PUBLIC UTILITY COMMISSION OF TEXAS
RECEIVED
APR - 9 2020
BY
FILING CLERK

OPEN MEETING COVER SHEET RULEMAKING

MEETING DATE: April 17, 2020

DATE DELIVERED: April 9, 2010

AGENDA ITEM NO.: 23

CAPTION: Project No. 48525 – Rulemaking Relating to Advanced Metering

ACTION REQUESTED: Discussion and possible action with respect to Proposal for Adoption

Electronic Distribution List:
- Commissioners' Offices (6)
- Urban, John Paul
- Connie Corona (2)
- Gleeson, Thomas
- Phillips, Michael
- Central Records (Open Meeting Notebook)
- Rogas, Keith (2)
- Tom Hunter (5)
- Journeay, Stephen
- Agenda
- Burch, Chris
- Tietjen, Darryl (2)
- Long, Mick (2)
- Zerwas, Rebecca (2)
- Benter, Tammy (2)
- Gonzalez, Andrea
- Woltersdorf, Paytyn
- Hoke, Mike
- Mueller, Paula

43

Public Utility Commission of Texas

Memorandum

To: Chairman DeAnn T. Walker
Commissioner Arthur C. D'Andrea
Commissioner Shelly Botkin

From: Therese Harris, Infrastructure Division

Date: April 9, 2020

Re: Open Meeting, April 17, 2020—**Agenda Item # 23**
Project No. 48525 – *Rulemaking Relating to Advanced Metering*

Commissioners,

Attached for your review is staff's proposal for adoption in Rulemaking Project No. 48525, *Rulemaking Relating to Advanced Metering,* to be considered at the April 17, 2020 open meeting. This rulemaking proposes amendments to §25.5, relating to definitions; §25.130, relating to advanced metering; and §25.133, relating to non-standard metering service.

The amendments to §§25.130 and 25.133 conform the rules to Senate Bill 1145, 85th Legislature, Regular Session, which amended Public Utility Regulatory Act (PURA) §39.452, and to the following bills from the 86th Legislature, Regular Session: House Bill 853, which amended PURA §39.5521, House Bill 986, which amended PURA §39.402, and House Bill 1595, which amended PURA §39.5021. These bills encourage deployment of advanced metering and meter information networks by extending the applicability of PURA §39.107(h) and (k) to electric utilities providing service in areas outside the Electric Reliability Council of Texas (ERCOT). In addition, the proposed amendments clarify existing rule language and remove obsolete and unnecessary rule language.

As a result of Commission direction received at the October 11, 2019 open meeting, the proposed amendments also remove the requirement for an electric utility to offer the home area network (HAN) feature due to limited customer interest; set minimum capabilities for on-demand reads of a customer's advanced meter data; and remove rule language relating to an electric utility's limitation of liability because these provisions are addressed in the electric utility's tariff.

Changes were made to rule language published in the proposal for publication as noted below:

- §25.130(c)(5) *(definitions)*
- §25.130(f) *(pilot programs)*

- §25.130(g)(1)(D) *(provision of time-stamped meter data)*
- §25.130(g)(1)(G) *(on-demand reads)*
- §25.130(g)(1)(H) *(on-board storage of AMS meter data)*
- §25.130(j)(1) *(access to meter data)*
- §25.130(j)(3) *(provision of data that has not gone through VEE)*

Please contact Therese Harris at therese.harris@puc.texas.gov or 512-936-7378 with questions.

PROJECT NO. 48525

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

(STAFF RECOMMENDATION)
ORDER ADOPTING AMENDMENTS TO §§25.5, 25.130, AND 25.133
FOR CONSIDERATION AT THE APRIL 17, 2020 OPEN MEETING

The Public Utility Commission of Texas (commission) adopts amendments to 16 Texas Administrative Code (TAC) §25.5, relating to definitions; §25.130, relating to advanced metering; and §25.133, relating to non-standard metering service, with changes to the proposed text as published in the November 29, 2019 issue of the *Texas Register* (44 TexReg 7263). The amendments to §§25.130 and 25.133 conform the rules to Senate Bill 1145, 85th Legislature, Regular Session, which amended Public Utility Regulatory Act (PURA) §39.452, and to the following bills from the 86th Legislature, Regular Session: House Bill 853, which amended PURA §39.5521; House Bill 986, which amended PURA §39.402; and House Bill 1595, which amended PURA §39.5021. These bills encourage deployment of advanced metering and meter information networks by extending the applicability of PURA §39.107(h) and (k) to electric utilities providing service in areas outside the Electric Reliability Council of Texas (ERCOT) region.

The amendments also remove the requirement for an electric utility to offer the home area network (HAN) feature and set minimum capabilities for on-demand reads of customers' advanced meter data. In addition, the amendments clarify and define rule language; remove rule language relating to an electric utility's limitation of liability because this issue is addressed in the electric utility's tariff; and remove obsolete and other unnecessary rule language. These amendments are adopted under Project No. 48525.

The commission received comments on the proposed amendments from Southwestern Electric Power Company, El Paso Electric Company, Entergy Texas, Inc., and Southwestern Public Service Company (collectively Joint Non-ERCOT Utilities); Alliance for Retail Markets (ARM); Texas Energy Association for Marketers (TEAM); Office of Public Utility Counsel (OPUC); Mission:Data Coalition (Mission:Data); Texas Advanced Energy Business Alliance (TAEBA); Enel X North America, Inc. (Enel X); Lone Star Chapter of Sierra Club (Sierra Club); Texas Solar Power Association (TSPA); and Solar Energy Industries Association (SEIA). In addition, the commission received joint initial comments from AEP Texas Inc. (AEP), CenterPoint Energy Houston Electric, LLC, (CenterPoint) and Texas-New Mexico Power Company (TNMP) and joint reply comments from these utilities and Oncor Electric Delivery LLC (Oncor; collectively Joint ERCOT TDUs). There was no request for a public hearing.

Comments on §25.5 (definitions)

ARM supported the commission's proposed inclusion of a definition for "retail electric provider (REP) of record" to distinguish it from the general definition for retail electric provider.

Commission Response

The commission agrees with ARM and adopts the definition as proposed.

Comments on §25.130(c) (definitions)

TSPA recommended two changes to the definition of "web portal." The first recommended change was to add the word "secure" before "read-only access" to add clarity that the web portal needs to be secure because of the growing threat of cyber-attacks. TSPA also recommended that data be accessible in a standardized format to facilitate software development so customers, REPs, and other entities authorized to have access will not be required to use the web portal graphical user interface.

The Joint Non-ERCOT Utilities opposed TSPA's proposed changes to the definition of web portal. The Joint Non-ERCOT Utilities pointed out that §25.130(j) already requires access to the web portal to be secure. Concerning TSPA's proposal to require data accessibility in a standardized format, the Joint Non-ERCOT Utilities argued that TSPA did not consider or quantify the cost that would be imposed on utilities and their customers. The Joint Non-ERCOT Utilities stated that the costs of this proposal outweigh the benefits to customers.

ARM acknowledged that data provided in a standardized format facilitates software development to make data more readily available to customers and REPs. However, ARM stated that Smart Meter Texas (SMT) already provides data in a standardized format, so it is unclear what additional format standardization TSPA is requesting.

TEAM recommended a change to the definition of "web portal" to delete "by an electric utility or a group of electric utilities." TEAM advocated for this change to leave open the possibility in the future for ERCOT to perform some or all the features of access to advanced meter data. However, TEAM did not advocate for this change presently. ARM expressed support for

TEAM's proposed amendment to the definition of web portal based on the same reason as TEAM. ARM also added it does not advocate for this change presently.

The Joint ERCOT TDUs responded by disagreeing with TEAM's proposed revision. The Joint ERCOT TDUs stated that there is no need to revise §25.130 now to address something that might come up in the future and noted that the commission routinely reviews and revises rules when appropriate.

Mission:Data proposed to add the following language to the definition of "web portal": "For non-ERCOT utilities, a portal shall also provide customer account information, billing information, and other information necessary to determine eligibility in, and for customers to participate in, any demand-side management program(s)." In addition, Mission:Data argued that Texas customers in non-ERCOT regions should be able to delegate access to their energy information to service providers so energy usage can be economically optimized to better serve customers.

The Joint Non-ERCOT Utilities opposed Mission:Data's proposal. The Joint Non-ERCOT Utilities stated that Mission:Data did not address the data privacy requirements of PURA §39.107(k) and §25.44, which require that "An electric utility shall not sell, share, or disclose information generated, provided, or otherwise collected from an advanced metering system or meter information network, including information used to calculate charges for service, historical load data, and any other customer information," or PURA §39.101(a)(2), which requires that the commission ensure retail customer protections that provide a customer with "privacy of customer consumption and credit information." Although the Joint Non-ERCOT Utilities acknowledged that customers are free to share their meter data and any other information with a competitive service provider, they stated that Mission:Data's proposal seems to make the sharing of virtually all customer information by the utility automatic via the web portal with customer approval of access to meter usage data. The Joint Non-ERCOT Utilities stated that this is inconsistent with PURA §39.107(k), which governs usage data. Further, the Joint Non-ERCOT Utilities stated that AMS does not produce the additional customer data requested by Mission:Data, and that it is improper to use this proceeding to attempt to alter the means by which third parties may access customer records.

Commission Response

The commission adopts TSPA's recommendation to add the word "secure" before "read-only access" in the definition of "web portal." This addition makes explicit the important requirement that access to customer data be secure.

The commission does not adopt TSPA's proposal to require data accessibility in a standardized format. TSPA did not provide enough information to justify its proposal.

The commission declines to adopt TEAM's proposal to delete "by an electric utility or a group of electric utilities" from the definition of web portal. If, in the future, the commission requires ERCOT to provide access to advanced meter data, the rule can be amended at that time.

The commission does not adopt the definition of web portal proposed by Mission:Data. Mission:Data did not provide enough information to justify its proposal.

Comments on §25.130(d)(4)(D) (web portal)

TEAM proposed a modification to subsection (d)(4)(D) relating to the requirement to provide a web portal in order to ensure that the amended rule language leaves open the possibility that, with proper approval from ERCOT and stakeholders, some or all of the features of access to advanced meter data currently performed by SMT could be performed by ERCOT. TEAM did not advocate for implementing such changes now but does not want to foreclose any efficiencies that might be brought about by participation of ERCOT in the future.

The Joint ERCOT TDUs responded by disagreeing with TEAM's proposed revision to §25.130 (d)(4)(D). The Joint ERCOT TDUs stated that there is no need to revise §25.130 now to address something that might come up in the future and noted that the Commission routinely reviews and revises rules when appropriate.

Commission Response

The commission declines to adopt TEAM's proposed addition to §25.130(d)(4)(D) relating to the requirement to provide a web portal. If, in the future, the commission requires ERCOT to provide access to advanced meter data, the rule can be amended at that time.

Comments on §25.130(d)(6) and (d)(9), and §25.130(g)(4) (progress reports)

The Joint Non-ERCOT Utilities urged the commission to reduce the frequency of the progress reports relating to the deployment status of an electric utility's AMS required under §25.130(d)(6) and (d)(9) from monthly to quarterly. In addition, they requested that the requirement to file such reports not begin until after deployment has commenced.

The Joint Non-ERCOT Utilities also urged the commission to reduce the frequency of progress reports relating to activities undertaken to enhance the electric utility's AMS, required under §25.130(g)(4), from monthly to quarterly.

Commission Response

The commission declines to reduce the frequency of reports required under §25.130(d)(6) and (d)(9) regarding the utility's deployment status, and retains the requirement that these reports commence after the electric utility files its deployment plan. Monthly reports are better suited than quarterly reports to timely identify and follow up on issues arising prior to and during deployment. The commission declines to reduce the frequency of reports required under §25.130(g)(4) relating to the status of activities undertaken to enhance AMS features for the same reason.

Comments on §25.130(d)(11) (outage notification)

Subsection (d)(11) requires that "notification of any planned or unplanned outage that affects access to customer usage data must be posted on the electric utility's web portal home page." In order to conform this requirement with Mission:Data's proposed modification to the definition of "web portal" in §25.130(c)(5), Mission:Data proposed to remove the word "usage" before "data." This change would broaden the existing requirement to require non-ERCOT utilities to provide account information, billing information, and other information through a web portal.

The Joint Non-ERCOT Utilities opposed Mission:Data's proposed modification to §25.130(d)(11) for the same data privacy reasons it opposed Mission:Data's proposed modification to the definition of "web portal" in §25.130(c)(5). Furthermore, the Joint Non-ERCOT Utilities argued that AMS does not produce the additional customer data discussed by Mission:Data, and that it is improper to use this proceeding to attempt to alter the means by which third parties may access customer records.

Commission Response

The commission declines to adopt Mission:Data's proposal to make changes to §25.130(d)(11) to broaden the existing provision to require non-ERCOT utilities to provide account information, billing information, and other information through a web portal. As stated in its response to the comments of Mission:Data regarding §25.130(c), the commission declines to modify the advanced metering rule to require that non-ERCOT electric utilities provide information through a web portal other than the information provided by the utility's AMS.

