Report to the 81st Texas Legislature

A Report on Advanced Electric Metering as Required by House Bill 2129

Public Utility Commission of Texas
September 2008

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Public Utility Commission of Texas

September 29, 2008

Honorable Members of the Eighty-first Texas Legislature:

We are pleased to submit our second Report on Advanced Electric Metering as required by HB 2129. HB 2129, passed by the 79th Texas Legislature directed the Commission to report on the efforts of utilities in Texas to deploy advanced metering systems and infrastructure, and to identify any barriers to the implementation of advanced metering, and make any recommendations to address those barriers.

The Commission believes that the deployment of advanced metering is a critical component of the evolving Texas electric market and over time will help to balance the dynamics of supply and demand. As deployment occurs, it can give customers more choice and control over their electric bill, enable market-based demand response, help the market to mature, yield savings for utilities, and create efficiencies in market processes for REPs and ERCOT.

Most importantly, AMI has the potential to provide enhancements in service to retail customers, and also give customers the tools to help manage energy costs.

We look forward to continuing to work with you on this and other issues relating to electric service. If you need additional information about any issues addressed in the report, please call on us.

Sincerely,

Barry T. Smitherman	Donna L. Nelson	Kenneth W. Anderson, Jr.
Chairman	Commissioner	Commissioner

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Summary & Introduction

Since the Commission submitted its first Report on Advanced Metering in 2006, the level of interest in electric demand response and advanced metering infrastructure (AMI) has increased significantly. As Texas continues to grow, the Electric Reliability Council of Texas (ERCOT) predicts that the state's electric demand will increase. Diverse electric generation is necessary to supply that growth, but Texas residential customers must also have the tools necessary to make informed decisions to control their electric demand; advanced metering provides that tool. The ability for retail customers to respond to the dynamics in the wholesale market will help facilitate the maturation of the Texas electric market.

AMI enables customers to have more control over their electric bills. Plentiful evidence demonstrates that customers will respond to the appropriate price signal and the right incentive, by reducing consumption. For example, a study in California revealed that with the real-time pricing that AMI can provide, customers reduced demand during times of highest demand by 27%. Customers with more advanced systems that automatically control electric consumption during times of peak demand reduced their consumption by 43%.

A growing number of utilities worldwide, driven either by a promise of savings or mandates, have started the deployment of AMI on a mass scale. In Europe, every third household will have an advanced meter five years from now. The Australian State of Victoria and the Province of Ontario in Canada have mandated AMI for all utilities.

AMI can help the electric market to mature, yield savings for utilities, and create efficiencies in market processes for retail electric providers (REPs) and ERCOT. Although AMI has a cost, that cost becomes less of an issue in an environment of rising electric prices and increased generation demand where the investment can be offset by a combination of operational savings realized by the utility and electric savings by retail customers.

HB 2129, enacted by the 79th Texas Legislature directed the Commission to report on the efforts of utilities in Texas to deploy advanced metering systems and infrastructure, and to identify any barriers to the implementation of advanced metering, as well as any recommendations to address those barriers. The Commission adopted a rulemaking in support of advanced metering, and the 80th Texas Legislature indicated a preference for the deployment of AMI in HB 3693.

The advanced metering industry is dynamic and technology continues to evolve. Since the adoption of the advanced metering rule in 2007, the technological barriers have subsided, and the costs of such technology are becoming increasingly competitive. Deployment under the statute is voluntary, and both CenterPoint Energy and Oncor Electric Delivery have filed plans with the Commission for cost-recovery. Meter deployment for both companies is scheduled to begin this Fall. Although American Electric Power and Texas New Mexico Power have not filed for cost recovery, both companies are in the process of developing their deployment plans and expect to pursue necessary approvals in the future.

Demand response and advanced metering should play a crucial role in the state's energy portfolio, especially during times of higher energy prices. AMI gives customers the tools to help manage their energy costs, and, over time, it has the potential to reduce peak demand. The Commission believes that AMI should be ubiquitously deployed give Texas retail electric customers an increased ability to control their electric use.

In response to the statutory directive to identify changes to Texas policy necessary to remove barriers to the use of advanced metering and metering information networks or other advanced transmission and distribution technologies, the Commission offers the following recommendations for consideration by the Texas Legislature:

- The Governor's Competitiveness Council in its Texas State Energy Plan recommended that the Commission have the authority to order utilities to deploy advanced meters. The legislature should clarify that the Commission has the authority to order utilities to deploy advanced meters, as rapidly as possible,[1] with the appropriate cost recovery provided under the Commission's advanced metering rule.

- The legislature should clarify whether the 2005 legislation relating to advanced meters, PURA §39.107, applies to utilities outside of ERCOT.[2]
- State policy should also ensure that all retail customers have the option to have their billing determined on actual interval data captured from the advanced meters, so they receive the full benefits of changes in consumption behavior.
- State policy should continue to recognize that the retail electric market will benefit from knowledgeable residential electric customers making informed purchasing decisions to meet their energy needs.

[1] *See* State Energy Plan adopted by the Governor's Competitiveness Energy Council, Recommendation 22 which states, "The state should require TDUs to deploy advanced meters, with an appropriate cost recovery mechanism to ensure that TDUs earn a reasonable return on this investment. The PUC should have the authority to require deployment of advanced meters as rapidly as possible."

[2] *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).

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I. Advanced Metering Infrastructure

A. Advanced Metering Infrastructure & the Smart Grid

Definition of Advanced Metering Infrastructure (AMI)

Most of the residential meters in service in the United States are simple mechanical devices that register the energy consumed by the customer. Customers receive a monthly bill and the customers only feedback related to electric usage comes with that bill. Meters must be read by personnel of the utility. Advanced meters, by contrast are digital devices that measure consumption and provide real-time feedback to electric customers on their electric usage. They also have information storage and communications capability. Metering technology has evolved substantially since the passage of HB 2129, and advanced metering (AMI) is more sophisticated and has become more cost effective. An advanced meter operates as part of the utility's advanced metering system, which includes the advanced meters, the associated hardware, software, and back-office communications systems, including meter information networks for validating and processing meter information.

AMI is based on digital electronic and communications technologies. Through the use of these technologies, AMI enables potential operational benefits and efficiencies and provides data collection and support for demand response and energy efficient behavior by consumers previously unsupported with older electromechanical meters.

AMI's most basic functions involve reading and recording customer electric usage at programmed intervals (hourly or even shorter-term intervals or on-demand), and then storing and forwarding that information for use by customers and customer-based systems, grid operators, and utilities. AMI also has the potential to provide operational efficiencies to utilities by allowing for automated remote meter readings and remote outage detection, diagnosis, and restoration. As a result, AMI should greatly enhance electric restoration after a storm.

The components of a robust and scalable AMI include standards-based, open architecture to create a network of smart meters that are fully integrated with demand-response capability.

Utilities can use the data recording and communications functions to meet the business and operational needs for accurate meter data collection, including interval consumption information, advanced billing and other business processes (such as outage detection). An AMI system also enables customers to understand their energy consumption better, make better informed choices about energy consumption and conservation, and participate in third-party demand-response programs.

Because AMI provides customers with real time feedback, AMI will support time-based rates and demand response to emergency conditions. Currently, customers only see their usage and price for electricity once a month, after the fact, when they receive their bills. However, AMI can allow for time-based rates, such as real-time pricing, where customers are charged rates that vary dynamically over some period, based on the underlying wholesale cost of electricity in the day-ahead (or real-time) market. With this information, customers can see their real-time usage and the corresponding price for that usage, and modify their usage in real-time in response to the price. Time-based rates have the potential of greatly reducing peak demand.

