PROJECT NO. 56897

ELECTRIC UTILITY OUTAGE TRACKER AND HAZARDOUS CONDITION REPORTING	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER ADOPTING AMENDMENTS TO §25.52

The Public Utility Commission of Texas (commission) adopts amendments to 16 Texas Administrative Code (TAC) §25.52 relating to Reliability and Continuity of Service with changes to the proposed text as published in the August 30, 2024, issue of the Texas Register (49 TexReg 6666). The rule is adopted in Project No. 56897.

The amended rule requires each transmission and distribution utility to maintain an online outage tracker that provides detailed information regarding power outages in English and in Spanish. The amended rule also requires a utility to notify the commission if the outage tracker or outage map becomes unavailable.

Public Comments

Comments were received by the Alliance for Retail Markets, (ARM); AEP Texas Inc. and Southwestern Electric Power Company, (AEP Companies); CenterPoint Energy Houston Electric, LLC, (CenterPoint); Electric Transmission Texas, LLC, (ETT); Entergy Texas, Inc, (ETI); LCRA Transmission Services Corporation, (LCRA TSC); Office of Public Utility Counsel, (OPUC); Octopus Energy LLC, (Octopus); Oncor Electric Delivery Company LLC, (Oncor); Sharyland Utilities, LLC, (Sharyland); Southwestern Public Service Company, (SPS); Texas Electric

Cooperatives, Inc, (TEC); Texas Energy Association for Marketers, (TEAM); Texas New Mexico Power Company, (TNMP); and Texas Public Power Association, (TPPA).

General Comments

Comments beyond the scope

OPUC requested that the rule require alerts of potential outages, clearly identify which customers may be affected by the outage, and limit the alerts to customers who may be affected, rather than all customers. Further, OPUC requested that alerts of potential outages should also be sent to OPUC.

TEC requested the addition of a new paragraph that would require transmission service providers to give updates regarding restoration efforts to their impacted distribution service providers during a system restoration event. TEC also requested the addition of a new subsection that would require transmission service providers to give equal priority to restoration of distribution systems that are operated by other utilities, municipally owned utilities, or electric cooperatives.

ARM proposed a new paragraph to authorize TDUs (Transmission and Distribution Utility) to use REPs' provided customer contact information for the purpose of communicating with customers about power outages and restorations during emergencies, when the TDU received such customer contact information from a REP pursuant to basic retail market transactions and the TDU's tariff. ARM recommended that the Commission withdraw the proposed revisions to §25.472, and instead, recommends adding amendments to 16 TAC §25.52 that specify TDU obligations with respect to the use of customer contact information, which is the more efficient and appropriate place to include TDU obligations.

TEAM proposed adding a new paragraph to establish a TDU's responsibilities with respect to the use of customer information provided by a REP, including permitted uses for contact information, content of the TDU' s outage and restoration communications, and requirements for the system used by the TDU to store the contact information and provide communications. Further, TEAM requested if the commission chooses to permit a utility to use contact information provided by a REP to facilitate customer communications, then TEAM recommends the adoption of rule language addressing a TDU's ability to use customer information that is currently provided by REPs.

ARM and TEAM recommended that the commission adopt a new paragraph to require TDUs to provide real-time outage information for impacted ESI IDs to the REP of record in a central repository, like Smart Meter Texas.

Octopus recommended the addition of a new subparagraph which would require transmission distribution utilities to provide retail electric providers with the option to receive customer outage status and restoration data for the retail electric provider own costumers via a REST API.

Commission response

The commission declines to modify the rule in response to the above comments. The focus of proposed subsection (b)(7) and this rulemaking proceeding is a utility's passive online resources. Issues involving active utility notification systems, consumer information, and power restoration priority are beyond the scope noticed in this proceeding.

Premise-specific information

TEAM stated that based on the proforma Tariff for Retail Delivery Service, the customer should not have to sign-up for an alert system or provide information other than their service address to receive basic, premise-specific outage information, and instead the responsibility should lie with the TDU.

Commission Response

The commission declines to modify the rule to specify what information a customer must provide to see premise-specific information. Some utilities have indicated that they do not provide premise specific information without a user providing some identifying information out of concern for the safety of the individuals and property in the unpowered houses illustrated on the outage tracker or outage map. This is a reasonable policy for a utility to have, and the commission will not prohibit it by rule.