Comments on §25.130(d)(12) (prohibition on provision of competitive energy services)

ARM requested that §25.130(d)(12) be revised to clarify that the prohibition on transmission and distribution utilities (TDUs) providing any advanced metering equipment or service under

§25.343, relating to competitive energy services, applies to any service provided through SMT, which is the web portal jointly owned and operated by the TDUs.

The Joint ERCOT TDUs opposed ARM's proposed revision and stated that the subsection already makes clear that a utility must not provide any advanced metering equipment or service that is deemed a competitive energy service under §25.343 of this title. The Joint ERCOT TDUs expressed belief that ARM's proposal to insert "including any service provided through a web portal" is too broad because it seems to capture any possible action taken by a utility on a web portal. The Joint ERCOT TDUs stated that not every action taken on a web portal should or would constitute a competitive energy service under §25.343. In addition, the Joint ERCOT TDUs stated that a modification to this subsection should not be used as a device to expand the definition of competitive energy services provided in §25.341(3) of this title. The Joint ERCOT TDUs expressed concern that if ARM's proposal is adopted, ARM or another party could assert that SMT is precluded from using dashboards, graphs, or charts to communicate meter data to customers. The Joint ERCOT TDUs were concerned that without these tools, it would be very difficult for customers to understand and use the meter data provided by SMT. Furthermore, the Joint ERCOT TDUs noted that the SMT business requirements approved in Docket No. 47472 address the manner in which meter data must be provided and displayed on SMT.

Commission Response

The commission declines to adopt ARM's request to modify §25.130(d)(12) to specify that the prohibition on TDUs relating to provision of competitive energy services under §25.343 of this title applies to any service provided through SMT. The provision already properly

addresses the issue raised by ARM. Furthermore, the commission agrees with the Joint ERCOT TDUs that the SMT business requirements approved in Docket No. 47472 clearly specify the way meter data must be provided and displayed on SMT.

Comments on §25.130(d)(13) (limitation of liability)

AEP, CenterPoint, and TNMP opposed elimination of the limitation of liability provision in §25.130(d)(13), and suggested language to revise the existing provision. They stated that the existing language resolves any uncertainty as to whether a utility's provision of AMS with the minimum features required by subsection (g) of this section constitutes provision of a delivery service. They were concerned that removal of the current provision would cause uncertainty and could lead to a court determination that provision of the minimum AMS features required under subsection (g) does not constitute provision of a delivery service under the utilities' retail delivery service tariff. In addition, these commenters stated that the proposed rule would require the utilities to provide access to a new class of entities: those authorized by the customer to receive such access. These commenters stated that their retail delivery service tariffs only cover competitive retailers and retail customers. Because of this, they urged the commission to extend the reach of the limits of liability in the retail delivery service tariff to all entities that the utilities would be required to provide access to. To accomplish this, they proposed retention of existing §25.130(d)(13) as modified by their revisions. The proposed revisions clarify that provision of AMS services and features constitute delivery services under the electric utility's tariff; and allow any commercial entity other than a REP that is authorized to access a customer's meter data under subsection (g) of this section, to be deemed a retail customer for purposes of the limitation of liability provisions in the electric utility's tariff.

ARM did not oppose the extension of limitation of liability, but rejected the proposed wording that any commercial entity other than a REP "shall be deemed a retail customer for purposes of limitation of liability provisions." ARM stated that deeming a person or entity to be a retail customer, who is not a retail customer, could raise a host of unintended consequences in the interpretation of other commission rules. ARM proposed alternate language for the commission to consider that would allow a commercial entity to be included within the limitation of liability in the electric utility's tariff if §25.130(d)(13) is retained.

Mission:Data and Enel X supported removal of the limitation of liability language in this subsection. Mission:Data stated that the language properly belongs in the Joint ERCOT TDUs' retail delivery tariffs. Mission:Data urged the commission to consider revisions to the Joint ERCOT TDUs' retail delivery tariffs in a separate proceeding. Mission:Data and Enel X reminded the commission that the Joint ERCOT TDUs agreed in Docket No. 47472 not to address issues relating to limitation of liability, because SMT's terms and conditions provide sufficient limitations on their liability. Enel X stated that the proposed language seems to be inconsistent with the agreement of the settling parties in Docket No. 47472, is not necessary, and should be rejected. Mission:Data stated that if the commission decides to address these issues in this proceeding, there are significant issues to be addressed concerning the TDU's liability for poor or negligent operation of SMT. Mission:Data argued that it is not necessarily reasonable for tort immunity provisions relating to retail delivery service to apply equally to an information technology service such as SMT. Mission:Data stated that these issues have not been adequately addressed in the present proceeding and should be addressed in a separate proceeding where a sufficient record can be developed.

Commission Response

The commission declines to make the changes to §25.130(d)(13) proposed by AEP, CenterPoint, and TNMP, which would retain the limitation of liability provision in the existing rule and modify its reach. The commission also declines to make the modifications to this proposal recommended by ARM. Provisions relating to an electric utility's limitation of liability properly belong in the utility's tariff. The commission's rules require that utilities take various actions, and it would be impractical and confusing for limitations of liability to be addressed throughout those rules. Deletion of the provision in the AMS rule that addresses limitation of liability is consistent with the commission's general practice of relying on utilities' tariffs to address that issue. The commission does not intend for this deletion to be a substantive change.

Further, the commission disagrees with the comments of AEP, CenterPoint, and TNMP that the proposed rule would require the utilities to provide access to a new class of entities: those authorized by the customer to receive such access. Existing §25.130(j)(5) provides: "A customer may authorize data to be available to an entity other than its REP." In the order adopting this provision, *Rulemaking Related to Advanced Metering*, Project No. 31418, order at 69 (May 10, 2007), the commission anticipated that access to customer data could be shared with any entity authorized by the customer when it stated: "The

commission concurs with the Joint DSPs that [it is] sufficient for the REP, the customer, and any authorized third party to have access to the advanced meter data..."

Comments on §25.130(f) (pilot programs)

Subsection (f) provides that an electric utility may deploy AMS with a limited number of meters that do not meet the requirements of subsection (g) of this section in a pilot program in order to gather information.

TSPA stated that notice and opportunity to participate in pilots should extend beyond REPs to include entities authorized by the customer to have access to customer data.

Commission Response

The commission makes the change proposed by TSPA. The commission agrees that notice and opportunity to participate in pilots should extend beyond REPs to include entities authorized by the customer to have access to customer data. Use of AMS has become widespread since this section was adopted in 2007. If an electric utility engages in a pilot program to gather additional information beyond the body of information currently available, the commission agrees with TSPA that notice and opportunity to participate in the pilot should be sent by the utility not only to REPs but also the entities authorized by a customer to have read-only access to the customer's advanced meter data. These entities may have systems that use the advanced meter data and these systems may be affected by broad deployment of the technology used in the pilot.

Comments on 25.130(g)(1)(D) (provision of time-stamped meter data)

The Joint Non-ERCOT Utilities noted that §25.130(g)(1)(D) requires that a utility's AMS provide or support sharing of time-stamped meter data to the independent organization or regional transmission organization for purposes of wholesale settlement. They stated that the intent of the provision seems to be that an organization that administers a retail marketplace have access to retail sales data in order to settle market transactions. The Joint Non-ERCOT Utilities explained that there is no reason for a vertically integrated utility to submit retail meter data to a regional transmission operator because the Southwest Power Pool (SPP) and the Midcontinent Independent System Operator (MISO) do not administer a retail market place, and utilities participating in SPP or MISO already have appropriate metering and processes in place to settle wholesale market transactions. The Joint Non-ERCOT Utilities proposed revisions to §25.130(g)(1)(D) to clarify that the provision applies only to utilities that participate in a retail marketplace administered by an independent organization or a regional transmission organization.

ARM did not oppose the comments of the Joint Non-ERCOT Utilities, but stated that because the ERCOT TDUs do not "participate" in the retail market the proposed revision could be confusing or have unintended consequences. ARM recommended language to address this distinction.

Commission Response

The commission agrees with the Joint Non-ERCOT TDUs that not all electric utilities are required to provide time-stamped meter data to an independent organization or regional

transmission organization. However, time-stamped meter data is necessary to identify when a meter read is made and is needed for on-demand meter reads and time of use rates. The commission has therefore changed §25.130(g)(1)(D) to require an AMS to provide time-stamped meter data, without reference to providing it to an independent organization or a regional transmission organization. A utility subject to requirements concerning time-stamped meter data by an independent organization or regional transmission organization will be subject to those requirements regardless of whether such requirements are addressed in the rule.

Comments on §25.130(g)(1)(E) (provision of direct, real-time access to customer usage data)

Enel X, Sierra Club, Mission:Data, and TSPA urged the commission to retain the existing provision in §25.130(g)(1)(E) that requires an AMS to provide or support the "capability to provide direct, real time" access to customer usage data. Enel X stated that new technologies are developing that would enable customers to make use of real-time data. TSPA acknowledged that HAN devices have not been widely adopted but stressed that continued access to real-time data is essential because alternative methods to access real-time data could be more successful. Enel X stated that removing this requirement would require customers that want real-time data to pay for duplicative meter equipment that can only provide similar data to the utility meter.

Enel X proposed a modification to the current provision in the rule that would expand the requirement to provide direct, real-time access to customer usage data to entities authorized by the customer. Enel X argued that its proposed revision is faithful to the settlement in Docket No. 47472 that only removes the HAN requirement and preserves the opportunity for new technologies to enable real-time access to customer usage data. Sierra Club supported Enel X's proposed revision to §25.130(g)(1)(E), because it preserves the opportunity for new technologies to access direct, real-time usage data.

Mission:Data stated that retail tariffs in non-ERCOT regions that include time-of-use, peak demand, or other time or demand charges are fundamentally unfair if customers, and the devices customers install, are deprived of real-time access to information needed to make economic decisions. Mission:Data argued that no cost-effective alternative to the HAN for acquiring real-time energy usage currently exists. Mission:Data stated that because there is no evidence on record concerning the costs, benefits, or customer uptake of HAN, any attempt to eliminate the HAN requirements is premature and unwarranted.

ARM agreed with ENEL X, Sierra Club, TSPA, and Mission:Data that access to direct, real-time customer usage data would be beneficial, but explained that they do not seek to upset the agreement reached in Docket No. 47472.

The Joint ERCOT TDUs and the Joint Non-ERCOT Utilities were opposed to the proposal to leave language in §25.130(g)(1)(E) that requires a utility's AMS to have the capability to provide direct, real-time access to customer usage data. The Joint Non-ERCOT Utilities argued that this would essentially continue to require HAN functionality without naming it. The Joint Non-ERCOT Utilities asserted that on-demand-reads, which provide near real-time access, is the reasonable minimum capability that should be required, because it seems that few people need or want HAN.

The Joint Non-ERCOT Utilities stated that HAN functionality should be permissive, and utilities that deploy HAN should be permitted to recover costs if it is shown that there is a sufficient level of customer interest or there is some reason to socialize costs.

Commission Response

The commission declines to retain the existing language in §25.130(g)(1)(E) that requires an electric utility's AMS to support the capability to provide direct, real-time access to customer usage data as proposed by Enel X, Sierra Club, Mission:Data, and TSPA. Furthermore, the commission declines to accept the changes proposed by Enel X that would expand the current requirement in the rule to provide direct, real-time access to customer usage data to entities authorized by the customer. Only a very small percentage of customers has taken advantage of the capability of AMS to provide direct, real-time access to customer usage data. The commission does not agree with the comments of Enel X that customer appetite for direct, real-time access to customer usage data will increase as a result of any new technologies that are being developed to make use of real-time data, or of methods to access real-time data other than through a HAN device as suggested by TSPA. In addition, the commission does not agree with the comments of Mission:Data that customer use of HAN would be significantly different in the non-ERCOT regions of Texas than in the ERCOT region of Texas. The commission found in *Commission Staff's Petition to Determine Requirements for Smart Meter Texas*, Docket No. 47472, Finding of Fact No. 62I (Jul. 12, 2018) that on-demand meter reading functionality is an adequate substitute for HAN functionality. On-demand meter reading gives a customer prompt access to usage

information without the costs incurred by the customer for a HAN. In addition, use of on-demand reads is increasing by customers in ERCOT, whereas use of HAN by customers in ERCOT is decreasing.

Comments on §25.130(g)(1)(E) (interval data recorder (IDR) meters)

ARM requested that the commission retain existing §25.130(g)(1)(E)(ii), which requires a stakeholder process and commission approval to determine when and how 15-minute IDR data will be made available on the electric utility's web portal. ARM stated this would balance the interests of all stakeholders. If the commission declines to retain §25.130(g)(1)(E)(ii), ARM requested the commission clarify that removal of the provision is not intended to foreclose a future proceeding to include IDR metered data on the SMT portal or via some other means. ARM stated that ERCOT Nodal Protocol Revision Request 877 provides a process for a TDU to replace a customer's IDR meter with an AMS meter but explained that not all premises can utilize an AMS meter in place of an IDR meter. ARM acknowledged that technical limitations keep IDR metered data from being available as frequently as AMS data and recommended that the TDUs undertake system modifications to allow for daily interval data to be available on SMT or some other means.

The Joint ERCOT TDUs opposed ARM's proposal. The Joint ERCOT TDUs stated that §25.130 is applicable only to AMS, not metering for those customers with IDR meters. In addition, the Joint ERCOT TDUs stated that, from a technical perspective, it would only be possible to make 15-minute IDR data available on SMT if all IDR meters were converted to AMS meters which, they observed, is not required by rule or statute.

