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APPLICATION OF CENTERPOINT	§	
ENERGY HOUSTON ELECTRIC, LLC	§	BEFORE THE STATE OFFICE
FOR APPROVAL OF ITS 2026-2028	§	OF
TRANSMISSION AND DISTRIBUTION	§	ADMINISTRATIVE HEARINGS
SYSTEM RESILIENCY PLAN	§	

WORKPAPERS TO THE DIRECT TESTIMONY

OF

SHAWN P. MCGLOTHLIN

ON BEHALF OF

TEXAS INDUSTRIAL ENERGY CONSUMERS

APRIL 9, 2025

DOCKET NO. 57579

APPLICATION OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC FOR APPROVAL OF ITS 2026-2028 TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN	**§ § § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

DIRECT TESTIMONY OF

EUGENE L. SHLATZ

ON BEHALF OF

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC

January 2025

cited in my prior two responses. While CenterPoint Houston's electric distribution system was constructed based on design standards established by the National Electrical Safety Code ("NESC") that were in effect at the time the system was constructed, the increased severity of extreme weather events indicate enhancements are needed to withstand these conditions.

Further, design standards have changed over time in recognition of the increased variability and severity of resiliency events. For example, many of CenterPoint Houston's distribution circuits built under prior design standards are capable of withstanding winds speeds up to 70 miles per hour ("mph"), but which are far less than the wind speeds measured during several recent storms. Similarly, extremely high winds measured during microbursts and tornados have exceeded transmission circuit design standards, resulting in tower failures on susceptible structures during recent extreme wind events. Similarly, recent floods have resulted in de-energization of substation equipment and customer outages. I address these risks in subsequent sections of my testimony.[14]

iii. BENEFITS ANALYSIS

Q. WHAT WAS THE PURPOSE AND APPROACH OF THE BENEFITS ANALYSIS CONDUCTED FOR RESILIENCY MEASURES INCLUDED IN CENTERPOINT HOUSTON'S SYSTEM RESILIENCY PLAN?

A. The purpose of Guidehouse's benefits analysis was to provide CenterPoint Houston guidance on which resiliency measures produce the highest resiliency value based on the program-level BCA analysis and qualitative assessment for each measure within each risk event category. CenterPoint Houston prioritized and selected projects within each measure

[14] Damage to transmission structures in Harris County during the January 2023 tornados and outages caused by substation flooding during Hurricane Harvey are recent manifestations of these risks.

that produced favorable BCA ratios by targeting resiliency investments in areas of greatest risk. As I described earlier in my testimony, Guidehouse expanded its county-level weather event forecasts to include more granular individual forecasts at approximately 3,300 hexagonal plots in CenterPoint Houston's service territory. CenterPoint Houston targeted investments within these plots to maximize the benefits of resiliency measures based on reductions in Customer Minutes of Interruption ("CMI").

Guidehouse quantified net benefits by performing a life-cycle analysis of costs versus benefits (i.e., benefit-cost analysis or BCA).[15] The BCA incorporates future risk based on the wind, flood inundation, and temperature forecasts presented in Section IV.ii and Section V of my testimony. Resiliency measure costs are those projected for years 2026 through 2028, and exclude amounts spent in prior or subsequent years, except for the and Advanced Aerial Imagery Platform / Digital Twin and Coastal Resiliency Upgrades where costs are expected to be incurred prior to 2026 and are expected to occur after 2028. The BCAs are derived for the composite total of all individual projects within each resiliency measure, except where investment mitigates impacts at a specific location (e.g., Control Center Facility Upgrades).

Quantitative benefits evaluated for each measure include the following:

- **Avoided Circuit Outages and Equipment Failures** – The reduction in customer interruptions achieved by resiliency measures during resiliency events.
- **Reduced Outage Duration** – The decrease in outage duration achieved by resiliency measures during resiliency events.
- **Avoided Collateral Damage** – The avoidance of the additional cost incurred

[15] Although some of the programs may continue for up to 10 to 15 years, CenterPoint Houston's SRP and Guidehouse's evaluation focuses on costs and outage reduction measures over the three-year Plan.

caused by equipment failure on nearby devices; for example, catastrophic substation transformer failures that cause adjacent transformers to fail.

- **Reduced Restoration Cost** – The savings in crew labor, truck rolls, and trouble order processing achieved by resiliency measures during resiliency events.
- **Operation and Maintenance (O&M) Cost** – The decrease (or increase for new equipment installed) in O&M resulting from the resiliency measure.

Qualitative benefits are those associated with societal factors such as regional impacts, economic considerations, public safety, inconvenience, capacity investment deferral, and disruption of critical facility operations. Guidehouse assessed the value each resiliency measure is expected to provide to its customers based on both quantitative and qualitative benefits, as BCA alone may not capture the full spectrum of benefits SRP measures will provide to CenterPoint Houston's customers and the Houston region.

Q. PLEASE DESCRIBE THE APPROACH AND PURPOSE OF THE CIRCUIT-LEVEL ANALYSIS.

A. The purpose of the circuit level analysis is to provide CenterPoint Houston with a granular forecast of weather-related risk and evaluation of CMI benefits at the circuit level. It also includes site-specific flood inundation forecasts for each of CenterPoint Houston's transmission and distribution substations. As described earlier, CenterPoint Houston applied Guidehouse's weather forecasts for each of the 3,300 hexagonal plots to identify projects within each measure that produced the greatest benefits as measures by reduction in CMI. Details on Guidehouse's methodology and results of the granular risk analysis is presented in Section 6 of Exhibit ELS-2.

DOCKET NO. 57579

APPLICATION OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC FOR APPROVAL OF ITS 2026-2028 TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN	§ § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY OF

NATHAN BROWNELL

ON BEHALF OF

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC

JANUARY 2025

vegetation management), but the purpose of resiliency projects is to mitigate the impact of Resiliency Events on customer outages, restoration times, and restoration costs.

Q. GIVEN THE NATURE OF THE COMPANY'S SERVICE AREA AND CUSTOMER PROFILE, HOW IMPORTANT IS IT FOR THE COMPANY TO HAVE A RELIABLE AND RESILIENT TRANSMISSION AND DISTRIBUTION SYSTEM.

A. It is very important and the Company's utmost priority in providing service to the Company's customers. The Company takes very seriously its obligation to provide safe and reliable service, and the Company has committed and will always commit to providing safe and reliable service. The Greater Houston area is an economic lynchpin in Texas, the nation, and global economies. As such, the Company is keenly aware of the role it plays locally and globally. The service provided by the Company enriches the customers and communities and enables millions of individuals, families, and businesses to function daily. The Company's investment in and implementation of system resiliency projects are therefore key components to ensuring that the Company is able to provide safe and reliable service to its residential, commercial, and industrial customers.

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

A. Since Winter Storm Uri in February 2021 and most recently with Hurricane Beryl, customers, communities, regulators, and elected officials have communicated increasing expectations for utilities, including the Company, to provide more reliable service, have more resilient infrastructure, and minimize customer outages and restoration times. Both the 87th and 88th Regular Sessions of the Texas Legislature produced significant legislation aimed at, among other things, improving the weatherizing of the electric delivery supply chain and strengthening the ERCOT grid, and included the T&D SRP Statute that encourages utilities to develop transmission and distribution system resiliency plans for Commission review and approval.

On August 28, 2024, the Commission established a VOLL of $35,000/MW based on a report and recommendation by the Brattle Group. The customer surveys cited in the Brattle report similarly reflect a willingness by customers to pay something for improved resiliency. The Company heard that same message directly from customers when it held public meetings following Hurricane Beryl.

Q. WHAT IS VOLL AND WHY IS IT IMPORTANT?

A. VOLL "represents a proxy for the economic costs that customers incur due to a power outage."[21] In other words, VOLL "can be considered an average customer's willingness to pay to avoid an outage."[22] The higher the VOLL, the more an average customer is willing to pay to avoid an outage, regardless of whether the outage occurs during a blue-sky day or during an extreme weather event.

Q. WHAT IS THE CURRENT VOLL FOR THE ERCOT POWER REGION?

A. The current VOLL for the ERCOT power region is $35,000 per MWh, as established by the Commission on August 28, 2024.[23] To put this number in perspective, Figure NB-8 below summarizes average market prices in ERCOT.[24]

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[21] *Review of Value of Lost Load in the ERCOT Market*, The Brattle Group's Value of Lost Load Study for the ERCOT Region at 6, Project No. 55837 (Aug. 22, 2024).

[22] *Id.*

[23] Project No. 55837, Chairman Gleeson Memorandum, (Aug. 28, 2024).

[24] *2023 State of the Market Report for the ERCOT Electricity Markets* at vi (May 2024). Link: 2023-State-of-the-Market-Report_Final_060624.pdf.

Figure NB-11
Average Annual Real-Time Energy Market Prices by Zone

	2015	2016	2017	2018	2019	2020	2021	2022	2023
Energy Prices ($/MWh)									
ERCOT	**$26.77**	**$24.62**	**$28.25**	**$35.63**	**$47.06**	**$25.73**	**$167.88**	**$74.92**	**$65.13**
Houston	$26.91	$26.33	$31.81	$34.40	$45.45	$24.54	$129.24	$81.07	$64.72
North	$26.36	$23.84	$25.67	$34.96	$46.77	$23.97	$206.39	$75.52	$68.55
South	$27.18	$24.78	$29.38	$36.15	$47.44	$26.63	$187.47	$72.96	$63.34
West	$26.83	$22.05	$24.52	$39.72	$50.77	$31.58	$105.27	$65.53	$61.62
Natural Gas Prices ($/MMBtu)									
ERCOT	$2.57	$2.45	$2.98	$3.22	$2.47	$1.99	$7.30	$5.84	$2.22

Q. WHAT VALUE HAS THE COMMISSION PREVIOUSLY SET AS THE VOLL?

A. Prior to Winter Storm Uri in February 2021, the VOLL for the ERCOT power region was $9,000 per MWh. Following Winter Storm Uri, VOLL was reduced to $5,000 per MWh. In December 2023, based on an interim report and recommendation by the Brattle Group, the VOLL was updated to $25,000 per MWh. Based on the Brattle Group's final report, the Commission set the VOLL to $35,000 per MWh in August 2024.

Q. IN YOUR OPINION, WHAT IS THE SIGNIFICANCE OF THE COMMISSION INCREASING VOLL FROM $5,000 PER MWH to $35,000 PER MWH WITHIN THE PAST 13 MONTHS?

A. By revising the VOLL to $35,000 per MWh, the Commission has recognized and further confirmed that avoiding customer outages is increasingly important to customers.

Q. ARE THERE ADDITIONAL INDICATIONS OF INCREASED CUSTOMER EXPECTATIONS FOR RELIABILITY AND RESILIENCY?

A. In addition to the quantitative data that VOLL utilizes to demonstrate increased expectations for reliability, customer survey data incorporated into the VOLL vocalizes the increased importance of reliability. Similar concerns were documented by the Commission in Exhibit NB-5 after Hurricane Beryl and the Derecho. The Commission found that

CHAPTER 25. SUBSTANTIVE RULES APPLICABLE TO ELECTRIC SERVICE PROVIDERS.

Subchapter S. WHOLESALE MARKETS

§25.508. Reliability Standard for the Electric Reliability Council of Texas (ERCOT) Region.

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

(1) **Exceedance tolerance** -- the maximum acceptable percentage of simulations in which the modeled ERCOT system experiences a loss of load event that exceeds the threshold for a given criterion of the reliability standard.

(2) **Loss of load event** -- an occurrence when the system-wide firm load plus minimum operating reserves required to avoid an energy emergency alert level three event is greater than the available resource capacity to serve that load, resulting in involuntary load shed.

(3) **Transmission operator** -- has the same meaning as defined in the ERCOT protocols.

(4) **Weatherization effectiveness** -- the assumed percentage reduction in the amount of weather-related unplanned outages for generation resources and energy storage resources included in the model, due to compliance with the weatherization standards in §25.55 of this title (relating to Weather Emergency Preparedness).

(b) **Reliability standard for the ERCOT region.** The bulk power system for the ERCOT region meets the reliability standard if an ERCOT probability-based model simulation demonstrates that the system meets each of the criteria provided in this subsection.

(1) **Frequency.** The expected loss of load events for the ERCOT region must be equal to or less than one event per ten years on average, i.e., 0.1 loss of load expectation (LOLE).

(2) **Duration.** The maximum expected length of a loss of load event for the ERCOT region, measured in hours, must be less than 12 hours, with a 1.00 percent exceedance tolerance.

(3) **Magnitude.** The expected highest level of load shed during a loss of load event for the ERCOT region, measured as the average lost load for a given hour, must be less than the maximum number of megawatts of load shed that can be safely rotated during a loss of load event, as determined by ERCOT, in consultation with commission staff and the transmission operators, with a 1.00 percent exceedance tolerance. Beginning in 2024, on or before December 1 of each year, ERCOT must file the maximum number of megawatts of load shed that can be safely rotated during a loss of load event and a summary of the methodology used to calculate this value.

(c) **Reliability assessment.** Beginning January 1, 2026, ERCOT must initiate an assessment to determine whether the bulk power system for the ERCOT region is meeting the reliability standard and is likely to continue to meet the reliability standard for the three years following the date of assessment. The assessment must be conducted at least once every three years.

(1) **Modeling assumptions.**

(A) Before conducting the assessment, ERCOT must file a comprehensive list of proposed modeling assumptions to be used in the reliability assessment. The proposed assumptions must include:

(i) the number of historic weather years that will be included in the modeling;

(ii) the amount of new resources and retirements, in megawatts, listed by resource type;

(iii) the weatherization effectiveness; and

(iv) any other assumptions that would impact the modeling results, along with an explanation of the possible impact of the additional assumptions.

(B) Commission staff will provide interested persons with at least 30 days from the date ERCOT files its proposed modeling assumptions to file comments recommending modifications to ERCOT's proposed modeling assumptions. Commission staff may include filing requirements or additional questions for comment.

(C) After reviewing filed comments, ERCOT, in consultation with commission staff, must file its final recommended modeling assumptions for commission review. Commission staff may provide a separate recommendation on ERCOT's final recommended modeling assumptions for the commission's consideration.

(2) **Assessment components.**

(A) ERCOT's assessment must include review and analysis of the resource fleet, loads, and other system characteristics for the ERCOT region for the following points in time:

(i) the current year's system configuration; and

(ii) the expected system configuration three years from the date of the current year's system analysis.

(B) The assessment results must include, at a minimum, the following metrics for each point in time:

(i) the LOLE;

(ii) the probability of a loss of load event exceeding the duration threshold established in subsection (b)(2) of this section;

(iii) the probability of a loss of load event exceeding the magnitude threshold established in subsection (b)(3) of this section;

(iv) the expected unserved energy; and

(v) the normalized expected unserved energy.

(3) **Commission review and determination.**

(A) ERCOT must file its assessment with the commission, including any information required under subparagraph (C)(i) of this paragraph.

(B) Commission staff will provide interested persons with at least 30 days from the date ERCOT files its assessment to file comments on ERCOT's assessment. Commission staff may include filing requirements or additional questions for comment.

(C) If the assessment shows that any reviewed system fails to meet the reliability standard described in subsection (b) of this section:

(i) ERCOT must provide the commission with a summary explanation of any identified deficiencies and its supporting analysis. ERCOT must also provide the commission with a menu of proposed recommended market design changes, including a primary recommendation, that are intended to address the identified deficiencies. ERCOT must provide the commission with the expected system costs associated with each of its proposed recommended changes;

(ii) the independent market monitor must conduct an independent review of ERCOT's proposed recommended market design changes, including associated expected system costs for each proposed recommended change, and file its review no later than the deadline established in subparagraph (B) of this paragraph; and

(iii) commission staff must provide a recommendation to the commission, considering expected system costs and reliability benefits, on whether any market design changes or other changes may be necessary to address the deficiency.