Outage tracker granularity and accuracy

TPPA requested the rule specify the magnitude and duration of outage that must be captured on the utility's outage tracker. TPPA offers the example of an outage effecting a single customer for a single hour.

ARM recommended the commission establish accuracy standards for a utility's outage tracker to ensure that the information provided to customers and to the public is reasonably reliable. ARM suggested the commission measure and establish standards for outage tracker load time, customer demand support, speed from outage report to outage tracker notice, and the stability/accuracy of restoration time estimates.

Commission Response

The commission declines to specify a magnitude or duration threshold below which an outage is not required to included on the outage tracker or outage map as recommended by TPPA. The commission expects utilities to provide information with as much granularity as is reasonably practicable and will use its enforcement discretion, as appropriate.

The commission also declines to develops accuracy standards for utility outage trackers as requested by ARM. This rulemaking represents the commission's first requirements related to utility outage trackers, and it is premature to adopt accuracy standards at this time.

Applicability of outage tracker requirements

Sharyland requested the commission clarify the rule to exempt transmission service providers with no certificated service territory or retail customers from the requirement to maintain an outage tracker.

Commission response

The commission agrees with Sharyland and modifies the rule to require an outage tracker or outage map from a utility that provides distribution service to retail customers. The primary

purpose of this rule is to provide end-use customers with information about whether their homes and businesses have power.

Implementation timeline requirements

Oncor, AEP Companies, SPS, and CenterPoint Energy requested additional time to implement the requirements of the proposed rule amendments. Oncor requested the commission consider the time and resources required to make these changes. AEP Companies requested that the deadline to comply with the outage rule be the end of the first quarter of 2025 to provide entities with ample time. CenterPoint Energy requested (b)(7)(A) be modified to provide an electric utility until June 1, 2025, to have the electric utility's outage tracker provide information in Spanish.

Commission Response

The commission declines to extend the effective date of this rule, as requested by commenters. Each utility must begin maintaining a functional outage tracker and comply with the notification requirements proposed in the rule immediately upon the effective date of the rule. However, the commission modifies the rule to allow a utility to make a filing in this project identifying specific requirements that it needs more time to implement, the reason it cannot implement the requirement immediately, and a projected implementation date that is no later than June 1, 2025. A utility that makes such a filing, may delay compliance of these identified requirements until the earlier of the requirement's projected implementation date and June 1, 2025. This approach ensures that retail customers have immediate access

to a functional outage tracker and there is transparency with regards to features that are not immediately available.

Rate treatment

SPS recommended amending subsection (b)(7)(D) to indicate that costs associated with necessary improvements be recoverable.

Commission Response

The commission declines to modify the rule to address what rate treatment is appropriate for system changes that a utility is required to make to comply with the provisions of this rule. Any costs incurred coming into compliance with this rule will be addressed in an appropriate rate case according to the applicable rules and standards.

Proposed §25.52(b)(6)

Proposed §25.52(b)(6) requires utilities to make available to state and local authorities a method to report a potential hazardous condition that may require disconnection of service six months after the effective date of this rule.

The commission received comments on subsection (b)(6) from AEP Companies, CenterPoint Energy, Oncor, SPS, TEC and TPPA. Commenters requested further clarity on the applicability of terms in this section, including "potential hazardous conditions" and "state and local authorities."

Commenters also expressed confusion on which party ultimately had the responsibility to report hazards and who ultimately would make the decision to disconnect.

Commenters requested further clarity on the reporting requirements applicable to MOUs and Cooperatives. To address the concerns listed, commenters recommended the commission host a workshop to fine tune these details. TPPA recommended modifying the rule to require contact information provided in EOPs be used by the Commission, the Railroad Commission, and State Fire Marshall to report potential hazardous conditions that may require a disconnection of service instead of creating new methods.

Commission Response

The commission modifies the rule to remove proposed subsection (b)(6). The commission already has sufficient authority to obtain the necessary contact information, as needed. Accordingly, the commission does not accept any commenter suggestions, because they are moot.

Proposed §25.52(b)(7)

Proposed §25.52(b)(7) requires each utility to provide access to an outage tracker on their website.