Commission Response

The commission declines to retain the language in §25.130(g)(1)(E)(ii) that requires a stakeholder process and commission approval to determine when and how 15-minute IDR data will be made available on the electric utility's web portal. As ARM acknowledged, there are technical problems with implementing this requirement. Methods to gain better access to energy usage data recorded by IDR meters may be considered in future proceedings.

Comments on §25.130(g)(1)(E) (time intervals for data collection)

TEAM proposed modifications to §25.130(g)(1)(E) to address the potential future approval of involvement of an independent organization to provide a database of meter data and a web portal to allow access to that data.

TSPA proposed that data on meters and AMS be stored in five-minute intervals. TSPA stated this move is necessary to predicate further wholesale market innovation that would include five-minute wholesale market settlement.

The Joint ERCOT TDUs opposed TEAM's and TSPA's proposed revisions. Regarding TEAM's proposal, the Joint ERCOT TDUs asserted there is no reason to make changes to address a circumstance that is not under consideration or lacks sufficient support at this time. The Joint ERCOT TDUs stated that TSPA's comments did not address the technical aspects of five-minute interval data collection and the AMS upgrades that would be required to move data collection to shorter than 15-minute intervals. In addition, the Joint ERCOT TDUs noted that extensive technical inquiry and cost evaluation would be required before such a significant change could be considered. The Joint Non-ERCOT Utilities also opposed TSPA's proposal and stated that they saw no value in requiring data storage and communication capability for 5-minute intervals when it is not necessary for settlement. The Joint Non-ERCOT Utilities supported the 15-minute interval requirement in the rule.

Commission Response

The commission declines to adopt TEAM's proposal to accommodate the possible future involvement by an independent organization. If, in the future, the commission requires ERCOT to provide access to advanced meter data, the rule can be amended at that time.

Further, the commission declines to adopt the changes proposed by TSPA to require that meter data be stored in five-minute intervals. The commission agrees with the Joint ERCOT TDUs that extensive technical inquiry and cost evaluation would be required before such a significant change could be considered, and there are insufficient reasons for doing so at this time.

Comments on §25.130(g)(1)(G) (on-demand reads)

The Joint Non-ERCOT Utilities requested that the commission clarify §25.130(g)(1)(G) to specify that access to "customer advanced meter data" is provided.

TSPA, Sierra Club, OPUC, and Enel X expressed concern regarding the proposed minimum requirements for on-demand reads provided through an application programming interface. TSPA remarked that merely allowing on-demand reads to be done via the graphical user interface (web page) will substantially diminish its usefulness because this method, typically accomplished by a user clicking a button on a website, is not scalable. TSPA stated that on-demand reads must be encouraged programmatically through software. TSPA asserted that two on-demand reads per hour per meter via an application programming interface is insufficient in times of significant strains on the grid when customer load can lead to dramatic differences in energy costs. In addition, TSPA asserted that far more than 6,000 on-demand reads per day per utility are necessary, and a level of service should be reliably expected without an exception for network traffic.

Sierra Club and OPUC also asserted that the proposed minimum requirement for provision of on-demand reads through an application programming interface is too low. Sierra Club stated that for the large utilities, the requirement represents only a tiny percentage of total advanced meters deployed. In order to make the minimum requirement more equitable, Sierra Club requested that the requirement be based on a percentage of meters or some other number based on the size of the utility. Alternatively, Sierra Club suggested that the commission determine appropriate requirements for provision of on-demand reads for each utility outside of the rule. OPUC preferred no minimum requirement be set and stated that many utilities currently provide more on-demand reads than the proposed minimum requirement. OPUC recommended that, if the commission keeps a minimum requirement in the rule, it be increased substantially, or the commission establish appropriate minimum requirements on an individual utility basis. OPUC did not oppose Sierra Club's suggestion to make the minimum requirement a percentage rather than a number but preferred no minimum requirement be set.

Enel X stated that deleting the proposed revision to §25.130(g)(1)(G) would allow the issue to be addressed by the terms of the settlement agreement in Docket No. 47472 for now and, at a future date, enable the commission to more easily consider alternate minimum requirements that more appropriately reflect the size and capability of each utility's system.

ARM agreed that it is unnecessary to include a minimum number of on-demand reads in the rule because the settlement in Docket No. 47472 already addresses the issue. ARM stated that if a minimum is included, it could create confusion as to whether the settlement in Docket No. 47472 or the rule controls. ARM recommended that the proposed changes to §25.130(g)(1)(G) that could be inconsistent with the settlement be dropped.

The Joint ERCOT TDUs opposed proposals to change the minimum number of on-demand reads required through an application programming interface. The Joint ERCOT TDUs stated that there is no need to require unlimited on-demand reads, because customer demand for on-demand reads are being met. In response to TSPA's comment that on-demand reads should be available programmatically through software, the Joint ERCOT TDUs responded that SMT already provides on-demand reads programmatically through software by offering on-demand reads through an application programming interface.

The Joint Non-ERCOT Utilities opposed TSPA's comment that on-demand reads be available programmatically through software. The Joint Non-ERCOT Utilities asserted that keeping the rule permissive for the Joint Non-ERCOT Utilities is a better approach, because on-demand reads through a graphical user interface are mandatory. The Joint Non-ERCOT Utilities believed the proposed language provides a reasonable balance of facilitating near real-time access to meter data and the costs and requirements of each utility's communications and information technology infrastructure. The Joint Non-ERCOT Utilities remarked that the benefit a non-ERCOT customer would receive as a result of mandating on-demand reads through an application programming interface has not been demonstrated.

The Joint Non-ERCOT Utilities also opposed TSPA's proposal to remove the rule's exception for network traffic. The Joint Non-ERCOT Utilities explained that the utility must retain the ability to protect core network data flow, particularly with respect to sensors and any distribution automation devices on the grid during an outage. The Joint Non-ERCOT Utilities believed that the exception provides reasonable protection against sudden increased demand on the communications system to protect core processes and mitigates risk of incurring unreasonable or unnecessary investment to expand the communication network solely to facilitate more on-demand reads, which to date are relatively few.

Commission Response

The commission makes the change proposed by the Joint Non-ERCOT Utilities to specify that access to "customer meter data" is provided by an on-demand read.

The commission agrees with the concerns of TSPA, Sierra Club, OPUC, Enel, and ARM about including specific numerical requirements in the rule relating to-demand reads through an application programming interface (API). The commission therefore does not adopt those requirements in the proposed rule, so that any specific numerical requirements will be addressed on a case-by-case basis. Therefore, the specific numerical requirements approved by the commission in Docket No. 47472 for the four ERCOT utilities will remain in place unless and until the commission changes them in a future proceeding. Version 2.0 of SMT, the web portal used by the four ERCOT utilities, was implemented in December 2019 and for the first time allows on-demand reads to be made through an API rather than manually through SMT's graphical user interface (web page). Because on-demand reads through an API are automated, this upgrade of SMT creates the potential for a quick and significant increase in the numbers of on-demand reads, which could overwhelm a utility's ability to provide timely on-demand reads. The specific numerical requirements approved by the commission in Docket No. 47472 addressed this concern.

The commission declines to adopt TSPA's proposed revision that would require the Joint Non-ERCOT Utilities to provide on-demand reads through an API. These utilities currently do not have retail competition or tariff offerings that create a potential need for API access. The rule permits but does not require a utility to support API access. Therefore, if there is a cost-justified reason for adding this functionality, a utility has the ability to do so under the rule.

The commission declines to adopt TSPA's proposal to remove the rule's provision making the availability of on-demand reads subject to network traffic. The commission agrees with the comments of the Joint Non-ERCOT Utilities that an electric utility must retain the ability to protect core network data flow.

Comments on §25.130(g)(1)(H) (on-board storage of AMS meter data)

Subsection(g)(1)(H) requires that an AMS must support on-board storage of meter data that complies with nationally recognized non-proprietary standards.

The Joint Non-ERCOT Utilities suggested that the range of relevant standards for on-board storage of meter data be expanded to include the International Electromechanical Commission (IEC) DLMS-COSEM standards, which are used by OpenWay Riva meters. They also proposed ending this subparagraph with the term "etc."

Commission Response

The commission agrees to expand the example of relevant non-proprietary standards for on-board storage of meter data as suggested by the Joint Non-ERCOT Utilities. However, the commission declines to add "etc." to §25.130(g)(1)(H) because the language is vague and unnecessary.

Comments on §25.130(g)(1)(J) (HAN devices)

Enel X and Sierra Club opposed the proposed revisions to §25.130(g)(1)(J) that would remove the requirement that an AMS have the capability to communicate with devices inside the home.

Sierra Club stated that it is open to some change in the language to reflect the limited use of HANs. However, Sierra Club preferred that the commission keep the requirement that an AMS have the capability to communicate with devices inside the premises so that customers can obtain their data in real-time. Furthermore, Sierra Club stated that not requiring non-ERCOT utilities' AMS to have the capability to communicate with devices inside the home is a disservice to ratepayers who will be funding deployment of advanced meters.

Enel X stated that the structure of §25.130(g)(1)(J) does not mandate that HAN be the only solution that may be used to provide real-time access to data from a customer's advanced meter. In addition, it stated that the result of the proposed revisions to §25.130(g)(1)(J) would be not only to limit access to real-time data through a HAN that communicates through the utility's AMS, but also to limit the customers who can have access to those grandfathered in the settlement agreement adopted in Docket No. 47472. Enel X proposed a more narrowly focused revision to the subsection that eliminates the ERCOT TDUs' obligation to maintain HAN functionality consistent with the agreement in Docket No. 47472 but retains clear authority for customers to use other potential means to receive data from their meters in real-time. Enel X believed that limiting customer access to their meter data on a delayed, after-the-fact, basis is not adequate in many circumstances. In addition, Enel X stated that as ERCOT looks for solutions to provide it with a better understanding of the status and activity of resources on the distribution grid, allowing pathways to provide awareness that is less cost-prohibitive than solutions used for larger resources on the transmission grid, such as access to real-time data from a customer's meter, could facilitate this awareness and allow smaller customers easier access to wholesale markets.

Mission:Data urged the commission to maintain the HAN requirement for the non-ERCOT utilities. Mission:Data asserted that retaining the HAN is necessary because there is no adequate or practical substitute for the HAN's ability to relay real-time electricity consumption information to devices inside the home. Mission:Data provided information to support its assertion that alternatives to HAN are expensive, difficult, and potentially dangerous to install, and may not be possible for certain electrical panels throughout Texas. Mission:Data argued that eliminating HAN will have significant impacts on distributed energy resources in the non-ERCOT regions of Texas. Mission:Data asserted that advanced systems involving rooftop solar, batteries, aggregated energy efficiency, or demand response resources in homes and businesses will be negatively impacted without access to cost-effective real-time energy usage data. Mission:Data stated that it does not necessarily follow that eliminating the requirement for ERCOT TDUs to provide HAN means that it is reasonable to eliminate HAN for the non-ERCOT investor-owned utilities. To the extent that customer longevity is required to finance market energy management systems that use HAN, Mission:Data believed that vertically integrated utilities may be in a better position than REPs in the ERCOT region. Furthermore, Mission:Data asserted that there has been no discussion in this proceeding about the rate design implications for non-ERCOT utilities of eliminating the only cost-effective method of providing customers with real-time feedback on their electricity usage.

The Joint Non-ERCOT Utilities asserted that Mission:Data's comments failed to provide the full scope of issues surrounding the HAN that weigh against proposals of HAN as a required minimum feature. The Joint Non-ERCOT Utilities asserted that Mission:Data's comments failed to recognize that HAN functionality has been available through the ERCOT TDUs' deployments for over ten years but never widely adopted by customers. The Joint Non-ERCOT Utilities pointed to testimony in support of the stipulation and settlement agreement filed in Docket No. 47472 that indicated less than 7,700 HAN devices were provisioned on SMT as of April 2018. The Joint Non-ERCOT Utilities stated that the commission found on-demand reads to be an acceptable substitute for HAN functionality.

ARM stated that AMS meters were designed to be pairable with HAN devices. ARM asserted that to the extent possible through manual support on an as-requested basis, customers should retain the ability to have self-provided or REP-provided on-premise devices supported for pairing to AMS meters provided the customer or REP is willing to pay for the reasonable cost of necessary modifications. ARM believed that this could be effectuated under §25.130(h), which provides a process for a REP to request TDUs to provide enhanced advanced meters, additional metering technology, or advanced meter features. ARM provided a proposed revision to §25.130(g)(1)(J) to acknowledge that REPs or customers may request that ERCOT TDUs support the pairing of a customer or REP-provided device to an AMS meter. The REPs asserted that their proposed amendment to the subsection would not alter the business requirements approved in Docket No. 47472 because those are in relation to SMT support for HAN, as distinct from AMS meters' support.

The Joint ERCOT TDUs opposed ARM's proposal unless the commission authorizes utilities to implement a discretionary service charge for that service. The Joint ERCOT TDUs also stated that ARM's proposal is inconsistent with the Order and Stipulation in Docket No. 47472. In addition, the Joint ERCOT TDUs stated that ARM's proposal would require the TDUs to enable the pairing of an AMS meter with a customer-provided HAN device or a HAN device provided by a REP or a competitive service provider. Furthermore, the Joint ERCOT TDUs stated that SMT 2.0 is not capable of pairing a HAN device to a meter because that functionality was removed under the stipulation and commission's order in Docket No. 47472.