(D) The commission will review ERCOT's assessment and any recommendations, the independent market monitor's review, commission staff's recommendations, and stakeholder comments to determine whether any market design changes may be necessary.

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
PUC DOCKET NO. 57579
SOAH DOCKET NO. 473-25-11558

TEXAS COAST UTILITIES COALITION
REQUEST NO.: TCUC-RFI02-01

QUESTION:

Reference CEHE's response to TCUC 01-01, Attachment 2, please provide a copy of the attachment with all sheets unprotected and in a format that is not Read Only so that inputs and formulae in the attached file can be adjusted by TCUC.

ANSWER:

TCUC-RFI02-01 - CNP_Model_Master_RFI TCUC 1-1_Unprotected Version CONFIDENTIAL.xls

SPONSOR:
Eugene Shlatz

RESPONSIVE DOCUMENTS:
CNP_Model_Master_RFI TCUC 1-1_Unprotected Version CONFIDENTIAL.xls

Measure Description	Resiliency Measure Number (RM)	Prior Measure from April 2024 Filing?	3-Year Total Cost ($MM)	3-Year O&M Savings / (Cost) ($MM)	Total Cost per Device / Unit Cost ($)	Net Failure Rate (%)	% Failures Causing Load Loss	Failure Rate Unit	Equipment Degradation (%)	Load at Risk (MW)	Outage Duration (Hrs)	Collateral Damage per Failure ($)	Incremental Restoration Cost/Failure ($)
Extreme Wind													
Distribution Circuit Resiliency	RM - 1	Y	$ 513.4	$ -	$ 20,536	3.50%	25%	Per line	0.0%	6.6	9	$ -	$ 4,240
Strategic Undergrounding - Freeway Crossings	RM - 2	Y	$ 60.0	$ -	$ 959,000	7.50%	25%	Per crossing	0.0%	13.2	18	$ -	$ 90,000
Strategic Undergrounding - Overhead Relocation	RM - 2	N	$ 800.0	$ -	$ 7,000,000	79.20%	25%	Per OH section	0.0%	12.0	18	$ -	$ 80,000
IGSD Installation	RM - 3	Y	$ 107.8	$ 0.49	$ 359,333	118.7%	100%	Per scheme	0.0%	4.7	18	$ -	$ 5,000
Distribution Pole Replacements/Bracing	RM - 4	Y	$ 251.6	$ -	$ 8,480	3.50%	25%	Per pole	0.5%	3.9	18	$ -	$ 4,240
Distribution Vegetation Management	RM - 5	Y	$ 146.1	$ 146.10	$ 12,487	100.00%	100%	Per Mile	33.0%	0.1	12	$ -	$ 525
Transmission System Hardening -138kV	RM - 6	Y	$ 1,002.6	$ -	$ 701,640	0.20%	25%	Per pole	0.0%	175.0	48	$ -	$ 300,000
Transmission System Hardening - 345kV	RM - 6	N	$ 465.4	$ -	$ 2,077,482	0.20%	25%	Per Tower	0.0%	729.0	72	$ -	$ 1,038,741
S90 Tower Replacements	RM - 7	Y	$ 118.4	$ -	$ 3,433,333	0.20%	75%	Per tower	0.0%	729.0	60	$ -	$ 858,333
69-138kV Conversion Projects	RM - 8	Y	$ 369.3	$ -	$ 26,840,000	5.47%	100%	Per line	0.5%	75.0	48	$ -	$ 25,000
Coastal Transmission Resliency Upgrades	RM - 9	Y	$ 178.1	$ 0.8	$ 178,100,000	2.61%	100%	Per line	0.0%	250.0	120	$ -	$ 15,000,000
Extreme Water													
Substation Flood Control	RM - 10	Y	$ 43.8	$ -	$ 3,650,000	3.00%	20%	Per substation	0.0%	75.0	36	$ 500,000	Inc'd in Damage
Control Center Facility Upgrades	RM - 11	Y	$ 7.0	$ -	$ 7,000,000	2.00%	10%	AOC Facility	0.0%	5000.0	24	$ 20,000,000	Inc'd in Damage
MUCAMS	RM - 12	N	$ 10.8	$ -	$ 900,000	3.66%	10%	Per location	0.0%	87.5	8	$ 25,000	Inc'd in Damage
Mobile Substations	RM - 13	N	$ 30.0	$ -	$ 5,000,000	1.5%	40%	Per station	0.0%	75.0	72	$ 500,000	Inc'd in Damage
Extreme Temperature (Freeze)													
Anti-Galloping Mitigation	RM - 14	N	$ 15.0	$ 1.0	$ 180,000	0.20%	25%	Per circuit mile	0.5%	175.0	36	$ -	$ 50,000
Extreme Temperature (Drought)													
Distribution Capacity Enhancement/Substations	RM - 16	N	$ 579.6	$ -	$ 14,490,000	158.3%	100%	Per feeder	0.0%	12.0	18	$ -	$ 5,000
MUG Reconductor	RM - 17	N	$ 245.0	$ -	$ 11,000,000	3.75%	100%	Per mile	0.0%	12.0	72	$ -	$ 25,000
URD Cable Modernization	RM - 18	N	$ 128.4	$ -	$ 7,020	2.00%	100%	Per URD section	1.0%	0.1	18	$ -	$ 15,000
Contamination Mitigation - Substations	RM - 19	N	$ 21.0	$ -	$ 1,615,385	0.60%	10%	Per Hi-side S/S	0.0%	175.0	48	$ 100,000	Inc'd in Damage
Contamination Mitigation - Distribution Cirucits	RM - 19	N	$ 129.0	$ 6.00	$ 18,656	0.50%	100%	Per pole	0.0%	2.5	8	$ -	$ 2,720
Substation Fire Protection Barriers	RM - 20	Y	$ 9.0	$ -	$ 250,000	0.20%	75%	Per station	0.0%	75.0	18	$ 2,500,000	Inc'd in Damage
Digital Substation	RM - 21	Y	$ 31.8	$ -	$ 2,446,154	10.0%	50%	Per substation	-10.0%	14.0	6	$ -	Inc'd in Damage
System Secuity													
Substation Physical Security Fencing	RM - 26	Y	$ 18.0	$ -	$ 714,000	2.0%	10%	Per station	1.0%	729.0	24	$ 500,000	Inc'd in Damage
Substation Security Upgrades	RM - 27	Y	$ 19.5	$ 0.09	$ 542,000	2.0%	10%	Per station	1.0%	729.0	24	$ 500,000	Inc'd in Damage
Situational Awareness													
Advanced Aerial Imagery Platform/Digital Twin	RM - 33	Y	$ 20.4	$ 2.0	$ 5,000	0.65%	100%	Per Device	5.0%	0.6	6	$ -	$ 1,000

Attachment A

Value of Lost Load Study for the ERCOT Region

PREPARED BY

Charles Gibbons, PhD
Sanem Sergici, PhD

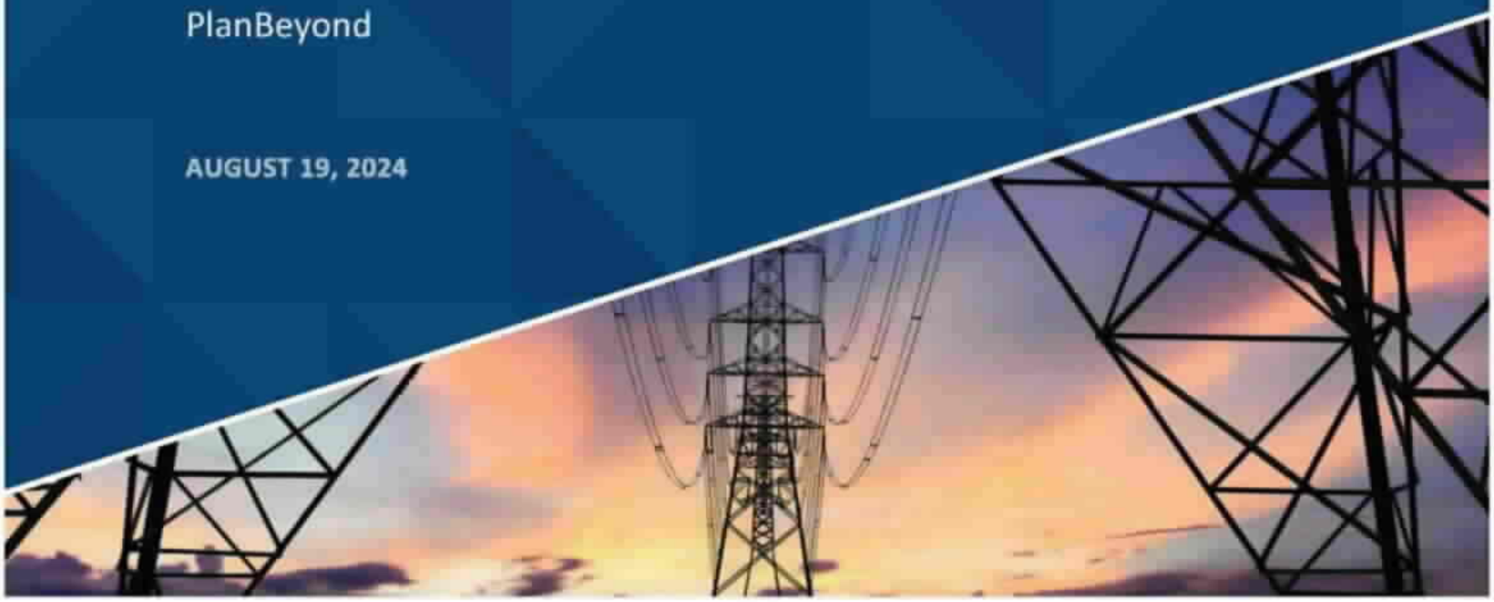
PREPARED FOR

Electric Reliability Council of Texas, Inc. (ERCOT)

WITH SUPPORT FROM

PlanBeyond

AUGUST 19, 2024



Brattle

PLANBEYOND

There are several potential reasons for this. First of all, the interim estimate was still fundamentally driven by the underlying response function from the US metadata from the LBNL study, even though we made adjustments to reflect ERCOT usage characteristics. Second, VOLLs per unserved MWh are very sensitive to the assumptions about the level of unserved load for a given outage duration. This study relied on the CBCI data to develop the average unserved load assumptions, whereas the interim VOLL estimates relied upon more generic EIA 861 consumption estimates for Texas and on customer class definitions that may not align perfectly with those used in this study.

TABLE ES.2: BRATTLE STUDY PART I ERCOT-WIDE INTERIM VOLL ESTIMATES (2023$/MWH)

Cost per Unserved Megawatt Hour (MWh)	30 Minute Outage	1 Hour Outage	8 Hour Outage
Residential	$9,283	$5,122	$1,817
Small C&I	$167,315	$102,490	$81,172
Medium / Large C&I	$130,797	$78,824	$53,954
Region-wide Option 1	$99,052	$60,093	$44,321
Region-wide Option 2a (cap using all studies)		$24,693	
Region-wide Option 2b (cap using all US studies)		$26,245	
Region-wide Option 2c (cap using all US that test a 1-hour duration outage)		$52,259	

Source: ERCOT PUC filing, December 21, 2023.

Other considerations. The primary case we have analyzed in this report and presented in Table ES.1 includes all customer classes, per the instructions of the Commission. In Section IV.D of this report, we also present an alternative case that excludes large C&I customers that are interconnected directly to the transmission system. Those customers could be subject to load shed, but in practice are generally not shed during system shortages, even during long and deep shortages. This is because the transmission service provider ("TSP") load shedding practices focus on distribution-connected customers. Our alternative calculation presented later in the report reflects the average VOLL solely of distribution-interconnected customers and is almost twice as high as our primary calculation. As long as load-shedding practices remain the same, this correspondingly higher VOLL may be more relevant when evaluating the benefits of adding generation or transmission that reduce the risks of shortages and load shedding.

Our survey respondents also include critical load customers, for whom the suspension of electric service would create dangerous or life-threatening conditions. Many of these customers may be on feeders that the TSPs protect from load shedding, but we do not exclude them from the sample since their critical load status is self-reported and we were not able to independently verify their status or prevalence in the overall ERCOT Region. While we did not develop a sensitivity that excludes critical load customers in a similar fashion to the transmission-interconnected customers, we investigate their VOLLs separately in Section IV.B of this report.

While this study estimated VOLLs for 1-day and 3-day outage durations, there is considerable uncertainty associated with those VOLLs. For long duration outages, the nature of costs changes and other indirect effects to the communities and economy should be considered.[2] A recent report from LBNL indicates that few survey-based studies have elicited preferences regarding longer-duration outages, in part because responses may be less informed by experience with such outage durations.[3] Therefore, these longer duration VOLLs should not be directly used for resiliency planning.

Lastly, it is important to bear in mind the inherent limitations in the use of surveys to evaluate customer behavior. The applicability of the results depends upon the reliability of the responses received. Residential customers are asked to state whether they would purchase protection to avoid an outage, but stated intentions may not match actual behavior. For C&I customers, they are asked to provide estimates of the expected costs associated with an outage, but the impact of an actual outage on a business is complex and may be difficult to evaluate in the context of hypothetical survey scenarios. To mitigate some of these issues, we removed response patterns that seemed unreasonable and used statistical methods capable of incorporating a variety of customer behavior.

[2] Michael J. Sullivan, Josh Schellenberg, and Marshall Blundell, "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States," January 2015, Lawrence Berkeley National Laboratory.

[3] Madeline Macmillan, Kyle Wilson, Sunhee Baik, Juan Pablo Carvallo, Anamika Dubey, and Christine A. Holland, "Shedding light on the economic costs of long-duration power outages: A review of resilience assessment methods and strategies," May 2023, Lawrence Berkeley National Laboratory.

I. Introduction

The Electric Reliability Council of Texas, Inc. ("ERCOT") has commissioned this Value of Lost Load ("VOLL") study on behalf of the Public Utility Commission of Texas ("Commission") to determine the estimated value of electric reliability in the ERCOT Region. Subsequently, ERCOT issued a Request for Proposal for a contractor to perform the VOLL study and has selected The Brattle Group ("Brattle") and their survey administration subcontractor, PlanBeyond (collectively "Brattle team"), to conduct the study by surveying residential, commercial, and industrial customers in the ERCOT Region to determine ERCOT-specific VOLL values for use in system planning efforts.

VOLL is an important metric for electric markets. It represents a proxy for the economic costs that customers incur due to a power outage. Alternatively, it can be considered an average customer's willingness to pay to avoid an outage. Given that electricity use-cases differ across customer classes, the costs incurred from an outage can vary widely based on the customer class under consideration and the characteristics of a potential outage event. For an industrial customer, this may involve a variety of labor- and production-related costs, while for the typical residential customer, it may primarily involve disruptions associated with not having power. Knowledge of the VOLL can prove useful for both planning and operations management. With respect to planning, it can help inform cost-benefit decisions with respect to generation and transmission investment and can drive resource adequacy and resiliency policy on the operations side.

The Brattle team initiated their work by undertaking a comprehensive literature review of VOLL studies in the United States and elsewhere.[4] Deriving VOLL values from the literature, even after adjusting them for ERCOT-specific circumstances, may fail to capture important aspects of valuations of uninterrupted power for customers in the ERCOT Region. The literature review also demonstrated that a survey is generally the most comprehensive means to determine how customers in an area value reliability. Therefore, the Brattle team undertook a customer survey in the ERCOT Region and estimated resulting VOLL values using well-established econometric techniques. While separate VOLL values are estimated for each customer class, the Brattle team also calculated a load-weighted average of the customer class VOLLs to be used for ongoing Commission market design initiatives, particularly the development of a reliability standard for the ERCOT Region.

[4] See Brattle Part I Study.

DOCKET NO. 57579

APPLICATION OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC FOR APPROVAL OF ITS 2026-2028 TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN	§ § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC FOR APPROVAL OF ITS 2026-2028 TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN

CenterPoint Energy Houston Electric, LLC ("CenterPoint Houston" or the "Company") requests that the Public Utility Commission of Texas ("Commission") approve the Company's 2026-2028 Transmission and Distribution System Resiliency Plan (the "System Resiliency Plan"). In support of its Application and request, the Company states the following:

I. SUMMARY

In 2023, the 88th Texas Legislature passed and the Governor signed into law H.B. 2555,[1] which created Public Utility Regulatory Act ("PURA") § 38.078 and permits an electric utility to request Commission approval of the electric utility's transmission and distribution system resiliency plan. In passing H.B. 2555, the 88th Legislature made the following findings:

- Protecting electrical transmission and distribution infrastructure from extreme weather conditions can effectively reduce system restoration costs to and outage times for customers and improve system resiliency and overall service reliability for customers;
- It is in the state's interest for each electric utility to seek to mitigate system restoration costs to and outage times for customers when developing plans to enhance electrical transmission and distribution infrastructure storm resiliency; and
- All customers benefit from reduced system restoration costs.[2]

With these specific legislative findings in mind and consistent with the Company's past, current, and future focus on and prioritization of resiliency-related projects, the Company has developed

[1] H.B. 2555, 88th Leg., R.S. (2023).

[2] *Id.*, Section 1, Subsections (3)-(5).

- Exhibit 15: The Company's proposed protective order.

A summary of each witness' testimony is provided in Figure APP-14 below:

Figure APP-14.

Witnesses and Corresponding Testimony Subjects

Witness	Testimony Subject
Mr. Nathan Brownell	Overall Policy and Strategy
Mr. Deryl Tumlinson	Overhead Distribution System
Mr. David Mercado	Transmission System and Substations
Mr. Randy Pryor	Strategic Undergrounding and Vegetation Management
Mr. Eric Easton	Damage Prediction, Use of Advanced Analytics, and Wildfire Mitigation
Mr. Ronald Bahr	Information Technology
Mr. Christopher Ford	Cybersecurity Operations
Mr. Brad Tutunjian	Microgrid Pilot Program
Mr. Muss Akram	Customer Value
Mr. Jeff Garman	Accounting Treatment
Mr. Eugene Shlatz	Guidehouse Independent Expert Witness supporting Operational Resiliency Measures
Dr. Joseph Baugh	Guidehouse Independent Expert Witness supporting Technology and Cybersecurity Resiliency Measures

B. Overview of the Company's System Resiliency Plan

The Company's System Resiliency Plan has thirty-nine (39) Resiliency Measures that, in total, will harden and modernize the Company's transmission and distribution system; implement flood mitigation measures; enhance the Company's information technology, including information technology used in support of operations; enhance the physical security of the Company's substations; proactively conduct vegetation management on select distribution circuits; and mitigate the identified risk of wildfires. Additionally, as part of the Company's System Resiliency Plan, the Company is proposing a pilot program that would assess the extent to which utility-scale microgrids may assist in restoration efforts during a Resiliency Event. The Company estimates that the thirty-nine (39) Resiliency Measures will cost approximately $5.543 billion in capital costs and will cost approximately $210.7 million in incremental O&M expense over the three-year period from 2026-2028.[5] Figure APP-15 below summarizes each Resiliency Measure and the proposed Microgrid Pilot Project in the Company's System Resiliency Plan.

Figure APP-15.
Resiliency Measures, Costs, and 3-Year CMI Savings

Resiliency Measure	Estimated Capital Costs (millions)	Estimated Incremental O&M Expense (millions)	Estimated 3-Year CMI Savings (millions)
Extreme Wind			
Distribution Circuit Resiliency (RM-1)	$513.4	-	263.0
Strategic Undergrounding (RM-2)	$860.0	-	81.1
Restoration IGSD (RM-3)	$107.3	$0.5	97.0
Distribution Pole Replacement/Bracing Program (RM-4)	$251.6	-	121.0
Vegetation Management (RM-5)	-	$146.1	137.0
Transmission System Hardening (RM-6)	$1,467.3	$0.8	223.8
69kV Conversion Projects (RM-7)	$369.3	-	65.5
S90 Tower Replacements (RM-8)	$118.4	-	59.5
Coastal Resiliency Projects (RM-9)	$177.4	$0.8	7.8
Extreme Water			

[5] Some Resiliency Measures in the Company's System Resiliency Plan may extend beyond the three-year period and thus there may be additional capital costs and additional incremental operations and maintenance expense beyond the three-year period. Additionally, and subject to available funding, personnel, and materials, the Company may accelerate some future resiliency projects, which would entail additional capital costs and additional incremental operations and maintenance expense.

Resiliency Measure	Estimated Capital Costs (millions)	Estimated Incremental O&M Expense (millions)	Estimated 3-Year CMI Savings (millions)
Substation Flood Control (RM-10)	$43.8	-	3.9
Control Center Flood Control (RM-11)	$7.0	-	2.5
Major Underground Control and Monitoring System (MUCAMS) (RM-12)	$10.8	-	0.6
Mobile Substation (RM-13)	$30.0	-	3.9
Extreme Temperature (Freeze)			
Anti-Galloping Technologies (RM-14)	$14.0	$1.0	5.3
Load Shed IGSD (RM-15)	$4.5	$0.1	N/A
Microgrid Pilot Project (PP-1)	$35.0	$1.5	N/A
Extreme Temperature (Heat)			
Distribution Capacity Enhancements/Substations (RM-16)	$579.6	-	138.1
MUG Reconductor (RM-17)	$245.0	-	13.6
URD Cable Modernization (RM-18)	$128.4	-	13.0
Contamination Mitigation (RM-19)	$144.0	$6.0	15.7
Substation Fire Barriers (RM-20)	$9.0	-	1.5
Digital Substation (RM-21)	$31.8	-	1.2
Wildfire Advanced Analytics (RM-22)	-	$0.9	N/A
Wildfire Strategic Undergrounding (RM-23)	$50.0	-	N/A
Wildfire Vegetation Management (RM-24)	-	$30.0	N/A
Wildfire IGSD (RM-25)	$19.4	$0.3	N/A
Physical Attack			
Substation Physical Security Fencing (RM-26)	$18.0	-	17.6
Substation Security Upgrades (RM-27)	$19.4	$0.1	25.1
Technology & Cybersecurity			
Spectrum Acquisition (RM-28)	$42.0	-	N/A
Data Center Modernization (RM-29)	$12.7	$1.3	N/A
Network Security & Vulnerability Management (RM-30)	$7.5	$2.0	N/A
IT/OT Cybersecurity Monitoring (RM-31)	$13.4	$4.2	N/A
Cloud Security, Product Security & Risk Management (RM-32)	$4.0	$6.0	N/A
Situational Awareness			
Advanced Aerial Imagery Platform / Digital Twin (RM-33)	$18.4	$2.0	10.8
Weather Stations (RM-34)	-	$0.3	N/A
Wildfire Cameras (RM-35)	-	$0.9	N/A
Voice and Mobile Data Radio System (RM-36)	$20.9	-	N/A
Backhaul Microwave Communication (RM-37)	$12.7	-	N/A

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.

(ii) 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.

(iii) 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.

(iv) 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.

(ii) 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.

(iii) 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:

$RCRR_{CLASS} = RR_{CLASS} / BD_{C\text{-}CLASS}$

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

(I) $RR_{CLASS} = RR_{TOT} * ALLOC_{C\text{-}CLASS}$

(II) $RR_{TOT} = ((RNDC * ROR_{RC}) + RDDEPR + RNDCFIT + RDOT) - IDCCR$

(III) $ALLOC_{C\text{-}CLASS} =$ $ALLOC_{RC\text{-}CLASS} * (BD_{C\text{-}CLASS} / BD_{RC\text{-}CLASS}) / \Sigma\ (ALLOC_{RC\text{-}CLASS} * (BD_{C\text{-}CLASS} / BD_{RC\text{-}CLASS}))$

(IV) $IDCCR = \Sigma\ (DISTREV_{RC\text{-}CLASS} * \%GROWTH_{CLASS}) - DCRFLGA$

(V) $DISTREV_{RC\text{-}CLASS} = (DIC_{RC\text{-}CLASS} * ROR_{AT}) + DEPR_{RC\text{-}CLASS} + FIT_{RC\text{-}CLASS} + OT_{RC\text{-}CLASS}$, with the variables in this formula as defined in §25.243 of this title.

(VI) $\%GROWTH_{CLASS}$ = The greater of $((BD_{C\text{-}CLASS} - BD_{RC\text{-}CLASS}) / BD_{RC\text{-}CLASS})$ or zero.

(iii) The terms used in this paragraph represent or are defined as follows:

(I) **Descriptions of calculated values.**

(-a-) **$RCRR_{CLASS}$** -- RCRR rate for a rate class.

(-b-) **RR_{CLASS}** -- RCRR class revenue requirement.

(-c-) **RR_{TOT}** -- Total RCRR Texas retail revenue requirement.

(-d-) **$ALLOC_{C\text{-}CLASS}$** -- RCRR class allocation factor for a rate class.

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

(-f-) **$DISTREV_{RC\text{-}CLASS}$** -- Distribution Revenues by rate class based on Net Distribution Invested Capital from the most recently completed comprehensive base-rate proceeding.

(-g-) **$\%GROWTH_{CLASS}$** – Growth in billing determinants by class.

(II) **RCRR billing determinants and distribution investment values.**

(-a-) **$BD_{C\text{-}CLASS}$** -- 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.

(III) **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-) **$BD_{RC\text{-}CLASS}$** -- 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-) **$ALLOC_{RC\text{-}CLASS}$** -- Rate class allocation factor value determined under the provisions of subparagraph (C) of this paragraph.

(-d-) **DCRFLGA** -- The value of $\Sigma(DISTREV_{RC\text{-}CLASS} * \%GROWTH_{CLASS})$ 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:

$[((DIC_{C} - DIC_{RC}) * ROR_{AT}) + (DEPR_{C} – DEPR_{RC}) + (FIT_{C} – FIT_{RC}) + (OT_{C} – OT_{RC}) + RAMORT – \Sigma (DISTREV_{RC-CLASS} * \%GROWTH_{CLASS})] * ALLOC_{CLASS} / BD_{C-CLASS}$

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:

(A) a report on the occurrence of any resiliency events the resiliency plan or a previously-implemented resiliency plan was intended to address, including a comparison of the frequency and magnitude of these events with any projections contained in the resiliency plan or a resiliency plan previously-implemented by the electric utility;

(B) an evaluation of the effectiveness of each implemented resiliency plan measure in preventing, withstanding, mitigating, or more promptly recovering from the risks posed by any resiliency events that measure was implemented to address. This evaluation must include an analysis using the metric or criteria contained in the resiliency plan for that measure, and a comparison of the measure's actual effectiveness with its projected effectiveness;

(C) an update on the expected impact of implemented resiliency plan measures, as appropriate for each measure, on system restoration costs, reduction in the frequency or duration of outages for customers at the location for which a resiliency plan was implemented, and any improvement in the overall service reliability for customers.

(3) When submitting an updated resiliency plan, the utility must include in the evidence supporting the plan, any information from prior resiliency benefit updates related to previously-approved measures designed to address the same or similar resiliency risks.

(4) An electric utility is required to maintain records associated with the information referred to in this subsection for five years, beginning the year after the plan is approved. Upon request by commission staff an electric utility must provide any additional information and updates on the status of the resiliency plan submitted.

As required by 16 Tex. Admin. Code § 25.62(c)(2)(G), the comprehensive chart below summarizes the SRP 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 plan's effectiveness, the plan's cost and benefits, all of which demonstrate that the overall plan is in the public interest.

Figure SRP-ES-3

Executive Summary Comprehensive Chart

Resiliency Measure	Description	Estimated costs	Estimated 3 Year CMI	Resiliency Event(s) Impact to be Mitigated	Anticipated Customer Benefits
Extreme Wind					
Distribution Circuit Resiliency (RM-1)	Rebuild and upgrade 25,000 poles and crossarms	Capital: $513.4 million Incremental O&M: None	263.0 million	Extreme wind events • Microburst • High wind • Tornado • Hurricane	Improved structural integrity Higher wind loading capabilities Reduce the frequency and number of customers impacted by outages Reduce total outage times Reduce system restoration costs
Strategic Undergrounding (RM-2)	Replace wooden distribution poles and equipment on overhead distribution lines at freeway crossings, critical facilities, and in	Capital: $860.0 million Incremental O&M: None	81.1 million	Extreme wind events • Microburst • High wind • Tornado • Hurricane Extreme Temperature	Improve structural integrity Reduce the frequency and number of customers impacted by outages

Resiliency Measure	Description	Estimated costs	Estimated 3 Year CMI	Resiliency Event(s) Impact to be Mitigated	Anticipated Customer Benefits
	hard to access areas; 111 miles			• Heat • Freeze Wildfires Third-party damage • Vehicular collision	Reduce total outage times Reduce system restoration costs
IGSD Installation (RM-3)	Install 900 Intelligent Grid Switching Devices (IGSDs)	Capital: $107.3 million Incremental O&M: $490,000	97.0 million	Extreme weather events Extreme wind events • Microburst • High wind • Tornado • Hurricane Extreme Temperature • Heat • Freeze Wildfires	Faster restoration Reduce time and expense associated with dispatching field personnel to restore an outage Reduce number of customers impacted by an outage Reduce total outage time
Distribution Pole Replacement/Bracing Program (RM-4)	Replace, upgrade, or brace 30,000 wooden distribution pole	Capital: $251.6 million Incremental O&M: None	121.0 million	Extreme wind events • Microburst • High wind • Tornado • Hurricane Wildfires Third-party damage • Vehicular collision	Improved structural integrity Higher wind loading capabilities Reduce the frequency and number of customers impacted by outages Reduce total outage

Resiliency Measure	Description	Estimated costs	Estimated 3 Year CMI	Resiliency Event(s) Impact to be Mitigated	Anticipated Customer Benefits
					times Reduce system restoration costs
Vegetation Management (RM-5)	Transition from a 5-year to a 3-year trim cycle on all distribution circuits; 11,700 miles in total	Capital: None Incremental O&M: $146.1 million	137.0 million	Extreme wind events • Microburst • High wind • Tornado • Hurricane Heavy rain and major storm Extreme freezes Extreme heat	Reduce the frequency and number of customers impacted by outages Reduce total outage times Reduce system restoration costs
Transmission System Hardening (RM-6)	Harden transmission structures by replacing wooden structures with steel or concrete structures, 1,715 structures in total	Capital: $1,467.3 million Incremental O&M: $750,000	223.8 million	Extreme wind events • Microburst • High wind • Tornado • Hurricane Wildfires Extreme temperature event Icing on conductors	Improved structural integrity Higher wind loading capabilities Reduce the frequency and number of customers impacted by outages Reduce total outage times Reduce system restoration costs
69kV Conversion Projects (RM-7)	Rebuild and reconductor 69kV transmission circuits to	Capital: $369.3 million	65.5 million	Extreme wind events • Microburst • High wind	Improved structural integrity Higher wind loading

Resiliency Measure	Description	Estimated costs	Estimated 3 Year CMI	Resiliency Event(s) Impact to be Mitigated	Anticipated Customer Benefits
	138kV; upgrade 462 structures	Incremental O&M: None		• Tornado • Hurricane Extreme temperature event • Freeze Wildfires	capabilities Mitigate loss of transmission during extreme weather events by providing multiple paths of redundancy Capacity for future load growth
S90 Tower Replacements (RM-8)	Replacement of S90 towers; replace 37 towers in total	Capital: $118.4 million Incremental O&M: None	59.5 million	Extreme wind events • Microburst • High wind • Tornado • Hurricane Extreme Temperature Events • Freeze Wildfires	Improved structural integrity Higher wind loading capabilities Reduce the frequency and number of customers impacted by outages Reduce total outage times Reduce system restoration costs
Coastal Resiliency Projects (RM-9)	Construct additional transmission circuits to the coastal portion of the Company's service area; upgrade current 69kV transmission	Capital: $177.4 million Incremental O&M: $750,000	7.8 million	Extreme wind events • Microburst • High wind • Tornado • Hurricane	Mitigate loss of transmission during extreme weather events by providing multiple paths of redundancy

CenterPoint Houston's Transmission System Hardening resiliency measure (along with 69kV and 138kV Conversions and Tower Replacements) is one of its key resiliency measures based on the proposed level of investment. The poles replaced will meet CenterPoint Houston's current wind loading standard. Figure 5-4 presents typical 138kV wood pole structures proposed for hardening.

Figure 5-4: Examples of Transmission 138kV Wood Structures

5.3.8.2 Revisions from the Prior System Resiliency Plan

CenterPoint Houston proposes to increase spending on the Transmission System Hardening measure, which will increase the number of wood structures replaced over the 3-year Resiliency Plan. In addition, the current SRP includes the replacement of at-risk double-circuit 345kV towers. Targeted upgrades include the replacement of all wood poles with monopoles by the end of 2028 and several hundred 345kV towers. It also includes the installation of larger conductors on most circuits where poles or towers are replaced to enhance grid resiliency further. Except for using a higher VoLL, all other values applied to derive benefits for wood pole 138kV structure upgrades in the prior SRP remain unchanged – all values for 345kV tower replacements are new. The criteria that will be used to identify wood structures that need to be replaced also remain unchanged. However, the wood and tower structures and conductor upgrade that CenterPoint Houston will select for replacement during the implementation phase is now based on other factors, such as line ratings and transmission network upgrades required to support the regional grid during resiliency events; additional details are provided in CenterPoint Houston in its SRP.

5.3.8.3 Resiliency Measure Targets

CenterPoint Houston's proposed Transmission System Hardening measure replacement quantities and investment amounts appear below.

- Miles of transmission targeted: Approximately **160 miles** over the 3-year SRP
- Number of Structures targeted: 1,715 structures (**1,473** wood poles and **242** towers, respectively)
- Total project cost (capital and expense): **$1,468 million** over the 3-year SRP period
- The annual expense to install the new structures is **$750,00** total over the 3-year SRP

5.3.8.4 Alternatives Considered

In reviewing the SRP, CenterPoint Houston, in collaboration with Guidehouse, evaluated three alternatives to replacing wooden transmission structures with steel or concrete poles. First, CenterPoint Houston evaluated using single, stronger wooden poles, but they offer only offer a marginal increase in system resiliency. Further, new wooden H-frame are an obsolete Company design standard and are not viable options for resiliency. Second, an alternative to replacing poles is to relocate lines underground. This option is a viable option but was rejected as cost prohibitive for the entire existing 138kV transmission lines since the cost of undergrounding transmission lines is $20 million per mile, which is 5 to 10 times more costly than overhead lines and the cost to underground all distribution circuits is also cost prohibitive at 2 to 5 times the cost of overhead lines per mile. Third, CenterPoint Houston could reduce outage exposure on at-risk lines by constructing new lines to operate at the same or higher voltage along the same or new rights-of-way. These new lines would be built to a higher capacity line rating to meet future load growth. This alternative is being discussed but has not yet been adopted and accepted by ERCOT and other Transmission System Providers.

5.3.8.5 Resiliency Measure Metrics and Effectiveness

CenterPoint Houston transitioned from an asset-centric program-based approach to a project-based approach using co-optimized sets of project types to address resiliency challenges specific to geographic regions in its service area. Using an array of best practice project type alternatives, different project types were selected in each area to enhance resiliency and structural hardening at a discrete asset level.

For substations and transmission assets, these mitigations were primarily structural enhancements, such as elevating substations above inundation levels or replacing existing transmission structures with designs capable of withstanding higher wind speeds. The discrete nature of these projects results in efficacy measurements that are more asset-centric.

Measurements:

1. Percent of planned asset installations completed by County

2. Percent of resilient power delivery asset failures projected to fail during a Resiliency Event
3. Percent of resilient power delivery asset failures occurring during a Resiliency Event

5.3.8.6 Benefits Analysis

Guidehouse evaluated the benefits associated with CenterPoint Houston's proposed Transmission System Hardening resiliency measure on a quantitative and qualitative basis. The quantitative analysis adheres to the BCA methodology described in Section 5.1, with project-specific inputs and assumptions described below.

1. **Quantitative Benefits** – Key assumptions include estimates of the average number of avoided sustained interruptions on transmission circuits targeted for structure replacement(s) during high wind resiliency events, the average number of customers or load at risk, and the estimated time to restore service. For 138kV wood poles, the failure rate of line sections where new structures are proposed is 0.2% annually, derived based on the wind severity and frequency analysis for tornadoes or microbursts described in Section 4.2. The likelihood that a severe wind event will cause two 138kV poles to fail (*e.g.*, an N-2 event) is estimated at 25%. The estimated average cost to replace a wood pole or structure with a steel or concrete monopole and to reconductor circuits is $700,000. The estimated average load at risk is 175MW, with an average restoration time of 48 hours.[82] The estimated average time to repair damaged lines is 5 days during extreme wind events.

   For 345kV towers, the failure rate of line sections where new steel monopole, double-circuit structures are proposed is 0.2% annually. This is derived from the wind severity and frequency analysis for tornadoes or microbursts described in Section 4.2. The likelihood that a severe wind event will cause load loss for a double-circuit 345kV tower failure (*e.g.*, a common model contingency event) is estimated at 25%.[83] The estimated average cost to replace a wood pole or structure with a steel or concrete monopole and to reconductor circuits is $2.1 million. The estimated load at risk is 729MW, with an average restoration time of 72 hours. During extreme wind events, the estimated average time to repair damaged lines is 5 days or longer.

   Measure benefits include reduced costs for truck rolls and crew labor to restore service absent the presence of replacement poles. The Transmission System Hardening resiliency measure is projected to reduce total CMI over the 3-year SRP period by approximately 224 million and 123 million annually by 2028. From these assumptions, Guidehouse derived a composite BCA of 3.9.

2. **Qualitative Benefits** – The potential for single wood poles or steel towers to fail and cause customer interruptions during extreme wind resiliency events is relatively low.

[82] Load at risk is based on the contingency events impact on more than one line, as CenterPoint's transmission system is designed to meet first contingency planning criteria without loss of load.

[83] Value accounts for the likelihood that other transmission lines may simultaneously fail during extreme wind events.

Vegetation Management Resiliency Measure (RM-5)	
Resiliency Event(s) addressed	Extreme wind events • Microburst • High wind • Tornado • Hurricane Heavy rain and major storm Extreme freezes Extreme heat
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.

Prioritization. In planning the three-year cycle, the Company will prioritize distribution circuits based multiple factors, such as accessibility, encroachment, and fall-in risk from the LiDAR model, vegetation caused outages, potential impact to critical loads, and overall customer count impacted.

History of Effectiveness. Vegetation management is a well-known measure within the utility industry that enhances resiliency. 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 feeder mains and laterals. As a part of this performance-based effectiveness, the Company has seen a reduction in outage durations and total number of customers impacted.

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. During Hurricane Beryl, approximately half of the circuit outages were driven by vegetation. The PA Consulting Hurricane Beryl After-Action report recommended that the Company revise its tree trimming cycles to a more frequent interval of 3 years to reduce the risk of outages caused by vegetation during extreme wind events.

Measuring Efficacy. Distribution system mitigations are focused on areas of higher predicted damage concentration to maximize overall system restoration efficiency. These mitigations, when optimized at the project level, require the consideration of interdependencies between mitigations contemplated for the same distribution feeder/area. For example, strategic undergrounding changes the needs for automation and vegetation management frequency. As a result of using the co-optimized project-based approach, the Company will use efficacy measures which capture the complementary nature of project-based system resiliency plans. This approach is consistent with industry best practice and measures success as a product of regional performance as opposed to individual asset performance.

The Vegetation Management Resiliency Measure Measurements of Efficacy are:

1. Percentage of planned asset installations complete by County;
2. Percentage change in predicted damage for areas of higher damage concentration based on the event type;
3. Normalized total system restoration performance during Resiliency Events pre and post completion of mitigation projects based on the event type; and
4. Normalized restoration performance of predicted high damage concentration area restoration performance compared to Normalized total system restoration performance pre and post completion of mitigation projects during Resiliency Events based on the event type.

Section 5.1.5.6. Transmission System Hardening (RM-6)

Description. Transmission System Hardening reduces the Company's exposure to multiple types of resiliency events, but as explained above, it is most closely associated with Extreme Wind Events. Risks that Extreme Wind poses, which Transmission System Hardening is meant to address, include temporary and sustained outages on the system, downed distribution circuits, and structural failures of the Company's transmission system.

The Transmission System Hardening Resiliency Measure will replace remaining wooden transmission structures (single pole and H-frame) with steel or concrete structures in line segments and upgrade any necessary tower structures where the structures do not meet the Company's current wind loading design standard for 138kV or 345 kV structures respectively.[17] The Company is targeting to replace approximately 1,473 structures over the three-year period.

In addition to the structures mentioned above, the Transmission System Hardening Resiliency Measure will also replace existing legacy transmission steel towers installed in the 1960's with steel or concrete structures in line segments, and upgrade or replace any additional necessary structures, where the structures do not meet the Company's current wind loading design

[17] The Company's current wind loading standard is from ASCE 7-16 and is based on the 100-year MRI Exposure C or D (dependent on proximity to Gulf of Mexico).

standard for double circuit 345 kV tangent structures. The Company is targeting to replace an additional 242 legacy 345kV tangent double circuit transmission towers over the three-year period. This program will extend through 2032.

A complete system outage is not required for installation, though segment outages may be. This resiliency measure will work in conjunction with similar existing system hardening measures as well as with other Resiliency Measures included in this SRP.

The following figure illustrates examples of the types of wooden transmission structures to be replaced through the Transmission System Hardening Resiliency Measure.

Figure SRP-45
Potential Transmission Structures for Replacement

Relevant Details. The following figure summarizes the Transmission System Hardening Resiliency Measure.

Figure SRP-46
Transmission System Hardening Resiliency Measure (RM-6)

Transmission System Hardening Resiliency Measure (RM-6)	
Estimated capital costs from 2026-2028	$1,467.30 million
Estimated incremental O&M expense from 2026 - 2028	$750,000
Estimated overall project duration	2026-2028 (100% wood structure replacement complete; 19% legacy steel replacement; ongoing thereafter)
Net salvage value	Salvage Value: None Removal costs: Are included as part of capital project costs

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
PUC DOCKET NO. 57579
SOAH DOCKET NO. 473-25-11558

HOUSTON COALITION OF CITIES
REQUEST NO.: HCC-RFP04-25

QUESTION:

For RM-6: Provide electronic data for each of the 1,473 structures showing:

a. the structure type;
b. the structure age;
c. failure probability; and
d. the replacement structure type and cost.

ANSWER:

The metric of approximately 1473 structures represents an initial estimate of new structures that would be installed on RM-6 Transmission System Hardening projects. This does not reflect an exact number of existing structures that would be replaced on RM-6. The exact number of structures that will be replaced on RM-6 will not be known until detailed engineering is complete for each identified project.

Based on preliminary estimates, approximately 1364 Structures will be removed on RM-6 projects. This structure replacement count is subject to change pending the outcome of detailed engineering.

a. Approximately 653 of these structures are wood pole structures as referenced in CenterPoint Energy's answer to TIEC 1-10 (a) and (b). The approximately 711 remaining structures are either concrete or steel structures.

The approximate breakdown of structure type for the preliminary structures identified:

Wood Pole – 653
Concrete Pole – 117
Steel Pole – 109
Steel Tower – 485

b. Approximate average age of structures to be replaced:

Wood Pole – 1985
Concrete Pole – 2008
Steel Tower – 1962
Steel Pole – 2018 (53 of the 109 steel poles identified for replacement on this resiliency measure are steel poles used mainly for restoration efforts. These poles are installed to facilitate the restoration of service to customers as quickly as possible while a permanent solution is designed and constructed, at which point the restoration steel poles are removed. Note that these are preliminary identifications, and based on engineering design criteria these structures may or may not be replaced based on the outcome of detailed engineering analysis).

For structures with foundations, CenterPoint Houston tracks the installation of the foundation as a metric to identify the age of the structure in question. For example, if a steel lattice tower with a foundation originally installed in 1950 had an additional extension installed in 2020 which required a new foundation, but the original tower was not replaced. The age of the structure would be updated to reflect the new foundation installed in 2020.

For direct-embed structures, the structure age will reflect the installation year of the direct-embed structure.

Please see table below for breakdown of approximate age of structure, by decade, by structure type.

Structure Type	1950's	1960's	1970's	1980's	1990's	2000's	2010's	2020's
Wood Pole	8	51	77	407	44	24	31	11
Concrete Pole	0	0	0	8	16	53	10	30
Steel Tower	193	260	12	2	3	7	4	4
Steel Pole	0	0	0	1	0	14	33	61

c. An independent third-party consultant (Guidehouse) has calculated failure rates for RM-6 that were presented in Section 4.2.1 (Hurricane Risk Profile) of Exhibit ELS-2. Figure 4-12, found on page 47 (PDF page 1202) of Exhibit ELS-2, presents the annual probability of occurrence for wind speeds for 2030. The probability that wind speeds are expected to exceed the design threshold for wood poles is 0.2% annually. Guidehouse did not derive failure rates for individual poles in its BCA calculations because there are over 1,000 structures that will be replaced for RM-6, it is not practicable to derive failure rates and BCA ratios for each pole.

d. All structures will be replaced with engineered materials (steel lattice towers, steel poles, or concrete poles) that meet current transmission design criteria. The exact structure replacement type will not be known until detailed engineering is complete for the projects included in this resiliency measure.

The costs included in the System Resiliency Plan filing do not distinguish between costs for individual structures, but rather, total project estimates. Due to the complexity and variability of individual structures within a project—such as differences in design requirements, site conditions, and construction methods—it is not practical to create estimates on a per-structure basis. Instead, the process produces an overall project estimate that accounts for the unique challenges and scope of each project. This approach ensures a more accurate and realistic projection of total project costs.

SPONSOR:
Eric Easton and David Mercado

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
PUC DOCKET NO. 57579
SOAH DOCKET NO. 473-25-11558

TEXAS INDUSTRIAL ENERGY CONSUMERS
REQUEST NO.: TIEC-RFI01-10

QUESTION:

Referring to the Transmission System Hardening Resiliency Measure in the SRP at pages 88-92:

a. State the quantity of 138 kV wooden structures being replaced.

b. State the quantity of 345 kV wooden structures being replaced.

c. Confirm that zero 69 kV wooden structures are proposed for replacement under this measure.

d. Confirm that CenterPoint will have zero remaining 138 kV and 345 kV wooden structures if this measure is executed.

e. State the current total quantity of legacy transmission steel towers in service, by vintage and by voltage.

f. State the quantity of legacy transmission steel towers that have been replaced in the past 10 years due to a resiliency event, by year, by vintage, by voltage, and by resiliency event.

g. State the quantity of legacy transmission steel towers that have been replaced in the past 10 years for reasons other than a resiliency event, by year, by vintage, and by voltage.

h. State the criteria used to define a transmission steel tower as "legacy."

i. Describe how CenterPoint determined to replace the 242 structures that are in this SRP out of the total quantity that meet its legacy criteria.

j. Describe and provide an illustration or photograph that depicts a double circuit 345 kV tangent structure that is also considered a legacy transmission steel tower.

k. Describe in more detail what "additional necessary structures" includes and excludes.

l. State the costs to replace wooden structures and to replace legacy transmission steel structures. If this does not equal the total cost listed, explain the remaining cost as well.

m. State the cost to replace "additional necessary structures."

n. What is CenterPoint's historical failure rate for non-wood transmission structures exposed to wind speeds which exceeded the Company's at-the-time design criteria?

o. What failure rate, or failure rate improvement, did CenterPoint assume for its new transmission structures in this SRP?

p. Please discuss the alternatives that were considered for the legacy transmission steel towers.

q. When did CenterPoint transition from an asset centric program-based approach?

r. Is the transition away from an asset centric program-based approach

ANSWER:

a. Approximately 651 structures.

b. 2 structures.

c. Confirmed.

d. CenterPoint Energy will have 0 energized wood structures on our transmission system if this measure is executed. There will be remaining wood structures on de-energized lines, however, these lines would likely be rebuilt with concrete or steel structures in the event they need to be energized in any permanent configuration.

e. There are currently 1267 total “Legacy Transmission Structures” identified in this resiliency measure (Internal Drawing Number 194-120-01) in service. All 1267 structures are on 345kV transmission circuits.

   Breakdown by Vintage

   1967 – 71
   1969 – 610
   1970 – 6
   1972 – 2
   1973 – 1
   1975 – 110
   1976 – 223
   1977 – 131
   1980 – 3
   1984 – 2
   1988 – 1
   1990 – 1
   1991 – 2
   1993 – 1
   1995 – 1
   1996 – 2
   1997 – 1
   1998 – 1
   1999 – 1
   2000 – 2
   2001 – 58
   2003 – 1
   2004 – 2
   2005 – 23
   2009 – 5
   2012 – 1
   2015 – 5

   Please note that while the vast majority of “legacy transmission steel towers” indicated for replacement in this SRP filing were installed in 1969, 8 of the 242 have previously been replaced.

   Breakdown of 242 legacy transmission structures to be replaced in this SRP filing by Vintage:

   1969 - 234
   1991 – 1 (Due to road relocation conflict)
   1996 – 2 (Due to railroad conflict)
   2009 – 5 (Due to thermal uprate project involving additional clearance requirements)

f. 17 legacy transmission steel towers were replaced due to damage sustained during the Derecho event in May 2024.

   Breakdown by Year, Vintage, and Voltage is below:

Replacement	Year	Vintage	Voltage
1	2024	1975	345
2	2024	1975	345
3	2024	1975	345
4	2024	1975	345
5	2024	2005	345
6	2024	1967	345
7	2024	2005	345
8	2024	1967	345
9	2024	2005	345
10	2024	1967	345
11	2024	2005	345
12	2024	1967	345
13	2024	2005	345
14	2024	1967	345
15	2024	1967	345
16	2024	1967	345
17	2024	1975	345

g. 5 total legacy steel towers were replaced in the past 10 years.

  a. 2016 – 1 Due to Highway Relocation Project.
  b. 2018 – 1 Due to new customer sub that required raising existing 345kV Circuit.
  c. 2022 – 1 Due to Relocation necessary for River Erosion.
  d. 2024 – 2 Due to clearance conflicts identified under NESC review.

h. "Legacy Transmission Steel Towers" identified in this resiliency measure have a specific Internal Drawing Number (194-120-01). These towers were modeled utilizing PLS-CADD line design software using 2023 NESC wind loading criteria (which was the current standard at the time of modeling) after the company experienced failures during the May 2024 Derecho event.

i. CenterPoint Energy made the decision to replace 242 of 1,267 "legacy transmission structures" in this SRP filing. The structures included in the filing were prioritized based on their proximity to the Gulf Coast and the expectation that additional transmission ROW would not be required. It was not feasible to replace all 1,267 legacy transmission towers in the timeline included in the

SRP filing (2026-2028). CenterPoint Energy intends to continue execution of this program in future resiliency plan filings.

j. Responsive Document "TIEC 1-10 j. Legacy Transmission Structure Image.docx" shows a legacy Double Circuit 345kV Tangent Steel Lattice Tower. The tower is 115' tall with a 27' base extension bringing the total height to 142'. This structure is one of the 242 being replaced in this SRP installed in 1969.

k. Included in "additional necessary structures" are required structure replacements to complete the scope of work on the identified projects. When replacing a transmission line structure(s), the new structure(s) must be designed to handle the necessary structural loads while maintaining the overall integrity of the line. However, if the new structure has significantly different mechanical properties, such as height, it can alter the structural load distribution along the line. This change can introduce higher forces or unbalanced tensions on adjacent structures, potentially requiring structure replacement. Detailed engineering design will determine the need to replace "additional necessary structures".

l. The total estimated project costs included in the Transmission System Hardening resiliency measure are approximately $1,468.0M.

   The estimates for the projects to replace legacy transmission steel structures total approximately $464.0M.

   The Transmission System Hardening resiliency measure includes approximately $585.6M in estimated project costs to replace wood transmission structures

   The Transmission System Hardening resiliency measure also includes approximately $418.4M in estimated costs associated with hardening projects to rebuild existing transmission infrastructure.

m. The costs included in the System Resiliency Plan filing do not distinguish between costs for individual structures, but rather, total project estimates. Based on preliminary engineering analysis, 30 additional structures have been identified outside of the 242 legacy structures identified for the projects referenced here.

n. CenterPoint Energy does not have the data to calculate the historical failure rate as requested.

   CenterPoint Energy Houston Electric has experienced approximately 83 wood transmission structure failures and approximately 28 non-wood transmission structure failures due to resiliency events dating back to Hurricane Ike in September of 2008.

o. CenterPoint Energy does not have the data to calculate the expected failure rate improvement. CenterPoint Energy has experienced no failures on transmission structures hardened in the last 10 years. For additional information regarding CenterPoint Energy hardening activities, see the storm hardening reports submitted by the Company in Project Nos. 38068 and 39339.

p. An alternative to replacing legacy transmission steel towers considered by CenterPoint Energy was to relocate the transmission circuits in question underground. This option was rejected as cost-prohibitive.

q. The transition from an asset centric program to project-based approach for use in developing its current System Resiliency Plan was adopted by CenterPoint Houston after the Company's System Resiliency Plan in Docket 56548 was filed in April 2024.

r. This transition is limited to resiliency plans.

SPONSOR:
David Mercado

RESPONSIVE DOCUMENTS:
TIEC-RFI1-10 j. Legacy Transmission Structure Image.pdf

History of Effectiveness. Transmission System Hardening projects have historically resulted in the modification of several transmission structures, incorporating updates that are designed to withstand higher wind loading associated with more extreme sustained wind speeds and gusts experienced in the Company's service area in more recent years. For example, experience during Hurricane Ike (2008) led to changing the standards for the transformer installation overhead design. The effects of this change were realized during Hurricane Beryl (2024) when pole failures associated with transformer equipment poles was greatly diminished in comparison.

With transmission system hardening implemented, the Company's system will be more able to withstand wind events and restore service to our customers more quickly after each type of extreme wind event like microbursts, high winds, and hurricanes. Because these transmission structures are designed for higher wind speeds, the structures will have a lower overall failure rate going forward.

Alternatives Considered. In reviewing the SRP, the Company, in collaboration with Guidehouse, evaluated three alternatives to the proposed replacement of wooden transmission structures with steel or concrete poles. First, the Company evaluated using single, stronger wooden poles, but they offer only offer a marginal increase in system resiliency. Further, new wooden H-frame are an obsolete Company design standard and are not viable options for resiliency. Second, an alternative to replacing poles is to relocate lines underground. This option is a viable option but was rejected as cost prohibitive for the entire existing 138kV transmission lines since the cost of undergrounding transmission lines is $20 million per mile, which is 5 to 10 times more costly than overhead lines and the cost to underground all distribution circuits is also cost prohibitive at 2 to 5 times the cost of overhead lines per mile. Third, the Company could reduce outage exposure on at-risk lines by constructing new lines to operate at the same or higher voltage along the same or new rights-of-way. These new lines would be built to a higher capacity line rating to meet future load growth. This alterative is being discussed but has not yet been adopted and accepted by ERCOT and other TSPs.

Measuring Efficacy. The Company transitioned from an asset centric program-based approach to a project-based approach using co-optimized sets of project types to address resiliency challenges specific to geographic regions in its service area. Using an array of best practice project type alternatives, different project types were selected in each area to enhance resiliency as well as structural hardening at a discrete asset level.

For substations and transmission assets these mitigations were primarily structural enhancements such as elevating substations above inundation levels or replacing existing transmission structures with designs capable of withstanding higher wind speeds. The discrete nature of these projects results in efficacy measurements which are more asset centric.

Accordingly, the Transmission System Hardening Resiliency Measure Measurements of Efficacy are:

1. Percentage of planned asset installations complete by County;
2. Percentage of resilient power delivery asset failures projected to fail during a Resiliency Event; and
3. Percentage of resilient power delivery asset failures occurring during a Resiliency Event.

Section 5.1.5.7. 69kV Conversion Projects (RM-7)

Description. The 69kV Conversion Projects Resiliency Measure will upgrade the Company's 69kV transmission circuits by rebuilding and reconductoring the transmission circuits to 138kV, thus allowing for greater switching options. The 69kV Conversion Projects Resiliency Measure will upgrade approximately 462 structures during the three-year period.

The program has several purposes: (1) remove aged 69kV transformers and replace structures that do not meet the Company's current wind loading design standard; (2) eliminate the need to maintain 69kV spare equipment; (3) provide additional 138kV paths into downtown Houston to relieve high loading on existing 138kV circuits; and (4) further enhance grid resiliency by increasing line ratings via voltage conversion. For these conversions, the Company proposes to replace wood poles with concrete or metal monopoles and replace conductor, insulators, and associated hardware. The steel or concrete structures used to upgrade the 69kV circuits will meet the Company's current design standard for transmission structures, and the upgraded circuits will be designed to meet the current applicable NESC standards.

A complete system outage is not required for installation, though segment outages may be required. This Resiliency Measure will work with similar existing system hardening measures as well as with other Resiliency Measures included in this Plan.

Relevant Details. The following figure summarizes the 69kV Conversion Projects Resiliency Measure.

Figure SRP-48
69kV Conversion Projects Resiliency Measure (RM-7)

69kV Conversion Projects Resiliency Measure (RM-7)	
Estimated capital costs from 2026-2028	$369.3 million
Estimated incremental O&M expense from 2026 – 2028	None
Estimated overall project duration	2026-2028 (approximately 93% complete, but extends through 2029)
Net salvage value	Salvage Value: None Removal costs: Are included as part of capital project costs
Resiliency Event(s) addressed	Extreme wind events • Microburst • High wind • Tornado • Hurricane Extreme temperature event • Heat • Freeze Wildfires
Anticipated benefits	Improved structural integrity Higher wind loading capabilities Mitigate loss of transmission during extreme weather events by providing multiple paths of redundancy Capacity for future load growth
Other relevant details	Availability of material and personnel may impact cost estimates Projects may undergo ERCOT review

Prioritization. The Company has identified the 69kV transmission circuits that will be upgraded to 138kV and will commence the design and engineering phase, place work orders, and dedicate appropriate resources for the work. The Company considered factors such as age of the 69kV circuit, geographic location, history of extreme wind-related and temperature-related outages, customer load, etc. to determine the 69kV transmission circuits that will be upgraded.

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PUC DOCKET NO. 57579
SOAH DOCKET NO. 473-25-11558

HOUSTON COALITION OF CITIES
REQUEST NO.: HCC-RFI04-80

QUESTION:

For RM-7: Provide the age and condition of the 462 structures to be replaced.

ANSWER:

The metric of approximately 462 structures represents an initial estimate of new structures that will be installed on 69kV Conversion projects. This does not reflect an exact number of existing structures that would be replaced on RM-7 69kV Conversion projects. CenterPoint Houston anticipates approximately 167 of the originally identified 462 structures to be replaced prior to the beginning of the SRP. The estimated costs for the projects replacing approximately 167 structures were not included in the SRP filing. The exact number of structures that will be replaced on RM-7 will not be known until detailed engineering is complete for each identified project.

Based on preliminary estimates to-date, approximately 286 Structures will be removed on projects included in RM-7. This structure replacement count is subject to change pending the outcome of detailed engineering. The 286 structures identified for removal in preliminary project estimates included in RM-7 have an average install year of 1977.

Please see below for breakdown of approximate age of structure, by decade.

1940's – 33
1950's – 63
1960's – 59
1970's – 22
1980's – 10
1990's – 50
2000's – 18
2010's – 24
2020's – 7

CenterPoint Houston maintains these Transmission structures on the Transmission line inspection and rehabilitation program discussed in response to HCC RFP 4-27.

SPONSOR:
Eric Easton and David Mercado

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
PUC DOCKET NO. 57579
SOAH DOCKET NO. 473-25-11558

TEXAS INDUSTRIAL ENERGY CONSUMERS
REQUEST NO.: TIEC-RFI01-11

QUESTION:

Referring to the 69kV Conversion Projects Resiliency Measure in the SRP at pages 92-95:

a. State the approximate circuit miles proposed for conversion.

b. Are new 138 kV transformers required? If yes, state the quantity.

c. State which of the proposed conversions are on circuits with NERC violations to be resolved.

d. State the NERC requirements that require CenterPoint to have “greater switching options.”

e. Do the conversions allow CenterPoint to meet minimum NERC requirements, or do these options go above and beyond NERC requirements?

f. State CenterPoint’s total quantity of 69 kV wooden structures.

g. State the quantity of 69 kV wooden structures that will be replaced with this measure.

h. Is the high loading on existing 138 kV circuits a NERC violation?

i. State the method in 16 TAC § 25.62 under which this measure is being implemented.

j. Was hardening the 69 kV system in its current ROW considered as an alternative? If no, please explain why it was not considered. If yes, provide the cost to harden the circuits proposed for conversion in the SRP.

ANSWER:

a. Approximately 100 circuit miles of existing 69kV will be converted to 138kv or de-energized. Approximately 55 circuits miles will be converted to 138kV and approximately 45 circuit miles will be de-energized.

b. Yes, Qty. (14) 138kV Transformers are expected to be required.

c. CenterPoint Energy recently completed the 2024 Annual Transmission Planning Assessment as required by TPL-001-5.1. The results show two concerns (one thermal loading issues on 69 kV HOC – Garden ckt 19 and low voltages at Dunlavy and Hyde Park 69 kV buses) during NERC P6 analysis. These are not to be considered violations because NERC P6 allows for consequential load loss which is the corrective action plan for these NERC P6 concerns. No other NERC Planning Events resulted in any of the 69 kV circuits to be converted to require a corrective action plan. The planned conversions will resolve the NERC P6 concerns identified in the 2024 Annual Transmission Planning Assessment.

d. There are no NERC requirements that require CenterPoint Energy to have “greater switching options”. The NERC TPL-001-5.1 standard requires transmission planners to develop corrective action plans for planning events where analysis indicates a potential inability of the transmission system to meet the performance requirements for the study base cases. The greater switching options comment is related to creating greater operational flexibility. Planning analyses are limited to limited operational scenarios; therefore, situations arise during real time operations where switching of loads from one distribution substation to another distribution substation could be limited by the limited available capacity on the 69 kV system serving those distribution substations. After converting those distribution substations currently served by the 69 kV system to 138 kV, there should be significantly more transmission capacity to allow load switching.

e. CenterPoint Energy will design the future system to meet NERC Reliability Standards, ERCOT Planning Criteria contained in ERCOT Planning Guide Section 4, and CenterPoint Energy Transmission Planning criteria. Several of the ERCOT Planning Criteria do 'raise the bar' in comparison to the NERC Reliability Standards. See Planning Guide Section 4 Table 1 ERCOT-specific Reliability Performance Criteria.

f. Approximately 176 Structures.

g. Approximately 176 Structures will be replaced or removed from the transmission system.

h. CenterPoint Energy recently completed the 2024 Annual Transmission Planning Assessment as required by TPL-001-5.1. The results show thermal loading concerns on multiple 138 kV underground cables around the Downtown Houston area for multiple planning events. The corrective action plans for these loading concerns involve generation redispatch; therefore, it is not a NERC violation. The planned conversions in the Downtown Houston area are being designed to create two new west to east 138 kV paths that will ultimately resolve these power flow concerns in the Downtown Houston area.

i. This measure is being implemented under methods (A) hardening electric transmission and distribution facilities; and (B) modernizing electric transmission and distribution facilities.

j. Hardening of the existing 69kV system was not considered as an alternative. CenterPoint Energy's new transmission design standards are for the 138kV and 345kV voltage levels. Modernizing the 69kV system would require building to current 138kV transmission design specifications.

SPONSOR:
David Mercado

RESPONSIVE DOCUMENTS:
None

Alternatives Considered. In reviewing the SRP, the Company, in collaboration with Guidehouse, evaluated two alternatives to the proposed conversion of 69kV transmission lines to operate at 138kV.

One alternative to upgrading 69kV transmission circuits is to relocate 69kV lines underground. This option was rejected as cost prohibitive since the cost of underground lines is 5 to 10 times more than the cost of overhead lines and would also prolong the Company's conversion of its 69kV network.

The other alternative is to reduce outage exposure on at-risk 69kV lines by relocating lines along new ROWs with less exposure to resiliency events. However, this option was eliminated from consideration because it would prolong the Company's conversion to its 69kV network. Further, this option was rejected due to added cost, desire to retain and maximize use of existing ROWs, and limited opportunities for relocation.

Measuring Efficacy. The Company transitioned from an asset centric program-based approach to a project-based approach using co-optimized sets of project types to address resiliency challenges specific to geographic regions in its service area. Using an array of best practice project type alternatives, different project types were selected in each area to enhance resiliency as well as structural hardening at a discrete asset level.

For substations and transmission assets these mitigations were primarily structural enhancements such as elevating substations above inundation levels or replacing existing transmission structures with designs capable of withstanding higher wind speeds. The discrete nature of these projects results in efficacy measurements which are more asset centric.

Accordingly, the 69kV Conversion Project Resiliency Measure Measurements of Efficacy are:

1. Percentage of planned asset installations complete by County;
2. Percentage of resilient power delivery asset failures projected to fail during a Resiliency Event; and
3. Percentage of resilient power delivery asset failures occurring during a Resiliency Event.

Section 5.1.5.8. S90 Tower Replacements (RM-8)

Description. The S90 Tower Replacements Resiliency Measure will replace 90-degree single-circuit steel lattice towers (S90 towers) installed between 1968 and 1982 on 345kV transmission circuits. These S90 towers will be replaced with steel poles that are engineered to meet the more stringent NESC C2-2023 Article 250 extreme wind loading conditions.

The S90 Towers Replacement Resiliency Measure is anticipated to replace 37 S90 towers, twenty-two S90 towers being replaced in 2026, ten S90 towers being replaced in 2027, and five S90 towers being replaced in 2028. Upon completion of the 37 identified towers, there will be no remaining S90 towers installed in the Company's transmission system.

A complete system outage is not required for installation, though segment outages may be. This Resiliency Measure will work in conjunction with similar existing system hardening measures as well as with other Resiliency Measures included in this SRP.

The following figure illustrates an example of lattice tower structures (left) to be replaced with new 90-degree steel towers (right) through the S90 Tower Replacement Resiliency Measure.

Figure SRP-50
Potential S90 Tower Replacements

Relevant Details. The following figure summarizes the S90 Towers Replacements Resiliency Measure.

Figure SRP-51
S90 Towers Replacements Resiliency Measure (RM-8)

S90 Towers Replacements Resiliency Measure (RM-8)	
Estimated capital costs from 2026-2028	$118.4 million
Estimated incremental O&M expense from 2026 – 2028	None
Estimated overall project duration	2026- 2028 (100% S90 towers replaced)
Net salvage value	Salvage Value: None Removal costs: Are included as part of capital project costs
Resiliency Event(s) addressed	Extreme wind events • Microburst • High wind • Tornado • Hurricane Extreme Temperature Events • Freeze Wildfires
Anticipated benefits	Improved structural integrity Higher wind loading capabilities Reduce the frequency and number of customers impacted by outages Reduce total outage times Reduce system restoration costs
Other relevant details	Availability of material and personnel may impact cost estimates A complete system outage or segment outage is not required for replacement, though the work will be done in conjunction with other hardening efforts

Prioritization. The Company has identified towers on the Company's transmission system that need replacing, commence the design and engineering phase, place work orders, and dedicate appropriate resources for the work. The Company considered factors such as geographic location, history of extreme wind-related outages, inspection of structures, structure loading, etc. to determine which S90 towers will be replaced.

Based on these considerations and underlying data analyses, as shown in Figure SRP-52 below, the Company determined at the polygon level where it anticipates implementing this measure.

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PUC DOCKET NO. 57579
SOAH DOCKET NO. 473-25-11558

HOUSTON COALITION OF CITIES
REQUEST NO.: HCC-RFI04-57

QUESTION:

For RM-8: Provide electronic data for each of the 37 towers showing:

a. the structure type;

b. the structure age;

c. failure probability;

d. the replacement structure type; and

e. the cost.

ANSWER:

The answers below will reflect that, upon further review, CenterPoint Houston has identified 38 S90 towers for replacement in this resiliency measure, contrary to the 37 S90 towers referenced in the SRP filing.

a. All existing towers identified for replacement in RM-8 are steel lattice towers.

b. The approximate average installation year of structures to be replaced on RM-8 is 1974.

CenterPoint Houston tracks the installation of the foundation as a metric to identify the age of the structure in question. For example, if a steel tower with a foundation originally installed in 1950 had an additional extension installed in 2020 which required a new foundation, but the original tower was not replaced. The age of the structure would be updated to reflect the new foundation installed in 2020.

Please see below for breakdown of approximate age of tower, by decade.

1960's – 15
1970's – 16
1980's – 6
1990's – 0
2000's – 1
2010's – 0
2020's – 0

c. An independent third-party consultant (Guidehouse) has calculated failure rates for RM-8 that were presented in Section 4.2.1 (Hurricane Risk Profile) of Exhibit ELS-2, beginning at PDF page 1193. Figure 4-12 of Exhibit ELS-2 (PDF page 1202) presents the annual probability of occurrence for wind speeds for 2030. The probability that wind speeds are expected to exceed the design threshold for the towers included for replacement in this resiliency measure is 0.2% annually.

d. Detailed engineering is still ongoing; however, CenterPoint Houston expects all S90 towers identified for replacement in RM-8 will be replaced with steel monopole structures.

e. Please see response to HCC RFP 4-25 (d).

SPONSOR:
Eric Easton and David Mercado

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
PUC DOCKET NO. 57579
SOAH DOCKET NO. 473-25-11558

TEXAS INDUSTRIAL ENERGY CONSUMERS
REQUEST NO.: TIEC-RFI01-12

QUESTION:

Referring to the S90 Tower Replacement Resiliency Measure in the SRP at pages 96-99.

a. State the quantity of S90 towers to be replaced that directly support conductors that cross major highways.

b. What is CenterPoint's historical failure rate for S90 towers exposed to wind speeds which exceeded the Company's at-the-time design criteria?

c. State the quantity of S90 towers that have been replaced in the past 10 years due to a resiliency event, by year, by vintage, by voltage, and by resiliency event.

d. State the quantity of S90 towers that have been replaced in the past 10 years for reasons other than a resiliency event, by year, by vintage, and by voltage.

e. Provide the project number and/or other locations in which the alternative of building new lines to a higher capacity are being discussed by ERCOT and other TSPs.

ANSWER:

a. No S90 towers directly support conductor that crosses a major highway.

b. The only historical failure of an S90 tower occurred in 1969 while stringing conductor on the tower. CenterPoint Energy has not yet experienced a failure on an S90 tower due to a wind event.

c. No S90 towers have been replaced as the results of a resiliency event in the last 10 years.

d. 36 S90 towers have been replaced in the past 10 years, 8 additional S90 towers are expected to be replaced in 2025.

Replacement	Year	Vintage	Voltage
1	2016	1982	345
2	2020	1969	345
3	2021	1981	345
4	2021	1974	345
5	2022	1977	345
6	2022	1982	345
7	2022	1974	345

8	2022	1974	345
9	2022	1974	345
10	2022	1974	345
11	2022	1969	345
12	2022	1969	345
13	2022	1969	138
14	2022	1974	345
15	2022	1974	345
16	2022	1974	345
17	2022	1980	345
18	2022	1980	345
19	2022	1980	345
20	2022	1980	345
21	2022	1969	345
22	2023	1965	138
23	2023	1969	345
24	2023	1969	345
25	2023	1976	345
26	2023	1976	345
27	2023	1976	345
28	2023	1976	345
29	2023	1976	345
30	2023	1980	345
31	2023	1980	345
32	2023	1975	345

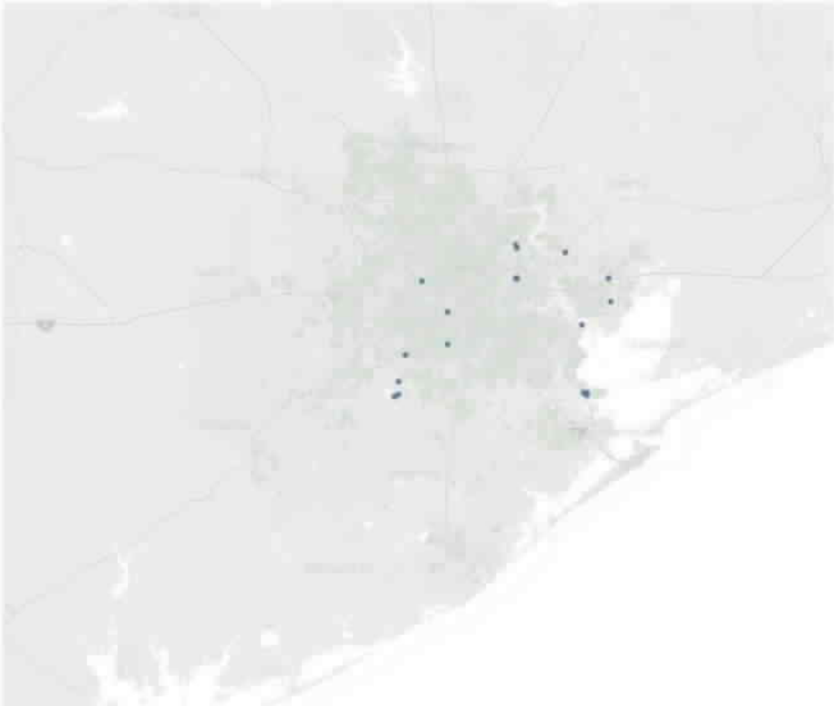
33	2023	1975	345
34	2023	1975	345
35	2023	1975	345
36	2024	1976	345
37	Expected 2025	1969	345
38	Expected 2025	1969	345
39	Expected 2025	1975	345
40	Expected 2025	1975	345
41	Expected 2025	1975	345
42	Expected 2025	1975	345
43	Expected 2025	1975	345
44	Expected 2025	1975	345

e. The following language was inadvertently included in the discussion of S90 Tower Replacement alternatives and does not represent a potential alternative solution to the S90 tower replacement resiliency measure: "Another alternative that CenterPoint Houston considered is constructing new transmission lines to operate at the same or higher voltage (along the same or new rights-of-way). These new lines would be built to a higher capacity line rating to meet future load growth. This alternative is being discussed but has not yet been adopted/accepted by ERCOT and other TSPs."

SPONSOR:
David Mercado

RESPONSIVE DOCUMENTS:
None

Figure SRP-52
S90 Tower Replacements Project Map



History of Effectiveness. Transmission system hardening projects have historically resulted in the addition of several transmission structures, incorporating updates capable of higher wind loading that can withstand the more extreme wind speeds seen in recent years. An improvement of this program includes the restoration of service to customers quickly after events like microbursts, high winds, and hurricanes as the core structures will be strengthened and improved with these high impact, low frequency events causing less damage to transmission structures.

Alternatives Considered. In reviewing the SRP, the Company, in collaboration with Guidehouse, evaluated two alternatives to the proposed replacement of S90 towers. One alternative to replacing lattice towers is to relocate overhead lines underground. This option was rejected as cost prohibitive (as seen in the pole replacement program) for almost all transmission lines constructed with towers, as relocating 345kV tower lines is prohibitively expensive.

Another alternative that the Company considered is constructing new transmission lines to operate at the same or higher voltage (along the same or new rights-of-way). These new lines would be built to a higher capacity line rating to meet future load growth. This alternative is being discussed but has not yet been adopted/accepted by ERCOT and other TSPs.

Measuring Efficacy. The Company transitioned from an asset centric program-based approach to a project-based approach using co-optimized sets of project types to address resiliency challenges specific to geographic regions in its service area. Using an array of best practice project type alternatives, different project types were selected in each area to enhance resiliency as well as structural hardening at a discrete asset level.

For substations and transmission assets these mitigations were primarily structural enhancements such as elevating substations above inundation levels or replacing existing transmission structures with designs capable of withstanding higher wind speeds. The discrete nature of these projects results in efficacy measurements which are more asset centric.

Accordingly, the S90 Towers Replacements Resiliency Measure Measurements of Efficacy are:

1. Percentage of planned asset installations complete by County;
2. Percentage of resilient power delivery asset failures projected to fail during a Resiliency Event; and
3. Percentage of resilient power delivery asset failures occurring during a Resiliency Event.

Section 5.1.5.9. Coastal Resiliency Upgrades[18] (RM-9)

Description. The Coastal Resiliency Upgrades Resiliency Measure will construct additional transmission circuits to certain coastal portions of the Company's service area to allow greater loading capabilities and switching flexibility so that customers may still receive service even if a circuit is compromised. Current 69kV transmission circuits will be upgraded to 138kV, and new underwater cables will be installed. Additionally, a transmission line will be re-routed, and a new transmission circuit will be constructed.

A complete system outage is not required for installation, though segment outages may be required. This Resiliency Measure will work with similar existing system hardening measures as well as with other Resiliency Measures included in this SRP.

The following figure illustrates an example of current coastal towers to be replicated through the Coastal Resiliency Upgrades Resiliency Measure.

[18] The Company is providing a separate, confidentially filed portion of the Company's System Resiliency Plan that provides additional specificity on the Coastal Resiliency Upgrades Resiliency Measure.

Figure SRP-53
Coastal Tower

Relevant Details. The following figure summarizes the Coastal Resiliency Upgrades Resiliency Measure.

Figure SRP-54
Coastal Resiliency Upgrades Resiliency Measure (RM-9)

Coastal Resiliency Upgrades Resiliency Measure (RM-9)	
Estimated capital costs from 2026-2028	$177.4 million
Estimated incremental O&M expense from 2026 – 2028	$750,000
Estimated overall project duration	2026-2028 (100% complete at one location; approximately 3% complete at second location, but extends through 2030)
Net salvage value	Salvage Value: None Removal costs: Are included as part of capital project costs
Resiliency Event(s) addressed	Extreme wind events • Microburst • High wind • Tornado • Hurricane Extreme temperature event • Heat • Freeze Wildfires Third-party damage

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REQUEST NO.: TIEC-RFI01-13

QUESTION:

Referring the Coastal Resiliency Upgrades Resiliency Measure in the SRP at pages 99-102:

a. State the reason that the 69 kV to 138 kV conversion in this measure was not included in the 69 kV Conversion Projects measure.

b. Are there existing NERC violations to be resolved? If yes, provide the evidence supporting this.

c. Does the measure allow CenterPoint to meet minimum NERC requirements, or does this measure go above and beyond NERC requirements?

d. Provide the cost to execute the following projects in this measure: (1) 69 kV to 138 kV conversion; (2) Installation of new underwater cable; (3) Re-routing of transmission line; and (4) Construction of new transmission circuit. If the total of the projects does not equal the total for this measure, please state the remaining cost and its purpose.

e. Has this project been proposed for ERCOT RTP? If yes, why is this project not moving forward there? If no, please explain the reason it has not been proposed.

f. Referring to Exhibit ELS-2, page 108, this project is described as mitigating low voltages, overloads, and power quality concerns – as such, explain why CenterPoint does not consider this a reliability project.

ANSWER:

a. The referenced circuit was constructed to 69kV design criteria. However, it is currently de-energized. Therefore, it was not included in the 69kV Conversion Projects Resiliency Measure.

b. CenterPoint Energy recently completed the 2024 Annual Transmission Planning Assessment as required by TPL-001-5.1. The results show numerous thermal loading and low voltage concerns during NERC P6 analysis in the Galveston area. These are not to be considered violations because NERC P6 allows for consequential load loss which is the corrective action plan for these NERC P6 concerns.

c. CenterPoint Energy will design the future system to meet NERC Reliability Standards, ERCOT Planning Criteria contained in ERCOT Planning Guide Section 4, and CenterPoint Energy Transmission Planning criteria. Several of the ERCOT Planning Criteria do 'raise the bar' in comparison to the NERC Reliability Standards. See Planning Guide Section 4 Table 1 ERCOT-specific Reliability Performance Criteria.

d.
   1. 69kV to 138kV conversion – $144.6M
   2. Installation of new underwater cable - $24.5M
   3. Re-routing of transmission line; and 4) Construction of new transmission circuit combined $9M in engineering and other preconstruction activities. This does not include construction activities which CenterPoint currently expects to begin in 2029 and be filed in a future resiliency plan.

   Total – $178.1M

e. No, ERCOT did not identify these projects as either a reliability or economic project in the 2024

RTP. ERCOT did not see the need for either project during RTP analysis.

f. The Coastal Resiliency Measure projects mitigate potential low voltage, overload, and power quality concerns in the occurrence of a system outage due to a Resiliency Event. ERCOT did not identify these projects as either a reliability or economic project in the 2024 RTP.

SPONSOR:
David Mercado

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
PUC DOCKET NO. 57579
SOAH DOCKET NO. 473-25-11558

HOUSTON COALITION OF CITIES
REQUEST NO.: HCC-RFI04-54

QUESTION:

For RM-9: For the new transmission circuit, please provide:

a. The circuit identity;

b. The capacity;

c. The justification for the new circuit;

d. The length;

e. The cost;

f. The projected peak loading after load transfer;

g. If it is replacing an existing circuit or if it is completely new construction

h. The circuit name, age, condition, design type, capacity, and peak loading of the circuit being replaced, if any;

i. Provide the load flow analysis including contingencies; and

j. Please provide information about considerations made for salt contamination and if it will be mitigated at the higher voltage.

ANSWER:

a.

New 138kV Transmission Circuit from Cedar Bayou Plant Substation to Mont Belvieu Substation. The Transmission circuit identifier has not yet been assigned.

b.

The projects included in RM-9 are still undergoing study by CenterPoint Energy's Transmission Planning department. The capacity of the new circuit will not be available until completion of Transmission Planning Study Reports. While the Transmission Planning Study and detailed engineering are not yet complete, any new conductor will likely have a normal rating of 854MVA and an emergency rating of 908MVA.

c.

The intent of the Spillman Island Replacement project is to avoid a catastrophic failure of structures on Spillman Island in a resiliency event which could result in severe loading and voltage concerns if not proactively addressed. The new 138 kV transmission line is expected to be needed as the two 138 kV circuits across Spillman Island will be de-energized, but reliability needs indicated another 138 kV circuit out of Cedar Bayou would be needed.

d.

Approximately 8.9miles.

e.

$9M in estimated preconstruction activities (engineering, permitting, etc.) is included in this SRP filing in RM-9 for the new transmission line (discussed in HCC RFI 4-54) and re-routed transmission line (discussed in HCC RFI 4-53) which are included in the same project.

f.

The projects included in RM-9 are still undergoing study by CenterPoint Energy's Transmission Planning department. Projected peak loading data will not be available until completion of Transmission Planning Study Reports.

g.

Based on preliminary project scoping, the new circuit referenced will include approximately 5.9 miles of new construction and approximately 3.0 miles of replacement of de-energized circuits.

h.

Circuit Name – 43Z1-1
Age – Structures on de-energized circuit 43Z-1 date back to approximately 1962.
Condition – De-energized.
Design Type – Overhead, 1-397ACSR conductor per phase.
Capacity - Not Applicable, this circuit is currently de-energized.
Peak Loading - Not Applicable, this circuit is currently de-energized.

Circuit Name – 88Z1-1
Age – Structures on de-energized circuit 88Z-1 date back to approximately 1971.
Condition – De-energized.
Design Type – Overhead, 2-795ACSR conductor per phase.
Capacity - Not Applicable, this circuit is currently de-energized.
Peak Loading - Not Applicable, this circuit is currently de-energized.

i.

The projects included in RM-9 are still undergoing study by CenterPoint Energy's Transmission Planning department. Load flow analysis, including contingencies, will not be available until completion of Transmission Planning Study Reports.

j.

The new circuit referenced in RM-9 will be constructed at 138kV, it is not an existing circuit operating at a lower voltage. In alignment with CenterPoint Houston's Transmission design criteria in coastal areas, high-leakage insulators will be used to mitigate salt contamination.

SPONSOR:
Eric Easton and David Mercado

RESPONSIVE DOCUMENTS:
None

EXHIBIT 1

TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN

Transmission and distribution system resiliency plan

CenterPoint Energy
Houston Electric, LLC

CenterPoint Energy

Energy for what matters most

Resiliency Measure	Description	Estimated costs	Estimated 3 Year CMI	Resiliency Event(s) Impact to be Mitigated	Anticipated Customer Benefits
	circuits to 138kV, install new underwater cables, re-route existing transmission line, and construct a new transmission circuit			Extreme temperature event • Heat • Freeze Wildfires Third-party damage	Capacity for future load growth Reduce the frequency and number of customers impacted by outages Reduce total outage times Reduce system restoration cost
Extreme Water					
Substation Flood Control (RM-10)	Elevate and mitigate flood risk at 12 substations in total	Capital: $43.8 million Incremental O&M: None	3.9 million	High water or flooding events	Reduction of risk of equipment failure or mis-operation Mitigate the impact of flooding or highwater events on equipment Enhance substation performance during flooding events Reduce the frequency and number of customers impacted by outages Reduce total outage time

Resiliency Measure	Description	Estimated costs	Estimated 3 Year CMI	Resiliency Event(s) Impact to be Mitigated	Anticipated Customer Benefits
Control Center Flood Control (RM-11)	Construct a protective flood wall at the Company's back-up control center	Capital: $7.0 million Incremental O&M: None	2.5 million	High water or flooding events	Mitigation of damage or inoperability of back-up control center due to flooding or high-water events Enhance control center performance during flooding events Reduce the frequency and number of customers impacted by outages Reduce total outage times
Major Underground Control and Monitoring System (MUCAMS) (RM-12)	Installed to monitor vault and pad-mounted equipment in dedicated underground areas, 318 sites in total	Capital: $10.8 million Incremental O&M: None	0.6 million	Extreme weather events • Flooding • High water Extreme Wind • Hurricanes Extreme Temperature Wildfires	Knowledge of inoperability of automated equipment in the field. Ability to determine status of critical customers remotely Reduce total outage times Reduce truck rolls
Mobile Substation (RM-13)	Purchase of 6 mobile substations for the 3-year period	Capital: $30.0 million	3.9 million	Flooding or high-water events Extreme Wind	Enhance substation performance during flooding events

Resiliency Measure	Description	Estimated costs	Estimated 3 Year CMI	Resiliency Event(s) Impact to be Mitigated	Anticipated Customer Benefits
		Incremental O&M: None		• Tornado • Hurricane Extreme Temperature • Drought • Freeze Wildfires Physical Attack • Physical Attack • Theft	Reduce the frequency and number of customers impacted by outages Reduce total outage times
Extreme Temperature (Freeze)					
Anti-Galloping Technologies (RM-14)	Installation of air flow spoilers to mitigate the accumulation of ice and lift from air flowing under and install sensors to detect ice accumulation	Capital: $14.0 Incremental O&M: $1.0 million	5.3 million	Extreme Weather Event Extreme Temperature (Freeze) events Extreme Wind events • High Wind • Derecho • Hurricane	Reduction of risk of equipment failure or mis-operation Reduce the frequency and number of customers impacted by outages Reduce total outage time
Load Shed IGSD (RM-15)	Install 36 IGSDs to support load shed events	Capital: $4.5 million Incremental O&M: $100,000	N/A	Extreme weather events Extreme Temperature • Heat • Freeze Wildfires	Faster restoration Reduce time and expense associated with dispatching field personnel to restore

History of Effectiveness. MUCAMS has resulted in a more accurate location determination of faults on underground cables and has resulted in fewer sustained outages and reduced the time and expense associated with the Company dispatching personnel to restore underground outages. The capability of MUCAMS to significantly reduce the number of sustained customer interruptions during severe storms and other extreme weather events at relatively low cost is high. The installation of MUCAMS is consistent with practices deployed at other utilities based on peer utility benchmarking survey results.

Alternatives Considered. In reviewing the SRP, the Company, in collaboration with Guidehouse, evaluated the following two alternatives to MUCAMS fiber optic installation: continuing with less sophisticated copper communications and the installation of new radio frequency radios to improve situational awareness within the major underground distribution system.

First, in lieu of fiber optics installation, the Company could continue to install copper conductor for communication in locations where the MUCAMS could offer coordination with other devices. Copper conductor offers similar connectivity (although not as great a distance is offered) and provide the same functionality as the existing system for most faults but have reduced communications information and visibility from the control centers, and therefore the Company eliminated this from consideration as a preferred alternative.

Second, constructing new radio frequency communications to improve situational awareness could be a viable alternative on the major underground distribution system. This solution is also typically far less reliable than its copper wire counterpart as it requires line of site communication and the use of an antenna which would require mounting above ground. Further, this would likely result in greater communications outages on the newly built communications platform as there could be interference issues, antenna issues, connection issues, and/or radio issues.

Measuring Efficacy. Distribution system mitigations are focused on areas of higher predicted damage concentration to maximize overall system restoration efficiency. These mitigations, when optimized at the project level, require the consideration of interdependencies between mitigations contemplated for the same distribution feeder/area. For example, strategic undergrounding changes the needs for automation and vegetation management frequency. As a result of using the co-optimized project-based approach, the Company will use efficacy measures which capture the complementary nature of project-based system resiliency plans. This approach is consistent with industry best practice and measures success as a product of regional performance as opposed to individual asset performance.

The MUCAMS Resiliency Measure Measurements of Efficacy are:

1. Percentage of planned asset installations complete by County;
2. Percentage change in predicted damage for areas of higher damage concentration based on the event type;
3. Normalized total system restoration performance during Resiliency Events pre and post completion of mitigation projects based on the event type; and
4. Normalized restoration performance of predicted high damage concentration area restoration performance compared to Normalized total system restoration performance pre and post completion of mitigation projects during Resiliency Events based on the event type.

Section 5.2.5.4. Mobile Substations (RM-13)

Description. The mobile substation is a transformer and switchgear on a two-trailer package that is used to restore power to customers after a high impact, low frequency event. These units are stored within service centers distributed throughout the service territory and can be deployed quickly (4–5-day timeframe typically) to mitigate damage and restore power to customers. These can and have been used in situations where flooding has caused significant damage to critical equipment within the substation (transformers, switchgear, control house, etc.) and require extended timeframes to replace equipment (months to years). These mobile substations will be connected to the high side voltage (dual voltage capable units for either 69kV or 138kV) and interconnect to circuits on the low side (dual voltage capable units for either 12kV or 35kV) completely autonomous of the existing substation.

Relevant Details. The following figure summarizes the Mobile Substation Resiliency Measure.

Figure SRP-73
Mobile Substation Resiliency Measure (RM-13)

Mobile Substation Resiliency Measure (RM-13)	
Estimated capital costs from 2026-2028	$30.0 million
Estimated incremental O&M expense from 2026 – 2028	None
Estimated overall project duration	2026-2028 (but is ongoing thereafter)
Net salvage value	None
Resiliency Event(s) addressed	Flooding or high-water events Extreme Wind • Tornado • Hurricane

Mobile Substation Resiliency Measure (RM-13)	
	Extreme Temperature • Heat • Freeze • Wildfires Physical Attack • Physical Attack • Theft
Anticipated benefits	Enhance substation performance during flooding events Reduce the frequency and number of customers impacted by outages Reduce total outage times
Other relevant details	Availability of material and personnel may impact cost estimates

Prioritization. In determining the mobile substation storage locations, the Company will consider factors such as recent floodplains, failure replacement locations, and overall distribution planning needs. Additionally, the Company will consider the number of customers served and whether circuits attached to the substation serve critical load public safety customers.

History of Effectiveness. Mobile substations have resulted in significantly faster restoration times post flooding events as evidenced by the Memorial Substation flood that took years to complete restoration after the flooding from Hurricane Harvey in 2017. The mobile substation was placed near the substation, and allowed for customers to be fed in days, even before the water had fully subsided. This benefitted several thousand customers as the Company worked to restore the substation over the next few years. The Company will also be able to use these mobile substations when a failure of a transformer or other work within the substations needs to occur.

Alternatives Considered. In reviewing the SRP, the Company, in collaboration with Guidehouse, evaluated two alternatives to mobile substations.

First, installing secondary transformers at substations to allow for additional load and switching capabilities along multiple circuits to be able to pick up load from circuits that are being fed from a compromised substation. This is a very expensive and complex process, however, and is not feasible in a timely fashion. It also does not make substations fully resilient (extreme water issues remain even with additional transformer).

