integrating these elements, electric utilities can minimize downtime, reduce economic impacts, and enhance the overall reliability of the power supply.

3.18.1 Findings

The transmission system withstood the test of Beryl with only one substation outage and minimal impact on the transmission lines. For many utilities, this poses a significant challenge during extreme weather events, reflecting the overall resiliency of the transmission and sub-transmission systems and the effectiveness of CenterPoint's investments. However, the number of circuit lockouts (nearly 78% of overhead feeders) represents the greatest area for grid performance improvement. Only about 83,000 of the 2.1 million customers out of service were not part of a circuit lockout. This represents an opportunity to limit the number of customers initially impacted and to free up crews to restore downstream segments of an impacted circuit faster. These lockouts took roughly three days to clear.

Preparedness

Segmentation provides greater resilience against storms, fewer customers without power, and faster storm recovery. Currently the CenterPoint circuit design largely is made up of single Intelligent Grid Switching Devices (IGSD) at the midpoint of the circuit and one at an end point (tie points to other circuits). Beyond the basic fault isolation benefits, sectionalizers give dispatchers more options to shift loads to restore customers quicker through remote switching. Today CenterPoint's isolation is primarily done through the operation of manual field operated switches. Finally, more automated sectionalizers with communications can direct damage assessors more quickly to the faulted areas. Many utilities have programs to get 500 customers or less per circuit segment (one utility has a goal of getting 250 customers per circuit segment) and it is a proven best practice. While the coordination of reclosers can be tricky there are solutions to accomplish the necessary segmentation.

Indeed, hardening the circuit main lines reduces the number of customers affected during a major storm and speeds up the restoration of those and all other downstream circuit segments. At the same time, it's estimated that while laterals and secondary outages accounted for a considerable portion of the restoration work, they affected only a small number of customers. The installation of TripSaver® reclosers can have a significant impact on minimizing lateral outages and these customers are the smallest in number, but those that were out the longest during Beryl. Finally, the amount of rear lot construction (primary and secondary) in the CenterPoint service territory is large by industry standards and represents a tremendous challenge in terms of both vegetation management and speed of restoration. Once again, the complexity of restoration in this circuit segment is exceedingly high and large numbers of crews are required to restore a small number of customers.

Improving the customer experience, as portrayed by the restoration curve, requires circuit redesign work in each circuit segment to achieve a multi-faceted reimagined distribution circuit design.

Performance

Beyond a robust targeted vegetation management program and circuit hardening, preventing, or minimizing circuit lockouts is most impacted by a strong main line fault-sectionalizing program. A good circuit-sectionalizing program has three main components: increased sectionalization on main line (backbone), looped circuits with manual, and automatic transfer capability and circuit inter-ties. When implemented at scale, the benefits include blue and grey-sky reliability improvements and substantial resiliency improvements including mitigating circuit lockouts.

3.18.2 Recommendations

Short-Term Actionable	Mid-Term Actionable
GRID-1 **Develop a Program to Segment Less than 500 Customers per Remotely Controllable Circuit**: Initiate a program to prioritize circuits for segmentation with the goal of eventually reaching 500 customers underneath an IGSD. Rebuild a prioritized group of circuits to new "withstand" standards (greater than 65 mph sustained). This will help limit the number of customers who are exposed to outages by providing Distribution Controllers the ability to remotely isolate the damage.	**GRID-3** **Increase Use of Composite Pole and Crossarms:** Consider increasing the use of composite pole and cross-arms use in the CenterPoint service territory. Composite poles and cross-arms have longer service lives and are more resistant to damage than comparable wooden poles and crossarms. This helps to improve system reliability and resiliency performance.
GRID-2 **Develop Laterals Protection and Sectionalizing Strategy:** Install TripSaver® (or similar) reclosers on all currently fused laterals, and then expand deployment to non- fused tap laterals. TripSaver® provides the ability to have a one-shot reclose capability on laterals, which may reduce the number of sustained outages affecting the lateral.	**GRID-4** **Replace Open Wire with Covered Conductors:** Where feasible, systematically replace open-wires in the service territory as open-wires are more prone to damage from felled trees / limbs and are less reliable and resilient to insulated conductors. Where practical, spacer cable (e.g., Hendrix or similar systems) should be used to increase mechanical strength, resist mechanical wear related outages, and better withstand contact related outages.

3.19 Strategic Undergrounding

Electric undergrounding involves installing power lines below ground rather than above it, which can significantly benefit utilities during storm outages. By burying lines, utilities reduce the risk of damage from high winds, falling trees, and other debris that affect overhead lines. This leads to fewer service interruptions and faster restoration times during storms. Undergrounding can enhance the overall reliability of the grid, decrease maintenance costs, and improve safety.

3.19.1 Findings

Preparedness

CenterPoint's electric distribution system is substantially underground in designated areas. There are 159 distribution circuits which supply those areas. CenterPoint currently has plans to extend underground lines into residential areas and for three phase services. The Company's standard practice is to install underground residential distribution (URD) systems to serve subdivisions with 24 or more lots. Normally, the URD installation will include buried primary lines and pad-mounted transformers. For subdivisions with less than 24 lots and for other new business circumstances, developers can pay the overhead underground cost differential to obtain URD service. CenterPoint also identifies areas to be dedicated underground areas such as downtown Houston and the medical center.

Performance

While there was minimal damage to URD systems from Beryl, customers served by most URD systems had their service interrupted due to damage to the overhead circuit supplying the URD system they are fed from.

Hurricane Beryl was not primarily a flooding event, and the underground circuits performed well or were restored swiftly following the storm. Where underground equipment was subject to outage, this was because the specific UG circuits that were fed from overhead circuits.

3.19.2 Recommendations

Short-Term Actionable	Mid-Term Actionable
UG-1 **Identify a Pilot to do Underground Replacement of Existing Overhead Rear Lot Construction:** Identify a pilot project to underground existing rear lot overhead construction. Relocate rear lot to public right of way with better access (sidewalk, street, etc.). **UG-2** **Develop Worst Performing Feeder Underground Program:** Expand and prioritize circuits to be undergrounded, identifying those that make the most feasible and cost-effective sense and that addresses the circuits that continue to lose power and/or are most likely to lose power often. Identify and prioritize key areas where undergrounding can have the most significant impact on reliability and storm resilience. Assess benefits and costs of undergrounding in varying sections of service territory.	**UG-3** **Expand UG Priority Circuits:** Focus on high-density urban areas, critical facilities, and regions prone to frequent outages. Identify funding and capital for undergrounding, incorporate advanced technologies such as real-time monitoring systems, automated underground fault detection, and predictive maintenance tools to enhance the ability to quickly identify and address issues in underground networks. Use high-quality materials and implement best practices for underground cable installation to reduce the likelihood of future faults. Consider designing systems with redundancy to minimize the impact of any single point of failure. Utilize data analytics to assess the performance of underground systems and inform decision-making. Analyze outage patterns, restoration times, and system performance to continuously improve the undergrounding program.

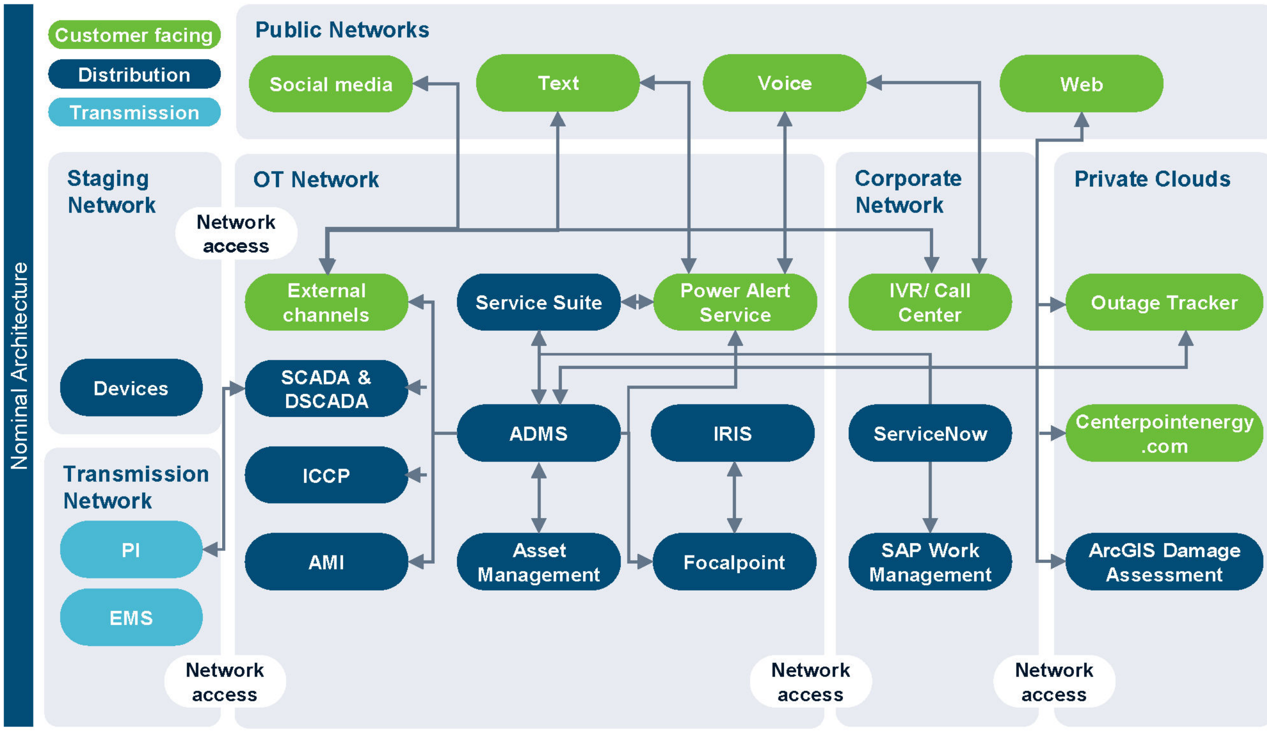
3.20 IT / OT

Other than the issues noted with CenterPoint's Outage Tracker, CenterPoint's information technology and operational technology functioned as designed prior to, during, and after Beryl. Only 13 technology problems were identified during Beryl and the restoration.

3.20.1 Findings

The overall technology landscape reflects normal practices with utility information technology and operational technology. The relevant components of the Information Technology (IT) and Operations Technology (OT) landscape are illustrated in Figure 3 - 7.

Figure 3 - 7: CenterPoint IT and OT Landscape



The systems that performed a notable role during Beryl are:

- Advanced Distribution Management System. CenterPoint uses a widely used ADMS solution hosted on-premise and provides functionality for distribution network monitoring and control, outage management, switching, powerflows, DER management. The ADMS is pivotal to managing outages and functioned as expected during Beryl.
- Asset Management is a collection of tools that maintain a registry, controls, inspection, documentation, prediction and performance models, imagery of assets and their surrounding locations and geographic information on distribution assets. Asset management tools provide asset information to ADMS and other systems so that they function as expected. Asset management also informs activities including Vegetation Management and inspection so that problem trees and access problems are identified and corrected.
- Damage Assessment is a collection of tools used by field inspectors, office-based supervisors and operations teams to assess damage and estimate repairs to distribution assets. CenterPoint uses ESRI tools to capture assessments, which are packaged into logical groupings to inform operations teams of the damage extent, priority and work required. These tools functioned as expected during Beryl.
- SCADA, Distribution Supervisory Control and Data Acquisition (DSCADA) is the solution architecture used for remote control of distribution automation devices such as reclosers, switches and IGSD. SCADA normally refers to transmission level devices and DSCADA refers to distribution level devices. The overlap between the two is within a substation for the reclosing devices used to control distribution circuits exiting the substation. The SCADA and DSCADA functioned as expected during Beryl.
- PAS is a voice, email, and text notification service for customers that is intended to notify customers of outage events and restoration information. Contact data allows CenterPoint to associate a meter number with a customer and the customers' phone, text, and email contact details. PAS is not a mobile app that customers can download, and it doesn't provide for outage or hazard reporting. Given the constraints of Texas energy market rules, CenterPoint only has contact details for 42% of actual electric customers, most of which are gas customers. PAS functioned as expected, within the

constraint of a limited and unknown quality customer contact database. Users of PAS experienced trouble with the service as a consequence of the infrastructure PAS operates on, in addition to external cellular bandwidth limitations.

- IRIS and FocalPoint provide a situational awareness capability with dashboards, driven by information collected from ADMS, Service Suite, and other systems. It is used as an input to command-and-control decisions on the deployment of field resources, as well as monitoring the progress of restoration. IRIS and FocalPoint functioned as expected during Beryl, except for occasional unavailability as a consequence of the infrastructure it operates on.
- Automation of Reports and Consolidated Orders System (ARCOS) is a callout tool typically used for the initial mobilization of field resources. ARCOS functioned as expected during Beryl.
- Service Suite is a work management solution that allows packages of work to be created, assigned, dispatched, updated, and completed. Outages that are detected automatically by SCADA and actioned by ADMS are communicated to Service Suite for further work assignments as well as work assignments created manually through command-and-control actions. Service Suite can be used centrally on large displays and by field workers using small screen devices. Service Suite functioned as expected during Beryl, except for occasional unavailability as a consequence of the infrastructure it operates on.
- Advanced Metering Infrastructure (AMI) is the advanced meters, communication infrastructure and control systems used to read, update and control electric meters. CenterPoint's AMI is 2010 era technology and is undergoing a phased upgrade to modern era technology through 2030. AMI can be used to detect loss of power and reenergize events automatically. It is not CenterPoint's practice to verify restoration with automated pings, but meter pings can be requested manually from the distribution control center. AMI functioned as expected during Beryl.
- OT Network is a secured network where OT systems and devices communicate.
- Corporate Network is a secured network where the main IT systems are available.
- Staging Network is a temporary secured network that enables field workers and supervisors to collaborate.
- IVR and automatic call distribution are call handling tools commonly used in call center operations.

Preparedness

Several perceived application failures were experienced by internal users, and PA expects, but has not verified, impacted external users. The root cause of these failures was not the applications but with the infrastructure they operate due to capacity limitations both internally and externally.

Performance

ServiceNow is used to manage the operation of CenterPoint's technology which is a common practice across well-managed modern companies.

Typical definitions for priorities are:

01 **Priority 1 (P1):** critical impact and/or urgency.

02 **Priority 2 (P2):** high impact and/or urgency

03 **Priority 3 (P3):** moderate impact and/or urgency

Typical levels of problem and incident rates are:

01 Highest performing IT operations achieve an annual rate of <1 per employee.

02 Average performance is in the 2-5 range.

03 Poor performance is 5+.

04 CenterPoint extrapolation from the storm period to one year yields an annual rate of 0.07 with is comfortably in the range for the highest performing operations.

The main observations from this performance are:

- No failures within the core systems or communications in the OT network
- Recommend storm volumes are factored into testing, provisioning and preparation for all critical systems and infrastructure. Commentary on the performance of centerpointenergy.com carries the implication that other systems besides centerpointenergy.com may also have been sized with normal growth rates rather than storm volumes.

3.20.2 Recommendations

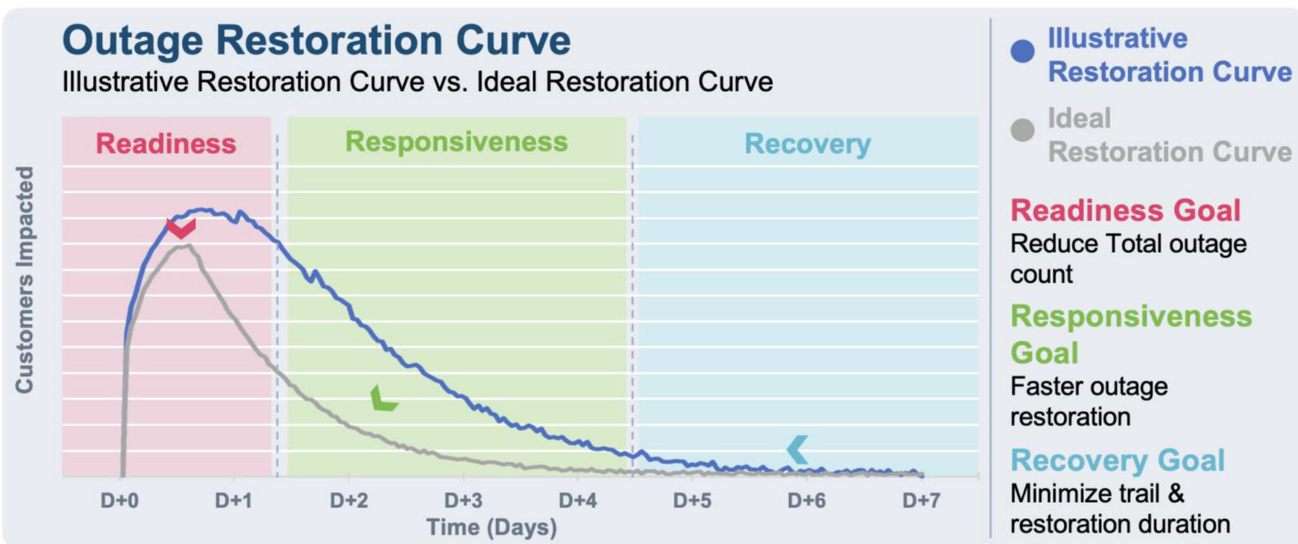
Short-Term Actionable	Mid-Term Actionable
IT/OT-1 **Factor Storm Volumes into All Systems:** Recommend storm volumes are factored into provisioning and preparation for all systems. Commentary on the performance of centerpointenergy.com carries the implication that other systems besides centerpointenergy.com may also have been sized with normal growth rates rather than storm volumes. **IT/OT-2** **Ensure Data Quality and Robustness:** Ensure there is a customer data quality process, so that contact information is maintained both securely and with high quality. Outage and problem reporting has multiple methods; rationalize applications to minimize customer information solutions, currently Outage Tracker, PAS, website, and other temporary solutions. Provide for storm, bad weather and blue sky scenario operation for all customer contact methods. Address mismatch between verbal reports of system failures and their absence in service records.	**IT/OT-3** **Harden IT/OT:** Harden IT and OT infrastructure and communications to increase availability. Use storm volumes, or larger, for load test exercises, covering for (1) all customer reporting/publishing and (2) all internal triggers arriving from AMI, SCADA, and DSCADA. Ensure there is redundancy for infrastructure and communication paths. Use cloud resources for high transaction or page views, triggered by major events.

4. Recommendations by Resiliency Phase

04

The restoration process is structured into three key phases: readiness, responsiveness, and recovery, with recommendations aligned to each phase. Since every phase has specific objectives, PA has developed targeted recommendations and actions to meet them. By following these steps, CenterPoint will not only accomplish the immediate objectives of each phase but also enhance its long-term resilience as a coastal grid. The timing (short- versus mid-term) of recommended actions refers to when CenterPoint should begin or initiate the action and, especially for those recommendations that are not feasible to complete within a short timeframe, does not refer to the completion timing.

Figure 4 - 1: Illustrative Restoration Curve by Phase



Readiness

Table 4 - 1: Recommendations for Reducing Total Outage Count

ID	Name	Timing	Description
Finding Area: Emergency Preparedness & Response			
EP&R-1	**Enact 24-Hour EOC/DOC Operations**	Short-Term Actionable	Switch to 24-hour EOC/DOC operations, operating on two, 13-hour shifts for key functions including Planning.
EP&R-2	**Reevaluate FCC Support**	Short-Term Actionable	Re-evaluate number of FSR needed to support the number of FCC during EOC activations to alleviate some of FCC administrative burden.

ID	Name	Timing	Description
EP&R-3	**Focus Planning Section on Strategic Functions**	Mid-Term Actionable	Revamp Planning Section to focus on more strategic functions. Upgrade the Planning Section Chief to a Vice President-level resource. Update the Planning Section role and responsibilities, including incorporation of Global ETR establishment and management. Establish the strategic response plan for the incident, including resources and allocations needed, restoration tactics, and a global ETR and ETR strategy. Encourage a constructive tension between Planning and Operations Sections.
Finding Area: Damage Prediction			
DM-PR-3	**Build, Develop, or Acquire more Comprehensive Damage Prediction Models**	Mid-Term Actionable	Many of the above limitations can be addressed through a more robust commercially available machine learning based software package. Key elements are the ability to archive small events and scale, use CenterPoint's historical outage data and leverage various sources of data to develop accurate models of damage predictions that can account for various modes of damage (e.g., in addition to the type of downed poles, laterals vs. primary circuit damage locations, transmission and substation damage).
Finding Area: Estimated Time of Restoration			
ETR-3	**Integrate ETR Manager Role into IC**	Mid-Term Actionable	Fully integrate ETR manager role into IC. Fully develop and map out flow of information needed to generate Global / Regional / Substation-level ETRs, as well as all ways to disseminate ETRs to customers and stakeholders, including soliciting additional customer contact information.
ETR-4	**Define and Track ETR Accuracy**	Mid-Term Actionable	Develop metrics to track the accuracy of ETRs that are generated and communicated. Common industry standards define an ETR as accurate if power is restored within a specific time band relative to the ETR, and if customers receive fewer than three updated ETRs for the same outage. Typical time bands include: 1) two hours before the stated ETR to zero hours after, and 2) one hour before to one hour after the stated ETR. Excessive updates can create a perception that ETRs are unreliable, ultimately hindering the ability to shape customer expectations and aid in informed decision-making.
Finding Area: Communications			
COMMS-2	**Revise the Current Communications Strategy**	Short-Term Actionable	Revise communication strategies to focus on delivering essential information to customers, including storm preparedness and expectations, while addressing key concerns like estimated restoration times. Utilize the most effective channels to help ensure clear and timely communication.
COMMS-3	**Expand Relationships with External Stakeholders and**	Mid-Term Actionable	To enhance collaboration and help ensure effective communication, it is vital to deepen relationships with external stakeholders and government officials. Establishing regular engagement and creating a schedule for regular meetings and updates with key stakeholders, including local government

ID	Name	Timing	Description
	Government Officials		officials, emergency management agencies, and community organizations will foster a sense of partnership and facilitate better information sharing. Conduct joint planning exercises and exercises with government agencies and stakeholders to help ensure alignment and coordination during emergencies. This collaborative approach will enhance preparedness and response capabilities.
Finding Area: Customer Experience			
CX-2	**Increase Customer Enrollment and Customer Contact Database**	Mid-Term Actionable	Increase the completeness of customer contact information from 42% to enhance ETR communications during storm events. Identify enrollment strategies, while ensuring the customer data quality process maintains contact information securely and accurately. Support legislative efforts to aid increased enrollment.
CX-3	**Enhance Customer Communication Channels**	Mid-Term Actionable	Assess the feasibility of having customer communication solutions that can both push alerts and receive reports from customers across channels (text, voice, email, social media and web).
Finding Area: Mutual Assistance			
MA-1	**Reevaluate FCC Support**	Short-Term Actionable	Re-evaluate number of FSRs needed to support the number of FCCs during EOC activations to alleviate some of FCC's administrative burdens. Provide FCC support such as administrative, runners, etc. FCC Team should be comprised of a LOTO qualified CenterPoint employee, a service planner or other technical type CenterPoint employee, and an external damage assessment resource (after damage assessment is done). Improve work package distribution. As a stop gap until more robust systems are developed and implemented, provide additional FCC field support to streamline field ETR updates.
Finding Area: Vegetation Management			
VM-1	**Revise Trimming Cycles**	Short-Term Actionable	To enhance the effectiveness of vegetation management, CenterPoint should immediately revise its tree trimming cycles to a more frequent interval of three years. This adjustment will allow for more proactive and responsive management of tree growth, significantly reducing the risk of outages caused by overgrown vegetation interfering with power lines.
VM-3	**Enhance Tree Replacement Programs**	Mid-Term Actionable	Enhance the existing tree replacement program by introducing a range of options for customers with at-risk vegetation. This initiative could include personalized consultations to assess individual properties, recommendations for suitable replacement species, and incentives for participating in the program. By actively engaging customers in the management of at-risk trees, CenterPoint can help reduce the risk of outages while fostering community involvement and promoting environmental sustainability.

ID	Name	Timing	Description
VM-4	**Develop a Digital Intelligence Program to Effectively Perform Condition-Based Trimming**	Mid-Term Actionable	Transition to a data driven, condition-based trimming approach to enhance the effectiveness of vegetation management. Unlike the current practice of relatively long cycle trims, condition-based trimming based on various imagery processing based analytics and tools (LiDAR) focusing on the specific health and growth patterns of trees and vegetation surrounding power lines. This method involves regular assessments of tree conditions, identifying which trees require trimming based on their growth, structural integrity, and proximity to power lines. By adopting this proactive strategy, CenterPoint can prioritize vegetation management efforts on high-risk areas, helping ensure timely interventions that reduce the likelihood of outages caused by falling branches or trees.
Finding Area: Grid Performance, Design, and Automation			
GRID-3	**Increase Use of Composite Pole and Crossarms**	Mid-Term Actionable	Consider increasing the use of composite pole and cross-arms use in the CenterPoint service territory. Composite poles and cross-arms have longer service lives and are more resistant to damage than comparable wooden poles and crossarms. This helps to improve system reliability and resiliency performance.
GRID-4	**Replace Open Wire with Covered Conductors**	Mid-Term Actionable	Where feasible, systematically replace open-wires in the service territory as open-wires are more prone to damage from felled trees / limbs and are less reliable and resilient to insulated conductors. Where practical, spacer cable (e.g., Hendrix or similar systems) should be used to increase mechanical strength, resist mechanical wear related outages, and better withstand contact related outages.
Finding Area: Strategic Undergrounding			
UG-1	**Identify a Pilot to do Underground Replacement of Existing Overhead Rear Lot Construction**	Short-Term Actionable	Identify a pilot project to underground existing rear lot overhead construction. Relocate rear lot to public right of way with better access (sidewalk, street, etc.).
UG-3	**Expand UG Priority Circuits**	Mid-Term Actionable	Focus on high-density urban areas, critical facilities, and regions prone to frequent outages. Identify funding and capital for undergrounding, incorporate advanced technologies such as real-time monitoring systems, automated underground fault detection, and predictive maintenance tools to enhance the ability to quickly identify and address issues in underground networks. Use high-quality materials and implement best practices for underground cable installation to reduce the likelihood of future faults. Consider designing systems with redundancy to minimize the impact of any single point of failure. Utilize data analytics to assess the performance of underground systems and inform decision-making. Analyze outage patterns, restoration times, and system performance to continuously improve the undergrounding program.

