PROJECT NO. 31418

RULEMAKING RELATED TO ADVANCED METERING	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER ADOPTING NEW §25.130 AND AMENDMENTS TO §§25.121, 25.123, 25.311, AND 25.346 AS APPROVED AT THE MAY 10, 2007 OPEN MEETING

The Public Utility Commission of Texas (commission) adopts new §25.130, relating to Advanced Metering; and amendments to §25.121, relating to Meter Requirements; §25.123, relating to Meter Readings; and §25.346, relating to Separation of Electric Utility Metering and Billing Service Costs and Activities, pursuant to Public Utility Regulatory Act (PURA) §39.107 as amended by House Bill (HB) 2129, 79th Legislature, Regular Session (2005), with changes to the proposed text as published in the November 10, 2006, issue of the *Texas Register* (31 TexReg 9183). The commission adopts §25.311, relating to Competitive Metering Services, pursuant to Public Utility Regulatory Act (PURA) §39.107 as amended by House Bill (HB) 2129, 79th Legislature, Regular Session (2005), with no changes to the text as proposed.

The new rule and amendments will implement HB 2129, relating to advanced metering and address: 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 electric utility advanced meter systems to qualify for the 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 advanced metering.

This new rule and the amendments are competition rules subject to judicial review as specified in PURA §39.001(e). These amendments and new rule are adopted under Project Number 31418.

The commission received written initial and reply comments on the proposed new rule and amendments from the Alliance for Retail Markets ("ARM" members participating include Constellation NewEnergy, Inc., Direct Energy, LP, Green Mountain Energy Company, and Stream Gas & Electric Ltd. (d/b/a Stream Energy)), CPL Retail Energy, LP; Texas Energy Association for Marketers ("TEAM" members include Accent Energy; Cirro Energy; Commerce Energy, Inc.; Green Mountain Energy Company; Just Energy Texas; StarTex Power; Stream Energy), Tara Energy and WTU Retail Energy, LP, (collectively the "Coalition of Retail Marketers" or "CRM"); the Joint Distribution Service Providers ("Joint DSPs", consisting of CenterPoint Energy Houston Electric, LLC; TXU Electric Delivery Company; AEP Texas Central Company; AEP Texas North Company; Southwestern Electric Power Company; Entergy Gulf States, Inc.; El Paso Electric Company; Nueces Electric Cooperative, Inc.; and Texas-New Mexico Power Company); Elster and Hunt Technologies; the Electric Reliability Council of Texas (ERCOT); the Office of Public Utility Counsel (OPC); Public Citizen; Reliant Energy Inc.; REPower Energy; Texas Legal Services Center (TLSC) and Texas Ratepayers' Organization to Save Energy (Texas Rose); Texas Industrial Energy Consumers (TIEC); TXU Cities Steering Committee (Cities); TXU Energy Retail Company, LP.; Xcel Energy Services Inc.; and Current Communications of Texas, L.P. Reply comments on behalf of CRM and Reliant were filed jointly by the Retail Electric Provider Coalition (REP Coalition or CRM).

In the preamble of the proposed rule as published in the *Texas Register*, the commission invited interested persons to comment on specific questions posed by the commission. The questions, along with the comments and the commission's responses are presented prior to a discussion of other comments on the proposed rules

The commission posed and received comments on four questions in this proceeding.

Question 1

Is there a minimum threshold of technical capability of advanced meters that should be met in order to get cost recovery through the surcharge mechanism?

Reliant, TXU Energy, and CRM stated that a minimum threshold of technical capability of advanced meters should be met in order to receive cost recovery through the surcharge mechanism.

CRM added that when the Legislature in 2005 enacted the amendments to PURA §39.107 pursuant to H.B. 2129, it sought to encourage the deployment of advanced meters by facilitating electric utility cost recovery by allowing utilities to impose a nonbypassable surcharge specifically dedicated to that purpose. CRM went on to state that an incentive was therefore established for utilities to deploy more sophisticated and innovative meters beyond today's norm, to the benefit of utilities, REPs, and customers alike, and that these meters are to be deployed for a variety of reasons, including: to potentially increase the reliability of the regional electrical network, encourage dynamic pricing and demand response, make better use of generation assets and transmission and generation assets, and provide more retail choices for consumers.

CRM further stated that in order for advanced meters to qualify for the surcharge, those meters should provide *all* of the benefits intended by the statute and rule, and that if an electric utility deploys new meters that do not include all of the minimum system features in the advanced metering rule or are deployed in a manner that is non-compliant with the rule, the electric utility should not be able to use the nonbypassable surcharge mechanism. CRM argued that only an electric utility in full compliance with §25.130 should be allowed to use the surcharge as a cost recovery mechanism, unless it has been granted a waiver under the rule.

CRM pointed out that meter manufacturers have announced the availability of competitively priced advanced meters that provide the functionalities at issue in this proceeding. Specifically, CRM noted that Itron, Inc., announced on November 1, 2006, that CenterPoint Energy will deploy Itron's OpenWay meters, which enable remote connections and disconnections as well as home access to meter data through an industry standard wireless protocol, ZigBee. CRM went on to state that USCL, DCSI, AMPY, ORION, and other companies recently have deployed meters with similar advanced features. CRM urged the commission to encourage all utilities to undertake the deployment of this forward-looking technology and to take advantage of the specialized cost recovery mechanism authorized by the Legislature for advanced meters in compliance with the commission's rule.

TXU Energy stated that by meeting the minimum requirements, REPs and end-use customers are assured of receiving the functionality and benefits of advanced metering systems (AMS) consistently, and can better understand the functionality and benefits. TXU Energy recommended that the benefits of standardized minimum requirements be balanced against a regulatory scheme that maximizes the opportunities for innovation. Therefore, TXU Energy proposed that minimum thresholds be limited to those that are needed to support the overall functionality and benefits of AMS. Moreover, the appropriate minimum technical requirements can reasonably change in response to technological advancements. TXU Energy therefore endorsed the inclusion of minimum standards, but urged the commission to avoid imposing a list of requirements that might stifle competitive creativity and innovation.

Joint DSPs commented that the minimum threshold of technical capability required for deployment of advanced meters for purposes of cost recovery should be the factors in proposed §25.130(g)(1) or the capabilities granted in a waiver pursuant to proposed §25.130(g)(3), and that in order to receive cost recovery through a surcharge, utilities should not be held to a higher standard of advanced meter technology than required by PURA and the adopted rule, or the capabilities approved in a waiver request. In its reply comments, Hunt and Elster agreed, stating that the very minimum should be included so as to allow flexibility to the electric utility.

Joint DSPs urged the commission to consider setting minimum standards for advanced metering such that end-use customers can benefit from the deployment of advanced metering in the most cost-efficient manner, and so that all customers do not have to pay for functionality from which only a few are likely to receive benefits.

The CRM argued that the proposed minimum standards would allow for innovative product offerings for customers, which would benefit the market substantially.

Joint DSPs also added that Nueces Electric Cooperative, Inc. (“NEC”) is the only electric cooperative in Texas whose distribution territory is open to competition. The Joint DSPs explained that the cost for a small electric utility like NEC to implement advanced metering and interval data processing and posting is not economically justified. Joint DSPs stated further that if Interval Data Recorder (IDR) processing as proposed in the rule were to become a requirement for electric cooperatives that choose to open their distribution areas to competition, this requirement and its accompanying costs are likely to become a significant barrier to entry for electric cooperatives considering entry into the Texas electric choice market.

Regarding the waiver of certain functionalities, TXU Energy agreed that it was a reasonable way to address features that may not be cost-effective in certain parts of electric utility service areas. TXU Energy noted that while this could inevitably lead to some customers receiving a different set of features and functionality, the proposal under which waivers would be granted ensures that the AMS functionality and benefits would be at least equivalent, even if certain features and functionality are not included.

TXU Energy added that in order to receive approval of the waiver, the electric utility should be required to disclose all evidence on which it relies for its claim that implementation would be uneconomic or technically infeasible, and to bear the burden of proof regarding whether the proposed substitute AMS “meets, exceeds, or is an adequate substitute.”

In it reply comments, Current stated that minimum functional capabilities should be established for meters to qualify for cost recovery, and that such standards should encourage enhanced functionality while recognizing that such enhanced functionality may not be appropriate or justifiable for 100% of an electric utility's service area. Current also urged the commission to adopt standards that are technology neutral.

The REP Coalition stated in reply comments that the minimum features set forth in a commission rule will allow a common platform upon which REPs can develop and market products to any advanced metering customer, regardless of which electric utility serves that customer. Reliant favored a requirement for minimum functionality and stated that the proposed requirements contained the basic components for mass deployment of advanced meters. Reliant stated that the minimum functionality must be met in order for an AMS to be eligible to cost recovery through the surcharge mechanism. Reliant explained further that similarity across electric utility territories will prevent REPs from offering electric utility-specific products. Reliant added that commercial customers frequently have locations across electric utility territories and require product attributes to be the same regardless of location.

Cities argued that the commission should not set minimum functionality in order to receive cost recovery. Rather than specify minimum standards in the rule that may simply contribute to higher expenditures for metering capabilities that are not cost justified, utilities should be required to provide reports concerning the existing deployed advanced meters or use pilot programs to test and demonstrate that advanced meters are “cost-justified in terms of offering tangible benefits from enhanced reliability, improved meter reading efficiency, or facilitating the development of new retail energy products that offer savings to retail customers over what could have been achieved without advanced metering." Cities expressed skepticism that advanced meters will lead to substantial savings in metering costs, and that time differentiated retail energy pricing would be offered to small customers. Cities added that minimum standards may only serve to increase investment costs of such equipment, which in turn will drive up costs to small retail consumers who already are paying very high prices for energy in the new competitive market.

In its reply comments, CRM urged the commission to consider that the substantial savings in meter reading automation alone will provide benefit to customers. CRM also contended that experience from companies that have installed advanced meters demonstrates that the ability to locate outages, identify false alarms, and monitor performance, which help to substantially increase reliability.

OPC suggested that if there are commonly accepted industry standards regarding a minimum threshold of technical capability and if such a standard is approved by independent organizations charged with quality control and evaluation in the advanced metering industry, it may be acceptable to obtain cost recovery through surcharge. OPC cautioned that the rule should provide some protections to customer classes, especially those in poorer areas so the electric utility does not deploy advanced meters that unreasonably exceed the technical capabilities necessary to deliver, monitor, and provision electric products for ratepayers. OPC added that a customer may not need the "Hummer" of advanced meters where a "Civic" will reasonably suffice. OPC also stated that the minimum functions should be narrowly targeted to the customer classes and regions.

Conversely, Hunt and Elster asserted that there is a considerable difference from state to state, utility to utility, and technology company to technology company, as to what they believe are rational, objective, technological capabilities that could be labeled as a “minimum threshold.” Hunt and Elster explained that the COMET Working Group process at ERCOT included discussions, before the formal comment period for the strawman in this docket, of what should be accepted as a “smart or advanced meter” and what should be the capabilities of an advanced metering infrastructure (AMI). Hunt and Elster argued that the advances being made across the entire metering industry will make it next to impossible for the commission to entertain a position that will satisfy all parties to this rulemaking. It added that the commission should focus on what functionality the commission would like to achieve in an AMI deployment and allow the utilities, along with the technology companies, to determine how best to fulfill those requirements. Hunt and Elster suggested that the initial list discussed in the COMET Working group provide the starting point for the commission.

Public Citizen argued that advanced meters should provide data to consumers, the REP, and the independent organization or regional transmission organization in 15-minute increments and that the information from advanced meters should be stored for a minimum of one year. Public Citizen stated that the mechanism for conveying information to the consumer must be specific and instantaneous so consumers can voluntarily control the deployment of certain electrical appliances during periods of peak demand.

Commission response

The commission concludes that a minimum threshold of technical capability of advanced meters should be met in order to receive cost recovery under the surcharge mechanism. In making its assessment of the required functionalities, the commission is balancing the interest in minimizing the costs of deployment and obtaining broad capabilities that will support higher levels of service quality, both through automation of the meter reading and data management processes and providing more information on a more timely basis to REPs, so that they can offer valuable new services to customers. The commission agrees with CRM that in order for advanced meters to qualify for the surcharge, those meters should provide *all* of the benefits intended by the statute and rule. The commission also agrees with the Joint DSPs that minimum standards should be set for customers to benefit from AMI in the most cost-efficient manner.

The provisions relating to waivers will permit the commission to address special situations, including circumstances in which robust communications networks are not expected to be available, AMS deployed prior to the adoption of the rule, and other situations. The commission believes that utilities with smaller service territories can apply for a waiver if they are unable to meet the minimum standards. The waiver provision is also important in achieving the appropriate balance of costs and benefits. In addition to special situations, the commission has included provisions to address advanced meters without remote disconnection and reconnection capability that were ordered prior to the effective date of this rule.

The commission agrees with TXU Energy that in order to receive approval of the waiver, the electric utility should be required to disclose all evidence on which it relies for its claim that implementation would be uneconomic or technically infeasible. Regarding Public Citizen's request that meter information from advanced meters be stored for a minimum of one year, the commission concludes that this issue should not be addressed in the rule. Information storage standards can be addressed in ERCOT forums such as the COMET working group. For AMS deployment in non-ERCOT areas, the utilities should determine appropriate information-storage protocols.

The commission acknowledges the recommendation from Public Citizen that 15-minute data be provided to consumers, the REP, and the independent organization or regional transmission organization. At this time, ERCOT does not require 15-minute data for settlement. Until the settlement processes are modified, electric utilities are not required to transmit that data to ERCOT. Customers will have access to real-time data provided they have an in-home display that can communicate with the advanced meter. Because many of these in-home displays have two-way communications capabilities, this also provides near-real-time access to the data to the REPs. Regarding Public Citizen's recommendation that meter data be stored for a minimum of one year, the commission believes this should be addressed in the implementation proceeding and in the ERCOT stakeholder process, and ultimately decided by the commission.

Question 2

Should the limitation in proposed §25.130 (j)(8) that a customer's demand exceed at least 100 kW be eliminated in order to provide that all advanced meters within the scope of the rule would provide, simultaneous, direct, password protected, read-only access to the customer's meter through a phone line, internet or other technology? Is it acceptable to have information on a day-after basis, day of basis or instantaneous basis?

Reliant stated that the 100 kilowatt (kW) limitation should be eliminated and that all advanced meters within the scope of the rule, regardless of demand level, should allow direct access to the meter by REPs. CRM and Public Citizen agreed. TXU Energy agreed that the limitation should be eliminated if the commission determines it is necessary to have a minimum requirement for all customers. However, TXU Energy noted that it is difficult to render an opinion at this time because TXU Energy does not know how the electric utility would provide this functionality, much less how much it would cost. TXU Energy opined that the higher the cost in the tariff, the harder it is to exceed the cost-benefit hurdle of leveraging simultaneous, direct, password protected, read-only access to the customer's meter, through a phone line, internet, or other technology.