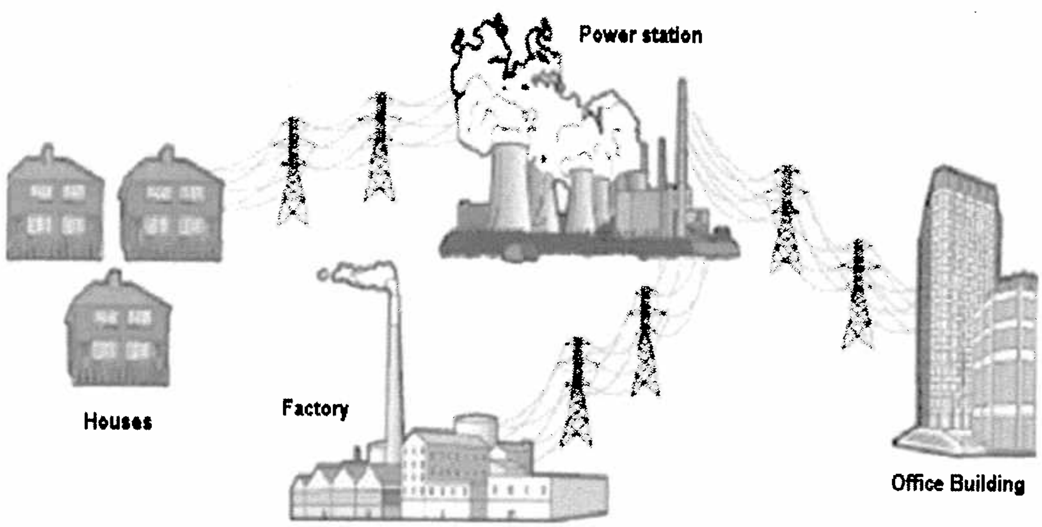
AMI can also provide utilities and grid operators the capability to monitor electric usage by an individual customer as well as by groups of customers, and to perform automated or manual load control and distribution system operations and maintenance. By monitoring consumption of individual customers, utilities can quickly gather accurate information on the nature of an outage and send crews to restore service.

Finally, AMI is the building block of a "smart grid".[3] A smart grid is an efficient, dynamic and more resilient electrical and communications delivery system. It creates incentives for

[3] Section 1301 of the EISA defines the Smart Grid as enabling the following capabilities: Increased use of digital information and controls to improve operation of the electric grid; optimization of grid operations and resources with full cyber-security; deployment and integration of distributed generation, including renewable resources; development and incorporation of demand response, and energy-efficiency resources; deployment of "smart" technologies for metering, communications concerning grid operations and status, and distribution automation; integration of "smart" appliances and other consumer devices; deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid-electric vehicles, and thermal-storage air conditioning; provision of timely information and control options to consumers; development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid; and

conservation, has the potential to improve the carbon footprint of the grid[4], reduces systemic maintenance, prevents outages and mitigates restoration in the wake of those outages that do occur, and improves reliability of supply. A smart grid includes real-time visualization technologies on the transmission level and smart meter and communications technologies on the distribution level that enable demand response, distributed energy systems (generation, storage, thermal), consumer energy management systems, distributed automation systems and smart appliances. Reid Detchon of the Energy Future Coalition commented, "running today's digital society through yesterday's grid is like running the internet through an old telephone switchboard".[5] The creation of a smart grid is not a single event; rather it will occur over time as meters are installed and with improvement to utilities distribution and transmission systems.

Figure No. 1
The Conventional Electric Grid



Source: Clean Texas Energy Forum

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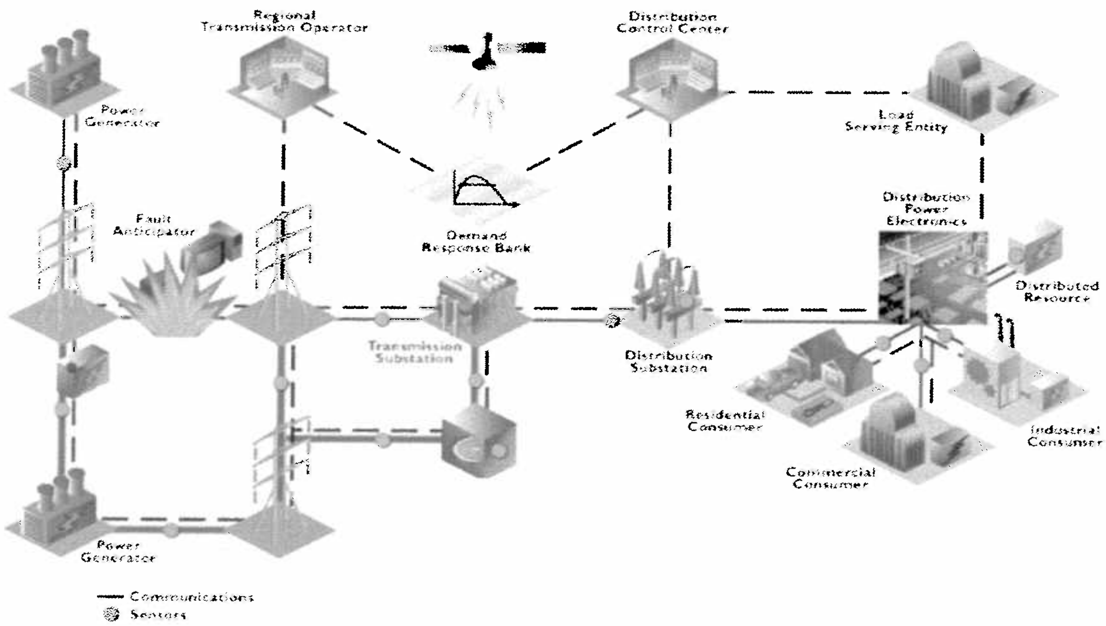
identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

[4] During peak periods, natural gas plants are running at full capacity to support load. Real-time information provided as a result of AMI, allows customers to shift or reduce consumption. This can impact peak periods because output from natural gas plants is reduced.

[5] As presented at the CleanTX Energy Forum, May 2008.

Figure No. 2
The Future Smart Grid



Source: Clean Texas Energy Forum

The many anticipated benefits of implementing a smart grid include:

- Improved reliability and power quality;
- Reduction in restoration time and reduced operations and maintenance because of self-healing attributes of smart-grid capabilities;
- Reduction in peak demand;
- Reduction in transmission congestion costs;
- Increased integration of distributed-generation resources and higher transmission and distribution capacity utilization;
- Increased security and durability in response to attacks or natural disasters;
- Increased capital investment efficiency because of tighter design limits and optimized use of grid assets; and
- Environmental benefits gained by increased asset utilization.

B. Successful Dynamic Pricing Pilots & Programs

Most utilities with AMI installed are still in the process of developing dynamic pricing programs in conjunction with their deployment. In many states, both utilities and state regulators are uncertain whether customers will respond to such pricing signals. The Brattle

Group identified 14 barriers to price-responsive demand response, which can be aggregated into two broad problem areas: a lack of dynamic pricing and a lack of enabling technologies.[6]

Still, new experimental evidence from different states and countries, as described below, shows that, on average, customers will respond to higher prices by lowering usage during peak hours and by so doing, they will reduce their annual power bills. The largest and most comprehensive trial of dynamic pricing to date was carried out in California. In a $20 million pilot that involved some 2,500 residential, small commercial and industrial customers over a three-year period, the state's three investor-owned utilities tested several dynamic pricing designs. The pilot involved a working group that was facilitated by the state's two energy regulatory commissions and received input from dozens of interested parties and stakeholders, including opponents and supporters of dynamic pricing. The experiment provided time-varying prices and smart meters to all participants. In addition, some of the participants also received enabling tools such as smart thermostats and always-on gateway systems. Smart thermostats automatically raise the temperature setting on the thermostat by two or four degrees when the price becomes critical and always-on gateway systems adjust the usage of multiple appliances in a similar manner. The results showed that the average customer (a customer without a smart thermostat or gateway) reduced demand during the 60 summer hours of highest demand by 13% in response to prices that were five times higher that customers' standard tariff. Customers with smart thermostats reduced their load about twice as much, by 27%, while those who had the gateway system reduced their load by 43%.[7]

The District of Columbia's PSC approved a "PowerCentsDC" pilot program that allows residential customers to test three different pricing models: hourly pricing, critical peak pricing and critical peak rebate. The pilot program, launched in July 2008, is the first in the electric industry to test the response of residential customers to three pricing options under one program. Each of these options will enable participating customers to save on their bills by reducing electricity usage during designated hours when wholesale electricity prices are high. Participants will be notified of on a day-ahead basis of high prices on the following

[6] "Mandating Demand Response", Jackalyne Pfannenstiel and Ahmad Faruqui, January 2008, Public Utilities Fortnightly.
[7] "The Power of Five Percent", The Brattle Group, May 16, 2007.

day. The two-year pilot project, funded by $2 million from the utility through a settlement agreement, will include about 1,200 residential customers.[8]

In January 2008, the Department of Energy's (DOE) Pacific Northwest National Laboratory released the results of a yearlong study showing that if households have digital tools to control temperature and price preferences, the peak loads on utility grids can be shaved by up to 15% per year translating into $70 billion saved over a 20-year period on spending for power plants and infrastructure. The project, funded mostly by DOE, comprised two separate studies to test demand-response concepts and technologies. The Olympic Peninsula Project was one of the first in the country to demonstrate that homeowners are willing to adjust their energy use based on real-time price signals provided through in-home technology tools. The Grid Friendly™ Appliance Project demonstrated that everyday household appliances can automatically lower energy consumption at critical moments if they are fitted with controllers that receive information about stress on the grid. Both studies helped reduce pressure on the grid during periods of peak demand.[9]

