemaking Relating to Disconnection of Electric Service and Deferred Payment Plans*, Project No. 36131, Order Adopting Amendments to §§ 25.454, 25.480, and 25.483 (September 29, 2011).

these payment plans and help protect customers from higher prices that may result from the increased risk of non-payment associated with the extension of additional credit.

The amendments also prohibit REPs from ordering disconnection of a Critical Care Residential Customer[6] when the customer has established that disconnection of service will cause someone at that residence to become seriously ill or more seriously ill. The prohibition against service disconnection lasts 63 days from the issuance of the electric bill or a shorter period agreed upon by the REP and the customer, secondary contact, or attending physician. As an additional protection for Critical Care Residential Customers, TDUs are required to contact the customer and the secondary contact prior to disconnecting electricity.

e. Expedited Customer Switch Time

The Commission adopted rule amendments to facilitate more rapid transfers from one REP to another when a customer decides to switch REPs.[7] Under previous rules, switching REPs could take as long as 45 calendar days, but the amendments shorten that time to seven business days or less. The amendments modify the switch notification sent to the customer by ERCOT upon receipt of a switch request from a REP, and require TDUs to process meter reads for customers who are switching REPs within four business days of receiving a request. The amendments also require REPs to request switches consistent with the customer's requested switch date.

REPs are now required to notify customers of the termination of a term contract for electric service at least 14 days before the termination date. The combination of notifying the customer of pending contract term expiration and providing for a significantly shortened process for changing REPs should improve customers' ability to make timely choices, thus making the competitive electricity market more responsive to the needs of retail electric customers.

f. Common Billing Terms

As required by HB 1822 and HB 1799 passed by the 81st Legislature (2009), the Commission amended its rules to ensure that certain common terms and the definitions of those terms are uniform among electric service providers.[8] The revised rule also requires that information concerning the Commission's customer information website be included on a customer's bill. In addition, a statement of the date a fixed-rate product expires must be included on each residential and small commercial customer bill.

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[6] A residential customer who has a person permanently residing in his or her home who has been diagnosed by a physician as being dependent upon an electric-powered medical device to sustain life.

[7] *Rulemaking to Expedite Customer Switch Timelines*, Project No. 36536, Order Adopting Amendments to §25.214 and §25.474 (July 15, 2009).

[8] *Rulemaking Proceeding to Adopt Common Terms Used in Billing Telecommunications and Electric Customers*, Project No. 37070, Order Adopting Amendments to § 25.25 and § 25.479 (December 7, 2009).

g. REP Requirements and Information Disclosures

Other provisions in House Bill 1822 from the 81st Legislature required the Commission to amend its information disclosure rule.[9] The amended rule requires that the date of contract expiration appear on each billing statement and that a notice of contract expiration be sent to the customer between 30 and 60 days before the contract expiration date. The amended rule also provides that if the contract expiration is an exact date, then no termination penalties would apply 14 days prior to contract expiration, and if the contract expiration is an estimated date, then the customer would not be charged a termination penalty from date of receipt of the notice.

h. Termination of Electric Service by Landlords

In response to House Bill 882 passed by the 81st Legislature (2009), which amended Property Code § 92.008(b), the Commission adopted amendments to its rules to provide that a landlord of an apartment house or landlord that leases mobile homes in a mobile home park cannot disconnect electric service because of a tenant's nonpayment for that service.[10] The Commission adopted the amendments at the December 16, 2010 Open Meeting.

i. Texas Prompt Payment Act

The Commission adopted new rules to reflect the Prompt Payment Act[11] (PPA) requirements for billing governmental agencies by electric providers.[12] The PPA, relating to payment for goods and services, is the controlling statute for an electric service provider billing state agencies and political subdivisions. The PPA is administered by the Texas Comptroller of Public Accounts, but the Commission has authority over electric service provider billing.

2. Transmission Service Provider/Transmission Distribution Utility Rulemakings

The Commission adopted several rule changes that affect transmission and distribution service providers. Some of these rules affect customers directly, while others are focused on utility programs and operations.

a. Meter Tampering

The Commission adopted new rules to deter meter tampering. Prior rules permitted the disconnection of electric service where meter tampering had occurred; to

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[9] *Rulemaking to Implement Changes to Customer Disclosures as Required by HB 1822*, Project No. 37214, Order Adopting Amendment to § 25.475 (December 7, 2009).

[10] *Rulemaking Proceeding Relating to Electric Submetering and Master-Metered Apartment Buildings*, Project No. 37684, Order Adopting Amendments to § 25.141 and § 25.142 (December 20, 2010).

[11] TEX. GOV'T. CODE § 2251.001 -.055 (Vernon 2007 & Supp. 2009).

[12] *Rulemaking Relating to the Obligations of Electric Service Providers under the Texas Prompt Payment Act*, Project No. 37981, Order Adopting New §§ 25.33 and 25.482 (September 14, 2010).

provide an additional deterrent, REPs may now require a customer to pay for the electricity that the customer used before switching to another REP. The new rules also require a TDU to provide notice to both the retail customer and the REP if it detects tampering and reduce the timeframe that a TDU can back bill for energy charges once a determination of meter tampering is made.[13] Finally, the new rules require utilities to set up a customer hotline for the reporting of suspected tampering and require reporting of information concerning meter tampering for all utilities in Texas.

b. Critical Care Customers

The Commission adopted a new rule that provides uniform requirements regarding residential customers with certain medical conditions who face disconnection of electric service by a TDU.[14] Previous rules included critical care and ill and disabled categories, which were not defined. The new rule eliminated the ill and disabled category, and created an additional critical care category. The new rule developed uniform procedures for qualifying customers as critical care customers.

c. Reliability and Continuity of Service

In compliance with HB 2052 passed by the 81st Legislature (2009), the Commission amended its rule related to reliability and continuity of service to delete certain obsolete references and to add an enforcement paragraph that details the factors the Commission will consider in determining an appropriate enforcement action.[15] The amended rule provides that the reliability index for each feeder line may be no more than 300% worse than the system average of all feeder lines during any two consecutive reporting years.

d. Energy Efficiency

In 2010, the Commission amended its energy efficiency rule to raise the electric utilities' energy efficiency goals from 20% of annual growth in the electric utility's demand for electricity of residential and commercial customers to 25% of the growth in demand of these customers in 2012, and to 30% of the growth in demand in 2013.[16] The amended rule also includes cost caps to limit the impact of the higher goals on residential customers to $1.30 per month or 1/10 of a cent per kilowatt-hour of consumption for 2011 and 2012 and to $1.60 per month or $0.0012 per kilowatt-hour of consumption for 2013 and thereafter. Growth in demand has not increased for most utilities in recent

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[13] *Rulemaking Relating to Meter Tampering and Disconnection and Reconnection of Service for Customers with Advanced Meters*, Project No. 37291, Order Adopting the Repeal of §§ 25.125 and 25.126; New §§ 25.125, 25.126, and 25.132; and Amendments to § 25.214 (May 24, 2010).

[14] *Rulemaking to Amend Customer Protection Rules Relating to Designation of Critical Care Customers*, Project No. 37622, Order Adopting the Repeal of § 25.497 and the New § 25.497 as Approved at the September 15, 2010 Open Meeting (September 29, 2010).

[15] *Rulemaking to Amend P.U.C. SUBST. R. 25.52 Related to Reliability and Continuity of Service*, Project No. 37387, Order Adopting Amendments to § 25.52 as Approved at the December 17, 2009 Open Meeting (December 18, 2009).

[16] *Rulemaking Proceeding to Amend Energy Efficiency Rules*, Project No. 37623, Order Adopting Amendment to § 25.181 (August 9, 2010).

years and is not expected to increase in the immediate future; therefore, it is expected that the utility's energy efficiency program costs will not increase until load growth resumes. Legislation enacted during the 80th Legislative session in 2007 permitted the Commission to award performance bonuses, and the amended rule clarifies that any bonus earned by a utility is subject to the cost caps.

e. Transmission Cost of Service

The Commission adopted an amendment to its rule relating to transmission service rates.[17] The amendment increases from once to twice per year the number of times a transmission provider (TSP) may file for an interim update to its transmission rates to reflect changes in the level of investment in transmission facilities. The amendment also provides for administrative processing of interim updates that are uncontested.

f. Distribution Service Provider Transmission Cost Recovery Factor

In September 2010, the Commission adopted an amendment to its rule relating to distribution service provider (DSP) transmission cost recovery factors (TCRF).[18] The amendment addresses the previous inability of DSPs to promptly recover certain increases in wholesale transmission costs passed on to them periodically by TSPs as a result of TSPs' rate cases and interim updates. The amendment addresses this situation by allowing a DSP to reflect in its rates an adjustment that reconciles the difference between 1) the transmission costs that are paid by the DSP but not included in its base rates, and 2) the revenues recovered through the DSP's TCRF.

g. Recovery of Electric Utility Distribution Costs

In June 2010, the Commission approved for publication a proposed rule that would have provided for more timely recovery by electric utilities of capital investments in distribution infrastructure.[19] The basic workings of the rule would parallel very closely those of P.U.C. SUBST. R. 25.192, which allows utilities to periodically file for an increase in rates to reflect capital investment in transmission facilities and includes appropriate depreciation expense, taxes, and the Commission-authorized rate of return. The proposed rule would have allowed the same treatment for *distribution* facilities—that is, it would have allowed utilities to file a request once per year for updated rates reflecting the additional depreciation and return related to new distribution plant investments, along with related taxes.

At the December 16, 2010 Open Meeting, the Commission considered Staff's Proposal for Adoption of the rule. The Commission stated that while it believes it has

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[17] *Rulemaking Proceeding to Amend P.U.C. SUBST. R. 25.192(g), Relating to Transmission Service Rates*, Project No. 37519, Order Adopting Amendment to § 25.192 (August 5, 2010).

[18] *Rulemaking Proceeding to Amend P.U.C. SUBST. R. § 25.1932, Relating to Distribution Service Provider Transmission Cost Recovery Factors (TCRF),* Project No. 37909, Order Adopting Amendment to § 25.193 (October 5, 2010).

[19] *Rulemaking Related to Recovery by Electric Utilities of Distribution Costs*, Project No. 38298, Proposal for Publication of New § 25.243 (June 11, 2010).

the legal authority to adopt such a rule, waiting to do so until after the Legislature has had the opportunity to consider the issue and provide more specific direction would be prudent. The Commission stated that it plans to revisit this rule in the summer of 2011 consistent with any action taken by the Legislature.

3. Other Rulemakings

The remaining rulemakings undertaken by the Commission addressed wholesale market issues and administrative requirements. These rules affect ERCOT, renewable energy development, infrastructure, electric market design, and more.

a. Infrastructure Improvement and Maintenance

Through the passage of HB 1831 the 81st Legislature emphasized the importance of transmission and distribution infrastructure risk management and maintenance. The Commission adopted a rule requiring each utility to submit a report to the Commission by May 1 of each year that describes the utility's efforts both to identify areas within its service territory that are particularly susceptible to damage during severe weather and to harden transmission and distribution facilities in those areas.[20] The report will also include a summary of the utility's vegetation management practices, distribution pole inspections, and a summary of the utility's activities related to preparing for emergency operations.

b. Infrastructure Storm Hardening

Following Hurricane Ike, the Commission determined that storm hardening activities of electric utilities in Texas should be more closely examined. In December 2008, the Commission awarded a contract to Quanta Technology to undertake an evaluation of 1) historical data on infrastructure damage from storms and associated restoration costs, 2) the impact of new technologies such as advanced meters and smart grid on the provision of electric service after a disaster, 3) the cost of annual inspections of overhead facilities, poles, and other support structures versus the longer cycles in current codes and standards, and 4) the costs and benefits of implementing more stringent infrastructure requirements in hurricane-prone areas within 50 miles of the Texas coast.

After examining the Quanta studies and holding several workshops, the Commission adopted a new rule that requires each electric utility to develop a storm hardening plan that provides for the implementation of cost-effective strategies to increase the ability of its transmission and distribution facilities to withstand extreme weather conditions.[21] The rule also requires each utility to submit to the Commission forward-looking plans over a five-year period beginning January 1, 2011 and to update its plan at least every five years.

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[20] *Infrastructure Improvement and Maintenance Report Pursuant to House Bill 1831*, Project No. 37472, Order Adopting New §25.94 (December 14, 2009).

[21] *Rulemaking for Utility Infrastructure Storm Hardening*, Project No. 37475, Order Adopting New § 25.95 (June 24, 2010).

c. Accountability and Performance of ERCOT

The Commission has proposed amendments to its substantive rules relating to the governance and rate setting requirements for ERCOT.[22] The amendments would make ERCOT more accountable to the Commission and introduce additional controls over the budget and fees of the organization. Key amendments proposed by the Commission would:

a) prohibit a person employed by a market participant from serving as an unaffiliated member of the governing board;
b) require Commission approval of the selection of chief executive officer and other executives of ERCOT;
c) require ERCOT to provide information to the Commission at the request of the Commission or Executive Director;
d) require Commission review of the adoption or modification of the ERCOT strategic plan;
e) prohibit ERCOT from exceeding the Commission-approved budget;
f) establish a staffing limit, to be set by the Commission;
g) require annual Commission review of ERCOT's budget and fees, budget strategies, and staffing; and
h) require prior Commission approval of debt incurrence.

The Commission has requested public comments and is expected to take action in early 2011.

d. Decertification of an Independent Organization

The Commission has the responsibility under PURA to certify the independent organizations that oversee the operation of the regional electrical networks. Currently, ERCOT performs the functions of an independent organization in the intrastate network in Texas. In 2009, the Commission adopted a new rule to provide an explicit procedure by which it could decertify an independent organization and transfer its assets to a successor organization.[23] The Commission also maintained flexibility to take less drastic corrective actions if appropriate.

e. CREZ Financial Commitment and Excess Development

PURA § 39.904 directs the Commission to consider the level of financial commitment by renewable generators for each CREZ in determining whether to grant a CCN for a transmission project serving that zone.

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[22] *Rulemaking Relating to the Accountability and Performance of the Electric Reliability Council of Texas*, Project No. 38338, Proposal for Publication of Amendments to §§ 25.361, 26.362, and 25.363 (August 24, 2010).

[23] *Rulemaking to Implement Requirement of PURA § 39.151(d) Concerning Decertification of an Independent Organization*, Project No. 33812, Order Adopting Amendment to § 25.361 and New § 25.364 (October 9, 2009).

To address this issue, the Commission amended P.U.C. SUBST. R. 25.172 to establish a framework for determining whether sufficient financial commitment exists for a CREZ. Under this framework, installed generating capacity, evidence that the construction of new generation has been initiated, and signed interconnection agreements are considered the best measures of renewable generator financial commitment. The amended rule provides a threshold of wind generators' financial commitment as shown by these standards. The Commission found that sufficient financial commitment has been shown for those, the three West Texas CREZs as evidenced by the amount of renewable generation already developed, the amount of additional renewable generation under development, and the renewable capacity represented by signed interconnection agreements.

For the two Texas Panhandle CREZs, however, the Commission determined that sufficient financial commitment by renewable generators had not yet been demonstrated, principally because those areas are outside the existing ERCOT transmission grid and have very few existing generation facilities and signed interconnection agreements. The Commission's amended rule also allows renewable generators to demonstrate their financial commitment to a CREZ by posting collateral. The Commission, therefore, allowed renewable generators to post such collateral and, in July 2010, determined that there was sufficient evidence of financial commitment by renewable generators to grant CCNs for transmission facilities serving the two Panhandle CREZs.[24]

During the course of the Commission's rulemaking to amend P.U.C. SUBST. R. 25.174, wind developers expressed concern that the actual development of wind facilities in the CREZs might exceed the transmission capacity in the CREZ transmission plan, which could result in severe transmission congestion.[25] To address this overbuilding concern, the Commission amended its rule to specify the conditions under which it could initiate a proceeding to either limit interconnection to the grid or establish dispatch priorities that would afford preferential access to the transmission system to entities that, among other things, demonstrated financial commitment at an early stage of the CREZ proceedings.

f. Initial Implementation of the Nodal Market

The nodal market is a large and complex system involving new hardware and software to manage the electric system and wholesale market and the interaction of many business entities that participate in the market. To enable ERCOT to address any transition issues that may arise during the startup period of the nodal market, the Commission adopted amendments to its rules relating to pricing safeguards and resource adequacy in ERCOT.[26] These amendments allow ERCOT to adopt temporary

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[24] *Commission Staff's Petition for Determination of Financial Commitment for the Panhandle A and Panhandle B Competitive Renewable Energy Zones*, Docket No. 37567, Order (July 30, 2010).

[25] *Proceeding to Establish Policy Relating to Excess Development in Competitive Renewable Energy Zones*, Project No. 34577, Order Adopting Amendments to § 25.174 (October 15, 2009).

[26] *PUC Rulemaking to Address Initial Implementation of the Nodal Market*, Project No. 35392, Order Adopting Amendments to §§ 25.502 and 25.505 (July 9, 2010).

safeguards to mitigate potential pricing anomalies that may result from unexpected system performance or bidding behavior by market participants. Specifically, during the first 45 days of the nodal market, the amendments permit ERCOT to impose lower system wide offer caps than those ordinarily imposed by Commission rule and to apply stricter offer mitigation rules for the management of all transmission network congestion.

g. Goal for Renewable Energy

PURA § 39.904(a) provides that the Commission shall establish a target of having at least 500 MW of capacity from a renewable technology other than wind. The Commission's rules currently provide that a non-wind resource may earn both a renewable energy credit (REC) and a compliance premium for each megawatt-hour (MWh) it generates. In 2010, the Commission evaluated the costs and benefits of additional incentives that could be added to its rules for non-wind renewable resources. In December 2010, the Commission voted to publish proposed amendments to P.U.C. SUBST. R. 25.173 relating to the Goal for Renewable Energy. These amendments would create two additional tiers of RECs and a corresponding requirement for the retirement of these new RECs. The amendments also include the option for retail providers to make alternative compliance payments in lieu of meeting their tiered REC requirements. The Commission expects to address these amendments and comments received on them in early summer of 2011.[27]

h. Record Retention and Requirements

Following the adoption of new P.U.C. SUBST. R. 25.107, relating to Certification of Retail Electric Providers, the Commission adopted amendments to P.U.C. SUBST. R. 25.491,[28] relating to Record Retention and Requirements**,** P.U.C. SUBST. R. 25.475, relating to General Retail Electric Provider Requirements and Information Disclosures to Residential and Small Commercial Customers, and P.U.C. SUBST. R. 25.476, relating to Renewable and Green Energy Verification. These revisions removed a June 1st reporting deadline, instead requiring the REPs to provide the required customer protection data in their Annual REP Reports pursuant to new P.U.C. SUBST. R. 25.107, and conformed the titles of P.U.C. SUBST. R. 25.475 and 25.476 to reflect previous amendments to those rules.

B. Contested Cases

The Commission conducted several cases to address major issues during the past two years. These cases have included several traditional rate cases, hurricane restoration cost recovery cases, mergers and sales, renewable energy infrastructure, and advanced meter deployment.

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27 *Rulemaking Proceeding to Amend Rules Relating to Renewable Energy*, Project No. 35792 (June 20, 2008).

28 *Rulemaking for Administrative Correction to SUBST. R. § 25.491, Record Retention and Requirements*, Project No. 37007, Order Adopting Amendment to § 25.491 as Approved at the October 8, 2009 Open Meeting (October 16, 2009).

1. Entergy Rate Case

In September 2007, Entergy Gulf States initiated a rate case with the Commission requesting to recover $107 million through a combination of base rate increases and various riders.[29] In January 2008, Entergy completed its jurisdictional separation plan, dividing Entergy Gulf States into two subsidiaries, Entergy Gulf States Louisiana, which serves customers in Louisiana, and Entergy Texas, which serves customers in Texas.

Entergy reached a non-unanimous settlement (NUS) with some of the parties to the case, including the Office of Public Utility Counsel, that would have allowed Entergy to receive approximately all of its request, but which would have reallocated the revenue requirement among the customer classes so that all classes' rates, including residential, would have increased by about eight percent. Commission Staff, the Texas Industrial Energy Consumers, and the State of Texas agreed to a second NUS that would have resulted in Entergy's rates staying very nearly the same as before the rate case. A hearing was held on both NUSs. Following the issuance of a proposal for decision by administrative law judges of the State Office of Administrative Hearings (SOAH) that accepted the Entergy NUS, the Commission rejected the Entergy NUS for failing to meet the legal standards for approval of an NUS and remanded the case to SOAH for a hearing on the original application. In March 2009, the Commission approved a unanimous stipulation reached by the parties, resulting in a base rate increase for Entergy of $46.7 million.

2. Oncor Rate Case

Oncor Electric Delivery Company (Oncor) filed an application requesting an increase in revenues of approximately $275 million or 10.9%. During the course of the proceeding, Oncor revised its requested increase to $253 million. Following a hearing, the Commission approved in November 2009 an increase in revenues of approximately $115 million. Among other things, the Commission found that a consolidated tax savings adjustment should not be made pursuant to PURA § 36.060 because Oncor is not a member of an affiliated group eligible to file a consolidated tax return.

3. SPS Rate Case

In May 2010, Southwestern Public Service Company (SPS) filed an application to change its rates, seeking authority to increase its base rate charges for the Texas retail jurisdiction by $62 million which represented an overall increase of 7.0% in rates.[30] This case is ongoing.

4. SWEPCO Rate Case

In August 2009, Southwestern Electric Power Company (SWEPCO) filed an application and statement of intent to change its rates, seeking an increase in annual

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[29] *Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs*, Docket No. 34800 (Sept. 26, 2007).

[30] *Application of Southwestern Public Service Company for Authority to Change Rates and to Reconcile Fuel Costs and Purchased Power Costs for 2008 and 2009*, Docket No. 38147 (April 12, 2010).

Texas retail revenues of nearly $75 million or 34.56%.[31] SWEPCO's request included an increase of $31.6 million to provide a return on SWEPCO's investment in generating plants under construction to be collected through two "Generation Recovery Riders" and an increase of $16.3 million collected through a "Reliability Rider" to fund increased vegetation management activities. In March 2010, SWEPCO filed an unopposed settlement agreement. The agreement, which was approved by the Commission, provided for an increase of $25 million, comprising a $15 million annual base rate increase and a one year, $10 million surcharge that will be dedicated to vegetation management.

5. El Paso Rate Case

In December 2009, El Paso Electric (EPE) filed an application seeking authority to increase its base rate charges for the Texas retail jurisdiction by $51.6 million, an overall increase of 12.9% in rates.[32] In June 2010, EPE filed a unanimous settlement agreement that provided for an overall increase of $17.15 million. The Commission subsequently approved the settlement.

6. CenterPoint Hurricane Restoration Costs

In April 2009, CenterPoint Energy Houston Electric, LLC (CenterPoint) filed an application under PURA §§ 36.401-36.406 to recover and securitize system restoration costs related to Hurricane Ike in the amount of $677.8 million.[33] Enacted in 2009, Senate Bill 769 enables an electric utility to obtain timely recovery of system restoration costs and to use securitization financing to recover these costs. Securitization lowers the cost of debt, thus lowering the rate paid by the electric customers served by CenterPoint.

On July 8, 2009, CenterPoint filed its application for a financing order to securitize the settlement amount of system restoration costs related to distribution operations, plus carrying costs and upfront qualified costs.[34] On August 4, 2009, CenterPoint filed a settlement agreement providing that the total dollar amount eligible for securitization or other recovery would be $662.8 million, plus carrying costs. On August 14, 2009, the Commission approved the settlement. The Commission issued its financing order on August 26, 2009, approving the securitization requested by CenterPoint and authorizing the issuance of transition bonds. In November 2009, CenterPoint issued the transition bonds for a total amount of $664.8 million. Over the life of the bonds, the transaction will provide cost savings to ratepayers of $417 million on a nominal basis and $326 million on a present-value basis.

[31] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 37364 (August 17, 2009).

[32] *Application of El Paso Electric Company for Authority to Change Rates, to Reconcile Fuel Costs, to Establish Formula-Based Fuel Factors, and to Establish an Energy Efficiency Cost Recovery Factor*, Docket No. 37690 (November 18, 2009).

[33] *Application of CenterPoint Energy Houston Electric, LLC for Determination of 2008 System Restoration Costs*, Docket No. 36918 (April 17, 2009).

[34] *Application of CenterPoint Energy Houston Electric, LLC for a Financing Order*, Docket No. 37200, Financing Order (August 26, 2009).

7. Entergy Hurricane Restoration Costs

Entergy Texas, Inc. (ETI) was similarly affected by hurricanes in 2008. In April 2009, ETI filed an application under PURA §§ 36.401-36.406 to recover and securitize system restoration costs related to Hurricanes Ike and Gustav in the amount of $577.5 million.[35] Like CenterPoint, ETI sought timely recovery of system restoration costs and to use securitization financing to recover these costs. Securitization lowers the cost of debt, thus lowering the rate paid by the electric customers served by ETI.

On August 5, 2009, parties to the proceeding filed a settlement agreement providing that the total dollar amount eligible to be securitized would be $566.3 million, plus carrying costs and other qualified costs, and less an estimated amount of $70 million related to insurance payments expected to be made to ETI. On August 18, 2009, the Commission approved the settlement. On July 16, 2009, ETI filed its application for a financing order to securitize the settlement amount.[36] The Commission issued its financing order on September 11, 2009, approving the securitization requested by ETI and authorizing the issuance of transition bonds in an aggregate principal amount of $539.8 million plus estimated up-front qualified costs of issuing, supporting and servicing the transition bonds, and adjustments related to carrying costs. In November 2009, ETI issued transition bonds for a total amount of $545.9 million. Over the life of the bonds, the transaction will provide cost savings to ratepayers of $322 million on a nominal basis and $240 million on a present-value basis.

8. Sharyland Acquisition of Cap Rock

In February 2010, Sharyland Utilities (Sharyland) and Cap Rock Energy Corporation (Cap Rock) filed a request for approval of the proposed acquisition of Cap Rock by Sharyland. Cap Rock's Stanton and Lone Wolf Divisions serve customers located in the Southwest Power Pool (SPP) power region and Cap Rock's McCulloch and Hunt-Collins Divisions serve customers located in the ERCOT power region. In issuing an order approving a unanimous stipulation and concluding that this transaction was in the public interest, the Commission approved a requirement that Sharyland (1) conduct a study of whether it was appropriate to introduce retail competition in the Cap Rock service area, to be completed within one year of the closing of the merger transaction, and (2) initiate a study to evaluate moving the Stanton and Lone Wolf loads into ERCOT.[37]

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[35] *Application of Entergy Texas, Inc. for Determination of 2008 System Restoration Costs*, Docket No. 36931, Order (August 18, 2009).

[36] *Application of Entergy, Texas, Inc. for a Financing Order*, Docket No. 37247, Financing Order (September 11, 2009).

[37] *Joint Report and Application of Sharyland Utilities, LP, Sharyland Distribution and Transmission Services, LLC, Hunt Transmission Services, LLC, Cap Rock Energy Corporation, and NewCorp Electric Cooperative, Inc. for Regulatory Approvals Pursuant to PURA §§ 14.101, 37.154, 39.262, and 39.915*, Order (July 8, 2010).

9. SPS Sale to the City of Lubbock

In January 2010, SPS filed an application to sell its electric distribution assets within the City of Lubbock and a small adjacent area to Lubbock's municipally owned electric utility, Lubbock Power and Light (LP&L), for $87 million subject to adjustments at closing. The assets included poles, lines, transformers, meters, and 21 distribution substations. The area was dually certified, with both SPS and LP&L providing retail electric service. SPS requested that this portion of its service area be decertified so that it would no longer provide retail electric service to the area. LP&L served 75% of the retail electric customers in the affected area (75,000 customers), and the SPS customers in the area would become LP&L customers. LP&L's rates at the time of the proceeding were lower than SPS's rates. In June 2010, the parties filed an unopposed stipulation resolving all of the issues in the docket, which was approved by the Commission.

10. AEP Texas Central and AEP Texas North Advanced Meters

In April 2009, AEP Texas Central Company (TCC) and AEP Texas North Company (TNC) (collectively, AEP Texas) filed a request for approval of their advanced metering system (AMS) deployment plan and a request for AMS surcharges. TCC and TNC proposed plans that provided for the deployment of advanced meters by the end of the third quarter of 2013 to all residential and non-residential retail electric customers in the TCC and TNC service areas, except for those customers who are required to have interval data recorder (IDR) meters or who take non-metered service. TCC and TNC also requested approval of surcharges to recover costs associated with the deployment of the AMS.

In November 2009, a settlement agreement was reached, and it was approved by the Commission. TCC and TNC were authorized to implement surcharges to support their AMS deployments over a nine-year period. TCC residential customers pay a surcharge of $3.15 per month that decreases to $2.89 per month in January 2012 and then to $2.26 per month in January 2014. TNC residential customers pay a surcharge of $3.15 per month that decreases to $2.77 per month in January 2012 and then to $2.13 per month in January 2014.

The total estimated capital cost for AEP Texas' advanced metering facilities is $269.7 million ($211.71 million for TCC and $58.00 million for TNC) and the total estimated operating and maintenance expenses are $159.7 million ($124.27 million for TCC and $35.50 million for TNC) for the surcharge period. The approved deployment plan includes estimated savings and benefits for the surcharge period of $121.7 million, consisting of $114.5 million ($83.55 million for TCC and $30.99 million for TNC) in meter reading savings and $7.2 million ($5.65 million for TCC and $1.57 million for TNC) in ad valorem tax savings. These estimated cost savings are reflected in the customer surcharge.

