with the primary data center.

Tiered Storage Solution: This effort will be implemented based on physical data center, beginning with the primary data center.

ii. History of Effectiveness

Resilient Communications to Plan for Unplanned Outages: This is a new program the company is developing. However, this program is based on the common framework for industry action to improve network redundancy and reduce the risk of impacts to communication traffic.

Disaster Recovery Enterprise Toolset: This is a new program the company is developing. However, this program is based on a recognized industry standard for quicker recovery times of critical systems supporting critical business processes following resiliency events.

On-Premises Infrastructure Refresh: This is a new program the company is developing; however, this enhancement is well-known within the utility industry as proven to enhance resiliency and to allow for more agility in managing these needed resources when responding to resiliency events.

SAN Fabric Redesign: The company has general experience operating SAN fabrics and anticipates the redesigned fabric will simplify its operations, increasing reliability and speed.

Tiered Storage Solution: The Company has been impacted in the past by issues with SAN access to customer data. Implementing a Tiered Storage Solution is a recognized industry measure that should result in less risk of associated outages to accessing customer data allowing the business to provide consistent service for customers.

c. Alternatives Considered

In reviewing the Resiliency Plan, the Company, in collaboration with Guidehouse, considered the following alternatives:

Resilient Communications to Plan for Unplanned Outages: The company evaluated various alternatives to enable automatic failover. The alternatives were either continue the manual process for failing over to the secondary data center or contract with other vendors for implementing an automatic failover. The Company chose to continue leveraging Cisco equipment with the capability to auto failover. The selected solution was the best option to mitigate associated risks of communication failure to/from existing Data Centers.

Disaster Recovery Enterprise Toolset: The Company considered continuing operations without the Disaster Recovery Enterprise Toolset, but determined the increased efficiency, redundancy, and reduced recovery time justified the program.

On-Premises Infrastructure Refresh: The alternative to the On-Premises Infrastructure Refresh program is to continue utilizing non-cloud-based infrastructure. The Company determined that cloud-based infrastructure is more efficient and cost-effective.

SAN Fabric Redesign: The Company considered leaving the existing multiple SAN Fabric Solutions in place but determined the reduction in outage risk associated with the SAN Fabric Redesign and the reduction in monitoring/managing activities justified the program.

Tiered Storage Solution: The Company currently has storage appliances with 3 different vendors and collaborated with each of them to determine the best upgrade option. After a review of each vendor's tiering storage capabilities, the Company selected one vendor to consolidate storage appliances across the data centers. The improvement selected will reduce the cost and complexity while allowing for more efficient monitoring and management of the Tiered Storage Solution.

d. Measuring Efficacy

In reviewing the Resiliency Plan, the Company, in collaboration with Guidehouse, determined the following efficacy measures:

Resilient Communications to Plan for Unplanned Outages: The efficacy metric will be the reduction in the duration of annual communication outages to/from Data Centers.

Disaster Recovery Enterprise Toolset: The efficacy metric will be the time required for critical system recovery and associated testing.

On-Premises Infrastructure Refresh: The efficacy metric will be the duration it takes to add storage, server, or network capacity to existing/new environments when necessary for performance efficiencies.

SAN Fabric Redesign: The efficacy metric will be annual counts of SAN Fabric related outages causing issues for the business accessing customer information. Collapsing onto one SAN Fabric Solution should reduce SAN related issues accessing customer data.

Tiered Storage Solution: The efficacy metric will be annual counts of storage related outages causing issues for the Company accessing customer information.

Overall, the Company determined the following metrics will be tracked:

- Number of replaced systems;
- Number of manual processes replaced by automation;
- Decreased storage footprint (on premises) vs. Increased resource management/storage efficiency improvements (cloud-based system);
- Decreased data compression rates; and
- Decreased application recovery time.

4. Network Security and Vulnerability Management

a. Description

The Network Security and Vulnerability Management Resiliency Measure will consist of the following projects:

Application Security: This project will develop and operationalize tools and processes to complete all application development securely with control of the point of origin/subcomponents of every in-house developed software product. The implementation process consists of assessing the current development environment; understanding gaps in current processes; working with development teams and leadership to evaluate products in the market that facilitate a consistent, measurable, auditable development process that includes software vulnerability scanning during the development process; implementing the chosen cybersecurity application development tool; and implementing process changes to meet Company objectives.

Vulnerability Management: This project will be an ongoing process of identifying, assessing, prioritizing, and mitigating cybersecurity vulnerabilities across endpoints and systems. This project reduces the likelihood and impact of security incidents by addressing weaknesses that could be exploited and allows the Company to stay ahead of potential threats and minimize the likelihood of security breaches. This project will include both comprehensive patching of all operating system and application vulnerabilities and a penetration testing program. The implementation process consists of assessing the current development environment, understand gaps in current processes; working with development teams and leadership to evaluate products in the market that facilitate a consistent, measurable, auditable development process that includes software vulnerability scanning during the development process; implementing the chosen cybersecurity application development tool; and implementing process changes to meet Company objectives.

Security Infrastructure/Network Segmentation: This project is a comprehensive program that will include deployment of advanced firewalls, passive network sensors, and other cyber technologies to over four hundred sites. This project will also include the re-design/re-build of the Cybersecurity Operations Center and the build-out of a dedicated operations technology lab and technology deployment factory. The implementation process will consist of assessing the current development environment, understanding gaps in current processes; working with development teams and leadership to evaluate products in the market that facilitate a consistent, measurable, auditable development process that includes software vulnerability scanning during the development process; and implementing the chosen process changes to meet Company objectives.

b. Relevant Details

The following Figure RP-49 summarizes the Network Security and Vulnerability Resiliency Measure.

Figure RP-49.

Network Security and Vulnerability Resiliency Measure	
Estimated capital costs from 2025 - 2027	$1.0 million[13]
Estimated incremental O&M expense from 2025 – 2027	None
Estimated overall project duration	2025-2027 (but extends through 2032)
Net salvage value	None
Resiliency Event(s) addressed	Cybersecurity Unauthorized access Loss of critical or sensitive data
Anticipated benefits	Provide capability to monitor and control the distribution grid during the resilience event Reduce risk of disruption of critical computing systems or energy delivery systems Prevents loss of critical/sensitive data Increase compliance with regulatory requirements by implementing measures to protect software and its components from vulnerabilities and threats
Other relevant details	N/A

i. Prioritization

Application Security: Implementation will be prioritized by risk, considering impact and likelihood, including criticality, risk exposure, compliance requirements, and user impact which will create a prioritization framework to effectively manage security within development, security, and operations pipeline.

Vulnerability Management: Implementation will be prioritized by age of the equipment and software lifecycle management.

Security Infrastructure/Network Segmentation: Implementation will be prioritized by age of the equipment and software lifecycle management.

[13] The Company's Network Security and Vulnerability plan to refresh data center infrastructure extends beyond 2027. Subject to available funding, personnel, and materials, the Company may accelerate future network security projects that are anticipated to include all or a portion of such projects in the Network Security and Vulnerability Resiliency Measure. The Company estimates that accelerating future network security projects will cost approximately $1 - 3 million in additional capital costs and no additional incremental O&M expense from 2025 - 2027.

ii. History of Effectiveness

The Network Security & Vulnerability Management Program Resiliency Measure is known in the Company's experience and within the industry to protect digital assets including, but not limited to, network, network equipment, client computers, control systems. Without a Network Security & Vulnerability Management Program in place, the Company's digital assets and data would be at risk of vulnerabilities that may allow unauthorized access or attacks by bad actors.

The Security Infrastructure/Network Segmentation Resiliency Measure is known from the Company's experience and within the industry as being proven to enhance resiliency. Thus, the Company anticipates that the Cybersecurity Resiliency Measures in the Company's Resiliency Plan will mitigate the impact of certain Resiliency Events, thus reducing overall outage times, the number of customers impacted, and system restoration costs associated with Resiliency Events.

While the elements of these program are not dependent, they are complimentary and together are more effective in providing increased resiliency to the Company's system.

c. Alternatives Considered

In reviewing the Resiliency Plan, the Company, in collaboration with Guidehouse, determined additional due diligence will be performed to consider vendor alternatives and solution options.

d. Measuring Efficacy

In reviewing the Resiliency Plan, the Company, in collaboration with Guidehouse, determined the following performance metrics will be tracked:

- Number of applications in scope having gone through their respective secure software development lifecycle process;
- Amount of peer reviews, code reviews, code scans;
- Number of application security vulnerabilities detected/remediated;
- Number of network segments ingested on a daily basis;
- Number of suspicious/malicious alerts;
- Number of packets stopped at firewalls;
- Number of packets inspected; and
- Net number of rules moved from layer 4 to layer 7 load balancing.

5. IT/OT Cybersecurity Monitoring Program

a. Description

The IT/OT Cybersecurity Monitoring Program Resiliency Measure is a comprehensive program that will include deployment of advanced firewalls, passive network sensors and other cyber technologies to over 400 sites. The IT/OT Cybersecurity Monitoring Program Resiliency Measure will also include re-design/re-build of the Company's Cybersecurity Operations Center and build-out of a dedicated operational technology lab and technology deployment factory. The IT/OT Cybersecurity Monitoring Program Resiliency Measure will promote business continuity by protecting downtime of systems and preventing disruption of operations; will work to respond to the ever-evolving cyber threat landscape investments; will mitigate risk associated with data breaches; and protect the Company's digital assets, confidential data, intellectual property, and critical infrastructure from damage, unauthorized access, or theft.

b. Relevant Details

The following Figure RP-50 summarizes the IT/OT Cybersecurity Monitoring Resiliency Measure.

Figure RP-50.

IT/OT Cybersecurity Monitoring Program Resiliency Measure	
Estimated capital costs from 2025 - 2027	$22.5 million
Estimated incremental O&M expense from 2025 – 2027	None
Estimated overall project duration	2025 – 2027 (but extends through 2032)
Net salvage value	None
Resiliency Event(s) addressed	Cybersecurity Unauthorized access Loss of critical or sensitive data
Anticipated benefits	Provide capability to monitor and control the distribution grid during the resilience event Identify and respond to outage events
Other relevant details	Availability of inventory and personnel may impact cost estimates

i. Prioritization

Sites have been prioritized based on the following criteria; NERC Medium, NERC Low, Non-NERC/Distribution and Non-Company-owned substations. The implementation schedule is still being finalized for the next four years however the schedule will account for prioritization of site and ability to adjust specific implementation dates due to unplanned events (e.g., unexpected hands off or outages, technician availability) and alignment with similar projects (e.g., router refresh).

ii. History of Effectiveness

Threat and intelligence data and scanning systems data employed by the Company suggest that the IT/OT environment has a continuous target of bad actors. The IT/OT Cybersecurity Monitoring Program Resiliency Measure is known within the industry to protect all digital assets including the network, network equipment, client computers, and control systems.

c. Alternatives Considered

In reviewing the Resiliency Plan, the Company, in collaboration with Guidehouse, assessed various alternatives considering the technological capabilities of the hardware and software chosen, cost, experience in the industry yielding success, organizational reputation, sustainability, and supportability. The selected measures are well-known within the utility industry as being proven to mitigate against cyber-attacks via prevent, detection, and response functionalities and thus enhance resiliency.

d. Measuring Efficacy

In reviewing the Resiliency Plan, the Company, in collaboration with Guidehouse, determined the following performance metrics will be tracked:

- Number of alerts,
- Number of systems being monitored (system transparency),
- Incident response time,
- System information ingestion rates,
- Volume of recorded malicious behavior,
- Volume of data inspected,
- Number of data sources migrated to SOC, and
- Number of SOC rules, use cases, and SOC playbooks developed.

F. Physical Security PURA § 38.078(b)(8), 16 TAC § 25.62(c)(1)(H)

The Company's Resiliency Plan has two Resiliency Measures that will enhance the physical security at the Company's substations. The Company estimates that the two Resiliency Measures that will enhance physical security will cost approximately $34.5 million in capital costs and $0.09 million in incremental O&M expense. The two measures will be implemented over a three-year period from 2025-2027. The Company's two physical security Resiliency Measures are summarized below in Figure RP-51.

Figure RP-51.

Physical Security Resiliency Measure	Estimated Capital Costs (millions)	Estimated Incremental O&M Expense (millions)	Estimated Timeframe (years)
Substation Physical Security Fencing	$15.0	None	2025-2027
Substation Security Upgrades	$19.5	$0.09	2025-2027
Subtotal	**$34.5**	**$0.09**	

1. Substation Physical Security Fencing

a. Description

The Substation Physical Security Fencing Resiliency Measure will replace chain link fences with more resilient and less permeable wire mesh fences (such as shown in Figure RP-52 below) at substations to better deter unauthorized access and equipment damage caused by third parties. The Company's Substation Physical Security Fencing Resiliency Measure will replace chain link fences with more resilient and less permeable wire mesh fences at critical substations to thwart unauthorized access and equipment damage from vandals (stealing copper wire) or terrorists.

The Substation Physical Security Fencing Resiliency Measure will replace security fencing at five substations per year for a total of fifteen substations from 2025-2027. The Company estimates that the Substation Physical Security Fencing Resiliency Measure will cost approximately $15 million in capital costs and no incremental O&M expense. A system outage is not required for installation.

Figure RP-52.

b. Relevant Details

The following Figure RP-53 summarizes the Substation Physical Security Fencing Resiliency Measure.

Figure RP-53.

Substation Physical Security Fencing Resiliency Measure	
Estimated capital costs from 2025 - 2027	$15.0 million
Estimated incremental O&M expense from 2025 – 2027	None
Estimated overall project duration	2025 – 2027 (but ongoing)
Net salvage value	None
Resiliency Event(s) addressed	Physical intrusion and vandalism
Anticipated benefits	Enhance physical deterrence capability Physical threats to substations, including unauthorized entry, theft, and vandalism
Other relevant details	Availability of inventory and personnel may impact cost estimates

i. Prioritization

Substations targeted for enhanced fencing will be chosen based on network vulnerability, load criticality, and location (e.g., those located in remote or hidden areas). Substation security in locations targeted for enhanced fencing will typically be supplemented with mobile cameras to monitor and detect intrusions.

ii. History of Efficacy

Like most electric utility substations, the Company's substations are located above ground and in view of the general public. Unauthorized entry, theft, or vandalism at the Company's substations are rare, largely because of the various physical security measures the Company has in place. The Company takes seriously the physical security of its transmission and distribution system, including substations, and previously implemented physical security measures designed to minimize the risk of physical intrusions or physical attacks on the Company's substations. The electric industry nationally has seen an increase in the number of instances of physical attacks on its infrastructure. In 2023 alone, the electric utility industry reported to the DOE over 90 instances of physical attack, vandalism, and suspicious activity. The order of upgrades will be based on the condition of the existing fence, the age of the fence, and the number of times there have been attempted intrusions within each substation.

c. Alternatives Considered

In reviewing the Resiliency Plan, the Company, in collaboration with Guidehouse, evaluated two alternatives to address substation security. First, concrete fences would prevent unauthorized access equally well as wire mesh fencing, but at a much higher cost. The Company may consider concrete fencing in lieu of mesh fencing in key high-risk locations if analysis determines this option to be recommended.

Second, mobile cameras and motion detection systems can detect intrusion but are unlikely to completely prevent access into substations equipped with chain link fences (chain link fencing is more easily cut than the proposed wirewall fencing). As noted above, the Company proposes to install security cameras as an additional security measure in some substations where chain link fences will be replaced with wire mesh.

d. Measuring Efficacy

To determine the effectiveness of the Substation Physical Security Fencing Resiliency Measure, the Company will monitor substation physical intrusions and report to the Commission the Company's findings.

Substation access by unauthorized individuals that results in damaged equipment and load interruption is a low probability, high impact event. Efficacy will be analyzed based on design criteria for substation security fencing, using standards related to crash ratings (ASTM F2656-15) and cut resistance (ASTM F2781-10). Within 24 hours of occurrence, the Company will report any break-in at a substation that causes load loss.

The Company will track and report to the Commission on successful substation break-ins that cause load loss within 24 hours of the events occurrence. These reports will describe the nature of the intrusion, damage to equipment, load loss, and law enforcement follow-up actions, where applicable. Annually the Company will report on intrusions avoided by enhanced fencing to measure program effectiveness. Depending on location and nature of the event, reporting may be considered confidential and may be restricted by the Company.

2. Substation Security Upgrades

a. Description

The Substation Security Upgrades Resiliency Measure will upgrade existing security monitoring systems at critical transmission substations to enhance the detection of unauthorized access from individuals committing vandalism or terroristic activities. Substation security includes unauthorized entry detection systems, video surveillance cameras, and associated communications that link to the Company's control center. These systems will enable operating center staff to rapidly notify law enforcement of an effort at or active intrusion to reduce potential equipment damage and customer outages caused by vandals or individuals with terroristic intentions. Substations targeted for security will be chosen based on network vulnerability, load criticality, and location (e.g., those located in remote or hidden areas). Enhanced security in some substations will include upgraded perimeter fencing.

The Substation Security Upgrades Resiliency Measure will upgrade security monitoring systems at twelve substations per year for a total of thirty-six substations from 2025-2027. The Company estimates that the Substation Security Upgrades Resiliency Measure will cost approximately $19.5 million in capital costs and will not carry an incremental O&M expense. To determine the effectiveness of the Substation Security Upgrades Resiliency Measure, the Company will monitor substation physical intrusions and report to the Commission the Company's findings. No system outages are required for installation.

b. Relevant Details

The following Figure RP-54 summarizes the Substation Security Upgrades Resiliency Measure.

Figure RP-54.

Substation Security Upgrades Resiliency Measure	
Estimated capital costs from 2025 - 2027	$19.5 million
Estimated incremental O&M expense from 2025 – 2027	$90,000
Estimated overall project duration	2025 – 2027 (but ongoing)
Net salvage value	None
Resiliency Event(s) addressed	Physical intrusion and vandalism
Anticipated benefits	Deter, prevent, and mitigate unauthorized entry into, theft at, and vandalism of the Company's substations Prevent outages from physical threats Increase difficulty for bad actors to gain undetected and unauthorized access to the Company's substations
Other relevant details	Availability of inventory and personnel may impact cost estimates

i. Prioritization

The Company takes seriously the physical security of its transmission and distribution system, including substations, and the Company has implemented physical security measures to minimize the risk of physical intrusions into or physical attacks on the Company's substations. In 2023 alone, the utility industry reported to the DOE over 90 instances of physical attack, vandalism, and suspicious activity. Notably, there have been instances in which substations have been physically attacked. This measure is a concern throughout the Company's system, and the order of upgrades will be based on the age of the security system and number of maintenance requests a substation received. Older systems will be replaced first and then systems with a greater number of maintenance requests, then systems of similar age that are replaced with lower maintenance requests last. The Company may also consider factors such as: network vulnerability, load criticality, and location in determining which substations will have security monitoring systems upgraded.

ii. History of Effectiveness

Like most electric utility substations, the Company's substations are located above ground and in view of the general public. Unauthorized entry, theft, or vandalism at the Company's substations are rare, largely because of the various physical security measures that the Company has in place.

c. Alternatives Considered

In reviewing the Resiliency Plan, the Company, in collaboration with Guidehouse, evaluated other viable alternatives to security monitoring systems such as upgrade perimeter fences to prevent or discourage unauthorized access or increase security personnel to monitor substations. Increasing security personnel will increase costs and is not as feasible from a resource perspective, especially considering that the Company has almost three hundred (300) substations. The Company proposes to upgrade chain link fences to wire mesh as a separate program as described in the prior section to work concurrently with this resiliency measure to maximize substation security.

d. Measuring Efficacy

Substation access by unauthorized individuals that results in damaged equipment and load interruption is a low probability, high impact event. Accordingly, the Company will track and report on substation intrusions with damage causing outages to the Commission within 24 hours of the events occurrence. These reports will describe the nature of the intrusion, damage to equipment, load loss, and law enforcement follow-up actions, where applicable. On an annual basis, The Company will report on intrusions avoided by enhanced security to measure program effectiveness. The Company proposes to report physical security measures (fences and security upgraded locations) with monitoring systems as a single category. Depending on location and nature of the event, reporting may be considered confidential and may be restricted by the Company.

G. Vegetation Management: PURA § 38.078(b)(9), 16 TAC § 25.62(c)(1)(I)

a. Description

i. Existing Vegetation Management Procedures

The existing vegetation management programs for the Company's distribution system fall into four categories: (1) scheduled vegetation management (proactive tree trimming), (2) unscheduled vegetation management (reactive tree trimming/removal), (3) tree risk management (proactive hazard tree removal), and (4) emergency and post-storm activities. The Company schedules at a minimum 3,500 miles of distribution circuits for proactive tree trimming per year. The Company's proactive tree trimming program prioritizes distribution circuits for trimming based on each circuit's trim cycle and the reliability of each circuit. Additionally, laterals along with the feeder-main are trimmed on circuits identified for trimming. Each year, the Company analyzes a representative sample of approximately 5,500 miles of distribution circuits to determine tree trimming locations. All circuits that initially meet the recommended trim cycle criteria are then ranked and prioritized based on reliability performance (i.e., 10% of lowest performing circuits for either SAIDI or SAIFI, circuits that have 300% greater than systemwide SAIDI or SAIFI). The recommended trim cycle for all circuits is dependent upon multiple factors, such as last trim date, vegetation-caused outages, potential impact on critical loads, and overall customer count. For the proactive hazard tree removal program, the Company performs a patrol of the feeder-mains for those circuits known for higher tree mortality to reduce the risk of falling trees impacting electrical facilities as well as to minimize impacts in an extreme weather event. Mid-Cycle or reactive tree trim maintenance is performed by the Company to address vegetation issues that require immediate attention. Emergency and post-storm activities are reactive efforts to remediate vegetation issues caused by major storms. These vegetation management activities are currently built into the Company's existing rates and will continue to be a base rate activity going forward.

ii. New Targeted Critical Circuit Vegetation Management Resiliency Measure

A new Targeted Critical Circuit Vegetation Management ("Critical Circuit VM") Resiliency Measure will proactively trim trees and other vegetation for distribution circuits previously identified by the Company as being relay exempt from the Company's load shed process due to serving critical load public safety customers. The number of relay exempt circuits is dynamic based on the customers connected to a given feeder over time. Proactive tree trimming for backbone and laterals on these critical distribution circuits will be done on a 3-year trim cycle. The Company estimates that the Critical Circuit VM Resiliency Measure will cost approximately $25M in incremental O&M expense for the period of 2025-2027. This new Critical Circuit VM resiliency measure, as well as the vegetation management activities included in the Wildfire Resiliency Measure, are the only vegetation management expenses included in the request for a deferred regulatory asset as permitted in Subsection (k) of the Resiliency Statute.

b. Relevant Details

The following Figure RP-55 summarizes the Vegetation Management Resiliency Measure.