In Pennsylvania, PECO Energy has initiated two pilot programs to determine the best way to use advanced metering data to improve overall distribution-system operations. The first, which started in 2007, uses meter data from Philadelphia's Old City neighborhood to determine whether upstream devices like transformers, fuses and cables are adequately sized to handle increasing loads. The Automated Meter Reading (AMR) system is used to collect and monitor hourly data from 4,500 meters to establish the loads being placed on individual system devices throughout the day. The second pilot is taking place in Jenkintown, located north of Philadelphia. In that pilot, devices are collecting data every 30 minutes from 15,000 existing one-way meters and two dozen new two-way meters, and utility distribution equipment. The purpose is to use the metering data to get a clear idea of how one part of the company's distribution network is functioning and leverage the data to enhance overall load management. The long-term goal is to move away from the company's old approach of

[8] "PowerCentsDC to Test Smart Metering for DC Electric Customers", Transmission & Distribution World, July 24, 2008, available at http://tdworld.com/info_systems/highlights/powercentsdc-smart-metering-0807/.
[9] "Department of Energy Putting Power in the Hands of Consumers through Technology", New Release, January 9, 2008, available at http://www.oe.energy.gov/DocumentsandMedia/GridWiseRelease_2008_01_09.pdf.

using historical data to model system behavior and optimize the network with real-time metering data delivered every 30 minutes.[10]

In France, the Tempo tariff is a longstanding Time of Use (TOU) and Critical Peak Pricing (CPP) tariff that has been used since the early 1990s to smooth annual and daily electricity consumption profiles, thereby reducing marginal generation and network costs. This tariff has six rates based upon the weather on particular days and hours. Each day of the year has a color code – blue, white and red – corresponding to low, medium and high electricity prices. The customers are informed each night of the color for the next day through a power line signal. They can adjust their electricity consumption manually by turning off appliances, adjusting thermostat settings, or selecting load control programs which enable automatic connection and disconnection of water-heating and space-heating equipment. Compared with blue days, the tariff has resulted in reduced consumption by 15% on white days and 45% on red days. The results of implementation of this tariff show the effectiveness of the pricing strategy used in reducing peak loads.[11]

Based on the results of the various projects and studies, electric use, particularly at peak is substantially reduced by customers. There is no reason to believe that this will not occur in Texas, once AMI is deployed, and new pricing options are offered to customers.

C. Texas Policy Regarding AMI and Smart Grid

House Bill (HB) 2129 in 2005, enacted by the 79th Texas Legislature, directed the Commission to establish a cost-recovery mechanism for utilities that deploy more sophisticated and innovative meters, to the benefit of the utilities, REPs, and customers. HB 2129 did not require that advanced meters be deployed by utilities in Texas – deployment is voluntary. HB 3693 enacted by the 80th Texas Legislature encouraged "Advanced metering networks be deployed as rapidly as possible." The Commission adopted a rule[12] pursuant to

[10] "Demonstrating the Smart Grid", Scott M. Gawlicki, June 2008, Public Utilities Fortnightly.
[11] Advanced Metering for Energy Supply in Australia, David Crossley, Energy Futures Australia, July 17, 2007, available at http://www.efa.com.au/Library/David/Published%20Reports/2007/AdvancedMeteringforEnergySupplyinAustralia.pdf.
[12] See P.U.C. SUBST. R. 25.130.

HB 2129, which addresses: 1) the importance of balancing the interests of customers, retail electric providers (REPs), and electric utilities with respect to advanced metering; 2) the minimum functionality for advanced meter systems to qualify for a cost recovery surcharge; 3) the process for an electric utility to notify the Commission and REPs of the deployment of advanced metering; and 4) the cost recovery surcharge for AMI deployment.

Deployment of AMI under the rule is voluntary. The Commission's rule takes an approach to deployment of AMI that is intended to be flexible to accommodate future innovations. The Commission concluded that a comprehensive set of AMI functions is necessary to achieve the benefits listed in HB 2129. Additionally, standardization of capabilities across ERCOT is extremely important for REPs offering products to customers in multiple utility territories. Therefore, an AMI deployed by a utility pursuant to the rule must support the following functions:[13]

- automated meter reading;
- two-way communications;
- remote disconnection and reconnection capability;
- the capability to time-stamp meter data sent to ERCOT or a regional transmission organization for purposes of wholesale settlement;
- the capability to provide direct, real-time access to customer usage data to the customer and the customer's REP;
- means by which the REP can provide price signals to the customer;
- the capability to provide 15-minute or shorter interval data to REPs, customers, and ERCOT or a regional transmission organization, on a daily basis, consistent with data availability, transfer and security standards adopted by ERCOT or a regional transmission organization;
- on-board meter storage of meter data that complies with nationally recognized non-proprietary standards such as in American National Standards Institute (ANSI) C12.19 tables;
- open standards and protocols that comply with nationally recognized non-proprietary standards such as ANSI C12.22;
- capability to communicate with devices inside the premises, including usage monitoring devices, load control devices, and prepayment systems through a home area network (HAN), based on open standards and protocols that comply with nationally recognized non-proprietary standards such as ZigBee, Home-Plug, or the equivalent; and

[13] See P.U.C. Subst. R. 25.103(g)(1)

- the ability to upgrade these minimum capabilities as technology advances and they become economically feasible.

The rule includes requirements for access to meter data by the market, the deployment plan to be filed by the utility, and provisions for cost recovery. The rule was adopted in May 2007, and since that time, the Commission has been working closely with utilities, REPs, customers, ERCOT, and other stakeholders to address the implementation of the rule.

HB 2129 states that the customer owns the data. As AMI is deployed, customers will not have to pay a charge have to obtain special permission to view their data. Customers will also be able to view their consumption real-time, as HAN devices are installed in their homes. The installation of HAN devices that show electricity usage can be purchased by customers, or can be provided by REPs or other third-parties. To fully enjoy the benefits an advanced meter can bring, ERCOT must revise its settlement process to provide for 15-minute settlement. A stakeholder process is underway to determine when and how 15-minute consumption data can be made available to REPs and customers in a centralized market portal that customers, as well as REPs, and ERCOT will be able to access. In the interim, customer usage data will be made available to REPs on a day-after basis, electronically through an internet portal or other means, operated by the electric utility.

The Commission adopted a more expedited cost recovery process in its rule. The rule permits the commission to establish a nonbypassable surcharge for an electric utility to recover reasonable and necessary costs incurred in deploying AMS to residential customers and nonresidential customers other than those required by the independent system operator to have an interval data recorder meter. In addition, the surcharge shall not ultimately recover more than the AMS costs that are spent, reasonable and necessary, and fully allocated, but may include estimated costs, less any expected savings, that shall be reconciled in a subsequent proceeding. The rule states that "costs spent in accordance with its deployment plan are reasonable and necessary."

The Commission addressed the type of cost information to include in a surcharge request in Project No. 33874, *Form for Transmission and Distribution Utility Advanced Metering*

Infrastructure Surcharge. The Commission approved a model in this project, which analyzes the costs and benefits of deploying AMI in its service territory.

D. Federal Policy Regarding AMI and Smart Grid

The Public Utility Regulatory Policies Act of 1978 (PURPA) was modified by the Energy Policy Act of 2005 (Act). PURPA Section 1252 of the 2005 Act required regulatory commissions to consider new standards relating to electric rates and service. Commissions are not required to adopt these new standards but must consider them. Section 1252 of the Act states that it is the policy of the United States to encourage "time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them." It also states that, "deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy capacity and ancillary services markets shall be eliminated."

The Energy Independence and Security Act of 2007 (EISA) expands federal support for investments in smart grid technologies and addresses some of the regulatory and technological barriers to widespread installation. Title XIII is devoted entirely to the smart grid concept. EISA sends a strong signal to the market that smart grid is a part of the national focus and national agenda.[14]

Other sections of EISA direct the U.S. Department of Energy (DOE) to report to Congress on the deployment of smart grid technologies and any barriers for deployment, and conduct research on smart grid and assess the resulting energy savings and other aspects of implementation. EISA directs the National Institute of Standards and Technology to establish protocols and standards to increase the flexibility of use for smart grid equipment and systems and directs DOE to create a program that reimburses 20% of qualifying smart

[14] "The SmartGrid: It Makes for Real Sense for Consumers and the North American Electric Utility Industry", Ethan L. Cohen, Utilipoint IssueAlert, February 8, 2008, available at http://www.utilipoint.com/IssueAlert/article.asp?id=2975.

grid investments. The law directs states to encourage utilities to employ smart grid technology and allows utilities[15] to recover smart grid investments through rates.