11. TNMP Advanced Meters

In May 2010, Texas-New Mexico Power Company (TNMP) filed a request for approval of its AMS deployment plan and a request for AMS surcharges. TNMP proposed plans that provided for the deployment of advanced meters by the end of 2015 to all residential and non-residential retail electric customers in the TNMP service areas, except for those customers who are required to have interval data recorder (IDR) meters or who take non-metered service. TNMP also requested approval of a surcharge in the amount of $4.80 for 144 months to recover the costs of deploying the AMS.[38] This case is ongoing.

12. Electric Transmission Texas Sodium Battery

In August 2008, Electric Transmission Texas, LLC (ETT) filed an application to install of a sodium battery at Presidio, Texas.[39] The battery is intended to improve service to Presidio, which has experienced several electrical outages and poor voltage service events. The Commission issued an order holding that the battery was a transmission asset, not a generation asset, and therefore eligible for inclusion in ETT's transmission costs of service.

13. CPS Energy Pole Attachments

In January 2009, CPS Energy[40] filed a petition against Southwestern Bell Telephone Company, d/b/a AT&T Texas (AT&T) and Time Warner Cable San Antonio, L.P. (TWC) concerning the charges that CPS Energy imposes on these companies for their attachment of facilities on CPS Energy's electricity poles.[41] The Commission ruled that it has jurisdiction to determine if CPS Energy's pole attachment rates comply with PURA. This case is one of first impression because the Commission has not previously addressed the requirements of the 2006 amendments to PURA § 54.204(c). This case is ongoing.

14. CREZ Cases

In October 2008, the Commission designated five areas in West Texas and the Panhandle as CREZs and identified major transmission improvements necessary to deliver 18,456 MW of renewable resources to customers in other parts of the state. This level of renewable capacity is roughly two times the current renewable capacity in Texas. In December 2008, the Commission held a hearing to select the entities to build the CREZ facilities. Many Texas transmission providers and other foreign and domestic companies submitted applications to build and operate the CREZ facilities. In May of 2009, the Commission designated the transmission providers that would construct the CREZ facilities and assigned them specific facilities to construct. The new CREZ transmission facilities require the Commission issuance of CCNs prior to construction, and the Commission adopted a schedule for the filing of the CREZ CCNs.

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[38] *Texas New Mexico Power Company's Request for Approval of Advance Metering System Deployment and AMS Surcharge*, Docket No. 38306 (May 26, 2010).

[39] *Application of Electric Transmission Texas, LLC for Regulatory Approvals Related to Installation of Sodium Sulfur Battery at Presidio, Texas*, Docket No. 35994 (August 12, 2008).

[40] "CPS Energy" is the trade name of the City of San Antonio acting by and through the City Public Service Board.

[41] *Petition of CPS Energy for Enforcement Against AT&T Texas and Time Warner Cable Regarding Pole Attachments*, Docket No. 36633 (pending).

Pursuant to the order on rehearing in Docket No. 35665,[42] Docket Nos. 36801 and 36802 were established to sequence the filing of the CCN applications for the CREZ transmission projects. Docket No. 36801 sequenced the filing dates for the CREZ transmission projects designated by ERCOT as priority projects.[43] Docket No. 36802 sequenced the subsequent non-priority CREZ projects.[44]

All of the CREZ priority projects were assigned to either Oncor or LCRA Transmission Services Corporation (LCRA TSC). In September and October 2009, Oncor filed seven CREZ priority project CCNs.[45] Three of the cases were resolved by settlement among the parties.[46] The other four CCN applications proceeded to hearing and eventually were approved by the Commission with various routing modifications. LCRA TSC was originally scheduled by Docket No. 36801 to file two CREZ priority CCN applications in 2009, but the company was granted a delay to study more routing

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[42] *Commission Staff's Petition for Selection of Entities Responsible for Transmission Improvements Necessary to Deliver Renewable Energy From Competitive Renewable Energy Zones*, Docket No. 35665, Order on Rehearing (May 15, 2009).

[43] *Proceeding to Sequence Certificate of Convenience and Necessity Applications for the Priority Projects for the Competitive Renewable Energy Zones*, Docket No. 36801, Order (July 8, 2009).

[44] *Proceeding to Sequence Certificate of Convenience and Necessity Applications for the Subsequent Projects for the Competitive Renewable Energy Zones*, Docket No. 36802, Order (April 5, 2010).

[45] *Application of Oncor Electric Delivery Company, LLC, to Amend its Certificate of Convenience and Necessity for the Tonkawa – Sweetwater East – Central Bluff CREZ 345 kV Transmission Line in Scurry, Mitchell, Fisher, Nolan, and Taylor Counties, Texas*, Docket No. 37407, Order (March 11, 2010); *Application of Oncor Electric Delivery Company, LLC, to Amend its Certificate of Convenience and Necessity for the Riley-Bowman CREZ 345 kV Transmission Line (Formerly Oklaunion – Bowman Line) within Archer, Wichita, and Wilbarger Counties, Texas*, Docket No. 37408, Order (March 11, 2010); *Application of Oncor Electric Delivery Company, LLC, to Amend its Certificate of Convenience and Necessity for the Central B-Central A-Tonkawa345 kV CREZ Transmission Line in Scurry and Mitchell Counties*, Docket No. 37409, Order (March 8, 2010); *Application of Oncor Electric Delivery Company, LLC, to Amend its Certificate of Convenience and Necessity for the Newton-Killeen CREZ 345 kV Transmission Line in Bell, Burnet, and Lampasas Counties, Texas*, Docket No. 37463, Order (April 5, 2010); *Application of Oncor Electric Delivery Company, LLC, to Amend its Certificate of Convenience and Necessity for the Brown-Newton 345 kV CREZ Transmission Line in Brown, Mills, Lampasas, McCullloch, and San Saba Counties, Texas*, Docket No. 37464, Order (April 5, 2010); *Application of Oncor Electric Delivery Company, LLC, to Amend its Certificate of Convenience and Necessity for the Central Bluff-Bluff Creek 345 kV CREZ Transmission Line in Nolan, Taylor, and Runnels Counties, Texas,* Docket No. 37529, Order (April 15, 2010); *Application of Oncor Electric Delivery Company, LLC, to Amend its Certificate of Convenience and Necessity for the Proposed Bluff Creek to Brown 345 kV CREZ Transmission Line in Taylor, Runnels, Coleman, and Brown Counties, Texas*, Docket No. 37530, Order (April 26, 2010).

[46] *Application of Oncor Electric Delivery Company, LLC to Amend a Certificate of Convenience and Necessity (CCN) for the Riley – Bowman 345 kV CREZ Transmission Line (Formerly Oklaunion – Bowman Line) Within Archer, Wichita, and Wilbarger Counties*, Docket No. 37408, Order (March 11, 2010); *Application of Oncor Electric Delivery Company, LLC to Amend its Certificate of Convenience and Necessity (CCN) for the Central B – Central A – Tonkawa 345-kV CREZ Transmission Line in Scurry and Mitchell Counties*, Docket No. 37409, Order (March 8, 2010); and *Application of Oncor Electric Delivery Company LLC to Amend its Certificate of Convenience and Necessity for the Central Bluff – Bluff Creek 345-kV CREZ Transmission Line in Nolan, Taylor, and Runnels Counties,* Docket No. 37529, Order (April 15, 2010).

options for one of the projects.[47] In October 2009, LCRA TSC filed an application for the Gillespie to Newton CREZ priority project.[48] This application was ultimately denied by the Commission on the grounds that no route in the application met the statutory and regulatory requirements. ERCOT subsequently was asked to review whether the Gillespie to Newton project was still needed or if alternate transmission facility configurations could replace it. A second LCRA TSC CCN application for the CREZ priority project Twin Buttes to McCamey D transmission line was resolved by settlement and approved by the Commission.[49]

In February 2010, the order sequencing the filing of the subsequent CREZ CCN applications was suspended in response to the January 2010 ruling of a Travis County District Court reversing and remanding the order in Docket No. 35665, in which the Commission designated the companies that would build and operate the various CREZ facilities. A new order sequencing the subsequent CREZ CCN application filings was issued in April 2010 and was again revised in June 2010. Twenty-two CREZ CCN applications were scheduled to be filed in 2010. One CREZ CCN application, for the Odessa to McCamey A to McCamey C project originally assigned to LCRA TSC but subsequently reassigned to the City of Garland and South Texas Electric Cooperative, was scheduled to be filed in March 2011, as a consequence of the reversal and remand of the Docket No. 35665 order. Two CREZ projects assigned to LCRA TSC, the Kendall to Gillespie and Gillespie to Newton transmission lines, were determined to be no longer needed by ERCOT subject to the completion of alternative upgrades of existing transmission infrastructure. These projects were removed from the CREZ plan and LCRA TSC was relieved of the obligation to complete them in Docket No. 38577.

15. Luminant Administrative Penalty

In November 2009, Commission Staff and Luminant Energy Company LLC (Luminant) filed a settlement agreement partially resolving Luminant's failure to adhere to ERCOT protocols relating to the deployment of Load acting as Resource (LaaR) following an ERCOT deployment instruction.[50] The settlement stipulated the facts of the violation and Luminant agreed to pay an administrative penalty. Staff and Luminant disagreed on what maximum monetary penalty could be applied pursuant to PURA § 15.023 and certified this issue to the Commission. In February 2010 the Commission

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[47] *Comments Concerning LCRA Transmission Services Corporation's Proposed CREZ Priority Transmission Lines*, Docket No. 37049, Order Extending Filing Date (October 19, 2009).

[48] *Application of LCRA Transmission Services Corporation to Amend its Certificate of Convenience and Necessity for the Gillespie to Newton 345-kV CREZ Transmission Line in Gillespie, Llano, San Saba, Burnet, and Lampasas Counties, Texas,* Docket No. 37448, Order (April 28, 2010).

[49] *Application of LCRA Transmission Services Corporation to Amend its Certificate of Convenience and Necessity for the Proposed Twin Buttes to McCamey D CREZ 345 kV Transmission Line in Tom Green, Irion, and Schleicher Counties, Texas*, Docket No. 37778, Order (July 9, 2010).

[50] *Agreed Notice of Violation and Settlement Agreement Relating to Luminant Energy Company LLC's Violation of PURA § 39.151(j) and P.U.C. SUBST. R. 25.503(f)(2), Relating to Failure to Adhere to ERCOT Protocol § 6.10.5.4(1) Concerning Load Acting as Resource Service Requirements*, Docket No. 37634, Order on Certified Issue (February 25, 2010).

issued an order determining that Luminant's failure to timely deploy LaaR constituted a single violation and assessed an administrative penalty of $25,000.

C. Competitive Market Oversight Activities

The Competitive Markets Division is responsible for evaluating market design issues and analyzing the competitiveness and effectiveness of the market. This division also administers the energy efficiency and renewable energy programs. The Competitive Markets Division consists of two sections: Retail Markets and Wholesale Markets.

1. Retail Market Oversight

The Retail Markets section performs oversight of the retail electric market in several ways:

- ongoing review of the operation of the market as measured through the number of providers in the market, retail prices in the market, switching rates and other competitive market indicators;
- representing the public interest in contested cases, formal complaints and rulemaking proceedings;
- ongoing review of the appropriateness of Commission rules governing the operation of the retail market, including customer protections; and
- monitoring retail market issues, participating in ERCOT stakeholder discussions of retail issues, working to find solutions to retail market issues and analyzing trends in the retail market.

Retail Markets Staff also communicate with REPs and ERCOT in connection with significant retail market events, such as the exit of a REP from the market where customers may be transferred to a POLR. In such cases, Staff seeks to ensure an efficient transfer and protection of customers' rights under Commission rules, including continued benefits for low-income customers provided by the System Benefit Fund and the return of customers' deposits by the existing REP within seven calendar days of the initiation of the transition.

The Commission received a grant from the U.S. Department of Energy in 2010 to enhance the Commission's capabilities in a number of areas that are supported by the American Recovery and Reinvestment Act. The Retail Markets section hired two new employees as a result of the grant. This enables Retail Markets to focus additional effort on smart metering implementation, energy efficiency, distributed renewable generation and electric vehicles.

2. Wholesale Market Oversight

The Commission's wholesale market oversight continues to be supported by the activities of the Independent Market Monitor (IMM). The consulting firm Potomac Economics has served as the IMM since the summer of 2006. Potomac Economics' contract with the Commission was amended in October 2008 to expand the scope of work and extend the term from December 31, 2009 to December 31, 2012. The IMM carries out the following activities:

- conducts real time monitoring of the ERCOT market, reviews market operations, analyzes market indicators, and reports to the Commission when abnormal outcomes are detected;
- reviews the ERCOT Protocols governing the operations of the wholesale market and analyzes protocol revision requests (PRRs) submitted by market participants or ERCOT;
- reviews market design and operations in a broad sense and provides an annual report to the market; and
- monitors ERCOT's operation of the wholesale market.

Commission Staff attends ERCOT stakeholder meetings to monitor the development of the nodal market design and participates in discussions of issues related to market efficiency, competitiveness and grid reliability.

a. Wholesale Market Outcomes

Analysis of Competitive Performance

The IMM performed an analysis of market power in 2009 using structural and behavioral indicators that would indicate attempts by one or more market participant to exercise market power. One of the tests that it applied was to measure the frequency with which at least one supplier had the ability to exercise market power because it was pivotal in the market (that is, the load could not be served without this supplier's resources). The frequency of a supplier being pivotal has fallen consistently over the last five years. This means that the market has, from a structural perspective, become more competitive over this period. The IMM also found that the competitiveness of supplier offers improved considerably in 2006 compared to 2005, with even more substantial improvements in the period 2007 through 2009. Overall, based on its analysis, the IMM found that the ERCOT wholesale market performed competitively in 2009.

Transmission and Congestion

One of the most important functions of ERCOT is to manage the flow of power over the transmission network. Under the zonal market design, ERCOT had to manage two types of transmission congestion: zonal congestion, which limits the amount of power that can flow between zones, and local congestion caused by transmission constraints within a zone. ERCOT is divided into four zones and has five transmission interfaces. In 2009, inter-zonal congestion was most frequent on the West to North interface, followed by the North to Houston and the North to South interfaces. In 2009, there was a significant reduction in the congestion on the North to Houston and North to South interfaces, both in the frequency and magnitude of the congestion, a trend that continued in 2010. The decreased congestion is primarily attributable to a revision of the ERCOT Protocols that gave ERCOT better tools to manage certain transmission constraints efficiently.[51]

North to Houston Interface

Even though congestion has decreased in the North to Houston interface over the last two years, the Houston area continues to be affected by import limitations that translate into slightly higher wholesale prices in the Houston area. Over the years, these high prices have not attracted additional generation projects in the zone. Because Houston is an air quality non-attainment area, it may be difficult for generation builders to obtain air permits. To relieve the problem, ERCOT Staff developed the "Houston Import Project," which would add transmission facilities and improve existing lines to increase transfer capabilities into the area. A cost-benefit analysis showed that the cost of the project would not exceed expected production cost savings. Pursuant to the transmission planning guidelines, ERCOT Staff conducted an additional test to determine whether the Houston Import Project would benefit customers. The Staff concluded that the project would reduce revenues for generators (thus providing benefits to customers) and that the project will be needed for reliability reasons, possibly as early as 2015-2016. The ERCOT Board found that the project would promote competitiveness and improve reliability, and it approved the project.

West to North Interface

The West to North interface saw increasing congestion in 2008 and 2009. This was primarily caused by the significant development of wind generation in the West zone that cannot be absorbed by the load there and the limited transmission export capabilities out of that zone. The quantity of wind production that can be reliably accommodated in the West zone will continue to be significantly limited for several years until the planned CREZ transmission improvements are completed in the 2013-2014 timeframe. The Commission has identified CREZ projects that would relieve congestion for existing West zone wind generators as priority projects, and those projects were first to have their CCN applications considered by the Commission.

b. Wholesale Market Design

Preparations for Nodal Market

The Commission adopted a rule in August 2003 directing ERCOT to implement a nodal market design and in April 2006 approved the Protocols for the operations of the nodal market. The rule contemplated that the nodal market would begin operating in January 2009. ERCOT subsequently delayed the nodal market launch and in November 2008 ERCOT established December 2010 as the new launch date. The estimated budget for completing the nodal market design increased from $319.5 million in February 2008 to $510.1 million in March 2009. As of the end of November 2010, ERCOT had actually spent $523.4 million, with an additional $13 million in interest charges, and $25

[51] *See* Protocol Revision Request No. 764, *Zonal Congestion and CSCs/CREs*. Available online at: http://www.ercot.com/mktrules/issues/prr/750-774/764/index.

million set aside for nodal stabilization efforts after market launch. ERCOT conducted extensive market trials throughout 2010 to test the new system and successfully launched the nodal market on December 1, 2010.

New Ancillary Service Methodology

Ancillary Services include short-term capacity reserves and balancing energy used by ERCOT to balance load and generation at all times and maintain a stable frequency in the system. In October 2008, ERCOT adopted a new methodology for the procurement of non-spinning reserves (capacity reserves that can come on line within 30 minutes,) and started procuring non-spinning reserves on a 24-hour basis, whereas this service was previously procured during peak hours only. This change was made necessary by an increase in the frequency and size of sudden changes in output by wind generators as the amount of wind generation has increased. In the nodal market, ERCOT is not considering any additional change in the procurement of non-spinning reserves.

In the nodal market, ERCOT anticipates a reduced requirement for Regulation Service. Regulation is deployed every four seconds to balance generation and load and maintain a stable frequency. Regulation is the fine adjustments made to match supply and demand between the balancing energy changes, which occur at regular, longer intervals with balancing energy service. Under the zonal market, balancing energy was deployed every 15 minutes. Under the current nodal market, the balancing energy market is replaced by a Security Constrained Economic Dispatch model that executes energy deployments orders every five minutes. The deployment of balancing energy at shorter intervals should result in a reduced requirement for Regulation Service. At the inception of the nodal market, Regulation Service requirements were reduced by one-half, on average. Once ERCOT acquires experience with regulation deployment needs under nodal, the methodology will be re-evaluated and adjustments in the procurement of these short-term capacity reserves will be adopted as appropriate.

Allocation of Ancillary Services Costs to Wind Generators

In 2008, when ERCOT adopted a new methodology for procuring higher levels of non-spinning reserves in response to the increase of wind generation, an ERCOT Board member expressed interest in exploring the assignment of ancillary service costs to wind generators based on a principle of cost causation. The evaluation of this proposal was assigned to the Cost Allocation Task Force (CATF), which examined the function of ancillary services and the possibility of identifying and assigning costs related to incremental amounts of ancillary services. The CATF concluded that ancillary service costs are not directly assignable to individual generation entities primarily because ancillary services are purchased for the system as a whole (ancillary services are currently paid for by load for that reason). However, some Board members insisted that wind impacts on ancillary service costs ought to be quantifiable, and a new task force was established to develop a methodology for assigning ancillary service costs to wind, the Wind Cost Allocation Task Force (WCATF).

The WCATF developed two different allocation methodologies for the Board's consideration, noting that it was not recommending approval of either of its proposals. A vigorous discussion followed among the stakeholders. This debate took a substantial amount of market participant and ERCOT Staff time and some market participants and Board members raised questions whether the issue should take the focus away from preparations for the nodal market. In the end, no clear instructions were issued from the Board on how to proceed, and the WCATF was eventually disbanded. This issue may be raised again, when ERCOT has the opportunity to re-evaluate the ancillary service procurement methodology using on nodal market data.

Enabling Load Response through Price Transparency

Demand response to energy prices is an essential part of a competitive market as it allows customers to reduce demand given the signal of high prices and it provides an additional tool to maintain reliability. In the nodal market design, the timing of the posting of local marginal prices (LMPs) has been an issue for demand resources, as the market design initially provided for posting of LMPs after each interval, making load response to prices difficult or impossible. The market rules were revised so that LMPs will now be posted for market participants to see just before each interval.[52] The posting of LMPs for the load zones and hubs will allow all market participants to better assess when demand response is needed and whether the prices are sufficient that market participants may elect to reduce their consumption. ERCOT stakeholders and Commission Staff continue to look for ways to facilitate load participation in the nodal market.

c. Budget Oversight

Under the ERCOT budget proposal, ERCOT's current system administration fee of $0.4171 per MWh, approved by the Commission in May 2006, will remain in effect in the 2011 budget. The nodal market implementation surcharge of $0.375 MWh will also remain in effect in 2011. ERCOT will be able to hold the administration fee and nodal surcharge at current levels by using $25.2 million of the $113 million ERCOT Board discretionary fund to pay for post go-live charges on the nodal program, and applying excess funds from 2010 to the 2011 budget. These provisions of the ERCOT budget proposal were approved by the ERCOT Board at its November 16, 2010 meeting. Commission review of the ERCOT budget is pending.

3. Resource Adequacy and Energy Prices

The wholesale market is a competitive market, in which most of the owners and developers of generation facilities respond to their perception of the market opportunities and risks, and deploy capital accordingly. The supply of generation relative to demand will influence energy prices, which in turn can serve to encourage or discourage development of new generation.

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[52] *See* Nodal Protocol Revision Request No. 169, "Clarify the Calculation and Posting of LMPs for the Load Zone and LMPs for Each Hub." Available online at: http://www.ercot.com/mktrules/issues/nprr/151-175/169/index.

Roughly 8,400 MW of new generating capacity was completed in 2009 and 2010. This included 3,041 MW of coal-fired capacity, 1,987 MW of wind capacity and 3,240 MW of natural gas capacity. At present, ERCOT is tracking 194 active new generation interconnection requests totaling about 65,500 MW. Of this amount, about 19.4% is natural gas, 8.6% is nuclear, 7.6% is coal, and 59% is wind. The amount of this new proposed capacity that will eventually be built is not known.

To ensure reliability, ERCOT established a minimum target planning reserve margin, which represents generation reserves in excess of forecasted peak demand needed to ensure reliability against extreme temperatures and generation outages. Since 2002, ERCOT's target reserve margin has been 12.5%. In November 2010, the ERCOT Board approved an increased target reserve margin of 13.75%. The decision to increase the target reserve margin was based on an updated loss-of-load study that quantified the reliability impacts of generation outage, load forecast uncertainties, and intermittent generation resources.

In June 2010, ERCOT projected that reserves would exceed the 12.5% target level through 2015. The load forecast, which was based on econometric modeling, shows annual load growth ranging from 1.5% to 2.4% during that period. In December 2010, ERCOT released an updated forecast of generation capacity, electricity demand, and reserves. When compared to the new 13.75% target reserve margin, ERCOT projects adequate reserves through 2015, except in 2013, when the projected reserve margin drops to 13.14%.

Table 1 – ERCOT Reserve Margin Projection through 2016[53]

	2011	2012	2013	2014	2015	2016
Firm Load (MW)	63,532	64,947	66,514	67,655	68,672	69,477
Resources (MW)	73,973	75,195	75,252	77,449	78,245	78,905
Projected Reserve Margin	16.43%	15.78%	13.14%	14.48%	13.94%	13.57%
Potential Capacity in Full Interconnection Study (MW)	4,307	9,211	10,239	13,430	14,711	18,062

For purposes of the resource forecast, ERCOT includes only existing capacity, expected new capacity with a signed interconnection agreement and air permit[54], if applicable, and mothballed capacity that owners have projected will return to service. Wind generation, which provides energy but comparatively little capacity value, is included in the forecast at 8.7% of its nameplate capacity rating. These projected capacity additions are conservative assumptions that do not consider new capacity that

53 *Capacity, Demand and Reserves Report* , ERCOT (December 2010). Available online at: http://www.ercot.com/news/press_releases/2010/nr-12-16-10.

54 Cobisa Greenville (1,792 MW) has a signed interconnection agreement and air permit, but is not included in the Capacity, Demand, and Reserves Report based on a formal letter from a corporate officer to ERCOT stating that, based on its current expectations, its planned unit should not be included in the reserves calculation.

may still be in the planning and development stages. The last row of the above table shows additional capacity under study that may be built but which is not included in ERCOTs projected reserve margins.

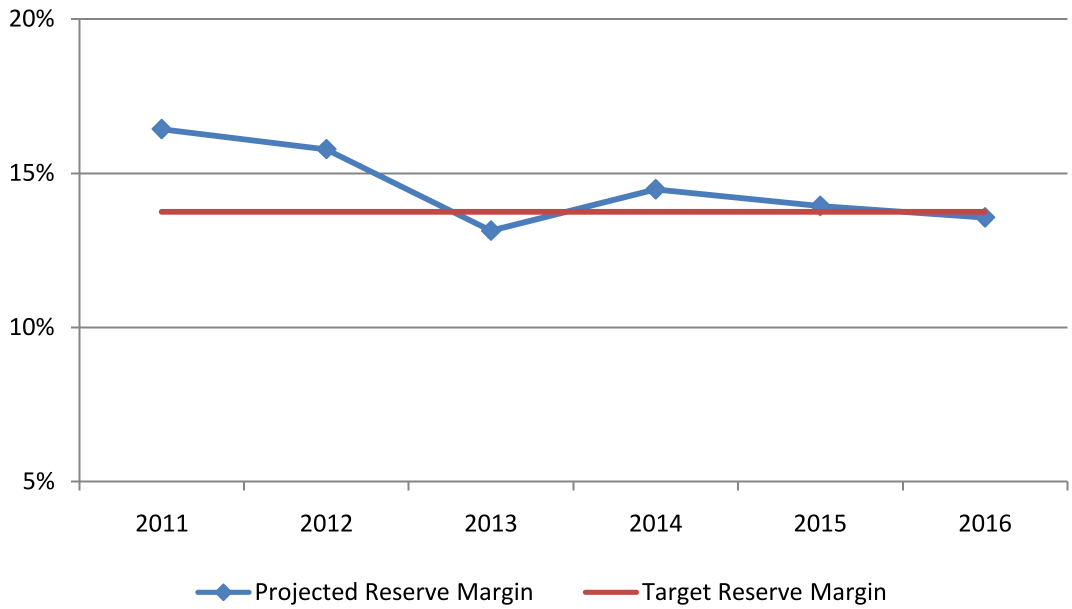

Figure 1 – ERCOT Planning Reserve Margin

During August 2010, ERCOT set a new all-time peak demand record of 65,715 MW. Like all other regions of the country, ERCOT plans to meet “firm” demand which is lower than “peak” demand, because some loads act as resources at the time of peak demand. In other words, those loads are paid to reduce their consumption when called upon by ERCOT to do so. Nonetheless, the actual peak demand in 2010 was higher than expected.

D. Oversight and Enforcement

The Commission protects consumers, the electric market, the reliability of the electric grid, and promotes fair competition by enforcing statutes, rules, and orders applicable to entities under its jurisdiction. The Commission’s enforcement efforts in the electric industry focus on violations of PURA, the Commission’s Substantive Rules and ERCOT protocols.

1. Commission Enforcement Structure

The Commission’s Oversight and Enforcement Division (O&E) was initiated on October 1, 2007. O&E’s goal is to promote compliance with PURA and other applicable laws, and PUC Substantive Rules by electric and telecommunication service providers to protect customers and markets, and to ensure reliability. O&E works with the Commission Legal Division, as well as other divisions, in its investigations and enforcement activities. In the electric market, the main areas of oversight and enforcement are:

- Wholesale electric issues
- Retail electric issues
- Service quality
- ERCOT protocol violations
- Market manipulation and market power abuse

The Commission's primary enforcement tool is the imposition of administrative penalties. The Commission's enforcement and administrative penalty authority is outlined in Chapter 15 of PURA, which provides for administrative penalties of up to $25,000 per violation per day.

2. Enforcement Process

O&E has set up programs and processes to accomplish oversight of the industries it oversees through coordination with other Commission divisions regarding information on potential violations, and to review or audit formal reports submitted to the Commission. The programs may be categorized as follows:

- Retail Electric
- Audit of retail electric providers
- Complaint-based investigations
- Other investigations
- Wholesale Electric
- IMM-referred market manipulation and market power abuse investigations
- TRE-referred protocol violations
- ERCOT protocol development and revisions
- Telecommunications and Miscellaneous
- Telecom investigations
- No-Call investigations
- Service quality

O&E has several sources of information regarding potential violations that might generate an investigation by the Division. These include the Commission-contracted reliability monitor, the Commission-contracted market monitor, other PUC divisions, filed reports, industry stakeholders, ERCOT, and other sources.

Once O&E has received information regarding a potential violation, the information is reviewed to determine if an investigation is warranted. If warranted, an investigation is opened and the provider is notified of the investigation. The investigation is conducted through research, meetings with the provider, and requests for information to the provider. An investigation may be concluded with a recommendation for action, if needed, or no further action, if it is determined that no violation occurred. If a violation is found, the provider may be sent a warning letter for a minor violation. Otherwise, the investigation is closed and the Notice of Violation (NOV) process begins.

The first step in the NOV process is to send a Pre-NOV letter to the provider describing the violation and recommending an administrative penalty. The provider has the opportunity to meet with Commission Staff to resolve the matter. The Staff and the provider may enter into a settlement agreement resolving the issues of the violation, the amount of administrative penalty, and any other appropriate remedies such as a mitigation plan. Settlement documents are filed with the Commission.

PURA provides for a three-level classification system for violations, which includes a range of administrative penalties.[55] The classification system includes the following factors for determining penalty levels:

- The seriousness of the violation;
- The economic harm caused;
- The history of previous violations;
- The amount of penalty necessary to deter future violations;
- The efforts to correct the violation; and
- Any other matter justice may require.

