



2024 Grid Reliability and Resiliency Assessment for the ERCOT Region

December 2024

Executive Summary

The 2024 Grid Reliability and Resiliency Assessment (GRRRA) is the inaugural biennial report performed pursuant to the requirements established in 16 Texas Administrative Code (TAC) § 25.101(b)(3)(E). The Public Utility Commission of Texas (PUCT) adopted this rule in December 2022 to implement the requirements from Senate Bill (SB) 1281 (87th Legislature).

The 2024 GRRRA addresses ERCOT System transmission needs under extreme weather conditions for year 2029. The assessment considers the impact of different levels of thermal and renewable generation availability and the impact of potential outages caused by extreme weather conditions on customers, identifies areas of Texas within the ERCOT Region that face significant grid reliability and resiliency issues based on the scenarios studied, and proposes transmission projects to increase the grid's reliability or resiliency under such extreme weather conditions. ERCOT submitted Planning Guide Revision Request (PGRR) 117 to establish the resiliency criteria in the Planning Guide, which is currently proceeding through the stakeholder review process. The 2024 GRRRA uses the resiliency criteria to be established by PGRR117, which was supported by stakeholders, to identify the resiliency needs of the ERCOT System. The assessment identifies transmission projects that are necessary to:

1. Prevent cascading, instability, or uncontrolled islanding; and/or
2. Reduce the impact of outages on customers.

The 2024 GRRRA assesses the impacts of two extreme weather scenarios:

1. An extreme winter peak scenario that considers a weather condition similar to the 2021 Winter Storm Uri event but with the impacts of the PUCT's weatherization rules effective since then factored in; and
2. A hurricane scenario using information provided in Argonne National Laboratory's *2024 Hurricane Study for ERCOT* representing a worst-case scenario Category 5 hurricane making landfall near Houston.

The focus of the GRRRA is to study the impact of the extreme weather conditions on the ERCOT Transmission Grid. It is not intended to resolve any resource adequacy issues caused by such extreme weather conditions. If the studied extreme weather scenarios resulted in a deficit in generation to supply the forecasted system load, system load was reduced to achieve the balance between generation and load before the assessment was performed in order to limit the evaluation to the impacts of extreme weather conditions on the ERCOT Transmission Grid and not resource adequacy.

During the scenario development process, ERCOT engaged stakeholders at the Regional Planning Group (RPG) meetings to solicit feedback and comments on the assumptions to be used in the GRRRA. ERCOT also provided the detailed study results from the Argonne National Laboratory's *2024 Hurricane Study for ERCOT* to affected Transmission Service Providers (TSPs) to facilitate collaboration.

The key takeaways from the 2024 GRRR are as follows:

1. Additional transmission enhancements were found to be beneficial to increase the resiliency of the ERCOT Transmission Grid under both the extreme winter peak and hurricane scenarios studied.
2. Reinforcement of the 345-kilovolt (kV) transmission pathways from the Coast Weather Zone to Central Texas and the 345-kV pathways between South Dallas and Central Texas were found to be beneficial to increase the system resiliency under the extreme winter peak scenario. This reinforcement was also found to be needed for system reliability in the 2024 Regional Transmission Plan (RTP).
3. Substation hardening was found to have a critical role in increasing system resiliency under the hurricane scenario.
4. Though distribution hardening was out of the scope of this assessment, a more resilient distribution system was deemed crucial to increasing overall system resiliency under the hurricane scenario.

The transmission projects identified in the 2024 GRRR do not represent ERCOT's endorsement of those projects. As required by 16 TAC § 25.101(b)(3)(A)(iii)(I)-(IV), the PUCT will consider the following in determining whether to approve a transmission project on resiliency grounds:

- I. "the margin by which the transmission project was unable to demonstrate sufficient economic savings or reliability benefits to merit approval on those grounds";
- II. "whether the resiliency benefits the transmission project would provide by reducing the impacts to customers of potential outages caused by regional extreme weather scenarios are sufficient to compensate for the project's inability to demonstrate sufficient economic savings or reliability benefits to merit approval on those grounds";
- III. "the cost effectiveness of the transmission project's ability to address the resiliency issue identified by ERCOT compared to other possible solutions"; and
- IV. "other factors listed in PURA §37.056(c), as appropriate."