Oncor requested that the references to outage tracker be replaced with "outage map or outage tracker." ETT recommended subsection (b)(7) be modified to specify that it applies to a utility that serves retail delivery customers.

LCRA TSC noted that the proposed rule does not distinguish the distribution system from the transmission system and, therefore, it is unclear whether the requirement to maintain a publicly available outage tracker applies to both transmission and distribution systems. LCRA TSC stated that because transmission-level outage information is protected from public disclosure under federal and state law and requested that this information not be disclosed to the public.

TPPA requested clarity on the applicability of the rule to river authorities.

Commission response

The commission agrees with Oncor and modifies the rule to refer to an outage tracker or "outage map".

The commission agrees with ETT, LCRA TSC, and TPPA and modifies the rule's applicability for clarity. Specifically, the commission modifies the rule to clarify the outage tracker requirements apply to distribution systems. This edit also sufficiently addresses LCRA and TPPA's concerns.

Proposed §25.52(b)(7)(A) – Map Requirements

Proposed §25.52(b)(7)(A) requires that the publicly available online outage tracker contain a map of the utility's service territory that identifies, for each active outage, the location of the outage, the date and time the outage was reported or otherwise identified, an estimated restoration time, the status of the restoration effort, and the date and time the information was most recently updated.

TEAM recommended the addition of language to subsection (b)(7)(A) that specifies the frequency with which the map and outage tracker are updated to ensure that new construction is captured in a timely manner. ARM requested modifying (b)(7)(A) to require that utilities regularly update the service addresses included in the outage tracker.

Commission response

The commission agrees with commenters that it is necessary that the outage tracker or outage map be updated to reflect new or updated service addresses as soon as practicable and modifies the rule accordingly.

AEP Companies requested that the outage tracker requirements be modified to require a general outage location instead of premise specific location and to remove the requirement for the status of restoration efforts.

TNMP and Oncor requested (b)(7)(A) be modified to require a map showing the "*approximate* location of the outage" and the "*genera*l status of the restoration effort."

Oncor recommended (b)(7)(A) be modified to require "*a general*, estimated restoration time *for outages in a given area or region*." Oncor argued that during large-scale outages where there has been significant damage to its facilities, Oncor typically uses banner messaging that provides updates on a region-based level. In these instances, Oncor provides a date and time when it expects a majority of customers that are capable of receiving power to be restored. Oncor also explained that during multi-day events, there may be subsequent outages that interfere with initial restoration attempts, further complicating Oncor's ability to provide accurate estimates.

Oncor also recommended the deletion of the requirement to provide the date and time the outage was reported or otherwise identified in (b)(7)(A). Oncor argued that in many cases, infrastructure damage and resulting outages may occur in an ongoing, compounding fashion, leading to nesting outages. Oncor also explained that during extended weather events, an area may lose power multiple times in succession. Oncor indicates that in many of these cases, providing information on when an outage began may result in a utility providing inconsistent information to customers.

With regard to the above issues, Oncor also noted that customers could receive more specific outage information via the My Oncor Alerts program.

Commission response

The commission agrees that providing an exact location and exact status of restoration may not be practical for utilities. The commission modifies the rule to require an *approximate* location of outages and a *general* status of restoration efforts.

However, the commission declines to revise the rule to eliminate the requirement that a utility provide the date and time the outage was reported or otherwise identified or modify the rule to only require a "general, estimated restoration time for outages in a given area or region" as requested by Oncor. While the commission acknowledges that there are challenges involved with providing this information during extended, significant outages events, it is

incumbent upon utilities to provide customers with the best available information and estimates regarding ongoing outages as possible – and to continue to explore best practices across the industry to achieve improvements in this area.

Proposed §25.52(b)(7)(B) – Notice for Unavailable Tracker

Under proposed §25.52(b)(7)(B), if a utility's outage tracker is scheduled to be taken offline, it must post details of the scheduled activity on its website and provide notice of the scheduled activity to the commission no later than seven days prior to the scheduled activity. A utility must also immediately notify the commission if its outage tracker becomes unexpectedly unavailable.

Oncor recommended modifying subsection (b)(7)(B) to require a utility to notify the commission "as soon as reasonably practicable after discovering a malfunction" if the utility's outage tracker or map unexpectedly becomes unavailable and removing the requirement that the notification be made "in writing."