The Commission opened a project following the passage of EPAct to conduct an investigation of time-differentiated rates, advanced metering and net-metering requirements.[16] With the adoption of the advanced metering rule[17], as well as the expected completion of the net metering rule[18], the conclusion of this project is expected by the year end 2008. The Commission intends to open a separate project to address the requirements under the EISA later this year. This project will review the requirements under EISA and make a determination regarding the applicability in Texas, both inside and outside of ERCOT.

[15] Title III – Energy Savings Through Improved Standards for Appliance and Lighting, Sec. 371:
''(9) OTHER TERMS.—The terms 'electric utility', 'non regulated electric utility', 'State regulated electric utility', and other terms have the meanings given those terms in title I of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2611et seq.).

[16] Project No. 32854, *Consideration of Electric Ratemaking Standards under the Public Utilities Regulatory Policy Act.*

[17] See P.U.C. SUBST. R. 25.130.

[18] See Project No. 34890, *Rulemaking Relating to Net Metering and Interconnection of Distributed Generation.*

II. Benefits & Trends of Advanced Metering

A. Anticipated Benefits

HB 2129 states that:

> In recognition that advances in digital and communications equipment and technologies, including 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 legislature encourages the adoption of these technologies by electric utilities in this state.

AMI creates savings and benefits for the customer, the utility, ERCOT, and REP. Benefits are realized with respect to increased efficiency, reduced costs, remote disconnection and reconnection, remote detection of outages and other system problems, improved system planning, new product offerings, and consumption control options.

Figure No. 3
Advanced Metering Benefits & Savings

Benefits & Savings Include:	Customer	REP	Utility
More timely move-in/move-out, switching among REPs	X	X	
Reduced usage during peak periods and scarcity conditions	X	X	
Utility operational savings (meter reading, outage detection)	X		X
Environmental savings	X	X	
Demand response & reliability	X	X	X
Prepayment capability	X	X	
Innovative retail product offerings	X	X	
Better customer service	X	X	X
Ability to control costs and minimize price risk	X		
Reduced costs from shifting load to off-peak	X	X	

The utility will benefit from AMI due to the reduction in meter-reading labor costs. Such cost savings have been the central reason offered in support of deployment by utilities, particularly integrated utilities that have deployed these systems. AMI also provides operational savings to the utility through increased automation, data collection, information management, and billing processes. This allows the utility to collect system-wide and consistent usage profile data to better understand the impact of loads on the reliability of the transmission and distribution systems. The customer, the REP, and the utility should benefit from cost savings associated with the automated reading, data-collection and billing process. This savings realized by the utility is used offset the surcharge.

AMI has the potential to increase competition in the retail electric market. AMI development should permit the customer to take advantage of better consumption information by opting for innovative price offerings from REPs in the ERCOT competitive market, improved customer service, and more energy efficiency and demand response programs. For consumers, the REP will be able to offer innovative products that are not feasible with conventional meter technology. Retail electric customers should be able to immediately change REPs with actual meter data, without waiting for the next scheduled meter read. Customers with real-time information regarding their consumption can choose whether to respond in a period of high prices. Advanced meters can also permit the connection and disconnection on demand, rather than requiring customers to wait while service orders are scheduled and executed by a technician in the field. Customer billing cycles should be more flexible, allowing cycles and billing dates to match customers' preferences.

AMI also gives customers the ability to pay in advance for power. Advance-payment programs can eliminate onerous deposits for customers with poor credit. Typically with prepaid service, real-time information is provided to the customer through an in-home display. Participants in a prepaid program may be able to use the meter as a payment device, depositing value in the meter through an in-home display unit with a smart-card reader. Customers can purchase or add value to smart cards at locations designated by the service provider. Even if the advanced meter is not used as a payment device, advance-payment plans are made possible by the meter's ability to remotely connect and disconnect service.

B. Infrastructure and the Reliance on Demand Response

The fundamental concept behind demand response is to provide accurate and transparent price signals to customers upon which consumption decisions may be made. Because electricity cannot be stored and has to be consumed instantly, and because generation plants of varying efficiency are used to meet demand, the price of power varies by time of day, day of the week, and season.

Demand response, broadly defined, refers to active participation by retail customers in electricity markets, by responding to prices as they change over time or to direct incentives. Most electricity customers are offered pricing opportunities that are based on average electricity costs that have little relation to the true costs of electricity as they vary over time. Demand-response programs facilitate customer participation by allowing customers to reduce their energy costs by changing their consumption patterns to avoid periods of high prices, or receive payments for reducing or curtailing consumption during a system emergency.

Demand for electricity continues to grow in Texas as economic development spurs growth in the Texas economy. Because of growth and demand for all types of energy is increasing, some analysts believe that the energy industry needs to prepare for a period of much higher capital expenditures.[19] (News accounts from around the United States during the third quarter of 2008 support this proposition, as evidenced by the number of applications seeking rate base increases including: 29% for a Virginia utility, 38% for Xcel Energy in Colorado, 25% for Public Service Company of Oklahoma, 31% for Florida Power & Light in Florida, to name but a few.) This results from the confluence of several factors:

[19] "Banking on the Big Build", Public Utilities Fortnightly, October 2007, (by Roger Wood at page 49) and cited with approval in National Regulatory Research Institute report *Private Equity Buyouts of Public Utilities: Preparation for Regulators*, December 2007 by Stephan G. Hill at page 36. Unpublished estimates in 3Q 2008 place the number at nearly $1.5 trillion for new/replacement of transmission and generation infrastructure.

- Shrinking generation reserve margins, as the glut of surplus capacity from earlier in the decade decreases;
- Increased spending on pollution controls, especially to comply with nitrogen-oxide, sulfur, and mercury requirements;
- The perception that the federal government will enact carbon legislation;
- The need to replace aging transmission and distribution infrastructure, much of which was put in place 30-40 years ago and is nearing the end of its design life;
- Continued robust rates of population growth and economic growth in many parts of the United States, resulting in the need for system expansion; and
- Technology spending on areas such as customer information systems and AMI and smart grid technologies.

In Texas, both integrated and non-integrated utilities have also filed for increases: 13.2% for Oncor Electric Delivery, 21.6% for Entergy, 10% for Southwestern Public Service (SPS), and 23.8% for Texas New Mexico Power (TNMP).[20]

Cambridge Energy Research Associates estimates that $900 billion of direct infrastructure investment will be required by electric utilities over the next 15 years.[21] That compares with $750 billion of generation, transmission, and distribution plant currently in place.

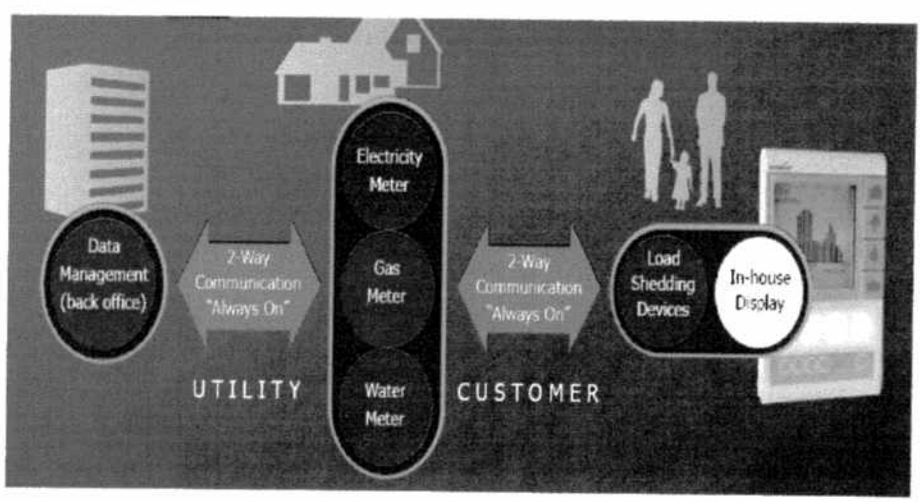
To ensure reliability and competitive functioning of markets, Texas must rely upon an integrated approach that combines traditional solutions involving building new transmission and generation facilities, with demand-side solutions that give customers the ability to better understand and control their usage. Demand-side programs have the potential to permit customers' needs to be met with lower levels of investment in generation, transmission, and distribution facilities. If customers participate in programs to reduce demand during periods of high demand, then fewer additions to the generation, transmission and distribution facilities need to be constructed than would be required to meet the higher levels of demand that would occur in the absence of the demand-reduction program. In addition, dynamic

[20] Percentage Increases noted above reflect the increase to rates for an average residential customer with 1000 kWh usage per month.
[21] Ibid. pg. 50

pricing programs will encourage customers to reduce demand when wholesale market prices are high and resources are scarce, thereby potentially reducing peak demand and the cost of providing electricity to both the customers participating in such programs and the customers who do not participate.