Commission Response

The commission makes no change to the proposed language in §25.130(g)(1)(J). The language in the proposed rule narrows the requirement for an AMS to have the capability to communicate with devices inside a customer's premises to an electric utility in the ERCOT region with a HAN device paired to a meter and in use at the time the version of the web portal approved in Docket No. 47472 was implemented. As found in Docket No. 47472, only a very small percentage of customers have taken advantage of the capability of AMS to provide access to direct, real-time data through a HAN device. Furthermore, as stated in response to comments made on §25.130(g)(1)(E), on-demand meter reading gives a customer prompt access to usage information without the costs incurred by the customer for a HAN. In addition, use of on-demand reads is increasing by customers in the ERCOT region, whereas use of HAN by customers in the ERCOT region is decreasing. For the same reason, the commission declines to adopt the changes proposed by Enel X and Sierra Club to retain the requirement that an AMS have the capability to communicate with

devices inside the home, and the changes proposed by Mission:Data to retain the HAN requirement for non-ERCOT investor-owned utilities. The commission also declines to adopt ARM's proposal to revise §25.130(g)(1)(J) to permit REPs or customers to request that ERCOT TDUs support the pairing of a customer or REP-provided device to an AMS meter, because the commission is eliminating the requirement that an AMS meter be capable of pairing with a customer or REP-provided device. The commission's finding in Docket No. 47472 remains correct that "On-demand meter reading functionality through SMT is an adequate substitute for HAN functionality."

Comments on §25.130(h)(2) (discretionary service charges)

ARM recommended removal of proposed language in §25.130(h)(2) that require a REP to be responsible for the cost of system changes necessary to provide enhanced advanced meters requested by the REP. The REPs asserted that the term "system changes" is broad, undefined, and could result in REPs being charged for a variety of TDU overhead and administrative costs that could be inappropriately attributed to a single request for an enhanced advanced meter. Should the commission retain system changes as a potential cost, the REPs requested that they only be charged the pro-rata share of the differential costs directly attributable to any individual request for the enhanced meter or feature.

The Joint ERCOT TDUs opposed ARM's request. The Joint ERCOT TDUs stated that REPs should pay for enhanced meters or features; otherwise, REPs will be empowered to request features regardless of the changes required to the utility's system or the costs associated with system changes.

Commission Response

The commission declines to make ARM's proposed change that would eliminate the requirement that a REP be responsible for the cost of system changes necessary to provide enhanced advanced meters requested by the REP. Further, the commission disagrees with ARM's alternate proposal that would charge a REP only the pro-rata share of the differential costs directly attributable to any individual request for the enhanced meter or feature. The commission declines to adopt either of ARM's proposals, in order to prevent costs related to an enhanced advanced meter or feature from being charged to customers that did not cause the costs to be incurred.

Comments on §25.130(j)(3) (access to meter data)

TSPA and ARM requested that the commission replace "appropriate and reasonable" standards for data access with "robust and reliable" standards in §25.130(j)(3). ARM stated that the competitive retail market relies on consistent and timely access to meter data and the commission's support for robustness of that access would support innovation.

In addition, TSPA stated that allowing access to meter data as soon as it is available, rather than the following day, could reduce the need for on-demand reads. TSPA suggested that utilities be required to provide access to data before validation, estimation, and editing of the data to ensure same day access to the data.

The Joint ERCOT TDUs and the Joint Non-ERCOT Utilities opposed TSPA's proposal for access to unvalidated data, because providing access to that data creates the possibility that customers, REPs, and other entities will make decisions based on incorrect or incomplete data. The Joint ERCOT TDUs asserted that it is crucial that data provided to customers be as correct as possible, because customers may not have the technical expertise to understand the differences that can occur between initial as-read data and data that has been validated or re-versioned.

Commission Response

The commission agrees with the comments of TSPA and ARM to change §25.130(j)(3) to require "robust and reliable" standards and makes that change.

The commission declines to adopt TSPA's proposal to require electric utilities to provide access to data before validation, estimation, and editing of the data in order to ensure same day access to the data. The commission agrees with the Joint ERCOT TDUs and the Joint Non-ERCOT Utilities that providing data that has not been through the electric utilities' validation process creates a significant risk that customers, REPs and other entities would make decisions based on incorrect or incomplete usage data. In addition, extensive technical inquiry and cost evaluation may be required before such a change could be considered, and there are insufficient reasons for doing so at this time.

Comments on §25.130(j)(5) (customer authorization of access to meter data)

TAEBA, Mission:Data, ENEL X, and Sierra Club requested that the commission retain §25.130(j)(5), which provides that "a customer may authorize its data to be available to an entity other than its REP." They stated that the provision is consistent with PURA §39.107(b), which provides that the end-use customer owns and controls all its meter data. TAEBA suspected that the proposal to delete the provision may be based on the perception that the language is unnecessary and potentially redundant to §25.130(j)(1), which states that a utility must provide the customer, the customer's REP, and other entities authorized by the customer read-only access to the customer's meter data. However, TAEBA stated that deleting the explicit provision in §25.130(j)(5) may create unnecessary confusion.

Furthermore, Mission:Data, Enel X, and Sierra Club disagreed with the Joint ERCOT TDUs' interpretation offered in their comments on §25.130(d)(13) that the proposed changes to the AMS rule open up a utility's provision of AMS access to a new class of entities: those that have been authorized by a retail customer to receive such access. Mission:Data, Enel X, and Sierra Club asserted that the existing rule already provides this access. Enel X stated that when the commission adopted §25.130, it recognized that customers could authorize third-parties to receive access to their meter data through the utility's web portal: "The Commission concurs with the joint DSPs that 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, as well as through the customer's home area network (HAN)..." Mission:Data, Enel X, and the Sierra Club stated that the Joint ERCOT TDUs' narrow interpretation of the rule also conflicts with PURA §39.107(b). Enel X asserted that customers need to be able to continue to share their data with entities other than REPs, because most customers do not have the means to analyze their data or to understand the breadth of services available to them for energy management purposes. In addition, Enel X stated that energy management services provide benefits that extend beyond the customer premises to the electric grid. To avoid confusion regarding the ability of a customer to authorize access to its data to an entity other than its REP, Mission:Data and Enel X suggested replacing "an" with "any" to strengthen the provision in §25.130(j)(5) by revising it to read: "A customer may authorize data to be available to any entity other than its REP." Sierra Club agreed with this proposal.

Commission Response

The commission agrees with TAEBA, Mission:Data, ENEL X, and Sierra Club that the rule should clearly state a customer's right to authorize its meter data to be available to an entity other than its REP. Therefore, the commission keeps the language in existing §25.130(j)(5), with clarifications, and moves it to §25.130(j)(1) in order to streamline §25.130(j).

Comments on §25.130(k) (fees for distributed generation)

TSPA stated that because advanced meters are capable of multiple channels, an electric utility with an approved advanced meter deployment plan should not be allowed to charge an additional metering fee for distributed generation. Furthermore, TSPA asserted that any cost that would be recovered by such a fee should be included in the AMS surcharge or rates. Sierra Club and SEIA agreed with TSPA that a utility should be prohibited from charging an additional metering fee associated with distributed generation.

ARM stated that this rulemaking was undertaken to harmonize the rules with legislative amendments extending AMS deployment to non-ERCOT electric utilities. Considering this, ARM recommended that TSPA, SEIA, and Sierra Club's issue would be better addressed in a separate proceeding.

The Joint Non-ERCOT Utilities stated that, although it is true that advanced meters typically have multiple channels that could be used for distributed generation, a fee charged for premises with distributed generation might include costs other than the meter, such as a manual monthly billing calculation if this is not an automated feature, or provision of bi-directional meter data. The Joint Non-ERCOT Utilities also stated that failure to charge these costs to the distributed generation customer directly would put the burden for cost recovery on all customers.

Commission Response

The commission agrees with the Joint Non-ERCOT Utilities that there may be costs associated with premises with distributed generation that warrant a fee charged to such premises. Therefore, TSPA's proposal to prohibit such fees is inappropriate.

Comments on §25.133(d)(1) (termination of non-standard metering service)

This provision requires a utility to offer the following four different specific means of non-standard metering: disabling communications technology in an advanced meter if feasible; if applicable, allowing the customer to continue to receive metering service using the existing meter if the electric utility determines that it meets applicable accuracy standards; if commercially available, an analog meter that meets applicable meter accuracy standards; and a digital, non-communicating meter.

The Joint Non-ERCOT Utilities proposed to replace "and" with "or" in subsection(d)(1)(E)(iii) so a utility is not required to make all four alternative non-standard metering solutions available when any one of the options would be sufficient for offering non-standard metering service.

OPUC agreed with the Joint Non-ERCOT Utilities' proposal and argued that requiring a utility to provide all four non-standard metering options will increase costs passed onto ratepayers.

ARM opposed the Joint Non-ERCOT Utilities' proposed edit to this subsection, because all four means may be required in some instances. ARM further argued that the Joint Non-ERCOT Utilities' concern is addressed in the rule by the qualifying statements of "if feasible" in clause (i), "if applicable" in clause (ii), and "if commercially available" in clause (iii).

Commission Response

The commission does not adopt the Joint Non-ERCOT Utilities' proposal to change the language in §25.133(d)(1) that requires a utility to offer non-standard metering using one of four alternative non-standard metering solutions. Electric utilities in ERCOT have been offering non-standard metering service for a number of years under the rule that Joint Non-ERCOT Utilities seek to change and significant issues with this requirement have not been raised with the commission. The provision that non-ERCOT utilities propose to change already properly addresses the issue raised by the Joint Non-ERCOT Utilities. The Joint Non-ERCOT Utilities' concern about being required to make all four alternative non-standard metering solutions available is addressed by qualifying statements in the provision. Specifically, "if feasible" applies to disabling communications technology in an

advanced meter; "if applicable" applies to allowing the customer to continue to receive metering service using the existing meter if the electric utility determines that it meets applicable accuracy standards; and "if commercially available" applies to an analog meter that meets applicable meter accuracy standards.

Comments on §25.133(d)(2) (termination of non-standard metering service)

This subsection allows a customer to terminate non-standard metering service by contacting the customer's electric utility. The customer is responsible for any remaining non-standard metering costs.

ARM proposed a change to this subsection to clarify the customer's cost responsibility ends when terminating non-standard metering service. This edit adds "until the electric utility has terminated the service" to ensure a customer's cost responsibility ends once the utility terminates service and does not continue indefinitely. OPUC agreed with ARM's proposal.

The Joint Non-ERCOT Utilities opposed ARM's proposal, because it could have unintended consequences. They stated that it is possible that some capital costs incurred to provide non-standard metering service may not be fully recovered by the utility when a customer terminates non-standard metering service. The Joint Non-ERCOT Utilities provided the example of when a utility incurs costs for making back office programming changes to provide non-standard metering service for a customer request. The utility will incur costs to obtain and install the non-standard meter and update the billing system. If the non-standard metering service is terminated before these costs have been fully recovered, then the utility or other customers would be responsible for the remainder of these costs. The Joint Non-ERCOT Utilities recommended the rule as proposed to give the utilities and the commission flexibility to determine recovery of non-standard metering service costs from the customers who caused the costs to be incurred.

Commission Response

The commission agrees with the Joint Non-ERCOT Utilities that it is appropriate for the commission to retain the flexibility to determine recovery for any non-standard metering service costs that may not have been recovered upon the termination of non-standard metering service. Therefore, the commission declines to adopt ARM's proposed change that would specify that the customer's cost responsibility ends when terminating non-standard metering service.

All comments, including any not specifically referenced herein, were fully considered by the commission.

These amendments are adopted under §14.001 of the Public Utility Regulatory Act, Tex. Util. Code Ann. (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; PURA §36.003, which grants the commission the authority to ensure that each rate be just and reasonable and not unreasonably preferential, prejudicial, or discriminatory; PURA §39.107, which grants the commission the authority to approve electric utility surcharges for the deployment of advanced meters, adopt rules relating to the transfer of customer data, and approve non-discriminatory rates for metering service; and PURA §§39.402, 39.452, 39.5021 and 39.5521, which permit the electric utilities outside of the ERCOT region that elect to deploy advanced meters and meter information networks to recover reasonable and necessary deployment costs and subjects the deployment to commission rules adopted under PURA §39.107(h) and (k).

Cross reference to statutes: PURA §§14.001, 14.002, 36.003, 39.107, 39.402, 39.452, 39.5021 and 39.5521.

§25.5. Definitions.

The following words and terms, when used in this chapter, shall have the following meanings, unless the context clearly indicates otherwise:

(1) **Above-market purchased power costs** -- Wholesale demand and energy costs that a utility is obligated to pay under an existing purchased power contract to the extent the costs are greater than the purchased power market value.

(2) **Affected person** -- means:

(A) a public utility or electric cooperative affected by an action of a regulatory authority;

(B) a person whose utility service or rates are affected by a proceeding before a regulatory authority; or

(C) a person who:

(i) is a competitor of a public utility with respect to a service performed by the utility; or

(ii) wants to enter into competition with a public utility.