Responsiveness

Table 4 - 2: Recommendations for Restoring Outages Faster

ID	Name	Timing	Description
Finding Area: Incident Command			
IC-1	**Streamline EOC Layout**	Short-Term Actionable	EOC physical layout should be updated to facilitate communications and information flow. Planning, Operations, CMC, Logistics, and Finance/Administration each should have dedicated work room in adjacent spaces. Provide workspaces for other IC leader team members as required (Legal, Liaison, Safety, Customer, etc.). Physically align the EOC and the Distribution Operations Section Chief, when the EOC is open for an electric event. Co-locate the EOC and CMC until each entity is fully established and independently operational.
IC-2	**Revise IC Roles and Responsibilities**	Short-Term Actionable	All roles and responsibilities within the EOC structure need to be reviewed and updated as appropriate. The actual personnel staffing these positions should be at the executive level and be the most experienced CenterPoint personnel in major storm restoration. IC organization needs to be at least two-deep across IC section chief and higher roles. Use Deputies as a professional growth and development opportunity.
IC-3	**Expand IC/EOC Training**	Short-Term Actionable	To the extent where possible, arrange for the current Planning Section Chief and Deputy to observe the Planning Section in action during the next major event in the Eastern United States. Tabletop exercise the revised Planning Section responsibilities. In the event of a major weather event in the Atlantic region during the 2024 storm season, designated CenterPoint personnel should shadow with the affected utility's IC to gain valuable insights and experience. Train additional personnel to function in IC roles (e.g., primary as well as backup roles), use shadowing opportunities to create 2-in-box type operations throughout EOC operations.
IC-4	**Continue to Streamline EOC Layout**	Mid-Term Actionable	Split the District Operations Branch during an EOC electric event to maximize impact of restoration efforts. Distribution Operations Branch Leadership located at the EOC. Region 1 work assignment located at Addicks Operations Center. Region 2 work assignment located at the ECDC.
IC-5	**Establish EOC-Sections Daily Meeting**	Mid-Term Actionable	Establish a new daily meeting cadence for the EOC and Sections (e.g., Planning, Operations, Logistics, and Finance/Administration).
Finding Area: Safety			
SAF-1	**Expand Safety Standdowns**	Short-Term Actionable	Safety is an entire-property, all personnel program and significant events should have safety standdown–all resources, operating or support, should know about the incident. Should be top-down decision and responsibility to communicate standdown to all response personnel.

ID	Name	Timing	Description
SAF-2	**Revise Substation Breaker Reclose Policy**	Short-Term Actionable	Change the breaker recloser policy in the event of a storm to require visual confirmation on the circuit before reclosing to ensure it is safe to do so. This would require additional communications and integration of processes between Field Operations (e.g., crews and FCCs as appropriate).
SAF-3	**Bolster Safety Leadership Responsibility**	Mid-Term Actionable	To enhance overall safety management and facilitate effective operational oversight, it is recommended that the responsibilities of the safety group leadership be expanded. Empower safety group leaders with greater authority to enforce safety protocols and make real-time decisions during storm restoration efforts. This will support timely responses to safety concerns and incidents. Provide continuous training on best practices and regulatory updates to help ensure leaders are well-prepared. Establish clear protocols for regular briefings between the safety group and operational teams to address safety concerns promptly.
Finding Area: Damage Prediction			
DM-PR-1	**Gather Beryl Damage Data for Model Refinement**	Short-Term Actionable	Gather granular weather data (e.g., wind gusts, directions) and restoration data from Hurricane Beryl in a well-documented manner to allow for refinement of existing damage prediction model inputs. Gathering this data will help future efforts to improve model accuracy and can be used for future analytics/modeling efforts as well.
DM-PR-2	**Refine Restoration Productivity Assumptions**	Short-Term Actionable	Analyze Beryl's restoration data (e.g., type of pole damage, pole reset durations) that are currently used in the damage prediction models to refine and enhance accuracy of the damage prediction model.
Finding Area: Estimated Time of Restoration			
ETR-1	**Calculate and Disseminate Global ETRs**	Short-Term Actionable	Develop processes to calculate Global ETRs when most customers (e.g., 90% of impacted customers) would be restored. Global ETRs should be calculated and released publicly within 48 hours of storm impact, ideally within 24 hours of the storm leaving the area. Develop internal and external facing material to educate what the Global/Regional/ Substation-levels of ETRs mean, as well as when they would be communicated publicly.
ETR-2	**Develop ETR Strategy and Processes**	Mid-Term Actionable	Develop strategy to calculate Global/Regional/Substation-level ETRs (e.g., approaches to when to disseminate, inputs needed, and roles and responsibilities). Develop processes to consolidate ETR updates from the field and aggregate them to enable the calculation of Regional/Operating Area, or Substation-level ETRs.
Finding Area: Communications			
COMMS-1	**Update the Current Communications Plan**	Short-Term Actionable	Enhancing the plan with additional governance and structure will empower CenterPoint to make communication decisions more quickly, effectively, and consistently during major events.

ID	Name	Timing	Description
			Proactive and informative communication is crucial during power outages, helping enable customers to plan and make necessary accommodations. For utilities, getting this right is a critical component of customer satisfaction.
COMMS-4	**Develop a Liaison Protocol**	Mid-Term Actionable	Clearly define the liaison protocols for both routine (blue sky) days and during emergencies (black/grey sky days). This should include identifying preferred communication methods for different scenarios, ensuring rapid dissemination of information during crises. CenterPoint should designate specific individuals within the organization to serve as liaisons for various stakeholders, ensuring that inquiries and concerns are addressed promptly expanding on what currently exists. Provide training for liaison personnel on effective communication and relationship management, focusing on how to handle inquiries from stakeholders during normal operations and in crisis situations.
COMMS-5	**Establish Customer Experience Feedback Mechanisms**	Mid-Term Actionable	Implement a system to gather feedback from stakeholders (e.g., elected officials, media, key accounts, customers, etc.) regarding the effectiveness of communication strategies and areas for improvement. This will help refine protocols and strengthen relationships over time.
Finding Area: Outage Tracker			
OT-1	**Replace Outage Map**	Short-Term Actionable	Replace the public-facing Outage Map with an Outage Tracker featuring comparable capabilities to the previous version.
OT-2	**Revise Technology Selection and Testing Processes**	Short-Term Actionable	The decision-making process for technology solutions should be reviewed so that critical systems receive heightened scrutiny. This includes clearly defining what constitutes a critical system (to include more than just operational continuity) and preventing any critical system from being taken offline without having a suitable replacement in place.
OT-3	**Expand Customer Reporting**	Short-Term Actionable	Enable customers to report a broader range of issues, including trouble, safety, and hazard incidents (such as wires down or fire), along with guidance for reporting life-threatening situations to the proper emergency agencies. Currently, the Outage Tracker only allows reports for ‘Lights Out,’ ‘Partial Service,’ and ‘Dim Lights’.
OT-4	**Use Positive Language in Outage Tracker**	Mid-Term Actionable	Modify the messaging on the outage tracker to address customer journeys with positive rather than negative language. Outage statistics can be reported accurately using availability in addition to customers impacted. Currently there are two methods for reporting outages, safety, and hazards, using a local phone number or using the outage map. Multi-channel reporting and alerting are now commonly available from electric utilities. Guidance can be provided on a variety of relevant customer requirements or journeys including resetting customer breakers, preparing for a storm, post storm, gas leaks, fire, cooling and charging center locations, and others.

ID	Name	Timing	Description
OT-5	**Host Software Platforms Reliably**	Mid-Term Actionable	Ensure that all public facing communication solutions are hosted on reliable and scalable infrastructure. The easiest way to achieve this is with major cloud providers including the ESRI. The current outage map is deployed on ESRI's arcgisonline.com. Ensure there is a storm mode designed within the system that protects and isolates the critical internal systems such as ADMS from storm-level traffic and reporting.
Finding Area: Customer Experience			
CX-1	**Implement Real-Time Customer Feedback during Major Events**	Short-Term Actionable	To improve communication and customer satisfaction during major events, the implementation of immediate customer feedback mechanisms is important. This goal focuses on establishing real-time channels for customers to voice their concerns, report outages, and provide feedback on restoration efforts.
CX-4	**Inform Customers of the Potential Need for Electrical Service Work**	Mid-Term Actionable	Once a global ETR is issued, CenterPoint should promptly inform customers to inspect their property. If there is damage to the weatherhead, mast, or panel, advise them to hire an electrician to complete the necessary repairs. This allows them to act before their neighborhood is re-energized, helping to expedite their individual restoration.
Finding Area: Mutual Assistance			
MA-2	**Develop Mutual Assistance Tool**	Short-Term Actionable	Develop mutual assistance resource tracker and onboarding tool. Assess available tools by function and user experience. Eversource Energy onboarding process is publicly available and can be used as a starting point to model a more efficient onboarding process. Foreign Crew (non-native contractors and mutual assistance) management is critical, and the CenterPoint Energy team identified securing a system to manage this which should help them manage logistical support and cost tracking of these resources.
MA-3	**Reevaluate Storm Rider Policy**	Short-Term Actionable	Storm Rider Policy and decision needs to be reevaluated. During Beryl, most employees or contractors were asked to come in after the storm passed which could have delayed immediate restoration efforts.
MA-4	**Supply Mobile Technology to Mutual Assistance Crews**	Mid-Term Actionable	Provide technology for crews (foreign and non-foreign). Equip all CenterPoint and native contract field workers with mobile access to work, outage, circuit, damage assessment and other types of data. Distribute mobile devices (or supply digital apps to personal phones) to all field personnel with an application/tool for time/vehicle/work reporting as well as for onboarding – safety, system information, etc.
MA-5	**Create Equipment Equivalents List**	Mid-Term Actionable	Develop a comprehensive list of equipment equivalents across manufacturers and utilities to facilitate mutual assistance. This will expedite onboarding and task orders, streamline equipment requests, and enhance monitoring through barcode scanning and GPS tracking. Implementing this list will improve future restoration efforts, ETR accuracy, and staging site efficiency.

ID	Name	Timing	Description
MA-6	**Streamline Mutual Assistance Crew Operations for Enhanced Efficiency Across All Functions**	Mid-Term Actionable	Generally, utilize mutual assistance crews in the same efficiency as internal crews. This applies to tagging and grounding and lockout tagout switch out, switching dispatch, communications, how they get to a job every day, what they do, what they need to have.
Finding Area: Logistics			
LOG-1	**Enhance Operational Efficiency through Alternative Staging Site and Logistics Solutions**	Short-Term Actionable	To reduce crew travel time and expedite work, staging sites should be strategically located. In instances where a hotel is identified as a staging site and the hotel is without power, CenterPoint can coordinate and deploy temporary generators to restore electricity, where feasible (e.g., sites can accept power), benefiting both the hotel and restoration efforts. Strategically selecting locations near service centers will help minimize travel time for crews. If applicable, it is essential to confirm that staging sites have adequate staffing to manage operations, clean, and prepare rooms for crews. Additionally, having leadership present at these locations will help maintain an efficient schedule for restoration activities.
LOG-2	**Use Select Service Centers for Staging**	Short-Term Actionable	Where feasible, use existing service centers as staging sites. Staging site versus service center operations should be reevaluated (i.e., move the operations team from staging site to service centers as it is too decentralized currently). Minimize moving workforce to decentralized staging sites. Streamline communications and collaboration between system operations employees and field employees. Depending on where storm damage is located, CenterPoint could use those locations which make most geographic sense.
Finding Area: Damage Assessment			
DM-AS-1	**Integrate Damage Assessment and Vegetation Management Crews**	Short-Term Actionable	Integrate the vegetation management crews and damage assessors with the “cut and clear” resources as a first responder team to be dispatched together.
DM-AS-2	**Pre-Stage Materials/ Equipment**	Short-Term Actionable	While thorough damage assessments may not completely eliminate the need for an FCC to inspect a circuit segment for LOTO and safety purposes, efforts should be made to enhance the identification of required materials, equipment, and vegetation clearing before the arrival of line restoration resources. This proactive approach can help streamline the restoration process and improve overall efficiency.
DM-AS-3	**Streamline Damage Assessment for Work Packages**	Short-Term Actionable	Rework damage assessment processes to improve the usefulness of work packages. During the initial wave of damage assessments, validate and verify damage prediction models regarding required resources and materials. Following this initial assessment, the focus should shift to estimating restoration times to provide accurate timelines for stakeholders. Subsequently, attention should be directed toward proactively supporting line restoration and pole-setting crews to facilitate

ID	Name	Timing	Description
			an efficient recovery process. This structured approach will enhance operational effectiveness and help ensure a timely restoration of services.
DM-AS-4	**Upgrade Damage Assessment Technology**	Mid-Term Actionable	Explore and leverage LiDAR sensors and machine learning to quickly assess and integrate data with ESRI tools. The damage model should be able to take storm tracks, CenterPoint asset information, and develop an estimate for the level of repair efforts that are needed to help the Incident Commander and other IC Staff to confidently determine level of crewing required for restoration duration. The Planning Section Chief should be ultimately responsible for making sure the model is populated, tested, and exercised for accurate results and restoration preparedness.
DM-AS-5	**Revise Resource Utilization**	Mid-Term Actionable	Currently the DOC decides how to utilize the damage assessors. Consider using the damage assessors after initial assessments to be patrol inspectors during the circuit sweep operations. Harmonize veg and line crews and damage assessors, in a way that's more real-time and less sequential – eliminate wait times. "Advance deployment team" (slot team) preparing next line section(s) for work while other crew is working (assess damage, deliver materials, set up isolation and grounding points). So that when line crew moves on to the next section, they can immediately begin work.
Finding Area: Restoration Management			
RM-1	**Expedite IAP Completion**	Short-Term Actionable	The IAP should be finalized and approved before the operating period begins, establishing a clear set of objectives to serve as execution targets for the various operational areas. The IAP should encompass the ETR strategy and resource allocation, along with the prioritization of remaining tasks. Additionally, EOC briefings should concentrate on executing the plans outlined in the IAP rather than developing new plans for the day.
RM-2	**Evaluate FCC Pool Size**	Short-Term Actionable	The effectiveness of decentralization is directly linked to the number of FCCs available and their operational efficiency. To enhance scalability during restoration efforts, it is recommended to assess and potentially expand the FCC pool size. Engaging native contractors with journeyman-level experience as additional FCCs can significantly bolster capacity, allowing for improved management and coordination of field operations. This approach will help ensure that resources align with restoration needs, thereby optimizing overall response efforts.
RM-3	**Use Substation Restoration Segmentation**	Short-Term Actionable	Implement segmentation of restoration efforts by assigning specific crews to operate from designated staging centers associated with their respective substations. This approach will allow crews to focus on the circuits linked to their assigned substation, thereby minimizing the potential for overlap and interference with other crews working across different substations. By clearly delineating responsibilities and

ID	Name	Timing	Description
			operational areas, this strategy should enhance coordination and efficiency during restoration efforts.
RM-4	**Leverage Low Voltage Resources for Parallel Restoration**	Short-Term Actionable	In cases of significant damage to overhead services, deploy low voltage restoration teams to start repairing and replacing services ahead of the primary repairs in an area. This approach optimizes additional resources and helps shorten the tail end of the restoration process.
RM-5	**Test Processes and Technology**	Mid-Term Actionable	Test all revised processes and technologies during smaller storm events, moving beyond simulations or training exercises. Engaging native contractors to implement these new processes in real-world scenarios will provide valuable insights and practical experience. Additionally, conducting after-action reviews following these smaller events will facilitate the gathering of lessons learned, enabling continuous improvement and refinement of operational procedures. This proactive approach will help ensure that processes are effective and efficient when faced with larger storm restoration efforts.
RM-6	**Change RTO/DCO Jurisdictional Boundary**	Mid-Term Actionable	Operational jurisdiction and control of the distribution feeder breaker should be transitioned to the DCO. This will eliminate the bottlenecks inherent in Distribution Controllers calling RTO operators to operate a distribution circuit breaker. This revised boundary will also align much better to the modern distribution system, where automated circuit ties, distributed energy resources, and active voltage management each play key roles in serving customers on both blue sky and grey sky days.
Finding Area: Vegetation Management			
VM-2	**Optimize Crew Coordination**	Short-Term Actionable	To maximize the effectiveness of vegetation management efforts, CenterPoint should focus on enhancing the coordination and optimization of vegetation resources and crews. This involves implementing strategies that streamline operations, improve communication, and helps ensure that the right crews and resources are deployed to the most critical areas.
Finding Area: Call Center/Handling			
CCH-1	**Increase Call Center Resource Pool**	Short-Term Actionable	Identify and train additional resources, whether within the CenterPoint workforce or from third-party agencies, to ensure they can effectively assist during storm response. Train existing CenterPoint gas and Indiana call center organizations to provide supplemental support during storm response.
CCH-2	**Analyze Root Cause of IVR Containment Drop**	Short-Term Actionable	Conduct a root cause analysis to determine why the call center experienced a noticeable drop in the IVR containment rate sustained for five days.
CCH-3	**Forecast Call Center Resource Needs**	Mid-Term Actionable	Develop a framework to forecast additional call center support required during storm response, utilizing historical data from past storms.

ID	Name	Timing	Description
CCH-4	**Establish a Call Center Storm Response Plan**	Mid-Term Actionable	The plan should outline the tiers of additional assistance needed to maintain full operational capacity and establish criteria for deploying these resources. Once the plan is completed, train all mutual assistance call center representatives, including those from third-party agencies.
Finding Area: Grid Performance, Design, and Automation			
GRID-2	**Develop Laterals Protection and Sectionalizing Strategy**	Short-Term Actionable	Install TripSaver® (or similar) reclosers on all currently fused laterals, and then expand deployment to non- fused tap laterals. TripSaver® provides the ability to have a one-shot reclose capability on laterals, which may reduce the number of sustained outages affecting the lateral.
Finding Area: IT/OT			
IT/OT-1	**Factor Storm Volumes into All Systems**	Short-Term Actionable	Recommend storm volumes are factored into provisioning and preparation for all systems. Commentary on the performance of centerpointenergy.com carries the implication that other systems besides centerpointenergy.com may also have been sized with normal growth rates rather than storm volumes.
IT/OT-2	**Ensure Data Quality and Robustness**	Short-Term Actionable	Ensure there is a customer data quality process, so that contact information is maintained both securely and with high quality. Outage and problem reporting has multiple methods; rationalize applications to minimize customer information solutions, currently Outage Tracker, PAS, website, and other temporary solutions. Provide for storm, bad weather and blue sky scenario operation for all customer contact methods. Address mismatch between verbal reports of system failures and their absence in service records.
IT/OT-3	**Harden IT/OT**	Mid-Term Actionable	Harden IT and OT infrastructure and communications to increase availability. Use storm volumes, or larger, for load test exercises, covering for (1) all customer reporting/publishing and (2) all internal triggers arriving from AMI, SCADA, and DSCADA. Ensure there is redundancy for infrastructure and communication paths. Use cloud resources for high transaction or page views, triggered by major events.

Recovery

Table 4 - 3: Recommendations for Minimizing Restoration Duration

ID	Name	Timing	Description
Finding Area: Distributed Energy Resources			
DER-1	**Continue to Catalog DERs and Microgrids in CenterPoint Territory**	Short-Term Actionable	Understanding deployments within CenterPoint's territory can help the utility identify locations where DER and microgrids could be used for resiliency purposes in the future. Identify locations where a DER or microgrid could help temporarily restore power to surrounding areas or temporary emergency response locations.
DER-2	**Leverage Capacity Maps**	Mid-Term Actionable	Leverage capacity maps with relevant parties to encourage behind-the-meter DER installation in certain locations on CenterPoint's circuit where deployments could offer resiliency solutions.
DER-3	**Use DERs during Restoration Efforts**	Mid-Term Actionable	Consider establishing emergency solutions such as staging sites, cooling centers, or other community shelters in areas that can be powered by DERs or microgrids.
Finding Area: Temporary Generation			
TG-1	**Catalog Critical Customers**	Short-Term Actionable	Compile the list of all critical customers in the service territory, prioritize this list taking into account the risk of an extended outage at the specific customer location, the presence of customer owned backup generation, and other relevant factors, and understand how the priority customers with the highest risk of suffering an extended outage can be served by temporary generation.
TG-2	**Test Existing On-site Generation**	Short-Term Actionable	Educate and encourage critical sites that have on-site backup generation to routinely test their generators to ensure performance during a storm event.
TG-3	**Establish Deployment Priority Matrix**	Short-Term Actionable	Establish a priority matrix to deploy and utilize generators at critical facilities including which units are compatible at which site, what size units are available for each site, and what is the priority of deploying generation to each critical site within CenterPoint's territory. In the case of more deployment requests than available generation units, the priority matrix should be followed.
TG-4	**Develop and Promote Interconnection Services for Temporary Generation**	Mid-Term Actionable	Develop and promote an efficient interconnection process that coordinates with and supports critical sites lacking standby generation, helping ensure a seamless interconnection experience. Advise sites to build infrastructure, including bays and cables at all critical sites such as hospitals, cooling centers, and water treatment plants which enable quick deployment of temporary generation with limited additional work to be done to begin supplying sites with energy.
TG-5	**Procure Additional Distribution-scale Generation**	Mid-Term Actionable	Acquire additional smaller generators, between 230 kW and 5 MW in size, to enable greater use of temporary generators during future events.

ID	Name	Timing	Description
Finding Area: Grid Performance, Design, and Automation			
GRID-1	**Develop a Program to Segment Less than 500 Customers per Remotely Controllable Circuit**	Short-Term Actionable	Initiate a program to prioritize circuits for segmentation with the goal of eventually reaching 500 customers underneath an IGSD. Rebuild a prioritized group of circuits to new "withstand" standards (greater than 65 mph sustained). This will help limit the number of customers who are exposed to outages by providing Distribution Controllers the ability to remotely isolate the damage.
Finding Area: Strategic Undergrounding			
UG-2	**Develop Worst Performing Feeder Undergrounding Program**	Short-Term Actionable	Expand and prioritize circuits to be undergrounded, identifying those circuits that make the most feasible and cost-effective sense and that addresses the circuits that continue to lose power and/or are most likely to lose power often. Identify and prioritize key areas where undergrounding can have the most significant impact on reliability and storm resilience. Assess benefits and costs of undergrounding in varying sections of service territory.

Glossary

ADMS	Advanced Distribution Management System	IAP	Incident Action Plan
AHT	Average Handle Time	IC	Incident Command
AMI	Advanced Metering Infrastructure	IGSD	Intelligent Grid Switching Device
ARCOS	Automation of Reports & Consolidated Orders System	IT	Information Technology
ASA	Average Speed of Answer	IVR	Interactive Voice Response
CCA	Call Center Agent	kW	Kilowatt
CEHE	CenterPoint Energy Houston Electric	LiDAR	Light Detection and Ranging
CI	Customers Interrupted	LOTO	Lockout/Tagout
CMC	Crisis Management Committee	MW	Megawatt
CMI	Customer Minutes Interrupted	NIMS	National Incident Management System
CNP	CenterPoint Energy	NOAA	National Oceanic & Atmospheric Administration
CSAT	Customer Satisfaction	OH	Overhead
CST	Central Standard Time	OMS	Outage Management System
DCO	Distribution Control Operations	OT	Operations Technology
DER	Distributed Energy Resource	PA	PA Consulting
DOC	Distribution Operations Center	PAS	Power Alert Service®
DSCADA	Distribution Supervisory Control and Data Acquisition	PI	OSI PI Data Historian
DVAL	Distribution Evaluation	PUCT	Public Utility Commission of Texas
ECDC	Energy Control/Data Center	QA	Quality Assurance
EMS	Energy Management System	REP	Retail Energy Provider
EOC	Emergency Operations Center	RFI	Request for Information
EOP	Emergency Operations Plan	RMAG	Resources Mutual Assistance Group
EP&R	Emergency Preparedness and Response	RTO	Regional Transmission Organizations
EPRI	Electric Power Research Institute	SCADA	Supervisory Control and Data Acquisition
ERCOT	Electric Reliability Council of Texas	SEE	Southeastern Electric Exchange
ESRI	Environmental Systems Research Institute	SIF	Serious Injury and Fatality
ETI	Entergy Texas, Inc.	SOC	State Operations Center
ETR	Estimated Time of Restoration	TDEM	Texas Division of Emergency Management
FCC	Foreign Crew Coordinator	TIMS	Trouble Information Monitoring System
FEMA	Federal Emergency Management Agency	TNMP	Texas New Mexico Power Co.
FSR	Field Service Representative	TXMAG	Texas Mutual Assistance Group
FTE	Full Time Employee	UG	Underground
GIS	Geographic Information System	URD	Underground Residential Distribution
GPS	Global Positioning System	VOC	Voice of Customer

Figures

Tables

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PUBLIC UTILITY COMMISSION OF TEXAS

INVESTIGATION OF EMERGENCY PREPAREDNESS AND RESPONSE BY UTILITIES IN HOUSTON AND SURROUNDING COMMUNITIES

PROJECT NO: 56822

November 2024

Project Supervisors: John Lajzer and Luisa Venegoni

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Executive Summary

Background and Objectives

In May and July 2024, two major weather events tested utilities in the Greater Houston area. A fast-moving thunderstorm called a derecho hit Southeast Texas in May with winds over 100 MPH, damaging electric infrastructure and causing over 1 million power outages. In July, Hurricane Beryl made landfall in Matagorda Bay, disrupting electric service for 2.7 million customers, including 2.2 million CenterPoint customers.

