Filing Receipt

Filing Date - 2023-08-11 05:25:03 PM

Control Number - 55250

Item Number - 5

Public Utility Commission of Texas

Memorandum

TO: Interim Chairwoman Kathleen Jackson
Commissioner Will McAdams
Commissioner Lori Cobos
Commissioner Jimmy Glotfelty

FROM: David Smeltzer, Director of Rules and Projects
Rama Singh Rastogi, Project Manager, Rules and Projects

DATE: August 11, 2023

RE: August 17, 2023, Project 55250 – Transmission and Distribution System Resiliency Plans – Workshop Agenda.

Commission Staff will host a public workshop to receive stakeholder input on topics related to implementation of House Bill (HB) 2555 passed by the 88th Texas Legislature (R.S.). HB 2555 allows an electric utility to file a *Transmission and Distribution System Resiliency Plan* to enhance the resiliency of its transmission and distribution systems. This workshop will be open to members of the public and will be broadcast live on AdminMonitor.

Workshop Details

Thursday, August 17, 2023

10:00 am – 12:00 noon

Commissioners' Hearing Room

7th Floor, William B. Travis Building

This workshop will be conducted in an open discussion format. To facilitate this approach, Commission Staff requests that participants keep their oral comments concise and that organizations or other stakeholder groups with aligned interests designate a spokesperson to present their policy recommendations. All persons who wish to provide comments at the workshop should first identify their name and the market participant they represent.

Written comments in advance of the workshop – including suggestions for additional workshop discussion questions – are welcome, but not required. Written comments can be filed under Project No. 55250. *Transmission and Distribution System Resiliency Plans*.

Workshop Objectives

Commission staff is seeking input on the attached draft rule. In particular, Commission Staff is interested in feedback on the following topics:

1. Assessment criteria for reviewing resiliency plans.
    a. Possible requirement for plans to include alternative methods of addressing identified resiliency issues.
2. Cost recovery for resiliency measures.
    a. Types of costs (eg. capital costs, operating expenses) included in resiliency plans that are eligible for recovery.
3. Reporting metrics and reporting frequency for approved resiliency plans.

a. Distribution feeder indices (SAIDI/SAIFI[1]) as tools for measuring effectiveness of implemented resiliency measures.

[1] SAIDI- System Average Interruption Duration Index - 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.

SAIFI - System Average Interruption Frequency Index - 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.

The following draft language was provided by the investor owned utilities for workshop discussion purposes at the request of Commission Staff. This language should not be viewed as either consensus language or the stated position of Commission Staff or any individual stakeholder. Each individual utility may advocate for different positions during the workshop discussion or subsequent rulemaking process..

§ 25.##.System Resiliency Planning and Cost Recovery.

(a) **Purpose and Applicability.** This section implements Public Utility Regulatory Act § 38.078, which permits an electric utility to submit a transmission and distribution resiliency plan for review and approval by the commission.

(b) **Applicability.** This section applies to an electric utility that owns and operates a transmission and distribution system.

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

(1) **Cybersecurity measures** -- Includes, but is not limited to, cybersecurity activities, standards, policies, procedures, and practices and related technology employed to prevent, detect, identify, protect, respond to, or recover from events that may compromise or attempt to compromise or disrupt the processes, resources, network, hardware or software of electronic devices that operate or facilitate the operation of an electric utility's transmission and distribution systems and systems that support reliable metering, billing, and customer service, and interrelated enterprise systems.

(2) **Flood mitigation** -- Includes, but is not limited to, activities, standards, policies, procedures, practices, and structures employed to reduce the risk or mitigate the impact of flooding and high waters such as the elevation of substation equipment, the erection of physical barriers, and the installation of monitoring devices.

(3) **Hardening** -- Includes, but is not limited to, construction and materials, activities, inspection, assessment, treatment, standards, policies, procedures, practices, structures, and equipment or facilities employed to protect, strengthen, or improve system resiliency and situational awareness, and reduce system restoration times, such as the replacement of aging infrastructure, improving back-stand capabilities, inspection and monitoring, and

increased inventory of long-lead time critical assets.

(4) **Information technology** -- Includes, but is not limited to, activities, standards, policies, procedures, practices, hardware or software, services, and supporting infrastructure and systems used to support metering, billing, customer service, work management, data analysis and interrelated enterprise systems, and to manage, store, retrieve, deliver, or protect information or associated information technology assets for both on premise and cloud-based platforms.

(5) **Lightning mitigation** -- Includes, but is not limited to, activities, standards, policies, procedures, practices, systems, and associated equipment or facilities that are employed to mitigate the impact of lightning, including but not limited to, the inspection and maintenance of existing protection equipment and the installation of ground wires, phase protectors, surge arrestors or other equipment.