If the issues are not resolved through a settlement agreement, the Executive Director sends a Notice of Violation to the provider. This action initiates a contested case proceeding to resolve the issues of the violation and the administrative penalty. The NOV is referred to the State Office of Administrative Hearings (SOAH) and a hearing is conducted.[56] The SOAH judge issues a proposal for decision that is subsequently ruled on by the Commissioners to determine whether a violation has occurred and, if so, the appropriate penalty.

3. Current Penalty Activities

During the period from January 2009 through December 2010, the Commission assessed over $9.8 million in penalties to electric market participants. The following table provides of summary of completed electric industry Notices of Violation since January 2009. A complete list of the Notices of Violations appears in Appendix B. In total during 2009 and 2010, Commission Staff opened 136 investigations for the electric industry and closed 99 investigations. An investigation is considered closed if it has either been closed with no NOV having been issued, or when an NOV has been issued.

Table 2 – Completed Electric Industry Notices of Violations

Violation Type	Penalty Amount
Retail Market Violations	$4,455,000
Service Quality Violations	$1,771,500
Wholesale Market Violations	$3,618,000
TOTAL	$9,844,500

55 PURA § 15.023.

56 While in most contested cases the Commission may conduct the hearing, in the Notice of Violation (NOV) process the hearing must be conducted by a SOAH judge.

E. Non-ERCOT Utilities: Market Development Activities

Senate Bill 7, the law that introduced retail competition in electricity in Texas, permitted the Commission to delay retail competition in an area where deregulation in accordance with Chapter 39 of PURA would not result in fair competition and reliable service.[57] In addition, provisions of PURA that applied to El Paso Electric Company and Southwestern Public Service Company resulted in the delay of competition in the areas served by these companies. Relying on its discretion under Chapter 39, the Commission delayed retail competition for the Entergy Gulf States service area (now Entergy Texas) and for the Southwestern Electric Power Company (SWEPCO) service area. The result was that retail competition was initiated within ERCOT but was delayed outside of ERCOT.

Senate Bill 7 included provisions recognizing that it would be more difficult to implement retail competition in areas outside of ERCOT, based on the lack of an independent organization and the concentration of ownership in the generation sector in some of those areas. In particular, PURA § 39.152 established competitive criteria that must be met for the Commission to certify a power region:

1. a sufficient number of interconnected utilities in the power region are under the operational control of an independent organization;
2. a generally applicable tariff guarantees open and nondiscriminatory access to transmission and distribution facilities in the region; and
3. no person owns and controls more than 20% of the installed generation capacity located in or capable of delivering electricity to the region.

The Commission has not certified that any area outside of ERCOT meets the criteria in PURA § 39.152.

An important element in the success of a competitive energy market is an independent organization to manage transmission access and operate short-term energy and capacity markets to maintain the reliability of the electric system.[58] When competition was introduced in ERCOT, a regional transmission organization was operating in the Panhandle and Northeast Texas. This organization, SPP, was providing independent management of the transmission system in these areas, but it was not operating short-term energy and capacity markets to maintain reliability. In Southeast Texas and the far West Texas area in and adjacent to El Paso, there was not an independent organization operating. SPP continues to operate in the Panhandle and Northeast Texas, and today it operates a short-term energy market, the Energy Imbalance Service, and it is planning to expand its market to include short-term capacity products. In Southeast and far West Texas, there is still not an independent organization performing the transmission management and market functions.

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[57] PURA § 39.103.

[58] PURA § 39.151.

After the enactment of Senate Bill 7, legislation was enacted relating to retail competition in some of the areas outside of ERCOT. In addition, the Commission adopted rules addressing retail competition in some of the utility service areas. This section summarizes the history and current status with respect to the possible introduction of retail competition in the non-ERCOT areas of Texas.

1. Entergy Texas

Retail competition was delayed in the Entergy region pursuant to an order of the Commission.[59] In 2005 the Legislature enacted Subchapter J of PURA Chapter 39, which addressed the process by which Entergy would be regulated and might transition to retail competition.[60] A proceeding was initiated in December 2006 to determine the appropriate power region for Entergy, and this proceeding was pending before the Commission when the Legislature met in 2009.[61] Entergy operates in the SERC Reliability Corporation (SERC) area, and it argued that it should be moved into ERCOT. While moving to SPP appeared to be an option available to the utility, Entergy argued that it should not be required to pursue moving into SPP, because it believed that full customer choice could not reasonably be expected to be implemented in SPP in the foreseeable future. Other participants in that proceeding were concerned about the cost of integrating Entergy into ERCOT. One of the reasons that this case was still pending in 2009 was that the Commission ordered Entergy to request the SPP staff to conduct an analysis of the costs of integrating Entergy into SPP.

The 81st Legislature amended the provisions in Subchapter J relating to Entergy's transition to competition. Key amendments were:

- Entergy was directed to cease activities relating to the approval of a plan to transition to retail competition;
- The Commission was permitted to conduct a proceeding to determine the appropriate power region for Entergy, when the conditions supporting such a proceeding exist; and
- The Commission was prohibited from approving a plan for Entergy to transition to retail competition until four years after it approved the power region.[62]

Entergy Texas is a part of a larger Entergy system that also includes electric utilities in Arkansas, Mississippi, and Louisiana. Entergy Arkansas and Entergy Mississippi have given notice that they will cease operating under the Entergy System Agreement that currently governs operations and the allocation of costs among the companies in the system. Entergy Arkansas will leave the system agreement in December 2013, and Entergy Mississippi will leave in November 2015. In addition, the

[59] *Staff's Petition to Determine Readiness for Retail Competition in the Portions of Texas Within the Southeastern Electric Reliability Council*, Docket No. 24469, Order (Dec. 20, 2001).

[60] PURA § 39.451-.463.

[61] *Application of Entergy Gulf States, Inc. for Transition to Competition Plan (TTC Plan)*, Docket No. 33687.

[62] PURA § 39.452(i).

Federal Energy Regulatory Commission (FERC) commissioned a study of the costs and benefits of the Entergy companies joining SPP. The study was completed in September 2010 and it showed a net present value of $739 million cost savings over a ten year period, although this total included CLECO Power which is a smaller non-Entergy company within the Entergy service area.[63]

There is some uncertainty about the appropriate power region for Entergy Texas. The FERC study showed that there are benefits associated with the Entergy companies joining the SPP, and such a conclusion could result in pressure from the FERC and state regulators for Entergy to join the SPP. At this point, the Commission has not initiated a proceeding to determine the appropriate power region for Entergy Texas, and it seems prudent not to initiate such a proceeding before the results of the FERC study have been fully analyzed.

2. Southwestern Electric Power Company

Retail competition was also delayed for SWEPCO, pursuant to a Commission order.[64] In August 2006, to provide greater certainty about the conditions under which retail competition might be introduced in the SWEPCO area, the Commission adopted a rule to address SWEPCO's transition to competition.[65] The rule established that retail competition would not begin before January 1, 2011. It also prescribed a long set of pre-conditions that must be completed before retail competition begins. These pre-conditions include actions such as the completion of business separation of regulated and competitive functions, certification of a qualified power region, and the approval of unbundled transmission and distribution rates.

The 81st Legislature adopted Subchapter K of PURA Chapter 39, relating to SWEPCO's transition to competition. Subchapter K includes a set of pre-conditions for retail competition similar to those in the rule described above. Unlike the Commission's rule, Subchapter K does not include a date before which retail competition may not be initiated. One pre-condition is the approval of a regional transmission organization by the FERC and the commencement of independent operation of the transmission grid.[66] SWEPCO operates in the SPP, and it appears that the FERC approval of the SPP and its tariff for the Energy Imbalance Service meets this criterion. However, the other pre-conditions have not yet been satisfied.

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[63] Charles River Associates and Resero Consulting, *Cost-Benefit Analysis of Entergy and CLECO Power Joining the SPP RTO*, (September 30, 2010).

[64] *Staff's Petition to Determine Readiness for Retail Competition in the Portions of Texas Within the Southwest Power Pool*, Docket No. 24468, Order on Rehearing (February 1, 2002).

[65] P.U.C. SUBST. R. 25.422.

[66] PURA § 39.503(b)(1).

3. Southwestern Public Service Company

Senate Bill 7 from the 1999 legislative session included Subchapter I of PURA Chapter 39, which governs the transition to retail competition for SPS.[67] This subchapter established distinct rules for the SPS region to transition to competition and required SPS to file a transition plan with the Commission not later than December 1, 2000.[68] A number of amendments to sections of Subchapter I were enacted in the 2001 legislative session, and the current provisions of Subchapter I permit SPS to "choose to participate in customer choice." If SPS makes such a choice, it must file a transition plan for Commission review. Subchapter I also includes provisions concerning market concentration. The Commission is prohibited from certifying a power region if any utility has more than 20% of the generation capacity in or capable of delivering power to the area, and SPS currently owns a significant share of the generation capacity in or capable of delivering power to the region.[69] SPS, like SWEPCO, operates within SPP.

4. El Paso Electric Company

Retail competition was delayed for EPE by statute, until a rate freeze adopted in the mid-1990s expired.[70] In October 2004, to provide greater certainty about the conditions under which retail competition might be introduced in the EPE area, the Commission adopted a rule to address its transition to competition.[71] The rule prescribes a set of pre-conditions for retail competition. These conditions would be required to be completed before retail competition begins. One of the pre-conditions is the approval of a regional transmission organization by the FERC and the commencement of independent operation of the transmission grid.[72] EPE operates in the Western Electricity Coordinating Council (WECC), which is a reliability organization, not a regional transmission organization. The California Independent System Operator is the only organization in the Western region that has obtained FERC approval as a regional transmission organization, and it does not operate EPE's transmission systems.

5. Cap Rock Energy Corporation

Prior to the start of retail competition in ERCOT, Cap Rock was an electric cooperative owned by its members. In 1998, the members of the cooperative approved a plan to convert it to an investor-owned utility. Senate Bill 7 from the 1999 legislative session amended the definition of "electric cooperative" in PURA to include the successor organization of a cooperative that converted to a corporation in accordance with a plan approved by the members of the cooperative.[73] This amendment meant that

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[67] PURA § 39.401 -410.

[68] PURA § 39.502(c).

[69] PURA § 39.407(a).

[70] PURA § 39.102(c).

[71] P.U.C. SUBST. R. 25.421.

[72] P.U.C. SUBST. R. 25.421(e)(1).

[73] PURA § 11.003(9).

Cap Rock Energy Corporation, the successor to the cooperative, was not required to introduce retail competition and, like other cooperatives, could decide whether to do so. In the 2003 legislative session, Senate Bill 1280 was enacted, which restored the original definition of "electric cooperative" and made it clear that a company that had previously not been subject to Chapter 39 was now subject to it. This section also established criteria for the Commission to consider in deciding how Chapter 39 would apply to such a company.[74] In February 2010, Sharyland Utilities and Cap Rock Energy Corporation filed a notice that they planned to merge, with Sharyland the surviving entity, and Cap Rock Energy becoming the Cap Rock Division of Sharyland Utilities. In issuing an order concluding that this transaction was in the public interest, the Commission approved a requirement that Sharyland conduct a study of whether it was appropriate to introduce competition in the Cap Rock service area, to be completed within one year of the closing of the merger transaction.[75] The Cap Rock Division of Sharyland has customers both in ERCOT and in the SPP.

F. Customer Education Activities

Since its inception in February 2001, the goal for the "Texas Electric Choice" campaign has been to educate Texans about the changes and choices in the retail electric market. The eighth and ninth years of the campaign (September 1, 2008 through August 30, 2010) continued to educate Texans about electric choice, Retail Electric Providers, and plan options. The education campaign uses a number of means, in both English and Spanish, to reach and educate the public. A summary of each of these methods is included below.

1. Outreach and Public Service Announcements

The Commission conducted a number of activities to improve the public visibility of retail choice, largely designed to let electric customers know that the campaign website, www.PowerToChoose.org, and call center were neutral, credible sources of information about retail choice.

Lone Star Radio Network – This series of public service announcements about Electric Choice, Energy Star Tax Holiday, and Lite-Up Texas on a statewide network of radio stations reached an estimated cumulative audience of more than three million listeners per year in FY 2009 and FY 2010.

Education Partners – The Commission continued its partnership with local police departments and community groups around the state of Texas during the 2009-2010 biennium.

[74] PURA § 39.102(d) and (e).

[75] *Joint Report and Application of Sharyland Utilities, LP, Sharyland Distribution and Transmission Services, LLC, Hunt Transmission Services, LLC, Cap Rock Energy Corporation, and NewCorp Electric Cooperative, Inc. for Regulatory Approvals Pursuant to PURA §§ 14.101, 37.154, 39.262, and 39.915*, Docket No. 37990, Order (July 8, 2010).

For FY 2009, Sherry Matthews Advocacy Marketing continued to coordinate all National Night Out (NNO) efforts by contacting previous participants and distributing Texas Electric Choice campaign materials. Over 129,800 pieces of campaign materials were distributed by forty-one groups. For FY 2010, the Information & Education Department (I&E) of the Commission took on this task when the Sherry Matthews contract lapsed on February 28, 2010. In May 2010, I&E sent a letter to all past participants letting them know that the campaign had been moved in-house. The letter included I&E staff's contact information. A follow-up letter was mailed July 2010 to remind past participants that materials were available for distribution. For FY 2010 eighty-five groups participated and 234,350 pieces of campaign materials were distributed. These events have reached over a million people during the 2009-2010 biennium.

I&E attended and supplied various educational materials to numerous community events/venues and civic "town hall" events for FY 2009/FY 2010, including Primrose at Highland Meadows Senior Apartments, Hurst-Euless-Bedford School District's Back2School day, Houston's Sheltering Arms, IBM's Earth Day, and the City of Hutto's "How to Shop for a Retail Electric Provider" workshop. In addition, I&E staff frequently teamed up with Office of Public Utility Counsel staff or passed out educational materials on their behalf. In FY 2009, 252,244 pieces of educational materials were distributed to customers. In FY 2010, 258,040 pieces of educational materials were distributed to customers.

<u>TAB NCSA Program</u> – In FY 2009, the Commission participated in the Texas Association of Broadcasters' Non-Commercial Sustaining Announcement program, which allowed the Commission's public service announcements on Electric Choice to be aired throughout competitive retail electric markets in Texas at about 20-25% of the cost of buying commercial airtime with the same reach.

<u>Energy Star Tax-Free Weekend Video News Release</u> – During Memorial Day Weekend 2009, the Commission distributed a video news release statewide that alerted consumers to the Comptroller's tax-free weekend for energy-efficient appliances and related products. The releases were picked up by television stations across the state and reached 7.3 million Texans with a total cost of about $13,000.

<u>Websites</u> – The Texas Electric Choice campaign website, www.PowerToChoose.org, and its Spanish-language counterpart www.PoderDeEscoger.org, are vital parts of the customer education process. During FY 2010, the website was updated to include information on Smart Meters, Distributed Renewable Generation, and Renewable Energy Credits. Key statistics for these websites during the 2009-2010 biennium include:

Table 3 – PowerToChoose Website Statistics

Unique Visitors	1,904,615
Visits	3,974,979
Downloads - (PUC Website Publications only - not PTC or PDE)	517,217

Table 4 – PoderDeEscoger Website Statistics[76]

Unique Visitors	26,920
Visits	63,513

2. Internet Search Engine Marketing

The campaign initiated a targeted Internet search engine marketing program in the summer of 2007. The goal of the program was to drive Internet users to the PowerToChoose website to shop for a retail electric provider. Internet users who did Google and Yahoo! searches on terms relating to electric service in Texas would see banner ads on the right column of the search engine results page linking the user to the PowerToChoose website. When a user clicked on the link to the site, the Commission paid a small fee to the search engine provider. During the summer of 2007, more than 16,000 people followed the link to the PowerToChoose website and clicked through to the site's retail offers page. During the summer of 2008, 63,996 people followed the link to PowerToChoose website and clicked through to the site's retail offers page. During summer 2010, 25,778 people compared offers on the PowerToChoose website.

3. Call Center

For FY 2007/FY 2008, the Texas Electric Choice campaign provided a Texas-based, toll-free, bilingual, independently contracted call center (1-866-PWR-4-TEX (1-866-797-4839)) as a way to give customers another point of contact with the campaign. Customer service representatives were available five days-a-week, and an automated system served customers seven days-a-week. Customers could ask questions, learn which REPs serve their area, and request educational materials (fulfillment packets). This call center was maintained during FY 2009 and FY 2010 through February 28th, 2010. Beginning March 1, 2010, Customer Protection Division (CPD) brought this service in house and trained Intake Center staff to answer these calls. I&E staff were tasked with putting together and mailing out all fulfillment packets that were requested by customers. The fulfillment packets include a cover letter, the award-winning "Official Guide to Electric Choice" brochure, the "How to Choose a Retail Electric Provider" brochure, and a list of REPs and their phone numbers. Currently, all CPD Intake Center staff are trained and available to answer Texas Electric Choice calls.

Table 5 – Contracted Call Center Activity September 1, 2008 - February 28, 2010

Total Calls	187,787
Total Representative-assisted Calls	136,078
Total Spanish-Language Calls	19,857

[76] No statistics for PoderDeEscoger were collected before March, 2009.

Table 6 – CPD Call Center Activity March 1, 2010 - August 30, 2010

Total Calls	19,528
Total Representative Calls	16,539
Total Spanish - Language Calls	2,071

Table 7 – Number of Fulfillment Packets March 1, 2010 - August 30, 2010

March 2010	172
April 2010	167
May 2010	181
June 2010	167
July 2010	153
August 2010	170
Total	1,010

4. Educational Literature

Brochures, fact sheets, and other educational materials are distributed via mail, e-mail, at campaign events, through a network of community-based organizations, and via the campaign's Websites and Call Center. Fact sheets, which can be found on the Commission's website as well as through both PowerToChoose.org and PoderDeEscoger.org, are routinely created and updated for distribution as part of the Commission's outreach efforts. The fact sheets provide information on a number of current industry and consumer topics. The Commission distributed nearly 2 million pieces of information products during 2009 and 2010. In the spring of 2010, I&E created a new brochure (How to Shop for a Retail Electric Provider) that is a step-by-step guide for navigating the PowerToChoose.org website when shopping for a REP. This brochure has been included in the Texas Electric Choice fulfillment packets and, along with all of the Commission's other informational pieces, can be accessed on all three websites.

5. Advanced Metering Deployment

The I&E Division collaborated with the Competitive Markets Division to assist the TDU's with their Advanced Meter consumer education campaigns – Oncor's "Smart Texas – rethinking energy" campaign, CenterPoint Energy's "energy InSight" campaign, and AEP's gridSMART campaign. Their marketing efforts included door hangers, billboards, brochures, website ads, and movie theatre ads. Additionally, I&E created a Smart Meter fact sheet for visitors to the Commission's website and added a Smart Meter benefits and FAQ section on the PowerToChoose.org website.

G. Low Income Discount: System Benefit Fund

The Legislature appropriated $119,570,603 for FY 2010, from which low-income discounts were provided in September 2009 and May through August 2010. It also appropriated $132,291,594 for the FY 2011, for low-income discounts in September 2010 and May through August 2011. In January 2010, a memo requesting a 5% budget savings plan was sent to State agencies for FY 2010 and FY 2011. The savings associated with the low-income discount program are $6,126,254 for FY 2010 and $6,762,303 for FY 2011. The new appropriated amounts for the low-income discount program are $113,444,349 for FY 2010 and $125,529,291 for FY 2011. Of the funds for FY 2009, 2,219,480 discounts were distributed to 699,549 separate households equating to $93,203,704 in discounts given. Each household that is deemed is eligible may receive up to five months of discounts depending on when they submit their application. For FY 2010, figures show 2,525,086 discounts distributed to 807,797 households which equate to $81,413,764 in total discounts given.

The SBF discount is based on the POLR rate in effect, the FY 2009 POLR rate was $0.191 per kWh and the FY 2010 was $0.141 per kWh.

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III. EFFECTS OF COMPETITION ON RATES AND SERVICE

In the last two years, customers in every competitive area of the Texas retail electric market have enjoyed an enviable position of choice of variable and one-year fixed rates that are up to three cents per kWh below the national average. Average all-in wholesale prices for electricity in ERCOT were $35.09 per MWh in 2009 and $43.02 MWh in 2010, compared to $78 per MWh in 2008. In comparison, in 2009 all-in prices for electricity were $38 per MWh in the California electricity market, $55 per MWh in the New York market, $50 per MWh in the Pennsylvania-New Jersey-Maryland (PJM) market, and $59 per MWh in the New England market.

Electricity rates in Texas are greatly affected by natural gas prices as gas is burned to generate about 42% of electricity (2009), with an even higher percentage during periods when electricity demand is high. In the last two years natural gas prices have fallen from a 2008 peak of about $13 per MMBtu. With natural gas prices averaging $4.50 per MMBtu this year, most competitive offers in the Texas power market are below the 2001 regulated rates in effect prior to the introduction of retail competition. Most competitive offers in the Texas power market have decreased an average of 13.1% for fixed rates and 17.5% for variable rates, not adjusted for inflation, since the state opened its market to retail competition in 2002.

New REPs have continued to enter the market, selling plans with an array of terms of service, from one month to multiple years, up to 100% renewable energy, fixed rates, indexed rates and variable rates. In the residential sector, most retail customers may choose from over 35 REPs offering as many as 226 different rate packages. ERCOT reports that 26 new REPs entered the market in 2009. Residential customers have about 2.5 times more service plans options than they did at the end of 2008.

As of June 2010, over 3.4 million individual customer premises were taking service from REPs other than the incumbent provider in their area, based on data reported to the Commission by the transmission and distribution utilities (TDUs). This accounts for more than 52% of all customers in service areas open to competition. Of these customers, 83.7%, or approximately 2.9 million, are residential customers.

As of January 2010, more than half of the residential customers in the competitive areas of ERCOT had chosen a non-incumbent provider. Texas is the only state with a competitive retail electric market in the nation to have achieved such a high rate of switching. Within the ERCOT region, the highest rate of switching is in the TNMP service area, at 66.89%, and the lowest rate is in the Oncor service area, at 45.86%. The high switching rate is further evidence that the state's well-structured competitive market is promoting competition among market participants to the economic benefit of customers. Competing REPs originally focused their efforts on winning customers in the large urban markets of Houston and Dallas-Fort Worth but have now branched out with most residential competitive REPs marketing throughout ERCOT.

A. Effect of Competition on Rates

1. Wholesale Market Prices

There are three major components to the ERCOT wholesale market:

- The bilateral market, which compromises 90% to 95% of all power traded;
- The balancing energy market, which makes up the other 5% to 10% of energy bought and sold and is used by ERCOT to match supply and demand in the short term, and;
- The ancillary service markets, which are used by ERCOT to procure capacity to maintain system reliability.

In general, Texas wholesale power prices tend to follow natural gas prices because 59% of installed capacity generation is fueled by natural gas. As a result, natural gas-fueled generation typically sets the market price for energy in the balancing energy market. Although most power is purchased through bilateral forward contracts, prices in the balancing energy market are highly visible and influence prices in bilateral market.

a. Balancing Energy, Bilateral, and Gas Prices

Natural gas prices in 2009 were the lowest they have been since 2003, averaging \$3.74 per MMBtu, compared to \$8.50 per MMBtu in 2008. Gas prices edged higher in the first 9 months of 2010, averaging \$4.54 per MMBtu through September 2010. Average bilateral wholesale electricity prices were \$38.18 in 2009 and \$44.17 through September 2010,[77] reflecting the higher 2010 natural gas prices.

The ERCOT market relies on bilateral contracts between buyers and sellers of electricity as the principal mechanism for trading power. While bilateral agreements are negotiated in private, reporting agencies like SNL Financial compile daily wholesale market prices that are generally indicative of bilateral contract prices. Figure 2 shows that bilateral wholesale electricity prices and natural gas prices follow the same general trend.

[77] *SNL Financial* (2010). Available online at: http://www.snl.com.

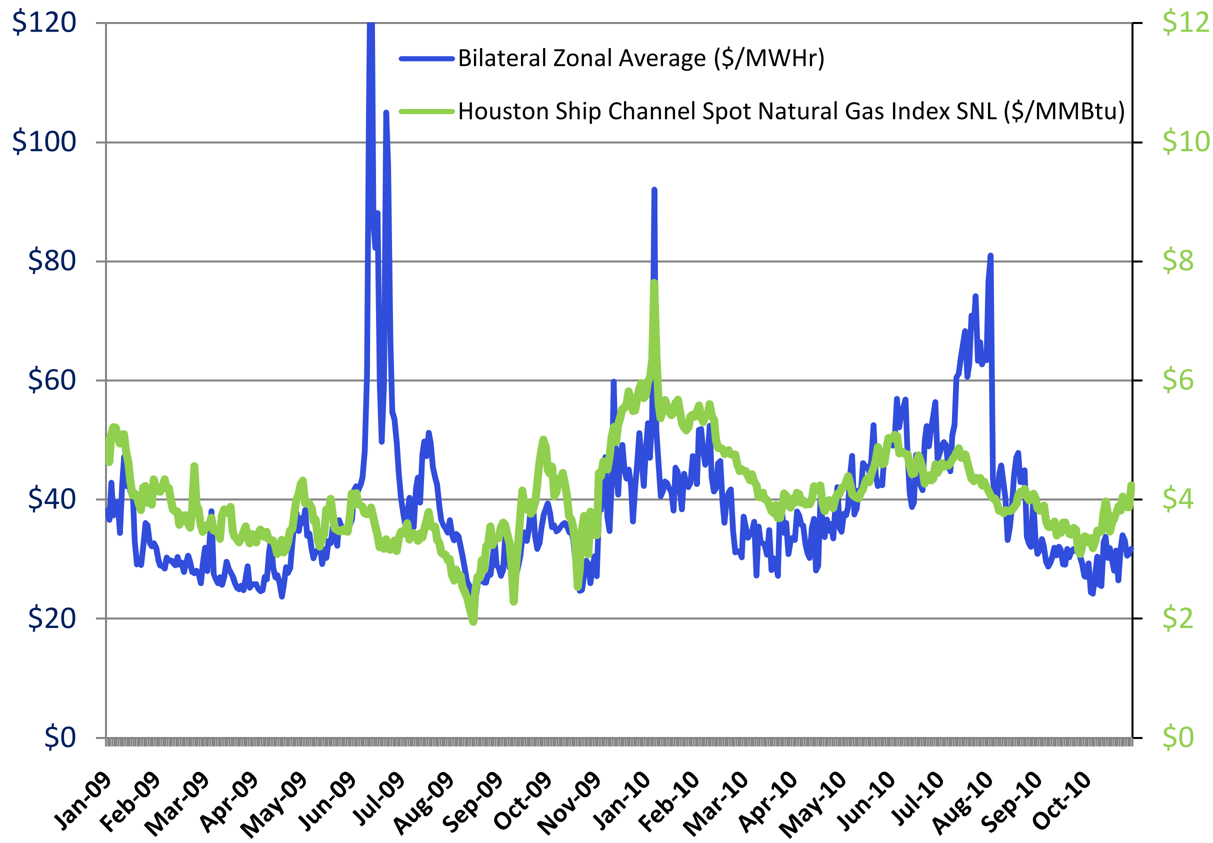

Figure 2 – Bilateral Electricity Prices and Natural Gas Prices

b. Balancing Energy Market Prices

ERCOT procures and deploys balancing energy to maintain the balance between load and generation and to resolve transmission congestion through a centralized auction process. At times when there is no transmission congestion, prices in all zones are equal. When transmission congestion limits the transfer of power between zones, prices will typically be higher in zones that are import constrained. Prices are typically lower in the West zone because the West zone is export constrained and prices within that zone are affected by the large amount of low-cost wind energy.

Price volatility in the balancing energy market generally results from a variety of unexpected short-term factors such as unforeseen generation or transmission outages, unexpected changes in weather, and changes in transmission congestion. Other factors that affect prices are more predictable, such as natural gas prices and seasonal variations in the demand for electricity.

The market clearing price of energy (MCPE) in the balancing energy market generally followed natural gas prices over the last two years, averaging $34 per MWh in 2009 and $42.14 per MWh in 2010, compared to $77.19 per MWh in 2008. Figure 3 shows that average balancing energy prices generally reflect natural gas prices for all months except June 2009, when ERCOT experienced congestion it was not able to resolve efficiently, and August 2010 when temperatures were unusually high throughout the month.