Figure RP-55.

Targeted Critical Circuit Vegetation Management Resiliency Measure	
Estimated capital costs from 2025 - 2027	None
Estimated incremental O&M expense from 2025 - 2027	$25 million
Estimated overall project duration	Ongoing
Net salvage value	N/A
Resiliency Event(s) addressed	Extreme wind events • Microburst • High wind • Tornado • Hurricane Heavy rain and major storm Extreme freezes Extreme heat

Targeted Critical Circuit Vegetation Management Resiliency Measure	
Anticipated benefits	Reduce the frequency and number of customers impacted by outages Reduce total outage times Reduce system restoration costs
Other relevant details	Availability personnel may impact cost estimates.

i. *Prioritization*

In planning the three-year cycle, the Company will prioritize critical circuits that serve the largest number of critical load public safety customers, while maintaining geographic diversity.

ii. *History of Effectiveness*

Targeted vegetation management is a well-known measure within the utility industry that enhances resiliency. Targeted vegetation management reduces vegetation-related outages due to extreme wind events such as microbursts, high winds, hurricanes, and heavy storms. In past use, the Company has found vegetation management to be effective in mitigating fault conditions caused by vegetation along backbone and lateral feeders. As a part of this performance-based effectiveness, the company has seen a reduction in outage durations and total number of customers impacted.

c. Alternatives Considered

Vegetation management is the only reasonable and readily identifiable measure available to reduce vegetation-related outages due to extreme wind events such as microbursts, high winds, hurricanes, and heavy storms.

d. Measuring Efficacy

To determine the effectiveness of the Critical Circuit VM Resiliency Measure, the Company will monitor the distribution circuits that were trimmed during Resiliency Events and report to the Commission the Company's findings. The Company proposes that the effectiveness of the Critical Circuit VM Resiliency Measure be evaluated on a post-Resiliency Event analysis. The Company proposes that after a Resiliency Event, the Critical Circuit VM Resiliency Measure be analyzed to determine whether the measure reduced outages, reduced service restoration times, and reduced service restoration costs vs circuits that did not receive this treatment.

H. Wildfire Mitigation: PURA § 38.078(b)(10), 16 TAC § 25.62(c)(1)(J)

a. Company Procedures for the Monitoring of and Response to Wildfire Risk

Wildfires are relatively uncommon in, and have not historically been a major risk in, the Company's service territory. A brief review of historical 3-day forecasts by Texas A&M Forest Service typically shows the Company's service area to be classified as low or moderate fire danger forecast. However, within the past few years (and particularly during the past 12 months), wildfires have emerged as a real and pressing issue within the State of Texas and, albeit to a lesser extent, the

Company's service territory.[14] Indeed, 2023 saw prolonged periods of high heat and low precipitation over much of our service territory. Recent events such as the Smokehouse Creek Fire in the Texas panhandle have demonstrated that wildfires carry the potential to rapidly inflict significant damage to a system and the communities within it, endangering people and property.[15] The need to address wildfires as a Resiliency Event was also raised in Guidehouse's initial review of the Company's Resiliency Plan, which found that wildfire risk in the Company's service area, while low, is nevertheless projected to increase during the summer months over the next few decades. Given the Company's own commitment to provide safe and reliable service, the heightened attention across the state to this issue, and Guidehouse's recommendation, the Company has chosen to include wildfire risk in its Resiliency Plan.

The Company is not starting from scratch on wildfire mitigation. While the Company is taking a fresh look at wildfire risk and the appropriate resiliency measures in its service area as part of this filing, the existing Wildfire Annex to the Company's EOP covers actions and strategies already in place to prepare for, mitigate against, respond to, and recover from a wildfire.[16] The Wildfire Annex outlines the Company's existing processes in mitigating wildfire risk, monitoring wildfire risk conditions, and responding to wildfire risk conditions, including procedures for activating the Company's use of PSPS, which is a plan for temporarily shutting off power during extreme wildfire risk conditions.

As part of taking a fresh look at wildfire risk, the Company has identified ten best practice measures that may prove to be useful in mitigating wildfire risk. Each of the ten measures is recognized as part of the common framework for industry action based on the experience of utilities around the country. The Company is gathering additional data and considering whether and how to best implement these resiliency measures to address appropriately the risks specific to its own service area. Once the Company concludes its wildfire analysis, it will employ a combination of all or some of the measures described below to minimize wildfire risks.

i. Proactive Mitigation of Wildfire Risk

The Company has an asset management program for the periodic inspection and maintenance of the facilities and equipment that comprise the Company's transmission and distribution system. The Company engages in both proactive and reactive vegetation management to clear trees and other vegetation within Company ROW and to remove tree limbs and other vegetation that may come into contact with Company facilities. For 35 kV

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[14] *Wildfires*, Cybersecurity & Infrastructure Security Agency (Accessed at: https://www.cisa.gov/topics/critical-infrastructure-security-and-resilience/extreme-weather-and-climate-change/wildfires#:~:text=The%20National%20Oceanic%20and%20Atmospheric,when%20damages%20totaled%20%248.6%20billion).

[15] *See, e.g.*, Representative Ken King, *Day 3 of Testimony in Legislative Hearings on Deadly Panhandle Wildfires (Part 1)*, at 18:53, YOUTUBE (Apr. 4, 2024), https://www.youtube.com/watch?v=3zXz9j7e2D8 (testimony of Craig Cowden, owner of Breezy Point Ranch); Julián Aguilar, *We need to understand the devastation*, *Texas Panhandle ranchers describe losses from wildfires*, KERA News (Apr. 5, 2024) (Accessed at: https://www.keranews.org/texas-news/2024-04-05/we-need-to-understand-the-devastation-texas-panhandle-ranchers-describe-losses-from-wildfires).

[16] The most recent version of the Company's EOP is available and filed with the Commission in Project No. 53385.

and some selected 12 kV distribution circuits, proactive vegetation management is performed approximately every four years. For the remaining 12 kV distribution circuits, proactive vegetation management is performed approximately every six years. Reactive vegetation management is performed on both 35 kV and 12 kV distribution circuits in response to issues identified by the Company or as reported by customers. For the Company's transmission system, the Company performs an annual aerial inspection of the whole transmission system to identify hazardous trees or other vegetation issues which are immediately addressed upon completion of the aerial inspection. Full scale ground-based proactive vegetation management and right of way tree clearing and vegetation maintenance is performed on transmission circuits on a five-year cycle basis, and facilities are inspected again after vegetation management has been performed.

ii. Proactive Response to Weather and Drought Conditions that Elevate Wildfire Risk

When weather conditions indicate elevated drought conditions exist, and therefore an elevated fire risk, the Company may perform additional enhanced inspections on select portions of the Company's transmission and distribution system in select areas of the Company's service territory. These additional enhanced inspections include the evaluation of vegetation growth within and adjacent to transmission and distribution ROW and inspection of the Company's facilities and equipment. Additionally, when advance notice of hazardous fire conditions has been issued by the local fire marshal and the conditions could involve transmission ROW and Company facilities and equipment, the Company will dispatch personnel to reduce brush within the affected ROW and apply fire retardants to the base of transmission towers and structures to mitigate or reduce potential fire damage.

iii. Monitoring of and Response to Wildfire Conditions

The Company continuously monitors weather and drought conditions to assess wildfire risk, and the Company has a tiered approach in responding to conditions that may pose an elevated risk of a wildfire. When weather and drought conditions indicate extreme drought conditions and elevated fire risk, the Company will issue work tags to disable automatic reclosing[17] on distribution circuits that are located in the area subject to extreme drought conditions and elevated fire risk. Additionally, the Company will activate its PSPS if certain conditions related to humidity, sustained winds, and drought status are met.[18]

The following Figure RP-56 summarizes the Company's tiered approach to responding to wildfire conditions.[19]

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[17] Automatic reclosing allows a distribution circuit to remotely and automatically attempt re-energization following a fault. For momentary faults, the automatic reclosers result in an immediate restoration of the circuit. Disabling this functionality during elevated wildfire conditions can mitigate the reoccurrence of a fault and a potential source of ignition.

[18] Page 51 of the Company's EOP details the Company's process for activating its PSPS.

[19] Pages 56-57 of the Company's EOP detail the Company's process for recovery operations, including Company actions to be taken in response to an active wildfire.

Figure RP-56.

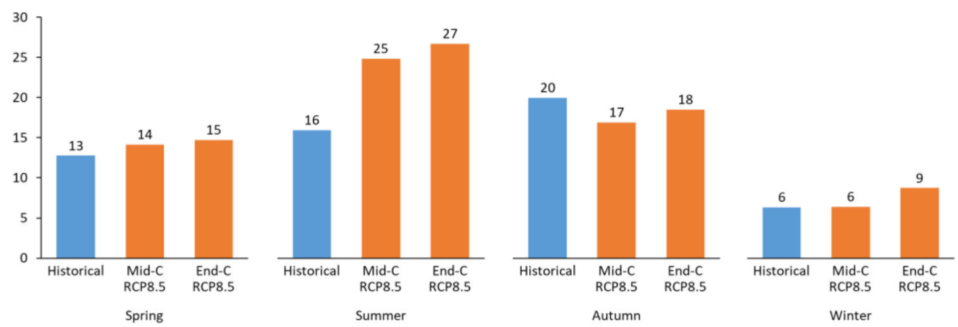
Operations	Task
Enter Drought/High Fire Danger Risk	
Transmission and Distribution	Begin evaluation of heightened/targeted vegetation management; increased maintenance and inspections
Extreme Drought/Red Flag	
Distribution	Issue work tags to disable automatic reclosing for all affected circuits
Distribution	Disable automatic reclosers
Transmission	Heightened/targeted inspections
Transmission and Distribution	Analyze potential switching scenarios[20]
Activate PSPS	
Transmission and Distribution	Review additional criteria to determine heightened risk factors and proactively de-energize

b. General Analysis of Wildfire Risk

Guidehouse conducted a general analysis of wildfire risk in the Company's service area. Guidehouse's general analysis indicated that wildfire risk is low in the Company's service area, but it is projected to increase for the summer months over the next few decades. By way of example, Figures RP-57 and RP-58 summarize the historical and projected mid-century fire weather indices for Harris County and Colorado County. A fire weather index value above 25 is considered high for Texas.

Figure RP-57.

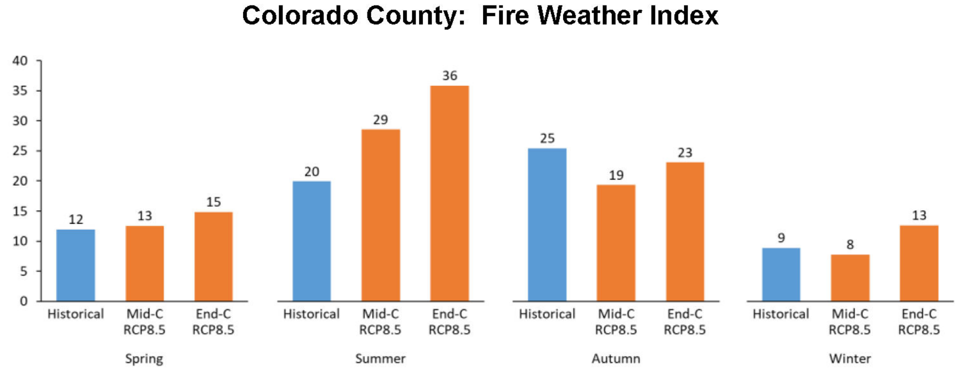
Harris County: Fire Weather Index



Source: Guidehouse analysis, with inputs from Argonne National Laboratory Fire Weather Index data

[20] Distribution feeder switching may allow for de-energization of a segment of a distribution circuit in a high fire risk area while minimizing customer outages.

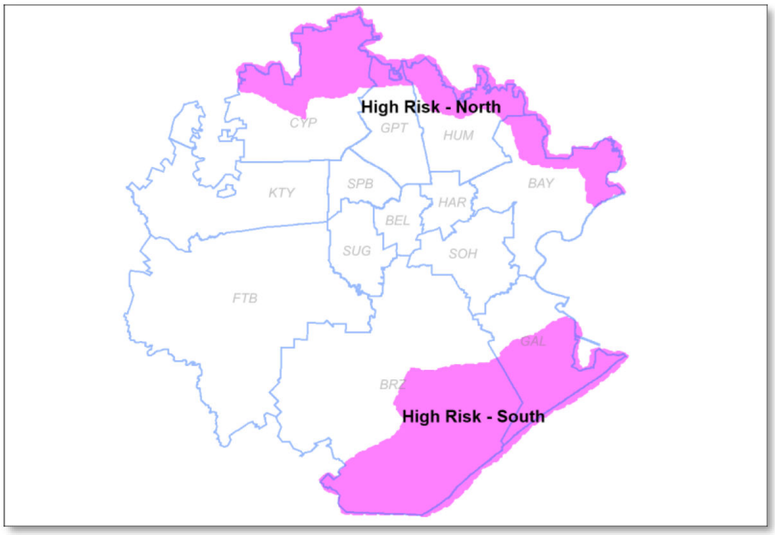
Figure RP-58.



Source: Guidehouse analysis, with inputs from Argonne National Laboratory Fire Weather Index data

Additionally, the USA Wildfire Hazard Potential Index has identified the outer areas of the Company's service area as having elevated wildfire risk, as depicted in Figure RP-59 below.

Figure RP-59.

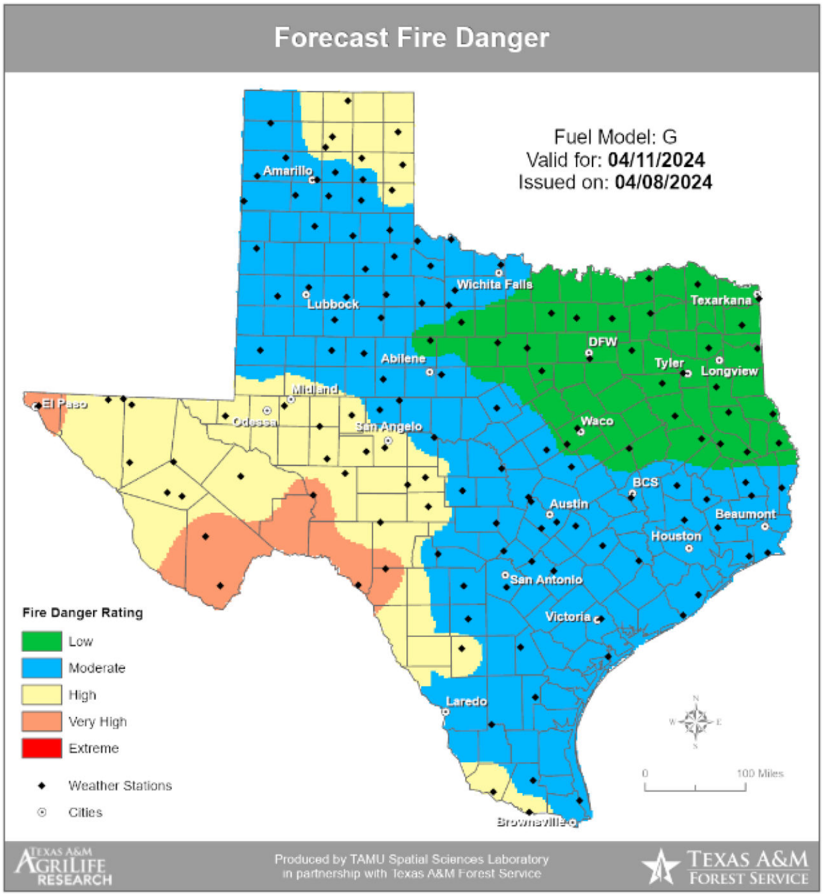


Source: USA Wildfire Hazard Potential Index

As seen by the above image shown in RP-59, the high fire risk areas make up approximately 25% of our service area. However, upon review, it was determined the facilities and equipment within these areas that are at increased wildfire risk are approximately 160 miles of facilities and equipment out of our approximately 57,000 miles in total for our service area.

As mentioned previously, the Texas A&M Forest Service also provides a daily 3 day-ahead Fire Danger Rating forecast. As seen in the Figure RP-59 map below, the Company's service territory is rated as Moderate for the forecasted day when the map was captured.

Figure RP-60.



Source: Texas A&M University Forest Service. (n.d.). FIRE DANGER: OBSERVED & FORECAST FIRE DANGER. Wildfires and Disasters | OBSERVED & FORECAST FIRE DANGER TFS (tamu.edu).

c. Additional Analysis of Wildfire Risk to be Conducted by the Company

The Company will utilize internal and external data to analyze, among other things, the geography; historical climate, weather-related, and drought conditions; and forecasted climate, weather-related, and drought conditions in the Company's service area. The Company will use such analysis to identify:

- specific areas in the Company's service area that may be susceptible to a wildfire or have an elevated level of wildfire risk relative to other specific areas in the Company's service area;
- portions of the Company's transmission and distribution system that may be susceptible to a wildfire or have an elevated risk of starting a wildfire relative to other portions of the Company's transmission and distribution system; and

- portions of the Company's transmission and distribution system that are adjacent to or tie into another entity's transmission system that may be susceptible to a wildfire or have an elevated level of wildfire risk relative to other portions of the Company's transmission and distribution system.

Upon analysis and identification of the portions of the Company's transmission and distribution system or specific areas in the Company's service area that are susceptible to a wildfire or have an elevated level of wildfire risk, the Company will analyze the ten wildfire mitigation Resiliency Measures described below to determine whether the wildfire mitigation Resiliency Measures will, implemented individually or collectively, reduce the risk, mitigate the spread, or mitigate the impact of a wildfire on the Company's transmission and distribution system and the communities we serve. Additionally, the Company will analyze the impact that each wildfire mitigation Resiliency Measure may have on the Company's transmission and distribution system, including whether the specific wildfire mitigation Resiliency Measure would result in the de-rating of certain Company facilities or equipment. The Company will implement a wildfire mitigation Resiliency Measure, individually or collectively with other wildfire mitigation Resiliency Measures, if, under Good Utility Practice and in the Company's engineering and operational judgment, the wildfire mitigation Resiliency Measure will reduce the risk, mitigate the spread, or mitigate the impact of a wildfire on the Company's transmission and distribution system.

d. Summary of Potential Wildfire Mitigation Resiliency Measures

The Company's Resiliency Plan has ten Resiliency Measures that may be implemented, individually or collectively, to mitigate wildfire risk, subject to the Company's analysis and identification efforts detailed in the previous section. In total, the Company estimates that the ten wildfire mitigation Resiliency Measures that may be implemented will cost approximately $137.2 million in capital costs and approximately $43.7 million in incremental O&M expense and will be implemented over a three-year period. The ten wildfire mitigation Resiliency Measures, as well as complementary Resiliency Measures, are summarized below in Figure RP-61.

Figure RP-61.

Wildfire Resiliency Measure	Estimated Capital Costs[21] (millions)	Estimated Incremental O&M Expense[22] (millions)	Estimated Timeframe (years)
Undergrounding	$79.2	None	3 years
Overhead Conductor Covering	$22.5	None	3 years
Wildfire Camera Monitoring	$4.95	$0.99	3 years

[21] The estimated capital costs cover a three-year period.

[22] The estimated incremental O&M expense covers three-year period.

Wildfire Resiliency Measure	Estimated Capital Costs[21] (millions)	Estimated Incremental O&M Expense[22] (millions)	Estimated Timeframe (years)
Wildfire Vegetation Management	None	$30.0	3 years
Expansion of ROW	$6.0	None	3 years
Asset Inspections	None	$3.0	3 years
Relay Protection Schemes	None	None	3 years
Wildfire IGSD Installation	$4.0	$0.05	3 years
Wildfire Advanced Analytics	$18.7	$6.0	3 years
Real-time Risk Analysis	$1.8	$3.6	3 years
Projects Included Within Other Resiliency Measures			
Transmission Hardening*			
TripSaver*			
Distribution Hardening (Pole Replacement)*			
Distribution Circuit Resiliency			
TEEEF and Microgrids*			
Lightning Surge Arresters*			
Substation Animal Abatement*			
Grid Response Procedures and Notifications*			
Avian Protection*			
Subtotal	**$137.15**	**$43.65**	

* Projects included within other Resiliency Measures but also effective for wildfire risk mitigation.

1. Undergrounding

a. Description

The Undergrounding Resiliency Measure will bury select portions of transmission or distribution lines underground that have elevated wildfire risk, as analyzed and identified by the Company. The Company will implement the Undergrounding Resiliency Measure if, under Good Utility Practice and in the Company's engineering and operational judgment, the Undergrounding Resiliency Measure will reduce the risk, mitigate the spread, or mitigate the impact of a wildfire on the Company's transmission and distribution system. A complete system outage is not required for the Undergrounding Resiliency Measure, though segment outages may be required. Estimates are based on these assumptions and may change as additional analysis is completed.

b. Relevant Details

The following Figure RP-62 summarizes the Undergrounding Resiliency Measure.

Figure RP-62.