(3) **Affiliate** -- means:

(A) a person who directly or indirectly owns or holds at least 5.0% of the voting securities of a public utility;

(B) a person in a chain of successive ownership of at least 5.0% of the voting securities of a public utility;

(C) a corporation that has at least 5.0% of its voting securities owned or controlled, directly or indirectly, by a public utility;

(D) a corporation that has at least 5.0% of its voting securities owned or controlled, directly or indirectly, by:

(i) a person who directly or indirectly owns or controls at least 5.0% of the voting securities of a public utility; or

(ii) a person in a chain of successive ownership of at least 5.0% of the voting securities of a public utility;

(E) a person who is an officer or director of a public utility or of a corporation in a chain of successive ownership of at least 5.0% of the voting securities of a public utility; or

(F) a person determined to be an affiliate under Public Utility Regulatory Act §11.006.

(4) **Affiliated electric utility** -- The electric utility from which an affiliated retail electric provider was unbundled in accordance with Public Utility Regulatory Act §39.051.

(5) **Affiliated power generation company (APGC)** -- A power generation company that is affiliated with or the successor in interest of an electric utility certificated to serve an area.

(6) **Affiliated retail electric provider (AREP)** -- A retail electric provider that is affiliated with or the successor in interest of an electric utility certificated to serve an area.

(7) **Aggregation** -- Includes the following:

(A) the purchase of electricity from a retail electric provider, a municipally owned utility, or an electric cooperative by an electricity customer for its own use in multiple locations, provided that an electricity customer may not avoid any non-bypassable charges or fees as a result of aggregating its load; or

(B) the purchase of electricity by an electricity customer as part of a voluntary association of electricity customers, provided that an electricity customer may not avoid any non-bypassable charges or fees as a result of aggregating its load.

(8) **Aggregator** -- A person joining two or more customers, other than municipalities and political subdivision corporations, into a single purchasing unit to negotiate the purchase of electricity from retail electric providers. Aggregators may not sell or take title to electricity. Retail electric providers are not aggregators.

(9) **Ancillary service** -- A service necessary to facilitate the transmission of electric energy including load following, standby power, backup power, reactive power, and any other services the commission may determine by rule.

(10) **Base rate** -- Generally, a rate designed to recover the cost of service other than certain costs separately identified and recovered through a rider, rate schedule, or other schedule. For bundled utilities, these separately identified costs may include items such as a fuel factor, power cost recovery factor, and surcharge. Distribution service providers may have separately identified costs such as transition costs, the excess mitigation charge, transmission cost recovery factors, and the competition transition charge.

(11) **Bundled Municipally Owned Utilities/Electric Cooperatives (MOU/COOP)** -- A municipally owned utility/electric cooperative that is conducting both

transmission and distribution activities and competitive energy-related activities on a bundled basis without structural or functional separation of transmission and distribution functions from competitive energy-related activities and that makes a written declaration of its status as a bundled municipally owned utility/electric cooperative pursuant to §25.275(o)(3)(A) of this title (relating to Code of Conduct for Municipally Owned Utilities and Electric Cooperatives Engaged in Competitive Activities).

(12) **Calendar year** -- January 1 through December 31.

(13) **Commission** -- The Public Utility Commission of Texas.

(14) **Competition transition charge (CTC)** -- Any non-bypassable charge that recovers the positive excess of the net book value of generation assets over the market value of the assets, taking into account all of the electric utility's generation assets, any above market purchased power costs, and any deferred debit related to a utility's discontinuance of the application of Statement of Financial Accounting Standards Number 71 ("Accounting for the Effects of Certain Types of Regulation") for generation-related assets if required by the provisions of the Public Utility Regulatory Act (PURA), Chapter 39. For purposes of PURA §39.262, book value shall be established as of December 31, 2001, or the date a market value is established through a market valuation method under PURA §39.262(h), whichever is earlier, and shall include stranded costs incurred under PURA §39.263. Competition transition charges also include the transition charges established pursuant to PURA §39.302(7) unless the context indicates otherwise.

(15) **Competitive affiliate** -- An affiliate of a utility that provides services or sells products in a competitive energy-related market in this state, including telecommunications services, to the extent those services are energy-related.

(16) **Competitive energy efficiency services** -- Energy efficiency services that are defined as competitive energy services pursuant to §25.341 of this title (relating to Definitions).

(17) **Competitive retailer** -- A retail electric provider; or a municipally owned utility or electric cooperative, that has the right to offer electric energy and related services at unregulated prices directly to retail customers who have customer choice, without regard to geographic location.

(18) **Congestion zone** -- An area of the transmission network that is bounded by commercially significant transmission constraints or otherwise identified as a zone that is subject to transmission constraints, as defined by an independent organization.

(19) **Control area** -- An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(A) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(B) maintain, within the limits of good utility practice, scheduled interchange with other control areas;

(C) maintain the frequency of the electric power system(s) within reasonable limits in accordance with good utility practice; and

(D) obtain sufficient generating capacity to maintain operating reserves in accordance with good utility practice.

(20) **Corporation** -- A domestic or foreign corporation, joint-stock company, or association, and each lessee, assignee, trustee, receiver, or other successor in interest of the corporation, company, or association, that has any of the powers or privileges of a corporation not possessed by an individual or partnership. The term does not include a municipal corporation or electric cooperative, except as expressly provided by the Public Utility Regulatory Act.

(21) **Critical loads** -- Loads for which electric service is considered crucial for the protection or maintenance of public health and safety; including but not limited to hospitals, police stations, fire stations, critical water and wastewater facilities, and customers with special in-house life-sustaining equipment.

(22) **Customer choice** -- The freedom of a retail customer to purchase electric services, either individually or through voluntary aggregation with other retail customers, from the provider or providers of the customer's choice and to choose among various fuel types, energy efficiency programs, and renewable power suppliers.

(23) **Customer class** -- A group of customers with similar electric service characteristics (e.g., residential, commercial, industrial, sales for resale) taking service under one or more rate schedules. Qualified businesses as defined by the

Texas Enterprise Zone Act, Texas Government Code, Title 10, Chapter 2303 may be considered to be a separate customer class of electric utilities.

(24) **Day-ahead** -- The day preceding the operating day.

(25) **Deemed savings** -- A pre-determined, validated estimate of energy and peak demand savings attributable to an energy efficiency measure in a particular type of application that a utility may use instead of energy and peak demand savings determined through measurement and verification activities.

(26) **Demand** -- The rate at which electric energy is delivered to or by a system at a given instant, or averaged over a designated period, usually expressed in kilowatts (kW) or megawatts (MW).

(27) **Demand savings** -- A quantifiable reduction in the rate at which energy is delivered to or by a system at a given instance, or averaged over a designated period, usually expressed in kilowatts (kW) or megawatts (MW).

(28) **Demand-side management (DSM)** -- Activities that affect the magnitude or timing of customer electrical usage, or both.

(29) **Demand-side resource or demand-side management** -- Equipment, materials, and activities that result in reductions in electric generation, transmission, or distribution capacity needs or reductions in energy usage or both.

(30) **Disconnection of service** -- Interruption of a customer's supply of electric service at the customer's point of delivery by an electric utility, a transmission and distribution utility, a municipally owned utility or an electric cooperative.

(31) **Distribution line** -- A power line operated below 60,000 volts, when measured phase-to-phase, that is owned by an electric utility, transmission and distribution utility, municipally owned utility, or electric cooperative.

(32) **Distributed resource** -- A generation, energy storage, or targeted demand-side resource, generally between one kilowatt and ten megawatts, located at a customer's site or near a load center, which may be connected at the distribution voltage level (below 60,000 volts), that provides advantages to the system, such as deferring the need for upgrading local distribution facilities.

(33) **Distribution service provider (DSP)** -- An electric utility, municipally-owned utility, or electric cooperative that owns or operates for compensation in this state equipment or facilities that are used for the distribution of electricity to retail customers, as defined in this section, including retail customers served at transmission voltage levels.

(34) **Economically distressed geographic area** -- Zip code area in which the average household income is less than or equal to 60% of the statewide median income, as reported in the most recently available United States Census data.

(35) **Electric cooperative** --

(A) a corporation organized under the Texas Utilities Code, Chapter 161 or a predecessor statute to Chapter 161 and operating under that chapter;

(B) a corporation organized as an electric cooperative in a state other than Texas that has obtained a certificate of authority to conduct affairs in the State of Texas; or

(C) a successor to an electric cooperative created before June 1, 1999, in accordance with a conversion plan approved by a vote of the members of the electric cooperative, regardless of whether the successor later purchases, acquires, merges with, or consolidates with other electric cooperatives.

(36) **Electric generating facility** -- A facility that generates electric energy for compensation and that is owned or operated by a person in this state, including a municipal corporation, electric cooperative, or river authority.

(37) **Electricity Facts Label** -- Information in a standardized format, as described in §25.475(f) of this title (relating to Information Disclosures to Residential and Small Commercial Customers), that summarizes the price, contract terms, fuel sources, and environmental impact associated with an electricity product.

(38) **Electricity product** -- A specific type of retail electricity service developed and identified by a REP, the specific terms and conditions of which are summarized in an Electricity Facts Label that is specific to that electricity product.

(39) **Electric Reliability Council of Texas (ERCOT)** -- Refers to the independent organization and, in a geographic sense, refers to the area served by electric utilities, municipally owned utilities, and electric cooperatives that are not synchronously interconnected with electric utilities outside of the State of Texas.

(40) **Electric service identifier (ESI ID)** -- The basic identifier assigned to each point of delivery used in the registration system and settlement system managed by the Electric Reliability Council of Texas (ERCOT) or another independent organization.

(41) **Electric utility** -- Except as otherwise provided in this Chapter, an electric utility is: A person or river authority that owns or operates for compensation in this state equipment or facilities to produce, generate, transmit, distribute, sell, or furnish electricity in this state. The term includes a lessee, trustee, or receiver of an electric utility and a recreational vehicle park owner who does not comply with Texas Utilities Code, Subchapter C, Chapter 184, with regard to the metered sale of electricity at the recreational vehicle park. The term does not include:

(A) a municipal corporation;

(B) a qualifying facility;

(C) a power generation company;

(D) an exempt wholesale generator;

(E) a power marketer;

(F) a corporation described by Public Utility Regulatory Act §32.053 to the extent the corporation sells electricity exclusively at wholesale and not to the ultimate consumer;

(G) an electric cooperative;

(H) a retail electric provider;

(I) the state of Texas or an agency of the state; or

(J) a person not otherwise an electric utility who:

(i) furnishes an electric service or commodity only to itself, its employees, or its tenants as an incident of employment or tenancy, if that service or commodity is not resold to or used by others;

(ii) owns or operates in this state equipment or facilities to produce, generate, transmit, distribute, sell or furnish electric energy to an electric utility, if the equipment or facilities are used primarily to produce and generate electric energy for consumption by that person; or

(iii) owns or operates in this state a recreational vehicle park that provides metered electric service in accordance with Texas Utilities Code, Subchapter C, Chapter 184.

(42) **Energy efficiency** -- Programs that are aimed at reducing the rate at which electric energy is used by equipment and/or processes. Reduction in the rate of energy used may be obtained by substituting technically more advanced equipment to produce the same level of end-use services with less electricity; adoption of technologies and processes that reduce heat or other energy losses; or reorganization of processes to make use of waste heat. Efficient use of energy by customer-owned end-use devices implies that existing comfort levels, convenience, and productivity are maintained or improved at a lower customer cost.

(43) **Energy efficiency measures** -- Equipment, materials, and practices that when installed and used at a customer site result in a measurable and verifiable reduction in either purchased electric energy consumption, measured in kilowatt-hours (kWh), or peak demand, measured in kW, or both.

(44) **Energy efficiency project** -- An energy efficiency measure or combination of measures installed under a standard offer contract or a market transformation

contract that results in both a reduction in customers' electric energy consumption and peak demand, and energy costs.

(45) **Energy efficiency service provider (EESP)** -- A person who installs energy efficiency measures or performs other energy efficiency services. An energy efficiency service provider may be a retail electric provider or large commercial customer, if the person has executed a standard offer contract.

(46) **Energy savings** -- A quantifiable reduction in a customer's consumption of energy.

(47) **ERCOT protocols** -- Body of procedures developed by ERCOT to maintain the reliability of the regional electric network and account for the production and delivery of electricity among resources and market participants. The procedures, initially approved by the commission, include a revisions process that may be appealed to the commission, and are subject to the oversight and review of the commission.

(48) **ERCOT region** -- The geographic area under the jurisdiction of the commission that is served by transmission service providers that are not synchronously interconnected with transmission service providers outside of the state of Texas.

(49) **Exempt wholesale generator** -- A person who is engaged directly or indirectly through one or more affiliates exclusively in the business of owning or operating all or part of a facility for generating electric energy and selling electric energy at wholesale who does not own a facility for the transmission of electricity, other than an essential interconnecting transmission facility necessary to effect a sale of electric energy at wholesale, and who is in compliance with the registration

requirements of §25.109 of this title (Registration of Power Generation Companies and Self-Generators).

(50) **Existing purchased power contract** -- A purchased power contract in effect on January 1, 1999, including any amendments and revisions to that contract resulting from litigation initiated before January 1, 1999.