ERCOT intends to propose a Nodal Protocol Revision Request (NPRR) to address the process for determining whether a project that meets the proposed resiliency criteria provides sufficient benefit balanced with economic savings and/or reliability benefits, in accordance with 16 TAC § 25.101(b)(3)(A)(iii). This NPRR is currently under development and will be brought to the stakeholder process in 2025.

ERCOT will continue to work with stakeholders to identify areas of the state within the ERCOT Region that face significant grid reliability and resiliency issues for inclusion in the subsequent 2026 GRRR. ERCOT will start engaging stakeholders in the scenario development discussion in 2025 to identify the extreme weather conditions that may impose resiliency risks to the ERCOT System.

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1. Introduction

While the power industry is dealing with tremendous challenges brought by the fast-evolving grid on both the demand and supply side, the resiliency risks of the system under extreme weather conditions also became a focal point in recent years and triggered the discussion of the need for additional reliability criteria to help plan the system with these resiliency risks in mind. As stated in Federal Energy Regulatory Commission (FERC) Order No. 896,¹ “Extreme heat and cold weather events have occurred with greater frequency in recent years and are projected to occur with even greater frequency in the future.” The extreme weather conditions not only resulted in risk to life but also had significant economic impact. Based on the information provided by National Centers for Environmental Information (NCEI),² “Between 1980 and 2024, 66 Tropical Cyclone, 203 Severe Storm, 23 Wildfire, 24 Winter Storm, 44 Flooding, 31 Drought, and 9 Freeze billion-dollar disaster events affected the United States (CPI-adjusted).” It is important to review the existing reliability criteria to address any gaps under extreme weather conditions.

State and federal regulators introduced new rules and regulations designed to mitigate the impacts of extreme weather conditions on the electric system. At the state level, SB1281 (87th Legislature) introduced the requirement for ERCOT to conduct a biennial assessment of the ERCOT power grid’s reliability and resiliency under extreme weather conditions. The requirement was incorporated in 16 Texas Administrative Code § 25.101 as amended in December 2022. The goal of the assessment is to identify areas of the state within the ERCOT Region that face significant reliability and resiliency issues and recommend transmission projects that may increase the ERCOT Transmission Grid’s reliability or resiliency under extreme weather conditions. FERC issued Order No. 896 on June 15, 2023, to direct the North American Electric Reliability Corporation (NERC) “to develop a new or modified Reliability Standard no later than 18 months of the date of publication of this final rule in the Federal Register to address reliability concerns pertaining to transmission system planning for extreme heat and cold weather events that impact the Reliable Operation of the Bulk-Power System.” A new Reliability Standard, TPL-008-1, Transmission System Planning Performance Requirements for Extreme Temperature Events, is currently under development by NERC in response to FERC Order No. 896.

ERCOT submitted PGRR117 in 2024 to establish the resiliency criteria under extreme weather conditions and to incorporate the biennial Grid Reliability and Resiliency Assessment (GRRRA) into the Planning Guide. PGRR117 is currently going through the stakeholder process and has received stakeholder support. The 2024 GRRRA was performed based on the guidelines and criteria established in PGRR117. The extreme weather conditions included in the 2024 GRRRA were carefully selected to reflect the types of events that imposed significant risks to the ERCOT Region. An extreme winter peak scenario reflecting similar weather conditions to the 2021 Winter Storm Uri event and a hurricane scenario reflecting a worst-case Houston landfall Category 5 hurricane were selected for the 2024

¹ <https://www.ferc.gov/media/e-1-rm22-10-000>.

² <https://www.ncei.noaa.gov/access/billions/events>.

GRRA. The scenario selection and assumption development were shared with stakeholders through RPG meetings to solicit feedback and comments.

The study assumptions, study methodology, and study results are discussed in more details in the subsequent sections of this report.