Undergrounding Resiliency Measure	
Estimated capital costs from 2025 - 2027	$79.2 million
Estimated incremental O&M expense	None
Estimated overall project duration	3-year period
Net salvage value	Salvage Value: None Removal costs: Are included as part of capital project costs
Resiliency Event(s) addressed	Wildfire
Anticipated benefits	Reduction of risk that a failed overhead structure or conductor is the source of wildfire ignition Reduction of risk that vegetation contact with a conductor is the source of wildfire ignition Reduction of risk that a fault is the source of wildfire ignition
Other relevant details	Undergrounding of transmission or distribution line may result in de-rating Availability of material and personnel may impact cost estimates

i. Prioritization

If the Company implements the Undergrounding Resiliency Measure, the Company will prioritize the portions of the Company's transmission or distribution lines that have elevated levels of wildfire risk, as analyzed and identified by the Company.

ii. History of Effectiveness

The electric utility industry has recognized that burying transmission or distribution lines may potentially reduce the risk, mitigate the spread, or mitigate the impact of a wildfire. Efforts to bury transmission or distribution lines at scale are still in the early stages, so empirical data on effectiveness is not readily available.

c. Alternatives Considered

As described in subsection H. a. above, the Company has identified and is assessing ten wildfire Resiliency Measures—each a recognized best practice within the utility industry—as measures most likely to be useful in mitigating the risk of wildfires in the Company's service area and areas outside its service area in which it operates facilities. Upon completion of the Company's analysis of wildfire risk in its own service area, the Company will implement an appropriate combination of all or some of the ten measures. The Company will consider how all or some of the measures can work in combination to address most appropriately the specific service area risk confronting the Company.

d. Measuring Efficacy

If the Company implements the Undergrounding Resiliency Measure, the Company will track and report to the Commission annually:

- any pre-emptive actions taken by the Company pursuant to the Tiered Level of Action/PSPS Activation procedures in the Company's EOP in response to elevated wildfire risk; and

- wildfire events in the Company's service area, the Company's response to the wildfire events, and, to the extent reasonably practicable, whether the Undergrounding Resiliency Measure reduced the risk, mitigated the spread, or mitigated the impact of the wildfire events.

2. Overhead Conductor Covering

a. Description

The Overhead Conductor Covering Resiliency Measure will replace select overhead conductors with a covered conductor that has a protective coating (e.g., polymer sheath). The Company will implement the Overhead Conductor Covering Resiliency Measure if, under Good Utility Practice and in the Company's engineering and operational judgment, the Overhead Conductor Covering Resiliency Measure will reduce the risk, mitigate the spread, or mitigate the impact of a wildfire on the Company's transmission and distribution system. A complete system outage is not required for the Overhead Conductor Covering Resiliency Measure, though segment outages may be required.

b. Relevant Details

The following Figure RP-63 summarizes the Overhead Conductor Covering Resiliency Measure.

Figure RP-63.

Overhead Conductor Covering Resiliency Measure	
Estimated capital costs from 2025 - 2027	$22.5 million
Estimated incremental O&M expense from 2025 - 2027	None
Estimated overall project duration	3-year period
Net salvage value	N/A
Resiliency Event(s) addressed	Wildfire
Anticipated benefits	Reduction of risk that a failed overhead structure or conductor is the source of wildfire ignition Reduction of risk that vegetation contact with a conductor is the source of wildfire ignition Reduction of risk that a fault is the source of wildfire ignition
Other relevant details	Covering overhead transmission or distribution line may result in de-rating Availability of material and personnel may impact cost estimates

i. Prioritization

If the Company implements the Overhead Conductor Covering Resiliency Measure, the Company will prioritize the portions of the Company's transmission or distribution lines that have elevated levels of wildfire risk, as analyzed and identified by the Company.

ii. History of Effectiveness

The electric utility industry has recognized that the use of covered transmission or distribution lines leveraging a protective coating may potentially reduce the risk, mitigate the spread, or mitigate the impact of a wildfire. Efforts to insulate transmission or distribution lines at scale are still in the early stages, so empirical data on effectiveness is not readily available.

c. Alternatives Considered

As described in subsection H. a. above, the Company has identified and is assessing ten wildfire Resiliency Measures—each a recognized best practice within the utility industry—as measures most likely to be useful in mitigating the risk of wildfires in the Company's service area and areas outside its service area in which it operates facilities. Upon completion of the Company's analysis of wildfire risk in its own service area, the Company will implement an appropriate combination of all or some of the ten measures. The Company will consider how all or some of the measures can work in combination to address most appropriately the specific service area risk confronting the Company.

d. Measuring Efficacy

If the Company implements the Overhead Conductor Covering Resiliency Measure, the Company will track and report to the Commission annually:

- any pre-emptive actions taken by the Company pursuant to the Tiered Level of Action/PSPS Activation procedures in the Company's EOP in response to elevated wildfire risk; and

- wildfire events in the Company's service area, the Company's response to the wildfire events, and, to the extent reasonably practicable, whether the Overhead Conductor Covering Resiliency Measure reduced the risk, mitigated the spread, or mitigated the impact of the wildfire events.

3. Wildfire Camera Monitoring

a. Description

The Wildfire Camera Monitoring Resiliency Measure will install a camera system and/or other monitoring equipment at select locations on or near the Company's transmission and distribution system that have elevated wildfire risk, as analyzed and identified by the Company. The Company will implement the Wildfire Camera Monitoring Resiliency Measure if, under Good Utility Practice and in the Company's engineering and operational judgment, the Wildfire Camera Monitoring Resiliency Measure will reduce the risk, mitigate the spread, or mitigate the impact of a wildfire on the Company's transmission and distribution system. Outages are not required for the Wildfire Camera Monitoring Resiliency Measure.

b. Relevant Details

The following Figure RP-63 summarizes the Wildfire Camera Monitoring Resiliency Measure.

Figure RP-63.

Wildfire Camera Monitoring Resiliency Measure	
Estimated capital costs from 2025 - 2027	$4.95 million
Estimated incremental O&M expense from 2025 - 2027	$995,000
Estimated overall project duration	3-year period
Net salvage value	N/A
Resiliency Event(s) addressed	Wildfire
Anticipated benefits	Real-time monitoring capability in select regions Faster response time in the event that issues are identified or in the event of a wildfire
Other relevant details	Availability of material and personnel may impact cost estimates

i. Prioritization

If the Company implements the Wildfire Camera Monitoring Resiliency Measure, the Company will prioritize the portions of the Company's transmission and distribution system that have elevated levels of wildfire risk, as analyzed and identified by the Company.

ii. History of Effectiveness

Camera monitoring has proven to be effective in providing data in real-time, thus enabling faster response times. The Company utilizes real-time camera monitoring as part of its physical security measures at the Company's facilities, including substations.

c. Alternatives Considered

As described in subsection H. a. above, the Company has identified and is assessing ten wildfire Resiliency Measures—each a recognized best practice within the utility industry—as measures most likely to be useful in mitigating the risk of wildfires in the Company's service area and areas outside its service area in which it operates facilities. Upon completion of the Company's analysis of wildfire risk in its own service area, the Company will implement an appropriate combination of all or some of the ten measures. The Company will consider how all or some of the measures can work in combination to address most appropriately the specific service area risk confronting the Company.

d. Measuring Efficacy

If the Company implements the Wildfire Camera Monitoring Resiliency Measure, the Company will track and report to the Commission annually on whether camera monitoring detected any pending wildfire risk or wildfire ignition.

4. Wildfire Vegetation Management

a. Description

The Wildfire Vegetation Management Resiliency Measure will inspect ROW and extensively trim trees and other vegetation. The Company will implement the Wildfire Vegetation Management Resiliency Measure if, under Good Utility Practice and in the Company's engineering and operational judgment, the Wildfire Vegetation Management Resiliency Measure will reduce the risk, mitigate the spread, or mitigate the impact of a wildfire on the Company's transmission and distribution system. If implemented, the Wildfire Vegetation Management Resiliency Measure will inspect ROW and trim trees and other vegetation on specific portions of the Company's transmission and distribution system or specific areas in the Company's service area that have elevated wildfire risk, as analyzed and identified by the Company. Fire retardant material will also be placed near transmission tower structures. Outages are typically not required for the Wildfire Vegetation Management Resiliency Measure.

b. Relevant Details

The following Figure RP-64 summarizes the Wildfire Vegetation Management Resiliency Measure.

Figure RP-64.

Wildfire Vegetation Management Resiliency Measure	
Estimated capital costs from 2025 - 2027	None
Estimated incremental O&M expense from 2025 - 2027	$30 million
Estimated overall project duration	3-year period
Net salvage value	N/A
Resiliency Event(s) addressed	Wildfire
Anticipated benefits	Reduction of risk that a failed overhead structure or conductor is the source of wildfire ignition Reduction of risk that vegetation contact with a conductor is the source of wildfire ignition Reduction of risk vegetation is the source of wildfire ignition
Other relevant details	Availability of personnel may impact cost estimates

i. Prioritization

If the Company implements the Wildfire Vegetation Management Resiliency Measure, the Company will prioritize the portions of the Company's transmission and distribution system or specific areas in the Company's service area that have elevated levels of wildfire risk, as analyzed and identified by the Company.

ii. History of Effectiveness

Targeted vegetation management is a well-known measure within the utility industry that enhances resiliency, including resiliency against a wildfire. The Company has seen vegetation management be effective at mitigating fault conditions caused by vegetation along backbone and lateral distribution feeders, resulting in reduced outage durations and the total number of customers impacted by an outage when implemented.

c. Alternatives Considered

As described in subsection H. a. above, the Company has identified and is assessing ten wildfire Resiliency Measures—each a recognized best practice within the utility industry—as measures most likely to be useful in mitigating the risk of wildfires in the Company's service area and areas outside its service area in which it operates facilities. Upon completion of the Company's analysis of wildfire risk in its own service area, the Company will implement an appropriate combination of all or some of the ten measures. The Company will consider how all or some of the measures can work in combination to address most appropriately the specific service area risk confronting the

Company.

d. Measuring Efficacy

If the Company implements the Wildfire Vegetation Management Resiliency Measure, the Company will track and report to the Commission annually the miles of ROW that have elevated wildfire risk that have been inspected and the amount spent on vegetation management to mitigate wildfire risk.

5. Expansion of ROW

a. Description

The Expansion of ROW Resiliency Measure will expand the ROW on select portions of the Company's transmission and distribution system that have elevated wildfire risk, as analyzed and identified by the Company. The Company will implement the Expansion of ROW Resiliency Measure if, under Good Utility Practice and in the Company's engineering and operational judgment, the Expansion of ROW Resiliency Measure is necessary to reduce the risk, mitigate the spread, or mitigate the impact of a wildfire on the Company's transmission and distribution system. Outages are not required for the Expansion of ROW Resiliency Measure.

b. Relevant Details

The following Figure RP-65 summarizes the Expansion of ROW Resiliency Measure.

Figure RP-65.

Expansion of ROW Resiliency Measure	
Estimated capital costs from 2025 – 2027	$6.0 million
Estimated incremental O&M expense from 2025 - 2027	None
Estimated overall project duration	3-year period
Net salvage value	N/A
Resiliency Event(s) addressed	Wildfire
Anticipated benefits	Allows for implementation of wildfire mitigation measures on a larger portion of land adjacent to Company facilities and equipment Allows for vegetation management of trees and other vegetation that are in the expanded ROW Further reduction of risk that a failed overhead structure or conductor is the source of wildfire ignition Further reduction of risk that vegetation contact with a conductor is the source of wildfire ignition Further reduction of risk that a fault is the source of ignition

Expansion of ROW Resiliency Measure	
Other relevant details	Availability of personnel may impact cost estimates

i. Prioritization

If the Company implements the Expansion of ROW Resiliency Measure, the Company will prioritize the portions of the Company's transmission and distribution system or specific areas in the Company's service area that have elevated levels of wildfire risk, as analyzed and identified by the Company.

ii. History of Effectiveness

Prior expansion of Company ROW has enabled the Company to expand the scope of its vegetation management programs, including the trimming of trees and other vegetation and the application of herbicide/fire retardant allowing vegetation to remain at safe distances from conductors and potential ignition sources from the Company's equipment.

c. Alternatives Considered

As described in subsection H. a. above, the Company has identified and is assessing ten wildfire Resiliency Measures—each a recognized best practice within the utility industry—as measures most likely to be useful in mitigating the risk of wildfires in the Company's service area and areas outside its service area in which it operates facilities. Upon completion of the Company's analysis of wildfire risk in its own service area, the Company will implement an appropriate combination of all or some of the ten measures. The Company will consider how all or some of the measures can work in combination to address most appropriately the specific service area risk confronting the Company.

d. Measuring Efficacy

If the Company implements the Expansion of ROW Resiliency Measure, the Company will track and report to the Commission annually the miles of ROW that have been expanded and the wildfire mitigation measures implemented in the expanded ROW.

6. Asset Inspections

a. Description

If implemented, the Asset Inspections Resiliency Measure will involve the Company conducting additional inspections of Company facilities and equipment. The Company will implement the Asset Inspections Resiliency Measure if, under Good Utility Practice and in the Company's engineering and operational judgment, the Asset Inspections Resiliency Measure will reduce the risk of ignition from the Company's transmission and distribution equipment, mitigate the spread, or mitigate the impact of a wildfire on the Company's transmission and distribution system. This would be accomplished by physically evaluating feeders or portions of feeders in high fire risk areas as identified by 3rd Party Real-time Risk Analysis tools, looking for burn marks, damaged structures and failed/disconnected equipment with the potential to cause ignition hazards in high fire risk areas. This resiliency measure would be implemented when pre-determined risk criteria are met and the first stages of the Wildfire Mitigation Plan are enacted. Items mentioned above would generate high-priority work orders and repairs. Outages are not required for the Asset Inspections Resiliency Measure. Estimates are incremental to the current ongoing inspection program, are based on the above assumptions, and may change as additional analysis is completed.

b. Relevant Details

The following Figure RP-66 summarizes the Asset Inspections Resiliency Measure.

Figure RP-66.

Asset Inspections Resiliency Measure	
Estimated capital costs from 2025 - 2027	None
Estimated incremental O&M expense from 2025 - 2027	$3.0 million
Estimated overall project duration	3-year period
Net salvage value	N/A
Resiliency Event(s) addressed	Wildfire
Anticipated benefits	Identification of and pre-emptive corrective action taken in response to pending equipment failure
Other relevant details	Availability of personnel may impact cost estimates

i. Prioritization

If the Company implements the Asset Inspections Resiliency Measure, the Company will proactively inspect the high fire risk portions of the Company's transmission and distribution system or other specific areas in the Company's service area that have elevated levels of wildfire risk, as analyzed and identified by the Company.

ii. History of Effectiveness

Proactive inspections of Company facilities and equipment have proven to be effective in identifying and taking pre-emptive corrective action in response to pending equipment failure that has been identified.

c. Alternatives Considered

As described in subsection H. a. above, the Company has identified and is assessing ten wildfire Resiliency Measures—each a recognized best practice within the utility industry—as measures most likely to be useful in mitigating the risk of wildfires in the Company's service area and areas outside its service area in which it operates facilities. Upon completion of the Company's analysis of wildfire risk in its own service area, the Company will implement an appropriate combination of all or some of the ten measures. The Company will consider how all or some of the measures can work in combination to address most appropriately the specific service area risk confronting the Company.

d. Measuring Efficacy

If the Company implements the Asset Inspections Resiliency Measure, the Company will track and report to the Commission annually the total number of circuits inspected within the high fire risk areas conducted by the Company, the number of pending equipment failures identified during such inspections, and the corrective actions taken in response to the identified pending equipment failures.

7. Relay Protection Schemes

a. Description

The Relay Protection Schemes Resiliency Measure will modify the protection schemes[23] on select transmission or distribution circuits to be more sensitive to faults or abnormal conditions and thus have quicker activation to stop the flow of electricity in the event of a fault or abnormal condition and/or eliminate the reclosing capabilities within areas that have an elevated wildfire risk. The Company will implement the Relay Protection Schemes Resiliency Measure if, under Good Utility Practice and in the Company's engineering and operational judgment, the Relay Protection Schemes Resiliency Measure will reduce the risk, mitigate the spread, or mitigate the impact of a wildfire on the Company's transmission and distribution system. If implemented, the Relay Protection Schemes Resiliency Measure will modify certain protection schemes on transmission or distribution circuits per year over a 3-year period. A complete system outage is not required for the Relay Protection Schemes Resiliency Measure, though segment outages may be required.

b. Relevant Details

The following Figure RP-67 summarizes the Relay Protection Schemes Resiliency Measure.

Figure RP-67.

Relay Protection Schemes Resiliency Measure	
Estimated capital costs from 2025 - 2027	None
Estimated incremental O&M expense from 2025 - 2027	None
Estimated overall project duration	3-year period
Net salvage value	N/A

[23] Protection schemes are fundamental principles utilizing relays, fuses, and various communication methods to send signals for fault detection and relay coordination that allow for high-speed fault detection and isolation.

Relay Protection Schemes Resiliency Measure	
Resiliency Event(s) addressed	Wildfire
Anticipated benefits	Greater sensitivity and response to faults and abnormal operating conditions on circuits
Other relevant details	Modification of relay protection schemes may impact SAIDI and SAIFI along with the possibility for extended or repeated outages for some customers

i. Prioritization

If the Company implements the Relay Protection Schemes Resiliency Measure, the Company will prioritize the portions of the Company's transmission and distribution system or specific areas in the Company's service area that have elevated levels of wildfire risk, as analyzed and identified by the Company.

ii. History of Effectiveness

As part of the Company's operations in providing safe and reliable electric delivery service, the Company has protection schemes on its transmission and distribution system for the detection of and response to faults and other abnormal conditions. Once activated, protection schemes help prevent faults and other abnormal conditions from damaging equipment or exacerbating the risk of Company facilities or equipment igniting a fire.

c. Alternatives Considered

As described in subsection H. a. above, the Company has identified and is assessing ten wildfire Resiliency Measures—each a recognized best practice within the utility industry—as measures most likely to be useful in mitigating the risk of wildfires in the Company's service area and areas outside its service area in which it operates facilities. Upon completion of the Company's analysis of wildfire risk in its own service area, the Company will implement an appropriate combination of all or some of the ten measures. The Company will consider how all or some of the measures can work in combination to address most appropriately the specific service area risk confronting the Company.

d. Measuring Efficacy

If the Company implements the Relay Protection Schemes Resiliency Measure, the Company will track and report to the Commission annually the number of relay protection schemes on transmission or distribution circuits that were modified and leveraged due to wildfire mitigations being enacted.

8. Wildfire IGSD Installation

a. Description

The Wildfire IGSD Installation Resiliency Measure will install additional IGSDs on select locations of the Company's distribution system to enable the isolation of portions of the Company's distribution system that have an elevated level of wildfire risk. The Company will implement the Wildfire IGSD Installation Resiliency Measure if, under Good Utility Practice and in the Company's engineering and operational judgment, the Wildfire IGSD Installation Resiliency Measure will reduce the risk, mitigate the spread, or mitigate the impact of a wildfire on the Company's transmission and distribution system. This measure is in addition to what is proposed in the stand alone IGSD Installation Resiliency Measure described earlier in the Resiliency Plan. A complete system outage is not required for the Wildfire IGSD Installation Resiliency Measure, though segment outages may be required. Estimates are incremental to the current ongoing IGSD resiliency program, are based on the above assumptions, and may change as additional analysis is completed.

b. Relevant Details

The following Figure RP-68 summarizes the Wildfire IGSD Installation Resiliency Measure.

Figure RP-68.

Wildfire IGSD Installation Resiliency Measure	
Estimated capital costs from 2025 – 2027	$4.0 million
Estimated incremental O&M expense from 2025 - 2027	$54,750
Estimated overall project duration	3-year period
Net salvage value	N/A
Resiliency Event(s) addressed	Wildfire
Anticipated benefits	Faster restoration due to reduced exposure of number of customers subject to PSPS Reduce time and expense associated with dispatching field personnel to restore an outage by reducing the need to perform ground patrol on the segment of the sectionalized circuit Reduce number of customers impacted by an outage Reduce total outage time
Other relevant details	Availability of material and personnel may impact cost estimates

i. Prioritization

If the Company implements the Wildfire IGSD Installation Resiliency Measure, the Company will install additional IGSDs on select portions of the Company's distribution system that have elevated levels of wildfire risk, as analyzed and identified by the Company.

ii. History of Effectiveness

IGSD Installation has resulted in fewer sustained outages and reduced the time and expense associated with the Company dispatching personnel to restore outages. The capability of IGSD to significantly reduce the number of sustained customer interruptions during a Resiliency Event at relatively low cost is high. The installation of IGSD schemes is consistent with practices deployed at other utilities based on peer utility benchmarking survey results. IGSD installations at targeted locations on distribution circuits that are part of a high fire risk area can result in further sectionalization of a circuit which reduces the exposure of the number of customers subject to PSPS, expedites restoration by reducing the need to perform ground patrol on the segment of the sectionalized circuit, and further narrowing the circuit mileage located in high fire risk areas.

c. Alternatives Considered

As described in subsection H. a. above, the Company has identified and is assessing ten wildfire Resiliency Measures—each a recognized best practice within the utility industry—as measures most likely to be useful in mitigating the risk of wildfires in the Company's service area and areas outside its service area in which it operates facilities. Upon completion of the Company's analysis of wildfire risk in its own service area, the Company will implement an appropriate combination of all or some of the ten measures. The Company will consider how all or some of the measures can work in combination to address most appropriately the specific service area risk confronting the Company.

d. Measuring Efficacy

If the Company implements the Wildfire IGSD Installation Resiliency Measure, the Company will track and report to the Commission annually the number of successful isolations necessary by Wildfire IGSD schemes during a wildfire. The Company will track and report to the Commission annually on IGSD operations to mitigate a potential ignition source during a wildfire. The reduction of potential ignition sources will be reported using the number of de-energized circuit miles.