To restore power, utilities had to clear vegetation and debris and fix damaged infrastructure. Even a week after Hurricane Beryl hit, hundreds of thousands of Texans were still without power, making daily life difficult.

On July 14, 2024, Governor Greg Abbott directed the Public Utility Commission of Texas (PUCT) to thoroughly review how well utilities in the Greater Houston area were prepared for and responded to these severe weather events.

The investigation had these goals:

1. Determine how well utilities in the Greater Houston area were prepared for and responded to severe weather events, especially the power outages after the May 2024 derecho and Hurricane Beryl.
2. Develop recommendations for utilities and the Legislature to reduce the length and impact of power outages after following future storms and recommend possible changes to Commission rules.

Methodology

To gather information, PUCT Staff sent 94 formal requests for information (RFIs) to electric, water, and telecommunications providers in the Greater Houston area.

The investigation's findings and recommendations are based on:

- Staff's analysis of responses to these requests
- Reports filed by utilities, including emergency operations plans (EOPs) and vegetation management reports
- Public input collected online and at a first-of-its kind PUCT workshop held in Houston
- Input from affected people, entities and organizations in the Greater Houston area
- Information provided by emergency-response and weather experts at the Houston workshop.

PUCT staff, including engineers, attorneys, and investigators, analyzed this information to create the investigation's findings and recommendations. This report summarizes and discusses common practices in utilities' severe weather preparedness and response, and specific examples of successes and shortcomings.

Findings and Recommendations

Recommendations are numbered for ease of reference and not in order of importance.

Impacts of the Outages

- *Texans' Lived Experience:* Feedback from a public questionnaire shows that Texans felt severe discomfort and stress, mainly due to health-related and financial concerns. They also had trouble getting reliable, accurate information during the power restoration process.

- *Water and Telecommunications:* Water and telecommunications utilities need electricity to operate their facilities. During power outages, they have to use backup generators. Water utilities without enough mobile generators had longer service disruptions. Telecommunications outages made it hard for electric service providers to coordinate with field crews to restore power.

- *Retail Electric Providers (REPs):* REPs had trouble getting timely, specific outage information from utilities. Many REPs had to rely on publicly available information.

Utility Emergency Preparedness and Response

Planning: Utilities generally had emergency preparedness plans in place and conducted major storm drills, but they did not involve other important stakeholders. Larger utilities had more sophisticated storm tracking, outage tracking, and emergency operations management. However, many did not test outage trackers before storms.

1. Utilities should include neighboring utilities, local governments, and emergency services in annual hurricane and major storm drills.
2. The Commission should require pre-storm communication procedures in emergency operations plans.
3. Utilities should incorporate outage tracker disruptions and high user demand as scenarios in annual hurricane and major storm drills.

Communication and Coordination: Lack of reliable and accurate communication was the top challenge customers faced during power restoration. CenterPoint's outage tracker failed before Hurricane Beryl, so customers could not get critical information. Critical loads had difficulty contacting their service providers. Less sophisticated utilities relied too much on social media and many do not have a 24-hour phone line or an outage map.

4. The Legislature should codify a customer's right to information about restoration times and the right to contact an electric service provider by phone.

Customer Restoration Workflow: Utilities focus on restoring power to critical loads and repairing damage that impacts the greatest number of customers. This means customers in less populated areas or served by a single line might have longer outages.

5. The Legislature should consider establishing a framework and penalty structure to assess IOU service quality during major outage events.

Physical Infrastructure: Utility pole infrastructure construction standards appear to be consistent and aligned with the National Electric Safety Code's (NESC) standards for the gulf coast region. Few poles failed; however, meeting standards should not be the only goal.

6. Utilities should assess poles constructed under prior NESC standards for replacement with poles that meet current extreme wind and ice loading design standards.
7. 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.
8. In more densely vegetated areas, utilities should assess whether to replace distribution lines with covered conductor.

Vegetation Management: Utilities relying on analytics-based vegetation management strategies might wait longer between trims in some areas. Most vegetation-related outages during Hurricane Beryl were caused by trees outside of utility easements and rights-of-way. Utilities can only access these areas with landowner permission. Fixing these issues requires better customer engagement. Vegetation management is mostly outsourced. Staffing decisions are influenced by vegetation clearing schedules.

9. The Commission should require utilities to establish a designated method for customers to report vegetation hazards.
10. Utilities should use analytics-based vegetation management strategies to augment, not replace, cyclical vegetation management plans.
11. The Legislature should consider increasing the penalty cap for electric service quality violations.

Staffing and Mutual Assistance: Utilities use storm forecasts and damage predictions to plan for restoration. During Hurricane Beryl, many outside workers came to help, causing coordination problems. The challenges were made worse by telecommunications outages.

12. Utilities should scale up training in emergency response and Incident Command Response.
13. Utilities should ensure a resilient emergency communications platform is available to both local and mutual assistance crews.

Mobile Generation Facilities: CenterPoint's process for deploying mobile generation to customers was inefficient. In addition, the fleet was not right-sized for a Hurricane Beryl-type restoration event. As a result, the company acquired an additional 21 units through mutual assistance or short-term leases *after* landfall.

14. Utilities should pre-identity critical customer locations suitable for deployment of Temporary Emergency Electric Energy Facilities.

GOVERNOR GREG ABBOTT

July 14, 2024

Mr. Thomas J. Gleeson
Chairman
Public Utility Commission of Texas
1701 North Congress Avenue
Austin, Texas 78711-3326

Dear Chairman Gleeson:

It is unacceptable that millions of Texans in the Greater Houston area have been (or were) left without electricity for multiple days. It is imperative we investigate how and why some Texas utilities were unable to restore power for days following a Category 1 Hurricane.

Texas utilities bear the responsibility of ensuring system resiliency in their respective service territories. While weather-related disasters are outside of human control, their impact to our daily lives can be mitigated or alleviated if proper system planning and pre-storm preparations are made.

Hurricane Beryl made it clear—improvements must be made. I am directing the Public Utility Commission of Texas (PUC) to undertake a rigorous study to determine the causes of the repeated and ongoing power failures in the Greater Houston area after severe weather events. Some questions that must be answered include: Is the cause of the magnitude and duration of customer outages a result of a physical infrastructure or personnel issue? What were the utilities pre-event planning processes? Why exactly were so many Texans left without power for so many days? When and for what purposes did utilities use their mobile generation resources?

These questions and more must be asked and answered by Texas utility companies. We must identify why Hurricane Beryl impacted millions of Texans when there have been many similar events in Texas' recent past that did not, and we must work to prevent any such future impacts.

I am instructing the PUC to deliver a report on its finding by December 1, 2024, to inform the Texas Legislature prior to the 89th Legislative Session. I thank the PUC for its commitment to Texas and look forward reviewing its report.

Sincerely,

Greg Abbott

Greg Abbott
Governor

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1.0 Introduction

1.1 Investigation Approach and Methods

On July 14, 2024, Governor Abbott directed the Commission to take a comprehensive look at the state of preparation of and immediate response by electric utilities in the Greater Houston area to severe weather events. Commission Staff opened Project No. 56822, *Investigation of Emergency Preparedness and Response by Utilities in Houston and Surrounding Communities*, the following day.

To meet objectives of the investigation, Commission Staff identified seven primary areas of focus:

- Emergency preparedness and response planning
- Communication and coordination
- Customer restoration workflow
- Physical infrastructure
- Vegetation management
- Staffing and mutual assistance
- Mobile generation resources

Data and Information Gathering

In August 2024, Commission Staff issued 94 formal, comprehensive Requests for Information (RFIs) to collect information relevant to the seven primary focus areas. Electric, water, and telecommunications providers in the Greater Houston area were required to respond in writing to detailed questions. The topics included preparation efforts, outage response, and restoration efforts related to Hurricane Beryl and the May 2024 derecho. Each RFI included from 19 (water and sewer service providers) to 120 mandatory questions (electric service providers). The responses generated over 12,000 pages of information.

Three classes of electric service providers received RFIs: 28 municipally owned utilities (MOUs), 32 electric cooperatives (co-ops); and five investor-owned utilities (IOUs). Service providers were selected based on their location in the path of the storm systems that created the conditions for the May 2024 derecho or of Hurricane Beryl. A list of all entities issued RFIs can be found in the Appendix.

Commission Staff prioritized transparency with the public throughout the investigation. To this end, documents used to inform the findings are filed in Project No. 56822.[1] RFIs and responses were filed publicly, except where information was otherwise protected in law from disclosure– for example, personally identifiable information. Where information was filed confidentially, Commission Staff conducted outreach to confirm the reason for confidential filing.

[1] These filings are accessible through the Commission's Interchange at the following link: https://interchange.puc.texas.gov/search/filings/?UtilityType=A&ControlNumber=56822&ItemMatch=Equal&DocumentType=ALL&SortOrder=Ascending. The Interchange is a web-based tool that allows the public to locate information that is filed with the Commission. The public can access the Interchange's general filing search at the following link: https://interchange.puc.texas.gov.

PUCT attorneys, investigators, engineers, and subject matter experts analyzed the responsive information. In conjunction with the RFI response analysis, Staff reviewed utilities' existing Emergency Operations Plans, vegetation management plans, and storm hardening plans.

Public Comments and Input from Other Impacted Entities

Members of the public and small businesses were encouraged to share their experiences with electric service outages and restoration through an online questionnaire on the PUCT's website. The questionnaire was live from August 1 to October 6, 2024, and the Commission received 16,560 responses. Section 2.1 details the substance of this public comment.

Commission Staff also sought input from local governments, medical and eldercare facilities, trade associations, and community organizations. Retail electric providers (REPs) and power generation companies (PGCs) were also asked to provide feedback on their experiences during the restoration periods. In filings on August 2, 2024, Commission Staff invited these groups to respond to separate sets of voluntary questions and received 16 responses.

Houston Workshop

On Saturday, October 5, the Commission held a workshop in Houston on utility preparedness and response to severe storms. The Commissioners and Staff heard from 30 members of the public who described their experiences with power outages following Hurricane Beryl and the May 2024 derecho. The Commission also heard from invited experts on emergency preparedness, vegetation management, infrastructure storm hardening, and mutual assistance. These experts represented:

- Texas Division of Emergency Management
- National Weather Service
- Texas A&M Forest Service
- MG Spoor Consulting
- GridSky Strategies Inc.
- Edison Electric Institute
- Southeastern Electric Exchange

1.2 May 2024 Derecho Overview and Impacts

On May 16, an expansive and fast-moving thunderstorm, called a derecho, pushed through southeast Texas. Wind speeds were estimated to reach 100 MPH, with sustained winds above 75 MPH.

Unlike a hurricane, a derecho typically begins as a thunderstorm and develops quickly and with little or no warning. Forecasts in the days prior to the May derecho had only noted a slight risk of thunderstorms. This risk increased to moderate on the morning of the storm.

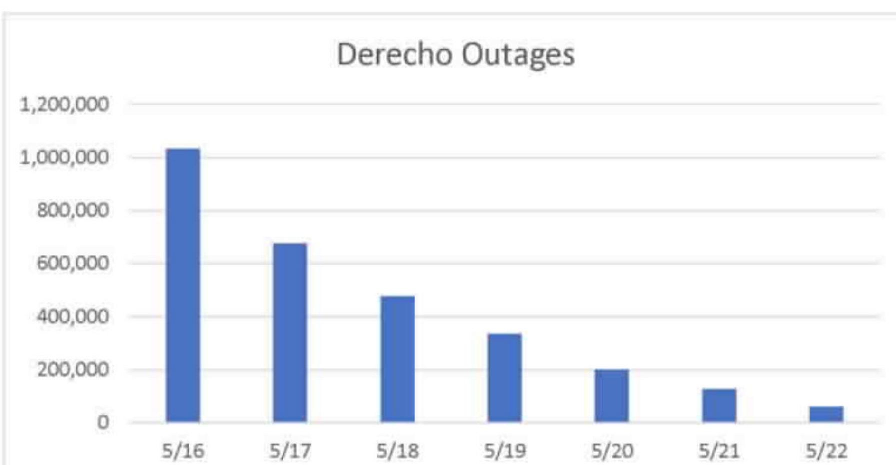
The storm spawned several tornados, and a track of straight-line wind damage was seen across Houston and down through Baytown. The high winds associated with the storm caused significant damage to power lines and transmission towers.

- Thursday May 16 – Statewide outages peaked at 8 p.m. on May 16 with 1.05 million customers without power and at least 14 transmission lines sustaining damage. The bulk of the impacts were within the CenterPoint service territory. Sam Houston Electric Cooperative, Entergy, San Bernard Electric Cooperative, Bluebonnet Electric Cooperative and Jasper Newton Electric Cooperative also sustained damages. The most heavily impacted location was the Highway 290 corridor going west into Houston and tracking southeast along I-10 into Baytown.

  During early assessments, utilities projected this would be a multi-day restoration effort, especially for the CenterPoint service territory. CenterPoint estimated restoration to be complete around May 22, while other utilities projected outage restoration by May 19.

Source: National Weather Service

- Friday, May 17– At 3 p.m. on May 17, less than 24 hours after peaking with just over 1 million outages, outage counts were down to about 675,000.
- Saturday, May 18 – At 3 p.m., outages had been reduced to about 477,000.
- Sunday, May 19 – At 3 p.m., outages were down to approximately 335,000, with 10,000 of those outside CenterPoint.
- Monday, May 20— At 3 p.m. on May 20, outages were down to 200,000.
- Tuesday, May 21 – At 3 p.m., outages from the Derecho were down to 125,000, all in the CenterPoint service territory.
- Wednesday, May 22– Outage numbers continued to decline, and by May 22 there were 59,000 outages and three transmission lines needing repairs.
- By Thursday, May 23, additional storm activity in other parts of the state drove overall outages up, but restoration from the derecho was essentially complete.



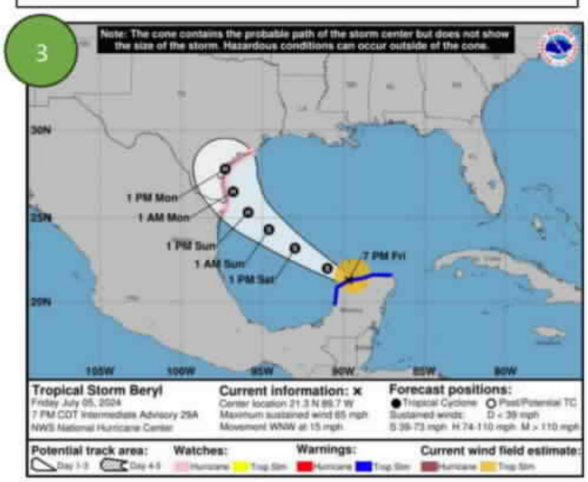
The weather incidents during the months preceding Hurricane Beryl were so numerous and impactful that they were grouped together into a single federal disaster declaration. "Texas Severe Storms, Straight-line Winds, Tornadoes, and Flooding," (DR-4781-TX) covered the period from April 26, 2024, through June 5, 2024.

1.3 Hurricane Beryl Overview and Impacts

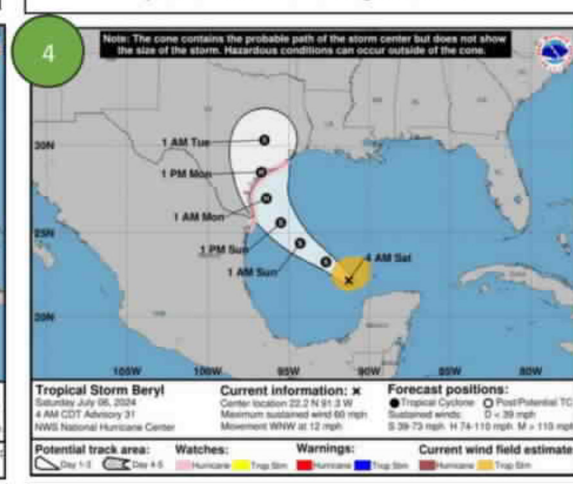
Hurricane Beryl developed as a Category 1 hurricane in the lesser Antilles on June 29. It rapidly intensified as it moved westward, becoming the earliest in the hurricane season that a storm intensified into a Category 5.

On Thursday, July 4, the National Hurricane Center's "Cone of Uncertainty" (Cone) began to indicate that Hurricane Beryl could potentially impact southern Texas near Brownsville.

At 4 a.m. on Friday, July 5, Brownsville was firmly in the center of the Cone as the projected track began to shift eastward, indicating that Texas was facing a probable landfall along its coast.

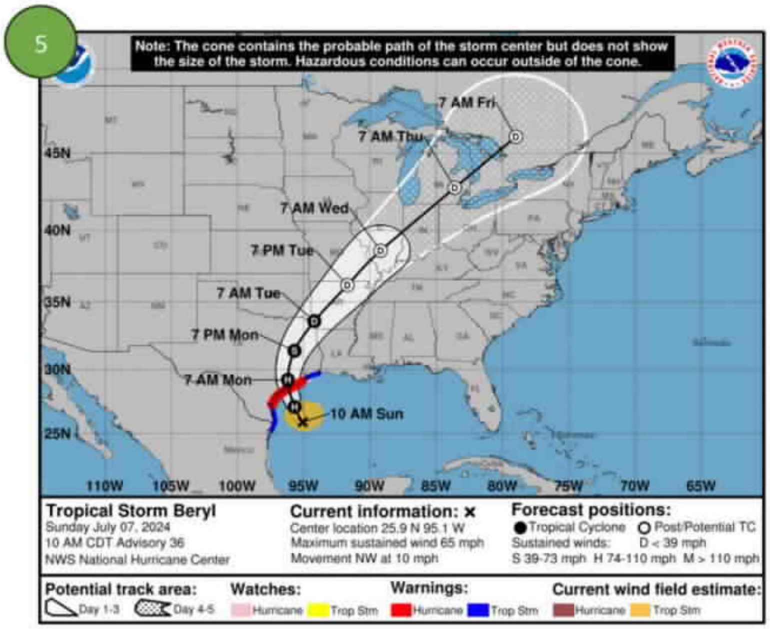


Twelve hours later, at 4 p.m. Friday, July 5, the track had again shifted further to the east, projecting landfall near Corpus Christi.



By 4 a.m. Saturday, July 6, the track indicated landfall in Matagorda Bay, where the modeling remained fairly consistent until landfall.

On Monday, July 8, at approximately 4 a.m., Hurricane Beryl made landfall as a Category 1 storm in Matagorda Bay, Texas. Maximum sustained winds at landfall were reported at 80 MPH. The path curved around the western part of the Houston Metro and continued through upper east Texas. By 10 p.m., Beryl was in far east Texas and exited the state soon after.



Hurricane Beryl resulted in significant electric outages across southeast Texas. At the peak, there were 2.7 million hurricane-related outages.

There are a few reasons Hurricane Beryl had such a devastating impact on southeast Texas and the Greater Houston area. High winds, heavy rainfall, vegetation issues, location of impact, and compounding impacts from previous events all contributed. According to the National Weather Service (NWS), Hurricane Beryl strengthened as it made landfall. The strongest winds associated with the thunderstorms in the eyewall were more likely to make it to the ground and travel farther inland than they would have with a steady-state or weakening storm. Per the NWS: "Beryl as a CAT 1 actually produced stronger winds in the Houston area than Hurricane Ike did as a CAT 2 landfalling hurricane and the eyewall with Ike went right over Houston."

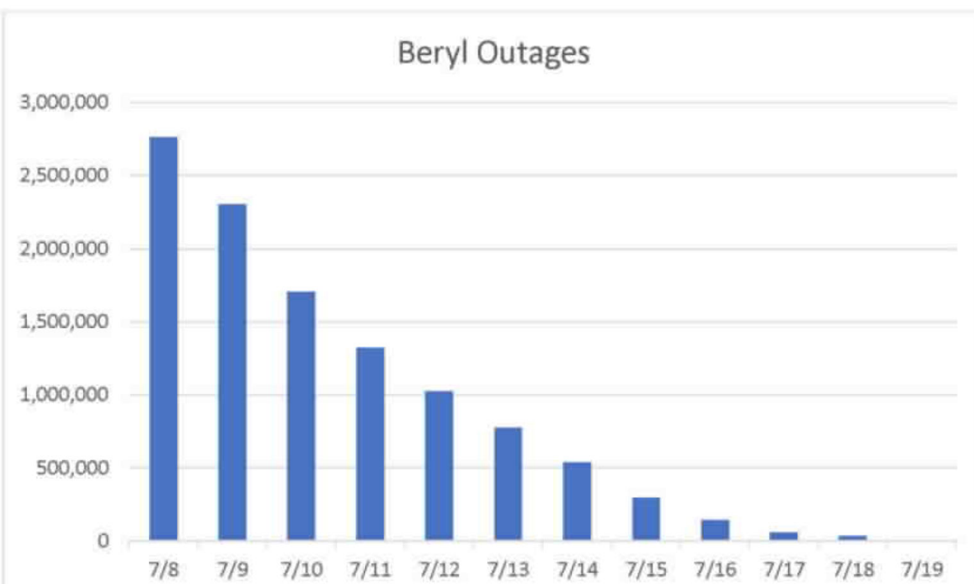
In addition, Beryl approached Houston from the southwest, placing the city on the storm's "dirty" side, which has the highest winds, storm surge, and tornado threat. Heavy rains experienced in Southeast Texas during the preceding winter and spring kept soils moist and made trees and vegetation more susceptible to being uprooted. Trees and vegetation had also been weakened by recent cycles of freezing temperatures in the winter and significant drought in the summers. The combination of these factors resulted in considerable damage from Hurricane Beryl to electric infrastructure. The storm snapped power poles and sent vegetative debris into power lines.

Source: [Houston Public Media, Colleen DeGuzman]

Source: [Canary Media]

Hurricane Beryl-Related Outages and Restoration Timelines

- Monday, July 8 – At 9 a.m. there were 1.5 million hurricane-related outages across the state. By 3 p.m. that number had increased to 2.7 million, and ERCOT reported damage to a little over 100 transmission circuits. All utilities affected anticipated this would be an extended multi-day restoration event.
- Tuesday, July 9 – At 9 a.m. on July 9 there were 2.3 million hurricane-related outages, and ERCOT reported 61 transmission circuits were still damaged.
- Wednesday, July 10 – On the morning of July 10 there were 1.7 million outages, bringing the restoration total close to 1 million.
- Thursday July 11 – On July 11, 1.3 million outages remained, and utilities began giving estimated restoration times.
- Friday, July 12 – Four days after Hurricane Beryl made landfall, approximately 1 million outages remained across the state.

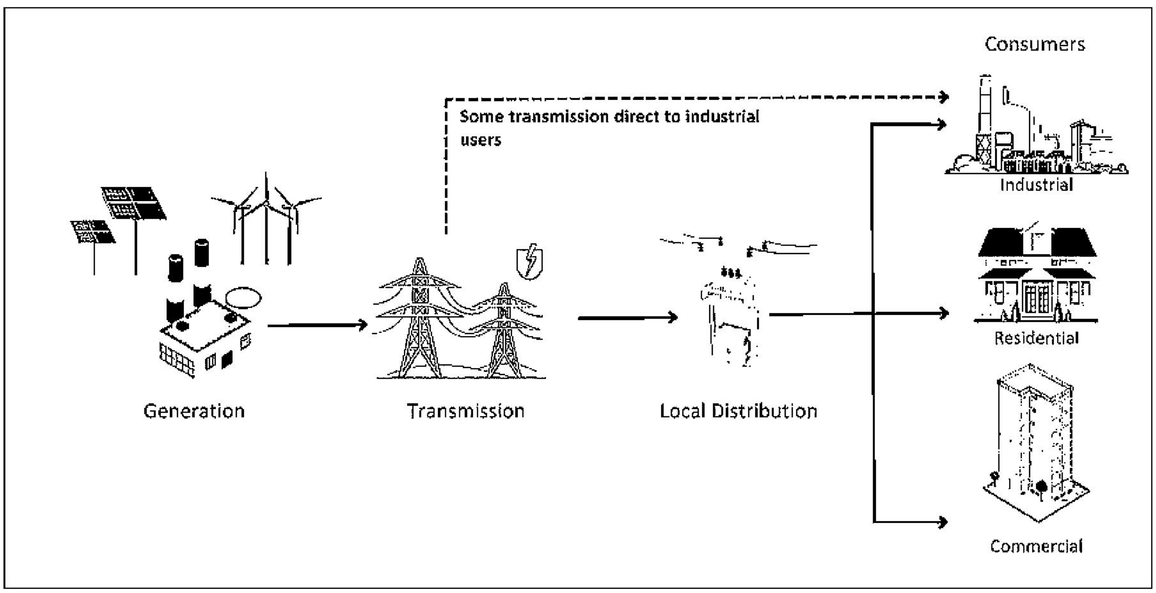


Restoration efforts continued over the next week. Outages steadily declined until July 19, when they fell below 10,000. Restoration timelines varied widely among the utilities, depending on the number and location of the outages. AEP Texas, Oncor, Sam Houston Electric Cooperative, and various other co-ops had fully restored power to affected customers within a week of landfall. In the second week, Entergy, TNMP, and CenterPoint fully restored power to their service territories.