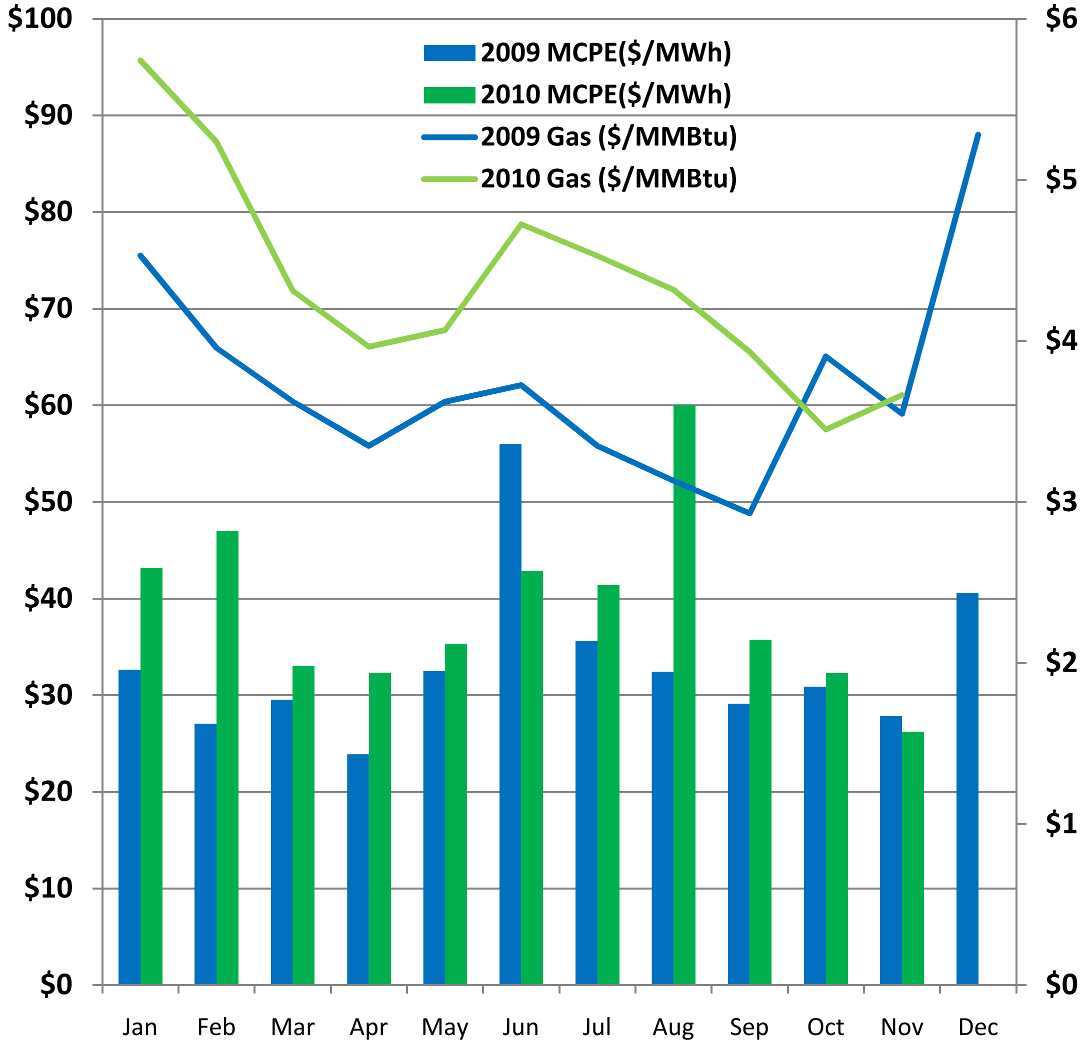

Figure 3 – Monthly Average ERCOT Balancing Energy Prices in 2009-2010 v. Gas Prices

A large number of energy price spikes occurred in the balancing energy market in June 2009 and August 2010 because of transmission congestion and unusually high temperatures. A price spike is defined as a price that exceeds 18 times the price of fuel (natural gas.) Figure 4 shows the number of price spikes by month and the impact of the spikes on prices.[78] In 2009, the average monthly number of spikes was 54, while in the first nine months of 2010 that number increased to 104 because of the high number of weather-related price spikes in August 2010. August 2010 had a record number of price spikes, including a price of $2200 per MWh in one interval on August 23, when ERCOT

[78] *2009 State of the Market Report for the ERCOT Wholesale Electricity Markets*, Potomac Economics, Ltd (2009 SOM Report) (July 2010).

experienced a new peak load of 65,770 MW. The Commission's mandated cap on offer prices is currently at $2250 per MWh (ensuring that prices will not exceed this limit most of the time)[79] and will increase to $3000 per MWh two months after the Nodal start date of December 1, 2010.

The impact of price spikes is shown by the top portion of the stacked bars in the graph. Price spikes account for a small portion of total intervals, but they have a significant impact on overall wholesale price levels. Price spikes raised the average price of wholesale energy by 18% in 2009 and 19% in 2010. Price spikes play an important role in signaling to the market the need for additional generation capacity. While the implementation of the nodal market should reduce the number of price spikes related to transmission congestion, as it provides a more effective means of managing congestion, price spikes that result from weather-related demand are an indication that more resources are needed for the hottest hours of the summer.

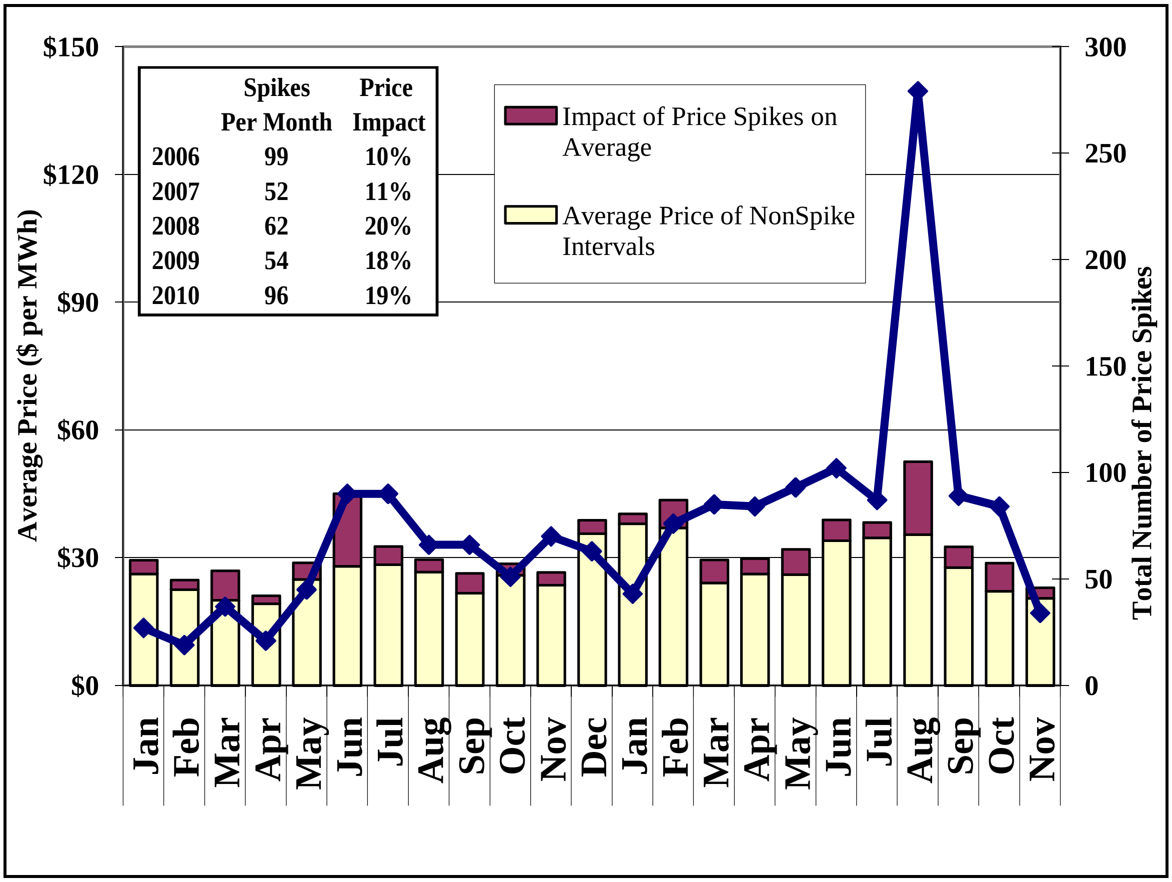

Figure 4 – Average Monthly Balancing Energy Prices and Monthly Number of Prices Spikes in 2009-2010

[79] Under certain circumstances when ERCOT experiences transmission congestion that is difficult to resolve, the price can theoretically go higher than the offer cap.

c. Ancillary Service Capacity Market Prices

As the system operator, ERCOT procures ancillary services, including short-term capacity reserves and balancing energy, which it deploys as needed to meet system demand, maintain reliability, and resolve transmission congestion. The capacity reserve services include regulation up (URS), regulation down (DRS), responsive reserve (RRS), and non-spinning reserve (NSRS). They are procured the day ahead of the operating day and their prices vary in relation to balancing energy prices. In 2009 and 2010, the cost of procuring capacity reserve services added less than $2.00 to the price of each MWh. Figure 5 shows the monthly average amount ancillary services added to the price of a MWh of Load.

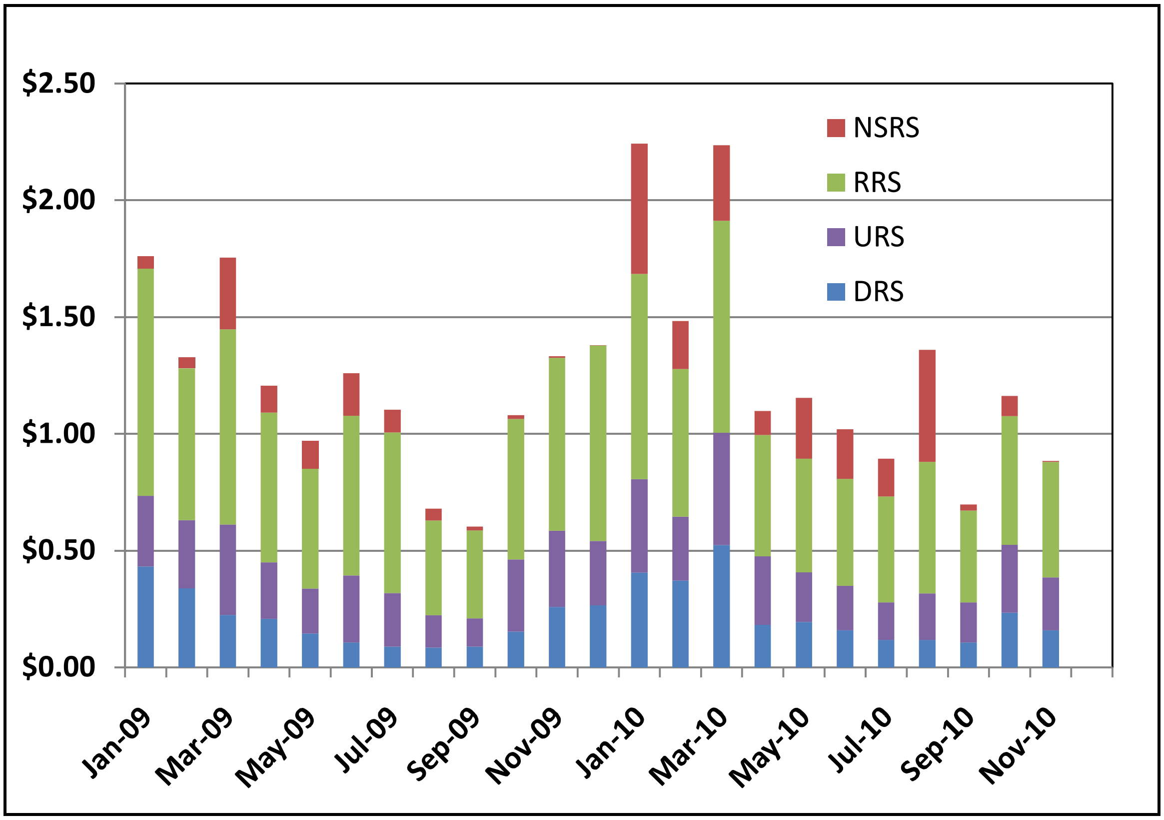

Figure 5 – Monthly Average Ancillary Service Prices per MWh of Load, 2009-2010

d. All-in Price for Electricity

A total or "all-in" cost of electricity at the wholesale level can be calculated by summing the costs for balancing energy, capacity reserve services, and other charges paid for by loads. Energy costs make up the bulk of the all-in cost, with capacity reserve services and uplift charges accounting for about five to eight percent of the total. Uplift charges represent additional services that ERCOT purchases to maintain system reliability but which ERCOT cannot assign to a specific market participant and are spread to the market on a load ratio share basis.

Average all-in prices for electricity in ERCOT were $35.09 in 2009 and $43.02 in 2010, compared to $78 in 2008. Across the country, all-in prices for electricity in 2009 were $38 in the California electricity market, $55 in the New York market, $50 in the PJM market, and $59 in the New England market.[80]

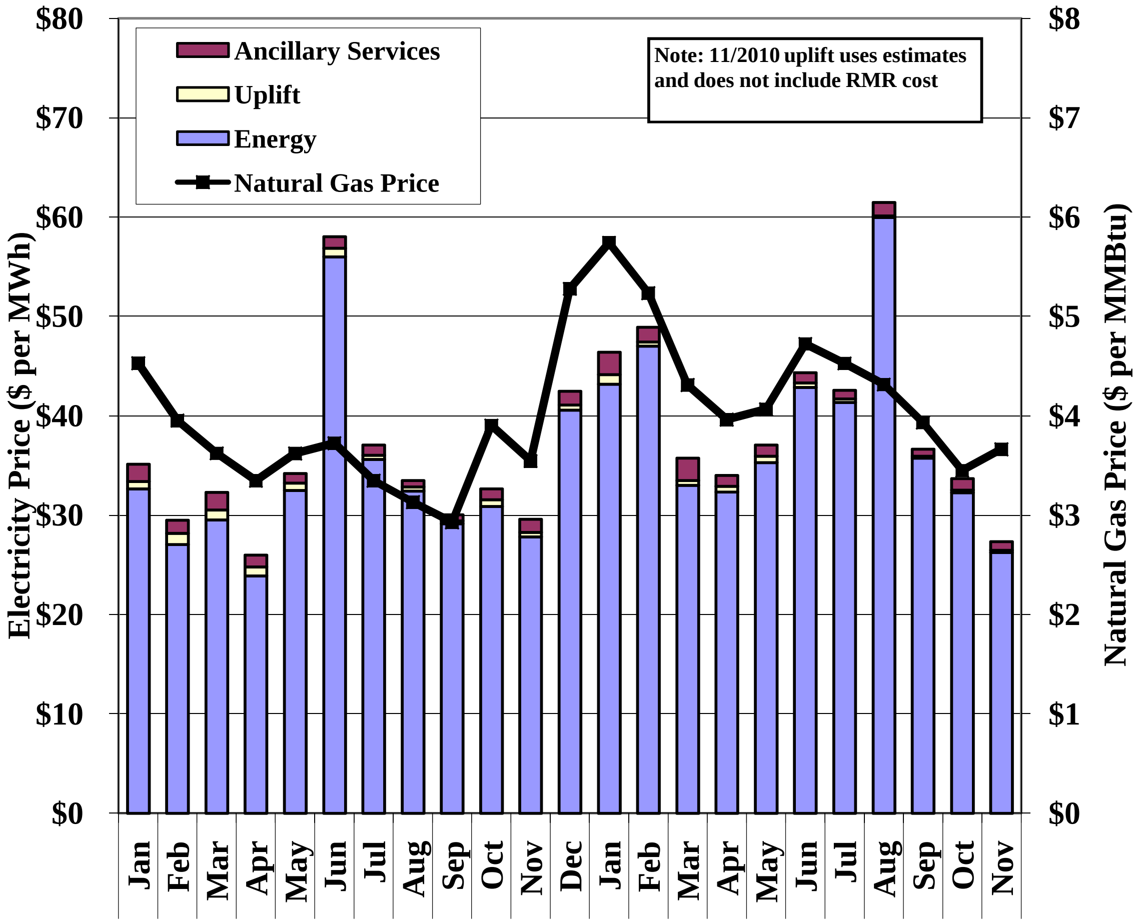

Figure 6 – Average All-in Price for Electricity in ERCOT vs. Gas Prices, 2009-2010

The figure above indicates that natural gas prices were the primary driver of all-in electricity prices in ERCOT in 2009-2010.

e. Congestion

One of ERCOT's primary functions is to manage the flow of power over the transmission system. When the power flow over transmission facilities reaches the operating limits of the facilities, ERCOT must restrict the power flow over such facilities, and it does so in two ways. In the case of inter-zonal congestion, the congestion affects the interface between two zones. To relieve inter-zonal congestion, ERCOT will reduce energy production in the exporting zone and increase it in the other zone to manage flows between the two zones. The cost of managing inter-zonal congestion is directly assigned to the generators that cause the congestion by attempting to transfer power over the

[80] *2009 SOM Report*, (July 2010).

congested interface. In the case of intra-zonal or local congestion, ERCOT manages the congestion by re-dispatching generating resources on each side of the local constraint, and the cost is uplifted to all loads.

The cost of resolving inter-zonal congestion was $349 million in 2009 and $34 million in the first nine months of 2010. The costs for resolving local congestion was $115 million in 2009 and $55.56 million for the first nine months of 2010.

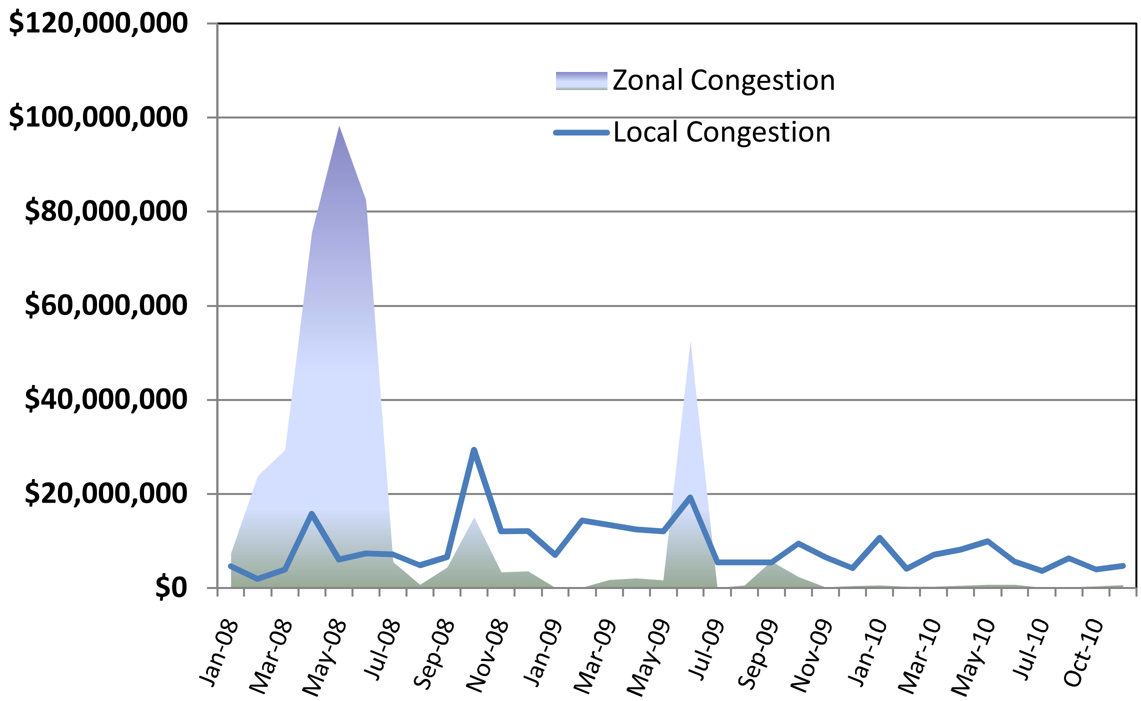

Figure 7 – Zonal and Local Congestion Charges, Jan. 2008 to Oct. 2010

Figure 7 shows that in June 2009 very high congestion existed in ERCOT, some of which occurred on the North to South interface. This was attributable to very high temperatures and associated increases in electricity consumption at a time when a number of generating facilities in the South zone had experienced an outage. This combination of events led to an increase in the frequency of congestion on the North to South interface as well as local congestion related to import limitations into the San Antonio area from the north. ERCOT implemented a temporary transmission switching solution in late June that effectively increased the transfer capability on the North to South interface.

In 2009-2010, inter-zonal congestion was most frequent on the West to North interface, followed by the North to Houston and the North to South interfaces. Both the frequency and the cost of resolving congestion over the North to Houston and the North to South interfaces were significantly reduced in 2009 compared to 2008. The decreased congestion on these two interfaces is primarily attributable to a revision of the ERCOT Protocols that allowed ERCOT to use more efficient tools to manage inter-zonal congestion.

The West to North interface was congested more frequently than any other interface in 2009. The primary reason for the high frequency of congestion on the West to North interface is the significant increase in installed wind generation relative to the load in the West Zone, and the limited transfer capability to the broader market.

2. Retail Market Development and Prices

a. Available Choices for Customers

An important gauge of retail market competitiveness is the number of providers competing for customers. Today, a wide variety of products and service offers are available for Texans. By June 2010, 86 REPs were providing electric service to customers. There are 52 REPs serving at least 500 residential customers, and residential customers throughout the competitive market have dozens of providers from which to choose. As of September 3, 2010, customers visiting the Commission's Power To Choose website would find as many as 38 REPs offering products throughout the competitive area of the state. Those REPs were offering as many as 233 different products in various territories, including 26 REPs that in combination were offering 68 different environmentally beneficial products with 100% renewable content at fixed and variable rates as low as $0.09 per kWh and $0.08 per kWh, respectively.

The number of REPs and competitive offers has continued to grow steadily since 2002. ERCOT reports that 26 new REPs entered the market in 2009, up from 19 in 2008. Residential customers have about 2.5 times more options than they did at the end of 2008.

Table 8 – Number of REPS Serving Residential Customers by Service Territory

Transmission and Distribution Utility	Number of REPs Serving Residential Customers (Incl. affiliated REPs)	Number of Residential Products	Number of Products with 100 % Renewable Content
Oncor	38	233	53
CenterPoint	36	233	55
AEP TCC	37	225	68
AEP TNC	37	226	67
TNMP	35	222	61

Texas continues to be recognized as the most successful competitive retail market in North America as demonstrated by its number one rank for the past three years in the Annual Baseline Assessment of Choice in Canada and the United States. This assessment noted the state's progress in implementing retail electric choice for residential customers, and Texas was the only market ranked "excellent" in the commercial and industrial category for the past two years.[81]

[81] *Annual Baseline Assessment of Choice in Canada and the United States*. Available online at: http://www.defgllc.com/content/defg/abaccus.asp.

Reduced electricity prices have increased overall customer satisfaction with REPs. The J.D. Power and Associates' 2010 Texas Residential Retail Electric Provider Customer Satisfaction Study, now in its third year, reveals that residential customer satisfaction with price, the major factor in overall satisfaction, improved in 2010 to 610 on a 1,000-point scale, up nine points from 2009. The study shows that in 2010, 41% of customers have been with their current provider for at least three years, versus 49% in 2009, with slightly more than 10% "highly committed" to their REP and another 25% indicating they "definitely will" stay with their REP. Nearly 10% of customers indicated that they were using renewable energy, an increase from seven percent in 2009, with satisfaction among such customers 120 points higher than customers on other pricing plans.[82]

b. Residential Rates

Retail competition started January 1, 2002, when all residential customers in the competitive areas of ERCOT were moved from fully regulated service to price to beat rates that were established at a discount of six percent off the then existing residential rates. As provided by PURA on January 1, 2005, the incumbent REPs were given the opportunity to offer rates other than the price to beat, but the requirement that the price to beat be offered to all customers expired on January 1, 2007, at which time all customers began to be served at rates set by market forces.

Electricity rates in Texas are greatly affected by natural gas prices because gas is burned to generate about 42% of electricity (2009), with its share increasing even more during periods when demand is high. In the last two years residential rates have seen a steady decline from the highest levels of mid-2008 when natural gas prices peaked at above $13 per MMBtu. With natural gas prices averaging $4.54 per MMBtu in the first nine months of 2010, the most competitive offers in the Texas power market are below the level of prices before the introduction of retail competition.

The figure below shows the average standard residential rate offered by incumbent providers against the lowest competitive offers across all service territories. As of mid-2010, legacy providers' standard rates were 12 to 57% higher than January 2002 prices, while the average lowest competitive offers were slightly above $0.08 per kWh, which almost mirrored the rates in early 2002. Savings of up to 35% relative to the legacy providers' standard rate were available for a typical residential customer using 1,000 kWh per month. Competitive rates were even lower later in 2010. Numbers used in the following figures and charts are based on Commission data used in compiling the average annual rate comparison and the monthly retail electric service bill comparison as well as REP offers posted on the Power To Choose website.

[82] J.D. Power and Associates Press Release (August 18, 2010). Available online at: http://businesscenter.jdpower.com/news/pressrelease.aspx?ID=2010157.

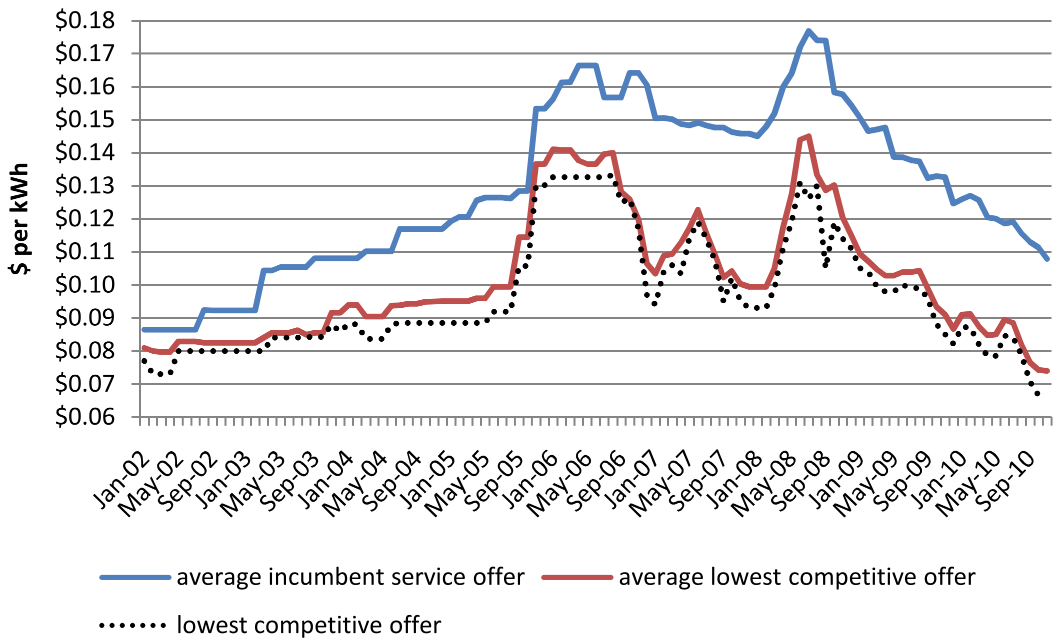

Figure 8 – Average Incumbent Service Offers vs. Average Lowest Competitive Offer

The figures below show that in December 2010 the most competitive offers in the Texas power market have decreased an average of 23.8% for fixed rates and 28.4% for variable rates, not adjusted for inflation, since the state opened its market to retail competition in 2002.

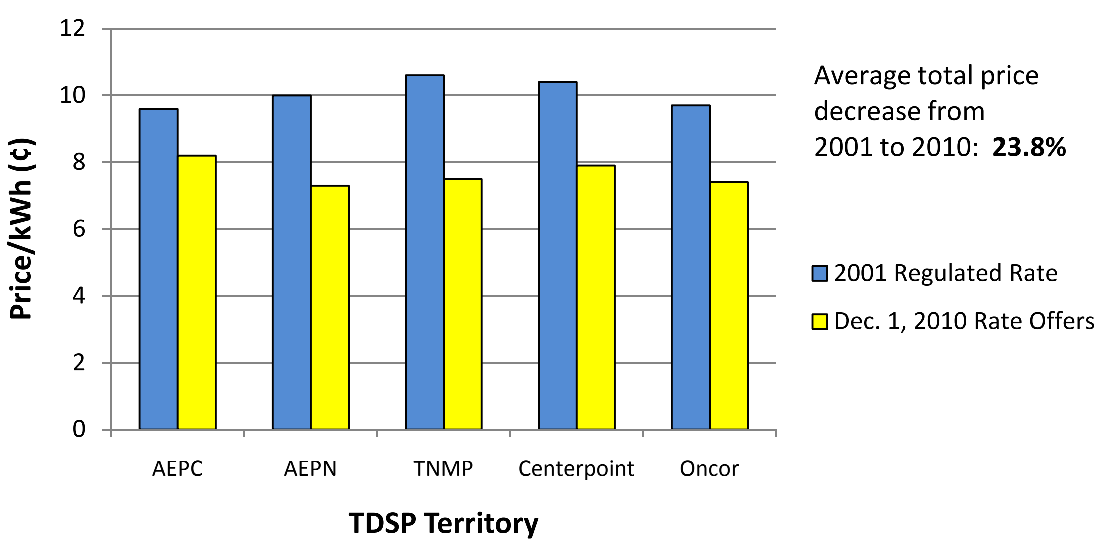

Figure 9 – Lowest Retail Fixed Rates in Texas vs. Last Regulated Rates

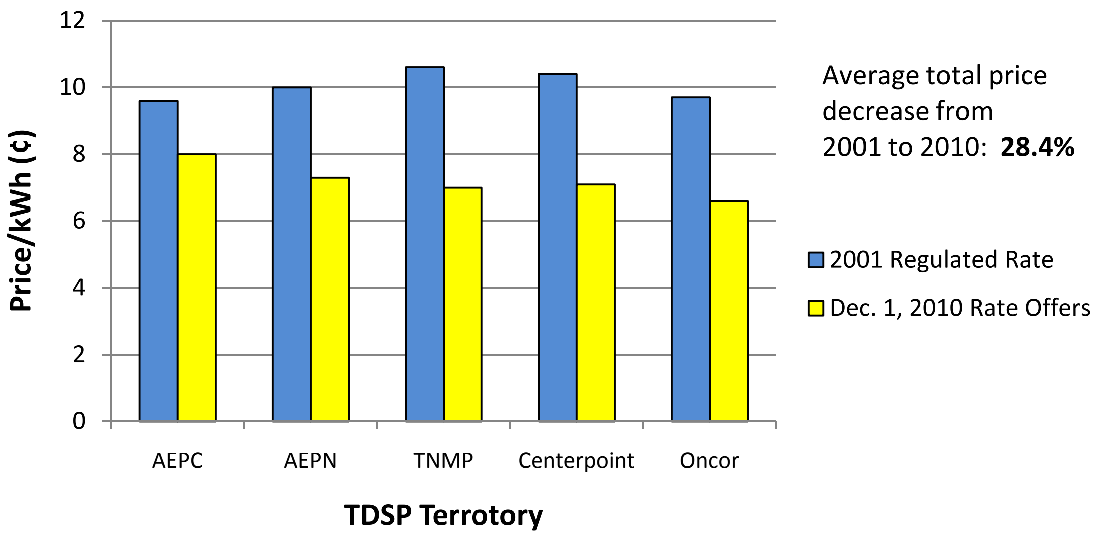

Figure 10 – Lowest Retail Variable Rates in Texas vs. Last Regulated Rates

As demonstrated in the following figure, every competitive area in Texas has variable and one-year fixed rates that are up to three cents per kWh below the national average.