ARM requested modifying (b)(7)(B) to clarify that TDUs must notify the commission any time the outage tracker is down for any reason outside of planned maintenance or upgrades.

ETI request that the seven-day lead time proposed in (b)(7)(B) for notification and posting regarding planned or schedule maintenance of its outage tracker be changed to "as soon as reasonably practicable." Alternatively, ETI proposes that the required notice be reduced to two days. Additionally, ETI requests clarification of how a utility must notify the commission "in writing" if an outage tracker unexpectedly becomes unavailable, and what individuals or divisions should be notified.

Commission response

The commission agrees with Oncor that it may not be possible for a utility to notify the commission in writing immediately when its outage tracker becomes unexpectedly unavailable. The commission also agrees with ARM that the requirement to notify the commission as soon as practicable should apply more broadly than in the proposed rule. The commission also agrees with ETI that there may be instances when a utility determines that maintenance is required that needs to be initiated quicker than the seven day notice requirements allow. The commission modifies the rule to require a utility to notify the commission as soon as reasonably practicable if the utility's outage tracker unexpectedly becomes unavailable or if the utility determines that maintenance is required within the next seven days.

The commission declines to codify in rule exactly how a utility must notify the commission in writing of its outage tracker becoming unavailable, because communication pathways between the commission and utilities during emergency conditions may change. Initially, utilities should notify the commission regarding outage tracker unavailability at emc@puc.Texas.gov.

Proposed §25.52(b)(7)(C) – Reporting Methods

Proposed §25.52(b)(7)(B) requires that the outage tracker provide or link to information that indicates the different methods a customer may use to report an outage or hazardous condition, and a link to provide updates on the hazardous condition reported.

TEAM recommended modifying subsection (b)(7)(C) to require that either the outage tracker itself or the methods for reporting an outage or hazardous condition include one digital means for a consumer to make a report that will be received by the TDU.

Commission response

The commission agrees with TEAM and modifies the rule to require a utility to provide at least one digital means for a consumer to report an outage.

Statutory Authority

The amendment is adopted under Public Utility Regulatory Act (PURA) §14.001, which grants the commission 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 this title that is necessary and convenient to the exercise of that power and jurisdiction; §14.002, which authorizes the commission to adopt and enforce rules reasonably required in the exercise of its powers and jurisdiction; §38.005, which requires the commission to implement service quality and reliability standards relating to the delivery of electricity to customers by electric utilities; and PURA §38.072, which requires an electric utility to give nursing facilities, assisted living facilities and hospice facilities the same priority that it gives to a hospital in the utility's emergency operations plan for restoring power after an extended outage; and §38.074, which requires the commission to, in collaboration with the Railroad Commission of Texas, rules to establish a process to designate certain natural gas facilities and entities as critical natural gas customers during energy emergencies and to require utilities to prioritize these facilities for load-shed and power restoration purposes during an energy emergency.

Cross Reference to Statute: Public Utility Regulatory Act §§14.001, 14.002, 38.005, 38.072, 38.074.

§25.52. Reliability and Continuity of Service.

(a) **Application.** This section applies to all electric utilities as defined by §25.5 of this title (relating to Definitions) and all transmission and distribution utilities as defined by §25.5 of this title. When specifically stated, this section also applies to electric cooperatives and municipally-owned utilities (MOUs). The term "utility" as used in this section means an electric utility and a transmission and distribution utility.

(b) **General.**

(1) Every utility must make all reasonable efforts to prevent interruptions of service. When interruptions occur, the utility must reestablish service within the shortest possible time.

(2) Each utility must make reasonable provisions to manage emergencies resulting from failure of service, and each utility must issue instructions to its employees covering procedures to be followed in the event of emergency in order to prevent or mitigate interruption or impairment of service.

(3) In the event of national emergency or local disaster resulting in disruption of normal service, the utility may, in the public interest, interrupt service to other customers to provide necessary service to civil defense or other emergency service entities on a temporary basis until normal service to these agencies can be restored.

(4) Each utility must maintain adequately trained and experienced personnel throughout its service area so that the utility is able to fully and adequately comply with the service quality and reliability standards.