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
PUC DOCKET NO. 57579
SOAH DOCKET NO. 473-25-11558

TEXAS INDUSTRIAL ENERGY CONSUMERS
REQUEST NO.: TIEC-RFI01-14

QUESTION:

Referring to the Mobile Substation Resiliency Measure in the SRP at pages 124-126:

a. Provide a table in “live” Excel format that lists all mobile substations in CenterPoint’s current inventory, along with the following information: MVA, input and output voltage configuration(s), asset age, and cost functionalization. If any are expected to be retired this year, please identify them.

b. Provide a table in “live” Excel format that lists all mobile substations that are on-order or planned to be ordered in 2025 (excluding this SRP), along with the following information: MVA, input and output voltage configuration(s), and cost functionalization.

c. Provide a table in “live” Excel format that lists the six mobile substations proposed in this SRP, along with the following information: MVA, input and output voltage configuration(s), and cost functionalization.

d. In the past 10 years, state the maximum quantity of mobile substations that were simultaneously actively supplying customers during a resiliency event. How many of the quantity listed were deployed for reasons other than the resiliency event?

e. For subpart (d), provide the date and resiliency event.

f. In the past 10 years, has CenterPoint experienced a resiliency event situation in which all of its mobile substations were deployed and it would have benefitted from additional mobile substations? If yes, please describe the resiliency event and provide relevant information that substantiates that additional mobile substation(s) would have provided incremental benefit.

g. Describe how CenterPoint will distinguish its SRP mobile substations from its current inventory.

h. In determining the type and quantity of mobile substations necessary, did CenterPoint perform any benchmarking with other utilities? If yes, please provide the benchmarking analysis.

ANSWER:

a. The company has 5 Mobile Substations. Please see TIEC RFI01-14a-b Attachment 1.

b. The company has 2 mobile substations on order in 2025. Please see TIEC RFI01-14a-b Attachment 1.

c. Please see attachment TIEC RFI01-14c Attachment 1.

d. In the past ten years, the Company has not deployed more than one mobile substation simultaneously to respond to a resiliency event. The Company has used mobile substations to provide service to customers five times during a resiliency event. (See subpart (e), below.) In one of those five instances, the Sealy microburst in May 2017, the mobile substation was initially deployed not in response to the resiliency event (microburst) but to assist with loading concerns in the area while the Company completed planned work. Similarly, in September 2022, the Company used three mobile substations to provide service to customers while performing scheduled work that was undertaken during an extreme heat event.

e. See resiliency events and dates, below.

- May 23, 2017 -- Sealy microburst
- August 25, 2017 -- Hurricane Harvey made landfall
- September 2022 – Extreme Heat
- August-September 2023 -- Extreme Heat
- June-July of 2024 – Extreme Heat

f. No

g. The Company will clearly identify the mobile substations ordered as part of the SRP with a unique identifier through the existing naming convention process used today.

h. Yes, the Company participates in the TXMAG group in which neighboring utilities in the state of Texas share industry best practices and processes to learn from each other in many different facets of an electric utility, up to and including mobile substation processes.

SPONSOR:
David Mercado

RESPONSIVE DOCUMENTS:
TIEC-RFI01-14a-b Attachment 1
TIEC-RFI01-14c Attachment 1

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
PUC DOCKET NO. 57579
SOAH DOCKET NO. 473-25-11558

TEXAS COAST UTILITIES COALITION
REQUEST NO.: TCUC-RFI01-13

QUESTION:

Please provide CEHE's Transmission system SAIDI, SAIFI and CMI including extreme weather events for each year since 2017.

ANSWER:

CenterPoint Houston's focus during an extreme weather event is on the rapid restoration of power to our customers. The Company does track the cause of a particular outage; However, crews focusing on the rapid restoration of power are not always precise in their cause selection. Therefore, the Company does not believe this source of information is reliable for answering the question posed. However, in the interest of transparency, CenterPoint is providing the data. See attachment TCUC01-13.xlsx for annual Transmission system SAIDI, SAIFI, and CMI including extreme weather events.

SPONSOR:
David Mercado

RESPONSIVE DOCUMENTS:
TCUC01-13 - CEHE Transmission SAIDI, SAIFI, and CMI Including Extreme Weather Events.xlsx

> distribution-related costs relating to the implementation of the Company's System Resiliency Plan over a 3-year period for future recovery as a regulatory asset, including depreciation expense and carrying costs at the Company's weighted average cost of capital as established by the Commission's final order in the Company's most recent base rate proceeding, and use Commission-authorized cost recovery alternatives under 16 Tex. Admin. Code §§ 25.239 and 25.243 or another general rate proceeding.

The Company also requests specific accounting language that would allow the Company to defer costs associated with distribution-related vegetation management costs relating to the implementation of the Company's System Resiliency Plan. The Company requests the following language in any Commission order approving the Company's System Resiliency Plan:

> Effective on the earlier of the date of a final order in this proceeding or January 1, 2026, CenterPoint Houston may defer the annual incremental distribution-related vegetation management costs relating to the implementation of the Company's System Resiliency Plan over a 3-year period for future recovery as a regulatory asset, including carrying costs at the Company's weighted average cost of capital established in the Commission's final order in the Company's most recent base rate proceeding, and use Commission-authorized cost recovery alternatives under 16 Tex. Admin. Code §§ 25.239 and 25.243 or another general rate proceeding. The annual baseline amount that will be used to determine the annual incremental distribution-related vegetation management costs shall be $46 million. Annual distribution-related vegetation management costs that exceed the annual baseline amount of $46 million shall be considered the annual incremental distribution-related vegetation management costs relating to the implementation of the Company's System Resiliency Plan and thus eligible to be deferred for future recovery as a regulatory asset.

VI. PROTECTIVE ORDER

The Company has designated certain documents included in this Application as either Protected Material or Highly Sensitive Protected Material under the terms of the proposed protective order and anticipates it being necessary for the Company or other parties to submit additional documents containing confidential material during discovery in this case. The Company therefore requests approval of the proposed protective order attached as Exhibit 15. The proposed protective order is the Commission protective order and has been approved in prior Commission proceedings. Until a protective order is issued in this proceeding, the Company will provide access to the confidential information submitted with this Application to parties that agree in writing to be bound by the proposed protective order as if it had been issued by the Commission.

VII. CONCLUSION AND REQUEST

The Company anticipates that the Resiliency Measures in its System Resiliency Plan will provide benefits to its customers by enhancing resiliency of the Company's transmission and distribution system, by reducing CMI by approximately 1.3 billion, by reducing the total number of customers affected by an outage due to a Resiliency Event, by reducing total outage times due to a Resiliency Event, and by reducing system restoration costs incurred in response to a Resiliency Event. As demonstrated by the Company's track record in controlling and reducing operations and maintenance expense, the Company anticipates being able to implement the Resiliency Measures in the Company's System Resiliency Plan while maintaining the Company's commitment to customer affordability. Thus, the Company requests that the Commission:

- approve the Company's System Resiliency Plan and the Company's proposed Resiliency Measures;
- approve the Company's microgrid pilot program;
- include the Company's requested accounting language in the Commission's order approving the Company's System Resiliency Plan; and
- include language in the Commission's order that would provide the Company the flexibility to immediately begin implementation of all or portions of the System Resiliency Plan, as labor and material allow.

The Company also requests that the Commission grant the Company such other relief to which the Company is entitled.

Date: January 31, 2025

Respectfully submitted,

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COUNSEL FOR CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC

DOCKET NO. 57579

APPLICATION OF CENTERPOINT	**§**	
ENERGY HOUSTON ELECTRIC,	**§**	**PUBLIC UTILITY**
LLC FOR APPROVAL OF ITS 2026-	**§**	
2028 TRANSMISSION AND	**§**	**COMMISSION OF TEXAS**
DISTRIBUTION SYSTEM	**§**	
RESILIENCY PLAN		

DIRECT TESTIMONY OF

ERIC D. EASTON

ON BEHALF OF

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC

JANUARY 2025

Q. DOES THE COMPANY ANTICIPATE THAT SIMILAR EXTREME WIND EVENTS, FLOODING AND OTHER EXTREME WATER EVENTS, AND EXTREME FREEZE AND DROUGHT EVENTS WILL OCCUR IN THE GREATER HOUSTON AREA IN THE FUTURE AND THUS IMPACT THE COMPANY'S TRANSMISSION AND DISTRIBUTION SYSTEM?

A. Yes. Based on Guidehouse's independent, third-party risk assessment, the frequency and magnitude of extreme wind events, flooding and other extreme water events, and extreme freeze and drought events in the Greater Houston area are forecasted to increase over time. For example, maximum wind speeds in the twelve (12) counties in which the Company provides service are forecasted to increase between 2020 and 2050.

Q. HOW DID THE COMPANY INCORPORATE ITS CONCLUSION OF PAST RESILIENCY EVENTS INTO THE 2026-2028 T&D SRP?

A. Recognizing that extreme wind events, flooding and other extreme water events, extreme freeze events, and extreme drought events pose the highest resiliency-related risk and are forecasted to occur with greater frequency and magnitude, the Company included twenty-five (25) hardening, modernization, undergrounding, flood mitigation, wildfire mitigation, and vegetation management Resiliency Measures in the 2026-2028 T&D SRP to mitigate the impact of such events. Of the approximately $5.754 billion that the Company will invest as part of its 2026-2028 T&D SRP, approximately $5.405 billion of the $5.754 billion will be invested for these twenty-five (25) Resiliency Measures. Additionally, of the $5.405 billion that will be invested for these twenty-five (25) Resiliency Measures, approximately $4.013 billion of the $5.404 billion will be invested in Resiliency Measures intended to mitigate the impact of extreme wind events. However, the Company's execution strategy requires flexibility to pivot within each Resiliency Measure, and from one Resiliency Measure to another as constraints are encountered so that program scope and activities pursued within each Resiliency Measure may be adjusted based on the needs of the Company's transmission and distribution system, as determined by the Company's analyses of the resiliency-related investment decisions. The need for flexibility is consistent with the Commission's SRP Rule, which acknowledges that each electric utility's transmission and distribution system has different system characteristics, is subject to different Resiliency Events and risks, and therefore should be given flexibility in developing the manner in which is appropriate to approach those risks.[6] With that need for flexibility in mind, Figure EE-8 below breaks down how the Company anticipates investing $5.405 billion in Resiliency Measures intended to mitigate the impact of extreme wind events, flooding and other extreme water events, extreme freeze events, and extreme heat events.

<u>Figure EE-8</u>

Estimated Costs for Extreme Wind, Flooding and Extreme Water, Extreme Freeze, and Extreme Drought-Related Resiliency Measures (in millions)

Resiliency Measure	T&D SRP Rule Category	Estimated Capital Costs 2026-2028	Estimated O&M Costs 2026-2028	Estimated Total Costs 2026-2028	Estimated 3-Year CMI Savings
Extreme Wind					
Distribution Circuit Resiliency (RM-1)	Hardening	$513.4	None	$513.4	263.0
Strategic Undergrounding	Undergrounding	$860.0	None	$860.0	81.1

[6] Subsection (a)(1), T&D SRP Rule.

Resiliency Measure	T&D SRP Rule Category	Estimated Capital Costs 2026-2028	Estimated O&M Costs 2026-2028	Estimated Total Costs 2026-2028	Estimated 3-Year CMI Savings
(RM-2)					
IGSD Installation (RM-3)	Modernization	$107.3	$0.5	$107.8	97.0
Distribution Pole Replacement and Bracing (RM-4)	Hardening	$251.6	None	$251.6	121.0
Vegetation Management (RM-5)	Vegetation Management	None	$146.1	$146.1	137.0
Transmission System Hardening (RM-6)	Hardening	$1,467.3	$0.8	$1,468.0	223.8
69 kV Conversions (RM-7)	Hardening	$369.3	None	$369.3	65.5
S90 Tower Replacements (RM-8)	Hardening	$118.4	None	$118.4	59.5
Coastal Resiliency Projects (RM-9)	Hardening	$177.4	$0.8	$178.1	7.8
Extreme Wind Total		**$3,864.6**	**$148.1**	**$4,012.7**	**1,055.7**
Extreme Water					
Substation Flood Control (RM-10)	Flood Mitigation	$43.8	None	$43.8	3.9
Control Center Flood Control (RM-11)	Flood Mitigation	$7.0	None	$7.0	2.5
MUCAMS (RM-12)	Modernization	$10.8	None	$10.8	0.6
Mobile Substations (RM-13)	Modernization	$30.0	None	$30.0	3.9
Extreme Water Total		**$91.5**	**None**	**$91.5**	**11.0**
Extreme Temperature (Freeze)					
Anti-Galloping Technologies (RM-14)	Hardening	$14.0	$1.0	$15.0	5.3
Load Shed IGSD (RM-15)	Modernization	$4.5	$0.1	$4.6	N/A*
Microgrid Pilot Program (PP-1)	Modernization	$35.0	$1.5	$36.5	N/A*
Extreme Temperature (Freeze)		**$53.5**	**$2.6**	**$56.1**	**5.3**
Extreme Temperature (Heat)					
Distribution Capacity Enhancement/Substation (RM-16)	Modernization	$579.6	None	$579.6	138.1
MUG Reconductor (RM-17)	Modernization	$245.0	None	$245.0	13.6
URD Cable Modernization (RM-18)	Modernization	$128.4	None	128.4	13.0
Contamination Mitigation (RM-19)	Modernization	$144.0	$6.0	$150.0	15.7
Substation Fire Barriers (RM-20)	Hardening	$9.0	None	$9.0	1.5
Digital Substation (RM-21)	Modernization	$31.8	None	$29.4	1.2

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
PUC DOCKET NO. 57579
SOAH DOCKET NO. 473-25-11558

TEXAS INDUSTRIAL ENERGY CONSUMERS
REQUEST NO.: TIEC-RFI01-03

QUESTION:

Referring to various places that discuss flexibility (i.e., Application at page 20, SRP at page 34, and Direct Testimony of Eric D. Easton at page 16), please summarize and restate the flexibility approval that CenterPoint is seeking from the Commission in this filing.

ANSWER:

The Company has not undertaken a search for every use of the word "flexibility" in its filing. However, the Company has generally requested two types of flexibility: flexibility to immediately begin implementation of all or portions of the Company's System Resiliency Plan (SRP) and flexibility as it relates to implementation of Resiliency Measures on a specific portion or portions of the Company's transmission and distribution system or the Company's service area.

The reference to flexibility in the Company's Application at page 20 refers to the former—flexibility to immediately begin implementation of all or portions of the Company's SRP. Depending on when the Company's SRP is approved by the Commission, there is a possibility that implementation of some Resiliency Measures could begin in 2025, as labor and material allow.

The references to flexibility in the SRP at page 34 and Direct Testimony of Eric D. Easton at page 16 refer to the second type of flexibility—flexibility as it relates to implementation of Resiliency Measures on a specific portion or portions of the Company's transmission and distribution system or the Company's service area. As Mr. Easton explains in his testimony, "the Company's execution strategy requires flexibility to pivot within each Resiliency Measure, and from one Resiliency Measure to another as constraints are encountered so that program scope and activities pursued within each Resiliency Measure may be adjusted based on the needs of the Company's transmission and distribution system, as determined by the Company's analyses of the resiliency-related investment decisions."

SPONSOR:
Nathan Brownell

RESPONSIVE DOCUMENTS:
None

NATIVE FILE UPLOADED TO PUC INTERCHANGE

Exhibits and tables - Final.xlsx

The following files are not convertible:

Exhibits and tables - Final.xlsx

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