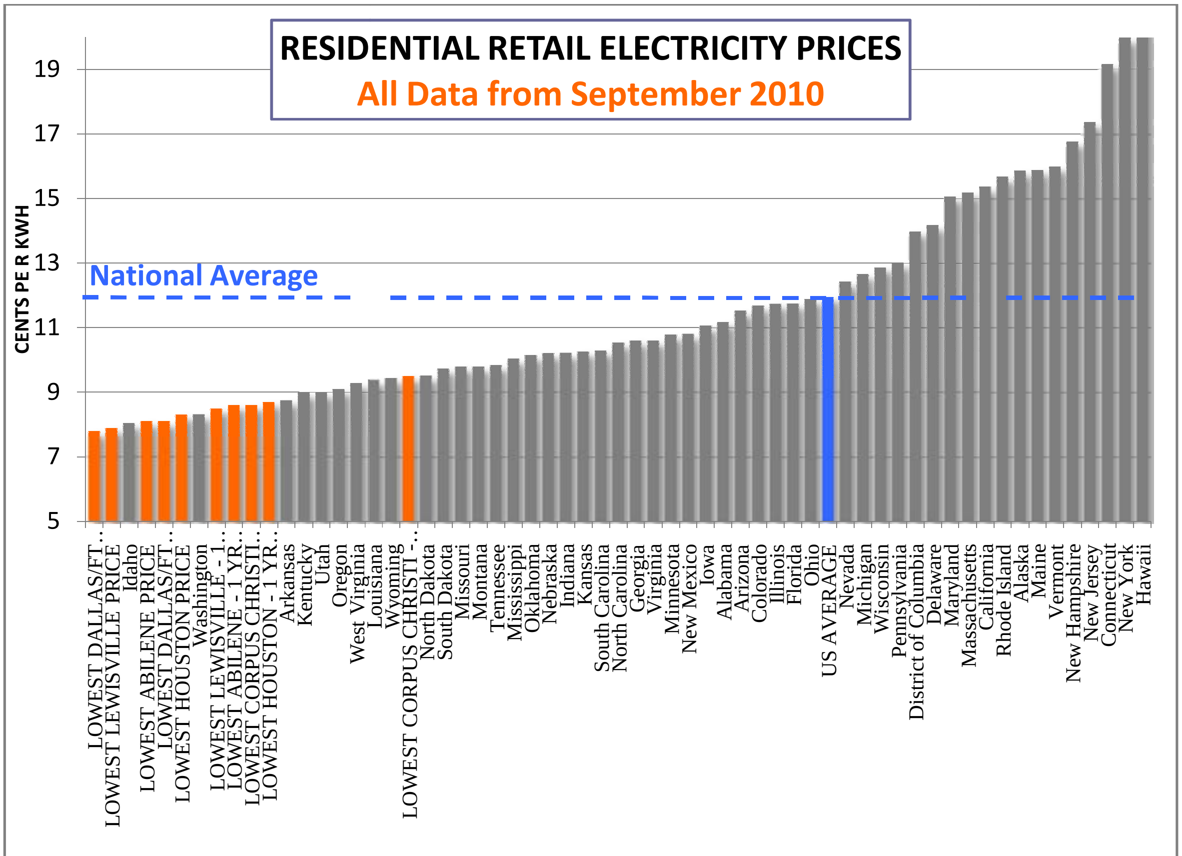

Figure 11 – Lowest Retail Rates in Texas Compared to Other States[83]

B. Switching Activity

As of September 2010, over 3.5 million individual customers were taking service from REPs other than one of the incumbent providers, based on data reported to the Commission by the TDUs. This accounts for more than 53% of all customers in service areas open to competition. Of these customers, 83.7%, or over 2.9 million, are residential customers. Another 514,000, or 14.5%, are customers taking delivery at secondary-voltage levels, such as retail establishments and offices. The balance consists of approximately 6,100 large facilities taking high-voltage power, such as factories and refineries, and 57,000 lighting systems, such as streetlights and security lighting.

In September 2010, a total of 15.5 million MWh of electricity was consumed by customers of a REP other than a legacy provider, accounting for approximately 68% of all electricity sold that month in the area open to customer choice. This number is higher than the percentage of customer premises switched because large commercial and industrial customers comprise a significant percentage of Texas energy usage, and these customers have higher switching rates than smaller customers who use less power. Even though residential customers account for 83.7% of total switches, they represent only 32% of the electricity sold to switched customers in September 2010.

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83 *AECT Electricity 101* (January 2011). Available online at: http://www.aect.net/.

The figures below show that switching rates vary by service area, with the highest rate of switching in the TNMP service area, at 68.2%, and the lowest rate in the Oncor service area, at 47.3%. Oncor's is the only service area yet to achieve a 50% switching rate. The lowest level of energy consumed by customers of competitive REPs is also in the Oncor service area, at 62.5%, and the highest is in the AEP North service area, at 86.1%.

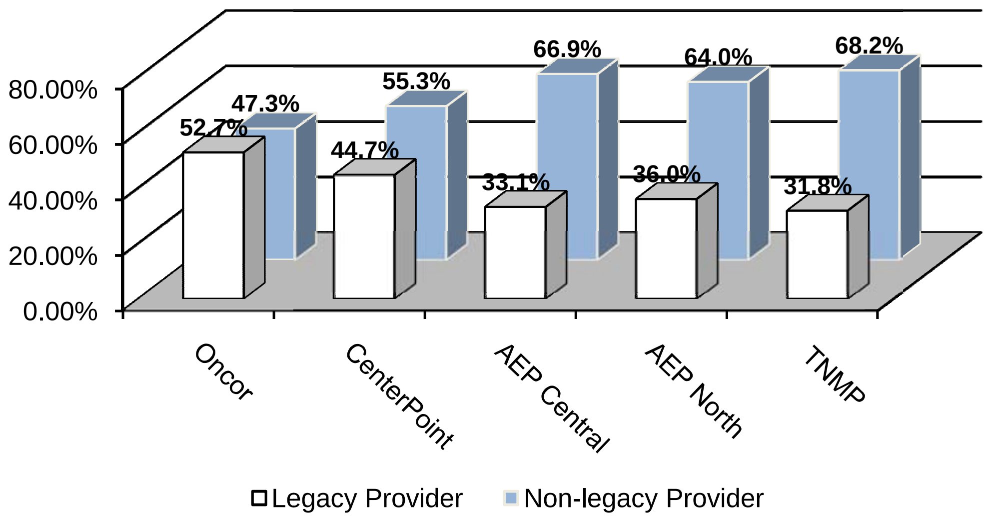

Figure 12 – Customers by REP Status

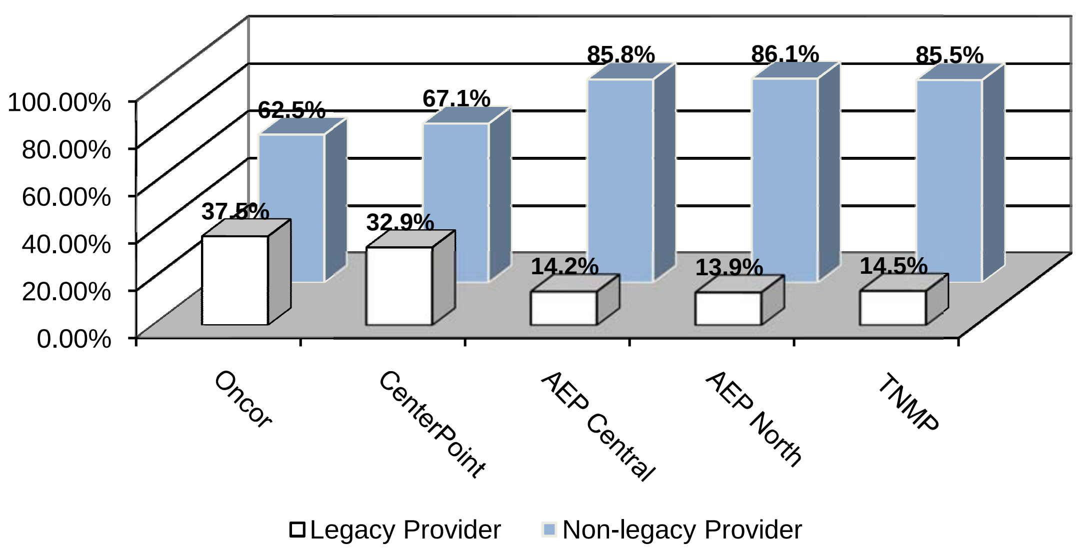

Figure 13 – Energy by REP Status

1. Residential Customers

Historically, approximately seven percent of residences annually switched to a provider unaffiliated with the previously integrated, regulated utility. In the last two years, that switching rate has slowed down to approximately four percent. Further, in Texas more than half of residential customers have chosen to be served by unaffiliated providers. This is additional evidence that the state's well-structured competitive market is promoting competition among market participants to the economic benefit of customers. Even though retail choice exists in more than a dozen states, switching rates for residential customers in those states are far lower than in Texas. Only Connecticut, New York and Massachusetts have achieved a measurable success in residential customer switching, with rates of 29%, 17.9%, and 14%, respectively. In all other states offering retail choice, the residential switching rates have been negligible or even decreased in the last few years.

Competing REPs originally focused their efforts on winning customers in the large urban markets of Houston and Dallas-Fort Worth but have now branched out; most residential competitive REPs now market throughout the competitive areas of the state. REPs have been most successful in attracting new customers in the TNMP area, with a switching rate of 69.6% in September 2010 versus 55.6% in September 2008. These percentages do not account for the number of residential customers who originally switched to a new provider, but returned to the legacy provider at a later date. The switching rates also do not explicitly recognize that customers make a choice when they initiate service, and the percentages above represent new customers who have selected an incumbent provider as not having switched.

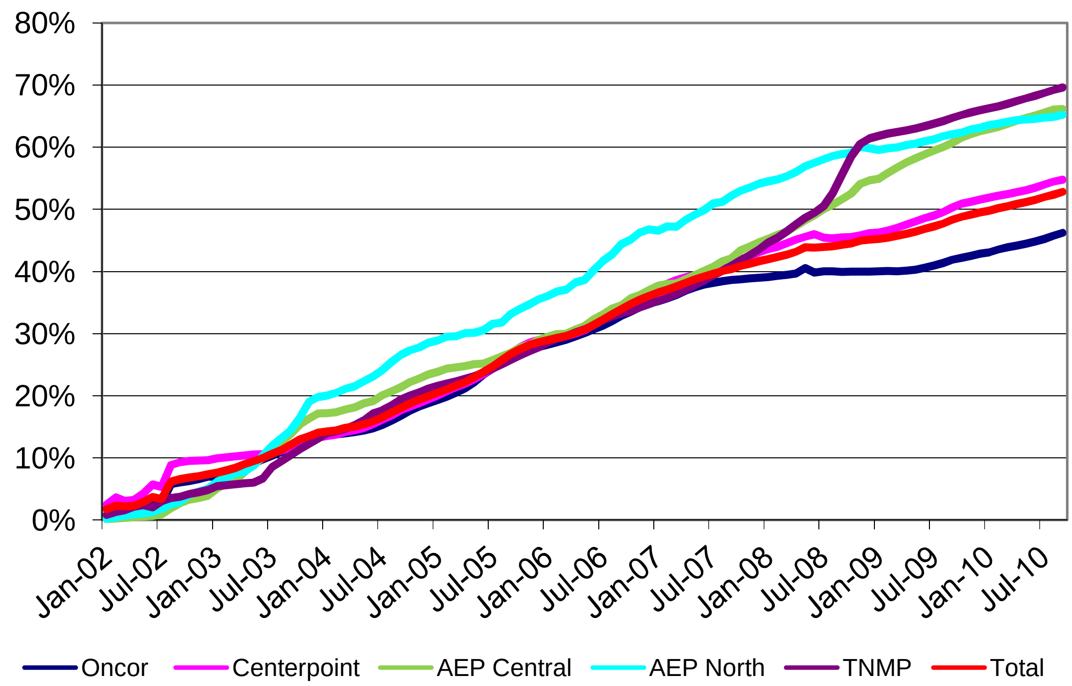

Figure 14 – Residential Customers with Non-legacy REP by Service Territory

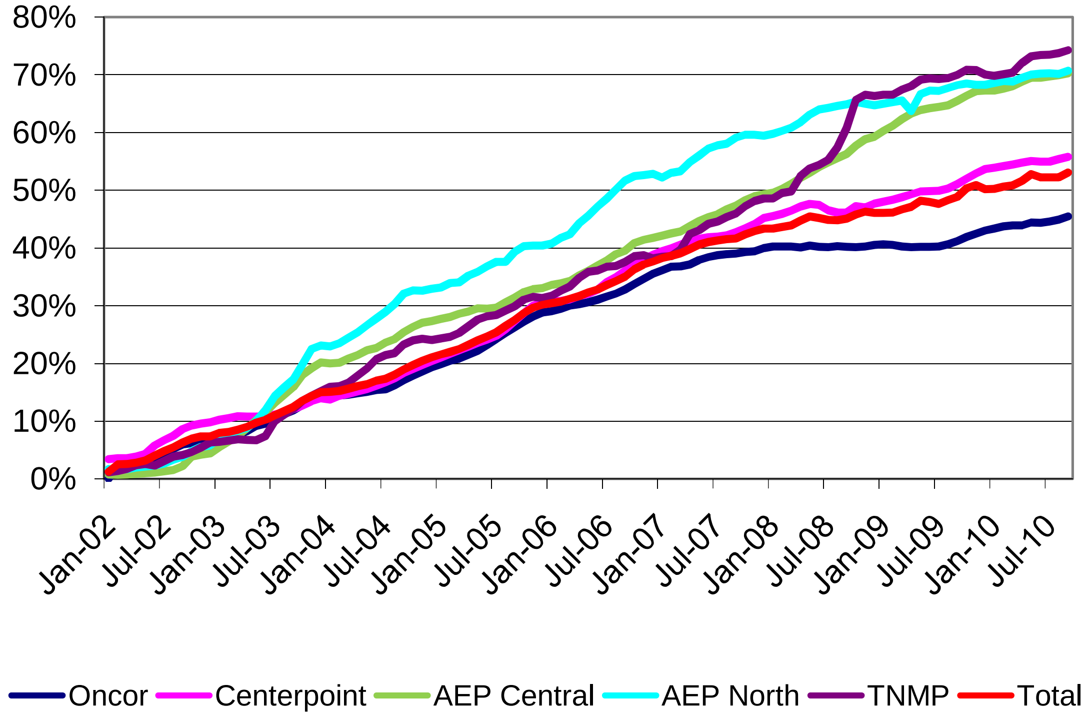

Figure 15 – Residential MWh Switched to Non-legacy REP by Service Territory

2. Secondary Voltage Commercial and Industrial Customers

Large commercial and industrial customers have shown a greater tendency to switch than residential customers. These customers typically have higher energy usage and higher electric bills than most residential customers, and thus they have greater incentive to seek lower rates. As of September 2010, 62.2% of commercial and industrial customers had changed providers, ranging from 57.6% in the Oncor territory to 77.8% in the AEP Central service territory. These switching counts have grown more or less linearly since 2002.

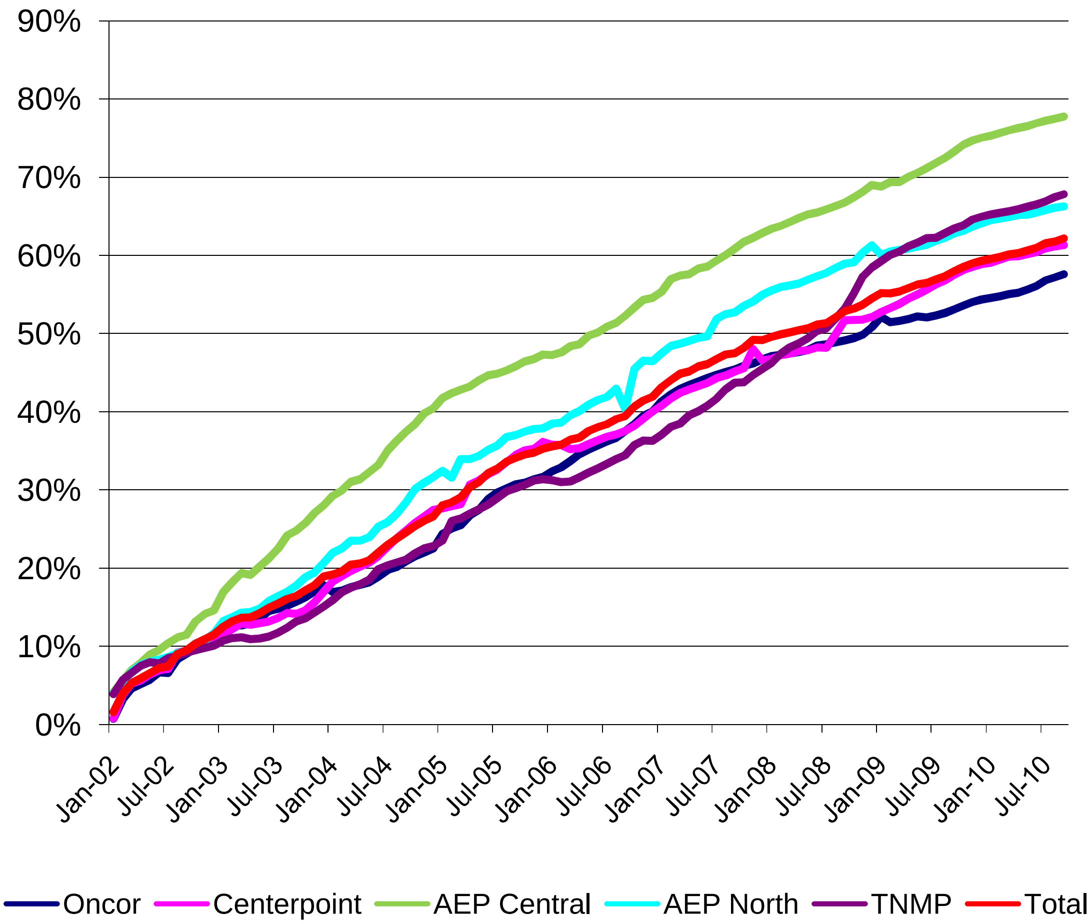

Figure 16 – Secondary Voltage Customers with Non-legacy REP

The largest customers in this class have a greater propensity to switch, as is shown by the fact that 77.3% of MWh sold to this class in June 2008 were sold by REPs other than the legacy provider. By territory, as little as 72.9% of MWh in the Oncor territory to as much as 94.8% of MWh in the AEP Central territory are sold by non-legacy providers.

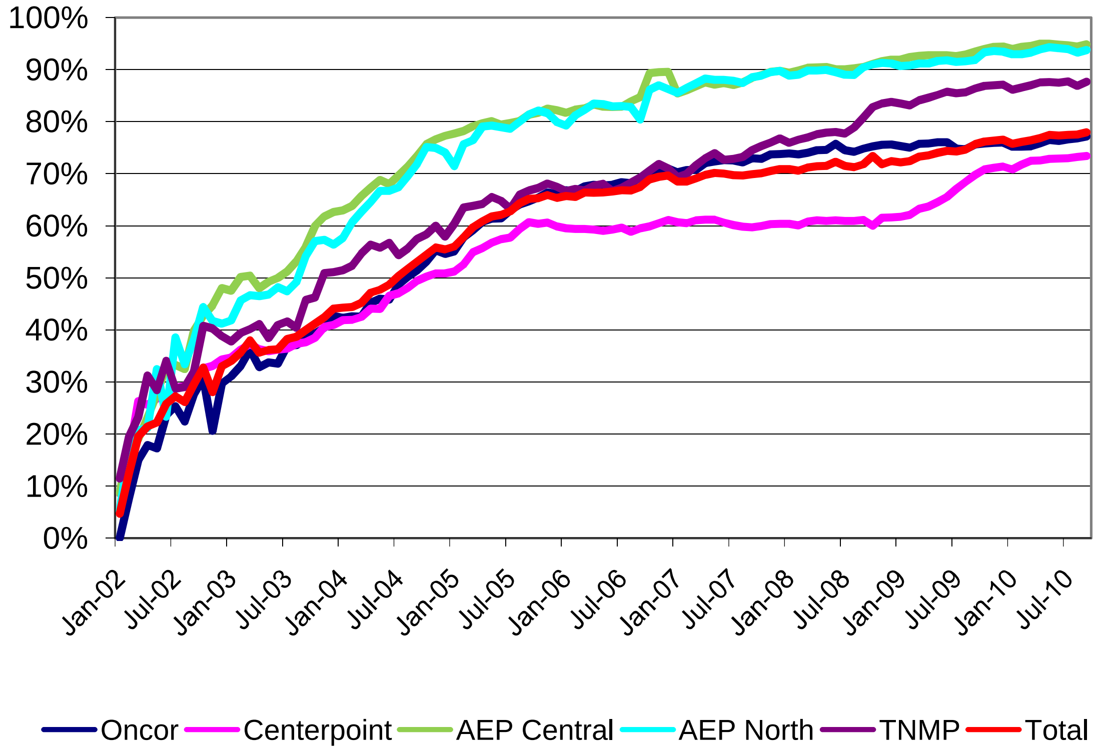

Figure 17 – Non-Affiliated REP Share of Secondary Voltage MWh

3. Primary Voltage Commercial and Industrial Customers

Primary-voltage and transmission-voltage customers are large electricity consumers. Over 71% of the primary and transmission customers had switched by September 2010, up from about 65% in September 2008. The remaining 29% have stayed with the legacy provider with rates set by negotiation between those large customers and the REPs. Approximately 79% of MWh sold to this class were provided by REPs other than the legacy provider, up from 74% two years ago.

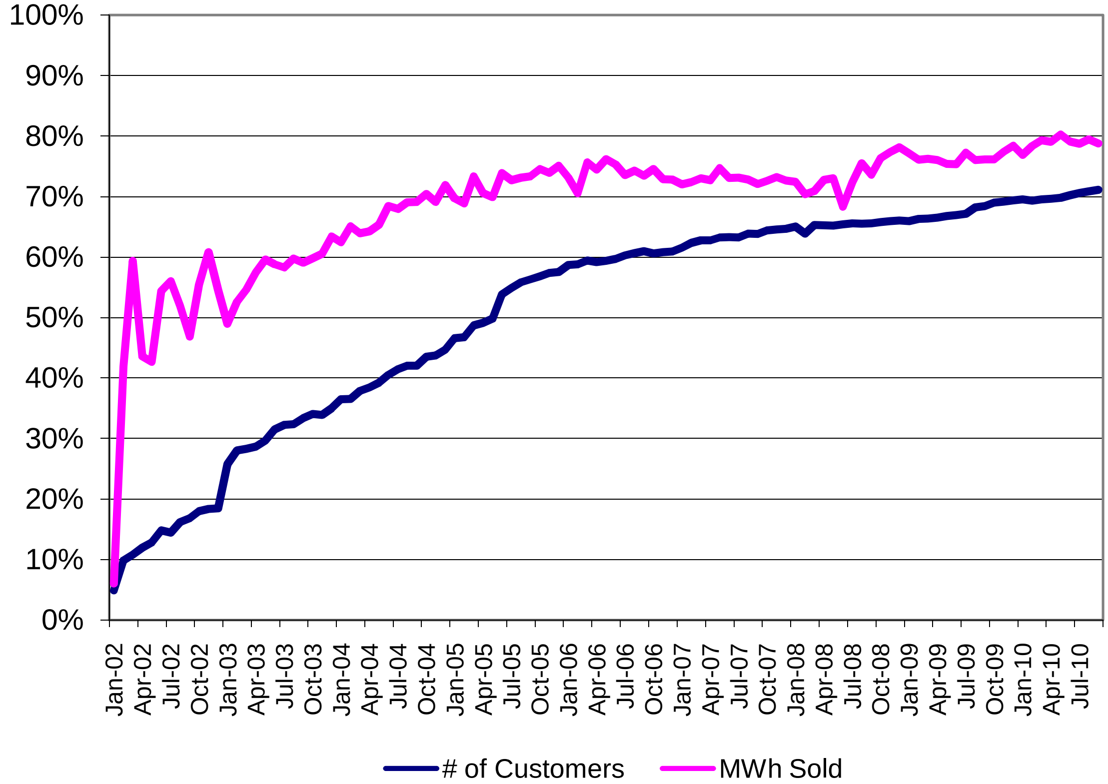

Figure 18 – Primary Voltage Customers not with Non-legacy REP

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IV. Assessment of Other Senate Bill 7 Goals and Benefits

A. Customer Protection and Complaint Issues

Complaint statistics serve as a barometer for gauging company behavior and its effect on customers. The statistics also help Commission management identify company-specific trends that may lead to enforcement action or meetings with companies to address issues. In late April 2008, CPD experienced a spike in the number of customer complaints resulting from high electricity prices coupled with some REPs exiting the market. Also prompting the spike were complaints from customers on variable rate plans, which generally had the highest electricity prices offered by REPs during this time frame.

The increase in complaints can also be explained by increased customer awareness of not only the structure of the deregulated market and various REP plans and offers, but also of events affecting the market.

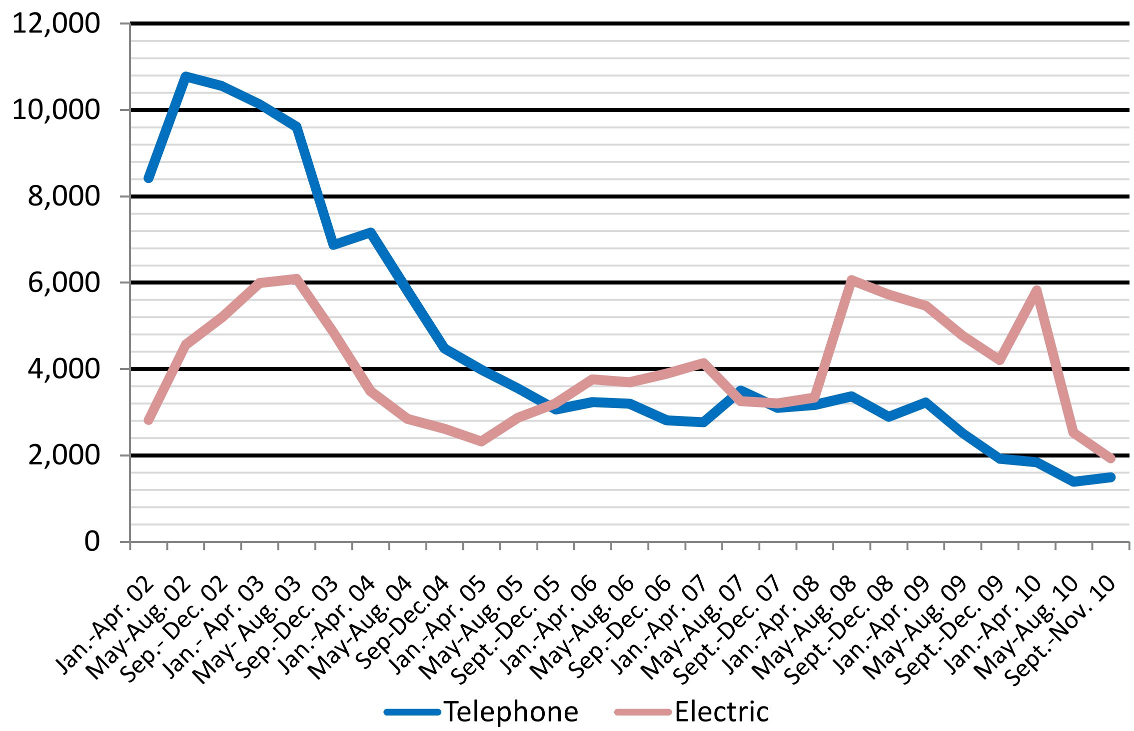

Figure 19 – Total Complaints Received

Complaints remained high in September 2008 because of the onset of Hurricane Ike and complications involving customers of REPs that discontinued their business operations. Additionally, many REPs initiated operational upgrades to their bill format and billing systems to comply with new or amended customer protection rules and provisions. In some cases, the upgrades were not seamless and prompted complaints covering billing errors, delayed billing, and errors in billing the correct premise.