(5) With regard to system reliability, a utility must not neglect any local neighborhood or geographic area, including rural areas, communities of less than 1,000 persons, and low-income areas.

(6) Each utility that provides distribution service to retail customers must maintain an accurate and publicly available online outage tracker or outage map on its website.

(A) An online outage tracker or outage map must contain a map of the utility's distribution service territory that identifies, for each active outage impacting retail distribution customers, the approximate location of the outage, the date and time the outage was reported or otherwise identified, an estimated restoration time, the general status of the restoration effort, and the date and time the outage and restoration status information was most recently updated. Information provided by the outage tracker or outage map under this subparagraph must be updated to include new or updated service addresses in the utility's service territory as soon as practicable, and be available in English and Spanish, as applicable.

(B) If a utility's outage tracker or outage map is scheduled to be taken offline or may otherwise become unavailable due to maintenance or upgrades, the utility must post details of the scheduled activity on its website and provide notice of the scheduled activity to the commission's Consumer Protection and Critical Infrastructure Security and Risk Management divisions no later than seven days prior to the scheduled activity. A utility must, as soon as reasonably practicable, notify the commission in writing if the utility's outage tracker or outage map unexpectedly becomes unavailable or if the utility determines that maintenance is required within the next seven days.

(C) An outage tracker or outage map must provide or link to information that indicates the different methods a customer may use to report an outage or hazardous condition and provide or link to information on how a customer may request to receive updates on the status of outages and outage restoration efforts. The outage tracker or outage map must include at least one digital means for a customer to report an outage to the utility.

(D) Each utility must comply with each of the requirements of this paragraph upon the effective date of this rule except as provided in this subparagraph. A that utility requires additional time to upgrade its outage tracker or outage map to comply with one or more requirements of this paragraph must file an update in this project no later than five working days after the effective date of this rule identifying which requirements it is not capable of complying with, a brief explanation for why immediate compliance is infeasible, and a projected compliance date that is no later than June 1, 2025. A utility may delay compliance with any requirement described in a filing under this subparagraph until the earlier of its projected compliance date and June 1, 2025.

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

(1) **Critical loads** — Loads for which electric service is considered crucial for the protection or maintenance of public 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.

(2) **Critical natural gas facility** — A facility designated as a critical customer by the Railroad Commission of Texas under §3.65(b) of this title (relating to Critical Designation of Natural Gas Infrastructure) unless the facility has obtained an exception from its critical status. Designation as a critical natural gas facility does not guarantee the uninterrupted supply of electricity.

(3) **Energy emergency** — Any event that results in or has the potential to result in firm load shed required by the reliability coordinator of a power region in Texas.

(4) Interruption classifications:

(A) **Forced** — Interruptions, exclusive of major events, that result from conditions directly associated with a component requiring that it be taken out of service immediately, either automatically or manually, or an interruption caused by improper operation of equipment or human error.

(B) **Scheduled** — Interruptions, exclusive of major events, that result when a component is deliberately taken out of service at a selected time for purposes of construction, preventative maintenance, or repair. If it is possible to defer an interruption, the interruption is considered a scheduled interruption.

(C) **Outside causes** — Interruptions, exclusive of major events, that are caused by influences arising outside of the distribution system, such as generation, transmission, or substation outages.

(D) **Major events** — Interruptions that result from a catastrophic event that exceeds the design limits of the electric power system, such as an earthquake or an extreme storm. These events must include situations where there is a loss of power to 10% or more of the customers in a region over a 24-hour period and with all customers not restored within 24 hours.

(5) **Interruption, momentary** — Single operation of an interrupting device which results in a voltage zero and the immediate restoration of voltage.

(6) **Interruption, sustained** — All interruptions not classified as momentary.

(7) **Interruption, significant** — An interruption of any classification lasting one hour or more and affecting the entire system, a major division of the system, a community, a critical load, or service to interruptible customers; and a scheduled interruption lasting more than four hours that affects customers that are not notified in advance. A significant interruption includes a loss of service to 20% or more of the system's customers, or 20,000 customers for utilities serving more than 200,000 customers. A significant interruption also includes interruptions adversely affecting a community such as interruptions of governmental agencies, military bases, universities and schools, major retail centers, and major employers.