9. Wildfire Advanced Analytics

a. Description

The Company's Wildfire Advanced Analytics Resiliency Measure is an additional analytical tool that the Company plans to use in conjunction with the Advanced Aerial Imagery Platform/Digital Twin Resiliency Measure. The Wildfire Advanced Analytics Resiliency Measure entails combining and inputting data—such as LiDAR imagery data, device data (meters, IGSDs, sensors, etc.), weather data, inspection data, and monitoring data—into the advanced analytics software module. Doing so then enables the Company to overlay imagery, determine wildfire risks, and analyze potential improvements. When used in tandem with the Advanced Aerial Imagery Platform/Digital Twin Resiliency Measure, proposed elsewhere in this Resiliency Plan, the Company can leverage this analysis to "rank" improvement regions based on their value add to customers and strategically optimizing the higher fire risk locations. Doing so will help reduce costs over time by focusing on improvements having the greatest benefit in reducing the risk, mitigating the spread, or mitigating the impact of a wildfire. No system outages are required for the Wildfire Advanced Analytics Resiliency Measure.

b. Relevant Details

The following Figure RP-69 summarizes the Wildfire Advanced Analytics Resiliency Measure.

Figure RP-69.

Wildfire Advanced Analytics Resiliency Measure	
Estimated capital costs from 2025 – 2027	$18.7 million
Estimated incremental O&M expense from 2025 - 2027	$6.0 million
Estimated overall project duration	3-year period
Net salvage value	N/A
Resiliency Event(s) addressed	Wildfire
Anticipated benefits	Enhanced ability to proactively plan and implement projects to reduce the risk, mitigate the spread, or mitigate the impact of a wildfire Determine future improvements to the Company's transmission and distribution system to reduce the risk, mitigate the spread, or mitigate the impact of a wildfire Reduce restoration times Reduce the frequency and number of customers impacted by outages attributable to a wildfire Reduce total outage times attributable to a wildfire Reduce system restoration costs attributable to a wildfire
Other relevant details	Cost estimates may be impacted by the need to reformat data to align with advanced data analytics techniques The Company has applied for DOE grants related to this Resiliency Measure

i. Prioritization

The Wildfire Advanced Analytics Resiliency Measure will be for the Company's entire service area.

ii. History of Effectiveness

The Wildfire Advanced Analytics measure is a new program that the Company is developing. However, the Company has used mapping tools to visualize areas of impact for potential weather events to coordinate response, which has proven effective when preparing for Resiliency Events.

c. Alternatives Considered

As described in subsection H. a. above, the Company has identified and is assessing ten wildfire Resiliency Measures—each a recognized best practice within the utility industry—as measures most likely to be useful in mitigating the risk of wildfires in the Company's service area and areas outside its service area in which it operates facilities. Upon completion of the Company's analysis of wildfire risk in its own service area, the Company will implement an appropriate combination of all or some of the ten measures. The Company will consider how all or some of the measures can work in combination to address most appropriately the specific service area risk confronting the Company.

d. Measuring Efficacy

In reviewing the Resiliency Plan, the Company proposes to perform an analysis of events to determine the accuracy of the algorithms for the advanced analytics tool.

10. Real Time Advanced Analytics Resiliency Measure

a. Description

The Company's Real Time Advanced Analytics Resiliency Measure is an additional analytical tool that the Company plans to use to proactively forecast and map locations with high fire risk. The Real Time Advanced Analytics Resiliency Measure entails receiving wildfire risk data from the vendor and overlaying this data onto graphical maps of the Company's service area, providing extremely granular forecast views of high fire risk locations. When used in tandem with the Advanced Analytics Platform Resiliency Measure, proposed above, the Company can leverage this data and analysis to further assist in ranking high fire risk locations to aid in leveraging other wildfire risk resiliency measures. Doing so will help reduce costs over time by focusing on improvements having the greatest benefit in reducing the risk, mitigating the spread, or mitigating the impact of a wildfire. No system outages are required for the Wildfire Advanced Analytics Resiliency Measure.

b. Relevant Details

The following Figure RP-70 summarizes the Wildfire Advanced Analytics Resiliency Measure.

Figure RP-70.

Real-Time Advanced Analytics Resiliency Measure	
Estimated capital costs from 2025 – 2027	$1.8 million
Estimated incremental O&M expense from 2025 – 2027	$3.6 million
Estimated overall project duration	3-year period
Net salvage value	N/A

Real-Time Advanced Analytics Resiliency Measure	
Resiliency Event(s) addressed	Wildfire
Anticipated benefits	Enhanced ability to proactively plan and implement projects to reduce the risk, mitigate the spread, or mitigate the impact of a wildfire Determine future improvements to the Company's transmission and distribution system to reduce the risk, mitigate the spread, or mitigate the impact of a wildfire Reduce restoration times Reduce the frequency and number of customers impacted by outages attributable to a wildfire Reduce total outage times attributable to a wildfire Reduce system restoration costs attributable to a wildfire
Other relevant details	Cost estimates may be impacted by the need to reformat data to align with advanced data analytics techniques

i. Prioritization

The Real Time Advanced Analytics Resiliency Measure will be for the Company's entire service area.

ii. History of Effectiveness

The Real Time Advanced Analytics measure is a new program that the Company is developing. However, the Company has used mapping tools to visualize areas of impact for potential weather events to coordinate response, which has proven effective when preparing for Resiliency Events.

c. Alternatives Considered

As described in subsection H. a. above, the Company has identified and is assessing ten wildfire Resiliency Measures—each a recognized best practice within the utility industry—as measures most likely to be useful in mitigating the risk of wildfires in the Company's service area and areas outside its service area in which it operates facilities. Upon completion of the Company's analysis of wildfire risk in its own service area, the Company will implement an appropriate combination of all or some of the ten measures. The Company will consider how all or some of the measures can work in combination to address most appropriately the specific service area risk confronting the Company.

d. Measuring Efficacy

In reviewing the Resiliency Plan, the Company proposes to perform an analysis of events to determine the correctness of the algorithms for the real time advanced analytics tool.

VII. Resiliency Activity and Pilot Programs

In addition to and distinct from the Resiliency Measures, the Company proposes two pilot programs and one activity to further improve the resiliency of the Company's transmission and distribution systems. These include the Microgrid Pilot Program, City of Houston Resiliency Employee Pilot Program, and SAP S/4 Transformation and Phase 0. The Company is seeking deferred accounting treatment for the two pilot programs but not for the SAP S/4 Transformation and Phase 0. If the Commission approves these initiatives, the results will be provided in detail in the Company's next Resiliency Plan filing (2028-2030).

A. Microgrid Pilot Program

The Microgrid Pilot Program will enable the Company to coordinate with select third-party entities to study, design, implement, and operate microgrids in the Company's service area. The purpose of the Microgrid Pilot Program is to establish, monitor and assess participating utility-scale microgrids' performance before and during Resiliency Events.

The Company believes that utility-scale microgrids may provide a benefit to customers during a Resiliency Event that causes a power outage. If a Resiliency Event damages the distribution system to where loads interconnected to a utility scale microgrid cannot be served from the distribution system, a utility scale microgrid would enable service to the interconnected loads to be restored, leveraging the energy from the distributed energy resource(s) interconnected to the utility scale microgrid. However, the Company does not have sufficient operational data and experience as to how a utility-scale microgrid would perform during a Resiliency Event.

The implementation process for the Microgrid Pilot Program includes the following:

- Request for Proposal (RFP): The Company will issue a Request for Approval ("RFP") to the market and interested parties. The RFP will contain the relevant technical, operational, and financial requirements needed to qualify for eligibility to participate in the Company's Microgrid Pilot Program.

- Evaluation: The Company will evaluate the bids submitted by interested parties. Submitted bids will be evaluated considering criteria such as: total amount of load that would be proposed to be interconnected to the utility scale microgrid; the total amount of and type(s) of local distributed generation resources that would be interconnected to the utility scale microgrid; modifications that would be necessary to the Company's distribution system, telecommunications network, information technology, and operational technology needed to support safe and reliable operation of the utility scale microgrid and the Company's distribution system; and the type(s) of customer load that would be interconnected to the utility scale microgrid (e.g. critical load public safety customer, public infrastructure, residential customer, etc.).

- Study, Design, and Engineering: Upon determining which submitted bids will be part of the Company's Microgrid Pilot Program, the Company will commence the study, design, and engineering phase.

- Construction and Installation: The Company will construct or install the distribution equipment and facilities necessary for the safe and reliable operation of the Company's distribution system.

- Operations: Upon commencement of operations, the Company's Microgrid Pilot Program will operate as called upon by the Company. The Company will monitor and analyze the microgrids that are participating in the Microgrid Pilot Program during Resiliency Events.

Upon conclusion of the Microgrid Pilot Program, the Company will report its findings to the Commission on the performance of the participating microgrids. The Company will give the Commission recommendations for potential future integration of microgrids in the Company's service area.

B. City of Houston Resiliency Employee Pilot Program

As part of its Resiliency Plan, the Company also proposes to provide funding to the City of Houston to hire an employee that would oversee resiliency issues for the City of Houston. The City of Houston employee funded through the Company's Resiliency Plan will be responsible for the implementation of new and existing City of Houston resiliency projects related to increasing power resilience and energy efficiency (as defined in the City of Houston's Climate Action Plan and the Resilient Houston Plan) at City of Houston facilities and in the community. Additionally, the City of Houston employee funded through the Company's Resiliency Plan will have responsibilities that include collaborating with City of Houston Departments, community partners, consultants, the Company, and others to design and implement projects; managing community and stakeholder engagement for power resilience projects; identifying critical City of Houston facilities and equipment to harden and modernize; and collaborating with the Company and City of Houston Departments on vegetation management projects to increase power resilience and improve natural habitats.

C. SAP S/4 Transformation and Phase 0 Activity

The SAP system is the backbone of the Company's business processes, supporting activities such as supply chain, restoration, and dispatching, all of which are critical to providing resiliency from an operational perspective, in support of the Company's transmission and distribution system. Without a platform such as the SAP system, the Company would be unable to integrate its numerous software programs and efficiently deploy and upgrade software across its system. The Company relies heavily on this software to support continuity of business and communication with our customers during all stages of operations including normal and emergency operations.

While the existing system has served the Company well for more than 25 years, the system is nearing the end of its life. The manufacturer has announced it will no longer support the existing system, which will make it difficult and expensive for the Company to continue to maintain it. Additionally, the existing system struggles to handle the large volumes of data generated by modern software, data which enables the Company to make better-informed operational decisions and to respond more quickly to outages and fluctuations in demand.

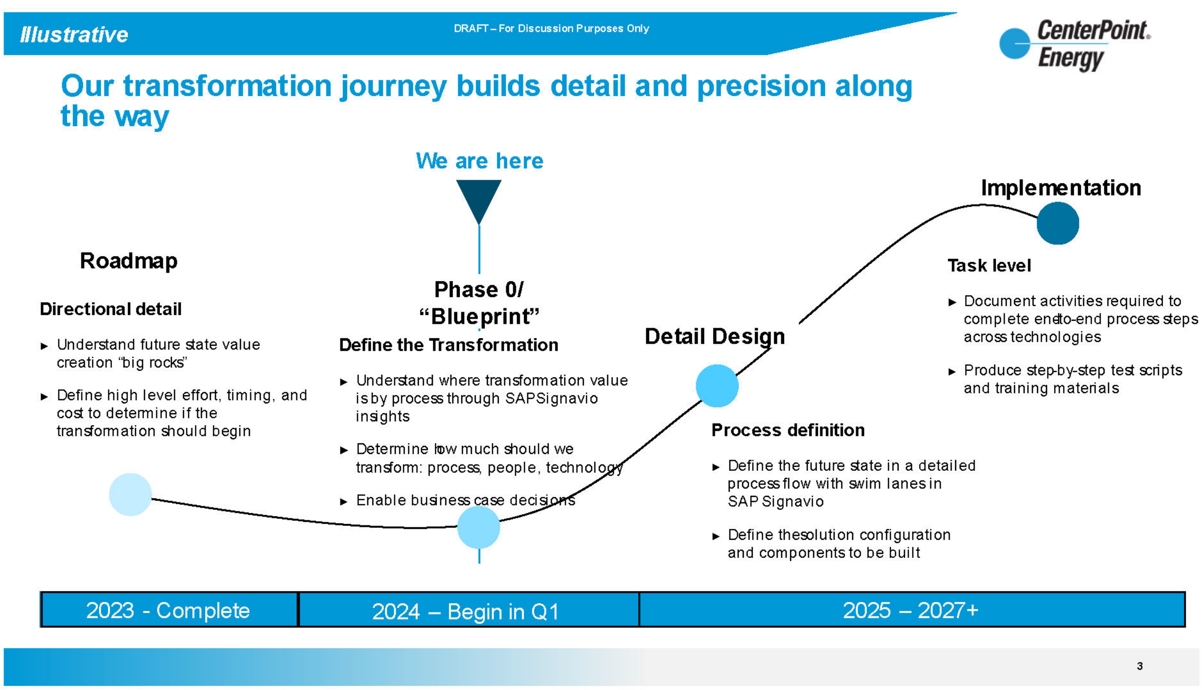
Transitioning the Company's software system to the latest SAP version, S/4HANA ("SAP S/4"), will enable the Company to provide a higher level of grid resiliency, enhance business process core functionality, and provide an overall improvement to the Company's business processes, supporting transmission and distribution system resilience. This would include the transformation of business processes related to asset maintenance, field operations, customer services, planning, application high availability, and disaster recovery, among other opportunities.

Additionally, it will enable the migration of critical SAP based applications to the cloud. Benefits of cloud migration include higher availability provided by cloud systems, advanced security capabilities provided by the cloud, and enhanced resiliency, business continuity and disaster recovery capabilities by hosting the applications in multiple geographic regions close to, and far from, the greater Houston area. The cloud model also adds layers of defense by providing security measures to protect an organization's assets, as well as offering resiliency and stability to the transmission and distribution systems.

The Company has confirmed that its proposed adoption of SAP S/4 is consistent with the approaches taken by other large investor-owned utilities; 16 of the top 25 North American investor-owned utilities have adopted or are in the process of adopting the SAP S/4 platform.

The SAP S/4 Transformation program includes multiple elements and stages (as shown in Figure RP-71 below): (1) the creation of a "roadmap"—the initial evaluation to determine high level effort, timing, and cost; (2) Phase 0 "Blueprint"—the creation of a more detailed analysis to determine scope and plan the project, (3) "Detailed Design" Phase—the identification and planning of the specific tasks needed to implement the blueprint; and (4) "Implementation" Phase. These steps are laid out in more detail in the following diagram:

Figure RP-71.



The Company has completed the roadmap phase and is beginning Phase 0, which it hopes to complete by the end of the year. The Company currently anticipates completing the Detailed Design and Implementation phases by 2027; however, this timeline may change after the completion of Phase 0.

DOCKET NO. 56548

APPLICATION OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC FOR APPROVAL OF ITS RESILIENCY PLAN	**§ § § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

DIRECT TESTIMONY OF

JASON M. RYAN

FOR

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC

April 2024

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TABLE OF EXHIBITS AND WORKPAPERS

Exhibit	**Description**
Exhibit JMR-1	Glossary of Acronyms
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Exhibit JMR-3	Resiliency Statute
Exhibit JMR-4	Resiliency Rule
Exhibit JMR-5	House Research Organization's Bill Digest for H.B. 2555
Exhibit JMR-6	Bill Analysis for the Committee Substitute C.S.H.B. 2555
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Exhibit JMR-9	Summaries of Direct Testimony

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND CURRENT POSITION.

A. My name is Jason M. Ryan. I am Executive Vice President, Regulatory Services and Government Affairs for CenterPoint Energy, Inc. ("CNP"), the parent company of applicant CenterPoint Energy Houston Electric, LLC ("CenterPoint Houston" or the "Company"). I am one of the five officers who make up the CNP Executive Committee and, as part of that group, I have general corporate oversight responsibilities beyond just the team that I directly lead. In addition to the CenterPoint Houston electric transmission and distribution utility ("TDU") business in the Houston area, CNP owns and operates an integrated electric utility in Indiana, and gas utilities in Indiana, Louisiana, Minnesota, Mississippi, Ohio, and Texas. My role includes responsibility for all of these CNP businesses.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND WORK BACKGROUND.

A. I graduated with honors in 1998 from The University of Texas at Austin with a bachelor's degree in business administration. In 2001, I received my law degree with honors from The University of Texas School of Law. I began my career at CNP in December 2009 and in January 2022, I was named Executive Vice President, Regulatory Services & Government Affairs following service as the company's general counsel and in other legal leadership positions. Prior to joining CNP, I represented the Company as outside regulatory counsel as the managing partner at energy law firm Ryan Glover LLP and as an energy regulatory attorney at Baker Botts, LLP. In addition to my legal and utility experience, I was commissioned by President George W. Bush as an intelligence officer in the Navy and served with a reserve unit from 2005-2015. I was appointed by Texas Governor Perry to the Texas Diabetes Council in 2013 for a term ending in 2019; in 2019, I was reappointed by Texas Governor Abbott for a term ending in 2025.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES AT CNP?

A. In my current role, I report directly to CNP's Chief Executive Officer and lead about 100 colleagues on the rates and regulatory portfolio management team; the regulatory policy team; the regulatory legal team; and the local, state, and federal government affairs team. These teams are responsible for: (1) representing our utility businesses—including CenterPoint Houston—in proceedings before the Public Utility Commission of Texas (the "Commission" or "PUC") and other state and federal agencies and any related appeals in the courts, and (2) spearheading state and federal legislative initiatives that support our company, customers, and communities.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of CenterPoint Houston.

Q. HAVE YOU TESTIFIED PREVIOUSLY?

A. Yes. I am currently a witness in the Company's base rate case before the Commission in Docket No. 56211. I testified on behalf of our Minnesota gas utility before the Minnesota Public Utilities Commission in 2012 and 2022 during proceedings relating to extraordinary gas costs resulting from Winter Storm Uri. I also previously testified before the Railroad Commission of Texas on behalf of our Texas gas utility about the reasonableness of rate case expenses. In addition to testimony before those commissions, I have testified on behalf of CNP utilities before the legislatures of Texas, Indiana, and Minnesota. In Texas, I have testified for more than a decade before the relevant committees of the Texas Legislature on legislation regarding energy efficiency and conservation,[1] capital recovery mechanisms and other ratemaking issues,[2] and transmission project criteria and timelines.[3] Since August 2022, I have also appeared before the Commission in my role as Chair of the Aggregated Distributed Energy Resources ("ADER") Task Force. As reflected in the record in Project No. 53911, the ADER Task Force includes 20 stakeholder representatives and is charged to work with ERCOT and the Commission to advance a pilot project for small, distributed generation assets on the distribution system to be aggregated and act in concert to provide energy and ancillary services in the ERCOT market. Integrating more distributed generation resources into the distribution system is one of the many trends leading to changed customer expectations regarding the resiliency of our utility system—in this case, being able to use the distribution system not just to receive electricity for their own consumption, but to transport their excess electricity back onto the system so they can sell it.

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[1] Including, most recently, S.B. 1699, 88th Leg., R.S. (2023), amending Public Utility Regulatory Act (PURA) § 39.101(b) to permit customer participation in demand response programs offered by retail electric providers and H.B. 2263, 88th Leg., R.S. (2023), creating Tex. Util. Code §§ 104.401-403 to permit gas local distribution companies to offer energy conservation programs to customers.

[2] Including, most recently, S.B. 1015, 88th Leg., R.S. (2023), amending PURA § 36.210 to streamline distribution cost recovery factor proceedings and permit two filings per year, S.B. 1016, 88th Leg., R.S. (2023), creating PURA § 36.067 to permit recovery of electric utility employee compensation and benefit expenses, and H.B. 1520, 87th Leg., R.S. (2021), creating Tex. Gov't Code § 1232.1072 and Tex. Util. Code §§ 104.361-380 to authorize the Texas Public Finance Authority to issue customer rate relief bonds for extraordinary gas costs incurred during Winter Storm Uri that were reviewed and approved by the Railroad Commission of Texas.

[3] Including, most recently, S.B. 1076, 88th Leg., R.S. (2023), amending PURA § 37.057 to shorten the statutory deadline for approval of certificates of convenience and necessity, and S.B. 1281, 87th Leg., R.S. (2021), amending PURA § 37.052 to add criteria for certificates of convenience and necessity for certain types of transmission line projects.

Q. WHAT EXHIBITS HAVE YOU INCLUDED WITH YOUR TESTIMONY?

A. I sponsor Exhibits JMR-1 through JMR-9 with my testimony.

Q. WAS YOUR TESTIMONY PREPARED BY YOU OR BY OTHERS WORKING UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

Q. WHAT WITNESSES ARE PROVIDING DIRECT TESTIMONY IN SUPPORT OF THE APPLICATION?

A. In addition to me, three other Company witnesses provide direct testimony in support of the application: Brad Tutunjian, Ron Bahr, and Jeff Garmon. The application also includes an independent analysis of the Company's Transmission and Distribution System Resiliency Plan ("Resiliency Plan") prepared by, and supported with testimony from, Guidehouse, Inc. ("Guidehouse"). Summaries of each piece of testimony can be found in Exhibit JMR-9.

II. <u>OVERVIEW OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. First, in Section III, I describe the public policy goals of Tex. Util. Code § 38.078 (the "Resiliency Statute"), as implemented by 16 Tex. Admin. Code § 25.62 (the "Resiliency Rule"). Next, in Section IV, I put some additional context around why the Company is proposing the Resiliency Plan. My testimony describes the Company's service territory, including recent population and load growth trends, severe weather risk trends (predominantly, high wind and water) in and around the Houston metropolitan area, the increased demand on the Company's TDU system from electrification, and how that is expected to continue into the next few decades. In Section V, I discuss the capital investment necessary to address those trends and the increasing need for resiliency. In Section VI, I summarize the Company's application by providing an overview of the Resiliency Measures included in the Company's Resiliency Plan, the estimated capital cost and estimated incremental operations and maintenance ("O&M") expense of the individual measures, and the benefits of the portfolio of measures. Lastly, in Section VII, to address affordability of the Company's Resiliency Plan, I describe how the portion of the average residential customer's electric bill attributable to CenterPoint Houston has remained relatively flat over the past decade, despite significant growth in capital expenditures. Customer growth, the expiration of various charges, and yearly reductions in O&M expenses are expected to continue to keep requested rate increases below the level of inflation, even with the addition of the Resiliency Measures included in the Company's Resiliency Plan.