Residential consumers account for approximately 45% of the energy demand in ERCOT. And yet, they receive little or no information about how changes in their usage patterns and consumption behaviors could reduce their energy costs. The Commission believes that as advanced meters are deployed, customers over time will have access to real-time information about their electricity consumption, and be able to choose whether to participate in demand response programs or choose dynamic and innovative pricing products from their REP. Today, because these customers have meters that are read once a month, and because a customer is billed several days after the reading is made, there is no way for the customer to correlate specific consumption decisions to energy consumption or the level of the bill. A customer who is interested in the level of consumption and the price paid for electricity gets information on a monthly basis, after the fact, with no indication of when, within the month, consumption was high or low. With advanced meters, the customers will be able to obtain consumption information on a next-day basis, or with a HAN device, in real time, and they will have access to time-differentiated consumption information.

Figure No. 4
AMI Creates Transparency for Customers



AMI can be a technology for enabling customers to receive the price signals or alerts necessary for them to be demand response participants, and it records consumption information that shows how the customer responded to the signal or alert. Electric prices today are subject to significant variation over time. Day-ahead pricing that is communicated to customers will give customers advance notice of high-price times and places, which will indicate when and where it will be advantageous for them to reduce their consumption. AMI deployment is the crucial infrastructure that will provide the necessary visibility to energy prices, allowing customers the ability to respond accordingly.

C. AMI Deployment Outside of Texas

According to the Federal Energy Regulatory Commission (FERC), AMI currently has a market penetration of a little more than 6%. Electric cooperatives lead deployment efforts, with a penetration close to 13%, followed by investor-owned utilities with close to 6% penetration. AMI installation varies widely across states as well. The five states with the highest penetration of AMI are Pennsylvania, Wisconsin, Connecticut, Kansas, and Idaho. Certain states, such as Pennsylvania and Wisconsin, have AMI penetration rates in excess of 40%. AMI penetration rates exceed 10% in eight states.[22]

The states, provinces, and countries that have been most active in AMI deployment and initiatives recently are California, Colorado, Connecticut, Ohio, Oregon, Pennsylvania, Vermont, Virginia, Ontario, Australia and several European nations. Additional information on these efforts is provided in Appendix C. This report describes the efforts in California, because two of the utilities, San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE) are implementing AMI technologies similar to what is being deployed in Texas.

In 2004, the California Commission (CPUC) instructed investor-owned utilities to develop business cases for installing AMI. The CPUC has approved AMI deployments for utilities throughout the state at a cost of roughly $4 billion. Pacific Gas and Electric Company (PG&E) is spending nearly $2 billion to install more than five million *SmartMeter* electric

[22] FERC, "Assessment of Demand Response and Advanced Metering," Staff Report, September 2007.

and four million gas meters for all its customers by 2012. Beginning in 2009, SCE is planning a $1.7 billion rollout of 5.3 million advanced meters in all household and businesses with a demand of less than 200 kW throughout its service territory, under an AMI deployment program called *SmartConnect.* Demand response is expected at peak times to save the utility up to 1,000 MW of capacity additions. SDG&E will replace 1.4 million electric meters and retrofit 900,000 gas meters with advanced meters at a cost of about $572 million. AMI technology will allow SDG&E to develop a system capable of collecting and storing data from meters at hourly intervals.

III. Implementation of Advanced Metering

A. Market Implementation Effort

Following the adoption of the advanced metering rule which provided a structure for deployment and cost recovery, the Commission opened Project No. 34610 to address the implementation of AMI, including the impacts on the ERCOT retail and wholesale markets and to ensure that customers receive benefits from AMI investments. Many of the issues in this project are complex and interdependent, and the implementation affects all market segments. It will require a fine tuning of existing market processes for customers to receive the full benefits of AMI. Realizing the full benefits of AMI deployment will require future modifications to substantive rules, ERCOT Protocols and market guides; system changes for REPs, utilities and ERCOT; new transactions and modification of existing transactions; new business processes; and new data transport mechanisms.

The implementation project has included broad participation from market participants including utilities, ERCOT, Commission staff, vendors, consumers, REPs and others. There are four main areas under consideration as part of the implementation project: the HAN; access to customer data and related security; ERCOT settlement; and customer education.

Settlement

P.U.C. SUBST. R. 25.130(h) states that ERCOT shall be able to use 15-minute interval data from advanced meters for wholesale settlement purposes no later than January 31, 2010.[23] In the AMI rulemaking, the Commission agreed with ERCOT "that a study in conjunction with the implementation proceeding will provide guidance for future settlement at ERCOT as advanced meters are deployed."[24] ERCOT has developed a method for achieving settlement in the short term to meet the goal provided in the rule.[25] ERCOT has also contracted for a

[23] *See* P.U.C. SUBST. R. 25.130(h).
[24] *See* Order Adopting New P.U.C. SUBST. R 25.130 and Amendments to §§ 25.121, 25.123, 25.311, and 25.346 as Approved at the May 10, 2007 Open Meeting, Project No. 31418 at 63.
[25] This short-term method for settlement is expected to be operational by the Summer of 2009. This method will allow for the settlement of approximately one million AMS meters.

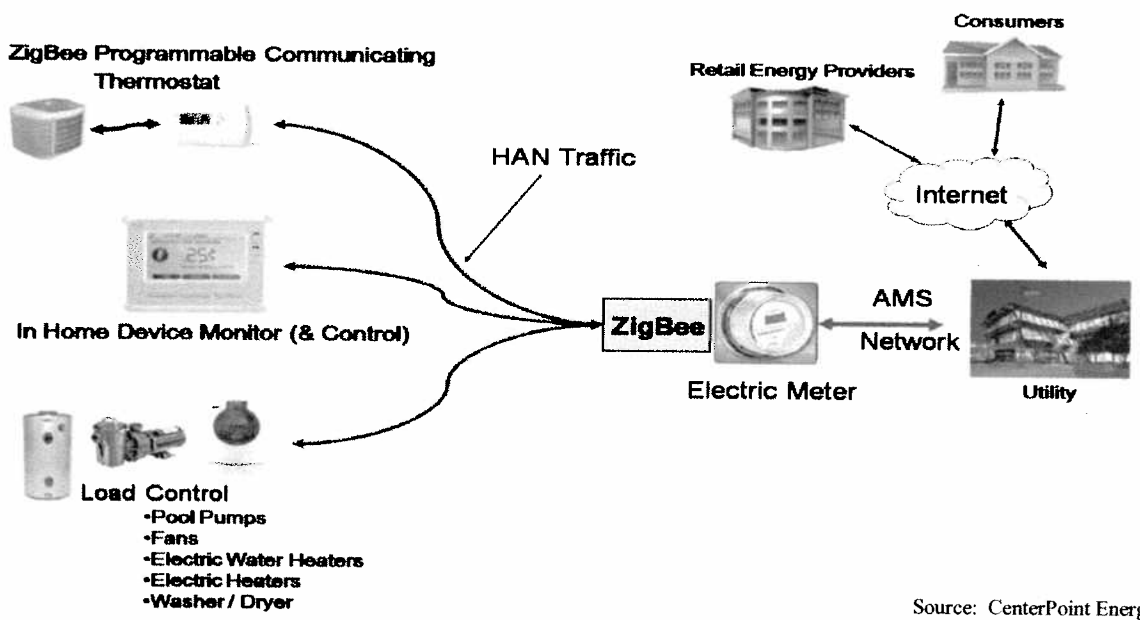
study to determine the best method to achieve 15-minute settlement in the long term as meters are deployed.[26]

Home Area Network

The HAN is an integral feature of the AMI. Outside of the advanced metering context, HAN is defined as a network contained within a user's home that connects a person's digital devices from multiple computers and peripheral devices to telephones, VCRs, televisions, video games, home security systems, "smart" appliances, fax machines and other digital devices that are wired into the network. Including a HAN module into the AMI allows multiple in-premises (or in-home) appliances to be interconnected, yet individually identified and controlled, potentially allowing the user to carry out the following functions:

- remote load control over multiple in-home appliances;
- through its two-way communications capability: improved measurement, verification and dispatch of demand response directives, and
- feedback displays to consumers showing the consumption and cost associated with usage of various appliances.