(51) **Facilities** -- All the plant and equipment of an electric utility, including all tangible and intangible property, without limitation, owned, operated, leased, licensed, used, controlled, or supplied for, by, or in connection with the business of an electric utility.

(52) **Financing order** -- An order of the commission adopted under the Public Utility Regulatory Act §39.201 or §39.262 approving the issuance of transition bonds and the creation of transition charges for the recovery of qualified costs.

(53) **Freeze period** -- The period beginning on January 1, 1999, and ending on December 31, 2001.

(54) **Generation assets** -- All assets associated with the production of electricity, including generation plants, electrical interconnections of the generation plant to the transmission system, fuel contracts, fuel transportation contracts, water contracts, lands, surface or subsurface water rights, emissions-related allowances, and gas pipeline interconnections.

(55) **Generation service** -- The production and purchase of electricity for retail customers and the production, purchase and sale of electricity in the wholesale power market.

(56) **Good utility practice** -- Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act, to the exclusion of all others, but rather is intended to include acceptable practices, methods, and acts generally accepted in the region.

(57) **Hearing** -- Any proceeding at which evidence is taken on the merits of the matters at issue, not including prehearing conferences.

(58) **Independent organization** -- An independent system operator or other person that is sufficiently independent of any producer or seller of electricity that its decisions will not be unduly influenced by any producer or seller.

(59) **Independent system operator** -- An entity supervising the collective transmission facilities of a power region that is charged with non-discriminatory coordination of market transactions, systemwide transmission planning, and network reliability.

(60) **Installed generation capacity** -- All potentially marketable electric generation capacity, including the capacity of:

(A) generating facilities that are connected with a transmission or distribution system;

(B) generating facilities used to generate electricity for consumption by the person owning or controlling the facility; and

(C) generating facilities that will be connected with a transmission or distribution system and operating within 12 months.

(61) **Interconnection agreement** -- The standard form of agreement, which has been approved by the commission. The interconnection agreement sets forth the contractual conditions under which a company and a customer agree that one or more facilities may be interconnected with the company's utility system.

(62) **License** -- The whole or part of any commission permit, certificate, approval, registration, or similar form of permission required by law.

(63) **Licensing** -- The commission process for granting, denial, renewal, revocation, suspension, annulment, withdrawal, or amendment of a license.

(64) **Load factor** -- The ratio of average load to peak load during a specific period of time, expressed as a percent. The load factor indicates to what degree energy has been consumed compared to maximum demand or utilization of units relative to total system capability.

(65) **Low-income customer** -- An electric customer who receives Supplemental Nutrition Assistance Program (SNAP) from Texas Health and Human Services Commission (HHSC) or medical assistance from a state agency administering a part of the medical assistance program.

(66) **Low-Income List Administrator (LILA)** -- A third-party administrator contracted by the commission to administer aspects of the low-income customer identification process established under PURA §17.007.

(67) **Market power mitigation plan** -- A written proposal by an electric utility or a power generation company for reducing its ownership and control of installed generation capacity as required by the Public Utility Regulatory Act §39.154.

(68) **Market value** -- For nonnuclear assets and certain nuclear assets, the value the assets would have if bought and sold in a bona fide third-party transaction or transactions on the open market under the Public Utility Regulatory Act (PURA) §39.262(h) or, for certain nuclear assets, as described by PURA §39.262(i), the value determined under the method provided by that subsection.

(69) **Master meter** -- A meter used to measure, for billing purposes, all electric usage of an apartment house or mobile home park, including common areas, common facilities, and dwelling units.

(70) **Municipality** -- A city, incorporated village, or town, existing, created, or organized under the general, home rule, or special laws of the state.

(71) **Municipally-owned utility (MOU)** -- Any utility owned, operated, and controlled by a municipality or by a nonprofit corporation whose directors are appointed by one or more municipalities.

(72) **Nameplate rating** -- The full-load continuous rating of a generator under specified conditions as designated by the manufacturer.

(73) **Native load customer** -- A wholesale or retail customer on whose behalf an electric utility, electric cooperative, or municipally-owned utility, by statute, franchise, regulatory requirement, or contract, has an obligation to construct and operate its system to meet in a reliable manner the electric needs of the customer.

(74) **Natural gas energy credit (NGEC)** -- A tradable instrument representing each megawatt of new generating capacity fueled by natural gas, as authorized by the Public Utility Regulatory Act §39.9044 and implemented under §25.172 of this title (relating to Goal for Natural Gas).

(75) **Net book value** -- The original cost of an asset less accumulated depreciation.

(76) **Net dependable capability** -- The maximum load in megawatts, net of station use, which a generating unit or generating station can carry under specified conditions for a given period of time, without exceeding approved limits of temperature and stress.

(77) **New on-site generation** -- Electric generation capacity greater than ten megawatts capable of being lawfully delivered to the site without use of utility distribution or transmission facilities, which was not, on or before December 31, 1999, either:

(A) A fully operational facility, or

(B) A project supported by substantially complete filings for all necessary site-specific environmental permits under the rules of the Texas Natural Resource Conservation Commission (TNRCC) in effect at the time of filing.

(78) **Off-grid renewable generation** -- The generation of renewable energy in an application that is not interconnected to a utility transmission or distribution system.

(79) **Other generation sources** -- A competitive retailer's or affiliated retail electric provider's supply of generated electricity that is not accounted for by a direct supply contract with an owner of generation assets.

(80) **Person** -- Includes an individual, a partnership of two or more persons having a joint or common interest, a mutual or cooperative association, and a corporation, but does not include an electric cooperative.

(81) **Power cost recovery factor (PCRF)** -- A charge or credit that reflects an increase or decrease in purchased power costs not in base rates.

(82) **Power generation company (PGC)** -- A person that:

(A) generates electricity that is intended to be sold at wholesale, including the owner or operator of electric energy storage equipment or facilities to which the Public Utility Regulatory Act, Chapter 35, Subchapter E applies;

(B) does not own a transmission or distribution facility in this state, other than an essential interconnecting facility, a facility not dedicated to public use, or a facility otherwise excluded from the definition of "electric utility" under this section; and

(C) does not have a certificated service area, although its affiliated electric utility or transmission and distribution utility may have a certificated service area.

(83) **Power marketer** -- A person who becomes an owner of electric energy in this state for the purpose of selling the electric energy at wholesale; does not own generation, transmission, or distribution facilities in this state; does not have a

certificated service area; and who is in compliance with the registration requirements of §25.105 of this title (relating to Registration and Reporting by Power Marketers).

(84) **Power region** -- A contiguous geographical area which is a distinct region of the North American Electric Reliability Council.

(85) **Pre-interconnection study** -- A study or studies that may be undertaken by a utility in response to its receipt of a completed application for interconnection and parallel operation with the utility system at distribution voltage. Pre-interconnection studies may include, but are not limited to, service studies, coordination studies and utility system impact studies.

(86) **Premises** -- A tract of land or real estate or related commonly used tracts including buildings and other appurtenances thereon.

(87) **Price to beat (PTB)** -- A price for electricity, as determined pursuant to the Public Utility Regulatory Act §39.202, charged by an affiliated retail electric provider to eligible residential and small commercial customers in its service area.

(88) **Proceeding** -- A hearing, investigation, inquiry, or other procedure for finding facts or making a decision. The term includes a denial of relief or dismissal of a complaint. It may be rulemaking or nonrulemaking; rate setting or non-rate setting.

(89) **Proprietary customer information** -- Any information compiled by a retail electric provider, an electric utility, a transmission and distribution business unit as defined in §25.275(c)(16) of this title (relating to Code of Conduct for Municipally Owned Utilities and Electric Cooperatives Engaged in Competitive

Activities) on a customer in the course of providing electric service or by an aggregator on a customer in the course of aggregating electric service that makes possible the identification of any individual customer by matching such information with the customer's name, address, account number, type or classification of service, historical electricity usage, expected patterns of use, types of facilities used in providing service, individual contract terms and conditions, price, current charges, billing records, or any information that the customer has expressly requested not be disclosed. Information that is redacted or organized in such a way as to make it impossible to identify the customer to whom the information relates does not constitute proprietary customer information.

(90) **Provider of last resort (POLR)** -- A retail electric provider (REP) certified in Texas that has been designated by the commission to provide a basic, standard retail service package in accordance with §25.43 of this title (relating to Provider of Last Resort (POLR)).

(91) **Public retail customer** -- A retail customer that is an agency of this state, a state institution of higher education, a public school district, or a political subdivision of this state.

(92) **Public utility or utility** -- An electric utility as that term is defined in this section, or a public utility or utility as those terms are defined in the Public Utility Regulatory Act §51.002.

(93) **Public Utility Regulatory Act (PURA)** -- The enabling statute for the Public Utility Commission of Texas, located in the Texas Utilities Code Annotated, §§11.001 *et. seq*.

(94) **Purchased power market value** -- The value of demand and energy bought and sold in a bona fide third-party transaction or transactions on the open market and determined by using the weighted average costs of the highest three offers from the market for purchase of the demand and energy available under the existing purchased power contracts.

(95) **Qualified scheduling entity** -- A market participant that is qualified by the Electric Reliability Council of Texas (ERCOT) in accordance with Section 16, Registration and Qualification of Market Participants of ERCOT's Protocols, to submit balanced schedules and ancillary services bids and settle payments with ERCOT.

(96) **Qualifying cogenerator** -- The meaning as assigned this term by 16 U.S.C. §796(18)(C). A qualifying cogenerator that provides electricity to the purchaser of the cogenerator's thermal output is not for that reason considered to be a retail electric provider or a power generation company.

(97) **Qualifying facility** -- A qualifying cogenerator or qualifying small power producer.

(98) **Qualifying small power producer** -- The meaning as assigned this term by 16 U.S.C. §796(17)(D).

(99) **Rate** -- A compensation, tariff, charge, fare, toll, rental, or classification that is directly or indirectly demanded, observed, charged, or collected by an electric

utility for a service, product, or commodity described in the definition of electric utility in this section and a rule, practice, or contract affecting the compensation, tariff, charge, fare, toll, rental, or classification that must be approved by a regulatory authority.

(100) **Rate class** -- A group of customers taking electric service under the same rate schedule.

(101) **Rate year** -- The 12-month period beginning with the first date that rates become effective. The first date that rates become effective may include, but is not limited to, the effective date for bonded rates or the effective date for interim or temporary rates.

(102) **Ratemaking proceeding** -- A proceeding in which a rate may be changed.

(103) **Registration agent** -- Entity designated by the commission to administer registration and settlement, premise data, and other processes concerning a customer's choice of retail electric provider in the competitive electric market in Texas.

(104) **Regulatory authority** -- In accordance with the context where it is found, either the commission or the governing body of a municipality.

(105) **Renewable demand side management (DSM) technologies** -- Equipment that uses a renewable energy resource (renewable resource) as defined in this section, that, when installed at a customer site, reduces the customer's net purchases of energy (kWh), electrical demand (kW), or both.

(106) **Renewable energy** -- Energy derived from renewable energy technologies.

(107) **Renewable energy credit (REC)** -- A tradable instrument representing the generation attributes of one MWh of electricity from renewable energy sources, as authorized by the Public Utility Regulatory Act §39.904 and implemented under §25.173(e) of this title (relating to Goal for Renewable Energy).

(108) **Renewable energy credit account (REC account)** -- An account maintained by the renewable energy credits trading program administrator for the purpose of tracking the production, sale, transfer, purchase, and retirement of RECs by a program participant.

(109) **Renewable energy resource (renewable resource)** -- A resource that produces energy derived from renewable energy technologies.

(110) **Renewable energy technology** -- Any technology that exclusively relies on an energy source that is naturally regenerated over a short time and derived directly from the sun, indirectly from the sun or from moving water or other natural movements and mechanisms of the environment. Renewable energy technologies include those that rely on energy derived directly from the sun, on wind, geothermal, hydroelectric, wave, or tidal energy, or on biomass or biomass-based waste products, including landfill gas. A renewable energy technology does not rely on energy resources derived from fossil fuels, waste products from fossil fuels, or waste products from inorganic sources.

(111) **Repowering** -- Modernizing or upgrading an existing facility in order to increase its capacity or efficiency.

(112) **Residential customer** -- Retail customers classified as residential by the applicable bundled utility tariff, unbundled transmission and distribution utility

tariff or, in the absence of classification under a residential rate class, those retail customers that are primarily end users consuming electricity at the customer's place of residence for personal, family or household purposes and who are not resellers of electricity.

(113) **Retail customer** -- The separately metered end-use customer who purchases and ultimately consumes electricity.

(114) **Retail electric provider (REP)** -- A person that sells electric energy to retail customers in this state. A retail electric provider may not own or operate generation assets.

(115) **Retail electric provider (REP) of record** -- The REP assigned to the electric service identifier (ESI ID) in ERCOT's database. There can be no more than one REP of record assigned to an ESI ID at any specific point in time.

(116) **Retail stranded costs** -- That part of net stranded cost associated with the provision of retail service.

(117) **Retrofit** -- The installation of control technology on an electric generating facility to reduce the emissions of nitrogen oxide, sulfur dioxide, or both.

(118) **River authority** -- A conservation and reclamation district created pursuant to the Texas Constitution, Article 16, Section 59, including any nonprofit corporation created by such a district pursuant to the Texas Water Code, Chapter 152, that is an electric utility.

(119) **Rule** -- A statement of general applicability that implements, interprets, or prescribes law or policy, or describes the procedure or practice requirements of the commission. The term includes the amendment or repeal of a prior rule, but

does not include statements concerning only the internal management or organization of the commission and not affecting private rights or procedures.

(120) **Separately metered** -- Metered by an individual meter that is used to measure electric energy consumption by a retail customer and for which the customer is directly billed by a utility, retail electric provider, electric cooperative, or municipally owned utility.

(121) **Service** -- Has its broadest and most inclusive meaning. The term includes any act performed, anything supplied, and any facilities used or supplied by an electric utility in the performance of its duties under the Public Utility Regulatory Act to its patrons, employees, other public utilities or electric utilities, an electric cooperative, and the public. The term also includes the interchange of facilities between two or more public utilities or electric utilities.

(122) **Spanish-speaking person** -- A person who speaks any dialect of the Spanish language exclusively or as their primary language.

(123) **Standard meter** -- The minimum metering device necessary to obtain the billing determinants required by the transmission and distribution utility's tariff schedule to determine an end-use customer's charges for transmission and distribution service.

(124) **Stranded cost** -- The positive excess of the net book value of generation assets over the market value of the assets, taking into account all of the electric utility's generation assets, any above-market purchased power costs, and any deferred debit related to a utility's discontinuance of the application of Statement of Financial Accounting Standards Number 71 ("Accounting for the Effect of

Certain Types of Regulation") for generation-related assets if required by the provisions of the Public Utility Regulatory Act (PURA), Chapter 39. For purposes of PURA §39.262, book value shall be established as of December 31, 2001, or the date a market value is established through a market valuation method under PURA §39.262(h), whichever is earlier, and shall include stranded costs incurred under PURA §39.263.

(125) **Submetering** -- Metering of electricity consumption on the customer side of the point at which the electric utility meters electricity consumption for billing purposes.

(126) **Summer net dependable capability** -- The net capability of a generating unit in megawatts (MW) for daily planning and operational purposes during the summer peak season, as determined in accordance with requirements of the reliability council or independent organization in which the unit operates.

(127) **Supply-side resource** -- A resource, including a storage device, that provides electricity from fuels or renewable resources.

(128) **System emergency** -- A condition on a utility's system that is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

(129) **Tariff** -- The schedule of a utility, municipally-owned utility, or electric cooperative containing all rates and charges stated separately by type of service, the rules and regulations of the utility, and any contracts that affect rates, charges, terms or conditions of service.

(130) **Termination of service** -- The cancellation or expiration of a sales agreement or contract by a retail electric provider by notification to the customer and the registration agent.

(131) **Tenant** -- A person who is entitled to occupy a dwelling unit to the exclusion of others and who is obligated to pay for the occupancy under a written or oral rental agreement.

(132) **Test year** -- The most recent 12 months for which operating data for an electric utility, electric cooperative, or municipally-owned utility are available and shall commence with a calendar quarter or a fiscal year quarter.

(133) **Texas jurisdictional installed generation capacity** -- The amount of an affiliated power generation company's installed generation capacity properly allocable to the Texas jurisdiction. Such allocation shall be calculated pursuant to an existing commission-approved allocation study, or other such commission-approved methodology, and may be adjusted as approved by the commission to reflect the effects of divestiture or the installation of new generation facilities.

(134) **Transition bonds** -- Bonds, debentures, notes, certificates, of participation or of beneficial interest, or other evidences of indebtedness or ownership that are issued by an electric utility, its successors, or an assignee under a financing order, that have a term not longer than 15 years, and that are secured or payable from transition property.

(135) **Transition charges** -- Non-bypassable amounts to be charged for the use or availability of electric services, approved by the commission under a financing order to recover qualified costs, that shall be collected by an electric utility, its

successors, an assignee, or other collection agents as provided for in a financing order.

(136) **Transmission and distribution business unit (TDBU)** -- The business unit of a municipally owned utility/electric cooperative, whether structurally unbundled as a separate legal entity or functionally unbundled as a division, that owns or operates for compensation in this state equipment or facilities to transmit or distribute electricity at retail, except for facilities necessary to interconnect a generation facility with the transmission or distribution network, a facility not dedicated to public use, or a facility otherwise excluded from the definition of electric utility in a qualifying power region certified under the Public Utility Regulatory Act §39.152. Transmission and distribution business unit does not include a municipally owned utility/electric cooperative that owns, controls, or is an affiliate of the transmission and distribution business unit if the transmission and distribution business unit is organized as a separate corporation or other legally distinct entity. Except as specifically authorized by statute, a transmission and distribution business unit shall not provide competitive energy-related activities.

(137) **Transmission and distribution utility (TDU)** -- A person or river authority that owns, or operates for compensation in this state equipment or facilities to transmit or distribute electricity, except for facilities necessary to interconnect a generation facility with the transmission or distribution network, a facility not dedicated to public use, or a facility otherwise excluded from the definition of "electric utility", in a qualifying power region certified under the Public Utility Regulatory

Act (PURA) §39.152, but does not include a municipally owned utility or an electric cooperative. The TDU may be a single utility or may be separate transmission and distribution utilities.

(138) **Transmission line** -- A power line that is operated at 60 kilovolts (kV) or above, when measured phase-to-phase.

(139) **Transmission service** -- Service that allows a transmission service customer to use the transmission and distribution facilities of electric utilities, electric cooperatives and municipally owned utilities to efficiently and economically utilize generation resources to reliably serve its loads and to deliver power to another transmission service customer. Includes construction or enlargement of facilities, transmission over distribution facilities, control area services, scheduling resources, regulation services, reactive power support, voltage control, provision of operating reserves, and any other associated electrical service the commission determines appropriate, except that, on and after the implementation of customer choice in any portion of the Electric Reliability Council of Texas (ERCOT) region, control area services, scheduling resources, regulation services, provision of operating reserves, and reactive power support, voltage control and other services provided by generation resources are not “transmission service”.

(140) **Transmission service customer** -- A transmission service provider, distribution service provider, river authority, municipally-owned utility, electric cooperative, power generation company, retail electric provider, federal power marketing agency, exempt wholesale generator, qualifying facility, power marketer, or other person whom the commission has determined to be eligible to be a transmission

service customer. A retail customer, as defined in this section, may not be a transmission service customer.

(141) **Transmission service provider (TSP)** -- An electric utility, municipally-owned utility, or electric cooperative that owns or operates facilities used for the transmission of electricity.

(142) **Transmission system** -- The transmission facilities at or above 60 kilovolts (kV) owned, controlled, operated, or supported by a transmission service provider or transmission service customer that are used to provide transmission service.

§25.130. Advanced Metering.

(a) **Purpose.** This section addresses the deployment, operation, and cost recovery for advanced metering systems.

(b) **Applicability**. This section is applicable to all electric utilities, including transmission and distribution utilities. Any requirement applicable to an electric utility in this section that relates to retail electric providers (REPs) or REPs of record is applicable only to electric utilities operating in areas open to customer choice.

(c) **Definitions**. As used in this section, the following terms have the following meanings, unless the context indicates otherwise:

(1) Advanced meter -- Any new or appropriately retrofitted meter that functions as part of an advanced metering system and that has the minimum system features specified in this section, except to the extent the electric utility has obtained a waiver of a minimum feature from the commission.

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

(5) Web portal --The website made available on the internet in compliance with this section by an electric utility or a group of electric utilities through which secure, read-only access to AMS usage data is made available to the customer, the customer's REP of record, and entities authorized by the customer.

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

(1) Deployment and use of an 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 must 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 must 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 under 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 will be a ratemaking proceeding and a proceeding involving only a request for approval of deployment will not be a ratemaking proceeding.

(3) The statement of AMS functionality must:

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

(B) describe any variances between technologies and meter functions within the electric utility's 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 must 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 or integration into an existing web portal;

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

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

(5) An electric utility must 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 the monthly progress reports required under paragraph (9) of this subsection may be filed confidentially. An electric utility's deployment plan must be maintained and

made available for review on the electric utility's website. Competitively sensitive information contained in the deployment plan must 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 will 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 must not be unreasonably discriminatory, prejudicial, preferential, or anticompetitive.

(9) Each electric utility must provide progress reports on a monthly basis following the filing of its deployment plan with the commission until deployment is complete. Upon filing of such reports, an electric utility operating in an area open to customer choice must notify all REPs of the filing through standard market notice procedures. A monthly progress report must be filed within 15 days of the end of the month to which it applies, and must include the following information:

(A) the number of advanced meters installed, listed by electric service identifier for meters in the Electric Reliability Council of Texas (ERCOT) region. Additional deployment information if available must also be provided, such as county, city, zip code, feeder numbers, and any other easily discernable geographic identification available to the electric utility about the meters that have been deployed;

(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 must obtain commission approval before making any changes to its AMS that would affect the ability of a customer, the customer's REP of record, or entities authorized by the customer 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 will 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 must file an amendment to its notice of deployment at least 45 days before making any changes to its AMS that would affect the ability of a customer, the customer's REP of record, or entities authorized by the customer 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 from the system must be communicated to the REP through the outage and 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). Notification of any planned or unplanned outage that affects access to customer usage data must be posted on the electric utility's web portal home page.

(12) An electric utility subject to §25.343 of this title (relating to Competitive Energy Services) must not provide any advanced metering equipment or service that is deemed a competitive energy service under that section. Any functionality of the AMS that is a required feature under this section or that is included in an approved deployment plan or otherwise approved by the commission does not constitute a competitive energy service under §25.343 of this title.

(e) **Technology requirements.** Except for pilot programs, an electric utility must 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 must be sent by the electric utility to all REPs and all entities authorized by a customer to have read-only access to the customer's advanced meter data.

(g) **AMS features.**

(1) An AMS must provide or support the following minimum system features:

(A) automated or remote meter reading;

(B) two-way communications between the meter and the electric utility;

(C) remote disconnection and reconnection capability for meters rated at or below 200 amps.

(D) time-stamped meter data;

(E) access to customer usage data by the customer, the customer's REP of record, and entities authorized by the customer provided that 15-minute interval or shorter data from the electric utility's AMS must be transmitted to the electric utility's or a group of electric utilities' web portal on a day-after basis;

(F) capability to provide on-demand reads of a customer's advanced meter through the graphical user interface of an electric utility's or a group of electric utilities' web portal when requested by a customer, the customer's REP of record, or entities authorized by the customer subject to network traffic such as interval data collection, market orders if applicable, and planned and unplanned outages;

(G) for an electric utility that provides access through an application programming interface, the capability to provide on-demand reads of a customer's advanced meter data, subject to network traffic such as interval data collection, market orders if applicable, and planned and unplanned outages;

(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 or International Electrotechnical Commission (IEC) DLMS-COSEM standards;

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

(J) for an electric utility in the ERCOT region, the 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 through the electric utility's AMS. This requirement applies only to a HAN device paired to a meter and in use at the time that the version of the web portal approved in Docket Number 47472 was implemented and terminates when the HAN device is disconnected at the request of the customer or a move-out transaction occurs for the customer's premises; and

(K) the ability to upgrade these features as the need arises.

(2) A waiver from any of the requirements of paragraph (1) of this subsection may be granted by the commission if it would be uneconomic or technically infeasible to implement or there is an adequate substitute for that particular requirement. The electric utility must meet its burden of proof in its waiver request.

(3) 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.

(4) Once an electric utility has deployed its advanced meters, it may add or enhance features provided by AMS, as technology evolves. The electric utility must 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 must follow the monthly progress report process described in subsection (d)(9) of this section until the enhancement process is complete.

(h) **Discretionary Meter Services.** An electric utility that operates in an area that offers customer choice must offer, as discretionary services in its tariff, installation of enhanced advanced meters and advanced meter features.

(1) A REP may request the electric utility to provide enhanced 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.

(2) The REP must pay the reasonable differential cost for the enhanced advanced meters or features and system changes required by the electric utility to offer those meters or features.

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

(4) If an electric utility deploys enhanced advanced meters or advanced meter features not addressed in its tariff at the request of the REP, the electric utility must expeditiously apply to amend its tariff to specifically include the enhanced advanced meters or meter features that it agreed to deploy. Additional REPs may

request the tariffed enhanced advanced meters or advanced meter features under the process described in this paragraph of this subsection.

(i) **Tariff.** All discretionary AMS features offered by the electric utility must be described in the electric utility's tariff.

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

(1) A customer may authorize its meter data to be available to an entity other than its REP. An electric utility must provide a customer, the customer's REP of record, 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 must be convenient and secure, and the data must 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 must 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 must begin no later than six months from the filing of the notice of deployment with the commission.

(3) An electric utility's or group of electric utilities' web portal must use robust and reliable standards and methods to provide secure access for the customer, the customer's REP of record, and entities authorized by the customer to the meter data. The electric utility must have an independent security audit conducted within one year of providing that access to meter data. The electric utility must promptly report the audit results to the commission.

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

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

(1) **Recovery Method.** The commission will 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 must not be established until after a detailed deployment plan is filed under subsection (d) of this section. In addition, the surcharge must not ultimately recover more than the AMS costs that are spent, reasonable and necessary, and fully allocated, but may include estimated costs that will 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 must not be included in the surcharge provided for by this subsection unless an electric

utility has received a waiver under subsection (g)(2) of this section. The costs of providing AMS services include those costs of AMS installed as part of a pilot program under this section. Costs of providing AMS for a particular customer class must 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 must 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 must be correspondingly adjusted to reflect the new authorized WACC.

(3) **Surcharge Proceeding.** In the request for surcharge proceeding, the commission will set the surcharge based on a levelized amount, and an amortization period based on the useful life of the AMS. 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 will 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 must file annual reports with the commission updating the cost information used in setting the surcharge. The annual reports must 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 will not be a ratemaking proceeding, but an application by the electric utility to update the surcharge must be a ratemaking proceeding.

(6) **Reconciliation Proceeding.** All costs recovered through the surcharge must be reviewed in a reconciliation proceeding on a schedule to be determined by the

commission. Notwithstanding 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, must be refunded to electric utility's customers. In addition, the commission will 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 must be at the electric utility's WACC and must begin at the time the under or over recovery occurred.

(7) **Cross-subsidization and fees.** The electric utility must account for its costs in a manner that ensures 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.

§25.133. Non-Standard Metering Service.

(a) **Purpose.** This section allows a customer to choose to receive electric service through a non-standard meter from an electric utility that has deployed or is requesting to deploy advanced meters under a commission-approved deployment plan or notice of deployment and authorizes the electric utility to assess fees to recover the costs associated with this section from a customer who elects to receive electric service through a non-standard meter.

(b) **Applicability.** This section is applicable to an electric utility, including a transmission and distribution utility, that has deployed or is requesting to deploy advanced meters under a commission-approved deployment plan or notice of deployment. Any requirement in this section that relates to retail electric providers (REPs) is applicable only to REPs and electric utilities that operate in areas open to customer choice.

(c) **Definitions.** As used in this section, the following terms have the following meanings, unless the context indicates otherwise:

(1) Advanced meter -- As defined in §25.130 of this title (relating to Advanced Metering).

(2) Non-standard meter -- A meter that does not function as an advanced meter.

(3) Non-standard metering service -- Provision of electric service through a non-standard meter from an electric utility that has deployed or is requesting to deploy

advanced meters under a commission-approved deployment plan or notice of deployment.

(d) **Initiation and termination of non-standard metering service.**

(1) **Initiation of non-standard metering service.** An electric utility that has deployed or is requesting to deploy advanced meters under a commission-approved deployment plan or notice of deployment must offer non-standard metering service to customers.

(A) An electric utility filing a deployment plan or notice of deployment under §25.130 of this title after the effective date of this section must include non-standard metering service as a part of the plan or notice.

(i) Within 30 days of the date of commission approval of an electric utility's deployment plan or the filing of a notice of deployment, the electric utility must provide information on its website that describes its non-standard metering service, the process under this section to request non-standard metering service, and all the costs associated with the service.

(ii) An electric utility must provide a statement that non-standard metering service is available and provide a hyperlink to the information required under clause (i) of this subparagraph in all notices and messages delivered to a customer relating to the deployment date of advanced meters in the customer's geographic area.

(B) An electric utility must provide notice to a customer consistent with subparagraph (C) of this paragraph within seven days of the customer's request for non-standard metering service, using an appropriate means of service.

(C) An electric utility must notify a customer that requests non-standard metering service of the following through a written acknowledgement.

(i) The customer will be required to pay the costs associated with the initiation of non-standard metering service and the ongoing costs associated with the manual reading of the meter, and other fees and charges that may be assessed by the electric utility that are associated with the non-standard metering service;

(ii) The current one-time fees and monthly fee for non-standard metering service;

(iii) The customer may be required to wait up to 45 days to switch the customer's REP of record;

(iv) The customer may experience longer restoration times in case of a service interruption or outage;

(v) The customer may be required by the customer's REP of record to choose a different product or service before initiation of the non-standard metering service, subject to any applicable charges or fees required under the customer's existing contract, if the customer is currently enrolled in a product or service that relies on an advanced meter; and

(vi) For a customer that does not currently have an advanced meter, the date (60 days after service of the notice) by which the customer must provide a signed, written acknowledgement and payment of the one-time fee to the electric utility prescribed by subsection (f)(3) of this section. If the signed, written acknowledgement and payment are not received within 60 days, the electric utility will install an advanced meter on the customer's premises.

(D) The electric utility must retain the signed, written acknowledgement for at least two years after the non-standard meter is removed from the premises. The commission may adopt a form for the written acknowledgement.

(E) An electric utility must offer non-standard metering through the following means:

(i) disabling communications technology in an advanced meter if feasible;

(ii) if applicable, allowing the customer to continue to receive metering service using the existing meter if the electric utility determines that it meets applicable accuracy standards;

(iii) if commercially available, an analog meter that meets applicable meter accuracy standards; and

(iv) a digital, non-communicating meter.

(F) The electric utility must not initiate the process to provide non-standard metering service before it has received the customer's payment and signed, written acknowledgement. The electric utility must initiate the approved standard market process to notify the customer's REP of record within three days of the electric utility's receipt of the customer's payment and signed, written acknowledgement. Within 30 days of receipt of the payment of the one-time fee and the signed written acknowledgement from the customer, the electric utility, using the approved standard market process, must notify the customer's REP of record of the date the non-standard metering service was initiated.

(2) **Termination of non-standard metering service**. A customer receiving non-standard metering service may terminate that service by notifying the customer's electric utility. The customer will remain responsible for all costs related to non-standard metering service.

(e) **Other electric utility obligations.**

(1) When an electric utility completes a move-out transaction for a customer who was receiving non-standard metering service, the electric utility must install or activate an advanced meter at the premises.

(2) An electric utility must read a non-standard meter monthly. In order for the electric utility to maintain a non-standard meter at the customer's premises, the customer must provide the electric utility with sufficient access to properly operate and maintain the meter, including reading and testing the meter.

(f) **Cost recovery and compliance tariffs.** All costs incurred by an electric utility to implement this section must be borne only by customers who choose non-standard metering service. A customer receiving non-standard metering service must be charged a one-time fee and a recurring monthly fee.

(1) An electric utility's application for approval of its non-standard metering service tariff or amended tariff must be fully supported with testimony and documentation. The application must include one-time fees and a monthly fee for non-standard metering service and must also include the fees for other discretionary services performed by the electric utility that are affected by the customer's selection of non-standard metering service. The commission will allow the electric utility to recover the reasonable rate case expenses that it incurs under this paragraph as part of the one-time fee, the monthly fee, or both. The application must describe the extent to which the back-office costs that are new and fixed vary depending on the number of customers receiving non-standard metering service. Unless otherwise ordered, the electric utility must serve notice of the approved rates and the effective date of the approved rates within five working days of the filing of the commission's final order to REPs that are authorized by the registration agent to provide service in the electric utility's service area. Notice to REPs under this paragraph may be served by email and must be served at least 45 days before the effective date of the rates.

(2) An electric utility must have a single recurring monthly fee for non-standard metering service and several one-time fees, one of which must apply to the customer depending on the customer's circumstances. A one-time fee must be charged to a customer that does not have an advanced meter at the customer's premises and will continue receiving metering service through the meter currently

at the premises. For a customer that currently has an advanced meter at the premises, the fee will vary depending on the type of meter that is installed to provide non-standard metering service, and the fee must include the cost to remove the advanced meter and subsequently re-install an advanced meter once non-standard metering service is terminated. The one-time fee must recover costs to initiate non-standard metering service. The monthly fee must recover ongoing costs to provide non-standard metering service, including costs for meter reading and billing. Fixed costs not related to the initiation of non-standard metering service may be allocated between the one-time and monthly fees and recovered through the monthly fee over a shortened period of time.

(g) **Retail electric product compatibility.** After receipt of the notice prescribed by subsection (d)(1)(C) of this section, if the customer's current product is not compatible with non-standard metering service, the customer's REP of record must work with the customer to either promptly transition the customer to a product that is compatible with non-standard metering service or transfer the customer to another REP, subject to any applicable charges or fees required under the customer's existing contract. If the customer is unresponsive, the customer's REP of record may transition the customer without the customer's affirmative consent to a market-based, month-to-month product that is compatible with non-standard metering service. Alternatively, if the customer is unresponsive, the customer's REP of record may transfer the customer to another REP under §25.493 (relating to Acquisition and Transfer of Customers from One Retail Electric Provider or Another) so long as the new REP serves the customer using a market-based, month-to-month product with a rate (excluding charges for non-standard metering service or other discretionary services) no higher than one of the tests prescribed by §25.498(c)(15)(A)-(C) of this title (relating to Prepaid Service). The customer's REP of record must promptly provide the customer notice that the customer has been transferred to a new product and, if applicable, to a new REP, and must also promptly provide the new Terms of Service and Electricity Facts Label.

This agency 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 §_____ relating to [insert title in lowercase] [is or are] hereby adopted ["with" or "with no"] changes to the text as proposed.

Signed at Austin, Texas the ______ day of April 2020.

PUBLIC UTILITY COMMISSION OF TEXAS

____

DEANN T. WALKER, CHAIRMAN

____

ARTHUR C. D'ANDREA, COMMISSIONER

____

SHELLY BOTKIN, COMMISSIONER

PROJECT NO. 48525

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

(STAFF RECOMMENDATION)
ORDER ADOPTING AMENDMENTS TO §§25.5, 25.130, AND 25.133 FOR CONSIDERATION AT THE APRIL 17, 2020 OPEN MEETING

The Public Utility Commission of Texas (commission) adopts amendments to 16 Texas Administrative Code (TAC) §25.5, relating to definitions; §25.130, relating to advanced metering; and §25.133, relating to non-standard metering service, with changes to the proposed text as published in the November 29, 2019 issue of the *Texas Register* (44 TexReg 7263). The amendments to §§25.130 and 25.133 conform the rules to Senate Bill 1145, 85th Legislature, Regular Session, which amended Public Utility Regulatory Act (PURA) §39.452, and to the following bills from the 86th Legislature, Regular Session: House Bill 853, which amended PURA §39.5521; House Bill 986, which amended PURA §39.402; and House Bill 1595, which amended PURA §39.5021. These bills encourage deployment of advanced metering and meter information networks by extending the applicability of PURA §39.107(h) and (k) to electric utilities providing service in areas outside the Electric Reliability Council of Texas (ERCOT) region.

The amendments also remove the requirement for an electric utility to offer the home area network (HAN) feature and set minimum capabilities for on-demand reads of customers' advanced meter data. In addition, the amendments clarify and define rule language; remove rule language relating to an electric utility's limitation of liability because this issue is addressed in the electric utility's tariff; and remove obsolete and other unnecessary rule language. These amendments are adopted under Project No. 48525.

The commission received comments on the proposed amendments from Southwestern Electric Power Company, El Paso Electric Company, Entergy Texas, Inc., and Southwestern Public Service Company (collectively Joint Non-ERCOT Utilities); Alliance for Retail Markets (ARM); Texas Energy Association for Marketers (TEAM); Office of Public Utility Counsel (OPUC); Mission:Data Coalition (Mission:Data); Texas Advanced Energy Business Alliance (TAEBA); Enel X North America, Inc. (Enel X); Lone Star Chapter of Sierra Club (Sierra Club); Texas Solar Power Association (TSPA); and Solar Energy Industries Association (SEIA). In addition, the commission received joint initial comments from AEP Texas Inc. (AEP), CenterPoint Energy Houston Electric, LLC, (CenterPoint) and Texas-New Mexico Power Company (TNMP) and joint reply comments from these utilities and Oncor Electric Delivery LLC (Oncor; collectively Joint ERCOT TDUs). There was no request for a public hearing.

Comments on §25.5 (definitions)

ARM supported the commission's proposed inclusion of a definition for "retail electric provider (REP) of record" to distinguish it from the general definition for retail electric provider.

Commission Response

The commission agrees with ARM and adopts the definition as proposed.

Comments on §25.130(c) (definitions)

TSPA recommended two changes to the definition of "web portal." The first recommended change was to add the word "secure" before "read-only access" to add clarity that the web portal needs to be secure because of the growing threat of cyber-attacks. TSPA also recommended that data be accessible in a standardized format to facilitate software development so customers, REPs, and other entities authorized to have access will not be required to use the web portal graphical user interface.

The Joint Non-ERCOT Utilities opposed TSPA's proposed changes to the definition of web portal. The Joint Non-ERCOT Utilities pointed out that §25.130(j) already requires access to the web portal to be secure. Concerning TSPA's proposal to require data accessibility in a standardized format, the Joint Non-ERCOT Utilities argued that TSPA did not consider or quantify the cost that would be imposed on utilities and their customers. The Joint Non-ERCOT Utilities stated that the costs of this proposal outweigh the benefits to customers.

ARM acknowledged that data provided in a standardized format facilitates software development to make data more readily available to customers and REPs. However, ARM stated that Smart Meter Texas (SMT) already provides data in a standardized format, so it is unclear what additional format standardization TSPA is requesting.

TEAM recommended a change to the definition of "web portal" to delete "by an electric utility or a group of electric utilities." TEAM advocated for this change to leave open the possibility in the future for ERCOT to perform some or all the features of access to advanced meter data. However, TEAM did not advocate for this change presently. ARM expressed support for