(8) **Reliability indices:**

(A) **System Average Interruption Frequency Index (SAIFI)** — The average number of times that a customer's service is interrupted. SAIFI is calculated by summing the number of customers interrupted for each event and dividing by the total number of customers on the system being indexed. A lower SAIFI value represents a higher level of service reliability.

(B) **System Average Interruption Duration Index (SAIDI)** — The average amount of time a customer's service is interrupted during the reporting period. SAIDI is calculated by summing the restoration time for each interruption event times the number of customers interrupted for each event and dividing by the total number of customers. SAIDI is expressed in minutes or hours. A lower SAIDI value represents a higher level of service reliability.

(d) **Record of interruption.** Each utility must keep complete records of sustained interruptions of all classifications. Where possible, each utility must keep a complete record of all momentary interruptions. These records must show the type of interruption, the cause for the interruption, the date and time of the interruption, the duration of the interruption, the number of customers interrupted, the substation identifier, and the transmission line or distribution feeder identifier. In cases of emergency interruptions, the remedy and steps taken to prevent recurrence must be recorded. Each utility must retain records of interruptions for five years.

(e) **Notice of significant interruptions.**

(1) **Initial notice.** A utility must notify the commission, in a method prescribed by the commission, as soon as reasonably possible after it has determined that a significant

interruption has occurred. The initial notice must include the general location of the significant interruption, the approximate number of customers affected, the cause if known, the time of the event, and the estimated time of full restoration. The initial notice must also include the name and telephone number of the utility contact person and must indicate whether local authorities and media are aware of the event. If the duration of the significant interruption is greater than 24 hours, the utility must update this information daily and file a summary report.

(2) **Summary report.** Within five working days after the end of a significant interruption lasting more than 24 hours, the utility must submit a summary report to the commission. The summary report must include the date and time of the significant interruption; the date and time of full restoration; the cause of the interruption, the location, substation and feeder identifiers of all affected facilities; the total number of customers affected; the dates, times, and numbers of customers affected by partial or step restoration; and the total number of customer-minutes of the significant interruption (sum of the interruption durations times the number of customers affected).

(f) **Priorities for power restoration to certain medical facilities.**

(1) A utility must give the same priority that it gives to a hospital in the utility's emergency operations plan for restoring power after an extended power outage, as defined by Texas Water Code, §13.1395, to the following:

(A) An assisted living facility, as defined by Texas Health and Safety Code, §247.002;

(B) A facility that provides hospice services, as defined by Texas Health and Safety Code, §142.001;

(C) A nursing facility, as defined by Texas Health and Safety Code, §242.301; and

(D) An end stage renal disease facility, as defined by Texas Health and Safety Code, §251.001.

(2) The utility may use its discretion to prioritize power restoration for a facility after an extended power outage in accordance with the facility's needs and with the characteristics of the geographic area in which power must be restored.

(g) **System reliability.** Reliability standards apply to each utility and are limited to the Texas jurisdiction. A "reporting year" is the 12-month period beginning January 1 and ending December 31 of each year.

(1) **System-wide standards.** The standards must be unique to each utility based on the utility's performance and may be adjusted by the commission if appropriate for weather or improvements in data acquisition systems. The standards will be the average of the utility's performance from the later of reporting years 1998, 1999, and 2000, or the first three reporting years the utility is in operation.

(A) **SAIFI.** Each utility must maintain and operate its electric distribution system so that its SAIFI value does not exceed its system-wide SAIFI standard by more than 5.0%.

(B) **SAIDI.** Each utility must maintain and operate its electric distribution system so that its SAIDI value does not exceed its system-wide SAIDI standard by more than 5.0%.

(2) **Distribution feeder performance.** The commission will evaluate the performance of distribution feeders with ten or more customers after each reporting year. Each utility must maintain and operate its distribution system so that no distribution feeder with ten or more customers sustains a SAIDI or SAIFI value for a reporting year that is more than 300% greater than the system average of all feeders during any two consecutive reporting years.

(3) **Enforcement.** The commission may take appropriate enforcement action, including action against a utility, if the system and feeder performance is not operated and maintained in accordance with this subsection. In determining the appropriate enforcement action, the commission will consider:

(A) the feeder's operation and maintenance history;

(B) the cause of each interruption in the feeder's service;

(C) any action taken by a utility to address the feeder's performance;

(D) the estimated cost and benefit of remediating a feeder's performance; and

(E) any other relevant factor as determined by the commission.