Thereafter, a steady decline in complaints occurred until December 2009. In January 2010 complaints gradually increased and spiked in April. Customers to whom advanced meters were deployed expressed concerns that their advanced meters were faulty or inaccurate because their meter reads measured an increase in usage after installation. It was ultimately concluded that in November, December, January and February, record-breaking cold weather was experienced throughout most of the state causing higher than normal energy usage. Since April, a noticeable decline in complaints can be attributed to low and stable electric prices combined with mild temperatures and rainfall in the spring and early summer months. By the end of August 2010, complaints continued to remain low and trended downward. Complaints involving advanced meters also subsided because of, in part, the results of an independent study requested by the Commission that found advanced meters to be exceptionally accurate. This study is discussed more fully later in this report.

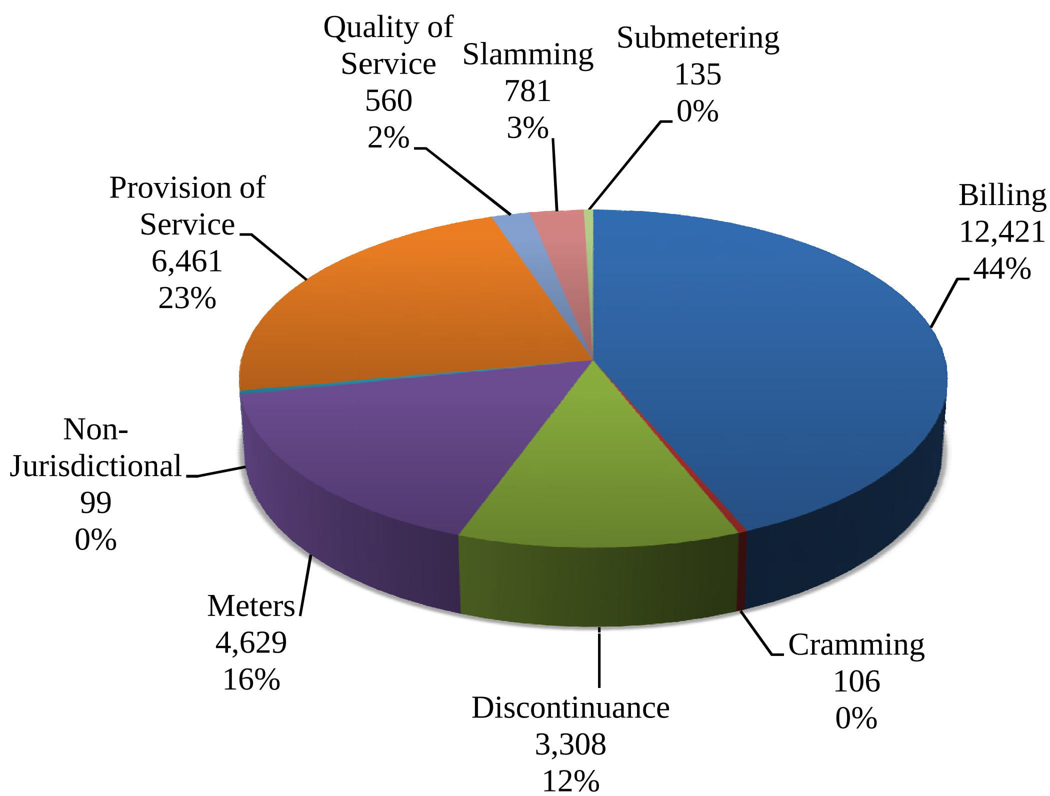

Figure 20 – Electric Complaints Received - Sept. 2008 - Aug. 9, 2010

A total of 28,500 electric complaints were received from September 2008 through August 9, 2010. The deployment of advanced meters and Hurricane Ike accounted for the 21% increase in billing complaints and an 81% increase in meter complaints when compared with the previous period of Sept 2006 through August 2008. Such complaints included high bills/usage, AMS surcharges, misapplied taxes, estimated meter reads, meter tampering and errors in matching the premise designation with the correct meter.

With the installation of advanced meters, high billing was a prominent complaint issue. During the spring of 2010 the Commission retained Navigant Consulting, LLC, an independent third party, to evaluate the accuracy of the meters being deployed. Many of the issues investigated were in response to complaints filed with the Commission, as well as various media reports and inquiries, targeted at concerns over the accuracy of the meters currently being deployed in the three utility territories.

Navigant reported that, in its opinion, the vast majority of smart meters currently installed by Oncor, CenterPoint and AEP Texas are accurately measuring and recording electricity usage and communicating that information through the AMS for use in customer billing. Navigant noted, however, that the evaluation and investigation uncovered certain discrete groups of smart meters that were not performing at acceptable levels. Further, Navigant stated that it was apparent that any potential impact to customers from the observed smart meter failures could have been limited, if not avoided entirely, if the respective TDU had effectively monitored and analyzed the performance of these smart meters using the information available to it.

The investigative process revealed other underlying issues contributing to the increase in complaints. These issues include:

- discovering meter tampering with the old meters during removal and installation of advanced meters resulting in back billing;
- small commercial customers either initially experiencing demand ratchets or experiencing an increase in demand;
- customers withholding bill payments until the advanced meters underwent testing for accuracy. After their accuracy was established many of these customers entered into deferred payment plans;
- customers discovering they selected variable rate or indexed rate plans;
- customers failing to renew their pricing plan or switching to a new provider and subsequently being placed on a variable rate plan per their Terms of Service agreement;
- customers incurring early termination fees because they were unaware of the expiration date of their contract; and
- customers assuming a critical care status without approved designation and withholding bill payments. Many of those customers subsequently entered into deferred payment arrangements and worked with local assistance agencies.

Complaints regarding provision of service increased by 26%, in most cases customers remitted payments and receiving delayed electric service or no electric service at all. Slamming complaints decreased by 23%, as did Discontinuance of Service complaints by 13% and Quality of Service complaints by 9%. The decreases can be attributed to ongoing process improvements by market participants and increased customer education and awareness of their rights and protections.

B. Increase Benefits and Functionality of Advanced Meters for Customers

The Commission has opened a rulemaking project to examine ways for customers to realize the benefits and functionality of smart meters.[84] In this project, the Commission will explore the expansion of market business hours, even adding Saturday as a business day, for the purpose of processing service orders from customers with advanced meters. The Commission will also explore the option of giving customers the ability to switch REPs within one business day. The Commission may also consider amendments to customer protection rules to provide benefits to customers from investment in smart meters.

C. Renewable Energy Mandate

In 1999, the Texas Legislature established a renewable energy portfolio standard whereby renewable energy goals are met through a renewable energy credit program. The credits are earned by companies that produce renewable energy, and they are required to be retired by REPs and electric utilities. The retail providers and utilities buy the credits from producers, and the sales and purchases of the credits establish a market value for the credits.

The original legislation established a goal of 2,000 MW of new renewable resource capacity by 2009. In 2005, PURA was amended to increase the goal to 5,000 MW of new renewable capacity by 2015. The amendments also established a target of 500 megawatts of non-wind renewable capacity by 2015 and 10,000 megawatts of renewable capacity of any type by 2025. Currently 10,000 MW of new renewable capacity is in operation in Texas, so the 2015 goal and 2025 target for total renewable capacity have been met.

The 2005 legislation also directed the Commission to designate CREZs and adopt a transmission plan to move renewable energy from those zones (to other areas of Texas.[85] The Commission has designated CREZs in West Texas and the Panhandle,[86] has adopted a transmission plan that will permit a significant increase in the production of wind energy in West Texas and delivery of the wind energy to more populous areas of the State outside of West Texas,[87] and has designated transmission companies to build the new transmission facilities.[88] The transmission plan approved by the Commission is

[84] *Amendments to Customer Protection Rules Relating to Advanced Meters*, Project No. 38674 (September 15, 2010).

[85] PURA § 39.904(g).

[86] *Commission Staff Petition for Designation of Competitive Renewable Energy Zone*, Project No. 33672, Order on Rehearing (October 7, 2008).

[87] *Id*.

[88] *Commission Staff's Petition for Selection of Entities Responsible for Transmission Improvements Necessary to Deliver Renewable Energy From Competitive Renewable Energy Zones*, Docket No. 35665, Order on Rehearing (May 15, 2009).

designed to permit 18,456 MW of wind capacity to operate within ERCOT by late 2013 or early 2014. The PUC is also considering adopting a system of renewable energy credits for non-wind renewable resources to provide incentives for the construction of non-wind renewable facilities, which could ensure that the 500 MW target is met. There are about 150 MW of qualifying non-wind resources currently in operation.

The best wind resource areas in Texas are primarily in West Texas, the Panhandle, and along the Gulf Coast between Corpus Christi and Brownsville. In many of these areas, investment in wind facilities has resulted in a significant increase in the property tax base for counties and school districts. The wind facilities have also generated employment in delivery, construction, operation, and maintenance of wind turbines and supporting infrastructure, construction of towers and other components, and other related jobs.

D. Energy Efficiency

The August 2008 State Energy Plan identified energy efficiency as one of five key areas essential to meet the energy demands of Texas consumers.[89] The State Energy Plan recommended that the state should raise the energy efficiency goals to the higher levels contemplated under current law if the Commission study required by HB 3639 indicated a greater potential for cost-effective energy efficiency reductions.[90]

The Commission hired Itron, Inc. to perform this study, and its report concluded that a 50% reduction of the growth in electricity demand could be met. Although the study indicated that reaching this goal by 2014 was possible, the Commission was concerned with the estimated cost of $2.20 per month to the ratepayer in the CenterPoint region; $2.80 in the Oncor region; and $4.00 in the TNMP region required to achieve this goal. The Commission reviewed the current cost and economic realities and ruled that a goal of 30% reduction in growth in demand by 2014 at a cost of $0.78, $1.30, and $1.15 respectively would be the more cost-effective energy efficiency reduction option.

Therefore, the Commission amended its existing rules relating to energy efficiency in 2010 to raise the electric utilities' energy efficiency goals from 20% of annual growth in the electric utilities' demand for electricity of residential and commercial customers to 25% of the growth in demand of these customers in 2012, and to 30% of the growth in demand in 2013.[91] The new rule also:

- updated the cost effectiveness standard by adjusting the avoided cost of capacity and the avoided cost of energy;

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89 *Texas State Energy Plan*, Governor's Competitive Council (2008). Available online at: http://governor.state.tx.us/priorities/economy/industry cluster efforts/governors competitiveness council/.

90 *Id*. at 9.

91 *Rulemaking Proceeding to Amend Energy Efficiency Rules*, Project No.37623, Order Adopting Amendments to § 25.181 as Approved at the July 30, 2010 Open Meeting (Aug. 9, 2010).

- modified the calculation of a performance bonus for an electric utility that exceeds its goal; and
- applied the requirement to all electric utilities, not just electric utilities that are subject to PURA § 39.905.

The new rule was adopted July 30, 2010 with the purpose of pacing the increase in the energy efficiency goal in a modest manner while capping the cost on a per customer basis at a reasonable level to meet the new goals, and subsequently providing the Commission the time to evaluate the continued cost effectiveness of the program. The Commission recognized that the adoption of the amended energy efficiency rule in July 2010 was just six months prior to the beginning of the 82nd Legislative Session and that the Commission might need to make further changes to its energy efficiency rules if the Commission receives additional direction from the Legislature.

The energy efficiency program under PURA § 39.905 is designed to improve utility customers' energy use through measures that reduce electric demand and energy consumption. This program is administered by the utilities and funded through an energy efficiency cost recovery factor paid for by customers. In 2009, the utilities spent approximately $106 million on this program. The goals of the PURA energy efficiency program are that:

- electric utilities administer energy efficiency incentive programs in a market neutral, nondiscriminatory manner;
- all customers have a choice of and access to energy efficiency alternatives to reduce energy consumption, peak demand or energy costs; and
- cost-effective energy efficiency measures are to be acquired for residential and commercial customers.

E. Smart Grid Deployment Update

The Energy Independence and Security Act of 2007 specifies that technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for smart metering, communications concerning grid operations and status, and distribution automation should be deployed. Texas is ahead of the rest of the country with its deployment in terms of meters deployed and features that ensure that the benefits of this investment will flow to the utility, the REP, and the customer. The Commission believes that smart meter deployment is a critical component of the evolving Texas electric market. As deployment occurs, it can enable market-based demand response, help the market to mature, yield savings for utilities, reduce bills for customers, and create efficiencies in market processes for REPs and ERCOT.

Most importantly, advanced metering infrastructure (AMI) can enhance service quality to retail customers in several areas:

- expediting connection and disconnection of service;
- providing a prepayment option that will reduce deposit requirements;

- giving customers the tools to help manage energy costs;
- enabling quicker service restoration following an outage; and
- helping balance the dynamics of supply and demand.

Over 2.5 million smart meters have been installed by investor-owned utilities in Texas, but smart meters are not exclusively a Texas phenomenon. It is anticipated that by year end 2010, approximately 16 million smart meters will be in place in the U.S and 50 million by 2015. By giving customers better information about their consumption and retail rates, smart meters should reduce customer demand as customers become more efficient in their use of electricity and shift consumption to lower-cost hours, thus reducing the need for investment in new peak generation capacity.

AMI is the cornerstone and the essential building block of a smart grid. Much more than just smart meters, the smart grid is an efficient, dynamic, and more resilient electrical and communications delivery system. Like the telecom and internet revolutions, technology holds the key to the smart grid and its benefits. The smart grid and the technologies embodied within it are an essential set of investments that will help bring our electric grid into the 21^{st} century using megabytes of data to move megawatts of electricity more efficiently, reliably, and affordably. In the process, the electric system of today will move from a centralized, producer-controlled network to a less centralized, more consumer-interactive, more environmentally responsive model.

The smart grid should facilitate identifying the extent of an outage and planning the efficient restoration of service. The results will be quicker restoration of service in the case of equipment failures that result in loss of service for dozens of customers following a thunderstorm, hurricane or tropical storm. Smart meters also automate meter reading, reducing the cost of electric delivery service, and will facilitate increased automation of the distribution system, so that restoring service after some outages will be achieved without dispatching a service crew. Over time, benefits will encompass the broad areas of reliability, power quality, economic vitality, efficiency, and environmental impact.

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V. EMERGING ISSUES

A. Proposal for Streamlining Rate Regulation

During 2008, AEP Texas began a series of discussions with Commission Staff and industry stakeholders to explore ways in which the traditional rate-setting process for regulated utilities could be streamlined. The primary focus of AEP's efforts was to consider and address:

- the often significant regulatory lag currently associated with formal rate cases; that is, the lag between the time that costs are incurred and a utility begins recovering higher rates to recover those costs;
- the adversarial focus in a rate case on relatively few cost items;
- the length, contentiousness, and associated expenditures of time and resources in litigating formal rate proceedings; and
- collaborative processes outside of a formal rate case that might be a more effective way to set rates.

AEP believes that the current regulatory model inhibits the timely recovery of costs and the flexibility of companies in making appropriate investments in an aging utility infrastructure.

An existing example of streamlined rate regulation that might be used for distribution service providers is the mechanism for adjusting transmission rates. Current Commission rules allow for each transmission utility in the ERCOT region, on an annual basis, to update its transmission rates to reflect changes in invested capital. If an ERCOT transmission utility elects to update its rates through this mechanism, the new rates reflect the addition and retirement of transmission facilities and also include appropriate depreciation, federal income tax and other associated taxes, the Commission-allowed rate of return, and changes in loads. Such updates of transmission rates are subject to reconciliation at the utility's next complete transmission cost-of-service review, in which the Commission reviews whether the costs of transmission plant additions were reasonable and necessary and, additionally, whether there was any over-recovery of costs.

In late 2007, for areas outside of ERCOT, the Commission adopted an analogous rule for streamlined recovery of transmission costs.[92] No similar provision exists, however, for capital additions related to distribution facilities, whether inside or outside the ERCOT region.

[92] This rule was adopted pursuant to HB 898, enacted in the 79th Legislative Session.

AEP has suggested four basic options that could be considered as a framework for streamlining the traditional rate-setting process without diminishing current regulatory oversight. These four options include:

Distribution Cost of Service (DCOS) mechanism—this approach would be patterned after the existing transmission cost recovery mechanism, and would allow annual recovery of and return on net incremental distribution-plant capital expenditures and associated tax effects. Capital investments added to rate base through the DCOS mechanism would be subject to review in full base-rate cases. Project No. 38298, *Rulemaking Related to Recovery by Electric Utilities of Distribution Costs,* currently pending at the Commission, incorporates this basic approach.

DCOS mechanism, including O&M—this approach would be implemented in the same general manner as described above, with additional recovery of certain operation-and-maintenance (O&M) expenses.

Targeted Programs—this option would allow a utility to file for preapproval of specific (targeted) capital and O&M expenditures designed to enhance the existing distribution infrastructure. Examples might include programs to enhance reliability, such as tree-trimming programs or infrastructure-hardening programs. Annual reporting requirements would ensure that the utility is complying with predetermined criteria, and revenue recovery would be achieved through a separate surcharge or an annual DCOS mechanism.

Formula Rate Plans—these plans would allow a utility to make annual filings and adjust revenues to a predetermined return-on-equity level. Such a program would be initiated for a specified period of time (for example, three years), and then reviewed to determine whether it should continue.

At issue in all these proposals to streamline certain aspects of the regulatory process is that some degree of uncertainty exists with respect to the extent of Commission authority for implementation of such a plan. At this time, the Commission has left Project No. 38298 pending. As discussed in an earlier chapter, the Commission believes it has the legal authority to adopt such a rule, but is waiting to do so until after the Legislature has had the opportunity to consider the issue and provide more specific direction. The Commission stated that it plans to revisit this rule in the summer of 2011 consistent with any action taken by the Legislature.

B. Operational Challenges of Wind Generation in Texas

Texas has experienced a rapid and significant addition of renewable energy generation in recent years, primarily in the form of large-scale wind generation resources. At the end of June 2010, new renewable facilities in Texas reached approximately 10,073 MW, which exceeds the legislative target of 10,000 MW by January 1, 2025. Wind represents 9,915 MW of this renewable capacity installed since September 1, 1999.

Most wind generation development has occurred in West Texas and the Panhandle, in areas with low population. In Section II.B.14 of this report, the subsection entitled “Competitive Renewable Energy Zone (CREZ) Cases” provides a discussion and update of the transmission cases currently under way to expand the transmission network in ERCOT. Such expansion is necessary so that wind energy from current and future wind developments can be transported from West Texas and the Panhandle to population centers in South, Central, and North Texas. This expansion of the electric transmission network is scheduled to be completed in the 2013-2014 timeframe. Wind developers are expected to synchronize the completion of their new generation projects in the CREZ zones of West Texas and the Panhandle to coincide with the completion of the transmission network, almost doubling the current wind capacity.

In the operation of an electrical network, the level of energy produced must match the level of energy demanded by customers at all times within a narrow tolerance. The matching of energy output and energy demand is achieved, for the most part, by increasing or decreasing the output of generation facilities as demand changes. But the output of wind farms, like the level of the wind, is intermittent and difficult to predict. Wind resources constitute about 15% of the total capacity in the ERCOT region today, and it has been feasible to incorporate this relatively low proportion of wind energy into the electric system operations. As the CREZ facilities are completed, the increased proportion of wind generation is expected to present challenges for the reliable operation of the electric network.

Wind energy production typically becomes a significant part of total energy production during the off-peak seasons and in the winter, and wind energy is more likely to affect reliability in these periods of lower demand. For example, on June 12, 2010, wind energy production in ERCOT reached a record of 7,016 MW, which represented 15.8% of system load at that time. On March 4, 2010, a non-peak period, wind production reached 6,272 MW, which represented 19% of system load at that time. When wind production reaches 20% to 30% of total system load, operational problems are increasingly likely to affect system reliability. ERCOT has implemented improvements in its operations to address the current levels of wind production, such as improving the forecasting of wind production, and it continues to assess and develop measures that will allow it to continue to operate reliably as wind development continues in Texas.

Forecast Uncertainty

It is important for ERCOT to be able to accurately forecast wind energy production so that it can dispatch resources to match generation and load at all times. ERCOT has acquired state-of-the-art forecasting tools to forecast wind generators’ output. Wind generators are now required to use the wind production forecast provided by ERCOT in their daily resource plan submittals rather than rely on their own forecasts, which can have varying degrees of sophistication and accuracy.

Even with state-of-the-art forecasting of wind production, there are still differences between the forecasted production and actual production. While the supply uncertainty caused by wind forecast error, together with other sources of supply and demand uncertainty, such as outages of the conventional generation and transmission facilities, ERCOT mitigates this risk by acquiring generation reserves, which is additional generation that may be called into operation when needed. These reserves act as a safety net and provide the system operator a tool to deploy quickly to meet sudden and unexpected changes in electricity supply or demand, such as when a sudden change in wind production occurs. For example, on January 28, 2010, ERCOT experienced wind gusts throughout the day, which were difficult to predict accurately. The variability of wind generator output is shown in Figure 21. These wind speed changes led to the deployment and depletion of operating reserves (RRS, in the figure).

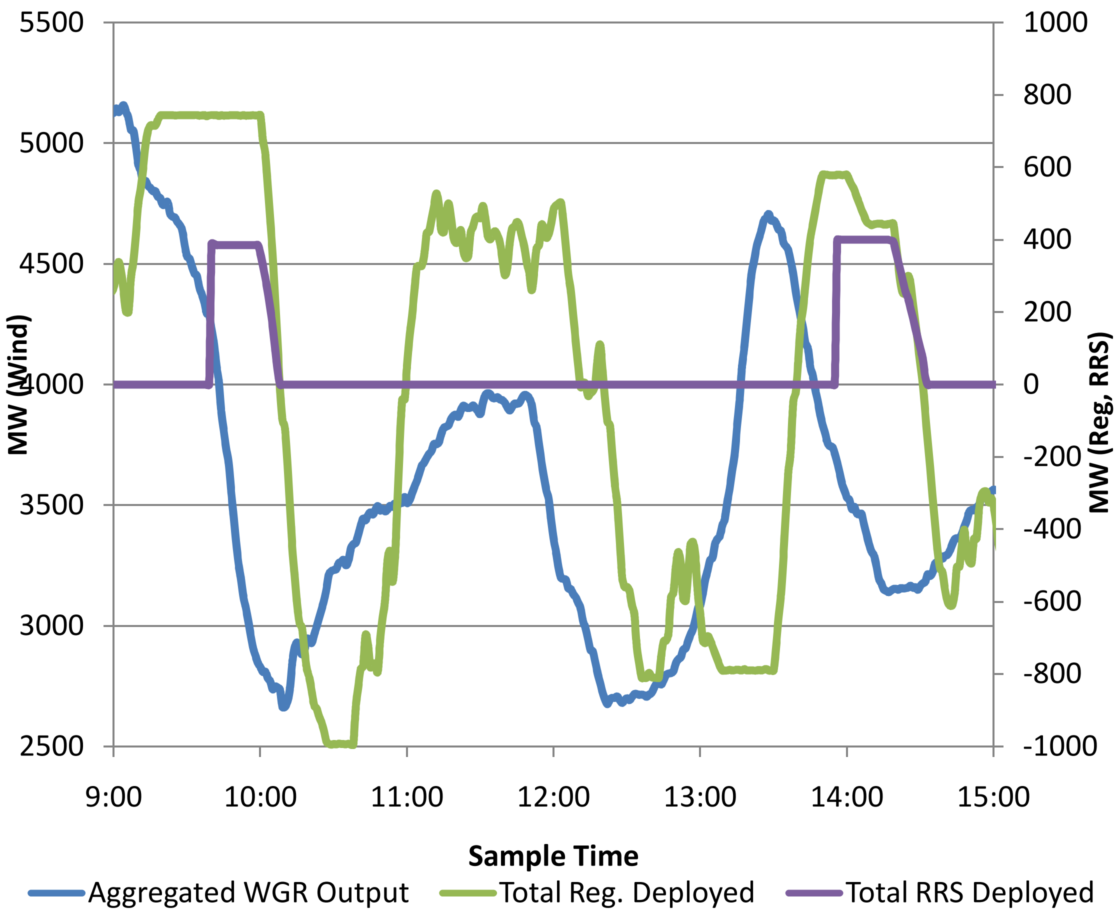

Figure 21 – Wind Output, Regulation and RRS for Jan. 28, 2010

In response to the increasing generation supply served by wind, ERCOT has adopted a new methodology to acquire additional operating reserves as the amount of wind generation increases.[93] In addition, ERCOT is considering adding reserve services

[93] For a discussion of the new Ancillary Services methodology adopted by ERCOT, see section C.2, Competitive Market Oversight Activities, Wholesale Market Oversight, of this report.

from quick-start generating units – units that can come on line within 10 minutes. ERCOT currently has 1,000 MW of resources capable of reaching full capacity in 10 minutes, and 550 MW of proposed resources with similar capability.

With the start-up of the nodal market on December 1, 2010, market design changes were implemented that are greatly improving ERCOT's ability to respond to wind variability. Previously, the ERCOT operator sent energy deployment instructions for energy resources approximately 10 minutes ahead of each 15-minute interval, and these instructions could not change until the end of the 15-minute interval. With the nodal market, ERCOT sends dispatch instructions at five-minute intervals, and if it detects changes in load or wind output within a five-minute interval, adjustments can be made to those instructions. It is expected that the shorter intervals will greatly improve ERCOT's operational flexibility and result in a reduced need for certain operating reserves, thereby reducing market operating costs that are passed on to electric customers.

System Stability

The expansion of wind energy production in Texas will bring about other operational changes to maintain system reliability. Wind generators historically have not contributed to stabilizing frequency at 60 Hz following a disturbance as conventional generators do. As a result, as wind generation displaces conventional generation in the electricity supply, greater reliance is placed on the remaining conventional generation to respond to and overcome frequency disturbances. However, technological improvements have brought a partial solution to this problem, and new wind turbines now come equipped with technology that allows these turbines to help restore the standard system frequency after a disturbance. New wind generators are now required by ERCOT rules to be equipped with such technology, and existing generators are required to retrofit their units if feasible.[94]

Similarly, wind generators historically have not provided the same degree of voltage support provided by conventional generators, support that is needed to reliably maintain the flow of electricity through transmission lines. Here again, technology is available to address this issue, and the new technology to address voltage support is now required of all new wind installations in ERCOT.[95] Going forward, wind generators will perform more like conventional generators when responding to frequency disturbances or providing voltage support to the electrical grid.

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[94] *See* Protocol Revision Request No. 833, *Primary Frequency Response Requirement from Existing WG*. Available online at: http://www.ercot.com/mktrules/issues/prr/825-849/833/. *See* Nodal Protocol Revision Request No. 258, *Synchronization with PRR824 and PRR833 and Additional Clarifications*. Available at: http://www.ercot.com/mktrules/issues/nprr/251-275/258/index.

[95] *See* Protocol Revision Request No. 830, *Reactive Power Capability Requirement*. Available online at: http://www.ercot.com/mktrules/issues/prr/825-849/830/. *See* Nodal Protocol Revision Request No. 269, *Synchronization of PRR830, Reactive Power Capability Requirement*. Available at: http://www.ercot.com/mktrules/issues/nprr/251-275/269/index.

C. Storage Technologies

In most utility networks, electricity cannot be stored and energy production must match energy demand, within narrow tolerances. Electric energy storage allows the "warehousing" of electricity for later use. As the electric industry has developed renewable energy resources that are dependent on environmental forces like solar and wind energy, interest in energy storage has increased. Energy storage could assist in making higher levels of intermittent resources adaptable for use on large electricity networks.[96] Storage could provide the flexibility to adjust energy production or consumption to offset changes in wind and solar power production, allowing energy output and demand to be matched. Storage could also provide an economical means of relieving transmission constraints or meeting demand during peak periods.[97]

Benefits and Applications

Storage could provide value to an electric network in several ways. It could do more than just balance the variable nature of wind and solar resources. Storage may be able to provide the following benefits:

Energy time-shift - Electric power produced during off-peak periods when prices are low could be stored for later use or sale when demand and prices are high.

Peak shaving - Energy storage could be dispatched to meet times of high peak demand, possibly deferring or reducing the need to invest in new generation capacity.

Ancillary services - Depending on the particular technology, energy storage has the capability to respond within seconds and to provide power for short or extended periods. It could, therefore, provide energy to respond to changes in load or production from power plants, offsetting the loss of generation resources or transmission capability.

Transmission support - Energy storage could improve transmission and distribution performance by compensating for disturbances on the system.

Transmission congestion - Storage could alleviate congestion by storing energy when there is no congestion and discharging energy during peak demand periods.

Defer transmission and distribution upgrades - Locating storage in an area where peak electric load is increasing and approaching the system's load carrying capacity could defer or eliminate the need for transmission and distribution upgrades. Backup power from a storage device can also give utilities the option to delay expensive upgrades in areas prone to loss of service.

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[96] Testimony of Jon Wellinghoff, Chairman, Federal Energy Regulatory Commission Before the Committee on Energy and Natural Resources, United States Senate, (December 10, 2009).

[97] Dan Rastler and Haresh Kamath, *Energy Storage: A Critical Asset to Enable Transformation to a Smart Grid* (August, 2010). Available online at: www.electricenergyonline.com.