III. PUBLIC POLICY GOALS OF THE RESILIENCY STATUTE

Q. WHAT HAS PROMPTED CENTERPOINT HOUSTON TO FILE A RESILIENCY PLAN?

A. CenterPoint Houston is filing its Resiliency Plan pursuant to the Resiliency Statute overwhelmingly passed by the Texas Legislature, and signed into law by the Governor in 2023, and the Commission's Resiliency Rule adopted on January 18, 2024, to implement that legislation.

Q. DID YOU PARTICIPATE IN THE LEGISLATIVE PROCESS THAT LED TO THE RESILIENCY STATUTE?

A. Yes. In my role for CNP, I actively participated in the legislative process that led to passage of the Resiliency Statute. After the filing of H.B. 2555, the bill that became the Resiliency Statute, I registered in support of it at the April 5, 2023, public hearing before the House State Affairs Committee. The bill then passed the full House on third reading with a vote of 147 yeas, 0 nays, and 1 present not voting. I testified in support of H.B. 2555 at the May 11, 2023, public hearing before the Senate Business & Commerce Committee. The bill, as substituted, then passed the full Senate on third reading with a vote of 29 yeas and 2 nays. I was then involved in the discussions after both votes that led to the final bill, which became the Resiliency Statute. The Resiliency Statute is attached to my testimony as Exhibit JMR-3, and the Resiliency Rule is attached to my testimony as Exhibit JMR-4.

Q. WHAT IS THE PUBLIC POLICY BEHIND THE RESILIENCY STATUTE?

A. According to the House Research Organization's bill digest for H.B. 2555, dated April 27, 2023 (attached to my testimony as Exhibit JMR-5), the Resiliency Statute was introduced in response to concerns "that current regulatory processes do not adequately provide for utilities to financially plan measures to increase the resiliency of electric infrastructure against inclement weather." The Bill Analysis for the committee substitute (C.S.H.B. 2555)—attached to my testimony as Exhibit JMR-6—further explained that severe weather events threaten electrical infrastructure, but because "the impact of electrical system threats varies greatly from year to year due to weather, it is difficult for utilities to financially plan for preventative activity using current regulatory processes." Recognizing that increasing the resiliency of utility transmission and distribution systems in Texas should "result in more rapid outage restoration times and less damage to existing structures," which in turn "reduces the long-term costs for utilities and their customers," the authors of the legislation sought to do at least two things. First, they sought "to provide the opportunity for electric utilities to develop and file resiliency plans" with the Commission. Second, they provided the Commission the ability to review a utility's filed resiliency plan and determine whether to approve enhanced cost-recovery methods authorized by the Resiliency Statute.

Q. ARE THERE PUBLIC POLICY BENEFITS OF THE RESILIENCY STATUTE?

A. Yes. As an initial matter, I would note that the Texas Legislature made the following findings when it passed the Resiliency Statute: (1) it is in Texas' interest to promote resiliency measures to protect transmission and distribution facilities; (2) protecting transmission and distribution facilities reduces system restoration costs and outage times; and (3) it is in Texas' interest for utilities to mitigate system restoration costs and outage times when developing resiliency plans. The Texas Legislature has recognized that resiliency efforts by utilities provide a benefit to customers and to Texas. By encouraging utilities to file resiliency plans, the Resiliency Statute gives the Commission and other stakeholders better visibility into what the utilities under its jurisdiction are doing to improve resiliency, provides the Commission and other stakeholders an opportunity to offer an assessment of those measures, and allows all utilities to learn from each other's initiatives. Better transparency for the Commission and other stakeholders combined with Commission and other stakeholder feedback to utilities should work together to contribute to a more resilient Texas electric grid.

Q. HOW DOES THE RESILIENCY STATUTE PASSED BY THE LEGISLATURE SUPPORT THE ABOVE PUBLIC POLICY GOALS?

A. First, including a broad number of measures that can be part of a utility's resiliency plan — from hardening and modernization, to cyber and physical security, to vegetation management and wildfire mitigation — allows a resiliency plan to be more comprehensive and coordinated and provides the Commission visibility into more of the measures that make up a utility's resiliency initiatives. Second, by providing mechanisms for more timely recovery of some resiliency plan costs, the Resiliency Statute directly improves the ability of an electric utility to financially plan and execute the resiliency measures and offers an incentive to voluntarily file its resiliency plan.

IV. COMPANY GOALS FOR THE RESILIENCY PLAN

Q. WHAT ARE THE GOALS OF CENTERPOINT HOUSTON'S RESILIENCY PLAN?

A. The Company's fundamental goal is to enhance the resiliency of its transmission and distribution system. The Resiliency Measures detailed in the Company's Resiliency Plan will support the continued safe and reliable operation of the Company's transmission and distribution system in the face of events defined in the Resiliency Statute as "Resiliency Events," including extreme weather described by Guidehouse, Inc. ("Guidehouse") witness Eugene Shlatz in Section IV of his testimony. The Company believes its investment in the Resiliency Plan will benefit customers by mitigating the impact of certain Resiliency Events that occur in its service area and over time lead to reduced customer outage times, and lower system recovery costs. (The independent analysis by Guidehouse supports this conclusion.) In some Resiliency Events, more resilient equipment will better withstand the effects of the event, survive the threat, and avoid damage to the system. In other cases, even when the system is damaged, the improved resiliency will reduce overall outage times, lessen the number of customers affected, and lower system restoration costs. The Company also has a goal of continuing to invest in fundamentals like resiliency, safety, and reliability while keeping CenterPoint Houston electric customer charge increases at or below the 2% historical level of inflation over the longer term. I will address this goal further in Section VII (Affordability of CenterPoint Houston's Resiliency Plan). A third goal of the Company's Resiliency Plan is to give the Commission improved visibility into, and a way to provide feedback on, CenterPoint Houston's ongoing efforts to make its transmission and distribution system more resilient. That includes offering the Commission and other stakeholders an opportunity to provide guidance to CenterPoint Houston on the Company's two proposed pilot programs and providing the Commission information on the Company's expected SAP update project. We have included the pilot programs, in particular, in our Resiliency Plan in the hope that the Commission will provide feedback on whether it considers it proper to invest in such measures.

Q. YOU MENTIONED THE COMPANY'S "ONGOING EFFORTS" RELATED TO RESILIENCY. PLEASE EXPLAIN THAT.

A. The Company is filing its Resiliency Plan as contemplated by the new Resiliency Statute, but resiliency efforts are not new to CenterPoint Houston. As Brad Tutunjian explains in his direct testimony, the Company has been investing in and implementing resiliency measures for a long time. In Mr. Tutunjian's testimony, he identifies a number of resiliency projects undertaken in 2019-2023. Just two of those projects—IGSD installation and distribution pole replacement or bracing—account for approximately $230 million of resiliency investments during the past five years. In addition, following the passage in 2021 of House Bill 2483, in the aftermath of Winter Storm Uri, the Company invested in emergency generation to provide greater resiliency during load shedding events or after major storms. But even before all of that, we invested in resiliency assets like mobile substations, which we used after Hurricane Harvey in 2017.

So, resiliency planning is not new to CenterPoint. What is new is the framework for providing the Commission and other stakeholders better visibility into the Company's Resiliency Plan and the financial context in which CenterPoint Houston' Resiliency Plan is to be carried out. The Company's ongoing efforts to strengthen its transmission and distribution systems coincide with three major developments in the Company's service area: customer growth, severe weather, and increased electrification.

A. CUSTOMER GROWTH

Q. PLEASE DESCRIBE THE COMPANY'S SERVICE AREA AND CUSTOMERS.

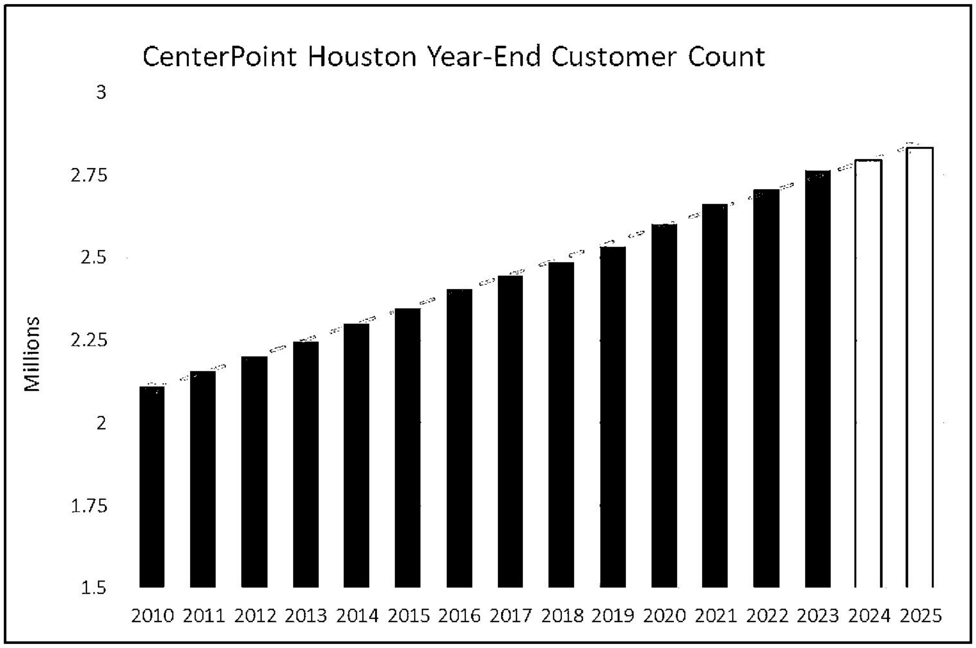
A. CenterPoint Houston has a compact, urban, and dense service area serving approximately 2.8 million homes and businesses. The service area covers approximately 5,000 square miles in the Greater Houston region, including portions or all of Brazoria, Chambers, Galveston, Fort Bend, Harris, Liberty, Montgomery, Waller, and Wharton Counties. While the Company's service area is only about 2% of the geographic area of Texas, the customers in the Company's service area account for approximately 25% of the total load in the ERCOT power region. Presently there are not sufficient local generation resources in the Houston area to power the growing region's needs; and during many parts of the year, we need to import most of the power from other parts of ERCOT to serve our customers.

Our service area includes the city of Houston, the largest city in the state, and the Greater Houston area, which is currently the fourth largest metropolitan area in the country. Based on current projections, the Company anticipates that the population of the Greater Houston area will soon surpass the Greater Chicago area and become the third largest metropolitan area in the country. This large and growing population requires the Company to serve and interconnect a large number of new residential and commercial customers each year. In addition, the Greater Houston area is the home to large petroleum refineries and petrochemical facilities, meaning the Company has many industrial customers that consume large amounts of electricity. The Greater Houston area also has some particularly important public-serving facilities and infrastructure. For example, the Texas Medical Center, the world's largest medical complex and home to multiple medical and research institutions, is located in Houston. Likewise, the Port of Houston, one of the country's busiest container ports, is in the Greater Houston area. Additionally, the city of Houston has two airports, George Bush Intercontinental Airport and William P. Hobby Airport, that serve millions of passengers and are local hubs for connecting flights, as well as Ellington Airport/Houston Spaceport.

Q. HOW WOULD YOU DESCRIBE THE RECENT GROWTH IN CENTERPOINT HOUSTON'S SERVICE AREA?

A. The pace of growth in the Company's service area has been rapid, and that growth has been sustained. At the time of its electric base rate proceeding in 2010, the Company had just under 2.1 million metered customers. By 2019, that number had grown to approximately 2.5 million. Today, only five years later, CenterPoint Houston has the privilege to serve approximately 2.8 million homes and businesses. Figure JMR-1 illustrates both customer growth in the Company's service area since 2010 and estimated customer growth through 2025.

Figure JMR-1
CenterPoint Houston Year-End Customer Count



To put into perspective the past customer growth in the Company's service area, the Company has added into its service area the equivalent of a city roughly the size of Waco, Texas every single year since 2010. That significant annual growth requires building new infrastructure, or upgrading existing infrastructure, to serve that ever-increasing customer base. Whether building new or upgraded transmission lines to bring more power into the Houston region, new or upgraded substations, or new distribution circuits to new homes and businesses, this customer growth has been a large driver of the increased capital expenditures of the Company.

Also, as mentioned above, our service area is home to important public-serving infrastructure including the Texas Medical Center, the largest medical complex in the world. The Texas Medical Center employs over 100,000 people, is responsible for 10 million patient encounters per year, and is home to the world's largest children's hospital and cancer hospital.[4] Our service area is also home to the Houston Ship Channel complex, the largest port in the country in terms of waterborne tonnage. One study has estimated that the Houston Ship Channel complex supports over 1.5 million jobs throughout Texas and nearly 3.4 million jobs nationwide.[5]

Moreover, Houston's airports serve over 50 million passengers per year and position Houston as a gateway to the south-central United States and Latin America.[6] Finally, most people recognize Houston as the energy capital of the world, but many may not know that 26 companies in the Fortune 500 are headquartered in Houston (and two of those relocated as recently as 2023), which puts the area third in the country for number of Fortune 500 headquarters, after New York (62) and Chicago (30).[7]

Q. IS THE RAPID GROWTH IN THE HOUSTON AREA EXPECTED TO CONTINUE WELL BEYOND THE NEXT FEW YEARS AS SHOWN ABOVE?

A. Yes. Figure JMR-2, which was prepared by the Texas Demographic Center[8], shows projected population change for Texas counties for 2020–2060.

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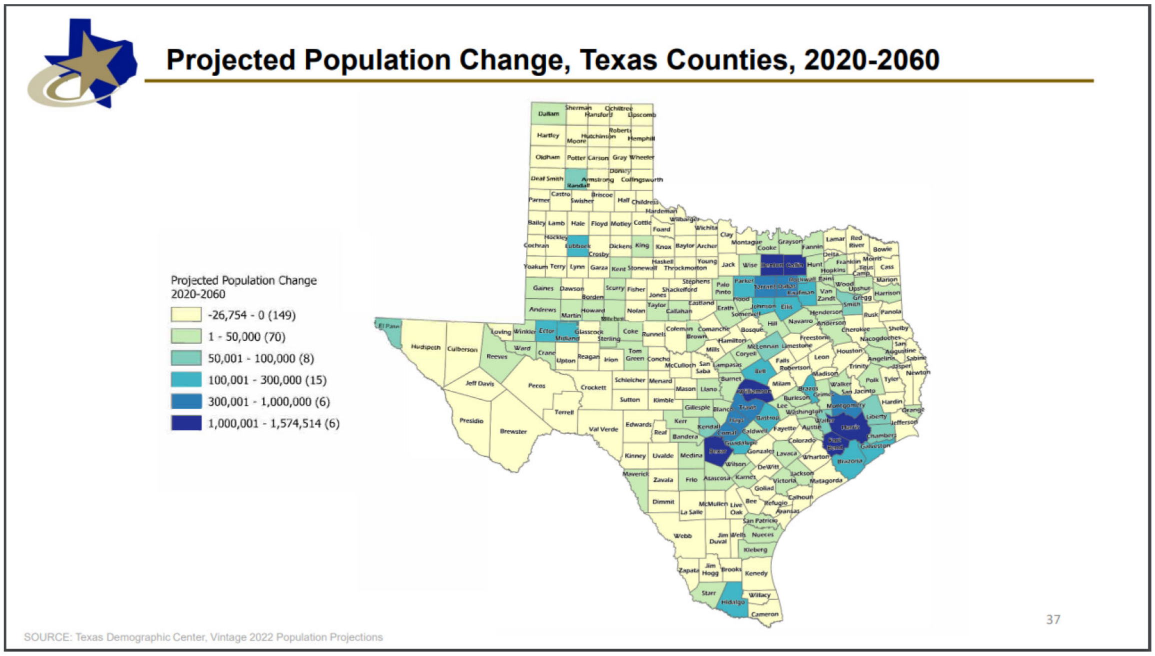
[4] https://www.tmc.edu/ (last accessed Feb. 9, 2024).
[5] https://porthouston.com/about/our-port/statistics/ (last accessed Feb. 9, 2024).
[6] https://www.fly2houston.com/biz/about (last accessed Feb. 9, 2024).
[7] https://www.houston.org/houston-data/fortune-500-companies (last accessed February 9, 2024).
[8] The Texas Demographic Center is housed within The University of Texas at San Antonio and the Stephen F. Austin building in the Capitol Complex in Austin.

Figure JMR-2

Projected Population Change, Texas Counties, 2020-2060



As Figure JMR-2 illustrates, Harris County, the heart of the Company's service area, is expected to continue growing, increasing by between 1 million and 1.57 million people between 2020 and 2060. Fort Bend County, also in our service area, is projected to see similar growth. As the map shows, similar growth is projected to occur in the Austin and Dallas-Ft. Worth areas, but unlike those regions, the CenterPoint Houston service area is located along the Texas Gulf Coast, exposing it to hurricanes and other types of severe weather events that may not occur further inland. Mr. Tutunjian also discusses customer growth in his direct testimony.

B. SEVERE WEATHER

Q. PLEASE DESCRIBE THE SEVERE WEATHER THREATS AFFECTING THE COMPANY.

A. There are few, if any, locations in the United States where customers are as susceptible to substantial impacts from severe weather events as customers in Harris County, Texas. According to data collected by the National Centers for Environmental Information ("NCEI") at the National Oceanic and Atmospheric Administration ("NOAA") presented in Figure JMR-3 below, Harris County has the highest possible risk and vulnerability rating (100 out of 100) for flooding risk and hurricane (a.k.a., tropical cyclone) risk and has a very high risk and vulnerability rating for severe storms (94.56 out of 100) and winter storms (65.33 out of 100).

Figure JMR-3
Risk and Vulnerability Ratings for Harris County
NOAA National Centers for Environmental Information[9]

Risk and Vulnerability

Data Type	Census Tract 5505	Harris County	Texas	U.S.
Weather and Climate Risk				
Drought Risk	3.40	20.36	14.32	11.61
Flooding Risk	35.88	100.00	12.97	9.13
Freeze Risk	3.40	12.05	13.09	15.72
Severe Storm Risk	35.62	94.56	20.58	16.99
Tropical Cyclone Risk	44.35	100.00	6.41	4.36
Wildfire Risk	--	11.81	11.28	6.30
Winter Storm Risk	16.97	65.33	15.99	13.71
Weather and Climate Combined Risk	29.74	100.00	17.29	13.30

As Figure JMR-3 demonstrates, those risk and vulnerability ratings are much higher than for Texas or the U.S. generally.

[9] NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2024). https://www.ncei.noaa.gov/access/billions/, DOI: 10.25921/stkw-7w73 (last accessed on February 9, 2024).

C. INCREASED DEMAND AND ELECTRIFICATION

Q. PLEASE DESCRIBE THE ELECTRIFICATION TREND THAT IS AFFECTING THE COMPANY.

A. Electrification takes several forms. First, we have seen an increase in generator interconnection application requests. Since Docket No. 49421, our last base rate proceeding, the Company has built transmission interconnection facilities to interconnect twenty-five new resource plants collectively representing approximately 6,435 MW of planned capacity out of which wind, solar, and storage resources constitute approximately 4,685 MW (or 73%) of the planned capacity.

Second, on the distribution side, more homes and businesses are installing distributed energy resources, primarily roof-top solar systems. These systems allow customers to offset their on-premises energy demands and to be able to export excess energy back onto the distribution system. Distribution circuits that were originally designed for power to flow in one direction, from the grid to the customer, are now being called upon to handle the flow of power in both directions, which requires changes to system design and creates operational challenges as well.

Third, the Company continues to see more customers adopting electric vehicles, commercial fleet conversions, and electrifying other operational aspects of their facilities.

Fourth, quite a few of our large industrial customers are moving to electrify their operations. It is important to note that each of these trends—new generation interconnections, increasing penetration of distributed energy resources, a move to adopt more electric vehicles, and industrial electrification—is *customer*-initiated. As the electric utility with an obligation to serve these customers, CenterPoint Houston must invest in the necessary transmission and distribution infrastructure to meet their customers' growing and changing needs.

Q. WHAT IS THE EXPECTED PACE OF ELECTRIFICATION IN CENTERPOINT HOUSTON'S SERVICE AREA?

A. The Greater Houston Partnership, which is the Houston region's equivalent of a chamber of commerce, is currently conducting a comprehensive study of projected customer load growth in the region, because of customer-initiated electrification efforts and the region being picked as a hydrogen hub by the Department of Energy ("DOE"). Electrification and hydrogen development in the Houston area are being supported by an unprecedented level of federal grant and loan funding under the Bipartisan Infrastructure Law (as enacted in the Infrastructure Investment and Jobs Act of 2021) and the Inflation Reduction Act of 2022. Many of our large industrial customers have shared that they are applying for grants under these programs established by these federal laws, which will only accelerate electrification efforts and hydrogen development. It is anticipated that the Greater Houston Partnership study will be released in the near future. Once it is released, I will provide it in supplemental direct testimony. Based on our involvement in the study, however, I expect it will show the potential for at least doubling or tripling of customer load in the Houston area by 2050, primarily caused by customer-driven activities.