1.4 Greater Houston Area Electric Service Providers

Investor-Owned Utilities (IOUs)

Investor-Owned Utilities (IOUs) are private companies that transport electricity from the generating power plant to the consumer. IOUs with service areas in the greater Houston area include CenterPoint Energy (CenterPoint), Entergy Texas (Entergy), Texas-New Mexico Power (TNMP), and American Electric Power (AEP). These companies operate and maintain poles, wires, and substations.



Investor-Owned Utilities (IOUs) in the Greater Houston Area

<u>*CenterPoint Energy*</u>

CenterPoint Energy ("CenterPoint") is an IOU that serves the central Houston area. CenterPoint has operated in Texas since January 1, 1906. The company has approximately 2,753,976 points of electric delivery and roughly 2,781 employees in Texas.

As an IOU, CenterPoint is regulated under the Public Utility Regulatory Act (PURA).[2] All rates charged by CenterPoint for electric delivery service must be approved by the Commission through a ratemaking proceeding. CenterPoint's last full ratemaking proceeding was in 2020,[3] with recent interim adjustments in 2024 to reflect changes in wholesale transmission costs[4] and the legislature's energy efficiency initiatives.[5]

CenterPoint currently has a pending rate case with the Commission.

In addition to rate regulation, PURA also tasks the Commission with oversight of CenterPoint's system operations, including system reliability, safety, improvement and maintenance. The Commission has the authority to impose administrative penalties of up to $25,000 against CenterPoint for each failure to meet its service quality and system reliability standards, as well as any other failure to comply with requirements under PURA, Commission rules, or the ERCOT Nodal Protocols.[6] Over the past 10 years, the Commission has fined CenterPoint $459,000 for violations of Commission rules, including $149,000 for failures to meet standards for service quality.[7]

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[2] Public Utility Regulatory Act, Tex. Util. Code §§ 11.001-66.016.

[3] *Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates,* Docket No. 49421, Final Order (Mar. 9, 2020).

[4] *Petition of CenterPoint Energy Houston Electric, LLC to Update its Transmission Cost Recovery Factor,* Docket No. 56680, Notice of Approval (Jul. 25, 2024).

[5] *Petition of CenterPoint Energy Houston Electric, LLC to Update its Energy Efficiency Cost Recovery Factor,* Docket No. 55088, Order (Nov. 3, 2023). *See also* PURA § 39.905.

[6] PURA § 15.023(b).

[7] Since 2014, the Commission has fined CenterPoint $149,000 for violations of the service quality metrics established under PURA § 38.005(a) and 16 TAC § 25.52(g). However, it is important to note that the Commission's ability to pursue administrative penalties for violations of 16 TAC § 25.52(g) is limited by the administrative penalty cap of $25,000 per violation. *See* section 3.5 of the report.

Entergy Texas

Entergy Texas ("Entergy") is an IOU that serves the northeastern part of the greater Houston area.

The company was originally organized in Texas on August 25, 1925. Entergy has approximately 511,718 utility customers in the state.

Entergy's current rates were approved by the Commission on August 24, 2023.

Over the past 10 years, the Commission has imposed administrative penalties totaling $278,600 against Entergy, including $203,600 for failures to meet system reliability standards.

Texas-New Mexico Power (TNMP)

Texas-New Mexico Power (TNMP) is an IOU that serves several areas of Texas, including two portions of the southern greater Houston area.

TNMP has been operating in Texas since January 1, 1925 and has operated solely in Texas since 2006. The company has approximately 274,149 points of electric delivery and roughly 390 employees in Texas.

TNMP's current rates were approved by the Commission on December 20, 2018.

Over the past 10 years, the Commission has imposed administrative penalties totaling $293,000 against TNMP for failures to meet system reliability standards.

American Electric Power Company (AEP)

American Electric Power Company (AEP) Texas is an IOU that serves both North Texas and South Texas, including the southwestern greater Houston area.

AEP Texas was established through AEP's acquisition of Central & South West Corporation in 1997. Central & South West formed in 1925. AEP Texas has approximately 1,111,341 points of electric delivery and 1,594 employees in Texas.

AEP's current rates were approved by the Commission on October 3, 2024.

Over the past 10 years, the Commission has imposed administrative penalties totaling at least $821,000 against AEP Texas, including $540,000 for failures to meet service quality standards.

Electric Cooperatives and Municipally Owned Utilities

Electric transmission and delivery services across Texas can also be provided by electric cooperatives and municipally owned utilities (MOUs). An electric cooperative is an entity created by an agreement of consumers in a designated area to distribute electricity. There are 32 member-owned electric cooperatives in the greater Houston area governed by elected boards – for example: San Bernard Electric Cooperative, Inc., Mid-South Electric Cooperative Association, and Sam Houston Electric Cooperative, Inc. There are 30 municipalities that own and operate utilities in the greater Houston area, including Bellville Light & Power System, City of Hempstead, and City of Liberty. The PUCT does not have retail rate-setting authority over electric cooperatives or MOUs. However, the PUCT does have limited appellate authority for the retail rates of MOUs.

2.0 Impacts of Power Outages Following Hurricane Beryl and Derecho Event

2.1 Texans' Lived Experience

To get public feedback about outages and restoration, the PUCT used an online questionnaire, reviewed complaints submitted to its Consumer Protection Division (CPD) and held a workshop in Houston. The strong response provides the PUCT valuable insight from each of these efforts, as detailed below.

Questionnaire:

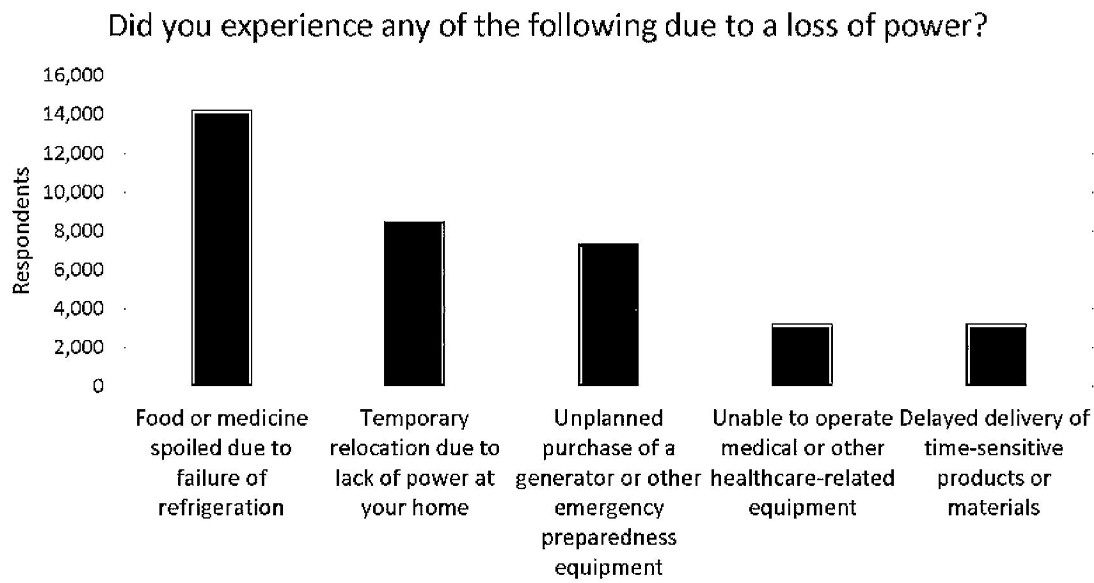
The online questionnaire asked individual customers and small businesses about duration of outages, impact of the outages on daily life, and communications from electric service providers. The questionnaire was available on the PUCT's website from August 1 until October 10, 2024, and the PUCT received 16,560 responses. Respondents to the questionnaire were overwhelmingly dissatisfied with the preparedness and response of electric service providers. Customers report outages ranging in duration from less than a day to over 16 days. The largest category of respondents reported three to seven days without power. Hardships included spoiled food and medication, temporary relocations, unplanned purchases, health risks, financial strain, and discomfort. Respondents also expressed appreciation for the efforts of line workers and the support from neighbors and community members.

Impact of Outages on Daily Life

Many people described losing all the food in their refrigerators and freezers, as well as refrigerated medications, such as insulin. Health risks due to loss of refrigerated medications and inability to operate electrically powered medical devices were key concerns. Some used personal generators or relocated to locations with power to safeguard their health. Lack of reliable communication and updates from electric service providers exacerbated the situation, making it difficult to plan and to manage medication needs.

People also discussed significant financial impacts stemming from the power outages. There were many reports of financial strain associated with:

- Cost to replace lost refrigerated food and medication;
- Unplanned purchases of generators and other emergency preparedness equipment;
- Lost income due to inability to work or operate businesses;
- Costs of temporary relocation



Impacts from the outages were particularly hard on vulnerable individuals, including the elderly, individuals with fixed or low incomes, and those with specific medical needs or mobility impairments. Some quotes from questionnaire respondents highlighting the impacts of the outages are included below:

I am 74 with respiratory issues and I had several episodes where I had to get in my vehicle to use my CPAP machine. The intense heat affected my heart condition as well.

We lost food and refrigerated medication due to the power outage. My husband has diabetes and heart problems, and we didn't have lights for ten miserable days.

[M]aintaining the generator was a significant burden physically, mentally, and financially.

I devastatingly lost thousands of dollars' worth of refrigerated fertility medication that I paid for out of pocket. As a cancer patient trying to start a family, losing my medicine has caused more undue burden and financial stress for my family.

In addition to not being able to work for an entire week, the only viable option was for me to use all of my leave balance to receive compensation for the missed days.

<u>Areas for Improvement</u>

Respondents overwhelmingly noted communications from electric service providers as the biggest area for improvement. Lack of reliable and accurate communication was the main issue faced during the Hurricane Beryl and derecho power outages. More than a third of respondents indicated they never heard from their electric service provider. Those who did reported receiving less than one communication per day. When they did receive communications, the information was often vague or inaccurate and did not provide specific timelines for power restoration. Respondents noted:

> *CenterPoint emailed us to say our power was out on... the 9th...and then told us it was restored on the 10th when it wasn't. It was stressful thinking that they might think our power was on when it wasn't.*
>
> *Two texts were received after power loss which indicated that the power to my home had been restored – that was on day one – but power was out and continued to be out for five days.*
>
> *Generic non-answers. No specifics. No explanation. No believable estimates for service restoration.*
>
> *Communication is key in a crisis. The failure to communicate clearly what was happening created a great deal of stress.*

The questionnaire responses also indicated that one of the most significant issues with communication was CenterPoint's often non-functioning and inaccurate outage map. The issues with CenterPoint's outage map are described in more detail in *Section 3.2 – Customer Communication and Coordination.*

Workshop:

The PUCT conducted a workshop on October 5, 2024 in Houston that included four hours of public comment from 30 attendees. The individuals told personal stories about their experiences during Hurricane Beryl, the derecho, and with power outages over the years. Nearly everyone noted the persistent stress of power outages, as well as a loss of trust in CenterPoint's ability to adequately handle severe storms. Even those with backup generators expressed concern about their growing reliance on generators and affordability. Many recommended a thorough review of CenterPoint's rates and the performance of CenterPoint's Temporary Emergency Electric Energy Facilities during Hurricane Beryl. Many commenters had to rely on themselves or neighbors to provide necessary relief or information given the widespread communication issues during the outages. Commenters also called for increased coordination with local communities. Many suggested that electric service providers use fewer contractors when responding to severe weather events. Commenters said that in-house workers are likely to know the local communities better.

Customer Complaints:

The PUCT's Consumer Protection Division (CPD) received over 2,000 complaints related to Hurricane Beryl and the derecho. Complaints against electric utilities described outages, hazardous conditions, inability to report or receive information, and consumption charges while the customer was without service. Complaints against REPs described inability to reach customer representatives and inaccurate billing for service when consumers had no power. Complaints concerning water service described outages and inability to report or receive information. Complaints concerning telecommunications described service outages, but the number of complaints was minimal. The PUCT continues to receive and address consumer complaints stemming from the power outages.

2.2 Impacts to Water Utilities

Water and sewer utilities are largely dependent on electricity to provide service to their customers. Power is needed to operate pumps and other equipment used to make water safe for consumption. For this reason, these facilities are considered critical loads under the Commission's rules.

A water utility is the company that owns and operates a water or sewer system. A single utility may operate multiple water or wastewater systems in different areas or may operate only one system. To determine how water and sewer utilities prepared for and responded to Hurricane Beryl and the May 2024 derecho, Staff issued requests for information (RFIs) to the 20 largest utilities operating public water or sewer systems in impacted counties[8]. PUCT Staff received responses from 14 of the selected utilities. Because utilities emphasized their experience with Hurricane Beryl in their responses, the discussion below focuses on this storm rather than the derecho.

Emergency Preparation

Most water and sewer utility managers perform pre-storm site walkthroughs to ensure their facilities are ready for forecasted severe weather. During a physical site inspection, water operators or other utility staff secure or remove items that could be damaged due to high winds or flooding. Overflow tanks are emptied to ensure maximum retention during severe weather. Ground tanks are filled with potable water to ensure continuous and adequate service during and immediately after a disaster. Finally, utility staff ensure that any backup generators are tested and topped off with fuel and water treatment tanks are topped off with sufficient chemicals.

The majority of the water and sewer utilities contacted by PUCT Staff have their own backup generation at critical facilities. Following Winter Storm Uri, the Texas Legislature passed legislation (SB 3 (2021, 87th Leg., R.S.) that set standards for how a water or sewer utility can ensure continuous and adequate service. Texas Water Code (TWC) § 13.1394(c) requires affected utilities to adopt an emergency preparedness plan using at least one of thirteen specified methods to ensure continuous and adequate service during an extended power outage. Water and sewer utilities can either install permanent backup generators or provide reasonable alternatives to such measures to ensure continuous and adequate service during an extended power outage.[9]

Effects of Hurricane Beryl

Many of the contacted water and sewer utilities had access to either mobile generation facilities or had permanently installed backup generators at critical facilities. As a result, disruptions were generally limited to facilities that experienced mechanical or operational failures with existing backup generators or were

[8] See the appendix for the list of impacted counties.
[9] TWC § 13.1395(d)(2

delayed while mobile generation facilities were connected. Aqua Texas and Undine, LLC experienced the greatest numbers and longest durations of disruption of service, due in large part to an insufficient number of mobile generators.[10]

Aqua Texas operates 107 water systems in the selected counties.[11] Permanent backup generation is installed at 34 of those systems. The remaining 73 water systems were left to share 18 mobile generators in Aqua Texas's fleet (plus any mobile generators that could be acquired after the hurricane) to power critical facilities. Service was interrupted for 72 hours for some Aqua Texas customers as generators were relocated from systems that already had electric service restored.[12]

Undine, LLC operates 87 water systems in the selected counties. Undine, LLC obtained an additional five mobile generation facilities (at a reported cost of $300,000) to assist with its restoration efforts in the immediate aftermath of Hurricane Beryl. In several instances, Undine's customers were only able to be returned to service once mobile generators were released from a different Undine water system.

CSWR-Texas has installed permanent backup generators at all critical facilities supporting the water systems it operates.[13] One backup generator ran for 360 hours (15 days) while waiting for electric service to be restored.

Both mobile generation and permanent onsite backups are permissible approaches for emergency preparedness plans under Texas Water Code §13.1394(c). The decision to use mobile generation instead of installing permanent backup generators at each critical facility is likely economically efficient. However, water and sewer utilities should carefully consider the proper ratio of generators owned or obtainable through contractual agreement and the total number of facilities that could require backup power. A ratio of one mobile generator for every four water systems – not facilities – likely requires reassessing.[14]

Challenges to Service Restoration

Water and sewer utilities also reported frustration with the level of communication with their electric utilities. Lack of access to a priority contact method with the electric utility resulted in water and sewer utilities reporting outages in the same manner as an individual customer. For example, Quadvest commented that their electric utility's automated system would not permit information to be entered for more than three addresses per call.[15] Due to this limitation, Quadvest had to place 18 calls to the electric utility to report all 54 of their systems affected by Hurricane Beryl.[16]

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[10] A water and sewer utility may operate multiple public water systems or sewer systems in different areas.
[11] The selected counties for the water and sewer RFIs were Austin, Brazoria, Chambers, Colorado, Fort. Bend, Galveston, Harris, Liberty, Matagorda, Montgomery, Waller, and Wharton Counties.
[12] Id.
[13] RFI 1-4(f).
[14] RFI 1-8(b)
[15] RFI 1-16.
[16] See generally, RFI 1-3

Resilience and Lessons Learned

A water and sewer utility's ability to provide continuous and adequate service to its customers is tied to its access to reliable electricity. Water and sewer utilities contacted as part of this investigation leveraged permanent backup generation, mobile generation, or a mix of the two. The water and sewer utilities that experienced the shortest interruptions tended to have either permanently installed backup generators or enough mobile generators to cover all critical facilities.

- Review of Emergency Preparedness Plans to Determine Needs Are Adequately Addressed: Water utilities should ensure their emergency preparedness plans account for the number of mobile generators necessary to provide coverage for all critical facilities. Several water systems experienced prolonged disruptions while waiting for mobile generators to become available and relocated. Utilities should also consider re-evaluating contractual agreements to obtain additional mobile generators during emergencies to account for a possible shortage of available units during times of high demand.

2.3 Impacts to Telecommunication Utilities

The telecommunications market in Texas is made up of voice, broadband, and cable and video services. The Commission only regulates the intrastate rates and services of certain providers of landline service. Other telecommunications services, including broadband and wireless service, are regulated by the Federal Communications Commission. For purposes of this report, the Commission issued requests for information to all telecommunications service providers operating in Texas that may have been affected by Hurricane Beryl.

The telecommunication sector is critical for ensuring continuity of electric service during and after severe weather events due to its interdependence with electric utility operations. Electric utilities rely on telecommunications for real-time coordination with field teams during a restoration event. Conversely, the telecommunications networks depend on power from utility services to function. Without effective communications systems, electric utilities face delays in restorations, while telecommunications utilities need stable electric service to maintain their networks.

Effects of Hurricane Beryl

Telecommunications providers in the Greater Houston Area experienced widespread service disruptions from Hurricane Beryl, mainly due to infrastructure damage and electricity outages. Disruptions began on July 8 and lasted through July 16 for most providers. Nextlink restored services within days, while Spectrum/Charter (Charter) fully restored service by July 9. AT&T faced significant restoration challenges and achieved full recovery of wireless services by July 14 and wireline by July 18.

AT&T saw impacts to both wireless and wireline services affecting about 915,000 customers, with 11 counties operating at less than 80% capacity. AT&T also reported 351,000 customers with Voice/VoIP numbers were affected. A substantial portion of AT&T's service outages were attributable to infrastructure damage – 164 poles, 270,000 feet of fiber cable, and 120,000 feet of copper cable were affected. However, 75% of the impacted infrastructure could be rehung without replacement.

In contrast, smaller telecommunications companies such as Astound Broadband, Nextlink, and Charter experienced disruptions that were attributable to electricity outages, affecting approximately 620,000 customers. Astound and Nextlink reported minimal damage to infrastructure.

Challenges to Service Restoration

A major challenge for many telecommunications providers was the need to coordinate with electric utilities to restore power to telecommunications infrastructure. AT&T had representatives embedded within emergency operations centers and maintained direct communication with IOUs such as CenterPoint and Entergy. However, coordinating these efforts was often slow due to the unclear prioritization of telecommunications by electric utilities. Additionally, smaller telecommunications utilities were not proactively contacted by electric providers and made multiple unsuccessful attempts to communicate restoration needs.

Telecommunications utilities also faced issues repairing infrastructure damage and refueling backup power sources due to sustained inclement weather and right-of-way obstructions. Telecommunications companies faced access issues due to road closures, fallen trees or road debris, and unsafe working conditions. These challenges prevented timely infrastructure repair and complicated refueling of backup power sources. AT&T field crews, for example, were often unable to safely deploy immediately after the storm due to high winds and other dangerous conditions. These delays impeded access to critical infrastructure and hampered the speed of recovery efforts.

Logistical challenges related to refueling generators and deploying additional temporary backup units posed significant hurdles. The ability to deploy and maintain backup power was crucial to maintaining operations during the electricity outages. AT&T kept thousands of cell tower sites online using on-site backup and temporary generators. AT&T had dedicated teams periodically refueling these generators. In contrast, Astound used 150+ backup power supplies that had to be constantly monitored and refueled on an ad hoc basis. The ongoing need for fuel and the risk of generator failures created additional pressure during the restoration process.

Resilience and Lessons Learned

Telecommunication utilities rely on a combination of backup power systems, redundant infrastructure, and proactive disaster planning to minimize service disruptions during severe weather events. These resilience measures are critical to ensuring that customers—especially those in vulnerable and essential services—remain connected. Hurricane Beryl revealed numerous opportunities for telecommunications utilities to improve preparedness and response procedures for future events.

- Importance of Maintaining Backup Power Systems:
  Hurricane Beryl emphasized the need for adequate and sustained backup power. AT&T and Astound were able to keep much of their network operational with extensive use of backup generators, but prolonged outages showed the limitations of current systems. In some cases, battery systems provided only a limited window of service continuity, which prove insufficient

during extended outages. Proactive maintenance of backup power like testing and maintaining adequate reserves of fuel can minimize storm-related network issues. Providers should consider increasing the capacity and duration of backup power systems to handle longer power outages and incorporate more rigorous proactive maintenance.

- Improved Coordination with Electric Utilities:
  Effective coordination with electric utilities was essential for timely power restoration and, by extension, network recovery. AT&T's pre-storm engagement with CenterPoint and Entergy was a key factor in reducing service disruption. Improved pre-storm coordination can expedite recovery and reduce telecommunications service disruption.

- Rapid Deployment of Field Teams:
  Quick mobilization of trained field teams played a significant role in the restoration of telecommunications services. AT&T reported that pre-positioning of disaster recovery teams near high-risk areas enabled faster repairs and generator refueling once conditions permitted. Providers should continue to invest in mobile disaster recovery assets and ensure that personnel are trained and equipped to work under challenging conditions.

2.4 Impacts to Retail Electric Providers

In the ERCOT region, consumers that are not served by an MOU or electric cooperative have a choice of retail electric provider (REP). REPs buy power from power generators and sell power to consumers. REPs also manage the retail relationship with the consumer, including billing and customer service. Investor-owned transmission and distribution utilities (TDUs), like CenterPoint, are responsible for maintaining the infrastructure that physically delivers power to the end-use customer. This means that a REP must rely on the TDU for information regarding physical conditions on the transmission and distribution system that could impact the REP's individual customers.

In August 2024, Commission Staff submitted voluntary requests for information (RFIs) to REPs to assess REP experiences during the May 2024 derecho and Hurricane Beryl. Though the RFIs focused on these two storms, the REPs' responses highlighted general patterns and issues that could occur in any similar emergency. Consistent outreach efforts during both emergency events, the REPs had difficulty contacting the TDUs. In addition, the little information the TDUs provided to the REPs was unsatisfactory. REPs largely relied on TDU websites and local news reports for general restoration information. REPs could not obtain premise-specific information on outage status or times of restoration for customers.

The REPs communicated any information they did receive from the TDUs or through other outlets to their customers. REPs equipped customer relations employees with general information to field customer questions on topics such as power outages, recovery updates, available payment assistance, and invoices with estimated reads. Additionally, REPs used social media posts, press releases, emails, web page updates, and account updates to relay information to customers.

REP communications to customers before the storms largely focused on storm preparation. During and after the storms, communications with customers shifted to providing outage information and recovery resources. Questions to REPs about outages and restoration efforts were most common from customers in CenterPoint's service territory because CenterPoint was not easily accessible and struggled to maintain a functioning outage tracker. As recovery continued, communications pivoted to providing customers with information regarding availability of payment assistance and usage data for billing purposes. For example, REPs reported many instances of customer inquiries regarding charges for usage when electric service was out. For such instances, the REPs focused on confirming the TDU was aware of the outage, informing customers that the TDU was correcting any inaccuracies, and assuring customers that the REP would not assess charges for usage when electric service was out.

Responding REPs overwhelmingly indicated that the main issue faced by REPs before, during, and after the storms was the lack of timely, accurate outage information from the TDUs. REPs highlighted the absence of an operational online outage tracker map, the inability of customers to successfully report outages to the TDUs, and the absence of information regarding location of outages and estimated restoration times. Timely, accurate outage information from TDUs is valuable because such information enables REPs to provide meaningful responses to customer questions about outages. Many customers who contacted REPs wanted restoration timing estimates and confirmation that the customer's TDU knew about the customer's premise-specific outage. Because such information is not conveyed to REPs, communications between REPs and their customers were challenging.

The Commission is pursuing some communication-related solutions through rulemakings.[17]

[17] *Electric Utility Outage Trackers and Hazardous Condition Reporting*, Project No. 56897 (pending); *Provision of Emergency Contact Information to Transmission and Distribution Utilities by Retail Electric Providers*, Project No. 56898 (pending).

3.0 Assessment of Utility Emergency Preparedness and Response

3.1 Emergency Preparedness and Response Planning

Commission rules require electric service providers to maintain minimum levels of preparedness for emergencies. Utilities, TDUs, power generation companies, MOUs, electric cooperatives, REPs, and ERCOT must file emergency operation plans (EOPs).[18] EOPs are a key component of an emergency management program. They establish the overall authority, roles, and functions performed during an emergency event or incident. Under Commission rules, an entity must continuously maintain its EOP.[19] An entity also must include certain information in its EOP, including common operational functions that are relevant across emergency types and annexes (e.g., hurricane annex) that outline the entity's response to specific types of emergencies.[20] An entity is required to conduct or participate in at least one drill each calendar year to test its EOP unless the entity has activated its EOP in response to an emergency that calendar year.[21] Following an annual drill, the entity must assess the effectiveness of its emergency response and revise its EOP as needed.[22]

Hurricane and Major Storm Drills

The format of annual hurricane drills varied considerably both within and across the utility classifications.

The majority of IOUs conducted a tabletop hurricane drill in 2024.[23] The most commonly drilled conditions were Category 3 storms (111-129 mph winds) making landfall in or near the provider's service area. Drills were generally conducted as tabletop exercises, involving a series of discussions focused on how to implement aspects of the EOP to address the conditions contemplated for the drill. Condition sets were often based on previous major regional storms. For example, CenterPoint based its 2024 drill on storm surge and wind speed conditions of Hurricane Gilbert (1998) and outage figures from Hurricane Ike (2008).[24] Fewer than 20% of the contacted electric service providers conducted an operations-based or functional exercise as part of their annual hurricane or major storm drill.

IOUs generally excluded external participation in their hurricane drills. However, IOUs were more likely than MOUs and co-ops to invite third parties to observe at least a portion of their drill.

Just over 25% of the contacted MOUs and 54% of co-ops conducted hurricane drills. Five co-ops reported that responses to either the May 2024 derecho or Hurricane Beryl served in place of conducting a separate hurricane or major storm drill. MOUs and smaller co-ops were more likely to have static drill conditions (i.e., the overall format of the drill either does not change or has minimal adjustments year-to-year) than the IOUs.

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[18] *See* 16 Tex. Admin. Code (TAC) 25.53.
[19] *Id.*
[20] *Id.*
[21] *Id.*
[22] *Id.*
[23] Oncor did not conduct a hurricane drill but does conduct major spring and winter storm drills. *See* RFI 1-1
[24] CenterPoint's response to Staff RFI 1-1

CenterPoint adjusts its hurricane drills year-to-year.[25] CenterPoint conducted its 2024 hurricane drill as a tabletop exercise. The conditions experienced in Hurricane Beryl were not markedly different from the condition set used in the company's 2024 hurricane drill.

CenterPoint's 2024 Hurricane Drill Test Conditions	Hurricane Beryl's actual effect on CenterPoint
Category 3 storm 125 mph wind speed 150 mph gusts 2.1 million affected customers	Category 1 storm 80 mph wind speed 97 mph gusts 2.2 million affected customers

Performance during CenterPoint's 2024 drill was measured by participants' identifications and use of plans, processes, or procedures that addressed drill injects, issues, and areas for improvement. Drill participants stated that CenterPoint's drill conditions were plausible and realistic. After participating in the drill, all participants reported feeling better prepared to deal with the capabilities and hazards addressed in the drill. Additionally, 91% of participants reported increased understanding about and familiarity with CenterPoint's response procedures, resources, and capabilities. Participants also reported that the drill was well-structured, organized, and allowed for good collaboration and open communication. Overall, CenterPoint considered the 2024 drill a success.

External participation in hurricane and major storm drills

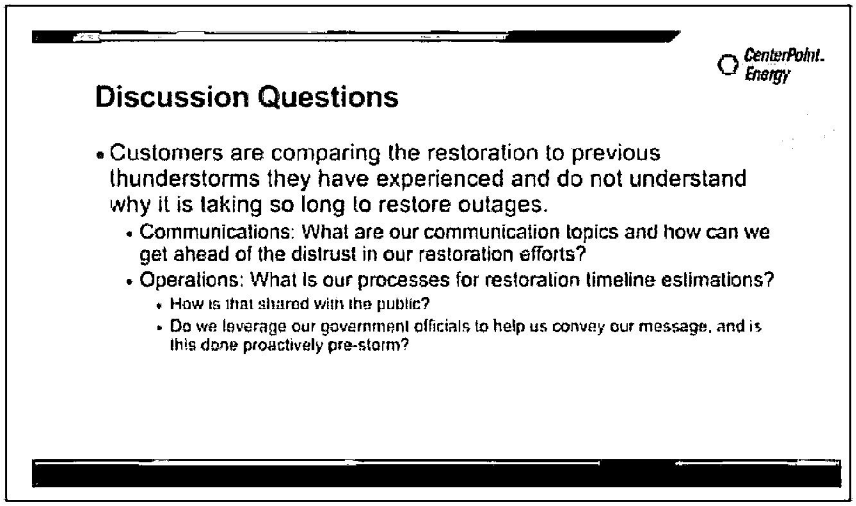
Many of the contacted electric service providers restricted participation in hurricane and major storm drills to the provider itself and its subsidiaries. Only three electric service providers invited unaffiliated parties to participate in their 2024 hurricane and major storm drills. For example, Hemphill City Government invited county emergency management officials, area hospitals, and eldercare facilities to participate in its hurricane drill. South Texas Electric Cooperative, which serves as the transmission service provider (TSP) for nine member cooperatives, extended invitations to all of its member utilities. Entergy invited Edison Electric Institute to observe its 2024 hurricane drill, but it did not invite its MOU customers to participate in the hurricane drill.

Several electric service providers cited confidentiality concerns centered around the provider's EOP as the reason for limiting participation. As an alternative to external participation in drills, some electric service providers attempted to incorporate feedback received from customers after major weather events into future drills.

CenterPoint, like most electric service providers contacted in this investigation, restricted participation in its hurricane drill to internal personnel.[26] The City of Houston reported, for example, its last participation

[25] CenterPoint conducted an operation-based drill in 2023.
[26] CenterPoint reported that it had invited local governments, trade associations, and eldercare facilities to participate in previous drills.

in a hurricane preparedness exercise with CenterPoint was a panel discussion in May 2020.[27] Restricted participation limits assessment of communication strategies. Without external participation, an electric service provider can only assess whether a message was delivered or speculate about customer expectations. Importantly, the provider cannot assess whether the drill communication achieved the desired result. For example, CenterPoint included a scenario in its 2024 hurricane drill in which customers compared the restoration efforts taken to address the fictional storm to restorations to previous thunderstorms:



Despite testing for how to address customer expectation concerning restoration efforts, CenterPoint was unprepared for how to address similar sentiment during its response to Hurricane Beryl.

Operation Condition Systems and Emergency Operations Plans

Nearly 70% of the contacted utilities use a multi-tiered operation condition system (OCS) in addition to an EOP. An OCS sets out clear steps for a utility to follow based on specific operating conditions, like percentage of customers without power or the duration of outages. Most contacted utilities had several OCS tiers that are designed to be activated before the EOP. This design allows utilities to handle minor disruptions without requiring a major interruption to normal operating procedures.

A key difference between OCSs and EOPs is that an OCS does not necessarily specify roles for individuals. When an EOP is activated, an individual may be assigned a specific task that differs from that person's usual duties. For example, Wharton County Electric Co-Op reported that during Hurricane Beryl, its Operations Chief managed the workflow of mutual assistance and in-house crews. Duties included handling lodging (and cooking for the crews) and serving as a contact for the media and government officials. By contrast, an OCS might address a relatively minor issue by shifting crews instead of shifting divisions, allowing the utility to continue normal operations during resolution.

[27] City of Houston response to Commission staff's first request for information to local governments, Project Number 56822.

Commission Staff reviewed several OCSs that required activation of the EOP toward the final stage of the OCS. This means assessing a utility's preparedness solely based on when it activated its EOP may overlook important pre-EOP steps. For example, confirming availability of preferred contractors, contacting mutual assistance organizations, and recalling critical personnel may occur in the second tier of OCS, before the EOP is activated. CenterPoint, which uses two distinct OCSs, activates its EOP only when conditions reach the third of four possible tiers of its transmission system-specific OCS. CenterPoint activated its EOP on July 6, 2024 – two days before Hurricane Beryl made landfall. However, response preparation within CenterPoint's Emergency Preparedness and Response Team (EP&R) began as early as June 25, 2024 (13 days before landfall, 11 days before EOP activation) and calls to line workers were made on July 2, 2024 (6 days before landfall, 4 days before EOP activation).

Storm Tracking

Better technological storm tracking tools generally meant storms could be tracked earlier and more accurately. At minimum, most utilities used a mix of local news and national weather services as part of their storm tracking programs. The overwhelming majority of the IOUs and approximately half of the electric cooperatives use advanced storm tracking resources, like StormGeo or Ventusky. Advanced storm tracking resources aggregate weather-related data from multiple national and international weather services. These resources allow the progression of weather systems to be modeled beyond a medium range (6 days out) forecast. Utilities that relied solely on local and national weather services generally began tracking Hurricane Beryl two to five days later than utilities leveraging more advanced tracking services. CenterPoint used a combination of storm tracking resources, including StormGeo, national weather services, and the Harris County Office of Homeland Security Emergency Management Tropical Awareness Update.

Most of the OCSs and EOPs reviewed by Commission Staff used either location of a storm or estimated time to landfall as trigger mechanisms for escalating conditions to a higher degree of system readiness. Utilities that implemented strategies to track storms by location (e.g., as they entered the Gulf of Mexico) tended to react and prepare for Hurricane Beryl faster than utilities that tracked storms based on estimated time to landfall. IOUs tended to track storms based on location instead of time to landfall, while MOUs and smaller co-ops were more likely to track storms based on estimated time to landfall. Notably, most IOUs acted on storms significantly earlier than MOUs and smaller co-ops.

Outage Tracker Testing

Thirty-three of the contacted electric service providers have an outage tracker that allows a customer to determine whether a home or business is experiencing an outage. For this purpose Cloud-based systems are often preferred over server-based systems because they can be scaled more easily to address surges in demand.[28] Commission Staff found that outage trackers are not meaningfully tested as part of pre-storm preparation and tracker disruptions were not incorporated into hurricane drill condition sets.

Utilities that had external-facing outage trackers generally review these systems on a daily or weekly basis. However, daily checks are not meaningful replacements for pre-storm checks. Daily checks confirm system availability and accuracy but don't necessarily test accessibility and capacity. For example, a daily check of a system might involve attempting to trip a set of test circuits to see if the information flags on the tracker. Stress tests help determine how many users can access the tracker simultaneously before it begins to fail.

Many utilities – especially coops and MOUs – do not incorporate outage tracker testing into system readiness operations before a hurricane or major storm. Only three MOUs and 18 coops tested their outage trackers (external and internal) as part of their pre-hurricane season or pre-storm preparations. TNMP did not test its outage tracker in advance of hurricane season or as part of pre-storm preparations, relying instead on daily monitoring. Oncor conducts internal tests on its cloud-based outage tracker[29], but

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[28] Cloud-based systems in other industries have been contacted by distributed denial-of-service (DDoS) attacks, which serve to disrupt the functionality of the system by overloading its capacity.
[29] Oncor's response to RFI Staff 1-8

does not stress test its tracker. However, Oncor does alert its vendor about the potential for heightened traffic on the outage tracker in advance of major weather events.[30] CenterPoint used an on-premises, server-based outage tracker until August 1, 2024. This tracker underwent monthly testing consisting of taking primary servers down and routing the program through the backup server. However, CenterPoint had never load tested its server-based outage tracker. As detailed in *Section 3.2 – Communication and Coordination*, CenterPoint's outage tracker failed during the May 2024 derecho and Hurricane Beryl because its servers could not handle the increased traffic.

None of the utilities reported incorporating outage tracker disruptions as part of the condition in their hurricane or major storm drills.

Pre-Storm Communications

Post-landfall communication with local and state officials are generally addressed in significant detail (with regard to frequency, duration, and content) in a utility's EOP. However, few EOPs addressed a utility's communication strategy or process with critical loads and government officials as part of pre-storm preparation. As discussed in *Section 2.2 - Impacts to Water Utilities*, none of the contacted water utilities reported being contacted by their electric utilities (generally utilities in the larger classification in this section) before Hurricane Beryl.

Many contacted MOUs and Co-Ops indicated either making no special effort to communicate with these stakeholders before a major storm or only reach out as needed. All IOUs reported plans to coordinate with government organizations before a major storm, but they are less proactive about working with other groups. For example, CenterPoint specifically stated that it "did not have a specific process in place to push out communication directly to all Critical Load customers in advance of the storm."[31] Critical load includes medical facilities, elder care facilities, police stations, firehouses, and other critical infrastructure. CenterPoint relied on a series of generalized stakeholder group meetings held between May and June to communicate with these facilities.

CenterPoint's communication strategy is representative of the plans exhibited by many other IOUs, MOUs, and cooperatives. These stakeholders are expected to reach out to the utility if special consideration is needed. By failing to proactively coordinate with these groups in advance, utilities may miss opportunities to address potential issues before they occur.

May 2024 Derecho Emergency Operations Plans Activations

The speed and suddenness of the May 2024 derecho led to varied EOP activation timelines across utilities. derechos, while rare, are typically predictable as severe weather systems. However, these storms are often initially treated as severe thunderstorms until the threat from high winds becomes clear. Only a few utilities reported tracking the systems that became the May 2024 derecho. Four (Oncor, Entergy, City of Bellville, and Sam Houston Electric Co-Op) activated their EOP in the days before the storm hit.

[30] *Id.*

[31] CenterPoint Energy Houston Electric, LLC's Response to the Public Utility Commission of Texas First Requests for Information at 1074-75 (Aug. 30, 2024).

EOP Activation Date	Utility
May 13	Entergy
May 14	Oncor; City of Bellville
May 15	Sam Houston Electric Co-Op

Around a third of the contacted utilities (21) reported outages due to the derecho, which affected approximately 1.1 million customers. The most common cause of outage was damage due to straight-line wind, at times exceeding 90 mph. These winds caused significant damage to 14 transmission lines within CenterPoint's service territory. Most utilities – even those significantly affected by the storm – did not activate their EOPs for the May 2024 derecho.

CenterPoint activated its EOP after 3:00 p.m. on May 16, 2024. Approximately 84% of the total effected customers were within the CenterPoint service territory, accounting for about 920,000 customer outages at the peak. Entergy had the second highest customers on outage, with a peak of 69,448 (6.3% of the total affected customers).

The suddenness of the derecho limited utilities' ability to pre-position additional line workers and vegetation management crews in advance of the storm. Similarly, pre-storm communication was largely impossible. CenterPoint did not report any issues with staging or acquiring mutual aid during the May 2024 derecho.

Recommendations

Recommendations are numbered throughout the report for ease of reference and not in order of importance.

1. **Utilities should include neighboring utilities, local governments, and emergency services in annual hurricane and major storm drills.**
   - Utilities that restricted participation in hurricane drills to internal participants could not effectively test key aspects of their EOP, specifically relating to communication with external stakeholders. Instead, utilities tested communication strategies by discussing them internally. Similarly, water, sewer, and telecommunications utilities should participate in periodic group drills because each utility has a downstream effect on the others. This is particularly true for electric utilities that serve as transmission service providers (TSPs) for smaller electric utilities.

2. **The Commission should require pre-storm communications procedures in emergency operations plans.**
   - Many electric utilities lack proactive strategies for communicating with other utilities and stakeholders before major weather events. Proactive outreach could allow utilities to identify and address potential issues before they arise. The Commission's current rules require that EOPs

include a communication plan.[32][33] However, this generally only addresses communication *during* emergencies.

3. **Utilities should incorporate outage tracker disruptions and high user demand as scenarios in annual hurricane and major storm drills.**
   - Functioning outage trackers provide the public with critical information concerning restoration status during electricity outages. The issues with CenterPoint's outage tracker during Hurricane Beryl highlight the importance of ensuring, before an emergency, that outage trackers are properly functioning and able to handle high user demand. Hurricane and major storm drills provide electric utilities with an opportunity to test the capability of outage trackers and practice scenarios involving disruptions to outage trackers.

3.2 Communication and Coordination

Commission Staff issued Requests for Information (RFIs) to electric service providers to determine how utilities communicate and coordinate with customers and stakeholders during major weather events. RFI response data indicates Investor-Owned Utilities (IOUs) employ more sophisticated communications strategies than Municipally Owned Utilities (MOUs) and electric cooperatives. Among all utilities, there is room to improve proactive coordination with community stakeholders and other utility services.

In addition to the RFIs, the Commission collected input from Houstonians about their experiences communicating with electric service providers during severe weather through an online questionnaire. Respondents identified the lack of reliable and accurate communication as a top issue faced during the power restoration process. For additional detail on questionnaire responses, see *Section 2.1 Texans' Lived Experience*.

Customer Communication Strategies

Customer communication strategies rely heavily on social media. Nearly all contacted utilities used at least two forms of media—typically their website and social media—to communicate with customers before, during, and after major weather events. Most IOUs and cooperatives indicated they also provide information using some form of text messaging service, email service, or smartphone application. Other electric utilities also used radio, news releases, and other forms of traditional media to deliver information to a broad customer base.

Before and during the May derecho and Hurricane Beryl, utilities overwhelmingly focused on social media to share storm preparation and safety messaging. In the aftermath of both storms, all impacted utilities used social media—particularly Facebook—to share information about physical damage, outages,

[32] 16 Tex. Admin. Code 25.53(d)(2).

[33] Specifically, an entity with transmission or distribution service operations must describe in its EOP the procedures *during* an emergency for handling complaints and for communicating with the public; the media; customers; the commission; the Office of Public Utility Counsel (OPUC); local and state governmental entities, officials, emergency operations centers, the reliability coordinator for its power region; and critical load customers directly served by the entity

restorations, and customer safety. With the exception of CenterPoint, Commission Staff's review of customer feedback showed no specific concerns about the sufficiency of public-facing, post-storm communications.

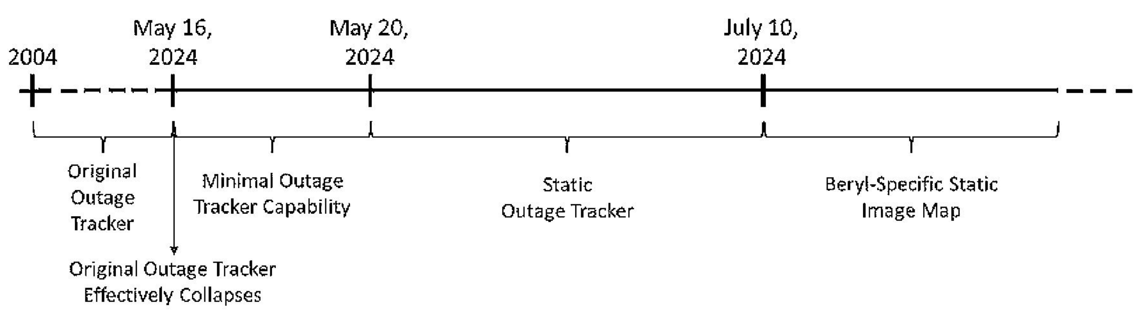
Critical Loads
Post-storm communications between utilities and critical loads were problematic, particularly for long-term care facilities. Hundreds of nursing and assisted living facilities were impacted by Hurricane Beryl. the Texas Assisted Living Association reported that its members had difficulty obtaining information following the storm. Assisted living facility staff waited on customer service hold lines for hours, and utility representatives "could not consistently note whether the assisted living facility's account showed a current priority restoration status." *See section 3.1 Emergency Preparedness and Response Planning* for additional discussion about proactive communication with critical loads.

CenterPoint's Outage Tracker

Customer feedback revealed widespread frustration with CenterPoint's outage tracking systems. The company's storm recovery communications focused largely on sharing general information through interviews, media inquiries, press releases, and social media posts. However, CenterPoint failed to provide its customers with critical information: a reliable estimate of when power would be restored in a given location.

CenterPoint's original outage tracker could not withstand the site traffic associated with the derecho. The utility failed to prioritize the development of a functional replacement tracker in the months that followed. Without a working outage tracker CenterPoint's customers were left without access to critical information about their restoration status in the aftermath of Hurricane Beryl.

Outage Tracker Failures
Between May 1 and July 31, 2024, CenterPoint utilized three different web-based outage tracking systems:



- The original outage tracker launched in 2004 and was last updated in July 2022. This outage tracker effectively collapsed on May 16, 2024, when it was overwhelmed by site traffic during and after the derecho. Less than two percent of impacted customers were able to successfully access the webpage.

- Four days later, on May 20, 2024, CenterPoint replaced the original outage tracker with a "static outage tracker" as an interim solution. The static outage tracker displayed only the total number customer outages and restorations. There was no information about specific outage status or estimated restoration times. A color-coded, derecho-specific map was later added to show restoration progress. However, customers reported it was still unreliable and inaccurate, sometimes reflecting restored power where outages were still ongoing. Despite these issues, CenterPoint retained the static tracker until July 10, 2024—two days after Hurricane Beryl knocked out power for approximately 90% of CenterPoint's customers.[52]

- For the first two days of Hurricane Beryl recovery, over 2.2 million CenterPoint customers lacked independent access to information about their outage statuses. On July 10, CenterPoint launched a third outage tracker: a Beryl-specific static image map updated daily with color-coded areas showing active service, assigned repairs, and areas still to be assessed. Like the previous map, it sometimes incorrectly reflected power had been restored to areas with ongoing outages, leaving customers to wonder if the company was aware of their outages.

CenterPoint's reliance on an inadequate tracker raises questions about why it did not prioritize launching a more functional interim outage tracker sooner. As an electric utility situated in a region prone to tropical weather patterns, the company was aware of the looming hurricane season. Further, following the derecho recovery efforts, it was aware its static outage tracker was insufficient.[53]

Current Outage Tracker
On August 1, 2024, CenterPoint launched a new, cloud-based interactive outage tracker. This new tracker is hosted by a vendor that employs "autoscaling" technology that automatically increases the number of servers hosting the application as user demand grows. The map is guaranteed to remain functional with 100,000 concurrent users. Prior to the launch, CenterPoint successfully load tested it with 30,000 concurrent users.

Municipally Owned Utility Customer Communication

RFI response data indicates that municipally owned utility (MOU) communication strategies fall short of their peers', leaving customers without reliable ways to contact their utility during an outage. For example, while 100% of contacted IOUs and over 90% of contacted cooperatives maintain a public-facing outage tracker, only 10% of responding MOUs do.[54]

Further, more than half of responsive MOUs have no call center or help desk resources and instead rely on other city employees to field calls during emergencies. MOUs that *do* maintain call centers overwhelmingly rely on the availability of other city employees to augment call center staff during emergency events—*if* they supplement call center staffing at all.[55] It is unclear how MOU customers can report outages or other emergencies in circumstances where other city employees are unavailable to answer calls, such as after regular business hours or during emergency weather events.

MOUs are often small utilities with fewer resources, and the costs of solutions like interactive outage trackers may outweigh the potential benefits they would provide. However, the majority of contacted MOUs appear underprepared to handle customer communication during a major outage event. Ensuring customers can contact their electric service provider by phone during emergencies is a key part of a modern customer communications strategy.

Recommendations

Recommendations are numbered throughout the report for ease of reference and not in order of importance.

4. **The Legislature should codify a customer's right to information about restoration times and the right to contact an electric service provider by phone.**
   - All customers experiencing an outage should have reasonable access to information about their outage status and estimated restoration time. The Commission has launched an administrative rulemaking requiring IOUs to maintain functional and accurate public-facing outage trackers. However, the Commission lacks the authority to require the same of MOUs and co-ops.

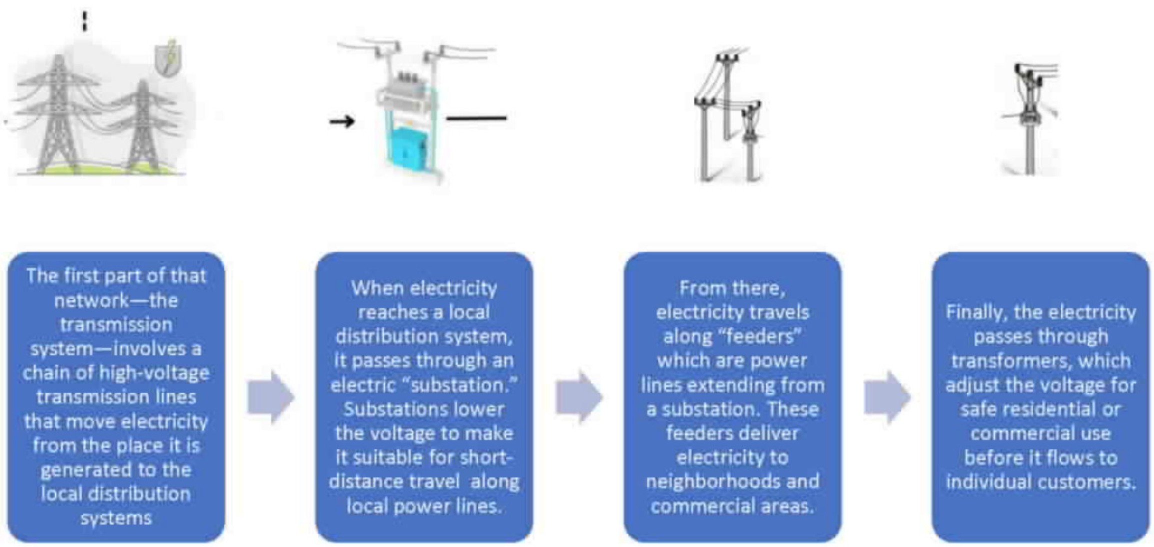
     Additionally, customers should have the ability to contact their electric service provider to report outages and other electrical emergencies 24 hours a day. Approximately half of the MOUs contacted by Commission during this investigation did not have call center resources.

     The Legislature should consider adding these protections to the Public Utility Regulatory Act (PURA) Chapter 17, which outlines customer protections.

   - Further, critical loads, such as assisted living facilities and water utilities, must be able to contact their electric service provider directly during an emergency. The Legislature should consider codifying a critical customer's right to timely contact with utility representatives during significant power outages. Some of these customers reported waiting on hold for hours to speak to a customer service representative following Hurricane Beryl.

3.3 Customer Restoration Workflow

Restoring power for electric customers depends on the continuous operation of a complex network of physical infrastructure.



Damage to any part of a utility's transmission or distribution system may disrupt service for customers located "downstream." For example, damage to a transformer may cause an outage on one side of a street, while damage to a substation may impact whole neighborhoods. After a major storm, it is not uncommon for customers to be impacted by damage to more than one of the electric facilities used to provide service to that customer. To restore power, the utility must repair all damage affecting the flow of electricity to a customer's premises.

A review of workflow restoration procedures indicates that the most effective way to optimize the restoration process is to proactively enhance the reliability of system infrastructure. Ensuring utility infrastructure is prepared to withstand the expected hazards of a utility's service territory will reduce the total number of outages following a major storm and reduce the extent of damage responsible for outages that do occur.

Outage Reporting and Management

Utilities follow similar procedures for incorporating outage reports into restoration workflow. Most IOUs and electric cooperatives use technology to ensure the outage reporting process is simple and accessible for most customers. Typically, customers can report outages to customer service agents, interactive voice response (IVR) systems, or online through utility websites or mobile applications. Outages reported to

IOUs and electric cooperatives are then entered into outage management systems, which allow utilities to track outages, assign restoration crews, and monitor restoration progress.[34]

The speed with which a utility responds to a specific outage is influenced by a number of factors. The presence of critical facilities, the size of the outage, safety concerns, and the equipment necessary to repair the damage each play a role. When there is widespread damage, utilities may delay the deployment of work crews until damage is assessed and utilities can determine how to allocate restoration resources. Effective pre-storm management—especially pre-staging crews and materials, when possible—helps reduce logistical delays in the restoration process.

For MOUs, the outage restoration process is less clear-cut. In August 2024, the Commission sent RFIs to MOUs to determine how customer calls were incorporated into restoration workflow following Hurricane Beryl. Most contacted MOUs did not provide a substantive response to the question, either because they were not impacted by Hurricane Beryl or because they do not have a customer call center.[35] MOUs that *did* provide a substantive response described strategies that mirrored those described by IOUs and electric cooperatives. It is not clear how MOUs that lack call center resources receive outage reports, or how long it takes those outages to be incorporated into utility workflow.

Restoration Prioritization

Customers in low-density areas may experience longer power outages. All contacted utilities indicated that, during an outage event, they attempt to prioritize restoration to critical loads and repairing damage that impacts the greatest number of customers. [36]

Restoring power to the greatest number of customers typically means prioritizing repairs to damage at transmission lines and substations before feeders and other downstream equipment. This approach ensures power is restored to more customers more quickly, but it may prolong outage durations for some customers based on their physical location. The design of electric distribution systems also plays a role. Utility service territories are divided into individual electric "circuits" (also called feeders) extending from substations.[37] Prioritizing repairs that will restore power to the greatest number of customers means restoration to more isolated circuits may be delayed. Circuits often have a looped design so customers located along damaged lines can be "back fed" power. However, some circuits have a "radial" design. If a radial circuit is damaged, customers cannot be "back fed" electricity from elsewhere in the system. Radial circuits are often located in less densely-populated areas, meaning rural and suburban customers – and others along radial circuits – may often experience more prolonged delays.

[34] While most contacted IOUs and cooperatives followed this general procedure, the specific procedures followed for restoring reported outages vary between utilities.

[35] *See* Section 3.2, above (explaining that approximately half of all contacted MOUs reported that they do not maintain call center resources but rely on other city employees to answer calls when available).

[36] Critical loads include, but is not limited to, hospitals, police stations, fire stations, other utilities, and customers with special in-house life-sustaining equipment. *See also* 16 TAC § 25.52(f) and (h)(2), 25.53(e), and 25.62(4)(C)(i)(IV).

[37] Isolating circuits allows utilities to limit the number of customers affected by a single outage—much like the circuits in a residential home, where a fault may cause the circuit breaker to "trip" for one room while allowing the remaining rooms to maintain power.

Recommendations

Recommendations are numbered throughout the report for ease of reference and not in order of importance.

5. **The Legislature should consider establishing a framework and penalty structure to assess IOU service quality during major outage events.**
   - The Commission oversees and enforces IOU compliance with service quality standards. However, since 1998, the Commission has excluded major events—extreme weather that disrupts power to at least 10% of customers—from these service quality calculations.[38][39] The exclusion reflects concerns that including such events would misrepresent a utility's typical reliability. While it's reasonable to exclude hurricane damage from average service quality metrics, utilities should not avoid accountability for insufficient storm preparation or response.

     Commission staff recommends establishing a new standard to assess IOU system reliability and response during major events. The standard would be applied to a utility's service quality performance during major events over the course of a year, similar to how the Commission's current service quality rules are designed. For violations of this standard, the Commission should have the authority to pursue enhanced administrative penalties.

3.4 Physical Infrastructure

Staff analyzed RFI responses pertaining to the resiliency of electric service providers' physical infrastructure in the Greater Houston area. Staff reviewed information related to infrastructure inspection cycles, minimum widths of rights-of-way, and the strength and wind loading design and construction standards. Additionally, staff reviewed infrastructure failures, the causes of those failures, and potential for those same failures to cause problems in the future. Utility standards and practices are generally consistent across the region. Most electric service providers in the Greater Houston area follow similar design and construction standards.

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[38] *See* 23 TexReg 11923 (1998) (to be codified at 16 TAC § 25.52) (proposed Jun. 12, 1998) (acknowledging that SAIFI and SAIDI standards may be adversely impacted by single outstanding weather events, contemplating excluding major events from SAIFI and SAIDI calculations once individual utility standards are established, and stating that "the commission does not intend to adopt requirements having the unintended consequence of requiring inefficient reliability expenditures due to adopting standards affected by abnormal operating experiences."). *See also* the Commission's annual service quality report form, which specifically limits SAIFI and SAIDI calculations to "forced outages," available at https://www.puc.texas.gov/industry/electric/forms/#electric-form-6a.

[39] These metrics include the system-average interruption frequency index (SAIFI) and system-average interruption duration index (SAIDI). A utility's SAIFI value represents the average number of times a customer's electric service is interrupted, and its SAIDI value represents the average amount of time service is interrupted.

National Electrical Safety Code Loading Factors

The National Electrical Safety Code (NESC) is a set of industry-defined standards designed to promote safe installation, operation, and maintenance of the electric utility systems. NESC Rule 250B, which specifies combined ice and wind loading criteria, defines four district loading areas due to typical weather conditions: Heavy, Medium, Light, and Warm Island loadings.[40] As shown below, Texas' gulf coast is located in the light loading district.

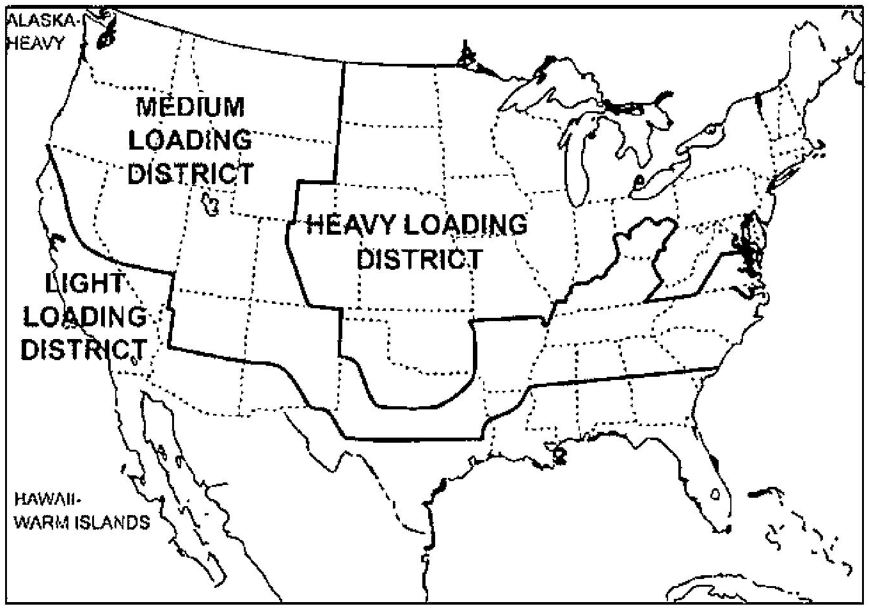


Figure 1: General loading map of the United States with respect to loading of overhead lines[41]

Within each of these loading areas, Rule 250B defines a specific horizontal wind pressure, radial ice thickness, and temperature that should be considered in the design of structures. NESC Rule 250C, extreme wind loading, applies to structures or their supported facilities that exceed 60 feet above ground or water level and require the design to withstand the extreme wind speeds. The figures below show extreme wind speed design standards of between 90 and 130 mph for areas located on or near the gulf coast, depending on structure's construction standard used.

[40] IEEE NESC C2-2023 at 178.
[41] *Id.* at 181.

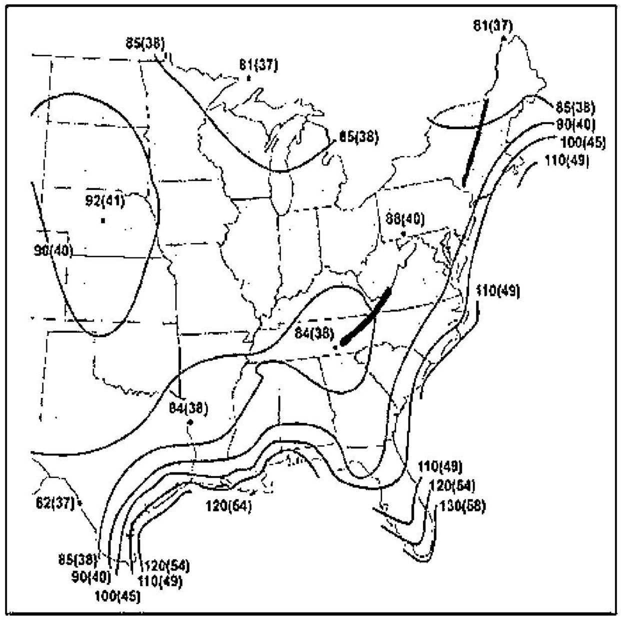


Figure 2: Grade C, 50-year Mean Recurrence Interval (MRI) 3 second gust wind speed map[42]

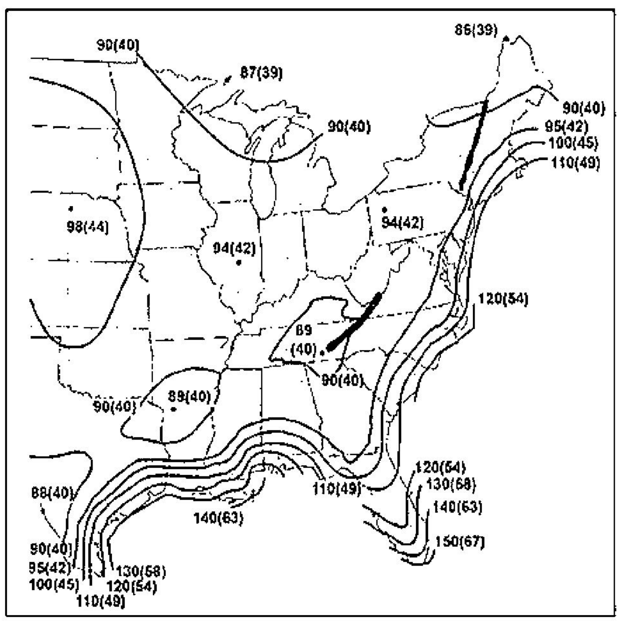


Figure 3: Grade B, 100-year MRI 3 second gust wind speed map[43]

Finally, NESC Rule 250D, extreme ice with concurrent wind loading, applies to structures or their supported facilities that exceed 60 feet above ground or water level. This rule requires a structure and its

[42] *Id.* at 185.
[43] *Id.* at 183.

supported facilities to be designed to withstand loads associated with the uniform ice thickness and concurrent wind speeds specified in the 2023 NESC.

The table below demonstrates the design standards used by various electric service providers in the greater Houston area as compared with the NESC light loading design standard.

	Horizontal Wind Pressure (psf)	Radial Ice Thickness (in.)	Extreme Wind Speed (mph)
NESC Light Loading	***9***	***0.0***	--
CenterPoint[44]	3	0.5	110-132
AEP Texas	20	1.0	103-150
Entergy	9	0.0	~95-135
TNMP	9	0.0	90-130

Notably, all utilities reported meeting or exceeding NESC Rule 250B standards. In 2022, CenterPoint began applying both NESC 250C and 250D to all new and replacement distribution facilities, regardless of structure height.[45] Additionally, CenterPoint stated that, while only 1.8% of the poles on its system have been installed to meet this standard, a sample of a small population of circuits revealed that approximately 50% of its existing poles already met these standards.[46]

Oncor will begin assessing and upgrading its existing overhead distribution facilities to meet NESC 250C and 250D, regardless of structure height.[47] Oncor will apply these rules to all new and replacement distribution facilities as well, similar to what CenterPoint began doing in 2022.

Most MOUs and co-ops report using the NESC strength and loading factors in effect at the time of construction and use the NESC 250B wind load district associated with the utility's location. There were seven co-ops that report building to Rural Utilities Services (RUS) standards that meet or exceed NESC specifications.[48]

Right-of-way (ROW) Design

Most electric service providers require similar rights-of-way when designing their distribution systems. Generally, utilities plan for between 10 and 15 feet of right-of-way, with the line running down the center of the easement.

[44] CenterPoint's current distribution system strength and loading design standards exceed NESC Rule 250B for Light Loading Districts by considering the weight of ice on its conductors. The utility's standards come close to meeting design standards for Heavy Loading Districts, which require construction considering 0.5 in. of ice plus 4 pounds per square foot (psf) of horizontal wind pressure.
[45] CenterPoint's Response to Staff RFI 1-81.
[46] CenterPoint's Response to Staff RFI 1-85.
[47] Application of Oncor Electric Delivery Company LLC for Approval of a System Resiliency Plan (May 6, 2024)
[48] Rural Utilities Services is a program of the US Department of Agriculture's Rural Development initiative.

Utility	Single Phase (ft.)	Three-Phase (ft.)
CenterPoint	10	10
Oncor	10	15
AEP Texas	10	10
Entergy	15	15
TNMP	10	16
Coops	10-15	10-15
MOUs	10	10

CenterPoint indicated that it requires a minimum 14 feet ground easement for single and three-phase lines when shared with other dry utilities, like gas or telecommunications. A 16 feet ground easement is used for single and three-phase lines when shared with other dry utilities and a wet utility, like water. Additionally, CenterPoint also has easements that were previously defined in platted dedications and negotiated agreements that pre-date the utility's minimum ROW standards. In some cases, the ROW is as narrow as 5 feet.

Pole Embedment

Several factors determine how far into the ground a distribution pole should be embedded, including pole height, pole class, pole material, structural loads, and soil conditions. Most utilities follow Rural Utilities Service (RUS) specifications for pole embedment: 10% of the total pole length plus two feet.[49]

CenterPoint uses a design software to determine pole embedment, with the following minimums:[50]

- Class 2 and smaller wood poles: 10% of total pole length plus 2 feet.
- Class 1 and larger wood poles: 10% of total pole length plus 3 feet.
- Fiberglass and ductile iron poles: 10% of total pole length plus 3 feet.

AEP Texas provided a chart showing the pole depths for 5 different soil types based on the length of pole used.[51] For normal soil conditions, with class 4, 5, and 6 poles, pole embedment averages the 10 percent of total pole length, plus 2 feet standard.

Entergy Texas began using the following pole embedment in 2022:[52]

- Wood poles: 10% of pole length plus 3 feet.
- Non-wood poles: 10% of pole length plus 4 feet.

TNMP, 26 MOUs, and 29 coops use the RUS standard of 10% of pole length plus 2 feet.

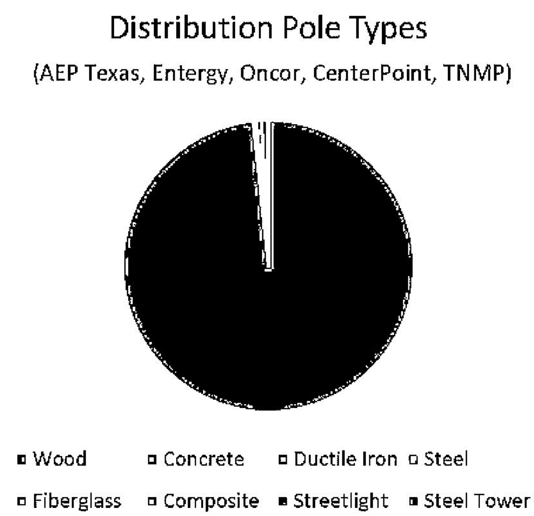
[49] US Department of Agriculture Rural Development Utilities Program: RUS Bulletin 1724E-205.
[50] CenterPoint Response to Staff RFI 1-79.
[51] AEP Texas Response to Staff RFI 1-58.
[52] Entergy Response to Staff RFI 1-58.

Pole Inspections

CenterPoint, AEP Texas, and Entergy inspect their distribution poles on a 10-year cycle, meaning approximately 10% are inspected annually. Oncor inspects high-impact poles on a 10-to-15-year cycle. TNMP conducts inspections as part of day-to-day operations or as warranted by operating conditions and/or reliability indicators. Of the contacted MOUs, 10 conduct pole inspections as an on-going manner part of daily operations. Others conducted pole inspections on cycles ranging from twice a year to every 10 years. Most co-ops inspect 10% of distribution poles each year.[53]

Pole Counts

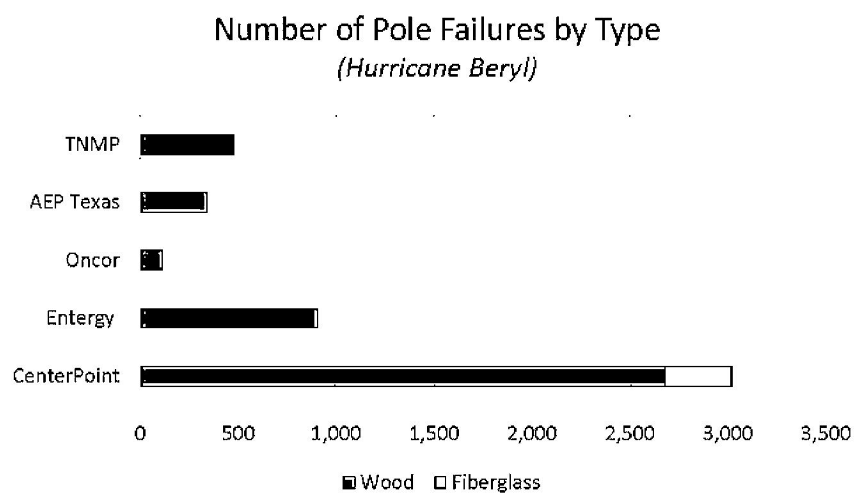
Prior to the May 2024 derecho event, the electric service providers contacted in the investigation had more than 3.7 million distribution poles in the ground providing service. The contacted IOUs own about 56% and the contacted MOUs and co-ops own about 44% of these. With one exception, more than 95% of each electric service provider's distribution pole fleet was made of wood.[54]



[53] Response to Staff RFI 1-54(a) (Other Utilities) and Staff RFI 1-75(a) (CenterPoint).
[54] Response to Staff RFI 1-56(a) (Other Utilities).

Pole Failures

Utilities reported that most poles that failed during Hurricane Beryl were wood.



These failures represent less a small fraction (less than one percent) of each IOU's total wood poles.

Pole Type	CenterPoint	Entergy Texas	Oncor	AEP Texas	TNMP
Wood	0.24%	0.19%	0.06%	0.26%	0.48%
Fiberglass	2.69%				

CenterPoint reported that about 3,000 of its 1.6 million distribution poles failed.[55] The company did not formally track the failure mode for each pole but stated that evidence suggests most pole failures were due to structural loading from vegetation and other debris.

Using more composite materials in pole and crossarm construction can reduce customer outages and restoration times by enabling the distribution system to withstand the latest extreme wind loading and ice design criteria found in NESC rules 250C and 250D. This includes using non-wood engineered structures and a combination of trussing, cross arm replacement, or pole replacement. However, given that less than 1% of wood poles actually failed during Hurricane Beryl, strategic placement of poles built from composite materials will minimize overall costs to consumers while enhancing the resiliency of critical portions of the utility's distribution grid.

[55] CenterPoint stated the company does not have records regarding each pole that was replaced or the reasons each pole was replaced. However, the company provided the total number of replacement poles that were sent to crews in the field and stated that these numbers correlate closely, if not exactly, to the total number of distribution poles that failed.

Impacts of Vegetation

Staff's investigation was hindered by CenterPoint's inability to track the failure modes for its distribution system.[56] However, PA Consulting assessed CenterPoint's storm preparedness and restoration efforts associated with Hurricane Beryl and discovered that over 75% of overhead distribution circuits experienced lockouts, which left more than 2.1 million CenterPoint Energy customers without power.[57] A lockout is when a circuit breaker attached to a pole locks in the open position until a line worker clears the fault and manually closes the circuit breaker. These lockouts appear primarily related to vegetation affecting grid performance.

The majority of vegetation-related outages resulting from Hurricane Beryl were caused by vegetation originating from outside the ROW. For additional discussion, see *Section 3.5 – Vegetation Management.*

When wind uproots vegetation and blows it into a pole or line, cross arms might fail even if the pole itself remains intact. If the cross arm fails, the line itself might fall to the ground, short-circuiting the entire line. This in turn causes a lockout until the line can be rehung and the circuit breaker is closed. This type of structural problem may account for a large percentage of the nearly 800,000 affected distribution poles.

PA Consulting made the following recommendations with regard to CenterPoint's grid performance, design, and automation:[58]

- Develop a program to segment less than 500 customers per remotely controllable circuit
- Develop protection and sectionalizing strategy for neighborhoods served by only one line
- Increase use of composite pole and crossarms
- Replace Open Wire with Covered Conductors

Staff agrees with these recommendations.

Sectionalizers

Sectionalizers—devices that isolate faulted line sections from the functioning parts of a system—can prevent premature lockouts on main feeders, keeping the rest of the feeder energized. Sectionalizers combined with circuit breakers can identify the approximate location of the problem area which aids in restoration times. When properly applied, sectionalizers can prevent cable and other equipment from burning out and, when tied with communications packages, sectionalizers can be turned on or off from a remote location.

[56] CenterPoint Response to Staff RFI 1-77.
[57] CenterPoint Energy response to RFI Staff RFI01-019S Supplemental
[58] *Id.*

Recommendations

Recommendations are numbered throughout the report for ease of reference and not in order of importance.

6. **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.

7. **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.**

8. **In more densely vegetated areas, utilities should assess whether to replace distribution lines with covered conductor.**
   - The conductor is the wire that carries the electricity. Covered conductors have an insulating outer layer. This replacement may yield better protection against vegetative debris blown-in from outside the ROW and decrease overall outage rates.

3.5 Vegetation Management

Effective vegetation management minimizes storm-related outages by reducing the risk of vegetative debris contacting power lines. Hurricane Beryl caused more extensive damage from fallen trees compared to previous severe weather events. The compounding effects of rains, freezing temperatures, and droughts in recent years made trees and vegetation more susceptible to uprooting. The high winds sent branches and entire trees into power lines from inside and outside utility rights of way. Approximately half of CenterPoint's Hurricane Beryl-related circuit outages were the result of vegetation.[59]

Commission Staff reviewed how utilities plan for and implement vegetation management strategies, including how they approach vegetation hazards located outside of easements and rights-of-way (ROWs).

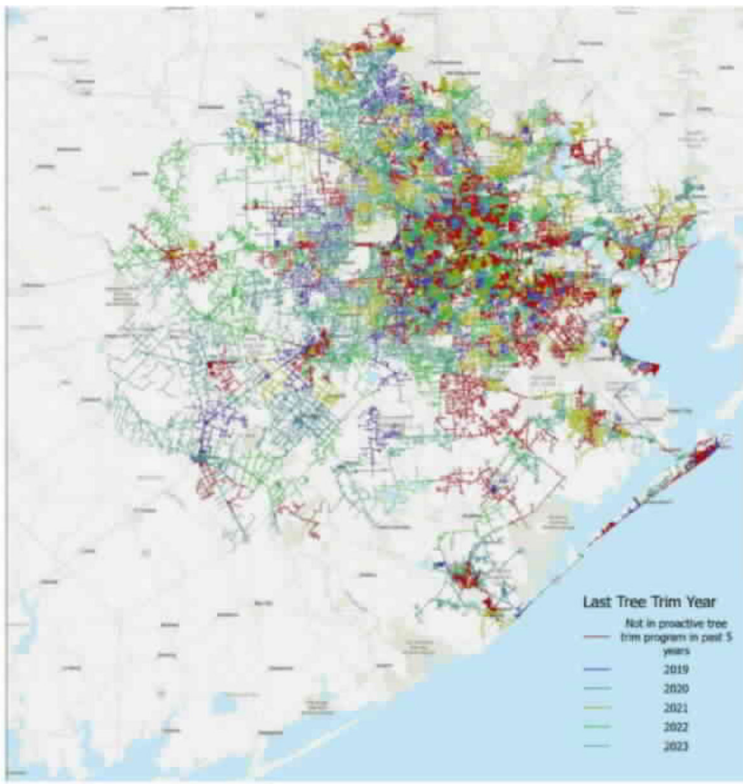
Cyclical and Analytical Vegetation Management Plans

Vegetation management practices can be divided into cyclical and analytical plans. Under a *cyclical vegetation management plan*, a utility identifies the desired number of years required to trim its entire system once and then divides up the work. Time and budget are the predominant factors in cyclical planning. The most common cyclical vegetation management plans used a five- to eight-year clearing schedule. These plans allow for easier budgeting because the utility knows exactly how many circuit miles

[59] CenterPoint Energy response to RFI Staff RFI01-019S Supplemental

must be cleared each year. Smaller utilities included in the investigation tended to favor a cyclical vegetation management plan.

Analytical vegetation management plans determine the trimming schedule based on datapoints. CenterPoint switched to a more analytical plan in 2020. It ranks and prioritizes circuits based on potential impact to critical loads, overall customer count, and previous vegetation-related outages. The time between trimmings is considered but it is not a controlling factor. Circuits with more vegetation issues are addressed more frequently under this type of plan.



The image above overlays circuits within CenterPoint's service territory that experienced an outage due to Hurricane Beryl. The image is color-coded to indicate the last year CenterPoint performed work on these circuits. Circuits in blue were trimmed most recently under CenterPoint's final cyclical vegetation management plan in 2019. Circuits in red had not been trimmed in the last five years.[60] Large parts of south and central Houston had not undergone trimming since at least 2018, and parts of central Houston, west Houston, and north Houston had not been trimmed under CenterPoint's current plan.[61]

Not every outage in CenterPoint's system can be associated with a failing in its vegetation management policy, but the map suggests CenterPoint's criteria should be adjusted to trim more frequently.

[60] CenterPoint did not provide information as to which circuits had been trimmed in 2024 in advance of either the May 2024 derecho or Hurricane Beryl.
[61] As of September 2024, when the image was generated.

The majority of co-ops and MOUs contacted in the investigation budget for trimming their entire system once every three to five years. However, vegetation management is not simply based on the number of crews, but the type of work being performed. The City of Halletsville, which reported only having one problematic tree near its main substation, does not have the same vegetation concerns as Oncor, which sends vegetation patrols into the heavily wooded areas within its service territory.

Vegetation Management Staffing

At the August 29, 2024 Texas Senate Special Committee on Hurricane Beryl hearing, CenterPoint CEO Jason Wells testified that the company outsourced its vegetation management to approximately 500 contractors before July 8, 2024, but was looking to bring more crews in-house.[62] He committed to expanding the company's vegetation management plan to add an additional 2,000 distribution line miles to its annual clearance schedule. To accomplish this task, CenterPoint stated it would increase its vegetation management workforce from 628 (12 fulltime, 616 contractors) to more than 2,700 resources, which would make it the largest team of any utility contacted for the investigation.

IOUs contacted in the investigation reporting vegetation management staffs of between 147 and 1,650 people. Co-ops typically reported vegetation management departments between 30-50 people. MOUs typically employed between 10-20.

The variation in staffing across utilities is driven by the differences in each utility's service territory. Utilities consider how many crews are required to clear the entire system within the utility's trimming cycle, what type of vegetation exists in the service area, and the risks to service quality that vegetation presents to the utility's customers.

Contracted vegetation management work

The decision to outsource vegetation management work appears to be the industry standard.

None of the IOUs contacted for the investigation employed any fulltime vegetation management staff other than in managerial or expert roles, like foresters. Vegetation management work, like line work, is inherently dangerous but generally requires less training than line work. From an economic perspective, outsourcing an equally dangerous, but less technical, function allows a utility to allocate resources to expand the scope of the outsourced work or to reinvest into other critical business areas. For example, City of Caldwell noted that its decision to outsource nearly its entire vegetation management staff came down to the need to fit critical work into a tight budget. Caldwell opted to hire five contractors for the same cost as one fulltime employee. Karnes Electric Co-op, which uses a mix of fulltime and contract staff, stated that its contracted vegetation management crews cost approximately one-third of a similarly experienced in-house employee.

Some utilities contacted in this investigation took slightly different approaches to staffing their vegetation management departments:

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[62] *See Senate Special Committee on Hurricane and Tropical Storm Preparedness, Recovery, and Electricity,* 88TH TEX. LEG. INTERIM SESS., 5:20:47-5:21:20 https://senate.texas.gov/cmte.php?c=549 (July 29, 2024).

- Karnes Electric Co-Op and Bluebonnet Electric Co-Op appeared to have a 40-60 split between inhouse crews and outsourced crews.
- Houston County Electric Co-Op uses in-house crews for work like removing hazardous trees and uses contractors for more routine vegetation work.
- Mid-South Electric Co-Op and several MOUs (City of Hemphill, Newton Municipal Utilities) indicated that they cross train in-house line workers to handle both vegetation management and line work. While this strategy maximizes resources, a reliance on line workers to perform vegetation management work necessarily reduces the amount of either task these crews could accomplish.

Vegetation-Related Reporting

Causes of Forced Outages

Each IOU must report each year on its electrical service quality.[63] These reports include the system-average interruption frequency index (SAIFI) and system-average interruption duration index (SAIDI). A utility's SAIFI value represents the average number of times an average customer's electric service may be interrupted over the course of a year, and its SAIDI value represents the average number of minutes service may be interrupted over the course of a year.[64][65] These values are reported for both the utility's entire distribution and for certain qualifying feeders. Lower SAIFI and SAIDI values reflect better service quality. Utilities can face administrative penalties for failing to meet the standards set by the Commission.[66]

Service interruptions are reported by the type of outage, and vegetation-related outages are generally reported in forced-interruption figures. Importantly, outages caused by major events – such as hurricanes – are not included in forced-interruption calculations.[67]

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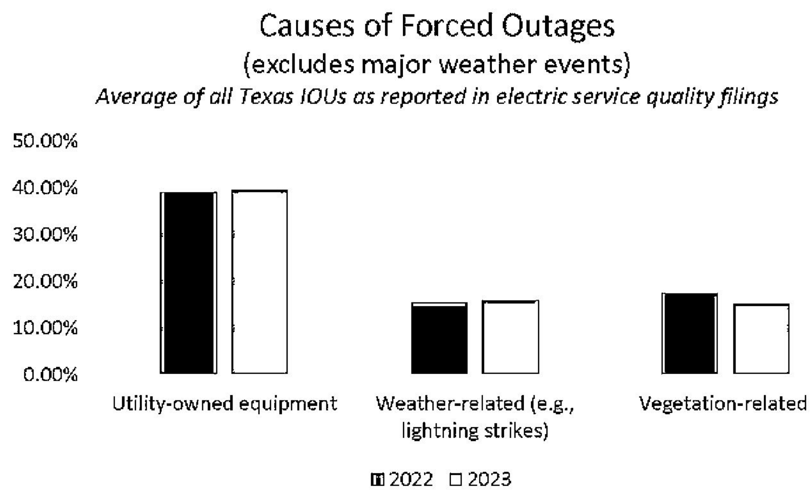
[63] 16 TAC 25.81. See also 16 TAC 25.52

[64] SAIFI is calculated by summing the number of customer interruptions for each event dividing by the total number of customers on the system being indexed. See generally, 16 TAC 25.52(c)(8)(A).

[65] SAIDI is calculated by summing the restoration time for each interruption event times the number of customers interrupted for each event and dividing by the total number of customers. See generally 16 TAC 25.52(c)(8)(B).

[66] A utility's annual electric service quality is measured against its average SAIFI and SAIDI values for the later of reporting years 1998 through 2000, the first three reporting years the utility was in operation, or the last time the Commission updated the utility's service quality standards. Utilities reporting SAIFI and SAIDI values for forced outages that exceed five percent of the system wide standard or who have qualifying feeders exceeding 300% of the actual reporting year value for two or more consecutive years are subject to administrative penalties. These thresholds are codified in PURA § 38.005(b).

[67] A forced-interruption is an interruption, exclusive of major events, that results from conditions directly associated with a component requiring that it be taken out of service or an interruption caused by improper operation of equipment or human error. See generally 16 TAC 25.52(c)(4)(A).

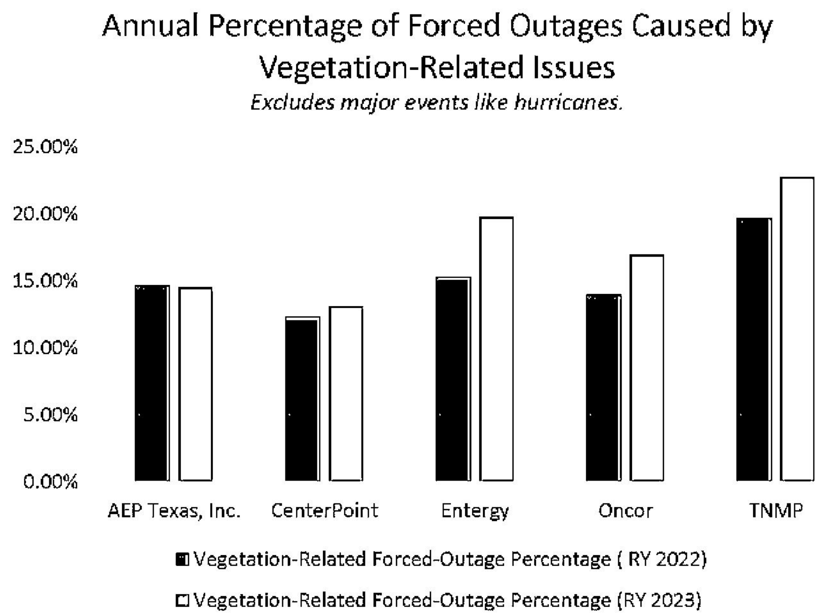


Administrative fines for electric service quality are classified as Class A violations and are capped at $25,000 per violation per day.[68] However, because these violations are based on an annual average, penalties are often less than $100,000 annually.[69] It is often cheaper for IOUs to pay annual service quality penalties than to correct issues that lead to longer and more frequent outages.

Increasing the penalty amounts and reducing the per-feeder threshold should increase an IOU's effort to address vegetation issues across its system. Vegetation-related outages are largely within the utility's control and can often be mitigated by effective vegetation management.

IOUs contacted in the investigation reported in their electric service quality reporting that between 12.37% and 22.8% of forced outages were caused by vegetation-related issues in 2022.[70]

[68] *See* PURA § 15.023(b)
[69] The Commission's ability to penalize those violations is limited to a one-time $25,000 penalty for each system-wide or per-feeder violation in the applicable reporting year.
[70] See generally Project No. 54467, CY 2022 Utility Service Quality Report Under 16 TAC 25.81.



In 2023, most utilities contacted in the investigation, except AEP Texas, reported more vegetation-related outages compared to 2022.[71] Entergy saw the largest percentage increase (22% increase).

Annual Vegetation Management Reporting

Electric utilities are required to file an annual report concerning their vegetation management plan with the Commission.[72] Each plan must estimate how many circuit miles the utility estimates it will clear that year and provide information about whether it met its previous year's goal.[73]

The IOUs contacted in this investigation met or exceeded their 2023 vegetation management goals[74]:

Utilities	2023 Distribution Miles	2023 VM Plan Clearing Goal (miles)[75]	2023 Clearing Goal Met or Exceeded?
Oncor	90,740	3,100[76]	Yes
CenterPoint	29,270	3,500	Yes
Entergy	14,400	1,212	Yes
AEP Texas	45,070	1,000	Yes

[71] See generally Project No. 56005, CY 2023 Utility Service Quality Report Under 16 TAC 25.81
[72] *See* 16 TAC § 25.96.
[73] *See* 16 TAC § 25.96(f)(1)(H).
[74] TNMP's figure is not included because Commission Staff suspects a possible filing error. Separate filings indicate 2023 clearing goals of both 908 miles and 614 miles. Reports of work completed reflect 453 miles.
[75] Utilities' vegetation management plans
[76] Oncor response to RFI Staff 1-81

CenterPoint reported exceeding its 2023 vegetation management clearing goal by 30%. However, it had an increase (5.72%) in vegetation-related force-outages between 2022 and 2023. This suggests that the actual number of distribution line miles cleared helped mitigate some, but not all, of the threats posed to CenterPoint's electric service quality by hazardous vegetation.

Addressing Vegetation Hazards Through Customer Engagement

Clearing circuit miles is central to every vegetation management plan, but electric utilities must also be equipped to address unscheduled vegetation issues as they are reported. MOUs and coops -are more likely than larger utilities to incorporate vegetation issue spotting into the functions of all utility employees. For example, at Mid-South Electric Cooperative, all employees are tasked with "spot[ting] hazard trees" while moving around the community they serve. Some larger utilities, like Oncor, focus vegetation issue spotting programs on specific geographic regions with unique challenges. Oncor's East Texas Hazard Tree Program sends foresters and vegetation management crews to patrol circuits in heavily wooded areas to address hazardous vegetation.

Historically, CenterPoint has not implemented vegetation management strategies and policies that could address unscheduled problems. CenterPoint customers have expressed concerns over an inability to effectively report potential hazards. During the October 5, 2024 workshop, several CenterPoint customers stated that CenterPoint had failed to trim trees around distribution poles.[77] One commentator stated that, despite many requests, CenterPoint had not trimmed trees on his property that were steadily growing nearer to a distribution pole in almost 30 years. Customer engagement is a necessary and vital component of effective vegetation management planning.

Oncor provides an online portal for customers to learn about and report potential vegetation management issues on their property.[78] The online portal allows customers to provide the information immediately. However, methods for reporting vegetation issues are normally not immediately obvious on a utility's website. Oncor's main page has portals to report power outages, downed power lines, and streetlight outages, but customers need to click through three pages before reporting a hazard tree. Entergy's customers must click through four pages before being told to call the utility's main contact number. A customer may be willing to navigate through their utility's website to locate a contact number for a tree issue at their residence but may not have the same patience when reporting a hazard identified on their commute. While above examples may not be ideal, CenterPoint's customer engagement on this issue may restrict the flow of customer-reported information. CenterPoint requires customers to call in to report a hazard tree and then arrange to speak with a forester at a later date.[79] Utilities should make all efforts to reduce roadblocks for customers attempting to report potentially hazardous vegetation issues.

[77] PUCT Workshop, October 5th https://www.adminmonitor.com/tx/puct/workshop/20241005/
[78] https://www.oncor.com/content/oncorwww/us/en/home/about-us/vegetation-management/location.html
[79] https://www.centerpointenergy.com/en-us/Safety/Pages/Tree-Trimming-Removal.aspx?sa=ho&au=res

Vegetation Outside the Right of Way

Utilities that tracked outages caused by vegetation during the May 2024 derecho and Hurricane Beryl reported that most outages were caused by trees growing outside of utility easements or the right-of-way (ROW).

- CenterPoint's largest vegetation management provider estimated 60% of the vegetation damaging the company's distribution infrastructure during Hurricane Beryl was caused by tree fall-ins from outside the easement or ROW.[80]
- Entergy attributed about 49% of its Beryl outages to vegetation outside the ROW.[81]
- AEP Texas reported that 100% of its outages in Matagorda and Wharton Counties were caused by vegetation fall-ins originating outside the ROW.[82]
- Co-ops estimated that generally between 50 -100% of their outages were caused by vegetation outside the ROW.

On average, utilities operating transmission facilities had easements or ROWs of at least 50 feet (25 feet on either side of the line), with up to 100 feet. Distribution lines generally had smaller easements and ROWs, usually between 20 to 30 feet (10-15 feet on either side of the line). Even a utility that clear cuts its easement can be impacted by tree growth outside the easement. Lamar County Electric Cooperative Association - which has clear cut its easements and ROWs since 2012 – reported one vegetation-related outage during Hurricane Beryl.[83] In that instance, a 75-foot tree from outside the 100-foot easement (50 feet on either side of the line) fell due to high winds and brought down a powerline.[84]

To address trees outside the ROW, most utilities attempt to work with the property owner and ask permission to address the hazardous condition at no cost. However, this is not always successful. City of Liberty noted that, "[p]roperty owners love their trees and refuse to work with [us] to clear any potentially hazardous trees."[85]

Other approaches include tree replacement programs and education strategies. Brownsville Public Utility offers to replace trees growing near an easement with others planted further back on the property.[86]

Some utilities take more extreme approaches to address the problem. One utility stated that they may disconnect a customer from power if a hazardous tree out of the easement posed a significant risk. Another utility adopted an "ask forgiveness, not permission" approach to the problem by proactively removing hazard trees regardless of their location.

[80] PUCT open meeting, July 25, 2024; https://www.adminmonitor.com/tx/puct/open_meeting/20240725/
[81] Entergy Texas response to RFI Staff 1-83.
[82] AEP Texas response to RFI Staff 1-83
[83] Lamar County Electric Co-op Association response to RFI Staff 1-83.
[84] Id.
[85] City of Liberty response to RFI Staff 1-84
[86] Brownsville Utility Trade a tree

Recommendations

Recommendations are numbered throughout the report for ease of reference and not in order of importance.

9. **The Commission should require utilities to establish a designated method for customers to report vegetation hazards.**
   - Most vegetation-related outages during Hurricane Beryl were caused by trees growing outside of utility easements and rights-of-way. Utilities can access these areas with landowner permission, but processes for customers to report hazard trees for mitigation or removal must be improved. While most utilities have a program in place, these programs are not immediately accessible on most utility websites.

10. **Utilities should use analytics-based vegetation management strategies to augment, not replace, cyclical vegetation management plans.**
    - Vegetation management practices within Texas are not standardized, with some utilities moving away from a cyclical plan to a more analytics-based vegetation management plan. Analytics-based plans can help prioritize sections of a service territory due to heightened vegetation hazard. However, utilities should take precaution to not minimize factors like "time between trims." To ensure all segments in the service territory are addressed, utilities should augment cyclical vegetation management plans with analytics instead of replacing them with a solely analytics-based approach. Alternatively, utilities should ensure that maximum duration between trims serves as a default or failsafe factor within their analytics-based plan. This may require vegetation management budgets to increase slightly to accommodate additional priority segment work.

11. **The Legislature should consider increasing the penalty cap for electric service quality violations.**
    - Vegetation-related outages generally represent 15 to 20% of system-wide forced-outages reported by IOUs in each reporting year (excluding major events like hurricanes). System-wide violations of electric service quality metrics are considered one violation for the entire reporting year and are capped at $25,000. To incentivize proactive measures to improve electric service quality, the Legislature could either increase the penalty cap or expand what may constitute a violation by placing a maximum threshold for forced-outages caused by vegetation-related issues. Enhanced penalties could apply if the utility crosses the threshold due to failure to trim circuits based on its trim cycle plan.

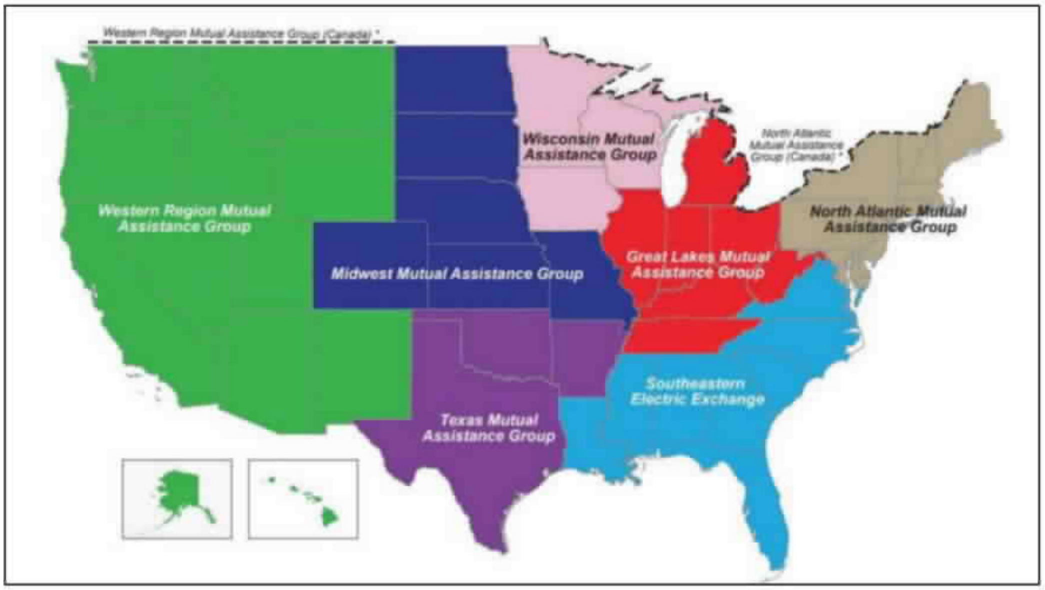
3.6 Staffing and Mutual Assistance

Mutual assistance groups are membership organizations that enable electric utilities to share personnel, materials, and equipment to help each other recover from a major event like a hurricane. Group members develop agreements that contain the terms and conditions for sharing these resources. Therefore, instead of negotiating a new agreement every time a disaster occurs, utilities can work from the pre-established agreements. This simplifies the logistics of sending and receiving help quickly.

There are seven regional mutual assistance groups in the country, and Texas is included in four of these:

- Midwest Mutual Assistance Group (MMAG)

- Western Region Mutual Assistance Group
- Texas Mutual Assistance Group (TXMAG)
- Southeastern Electric Exchange (SEE)



AEP Texas, TNMP, Entergy Texas, Oncor, and CenterPoint each belong to one or more mutual assistance groups. Most electric cooperatives and MOUs indicated that they participate in mutual assistance groups as well.

To request resources from a mutual assistance group, a member utility that faces a severe event first activates its own emergency operations plan (EOP). If the utility projects it will exhaust its own resources before service can be restored, it will submit a formal request through its mutual assistance group. Typically, a utility is expected to fully mobilize its internal workforce and utilize local contractors before requesting assistance under a mutual assistance program. For example, AEP Texas mobilized its employee and contracted workforce, then drew on resources from its AEP sister companies located closest to south Texas, and finally requested help from its mutual assistance partners.

Data from the responses to these RFIs about staffing and mutual assistance indicated that coordinating thousands of mutual assistance workers presented logistical challenges. Overcoming these challenges could help speed recovery from events like Hurricane Beryl.

Pre-Staging Strategies

Storm path forecasting and damage predictions are important to pre-staging decisions and mutual assistance requests. Because hurricanes often shift paths as they approach land, a utility must constantly reassess staging strategies to place resources near the expected impact zone, but not in the storm's direct path. Staging resources is crucial to managing restoration efforts. For example, AEP Texas held multiple internal meetings daily to review the storm development, including potential impact zone. The company reassessed its plan multiple times as Hurricane Beryl's track shifted north from Brownsville towards Matagorda Bay.

CenterPoint continued running its "damage prediction model"[87] to anticipate the storm's expected impacts and justify the requested assistance needed prior to landfall, and to make prestaging decisions.[88] This model estimates the number of resources required and types and number of poles estimated to be impacted. However, the damage prediction model was largely ineffective and offered little value in decision-making:

"At multiple times beginning on July 6, the Saturday before Beryl, the damage prediction model yielded estimates of 538 total FTEs for a 14-day restoration to 2,559 total FTEs for a 5-day restoration. The actual result was 14,000 FTEs who delivered an 11-day restoration (excludes damage assessors)."[89]

Importantly, when a utility is asked to provide mutual assistance, it must first assess its own needs and forecasted weather threats before releasing crews to assist others. Because storm paths can shift before landfall, requests for assistance are coordinated carefully within mutual assistance groups to ensure appropriate resource allocation.

Utilities are also expected to fully mobilize their internal workforce and local contractors before requesting aid through a mutual assistance program. AEP Texas began requesting mutual assistance resources on July 5.[90] CenterPoint and Sam Houston Electric Co-Op followed with requests on July 6, while TNMP requested assistance the morning of July 8.[91] Entergy secured all necessary resources through its own workforce and contactor network and did not request mutual assistance.[92] As damage assessments were completed after the storm, utilities further evaluated their needs and issued additional requests based on the full extent of the damage.

Staging and Mobilization

Hurricane Beryl affected a large geographic area, which required the mobilization of thousands of external personnel and equipment in a very short period of time. The large geographic impact meant many electric service providers were seeking assistance during the same time period. Unsurprisingly, the high demand for resources meant crews were dispatched to the Houston area from states like Missouri, Oklahoma, Tennessee, Alabama, among others.

CenterPoint's first four staging sites (of 22 total) were "check-in and dispatch" ready the day of Hurricane Beryl's landfall (July 8). This designation means the site had sufficient materials and resources to receive, check in, and dispatch crews.[93] To manage the large number of incoming workers and to avoid areas likely to be affected by the storm, CenterPoint set up staging sites located farther outside of the greater Houston area. These more remote locations resulted in longer transit times to work sites. Because vegetative debris

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[87] The model was limited to Hurricane Ike data (2008).
[88] CenterPoint Energy response to RFI Staff 1-109
[89] CenterPoint Energy supplemental response to RFI Staff 1-19
[90] CenterPoint Energy response to RFI Staff 1-111
[91] Texas-New Mexico Power response to RFI 1-91
[92] Entergy Texas, Inc. response to RFI Staff 1-95
[93] CenterPoint Energy response to RFI Staff 1-115

often blocked major road access, crews either were delayed in getting to work sites or had to remain idle until ingress routes were cleared. These delays understandably caused frustration for some Houstonians who saw field crews as idle and felt their needs were being overlooked as their neighborhoods went days without power. In a few regrettable incidents, some crews were threatened by individuals with weapons. CenterPoint deactivated and relocated one staging site due to safety concerns.

Coordination and Logistics Challenges

Some utilities experienced delays issuing work orders to field crews due to the sheer number of field personnel. Utilities noted that differences in communication protocols, lack of familiarity with local infrastructure, and damage to telecommunications systems complicated the integration of external crews.

CenterPoint reported challenges with coordinating communications between multiple mutual assistance partners and internal teams. With such a large number of external workers deployed across its service area, maintaining consistent and clear communication, and effectively deploying work crews was difficult. CenterPoint (and all the utilities) employed FEMA's National Incident Management System - Incident Command System (ICS) to establish a clear chain of command and communication structure. CenterPoint's leadership also held frequent conference calls with mutual assistance partners to keep all parties updated on progress and resource needs.

TNMP encountered significant communication difficulties due to Hurricane Beryl's impact on local telecommunications infrastructure. Cell towers and communication lines were damaged, limiting the utility's ability to maintain contact with external crews in the field. TNMP mitigated this challenge by relying on multiple communication methods—phone calls, text messages, emails, and in-person briefings—to ensure all crews received critical updates. Despite these efforts, communication breakdowns occasionally delayed restoration work, particularly in more remote areas. For additional detail on the telecommunications outages, see Section *2.3, Impacts to Telecommunications Service Providers.*

Recommendations

Recommendations are numbered throughout the report for ease of reference and not in order of importance.

12. Utilities should scale up training in emergency response and Incident Command System (ICS).

- Utilities should ensure sufficient local personnel are trained in both ICS and the utility's emergency operations plans so that the utility can effectively scale up its control of emergency response and restoration to meet the size of the event. In CenterPoint's case, for example, this means envisioning an event requiring 25 or 30 staging areas and planning for all the necessary ICS structure to seamlessly integrate throughout each site and with one another through the utility's operations center.

13. Utilities should ensure a resilient emergency communications platform is available to both local and mutual assistance crews.

- Relying on public telecommunications infrastructure may be sufficient for more localized events, but utilities need to plan for failure of these systems and still be able to effortlessly communicate with their own and mutual assistance crews.

3.7 Mobile Generation Facilities

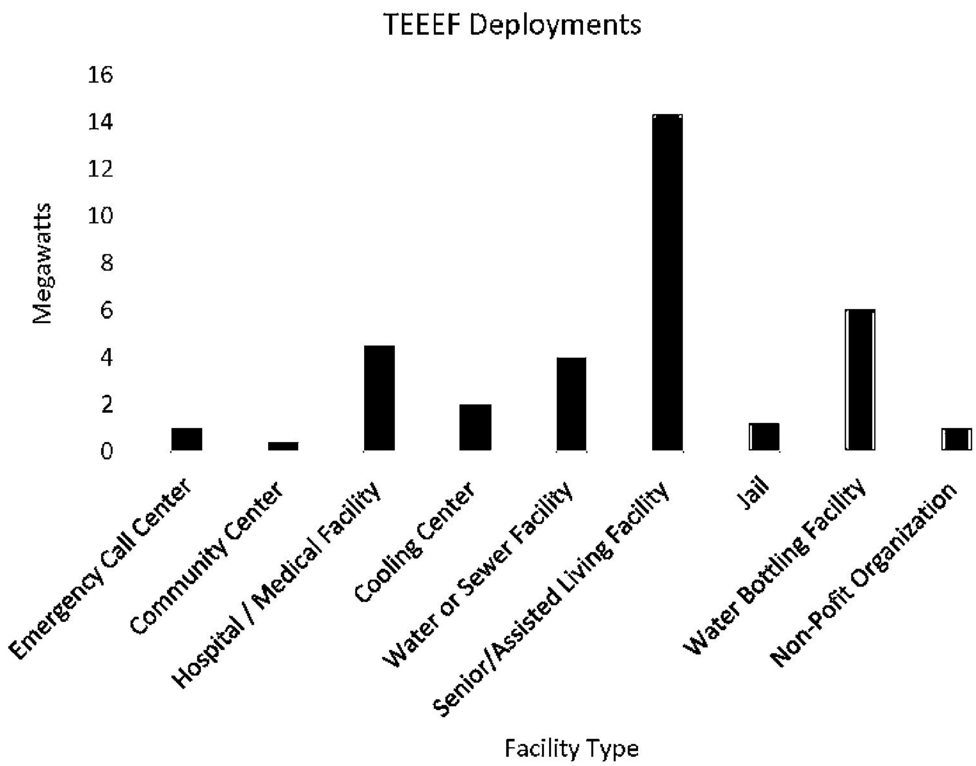
Temporary Emergency Electric Energy Facilities (TEEEF) are mobile generation units that can be used to provide temporary power to critical facilities. A TEEEF unit can be deployed to supply power to an end-use customer, such as a medical facility or cooling center, or to energize portions of a utility's distribution system. The units must be sized appropriately to meet the requirements of the deployment location. Commission Staff reviewed how electric service providers deployed and energized TEEEF. CenterPoint and Oncor were the only TDUs to deploy TEEEF following Hurricane Beryl. Oncor deployed just a single unit to the City of Lufkin Water Treatment Facility.[94]

Prior to Hurricane Beryl's landfall, CenterPoint's fleet consisted of 15 32-megawatt (MW) units (totaling 480 MW) and nine units of five MW or less (totaling 28 MW). CenterPoint did not deploy any of its 32 MW units following Hurricane Beryl because, the company asserts, these units were specifically procured to assist with "load shed support" during a grid level shortage of generation.[95]

Overview of TEEEF Deployment following Hurricane Beryl

CenterPoint attempted to deploy 30 mobile generation units.[96] Nine units were part of its existing fleet, nine units were acquired through short-term leases, and 12 units were borrowed through mutual assistance from Oncor and AEP. TEEEF deployment following Hurricane Beryl was used to restore power to critical facilities by both connecting directly to facilities and by energizing entire segments of a distribution circuit ("mid-span connection")[97]. CenterPoint energized 382 customers[98] with the TEEEF units it had under lease (15 customers directly and 367 via mid-span connection). In combination with the TEEEF it was loaned through Mutual Assistance, CenterPoint brought 460 customers online (13 customers directly and 65 via mid-span connection).[99]

[94] Oncor response to RFI Staff 1-112
[95] CenterPoint response to RFI Staff 1-126
[96] CenterPoint did not deploy two of its 5 MW units and one of the .56 MW units it obtained through mutual assistance.
[97] CenterPoint response to RFI Staff 1-134
[98] "Customers" is referring to a single meter, which could represent hundreds of people if it was connected to a site such as a cooling center or senior living facility.
[99] CenterPoint response to RFI Staff 1-134



Matching TEEEF Units to Customers

When considering where to deploy a TEEEF unit, a TDU must consider both technical (voltage and phasing requirements) and logistical (road access and physical space requirements) factors. Once these requirements are met, CenterPoint requires that the customer have an electrician on site during both the connection and disconnection of the TEEEF unit[100]. CenterPoint maintains a prioritized list of *facility types* eligible for TEEEF. However, no *specific customers* or locations were pre-identified. This led to delay in deploying TEEEF units to restore power to critical customers and facilities. Ultimately, CenterPoint was unable to deploy two of its 5 MW units and one of the .560 MW units it received through mutual assistance. The company stated it could not find a location to feasibly deploy these units because it could not match voltage requirements, phasing compatibility, or size for certain deployment sites.[101]

[100] CenterPoint response to RFI Staff 1-133

[101] CenterPoint response to RFI Staff 1-140

Priority	Category	Example Categories
1	Hospitals	100 Bed In-Patient Hospitals, Cancer Treatment, Level 1 Trauma Center
2	Emergency Services/ Airport	City and County Emergency Management, First Responder Facilities (Police, Fire Ambulatory), Airport Facilities
3	Cooling Centers	
4	Senior/Assisted Living	
5	Small Emergency Rooms/ Dialysis	Out-Patient Care Facilities, Dialysis Clinics, Small ER Centers
6	Clinics/Pharmacy	Urgent Care, Clinics, Commercial Pharmacies
7	Grocery Stores	Major Grocery Store Chains
8	Commercial facilities	Commercial facilities that support logistics/supply chain, community, individual relief, and restoration efforts

CenterPoint has acknowledged the need for necessary process improvements to its TEEEF deployments. Having more crews to enable additional TEEEF deployments each day, and to utilizing a tracking system to support deployment and fueling are among the identified improvements. CenterPoint also noted additional measures to implement, such as: maintaining a list of previously reviewed locations (to speed up technical review process) and the utilization of a pre-identified list of "of critical customer locations developed through coordination between various cities, counties, and customer engagements for faster review of outage impact and TEEEF deployment."[102]

CenterPoint's TEEEF Fleet and Additional Procurements

The day before landfall and in the days following the storm, CenterPoint procured an additional 21 units totaling approximately 7.43 MWs through either mutual assistance or short-term lease. In total, CenterPoint attempted to deploy 30 units, most of which were not part of its pre-Beryl fleet.

Procurement Date	**TEEEF Units ≤5 MW**
On hand before Hurricane Beryl	5 x 5 MW 2 x 1 MW 2 x .500 MW
July 7	4 x .400 MW
July 10	4 x 1.2 MW (from Mutual Assistance)
July 12	3 x .230 MW 2 x .200 MW
	4 x .560 MW 1 x.625 MW (from Mutual Assistance)
July 13	3 x .625 MW (From Mutual Assistance)

102 CenterPoint response to RFI Staff 1-141

Commission Rulemaking

The Public Utility Regulatory Act (PURA) § 39.918 authorizes transmission and distribution utilities (TDUs) to lease TEEEF and operate the facilities during a significant power outage.[103] The Commission has an ongoing rulemaking to implement PURA § 39.918 in Project No. 53404, titled "Temporary Emergency Energy Facilities and Long Lead-Time Facilities". Comments on the draft rule were initially due on July 18, 2024. However, the due date was extended to August 2, 2024, to allow interested parties to incorporate Hurricane Beryl response activities in their comments. The Commission will finalize the rule by the end of the year.

Recommendations

Recommendations are numbered throughout the report for ease of reference and not in order of importance.

14. **Utilities should pre-identify critical customer locations suitable for deployment of Temporary Emergency Electric Energy Facilities.**

4.0 CenterPoint's Greater Houston Resiliency Initiative

In response to the issues raised regarding CenterPoint's service following Hurricane Beryl, CenterPoint launched the Greater Houston Resiliency Initiative (GHRI). According to the CenterPoint, the GHRI is "a comprehensive suite of actions aimed at further strengthening the electric grid, improving communications, and enhancing partnerships across the Greater Houston area."

Commission Staff took the initiatives laid out by CenterPoint and created a chart that tracks each initiative in its designated category. As CenterPoint completes each initiative, Commission staff requests documentation from CenterPoint agents or designees with knowledge specific to the initiative in question. As of November 2024, this chart is available as item No. 29 in Project No. 56793.

[103] PURA § 39.918 does not authorize TDUs to own TEEEF.

Appendix

Entities receiving and responding to mandatory Requests for Information (RFIs)

Name	Response provided?
Investor-Owned Electric Utilities (IOUS)	
AEP Texas Inc.	Yes
CenterPoint Energy Houston Electric, LLC	Yes
Entergy Texas, Inc.	Yes
Oncor Electric Delivery Company LLC	Yes
Texas-New Mexico Power Company	Yes
Electric Cooperatives	
Bartlett Electric Cooperative, Inc.	Yes
Bluebonnet Electric Cooperative, Inc.	Yes
Bowie-Cass Electric Cooperative, Inc.	Yes
Cherokee County Electric Cooperative Association	Yes
Deep East Texas Electric Cooperative, Inc.	Yes
Fayette Electric Cooperative, Inc.	Yes
Guadalupe Valley Electric Cooperative, Inc.	Yes
Heart of Texas Electric Cooperative, Inc.	Yes
Houston County Electric Cooperative, Inc.	Yes
Jackson Electric Cooperative, Inc.	Yes
Jasper-Newton Electric Cooperative, Inc.	Yes
Karnes Electric Cooperative, Inc.	Yes
Lamar County Electric Cooperative Association	Yes
Lyntegar Electric Cooperative, Inc.	No
Magic Valley Electric Cooperative, Inc.	Yes
Medina Electric Cooperative, Inc.	Yes
Mid-South Electric Cooperative Association	Yes
Navarro County Electric Cooperative, Inc.	Yes
Navasota Valley Electric Cooperative, Inc.	Yes
Nueces Electric Cooperative, Inc.	Yes
Panola-Harrison Electric Cooperative, Inc.	Yes
Rio Grande Electric Cooperative, Inc.	Yes
Rusk County Electric Cooperative, Inc.	Yes
Sam Houston Electric Cooperative, Inc.	Yes
San Bernard Electric Cooperative, Inc.	Yes
San Patricio Electric Cooperative, Inc.	Yes
Southwest Arkansas Electric Cooperative Corp.	Yes
Trinity Valley Electric Cooperative, Inc.	Yes
Upshur-Rural Electric Cooperative Corp.	Yes
Victoria Electric Cooperative, Inc.	Yes
Wharton County Electric Cooperative, Inc.	Yes
Wood County Electric Cooperative, Inc.	Yes
Municipally Owned Utilities (MOUs)	

Bellville Light & Power System	Yes
Brenham Municipal Light & Power System	Yes
Brownsville Public Utilities Board	Yes
BTU Rural Electric Division	Yes
Caldwell City Government	Yes
College Station Utilities	Yes
Cuero Electric Utility	Yes
Flatonia Electric Department	Yes
Giddings Light & Power System	Yes
Hallettsville Municipal Utilities	Yes
Hearne Municipal Electric System	No
Hemphill City Government	Yes
Hempstead Electric Department	Yes
Jasper Light & Power System	Yes
Kirbyville Light & Power Company	Yes
La Grange Utilities	Yes
Lexington Municipal Electric Department	Yes
Liberty Municipal Electric System	Yes
Livingston Municipal Electric System	Yes
Moulton Electric Department	Yes
Newton Municipal Utilities	Yes
Robstown Utility System	Yes
San Augustine Light & Water Department	Yes
Schulenburg Utilities Department	Yes
Shiner City of	Yes
Timpson Light & Water Department	Yes
Weimar Electric Utilities	Yes
Yoakum Municipal Utilities	Yes
Water Utilities	
Aqua Texas	Yes
Texas Water Utilities LP	Yes
Quadvest LP	Yes
Undine Texas LLC	Yes
CSWR- Texas Utility Operating Company LLC	Yes
MSEC Enterprises	Yes
Corix Utilities Texas Inc.	Yes
T & W Water Service Company	Yes
Utilities Investment Companies Inc.	Yes
Crystal Springs Water	No
Nextera Water Texas LLC	Yes
Woodland Hills Water	Yes
C & R Water Supply Inc.	No
Midway Water Utilities Inc.	No
Orbit Systems	No
SRC Water Supply Inc.	No
Undine Texas Environmental LLC	No

Telecommunications Utilities	
Spectrum	Yes
AirCanopy Internet Services, Inc	No
Ameriphone Network, LLC	No
Astound Broadband	Yes
AT&T Texas	Yes
Cumby Telephone Cooperative	No
Gigamonster Network LLC	No
Nextlink Internet	Yes
South Texas Internet LLC	No

Acronyms

AEP	American Electric Power
CPD	Consumer Protection Division
CSWR	Central States Water Resources
EOP	Emergency Operations Plan
FTE	Full-Time Equivalent
ICS	Incident Command System
IOU	Investor-Owned Utility
MOU	Municipally Owned Utility
NESC	National Electric Safety Code
OCS	Operating Condition System
PGC	Power Generation Company
PURA	Public Utility Regulatory Act
PWS	Public Water System
REP	Retail Electric Provider
RFI	Request for Information
ROW	Right-of-Way
RUS	Rural Utilities Services
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TDU	Transmission and Distribution Utility
TEEEF	Temporary Emergency Electric Facilities
TNMP	Texas-New Mexico Power
TSP	Transmission Service Provider
TWC	Texas Water Code

Impacted Counties

Anderson
Angelina
Aransas
Austin
Bowie
Brazoria
Brazos
Burleson
Calhoun
Cameron
Camp
Cass
Chambers
Cherokee
Colorado
DeWitt
Fayette
Fort Bend
Freestone
Galveston
Goliad
Gregg
Grimes
Hardin
Harris
Harrison
Hidalgo
Houston
Jackson
Jasper
Jefferson
Kenedy
Kleberg
Lavaca

Lee
Leon
Liberty
Madison
Marion
Matagorda
Milam
Montgomery
Morris
Nacogdoches
Newton
Nueces
Orange
Panola
Polk
Refugio
Robertson
Rusk
Sabine
San Augustine
San Jacinto
San Patricio
Shelby
Trinity
Tyler
Upshur
Victoria
Walker
Waller
Washington
Webb
Wharton
Willacy

System Resiliency Plan Programs
Comparison of Docket 56548 vs Docket 57579

	CAPITAL			O&M			BCA			CMI		
Resiliency Measure	**56548**	**57579**	**Change**	**56548**	**57579**	**Change**	**56548**	**57579**	**Change**	**56548**	**57579**	**Change**
Extreme Wind												
Distribution Circuit Resiliency	312.8	513.4	200.6	-	-	-	7.0	12.1	5.1	137.4	263.0	125.6
Strategic Undergrounding	31.2	860.0	828.8	-	-	-	3.8	2.8	(1.0)	4.4	81.1	76.7
Restoration IGSD	53.8	107.3	53.5	0.8	0.5	(0.3)	15.7	19.3	3.6	58.1	97.0	38.9
Distribution Pole Replacement/Bracing	99.3	251.6	152.3	-	-	-	6.2	9.9	3.7	41.3	121.0	79.7
Vegetation Management	-	-	-	25.0	146.1	121.1	1.8	3.7	1.9	13.9	137.0	123.1
Transmission System Hardening	376.0	1,467.3	1,091.3	0.8	0.8	-	6.0	3.9	(2.1)	206.0	223.8	17.8
69kV Conversion Projects	268.4	369.3	100.9	-	-	-	1.9	2.7	0.8	46.8	65.5	18.7
S90 Tower Replacements	103.8	118.4	14.6	-	-	-	4.9	9.4	4.5	41.7	59.5	17.8
Coastal Resiliency Projects	259.0	177.4	(81.7)	0.8	0.8	-	1.4	2.0	0.6	21.9	7.8	(14.1)
	1,504.3	3,864.6	2,360.3	27.3	148.1	120.8				571.5	1,055.7	484.2
Extreme Water												
Substation Flood Control	30.6	43.8	13.2	-	-	-	7.5	2.1	(5.4)	14.2	3.9	(10.3)
Control Center Flood Control	7.0	7.0	-	-	-	-	12.5	15.2	2.7	6.1	2.5	(3.6)
MUCAMS	-	10.8	10.8	-	-	-	N/A	1.3	1.3	N/A	0.6	0.6
Mobile Substations	-	30.0	30.0	-	-	-	N/A	3.0	3.0	N/A	3.9	3.9
	37.6	91.6	54.0	-	-	-				20.3	11.0	(9.4)
Extreme Temperature (Freeze)												
Anti-Galloping Technologies	-	14.0	14.0	-	1.0	1.0	N/A	7.1	7.1	N/A	5.3	5.3
Loadshed IGSD	-	4.5	4.5	-	0.1	0.1	N/A	N/A	N/A	N/A	N/A	N/A
Microgrid Pilot Program	35.0	35.0	-	1.5	1.5	-	N/A	N/A	N/A	N/A	N/A	N/A
	35.0	53.5	18.5	1.5	2.6	1.1				-	5.3	5.3
Extreme Temperature (Heat)												
Distribution Capacity Enhancement/Substations	-	579.6	579.6	-	-	-	N/A	5.6	5.6	N/A	138.1	138.1
MUG Reconductor	-	245.0	245.0	-	-	-	N/A	1.4	1.4	N/A	13.6	13.6
URD Cable Modernization	-	128.4	128.4	-	-	-	N/A	2.2	2.2	N/A	13.0	13.0
Contamination Mitigation	-	144.0	144.0	-	6.0	6.0	N/A	2.4	2.4	N/A	15.7	15.7
Substation Fire Barriers	2.4	9.0	6.6	-	-	-	3.7	4.0	0.3	0.5	1.5	1.0
Digital Substation	25.0	31.8	6.8	(0.6)	-	0.6	1.9	1.8	(0.1)	1.3	1.2	(0.1)
Wildfire Advanced Analytics	18.7	-	(18.7)	6.0	0.9	(5.1)	N/A	N/A	N/A	N/A	N/A	N/A
Wildfire Strategic Undergroundng	79.2	50.0	(29.2)	-	-	-	N/A	N/A	N/A	N/A	N/A	N/A
Wildfire Vegetation Management	-	-	-	30.0	30.0	-	N/A	N/A	N/A	N/A	N/A	N/A
Wildfire IGSD	4.0	19.4	15.4	0.1	0.3	0.3	N/A	N/A	N/A	N/A	N/A	N/A
	129.3	1,207.2	1,077.9	35.5	37.2	1.8				1.8	183.1	181.3
Physical Attack												
Substation Physical Security Fencing	15.0	18.0	3.0	-	-	-	15.6	21.8	6.2	14.7	17.6	2.9
Substation Security Upgrades	19.5	19.4	(0.1)	0.1	0.1	0.0	19.9	28.7	8.8	25.1	25.1	-
	34.5	37.4	2.9	0.1	0.1	0.0				39.8	42.7	2.9
Technology & Cybersecurity												
Spectrum Acquisition	-	42.0	42.0	-	-	-	N/A	N/A	N/A	N/A	N/A	N/A
Data Center Modernization	2.9	12.7	9.8	0.2	1.3	1.0	N/A	N/A	N/A	N/A	N/A	N/A
Network Security & Vulnerability Management	1.0	7.5	6.5	-	2.0	2.0	N/A	N/A	N/A	N/A	N/A	N/A
IT/OT Cybersecurity Monitoring	22.5	13.4	(9.1)	-	4.2	4.2	N/A	N/A	N/A	N/A	N/A	N/A
Cloud Security, Product Security & Risk Management	-	4.0	4.0	-	6.0	6.0	N/A	N/A	N/A	N/A	N/A	N/A
	26.4	79.6	53.2	0.2	13.5	13.2				-	-	-
Situational Awareness												
Advanced Aerial Imagery/Digital Twin	9.9	18.4	8.5	0.1	2.0	2.0	3.4	4.8	1.4	0.8	10.8	10.0
Weather Stations	-	-	-	-	0.3	0.3	N/A	N/A	N/A	N/A	N/A	N/A
Wildfire Cameras	5.0	-	(5.0)	1.0	0.9	(0.1)	N/A	N/A	N/A	N/A	N/A	N/A
Backhaul Microwave Communication	12.1	12.7	0.6	-	-	-	N/A	N/A	N/A	N/A	N/A	N/A
Voice & Mobile Data Radio System	15.6	20.9	5.3	-	-	-	N/A	N/A	N/A	N/A	N/A	N/A
Emergency Operations Center	-	50.0	50.0	-	6.0	6.0	N/A	N/A	N/A	N/A	N/A	N/A
Hardened Service Centers	-	107.6	107.6	-	-	-	N/A	N/A	N/A	N/A	N/A	N/A
	42.6	209.5	167.0	1.1	9.2	8.2				0.8	10.8	10.0

System Resiliency Plan Programs
Comparison of Docket 56548 vs Docket 57579

	CAPITAL			O&M			BCA			CMI		
Resiliency Measure	**56548**	**57579**	**Change**	**56548**	**57579**	**Change**	**56548**	**57579**	**Change**	**56548**	**57579**	**Change**
Excluded												
TripSavers	58.9	-	(58.9)	0.0	-	(0.0)	61.3	N/A	N/A	240.3	N/A	N/A
Texas Medical Center Substation	102.0	-	(102.0)	0.2	-	(0.2)	0.7	N/A	N/A	4.9	N/A	N/A
Advanced Distribution Technology	225.8	-	(225.8)	15.0	-	(15.0)	4.8	N/A	N/A	61.1	N/A	N/A
Wildfire Other	30.3	-	(30.3)	6.6	-	(6.6)	N/A	N/A	N/A	N/A	N/A	N/A
	417.0	-	(417.0)	21.8	-	(15.2)				306.3	-	-
	$ 2,226.7	$ 5,543.3	$ 3,316.7	$ 87.4	$ 210.7	$ 129.8	6.6	5.0	(1.6)	940	1,309	674

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EXHIBIT 3

THE DIRECT TESTIMONY OF COMPANY WITNESS MR. DERYL TUMLINSON

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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

DERYL TUMLINSON

ON BEHALF OF

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC

JANUARY 2025

TABLE OF CONTENTS

TABLE OF EXHIBITS AND WORKPAPERS

Exhibit	**Description**
DT-1	Glossary of Acronyms

TABLE OF FIGURES