(6) **Modernizing** -- Includes, but is not limited to, activities, standards, policies, procedures, and practices employed to enhance outage resilience, faster outage restoration, or grid self-healing capabilities such as system automation, enhanced communications, replacement of aging infrastructure, and installation of devices to improve situational awareness.

(7) **Operations technology** -- Includes, but is not limited to, activities, standards, policies, procedures, practices, hardware or software, services, and supporting infrastructure used to manage, monitor, protect, or control information and associated technology assets to operate or facilitate the operation of an electric utility's transmission and distribution system. Operations technology includes programmable systems or devices that interact with the physical environment (or manage devices that interact with the physical environment through secure communications networks). These systems or devices detect or cause a direct change through the monitoring and/or control of devices, processes, and events and may include industrial control systems, building management systems, fire control systems, and physical access control mechanisms.

(8) **Physical security measures** -- Includes, but is not limited to, physical security activities, standards, policies, procedures, practices, and equipment that are employed to deter, detect, or protect an electric utility's transmission and distribution systems, data centers, and other

facilities that, if compromised, could impact transmission and distribution operations or utility service, against physical intrusions or attacks. This term includes physical barriers, facility access management systems, and remote monitoring.

(9) **Resilience or resiliency** -- The ability of electric utility infrastructure and operational processes to withstand or limit interruptions of service during an event by enabling an expedited restoration rate or process. This may include, but is not limited to, the ability to prepare for, adapt to, respond to, and recover from events such as hurricanes, tornadoes, heavy storms, flooding, high winds, freezes, lightning strikes, wildfires, cybersecurity or physical infrastructure incursions.

(10) **Resiliency plan** -- An electric utility's plan to enhance the resiliency of the electric utility's transmission and distribution system through at least one of the following methods:

(A) hardening electric transmission and distribution facilities;
(B) modernizing electric transmission and distribution facilities;
(C) undergrounding certain electric distribution lines;
(D) lightning mitigation measures;
(E) flood mitigation measures;
(F) information technology;
(G) operations technology;
(H) cybersecurity measures;
(I) physical security measures;
(J) vegetation management; or
(K) wildfire mitigation and response.

(11) **Undergrounding** -- The burying of electric lines, associated facilities, and equipment below ground level.

(12) **Vegetation management** -- Includes, but is not limited to, the actions an electric utility takes to prevent or curtail vegetation from interfering with the electric utility's infrastructure. The term includes, but is not limited to, capturing and processing aerial imagery to characterize vegetation, the mowing of, application of herbicides to, trimming of, removal of, or relocation of trees, shrubs, and other vegetation, and measures taken to

prevent the growth of trees, shrubs, and other vegetation.

(13) **Wildfire mitigation and response** -- Includes, but is not limited to, actions, activities, standards, policies, procedures, and practices employed to reduce the risk or mitigate the impact of wildfires such as risk modeling to identify high-risk areas and near real-time risk levels, installation of non-expulsion devices, upgrading infrastructure susceptible to and at risk of igniting wildfire, developing, training, and implementing supplemental emergency planning and preparedness protocols, installation of technologies including communications equipment for improved monitoring, fault clearing and sectionalization, and stakeholder outreach programs. Wildfire mitigation and response is subject to the electric utility's obligation to provide service under the Public Utility Regulatory Act and to the terms and conditions stated in the electric utility's commission-approved tariff.

(d) **Resiliency plan review and approval.**

(1) An electric utility may file a resiliency plan for review and approval by the commission.

(2) Upon filing a resiliency plan for review and approval by the commission, the electric utility must provide notice of its filing by first class or electronic mail to:

(A) All municipalities in the electric utility's service area that have retained original jurisdiction; and

(B) All parties in the electric utility's last base rate proceeding.

(3) An electric utility's resiliency plan must explain the systematic approach that the electric utility will use to carry out the resiliency plan during at least a three-year period.

(4) In determining whether to approve a plan filed under this section, the commission shall consider:

(A) The extent to which the resiliency plan is reasonably expected to enhance resiliency of the electric utility's system, through qualitative and/or quantitative measures, including whether the resiliency plan prioritizes areas of lower performance; and

(B) The estimated costs of implementing the measures proposed in the resiliency plan.

(5) As part of its request to review and approve a resiliency plan, an electric utility may file an application for approval of a rider to recover the electric utility's distribution investment that will be made to implement the resiliency plan. A request to approve a rider may be filed and approved before the electric utility places into service the distribution investment that it will make to implement a resiliency plan.

(A) The commission shall determine the appropriate terms of an approved rider.

(B) An approved rider and the electric utility's distribution-related investment to implement the resiliency plan are subject to reconciliation in the electric utility's next base rate proceeding.

(C) The electric utility can recover investment under an approved rider when the electric utility begins to use the distribution investment to provide service to the public.

(D) The electric utility with an approved rider may make compliance filings up to twice per calendar year to update the level of distribution investment under its resiliency plan that has been placed in service, or that will be placed in service within 90 days after the compliance filing, and to adjust the rider rates accordingly. The scope of compliance filings under this subsection shall be limited to whether the distribution investment will be placed in service within 90 days of the compliance filing and whether the electric utility has correctly calculated the new rider rates. No later than 90 days after making the compliance filing, the electric utility shall make an update filing stating the final amount of incremental invested capital closed to plant and the resulting rider rates to be implemented. Not later than 30 days after the update filing, the commission shall approve the updated rider and rates to the extent it finds the distribution investment was placed in service within 90 days of the compliance filing and the electric utility has correctly calculated the new rider rates.

(6) The commission may approve, modify, or deny an electric utility's proposed resiliency plan.

(A) An electric utility may request a good cause exception on implementing all or some of the measures or incurring all or some of the estimated costs of the resiliency plan if operational needs, business needs, financial conditions, supply chain conditions, or labor conditions dictate the exception.

(B) The actual costs incurred by the electric utility to implement an approved or approved with modifications resiliency plan that are prudently incurred and reasonable are not subject to disallowance for exceeding the cost estimates in the resiliency plan.

(C) The commission's denial of a resiliency plan is not considered to be a finding on the prudence or imprudence of a measure or estimated cost in the resiliency plan.

(D) Upon denial of a resiliency plan, an electric utility may file a revised resiliency plan for review and approval by the commission.

(c) **Updated resiliency plan.**

(1) An electric utility may file an updated resiliency plan for review and approval by the commission.

(2) The updated resiliency plan:

(A) May not take effect earlier than the third anniversary of the approval of the electric utility's most recently approved resiliency plan;

(B) Must comply with all the requirements in subsection (d) of this section; and

(C) May be approved, modified, or denied by the commission.

(f) **Resiliency plan costs.**

(1) An electric utility may recover only prudently incurred and reasonable incremental costs that are not already being recovered through the electric utility's base rates or any other rate rider. An electric utility may calculate incremental operations and maintenance costs by reference to the amount of costs included in the cost of service study filed during its last comprehensive base rate proceeding less any specific disallowance made by the commission in that proceeding or other method approved by the commission as part of review of its resiliency plan.

(2) Resiliency plan costs must be allocated to customer classes pursuant to the rate design for the electric utility most recently approved by the commission.

(3) If a capital investment is recoverable as a resiliency plan cost, the electric utility may recover all prudently incurred and reasonable costs associated with the capital investment, including the annual depreciation expense related to the capital investment calculated at the electric utility's currently approved depreciation rates, the after-tax return on the undepreciated balance of the capital investment calculated using the rate of return approved by the commission in the electric utility's last comprehensive base rate proceeding, and federal income tax and other taxes related to the capital investment.

(4) An electric utility that does not apply for a rider under subsection (d) may defer all or a portion of the distribution-related costs relating to the implementation of the resiliency plan for future recovery as a regulatory asset, including depreciation expense and carrying costs at the electric utility's weighted average cost of capital established in the commission's final order in the electric utility's most recent base rate proceeding.

(A) An electric utility may include distribution capital investment related to an approved resiliency plan in cost recovery mechanisms under Public Utility Regulatory Act §§ 36.209 and 36.210. Upon inclusion of capital investment in such a cost recovery mechanism, the electric utility shall cease the deferral of depreciation expense and carrying costs for such investment.

(B) As part of a comprehensive base rate proceeding, an electric utility may request consolidation of resiliency plan costs into its base rates and shall propose a recovery period for deferred costs recorded under this paragraph.

(5) An electric utility shall be permitted to continue recovering a return of and on any assets that have not yet been fully depreciated but have been replaced by assets installed under an approved resiliency plan.

(g) **Resiliency plan cost review and reconciliation.** The commission shall review and reconcile investments and associated costs recovered through a rider approved under subsection (d) or recorded as a deferred cost under subsection (f) in the electric utility's next comprehensive base rate proceeding, taking into consideration the reasonableness of the costs at the time and under the circumstances in which they were incurred by the electric utility. The reconciliation shall be limited to the issue of the extent to which the investments and costs related to the resiliency plan approved by the commission were reasonable and prudently incurred. Costs shall not be deemed unreasonable solely on the basis of the actual costs being different from the estimates provided in the resiliency plan. To the extent the commission determines that costs were unreasonable, the electric utility shall refund any such costs already recovered through a rider approved by the commission or may not recover costs that were deferred. The electric utility shall include carrying charges on any refunded amount as determined by the commission.