Cities and OPC stated that the limitation should be retained. Cities argued that costs and benefits of advanced metering capabilities, particularly for smaller customers, should be demonstrated before wide scale deployment of advanced meters is mandated.

Joint DSPs commented that the requirement should be deleted altogether, as deployment on a large scale is quite costly. Instead, the Joint DSPs stated, consumers, the REP, and other third party agents should only have web portal access provided by the electric utility to the advanced meter data and advanced meter functionality, which would allow the electric utility to manage data transport traffic, system security risks, meter operation and configuration, and compliance with minimal metering requirements, while meeting the REPs' need for customer data.

As for whether the data should be provided on an instantaneous, day-of or day-after basis, Reliant, CRM, and Public Citizen stated that the data should be provided instantaneously. TXU Energy also favored an instantaneous provision but was concerned about the cost. OPC also seemed to favor the instantaneous provision, as it stated that the more restrictions placed on time, the less valuable the data will be.

Current argued that "instantaneous" transfer is not physically possible; "real-time," which is within seconds, is physically possible but comes with a cost due to the bandwidth requirements on the network.

Joint DSPs stated that this rule should establish that the utilities provide hourly interval data on a day-after basis. While the Joint DSPs acknowledged that some direct load control programs may require more frequent reads, not all do, and most customers will likely not require such information any sooner than the following day. The Joint DSPs stressed that providing advanced metering data the day after it is recorded will support time of use rates, as REPs can retrieve the data to see if its customers have complied, and to see if the customer can retrieve the data to determine what its energy charges were for the previous day. Joint DSPs argued that more frequent data availability is not necessary and cost effective for all customers, and if a REP wants more frequent meter data intervals, then such information should be arranged on an account by account basis.

Hunt and Elster argued that these issues should be decided by an ERCOT working group.

Current encouraged the commission to be mindful of several principles when making this decision. Current explained that first, there will continue to be a need for higher and higher bandwidths to meet the potential of the AMS; second, not all technologies will be able to provide such capabilities nor will they be cost justified in all meters; third, the electric utility should be allowed to recover the costs as long as they are reasonably necessary; and finally, the commission should evaluate the benefits received from real-time data.

Commission response

The commission concludes that the language proposed in §25.130 (j)(8) is not necessary. The commission concludes that REPs and customers should have simultaneous, direct, password-protected, read-only access to the customer's meter *data*. The commission believes that direct access to the meter data through the electric utility's web portal as well as through a gateway inside the customer's premise is sufficient. The commission believes that the benefits from this level of information are readily available from current AMS systems and that the benefits to customers and the market of such systems will exceed the costs.

As for whether or not it is acceptable to have information on a day-after basis, day-of basis or instantaneous basis, the commission concludes that as long as the meters have the capability for REPs and customers to receive meter data inside the customer's premise, that hourly interval data should be provided to the web portal on a day-after basis.

The commission recognizes that 15-minute data is not currently needed for settlement. The commission therefore concludes that 15-minute data may be offered but is not required to be provided to REPs through the TDU web portal prior to implementing changes in the ERCOT settlement process. Exact requirements for 15-minute data availability through the TDU web portal or other means shall be addressed in the implementation proceeding following adoption of this rule.

In adopting this rule, the commission is distinguishing between minimum meter capabilities, which are prescribed in subsection (g), and required functions in subsection (j). The required capabilities in subsection (g) may require REPs or customers to deploy complementary equipment to take advantage of the capabilities, or the capabilities may be required now in the expectation that the market will evolve rapidly to take advantage of them. The required functions in subsection (j), on the other hand, are functions that the meters must provide, when they are deployed.

Question 3

Regarding §25.130(k)(3), is the weighted-average cost of capital (WACC) the appropriate interest rate to use in setting the surcharge? If not, what rate should be used and how should it be established?

Cities, OPC, and TIEC stated that the WACC is not appropriate for setting the return component of advanced metering surcharges. Cities and OPC recommended stated that the cost of capital applied to competitive transition charges under §25.263(1)(3)(A)(i) and (ii) provides a more appropriate interest rate for determining the return component of advanced metering surcharges.

OPC argued that the WACC would be the correct interest rate if the cost of the meters were considered in a rate case where both the benefits and costs to the electric utility are considered, but in the absence of that condition, the use of WACC is piecemeal ratemaking. OPC stated that §25.130(k)(3) addresses one drawback of using the WACC by changing the interest rate each time the WACC is adjusted.

TIEC stated that use of the WACC will over-compensate utilities for a voluntary investment for which they are guaranteed recovery, and that investment in AMS is distinguishable from traditional "wires and poles" investment because it will be recovered through a nonbypassable surcharge. TIEC stated that, arguably, the use of the WACC to establish carrying costs in the past reflected a perception that there was a higher risk associated with the financing of long-term assets for which recovery was not always certain, but that the establishment of a nonbypassable charge, however, lowers this risk and creates little cash flow uncertainty for the electric utility.

In reply comments, TIEC stated that the AMS assets are unique and need not be supported with a traditional capital structure, and it may be appropriate for these assets to be financed with debt. TIEC also stated that because the legislature provided the utilities with a specific recovery method that limits the risk of under-recovery, these assets need not necessarily be financed with the typical mixture of debt and equity. Thus, the cost of debt calculation that was set forth in the commission staff strawman is the appropriate interest rate to use in setting the surcharge. This rate reflects the lower risk associated with AMS recovery.

Conversely, TXU Energy, Reliant, and Joint DSPs stated that the WACC was the appropriate interest rate to use in setting the surcharge.

Joint DSPs stated that the WACC from the electric utility's last rate case is the appropriate interest rate to use in establishing the surcharge. The Joint DSPs explained that an adequate return on invested capital, including an adequate return on equity, is imperative to an electric utility's ability to attract the capital necessary to fund the deployment of advanced metering. Joint DSPs also stated that the deployment of advanced metering will require a substantial amount of capital to be invested over a relatively short period of time, which will be financed with both debt and equity. Therefore, it is reasonable that the return on investment allow a proper return on both debt and equity, not just debt. Joint DSPs went on to state that if only a debt-like return is allowed for investment in advanced metering, utilities would have an incentive to invest their limited capital dollars in other projects (transmission projects, for instance) where they could earn a full return on that investment.

Reliant submitted that because the costs included in the surcharge must be reduced by operational savings realized from deployment, it had no objection to using the WACC in setting the surcharge. Hunt & Elster agreed with Reliant that the carrying cost should only be applied to the unamortized balance, net of operating cost savings.

Hunt and Elster added that while the commission has crafted a set of cost recovery rules for deployment of AMI at §25.130(k), "we think that the commission may wish to include more specific calculation rules which would make determination of the surcharge piece easier to calculate whenever an electric utility chooses to invest in smart metering."

CRM argued that the rule should not require that the most recent commission-approved WACC for an electric utility be used. CRM explained that depending on when the commission last established a particular electric utility's WACC, such a rate may not reflect the current cost of electric utility investment today and may unduly inflate the surcharge. CRM further stated that the commission should have the discretion to conduct a review of the individual electric utility's current cost of capital and establish a new WACC in each individual surcharge proceeding, if it determines that the electric utility's most recently authorized WACC would not properly reflect the electric utility's current cost of capital.

Commission response

The commission agrees that the WACC is the appropriate interest rate in setting the surcharge mechanism. It would not be appropriate, in light of the enactment of HB 2129,

to make AMS systems a less favored investment for utilities than other investments that will earn a WACC rate of return. The commission believes that HB 2129 established an incentive for utilities to implement advanced metering, and that the WACC from the most recent rate case is the appropriate incentive to accomplish that objective. The commission concurs with CRM that the commission should have the discretion to review an electric utility's current cost of capital for use in a surcharge proceeding, and may establish a new WACC if it has not approved a WACC for the electric utility within the last four years.

Question 4

Should the commission approve an electric utility's initial deployment plan prior to an electric utility's deployment of AMS?

Reliant, CRM, and the Cities agreed that a deployment plan should be approved by the commission.

Conversely, TXU Energy argued that the commission should not have to pre-approve an electric's initial deployment plan prior to deployment of AMS. TXU Energy stated that it would be sufficient to have a process that includes the filing of an affidavit by the TDU stating that the electric utility's initial deployment plan complies with the minimum requirements of the advanced metering rule, allowing any REP that executes a non-disclosure agreement with the TDU to review the deployment plan during normal business hours, and having the electric utility provide accurate, monthly status reports regarding the AMS deployment.

The Joint DSPs argued that because the advanced metering rule will include a minimum set of requirements that must be deployed, and PURA §39.107 limits deployment to a minimum of a three-year period, a mandatory commission-approved deployment plan prior to deployment is not necessary. However, the TDUs should be allowed the option to seek pre-approval at their discretion. The Joint DSPs stated that due to the level of investment that is required to deploy advanced metering, a TDU may wish to obtain regulatory certainty of recovery of the investment prior to making the investment. The optional pre-approval should include a review of the reasonableness of the chosen technologies.

Reliant expressed concern that the process envisioned in the rule lacked a meaningful opportunity for input by REPs or for review by the commission. It suggested the rule could benefit from a more specific, more streamlined approach to notifying all parties concerned of relevant deployment information. Reliant recommended a three-step process. First the electric utility would file its plan with the commission, followed by a period of public comment. The commission would approve or not approve the plan. Any modifications to the plan would be submitted in step two. Upon deployment, Reliant proposed, the electric utility would provide progress reports, at least monthly, and a list of ESI IDs with AMS deployed to all REPs operating in its service area. In order for all interested parties to adequately evaluate the plan, information and expected savings must also be included. Reliant also recommended deletion of the requirement for the TDUs to report “the number of times customer data was accessed by customers or customers’ designated agents or REPs.”

CRM, in its reply comments, agreed with TXU Energy's recommendation that available information regarding areas of scheduled deployment be included in the deployment plans and progress reports.

CRM argued that there should be an opportunity to provide meaningful input into the design and development of the technology, the timeline for deployment, the cost of deployment, and any other matter germane to the initial deployment plan in a formal manner, *i.e.*, in a commission proceeding. CRM stated that informal one-on-one communications between the electric utility and REPs will not guarantee that legitimate REP concerns are considered by the electric utility and acted upon satisfactorily.

CRM was also concerned that code of conduct issues may arise from lack of review of the deployment plan and stated that there is nothing that would prevent an electric utility from installing its AMS initially in geographic areas, or solely in geographic areas, that are primarily served by its affiliated REP (AREP), thereby leaving competitive REPs that have less of a market presence in the geographic area at a disadvantage. In these circumstances, the AREP would have what amounts to a "test market" to develop various products and services related to AMS. Second, CRM noted that an electric utility could design its database and communications protocols in a manner that is preferential to its affiliate or another REP, placing other REPs at a competitive disadvantage.

CRM clarified that while it supports the concept of commission review and approval of the deployment plan, the process should not unreasonably delay deployment. Therefore, an abbreviated procedural schedule that nevertheless affords interested parties sufficient time to review and provide input about the initial deployment plan should be used for any such proceeding.

Cities commented that if initial deployment is conducted through the two-year pilot program advocated by Cities, and is therefore limited to an initial participation level of 15% of eligible customers, it would be reasonable to allow utilities to proceed with deployment before their initial deployment plan is finally approved.

OPC proposed that the information contained in a deployment plan pursuant to proposed rule §25.130(d) be specific, especially as to the type and features of the advanced meters proposed to be deployed. Moreover, stated OPC, such plans should be filed with the commission and subject to some type of review by the commission in the event that opposition to the plan is lodged by a party. OPC did not find the filing of a notice of deployment under the current rule to be sufficient.

TIEC added that customers will ultimately be paying the surcharge associated with the deployment of AMS and should therefore have access to the electric utility's plan. This is especially important in areas not currently subject to competition where REPs do not operate.

Hunt and Elster argued that approval of the deployment plan should not be mandatory. If the electric utility requests review of its deployment plans, the commission should conduct a review.

Commission response

The commission concludes that an electric utility should have the option to either file a Notice of Deployment or file a request for approval of its Deployment Plan. The commission agrees with Reliant that the rule could benefit from a more specific, more streamlined approach to notifying all parties concerned of relevant deployment information. The commission is adopting a three-step process for an electric utility to receive cost recovery under the surcharge that is similar to Reliant's recommendation. REPs and customers have an interest in the details of the deployment plans, and there are competitive concerns that may need to be reviewed in connection with a deployment plan. On the other hand, quick approval is also appropriate for utilities that seek approval of a deployment plan. The commission concludes that the Cities' proposal for a pilot program is not necessary and would unduly delay the improvements to metering service and the competitive retail market that advanced meters can bring.

General Comments

Xcel Energy stated that SPS is a member of the Southwest Power Pool ("SPP"), a regional transmission organization and reliability council, which is entirely outside of ERCOT. Senate Bill 7 added Chapter 39 to the PURA. Included in Chapter 39 is Subchapter I, Provisions for Certain Non-ERCOT Utilities, which applies specifically to SPS. Subchapter I recognized that transmission constraints and market power concerns in the Texas Panhandle required a more structured schedule to opening the SPS service territory to retail customer choice. Xcel went on to state that in 2001, HB 1692 amended Subchapter I to delay competition in the Texas Panhandle until at least January 1, 2007, when SPS may choose to participate in customer choice. Until SPS is authorized to move forward with retail open access, SPS is exempt from the requirements of Chapter 39, with the exception of §39.904, Goal for Renewable Energy and provisions relating to obtaining permits from the Texas Natural Resource Conservation Commission for generating facilities and reduction of emissions from generating facilities.

Therefore, Xcel Energy requested that §25.130(b) Applicability, be revised to reflect that SPS is not subject to the statutory provisions relating to advanced metering, pursuant to PURA 39.402(a). Even though the new rule provides that the deployment and use of advanced metering systems is voluntary, Xcel Energy believes that the applicability provision should more accurately identify the entities that are exempt from certain provisions of Chapter 39 of PURA. Excel also added that it has no plans to implement advanced metering in Texas at this time, but does have a pilot underway in Colorado.

Commission response

The commission does not agree with the Xcel's suggestion for an exemption. This rule is voluntary, and therefore Xcel is not required by this rule to implement advanced metering.