Reliable power - Storage could be used to provide highly reliable power. In the event of an outage, storage could be used to meet customers' needs for the duration of the outage, facilitate an orderly shutdown process, or transfer power to on site resources.[98]

Power quality - Energy storage could quickly provide power to address voltage and frequency variations to protect customers' equipment from fluctuations in power quality.[99]

Although storage costs are, for the most part, higher than other traditional energy options, costs appear to be heading down. By performing several functions, energy storage may soon be a viable economic option for utility-scale applications.

Barriers

The hurdles storage faces are its cost and the lack of industry experience in using it in a high-voltage alternating-current network. There is little to guide industry and regulators concerning how to define storage devices and develop operational standards and compensation. While storage is capable of providing multiple services, it is difficult to assign it a role in a competitive environment, in which utilities have been unbundled. Issues relating to cross-subsidization, competition, and discrimination could arise if storage served multiple roles or functions at the same time. Requiring a storage facility not to perform some of the functions of which it is capable could address these concerns but could also render storage devices uneconomical or result in their underutilization.

Technology

Different storage technologies have different characteristics. Two important characteristics are the amount of energy that the storage device may deliver and the amount of time it is able to deliver the energy. Figure 22 shows the system ratings for several of the most common energy storage technologies.[100]

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98 Sandia National Laboratories, *Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide*, at xv, xvi (February, 2010).

99 APS Panel on Public Affairs, *Challenges of Electricity Storage Technologies*, at 8 (May 2007).

100 Electricity Storage Association. Available online at: www.electricitystorage.org/ESA/technologies/.

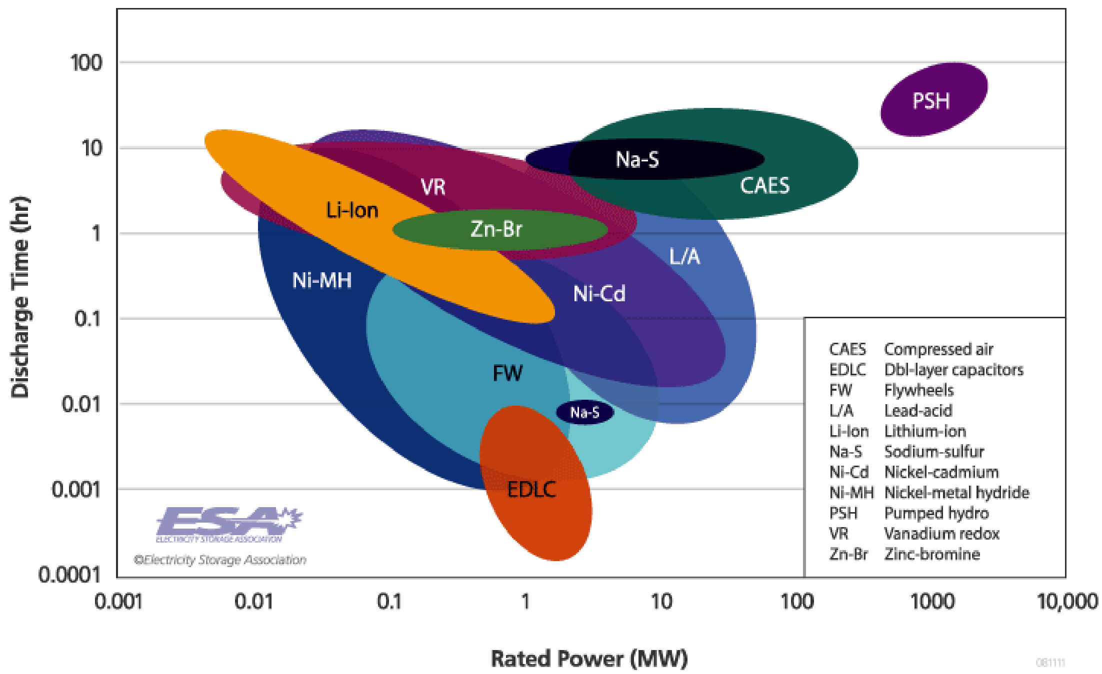

Figure 22 – System Ratings

Currently three types of energy storage are receiving most of the focus in the energy storage field. They are: compressed air storage (CAES), batteries, especially Lithium-ion and Sodium-sulfur (NaS), and flywheels.

CAES is a proven bulk storage technology capable of a discharge lasting 8-10 hours. In this technology, air is compressed and stored in underground reservoirs such as caverns or salt domes. As demand rises, the stored air is released through a natural gas turbine to produce electricity or is used in a combustion turbine. (Pressurizing the air is like putting a turbocharger on a combustion engine, increasing the output of the turbine.) Texas is well suited for a future CAES system. Salt domes are common and could be used to store off peak wind energy for later use when demand is high.

NaS battery storage systems have a successful operating history worldwide and in Texas. The NaS battery uses molten sodium and sulfur. It has high energy density (the amount of energy that can be stored in a given volume or mass), efficiency, a long cycle life, and can discharge up to eight hours if needed. NaS batteries offer the power and energy required for a variety of utility power system applications including voltage control, reactive power support, back-up power and deferring grid investment. Like CAES, these batteries can also be used to store excess wind power when demand is low and discharge it later to meet peak demand.

Lithium-ion batteries are used in laptop computers, and are being investigated for use in electric vehicles. Utility-level applications are emerging as research yields improvements that focus on energy density, durability, cost, and safety.

A flywheel is a mechanical battery with a wheel that spins at a high rate. When energy is needed, the flywheel can be used to provide the mechanical energy to drive a generator, but it typically has a short sustainable output period (about 15 minutes). They are presently being considered for use for load following (regulation) services.

Deployment in Texas

On March 31, 2010, Electric Transmission Texas's (ETT) four-MW NaS battery system was energized to the ERCOT grid. Located in Presidio, Texas, the battery is the first large scale installation in ERCOT and the largest in the United States. This NaS battery allowed the utility to defer the planned replacement of a 69-kV transmission line that is the sole source of electricity for Presidio. The battery is part of an ETT plan to improve transmission reliability in Presidio and the surrounding areas.[101] ETT expects that the battery will allow for more continuous service to the Presidio area, better response to voltage fluctuations and momentary outages, and the ability to repair the transmission line to the area without disrupting service.[102]

When the utility sought Commission approval of the Presidio battery, issues concerning ownership and control of energy storage systems were raised. The Commission ruled that:

> ETT's proposed use of the NaS battery is appropriate for a transmission utility because the battery system provides benefits associated with transmission service operations, including voltage control, reactive power, and enhanced reliability.[103]

American Recovery and Reinvestment Act (ARRA) Funding

Recently the U.S. Department of Energy increased funding for storage projects. In 2010, the DOE granted $185 million in ARRA funds for Energy Storage Demonstration projects to show the effectiveness of a range of technologies, applications, and deployment structures.[104] In addition, $435 million in funding was also made available for Smart Grid Regional Demonstrations of which $118 million will utilize energy storage.[105] The DOE also directed $2.4 billion in ARRA funding to promote

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[101] AEP News Release (September 2009). Available online at: www.AEP.com.

[102] *Application of Electric Transmission Texas, LLC for Regulatory Approvals Related to Installation of a Sodium Sulfur Battery at Presidio, Texas*, Docket No. 35994, at 7 (August 12, 2008).

[103] *Id.*, Final Order, at 3-4 (April 6, 2009).

[104] David Link and Clint Wheelock, *Executive Summary: Energy Storage on the Grid*, Pike Research (3Q2010).

[105] *Id.*

advanced battery technology and electric-drive components. The goal is to re-establish US battery manufacturing, reduce battery cost and improve performance.[106]

ARRA funding has quickened the pace of research and development in energy storage technologies, drawing not only the participant's matching funds but intense venture capital interest as well. Because of energy storage's ability to perform a variety of applications, the world market for energy storage could grow from $1.5 billion in 2010 to an estimated $35 billion in the next ten years. Much of this growth is expected to be driven by demand from the United States.[107]

D. Plug-in Electric Vehicles (PEVs)

Production of electricity for household, commercial, and industrial uses historically has been one of the major uses of energy in Texas and the United States. Another major consumer of energy has been the transportation sector. Unlike the electric sector, which relies to a great extent on domestic fuels, such as coal and natural gas, the transportation sector relies heavily on crude oil produced outside of the U.S. Until recently, there was little connection between these two sectors. However, domestic and foreign automobile manufacturers have announced that they intend to begin large-scale production of electric vehicles and to begin selling them in the U.S. The initial delivery of Chevrolet Volts was expected to include shipments to Austin dealers in November 2010. Nissan plans to sell the all-electric Leaf in Houston beginning in January 2011, and Ford has announced plans to sell a plug-in utility van in Houston in 2011 and passenger plug-in vehicles in Houston in 2012.[108]

The potential benefits of a fundamental change in the way the transportation sector is fueled include reducing reliance on a single source of primary imported fuel (crude oil) and reducing or eliminating tailpipe emissions. Developing an alternative transportation fuel could pose significant challenges. The nation and the state have a broad infrastructure to distribute gasoline and diesel fuel for transportation use, but switching to a different fuel, such as natural gas or hydrogen would require a new distribution infrastructure. The electric grid is already in place, and electrification in the transportation sector is less challenging than introducing a new fuel for which the current fueling infrastructure is not well suited. Texas homes and businesses have standard (120 volt) electrical outlets that are capable of charging the PEVs that automakers are planning to sell in Texas. The Commission highlights below several near term and long term issues for development of PEVs in Texas.

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[106] *Through ARRA, DOE Trying to Reestablish US Battery Manufacturing,* www.smartgridtoday.com (May 13, 2010).

[107] David Link and Clint Wheelock, *Executive Summary: Energy Storage on the Grid*, Pike Research (3Q2010).

[108] *Investigation of Electric Vehicles*, Project No. 37953, Agenda for the Workshop Scheduled for May 12, 2010 (May 4, 2010). http://www.puc.state.tx.us/rules/rulemake/37953/051210/Nissan-Presentation.pdf and http://www.puc.state.tx.us/rules/rulemake/37953/051210/Ford-Presentation.pdf.

Near Term Issues

The Commission conducted a workshop on electric vehicles on May 12, 2010, and several near-term issues emerged concerning the coming of PEVs to Texas. One of the concerns that participants identified was the need for automobile companies, utilities, and other entities to work together to ensure a positive experience for PEV buyers and provide them information on matters like recharging options and costs. While this concern is one that primarily is the responsibility of the auto manufacturers and dealers, the utilities and retail electric providers are affected, because home charging stations could have impacts on the electric network, in a broad sense, and on local distribution facilities, and because pricing options for electricity will be more important as electric consumption increases related to vehicle charging.

Based on customers' expectations and the lack of public facilities to recharge PEVs, the expectation is that initially most PEV charging will take place at home. All Texas homes with electric power have standard 120-volt outlets that will enable Level I "slow charging" of electric vehicles with a connector cord. The main drawback of Level I charging is the time needed to charge an electric vehicle battery. The Chevrolet Volt, for example, will take 6-8 hours to charge at 120 volts, and the Nissan Leaf will take up to 16 hours to charge. Texas homes will have the option of quicker Level II charging at 240 volts, but an Electrical Vehicle Supply Equipment (EVSE) unit would need to be installed to provide this level of charging, and some older homes may not have internal wiring to support a 240-volt EVSE. This EVSE equipment, in most cases, would charge the car batteries twice as fast as Level I charging. Some automobile manufacturers that plan to market PEVs in Texas are partnering with private EVSE companies to offer residential Level II EVSEs, and other companies have made announcements concerning deployment of chargers. For example, Austin Energy plans to provide home chargers to EV owners as part of a pilot program.[109] On September 23, 2010, TXU Energy announced it was investing in at least a dozen charging stations in Dallas/Fort Worth.[110] On November 18, 2010, NRG Energy, Inc. announced that it is launching a privately funded, comprehensive electric vehicle "ecosystem" in Houston in 2011.[111] In addition, Half- Price Books, AMD, Central Parking Systems, and Whole Foods have all announced installation of chargers.[112] As demand for public charging stations grows, additional public charging infrastructure development will likely occur.

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[109] *Austin Energy Pilot to Equip Electric Car Owners with Chargers*, AUSTIN BUSINESS JOURNAL. Available online at: http://www.bizjournals.com/austin/stories/2010/10/11/story7.html.

[110] TXU Press Release, *TXU Energy to Install Electric Vehicle Charging Stations*. Available at: http://www.txu.com/about/press-releases.aspx?year=2010.

[111] *NRG Launches Nation's First Privately Funded, Comprehensive Electric Vehicle Charging Ecosystem*, Business Wire. Available online at: http://www.businesswire.com/news/home/20101118005462/en/NRG-Launches-Nation%E2%80%99s-Privately-Funded-Comprehensive-Electric.

[112] *Half Price Books Offers First Electric Vehicle Charging Station at a North Texas Retailer*, Half-Price Books Press Release. Available online at: http://www.hpb.com/press/2010/press_release_09-20-2010.html. *AMD and Coulomb Technologies Help Develop the Burgeoning Electric Vehicle Market in*

The Commission hosted a meeting with the TDUs following the initial May 12th workshop to explore any system upgrade and cost allocation issues that the transmission and distribution utilities (TDUs) might encounter in their preparations for electric vehicle charging. The TDUs believe that the main transmission infrastructure components that will be affected by electric vehicle charging will be neighborhood transformers. If several electric vehicles are housed and recharged at homes in a neighborhood served from the same transformer, the transformer could be stressed. PEV charging requirements could affect transformers in two ways, increasing the use of the transformers and thus their internally-generated heat and reducing the cooling period that normally occurs at night, when other electrical uses are lower. The additional thermal load could shorten the lifespan of these transformers. However, night charging helps avoid increasing the electrical loads on the bulk electric system, which typically experiences its peak consumption hours in late afternoons. Night charging should better fit customers' needs initially, when public charging stations are not expected to be numerous or convenient to most customers. Transmission utility representatives assert that the transmission and distribution system impacts, particularly the possibility of transformer overload, will be minimal during the *initial* phases of PEV adoption, with the possible exception of local areas where there is a higher than average number of PEVs.[113] However, a study co-sponsored by KEMA and CenterPoint Energy in June 2010 found that the EV impact on distribution system feeders in the next decade will be minimal.[114]

The Commission also hosted a meeting on October 21, 2010, with REPs, as a follow-up to the initial May 12th workshop to seek input on "whether REPs see any regulatory issues that might act as barriers to the implementation of public charging stations." The REPs attending this meeting shared the view that no regulatory barriers currently exist to the development of public charging, given that charging equipment and services are in the competitive rather than regulated domain. However, the REPs also noted that EV development is intertwined somewhat with development of advanced metering and the smart grid, and it will be important to ensure that the smart grid is developed using national standards and adequate communications performance to support smart charging. Further, REPs stated that state and local governments can promote development of EVs and educate consumers by creating convenience benefits for EV owners, such as but not limited to HOV-lane access, preferred parking, and expedited permitting for installation of home chargers. REPs further noted that as non-traditional electric market participants, such as the automobile manufacturers, begin to be more involved in the electric market here in Texas, the Commission and its staff will have an

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Austin and Silicon Valley, AMD Press Release. Available online at: http://www.amd.com/us/press-releases/Pages/amd-coulomb-technologies-electronic-vehicle-2010nov23.aspx. *Houston's Central Parking Installs Coulomb ChargePoint Networked Charging Stations for Electric Vehicles in Downtown Parking Garage Locations*, Coulomb Technologies Press Release. Available online at: http://www.coulombtech.com/p^!news-press-releases-2010-0624a.php. *Whole Foods Market Unveils Coulomb Technologies ChargePoint Networked Charging Station Infrastructure for Electric Vehicles,* Coulomb Technologies Press Release. Available online at: http://www.coulombtech.com/pr/news-press-releases-2010-04 t 2.php.

113 *Electric Vehicles in Houston: Motivations, Trends, and Distribution System Impacts*, KEMA and CenterPoint Energy Whitepaper, at 48 (June 23, 2010).

114 *Id*. at 8-2.

important role in educating these stakeholders about the unique characteristics of the ERCOT market structure and the competitive retail market in Texas.

Long-Term Issues

In the long term, if the number of PEVs in use increases significantly, there are likely to be questions about how PEVs interact with the electrical network. PEVs represent an additional load on the network that will need to be met by a diverse set of resources, but they also represent a potential resource for the network that could help provide reliable service for all customers. PEVs store electricity in their batteries, and they could send electricity back to the grid when aggregate or local electricity demand is high or energy is needed to deal with system problems. These possibilities are beyond the capabilities of the first electric vehicles that auto makers are producing, but small pilot projects in other regions of the country are exploring how vehicle owners might receive compensation for supplying energy back to the electric grid.[115]

The attendees at the May 12, 2010 Commission workshop discussed the possibility of synchronizing plug-in electric vehicle charging with wind generation as car batteries, advanced metering, and smart phone technologies develop. Synchronizing wind generation with electric vehicle charging could allow plug-in electric vehicle owners in Texas to take advantage of lower price energy, because a large amount of wind generation typically occurs at night when demand from other electricity users is low. Researchers are also studying how PEVs might supply additional energy to offset a rapid reduction in output from wind farms. To achieve the synchronization of PEV charging to the grid, PEVs would have to be able to communicate with the grid and respond to signals that prices are low (because wind energy is abundant, for example) or that a problem has occurred for which the energy stored in PEV batteries could provide a solution. An advanced system of communications and control software could permit the independent electric system operator to send signals to the vehicle, which could respond by allowing the PEV's battery to charge or discharge. Thus the PEV would be responding to system conditions, based on the PEV owners' pre-selected preferences, supporting the electric system when needed and drawing energy from the electric system when energy is inexpensive. The possibility of electric vehicles giving energy back to the grid when needed is often referred to as vehicle to grid (V2G) technology.

E. Distributed Generation

Most of the resources that are envisioned as providing energy and capacity in an electrical network are large or utility-scale resources. Smaller-scale, distributed resources at customers' homes and businesses are now seen as resources that can provide several benefits, economically supplying the customer's energy needs, enhancing reliability at the home or business, and also supporting grid energy needs. Some resources, such as distributed solar energy, are also emission-free energy sources. The 1999 amendments to PURA included provisions that were intended to facilitate

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[115] *Vehicle to Grid Technology,* University of Delaware, (2009). Available online at: http://www.udel.edu/V2G/.

distributed generation (DG),[116] and the Commission has adopted rules to carry out those amendments.[117] Additional legislation related to renewable DG was enacted in 2007.[118]

Installing DG typically involves a significant up-front investment for a customer, with the expectation that the investment will pay off by reducing the customer's purchases from its retail provider, whether a utility or a competitive provider. Income tax benefits may be available for renewable DG to make an investment in such a resource more attractive. In addition, Austin Energy, the municipal utility for the City of Austin, and Oncor have provided incentives to customers to install solar DG, and a few utilities have provided incentives for solar DG as a part of their energy-efficiency programs.

A number of issues may arise if a homeowner or business intends to install distributed generation to supply a part of the energy needs of the home or business, beyond the cost of buying and installing the facilities. These issues include:

- regulatory obstacles, such as registration requirements;
- difficulty in obtaining approval from the utility that serves the customer to connect the DG facility to the utility delivery system;
- the cost of special metering facilities that will permit the measurement of energy that is delivered from the customer to the electric network; and
- lack of opportunity to sell any excess energy that is delivered to the electric network.

F. Federal Environmental Legislation

The U.S. Environmental Protection Agency (EPA) has a number of regulatory changes under consideration that could affect thermal generators in Texas and the U.S. According to the EPA, greenhouse gas (GHG) emissions caused by human activities in the country increased by 14% from 1990 to 2008, with carbon dioxide (CO_2) accounting for most of the emissions and most of this increase. Electricity generation is the largest source of GHG emissions in the United States, accounting for about 32% of total U.S. GHG emissions since 1990, followed by 27% for transportation. Emissions per person have remained about the same since 1990.[119]

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[116] PURA § 39.101(b).

[117] P.U.C. SUBST. R. 25.211, 25.212, and 25.213.

[118] PURA §§ 39.914 and 39.916.

[119] U.S. Environmental Protection Agency, *Climate Change Indicators in the United States* (April 2010). Available online at: http://www.epa.gov/climatechange/indicators/pdfs/ClimateIndicators_full.pdf.

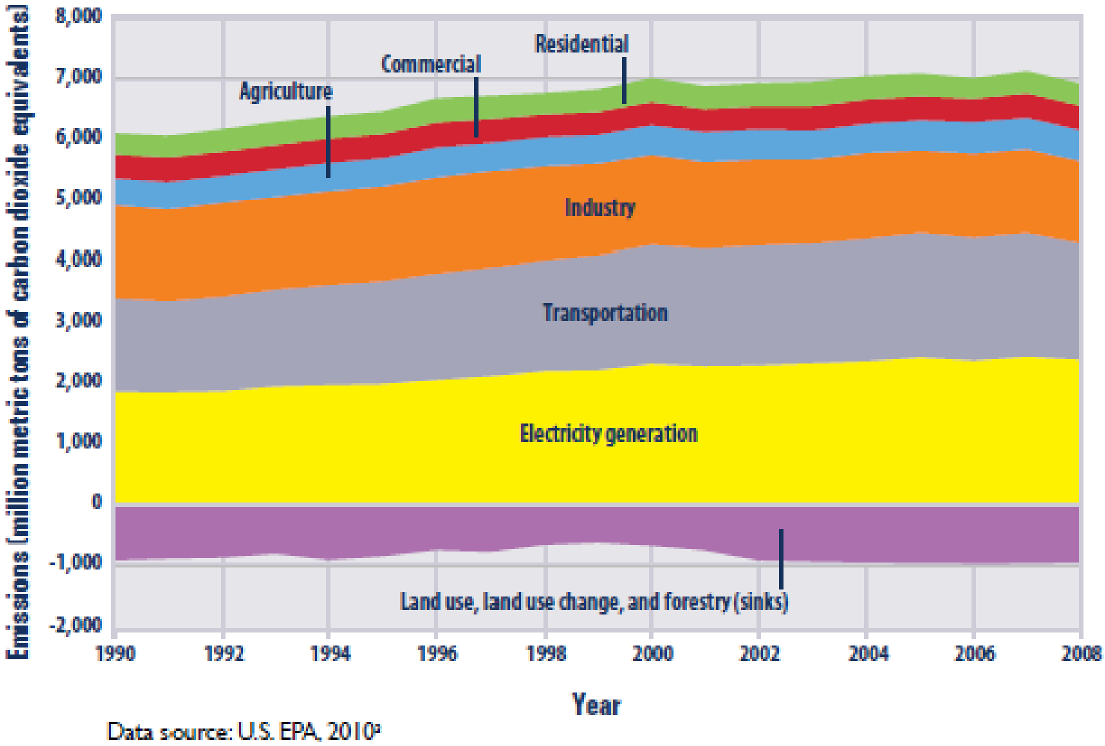

Figure 23 – U.S. GHG Emissions and Sinks by Economic Sector, 1990-2008

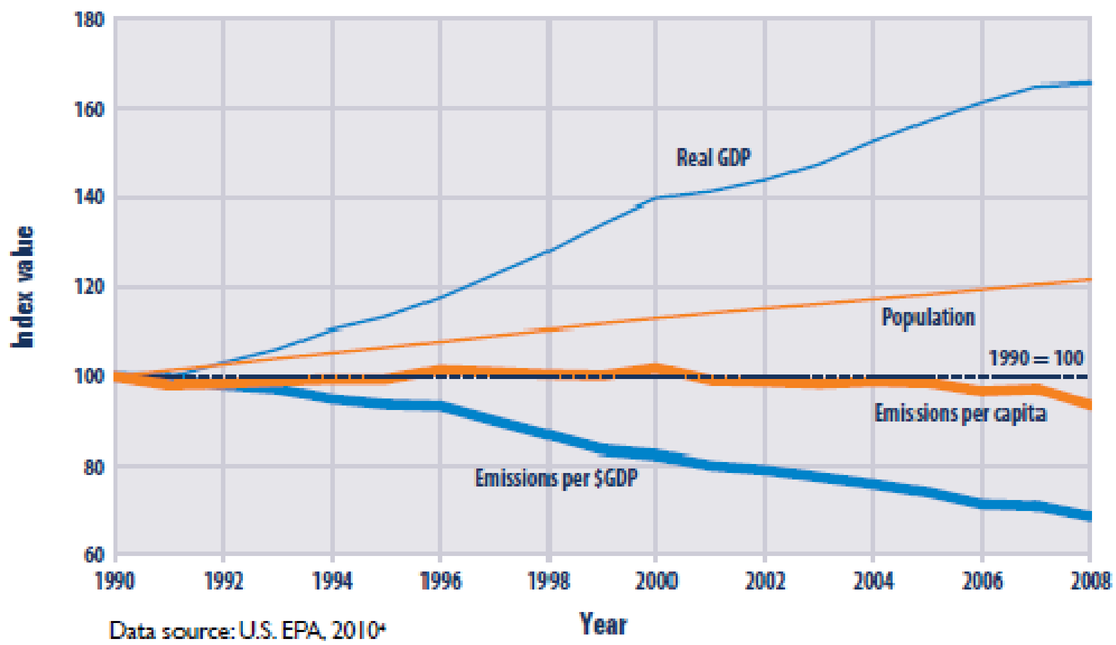

Figure 24 – U.S. GHG Emissions per Capita and Per Dollar of GDP, 1990-2008

In the last few years, significant measures have been taken at the national level to monitor and report emissions of GHGs. The Consolidated Appropriations Act of 2008, enacted on December 26, 2007, directed the EPA to develop a mandatory reporting rule for GHGs. On September 22, 2009, EPA approved final regulations requiring the monitoring and reporting of annual GHG emissions from large sources and suppliers across the U.S.[120] GHGs subject to these new requirements include CO_2, methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons (HFCs), perfluorocarbons and other fluorinated gases. EPA estimated that the rule would cover about 10,000 facilities nationwide, accounting for about 85% of GHG emissions. The emitters must begin to monitor their emissions from January 1, 2010, with the first annual reports due on March 31, 2011.

The ARRA included $3.4 billion for carbon capture and storage projects, with $1.52 billion made available for industrial carbon capture and energy efficiency improvement projects, $1 billion for the renewal of FutureGen, and $800 million for U.S. Department of Energy Clean Coal Power Initiative Round III solicitations, which specifically target coal-based systems that capture and sequester, or reuse, CO_2 emissions.[121]

Earlier this year, the U.S. government formally associated itself with the Copenhagen Accord by committing to achieve GHG emissions reduction in the range of 17% relative to 2005 levels by 2020 "in conformity with anticipated U.S. energy and climate legislation."[122]

Greenhouse gas legislation, however, has not been enacted at the national level. In June 2009, the House of Representatives passed the Waxman-Markey American Clean Energy and Security Act (ACESA) (H.R. 2454) that would reduce GHG emissions 17% from 2005 levels by 2020 and 83% by 2050, using a cap and trade emissions trading system. Under the system, companies, including electric generators, would be granted a certain number of credits or allowances for carbon emissions. Companies that wish to exceed their emission cap could purchase unused credits from other companies that have remained below their cap. EPA estimated that implementing ACESA would cost the average household $80 to $111 per year. A similar study by the Congressional Budget Office (CBO) estimated average household cost to be $175 per year, with some lower-income households receiving a net benefit.

In April 2009, concerned about the effects of the proposed legislation on electricity prices in the ERCOT market, Chairman Smitherman requested ERCOT to perform an analysis of the impact of the ACESA "discussion draft" stating that "it is important that the PUCT and the Texas legislature have some understanding of how federal climate change legislation is likely to affect electricity consumers in ERCOT."[123]

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[120] *Mandatory Reporting of Greenhouse Gases*, EPA. Available online at: http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.

[121] *American Recovery and Reinvestment Act of 2009* (January 2009). Available online at: http://www.recovery.gov/About/Pages/The_Act.aspx or at: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=111_cong_bills&docid=f:h1enr.pdf.

[122] http://unfccc.int/files/meetings/application/pdf/unitedstatescphaccord_app.1.pdf.

[123] Barry Smitherman, Chairman, Public Utility Commission of Texas, Letter to Bob Kahn, CEO, ERCOT (April 2, 2010), http://www.puc.state.tx.us/about/commissioners/smitherman/reports/Bob_Kahn_Ltr_040209.pdf.

In line with a similar study conducted by the PJM Interconnection, ERCOT focused on the near-term impacts of this potential legislation. ERCOT concluded that the effect of the legislation on the typical customer's monthly bill would range from a $5.57 increase to a $63 increase at CO_2/ton prices of $10 and $100 respectively.[124] The state Comptroller's Office estimated that Texas could lose 170,000 to 425,000 jobs by 2030 and state GDP could decrease by $25 to $58 billion by 2030.[125]

A similar bill, the Kerry-Boxer Clean Energy Jobs and American Power Act (S. 1713), passed out of the Senate Environment and Public Works Committee, but never made it to the Senate floor. Several other bills were introduced in the Senate in 2010 to address GHGs, but none of those bills was enacted.

In the absence of comprehensive federal climate legislation, EPA moved ahead to impose mandatory controls using its existing authority. On April 2, 2007, the U.S. Supreme Court ruled that Section 202(a)(1) of the Clean Air Act (CAA) gave EPA authority to regulate tailpipe emissions of GHGs. In December 2009, the agency formally determined that GHG emissions endanger public health and welfare and therefore are subject to regulation under Section 202 of the CAA.[126]

On February 16, 2010, Governor Rick Perry, the Attorney General of Texas, the Texas Agriculture Commission, TCEQ and PUC Chairman Barry Smitherman filed a petition with the U.S. Court of Appeals challenging EPA's endangerment finding.[127] In addition, the state filed a petition for reconsideration, asking EPA to review its decision on the basis that it was legally unsupported because it relied on flawed science. EPA denied the petition.