Figure No. 5
Advanced Metering & the Home Area Network (HAN)



Source: CenterPoint Energy

These functions may be used in connection with third-party demand response programs, and the customer's efforts to reduce consumption. The implementation project is addressing the market rules and processes which are needed to allow for the timely and cost-effective implementation of the HAN related issues in ERCOT.

Utilities that intend to deploy AMI over the coming years are working collaboratively with Commission staff and ERCOT to create an online web-portal for customers and their designated agents, ERCOT and REPs to access consumption data. This effort, along with customer education efforts, is described in more detail below. Standardizing web portal functionalities across Transmission and Distribution Utilities (TDUs) within ERCOT with a consistent content, availability and data format will be critical. The market is working to develop a reasonable set of web portal functions to allow the TDUs to design and build the necessary technology, systems, and system interfaces to provide a web portal that is compliant with the requirements in the AMI rule. A web portal will allow REPs to take full advantage of the AMI deployed, and develop retail electric services that incorporate dynamic pricing and demand response for residential and small commercial consumers. Standardization of web portals will ensure that REPs, customers and their agents have access to the same basic information in every territory, and that REPs do not have to develop different systems and processes for working in each TDU territory.

B. Deployment in Texas

CenterPoint Energy Houston Electric (CenterPoint) has filed two separate but complementary plans with the Commission for AMI deployment. The first, in Docket No. 35620, is a request to allow REPs to fund the deployment of AMI. The Commission approved a settlement in this docket on August 28, 2008. This deployment plan will allow a total of 127,000 advanced meters to be deployed in the CenterPoint territory on an expedited basis. Under the plan, REPs may finance the build-out of advanced meters and the related infrastructure before CenterPoint implements deployment across its service territory. Such accelerated deployment is consistent with "the intent of the legislature that net metering and advanced meter information networks be deployed as rapidly as possible to allow customers to better manage energy use and control costs, and to facilitate demand response initiatives."[27]

The second plan filed by CenterPoint, in Docket No. 35639, is for a first-phase of deployment. While this case is currently abated, CenterPoint filed a modified plan on September 18, 2008 for purposes of settlement. The modified plan is for a full deployment. The CenterPoint territory includes just over 2.1 million electric meters.

CenterPoint in early 2007 opened its Technology Center in Houston. This Technology Center demonstrates the company's vision for AMI and its future smart grid. The center includes a display that features the advanced metering system and the other functions it can perform. CenterPoint has given over 300 tours to the public, Commission staff, and policy makers from local, regional and national levels, as well as utilities from around the world.

Oncor Electric Delivery Company filed a plan with the Commission for full AMI deployment in its service territory, in Docket No. 35718, in May 2008. Oncor intends to deploy approximately 3.4 million advanced meters over the next four years, with an AMI that meets the requirements of the Commission's advanced metering rule. Oncor's surcharge covers an eleven-year period beginning in January 2009. Settlement among the parties was reached in this case and was approved by the Commission on August 28, 2008.

The estimated capital cost of the Oncor AMI deployment is $686 million and the estimated operating and maintenance costs is $153 million during the surcharge period. The Oncor plan includes an estimated total cost savings of $176 million for meter reading services, and $28 million of ad valorem tax savings related to the existing meters that will be replaced by the deployment. This cost savings is reflected in the surcharge to customers. Residential customers will pay $2.21 per month, beginning in January 2009.

Oncor's AMI deployment also includes a comprehensive customer education program called "SMART TEXAS - *rethinking energy*" that will work in tandem with Oncor's deployment of

[27] PURA § 39.107(i).

AMI technology to educate retail electric customers about the potential benefits that can be achieved through the use of an advanced meter. Oncor's plan includes $15 million for this education effort, which will include a Mobile Experience Center (a hands-on educational tool that will travel throughout Oncor's service territory in advance of the deployment), educational door hangers, and newspaper, billboard and movie theater advertisements. This education effort is critical because retail customers will need to take action themselves to realize some of the potential benefits.

In addition, as part of its AMI deployment to ensure that low-income customers have the ability to receive the potential benefits of advanced meters, the Oncor plan includes $10 million that will fund a low-income program. This program will work with the appropriate state and local agencies to coordinate the distribution of in-home usage monitors to low-income customers in Oncor's service area. These devices communicate with the advanced meters Oncor will be deploying, and low-income customers will have access to their energy usage information and will be able to take actions that could reduce their energy usage and monthly electric bills.

American Electric Power (AEP) and Texas New Mexico Power (TNMP) have not yet filed AMI deployment plans but expect to do so in the coming year. Both companies have been active in the Commission's implementation project.

Austin Energy has been working on building its smart grid since 2003, when it first replaced 125,000 of its electromechanical meters with advanced meters, primarily at apartment complexes. One of the benefits of such meters for the utility in multi-family housing with a large student population is to reduce the labor associated with initiating and terminating service as tenants move in and move out of an apartment. In January of 2008 the utility signed an expansion agreement to install a new system at a cost of $17 million for up to 300,000 residential and commercial customers to be funded from the operating budget of Austin Energy. Customers will not be charged for the conversion. The plan provides for installing the new meters by spring of 2009.[28]

[28] Information provided by Austin Energy to Commission staff, August 2008.

CPS Energy of San Antonio recently issued formal requests for proposals soliciting bids from advanced metering vendors for its AMI system. The utility plans to select vendors and start the negotiation process in December of 2008, followed by full-scale deployment in the fall of 2009. The program, which is intended to replace more than 700,000 electric meters and 330,000 natural gas meters, will take five to six years to complete and will be financed from the utility's capital fund.[29]

[29] Information provided by CP S Energy to Commission staff, August 2008.

IV. Conclusion & Recommendations

The Commission believes that the deployment of AMI is a critical component of the evolving Texas electric market. As deployment occurs, it can give customers more choice and control over their electric bill, enable market-based demand response, help the market to mature, yield savings for utilities, and create efficiencies in market processes for REPs and ERCOT.

The Energy Independence and Security Act of 2007 states that, "It is the policy of the United States to support the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet the future demand growth." Advanced metering deployment is part of the infrastructure of the future, and over time, will provide better information and services to customers.

Most importantly, AMI has the potential to provide enhancements in service to retail customers, particularly with connecting and disconnecting service and providing a prepayment option that will reduce deposit requirements. AMI gives customers the tools to help manage energy costs, and over time will help to balance the dynamics of supply and demand.[30]

The commission makes the following recommendations:

- The Governor's Competitiveness Council in its Texas State Energy Plan recommended that the Commission have the authority to order utilities to deploy advanced meters. The legislature should clarify that the Commission has the authority to order utilities to deploy advanced meters, as rapidly as possible,[31]

[30] In times when reserve margins are tight, having customers who can reduce usage at peak times adds additional security to the system. For instance, under an energy-only market, spot electricity prices in ERCOT markets can increase sharply, reaching over $1,000 per MWh when almost all available generation is being deployed to meet "super peak" demand. These high prices would signal to retail customers that ERCOT has very little available generation to maintain system reliability, and could prompt customers that have the flexibility, such as customers running oil and gas pumping jacks, commercial freezers, and residential water heaters, to voluntarily reduce their energy use. Large retail customers participate in operating reserve markets today, through voluntary curtailments, and the Commission and ERCOT are exploring additional opportunities for loads to provide reserves to assist ERCOT in maintaining system reliability. Enhancing the opportunities for demand response can provide improved levels of reliability for customers who do not participate in the programs and financial benefits for customers who do.

[31] See State Energy Plan adopted by the Governor's Competitiveness Energy Council, Recommendation 22 which states, "The state should require TDUs to deploy advanced meters, with an appropriate cost recovery mechanism to

with the appropriate cost recovery provided under the Commission's advanced metering rule.

- The legislature should clarify whether the 2005 legislation relating to advanced meters, PURA §39.107, applies to utilities outside of ERCOT.[32]
- State policy should also ensure that all retail customers have the option to have their billing determined on actual interval data captured from the advanced meters, so they receive the full benefits of changes in consumption behavior.
- State policy should continue to recognize that the retail electric market will benefit from knowledgeable residential electric customers making informed purchasing decisions to meet their energy needs.

ensure that TDUs earn a reasonable return on this investment. The PUC should have the authority to require deployment of advanced meters as rapidly as possible."

[32] See 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).

Appendices

A. Report Glossary
B. Report Acronyms
C. Advanced Metering Deployment
D. Advanced Metering Penetration by State

Glossary for the Report

Advanced Metering Infrastructure or System (AMS/AMI): A system, including the associated hardware, software, associated system and data management. Includes the programming, communications devices that collect time-differentiated energy usage from advanced meters. The system collects, processes, and records the information, and makes the information available to REPs, ERCOT, customers, and the utility.

Automated Meter Reading (AMR): Automatic or automated meter reading allows a meter read to be collected without actually viewing or touching the meter with any other equipment. One of the most prevalent examples of AMR is mobile radio frequency whereby the meter reader drives by the property, and equipment in the vehicle receives a signal sent from a communication device under the glass of the meter.

Conservation: Conservation includes consumer actions or decisions to use less energy, perhaps by reconsidering priorities and eliminating some energy use. Actions could include turning off extra lights, raising thermostats a few degrees in the summer or lowering them in the winter, and taking pre-vacation steps such as turning off power strips or lowering water-heater temperatures.

Critical Peak Pricing (CPP): CPP rates are a hybrid of the time-of-use (TOU) and real-time pricing design. The basic rate structure is TOU. However, provision is made for replacing the normal peak price with a much higher CPP event price under specified trigger conditions (e.g., when system reliability is compromised or supply prices are very high).

Demand: Represents the requirements of a customer or area at a particular moment in time. Typically calculated as the average requirement over a period of several minutes to an hour, and thus usually expressed in kilowatts or megawatts rather than kilowatt-hours or megawatt-hours. Demand and load are used interchangeably when referring to energy requirements for a given customer or area.

Demand Response: The planning, implementation, and monitoring of activities designed to encourage customers to modify patterns of electricity usage, including the timing and level of electricity demand. Demand response covers the complete range of load-shape objectives and customer objectives, including strategic conservation, time-based rates, peak load reduction, as well as customer management of energy bills.

Demand Response Event: A period of time identified by the demand response program sponsor when it is seeking reduced energy consumption and/or load from customers participating in the program. Depending on the type of program and event (economic or emergency), customers are expected to respond or decide whether to respond to the call for reduced load and energy usage. The program sponsor generally will notify the customer of the demand response event before the event begins, and when the event ends.

Demand Response Load: The load reduction that results from demand-response activities.

Direct Load Control (DLC): A demand response activity by which the program operator remotely shuts down or cycles a customer's electrical equipment (e.g. air conditioner, water heater) on short notice. Direct load control programs are primarily offered to residential or small commercial customers.

Fixed Network: A fixed network refers to either a communication infrastructure which allows the utility to communicate with meters without visiting or driving by the meter location.

Home Area Network (HAN): Network contained within a user's home that connects a person's digital devices, from multiple computers and their peripheral devices to telephones, VCRs and DVD players, televisions, video games, home security systems, "smart" appliances, fax machines and other digital devices that are wired into the network.

Interval Data: Interval data is a fine-grained record of energy consumption, with readings made at regular intervals throughout the day, every day. Interval data is collected by an interval meter, which, at the end of every interval period, records how much energy was used in the previous interval period.

Interval Data Collection: For purposes including load research, demand response and on-demand reads, meter data is frequently collected in hourly or even 15-minute intervals. Short-term storage of this interval data takes place before the system communicates the data to the utility. In general, interval data can be collected at the meter, or at an intermediary spot such as the fixed network collector unit that reads the meter's output. Finer resolution of data in smaller time increments requires communications systems that can transmit the data without bogging down.

Load (Electric): The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers.

Load Management: Demand management practices directed at reducing the maximum kilowatt demand on an electric system and/or modifying the coincident peak demand of one or more classes of services to better meet the utility system capability for a given hour, day, week, season, or year.

North American Electric Reliability Corporation (NERC): The organization certified by the Federal Energy Regulatory Commission (FERC) as the reliability organization for the nation's bulk power grid. NERC consists of eight Regional Reliability Councils in the lower 48 states. The members of these Councils are from all segments of the electricity supply industry - investor-owned, federal, rural electric cooperative, state/municipal, and provincial utilities, independent power producers, and power marketers.

Open Standards: An agreed-upon method or implementation defining how part of a process, product, or solution should operate. An open standard is made available so that any interested party or organization may provide part of an open system.

Power Line Carrier (PLC): Communication of meter data and other utility system data through power lines. PLC technology can be part of two-way systems.

Remote Connect/Disconnect: Disconnecting and reconnecting a customer's electrical service without accessing the customer's premises or sending a service vehicle into the field. A hard disconnect, that is, cutting off power to a premise by throwing a physical switch — can be performed remotely, but requires additional specialized equipment at the meter. A virtual disconnect, that is, obtaining an on-demand meter read at the time a premise is vacated or occupied — can be performed remotely through fixed network AMR systems. Virtual disconnect can also include monitoring of any consumption that should not be occurring after disconnect. In addition, some utilities are effectively utilizing mobile AMR systems to perform off-cycle, final reads associated with move-ins and move-outs.

Real Time Pricing (RTP): A retail rate in which the price for electricity typically fluctuates hourly reflecting changes in the wholesale price of electricity. RTP prices are typically known to customers on a day-ahead or hour-ahead basis.

Smart Grid: Real-time visualization technologies on the transmission level and smart meter and communications technologies on the distribution level that enable demand response, distributed energy systems (generation, storage, thermal), consumer energy management systems, distributed automation systems and smart appliances.

Smart Metering: See definition for Advanced Metering.

Smart Thermostat: Thermostats that adjust room temperatures automatically in response to price changes or remote signals from retail electric providers, utilities, authorized third-parties, and system operators. Also known as programmable, communicating thermostats.

Time Based Rate: A retail rate structure in which customers are charged different prices for different times during the day. Examples are time-of-use (TOU) rates, real time pricing (RTP), hourly pricing, and critical peak pricing (CPP).

Time of use Rate (TOU): A rate with different unit prices for usage during different blocks of time, usually defined for a 24-hour day. TOU rates reflect the average cost of generating and delivering power during those time periods. Daily pricing blocks might include an on-peak, partial-peak, and off-peak price for non-holiday weekdays, with the on-peak price as the highest price, and the off-peak price as the lowest price.

Acronyms

Advanced Metering	Advanced Metering Infrastructure or System
AMR	Automated Meter Reading or Automatic Meter Reading
AMI	Advanced Metering Infrastructure
AMS	Advanced Metering System
ANSI	American National Standards Institute
AMS/AMI	Advanced Metering System
BPL	Broadband over power-line
C&I	Commercial and industrial customers
CPP	Critical peak pricing
DLC	Direct load control
DR	Demand response
EE	Energy efficiency
EISA	Energy Independence and Security Act of 2007
EPAct or Act	Energy Policy Act of 2005
kW	Kilowatt
kWh	Kilowatt-hour (one thousand watt-hours)
MW	Megawatt
MWh	Megawatt-hour (one million watt-hours)
NERC	North American Electric Reliability Council
PLC	Power line communication
PURPA	Public Utility Regulatory Policies Act of 1978
RF	Radio frequency
RTP	Real-time pricing
TOU	Time-of-use (rate)
VPP	Variable peak pricing

Appendix C Advanced Metering Deployment

Colorado: In December 2007, Xcel Energy established the Smart Grid Consortium and chose Boulder, Colorado to be the nation's first fully integrated "Smart Grid City". The project, with a cost estimated at $100,000, provides for creation of a communication network providing real-time, high-speed, two-way communication throughout the power distribution grid (via broadband over power lines); conversion of substations to "smart" substations capable of remote monitoring, near-real-time data collection and communication; installation of programmable in-home control devices and the necessary systems to fully automate home energy use; integration of infrastructure to support easily dispatched distributed generation technologies (such as plug-in hybrid electric cars with vehicle-to-grid technology, battery systems, wind turbines, and solar panels). After initial assessment of the project in 2009, Xcel Energy will use the results to negotiate with state and federal officials a larger deployment throughout its eight-state service territory.[33]

Connecticut: The state passed a new DR-AMI bill requiring utilities to install new "smart" meters and associated technologies capable of measuring real-time prices, in support of mandatory TOU pricing and deploy AMI by January 1, 2009. United Illuminating Co. of New Haven recently received the Global AMI Utility Peer Group's 2007 Metering Award for the best revenue assurance initiative. The company installed several systems and software to support improvements to its metering and customer service programs. It employed a *CellNet* fixed-network radio-frequency advanced metering system in 2003 and a new billing system. The company also has used its *CellNet* system to support energy-efficiency programs designed to empower customers with Internet-based energy analyzer tools and historical data to help them make informed decisions about energy use and conservation.