Cities urged that the implementation of advanced metering be handled in a deliberate manner that ensures that benefits of advanced metering, particularly to smaller consumers, are demonstrated before wide scale deployment of advanced metering is allowed to proceed. Cities argued that there is no "industry evidence that would suggest that advanced metering would produce a dramatic improvement in system reliability or cost savings to retail consumers." Because of this, Cities stated that it would be unreasonable to rush the implementation of advanced metering before the benefits of such metering to Texas retail consumers can be addressed through pilot program results. Cities preferred that the commission require a mandatory two-year pilot program with a specified initial participation limit of 15% of eligible customers, to provide the experience necessary for the commission to determine if wider deployment of advanced metering is beneficial.

Cities alternately urged that each utility that currently has deployed advanced meters be required to provide a report concerning the costs of deployment, any cost savings due to deployment and benefits to each customer class, prior to full scale deployment of advanced meters. TLSC and Texas Rose agreed with the Cities that the commission should conduct an actual study of the potential costs and benefits to customers, as required by the Legislature, prior to any wide scale deployment.

Commission response

While the commission is in agreement with the Cities that implementation of advanced metering be handled in a deliberate manner that ensures that benefits of advanced metering, particularly to smaller consumers, it does not agree that there is a lack of evidence demonstrating the benefits of advanced metering. The commission is not "rushing" the implementation of advanced metering, but is adopting a three-step process that an electric utility shall follow in its deployment. This process includes opportunity for an examination of the costs and benefits to customers, REPs and the TDUs.

The commission does not agree with TLSC, Texas Rose and the Cities that the commission should conduct a study of the potential costs and benefits to customers, prior to any electric utility's wide scale deployment. HB 2129 does not mandate that an electric utility wait until the commission conduct such a study.

TLSC and Texas Rose argued that residential and low income customers might not benefit from AMI deployment and variable pricing offered by REPs, which could endanger health and safety. They added that a study would also enable the commission to study if the benefits will outweigh the costs, as well as other customer-related issues such as savings to customers, and customer protection. TLSC and Texas Rose added that deployment of advanced meters will "entail a wholesale change in the way the industry performs the metering function … in many ways represents a brave new world that will be less friendly and less forgiving to customers." Further, TLSC and Texas Rose stated that the customer protection rules as currently written are based on an industry model that will no longer exist once advanced metering systems are widely deployed. TLSC and Texas Rose commented that this rulemaking should focus on what additional customer safeguards will be necessary to ensure that the new model does not erode current customer protections or cause other harmful consequences that have not been anticipated.

Commission response

The commission disagrees with TLSC and Texas Rose that residential and low income customers may not benefit from AMI deployment and variable pricing offered by REPs. On the contrary, the commission believes that these customers stand to benefit the most from this new technology. This technology will allow a REP to provide additional consumption information and specific products, including prepayment and time of use which will allow customers to better manage their energy usage.

OPC also requested a specific cost benefit study be undertaken by the commission as noted by TXU Cities. OPC also noted the report published by the commission on advanced metering for the Texas Legislature in accordance with HB 2129. OPC stated that the report draws many conclusions but "provides little empirical evidence regarding the relative costs associated with deployment of advanced meters." OPC opined that this report opines on the assumed benefits associated with advanced meters and, while OPC agreed that there may be some benefits with such deployment, the costs to consumers should be more readily quantified in order to determine if widespread use of this technology is warranted and the cost should be borne by customers, especially those in impoverished areas. OPC noted that this may involve studies of pilot programs in other areas or possibly such a program in Texas involving a representative sampling of each customer class to determine more accurate results. OPC contended that the information provided to date does not provide enough justification for wide-scale deployment as to electric service delivery, variety of offerings and potential cost and surcharges to ratepayers.

OPC added that the rule should require that an electric utility or TDU identify all anticipated costs of deploying advanced meters. Investments should be made only when the benefits will exceed the costs and only after the technology is thoroughly tested and proven reliable, and any rule should be written to ensure that outcome. OPC stated that low-income customers should not be subsidizing the installation of advanced meters for upper income customers. OPC continued that the current system provides a safety net, whether intended or not, to guard against shutting off service when it is dangerous to the customer, such as if a member of the household is seriously ill, elderly, disabled, or on life support. OPC urged the commission to take steps to build other safety nets into the process to warn of impending disconnections and prevent erroneous disconnections. Consumers need rules that would only allow disconnections to occur during certain hours of the day such as regular business hours.

Commission response

The commission will address OPC's concerns regarding rules for remote disconnections in a separate proceeding.

Also, OPC argued that any rule adopted by the commission must establish security standards to ensure that remote access to meters is limited to the personnel who operate the system. Any need for open standards should take a back seat to securing remote access to the meter.

Commission response

The commission believes that OPC's concerns regarding security are addressed in the minimum functionality and security audit requirements of this rule.

REPower pointed out that it currently provides prepay electricity services by installing, operating and managing load-side meters and meter related equipment at customer premises, and asked that this rulemaking not prevent this type of market innovation from moving forward.

Commission response

This rule as adopted would not prevent the type of prepayment services offered by REPower.

TIEC supported the proposed rule's provisions regarding surcharge recovery. This subsection appropriately recognizes that certain customers are required by the ERCOT protocols to have an IDR meter, which currently includes all customers above 700 kW.

Joint DSPs stated that there are several overriding issues that should be addressed by the commission in adopting a rule for the deployment of advanced metering. First, an electric utility should not be directly involved in load control or demand response programs. Those programs are more appropriately provided by energy efficiency providers or REPs using communications technologies available to those providers and their customers to control the customer's equipment. Joint DSPs added that for an unbundled electric utility to engage in those programs constitutes a competitive energy service.

Commission response

This commission agrees with Joint DSPs that for a TDU to provide these products to customers is a violation of competitive energy service rules.

The commission further disagrees that use of the functions provided by a TDU meter by the REP, or customer, is a violation of the competitive energy service rules.

Second, Joint DSPs opposed mandatory direct access to the advanced meter by anyone other than the electric utility and its authorized agents. Rather, customers, their REPs, and authorized agents should be allowed to retrieve the relevant usage data from a web portal to be provided by the TDU. In their view, allowing millions of customers, their REPs, and agents direct access to the customers' advanced meters will not only require much more expensive advanced meters, but will introduce a variety of security concerns and serious data integrity issues.

The DSPs further commented that providing customers and REPs access to a customer's data through a web portal follows the consensus recommendation from the ERCOT market participants involved in the Competitive Metering Working Group ("COMET") meetings. Joint DSPs noted that the working group discussed providing direct access to the advanced meter and reached consensus that the market preference was access to meter data, not the advanced meter itself.

Joint DSPs also commented that minimum functionality required of all advanced meters should not be set so high that deployment becomes cost-prohibitive or virtually impossible to meet. A minimum standard that is set too high will have the effect of impeding the deployment of advanced metering rather than, as intended by the Legislature, encouraging the deployment of advanced metering.

The Joint DSPs argued that certain activities in the proposed rule constitute Competitive Energy Services as defined in §25.341. TDUs are prohibited by §25.342 and §25.343 and PURA from providing Competitive Energy Services. The Competitive Energy Services rules, and PURA, will have to be modified in order for a TDU to be allowed to provide such service. Joint DSPs added that these modifications cannot be made in this proceeding, as a properly-noticed proceeding relating to the specific Competitive Energy Services rules must be established to make changes to those rules. Should those changes be made, limitations of liability will have to be established to protect the TDUs from potential monetary damages due to equipment or communications failures that occur when the TDU is performing these activities on behalf of the REPs.

Commission response

The commission does not concur with the Joint DSPs that functions required in this rule constitute competitive energy services. The competitive energy services rule was adopted at a time when many of the AMS features studied in this rulemaking were considered appropriate for competitive metering. Since the state policy has changed regarding competitive metering, any functionality of the AMS that the electric utility must comply with as a result of this rule supersedes any conflicting limitation in the competitive energy services rule.

Lastly, Joint DSPs stated that an adequate return on advanced metering investment (including an adequate equity-related return) is imperative to encouraging TDUs to invest significant amounts to deploy advanced metering in their service territories.

Reliant suggested, and in reply comments TIEC disagreed that this proceeding is the appropriate vehicle for the commission's consideration of net metering as it applies to certain retail customers. TIEC also noted that it does not agree with identifying net metering as a "discretionary service."

Commission response

The commission disagrees with parties that assert further study is needed before broad deployment occurs. The commission disagrees with the Cities that there is a lack of evidence regarding the benefits of advanced metering. The utilities that are undertaking advanced metering deployment currently began with pilots in their territories, for purposes of testing and to gather results before moving to full deployment. Further, the commission believes the language in HB 2129 assumes the benefits of advanced metering, and authorizes a surcharge. The commission also believes that the Cities' concerns regarding savings will be addressed in the surcharge proceeding. While the commission has not undertaken an extensive advanced metering study, sufficient information has been provided by parties in this docket that suggests that the advanced meters will provide savings on metering expenses, foster new service offerings, and improve service, such as providing more timely connection and disconnection. This information supports its conclusion that AMS deployment will be beneficial for both competitive and non-

competitive areas in Texas. The commission agrees with TIEC that this proceeding is not the appropriate forum to decide whether net metering should be a discretionary service.

Comments for§25.121, Meter Requirements

Reliant agreed with the proposed amendments to §25.121.

REPower stated that §25.121(b) should specifically allow property owners, customers or customers' agents (which may be REPs) to install load-side meters and equipment, and commented that while the TDU meter data would be the basis for REPower to purchase electricity, customer consumption would be measured by the load-side meter. Joint DSPs replied that load-side meters should not be used for billing, as they would not always provide the same reading as the TDU supplied meter.

Commission response

The commission believes that the rule does not preclude load-side meters to be installed, and for this reason, it is not amending the rule to address REPower's concerns. The commission notes that REPower currently installs load-side meters to deliver and manage prepaid services and no actual billing is being conducted based on the load-side meter data, but the meters are being used to register customers' consumption under REPower's prepayment plan. The commission agrees with Joint DSPs to the extent that the TDU supplied meter data must be the basis for wholesale settlement.

§25.121 (d)(4)

REPower opined that “customer” in subsection (d)(4) should include the property owner, management company, or landlord of a multi-family property.

Commission response

The commission does not agree with REPower that, for this subsection “customer” should include the owner or manager of the property. Customers have rights to meter data and to protect it from release to others. The REPower proposal is inconsistent with these rights.

§25.121 (d)(5)

TXU Energy commented that the added subsection (d)(5), relating to conflicts between this section and §25.214 (and the tariff adopted under that section), should be deleted, with the same language added as a new §25.121(f). Conversely, CRM took the position that it is preferable for rule language supersede tariff language, and absent a better understanding of its implications for the tariff, this subsection should be deleted altogether.

Commission response

The commission disagrees with TXU Energy and agrees with CRM. Subsection (d)(5) should not be deleted.

§25.121 (f))

Joint DSPs stated that subsection (f) should be deleted, as it addresses the use of proprietary customer information and is therefore inappropriate to a rule on “Metering Requirements”.

Instead, Joint DSPs stated that §25.272(g)(1) was the appropriate place for changes to customer protection rules.

Commission response

The commission disagrees with the Joint DSPs that subsection (f) be deleted.

REPower commented that metering rules for REP owned meters should be similar to those for TDU owned standard meters. It also proposed a new subsection (f) that would make REP owned load-side meters exempt from the additional requirements for advanced meters set forth in this section and in §25.130.

Commission response

The commission concurs with REPower that rules for REP owned meters should be similar to those for TDU owned standard meters. However, the commission rejects the recommendation that a new subsection be added that would make REP owned load-side meters exempt from additional requirements for advanced meters. This rule, as proposed, does not apply to meters other than electric utility meters, so the change in the rule recommended by REPower is unnecessary.

Comments for §25.123 Meter Readings

Reliant was in agreement with all proposed amendments to this section.

TXU Energy commented that the term “display” should be added in subsection (a) to clarify that advanced meters will show units and quantities, expressed in kWh, which are the basis for electric utility charges to the REP, as distinct from the basis on which the REP is billing the customer.

Xcel Energy stated that the amended language in subsection (b) is too broad, and might be interpreted to mean that if meter reading schedules had to be altered due to extreme weather, the customer would have to be notified of the change. It suggested that the language be altered to indicate that customer notification would be required if the meter reading cycle would be altered for more than three cycles or if the reading cycle changes were a result of the customer moving to an advanced metering program. In this same subsection, CRM stated that notification of changes in meter reading frequency should be made to the customer’s REP rather than to the customer. TXU Energy stated that because it is not a defined term, “standard” should be added to the text of the subsection, and that language should be added to indicate that subsection (b) is not intended to apply to advanced meters.

Xcel commented regarding customer read programs in subsection (c) that the increase in frequency of electric utility reads from once every twelve months to once every six months was acceptable as long as the commission understood the need for some flexibility with regard to specific schedules.

CRM proposed adding a new subsection, designated "(c)" which would stipulate that reading intervals for advanced meters would be governed by Applicable Legal Authorities, anticipating that ERCOT would develop profiles appropriate for new service offerings by REPs.

Commission response

The commission agrees with the new subsection suggested by CRM. The commission also agrees with Xcel comments concerning the need for flexibility with regard to specific reading schedules. The commission agrees with TXU Energy that the term "display" should be added in subsection (a), and that the term "standard" be added to the text of subsection (b), and has made the changes accordingly. The commission concurs with Xcel comments relating to customer notification.

Comments for §25.130

§25.130(a)

Joint DSPs believed that the statement of the purposes should be reworded to conform to the legislation that encouraged the deployment of advanced meters and authorized the advanced metering surcharge.

Public Citizen suggested that this subsection refer to the ability of customers to lower their energy costs and have accurate information on energy at the time of use.

Reliant stated that the purposes of this section should be to authorize electric utilities to assess a nonbypassable surcharge to recover costs incurred for deploying advanced metering systems that are consistent with this section to increase the reliability of the regional electrical network, to encourage the deployment of metering technology necessary for retail electric providers to offer dynamic pricing and demand response products to enhance the efficiency of the deployment and operation of generation, transmission and distribution assets, and to facilitate the ability of retail electric providers (REPs) to offer additional products and more choices to electric customers.

REPower proposed to add a statement that this section would not preclude a REP from installing load-side meters and meter related equipment upon customer request.

Cities recommended that the statement of purposes be modified to make clear that the intent is to encourage advanced metering deployment in instances in which it can be demonstrated that such systems are cost effective and beneficial to consumers, and to authorize surcharge of costs of such advanced meters in instances wherein such benefits are demonstrated.