Consistent with what I expect to be shown in the Greater Houston Partnership study, an April 2022 report from The University of Texas at Austin notes that the City of Houston has set a net-zero target by 2050,[10] and suggests that to reach such a target relying on electrification, electric consumption would need to more than double over that time frame.[11]

It is important to also note that, unlike the steady increases in population mentioned above, which increase load gradually, industrial electrification will happen in larger increments. For example, when the Freeport LNG facility began operation in our service area, it required 690 MW of electricity, which was almost 9 times the Freeport area's previous load, which was less than 80 MW.[12] Given the growth in capital expenditures that has been needed to keep up with the current regional population growth, commercial and industrial electrification, and hydrogen development will require a game-changing level of infrastructure development by the Company.

V. INVESTING TO MEET THE NEEDS OF OUR CUSTOMERS

Q. HOW DOES THE COMBINATION OF RAPID AND SUSTAINED GROWTH, SEVERE WEATHER, AND ELECTRICFICATION AFFECT THE COMPANY?

A. To meet the needs of all our customers, maintain our system, make the grid more dynamic, and harden our systems in the face of severe weather, the Company has invested over $6 billion dedicated to its transmission and distribution operations over

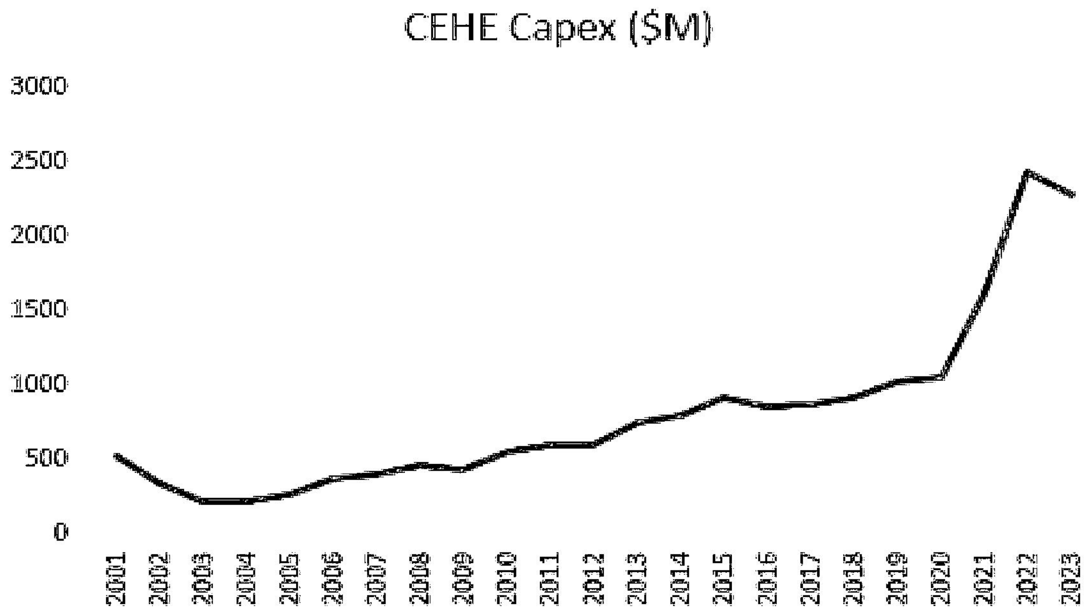
[10] Gee, Isabella *et al*, The University of Texas at Austin, "Don't Mess with Texas: Getting the Lone Star State to Net-Zero by 2050" at 23. UT_Texas_Net_Zero_by_2050_April2022_Full_Report.pdf (utexas.edu).

[11] *Id.* at 38 (Figure 3.2, showing overall electricity demand in Texas more than doubling by 2050 compared to 2020 for all net-zero scenarios).

[12] U.S. Energy Information Administration, Natural Gas Weekly Update, September 12, 2019, found at https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2019/09_12/#:~:text=Freeport%20LNG%20requires%20690%20megawatts,was%20less%20than%2080%20MW.

the past five years. Figure JMR-4 shows CenterPoint Houston historical capital expenditures, as reported in our annual Form 10-K reports, for 2001 through 2023.

<u>Figure JMR-4</u>
Historical Capital Expenditures, 2001-2023



After electric utility unbundling in 2001, capital expenditures by CenterPoint Houston remained at or below $500 million per year through 2009. Beginning in 2010 and through the next decade, however, capital expenditures would double in response to a 20% increase in the number of customers served by the Company, a generational storm in 2017 (Hurricane Harvey), and the deployment of approximately 2.5 million advanced meters. By 2019 and 2020, the Company's capital expenditures exceeded $1 billion per year. Needed capital expenditures increased to $2.436 billion in 2022 and fell only slightly in 2023 to $2.290 billion. To put CenterPoint Houston's historical capital expenditures in perspective, Figure JMR-5 summarizes the capital expenditures of

Houston Lighting & Power, CenterPoint Houston's predecessor, in the years leading up to the passage of S.B. 7[13] in 1999, which required the unbundling of vertically integrated electric utilities in the ERCOT power region and the transition to a competitive retail electric market by 2002. The capital expenditures below are for an integrated utility and include generating facilities, transmission facilities, distribution facilities, substation facilities, and general plant.

Figure JMR-5
HL&P Capital Expenditures (1993-1998)

Year	**Capital Expenditures** (Excludes Allowance for Funds Used During Construction)
1993	$329 million (includes nuclear fuel)
1994	$413 million
1995	$392 million (includes nuclear fuel)
1996	$383 million
1997	$234 million
1998	$429 million

Q. WHAT LEVEL OF ANNUAL CAPITAL INVESTMENT DOES THE COMPANY ANTICIPATE GOING FORWARD?

A. In our most recent annual report, the Company estimates that its annual capital expenditures over the next five years will average nearly $2.56 billion per year, as shown below in Figure JMR-6.

[13] S.B. 7, 76th Leg., R.S. (1999), creating Chapter 39 of PURA to unbundle vertically integrated utilities in the ERCOT power region and transition to a competitive retail electric market.

Figure JMR-6
CEHE Projected Capital Expenditures (2024-2028)

Year	Projected Capital Expenditures
2024	$1,895 million
2025	$2,598 million
2026	$2,663 million
2027	$2,822 million
2028	$2,816 million
Total	$12,794 million

We expect that level of investment to continue through at least 2033, as our current plans call for investing approximately $25 billion over the next decade.

Q. ARE THE COSTS OF THE RESLIENCY MEASURES INCLUDED IN THE COMPANY'S RESILIENCY PLAN INCLUDED IN THE ABOVE PROJECTED CAPITAL EXPENDITURES?

A. We currently expect to fund a substantial portion of the resiliency plan consistent with the above projected capital expenditures. In other words, the Resiliency Measures are not all additive to the above projected capital expenditures. The ability of the Company to fund the upper range of the cost estimate of the Resiliency Measures, which would be more than the above projected capital expenditures, depends on a number of factors, including the outcome of the Company's pending base rate proceeding in Docket No. 56211. In particular in that case, the Company has proposed using its actual capital structure in rates, which reflects how the Company actually funds its capital investments. In the event the Company's actual capital structure is adopted, rates would reflect the actual sources of equity and debt capital and thereby increase the likelihood of further investment in system resiliency. Success in one or more of our applications for state and federal grant funding, discussed in Section VII of my testimony, would also enhance the Company's capacity to invest in resiliency measures.

Q. IS INVESTMENT AT THAT LEVEL REALLY NECESSARY?

A. Yes, it is. Customer growth in our service area is not occurring in a vacuum. It is accompanied by changing customer expectations related to reliability and resiliency, as well as a marked trend toward increasing electrification, especially in our industrial customer sector.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY INCREASING EXPECTATIONS FOR RELIABILITY AND RESILIENCY.

A. CenterPoint Houston faces increasing expectations from customers and other stakeholders to have a more resilient system. In fact, letters received by the Company from some of its customers and stakeholders are compelling evidence that our customers recognize the benefits of greater resiliency. I have attached to my testimony as Exhibit JMR-7 letters of support that were included in the Company's recent federal grant applications, discussed more in Section VII. In those letters, a diverse group of organizations confirm that "[r]esiliency and reliable infrastructure are integral to our community" (Houston Business Development, Inc.), that a more resilient electric grid "brings a host of benefits beyond reduced vulnerability to severe weather" (Greater Houston Partnership), and that resiliency planning is "essential to further insulate our region's electrical infrastructure from severe weather events and improve service to CenterPoint's business and residential customers" (Tejano Center for Community Concerns).

VI. OVERVIEW OF THE RESILIENCY PLAN

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S RESILIENCY PLAN APPLICATION.

A. The Resiliency Plan Application presents the Company's strategy for implementing Resiliency Measures that will prevent, withstand, and mitigate risks posed to the Company's transmission and distribution system. The Resiliency Measures included in the Resiliency Plan are intended to build on resiliency investments made by the Company previously and achieve better outcomes for our customers during extreme weather events (including extreme cold and heat, high winds, flooding, lightning, hurricanes, microbursts, tornadoes, and wildfires), physical security events, and cybersecurity events. These Resiliency Measures and the related estimated costs from 2025-2027 are summarized below in Figure JMR-7.

Figure JMR-7
(Summary of CenterPoint Houston Resiliency Measures and Estimated Costs from 2025-2027)

	Estimated Capital Costs 2025-2027 (millions)	Estimated Incremental O&M Costs 2025-2027 (millions)
System Hardening Resiliency Measures		
Transmission System Hardening	$376.0	$0.75
S90 Tower Replacements	$103.8	None
69kV-138kV Conversion Projects	$268.4	None
Coastal Resiliency Upgrades	$259.0	$0.75
Substation Transformer Fire Protection Barriers	$2.4	None
Distribution Pole Replacement/Bracing	$99.3	None
Distribution Resiliency – Circuit Rebuilds	$312.8	None
Strategic Undergrounding / Freeway Crossings	$31.2	None
Grid Modernization Resiliency Measures		
TripSaver	$58.9	$0.03
IGSD Installation	$53.8	$0.82
Texas Medical Center Substation	$102.0	$0.15
Flood Mitigation Resiliency Measures		
Substation Flood Control	$30.6	None
Control Center Facility Upgrades	$7.0	None
Information Technology to Support Operations Resiliency Measures		
Advanced Aerial Imagery Platform/Digital Twin	$9.9	$0.06
Advanced Distribution Technology	$225.8	$15.0
Digital Substation	$25.0	($0.6)
Information Technology Resiliency Measures		
Voice and Mobile Data Radio System Refresh	$15.6	None
Backhaul Microwave Communication	$12.1	None
Data Center Refresh	$2.9	$0.25
Network Security and Vulnerability Management	$1.0	None
IT/OT Cybersecurity Monitoring Program	$22.5	None
System Security Resiliency Measures		
Substation Physical Security Fencing	$15.0	None
Substation Security Upgrades	$19.5	$0.09
Vegetation Management Resiliency Measure		
Vegetation Management	None	$25.0
Wildfire Mitigation Resiliency Measure		
Wildfire Mitigation Projects	$137.2	$43.7

As noted in the Resiliency Plan under some of the measures, the Company may accelerate certain measures subject to available funding, personnel, and materials, so the above estimates of capital costs and expense could vary as detailed in the Resiliency Plan.

Q. HOW HAS THE COMPANY EVALUATED EACH PROPOSED RESILIENCY MEASURE FOR EFFECTIVENESS?

A. The Resiliency Measures in the Resiliency Plan were independently evaluated for effectiveness by Guidehouse. As described in Mr. Shlatz's testimony, Guidehouse performed a quantitative benefits-costs analysis ("BCA") of the operational Resiliency Measures—System Hardening, Grid Modernization, Flood Mitigation, Information Technology to Support Operations, System Security, and Vegetation Management. Guidehouse quantified the net benefits of each operational Resiliency Measure with a life-cycle analysis of costs versus benefits. Figure JMR-8, below, summarizes Guidehouse's BCA results. Guidehouse calculated BCA ratios using a value of lost load of $25,000 per MWh.[14] A BCA ratio above 1.0 indicates the benefits outweigh the costs, which suggests that the Resiliency Measure should be implemented. A value under 1.0 indicates that the costs outweigh the benefits, but additional qualitative considerations may suggest that the Resiliency Measure should be implemented regardless of the BCA ratio. For example, one Resiliency Measure with a BCA below 1.0—the Texas Medical Center Substation—serves current and future critical load and justifies inclusion in the Company's Resiliency Plan, as discussed in more detail by

[14] *Review of Value of Lost Load in the ERCOT Market*, Project No. 55837, Staff Recommendation Memo on Interim VOLL (Jan. 25, 2024) (recommending that the interim VOLL be set at $25,000 per MWh); *id.*, ERCOT's Review of Value of Lost Load in the ERCOT Market (Mar. 14, 2024).

Mr. Shlatz.

Figure JMR-8

Measure	Cost ($MM)		O&M ($MM)		BCA Ratio
System Hardening					
Transmission System Hardening	$	376.0	$	0.75	6.0
S90 Tower Replacements	$	103.8	$	-	4.9
69kV-138kV Conversion Projects	$	268.4	$	-	1.9
Coastal Resliency Upgrades	$	259.0	$	0.75	1.4
Substation Transformer Fire Protection Barriers	$	2.4	$	-	3.7
Distribution Pole Replacements/Bracing	$	99.3	$	-	6.2
Distribution Resiliency – Circuit Rebuilds	$	312.8	$	-	7.0
Strategic Undergrounding/Freeway Crossings	$	31.2	$	-	3.8
Grid Modernization					
Trip Savers	$	58.9	$	0.03	61.3
IGSD Installations	$	53.8	$	0.82	15.7
Texas Medical Center Substation	$	102.0	$	0.15	0.7
Flood Control					
Substation Flood Control	$	30.6	$	-	7.5
Control Center Facility Upgrades	$	7.0	$	-	12.5
Information Technology					
Advanced Aerial Imagery Platform/Digital Twin	$	9.9	$	0.06	3.4
Advanced Distribution Technology	$	225.8	$	15.00	4.8
Digital Substation	$	25.0	$	(0.60)	1.9
System Secuity					
Substation Physical Security Fencing	$	15.0	$	-	15.6
Substation Security Upgrades	$	19.5	$	0.09	20.5
Vegatation Management					
Targeted Critical Circuit Vegetation Management	$	-	$	25.00	1.8
Totals	**$**	**2,000.4**	**$**	**42.05**	**6.6**

Q. HOW HAS THE COMPANY EVALUATED THE PROPOSED TECHNOLOGY RESILIENCY MEASURES FOR EFFECTIVENESS?

A. As explained by Guidehouse witness Mr. Baugh in his direct testimony, it is difficult to quantify the benefits of the enabling technology functions that support the effective operation of electric delivery systems. Therefore, Guidehouse conducted a *qualitative* analysis of the benefits of the Company's proposed Resiliency Measures, including the technology Resiliency Measures for which a quantitative analysis was not practical. Guidehouse applied the National Institute of Standards and Technology's Cybersecurity Framework ("NIST CSF") to compare the best practices and recommended cybersecurity controls used in the electric utility sector to the Company's cybersecurity activities and overall risk processes. Figure JMR-9, below, summarizes Guidehouse's qualitative findings on the types of investments made by other electric utilities. The blue arrows point to the five technology Resiliency Measures in the Company's Resiliency Plan. Based on the NIST CSF qualitative analysis, Guidehouse found evidence of effectiveness for each of the Company's five technology Resiliency Measures.

Figure JMR-9

Type of Investments	Utility Companies								
	102	103	106	107	108	109	114	122	123
Changes to emergency response plans		✓		✓			✓	✓	
Governance risk and compliance tracking		✓				✓	✓		
Threat intelligence and management	✓	✓					✓	✓	
Line/Circuit rebuilds	✓	✓	✓	✓	✓	✓	✓	✓	✓
Pole replacements	✓	✓	✓	✓	✓	✓	✓	✓	✓
Undergrounding of key lines or portions (e.g. freeway crossings)	✓	✓	✓		✓	✓		✓	✓
Conversion projects – e.g. from 69kV to 138kV	✓	✓				✓		✓	
Raising substations	✓	✓	✓		✓				
Reconductoring projects	✓	✓		✓	✓		✓		
Smart grid upgrades	✓	✓	✓	✓		✓	✓	✓	
Data Center Facilities upgrades	✓	✓					✓	✓	
Data storage and handling	✓	✓				✓	✓	✓	
Smart grid data modifications	✓	✓					✓	✓	
Operational data resiliency	✓	✓				✓	✓	✓	
Cyber Security	✓	✓	✓				✓	✓	✓
Monitoring of assets	✓	✓				✓	✓	✓	
Cloud based data handling improvements	✓	✓					✓	✓	
Application security							✓	✓	
Telecommunication infrastructure	✓	✓					✓	✓	
Microwave communications	✓	✓					✓	✓	
Voice and mobile data enhancements	✓	✓					✓	✓	
Use of monitoring cameras, communications	✓	✓	✓				✓	✓	
Substation fencing	✓	✓	✓				✓	✓	
Substation security upgrades	✓	✓	✓				✓	✓	
Network security	✓	✓					✓	✓	
Trip savers	✓	✓		✓		✓			
Digital substation OT systems	✓	✓				✓	✓	✓	
Substation automation	✓	✓	✓			✓	✓	✓	

Q. **PLEASE SUMMARIZE GUIDEHOUSE'S OVERALL FINDINGS REGARDING THE COMPANY'S RESILIENCY PLAN.**

A. The Guidehouse report demonstrates that the Company's Resiliency Plan presents vetted, cost-effective Resiliency Measures that the Company will implement with Commission approval to ensure safe and reliable service to its customers during

Resiliency Events.

Q. PLEASE IDENTIFY WHERE IN THE COMPANY'S FILING EACH RESILIENCY PLAN RULE REQUIREMENT FOR THE COMPANY'S PROPOSED RESILIENCY MEASURES IS SUPPORTED.

A. Please see Exhibit JMR-2.

Q. IN ADDITION TO THE RESILIENCY MEASURES IN FIGURE JMR-7, IS THE COMPANY PROPOSING ANY PILOT PROGRAMS IN THIS APPLICATION?

A. Yes. The Company is proposing the following two pilot programs:

(1) a utility-scale microgrid pilot program; and

(2) up to $200,000 per year to fund an employee at the City of Houston whose responsibility would be to focus on resiliency-related matters on behalf of the City of Houston.

If the Commission approves them, the results of the pilot programs would be shared in detail in the Company's next Resiliency Plan application (2028-2030).

Q. CAN YOU PROVIDE MORE DETAILS ABOUT THE FIRST PILOT PROGRAM, RELATING TO A MICROGRID?

A. The microgrid pilot program is detailed more in the Resiliency Plan itself and in the testimony of Mr. Tutunjian. The rationale for the pilot is, in part, based on my experience with the ADER Task Force. As more distribution-level customers install distributed energy resources ("DERs") capable of putting energy on the distribution system, we need to understand their abilities, how they may be used to avoid emergencies, how they could be useful during an emergency (so that they are not stranded), and when they could be used to provide power other customers. The Company does not have all the answers for exactly what should be prudently done in a world of increasing DERs to ensure that these resources are available for wider use when they are needed the most. The proposed utility-scale microgrid pilot program will advance that discussion for the benefit of all stakeholders.

Q. CAN YOU PROVIDE MORE DETAILS ABOUT THE SECOND PILOT PROGRAM, RELATING TO THE CITY OF HOUSTON POSITION?

A. Attached as Exhibit JMR-8 is a letter from the City of Houston describing the annual funding requested (not to exceed $200,000) and the job responsibilities of the employee they seek to assign to oversee the Company's Resiliency Plan work. Working closely with local stakeholders, like the City of Houston, will be key to implementing the Resiliency Plan and will help facilitate engagement with customers and communities we serve on the projects detailed in it. City of Houston engagement is especially important as it relates to building new infrastructure and replacing less resilient infrastructure. Having the City of Houston—the largest city in the Company's footprint—engaged through a dedicated employee will ensure a better flow of information, better situational awareness, and better coordination of other activities occurring throughout the larger community.

Q. IN ADDITION TO THE ABOVE RESILIENCY MEASURES AND PILOT PROGRAMS, HAS THE COMPANY INCLUDED ANYTHING ELSE IN ITS RESILIENCY PLAN?

A. Yes. The Company included in its Resiliency Plan a description of the need to transition to the latest version of SAP, SAP S/4. SAP is the backbone of CNP's business processes and supports activities such as supply chain management, system restoration, and dispatching, all of which are critical to operational resiliency. The Company's Resiliency Plan and Company witness Ron Bahr describe how the Company is currently evaluating the timing of and extent to which it must transition to SAP S/4. The current evaluative effort is known within the Company as the SAP S/4 Transformation and Phase 0.

Q. **IS THE COMPANY SEEKING DEFFERED ACCOUNTING TREATMENT FOR ANY OF THE RESILIENCY MEASURES, PILOT PROGRAMS, OR ACTIVITY IN THE RESILIENCY PLAN?**

A. Yes. The Company is seeking deferred accounting treatment, pursuant to the Resiliency Rule, for all of the Resiliency Measures and the two pilot programs presented in the Resiliency Plan. The Company is not presenting the SAP S/4 Transformation and Phase 0 as a Resiliency Measure, and it does not seek deferred accounting treatment under the Resiliency Rule for the SAP S/4 Transformation and Phase 0.

Q. **IS THE COMPANY SEEKING APPROVAL OF A NEW RIDER, AS PERMITTED UNDER THE RESILIENCY STATUTE, TO RECOVER THE RESILIENCY PLAN INVESTMENTS AND COSTS?**

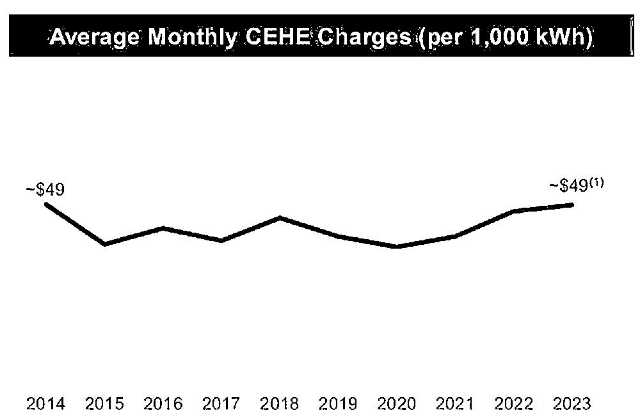
A. No. Instead, the Company intends to recover its investments and costs through existing recovery mechanisms, like the Distribution Cost Recovery Factor ("DCRF"), the Transmission Cost of Service ("TCOS") tariff, or in the Company's next rate case if there are categories of investments or costs not eligible for DCRF or TCOS.