Ohio: The PUC of Ohio adopted recommendations to require electric distribution companies to file reports that included a list of advanced metering technologies and costs. In the same decision the state PUC indicated that "all electric distribution utilities should offer tariffs to all customer classes, which are, at a minimum, differentiated according to on and off peak wholesale periods" and instructed that "time-of-use meters should be made available to customers subscribing to the on and off peak tariffs." The Commission initiated a proceeding to establish AMI workshops to study the cost/benefits of AMI deployment strategies and cost recovery mechanisms.

Oregon: Portland General Electric obtained approval May 5, 2008 from the Oregon PUC to install more than 850,000 "smart" electric meters over the next two years. The capital cost of the project is expected to be up to $135 million.[34] The Commission said that projections show a net present value benefit to customers of $33 million over 20 years. Other customer and system benefits attributable to the system are estimated to increase the net present value to a range of $37 million to $80 million over that period.[35] Through 2010, the AMI will be part of Portland General's rate base. After 2010, the utility will file a general rate case to capture the operating benefits for customers if the company is not already engaged in such a proceeding.

[33] "Boulder to Be First "Smart Grid City", Angela Neville, Power Magazine, June 2008.
[34] "Commission Approves PGE Investment in Smart Meter Technology", Transmission & Distribution World, May 8, 2008, available at http://tdworld.com/info_systems/highlights/pge-smart-tech-investment-0805/.
[35] UE 189 Opening Brief of PGE, Staff and ODOE, January 18, 2008, available at http://apps.puc.state.or.us/edockets/edocs.asp?FileType=HBC&FileName=ue189hbc124954.pdf.

Pennsylvania: The state PUC ordered the Pennsylvania Demand Side Response Working Group to perform cost-benefit assessments of all utilities to further develop their advanced metering infrastructure. Pennsylvania [PUC?] issued a policy statement stating the public should have access to historic billing data and real time metered data to facilitate retail choice, demand side response, and energy conservation initiatives.

Vermont: Vermont Public Service Board opened a docket requiring both statewide AMI and utility-by-utility AMI cost-benefit studies.

Virginia: In June 2008, Dominion Virginia Power announced its plan to deploy advanced meters for all its Virginia customers at a cost of $600 million to meet an energy conservation target approved by the state legislature in 2007. The project is expected to yield savings of more than $1 billion to its customers over the next 15 years.

The European Commission has developed a Strategic Research Agenda (SRA) for the electricity networks of the future. The SRA looks to solutions such as an Internet-like network, distributed generation, load flow analysis and geographic information systems. It aims to define a standard-based and interoperable customer-side energy management system capable of managing local power demand and re-dispatching local loads, so that the customer can take full advantage of real-time energy prices and other market based opportunities, with particular focus on distributed generation and demand side participation. The system will be based on a new, non-proprietary open access architecture that will lead to low-cost metering systems that are interoperable and therefore could be deployed on a large scale.[36] According to Berg Insight, the installed base of smart meters in Europe will grow at a compound annual growth rate of 15.6% between 2008 and 2013 to reach 81.2 million in five years. This will mean that every third household will receive electric bills based on its actual consumption, resulting in immediate financial benefits from energy savings.[37]

In **Italy**, the largest utility, Enel, deployed some 30 million smart meters over a five year period ending in 2005. The Italian meters are fully software-driven and capable of two-way communications over low voltage power lines using standards-based power line technology. Customers of Enel are able to monitor and manage their power consumption over the Internet using a Web portal developed by the utility. Enel is the only utility to have applied and tested this technology on a large scale. The utility's estimated €2 billion investment is yielding savings of about €500 million per year. Enel's program has been emulated across Europe.[38]

In **France**, ERDF, a subsidiary of EDF and the largest electricity distribution network in the European Union, has recently launched a major program to replace 35 million electricity meters, beginning with a pilot trial of 300,000 meters. The new smart meters are able to transmit and receive data for remote reading and optimized network management.[39]

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[36] Strategic Research Agenda for Europe's Electricity Networks of the Future, 2007 EUR 22580, European Commission, available at http://cordis.europa.eu/technology-platforms/pdf/smartgrids.pdf.
[37] News Release, Berg Insight, August 26, 2008, available at http://www.berginsight.com/News.aspx?m_m=6&s_m=1 .
[38] "Coming to America", Charles W. Thurston, March 2008, Public Utilities Fortnightly.
[39] EDF launches 300 000 smart meters pilot project. July 3, 2008, available at http://pepei.pennnet.com/display_article/333449/6/ARCHI/none/PRODJ/1/EDF-launches-300-000-smart-meters-pilot-project/.

In September 2007, the **Dutch government** proposed that all seven million households in the country should have a smart meter by 2013, as part of a national energy reduction plan. **Sweden** has begun 100% deployment to be completed in 2009.

The government of **Ontario, Canada,** adopted the Energy Conservation Responsibility Act of 2006, which mandates deployment of smart meters to all consumers by 2010 as a way to avoid investing in more coal-fired power stations.

In February 2006, the **Council of Australian Governments** committed all state governments to the progressive rollout of smart metering technology from 2007. Victoria, Australia has mandated 100% deployment to large businesses by 2008 and all customers by 2013.

Appendix D Advanced Metering Penetration by State

State	Advanced Meters	Non-Advanced Meters	Total Meters	Penetration
Alaska	1,358	303,565	304,922	0.4%
Alabama	75,861	2,332,450	2,408,311	3.1%
Arizona	34,342	2,638,468	2,672,810	1.3%
Arkansas	183,449	1,234,925	1,418,374	12.9%
California	41,728	14,206,721	14,248,449	0.3%
Colorado	95,582	2,237,762	2,333,344	4.1%
Connecticut	592,147	2,174,220	2,766,367	21.4%
Delaware	12	416,518	416,530	0.0%
District of Columbia	245	231,470	231,715	0.1%
Florida	243,591	9,429,060	9,672,651	2.5%
Georgia	118,239	4,221,386	4,339,625	2.7%
Hawaii	10	465,304	465,314	0.0%
Idaho	119,024	614,525	733,549	16.2%
Illinois	83,903	5,557,111	5,641,014	1.5%
Indiana	22,103	3,311,080	3,333,183	0.7%
Iowa	21,590	1,072,588	1,094,178	2.0%
Kansas	259,739	1,038,977	1,298,716	20.0%
Kentucky	119,221	2,207,524	2,326,745	5.1%
Louisiana	112	1,359,878	1,359,990	0.0%
Maine	112,104	673,197	785,301	14.3%
Maryland	641	2,573,546	2,574,187	0.0%
Massachusetts	6,613	3,644,426	3,651,039	0.2%
Michigan	29,065	4,665,504	4,694,569	0.6%
Minnesota	15,019	2,482,308	2,497,327	0.6%
Mississippi	101	985,411	985,512	0.0%
Missouri	400,310	2,596,411	2,996,721	13.4%
Montana	739	531,930	532,669	0.1%
North Carolina	7,208	4,521,491	4,528,699	0.2%
North Dakota	10,201	413,665	423,866	2.4%
Nebraska	64,442	885,019	949,461	6.8%
Nevada	17	1,194,001	1,194,018	0.0%
New Hampshire	19,070	755,259	774,329	2.5%
New Jersey	15,502	3,851,148	3,866,650	0.4%
New Mexico	4,708	887,354	892,062	0.5%
New York	6,933	7,988,548	7,995,481	0.1%
Ohio	2,199	6,079,222	6,081,421	0.0%
Oklahoma	138,602	1,788,326	1,926,928	7.2%
Oregon	5,284	1,820,389	1,825,673	0.3%
Pennsylvania	3,176,455	2,879,274	6,055,729	52.5%
Rhode Island	402	484,196	484,598	0.1%
South Carolina	65,726	1,987,174	2,052,900	3.2%
South Dakota	18,192	544,768	562,960	3.2%
Tennessee	110	3,044,306	3,044,416	0.0%
Texas	572,836	12,514,011	13,086,847	4.4%
Utah	239	1,051,350	1,051,589	0.0%
Vermont	1	329,966	329,967	0.0%
Virginia	139,601	3,189,764	3,329,365	4.2%
Washington	41,366	2,967,267	3,008,633	1.4%
West Virginia	30	668,972	669,002	0.0%
Wisconsin	1,199,432	1,782,717	2,982,149	40.2%
Wyoming	89	1,384,782	1,384,871	0.0%

Source: Federal Energy Regulatory Commission