Commission response

The commission agrees with the Joint DSPs that the statement of the purposes should be reworded to conform to the legislation that encouraged the deployment of advanced meters and authorized the advanced metering surcharge, and has made changes to reflect this. The commission also believes that nothing in this rule will preclude a REP such as REPower from installing load-side meters and meter related equipment upon customer request, but that this rule need not specifically permit such meters to be installed. The commission agrees with the suggestion to refer to the customers' ability to lower their energy costs and have more accurate information on energy at the time of use. The

commission agrees with Reliant and has made changes accordingly. The commission does not entirely agree with the Cities. The information presented in this proceeding suggests that advanced meters can provide enhancements in meter reading and data management to utilities, and that requiring modest additional investment in meters will provide more and more timely consumption information to customers and REPs, which will allow REPs to deploy products and services that will permit customers to better control their consumption of electricity. The commission concludes that there has been adequate exploration of the costs of advanced meters in this proceeding to support the rule that it is adopting, and that there is no need for further exploration of the issue through pilot projects.

§25.130(b)

Xcel Energy requested that this section be revised to reflect that SPS is also exempt pursuant to PURA §39.402(a).

Commission response

The commission does not agree with Xcel regarding the exemption. This rule does not require the deployment of advanced metering. Further, the commission believes that deployment has the potential to benefit all customers in Texas, inside and outside of ERCOT, and it may be appropriate at some future time to investigate whether particular utilities should be required to deploy advanced meters.

§25.130(c)(2)

Joint DSPs requested that the proposed language defining “Advanced Metering System” be amended. The term “communication devices” should be changed to “communications system” which is broader and will apply to all communication equipment that will need to be installed for implementation of advanced metering.

CRM recommended that the definition of “dynamic pricing” in subsection (c)(3) be clarified to narrow the relevant time period. CRM also recommended adding a definition of non-standard advanced meter, which would be a meter that contains features and functions in addition to the AMS features in the deployment plan approved by the commission.

Commission response

The commission agrees with the Joint DSPs suggested change to this subsection and also with CRMs proposed definitions and makes changes to the rule in accordance with these recommendations.

§25.130(d)(1)

Joint DSPs stated that the first sentence should be amended to delete the reference to “unless otherwise ordered by the commission.” Joint DSPs believe that because deployment of advanced meters is voluntary under PURA, the commission lacks the authority to “order” deployment of advanced meters.

Cities suggested that this subsection be modified to provide that electric utilities' advanced metering deployment plans should be made available for review by both REPs and end use customers.

The Joint DSPs argued that no advanced metering system that has been deployed prior to the adoption of this rule should be required to obtain a waiver from the requirements of the rule. The Joint DSPs believed that to attempt to apply the rule to deployments that are already in progress would be unfair and contrary to the Legislature's desire to encourage, not impede, the deployment of AMS.

CRM recommended that the second sentence of subsection (d)(1) be clarified as to whether this is an automatic exception to the requirements of the rule for certain AMS deployments, without the need for commission review or whether it intended to provide another basis for requesting a waiver. CRM stated that it does not support an automatic wholesale exception for an electric utility's entire AMS because the deployment began before the effective date of the rule.

Commission response

The commission does not agree with the Joint DSPs that deployment of advanced meters is voluntary under PURA or that the commission lacks the authority to "order" deployment of advanced meters. There may be circumstances in which it would be appropriate for the commission to order a electric utility that has not deployed advanced meters to do so, and, for this reason, it is not making the changes recommended by Joint DSPs. The commission disagrees with the Joint DSPs that no advanced metering system that has been deployed

prior to the adoption of this rule should be required to obtain a waiver from the requirements of the rule. While the legislature sought to encourage advanced metering deployment, the commission believes in order for an electric utility to receive cost-recovery under the surcharge in this rule, the functionality set out in §25.130(g) must be met or a waiver must be granted.

The commission agrees with CRM that an automatic wholesale exemption for an AMS deployed prior to the effective date of the rule is not appropriate. The commission also concurs with the Cities that an electric utility's deployment plan must be available to REPs and customers for review.

§25.130(d)(2)

Joint DSPs stated in their Initial and Reply Comments that TDUs should have the ability to choose between requesting pre-approval of a deployment plan and providing notice to the commission of advanced metering deployment.

Joint DSPs also recommended that the rule include a 90-day deadline on commission action in a request for approval of a deployment plan that a TDU submits. Joint DSPs also requested the removal of the requirement for the TDU to notify customers of the deployment plans.

TXU Energy proposed various amendments to §25.130(d)(2) intended to clarify the deployment process. Specifically, TXU Energy stated that it does not believe the electric utility should necessarily be responsible for notifying the customer of advanced meter deployment and associated features, and the expected costs of deployment, and that communication with the end-use customer is the duty of the REPs. TXU Energy also requested that available information regarding areas of scheduled deployment be included in the deployment plans and progress reports and that as much geographic or other information as possible be included in the deployment plans and progress reports. TXU Energy also suggested that the language be clarified to require that the detailed deployment plan be made available in Texas since some utilities may have offices outside of the state.

CRM proposed modifications to this subsection to require commission approval of the electric utility's initial deployment plan prior to the deployment. CRM also recommended that the deployment plan be made available in the electric utility's Austin office.

Current Communications of Texas, L.P. urged the commission to reject comments that requested mandatory approval prior to deployment. Current also urged the commission to reject the request for a cost benefit analysis of pilot programs.

Commission response

The commission agrees with the Joint DSPs that TDUs should have the ability to choose between requesting pre-approval of a deployment plan and providing notice to the commission of advanced metering deployment. The commission agrees with Current's recommendation that mandatory approval prior to deployment is not required. The commission concurs with the Joint DSPs that the electric utility shall not have to notify customers of its deployment plans, but shall notify REPs. The commission disagrees with

the Joint DSPs request for a 90-day deadline for commission action for approval of a deployment plan. Rather, the commission will have an expedited proceeding. The commission also agrees with Current that a cost benefit analysis of pilot programs is not necessary.

The commission agrees with CRM that the deployment plan should be made available at an electric utility's Austin office.

The commission concurs with TXU Energy that the TDU is not responsible for notifying the customer of advanced meter deployment; this communication is the duty of the REPs.

§25.130(d)(3)

CRM suggested that this subsection be modified to prohibit a deployment of advanced meters that is unreasonably prejudicial or preferential.

Commission response

The commission agrees with the suggested language by CRM and has made changes in accordance with this recommendation.

§25.130(d)(4)

Joint DSPs propose that this subsection be amended to require reporting only the number of times that the web portal is accessed.

The Joint DSPs stated that monthly progress reports would be burdensome and duplicative of the monthly report required by §25.130(d)(5). Additionally, the Joint DSPs rejected TXU Energy's proposal to include more detailed information in the reports required under §25.130(d)(2), (4), and (5) because, the Joint DSPs stated, the information is unnecessary and burdensome.

CRM recommended that this subsection be amended to require the electric utility to identify the advanced meters installed by county, zip code, and ESI ID. CRM stated that a standardization of the manner by which the utilities identify the advanced meters deployed is critical from electric utility to electric utility and that REPs need the granular information on the level of ESI ID in order to know which of their customers have advanced meters in place, so that new retail services can be marketed to those specific customers.

CRM recommended that subsection §25.130(d)(4)(v) be deleted as there is no need for that type of surveillance of customer or REP access to customer data

Commission response

The commission agrees with CRM and Joint DSPs that there is no need for surveillance of customer data. The commission also agrees with CRM that standardization of the manner by which utilities identify the advanced meter deployment is critical for REPs. The commission notes the Joint DSPs comments pertaining to monthly progress reports and has streamlined this process accordingly.

§25.130(d)(5)

TXU Energy recommended adding TDU "feeder id" to the monthly progress reports to the extent such information is available.

CRM supported regular monthly notification of the county, zip codes, and ESI IDs associated with installed advanced meters. They also stated that depending on the speed of installation, weekly reports may be more appropriate and helpful to facilitate the retail roll-out of new products.

Commission response

The commission concludes that more frequent reports as suggested by CRM would be unduly burdensome. The commission agrees with CRM regarding monthly notification of deployment progress, as well as the recommended identifiers. Notification of deployment by ESI ID shall be mandatory, and other information such as county and zip codes is optional.

§25.130(d)6)

Joint DSPs requested that this subsection be amended to require only approval of amendments to deployment plans that have been pre-approved by the commission. Joint DSPs recommended that the rule include a 45-day time period in which the commission must act on the request submitted by a TDU to amend the deployment plan.

Reliant fully supported the requirement for an electric utility to obtain commission approval before making any changes that would affect access to advanced metering features. Reliant offered clarifying language to that effect.

CRM recommended adding language to this subsection to address the need to provide notice to affected REPs if an AMS system is taken down for regular maintenance. CRM also recommended adding subsection (d)(7) to prevent electric utilities from providing competitive energy services relating to AMS.

Commission response

The commission agrees with Joint DSPs that amendments should only be approved for deployment plans that have been pre-approved. The commission agrees with the 45-day time period for approval. The commission accepts the language suggested by CRM for the notice requirement to REPs if the AMS is taken down for maintenance and has addressed this in the rule. The commission agrees with CRM that electric utilities should be prohibited from providing competitive energy services relating to AMS, but believes that the rule already contains this prohibition.

§25.130(e)

Hunt argued that the subsection should be amended so that an electric shall deploy only an AMS that has been already been successfully installed and tested with at least 10,000 advanced meters in North America, Canada, South America, Asia, Australia, or Europe, except for pilot programs.

Commission response

The commission does not agree with increasing the minimum requirement to 10,000 meters. Metering technology continues to change rapidly and an electric utility will need reasonable flexibility in choosing its technology.

§25.130(f)

Joint DSPs requested this subsection be amended to establish the limit for pilot programs at 10,000 meters. Hunt and Elster added that pilot programs should not need commission approval. CRM proposed to add language to ensure that all REPs that have the opportunity to participate in an AMS pilot program be able to do so to the extent practicable, as well as ensure that such a pilot program is not preferential or discriminatory with respect to the REPs that actually participate.

Commission response

The commission agrees with the Joint DSPs that the subsection should be amended to increase the limit for pilots to 10,000 meters.

§25.130(g)

Joint DSPs asked that the requirement to provide three month notice of changes to the AMS features be deleted. The time limit unnecessarily reduces the flexibility for TDUs to implement new technologies.

CRM recommended that the phase “or support” be stricken from proposed subsection (g)(1). If this language is included, potentially every meter, whether currently deployed or deployed in the future, would qualify as an advanced meter because the shell of a meter can "support" a variety of enhancements that would provide all the functionalities required by subsection (g)(1). Moreover, in order to qualify for the special cost recovery mechanism permitted under the statute and implemented pursuant to subsection (k), it is critical that all of these required minimum features must actually be functional at the time of deployment.

Commission response

The commission agrees with CRM that the phrase "or support" should be deleted and has made changes accordingly.

§25.130(g)(1)(D)

CRM also recommended that the remote disconnection and reconnection capability specified in subsection (g)(1)(D) should be included in *all* advanced meters. From a customer service perspective, enabling a premise to be immediately connected when a new customer establishes service without requiring a technician to visit the premises will result in better customer satisfaction. Additionally, in an instance in which a customer's electric service has been disconnected for non-payment, enabling a customer to obtain a more rapid re-connection after bill payment would be in the customer's best interest.

CRM argued further that deploying this functionality ubiquitously is likely to be more cost effective for utilities. If the cost of including this functionality is $40, but the cost of a single truck roll to connect or disconnect electric service is $100, then avoiding a single truck roll for a connect or disconnect of service is worth 2.5 meters. In a single disconnect/connect request, two truck rolls are required and several days can be required for the establishment of service.

Hunt and Elster disagreed that this should be a minimum functionality across all customer classes.

Commission response

The commission agrees with CRM that remote disconnection function provides the market with savings compared to the manner in which it is performed today. It also allows for prepayment services to be added by the REPs without having to install a second, special meter. The commission disagrees with the request by Hunt and Elster that this minimum functionality be deleted.

The commission acknowledges that meters deployed prior to enactment of this rule may not include this functionality. The commission will allow this functionality to be added on those meters previously deployed, at the request of the REP. The commission concludes that uniformity across TDU service territories is important for both REPs and customers, as is reflected in the CRM comments on a number of issues.

§25.130(g)(1)(F)

CRM recommended that the word "timely" be replaced with the phrase "direct, instantaneous, and unfettered access to" and the inclusion of the phrase "directly from the meter" in proposed subsection (g)(1)(F), consistent with its response to Question No. 2. CRM also recommended adding language to ensure that the advanced meter can provide customer usage data in this same manner to the customer as well as the customer's REP.

CRM also recommended that the phrase "so that the REP can monitor compliance with load management and demand response programs and protocols" in proposed subsection (g)(1)(F) be deleted in order to avoid any suggestion that these are the only uses for which direct and immediate access to a customer's usage data may be beneficial. CRM stated that this function has been demonstrated to help the customer reduce energy consumption alone, without the need for any formal demand response or load management program.

Commission response

The commission agrees with the changes recommended by CRM except that the rule uses the term real-time, rather than instantaneous.

§25.130(g)(1)

The Joint DSPs requested that this subsection be amended, because it is too specific as to the requirements for advanced metering system capabilities. Joint DSPs stated that TDUs should be allowed more flexibility to choose the vendors and the technology to be used for its advanced metering deployment. They asserted that some of the proposed requirements cannot currently be met by either the TDU or the systems at ERCOT.

Specifically, Joint DSPs stated §25.130(g)(1)(C) should be amended to clarify that all possible dynamic pricing options will not be supported as minimum system features. Section

25.130(g)(1)(D) should be amended to clarify that remote disconnection and reconnection capability will be installed at the TDU's option and only for self-contained meter applications, predominately residential and small non-residential customers.

Commission response

The commission agrees with the Joint DSPs and is not requiring that all possible dynamic pricing options be supported as a minimum system feature. The commission believes that the minimum functionality is not too specific, as current electric utility deployment appears to be consistent with meet these requirements. The commission has addressed remote disconnection above.

§25.130(g)(1)(E)

Section 25.130(g)(1)(E) should be amended to not require information to be sent to the independent organization. Instead, the information should be made available to the independent organization just as it is being made available to customers and REPs. This change would allow for TDUs to have portals installed that would not require sending data to systems, but would allow the independent organization to pull the data from the web portal.

Commission response

The commission rejects the recommendation of the Joint DSPs that information be pulled from the web portal by the independent organization. This issue shall be studied further in the commission implementation proceeding following adoption of this rule, in conjunction with the stakeholder process at ERCOT.

§25.130(g)(1)(F)

The Joint DSPs argued that §25.130(g)(1)(F) should be deleted. First, the information provided in proposed §25.130(g)(1)(H) will provide the necessary information to satisfy this requirement. Second, the provisions of demand response and load control are competitive energy services that each REP will develop and present to the market.

Commission response

The commission disagrees with the Joint DSPs that §25.130(g)(1)(F) should be deleted. The commission does concur with the Joint DSPs that offering demand response and load control products and services are the function of the REP. However, the advanced metering system significantly enhances REP's capability to offer these products and services. The commission has modified the language in this section to reflect this.

§25.130(g)(1)(G)

Joint DSPs also added that §25.130(g)(1)(G) should be deleted. CRM agreed. The provisions of demand response and load control (i.e., pricing signals) are competitive energy services that each REP will develop and present to the market. The functionality to allow different services by the REPs should be provided but not as a standard capability. CRM added that it is not necessary for a meter to provide a retail customer real-time pricing information. Rather, this functionality is more appropriate for equipment beyond the meter, such as an in-home display that is programmed to read the meter data, apply a pricing algorithm, and display the resulting information to the retail customer.

Commission response

The commission agrees with the Joint DSPs and CRM that provisions of demand response and load control are competitive energy services, and has modified the language in the rule in accordance with this.

§25.130(g)(1)(H)

Joint DSPs recommended that §25.130(g)(1)(H) should be amended. This subsection should require hourly interval data as a minimum standard. If 15 minute interval data is technically and economically feasible, then the TDU should make such data available. Hourly interval data should be the minimum requirement, and if certain customers desire 15 minute interval data in an area where it cannot be made available by the main communications technology, then those customers can pay the additional cost of providing a supplemental technology. CRM interpreted proposed subsection (g)(1)(H) to require an additional, not alternate, means by which a REP and its customer may access meter data. In other words, compliance with proposed subsection (g)(1)(H) would not eliminate the need to comply with the requirements of proposed subsection (g)(1)(F).

CRM added that a key issue in providing such access through a web portal is the question of how often the customer’s data should be transmitted from the meter to the electric utility. CRM believes that transmission on a daily basis would be appropriate. CRM also recommended that the rule as adopted establish that the 15 minute interval data is a minimum capability for recording interval use, but that a meter that provides more granular usage information would be also be consistent with the commission's definition of an advanced meter.

Commission response

The commission concurs with CRM's recommendation that the rule establish that 15-minute IDR data is a minimum capability. However, the commission acknowledges that 15-minute IDR data is not necessary for settlement at this time, and therefore does not need to be currently provided through the TDU web portal. The minimum standard for data for purposes of transmitting to the web portal shall be hourly data, on a day-after basis, until such time that it becomes cost-effective to provide the data on a daily basis. Fifteen minute IDR data shall be made available on the electric utility web portal on a regular basis, to be determined during the implementation proceeding following adoption of this rule. The commission does not agree with the Joint DSPs proposed language regarding the availability and transmission of data.

§25.130(g)(1)(I)

Joint DSPs added that §25.130(g)(1)(I) and (J) should be amended to delete the reference to the specific ANSI standards. These standards refer to how data is stored within the advanced meter and communicated within an AMS. They do not refer to how that data is actually presented to the REPs. Further, in the event that ANSI standards are changed in the future or new standards are adopted, the TDUs should be allowed the flexibility to use the most appropriate standard and best electric utility practice.

Hunt stated that the standards as set forth in ANSI relating to meters should be followed and would support general language to that effect.

Commission response

The commission disagrees with the Joint DSPs and agrees with Hunt and Elster that the reference to ANSI standards should remain in the rule. Standardization of protocols is important for cost-effective deployment of additional services by REPs in multiple service areas.

§25.130(g)(1)(J)

Hunt and Elster argued that this subsection should be deleted.

Conversely CRM recommended amending proposed subsection (g)(1)(J) to recognize that this open architecture communications standard can and should be available to more than just the electric utility. CRM added that ANSI C12.22 is the designation of a new standard that has been developed to allow the transport of ANSI C12.19 table data over communications networks of differing types. This standard was developed to allow electric utility companies a compatible secure communication protocol between ANSI meters, so they are not restricted to a single electricity meter vendor. CRM went on to point out that the benefit of this standard is that it helps ensure that these meters are able to communicate with other devices that can utilize their data, such as air conditioning controls. As a result, the language of this subsection should be revised to not unintentionally impede or restrict the use and benefits of an open standards architecture.

Commission response

The commission disagrees with Hunt and Elster that the ANSI standards for C12.22 be deleted. The commission agrees with CRM that open standards architecture benefits both the electric utility and the REPs.

§25.130(g)(1)(K)

CRM proposed an amendment to proposed subsection (g)(1)(K) to require that any decision with respect to future upgrades and add-ons to installed advanced meters be subject to input from the market, either through the ERCOT stakeholder process and/or a commission proceeding. Such a decision should not be left totally to the electric utility’s discretion.

Commission response

The commission concurs with CRM that any future upgrades proposed by the electric utility can be addressed in an amendment proceeding, or through the ERCOT stakeholder process. In addition, the requirement to provide REPs notice of changes in functionality should help them understand what changes are proposed and provide opportunity to raise concerns, if they have them.

§25.130(g)(1)(L)

CRM recommended adding subsection (g)(1)(L) to the list of minimum functionality to make clear that the advanced meter is capable of communicating with multiple devices in the home, such as an energy usage display panel, air conditioner controls, prepaid mechanisms, and other devices.

Commission response

The commission concurs with CRM and has added language to the rule to address this.

§25.130(g)(2)

Joint DSPs requested that the rule not mandate the provision of pre-pay capability at the meter. CRM requested that the subsection be deleted, because it implies that the electric utility would be providing prepaid service.

Joint DSPs also stated the subsection should also be amended to clarify that the electric utility is not required to amend its tariff for discretionary services requested by REPs prior to deployment of the non-standard advanced meters or functions. Only after the electric utility and REP have agreed to deploy the non-standard advanced meters should the electric utility be required to amend its tariff.

CRM also expressed concern about the proposed requirement in subsection (g)(2) mandating that a REP pay a fee for a report evaluating the cost and schedule for providing a nonstandard advanced meter or advanced meter feature of interest to the REP. The intent of the rule, as proposed, appears that the requesting REP would be required to pay for the report, but that any REPs that subsequently take advantage of the nonstandard advanced meter or feature would do so with no financial obligation as to the cost of the initial report. As long as the cost of such a report is not significant, this should not be a major impediment to the potential deployment of new features. Therefore, the word "reasonable" is added to describe the level of the fee. It should be cautioned that if the fee is too high, there is potential disincentive for a REP to be the first to request the investigation of a nonstandard advanced meter or feature.

The Joint DSPs also proposed that a new subsection be added to ensure that if an electric utility chooses to deploy advanced meters that have more functionality than the minimum system features established, there is not a presumption that such additional features are unreasonable. Instead, the electric utility should be allowed the flexibility to prove in the approval proceeding or a rate proceeding that the additional functions are reasonable and cost recovery should be allowed.

Commission response

The commission agrees with the Joint DSPs and CRM that prepayment capability at the meter should not be mandated in this rule. The commission agrees with the DSPs that only after the electric utility and REP have agreed to deploy the non-standard advanced meters should the electric utility be required to amend its tariff. The commission adopts the suggestion by CRM that the word reasonable be added to describe the fee for a report by the TDU for nonstandard or advanced meter features. The commission concurs with the Joint DSPs request that additional functionality deployed by an electric utility is not automatically deemed to be unreasonable, and that the electric utility will have the flexibility to prove in the surcharge proceeding that the additional functions are reasonable and necessary.

§25.130(g)(3)

Joint DSPs requested that the subsection be amended to delete the language addressing granting a waiver based on a system that meets or exceeds the minimum standards. Because the commission is establishing minimum standards, a waiver is only necessary in the event that a proposed system's standards do not satisfy the minimum standards. If an advanced metering system meets or exceeds the established minimum standards, a waiver is not necessary because the system will necessarily comply with the minimum standards.

CRM recommended that proposed subsection (g)(3) be amended to address a waiver for the portion of AMS that was deployed prior to the effective date of the rule and cannot meet the requirements of the rule, in particular the minimum functionality requirements.

Commission response

The commission agrees with the Joint DSPs that a waiver is only necessary in the event that a proposed system's standards do not satisfy the minimum standards. The commission does not concur with CRM that an additional waiver should be added for AMS deployed prior to the effective date of the rule that fails to meet the minimum requirements. This is one of the circumstances in which a waiver may be appropriate.

However, the commission recognizes that some meters deployed prior to the adoption of this rule do not contain the remote disconnect and reconnect function. The commission will allow for cost recovery through the surcharge mechanism for those meters, provided that additional deployment contains the minimum functionality required.

§25.130(g)(5)

CRM recommended modifying proposed subsection (g)(5) to include the term “Applicable Legal Authorities” to ensure that the electric utility does not have 100 percent discretion as to the addition or enhancement of advanced metering features, and to ensure there is an avenue for stakeholder and market input into any such decisions.

Commission response

The commission agrees with CRM that the electric utility will need to receive stakeholder input prior to make major additions or enhancements to its AMS.

§25.130(h)

Joint DSPs requested that this section be deleted for various reasons. First, the costs to accomplish settlement based on 15-minute interval data will outweigh any benefits that could be achieved. The amount of data storage for the TDUs as well as for ERCOT would be cost prohibitive. As the commission is aware, ERCOT is currently working towards implementation of a Nodal market. Joint DSPs stated that a massive change to the settlement system during this same time period would endanger implementation of the Nodal market.

Joint DSPs urged that the subsection be deleted, but if retained, the language should be amended to make it clear that settlement on 15-minute interval data will only occur based on data from advanced meters that have been deployed and when the advanced metering system is capable of providing such 15-minute interval data. All other settlement data will continue to be obtained from the traditional meter data and profiles.

TXU Energy recommended that this subsection be amended to reflect that no later than 18 months from the effective date of this rule, ERCOT shall file to the Board of Directors and to the commission a summary detailing the results of a study and recommendations regarding 15-minute mass settlement. ERCOT noted in reply comments that it is willing to undertake the study suggested by TXU Energy. ERCOT highlighted that it was not clear what the scope of the study would be, and what the scope and level of detail should be included in the study. Depending on how the study scope is defined and the level of detail expected, the study could either be completed quickly or entail a significant resource commitment. If the scope is broad and great detail is expected, ERCOT added that performance of the study could affect ERCOT resource availability for other key ERCOT efforts, most notably, Texas Nodal implementation.

CRM added that while this interval may be appropriate for some customer classes or sub-classes, it may not one that the market wants ERCOT to employ in the future for all customers. Therefore, the stakeholder process at ERCOT should be used to determine whether other settlement options, in addition to a 15-minute settlement interval, should be required.

Lastly, Joint DSPs pointed out that ERCOT does not perform "retail settlement." Instead, ERCOT performs settlements of the wholesale electric market. If the subsection is not deleted, the commission should amend the rule to reference "wholesale settlement."

Commission response

The commission disagrees with the assertion by Joint DSPs that the costs to accomplish settlement based on 15-minute interval data will outweigh any benefits that could be achieved. The commission is proposing an implementation proceeding following the adoption of this rule to study the objective for 15-minute settlement at ERCOT following the transition to Nodal. The commission agrees with the Joint DSPs that until such time, settlement will continue as it is performed today.

The commission agrees that the correction needs to be made to change retail to wholesale. The commission further agrees with the Joint DSPs that 15-minute interval data will only occur based on data from advanced meters that have been deployed and when the advanced metering system is capable of providing such 15-minute interval data. The commission agrees with CRM that the stakeholder process is the best forum to examine whether other settlement options should be available.

The commission agrees with TXU Energy and ERCOT that a study in conjunction with the implementation proceeding will provide guidance for future settlement at ERCOT as advanced meters are deployed. The commission recommends that the scope of any study or cost benefit analysis provided by ERCOT be determined following the adoption of this rule.

§25.130(i)

Joint DSPs stated that standard features are established in the proposed rule; therefore, these standard features do not need to be set forth in the electric utilities' tariff. The rule should be amended to require that the non-standard discretionary charges be set forth in the tariff.

Commission response

The commission agrees with the Joint DSPs that the rule should be amended to require that the non-standard discretionary charges be set forth in the tariff.

Joint DSPs requested that this section be clarified further. Joint DSPs argued that the TDUs' tariffs addressing advanced metering charges should be uniform, so that customers and REPs can easily access the information concerning functionality of advanced meters in each service territory. Joint DSPs proposed that additional specificity be provided as to the information to be provided in the tariffs. The minimum advanced metering system features are established in the proposed rule; therefore, these features do not need to be described in the tariff. If a TDU deploys advanced meters that contain additional standard functions, then such functions should be set forth in the surcharge tariff. Additional functions offered for a fee should be included in the Discretionary service tariff.

Commission response

The commission agrees with the Joint DSPs regarding clarification for the TDU's tariffs, and has made changes in accordance with this recommendation.

§25.130(j)(2)

CRM added that an introductory phrase should be added to subsection (j)(2) to make clear that the access provided through the web portal is in addition to the direct and instantaneous access to the meter that is required pursuant to the minimum features in subsection (g)(1).

Commission response

The commission agrees with CRM except that the access is in addition to direct and real-time access to the meter data, not the meter itself.

§25.130(j)(3)

Joint DSPs requested that this subsection be amended. The requirement to provide access to data from an advanced metering system should not apply to pilot programs, but should only apply to advanced metering systems that have actually been deployed for which the TDU is recovering the costs through the surcharge.

Commission response

The commission disagrees with the Joint DSPs that access to data should not apply to pilot programs. To the extent practicable, access to the meter data should be available to REPs participating in the pilot.

§25.130(j)(4)

CRM recommended that the independent security audit requirement in subsection (j)(4) should be deleted. Existing customer protection rules require the protection of customer data. This rule provides no new requirements or data that would be available and, consequently, no new security systems should be required. While security of customer data is essential, the costs for developing and maintaining these security systems should exist in rates today.

Commission response

The commission disagrees with CRM that an independent security audit is not necessary.

§25.130(j)(5)

CRM requested that the word "information" in proposed subsection (j)(5) be changed to "meter data" for consistency of terminology in the rule. Also, language should be added to ensure that ERCOT is not charged by the electric utility for access to this meter data, as the provision of such information should be considered an electric utility cost of doing business. Allowing the electric utility to charge ERCOT for such access will only increase the administration fee.

Commission response

The commission agrees with CRM and has made changes to reflect the phrase "meter data."

§25.130(j)(6)

CRM stated that subsection (j)(6) should be clarified such that an exception to third-party access to a customer's data if the customer has agreed in its contract with the REP not to disclose such information to an entity that is not the customer's REP. As currently worded, this proposed subsection could be interpreted to prevail over any contractual agreement entered into by the customer not to authorize third-party access.

Commission response

The commission agrees with CRM that if a customer has agreed in its contract with the REP not to disclose such information to an entity other than the customer's REP, the provision of the rule permitting the customer to disclose information does not supersede the contract. The commission concludes that it is not necessary to amend the rule to address this point, however.

§25.130(j)(7)

The Joint DSPs requested that this subsection be deleted. The subsection provides that the owner or management entity of a multifamily property shall have access to a customer's meter data for any apartment unit for the purpose of obtaining data for energy management purposes. However, PURA §39.107(b) provides that: "(a)ll meter data, including all data generated, provided, or otherwise made available, by advanced meters and meter information networks, shall belong to a customer, including data used to calculate charges for service, historical load data, and any other proprietary customer information." PURA §39.101(a)(2) provides that the commission shall ensure retail customer protections that provide a customer with "privacy of customer consumption and credit information." Joint DSPs further stated that this proposed rule provision, providing a blanket release of proprietary customer information to another entity without the customer's prior consent, is not permissible under the cited portions of PURA.

Commission response

The commission concurs with the Joint DSPs and has deleted this subsection.

§25.130(j)(8)

Joint DSPs stated that subsection (j)(8) which requires that REPs be given simultaneous, direct access to the meter for customers with a demand of 100 kW or more should be deleted. Allowing direct access raises unnecessary data integrity concerns and could greatly increase the cost of advanced metering deployment. It is sufficient for the REP, the customer, and any authorized third party to have access to the advanced meter data via the web portal, and not direct access to the advanced meter itself.

Joint DSPs added if the commission decides that REPs should be granted direct access to advanced meters, then proposed §25.130(g)(2) would allow REPs to request advanced meters with this additional functionality upon payment of the requisite additional cost. By making this functionality discretionary rather than mandatory, the cost of advanced metering deployment will be reduced, and the additional functionality will only be provided to those customers who determine that the benefits of the functionality will be worth the additional cost.

Commission response

The commission concurs with the Joint DSPs that its sufficient for the REP, the customer, and any authorized third party to have access to the advanced meter data via the web portal, as well as through the customer's home area network (HAN), and not direct access

to the advanced meter itself. The commission also adds language that clarifies that the meter will transmit usage data to the home area network (HAN).

§25.130(j)(9)

CRM recommended that subsection (j)(9) be deleted to eliminate the differential between which customers and REPs do and do not have the right to simultaneous, direct, password-protected, read-only access to the customer's meter data.

Commission response

The commission agrees with CRM's recommendation and has made changes accordingly.

§25.130(k)(1)

Joint DSPs requested that the second sentence in the subsection be deleted. Proposed §25.130(d)(2) does not require that a detailed deployment plan be filed with the commission; therefore, cost recovery should not be dependent on such a filing. The subsection should also be amended to clarify that a waiver can be obtained for advanced metering systems that were deployed prior to the rule and do not meet the minimum required standards.

CRM recommended that subsection (k)(1) be clarified regarding whether the surcharge can apply to certain customers who have advanced meters that were deployed prior to the effective date of the rule. The rule also would allow certain meters deployed prior to the effective date of the rule to be subject to cost recovery through the surcharge if a waiver is obtained. CRM recommended that, for those customers with advanced meters deployed prior to the effective date of the rule, those customers should be subject to the surcharge in the event the electric utility seeks to recover the costs of those meters through the surcharge in conjunction with a waiver from the commission.

Cities concluded that this section should be modified to qualify that cost recovery is contingent upon demonstration of consumer benefits based upon pilot program results. Furthermore, subsection (k)(1) should be amended to reflect that recoverable AMS investment amounts should be offset by the net value of meters that are replace by the AMS. In addition, Cities recommended that the allowed carrying costs on AMS investments be based on the method specified in the commission's rules governing the determination of interest charges on electric utility competitive transition charges.

REPower does not support approval of a cost-recovery mechanism for meters that meet the functionality in §23.130(g). REPower added that a rate case would provide the best mechanism to ensure that all electric utility costs and benefits are accurately assessed. REPower believes that the additional expense of these advanced meters should be born by customers or REPs requesting such features and not by all customers.

Commission response

The commission disagrees with the Joint DSPs that this subsection should also be amended to clarify that a waiver can be obtained for advanced metering systems that were deployed prior to the rule and do not meet the minimum required standards. The commission agrees with CRM that the surcharge would apply to customers who received an advanced

meter prior to the effective date of this rule. The commission disagrees with the cities that cost recovery should be contingent upon pilot program results. The commission agrees with REPower that a rate case is the best forum to ensure that all electric utility costs and benefits are accurately assessed. However, HB 2129 allows an electric utility the option to seek cost recovery outside of a rate case proceeding, and the rule is consistent with this approach.

§25.130(k)(2)

Joint DSPs requested that the second sentence in the subsection should be amended so that only actual meter-related savings are reduced from implementation costs. Savings that are predicted for future years should not reduce the costs to be recovered until such time as the savings are known with a measure of certainty. As currently proposed, the rule would require offsetting current costs by savings that are anticipated to be realized in future years, but that are not realized at the current time.

CRM recommended that the second sentence in proposed subsection (k)(2) be clarified by inserting the word "resulting" after the clause "cost savings" because the cost savings will be realized *after* the meters have been deployed, as opposed to from the deployment activity itself.

Commission response

The rule that the commission is adopting will leave the issue raised by the Joint DSPs to be resolved in connection with the surcharge proceedings. How to reflect savings may depend

on how the electric utility plans to recover the costs of deploying AMS and the level of proof of deployment costs and savings. The recommendation of CRM is being adopted.

§25.130(k)(4) and Proposed New §25.130(k)(5)

Joint DSPs asked that the proposed language be modified to reflect the statutory language. Joint DSPs stated that the provision could be read to limit recovery to only one-third the cost of final deployment, even if such deployment did not result in more than one-third of the electric utility's total meters being replaced in any given year. The Joint DSPs also proposed adding a new §25.130(k)(5) that would outline the manner in which the advanced metering surcharge would be updated. The Joint DSPs indicated that their proposal is similar to the updates to the interim transmission costs of service.

Commission response

The commission agrees with the Joint DSPs' premise that the proposed rule should be revised to permit a more expedited cost recovery process. Joint DSPs' proposed revisions would permit the commission to order the surcharge of costs not yet paid and costs not yet found to be reasonable and necessary, but require that they be reconciled in a subsequent proceeding. Including in the surcharge only costs that have been paid and found to be reasonable and necessary would result in a substantial delay between the time the costs are paid by the electric utility and the time they are recovered through the surcharge. The commission agrees that the rule should provide it broader discretion in determining the costs that should be included in the surcharge, and has revised the rule accordingly. The DSPs proposed surcharge updates as frequently as quarterly. The commission has revised

the rule to permit updates as frequently as annually, which is the appropriate balance between permitting timely adjustments to the surcharge and avoiding excessive administrative burdens and unpredictability to REPs that must pay the surcharge. The revised rule also does not address details concerning the types of costs included in the surcharge, because this issue warrants further consideration. The commission is addressing the type of cost information to include in a surcharge request in Project Number 33874, *Form for Transmission and Distribution Utility Advanced Metering Infrastructure Surcharge.*

Proposed new §25.130(l)

TXU Energy proposed a new subsection (l) be added to §25.130 to clarify that commission approval of a new time of use schedule ("TOUS") is not necessary prior to its implementation. TXU Energy elaborated that the benefits of the TOUS flow not only to the customer but also to the entire ERCOT system, by providing an economic incentive to customers to reduce load during peak hours of the day. With time of use information as contemplated under the proposed advanced metering rule, consumers will be presented with a price per kilowatt-hour difference between on-peak and off-peak that is sufficiently large to provide an incentive to consumers to conserve and/or shift energy use from peak demand hours to off-peak demand hours.

Commission response

The commission agrees with TXU Energy regarding this new section for TOUS and has added language to reflect this in the rule.

Comments for §25.311, Competitive Metering Services

Reliant agreed with all proposed changes for this section.

Elster and Hunt questioned the need for a list of meters qualified for Competitive Metering in subsection (e)(1), asking how meters would be placed on the list, how this relates to AMS data collection and why a list was needed if a meter met the standards of the rule.

Joint DSPs commented that subsection (f)(2) should be amended to refer to meters that are not owned by the TDU.

Joint DSPs stated that subsection (g) should not be changed to expand the parties who might request meter tests by the TDU, owing to the fact that the TDU's sole market relationship is with the customer's REP.

Elster and Hunt commented that in subsection (i)(1) there needs to be more detail on the process by which a REP can access meter data, as this has historically been the exclusive domain of the TDU.

Commission response

The commission disagrees with the Joint DSPs that subsection (f)(2) should be amended to reference meters not owned by the TDU. The commission agrees with the Joint DSPs that subsection (g) should not be changed. The commission agrees with Hunt that there needs

to be more detail regarding the process by which a REP will access meter data, and has addressed this in §25.130(j).

§25.311(g)

Joint DSPs requested this subsection should not be amended to require that the costs be the responsibility of the requesting party. The current rule places the cost responsibility on the customer's REP and such responsibility should not be changed. TDUs do not have market relationships with the customer or the competitive meter owner. The TDUs' sole market relationship is with the REP; therefore, the TDUs should be able to obtain payment for testing meters from the REP, which in turn should bill the appropriate party for the services.

Commission response

The commission agrees with the Joint DSPs that the TDUs should be able to obtain payment for testing meters from the REP.

Comments for §25.346, Separation of Electric Utility Metering and Billing Service Costs and Activities

§25.346(g)(2)(C)

The Joint DSPs commented that this subsection should not be amended as proposed in the publication. Instead, the rule should remain as currently adopted. Any metering equipment that is added by a consumer should be done on the customer's side of the meter. As currently drafted, a customer can place equipment on the TDU's side of the meter. This introduces security concerns as to the data collected and sent from the meter. Any customer owned equipment should be located within the customer's premises.

Commission response

The commission concurs with the Joint DSPs that any metering equipment added by a consumer should be conducted on the customer's side of the meter.

The proposed new section and amendments are adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.001 (Vernon 1998, Supplement 2006) (PURA), which provides the commission with the general power to regulate and supervise the business of each public utility within its jurisdiction and to do anything specifically designated or implied by PURA that is necessary and convenient to the exercise of that power and jurisdiction; PURA §14.002, which provides the commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction; and PURA §39.107, which directs the commission to approve utility surcharges for the deployment of advanced meters, authorizes the commission to adopt rules relating to the transfer of customer data, and authorizes the commission to approve non-discriminatory rates for metering service.

Cross Reference to Statutes: Public Utility Regulatory Act §§14.001, 14.002, and 39.107.

§25.121. Meter Requirements.

(a) **Use of meter.** All electricity consumed or demanded by an electric customer shall be charged for by meter measurements, except where otherwise provided for by the applicable rate schedule or contract.

(b) **Installation.** Unless otherwise authorized by the commission, each electric utility shall provide and install and shall continue to own and maintain all meters necessary for the measurement of electric energy to its customers.

(c) **Standard type.** All meters shall be of a standard type that meets industry standards. Advanced meters shall meet the standards in this section and §25.130 of this title (relating to Advanced Metering). Special meters used for investigation or experimental purposes are not required to conform to these standards.

(d) **Location of meters.**

(1) Meters and service switches in conjunction with the meter shall be installed in accordance with the latest revision of American National Standards Institute (ANSI), Incorporated, Standard C12 (American National Code for Electricity Metering), or other standards as may be prescribed by the commission, and will be readily accessible for reading, testing, and inspection, where such activities will cause minimum interference and inconvenience to the customer.

(2) Customer shall provide, without cost to the electric utility, at a suitable and easily accessible location:

(A) sufficient and proper space for installation of meters and other apparatus of electric utility;

(B) meter board;

(C) meter loop;

(D) safety service switches when required; and

(E) an adequate anchor for service drops.

(3) All meters installed after December 21, 1999, shall be located as set forth in this section, provided that, where installations are made to replace meters removed from service, this section shall not operate to require any change in meter locations which were established prior to this date, unless the electric utility finds that the old location is no longer suitable or proper, or the customer desires that the location be changed.

(4) Where the meter location on the customer's premises is changed at the request of the customer, or due to alterations on the customer's premises, the customer shall provide and have installed at his expense, all wiring and equipment necessary for relocating the meter.

(5) If provisions of this section are inconsistent with §25.214 of this title (relating to Tariff for Retail Delivery Service), the provisions of the Tariff shall control this section.

(e) **Accuracy requirements.**

(1) No meter that violates the test calibration limits as set by the American National Standards Institute, Incorporated, shall be placed in service or left in service. Whenever on installation, periodic, or other tests, a meter is found to violate these limits, it shall be adjusted or replaced.

(2) Meters shall be adjusted as closely as practicable to the condition of zero error.

(f) Notwithstanding any other commission rule, as a condition of receiving electric service or electric delivery service, the customer is deemed to have consented to the provision of meter data to the customer's electric utility, its retail electric provider, and the independent organization or regional transmission organization.

(g) If provisions of this subchapter are inconsistent with §25.214 of this title, the provisions of the Tariff shall control this subchapter.

§25.123. Meter Readings.

(a) **Meter unit indication.** Each meter display shall indicate clearly the kilowatt-hours or other units of service for which a charge is made to the utilities' customer.

(b) **Reading of standard meters.** As a matter of general practice, service meters shall be read at monthly intervals, and as nearly as possible on the corresponding day of each meter reading period, but may be read at other than monthly intervals if the circumstances warrant. The electric utility shall notify the customer of any changes to the customer's meter reading cycle. This subsection does not apply to advanced metering systems.

(c) **Reading of advanced meters.** Advanced meters shall be read by the electric utility at intervals required by the Applicable Legal Authorities defined in §25.214(d)(1) of this title (relating to Tariff for Retail Delivery Service).

(d) **Customer-read program.** For meters other than advanced meters, an electric utility in an area where retail competition has not been introduced, may use a customer-read program in which customers read their own meters and report their usage monthly. Such readings shall be considered an actual meter reading by the electric utility for billing purposes. However, an electric utility shall read the meters of customers on a customer-read program at least every six months to verify the accuracy of the electric utility's records.

§25.130. Advanced Metering.

(a) **Purpose.** The purposes of this section are to authorize electric utilities to assess a nonbypassable surcharge to use to recover costs incurred for deploying advanced metering systems that are consistent with this section; increase the reliability of the regional electrical network; encourage dynamic pricing and demand response; improve the deployment and operation of generation, transmission and distribution assets, and provide more choices for electric customers.

(b) **Applicability**. 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).

(c) **Definitions**.

(1) Advanced meter -- Any new or appropriately retrofitted meter that functions as part of an advanced metering system and that has the features specified in this section.

(2) Advanced Metering System (AMS) -- A system, including advanced meters and the associated hardware, software, and communications systems, including meter information networks, that collects time-differentiated energy usage and performs the functions and has the features specified in this section.

(3) Deployment Plan -- An electric utility's plan for deploying advanced meters in accordance with this section and either filed with the commission as part of the Notice of Deployment or approved by the commission following a Request for Approval of Deployment.

(4) Dynamic Pricing -- Retail pricing for electricity consumed that varies during different times of the day.

(5) Non-standard advanced meter -- A meter that contains features and functions in addition to the AMS features in the deployment plan approved by the commission.

(d) **Deployment and use of advanced meters.**

(1) Deployment and use of AMS by an electric utility is voluntary unless otherwise ordered by the commission. However, deployment and use of an AMS for which an electric utility seeks a surcharge for cost recovery shall be consistent with this section, except to the extent that the electric utility has obtained a waiver from the commission.

(2) Six months prior to initiating deployment of an AMS or as soon as practicable after the effective date of this section, whichever is later, an electric utility that intends to deploy an AMS shall file a Statement of AMS Functionality, and either a Notice of Deployment or a Request for Approval of Deployment. An electric utility may request a surcharge pursuant to subsection (k) of this section in combination with a Notice of Deployment or a Request for Approval of Deployment, or separately. A proceeding that includes a request to establish or amend a surcharge shall be a ratemaking proceeding and a proceeding involving only a Request for Approval of Deployment shall not be a ratemaking proceeding.

(3) The Statement of AMS Functionality shall:

(A) state whether the AMS meets the requirements specified in subsection (g) of this section and what additional features, if any, it will perform;

(B) describe any variances between technologies and meter functions within its service territory; and

(C) state whether the electric utility intends to seek a waiver of any provision of this section in its request for surcharge.

(4) A Deployment Plan shall contain the following information:

(A) Type of meter technology;

(B) Type and description of communications equipment in the AMS;

(C) Systems that will be developed during the deployment period;

(D) A timeline for the web portal development;

(E) A deployment schedule by specific area (geographic information);

(F) When postings of monthly status reports on the electric utility's website will commence; and

(G) A schedule for deployment of web portal functionalities.

(5) An electric utility shall file with the Deployment Plan, testimony and other supporting information, including estimated costs for all AMS components, estimated net operating cost savings expected in connection with implementing the Deployment Plan, and the contracts for equipment and services associated with the Deployment Plan, that prove the reasonableness of the plan.

(6) Competitively sensitive information contained in the Deployment Plan and monthly progress reports may be filed confidentially. An electric utility's Deployment Plan shall be maintained and made available for review on the electric utility's website for REP access. Competitively sensitive information contained in the Deployment Plan shall be maintained and made available at the electric utility's offices in

Austin. Any REP that wishes to review competitively sensitive information contained in the electric utility's deployment plan available at its Austin office, may do so during normal business hours upon reasonable advanced notice to the electric utility and after executing a non-disclosure agreement with the electric utility.

(7) If the request for approval of a Deployment Plan contains the information described in paragraph (4) of this subsection and the AMS features described in subsection (g)(1) of this section, then the commission shall approve or disapprove the Deployment Plan within 150 days, but this deadline may be extended by the commission for good cause.

(8) An electric utility's treatment of AMS, including technology, functionalities, services, deployment, operations, maintenance, and cost recovery shall not be unreasonably discriminatory, prejudicial, preferential, or anticompetitive.

(9) Each electric utility shall provide progress reports on a monthly basis and status reports every six months following the filing of its Deployment Plan with the commission until deployment is complete. Upon filing of such reports, the electric utility shall notify all certified REPs of the filing through standard market notice procedures. A monthly progress report shall be filed within 15 days of the end of the month to which it applies, and shall include the following information:

(A) the number of advanced meters installed, listed by ESI ID. Additional information if available may also be listed, such as county, city, zip code, feeder numbers, and any other easily discernable geographic identification available to the electric utility;

(B) significant delays or deviation from the Deployment Plan and the reasons for the delay or deviation;

(C) a description of significant problems the electric utility has experienced with an AMS, with an explanation of how the problems are being addressed;

(D) the number of advanced meters that have been replaced as a result of problems with the AMS; and

(E) the status of deployment of features identified in the Deployment Plan and any changes in deployment of these features.

(10) If an electric utility has received approval of its Deployment Plan from the commission, the electric utility shall obtain commission approval before making any changes to its AMS that would affect a REP’s ability to utilize any of the AMS features identified in the electric utility’s Deployment Plan by filing a request for amendment to its Deployment Plan. In addition, an electric utility may request commission approval for other changes in its approved Deployment Plan. The commission shall act upon the request for an amendment to the Deployment Plan within 45 days of submission of the request, unless good cause exists for additional time. If an electric utility filed a Notice of Deployment, the electric utility shall file an amendment to its Notice of Deployment at least 45 days before making any changes to its AMS that would affect a REP’s ability to utilize any of the AMS features identified in the electric utility’s Notice of Deployment. This paragraph does not in any way preclude the electric utility from conducting its normal operations and maintenance with respect to the electric utility’s transmission and distribution system and metering systems.

(11) During and following deployment, any outage related to normal operations and maintenance that affects a REP's ability to obtain information with the system shall be communicated to the REP through the outage/restoration notice process according to Applicable Legal Authorities, as defined in §25.214(d)(1) of this title (relating to Tariff for Retail Delivery Service).

(12) The electric utility shall not provide any advanced metering equipment or service that is deemed a competitive energy service under §25.343 of this title (relating to Competitive Energy Services). Any functionality of the AMS that is a required function under this section or that is included in an approved Deployment Plan does not constitute a competitive energy service under §25.343 of this title.

(13) An electric utility's deployment and provision of AMS services and features, including but not limited to the features required in subsection (g) of this section, are subject to the limitation of liability provisions found in the electric utility's tariff.

(e) **Technology requirements.** Except for pilot programs, an electric utility shall not deploy AMS technology that has not been successfully installed previously with at least 500 advanced meters in North America, Australia, Japan, or Western Europe.

(f) **Pilot programs.** An electric utility may deploy AMS with up to 10,000 meters that do not meet the requirements of subsection (g) of this section in a pilot program, to gather additional information on metering technologies, pricing, and management techniques, for studies, evaluations, and other reasons. A pilot program may be used to satisfy the requirement in subsection (e) of this section. An electric utility is not required to obtain commission approval for a pilot program. Notice of the pilot program and opportunity to participate shall be sent by the electric utility to all REPs.

(g) **AMS features.**

(1) An AMS shall provide or support the following minimum system features in order to obtain cost recovery through a surcharge pursuant to subsection (k) of this section:

(A) automated or remote meter reading;

(B) two-way communications;

(C) remote disconnection and reconnection capability for meters rated at or below 200 amps, provided that an electric utility shall be considered in compliance with this provision if it makes this function available in all advanced meters installed after the effective date of this rule, and the following meters shall also be considered in compliance with this provision: those advanced meters that were ordered prior to the effective date of this rule, not to exceed 65,000 meters over the number of meters received or ordered as of May 10, 2007, and are provisioned with all the features enumerated in this paragraph except remote disconnect and reconnect capability, if those advanced meters are installed by December 31, 2007, and the number of advanced meters installed with all the features enumerated in this paragraph except remote disconnect and reconnect capability does not exceed 18% of the total number of advanced meters installed by the electric utility pursuant to a Deployment Plan.

(D) the capability to time-stamp meter data sent to the independent organization or regional transmission organization for purposes of wholesale settlement, consistent with time tolerance standards adopted by the independent organization or regional transmission organization;

(E) the capability to provide direct, real-time access to customer usage data to the customer and the customer's REP, provided that:

(i) hourly data shall be transmitted to the electric utility's web portal on a day-after basis.

(ii) the commission staff using a stakeholder process, as soon as practicable shall determine, subject to commission approval, when and how 15-minute IDR data shall be made available on the electric utility's web portal.

(F) means by which the REP can provide price signals to the customer;

(G) the capability to provide 15-minute or shorter interval data to REPs, customers, and the independent organization or regional transmission organization, on a daily basis, consistent with data availability, transfer and security standards adopted by the independent organization or regional transmission organization;

(H) 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;

(I) open standards and protocols that comply with nationally recognized non-proprietary standards such as ANSI C12.22, including future revisions thereto;

(J) capability to communicate with devices inside the premises, including, but not limited to, 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

(K) the ability to upgrade these minimum capabilities as technology advances and, in the electric utility's determination, become economically feasible.

(2) An electric utility shall offer, as discretionary services in its tariff, installation of non-standard meters and advanced meter features.

(A) A REP may require the electric utility to provide non-standard advanced meters, additional metering technology, or advanced meter features not specifically offered in the electric utility's tariff, that are technically feasible, generally available in the market, and compatible with the electric utility's AMS;

(B) The REP shall pay the reasonable differential cost for the non-standard advanced meters or features.

(C) Upon request by a REP, an electric utility shall expeditiously provide a report to the REP that includes an evaluation of the cost and a schedule for providing the nonstandard advanced meters or advanced meter features of interest to the REP. The REP shall pay a reasonable discretionary services fee for this report. This discretionary services fee shall be included in the electric utility's tariff.

(D) If an electric utility agrees to deploy non-standard advanced meters or advanced meter features not addressed in its tariff at the request of the REP, the electric utility shall expeditiously apply to amend its tariff to specifically include the non-standard advanced meters or meter features that it agreed to deploy.

(3) An electric utility may petition the commission for a waiver of the requirements of paragraph (1) of this subsection for portions of its service area where it would be uneconomic or technically infeasible to implement particular system features. A waiver may also be granted for an AMS that exceeds or is an adequate substitute for the requirements in paragraph (1) of this subsection. The electric utility shall provide all relevant studies and cost-benefit analysis and other evidence supporting its waiver request and shall bear the burden of proof in its waiver request. An electric utility that has received a waiver shall explain in the report required by subsection (d)(7) of this section, technology changes and changes in the cost of deployment or savings to the electric utility that would make it economic or technically feasible to offer the system features in the affected portions of its service area. Any waiver granted by the commission shall extend only to those costs and expenses for which the waiver is granted in any proceeding in which the electric utility seeks to recover its costs through the surcharge mechanism addressed in subsection (k) of this section.

(4) In areas where there is not a commission-approved independent regional transmission organization, standards referred to in this section for time tolerance and data transfer and security may be approved by a regional transmission organization approved by the Federal Energy Regulatory Commission or, if there is no approved regional transmission organization, by the commission.

(5) Once an electric utility has deployed its advanced meters, it may add or enhance features provided by AMS, as technology evolves and in accordance with Applicable Legal Authorities. The electric utility shall notify the commission and REPs of any such additions or enhancements at least three months in advance of deployment, with a description of the features, the deployment and notification plan, and the cost of such additions or enhancements, and shall follow the monthly progress report process described in subsection (d)(8) of this section until the enhancement process is complete.

(6) Beginning January 1, 2008, or as soon as such meters are commercially available from the electric utility's current vendor, whichever is earlier, an electric utility shall replace, at no cost to the customer, an advanced meter with all the features enumerated in paragraph (1) of this subsection except remote disconnect and reconnect capability, if: the meter has reached the end of its useful life; the meter has been removed for repair; the premises at which the meter is located has experienced an unusually high number of disconnections and reconnections; or the REP has informed the electric utility that its customer has agreed to utilize a prepaid service and the REP has requested a meter with remote disconnection and reconnection capability. If by January 1, 2009, requests by REPs for replacement

of advanced meters with all the features enumerated in paragraph (1) of this subsection except remote disconnect and reconnect capability exceed 20% of those meters, then the electric utility shall replace all of those meters as soon as possible with meters that meet the requirements of paragraph (1) of this subsection and have remote disconnect and reconnect capability.

(h) **Settlement.** It is the objective of this rule that ERCOT shall be able to use 15-minute meter information from advanced metering systems for wholesale settlement, not later than January 31, 2010.

(i) **Tariff.** All non-standard, discretionary AMS features offered by the electric utility shall be described in the electric utility's tariff.

(j) **Access to meter data.**

(1) An electric utility shall provide a customer, the customer's REP, and other entities authorized by the customer read-only access to the customer's advanced meter data, including meter data used to calculate charges for service, historical load data, and any other proprietary customer information. The access shall be convenient and secure, and the data shall be made available no later than the day after it was created.

(2) The requirement to provide access to the data begins when the electric utility has installed 2,000 advanced meters for residential and non-residential customers. If an electric utility has already installed 2,000 advanced meters by the effective date of this section, the electric utility shall provide access to the data in the timeframe approved by the commission in either the Deployment Plan or request for surcharge proceeding. If only a Notice of Deployment has been filed, access

to the data shall begin no later than six months from the filing of the Notice of Deployment with the commission.

(3) An electric utility shall use industry standards and methods for providing secure customer and REP access to the meter data. The electric utility shall have an independent security audit of the mechanism for customer and REP access to meter data conducted within one year of initiating such access and promptly report the results to the commission.

(4) The independent organization, regional transmission organization, or regional reliability entity shall have access to information that is required for wholesale settlement, load profiling, load research, and reliability purposes.

(5) A customer may authorize its data to be available to an entity other than its REP.

(k) **Cost recovery for deployment of AMS.**

(1) **Recovery Method.** The commission shall 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. The surcharge shall not be established until after a detailed Deployment Plan is filed pursuant to subsection (d) of this section. 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 that shall be reconciled pursuant to paragraph (6) of this subsection. As indicated by the definition of AMS in subsection (c)(2) of this section, the costs for facilities that do not perform the functions and have the features specified in this

section shall not be included in the surcharge provided for by this subsection unless an electric utility has received a waiver pursuant to subsection (g)(3) of this section. The costs of providing AMS services include those costs of AMS installed as part of a pilot program pursuant to this section. Costs of providing AMS for a particular customer class shall be surcharged only to customers in that customer class.

(2) **Carrying Costs.** The annualized carrying-cost rate to be applied to the unamortized balance of the AMS capital costs shall be the electric utility's authorized weighted-average cost of capital (WACC). If the commission has not approved a WACC for the electric utility within the last four years, the commission may set a new WACC to apply to the unamortized balance of the AMS capital costs. In each subsequent rate proceeding in which the commission resets the electric utility's WACC, the carrying-charge rate that is applied to the unamortized balance of the utility's AMS costs shall be correspondingly adjusted to reflect the new authorized WACC.

(3) **Surcharge Proceeding.** In the request for surcharge proceeding, an electric utility may propose a surcharge methodology, but the commission prefers the stability of a levelized amount, and an amortization period ranging from five to seven years, depending on the useful life of the meter. The commission may set the surcharge to reflect a deployment of advanced meters that is up to one-third of the electric utility's total meters over each calendar year, regardless of the rate of actual AMS deployment. The actual or expected net operating cost savings from AMS deployment, to the extent that the operating costs are not reflected in base

rates, may be considered in setting the surcharge. If an electric utility that requests a surcharge does not have an approved Deployment Plan, the commission in the surcharge proceeding may reconcile the costs that the electric utility already spent on AMS in accordance with paragraph (6) of this subsection and may approve a Deployment Plan.

(4) **General Base Rate Proceeding while Surcharge is in Effect.** If the commission conducts a general base rate proceeding while a surcharge under this section is in effect, then the commission shall include the reasonable and necessary costs of installed AMS equipment in the base rates and decrease the surcharge accordingly, and permit reasonable recovery of any non-AMS metering equipment that has not yet been fully depreciated but has been replaced by the equipment installed under an approved Deployment Plan.

(5) **Annual Reports.** An electric utility shall file annual reports with the commission updating the cost information used in setting the surcharge. The annual reports shall include the actual costs spent to date in the deployment of AMS and the actual net operating cost savings from AMS deployment and how those numbers compare to the projections used to set the surcharge. During the annual report process, an electric utility may apply to update its surcharge, and the commission may set a schedule for such applications. For a levelized surcharge, the commission may alter the length of the surcharge collection period based on review of information concerning changes in deployment costs or operating costs savings in the annual report or changes in WACC. An annual report filed with

the commission shall not be a ratemaking proceeding, but an application by the electric utility to update the surcharge shall be a ratemaking proceeding.

(6) **Reconciliation Proceeding.** All costs recovered through the surcharge shall be reviewed in a reconciliation proceeding on a schedule to be determined by the commission. Nothwithstanding the preceding sentence, the electric utility may request multiple reconciliation proceedings, but no more frequently than once every three years. There is a presumption that costs spent in accordance with a Deployment Plan or amended Deployment Plan approved by the commission are reasonable and necessary. Any costs recovered through the surcharge that are found in a reconciliation proceeding not to have been spent or properly allocated, or not to be reasonable and necessary, shall be refunded to electric utility's customers. In addition, the commission shall make a final determination of the net operating cost savings from AMS deployment used to reduce the amount of costs that ultimately can be recovered through the surcharge. Accrual of interest on any refunded or surcharged amounts resulting from the reconciliation shall be at the electric utility's WACC and shall begin at the time the under or over recovery occurred.

(7) **Cross-subsidization and fees.** The electric utility shall account for its costs in a manner that ensures that there is no inappropriate cost allocation, cost recovery, or cost assignment that would cause cross-subsidization between utility activities and non-utility activities. The electric utility shall not charge a disconnection or reconnection fee that was approved by the commission prior to the effective date

of this rule, for a disconnection or reconnection that is effectuated using the remote disconnection or connection capability of an advanced meter.

(l) **Time of Use Schedule.** Commission approval of a time of use schedule (“TOUS”) pursuant to ERCOT protocols is not necessary prior to implementation of the new TOUS.

§25.311. Competitive Metering Services.

(a) **Purpose.** This section establishes the terms and conditions for competitive metering services to be offered to commercial and industrial customers served by an investor-owned transmission and distribution utility (TDU) beginning on January 1, 2004, as required by Public Utility Regulatory Act (PURA) §39.107(a), in areas where customer choice has been introduced. In areas where customer choice has been delayed, this section shall establish terms and conditions for competitive metering services to begin on a date determined by the commission, following the introduction of customer choice.

(b) **Definitions.** The following words and terms, when used in this section, shall have the following meanings unless the context clearly indicates otherwise.

(1) **Commercial and industrial customers** -- Those customers that do not receive electric service under a residential distribution tariff.

(2) **Data management** -- Includes validation, estimation, editing, extraction of billing components, support of retail transactions described in the Electric Reliability Council of Texas (ERCOT) protocols, and transfer of meter reading data to the settlement agent and other approved entities specified by the ERCOT protocols.

(3) **Maintenance** -- Activities necessary to maintain a meter in proper working order, including failure investigation, equipment repair, and replacement.

(4) **Meter owner** -- Entity that owns the settlement and TDU billing meter that is used for the measurement of electric energy delivered to a particular location.

(5) **Metering services** -- Activities relating to the measurement, for the purpose of settlement and TDU billing, of electricity provided to a retail customer, including,

but not limited to ownership, installation and removal, maintenance, testing and calibration, data collection, and data management.

(6) **Meter tampering** -- In areas where competitive metering has been introduced, meter tampering, bypass, or diversion is defined as tampering with a settlement and TDU billing meter or equipment, bypassing the same, or other instances of diversion, such as physically disorienting the meter; attaching objects to the meter to divert or bypass service; inserting objects into the meter; and other electrical and mechanical means of tampering with, bypassing, or diverting electrical service.

(7) **Testing** -- Activities as defined in §25.124 of this title (relating to Meter Testing).

(c) **Meter ownership.** A commercial or industrial retail customer may choose a meter owner. The meter owner may be, at the option of the retail customer:

(1) the retail customer;

(2) a retail electric provider (REP);

(3) the TDU; or

(4) other person authorized by the customer.

(d) **Data ownership.** The current retail customer shall own all meter data related to the premise occupied by that customer, regardless of whether the meter owner is the customer, the owner of the premise, or a third party. A third-party owner of the meter shall have access to the meter data. To the extent that data integrity is not compromised, the current retail customer shall have the right to physical access to the meter to obtain such meter data when technically feasible. The current retail customer shall have the right and capability, including necessary security passwords, to assign access to meter data related to the premise occupied by that customer.

(e) **Metering equipment**.

(1) No later than 60 days after the effective date of this section, ERCOT shall develop a process to establish, and periodically revise, a list of meters that shall be considered qualifying competitive meters for the purposes of this section. Each qualifying competitive meter shall meet commission-approved standards and shall be capable of providing the data necessary for billing in accordance with the TDU's delivery tariff and for settlement in accordance with the settlement agent's protocols.

(2) Requests for installation or removal shall be made to the TDU pursuant to the TDU's tariff.

(f) **Conformance with metering standards.**

(1) A meter that fails to meet commission-approved standards for accuracy shall not be placed in service or left in service. A meter found to violate these standards shall be adjusted or replaced in accordance with this subsection at the time the violation is discovered.

(2) Meters shall be adjusted as closely as practicable to the condition of zero error.

(3) If a meter owned by the TDU is found not to meet commission-approved standards for accuracy, the TDU shall install a replacement meter in accordance with its tariffs.

(4) If a meter that is not owned by the TDU is found not to meet commission-approved standards for accuracy, the TDU shall install a temporary replacement

meter. The temporary replacement meter shall be capable of providing the data necessary for billing in accordance with the TDU's tariff, and shall also provide settlement data in accordance with the settlement agent's protocols. The TDU shall notify the customer and the meter owner that the meter does not meet commission-approved standards for accuracy and shall take reasonable measures to safeguard the meter until the meter owner takes possession of it. The meter owner shall be responsible for the associated charges, in accordance with the TDU's tariff.

(g) **Testing of meters.** Costs for meter tests requested by the customer, REP, competitive meter owner, or TDU shall be the responsibility of the requesting party in accordance with the TDU's tariff, except that when a request is made to test a meter that is subsequently found not to meet commission-approved standards for accuracy, the cost of the meter test shall be the responsibility of the meter owner.

(1) Upon request for a meter test by a retail customer, a REP shall request that a meter be tested in accordance with the TDU's applicable tariff.

(2) A REP may request that a meter be tested in accordance with the TDU's applicable tariff.

(3) A meter owner other than the retail customer may request that a meter be tested in accordance with the TDU's applicable tariff.

(4) If the TDU suspects a meter malfunction, it shall promptly test the meter in accordance with its tariff.

(5) Following the completion of any meter test, the TDU shall promptly advise the requestor, and the retail customer's REP of the date of removal of the meter, the date of the test, the result of the test, and who made the test.

(h) **Use of meter data for settlement and TDU billing.**

(1) Both the TDU and the REP shall have the right and capability, including necessary security passwords, to access meter data for the purpose of rendering a bill, complying with settlement rules of an independent organization, and for load research and load profiling purposes. The TDU is responsible for the security of the data used for settlement and TDU billing and shall maintain the meter programming password capable of altering such billing parameters.

(2) No entity other than the TDU shall have the right, capability, or meter programming password to alter the data collected by the meter for the purpose of TDU billing.

(3) A TDU's requirements for load research shall not have the effect of limiting the type or frequency of meter data available to an end-use customer.

(i) **Competitive metering service credit.** ATDU shall file with the commission a tariff that provides a competitive metering service credit to the REP of a customer that selects a meter owner other than the TDU. Such tariff shall be accompanied by workpapers demonstrating the derivation of the credit.

§25.346. Separation of Electric Utility Metering and Billing Service Costs and Activities.

(a) **Purpose.** The purpose of this section is to identify and separate electric utility metering and billing service activities and costs for the purposes of unbundling.

(b) **Application.** This section shall apply to electric utilities as defined in Public Utility Regulatory Act (PURA) §31.002 in areas where customer choice is in effect.

(c) **Separation of transmission and distribution utility billing system service costs.**

(1) Transmission and distribution utility billing system services shall include costs related to the billing services described in §25.341(15) of this title (relating to Definitions).

(2) Charges for transmission and distribution utility billing system services shall not include any additional capital costs, operation and maintenance expenses, and any other expenses associated with billing services as prescribed by PURA §39.107(e).

(d) **Separation of transmission and distribution utility billing system service activities.**

(1) Transmission and distribution utility billing system services as defined in §25.341 of this title shall be provided by the transmission and distribution utility.

(2) The transmission and distribution utility may provide additional retail billing services pursuant to PURA §39.107(e).

(3) Additional retail billing services pursuant to PURA §39.107(e) shall be provided on an unbundled discretionary basis pursuant to a commission-approved embedded cost-based tariff.

(4) The transmission and distribution utility may not directly bill an end-use retail customer for services that the transmission and distribution utility provides except

when the billing is incidental to providing retail billing services at the request of a retail electric provider pursuant to PURA §39.107(e).

(e) **Uncollectibles and customer deposits.**

(1) The retail electric provider is responsible for collection of its charges from retail customers and measures to secure payment.

(2) For the purposes of functional cost separation in §25.344 of this title (relating to Cost Separation Proceedings), retail customer uncollectibles and deposits shall be assigned to the unregulated function, as prescribed by §25.344(g)(2)(I) of this title.

(f) **Separation of transmission and distribution utility metering system service costs.** Transmission and distribution utility metering system services shall include costs related to the transmission and distribution utility metering system services as defined in §25.341 of this title.

(g) **Separation of transmission and distribution utility metering system service activities.**

(1) Prior to the introduction of customer choice, metering service shall be provided in accordance with Subchapter F of this Chapter (relating to Metering). An electric utility shall continue to provide metering services pursuant to commission rules and regulations, but shall not engage in the provision of competitive energy services as defined by §25.341 of this title and prescribed by §25.343 of this title (relating to Competitive Energy Services).

(2) On the introduction of customer choice in a service area, metering services as described by §25.341(17) of this title for the area shall continue to be provided by the transmission and distribution utility affiliate (or successor in interest) of the

electric utility that was serving the area before the introduction of customer choice, but the transmission and distribution utility shall not engage in the provision of competitive energy services as defined by §25.341 of this title and prescribed by §25.343 of this title.

(A) Standard meter service shall be provided in accordance with this subparagraph. Advanced meter service shall be provided in accordance with §25.130 of this title (relating to Advanced Metering).

(i) The standard meter shall be owned, installed, and maintained by the transmission and distribution utility except as prescribed by §25.311 of this title (relating to Competitive Metering Services).

(ii) The transmission and distribution utility shall bill a retail electric provider for non-bypassable charges based upon the measurements obtained from each end-use customer's standard meter.

(iii) If the retail electric provider requests the replacement of the standard meter with an advanced meter, the transmission and distribution utility shall charge the retail electric provider the incremental cost for the replacement of the standard meter with an advanced meter owned, operated, and maintained by the transmission and distribution utility.

(iv) Without authorization from the retail electric provider, the transmission and distribution utility's use of advanced meter data shall be limited to that energy usage information necessary for the calculation of transmission and distribution charges in accordance with that end-use customer's transmission and distribution rate schedule.

(B) Nothing in this section precludes the retail electric provider from accessing the transmission and distribution utility's standard meter for the purposes of determining an end-use customer's energy usage.

(C) Nothing in this section precludes the end-use customer or the retail electric provider from owning, installing, and maintaining metering equipment in addition to the standard meter.

(h) **Competitive energy services.**

(1) Nothing in this section is intended to affect the provision of competitive energy services, including those that require access to the customer's meter.

(2) An electric utility shall not provide any service that is deemed a competitive energy service under §25.341 of this title except as provided under §25.343 of this title.

(i) **Electronic data interchange.**

(1) All transmission and distribution utilities, retail electric providers, power generation companies, power marketers, and electric utilities shall transmit data in accordance with standards and procedures adopted by the commission or the independent organization.

(2) All transmission and distribution utilities, retail electric providers, power generation companies, power marketers, and electric utilities shall abide by the settlement procedures adopted by the commission or the independent organization.

(3) Transmission and distribution utilities shall be allowed to recover such costs as prudently incurred in abiding by this subsection, to the extent not collected elsewhere, such as through the administrative fee of an independent organization.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority. It is therefore ordered by the Public Utility Commission of Texas that new §25.130 relating to Advanced Metering, and Amendments to §25.121, relating to Meter Requirements, §25.123, relating to Meter Readings, §25.311, relating to Competitive Metering Services, and §25.346, relating to Separation of Electric Utility Metering and Billing Service Costs and Activities are hereby adopted with changes as proposed.

ISSUED IN AUSTIN, TEXAS ON THE _________ DAY OF ___________ 2007.

PUBLIC UTILITY COMMISSION OF TEXAS

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PAUL HUDSON, CHAIRMAN

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JULIE PARSLEY, COMMISSIONER

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BARRY T. SMITHERMAN, COMMISSIONER

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