VII. AFFORDABILITY OF CENTERPOINT HOUSTON'S RESILIENCY PLAN

Q. WHAT IS "AFFORDABILITY" AND WHY IS IT IMPORTANT?

A. CenterPoint Houston believes it is important to focus not only on the overall cost of providing its services (its revenue requirement), but also the cost of the Company's services to the average residential customer (its rates). Rates, rather than revenue requirement, impact the ability of individual customers to afford electric service. CenterPoint Houston's revenue requirement was set at $1.4 billion in its 2010 rate case (Docket No. 38339). Nine years later, in the Company's 2019 rate case (Docket No. 49421), the revenue requirement had grown to approximately $2.5 billion. However, despite the growth in its revenue requirement, the portion of the average residential customer's electric bill attributable to CenterPoint Houston has remained relatively flat over the past ten years, as reflected in Figure JMR-10.

Figure JMR-10
CenterPoint Houston Average Monthly Charges per 1,000 kWh



Nearly flat charges on customer bills over the last 10 years at Houston Electric

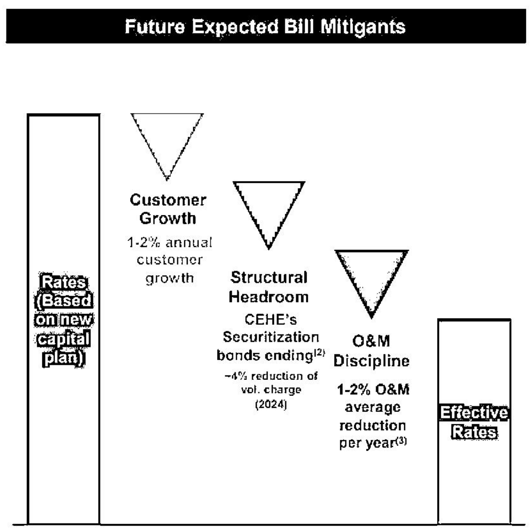
~2.8% average annual inflation rate for that same period

(1) As of December 31, 2023

Q. HOW CAN CENTERPOINT HOUSTON HOPE TO ACCOMPLISH THAT AFFORDABILITY GOAL WHILE SIGNIFICANTLY INCREASING ITS INVESTMENT IN RESILIENCY MEASURES?

A. As illustrated by Figure JMR-11, the Company has three factors working to help contain average residential customer rates, even as the Company increases its revenue requirements.

Figure JMR-11
CenterPoint Houston Future Expected Bill Mitigants



(2) Refers to Houston Electric's securitization bonds; One tranche of transition bonds remain, with a scheduled final payment date in 2024
(3) Projections based on internal forecast and are based on annual targets

First, customer growth spreads the cost of increased investments over an ever-larger number of customers, so that incremental capital does not result in the same incremental increase in rates. Second, since 2019, three securitization charges related to the transition to competition and hurricane restoration costs (TC2, TC3, and SRC/ADFIT) have been retired, resulting in a total reduction of $4.48 per month for the average residential customer. A fourth securitization charge (TC5) will be retired by October 2024, resulting in a similar reduction in the amount of $1.92 per month. Together, the retirement of these securitization charges will reduce average residential customer bills by approximately $6.40. Third, CNP has focused on reducing its O&M expenses by an average of 1-2% per year. The result is that the Company can increase its investment in its transmission and distributions system while keeping average customer charges within normal inflation rates and maintaining affordability.

Q. ARE ANY OTHER CURRENT CHARGES EXPECTED TO DECREASE DURING THE PERIOD COVERED BY THE RESLIENCY PLAN?

A. Yes. Rider Temporary Emergency Electric Energy Facilities ("Rider TEEEF") is expected to trend towards a zero-dollar charge over the course of this decade. Rider TEEEF collects charges for the emergency generation assets I mentioned above, which were first authorized following Winter Storm Uri through House Bill 2483 passed in 2021. The most recent charges for Rider TEEEF were approved by the Commission in Docket No. 54830, and the charge for residential customers is currently $0.002392 per kWh, or $2.392 per month for a residential customer using 1,000 kWh per month. However, Rider TEEEF is required to be adjusted each year to reflect the rate base remaining to be collected from customers. While there could be some additional costs incurred for these assets over time, such increases are not expected to change the general trend towards zero as recovery in prior bills brings down the overall amount of rate base remaining to be collected.

Q. ARE THERE OTHER STEPS AVAILABLE TO CENTERPOINT HOUSTON TO MAINTAIN AFFORDABILITY WHILE INVESTING IN RESILIENCY?

A. Yes. The Company has also worked to identify and pursue opportunities to obtain federal funding to offset the cost of its resiliency investments. In 2023, the Company submitted a $100 million application in the first round of the DOE Grid Resilience and

Innovation Partnerships ("GRIP") Program to fund a portion of the Distribution Pole Replacement/Bracing and Substation Flood Control measures but was not ultimately selected for a grant. Also in 2023, one of the Company's Coastal Resiliency Upgrades projects was included in the Commission's GRIP grant application, but that application was also not ultimately selected for a grant.

In January 2024, we submitted two concept papers, each seeking approval for $100 million in the second round of GRIP Program grant applications: (1) $100 million to fund a portion of the Distribution Pole Replacement/Bracing, Substation Flood Control and Advanced Aerial Imagery Platform/Digital Twin measures; and (2) $100 million to fund a portion of the Advanced Distribution Technology project. In March 2024, we were informed by DOE that the concept paper to fund $100 million of the Distribution Pole Replacement/Bracing, Substation Flood Control, and Advanced Aerial Imagery Platform/Digital Twin measures was encouraged for a full grant application, which we submitted in April 2024. On the second of the two concept papers, which sought $100 million for the Advanced Distribution Technology project, the DOE discouraged a full application.

Additionally, by June 2024, we expect to submit part of the Wildfire Mitigation Projects, and potentially other measures in the Resiliency Plan, for funding to the Texas Department of Emergency Management as part of its process to administer the Texas allocation of GRIP funding.

VIII. CONCLUSION

Q. IS IMPLEMENTATION OF THE RESILIENCY MEASURES IN THE COMPANY'S RESILIENCY PLAN IN THE PUBLIC INTEREST?

A. Yes. As intended by the Texas Legislature and the Resiliency Statute, the Resiliency Plan will:

- provide the Commission with better visibility into the ongoing resiliency efforts at CenterPoint Houston;
- more adequately provide for CenterPoint Houston to financially plan measures to increase the resiliency of electric infrastructure against inclement weather and other Resiliency Events; and
- thereby benefit customers by mitigating the impact of certain Resiliency Events that occur in the Company's service area, either preventing damage to the Company's facilities or reducing the duration and costs of damage that does occur.

Q. SHOULD THE COMMISSION APPROVE THE COMPANY'S RESILIENCY PLAN?

A. Yes.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

STATE OF Texas §
§
COUNTY OF Harris §

AFFIDAVIT OF JASON M. RYAN

BEFORE ME, the undersigned authority, on this day personally appeared Jason M. Ryan who having been placed under oath by me did depose as follows:

1. "My name is Jason M. Ryan. I am of sound mind and capable of making this affidavit. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in this document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Jason M. Ryan

SUBSCRIBED AND SWORN TO BEFORE ME on this 12th day of April, 2024.

Notary Public in and for the State of Texas

My commission expires: 10/18/26

BRANDI M SUMMERSILL
NOTARY ID #12841736-4
My Commission Expires
October 18, 2026

EXHIBIT JMR-1

GLOSSARY OF ACRONYMS

ADER Task Force	Aggregated Distributed Energy Resources Task Force
ADFIT	Accumulated Deferred Federal Income Tax
BCA	Benefit-cost analysis
CenterPoint Houston or the Company	CenterPoint Energy Houston Electric, LLC
CNP	CenterPoint Energy, Inc.
Commission or PUC	Public Utility Commission of Texas
DER	Distributed energy resource
DOE	Department of Energy
ERCOT	Electric Reliability Council of Texas
GRIP	Grid Resilience and Innovation Partnership
Guidehouse	Guidehouse, Inc.
IGSD	Intelligent grid switching device
kV	Kilovolt
kWh	Kilowatt hour
MWh	Megawatt hour
PURA	Public Utility Regulatory Act, Tex. Util. Code §§ 11.001-66.016
Resiliency Event	An event involving extreme weather conditions, wildfires, cybersecurity threats, or physical security threats that poses a material risk to the safe and reliable operation of the Company's transmission and distribution system.
Resiliency Measure	A measure designed to prevent, withstand, mitigate, or more promptly recover from the risks posed to the Company's transmission and distribution system by a Resiliency Event.

Resiliency Plan	The Company's Transmission and Distribution system resiliency plan
Resiliency Rule	16 Tex. Admin. Code § 25.62
Resiliency Statute	Tex. Util. Code § 38.078
O&M	Operations and maintenance
NCEI	National Centers for Environmental Information
NOAA	National Oceanic and Atmospheric Administration
NIST CSF	National Institute and Technology Cybersecurity Framework
SAP S/4	S/4HANA, the latest version of SAP
SAP	System applications and products in data processing
SRC	System Restoration Charges
TDU	Transmission and distribution utility
TripSaver	TripSaver® II cutout-mounted recloser devices

EXHIBIT JMR-2

RESILIENCY PLAN REQUIREMENTS MET IN COMPANY'S FILING

Subsection of Resiliency Plan Rule	**Requirement**	**Relevant Section in Testimony**
(c)(1)	Each resiliency measure must utilize at least one of the listed methods: Harden facilities, modernize, bury lines, mitigate lightening or flooding, IT, physical security, vegetation/wildlife management	Resiliency Plan, Section VI, subsection (b) of each measure
(c)(2)	Plan must be organized by measure	Reflected throughout Resiliency Plan Section VI
(c)(2)	Describe actions, equipment, etc. associated with each measure	Resiliency Plan, Section VI, subsection (a) of each measure
(c)(2)(A)	Identify risk (or risks) posed by resiliency events this measure will address	Resiliency Plan, Section VI, subsection (b) of each measure
(c)(2)(A)(i)	Explain prioritization of resiliency events (and if applicable, any geographic area, facilities, etc. Prioritized in a resiliency measure)	Resiliency Plan, Section V, A.; Resiliency Plan, Section VI, subsection (b)(i) of each measure
(c)(2)(A)(ii)	Present evidence on efficacy of this measure *in* preventing, withstanding, mitigating or recovering from the identified resiliency event(s) Evidence better if quantitative or performance-based	Resiliency Plan, Section VI, subsection (b)(ii) of each measure
(c)(2)(A)(iii)	Explain expected benefits of measure	Resiliency Plan, Section VI, subsection (b) of each measure
(c)(2)(A)(iv)	Identify if a measure is coordinated with federal, state, or local government programs/funding	Tutunjian Testimony Section VI.
(c)(2)(A)(v)	Explain why this measure was picked over alternatives, using sufficient analysis/evidence.	Resiliency Plan, Section VI, subsection (c) of each measure
(c)(2)(A)(vi)	Identify if an outage may be necessary for implementing the measure	Resiliency Plan, Section VI, subsection (a) of each measure

(c)(2)(A)(vi)	Upon request, a copy of CenterPoint Houston's Resiliency Plan must be given its ISO	CenterPoint Houston will comply with this requirement upon such request(s).
(c)(2)(B)(i)	Plan must identify and describe each resiliency event and related risks that the plan is designed to address	Resiliency Plan, Section V, A-B.
(c)(2)(B)(i)	Define each resiliency event	Resiliency Plan, Section V, B.
(c)(2)(B)(ii)	Magnitude thresholds included in definition, as appropriate	Resiliency Plan, Section V, B.
(c)(2)(B)(iii)	Describe system characteristics making it susceptible to each event identified	Resiliency Plan, Section V, A.
(c)(2)(B)(iv)	Evidence supporting the presence/risk of each event identified. Must include historical evidence, and (if applicable) forecasted risk.	Resiliency Plan, Section V, A.; Testimony of Eugene L. Shlatz, Section IV.
(c)(2)(C)	Each measure must include a proposed metric for evaluating efficacy	Resiliency Plan, Section VI, subsection (d) of each measure
(c)(2)(C)(i)-(ii)	Plan must explain appropriateness of selected metric. If it's not quantitative, must explain why that's impossible	Resiliency Plan, Section VI, subsection (d) of each measure
(c)(2)(C)(iii)	Estimate or analyze efficacy of each resiliency measure using the selected metric	Resiliency Plan, Section VI, subsection (d) of each measure
(c)(2)(D)	Distinguish Plan's measures from similar existing programs or any measures otherwise required by law (or explain if they work in conjunction)	Resiliency Plan, Section VI, and subsection (a) of each measure
(c)(2)(E)	Plan must be implemented using a systematic approach over at least 3 years	N/A
(c)(2)(E)	Explain systematic approach & implementation details for each measure, including: - Capital costs, estimated O&M, net salvage value - Remaining service life of any assets retied or replaced by resiliency-investments - Estimated timeline for completion	Resiliency Plan, Section VI, subsection (b) of each measure

	- Identify any relevant cost drivers (ex: line miles, inspections, etc.) that would affect time/cost estimates	
(c)(2)(G)	Plan must include an executive summary (or a comprehensive chart) on how it is in the public interest, events addressed, proposed measures, metrics, costs/benefits, and efficacy	Resiliency Plan, Section I
(c)(3)	Portions of plan may be filed as CEII	N/A

EXHIBIT JMR-3

RESILIENCY STATUTE

Text of section as added by Acts 2023, 88th Leg., R.S., Ch. 836 (H.B. 2555), Sec. 2

For text of section as added by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 13, see other Sec. 38.078.

Sec. 38.078. TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN AND COST RECOVERY. (a) In this section, "plan" means a transmission and distribution system resiliency plan described by Subsection (b).

(b) An electric utility may file, in a manner authorized by commission rule, a plan to enhance the resiliency of the utility's transmission and distribution system through at least one of the following methods:

(1) hardening electrical transmission and distribution facilities;

(2) modernizing electrical transmission and distribution facilities;

(3) undergrounding certain electrical distribution lines;

(4) lightning mitigation measures;

(5) flood mitigation measures;

(6) information technology;

(7) cybersecurity measures;

(8) physical security measures;

(9) vegetation management; or

(10) wildfire mitigation and response.

(c) A plan must explain the systematic approach the electric utility will use to carry out the plan during at least a three-year period.

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

(1) the extent to which the plan is expected to enhance system resiliency, including whether the plan prioritizes areas of lower performance; and

(2) the estimated costs of implementing the measures proposed in the plan.

(e) The commission shall issue an order to approve, modify, or deny a plan filed under Subsection (b) and any associated rider described by Subsection (i) not later than the 180th day after the plan is filed with the commission. The commission may approve a plan only if the commission determines that approving the plan is in the public interest.

(f) For a plan approved by the commission, with or without modification, an electric utility may request a good cause exception on implementing all or some of the measures in the plan if operational needs, business needs, financial conditions, or supply chain or labor conditions dictate the exception. The commission's denial of a plan is not considered to be a finding of the prudence or imprudence of a measure or cost in the plan for the purposes of Chapter 36 or this chapter.

(g) An electric utility for which the commission has approved a plan under this section may request that the commission review an updated plan submitted by the electric utility. The updated plan must comply with any applicable commission rules and take effect on a date that is not earlier than the third anniversary of the approval date of the utility's most recently approved plan. The commission shall review and approve, modify, or deny the updated plan in the manner provided by Subsections (d), (e), and (f).

(h) An electric utility's implementation of a plan approved under this section may be reviewed for the purposes of Chapter 36 or this chapter. If the commission determines that the costs to implement an approved plan were imprudently incurred or otherwise unreasonable, those costs are subject to disallowance.

(i) Notwithstanding any other law, an electric utility may file with a plan an application for a rider to recover the electric utility's distribution investment that is made to implement a plan and is used and useful to the electric utility in providing service to the public. The electric utility may file the application before the electric utility places into service the distribution investment to implement an approved plan. The commission may approve the rider application before the electric utility places into service the distribution investment to implement an approved plan. The commission may not approve a rider that would allow an electric utility to begin recovering the distribution investment before the utility begins to use the investment to provide service to the public. If the commission approves or modifies the plan, the commission shall determine the appropriate terms of the rider in the approval order. The commission shall adopt a procedure for reconciliation of an electric utility's distribution-related costs to implement an approved plan.

(j) As part of a review described by Subsection (g), the commission shall reconcile the rider authorized under Subsection (i) to determine the electric utility's reasonably and prudently incurred plan costs.

(k) If an electric utility that files a plan with the commission does not apply for a rider under Subsection (i), after commission review, the utility may defer all or a portion of the distribution-related costs relating to the implementation of the plan for future recovery as a regulatory asset, including depreciation expense and carrying costs at the utility's weighted average cost of capital established in the commission's final order in the utility's most recent base rate proceeding in a manner consistent with Chapter 36, and use commission authorized cost recovery alternatives under Sections 36.209 and 36.210 or another general rate proceeding.

(l) Plan costs considered by the commission to be reasonable and prudent may include only incremental costs that are not already being recovered through the electric utility's base rates or any other rate rider and must be allocated to customer classes pursuant to the rate design most recently approved by the commission.

Added by Acts 2023, 88th Leg., R.S., Ch. 836 (H.B. 2555), Sec. 2, eff. June 13, 2023.

Text of section as added by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 13

For text of section as added by Acts 2023, 88th Leg., R.S., Ch. 836 (H.B. 2555), Sec. 2, see other Sec. 38.078.

Sec. 38.078. CIRCUIT SEGMENTATION STUDY AND COST RECOVERY. (a) Not later than September 15, 2023, the commission shall direct each transmission and distribution utility to perform a circuit segmentation study.

(b) A circuit segmentation study must:

(1) use an engineering analysis to examine whether and how the transmission and distribution utility's transmission and distribution systems can be segmented and sectionalized to manage and rotate outages more evenly across all customers and circuits, while maintaining the protections offered to critical facilities;

(2) include an engineering analysis of the feasibility of using sectionalization, automated reclosers, and other technology to break up the circuits that host significant numbers of critical facilities into smaller segments for outage management purposes to enable more granular and flexible outage management;

(3) identify feeders with critical facilities that, if equipped with facility-specific backup power systems and segmentation, can enhance the utility's outage management flexibility; and

(4) include an estimate of the time, capital cost, and expected improvements to load-shed management associated with the circuit segmentation study.

(c) Each transmission and distribution utility shall submit a report of the conclusions of the utility's study to the commission not later than September 1, 2024.

(d) The commission shall review each circuit segmentation study not later than March 15, 2025.

Added by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 13, eff. September 1, 2023.

EXHIBIT JMR-4

RESILIENCY RULE

Texas Administrative Code

TITLE 16	ECONOMIC REGULATION
PART 2	PUBLIC UTILITY COMMISSION OF TEXAS
CHAPTER 25	SUBSTANTIVE RULES APPLICABLE TO ELECTRIC SERVICE PROVIDERS
SUBCHAPTER C	INFRASTRUCTURE AND RELIABILITY
RULE §25.62	Transmission and Distribution System Resiliency Plans

(a) Purpose and applicability. This section allows an electric utility that owns and operates a transmission or distribution system to file a resiliency plan to enhance the resiliency of the electric utility's transmission and distribution system. The requirements of this section will be construed, to the extent practicable, to reflect the following:

(1) Each transmission and distribution system has different system characteristics and faces different resiliency events and resiliency-related risks. The ability to precisely define, measure, and address these events and risks varies. Terms such as "event," "risk," "criteria," and "metric" will be construed pragmatically to provide each utility with the flexibility to develop a well-tailored and systematic approach to improving the resiliency of its system.

(2) A utility seeking approval of a resiliency plan bears the burden of proof on each aspect of its resiliency plan. Nothing in this section categorically limits the type of evidence that a utility may use to meet this burden. The weight given to each piece of evidence will be determined by the commission on a case-by-case basis based on the relevant facts and circumstances. Provisions contained in this section addressing the weight of certain types of evidence are advisory only.

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

(1) Distribution invested capital -- The parts of the electric utility's invested capital that are categorized or properly functionalized as distribution plant and, once they are placed into service, are properly recorded in Federal Energy Regulatory Commission (FERC) Uniform System of Accounts 303, 352, 353, 360 through 374, 391, and 397. Distribution invested capital includes only costs: for plant that has been placed into service or will be placed into service prior to rates going into effect; that comply with PURA, including §36.053 and §36.058; and that are prudent, reasonable, and necessary. Distribution invested capital does not include: generation-related costs; transmission-related costs, including costs recovered through rates set pursuant to §25.192 of this title (relating to Transmission Service Rates), §25.193 of this title (relating to Distribution Service Provider Transmission Cost Recovery Factors (TCRF)), or §25.239 of this title (relating to Transmission Cost Recovery Factor for Certain Electric Utilities); indirect corporate costs; capitalized operations and maintenance expenses; and distribution invested capital recovered through a separate rate, including a surcharge, tracker, rider, or other mechanism.

(2) Resiliency cost recovery rider (RCRR) billing determinant -- Each rate class's annual billing determinant (kilowatt-hour, kilowatt, or kilovolt-ampere) for the most recent 12 months ending no earlier than 90 days prior to an application for

a Resiliency Cost Recovery Rider, weather-normalized and adjusted to reflect the number of customers at the end of the period.

(3) Resiliency event -- an event involving extreme weather conditions, wildfires, cybersecurity threats, or physical security threats that poses a material risk to the safe and reliable operation of an electric utility's transmission and distribution systems. A resiliency event is not primarily associated with resource adequacy or an electric utility's ability to deliver power to load under normal operating conditions.