2. Study Assumptions and Methodology

Steady state reliability analysis was performed in the 2024 GRRA to identify resiliency issues in both the extreme winter peak and hurricane scenarios. ERCOT utilized PowerWorld version 23 with Security Constrained Optimal Power Flow (SCOPF) to conduct the needed analysis in the 2024 GRRA. This section describes the study assumptions, the scenario development, and the criteria used to conduct the assessment. The detailed input assumptions can be found in Appendix A.

2.1. Study Assumptions

The 2029 summer peak final reliability case from the 2023 Regional Transmission Plan (RTP), posted to the Market Information System (MIS) Secure Site in December 2023, was used as the start case for the 2024 GRRA. The start case was then updated to incorporate additional Generation Resources and projects that were endorsed or accepted by RPG that were not in the start case as appropriate. Scenario-specific load forecast, generation dispatch assumptions, and weather-related outages were then incorporated to create the study cases for the two scenarios. More details are provided in the sections below.

2.1.1 Generation and Transmission Update

Based on the February 2024 *Generator Interconnection Status (GIS) Report*³ posted on the ERCOT website on March 1, 2024, generators that met the requirements established in paragraph (1) of the ERCOT Planning Guide Section 6.9, *Addition of Proposed Generation to the Planning Models*, were added to the study base case if not already present in the start case.

Since both scenarios were expected to have significant generation losses due to the extreme weather conditions, ERCOT took the following steps outside of the normal planning process to incorporate more generation into the planning model used in the 2024 GRRA to make up for any generation deficit in the sequence below.

1. Added all units with a signed Interconnection Agreement (IA).
2. Added all dispatchable units with a Full Interconnection Study (FIS) officially underway.

The same approach was also adopted in the 2024 RTP.

Transmission projects endorsed or accepted by RPG were also added to the study base case.

These generation additions and transmission projects are listed in the Appendix A.

2.1.2 Extreme Winter Peak Scenario Study Case

The extreme winter peak scenario was constructed to reflect a weather condition similar to the 2021 Winter Storm Uri event but with the consideration of the impacts of the various weatherization rules that became effective since then.

³ <https://www.ercot.com/misdownload/servlets/mirDownload?doclookupId=984866754>.

2.1.2.1 Load

The *ERCOT 2024 Long-Term Load Forecast (LTLF) Report* published in January 2024 included a February 2021 winter weather scenario that simulated the historical weather from the 2021 Winter Storm Uri event and reflected the economic growth in the ERCOT Region. The load forecast for the extreme winter peak scenario was based on the load forecast from this particular scenario.

The base load forecast was then updated to incorporate the additional loads adopted in the 2023 RTP. This included both the Permian Basin load forecast from the TSP-sponsored *2020 IHS Markit Study Report* and the large load additions approved for inclusion in the 2023 RTP based on load review results.

This scenario did not incorporate the additional large loads included in the 2024 RTP since the reliability projects needed to reliably supply the significant amount of large load additions had not been available at the time the 2024 GRRA was performed. Without the reliability projects in place, the assessment would not be able to distinguish between the reliability needs to serve the additional large loads and the resiliency needs brought by the extreme winter peak scenario.

The load forecast used in the extreme winter peak scenario by weather zone are included in Table 1 below. This load forecast does not include the self-serve load.

Table 1: Load by Weather Zone for the Extreme Winter Peak Scenario

East (MW)	Coast (MW)	North (MW)	North Central (MW)	Southern (MW)	South Central (MW)	West (MW)	Far West (MW)	Total (MW)
3,804	20,955	4,020	28,607	8,123	21,635	3,172	14,807	105,123

2.1.2.2 Generation Dispatch Assumptions

Renewable generation dispatch was set based on historical data analysis of un-curtailed renewable capacity during the top four peak load hours of the coldest day and two following days during Winter Storms Uri in 2021, Elliott in 2022, and Heather in 2024.

Battery dispatch was set based on historical data analysis of the state of charge during the top four peak load hours of the coldest day and two following days during Elliott and Heather. The 2021 Winter Storm Uri event was excluded because very limited battery capacity was installed at the time of that event. The capacity factors used for renewable and battery generation dispatch are shown in Table 2.