In April 2010, based on its endangerment finding, EPA finalized mobile source emission standards which, under a CAA program called "prevention of significant deterioration," automatically triggered construction and operating permit requirements and installation of "best available control technologies" for all regulated pollutants for any new or significantly modified stationary sources, including power plants, whose potential emissions exceed 100 or 250 tons per year (depending on source type).

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124 *Analysis of Potential Impacts of CO2 Emissions Limits on Electric Power Costs in the ERCOT Region*, ERCOT (May 12, 2009). Available online at: http://www.puc.state.tx.us/about/commissioners/smitherman/reports/Carbon_Study_Rpt.pdf.

125 http://www.window.state.tx.us/finances/captrade/txpolicies_programs/CEE_Final_Report_to_Texas_Comptroller_of_Public_Accounts.pdf.

126 *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, EPA. Available online at: http://www.epa.gov/climatechange/endangerment/downloads/Federal_Register-EPA-HQ-OAR-2009-0171-Dec.15-09.pdf and http://www.epa.gov/climatechange/endangerment.html.

127 *Rick Perry, Governor of Texas, et al. v. EPA*, No. 10-1041 (D.C. Cir. filed on Feb. 16, 2010).

The Tailoring Rule[128] published by EPA in June 2010 would regulate stationary sources, such as power plants, that emit at least 75,000 tons of GHGs. In July 2012, the rule would expand to include all new facilities that emit at least 100,000 tons a year. Emissions from smaller sources will not be addressed until at least 2016.

EPA has also taken action on a number of conventional air pollutants. The agency announced in May 2010 that it is collecting data on dioxin, mercury and other emissions from utility boilers to support a proposed rule, called "Air Toxics Standards for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Source Facilities" that would set emissions standards from these sources. Under a separate proposal coal-fired power plants would be required to use the maximum achievable control technology (MACT). EPA estimates that MACT would yield health benefits of $18 to $44 billion per year at annual costs of installing and operating pollution controls of $3.6 billion. The final version of the MACT rule is expected late in 2011. The biomass industry expressed concern that the compliance cost of the new rule would be about $7 billion.[129]

In June 2010, the EPA published a final rule that would tighten the National Ambient Air Quality Standards (NAAQS) for sulfur dioxide (SO_2) under the CAA, abandoning the currently applicable 24-hour and annual standards in favor of a one-hour standard.[130] The NAAQS also establish a new monitoring network for areas where SO_2 emissions coincide with high population densities. This rule will mostly affect fossil fuel power plants, which account for 73% of SO_2 emissions.[131]

In July 2010, EPA proposed a final rule known as the Air Transport Rule[132] to address air emissions that cross state lines and contribute to ozone and particulate matter pollution in the eastern part of the U.S. The rule would create Federal Implementation Plans to reduce SO_2 and nitrogen oxide (NO_X) emissions from electric power plants in 32 states, including Texas, through a combination of direct abatement standards and a limited voluntary cap and trade program. The new rule would replace the Clean Air Interstate Rule of 2005 (CAIR) and require the 32 states to cut power plant SO_2 emissions by 71% and NO_X emissions by 52% from 2005 levels by 2014. The emissions reductions would start in 2012. EPA estimates annual compliance costs for the power sector at $2.8 billion and heath and public welfare benefits of $120-290 billion in 2014, including the prevention of 14,000 to 36,000 premature deaths a year. Texas

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128 *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule*, EPA. Available online at: http://www.gpo.gov/fdsys/pkg/FR-2010-06-03/pdf/ and http://www.epa.gov/NSR/actions.html.

129 *SNL Financial* (2010). Available online at: http://www.snl.com.

130 *The Primary National Ambient Air Quality Standard for Sulfur Dioxid*e, EPA. Available online at: http://www.epa.gov/ttn/naaqs/standards/so2/fr/20100622.pdf and http://www.epa.gov/ttn/naaqs/ or http://www.epa.gov/airquality/sulfurdioxide/actions.html.

131 *The Primary National Ambient Air Quality Standard for Sulfur Dioxide,* EPA. Available online at: http://www.epa.gov/ttn/naaqs/standards/so2/fr/20100622.pdf ; http://www.epa.gov/ttn/naaqs/ and http://www.epa.gov/airquality/sulfurdioxide/actions.html.

132 *The Clean Air Interstate Rule*, EPA. Available online at: http://www.epa.gov/cair/.

was required to reduce SO_2 and annual NO_X emissions in CAIR, but under the new rule it would only be required to reduce ozone season NO_X because its SO_2 emissions do not affect other states' levels.

In the absence of federal legislation to reduce GHG emissions, state and regional programs continue to evolve. As of August 2010, 23 states accounting for 48% of the U.S. population, over 50% of GDP and 37% of GHG emissions are involved in the design of three distinct regional cap and trade systems to reduce GHG emissions. The Regional Greenhouse Gas Initiative, a cap and trade system operating in 10 Northeastern states sets a limit on CO_2 emissions at 188 million short tons per year from 2009 to 2014. This cap will then be reduced by 2.5% per year from 2015 through 2018, resulting in a cut of 10%. The Western Climate Initiative (WCI), a coalition of seven U.S. Western states and four Canadian provinces, has the goal of reducing GHG emissions by 15% below 2005 levels by 2020 across the region through a regional trading program set to take effect in January 2012. The Midwestern Greenhouse Gas Reduction Accord signed by six Midwestern states and one Canadian province provides for reducing GHG emissions 20% below 2005 levels by 2020. Participants commit to establish a GHG emissions reductions tracking system and implement other policies, such as a two percent reduction in energy use by 2015, an increase in the percentage of gas stations offering ethanol from 3% to 15% and a region-wide 10% renewable energy standard.

Considering the possible impacts on the electricity generation industry and on Texas electricity customers, in December 2010, the Commission asked ERCOT to study the possible consequences of the proposed EPA rules. Specifically, the Commission asked ERCOT to evaluate the potential impacts of the EPA rules on generation facilities in ERCOT and the potential consequences on generation adequacy, reliability, and prices. Studies by NERC, the Brattle Group, and Credit Suisse have estimated significant retirements of coal-fired generation in ERCOT and nationwide, which could seriously affect generation adequacy.[133] These studies estimate the possible retirement of 5-13 GW of coal-fired generation in ERCOT.

[133] *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*, North American Electric Reliability Corporation (October 2010). Metin Celebi, Frank Graves, Gunjan Bathla, & Lucas Bressan, *Potential Coal Plant Retirements Under Emerging Environmental Regulations,* The Brattle Group (December 8, 2010). *Growth from Subtraction: Impact of EPA Rules on Power Markets,* Credit Suisse (September 23, 2010).

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VI. LEGISLATIVE RECOMMENDATIONS

1. Additional Oversight of ERCOT

The governance of ERCOT and the Commission's oversight of the organization are addressed in PURA § 39.151; this section was amended in 2005 to enhance the Commission's oversight authority. Despite the 2005 legislative changes, issues relating to governance and Commission oversight of ERCOT continue, and were most recently raised by the the Sunset Advisory Commission, which adopted several recommendations on this issue:

- requiring the Commission to conduct additional oversight of ERCOT by reviewing its budget on an annual basis and reviewing any debt financing undertaken by ERCOT;
- permitting the fee charged by ERCOT to vary, based on the level of revenues earned, in order to recover the annual budgeted expenses and requiring ERCOT to provide quarterly financial reports to the Commission;
- subjecting ERCOT to future sunset reviews on the same schedule as the Commission;
- modifying the membership of the board of directors, retaining the current stakeholder members and unaffiliated members, but adding one unaffiliated member who would be required to have financial experience, replacing the Chairman of the Commission with an unaffiliated, voting member selected by the Commission, and replacing the Public Counsel with an unaffiliated, voting member selected by the Public Counsel; and
- modifying the process by which ERCOT approves changes in market rules, by requiring that proposals for such changes be initiated by the governing board, eliminating the Technical Advisory Committee (TAC), and directing the board of directors to develop a stakeholder advisory body to replace the TAC.

In late 2010 the Commission initiated a rulemaking proceeding to revise its rules relating to ERCOT governance and oversight. The Commission proposed a number of provisions to enhance its oversight of ERCOT and improve the cost-effectiveness of the organization:

- annual Commission review and approval of the budget;
- prior Commission review and approval of any debt issuances;
- Commission-prescribed staffing limits;
- Commission approval of new unaffiliated members of the board of directors;
- Commission approval of the hiring of the ERCOT chief executive officer and other executives; and
- additional conflict-of-interest provisions that would apply to executives and unaffiliated members of the board.

One of the important functions of the ERCOT board of directors is to approve financial policies, adopt a budget, and approve the incurrence of debt. Current law does not *specifically* require Commission approval of ERCOT's budget or issuance of debt. Under current practice, the Commission reviews any changes in the amounts of the fees by which ERCOT recovers its operating costs but does not approve ERCOT's budget. Under this practice, ERCOT may incur additional debt that ultimately may lead to a higher fee to pay the principal and interest on the additional debt, which could effectively circumvent the Commission's review of the fees. While the Commission believes that it has the authority to adopt rules to require annual approval of the budget, one party that commented on this issue in the rulemaking proceeding contended that the Commission does not have the authority to require ERCOT to submit its budget for Commission review.

The Commission supports the modifications in ERCOT governance and oversight that were recommended by the Sunset Advisory Commission. In particular, it may be appropriate for the Legislature to clarify the Commission's ability to review the ERCOT budget and debt issuances. The Commission does not believe that it lacks this authority, but because some have argued that it does, legislation affirming the Commission's authority in these areas would facilitate the adoption of rules to strengthen the Commission's oversight of ERCOT.

2. Advanced Metering

As discussed in the Commission's Report to the Legislature on Advanced Metering and in an earlier section of this report, the deployment of advanced meters in ERCOT is well underway. Advanced meter deployment plans have been filed for all competitive areas and except for one area, those plans are approved and deployment has begun. The Commission made a single recommendation in its Report to the Legislature on Advanced Metering as required by HB 2129 and repeats that recommendation in this report: Clarify whether the Legislature intends that advanced meter information systems be deployed as rapidly as possible in areas outside of ERCOT, and, if so, clarify whether the Commission has the authority to adopt advanced meter surcharges for utilities outside of ERCOT.[134]

3. Nuclear Decommissioning

House Bill 1386 enacted during the 80th Legislative Session required the Commission, in conjunction with the Nuclear Regulatory Commission (NRC), to investigate and file legislative recommendations regarding the development of "a mechanism whereby the State of Texas could ensure that funds for decommissioning

[134] *See* P.U.C. SUBST. R. 25.130(b), which states, "This section is applicable to all electric utilities, including transmission and distribution utilities, other than an electric utility that, pursuant to Public Utility Regulatory Act (PURA) § 39.452(d)(1), is not subject to PURA § 39.107; and to the Electric Reliability Council of Texas (ERCOT)."

will be obtained when necessary in the same manner as if the State of Texas were the licensee under federal law."[135]

In early 2008, the Commission adopted a rule that established the terms for a power generation company (PGC) using a decommissioning trust to satisfy its the financial assurance requirements and to establish the rights and obligations of the PGC when using Texas customers' funds to satisfy the financial assurance requirements. While the Commission believes the rule is sufficient for a PGC to satisfy its nuclear decommissioning obligations, the Legislature could consider other options to help satisfy the NRC's financial assurance requirements.

In response to the directive in HB 1386, the Commission offers the following comments. The Commission provided a more detailed discussion of this issue in its 2009 Report on the Scope of Competition in Electric Markets.

Based on discussions with the staff of the NRC, the Commission understands that NRC regulations do not permit recognition of the State of Texas as a licensee unless the State assumes all licensee obligations, as owner or operator or both, through the NRC's formal licensing process. That is, the NRC will not consider the State as a licensee only for purposes of decommissioning funding. The State may, however, use its capabilities to access financial resources to provide assurance that decommissioning funds will be available when needed. In that case, the NRC would consider financial commitments made by the State to a potential licensee in assessing whether the potential licensee has complied with the NRC's financial assurance requirements for decommissioning funding. The Commission has identified three mechanisms whereby the State of Texas could provide such financial assurance: prepayment, an external sinking fund, and a guarantee agreement. However, each of these mechanisms has significant impediments, as outlined in the 2009 report to the Legislature.

First, the State of Texas could prepay the full amount required for decommissioning. Under this option, the Legislature would establish a trust or other protected account in accordance with NRC regulations[136] and deposit into that account funds sufficient to satisfy the decommissioning obligations for each nuclear power reactor licensed by the NRC for construction in Texas.[137] In the event that a licensee's sinking trust fund and other methods of financial assurance fail to satisfy the licensee's decommissioning obligations, the prepaid funds would be available to ensure decommissioning of the reactor.

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[135] Public Utility Regulatory Act, TEX. UTIL. Code ANN. § 39.206(q) (Vernon 2007 & Supp. 2008).

[136] 10 C.F.R. § 50.75(e)(1)(i). *See also* 10 C.F.R. § 50.75(h) (containing, *inter alia*, restrictions on withdrawal of funds from a decommissioning trust fund for purposes other than decommissioning and ordinary administrative costs).

[137] NRC regulations permit a licensee in certain circumstances to take credit for projected earnings on the prepaid decommissioning funds.

Second, the Texas Legislature could deposit funds periodically into an external sinking fund in accordance with NRC regulations.[138]

Third, the Texas Legislature could establish the State of Texas as a guarantor of the licensees' decommissioning funding obligations. NRC regulations describe the required terms for such a guarantee.[139]

4. Enhancement of Opportunities for Distributed Renewable Generation

In the 2007 session of the Legislature, two new sections were added to PURA to address issues related to distributed renewable generation (DRG), including solar generation. It appears that the Legislature expected that these new sections would foster additional renewable capacity that would be installed at customers' homes and businesses, including solar generation on the buildings of school districts. There remain provisions of PURA that may create obstacles to the installation of DRG, particularly where a person other than the owner of the home or business would own or operate the DRG. The Commission recently created a new type of REP that would be authorized to sell energy from a DRG to the business on whose property the DRG is located. This development may result in the installation of more DRG facilities for larger, non-residential customers. If the recent change is successful, the Commission could consider applying the same rules to third-party ownership of DGC at residential premises, too. Ownership of the DRG by a third party could provide economies of scale or tax benefits to the third-party owner of the DRG that would not be otherwise available to the customer. Another option for fostering DRG would be to amend PURA to remove the obstacles to third-party ownership of DRG for all customers.

5. Utility Funding of PUC Intervention at FERC

Utilities outside ERCOT are subject to the Commission's jurisdiction for retail issues and the FERC's jurisdiction for wholesale issues. These utilities are Entergy Texas, Southwestern Public Service, Southwestern Electric Power Company, and El Paso Electric Company. The types of issues that FERC addresses for these utilities include wholesale transmission rates and regional transmission organization issues, which in ERCOT are addressed by the Commission. FERC also addresses other issues such as the Entergy System Agreement, which is discussed in Legislative Recommendation 7.

Issues addressed by FERC can have significant cost impacts on utilities' retail customers, and other state commissions routinely intervene in FERC proceedings that affect utilities operating in their states. FERC's standards and procedures are significantly different than the Commission's, and the time, resources, and expertise necessary to effectively participate in them can be substantial. The Commission has participated in some FERC litigation proceedings and has been represented by the Attorney General in those proceedings. Consistent with the practice of some other

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[138] 10 C.F.R. § 50.75(e)(1)(ii). *See also* 10 C.F.R. § 50.75(h) (regarding restrictions on withdrawals from sinking funds).

[139] 10 C.F.R. § 50.75(e)(1)(iii).

states, notably, Arkansas and Louisiana,[140] the Legislature may want to consider authorizing the Commission to hire outside counsel with FERC expertise, as well as consultants, to represent it in FERC proceedings and to require the utilities affected by the proceeding to reimburse the Commission for its costs of participation, including any related court litigation. Under current Texas law, state agencies may contract for outside legal services, but they must obtain the approval of the Texas Attorney General before doing so.[141] The Legislature may also want to consider allowing the Commission to hire outside counsel without obtaining the prior approval of the Texas Attorney General.

6. Clarification of PURA regarding the Charging of Electric Vehicles

The Commission notes that as an emerging technology, development of plug-in electric vehicles (PEVs) was not contemplated when the Public Utility Regulatory Act was adopted, and therefore there is no mention of PEVs in PURA. The state policy established in PURA § 39.001(d) is that regulatory authorities shall "authorize or order competitive rather than regulatory methods . . . and shall adopt rules and issue orders that are both practical and limited so as to impose the least impact on competition." Therefore, the Commission believes that even though PURA is silent on PEVs, the Commission has ample regulatory authority and policy guidance to deal with issues that arise concerning EVs and their role within the Texas market structure. Nevertheless, the Legislature may wish to provide additional guidance to foster further development of PEVs as a competitive service, as well as consider measures to promote the widespread adoption of EVs and the development of this emerging sector of the Texas economy.

7. Clarification of Authority to Order a Utility to Join a Specific RTO

While the move to retail open access in the areas outside ERCOT has slowed, the importance of ensuring adequate competition in the wholesale markets that underlie the electricity supply in those areas has not diminished. FERC continues to promote wholesale markets and non-discriminatory access to transmission systems through regional transmission organizations (RTOs). While some Texas utilities outside ERCOT have joined an RTO, others have not.

One of the utilities that has not joined an RTO, Entergy, is facing significant changes in the next few years to the FERC-approved Entergy System Agreement (ESA) that governs system planning, operations and cost allocation among the various Entergy state operating companies, including Entergy Texas. In addition, an extension of an arrangement by which a third party oversees the Entergy transmission system was recently approved by FERC, but only on an interim two-year basis. FERC also recently completed a cost-benefit analysis of Entergy, including all of its state operating companies, joining the Southwest Power Pool (SPP) RTO. The analysis showed there would be substantial cost savings to Entergy's retail customers of joining the RTO. Entergy and its various state regulators have been discussing alternatives to the ESA, enhancements to the transmission oversight arrangement, and options for Entergy to join

[140] ARK. CODE ANN. 23-4-101, 23-4-102(c)(2) and (3); LA. CIV. CODE art. 1180 and 1181.

[141] TEX. GOV'T. CODE § 2254.153 (Vernon 2008) and § 402.0212 (Vernon 2005).

an RTO, and the ultimate path that Entergy takes will have significant impacts on Entergy Texas' customers.

To protect the interests of the Entergy Texas customers and the customers of other utilities that do not join RTOs, the Legislature may want to consider clarifying the Commission's authority to order utilities to join RTOs. The issue of Entergy Texas joining an RTO will likely need to be addressed before 2013, when Entergy Arkansas is scheduled to leave the current ESA.

8. Clarification of Authority to Classify Energy Storage Technologies

As previously discussed in Chapter V, electricity storage technologies are developing rapidly and are expected to find various roles in the electricity supply chain, depending on their capacity and operating characteristics. The characteristics of some of these technologies mean that some can participate in generation markets and compete against more traditional generation resources in energy, transmission congestion, and transmission ancillary services markets. The characteristics of other storage technologies mean that they are more suitable to function like transmission assets, and some technologies have the capability of functioning in both capacities. The competitive model in Chapter 39 of PURA contemplates a separation of transmission and generation, so that a regulated utility would not own generation facilities.

Because some storage technologies have the capability to function as both transmission and generation, the Legislature may wish to clarify the Commission's authority to determine the role or roles of storage in the competitive market, whether as a regulated transmission asset, the cost of which would be recovered through regulated rates, or as a generation asset that would recover its costs in the various competitive markets.

VII. APPENDICES

Appendix A

Acronyms

AEP	American Electric Power
AEP TCC	AEP Texas Central Company
AEP TNC	AEP Texas North Company
AMI	Advanced Metering Infrastructure
BES	Balancing Energy Service
BPL	Broadband over Powerline
CCN	Certificate of Convenience and Necessity
CenterPoint	CenterPoint Energy Houston Electric, LLC
CPL	CPL Retail Energy
CREZ	competitive renewable energy zone
CTC	competition transition charge
DRG	distributed renewable generation
EGSI	Entergy Gulf States, Inc.
EIS	Energy Imbalance Services
EPAct	federal Energy Policy Act of 2005
EPE	El Paso Electric Company
ERCOT	Electric Reliability Council of Texas
ERO	electric reliability organization
FERC	Federal Energy Regulatory Commission
IMM	Independent Market Monitor
IPP	independent power producer
kWh	kilowatt-hour
LNG	liquefied natural gas
MCPE	Market Clearing Price of Energy
MMBtu	million British thermal units
MW	megawatt
MWh	megawatt-hour
NERC	North American Electric Reliability Council
NOV	Notice of Violation
NRC	Nuclear Regulatory Commission
NUS	non-unanimous settlement
NYMEX	New York Mercantile Exchange
OOMC	Out-of-Merit Capacity

OOME	Out-of-Merit Energy
OPUC	Office of Public Utility Counsel
PGC	power generation company
PNM	PNM Resources, Inc.
POLR	Provider of Last Resort
PSA	public service announcement
PTB	price to beat
PURA	Public Utility Regulatory Act
QSE	qualified scheduling entity
REC	Renewable Energy Credit
REP	retail electric provider
RMR	Reliability-Must-Run
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SBF	System Benefit Fund
SERC	SERC Reliability Council
SOAH	State Office of Administrative Hearings
SPP	Southwest Power Pool
SPS	Southwestern Public Service Company
SWEPCO	Southwestern Electric Power Company
TCEQ	Texas Commission on Environmental Quality
TDU	transmission and distribution utility
TRE	Texas Regional Entity
TNMP	Texas-New Mexico Power Company
TPIA	Texas Public Information Act
TSP	transmission service provider
WACC	weighted average cost of capital
WECC	Western Electricity Coordinating Council

Appendix B.

Completed Electric Industry Notices of Violations

Company	Violation Type	Violation	Docket Number	Final Order Date	Penalty Amount
Tremcor Energy, Inc	Retail	Aggregator Reporting	38439	08/19/10	$2,500
Direct Energy	Retail	Customer Protection Rules	37133	07/30/09	$200,000
Vega Resources dba Amigo Energy	Retail	Customer Protection Rules	37263	08/26/09	$15,000
Pre-Buy Electric	Retail	Customer Protection Rules	36927	01/29/10	$1,866,000
National Power	Retail	Customer Protection Rules	36926	01/29/10	$1,824,000
Spark Energy LP	Retail	Customer Protection Rules	38394	08/19/10	$44,500
First Choice Power Special Purpose, L.P.	Retail	Customer Protection Rules	38433	08/19/10	$16,500
Ambit Texas Inc	Retail	Customer Protection Rules	38392	08/19/10	$22,500
Bounce Energy Inc	Retail	Customer Protection Rules	38395	09/02/10	$28,000
Affordable Power L.P.	Retail	Customer Protection Rules	38396	09/02/10	$40,000
Andeler Corporation (Andeler Power)	Retail	Customer Protection Rules	38393	09/02/10	$30,000
Gexa Energy, LP	Retail	Customer Protection Rules	38632	10/04/10	$65,000
Penstar Power, LLC	Retail	Customer Protection Rules	38596	10/04/10	$14,000
Accent Energy Texas, L.P.	Retail	Customer Protection Rules	38550	10/04/10	$50,000
Just Energy Texas, LP	Retail	Customer Protection Rules	38657	10/19/10	$17,250
Reliant Energy Retail Services, LLC	Retail	Customer Protection Rules	38785	11/12/10	$50,000
Penstar Power	Retail	Customer Protection Rules	38783	11/12/10	$6,000
Green Mountain Energy Company	Retail	Customer Protection Rules	38740	11/12/10	$16,500
Tara Energy, LLC	Retail	Customer Protection Rules	38839	12/07/10	$13,000
DPI Energy	Retail	Customer Protection Rules	38384	12/16/10	$104,250
Champion Energy Services	Retail	Customer Protection Rules	38905	12/16/10	$30,000
El Paso Electric Company	Service Quality	Electric Service Quality	36491	01/22/09	$100,000
Entergy Gulf States, Inc.	Service Quality	Electric Service Quality	36787	04/15/09	$85,000
Texas-New Mexico Power Company	Service Quality	Electric Service Quality	37071	07/08/09	$49,000
Oncor Eelctric Delivery Company	Service Quality	Electric Service Quality	37255	08/27/09	$420,000
Texas-New Mexico Power Company	Service Quality	Electric Service Quality	37638	12/02/09	$11,500
CenterPoint Energy	Service Quality	Electric Service Quality	37752	01/14/10	$84,000
El Paso Electric Company	Service Quality	Electric Service Quality	37740	01/14/10	$50,000
Cap Rock Energy Corporation	Service Quality	Electric Service Quality	37334	01/28/10	$25,000
Southwestern Public Service Company	Service Quality	Electric Service Quality	37396	02/12/10	$55,000
AEP Texas Central Company	Service Quality	Electric Service Quality	37940	03/05/10	$169,000
AEP Texas North Company	Service Quality	Electric Service Quality	37939	03/05/10	$80,000
AEP Southwestern Electric Power Company	Service Quality	Electric Service Quality	37938	03/05/10	$25,000
Entergy Texas Inc.	Service Quality	Electric Service Quality	37918	03/05/10	$68,500
Oncor Eelctric Delivery Company LLC	Service Quality	Electric Service Quality	38135	05/14/10	$197,000
TNMP	Service Quality	Electric Service Quality	38380	07/30/10	$9,000
El Paso Energy	Service Quality	Electric Service Quality	38454	08/19/10	$38,000
Cap Rock	Service Quality	Electric Service Quality	38472	08/19/10	$35,000
SPS	Service Quality	Electric Service Quality	38445	08/19/10	$57,000
CenterPoint	Service Quality	Electric Service Quality	38671	10/19/10	$142,500
Entergy Texas Inc.	Service Quality	Electric Service Quality	38391	12/16/10	$71,000
Occidental Energy	Wholesale	ERCOT Protocols	36442	01/21/09	$212,000
Constellation Energy	Wholesale	ERCOT Protocols	36546	02/03/09	$115,000
Eagle Energy	Wholesale	ERCOT Protocols	36607	02/27/09	$103,338
Eagle Energy	Wholesale	ERCOT Protocols	36607	02/27/09	$48,162
Luminant/TXU Power/QSE	Wholesale	ERCOT Protocols	36909	06/03/09	$17,500
Tenaska Power Services	Wholesale	ERCOT Protocols	36993	06/19/09	$325,000
Eagle Energy	Wholesale	ERCOT Protocols	37075	07/02/09	$100,000
American National Power	Wholesale	ERCOT Protocols	34738	07/02/10	$2,500,000
Shell Energy North America (US), LP	Wholesale	ERCOT Protocols	37954	03/05/10	$2,000
Luminant	Wholesale	ERCOT Protocols	37634	04/05/10	$25,000
City of Garland	Wholesale	ERCOT Protocols	38104	05/04/10	$15,000
FPL Energy	Wholesale	ERCOT Protocols	38303	07/01/10	$60,000
CPS (City of San Antonio)	Wholesale	ERCOT Protocols	38431	08/19/10	$35,000
Austin Energy	Wholesale	ERCOT Protocols	38415	08/19/10	$35,000
BTU	Wholesale	ERCOT Protocols	38496	09/15/10	$25,000
TOTAL					$9,844,500

Appendix C

Energy Storage Capabilities

Technologies	Advantages	Disadvantages	Major Applications	Power*	Energy**
Pumped Storage	High Capacity, Low Cost	Special Site Requirement	Energy Time Shift, Frequency regulation, Ancillary Services		Fully Capable
Compressed Air Storage (CAES)	High Capacity, Low Cost	Special Site Requirement Need Gas Fuel	Energy Time Shift, Frequency Regulation, Ancillary Services		Fully Capable
Flow Batteries: VRB, ZnBr	High Capacity, Independent Power/Energy Ratings	Low Energy Density	Peak Shaving for T&D upgrade deferral, Load Leveling, Backup Power	Reasonable for this Application	Fully Capable
NaS	High Power & Energy Densities, High Efficiency	Production Cost, Safety Concerns	Peak Shaving for T&D upgrade deferral, energy time shift, load leveling , voltage control, reactive power	Fully Capable	Fully Capable
Li-ion	High Power & Energy Densities, High Efficiency	High Production Cost, Special Charging Circuit	Consumer Electronics, PEV, PHEV, Utility Applications	Fully Capable	Feasible but not yet economical
Ni-Cd	High Power & Energy Densities, Efficiency		Utility/Telecom backup, Consumer Electronics	Fully Capable	Reasonable for this Application
Lead-Acid	Low Capital Cost	Limited Life Cycle	Automobile, UPS Telecom, Substation Reserve Power	Fully Capable	Feasible but not yet economical
Flywheels	High Power	Low Energy Density	Frequency Regulation, Power Quality, Emergency Bridging Power, Fluctuation	Fully Capable	Feasible but not yet economical
SMES	High Power	Low Energy Density, High Production Cost	Power Quality, Emergency Bridging Power	Fully Capable	
Electrochemical (EC) Capacitors	Long Life Cycle, High Efficiency	Low Energy Density	Power Quality, Emergency Bridging Power, Fluctuation	Fully Capable	Reasonable for this Application

* Stored energy suitable for short duration, high precision power quality and continuity of service when switching from one energy source to another.

** Stored energy suitable for decoupling the timing of generation and consumption of energy.