(4) Resiliency-related distribution invested capital -- Distribution invested capital associated with a resiliency plan approved under this section that will be placed into service before or at the time the associated rates become effective under this section, and that are not otherwise included in a utility's rates.

(5) Resiliency-related net distribution invested capital -- Resiliency-related distribution invested capital that is:

(A) adjusted for accumulated depreciation and any changes in accumulated deferred federal income taxes, including changes to excess accumulated deferred federal income taxes, associated with all resiliency-related distribution invested capital included in the electric utility's RCRR;

(B) reduced by the amount of net plant investment associated with any distribution invested capital included in a utility's rates that is retired or replaced, at the time the associated rates become effective under this section, by resiliency-related distribution invested capital; and

(C) further adjusted to remove accumulated depreciation and accumulated deferred federal income taxes associated with distribution invested capital included in a utility's rates that is retired or replaced, at the time the associated rates become effective under this section, by resiliency-related distribution invested capital.

(6) Weather-normalized -- Adjusted for normal weather using weather data for the most recent ten-year period prior to the year from which the RCRR billing determinants are derived.

(c) Resiliency Plan. An electric utility may file a plan to prevent, withstand, mitigate, or more promptly recover from the risks posed by resiliency events to its transmission and distributions systems. A resiliency plan may be updated, but the updated plan must not take effect earlier than three years from the date of approval of the electric utility's most recently approved resiliency plan.

(1) Resiliency measures. A resiliency plan is comprised of one or more measures designed to prevent, withstand, mitigate, or more promptly recover from the risks posed to the electric utility's transmission and distribution systems by resiliency events, as described in subsection (d) of this section. Each measure must utilize one or more 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) cybersecurity measures;

(H) physical security measures;

(I) vegetation management; or

(J) wildfire mitigation and response.

(2) Contents of the resiliency plan. The resiliency plan must be organized by measure, including a description of any activities, actions, standards, services, procedures, practices, structures, or equipment associated with each measure.

(A) The resiliency plan must identify, for each measure, one or more risks posed by resiliency events that the measure is intended to prevent, withstand, mitigate, or more promptly recover from.

(i) The resiliency plan must explain the electric utility's prioritization of the identified resiliency event and, if applicable, the prioritization of the particular geographic area, system, or facilities where the measure will be implemented.

(ii) The resiliency plan must include evidence of the effectiveness of the measure in preventing, withstanding, mitigating, or more promptly recovering from the risks posed by the identified resiliency event. The commission will give greater weight to evidence that is quantitative, performance-based, or provided by an independent entity with relevant expertise.

(iii) A resiliency plan must explain the expected benefits of the resiliency measures including, as applicable, reduced system restoration costs, reduction in the frequency or duration of outages for customers. and any improvement in the overall service reliability for customers, including the classes of customers served and any critical load designations.

(iv) The electric utility must identify if a resiliency measure is a coordinated effort with federal, state, or local government programs or may benefit from any federal, state, or local government funding opportunities.

(v) The resiliency plan must explain the selection of each measure over any reasonable and readily-identifiable alternatives. The resiliency plan must contain sufficient analysis and evidence, such as cost or performance comparisons, to support the selection of each measure. In selecting between measures, whether a measure would support the plan's systematic approach may be considered.

(vi) The resiliency plan must identify any measures that may require a transmission system outage to implement. The electric utility must coordinate with its independent system operator before implementing these measures. Upon request, the electric utility must provide its independent system operator, using mutually-agreed to transfer and data security procedures, a complete copy of its resiliency plan.

(B) Resiliency events.

(i) A resiliency plan must define identify and describe each type of resiliency event and any associated resiliency-related risks the plan is designed to prevent, withstand, mitigate, or more promptly recover from. A resiliency event may be defined using an established definition (e.g., a hurricane) or a plan- or measure-specific definition based on the risks posed by that type of event to the electric utility's systems (e.g. flooding of a specified depth). Each type of resiliency event must be defined with sufficient detail to allow the electric utility or commission to determine whether an actual set of circumstances qualifies as a resiliency event of that type.

( ) If appropriate, one or more magnitude thresholds must be included in the definition of a resiliency event type based on the risks posed to the electric utility's systems by that type of event. A resiliency plan may establish multiple magnitude thresholds for a single type of resiliency event (e.g., categories of hurricanes) when necessary to conduct a more granular analysis of the risks posed by the event and the options available to prevent, withstand, mitigate, or more promptly recover from them.

(i) The resiliency plan must include a description of the system characteristics that make the electric utility's transmission and distribution systems susceptible to each identified resiliency event type.

(ii) A resiliency plan must provide sufficient evidence to support the presence of and risk posed by each identified resiliency event. The resiliency plan must provide historical evidence of the electric utility's experience with, if applicable, and forecasted risk of the identified event type, including whether the forecasted risk is specific to a particular system or geographic area. In assessing the presence and risk posed by each resiliency event, the commission will give great weight to any studies conducted by an independent system operator or independent entity with relevant expertise.

(C) Evaluation metric or criteria. Each measure in the resiliency plan must include a proposed metric or criteria for evaluating the effectiveness of that measure in preventing, withstanding, mitigating, or more promptly recovering from the risks associated with the resiliency event it is designed to address.

(i) The resiliency plan must explain the appropriateness of the selected evaluation metric or criteria.

(iii) For an evaluation metric or criteria that is not quantitative, the resiliency plan must explain why quantitative evaluation of the effectiveness of that measure is not possible.

(iv) The resiliency plan must also include an estimate or analysis of the expected effectiveness of each measure using the selected evaluation metric or criteria.

(D) If a resiliency plan includes measures that are similar to other existing programs or measures, such as a storm hardening plan under §25.95 of this title (relating to Electric Utility Infrastructure Storm Hardening) or a vegetation management plan under §25.96 of this title (relating to Vegetation Management), or programs or measures otherwise required by law, the electric utility must distinguish the measures in the resiliency plan from these programs and measures and, if appropriate, explain how the related items work in conjunction with one another.

(E) A resiliency plan must be implemented using a systematic approach over a period of at least three years. The resiliency plan must explain this systematic approach and provide implementation details for each of the plan's measures, including estimated capital costs, estimated operations and maintenance expenses, an estimated timeline for completion, and, when practicable and appropriate, estimated net salvage value (value of the retired asset less depreciation and cost of removal) and remaining service lives of any assets expected to be retired or replaced by resiliency-related investments. The resiliency plan should identify relevant cost drivers (e.g., line miles, frequency of inspections, frequency of trim cycles, etc.) that would affect the estimates.

(F) A utility may deviate from the implementation schedule specified in an approved plan if its independent system operator has not approved an outage that would be required to timely implement the plan.

(G) The resiliency plan must include an executive summary or comprehensive chart that explains the plan objectives, the resiliency events or related risks the plan is designed to address, the plan's proposed resiliency measures, the proposed metrics or criteria for evaluating the plans' effectiveness, the plan's cost and benefits, and how the overall plan is in the public interest.

(3) An electric utility may designate portions of the resiliency plan as critical energy infrastructure information, as defined by applicable law, and file such portions confidentially.

(d) Commission processing of resiliency plan.

(1) Notice and intervention deadline. By the day after it files its application, the electric utility must provide notice of its filed resiliency plan, including the docket number assigned to the resiliency plan and the deadline for intervention, in accordance with this paragraph. The intervention deadline is 30 days from the date service of notice is complete. The notice must be provided using a reasonable method of notice, to:

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

(B) all parties in the electric utility's base-rate proceeding;

(C) if the resiliency plan is filed by an electric utility operating in an area in Texas that is open to competition and includes a request for a resiliency cost recovery rider, each retail electric provider that is authorized by the registration agent to provide service in the electric utility's service area;

(D) the Office of Public Utility Counsel. Notice delivered to the Office of Public Utility Counsel must include a copy of the resiliency plan, excluding critical energy infrastructure information; and

(E) the independent system operator. Notice delivered to the utility's independent system operator must include a copy of the resiliency plan, excluding critical energy infrastructure information.

(2) Sufficiency of resiliency plan. An application is sufficient if it includes the information required by subsection (c) of this section and the electric utility has filed proof that notice has been provided in accordance with this subsection.

(A) Commission staff must review each resiliency plan for sufficiency and file a recommendation on sufficiency within 28 calendar days after the resiliency plan is filed. If commission staff recommends the resiliency plan be found deficient, commission staff must identify the deficiencies in its recommendation. The electric utility will have seven calendar days to file a response.

(B) If the presiding officer concludes the resiliency plan is deficient, the presiding officer will file a notice of deficiency and cite the particular requirements with which the resiliency plan does not comply. The presiding officer must provide the electric utility an opportunity to amend its resiliency plan. Commission staff must file a recommendation on sufficiency within 10 calendar days after the filing of an amended resiliency plan, when the amendment is filed in response to an order concluding that material deficiencies exist in the resiliency plan.

(C) If the presiding officer has not filed a written order concluding that material deficiencies exist in the resiliency plan within 14 working days after a deadline for a recommendation on sufficiency, the resiliency plan is deemed sufficient.

(3) The commission will approve, modify, or deny a resiliency plan not later than 180 days after a complete resiliency plan is filed. A resiliency plan is complete once it is deemed sufficient in accordance with this subsection. The presiding officer must establish a procedural schedule that will enable the commission to approve, modify, or deny the plan not later than 180 days after a complete plan is filed. If the resiliency plan is determined to be materially deficient, the presiding officer must toll the 180-day deadline until a complete application is filed.

(4) Commission review of resiliency plan. In determining whether to approve, deny, or modify a plan, the commission will consider:

(A) the extent to which the plan is expected to enhance system resiliency, including whether the plan prioritizes areas of lower performance;

(B) the estimated costs of implementing the measures proposed in the plan; and

(C) whether the plan is in the public interest. The commission will not approve a plan that is not in the public interest. In evaluating the public interest, the commission may consider:

(i) the extent to which the plan is expected to enhance system resiliency, including:

(I) the verifiability and severity of the resiliency risks posed by the resiliency events the resiliency plan is designed to address;

(II) the extent to which the plan will enhance resiliency of the electric utility's system, mitigate system restoration costs, reduce the frequency or duration of outages, or improve overall service reliability for customers during and following a resiliency event;

(III) the extent to which the resiliency plan prioritizes areas of lower performance;

(IV) the extent to which the resiliency plan prioritizes critical load as defined in §25.52 of this title (relating to Reliability and Continuity of Service);

(ii) the estimated time and costs of implementing the measures proposed in the resiliency plan;

(iii) whether there are more efficient, cost-effective, or otherwise superior means of preventing, withstanding, mitigating, or more promptly recovering from the risks posed by the resiliency events addressed by the resiliency plan; or

(iv) other factors deemed relevant by the commission.

(5) The commission's denial of a resiliency plan is not a finding on the prudence or imprudence of a measure or estimated cost in the resiliency plan. Upon denial of a resiliency plan, an electric utility may file a revised resiliency plan for review and approval by the commission.

(e) Good cause exception. An electric utility must implement each measure in its most recently approved resiliency plan unless the commission grants a good cause exception to implementing one or more measures in the plan. The commission may grant a good cause exception if the electric utility demonstrates that operational needs, business needs, financial conditions, or supply chain or labor conditions dictate the exception, or if the electric utility has a pending application for a revised resiliency plan that addresses the same resiliency events.

(f) Resiliency Plan Cost Recovery. A utility may request cost recovery for costs associated with a resiliency plan approved under this section that are not otherwise included in the utility's rates. If a utility that files a resiliency plan with the commission does not apply for a rider or rates to recover resiliency plan costs under paragraph (1) of this subsection, after commission review and approval of the resiliency plan, the utility may defer all or a portion of the distribution-related costs relating to the implementation of the resiliency plan for recovery as a regulatory asset under paragraph (2) of this subsection, or in a base-rate proceeding. The regulatory asset may include associated depreciation expense and carrying costs at the utility's weighted average cost of capital established in the commission's final order in the utility's most recent base-rate proceeding in a manner consistent with PURA Chapter 36.

(1) Resiliency Cost Recovery Rider. This paragraph provides a mechanism for an electric utility to request to recover certain resiliency-related costs through a resiliency cost recovery rider (RCRR) outside of a base-rate proceeding or a distribution cost recovery proceeding as part of a resiliency plan approved under this section, consistent with Public Utility Regulatory Act (PURA) §38.078(i).

(A) RCRR Requirements. The RCRR rate for each rate class, and any other terms or conditions related to those rates, will be specified in a rider to the utility's tariff.

(i) An electric utility must not have more than one RCRR.

(ii) An electric utility with an existing RCRR may apply to amend the RCRR to include additional costs associated with an updated resiliency plan under PURA §38.078(g).

(iii) An electric utility may request an RCRR established under this section take effect at any time, except that before an RCRR established under this section may take effect:

(I) all distribution investment included in the RCRR must be providing service to the electric utility's customers, and

(II) the commission must approve RCRR rates in accordance with clause (iv) of this subparagraph. (iv) An electric utility must submit a separate application requesting RCRR rates.

(I) The utility must provide notice of its application, using a reasonable method of notice, to the parties listed in subsection (d)(1) of this section.

(II) The RCRR rate request must include: the final amount of resiliency-related distribution invested capital closed to plant and in service to be included in the RCRR rates, values necessary to calculate RCRR rates, attachments demonstrating the calculation of RCRR rates consistent with this section, and workpapers supporting the application.

(III) The commission will enter a final order on the application for RCRR rates under this section not later than the 60th day after the date the complete updated request is filed. The commission may extend the deadline for not more than 30 days for good cause.

(v) An electric utility must provide notice, using a reasonable method of notice, of the approved rates and effective date of the approved rates to retail electric providers that are authorized by the registration agent to provide service in the electric utility's distribution service area not later than the 45th day before the date the rates take effect.

(vi) As part of its next base-rate proceeding or distribution cost recovery factor proceeding for the electric utility, the electric utility may request to include its remaining unrecovered costs included in its RCRR in that proceeding and must request that RCRR rates be set to zero as of the effective date of rates resulting from that proceeding.

(B) Calculation of RCRR Rates. The RCRR rate for each rate class must be calculated according to the provisions of this subparagraph and subparagraphs (C) and (D) of this paragraph.

(i) The RCRR rate for each rate class will be calculated using the following formula: RCRRCLASS 'CLASS' BDC-CLASS

(ii) The values of the terms used in this paragraph will be calculated as follows:

(I) RRCLASS = RRTOT * ALLOCC-CLASS

(II) RRTOT = ((RNDC * ROR_{Itc}) + RDDEPR + RNDCFIT + RDOT) - IDCCR

(III) ALLOCC-CLASS = ALLOCRC-CLASS (^{3}DC-CLASS BDRC-CLASS) / &Sgr; (ALLOCRC-CLASS (^{3}DC-CLASS BDRC-CLASS))

(IV) IDCCR = &Sgr; (DISTREV$_{RC\text{-}CLASS}$ $^{\%GROW}$THCLASS - DCRFLGA

(V) DISTREV

RC-CLASS = (DICRC-CLASS RORAT) DEPRRC-CLASS PITRC-CLASS °TRC-CLASS

with the variables in this formula as defined in §25.243 of this title.

(VI) %GROWTHCLASS = The greater of ((BDC-CLASS BDRC-CLASS) / BDRc-CLASS) or zero. (iii) The terms used in this paragraph represent or are defined as follows:

(iii) Descriptions of calculated values.

(-a-) RCRRC$_{LASS}$ RCRR rate for a rate class.

(-b-) RItc LASS -- RCRR class revenue requirement.

(-c-) RRTOT Total RCRR Texas retail revenue requirement.

(-d-) ALLOCc-cLAsS RCRR class allocation factor for a rate class.

(-e-) IDCCR -- Incremental distribution capital cost recovery.

(-f-) DISTREVRC-CLASS -- Distribution Revenues by rate class based on Net Distribution Invested Capital from the most recently completed comprehensive base-rate proceeding.

(-g-) %GROWTHCLASS - Growth in billing determinants by class.

(II) RCRR billing determinants and distribution investment values.

(-a-) BDc-CLASS RCRR billing determinants.

(-b-) RNDC Resiliency-related net distribution invested capital.

(-c-) RDDEPR Resiliency-related distribution invested capital depreciation expense.

(-d-) RNDCFIT -- Federal income tax expense associated with the return on the resiliency-related net distribution invested capital.

(-e-) RDOT -- Other revenue-related tax expense associated with the resiliency-related net distribution invested capital as well as appropriate associated ad valorem tax expense.

(II) Baseline values. The following values are based on those values used to establish rates in the electric utility's most recent base-rate proceeding or distribution cost recovery factor proceeding, or if an input to the RCRR calculation from the electric utility's most recently completed base-rate proceeding is not separately identified in that proceeding, it will be derived from information from that proceeding:

(-a-) $BDRc\text{-}C_{LASS}$ Rate class billing determinants used to establish distribution base rates in the most recently completed base-rate proceeding. Energy-based billing determinants will be used for those rate classes that do not include any demand charges, and demand-based billing determinants will be used for those rate classes that include demand charges.

(-b-) ROR_{RC} -- After-tax rate of return approved by the commission in the electric utility's most recently completed base-rate proceeding.

(-c-) ALLOCRC-CLASS -- Rate class allocation factor value determined under the provisions of subparagraph (C) of this paragraph.

(-d-) DCRFLGA -- The value of &Sgr;(DISTREVRC-CLASS * $\%GROW_{THCLASS}$ in the most recent distribution cost recovery factor proceeding for the utility since its most recently completed base-rate proceeding, or zero if there are no distribution cost recovery factor proceedings since the utility's most recently completed base-rate proceeding.

(C) Class allocation factors. For calculating RCRR rates, the baseline rate-class allocation factors used to allocate distribution invested capital in the most recently completed base-rate proceeding will be used.

(D) Customer classification. For the purposes of establishing RCRR rates, customers will be classified according to the rate classes established in the electric utility's most recently completed base-rate proceeding.

(2) Distribution Cost Recovery Factor. This paragraph provides a mechanism for an electric utility to request to recover certain resiliency-related costs deferred as a regulatory asset as part of a distribution cost recovery factor proceeding under §25.243 of this title (relating to Distribution Cost Recovery Factor (DCRF)), consistent with PURA §38.078(k).

(A) Notwithstanding the existing requirements of §25.243 of this title, a utility eligible to request a distribution cost recovery factor under §25.243 of this title must, as part of an application under §25.243 of this title, request to include any resiliency-related costs deferred as a regulatory asset under this subsection in its DCRF rates.

(B) DCRF rates established consistent with this paragraph must be calculated in a manner identical to the DCRF rates described in §25.234 of this title, with the exception that the DCRF rate for each rate class must be calculated using the following formula: $((DIC_c - DIC_{Rc}) * ROR_{AT}) + (DEPR_C - DEPR_{Rc}) + (FIT_c - FIT_{Rc})$
$+ (OT_C - OT_{Rc}) + RAMORT -$ &Sgr; $(DISTREV_{RC\text{-}CLASS}\ {}^{\%GROW}THCLASS)] * ALLOCCLASS\ BDC\text{-}CLASS$
Where the value of RAMORT must be equal to a reasonable annual amortization amount of the resiliency-related regulatory asset.

(C) Upon the establishment of an DCRF rate under this paragraph, the resiliency-related regulatory asset balance will be reduced at an annual rate by the value of RAMORT.

(3) Reconciliation.

(A) Resiliency-related amounts recovered through rates approved under this subsection are subject to reconciliation in the first base-rate proceeding for the electric utility that is filed after the effective date of the rates. As part of the reconciliation, the commission will determine if the resiliency-related costs are reasonable, necessary, and prudent.

(B) Any amounts recovered through rates approved under this subsection that are found to have been unreasonable, unnecessary, or imprudent, plus the corresponding return and taxes, must be refunded with carrying costs. In any proceeding in which the commission determines that a utility has included in rates any amounts deemed unreasonable, unnecessary, or imprudent, the commission may order a compliance proceeding to determine the amounts and manner of any necessary refunds to ratepayers, including carrying costs. Carrying costs will be determined as follows:

(i)For the time period beginning with the date on which over-recovery is determined to have begun to the effective date of the electric utility's base rates set in the base-rate proceeding in which the costs are reconciled, carrying costs will accrue monthly and will be calculated using an effective monthly interest rate based on the same rate of return that was applied to the resiliency costs included in rates.

(ii)For the time period beginning with the effective date of the electric utility's rates set in the base-rate proceeding in which the costs are reconciled, carrying costs will accrue monthly and will be calculated using an effective monthly interest rate based on the electric utility's rate of return authorized in that base-rate proceeding.

(D) In any base-rate proceeding in which resiliency-related costs are being reconciled, the electric utility must separately include as part of its base-rate application testimony, schedules and workpapers sufficient to enable a comprehensive review of all resiliency-related costs included in each and every rider under this subsection that have not yet been reconciled. Such information must include, but is not limited to, the dates when the individual resiliency-related projects began providing service to the public, as well as the costs associated with the individual resiliency-related projects.

(g) Reporting requirements. An electric utility with a commission-approved resiliency plan must file an annual resiliency plan report by May **1** of each year, beginning the year after the plan is approved. The annual resiliency plan report must include the following information:

(1) until the resiliency plan is fully implemented, an implementation status update consisting of:

(A) a list of each resiliency plan measure completed in the prior calendar year, and the actual capital costs and operations and maintenance expenses incurred in the prior year attributable to each measure;

(B) a list of each resiliency plan measure scheduled for completion in the upcoming year, and an estimate of capital costs and operations and maintenance expenses for each resiliency plan measure scheduled for completion in the upcoming calendar year; and

(C) an explanation for any material changes in the implementation timeline or costs associated with implementing the resiliency plan; and

(2) until the third anniversary of the plan being fully implemented, a resiliency benefit update consisting of: