Figure AB-14

Current company standards require the installation of two float switches inside of every transformer vault. The first float switch is located at a height of 6” above grade and it triggers a warning to indicate the presence of liquid in the vault. The second float switch is located at 2’ above grade and it triggers a lock-out to safely de-energize the service to the customer. This lock-out is necessary to prevent the risk of fire or electrical shock from flooded equipment and to isolate the flooded equipment preventing a wider outage. The company provides the building owners with dry contacts for monitoring liquid and high temperature warnings in the company’s transformer vaults. The company’s supplemental terms and conditions for underground service provides instructions to the customer on how to notify the company in case of a warning light indication.

Underground equipment monitoring with Major Underground Control and Monitoring System (MUCAMS). MUCAMS is used to monitor vault and pad-mounted equipment primarily in the company’s dedicated underground areas. MUCAMS is planned to be deployed to approximately 461 sites in Downtown, Texas Medical Center, Galveston, NRG and Shell complex. During a storm response, the company can use MUCAMS to monitor the presence of liquids in vaults prior to any outages. MUCAMS sends an email notification in case of a warning indication and will also send another email notification in case of a service lock-out.

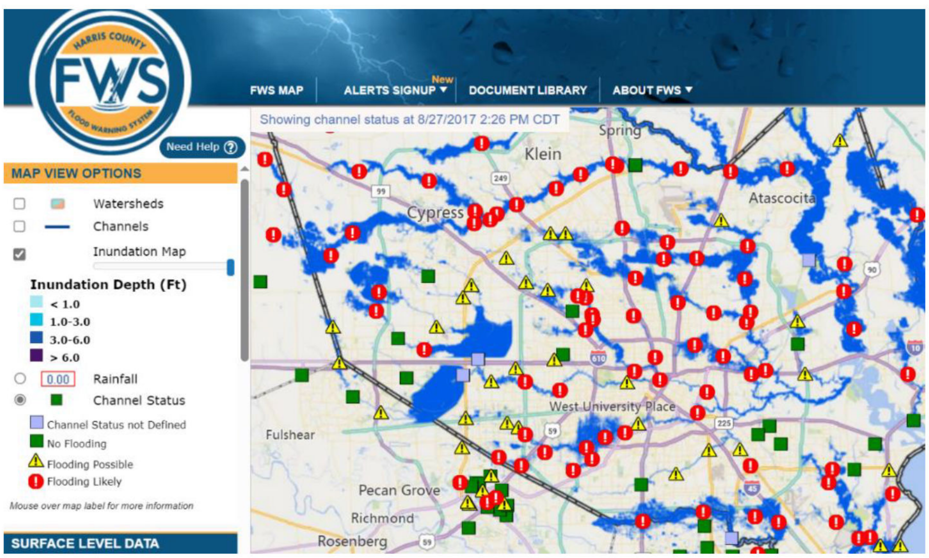
The company maintains a secondary street network in Downtown Houston. MUCAMS is used to monitor the real time load of the secondary street network. During a flood event, network transformers might lock-out due to high liquid levels in a transformer vault. With MUCAMS, the company can utilize real time loading data to assess the load flow of the secondary street network and strategically load shed to prevent failures and damage to electrical infrastructure.

Obtaining real time information on the presence of liquid in our transformer vaults allows the company deploy operations personnel more effectively to help improve our restoration time and prevent further damage the company’s and customer’s electrical infrastructure.

Mobile Substations. On an annual basis and prior to storm events, mobile substations are reviewed for operational readiness. These mobile substations are deployed to locations where the normal substation transformers are unable to meet the demands of customer load. Deployment of mobile substations is typically completed in less than 5 days and is dependent on available transmission and distribution systems.

Damage Assessment. The damage assessment process related to substations and underground vaults is prioritized based on model outputs and data collected from historical flood events. If conditions are safe to do so, crews are located at or near substations and underground vaults to maintain visual confirmation of conditions. In some cases, remote sensing including camera systems and flood monitors are installed to verify water levels as inaccessible sites. If water levels compromise relay protection; the system is reconfigured to allow the substation and associated transmission lines to be de-energized. Once safe to do so, locations are inspected for damage to determine if repair or replacement of components is required. Damage estimates are assisted with public, and Company owned remote monitoring. An example of publicly available information is the Harris County Flood Warning System which publishes inundation depths and rainfall amounts as shown in the figure below.

<u>Figure AB-15</u>



System Restoration. System restoration can vary based on the specifics of the extreme water event; however, there are fundamentals which hold for all events. With the exception of substation rebuilds, restoration from extreme water events can be completed with limited mutual assistance crews when compared to extreme wind events. To address these emergent issues, the Company embeds resources within city and county Emergency Operations Centers, activates its priority desk, and maintains communication with State Officials. The use of temporary generation will also be dependent on the safe accessibility of the points of interconnection to serve customers.

Complimentary Programs.

Distribution Circuit Rebuilds. Additional risk is associated with transmission structures and distribution poles near the banks of bayous and other channels where soil erosion may cause a structural failure.

Distribution Automation and Remote Switching. The ability to perform remote switching during extreme water events may be required when hazardous conditions have been confirmed by field inspection.

Section 2.2.3. System Susceptibility to Extreme Water Resiliency Events

Section 2.2.3.1. Historical Events. The Company is constantly identifying lessons learned and opportunities for enhancement of design and processes for each successive event. One such notable event was hurricane Ike in 2008 which led to changes in the design of coastal substations. The effects of this change were realized during subsequent coastal flood events where none of the elevated substations experienced water damage. The figure below summarizes some of the more recent extreme water Resiliency Events that have occurred in the Company's service area, the total number of customers affected by outages due to the Resiliency Event, and their respective restoration times for the years 2019 through 2024.

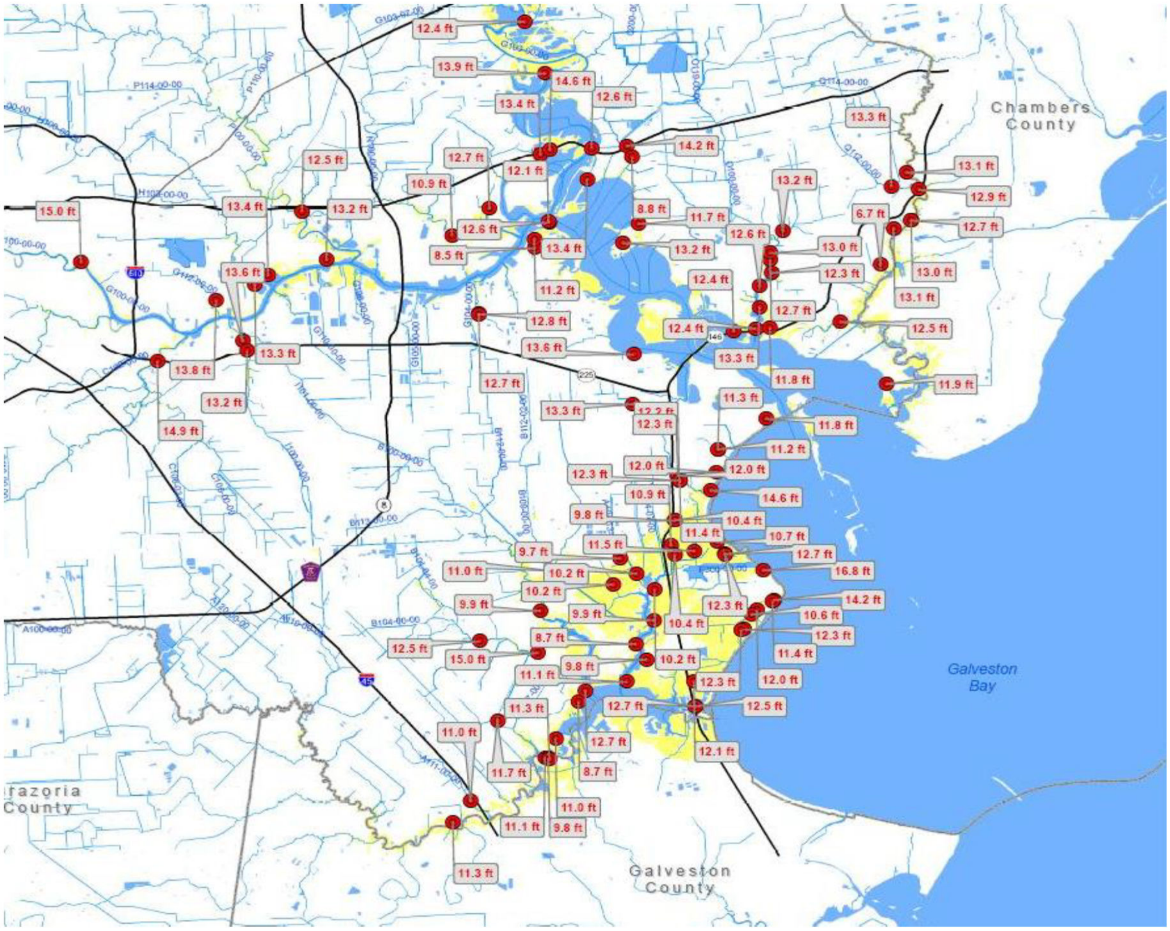
Figure AB-16

Year	Resiliency Event	Total Customers Affected	Restoration Time
2019	May 9th-11th: A stalled cold front combined with high instability, deep tropical moisture, and several disturbances produced strong thunderstorms and gusts, frequent cloud-to-ground lightning, heavy rainfall, and flooding.	238,015	48 hours, 55 minutes
2020	September 17th-18th: Hurricane Nicholas produced powerful, gusty winds, heavy rain, and flooding.	706,429	120 hours, 5 minutes

Section 2.2.3.2. Benchmark Events. While all significant events provide lessons learned, benchmark events are those which resulted in the highest customer impacts for a given event type. These events include Hurricane Ike which resulted in coastal flooding, the Tax Day floods of 2016, as well as Hurricane Harvey during which a large portion of the service territory was flooded. These benchmark events provided numerous data points which aid in validating modeling and project selection.

Hurricane Ike. On September 13, 2008, hurricane Ike made landfall on the northeast end of Galveston Island as a Category 2 hurricane with sustained winds of 110mph and a Category 5 equivalent storm surge. Higher-than-normal water levels affected virtually the entire U.S. Gulf Coast from Texas to Florida. The storm travelled north up Galveston Bay, along the east side of Houston resulting in evacuation orders for residents. The worst devastation from Hurricane Ike occurred on the Bolivar Peninsula, TX, which was inundated with 3.7-4.9 m (12 -16 ft) of water. The storm surge exceeded the island's elevation, leading to inundation, overwash and extreme coastal change. (Hurricanes: Science and Society: 2008- Hurricane Ike) Complete tide gauge records for this area are unavailable since many of the sensors failed during the storm, although ground assessment teams determined that the surge was generally between 15 and 20 ft. These depths are represented in the figure below.

Figure AB-17



Hurricane Ike resulted in the complete loss of the West Galveston substation control house as shown in the figure below.

Figure AB-18

As a result of Hurricane Ike, the Company began elevating existing substations in the Galveston and Freeport area based on modeling using maximum 100-year wave crest. Equipment designated for flood mitigation included the control house, circuit breaker controls, transformer controls, pull boxes and instrument transformers. The final elevation was determined to 21.8 feet as shown in the figure below.

Figure AB-19
(Substation Storm Hardening 08-27-11)

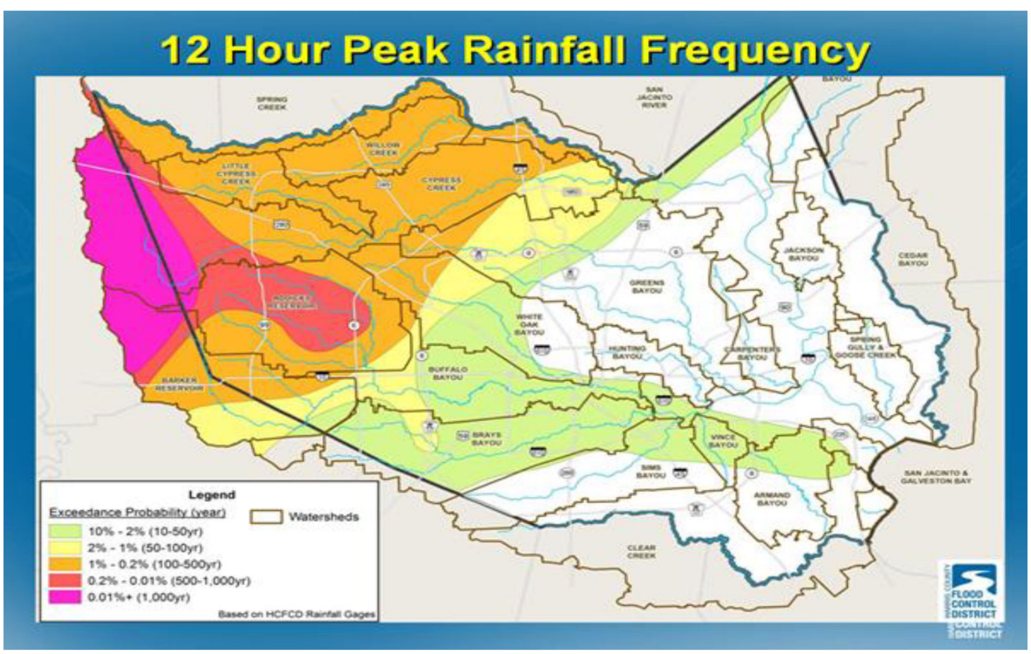
As new coastal substations were constructed, an alternative design using a combination of soil fill and concrete chain wall platforms were utilized providing an ability to compare design practices. The chain walls were effective in elevating the substation and can be seen in the figure below.

Figure AB-20

Tax Day Floods. On April 15, 2016, a storm started lasting multiple days and flooded more than 1,000 residences in the Houston area. Matt Lanza of Space City Weather wrote on April 26, 2016. "Harris County averaged 7.75 inches of rainfall for the event. That's equivalent to 240 billion gallons of water falling on the area. This exceeded Memorial Day (162 billion gallons) by almost 80 billion gallons of water." ([A look back at the devastation caused in Houston by the tax day flood of 2016](#)) The Tax Day Storm had a tremendous impact on north and west Harris County as shown in the figure below. Communities in Spring and Klein (Cypress Creek watershed); Cypress (Little Cypress Creek watershed); Tomball (Spring Creek and Willow Creek watersheds); Katy and Bear Creek (Addicks Reservoir watershed), and Cinco Ranch (Barker Reservoir watershed) experienced flooded homes, businesses, and roads.

Figure AB-21

Source: [Spring Floods 2016](#)

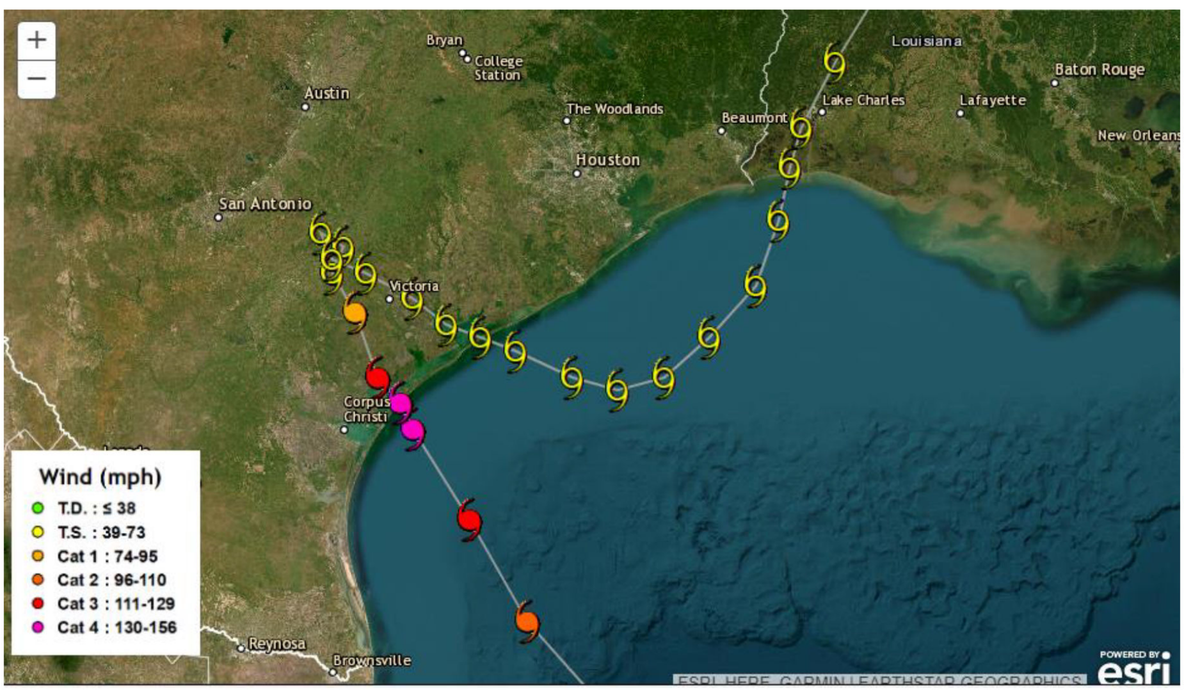


Several neighborhoods along Cypress Creek and Little Cypress Creek also saw secondary flooding after the creeks had drained local stormwater, and additional runoff from the upper watershed reached the lower reaches of the creeks. The secondary flood primarily affected roadways, which made it difficult for traffic to flow in the area.

The month after the Tax Day flood many of the same areas were impacted again during the Memorial Day Storm on May 27th, 2016. The channels and detention basins in north and northwest Harris County had previously been impacted by the historic Tax Day flood event six weeks earlier. The ground was saturated and several of the creeks and tributaries were still carrying stormwater from this slow-draining part of the county. Even though the heaviest rainfall occurred over northern Waller, southern Montgomery and Washington counties, there were areas that got 8-13 inches of rain in north Harris County. It was simply too much rain in a short period of time falling on saturated ground, and some homes and roads that flooded previously in north and northwest Harris County flooded again. These events highlighted the impacts of urbanization on inland flooding as well as the need to expand substation elevation project to non-coastal areas.

Hurricane Harvey. On August 25, 2017, the Company's service territory was subjected to historic flooding as Hurricane Harvey produced torrential rainfall and flash flooding. Harvey had a unique storm track and instead of moving inland and farther away from the coast, it stalled with the "dirty side" of the hurricane stationary over the Houston Area for days, continuing to gather precipitation from the Gulf of Mexico and producing catastrophic, devastating, and deadly flash and river flooding. Cedar Bayou in Houston received a storm total of 51.88 inches of rainfall which was a North American record. The figure below provides insights as to why the storm was so devastating from a flood perspective.

<u>Figure AB-22</u>



The historic rainfall produced floods in expected and unexpected locations and resulted in efforts by FEMA to develop new floodplain maps. These new maps represent risk beyond river flooding and include risk from urban flooding not previously shown on maps. Urban flooding results when intense rainfall

overwhelms stormwater systems regardless of proximity to a bayou or other channel. The new maps will also reflect updated rainfall estimates from the National Oceanic and Atmospheric Administration (NOAA) that better depict the reality that storms have intensified in recent decades, data that had not been updated since the 1960s. The Company had completed an assessment of inland substations following Tropical Storm Allison from June 5 – June 9, 2001, during which many areas of Houston experienced extensive flooding. One of the locations identified during the study was Grant substation, which is situated along the north bank of Brays Bayou by the Texas Medical Center at Fannin Street. The result of the flood study was a recommendation to protect for a 500-year flood elevation of 46.80 feet utilizing a flood wall. Alternatives to a floodwall surrounding the perimeter of the site would be to raise the
existing control buildings or build new ones at higher finished floor elevations; however, given the outage requirements for construction this option was not preferred by the company. The Grant substation flood wall and flood gate proved critical during Hurricane Harvey in mitigating extreme water risk as shown in the figure below.

Figure AB-23

Unfortunately, the waters of Hurricane Harvey overwhelmed the Memorial substation located just south of I-10 on the west side of Houston. Although several sites were affected by the storm, Memorial was the most impacted and required a complete rebuild. Flood waters seen in the figure below caused damage to both the control house and equipment in the substation yard.

Figure AB-24

The substation was rebuilt using design enhancements to make design and construction more efficient. Through collaboration with engineering, operations, construction, and 3rd Party vendors substation elevation projects have been increasingly standardized.

Figure AB-25

During system restoration and construction of the new substation, a mobile substation was used to serve customers normally served from the Memorial substation. Through collaboration with members of the community the Company was able to locate the mobile substation in a parking lot near the flooded location.

Mobile substations are capable of providing service to approximately 10,000 customers depending on system conditions at the time of deployment.

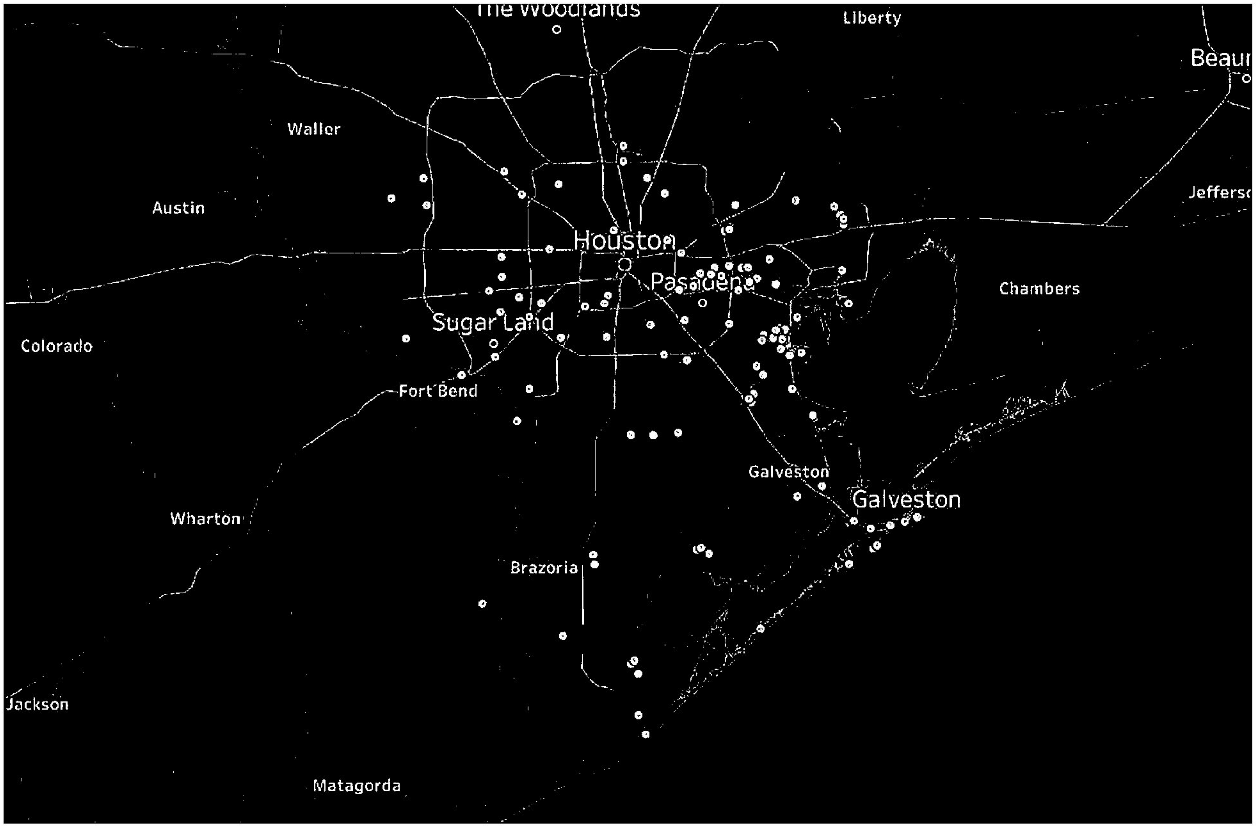
Figure AB-26

Section 2.2.3.3. County-Based Reviews. A critical phase of the review and modeling benchmark for events is the incorporation of insights from experts responsible for community emergency response. During discussions with the County OEMs the Company was able to receive feedback related to flood concerns and observations. These meetings also gave the company an opportunity for information sharing of County OEM flood mapping, flood monitors and associated data.

Section 2.2.3.4. Guidance from the Public Utility Commission of Texas. The Company did not receive Guidance specific to flood mitigation from the PUC.

Section 2.2.4. Damage Prediction Modeling. Following an analysis of potential enhancements, CEHE worked to revise the previous damage prediction model to assist in estimating the number of mutual assistance crews needed to achieve a desired restoration rate, recommend the optimal staging site locations to activate, identify locations for potential temporary generation deployments and areas for augmented field crew resource allocations based on predicted geographic concentrations of longer duration outages relative to other portions of the system.

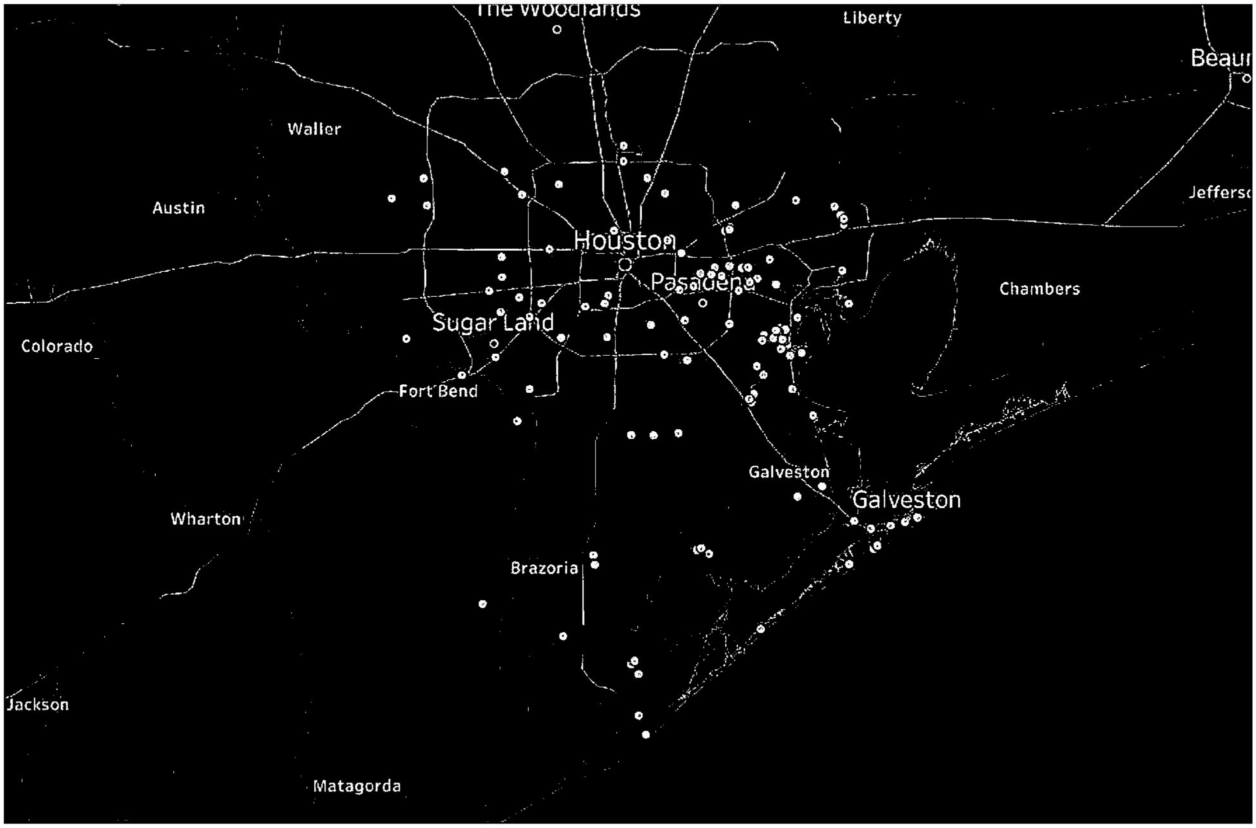
Figure AB-27
Substations in flood plain



Section 2.2.4.1. Control Center and Substation Extreme Water Mitigation

Damage prediction is informed by a combination of site-specific flood studies, observations from historical events and flood predictions based on climate modeling. The site-specific flood studies were associated with Tropical Storm Allison and Hurricane Ike. Locations experiencing flooding during Hurricane Harvey were documented and used to develop a list of substations for extreme water mitigation. Lastly, high resolution climate modeling was completed based on standard H3 polygons. The flood risks shown in the figure below could then be compared to substation locations.

Figure AB-28



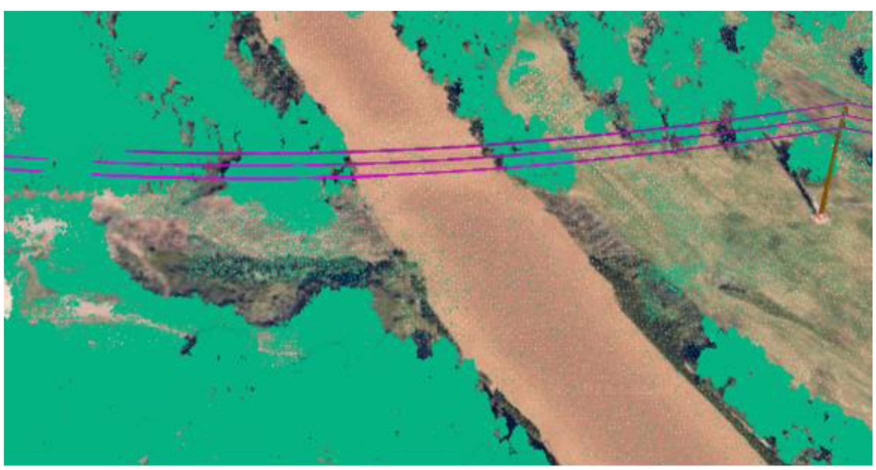
Section 2.2.4.2. Transmission and Distribution Hardening

Similar to the LiDAR based analysis completed for extreme wind events, the LiDAR data was used to identify river crossings which may be at risk due to the proximity of transmission structures and distribution poles to the bayou or other channel. An example of at-risk transmission location is shown in the figure below.

Figure AB-29

The figure below shows the same location from the LiDAR model following relocation of the tower. The 3D system model was utilized to identify locations which met the criteria for proximity to waterway, potential customer affected and critical customers.

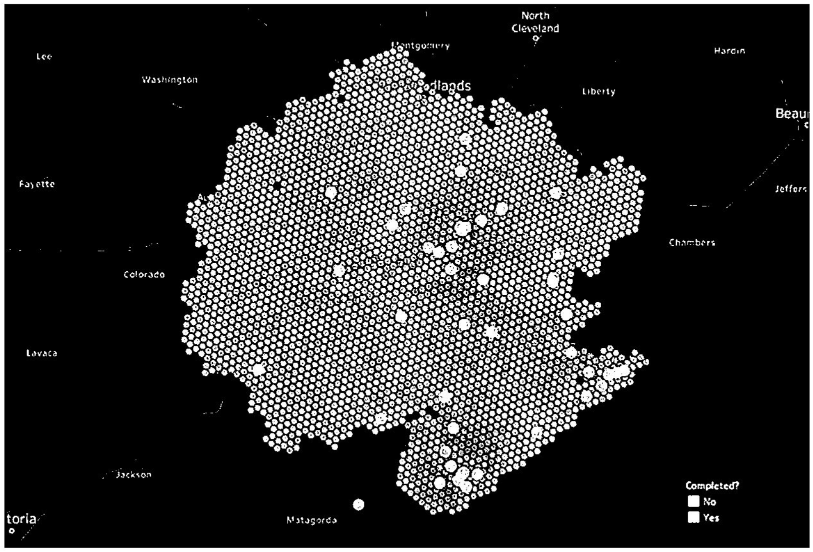
Figure AB-30
LiDAR Model of River Crossing



Section 2.2.4.3. Project Selection and Locations. Projects to mitigate the effects of extreme water events were evaluated for the Substation, Underground Vaults, Transmission, and Distribution structures.

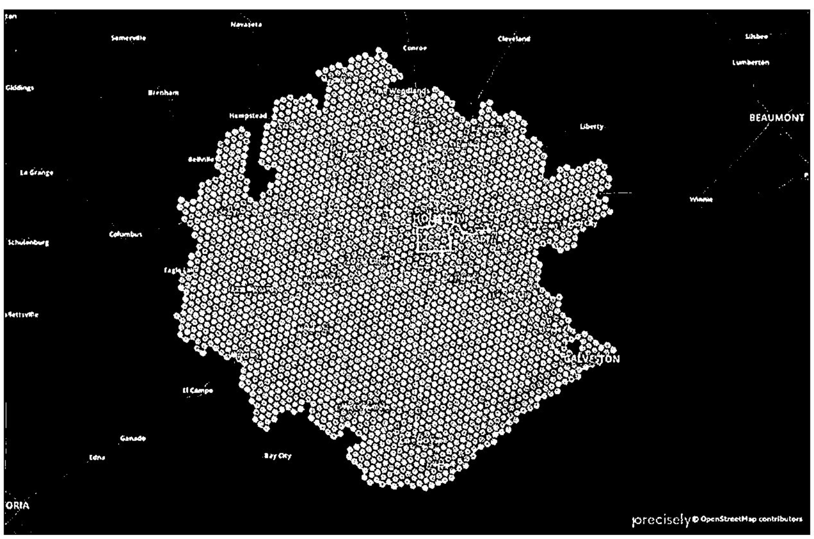
Substations and Control Center. Substation and Control Center locations were selected based on the historical field observations and climate forecast data and then prioritized using critical customer and total customer counts. The figure below shows the resulting project to be completed in orange and previously completed projects in green.

Figure AB-31
Elevated Substations



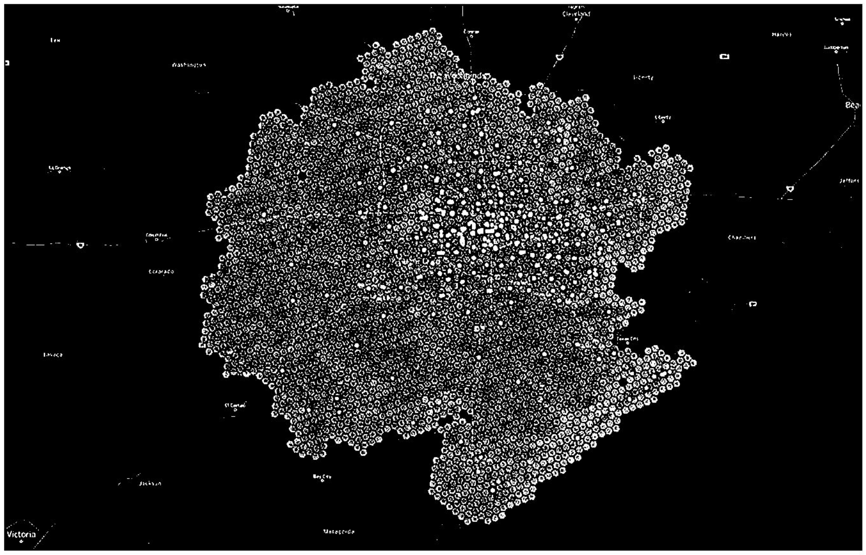
Underground Vaults. Distribution assets have experienced flooding during extreme water events; however, design changes following Tropical Storm Allison in 2001 have aided in mitigating risks through monitoring these high waters during extreme water events.

Figure AB-32
MUCAMS Locations



River Crossings. LiDAR data was utilized to identify locations where transmission structures and distribution pole relocations need to occur to mitigate risk of washout for the footings or base of the pole. The identified locations are shown in the figure below. Priority is given based on customer count and critical customers.

Figure AB-33
River Crossings



Distribution Substations. Distribution substation assets have experienced flooding during extreme water events; however, design changes following Tropical Storm Allison in 2001~~7~~ have aided in reducing these floods during extreme water events and the use of mobile substations has allowed a faster recovery post these events.

Prioritization. Model based prioritization of project locations used inundation risk, critical customers and total customer count to identify locations for reducing CMI during extreme events. The selected locations will also have benefits from a reliability perspective to help improve reliability in addition to resiliency.

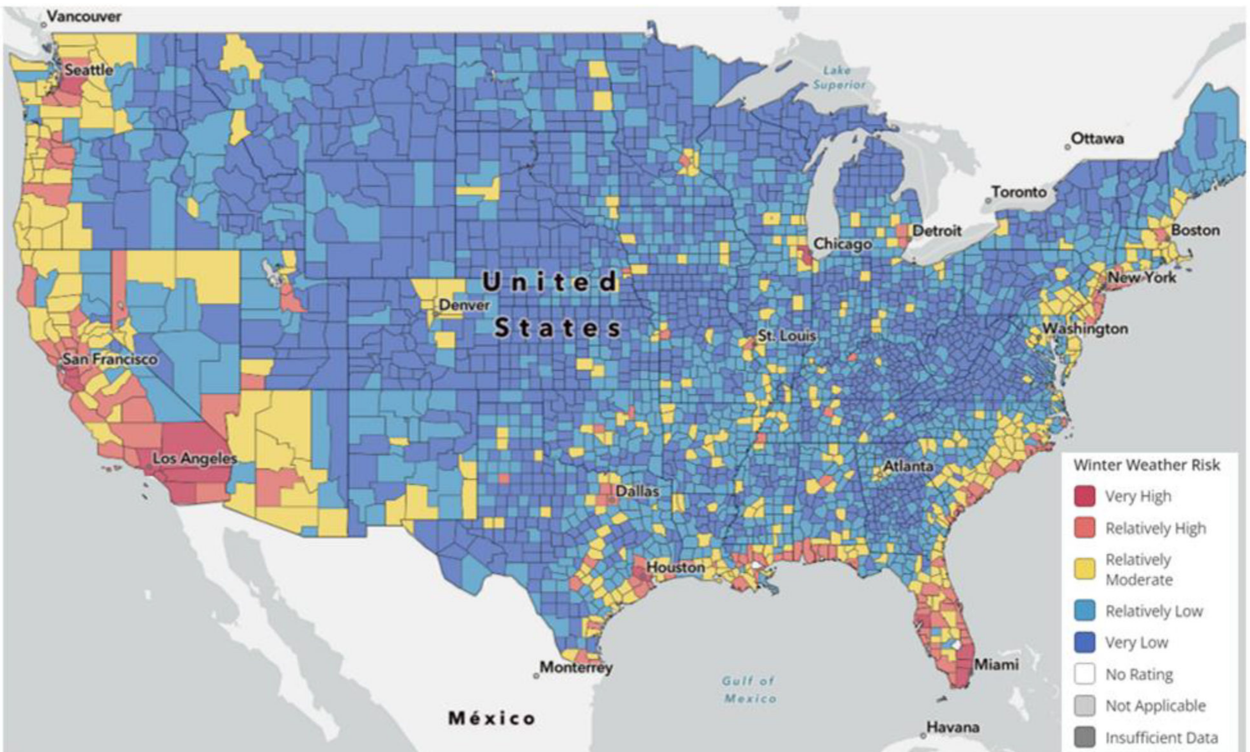
Appendix C - Extreme Temperature Events (Freeze)

Section 1. Overview of the Company's Service Territory

The Greater Houston area is particularly susceptible to damage from winter weather because its infrastructure is not designed for prolonged freeze conditions. As shown in the figure below, CEHE's service territory is ranked higher in winter weather risk index by the National Oceanic and Atmospheric Administration ("NOAA").

Figure AC-1

Winter Weather Risk Index



Impact to electric utility and its customers from freeze events can be attributed to two main factors:

- Freezing rain and ice storms – this results in ice buildup on power lines and trees which along with wind could result in outages from galloping conductors or from tree branches falling on wires. In January 2018, the Company experienced over 17 transmission circuit lock outs from galloping conductors and required teams of line crews to go to locations for field inspections to mitigate and restore service. This resulted in outages lasting several hours for tens of thousands of customers.

- Higher demand during extreme winter events from heating needs increasing the risk of load shed. In 2021, ERCOT interconnection was significantly impacted during Winter Storm Uri prompting ERCOT to issue load shed directive that lasted for 70 hours. Prior to Winter Storm Uri, a winter freeze event in 2011 also resulted in generation shortfall resulting in load shed of 4000 MW being issued by ERCOT for its overall territory. During these prior winter load shed events, CEHE's customers were disproportionately impacted due to the lower ERCOT load share that CEHE experienced during colder days compared to the load shed obligation based on the load share on summer peak days.

Section 1.1. Preparation for Temperature (Freeze) Events

Section 1.1.1. Modeling.

Modeling for extreme temperature events relies on a number of techniques including power flow, climatological, LiDAR based assessment of vegetation and conductor slack. Each of these models intends to determine how the event will affect the Company's assets and associated customer impacts. Climate Modeling is performed annually to determine if the season has the potential to impact CEHE's service territory.

Power Flow Modeling. Power flow, or load flow, is widely used in power system operation and planning. The power flow model of a power system is built using topological models of the distribution and transmission network, customer load demand, and expected generation dispatch. Outputs of the power flow model include system voltages and line flows used to determine the operational risk from normal and contingency conditions. To identify resiliency related projects, system planning engineers start with the normal system configuration and remove elements from service to simulate equipment failures. Following the simulation of the failure, assessments are made regarding the ability to reasonably restore customers to avoid sustained outages. Modeling will also help determine available load for potential load shed events.

Climatological Modeling. Data related to wind and precipitation is used to estimate the effects of weather patterns on power system equipment. Precipitation that occurs during extreme freeze conditions and prevailing northerly wind can result in galloping of conductors. The modeling determines which circuits are most susceptible to galloping conductors based on the direction of spans in relation to northerly wind, slack on the wires and distance between conductors.

Vegetation Modeling. Vegetation models work to identify locations with higher risk of encroachment for vegetation management and fall in risk reduction.

Section 1.1.2. Structural Hardening.

Structural hardening is utilized to reduce the risk of galloping conductors on transmission lines.

Section 1.1.3. Asset Monitoring.

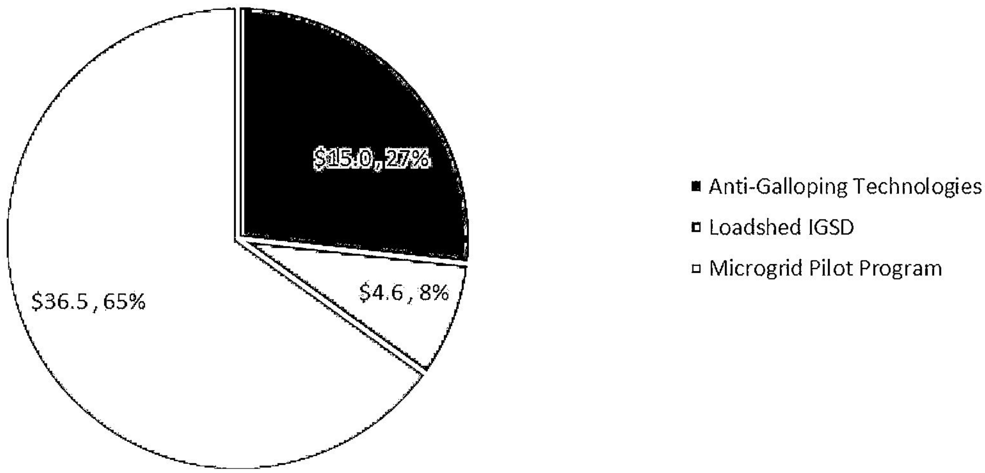
When extreme temperature events impact a significant portion of the Company's service territory, more than 60% of the 1,800 distribution feeders are exposed to the possibility of being disconnected from their substations.

Section 2. Advanced Modeling Methodology

Section 2.1. Cost Allocation

Based on best practice benchmarking, utilities similarly challenged by extreme temperature (freeze) events tend to bias initial hardening to transmission assets given the higher probability of conductor galloping on transmission lines exposed to precipitation and prevailing winds. Transmission conductors are placed higher compared to distribution circuits and also have longer spans making them more susceptible to ice buildup and impacts from wind. Distribution investment is primarily focused on responding to ERCOT load shed directives that result from generation shortage during times of high demand and generation outages. Making additional load available to be shed during load shed events helps reduced overall outage duration experienced by customer when rotating outages. Intelligent grid switching devices ("IGSDs") allows additional load on relay-exempt circuits that are typically not interrupted from the substation. Utility-scale microgrid is another concept that is being explored as a possible mitigation measure and allows for reducing loading on distribution circuits when load shed is directed by ERCOT, while mitigating sustained outages for customers. The allocation of investments for extreme temperature (freeze) is shown in the figure below.

Figure AC-2



Section 2.2. Characterization of Temperature Events

The Company used advanced modeling to quantify benefits based on event characteristics, asset vulnerability, benefits of automation and repair times of predicted damage based on expected crew productivity.

Section 2.2.1. Risk Characterization by Event Type

Extreme temperature events primarily cause customer outages from equipment failures such as transformers as well as from load shed conditions. The events differ in the amount of advanced warning, percentage of system impacted, temperature, and bulk electric system impacts.

Section 2.2.1.1. Loss of Transmission Generation. Extreme cold historically within the ERCOT footprint has presented challenges to generator operators and the inability to continue operations when their cooling systems for the generators freeze, causing the units to shut down due to overtemperature (ironically).

Section 2.2.1.2. Winds. As temperature conditions get colder, winds pick up and when coupled with humidity, cause ice to build up on transmission conductors typically causing these conductors to begin to oscillate uncontrollably (galloping).

Section 2.2.2. Planning and Response

Section 2.2.2.1. Pre-Year Annual Weather Review. Prior to each season a number of activities are completed to prepare for restoration activities.

Weather Modeling. Weather Modeling will be performed annually to determine if the season has the potential to impact CEHE's service territory.

Mutual Assistance. Mutual assistance resources are estimated based of the expected level of damage from the impending event.

Staging Sites. Staging Sites are informed by the prediction model as well.

Critical Customer Restoration. The Company maintains a database of priority customer locations in addition to utilizing processes during significant events to prioritize restoration.

Section 2.2.2.2. Response. Upon initial impact of the extreme temperature event, a combination of temporary and permanent outages could occur on the system.

Distribution Automation and Remote Switching. Temporary outages due to load shed, can be automatically restored using automation devices such as IGSDs and breakers.

Section 2.2.3. System Susceptibility to Extreme Temperature Resiliency Events

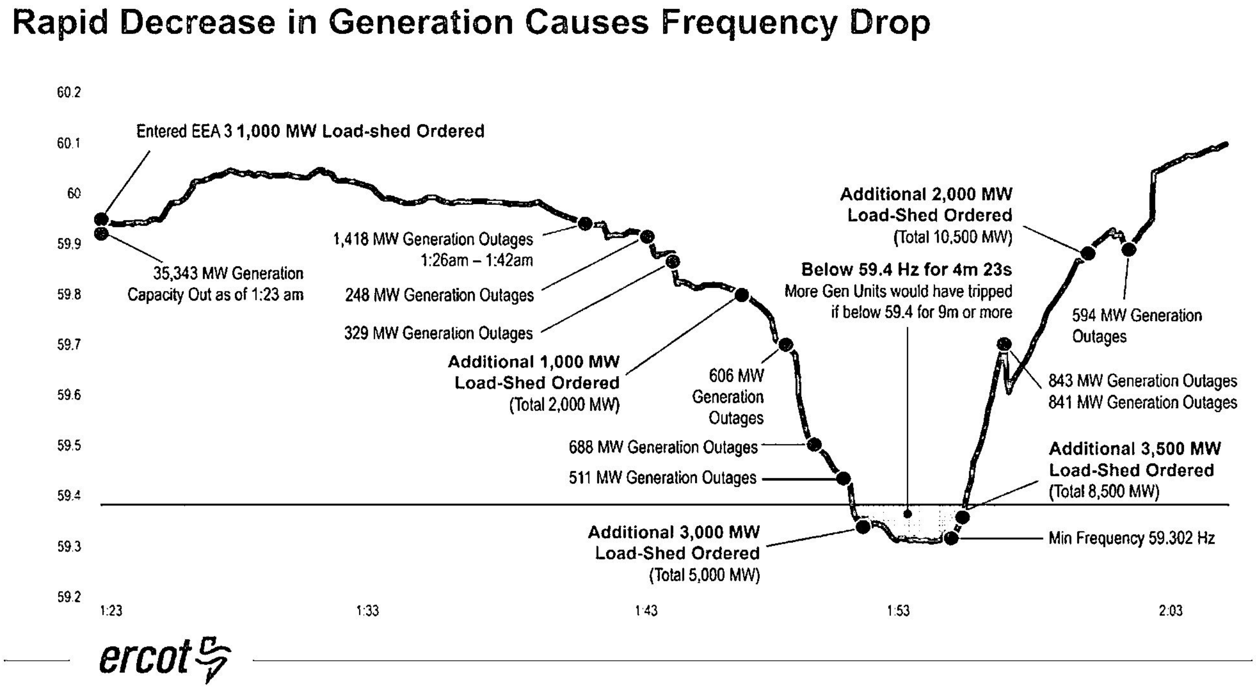
Section 2.2.3.1. Historical Temperature Events. The Company is constantly identifying lessons learned and opportunities for enhancement of design and processes for each successive event. One such notable event was the winter freeze in February of 2011 which led to losses of 4,000 MW of generation within the ERCOT area and significant load shed in the Company's territory. A second notable event was Winter Storm Uri in February of 2021 which again impacted the ERCOT generation management area and triggered the most significant load shed event in the Company's history. Although Winter Storm Uri was the Company's only significant freeze event in the last 5 years, this single event resulted in the equivalent of 6 years of customer minutes of interruption in 70 hours.

Section 2.2.3.2. Benchmark Events. While all significant events provide lessons learned, benchmark events are those which resulted in the highest customer impacts for a given event type.

While all significant events provide lessons learned, benchmark events are those which resulted in the highest customer impacts for a given event type. Each benchmark event and analysis are further detailed in Appendix C. Using the most recent benchmark event as an example, below are details on Winter Storm Uri's impact as an extreme temperature event.

A significant winter weather event was being forecasted for Sunday, February 14th, with the main threat being ice and wind. Late Sunday February 14, 2021, ERCOT system conditions quickly deteriorated beyond what had originally been predicted as generation became constrained and ERCOT load continued to rise; resulting in unprecedented load shed.

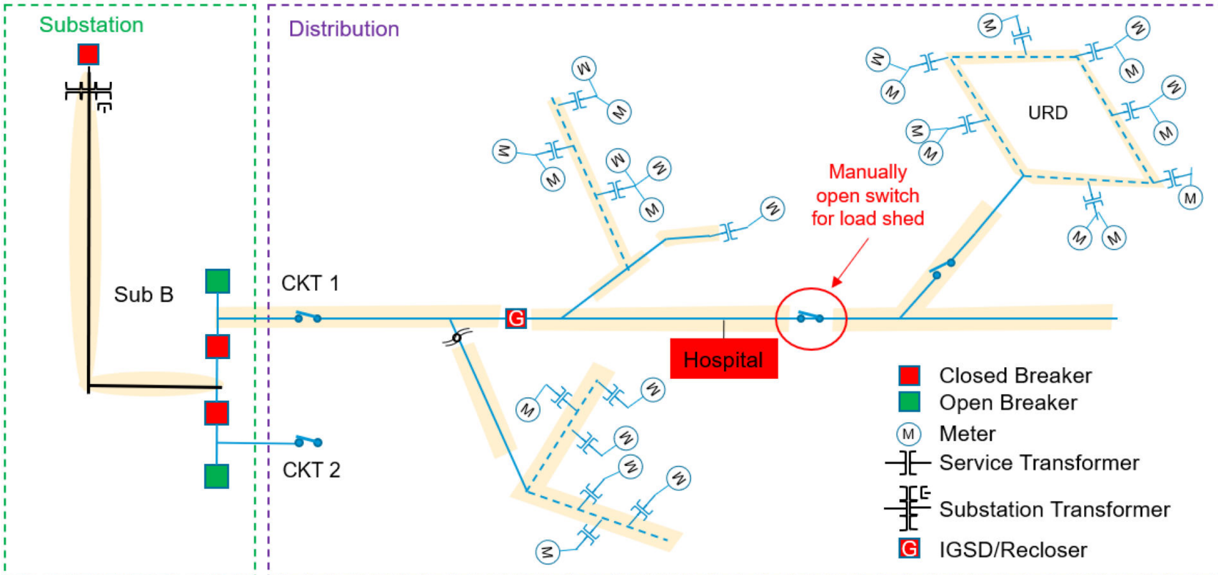
Figure AC-3



Due to the volume and rapid succession of these load shed orders, by 2:24 a.m. on February 15th, CNP could no longer automatically rotate customer outages on our system. At the peak of the load shed event, approximately 1.4 million customers were out in CenterPoint's territory alone and 18 transmission lines experienced sustained lockouts associated with galloping conductors. By Thursday morning the 18th and within six hours of sufficient generation being restored, customer outages were reduced to approximately 47,000 without power. By Friday evening, February 19th, CNP workers had replaced over 1,000 residential pad mounted transformers and substantially restored all service to our customers, including our industrial customers that were ready and had the ability to restore their operational loads. On Saturday the 20th, with adequate generation resources online and the Company's system operating and serving customer load, the Company sent mutual assistance contractors to support Oncor and Austin Energy. During the storm, the Company noted pre-identified load allocations used to assign load shed amounts were not consistent with the real-time load allocations. For example, the Company had a pre-identified load allocation of 25%; however, during the storm the Company's real-time allocation ranged from 16 – 19% due to warmer conditions along the coast relative to the central part of Texas as well as the inclusion of industrial load being included in the load allocation process. The difference in pre-identified and real-time load allocations meant the company was shedding per the ERCOT Protocols but at an allocation greater than real-time conditions would suggest are equitable. Subsequent changes to the ERCOT protocols introduced seasonal calculations.

The 2021 extreme winter event necessitated the Company rotate select loads designated as under frequency circuits manually to allow other customers to be rotated on manual to prevent their continued service interruption. Additional load rotation capacity was gained by manually isolating portions of circuits downstream of hospitals, police stations, etc. when possible. The manual isolation of load during winter storm Uri required Operations crews to drive to the location and open the switch.

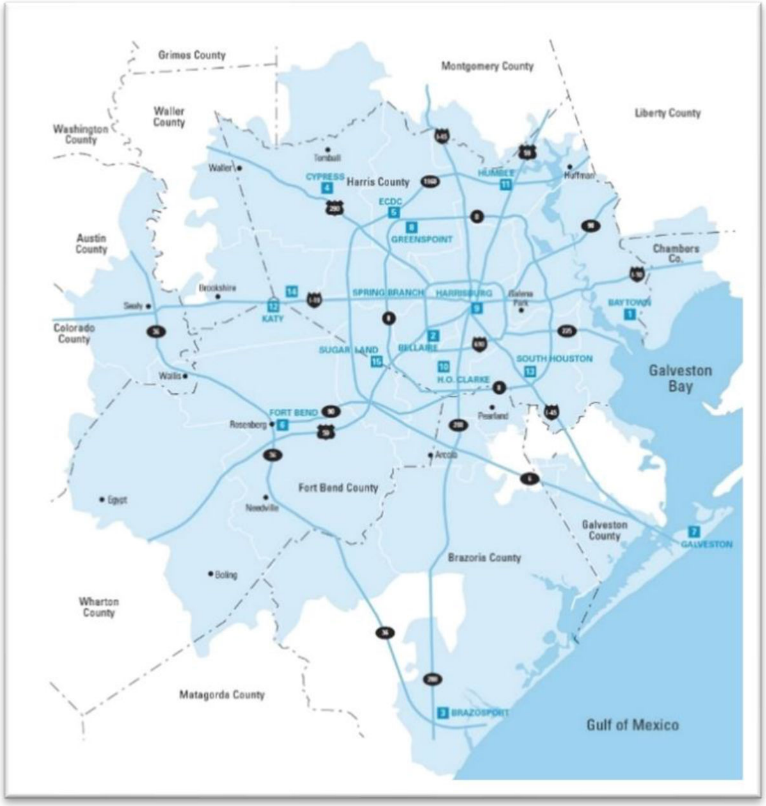
Figure AC-4



Following Winter Storm Uri, the Company began evaluating opportunities to automate manual processes utilized during the event including the rotation of underfrequency designated load and load shed specific circuit segmentation. Additionally, efforts were undertaken to develop analytical models for the purpose of evaluating extreme load shed events and the resulting ability to rotate load in a predictable manner. These analytical models allow for the incorporation of longer-term load growth projections which include industrial growth from hydrogen production, data centers etc. A significant increase in industrial load will also increase load rotation challenges, necessitating the deployment of new solutions such as microgrids to mitigate customer impacts.

Section 2.2.3.3. County-Based Models. A critical phase of the review and modeling benchmark for events is the incorporation of insights from experts responsible for community emergency response. Each of the County based models as well as key insights that are gathered from each County Emergency Operations Center are defined based on counties shown within the territory map below:

<u>Figure AC-5</u>



Section 2.2.3.4. Guidance from the Public Utility Commission of Texas. Additionally, insights were gained from the recent PUC report.

Section 2.2.4. Damage Prediction Modeling

Following an analysis of potential enhancements, CEHE worked to revise the previous damage prediction model to assist in estimating the number of mutual assistance crews needed to achieve a desired restoration rate, recommend the optimal staging site locations to activate, identify locations for potential temporary generation deployments and areas for augmented field crew resource allocations based on predicted geographic concentrations of longer duration outages relative to other portions of the system.

Section 2.2.4.1. Model Variables. For extreme temperature events with temperatures above or below the normal operating conditions of the transmission and distribution grids, the majority of outages are expected to be from outside causes including loss of transmission generation (in cold temperatures) and salt contamination accumulation along coastal area equipment such as insulators.

Section 2.2.4.2. Segmentation. When applied at a system-wide level, these calculations provide a generic prediction of the mutual assistance needs required to meet the desired restoration duration; however, these predictions can be improved by segmenting the service territory into more discrete geospatial areas.

Section 2.2.4.3. Project Selection and Locations. Projects to mitigate the effects of extreme temperature events were evaluated for both the Transmission and Distribution systems.

Transmission. Transmission assets have a higher risk of galloping conductors due to the wider Rights of Way (ROW) and taller construction heights.

Distribution. Distribution assets have not typically experienced mechanical failure during extreme temperature events; however, design changes following recent extreme temperatures (extremely hot or cold temperatures causing equipment to operate outside its operating parameters) have aided in reduced mechanical failures during extreme temperature events.

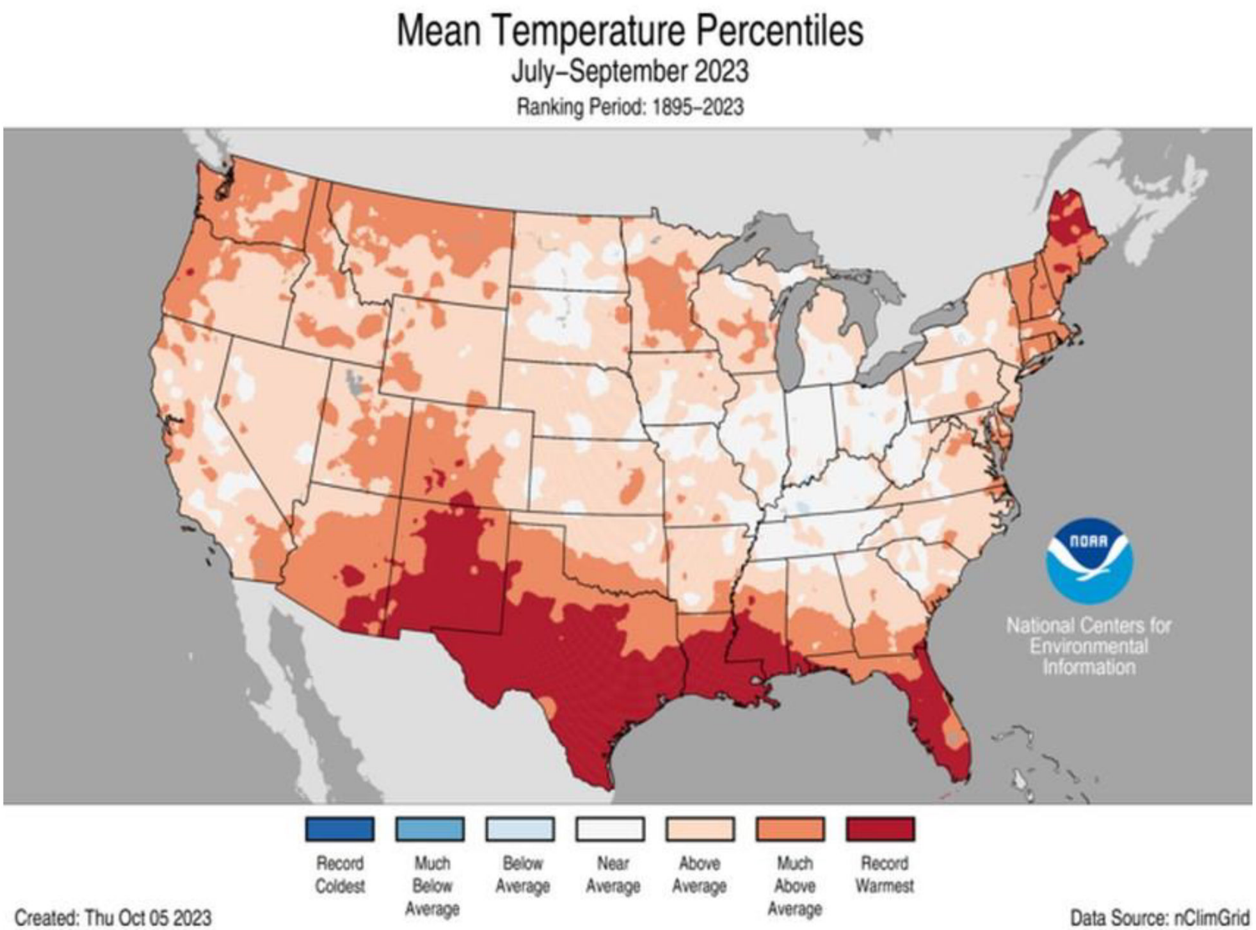
Prioritization. Model based prioritization of project locations used location risk, accessibility, and critical customers to identify mitigations for reducing CMI during extreme events. The selected mitigations will also have benefits from a reliability perspective to help improve reliability in addition to resiliency.

Appendix D - Extreme Temperature Events (Heat)

Section 1. Overview of the Company's Service Territory

The risk from extreme heat and drought events is related to the average peak temperatures and amount of precipitation both inside and outside the Company's service territory. Load within the ERCOT region correlates to ambient temperature with peak loads typically occurring after successive days of extreme heat. A series of extreme temperature days causes more air conditioners to run simultaneously increasing customer demand. The increased load can stress distribution system transformers and often results in higher probability of failure. The Company's service territory experienced its hottest and driest summer on record during 2023 as shown in the figure below[1].

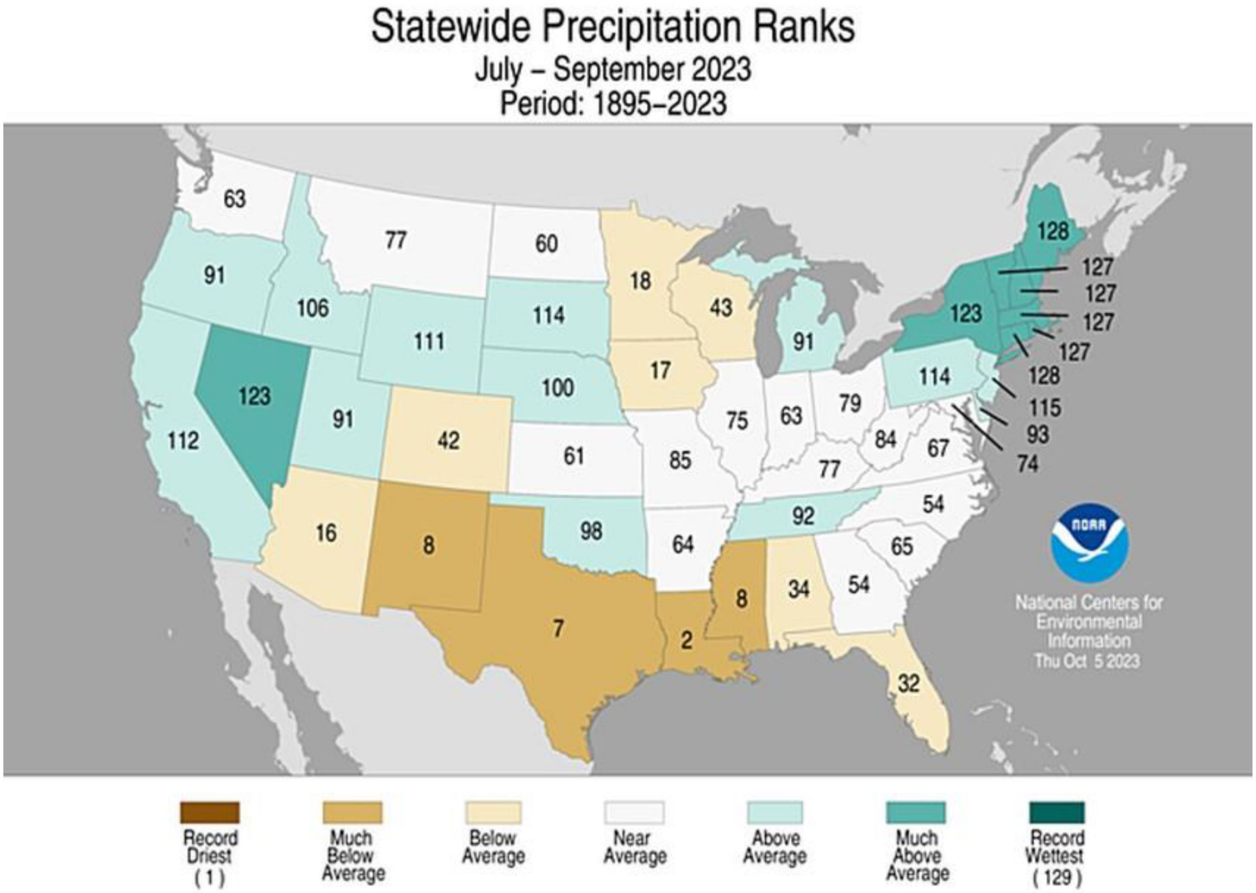
Figure AD-1



In addition to increased customer load from extreme temperatures, the lack of precipitation can increase risks of insulator flashover from contamination and wildfire. In 2023, Texas was experiencing its seventh driest year on record as shown in the figure below and one of the 5 driest summers for the Houston Area.

[1] Source: (Taking a look back at the worst summer Houston has ever experienced – Space City Weather)

Figure AD-2



Due to the fact the Company regularly imports up to 60% of the power needed for customer demand, conditions outside the service area can have a significant impact for the Houston area customers. While flashovers from contamination most likely result in localized outages, impacts from wildfires which compromise tie-line transfer capability could lead to severe impacts up to regional load shed for customers in the Company's service area.

2. Section 1.1. Preparation for Temperature (Heat) Events

Section 1.1.1. Modeling.

Modeling for extreme temperature events relies on a number of techniques including power flow, climatological, LiDAR based assessment of vegetation and conductor slack. Each of these models intends to determine how the event will affect the Company's assets and associated customer impacts. Climate Modeling is performed annually to determine if the season has the potential to impact CEHE's service territory.

Power Flow Modeling. Power flow, or load flow, is widely used in power system operation and planning. The power flow model of a power system is built using topological models of the distribution and transmission network, customer load demand, and expected generation dispatch. Outputs of the power flow model include system voltages and line flows used to determine the operational risk from normal and contingency conditions. To identify resiliency related projects, system planning engineers start with the normal system configuration and remove elements from service to simulate equipment failures. Following the simulation of the failure, assessments are made regarding the ability to reasonably restore customers to avoid sustained outages.

Climatological Modeling. Data related to wind and precipitation is used to estimate the effects of weather patterns on power system equipment. The lack of precipitation which can occur during extreme temperature and drought conditions can result in insulator contamination even in the absence of prevailing strong southeast winds. The modeling estimates when critical levels of contamination may occur as well as the most susceptible locations.

Vegetation Modeling. Vegetation models work to identify locations within High Fire Risk Areas (HFRAs) for vegetation management, fall in risk reduction and strategic undergrounding. Following the identification of risk, alternative mitigations can be evaluated for their ability to mitigate ignition risk and reduce the need for public safety power shutoffs.

Fire Spread Modeling. A simulation of wildfires to comprehend and predict fire behavior. Wildfire modeling can aid in increasing safety of the public and the Company's employees when extreme events result in fire spread. The use of fire spread models is often a collaborative effort with utilities coordinating with County OEMs, firefighters, academia and the public for education as well as situational awareness.

Section 1.1.2. Structural Hardening.

Structural hardening is utilized to reduce risks from extreme temperature events by increasing capacity to avoid failures from overloads, decrease the risk of flashover from salt contamination and mitigate the risk of ignition as well as fire spread.

Capacity Additions. The Company operates a distribution system with both 12kV and 35kV feeders. Where these systems are adjacent to each other, switching options may be limited resulting in longer outage durations for customers. Similar situations can result at the service center boundary where limited switching options may exist. Capacity added in the form of transformers and feeders provides the ability to restore customers following a contingency.

Substation Fire Barriers. The Company's Substation Fire Protection Barriers Resiliency Measure will install physical fire protection barriers, either concrete or metal, to protect power transformers and other equipment vulnerable to damage caused by the catastrophic failure of adjacent transformers. The Company proposes to install four fire protection barriers a year. Although substation transformer failures are uncommon compared to other distribution equipment failures (e.g., broken poles), the consequences and impact of a catastrophic failure can be severe. An enormous amount of energy is released when a transformer catastrophically fails, with the possibility of extensive damage to nearby equipment from associated fire and debris. The potential for lengthy outages and costly repairs if this were to occur is high. Extinguishing the fire also presents challenges to fire department personnel.

Underground Cable. Underground Cable is a growing portion of our distribution system, and it houses a number of critical customers (Medical Center and Downtown are examples). The conductors and duct banks that feed these facilities are aging and in need of refurbishment. Further, URD cables are in need of rejuvenation as well. A proactive approach will revitalize the underground cable systems and allow further resiliency from a significant number of extreme weather resiliency events.

Contamination Mitigation. Coastal components such as insulators and hardware can be replaced with more resilient versions to resist the effects of salt contamination and customer outage risk. The avoidance of flashovers can also reduce the probability of pole fires which could create an ignition risk. In addition to hardening the overhead systems, strategic undergrounding is an additional option for mitigating coastal contamination risks.

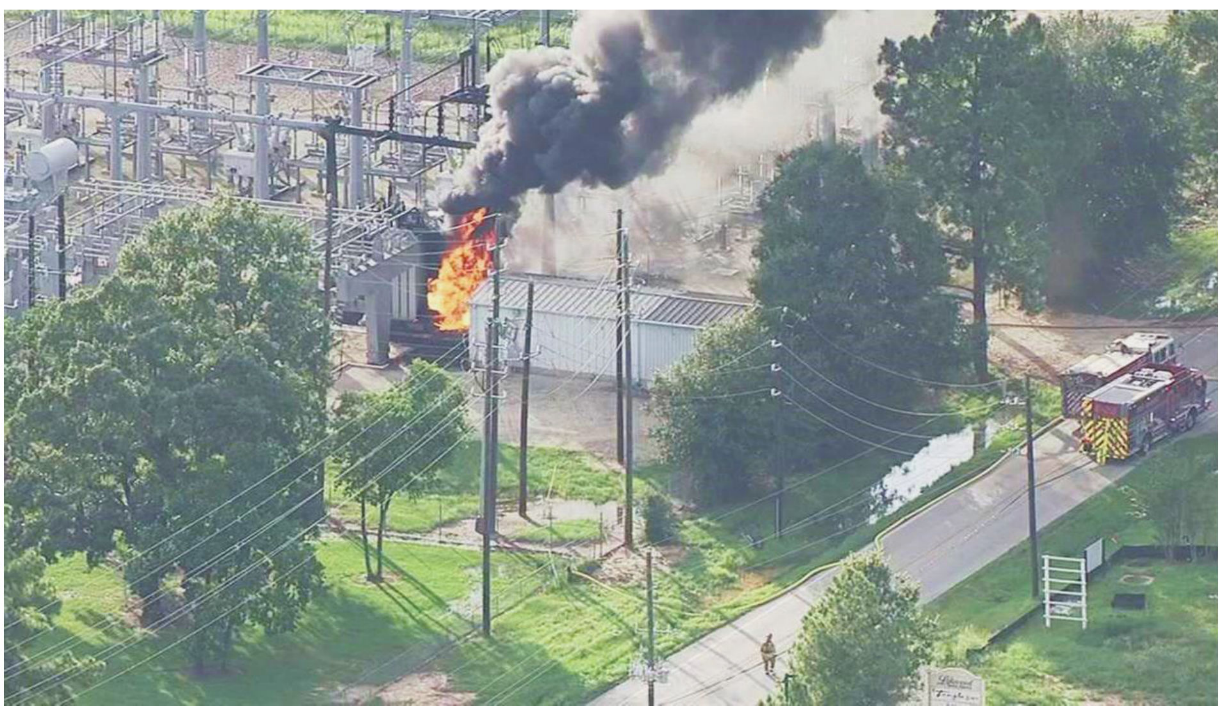
Vegetation Management. The ability to mitigate the vegetation risk can utilize various approaches including vegetation removal, relocation of infrastructure, and strategic undergrounding. Each of the options are considered for their ability to mitigate extreme temperature risk in addition to other extreme scenarios.

Digital Substations. The deployment of digital protection systems in substations allows for the use of advanced protection settings to reduce ignition risk and to leverage newer and more effective technologies (such as fiber optic cables instead of copper wires, merging units, and digital relaying). The relay settings can include reclose blocking, fast fuse curves and more sensitive ground fault protection. Enhanced system protection reduces the likelihood of ignition by allowing the use of functions not available in electromechanical relays.

Section 1.1.3. Asset Monitoring.

In the past 5 years, the Company experienced 5 transformer failures with 80% of the failures occurring in the summer months. The figure below shows a transformer failure from 2016 which propagated the control house requiring a complete replacement of the control house as well as the transformer. Substation fire barriers prevent the propagation of failures to limit the required asset replacement. Due to the propagation of the fire, the entire substation had to be de-energized placing a priority on adjacent feeder capacity to restore the several thousand customers out of service. The overall reconstruction of the substation required 9 months.

Figure AD-3



The result of contamination can be dry band arching with the potential to start pole fires. Dry band arcing is a process that can lead to wildfires and pole fires. It occurs when contaminants, such as salt moisture, dry and stick to the surface of overhead equipment and form a dry band that conducts electricity. The dry band can then heat up the metal king bolt that connects the crossarm to the pole, igniting the pole with hot embers or an all-out pole fire (if left long enough) and cause a wildfire. In cases where the insulator is on a metal structure such as in a substation, the risk of ignition is greatly reduced; however, customer outages are still a concern.

Figure AD-4

When extreme temperature events impact a significant portion of the Company's service territory, more than 60% of the 1,800 distribution feeders are exposed to the possibility of being disconnected from their substations. Such a severe outage scenario could result from a wildfire limiting transfer capability within the Company's service territory. Such a scenario nearly occurred in 2011 when wildfires threated transmission lines used to import power to the Houston area. These fires are shown in the figure below.

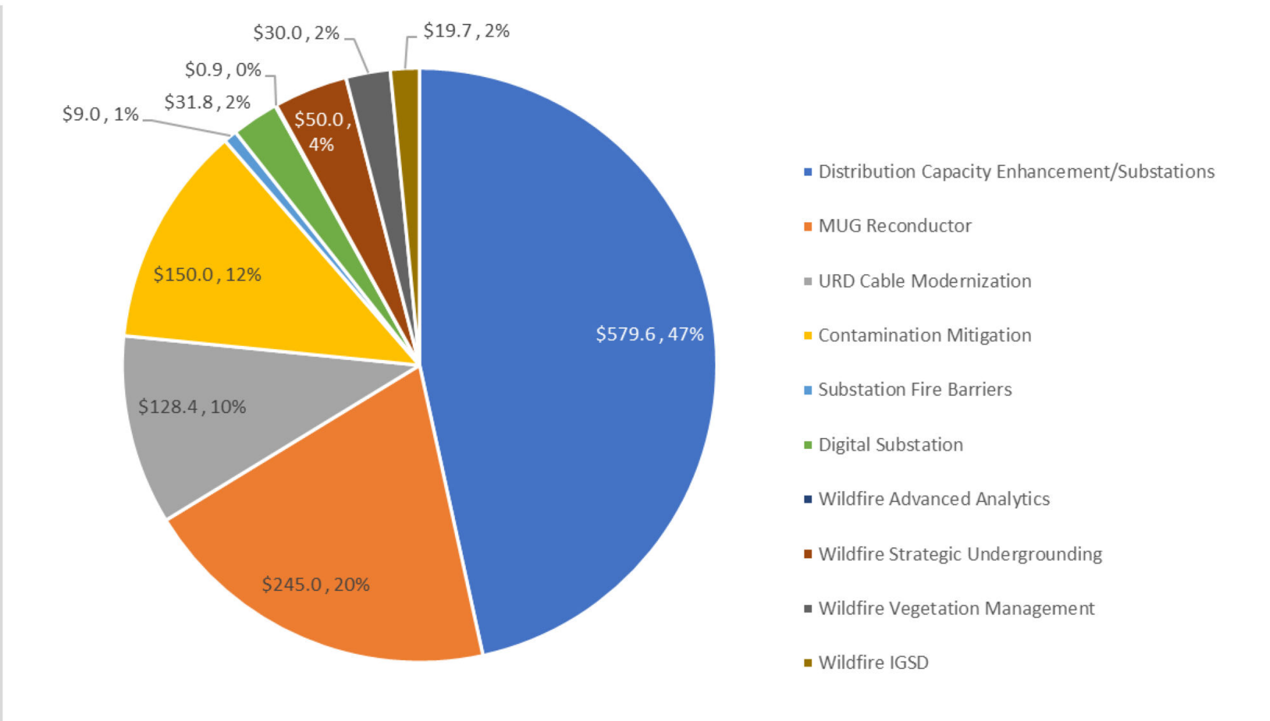
Figure AD-5

3. Section 2. Advanced Modeling Methodology

Section 2.1. Cost Allocation

For extreme temperature heat events, Distribution Capacity Enhancements have the highest allocation of dollars, followed by Contamination Mitigation and Wildfire. Distribution Capacity Enhancements aid in mitigating risks beyond extreme temperature drought conditions and provide benefits in any scenario which requires contingency switching to restore out of service customers. These scenarios can include extreme wind, extreme water, extreme temperature freeze and physical attack adding to the overall value of these investments. The allocation of investments for extreme temperature heat is shown in the figure below.

Figure AD-6



Section 2.2. Characterization of Temperature Events

The Company used advanced modeling to characterize extreme temperature heat risks, expected operational impacts and associated repair times of predicted damage. Furthermore, the analysis uses climate projections to complete a Benefit Cost Analysis ("BCA") over a longer period which accounts for changes in frequency and intensity of events. The BCA was calculated using the total cost of the extreme temperature heat mitigations and the benefits associated with faster event restoration or outage avoidance. The mitigations included in this resiliency plan are expected to reduce customer minutes of interruption by 183.1 million CMI. The following pages offer a detailed explanation of the event types, event sequence of events, present susceptibility of assets and historical events, the modeling methodology used to forecast future customer impacts, a review of best practice benchmarks and alternatives, prioritization of mitigations, as well as project selection and locations. The section concludes with additional details on the customer benefits of the mitigation within the context of an extreme temperature heat event.

Section 2.2.1. Risk Characterization by Event Type

Extreme temperature heat events can cause customer outages from a single event type or multiple event types occurring simultaneously. Conditions related to extreme heat events typically increase in severity over a time period of days or weeks until they reach a critical point. This assertion is supported by NOAA's statement that "It is a creeping phenomenon that slowly sneaks up and impacts many sectors of the economy and operates on many different time scales." (Did You Know? | Definition of Drought | National Centers for Environmental Information (NCEI)) This aspect makes pre-event hardening as well as monitoring and modeling an important component of mitigation. When the surface water in the tropical Pacific Ocean near Mexico and South America warms more than usual, it is known as a climate pattern called El Niño, which can help fuel more rain in Texas and the southern U.S. But when it is cooler than normal, the climate pattern is known as La Niña and tends to shift rainfall and cooler temperatures toward the north of the U.S., leaving the south with drier and hotter conditions. Summer weather, including triple-digit temperatures, also intensify drought conditions. The high temperatures, which are experiencing an increasing trend, make it easier for water to evaporate and harder for soil to retain moisture. El Niño and La Niña shift irregularly every two to seven years leading to a cyclical risk profile for extreme events. (A Texas drought threatens water supply, agriculture | The Texas Tribune)

Section 2.2.2. Planning and Response

Section 2.2.2.1. Pre-Event. The Company continuously monitors weather conditions for trends which may contribute to elevated risk profiles related to extreme temperatures. In addition to 3rd Party weather services, the Company's internal meteorologist provides daily reports to aid in situational awareness. For some event types, the Company utilizes sensor and monitoring technologies to signal a need to initiate mitigation projects or operational response. The nature of extreme temperature heat events leads to simultaneous effects of the system. As temperatures begin to increase in May, customer loads begin to place more load on system equipment. The increased load results in a higher probability of failure for transformers and underground cable. The increased heat can also decrease moisture, increasing the dry fuel risk related to wildfires and contamination buildup on insulators. The Company continually monitors conditions for initiating event specific mitigation actions such as relay settings changes, enhanced field inspections and insulator washing.

Weather Modeling. CenterPoint's meteorologist is producing daily weather updates, with a goal to expand coverage and frequency as the meteorology group grows. At present, the meteorologist uses all publicly available weather data (from NOAA, ECMWF, etc.) in addition to several proprietary weather models run by 3rd party vendors (StormVista, StormGeo, etc.) to assess and forecast conditions hours to days in advance across CenterPoint's service territories, with a heavy focus on the Greater Houston area. Over the next 6 months and beyond, the meteorologist will work to procure access to higher resolution modeling, specific and tuned to CenterPoint's service territories. CenterPoint is also going to deploy 100 weather stations to fill data coverage gaps in the Greater Houston area over the next six months and additional weather stations in the future that will also be part of the effort to improve forecast modeling for Houston, giving the meteorologist a unique and highly sophisticated forecasting tool to use to compliment the other data being used to create forecasts at present. CenterPoint will also engage Texas universities to develop an additional unique forecasting tool, rooted in machine learning and AI within the next few years. In addition to the daily weather model reports, annual climate assessments will be performed to determine longer term seasonal risk as well as informing project and operational decision making.

Mutual Assistance. Mutual assistance resources are estimated based of the expected level of damage from the impending event. The majority of extreme temperature events are expected to be managed using internal, on system contractors or specialized contract crews such a helicopter washing crews; however, wide-spread events requiring infrastructure rebuilds, such as wildfire, may require mutual assistance. Wildfire risks also increase the need for collaboration with external stakeholders responsible for wildfire monitoring, mitigation, and response.

Staging Sites. Staging Sites will be dependent on the number of mutual assistance resources required to respond to the event.

Critical Customer Restoration. The Company maintains a database of priority customer locations in addition to utilizing processes during significant events to prioritize restoration. The damage prediction modeling assist in forecasting when critical customers may be in areas of more significant damage. These predictions can assist in prioritizing restoration crews and/or the deployment of temporary generation as well as supporting the selection of hardening projects.

Public Safety Power Shut-off. In some cases, utilities de-energize circuits in the interest of public safety. To help mitigate the risk of wildfire ignition by company-owned assets, CEHE has developed a Public Safety Power Shutoff (PSPS) program. The objective of the PSPS program is to keep communities safe during wildfire-related weather conditions by proactively de-energizing CEHE facilities in areas that meet certain thresholds. PSPS threshold conditions are defined by several metrics, including, but not limited to: Wind Speed; Relative Humidity; Fuel Models; and asset data.

Section 2.2.2.2. Response. Upon initial impact of the extreme temperature event, a combination of temporary and permanent outages could occur on the system; however, monitoring typically results in mitigations beginning prior to outages. The typical actions taken during each event type is outlined below.

Capacity Additions. As the Company monitors loading on equipment, it determines options to mitigate overloads by rerouting power to other circuits. Overloads do not have to result in failures to necessitate the rerouting of power. Alternatively, the rerouting of power can aid in avoiding failures and prolonged customer outages. In order to perform switching operations to reroute power, adjacent circuits need to be of the appropriate voltage and have adequate capacity. Control center personnel open and close switches in real-time to manage system loading based on the installed capacity resulting from the annual capacity planning and construction process.

Substation Fire Barriers. In the event a substation transformer failure does occur, the company will de-energize all affected equipment within the substation and attempt to utilize contingency capacity to mitigate prolonged customer outages.

Underground Cable. In order to minimize the outages for customers fed from underground circuits, an overhaul of the cables and duct bank is necessary along with cable rejuvenation in URD cable systems. Undergrounding is one of the most effective methods for mitigating against most extreme weather events. These measures will mitigate prolonged customer outages within underground networks and URD systems.

Contamination Mitigation. Monitoring for contamination along with field inspections and washing are becoming more critical to the health of equipment located in contamination areas. Insulators have come a long way, but salt contamination can still occur leading to arc flash-overs and pole and equipment fires.

Monitoring and automation will attempt to mitigate these contamination fires and allow for reduced outages within these contamination areas.

Vegetation Management. LiDAR will be leveraged within the identification process to allow for a much greater perspective of the necessary trimming needing to take place and is more effective than field inspection, although field inspection is still necessary to gain a better picture of how overgrown areas and trees are. Overall, an improved cycle of vegetation trimming will improve circuit reliability and reduce outage duration for customers.

Digital Substation. Moving to an improved technology within the substation will allow for faster installation times, mitigate against physical attack, and improve the overall operation through improved technologies (software, relaying, and fiber optic cabling). Moving to a digital platform will also allow for improved special protection settings that can enable improved protection and allow for reduced outages for distribution customers.

Section 2.2.3. System Susceptibility to Extreme Temperature Resiliency Events

Section 2.2.3.1. Historical Temperature Events. The Company is constantly identifying lessons learned and opportunities for enhancement of design and processes for each successive event. In 2022, there were a total of 22 days of temperatures exceeding 100 degrees experienced. The summer of 2023 was historic from both temperature and lack of precipitation. In 2023, 23 consecutive days above 100 degrees were experienced with a total of 45 days exceeding 100 degrees for the year (second hottest and driest summer on record). Added stress from this extreme heat and drought condition caused a significant number of failures throughout the 2022 and 2023 timeframe. Equipment failures attributed to these extreme weather events include underground residential transformers totaling 1131 in 2022 and 965 in 2023.

Section 2.2.3.2. Benchmark Events. While all significant events provide lessons learned, benchmark events are those which resulted in the highest customer impacts for a given event type.

Substation Transformer Failures. Transformer failures are not common but do occur and are extremely volatile when they do occur, often causing damage to equipment adjacent if left unprotected. Between 2003 and 2023 there have been a noted 9 catastrophic fire events within substations (not all involved other equipment). Each of these events has provided insight into the catastrophic nature of failed transformers and the need to isolate these devices to mitigate against involving other equipment.

Coastal Contamination. 2011 was the hottest and driest summer on record. This led to a significant number of contamination events and aided in the further development of power washing insulators and substation bushings. Further enhancing this plan, in 2023 similar contamination buildup was seen as this was the second hottest and driest summer on record (by a single day).

Wildfire. In 2011, the state of Texas was hit hard by a significant number of wildfires, specifically in central Texas and the Hill Country. One of these outbreaks of Texas Wildfire included the Riley Road wildfire in the Northwestern portion of the Company's territory. Lessons learned centered around alternate designs.

Wildfire. 2024 also saw one of the most devastating wildfires in Texas, known as the Smokehouse Creek Fire located in the Panhandle. This fire tore through over 1 million acres and impacted communities in Hemphill and Roberts counties including the entire town of Canadian, ultimately destroying over 100 homes and stranding over 11,000 people without power. A second notable fire was the fire located in

Brazoria County Wildfire. Although this did not directly impact customers, it shows the Gulf Coast of Texas and the Company's territory is not immune to wildfires.

Section 2.2.3.3. County-Based Models. A critical phase of the review and modeling benchmark for events is the incorporation of insights from experts responsible for community emergency response. During discussions with the County OEMs the Company was able to receive feedback related to extreme heat related concerns and observations. These meetings also gave the company an opportunity for information sharing of County OEM wildfire concerns and associated data.

Section 2.2.3.4. Guidance from the Public Utility Commission of Texas. Additionally, insights were gained from the recent PUC report.

Section 2.2.4. Damage Prediction Modeling

Following an analysis of potential enhancements, CEHE worked to revise the previous damage prediction model to assist in estimating the number of mutual assistance crews needed to achieve a desired restoration rate, recommend the optimal staging site locations to activate, identify locations for potential temporary generation deployments and areas for augmented field crew resource allocations based on predicted geographic concentrations of longer duration outages relative to other portions of the system.

Section 2.2.4.1. Model Variables. For extreme temperature events with temperatures above normal operating conditions of the transmission and distribution grids, the majority of outages are expected to be from equipment loading.

Section 2.2.4.2. Segmentation. For extreme temperature heat scenarios, circuit segmentation is determined by the event type and although segmentation is applicable to all extreme event types for extreme temperature heat it is most frequently associated with post-contingency switching and wildfire. In response to an event, control center operations personnel will utilize remote switching capabilities to isolate the affected portion of the circuit minimizing the outage to the fewest number of customers in the shortest period of time. If opportunities exist, further isolation will be accomplished with manual switching by restoration personnel in the field. Optimally placing segmentation devices results in the fewest customer minutes of interruption during extreme temperature events.

Section 2.2.4.3. Project Selection and Locations. Projects to mitigate the effects of extreme temperature events were evaluated for both the Transmission and Distribution systems.

Prioritization. Model based prioritization of project locations used location risk, accessibility and critical customers to identify mitigations for reducing CMI during extreme events. The selected mitigations will also have benefits from a reliability perspective to help improve reliability in addition to resiliency.

Appendix E –
System Resiliency Plan Requirements Met in the Company's Filing

Subsection of Resiliency Plan Rule	Requirement	Relevant Section in Testimony
(c)(1)	Each resiliency measure must utilize at least one of the listed methods: harden facilities, modernize, bury lines, mitigate lightening or flooding, IT, physical security, vegetation/wildlife management	SRP, Figure SRP-17 "Resiliency Measures by Category"
(c)(2)	Plan must be organized by measure	Reflected throughout SRP Section 5 (Sections 5.1.5, 5.2.5, 5.3.5, 5.4.5, 5.5, 5.6, 5.7)
(c)(2)	Describe actions, equipment, etc. associated with each measure	SRP, "*Description*" subsection for each Resiliency Measure
(c)(2)(A)	Identify risk (or risks) posed by resiliency events this measure will address	SRP, "*Relevant Details"* subsection for each Resiliency Measure
(c)(2)(A)(i)	Explain prioritization of resiliency events (and if applicable, any geographic area, facilities, etc. Prioritized in a resiliency measure)	SRP, "*Prioritization*" subsection for each Resiliency Measure
(c)(2)(A)(ii)	Present evidence on efficacy of this measure *in* preventing, withstanding, mitigating or recovering from the identified resiliency event(s) Evidence better if quantitative or performance-based	SRP, "*History of Effectiveness*" subsection for each Resiliency Measure
(c)(2)(A)(iii)	Explain expected benefits of measure	SRP, "*Relevant Details"* subsection for each Resiliency Measure
(c)(2)(A)(iv)	Identify if a measure is coordinated with federal, state, or local government programs/funding	Akram Testimony, Section V; SRP, "*Relevant Details"* subsection for each Resiliency Measure

Subsection of Resiliency Plan Rule	**Requirement**	**Relevant Section in Testimony**
(c)(2)(A)(v)	Explain why this measure was picked over alternatives, using sufficient analysis/evidence.	SRP, "*Alternatives Considered*" subsection for each Resiliency Measure
(c)(2)(A)(vi)	Identify if an outage may be necessary for implementing the measure	The Company does not anticipate any complete transmission system outages will be required; SRP, "*Description*" subsection for each Resiliency Measure
(c)(2)(A)(vi)	Upon request, a copy of CenterPoint Houston's Resiliency Plan must be given its ISO	The Company will comply with this requirement upon such request(s)
(c)(2)(B)(i)	Plan must identify and describe each resiliency event and related risks that the plan is designed to address	SRP, Section 4.2, Figure SRP-15
(c)(2)(B)(i)	Define each resiliency event	SRP, Section 4.1, Figure SRP-12
(c)(2)(B)(ii)	Magnitude thresholds included in definition, as appropriate	SRP, Section 4.1, Figure SRP-12
(c)(2)(B)(iii)	Describe system characteristics making it susceptible to each event identified	SRP, Section 4.2, Figure SRP-16
(c)(2)(B)(iv)	Evidence supporting the presence/risk of each event identified. Must include historical evidence, and (if applicable) forecasted risk.	SRP, Section 4.2, Figure SRP-15; Reflected throughout SRP Section 5 (Sections 5.1.1, 5.2.1, 5.3.1, 5.4.1, 5.5.1); Mercado Testimony, Section VI; Ford Testimony, Section IV; Easton Testimony, Section V
(c)(2)(C)	Each measure must include a proposed metric for evaluating efficacy	SRP, "*Measuring Efficacy*" subsection for each Resiliency Measure

Subsection of Resiliency Plan Rule	**Requirement**	**Relevant Section in Testimony**
(c)(2)(C)(i)- (ii)	Plan must explain appropriateness of selected metric. If it's not quantitative, must explain why that's impossible	SRP, "*Measuring Efficacy*" subsection for each Resiliency Measure
(c)(2)(C)(iii)	Estimate or analyze efficacy of each resiliency measure using the selected metric	SRP, "*Measuring Efficacy*" subsection for each Resiliency Measure
(c)(2)(D)	Distinguish Plan's measures from similar existing programs or any measures otherwise required by law (or explain if they work in conjunction)	SRP, "*Description*" subsection for each Resiliency Measure
(c)(2)(E)	Plan must be implemented using a systematic approach over at least 3 years	SRP, Section 1
(c)(2)(E)	Explain systematic approach & implementation details for each measure, including: - Capital costs, estimated O&M, net salvage value - Remaining service life of any assets retired or replaced by resiliency-investments - Estimated timeline for completion - Identify any relevant cost drivers (ex: line miles, inspections, etc.) that would affect time/cost estimates	SRP, "*Relevant Details*" subsection for each Resiliency Measure
(c)(2)(G)	Plan must include an executive summary (or a comprehensive chart) on how it is in the public interest, events addressed, proposed measures, metrics, costs/benefits, and efficacy	SRP, Figure SRP-ES-3
(c)(3)	Portions of plan may be filed as CEII	N/A

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EXHIBIT 2

THE DIRECT TESTIMONY OF COMPANY WITNESS MR. NATHAN BROWNELL

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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

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NB-2	Customer Letters in Support
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NB-4	PA Consulting Hurricane Beryl After-Action Report
NB-5	Commission Report on Hurricane Beryl Restoration
NB-6	Comparison between the Company’s 2026-2028 T&D SRP and the Company’s 2025-2027 T&D SRP

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EXECUTIVE SUMMARY

The Company requests Commission approval of the Company's 2026-2028 T&D System Resiliency Plan in which the Company proposes to invest approximately $5.754 billion between 2026-2028 to further enhance the resiliency of the Company's transmission and distribution system. The Company anticipates that the 2026-2028 T&D SRP will provide a benefit to the customers and communities that the Company has the privilege to serve by saving approximately 1,309 million minutes of CMI. Under the 2026-2028 T&D SRP, the Company will:

- Harden, modernize, strategically underground, or elevate electric infrastructure;
- Upgrade information technology and cybersecurity infrastructure;
- Conduct accelerated vegetation management, including vegetation management to reduce wildfire risk;
- Incorporate AI and additional monitoring capability, including for wildfire risk; and
- Expand emergency response capability.

The Figure NB-1 summarizes the Company's 2026-2028 T&D SRP costs and CMI saved:

Figure NB-1
SRP Estimated Costs and CMI Saved
(in millions)

	2026	2027	2028	Total	Capital	O&M	CMI Saved
Extreme Wind	$981.2	$1,461.5	$1,570.0	$4,012.7	$3,864.7	$148.1	1,055.7
Extreme Water	$31.6	$31.7	$28.3	$91.6	$91.6	-	11.0
Extreme Temperature (Freeze)	$14.0	$21.0	$21.0	$56.0	$53.5	$2.6	5.3
Extreme Temperature (Heat)	$368.5	$430.0	$446.0	$1,244.5	$1,207.2	$37.2	183.1
Physical Attack	$12.5	$12.5	$12.5	$37.5	$37.4	$0.1	42.7
Technology & Cybersecurity	$67.2	$15.5	$10.3	$93.0	$79.6	$13.5	N/A
Situational Awareness	$88.4	$57.1	$73.3	$218.8	$209.6	$9.2	10.8
Totals	**$1,563.4**	**$2,029.2**	**$2,161.4**	**$5,754.0**	**$5,543.3**	**$210.7**	**1,308.6**

Figure NB-2 summarizes the Resiliency Event impacts that each Resiliency Measure in the Company's 2026-2028 T&D SRP is intended to mitigate against as it relates to the Company's transmission, distribution, and substation infrastructure as well as monitoring and response functions:

Figure NB-2
Resiliency Events and Mitigating SRP Measures

	Transmission	**Distribution**	**Substation and Control Center**	**Monitoring and Response**
Extreme Wind	Hardening: 1. Transmission System Hardening (RM-6 3. 69 kV Conversion Projects 4. Coastal Resiliency Projects	Hardening: 1. Distribution Pole Replacement/Bracing 2. Distribution Circuit Resiliency 3. Vegetation Management Modernization: 1. IGSD Installation Undergrounding: 1. Strategic Undergrounding		
Extreme Water		Flood Mitigation: 1. MUCAMS 2. Mobile Substations	Flood Mitigation: 1. Substation Flood Control 2. Control Center Flood Control	
Extreme Temperature (Heat)		Modernization: 1. Distribution Capacity Enhancements/Substations 2. Wildfire IGSD Installation 3. MUG Reconductor 4. URD Cable Modernization 5. Contamination Mitigation Undergrounding: 1. Wildfire Strategic Undergrounding Wildfire Mitigation 1. Wildfire Vegetation Management	Hardening: 1. Substation Fire Barriers 2. Digital Substation	Wildfire Mitigation: 1. Wildfire Advanced Analytics
Extreme Temperature (Freeze)	Hardening: 1. Anti-Galloping Technologies	Modernization: 1. Load Shed IGSD		
Physical Attack			Physical Security: 1. Substation Security Upgrades 2. Substation Physical Security Fencing	
Cybersecurity			IT: 1. Network Security & Vulnerability Management 2. Data Center	IT: 1. Spectrum Acquisition 2. IT/OT Cybersecurity

	Transmission	Distribution	Substation and Control Center	Monitoring and Response
			Modernization 3. Cloud Security, Product Security & Risk Management	Monitoring
Situational Awareness			IT 1. Backhaul Microwave Communication 2. Voice & Mobile Data Radio System Hardening: 1. Emergency Operations Center 2. Hardened Service Centers	Modernization: 1. Advanced Arial Imagery/Digital Twin 2. Weather Stations 3. Wildfire Cameras

The Company's 2026-2028 T&D SRP was developed in collaboration with Guidehouse, an independent third-party expert, and incorporates feedback received from customers, local and state officials and emergency management offices, PA Consulting in its Hurricane Beryl after-action review, and the Commission. The Company will also develop a communications plan that will be used to inform and communicate with customers and the general public regarding implementation of the Resiliency Measures in the 2026-2028 T&D SRP.

The Company's 2026-2028 T&D SRP complies with the T&D SRP Statute and the Commission's T&D SRP Rule, explains the Company's systematic approach to implement the associated Resiliency Measures, is anticipated to provide benefits to customers, and is in the public interest. Thus, the Company requests that the Commission:

- Approve the Company's 2026-2028 T&D SRP and associated Resiliency Measures;
- Include the Company's requested accounting language in the order approving the Company's 2026-2028 T&D SRP; and
- Approve the Company's proposed Microgrid Pilot Program.

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND CURRENT POSITION.

A. My name is Nathan Brownell, and I am employed by the Company as Vice President, Resilience and Capital Deliver.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND WORK EXPERIENCE.

A. I received a Bachelor of Science degree in Mining and Mineral Engineering from the Missouri University of Science and Technology, a Bachelor of Arts in Economics from the Missouri University of Science and Technology, a Master of Engineering in Mining and Mineral Engineering from the Missouri University of Science and Technology, and a Master of Business Administration from the University of Louisville. I have over 8 years of experience within the Company. In my prior roles within the CNP and legacy Vectren Corporation, my responsibilities included:

- Overseeing the operations of CNP's natural gas utility in Texas that serves approximately 1.9 million customers throughout the Greater Houston area, East Texas, and South Texas;
- Overseeing real-time distribution operations and control for the Company; and
- Overseeing metering operations and Houston emergency operations for the Company
- Overseeing substation operations for the Company.
- Overseeing gas distribution, electric transmission, distribution and substation operations in southwestern Indiana for the Company.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES AT CNP?

A. Effective January 1, 2025, I was appointed to my present position as Vice President of Resilience and Capital Delivery. To further reflect the importance of a reliable and resilient transmission and distribution system, the Company created this new executive position to ensure strategic oversight of the Company's 2026-2028 T&D SRP and execution of the Company's capital program. I will report directly to the Chief Executive Officer and I will oversee:

- The strategic implementation of the Company's 2026-2028 T&D SRP and the execution of the Company's capital program;
- The selection of regions in the Greater Houston area and portions of the Company's transmission and distribution system where Resiliency Measures will be implemented;
- The recordkeeping of the implementation of Resiliency Measures; and
- The assessment of the efficacy of implemented Resiliency Measures.

Q. AS A RESULT OF YOUR WORK EXPERIENCE AND RESPONSIBILITIES, ARE YOU FAMILIAR WITH THE RESILIENCY EVENTS THAT OCCUR AND HAVE OCCURRED IN THE COMPANY'S SERVICE AREA AND THE COMPANY'S PROPOSED RESILIENCY MEASURES INTENDED TO MITIGATE THE IMPACT OF SUCH RESILIENCY EVENTS?

A. Yes. My current and prior job responsibilities have made me well acquainted with Resiliency Events, typically extreme weather events, that have occurred throughout parts of or the Company's entire service area; Resiliency Events that are anticipated to impact our customers in the future; and Resiliency Measures that the Company is proposing in its 2026-2028 T&D SRP.

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

A. I am testifying on behalf of the Company.

Q. HAVE YOU TESTIFIED PREVIOUSLY?

A. Yes. I have filed testimony with the Railroad Commission of Texas in Gas Utility Docket OS-23-00015513.

Q. WHAT EXHIBITS HAVE YOU INCLUDED WITH YOUR TESTIMONY?

A. I have included the six exhibits listed in the Table of Contents as part of my testimony.

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

A. Yes.

OVERVIEW OF THE COMPANY'S APPLICATION

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY AND HOW IS IT ORGANIZED?

A. My testimony provides a general overview of the Company's service area, customer profile, and the resulting increased demand for electricity from customers in our service area. My testimony also describes historic and forecasted extreme weather events in the Company's service area, and the changing expectations of our customers for a reliable and more resilient electric system. With this context in mind, my testimony then provides a general overview of the Company's 2026-2028 T&D SRP; describes how it compares to the Company's 2025-2027 T&D SRP that was filed in Commission Docket No. 56548;[1] and explains how it incorporates feedback received from our customers, local and state elected officials, PA Consulting in its Hurricane Beryl after-action review, and the Commission. My testimony then explains the methodology used by the Company to develop its 2026-2028 T&D SRP; defines the Resiliency Events that are intended to be

[1] Docket No. 56548 was the Company's SRP for 2025-2027, which was subsequently withdrawn.

mitigated; and provides a general explanation of the Resiliency Measures, corresponding costs, and the anticipated benefits that the 2026-2028 T&D SRP will provide to the customers and communities that the Company has the privilege to serve.

Q. ARE THERE OTHER WITNESSES THAT SUPPORT THE COMPANY'S APPLICATION AND 2026-2028 T&D SRP?

A. Yes. In addition to my testimony, the Company offers the testimony of the following witnesses in support of the Company's Application and 2026-2028 T&D SRP:

Figure NB-3
Witnesses and Corresponding Testimony Subjects

Witness	Testimony Subject
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 & Cybersecurity Resiliency Measures

OVERVIEW OF THE COMPANY'S SERVICE AREA

Q. PLEASE DESCRIBE THE COMPANY'S SERVICE AREA.

A. The Company's service area is comprised of the Greater Houston area, which is approximately 5,000 square miles and is located along the Gulf Coast of Texas. The

Company's service area includes the city of Houston as well as cities and other areas located in the following 12 counties: Austin, Brazoria, Chambers, Colorado, Fort Bend, Galveston, Harris, Liberty, Matagorda, Montgomery, Waller, and Wharton.

Q. IS THE COMPANY'S SERVICE AREA UNIQUE?

A. Yes. The Company's service area is unique both in its size and density as well as in its vulnerability to weather and climate risks.

Q. HOW IS THE COMPANY'S SERVICE AREA UNIQUE IN ITS SIZE AND DENSITY?

A. While the size of the Company's service area comprises approximately 2% of the geographic size of the state of Texas, the Company serves approximately 25% of the load in the ERCOT power region. As discussed in Section V, the Company serves a disproportionate amount of ERCOT load due to the Company's customer profile, the fact that the Greater Houston area is the fifth largest metropolitan area in the country, and the historic customer load growth that has occurred and the customer load growth that is forecasted to occur in the Company's service area.

Q IN WHAT WAY IS THE COMPANY'S SERVICE AREA UNIQUELY VULNERABLE TO WEATHER AND CLIMATE RISK?

A. The Greater Houston area is geographically located along the Texas Gulf Coast, so many of the Resiliency Events that typically occur and are forecasted to occur in the Company's service area are related to weather conditions, specifically extreme temperature (heat and freeze), extreme winds, extreme water, lightning, flooding, tropical storms, tornadic activity, and hurricanes.

According to NOAA data presented in Figure NB-4 below, Harris County, which comprises the bulk of the Greater Houston area, has the highest possible risk and vulnerability rating for hurricane, a.k.a., tropical cyclone risk (100 out of 100), the highest possible risk and vulnerability rating for flooding (100 out of 100), a very high risk and vulnerability rating for severe storms (94.56 out of 100), and a very high risk and vulnerability rating for winter storms (65.33 out of 100). To put this risk score into perspective, Harris County's risk score of 100 is the highest in the country, much greater than the second-highest risk score in the country (Miami-Dade County's risk score of 71.53), and far greater than the risk scores for larger Texas counties, like Dallas County (53.94), Tarrant County (39.64), Bexar County (50.56), Travis County (28.97), and the state of Texas (17.29).

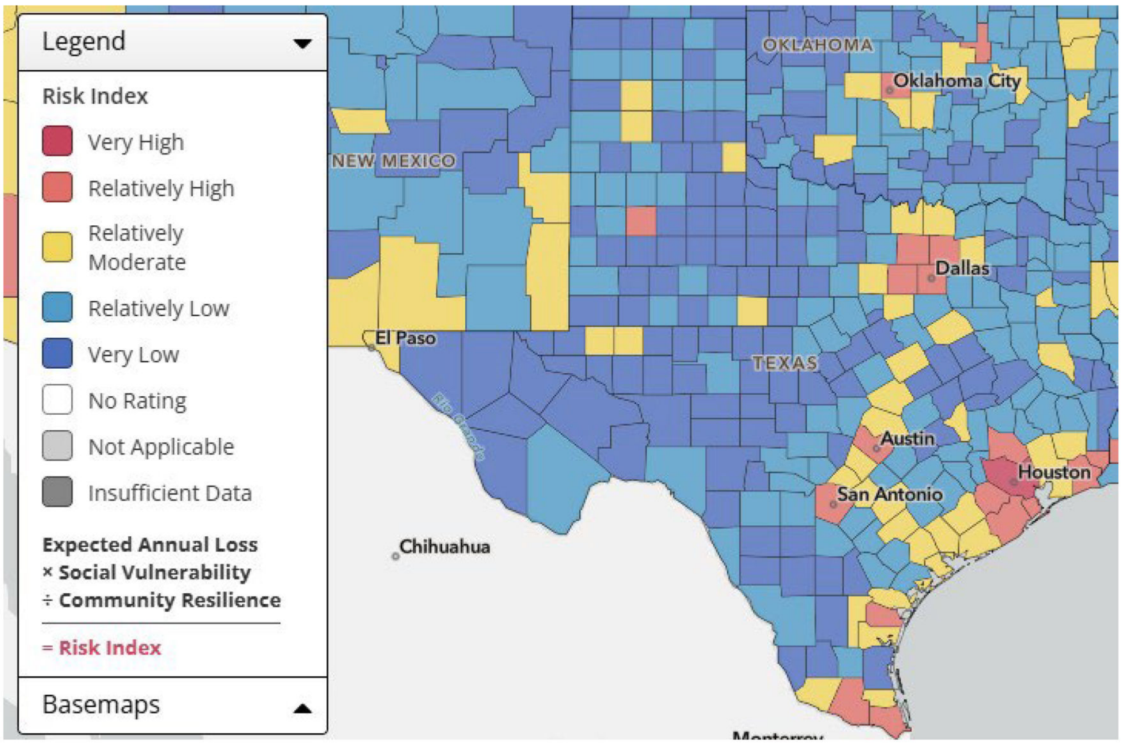
<u>Figure NB-4</u>
NOAA Weather and Climate Risk Scores (Harris County, Texas, United States)

Risk and Vulnerability

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

As depicted in the illustration below, FEMA has also categorized the Greater Houston area as being in the "very high" risk category for all hazards.[2]

<u>Figure NB-5</u>
FEMA Hazard Risk Map (Texas)

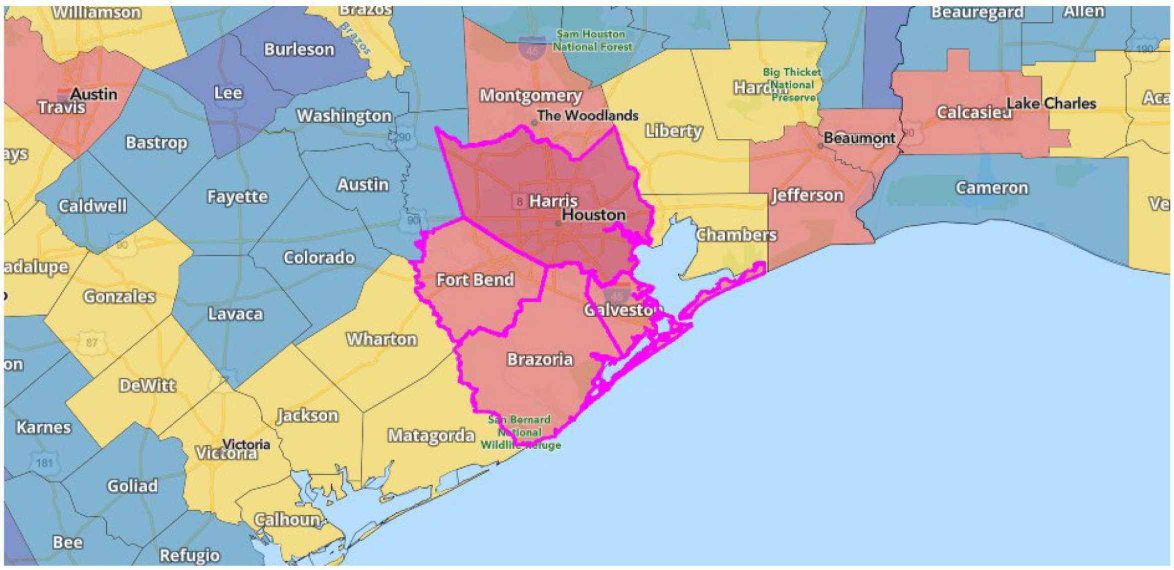


Additionally, as depicted in the table below, Harris County, Galveston County, Brazoria, and Fort Bend County, which comprise a large portion of the Greater Houston Area, have FEMA risk scores that put them in the 99.97, 99.52, 99.11, and 99.08 percentiles, respectively, in the country—a result very much in line with the NOAA data presented above.

[2] FEMA's risk index map is available online at: https://hazards.fema.gov/nri/map.

<u>Figure NB-6</u>
FEMA Hazard Risk Map
(Harris, Galveston, Brazoria, and Fort Bend Counties)

Risk Index



Risk Index Legend

Very High | Relatively High | Relatively Moderate | Relatively Low | Very Low

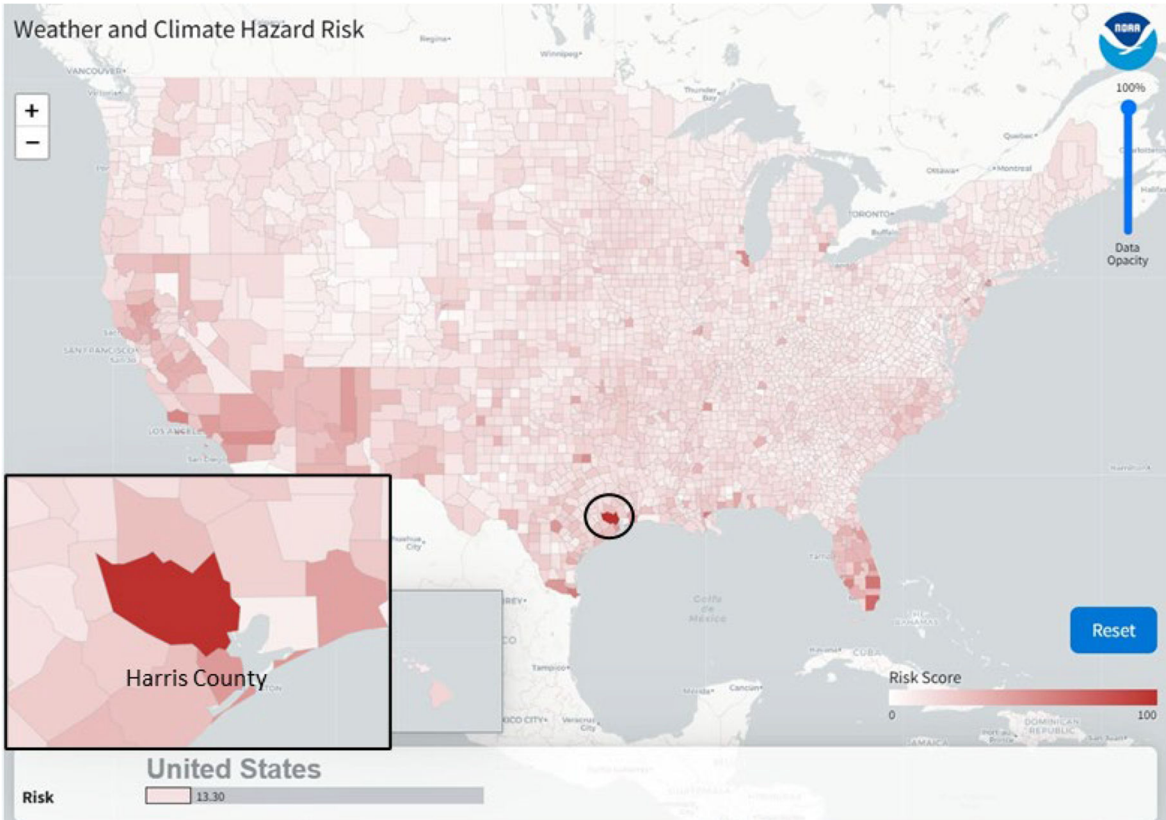
No Rating | Not Applicable | Insufficient Data

Rank	Community	State	Risk Index Rating	Risk Index Score	National Percentile
1	Harris County	TX	Very High	99.97	0 100
2	Galveston County	TX	Relatively High	99.52	0 100
3	Brazoria County	TX	Relatively High	99.11	0 100
4	Fort Bend County	TX	Relatively High	99.08	0 100

NOAA's risk map below illustrates Harris County's high risk relative to other counties throughout the country.[3]

[3] The NOAA's weather and climate risk map is available online at: https://www.ncei.noaa.gov/access/billions/risk.

<u>Figure NB-7</u>
NOAA Risk Map (United States)



Q. WHAT ARE SOME NOTABLE EXTREME WEATHER EVENTS THAT PREVIOUSLY OCCURRED IN THE GREATER HOUSTON AREA?

A. Notable extreme weather events that occurred in the Company's service area are the Memorial Day flooding in 2015, Hurricane Harvey in 2017, a microburst event in Sealy in 2017, an ice storm in 2018, Winter Storm Uri in 2021, Hurricane Nicholas in 2021, Winter Storm Elliott in 2022, an F3 tornado in February 2023, a microburst event in June 2023, the Derecho event and major storm in May 2024, and Hurricane Beryl in July 2024.

Q. PLEASE DESCRIBE THE EXTREME WEATHER THREATS THAT ARE FORECASTED TO OCCUR WITHIN THE GREATER HOUSTON AREA.

A. Based on an independent, third-party expert analysis, the Company anticipates that the Greater Houston area will see an increase in frequency and magnitude in extreme weather events. Guidehouse provided the Company with an independent analysis of the resiliency risks faced by CenterPoint Energy. The Guidehouse analysis included meetings and interviews with Company subject matter experts, a vulnerability analysis for weather-related Resiliency Events, and an assessment of the proposed Resiliency Measures using a cost-benefit framework. Additionally, the Guidehouse analysis included a comparison of the proposed Resiliency Measures to those adopted by other electric utilities.

Q. PLEASE DESCRIBE THE COMPANY'S TRANSMISSION AND DISTRIBUTION SYSTEM THAT SERVES THE CUSTOMERS IN THE COMPANY'S UNIQUE SERVICE AREA.

A. Generally, the Company's transmission and distribution system is comprised of approximately 3,900 miles of overhead transmission lines that deliver electricity at 69 kV, 138 kV, and 345 kV;[4] over 260 substations that step down (i.e., reduce) voltage to serve distribution customers; approximately 30,000 miles of overhead distribution lines and 28,000 miles of underground distribution lines and street lights; miscellaneous associated equipment (e.g. step-down transformers, insulators, capacitors, fuses); SCADA equipment, and a telecommunications network. Additionally, CNP and the Company have general technology infrastructure that provides back-office support functions necessary to provide

[4] The Company notes that it has been gradually phasing out 69 kV transmission circuits and converting them to 138 kV. One of the hardening Resiliency Measures in the Company's 2026-2028 T&D SRP is the conversion of select 69 kV circuits.

transmission and distribution service to our customers.

CUSTOMER PROFILE AND INCREASED DEMAND FOR ELECTRICITY

A. ROBUST AND SUSTAINED CUSTOMER GROWTH

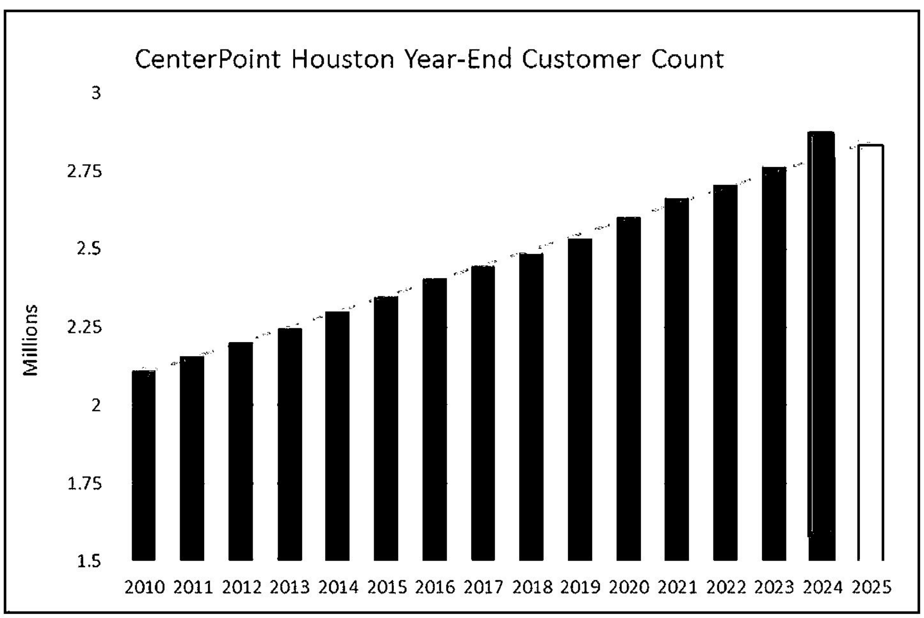
Q. HOW MANY CUSTOMERS ARE SERVED BY THE COMPANY?

A. The Company currently serves approximately 2.8 million metered residential, commercial, and industrial customers.

Q. HAS THERE BEEN CUSTOMER GROWTH IN THE COMPANY'S SERVICE AREA?

A. Yes. The Greater Houston region has experienced sustained population growth for well over a decade. In 2010, the Company had approximately 2.09 million customers, meaning that the Company experienced a 2% customer growth rate for almost 15 years. Figure NB-5 below illustrates the growth in the Company's customer count since 2010.

Figure NB-8
CenterPoint Houston Year-End Customer Count



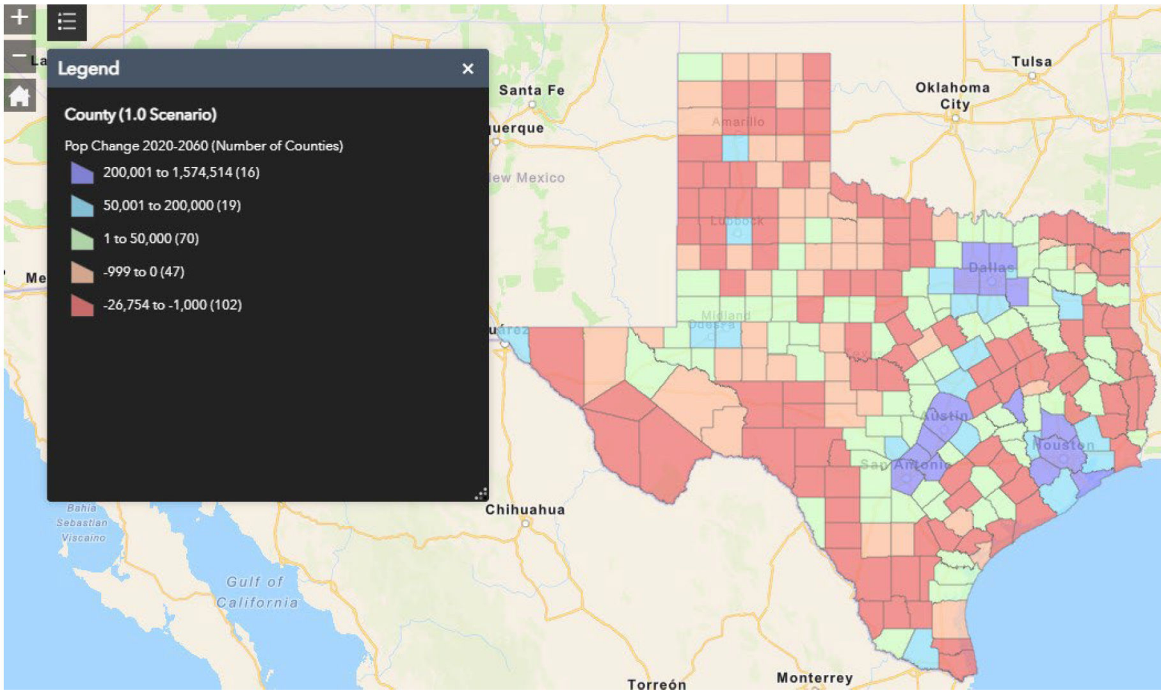
From 2019 to the present, the number of customers grew from approximately 2.5 million customers to approximately 2.8 million customers, which represents an annual customer growth rate of approximately 2.2% for the past five years. To help put this customer growth into perspective, since 2020, the Company has invested approximately $4.9 billion to build eight (8) additional distribution substations, two (2) additional transmission substations, 163 additional distribution circuits, and to install approximately 280,000 additional meters to serve these new customers.

Q. DOES THE COMPANY ANTICIPATE THAT CUSTOMER GROWTH WILL CONTINUE INTO THE FUTURE?

A. Yes. The Company anticipates that the approximate 2% annual customer growth rate will continue well into the future. The Company continues to see growth in residential and commercial customers throughout the Company's service area. As summarized in Figure NB-6, the Texas Demographic Center has projected that Harris County, the center of the Company's service area, will increase in population from approximately 1 million to 1.57 million people between 2020 to 2060. Fort Bend County, in the Southwest portion of the Company's service area, is also projected to experience similar population growth.[5]

[5] The Texas Demographic Center's interactive population project map is available online at: https://idser.maps.arcgis.com/apps/MapSeries/index.html?appid=88493fab762141d7b5a28d3430ab1ca8.

Figure NB-9
Projected Population Change, Texas Counties, 2020-2060



Q. IS THE COMPANY'S CUSTOMER PROFILE UNIQUE?

A. Yes. The Company's customer profile is unique in a few ways. First, from a population perspective, the city of Houston is the largest city in the state, and the Greater Houston area is the fifth largest metropolitan area in the country. As a result of the compact service area, large population concentration, and anticipated population growth, the Company is providing service to a large number of residential and commercial customers.

Second, because of its strategic location near the Texas Gulf Coast, the Greater Houston area has a large presence of petroleum and petrochemical refineries and related industries, meaning the Company has many industrial customers that consume large amounts of electricity. Relative to other Texas utilities, a disproportionate number of these industrial facilities are transmission-level customers.

Third, the Greater Houston area has several important public-serving facilities and infrastructure. For example, the Texas Medical Center, which is the world's largest medical complex, is home to multiple globally recognized medical and research institutions. Likewise, the Port of Houston is home to one of the country's busiest container ports.

Fourth, the Company's service area includes the potential for an increasing number of data centers as well as future hydrogen projects – two industries that require large amounts of energy, as explained in more detail below.

Finally, the city of Houston has two international airports, George Bush Intercontinental Airport and William P. Hobby Airport, which serve millions of domestic and international passengers and are hubs for connecting flights. The region is also home to NASA's Johnson Space Center. These diverse attributes collectively make the company's service area unique and significant to Texas, the nation, and global economies.

B. LARGE LOAD ADDITIONS

Q. WHAT IS THE COMPANY'S CURRENT PEAK LOAD?

A. The Company's current peak load is approximately 22,000 MWs.

Q. DOES THE COMPANY ANTICIPATE THAT ITS PEAK SYSTEM LOAD WILL GROW?

A. Yes. The Company anticipates that its peak system load will grow to approximately 30,000 MWs by 2030. This represents approximately a 36% increase over the Company's current peak load. Further, electricity consumption in the Greater Houston area is projected to continue growing to 2030 and beyond, as confirmed in a comprehensive study conducted by HETI and the Greater Houston Partnership. Specifically, HETI and the Greater Houston

Partnership's study anticipate that annual electricity consumption in the Greater Houston area will nearly triple by 2050.[6] This means that the Company's peak system load is anticipated to increase by approximately 170% within twenty-five years. This enormous customer and load growth further underscores the importance of the Company making the necessary resiliency-related investments to mitigate the impact of Resiliency Events and to be able to and to provide safe and reliable service to our customers.

Q. WHAT IS THE LOAD GROWTH ATTRIBUTABLE TO?

A. The load growth is primarily attributable to four main drivers: customer growth as a result of increased population, as previously discussed; forecasted data center demand; hydrogen projects to be sited in the Greater Houston area; and increased electrification.

Q. PLEASE EXPLAIN WHY THE COMPANY ANTICIPATES GROWTH IN DATA CENTER LOAD.

A. Currently, Houston has nineteen data centers located within its city limits.[7] Data centers are "one of the most energy-intensive building types."[8] Data centers consume 10 to 50 times more energy per square foot than a typical commercial office building.[9] In contrast with a traditional commercial office building, data centers may require additional electric infrastructure such as a dedicated substation consisting of high voltage transformers,

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[6] *Exploring Future Electricity Demand*, Houston Energy Transition Initiative at 20, Figure 6 (Jun. 20, 2024). Link: https://htxenergytransition.org/wp-content/uploads/2024/06/06.19.24-HETI-Power-Management-Report-V1-1.pdf.

[7] *Summary of Texas's Data Centers*, Data Center Journal. Link: https://www.datacenterjournal.com/data-centers/texas/.

[8] *Data Centers and Servers*, Department of Energy. Link: https://www.energy.gov/eere/buildings/data-centers-and-servers.

[9] *Id.*

breakers, switches, telemetry devices, and relays to ensure safe and reliable service. The rising use of AI by data centers will result in an additional increase in electricity demand. The U.S. EIA expects that electricity demand from large-scale computing facilities in the ERCOT power region will increase by approximately 60% from 2024 to 2025.[10] The Company has seen a considerable increase in interconnection requests from data centers, going from 1,000 MWs of data center load to over 8,000 MWs of data center load over the past year.

Q. PLEASE EXPLAIN WHY THE COMPANY ANTICIPATES GROWTH IN HYDROGEN-RELATED LOAD.

A. As part of the IIJA, also known as the Bipartisan Infrastructure Law, the Greater Houston area has been selected by the DOE as the site for the future Gulf Coast Hydrogen Hub.[11] The Gulf Coast Hydrogen Hub will "develop salt cavern hydrogen storage, a large open access hydrogen pipeline, and multiple hydrogen refueling stations. The Gulf Coast Hydrogen Hub will use the hydrogen for fuel cell electric trucks, industrial processes, ammonia, refineries and petrochemicals, and marine fuel (e-Methanol)."[12] Hydrogen-related activities for the Gulf Coast Hydrogen Hub will be energy intensive, as confirmed in the comprehensive study by HETI and Greater Houston Partnership study.[13] In addition

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[10] *Data Centers and Cryptocurrency Mining in Texas Drive Strong Power Demand Growth,* U.S. Energy Info. Admin. (Oct. 3, 2024).

[11] Link to DOE page: https://www.energy.gov/oced/regional-clean-hydrogen-hubs-0.

[12] Link to DOE page: https://www.energy.gov/oced/regional-clean-hydrogen-hubs-selections-award-negotiations.

[13] *Exploring Future Electricity Demand*, Houston Energy Transition Initiative at 20-21 (Jun. 20, 2024). Link: https://htxenergytransition.org/wp-content/uploads/2024/06/06.19.24-HETI-Power-Management-Report-V1-1.pdf.

to the Gulf Coast Hydrogen Hub, the Company has also received requests to interconnect other hydrogen-related projects.

Q. HAS THE STATE OF TEXAS RECOGNIZED THE GROWTH AND IMPORTANCE OF HYDROGEN-RELATED PROJECTS?

A. Yes. Recognizing the growth of hydrogen-related projects in the state of Texas, the 88th Texas Legislature created the Hydrogen Production Policy Council to study and make recommendations for a policy framework around hydrogen energy development in the state of Texas. The Hydrogen Production Policy is chaired by the Chair of the RRC and has ten (10) appointed members, some of which are representatives of the hydrogen industry. On December 4, 2024, the Hydrogen Production Policy Council issued its report to the 89th Texas Legislature.[14] The Hydrogen Production Policy Council's report found that by 2050:

- The state of Texas could see approximately $247 billion in hydrogen-related investments;
- New demand for approximately 70,000 to 90,000 MW of electricity; and
- The addition of approximately 90,000 to 180,000 jobs in the hydrogen industry.[15]

The report's findings further confirm the Company's belief that it will see significant growth in hydrogen-related load.

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[14] The Hydrogen Production Policy Council Report is available online at: https://www.rrc.texas.gov/media/4knabnt2/texas-hydrogen-production-policy-council-report-1224.pdf.

[15] *Hydrogen Energy Development in Texas*, Hydrogen Production Policy Council Report at 10.

C. TREND TOWARD ELECTRIFICATION

Q. IN ADDITION TO LOAD GROWTH DUE TO HYDROGEN-RELATED PROJECTS, IS THE PROJECTED LOAD GROWTH ALSO TIED TO INCREASING ELECTRIFICATION?

A. Yes. Customer growth in the Company's service area has also been associated with increasing electrification, particularly in our industrial customer sector.

Q. PLEASE DESCRIBE THE OBSERVED ELECTRIFICATION TRENDS THAT IS OCCURING IN THE COMPANY'S SERVICE AREA.

A. Electrification takes several forms. First, on the transmission side, the Company has seen an increase in generator interconnection requests. Since the Company's last completed base rate proceeding in Docket No. 49421, the Company has built transmission interconnection facilities to interconnect twenty-five new generation units collectively representing approximately 6,435 MW of generation capacity.

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

Third, the Company continues to see more customers adopting electric vehicles and commercial fleet conversions. The Company has proactively engaged with commercial customers who have decided to electrify, or are considering electrifying, some or all of their vehicle fleet to install the necessary infrastructure and charging stations.

Fourth, a number of the Company's large industrial customers are moving to electrify their operations. The Company expects that this demand will only increase as electrification and hydrogen development in the Greater Houston area grows, supported by an unprecedented level of federal grant and loan funding under the Bipartisan Infrastructure Law and the Inflation Reduction Act of 2022. Many of the Company's large industrial customers have indicated that they have or are applying for grants under federal programs to accelerate their planned electrification efforts. Figure NB-7 below, taken from the Hydrogen Production Policy Council's report, summarizes the status of federal hydrogen-related grants.[16]

Figure NB-10
Statuses of Federal Hydrogen-Related Grants

Recipient	Status	Agency	Amount	Description
Port Houston	Awarded	FHA (DOT)	$27MM	Purchase of zero emission drayage trucks
NCTCOG	Complete	DOT	$75k	Planning I-45 fueling corridor
NCTCOG	Awarded	DOT	$70MM	Constructing 5 fueling stations in Texas Triangle
GTI Energy	Awarded	DOT	$1.5MM	Houston to LA (H2LA) fueling infrastructure planning
Port Houston	Applied	EPA	$100+MM	Purchase of Heavy Duty H2 Fueled Trucks and H2 fueling infrastructure
HyVelocity Inc.	Awarded – in negotiations	DOE/OCED	$1.2B	Establish Gulf Coast Regional Clean Hydrogen Hub
Frontier Energy, University of Texas, and GTI Energy	Awarded	DOE	$13MM	H2@Scale demonstration facility

The Company anticipates making additional investments to serve the projects as they come online.

[16] *Id.* at 14.

Q. DO YOU HAVE ANY THOUGHTS ON THE OBSERVED ELECTRIFICATION TRENDS?

A. It is important to note that each of these trends – new generation interconnections, increasing penetration of distributed energy resources, a move to more electric vehicles, and industrial electrification – is customer-initiated. As the electric utility with an obligation to serve customers, the Company must make necessary investments in its transmission and distribution infrastructure to ensure that our customers' needs are met. These needed investments include resiliency-related investments imperative to mitigating the impact of Resiliency Events.

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

A. Unlike steady increases in population which increase load in gradual increments, commercial and industrial electrification happens in larger increments. For example, when the Freeport LNG facility began operation in the Company's service area, it required 690 MW of electricity, which was almost nine times the Freeport region's previous loa of under[17] The Company had to build a new transmission line to serve the Freeport LNG facility[18] Taken together, steady population growth; sudden demand from commercial and industrial projects, such as data centers and hydrogen-related projects; and increasing customer electrification will require a game-changing level of infrastructure investment by

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[17] *Natural Gas Weekly Update*, U.S. Energy Info. Admin., (Sept. 12, 2019) https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2019/09_12/#:~:text=Freeport%20LNG%20requires%20690%20megawatts,was%20less%20than%2080%20MW.

[18] *See generally Application of CenterPoint Energy Houston Electric, LLC to Amend a Certificate of Convenience and Necessity for a 345-kV Transmission Line in Brazoria, Matagorda, and Wharton Counties*, Docket No. 48629 (Nov. 21, 2019).

the Company, including resiliency-related investment. This increased demand for electricity is concurrent with increased expectations of reliability and resiliency from the customers and communities that the Company has the privilege to serve.

<u>INCREASED EXPECTATIONS FOR RELIABILITY AND RESILIENCY</u>

Q. WHAT IS RESILIENCY?

A. Based on the definitions of the terms "Resiliency Event" and "Resiliency Measure" in the Commission's T&D SRP Rule, resiliency is the ability "to prevent, withstand, mitigate, or promptly recover from the risks posed by"[19] events "involving extreme weather conditions, wildfires, cybersecurity threats, or physical security threats that poses a material risk to the safe and reliable operation"[20] of the Company's transmission and distribution system. Colloquially speaking, resiliency is the ability of a transmission and distribution system to "take a punch" against a high impact, low frequency event such as major storms and extreme wind events that are becoming more common in the Greater Houston area.

Q. IS THERE A DISTINCTION BETWEEN RESILIENCY AND RELIABILITY?

A. Yes, but the two concepts overlap. Resiliency is best characterized as a subset of reliability, not an entirely separate concept. Reliability addresses day-to-day transmission and distribution system performance during normal operating conditions. If resiliency is the ability of a transmission and distribution system to "take a punch" against a high impact, low frequency event, then reliability is the ability of the transmission and distribution system to provide service during normal, "blue sky" days. Resiliency projects may therefore provide reliability benefits (e.g. distribution pole replacement/bracing and

[19] Subsection (c), T&D SRP Rule.

[20] Subsection (b)(3), T&D SRP Rule.

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

"Texans felt severe discomfort and stress, mainly due to health-related and financial concerns."[25] I have attached to my testimony as Exhibit NB-2 letters from customers and stakeholders recognizing the benefits of greater system resiliency. A diverse group of organizations confirm that "[r]esiliency and reliable infrastructure are integral to our community" (Houston Business Development, Inc.), that a more resilient electric grid "brings a host of benefits beyond reduced vulnerability to severe weather" (Greater Houston Partnership), and that resiliency planning is "essential to further insulate our region's electrical infrastructure from severe weather events and improve service to [the Company's]'s business and residential customers" (Tejano Center for Community Concerns).

HISTORIC INVESTMENTS IN TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY

A. HISTORIC RESILIENCY INVESTMENTS

Q. HAS THE COMPANY PREVIOUSLY INVESTED IN AND IMPLEMENTED RESILIENCY PROJECTS?

A. Yes. Prior to the adoption of the T&D SRP Statute, the Company made significant investment in and implemented various resiliency-related projects. As mentioned earlier in my testimony, the Company has invested approximately $4.9 billion in its transmission and distribution system since 2020. As part of that $4.9 billion, from 2020 to 2023, the Company invested approximately $1.29 billion for resiliency-related projects. The

[25] *Investigation of Emergency Preparedness and Response by Utilities in Houston and Surrounding Communities*, Docket No. 56822, Final Report at 6 (Nov. 21, 2024).

following table provides examples of resiliency-related projects implemented by the Company from 2020 to 2023 and the corresponding costs:

Figure NB-12
2020-2023 Resiliency-Related Projects and Costs

Description	2020	2021	2022	2023	Total
IGSD Installation	1	5	12	13	$ 31
Transmission System Hardening	12	159	274	166	$ 611
Substation Flood Control	18	13	20	20	$ 71
Distribution Pole Replacement/Bracing	29	30	61	52	$ 172
Substation Security	5	20	24	10	$ 59
S90 Tower Replacements	3	20	55	14	$ 92
69/138 kV Conversions	16	3	49	90	$ 158
Distribution Resiliency - Circuit Rebuild	-	-	40	40	$ 80
Distribution Resiliency - TripSaver	-	-	7	5	$ 12
Total 2020 - 2023	**$ 84**	**$ 250**	**$ 542**	**$ 410**	**$ 1,286**

B. 2024 STORMS AND THE GREATER HOUSTON RESILIENCY INITIATIVE

Q. WHY DOES THE ABOVE DISCUSSION OF PRIOR RESILIENCY INITIATIVES FOCUSES ON 2020-2023 AND NOT EXTEND TO 2024?

A. The years 2020-2023 represent fairly typical weather and operations in the Company's service area. In contrast, 2024 was a departure and saw increasingly extreme weather and accelerated resiliency investments.

Q. PLEASE DESCRIBE THE CIRCUMSTANCES THAT MADE 2024 DIFFERENT.

A. The Company's service area was hit with a series of destructive storms in May 2024 (the "May 2024 Storms") and then by Hurricane Beryl in July 2024. Together, the May 2024 Storms and Hurricane Beryl necessitated the Company expending over $1.5 billion in storm restoration costs. In response to these events, the Company launched the GHRI, through which the Company has completed or committed to take further resiliency-related actions.

Q. WHAT IS THE GHRI?

A. The GHRI is a set of commitments the Company made after Hurricane Beryl to enhance the resiliency of the Company's transmission and distribution system, improve communications with customers, and strengthen community partnerships. Doing so will ensure that the Company is better prepared for and able to respond to the next major storm, weather event, or man-made event. The Company has completed Phase One of the GHRI and Phase Two is currently underway, with completion anticipated prior to the beginning of hurricane season on June 1, 2025. This SRP reflects our longer-term commitment to improved resiliency throughout the Greater Houston area.

Q. WHAT RESILIENCY-RELATED ACTIONS WERE COMPLETED AS PART OF PHASE ONE OF THE GHRI?

A. Immediately after Hurricane Beryl, the Company installed stronger and more resilient distribution poles (e.g. composite fiberglass), conducted incremental vegetation management trimming and removing on high-risk distribution circuits, and installed automation devices on the Company's distribution system. All of these initial GHRI Phase One actions were completed by August 27, 2024, less than two months after Hurricane Beryl impacted the customers in our service area. Figure NB-10 below summarizes the resiliency-related actions that were completed by the Company as part of Phase One of the GHRI.

<u>Figure NB-13</u>
GHRI Phase I Resiliency-Related Efforts

August 28, 2024 Taking Action Now to Reduce Outages	Completed August 27	Progress to Date	August Target
Installing stronger and more storm-resilient poles	WORK COMPLETE	1,133 poles	1,000 poles
Trimming or removing higher-risk vegetation	WORK COMPLETE	2,026 power line miles	2,000 power line miles
Installing automated devices, known as trip savers	WORK COMPLETE	307 devices	300 devices

Q. WHAT RESILIENCY-RELATED ACTIONS WERE COMMITTED TO OR HAVE BEEN COMPLETED AS PART OF GHRI PHASE TWO?

A. Similar to the resiliency-related actions in Phase One of the GHRI, in Phase Two the Company has committed to continue installing stronger and more resilient distribution poles, installing additional automated devices, like TripSavers and IGSDs, on locations on the Company's distribution system, conducting vegetation management trimming and removal on additional miles of high-risk distribution circuits, underground certain distribution lines, and installing new weather monitoring stations. The Company has targeted June 1, 2025, which is when hurricane season will begin for 2025, as the date by which all these resiliency-related actions will be completed. Figure NB-11 below summarizes the resiliency-related actions that were committed to by the Company as part of Phase Two of the GHRI.

Figure NB-14
GHRI Phase II Resiliency-Related Efforts

Near-Term Actions to Improve Resiliency	Target by June 1, 2025
Install new poles or replace existing wooden poles with stronger ones, including composite, capable of withstanding extreme winds (Coastal: 132 mph standard; Inland: 110 mph standard)	25,000 poles
Install automated reliability devices to reduce sustained interruptions in major storm events and reduce restoration times	4,500 automated reliability devices
Install Intelligent Grid Switching Devices (IGSDs)	350 IGSDs
Trim or remove vegetation from distribution line miles with higher-risk vegetation across our system	4,000 miles
Undergrounding of power lines	400 miles
Install new weather monitoring stations	100 stations

Q. ONCE COMPLETED, WILL THE RESILIENCY-RELATED ACTIONS IN PHASE ONE AND PHASE TWO COMMITTED TO BY THE COMPANY PROVIDE A BENEFIT TO THE CUSTOMERS AND COMMUNITIES SERVED BY THE COMPANY?

A. Yes. The Company anticipates that the resiliency-related actions in Phase One and Phase Two of the GHRI will lead to more than 125 million fewer customer outage minutes annually.

Q. WILL THE COMPANY TAKE FURTHER RESILIENCY-RELATED ACTIONS AND MAKE FURTHER SYSTEM RESILIENCY-RELATED INVESTMENTS UPON COMPLETION OF PHASE TWO OF THE GHRI?

A. Yes. As previously stated in my testimony, the GHRI includes the 2026-2028 T&D SRP as a key part of the Company's plan to make its transmission and distribution system the most resilient coastal grid in the country. The Company proposes to invest approximately $5.754 billion as part of its 2026-2028 T&D SRP to further enhance the resiliency of the Company's transmission and distribution system. As discussed in my testimony, the Company has made significant resiliency-related investments to harden and automate its transmission and distribution system. To become the most resilient coastal utility for our customers, the Company will continue to make resiliency-related investments well past 2028. To do so, the Company anticipates filing additional three-year system resiliency plans going forward, which will provide the Commission forward-looking visibility into the Company's investments.

<u>2026-2028 TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN</u>

A. THE COMPANY'S 2026-2028 T&D SRP

Q. PLEASE SUMMARIZE THE COMPANY'S 2026-2028 T&D SRP.

A. The Company's 2026-2028 T&D SRP proposes to invest $5.754 billion over three years to implement thirty-nine (39) Resiliency Measures related to hardening, modernization, undergrounding, flood mitigation, information technology and cybersecurity, physical security, vegetation management, wildfire mitigation, and monitoring and event response. The Resiliency Measures address all portions of the Company's infrastructure, from the transmission system to the substation environment to the distribution system to the control center environment and to back-office technology. Exhibit NB-3 of my testimony is a table that summarizes the Resiliency Measures in the Company's 2026-2028 T&D SRP, including estimated capital costs, estimated incremental O&M expense, and CMI saved.

Q. ARE THERE SPECIFIC RESILIENCY EVENT IMPACTS THAT THE COMPANY'S 2026-2028 T&D SRP IS INTENDED TO MITIGATE.

A. Yes. As confirmed by Guidehouse's independent, third-party analysis, the Resiliency Events that pose the most outage risk to the Company's customers are extreme wind events (e.g. hurricanes, tropical storms, major storms). Thus, 72% or $4.013 billion of the proposed $5.754 billion in resiliency investments in the Company's 2026-2028 T&D SRP are for Resiliency Measures that will harden the Company's transmission and distribution system against high wind events. For example, the Company is proposing to invest approximately $765.0 million in Resiliency Measures to strengthen distribution poles by either replacing wooden distribution poles with non-wooden distribution poles (e.g. composite fiberglass) or by bracing distribution poles. Similarly, the Company is proposing to invest approximately $1.468 billion in Resiliency Measures to strengthen transmission structures by replacing remaining wooden structures with non-wooden structures.

Q. WHY IS THE COMPANY PROPOSING TRANMISSION SYSTEM-RELATED RESILIENCY MEASURES IN ITS 2026-2028 T&D?

A. The Company's transmission system is the backbone of the Company's electric infrastructure and is critical to being able to serve the Company's customers. Given the current challenges of building new generation near the Greater Houston area, our customers depend on the Company's transmission system to import the necessary electricity from other areas in ERCOT. Outages on the Company's transmission system, especially to the transmission import paths, will have a significant impact on the Company's ability to transmit and distribute electricity to its customers. Thus, it is vital that the Company have and maintain a resilient transmission system.

In responses to the Company's first SRP filing last year, some parties did suggest excluding transmission projects, because the Resiliency Statute provides special accounting treatment only for Resiliency Measures related to the distribution system. However, that position ignores the express language of the statute, which defines "plan" as a "*transmission* and distribution system resiliency plan."[7] Indeed, the Commission's own rule is entitled, "*Transmission* and Distribution System Resiliency Plans."[8] Moreover, every investment made in improving distribution system resiliency is at risk of being less valuable if there are not corresponding investments made to improve the resiliency of the transmission system, without which the distribution system cannot receive power.

Furthermore, one of the great benefits of the Resiliency Statute is that it gives the Public Utility Commission, as well as other stakeholders, better forward-looking visibility into what the utilities under the Commission's jurisdiction are doing to improve resiliency. That transparency and holistic approach puts the Commission in a better position to oversee and provide guidance to utilities as they work to enhance the resiliency of the Texas power grid. Accordingly, the Company has proposed Resiliency Measures for every component of the electric delivery chain, from its transmission system to its substations, to its distribution system and all the way to the point of delivery. By the end of the 2026-2028 SRP, the Company will have replaced 100% of its wood transmission structures with more resilient structures, replaced 100% of its legacy transmission angle structures, and installed 100% of planned anti-galloping mitigation and detection equipment.

Q. WILL THE COMPANY INCREASE ITS VEGETATION MANAGEMENT ACTIVITIES AS PART OF ITS 2026-2028 T&D SRP?

A. Yes. In response to feedback received from stakeholders, the Company will go to a three-year trim cycle for distribution circuits, regardless of voltage. Currently, 12kV distribution circuits are trimmed on an approximately five-year trim cycle, and 35kV and select 12kV distribution circuits are trimmed on an approximately three-year trim cycle.[26] Additionally, the Company will undertake incremental O&M spending of approximately $146.1 million from 2026-2028 to conduct accelerated vegetation management on distribution circuits.

Q. WILL THE INCREASED VEGETATION MANAGEMENT COMMITTED TO BY THE COMPANY PROVIDE A BENEFIT TO CUSTOMERS?

A. Yes. Vegetation, located in or out of the Company's ROW, is a major cause of outages. Additional and increased vegetation management mitigates the risk of vegetation making contact with conductors and mitigates the risk that distribution circuits will be damaged by vegetation-related debris.

Q. IS THE COMPANY CURRENTLY MAKING ANY RESILIENCY-RELATED INVESTMENTS THAT ARE SIMILAR TO RESILIENCY MEASURES IN THE 2026-2028 T&D SRP?

A. Yes. Some Resiliency Measures in the Company's 2026-2028 T&D SRP are a continuation of resiliency-related investments that the Company normally makes, an expansion of past investments, or an acceleration of the types of resiliency-related

[26] The Company's proactive vegetation management activities are based on an analytics model that prioritizes distribution circuits based on several factors, including last trim date, vegetation-caused outages, potential impact on critical loads, and overall customer count impacted.

investment projects that the Company will make in the future. For example, from 2020-2023 the Company invested approximately $71 million to elevate select substations to mitigate the impact of flooding. The Substation Flood Control Resiliency Measure in the 2026-2028 SRP is a continuation of the Company's prior flood mitigation activities. Similarly, from 2020-2023 the Company invested approximately $80 million to rebuild, and thus harden, select distribution circuits. The Distribution Circuit Resiliency Measure in the SRP is both a continuation of those prior hardening activities and an acceleration over previously planned future hardening activities.

Q. WILL THE COMPANY'S 2026-2028 T&D SRP PROVIDE BENEFITS TO CUSTOMERS AND COMMUNITIES THAT THE COMPANY HAS THE PRIVILEGE TO SERVE?

A. Yes. The Company anticipates that the 2026-20208 T&D SRP will provide a benefit by saving approximately 1,309 million CMI. Several Resiliency Measures will harden both the Company's transmission and distribution systems, further mitigating the impact of extreme weather events and improving customer restoration times and costs. For example, the Distribution Circuit Resiliency and Distribution Pole Replacement/Bracing Resiliency Measures will further harden distribution circuits and enable them to better withstand vegetation and debris-related damage. Likewise, the Anti-Galloping Resiliency Measure mitigates the impact that extreme wind events would have on transmission conductors.

In addition to hardening the Company's transmission and distribution system, several Resiliency Measures modernize the Company's operations, thus mitigating the impact on customer outages and enable the Company to better monitor and respond to Resiliency Events. For example, the IGSD Installation Resiliency Measure would allow for the sectionalization and re-routing of power, thus mitigating distribution circuit-level customer outages. Likewise, the Weather Stations and Wildfire Camera Monitoring Resiliency Measures would further enhance the Company's monitoring capability and improve its ability to proactively identify and respond to potential issues. The Direct Testimonies of Company witnesses Eric Easton and Muss Akram, and independent expert Eugene Shlatz from Guidehouse further discuss and analyze the anticipated benefits of the Company's 2026-2028 T&D SRP.

B. DEVELOPMENT OF THE COMPANY'S 2026-2028 T&D SRP

Q. HOW DID THE COMPANY DEVELOP ITS 2026-2028 T&D SRP?

A. The Company developed its 2026-2028 T&D SRP with the following considerations in mind:

- Feedback received from customers, communities, and local and state officials following Hurricane Beryl;
- The Commission's report on Hurricane Beryl;
- Guidehouse, an independent, third-party expert, analysis of Resiliency Events that have occurred and are forecasted to occur in the Greater Houston area and an industry Resiliency Measures benchmark;and
- PA Consulting's recommendations in its Hurricane Beryl after-action report.

Q. WHAT WAS THE FEEDBACK RECEIVED FROM CUSTOMERS, COMMUNITIES, AND LOCALAND STATE OFFICIALS FOLLOWING HURRICANE BERYL?

A. The Company received feedback from customers, communities, and local and state officials in a few different forums. First, following Hurricane Beryl, the Company held nineteen (19) community open houses throughout its service area[27] to allow customers, community organizations, and local and state officials to: (1) learn and ask questions about the Company's transmission and distribution system operations; (2) test the Company's new Outage Tracker;[28] (3) enroll in the Company's Power Alert Service; and (4) provide feedback on hurricane and storm preparations and their preferred communication method. With regard to the resiliency of the Company's transmission and distribution system, the general feedback received at the community open houses is that resiliency is important, and outages must be minimized.

Second, the Company held initial and follow-up meetings with local and county officials and offices of emergency management from all twelve of the counties served by the Company to discuss the Company's 2026-2028 T&D SRP. During its initial meetings with local county officials and offices of emergency management, the Company provided an explanation of the Company's granular and data-driven approach in developing the Company's 2026-2028 T&D SRP. Additionally, the Company provided the summary of damage prediction and outage duration models used by the Company to identify regions in each county that may receive damage due to a weather-related Resiliency Event. For example, Figure NB-12 below depicts the regions in Harris County that may receive damage due to a weather-related Resiliency Event and the corresponding outage durations for customers in Harris County.

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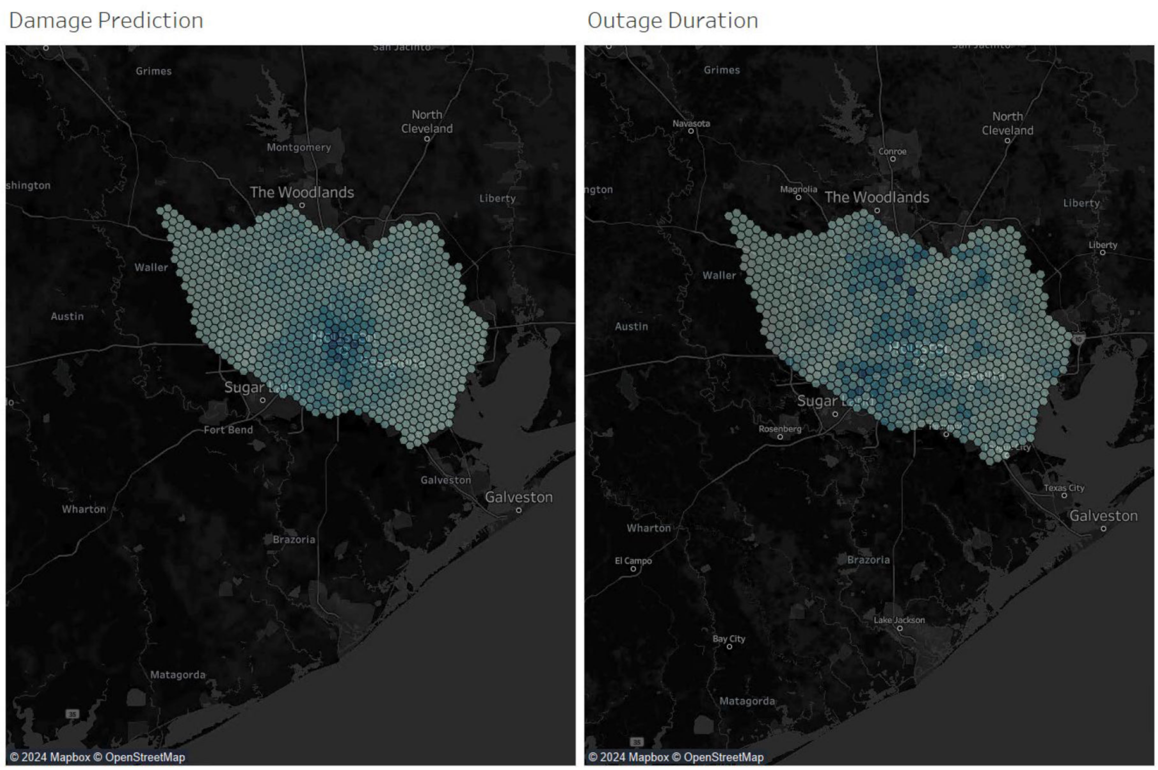
[27] The dates and times of the community open houses are listed on the following webpage: https://www.centerpointenergy.com/en-us/Documents/CNP_Open_House_Schedule_2024.pdf.

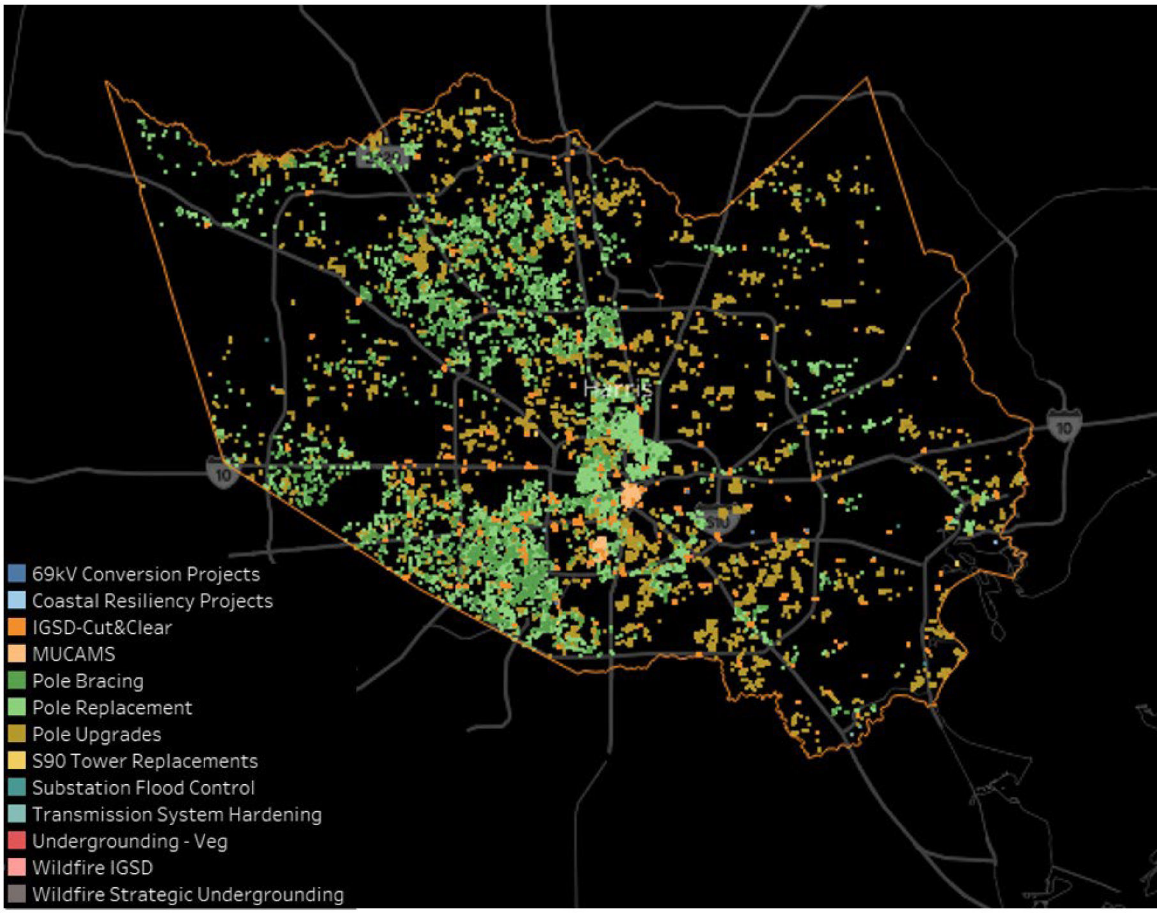
[28] https://tracker.centerpointenergy.com/map/.

<u>Figure NB-15</u>
Harris County Damage Prediction and Outage Durations



In the follow-up meetings local county officials and offices of emergency management, the Company provided locations in each county that have been identified, on a preliminary basis, as potential locations for implementation of Resiliency Measures. Using Harris County again as an example, Figure NB-13 below depicts the potential locations in Harris County where a Resiliency Measure may be implemented.

Figure NB-16
Harris County Potential Resiliency Measure Locations



Q. HOW DID THE COMPANY INCORPORATE INTO ITS 2026-2028 T&D SRP THE FEEDBACK RECEIVED FROM CUSTOMERS, COMMUNITIES, AND LOCAL AND STATE OFFICIALS FOLLOWING HURRICANE BERYL?

A. The central focus of the Company's 2026-2028 T&D SRP (and capital investments beyond 2028) is to enhance the resiliency of the Company's transmission and distribution system and, correspondingly, to mitigate the impact of and outages caused by Resiliency Events. The Company believes that the Resiliency Measures in the Company's 2026-2028 T&D SRP, which is anticipated to benefit customers by saving approximately 1,309 million CMI, directly addresses the resiliency and outage feedback received at the community open houses and from customers, elected officials, and community partners.

Q. DID THE COMPANY CONDUCT AN AFTER-ACTION REVIEW FOLLOWING HURRICANE BERYL?

A. Yes. The Company retained PA Consulting, an independent third-party expert, to conduct an after-action review of the Company's storm preparedness and restoration efforts related to Hurricane Beryl. Exhibit NB-4 of my testimony is a copy of PA Consulting's after-action report.

Q. DID PA CONSULTING PROVIDE RECOMMENDATIONS AS PART OF ITS AFTER ACTION REPORT?

A. Yes. PA Consulting made the following recommendations:

- Develop or acquire comprehensive damage prediction models;
- Revise vegetation management trimming cycles and develop data-driven models for vegetation management;
- Increase the use of composite distribution poles and crossarms;
- Underground select overhead distribution lines
- Expand and prioritize URD;
- Strategically locate staging sites;
- Additional sectionalization of distribution circuits; and
- Harden information technology and communications infrastructure.

Q. HOW DID THE COMPANY INCORPORATE INTO ITS 2026-2028 T&D SRP PA CONSULTING'S RECOMMENDATIONS?

A. The following Resiliency Measures in the 2026-2028 T&D SRP correspond to PA Consulting's recommendations:

- Develop or acquire comprehensive damage prediction models to help aid in preparedness for certain types of events;
- Revise vegetation management trimming cycles and develop data-driven models for vegetation management: Vegetation Management, Wildfire Vegetation Management;
- Increase the use of composite distribution poles and crossarms: Distribution Circuit Resiliency, Distribution Pole Replacement/Bracing;
- Underground select overhead distribution lines: Strategic Undergrounding, Wildfire Strategic Undergrounding;
- Expand and prioritize URD: MUCAMS, MUG Reconductor, Cable Life Extension Program/URD Replacements;
- Strategically harden four service centers and complete construction of an Emergency Operations Center
- Additional sectionalization of distribution circuits: IGSD Installation; and
- Harden information technology and communications infrastructure: Voice & Mobile Data Radio System; Network Security & Vulnerability Management; Data Center Modernization; Backhaul Microwave Communication; Spectrum Acquisition; and Cloud Security, Product Security & Risk Management.

Q. DID THE COMMISSION ISSUE A REPORT RELATED TO HURRICANE BERYL?

A. Yes. Exhibit NB-5 of my testimony is a copy of the Commission's report.

Q. DID THE COMMISSION PROVIDE RECOMMENDATIONS AS PART OF ITS REPORT?

A. Yes. The Commission made the following recommendations:

- Utilities should assess poles constructed under prior NESC standards for replacement with poles that meet current extreme wind and ice loading design standards.
- Utilities should target circuits chosen for upgrade according to those that serve critical facilities such as hospitals, water treatment plants, or police stations, and that support mobile generation or serve underserved communities.
- Utilities should consider automated grid performance devices, like sectionalizers or automatic circuit reclosers, to reduce unnecessary outage times and help restoration crews locate and resolve faults more quickly.
- In more densely vegetated areas, utilities should assess whether to replace distribution lines with covered conductor.

Q. HOW DID THE COMPANY INCORPORATE INTO ITS 2026-2028 T&D SRP THE COMMISSION'S RECOMMENDATIONS?

A. The following Resiliency Measures in the 2026-2028 T&D SRP correspond to the Commission's recommendations:

- Distribution Circuit Resiliency: Select distribution circuits (or portions of distribution circuits) will have non-wooden poles installed and equipment replaced to meet the Company's current and higher wind and ice loading standards (i.e., NESC 250C and 250D).
- IGSD Installation: Select distribution circuits will have IGSDs installed.

Additionally, in determining where to implement distribution system-related Resiliency Measures, the Company will consider factors such as whether a distribution circuit serves a critical facility.

Q. IN ADDITION TO THE FEEDBACK RECEIVED AT THE COMMUNITY OPEN HOUSES, PA CONSULTING'S RECOMMENDATIONS, AND THE COMMISSION'S RECOMMENDATION, HOW DID THE COMPANY DETERMINE WHICH RESILIENCY MEASURES TO INCLUDE IN ITS 2026-2028 T&D SRP?

A. The Company analyzed historical Resiliency Events that occurred in the Greater Houston area and have impacted the Company's transmission and distribution system. In analyzing historical Resiliency Events, the Company determined that extreme weather events – specifically extreme wind events (i.e., hurricanes, tropical storms, tornadoes, major storms), flooding and extreme water events, and extreme temperature (heat and freeze) – were the main cause of damage to the Company's transmission and distribution system. The Company focused on resiliency-related actions and investments that are well-known within the utility industry as being proven to enhance system resiliency. Guidehouse was hired to perform quantitative and qualitative analyses (as appropriate) for a range of proposed Resiliency Measures, and the Company made adjustments based on the results of Guidehouse's analyses. Additionally, the Company digitally modeled its transmission and distribution system under a variety of extreme weather conditions to evaluate other possible solutions and improvements for future consideration. The Direct Testimony of Eric Easton further discusses the risk-based analysis used by the Company to develop its 2026-2028 T&D SRP.

C. COMPARISON WITH THE COMPANY'S PRIOR 2025-2027 T&D SRP

Q. DID THE COMPANY PREVIOUSLY FILE A T&D SRP FOR COMMISSION REVIEW AND APPROVAL?

A. Yes, the Company filed its 2025-2027 T&D SRP in April 2024 in Commission Docket No. 56548 for Commission review and approval. The Company subsequently withdrew its 2025-2027 T&D SRP to focus its efforts on implementing Phase One of the GHRI and to allow for a broader assessment of additional resiliency-enhancing investments that are now included in the Company's 2026-2028 T&D SRP.

Q. PLEASE SUMMARIZE THE COMPANY'S 2025-2027 T&D SRP.

A. The Company's 2025-2027 T&D SRP proposed to invest approximately $2.28 billion between 2025-2027 implement twenty-five (25) Resiliency Measures related to hardening, modernization, undergrounding, flood mitigation, information technology and cybersecurity, physical security, vegetation management, and wildfire mitigation. The 2025-2027 T&D SRP was anticipated to save the customers approximately 940 million CMI.

Q. HOW DOES THE COMPANY'S 2026-2028 T&D SRP COMPARE WITH THE PRIOR 2025-2027 T&D SRP?

A. The Company's 2026-2028 T&D SRP proposes to invest over a three-year period – approximately $5.754 billion versus $2.28 billion – to implement more Resiliency Measures – i.e., thirty-nine (39) Resiliency Measures versus twenty-five (25) Resiliency Measures – and to accelerate the pace of resiliency of the Company's transmission and distribution system. Additionally, the 2026-2028 T&D SRP anticipates saving customers approximately 1,309 million CMI, compared to 940 million CMI saved in the 2025-2027

T&D SRP.

Q. DOES THE COMPANY'S 2026-2028 T&D SRP HAVE RESILIENCY MEASURES THAT WERE PROPOSED IN ITS PRIOR 2025-2027 T&D SRP?

A. Yes. There are several hardening, modernization, undergrounding, flood mitigation, technology and cybersecurity, physical security, vegetation management, and wildfire mitigation Resiliency Measures that are in the Company's 2026-2028 T&D SRP that were also proposed in the Company's prior 2025-2027 T&D SRP. Based on the feedback and recommendations received since Hurricane Beryl, there are some additional Resiliency Measures included, and the pace of some resiliency measures is increased. The changes result in different capital costs and scope of work. Exhibit NB-6 of my testimony is a chart that compares and summarizes the difference between the Company's current 2026-2028 T&D SRP and the Company's prior 2025-2027 T&D SRP.

Q. ARE THERE OTHER DIFFERENCES BETWEEN THE COMPANY'S 2026-2028 T&D SRP AND THE COMPANY'S PRIOR 2025-2027 T&D SRP?

A. Yes. As a result of the Company withdrawing its 2025-2027 T&D SRP to focus on implementing GHRI Phase One and Phase Two, the Company conducted a broader assessment of additional resiliency-enhancing investments using a forward-looking analysis.[29] The Resiliency Measures in the Company's 2025-2027 T&D SRP were to be implemented at a program level and based on historical trends. The Resiliency Measures in the Company's 2026-2028 T&D SRP are still based on historical trends and analysis but are proposed to be implemented at a more granular project level, are based on recently

[29] Refer to the Direct Testimony of Eric Easton for further discussion on the Company's granular and forward-looking risk-based analysis used to develop the 2026-2028 T&D SRP.

conducted service area LiDAR mapping data and incorporate predictive modeling and analysis. For example, both the 2025-2027 T&D SRP and 2026-2028 T&D SRP have Resiliency Measures related to the hardening of the Company's distribution system. Implementation of distribution system hardening projects in the 2026-2028 T&D SRP have the benefit of using LiDAR data, predictive modeling and analysis to determine the specific distribution circuits (or portions of distribution circuits) that have restricted access, are susceptible to fall-in risk, serve public safety infrastructure, and benefit the most customers from system resiliency investments.

Q. WHAT ARE THE NEW RESILIENCY MEASURES THAT ARE INCLUDED IN THE COMPANY'S 2026-2028 T&D SRP?

A. Yes. The new Resiliency Measures included in the 2026-2028 T&D SRP are:

- MUCAMS;
- Mobile Substations;
- Anti-Galloping Technologies;
- Load Shed IGSD;
- Distribution Capacity Enhancements/Substations
- MUG Reconductor;
- URD Cable Modernization;
- Contamination Mitigation;
- Load Shed IGSD;
- Wildfire Advanced Analytics;
- Wildfire IGSD;
- Wildfire Strategic Undergrounding;

- Wildfire Vegetation Management;
- Spectrum Acquisition;
- Cloud Security, Product Security & Risk Management;
- Weather Stations;
- Wildfire Cameras;
- Emergency Operations Center; and
- Hardened Service Centers

D. IMPLEMENTATION OF THE COMPANY'S 2026-2028 T&D SRP

Q. PLEASE GENERALLY EXPLAIN HOW THE COMPANY IMPLEMENTS CONSTRUCTION, INSTALLATION, AND REPLACEMENT PROJECTS.

A. The Company has well-established processes that ensure the Company has sufficient field crews consisting of internal Company employees and external contractors and material to implement construction, installation, and replacement projects. Using distribution pole replacements as an example, the Company conducts design and engineering work, procures in advance distribution poles from its vendor, and schedules external contractors to perform the replacement work.

Q. HOW DOES THE COMPANY IDENTIFY AND MANAGE WORK THAT IS NEEDED UNDER NORMAL, DAY-TO-DAY OPERATIONS?

A. The Company's work order process is central to the efficient organization, implementation and day-to-day management of projects, Work orders are created by internal employees and external contractors using SAP and a software product called Distribution Design Studio. Once work orders are created, they are reviewed and approved by Company leadership and assigned to appropriate crews for completion.

Q. HOW DOES THE COMPANY IMPLEMENT WORK ORDERS UNDER NORMAL, DAY-TO-DAY OPERATIONS?

A. The Company has well-established processes and systems for the day-to-day cross-departmental project/program planning and scheduling. Its implementation is updated continuously based on a combination of schedules, SAP work order statuses, daily status updates, etc. that ensure the Company has sufficient field crews and material to implement work orders for construction, installation, and replacement projects. The Company can and will augment and increase field crews, typically by staffing additional external contractors, depending on the nature of the work that is involved.

Q. HOW DOES THE COMPANY IDENTIFY WORK THAT IS NEEDED FOLLOWING A RESILIENCY EVENT, AND HOW IS IT DIFFERENT FROM THE NON-EMERGENCY PROCESS?

A. In a Resiliency Event, outage work orders are created by the Company's Outage Management System, as opposed to Distribution Design Studio and SAP. Prior to or during a Resiliency Event, the Company can and will augment and increase field crews, typically through the staffing of additional external contractors, depending on the nature of the work involved. During a Resiliency Event, field crews comprised of internal Company employees, external contractors, and mutual assistance partners and resources are shifted to focus solely on completing outage orders to quickly restore service to customers. The non-emergency work order process includes responding to customer outage cases, performing new construction, reliability, resiliency, system improvements, follow-ups, and customer service orders.

Q. **HOW DOES THE COMPANY RESPOND TO WORK ORDERS FOLLOWING A RESILIENCY EVENT?**

A. Following an event in which a portion of the system has sustained damage, the Company procures additional external contractors necessary to conduct power restoration and repair damages through a combination of requests to our current native (i.e., local) contractor resources and mutual assistance resources. The Company maintains relationships with and utilizes a mix of local and non-local contractors to support our work, including the installation of new structures, conductors, hardware, insulators, equipment or devices, and the removal of damaged facilities, and post-construction clean-up activities. In support of restoration efforts, our line contractors may temporarily increase their resource count, as requested by the Company, by bringing in additional resources from projects that were supporting other entities.

Q. DID THE COMPANY FOLLOW ITS WELL-ESTABLISHED PROCESSES TO IMPLEMENT THE RESILIENCY-RELATED ACTIONS IN PHASE ONE OF THE GHRI?

A. Yes. The Company followed its well-established processes to ensure that the Company had the necessary field crews consisting of internal Company employees and external contractors and material to install stronger and more resilient distribution poles, conduct additional vegetation management on high- risk distribution circuits, and install automation devices, like TripSavers, on the Company's distribution system. The Company did not experience any resource issues to complete Phase One of the GHRI.

Q. HAS THE COMPANY BEEN FOLLOWING ITS WELL-ESTABLISHED PROCESSES TO IMPLEMENT THE RESILIENCY-RELATED ACTIONS IN PHASE TWO OF THE GHRI?

A. Yes. The Company has been following its well-established processes to ensure that the Company has the necessary field crews consisting of internal Company employees and external contractors and material to install stronger and more resilient distribution poles, install automation devices, like TripSavers and IGSDs, on the Company's distribution system, conduct incremental vegetation management on high-risk distribution circuits, underground certain distribution lines, and install new weather monitoring stations. Thus far, the Company has not experienced any human or material resource issues that would hinder completing Phase Two of the GHRI by June 1, 2025.

Q. DID THE COMPANY AUGMENT AND INCREASE FIELD CREWS TO IMPLEMENT PHASE ONE AND PHASE TWO OF THE GHRI?

A. Yes. The Company augmented and increased field crews, as needed, to complete Phase One of the GHRI. Additionally, the Company may augment and increase field crews, as necessary, to complete Phase Two of the GHRI by June 1, 2025.

Q. WILL THE COMPANY FOLLOW ITS WELL-ESTABLISHED PROCESSES TO IMPLEMENT THE RESILIENCY MEASURES IN THE 2026-2028 T&D SRP?

A. Yes. I would also note that, in deciding which Resiliency Measures went into the 2026-2028 T&D SRP, the Company considered the implementation feasibility, from a human and materials resource perspective, for each Resiliency Measure. The Company has determined that the Resiliency Measures in the 2026-2028 T&D SRP can be implemented under the proposed timeframes, barring extraordinary circumstances.

Q. HOW WILL THE COMPANY FINANCE THE IMPLEMENTATION OF THE RESILIENCY MEASURES IN THE 2026-2028 T&D SRP?

A. Similar to how the Company currently and historically has financed capital investments, the Company will finance the implementation of the Resiliency Measures in the 2026-2028 T&D SRP through a combination of use of retained earnings and by utilizing the capital markets to raise funds.

F. CUSTOMER VALUE CONSIDERATIONS

Q. HOW WILL THE 2026-2028 T&D SRP BENEFIT CUSTOMERS?

A. The SRP will benefit customers by reducing costs over time. As the Company invests more in resiliency efforts, the system will become more resistant to damage from Resiliency Events. Thus, the Company will save money on repairs and restoration, and in turn, save customers money. Company witness Muss Akram further discusses affordability in his testimony.

Q. ARE THERE OTHER WAYS IN THE WHICH THE COMPANY WILL SAVE CUSTOMERS MONEY?

A. Yes. In early 2025, the Company intends to request to securitize storm recovery costs from the 2024 Derecho and Hurricane Beryl. The use of securitization allows the Company to extend the time it recovers storm costs from customers. Typically, capital investments are recovered through bi-annual DCRF proceedings and therefore reflected in customer rates within a few months, including carrying costs at the Company's approved weighted average cost of capital. By securitizing storm recovery costs, storm related capital investment recovery is spread out over multiple years using bonds with an interest rate that is lower than the Company's weighted average cost of capital, thus having a smaller and more gradual impact on customer rates.

Q. HOW WILL THE 2026-2028 T&D SRP IMPACT CUSTOMER AFFORDABILITY?

A. As a result of the SRP, customer bills will increase by approximately $7.33/month over the three-year period. However, the Company's investments will benefit customers in ways that do not show up on their electric bills, including reducing CMI, avoiding life-threatening outages, and decreasing costly system restoration efforts. Any increase in cost impacts affordability, but compromising system resiliency and reliability for customers is something we cannot afford. For a more in-depth analysis on both customer and societal affordability impacts, please see the direct testimony of Company witness Muss Akram.

CONCLUSION

Q. DOES THE COMPANY'S 2026-2028 T&D SRP COMPLY WITH THE T&D SRP STATUTE AND THE COMMISSION'S T&D SRP RULE?

A. Yes.

Q. WILL IMPLEMENTATION OF THE RESILIENCY MEASURES IN THE COMPANY'S 2026-2028 T&D SRP PROVIDE A BENEFIT TO THE CUSTOMERS AND COMMUNITIES THAT THE COMPANY HAS THE PRIVILEGE TO SERVE?

A. Yes. The Company anticipates that the benefit to customers and communities will be saving approximately 1,309 million CMI.

Q. IS THE COMPANY'S 2026-2028 T&D SRP IN THE PUBLIC INTEREST?

A. Yes.

Q. SHOULD THE COMMISSION APPROVE THE COMPANY'S 2026-2028 T&D SRP?

A. Yes. Additionally, the Company requests that the Commission include its requested accounting language in the order approving the Company's 2026-2028 T&D SRP and approve the Company's requested changes to the Company's Tariff needed to implement certain Resiliency Measures.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

STATE OF Texas §
§
COUNTY OF Harris §

AFFIDAVIT OF NATHAN BROWNELL

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

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

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

Further affiant sayeth not.

NATHAN BROWNELL

SUBSCRIBED AND SWORN TO BEFORE ME on this 6th day of January, 2025.

TERENCE GLENN RUSSELL
NOTARY ID #1093521-4
My Commission Expires
February 21, 2027

Terence Glenn Russell
Notary Public in and for the State of Texas

My commission expires: 02-21-2027

Exhibit NB-1: Glossary of Acronyms

2026-2028 T&D SRP or SRP	The Company's 2026-2028 Transmission and Distribution System Resiliency Plan
AI	Artificial intelligence
Company	CenterPoint Energy Houston Electric, LLC
CMI	Customer Minutes of Interruption
CNP	CenterPoint Energy, Inc.
Commission	Public Utility Commission of Texas
DOE	Department of Energy
ERCOT	Electric Reliability Council of Texas
GHRI	The Company's Greater Houston Resiliency Initiative
Guidehouse	Guidehouse Inc.
HETI	Houston Energy Transition Initiative
IGSD	Intelligent grid switching device
IIJA	Infrastructure Investment and Jobs Act
kV	kilovolt
LiDAR	Light detection and ranging
MUG	Major underground
MW	Megawatt
MWh	Megawatt hour
NASA	National Aeronautics and Space Administration
NCEI	National Centers for Environmental Information
NESC	National Electrical Safety Code
NOAA	National Oceanic and Atmospheric Administration

O&M	Operations and maintenance
Resiliency Event	An event involving extreme weather conditions, wildfires, cybersecurity threats, or physical security threats that poses a material risk to the safe and reliable operation of the Company's transmission and distribution systems
Resiliency Measure	A measure designed to prevent, withstand, mitigate, or more promptly recover from the risks posed to the Company's transmission and distribution system by a Resiliency Event
SCADA	Supervisory Control and Data Acquisition
T&D	Transmission and Distribution
URD	Underground residential distribution
U.S. EIA	U.S. Energy Information Association
VOLL	Value of loss load