(h) **Critical natural gas facilities.** In accordance with §3.65 of this title, critical natural gas standards apply to each facility in this state designated as a critical customer under §3.65 of this title. In this subsection, the term "utility" includes MOUs, electric cooperatives, and entities considered utilities under subsection (a) of this section.

(1) **Critical customer information.**

(A) In accordance with §3.65 of this title, the operator of a critical natural gas facility must provide critical customer information to the entities listed in clauses (i) and (ii) of this subparagraph. The critical customer information must be provided by email using Form CI-D and any attachments, as prescribed by the Railroad Commission of Texas.

(i) The utility from which the critical natural gas facility receives electric delivery service; and

(ii) For critical natural gas facilities located in the ERCOT region, the independent organization certified under PURA §39.151.

(B) The commission will maintain on its website a list of utility email addresses to be used for the provision of critical customer information under subparagraph (A) of this paragraph. Each utility must ensure that the email address listed on the commission's website is accurate. If the utility's email address changes or is inaccurate, the utility must provide the commission with an updated email address within five business days of the change or of becoming aware of the inaccuracy.

(C) Within ten business days of receipt, the utility must evaluate the critical customer information for completeness and provide written notice to the operator of the critical natural gas facility regarding the status of its critical natural gas designation.

(i) If the information submitted is incomplete, the utility's notice must specify what additional information is required and provide a deadline for response that is no sooner than five business days from when the critical natural gas facility receives the written notice. If the utility does not receive the additional information in a timely fashion, the utility may use its discretion to determine if it is possible to treat the natural gas facility as critical for load shed and power restoration purposes.

(ii) If the information submitted is complete, the utility's notice must notify the operator of the facility's critical natural gas status, the date of its designation, any additional classifications assigned to the facility by the utility, and notice that its critical status does not constitute a guarantee of an uninterrupted supply of energy.

(iii) A utility must provide an additional notice to the operator of the critical natural gas facility regarding any changes to the information provided in the notice required under clause (i) of this subparagraph. Notice must be provided within ten business days of the effective date of the change.

(D) A utility or an independent system operator receiving or sending critical customer information regarding a critical natural gas facility under this subsection must not release critical customer information to any person unless authorized by the commission or the operator of the critical natural gas facility. This prohibition does not apply to the release of such information to the commission, the Railroad Commission of Texas, the utility from which the critical natural gas facility receives electric delivery service, the designated transmission operator, or the independent system operator or reliability coordinator for the power region in which the critical natural gas facility is located. This prohibition also does not apply if the critical customer information is redacted, aggregated, or organized in such a way as to make it impossible to identify the critical natural gas facility to which the information applies.

(2) **Prioritization of critical natural gas facilities.** A critical natural gas facility is a critical load during an energy emergency. A utility must incorporate critical natural gas facilities into its load-shed and restoration planning. For purposes of this paragraph, a utility may also treat a natural gas facility that self-designated as critical using the *Application for Critical Load Serving Electric Generation and Cogeneration* form as a critical natural gas facility, as circumstances require.

(A) A utility must prioritize critical natural gas facilities for continued power delivery during an energy emergency.

(B) A utility may use its discretion to prioritize power delivery and power restoration among critical natural gas facilities and other critical loads on its system, as circumstances require.

(C) A utility must consider any additional guidance or prioritization criteria provided by the commission, the Railroad Commission of Texas, or the reliability coordinator for its power region to prioritize among critical natural gas facilities and other critical loads during an energy emergency.

(D) Compliance with directives of a regional transmission organization having authority over a utility outside of the ERCOT power region will be deemed compliance for that utility.

This agency hereby certifies that the rule, as adopted, 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 §25.52, relating to Reliability and Continuity of Service is hereby adopted with changes to the text as proposed.

Signed at Austin, Texas on the ______ day of __________________ 2025.

PUBLIC UTILITY COMMISSION OF TEXAS

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THOMAS J. GLEESON, CHAIRMAN

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KATHLEEN JACKSON, COMMISSIONER

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COURTNEY K. HJALTMAN, COMMISSIONER