Table 2: Renewable and Battery Capacity Factors for the Extreme Winter Peak Scenario

Wind-Coastal	Wind-Panhandle	Wind-Other	Solar	Battery
40%	34%	24%	13%	25%

2.1.2.3 Capacity Loss Due to Winter Event

ERCOT reviewed historical data from various past winter events to develop the assumptions for extreme weather-related generation capacity losses for the 2024 GRRA extreme winter peak scenario.

Thermal generation capacity lost was based on historical data analysis of forced outage data submitted during the top four peak load hours of the coldest day and two following days during Winter Storms Uri in 2021, Elliott in 2022, and Heather in 2024. Winter Storms Elliott and Heather were included to capture the impacts of the weatherization rules effective since Winter Storm Uri. The lost capacity was distributed by both fuel type and weather zone as a derate. The total derate amounts are shown in Table 3.

Table 3: Thermal Generation Capacity Lost

	East (MW)	Coast (MW)	North (MW)	North Central (MW)	Southern (MW)	South Central (MW)	West (MW)	Far West (MW)	Total (MW)
Gas	464	2,028	253	2,434	465	1,077	78	387	7,186
Coal	320	989	0	398	391	187	0	0	2,285
Total	784	3,017	253	2,832	724	1,264	78	387	9,471

Renewable generation capacity lost was captured implicitly as part of the historical data analysis used to determine the actual capacity factors (CFs) as described in Section 2.1.2.2. An estimate of the capacity lost was calculated by comparing the actual capacity factors presented in Section 2.1.2.2 to the winter peak capacity factors from the *December 2023 Capacity, Demand, and Reserves (CDR) Report*.⁴ The estimated renewable generation capacity lost is shown in Table 4.

Table 4: Estimated Renewable Generation Capacity Lost

	Wind Coastal	Wind Panhandle	Wind Other	Solar	Total
CF - CDR	56%	37%	26%	14%	
CF - Actual	40%	34%	24%	13%	
Est. Lost Capacity (MW)	945	158	636	579	2,138

2.1.2.4 Load and Generation Balance

A deficit in generation to supply the forecasted system load was observed after the renewable and battery generation were dispatched, and the weather-related derate to thermal generation capacity

⁴ https://www.ercot.com/files/docs/2023/12/07/CapacityDemandandReservesReport_Dec2023.xlsx.

was applied. System load was reduced to achieve a balance between generation and load with a minimum reserve level of 1,500 MW. Crypto loads were turned off and large industrial loads were scaled down by 31% based on their behavior from historical data analysis. Table 5 shows the initial load and generation capacity as well as the amount of load reduced to achieve a final reserve level of 1,500 MW. Self-serve loads and private network generation were excluded from the values shown. The Capacity value includes 5,652 MW of capacity from battery dispatch. As battery charge is depleted the reserves value will decrease which may result in a need for additional load reduction.

Table 5: Load and Generation Balance

	Load (MW)	Load + Losses (MW)	Capacity (MW)	Reserves (MW)
Initial	105,123	107,857	100,078	-7,779
Crypto Load Reduction	6,332			
Industrial Load Reduction	2,725			
Final	96,066	98,564	100,078	1,514

2.1.3 Hurricane Scenario Study Case

Hurricane impact on the ERCOT System varies based on the location of landfall. The Argonne National Laboratory *2024 Hurricane Study for ERCOT* assessed the impacts of three worst-case hurricane scenarios and nine historical hurricanes with landfalls in different areas along the Gulf of Mexico.⁵ ERCOT selected the worst-case Houston landfall scenario in the 2024 GRRA since this scenario was expected to cause more significant generation and transmission outages based on the study results. Other scenarios and historical hurricanes assessed in the Argonne National Laboratory study can be future candidates for a subsequent GRRA.

2.1.3.1 Load

Apart from the Coastal Weather Zone, the weather zone load levels in the case remained unchanged from the 2023 RTP final 2029 summer peak reliability case, used as the starting case for this study, which utilized the “bounded-higher-of” methodology to determine appropriate weather zone load levels. The details of this methodology can be found in ERCOT Planning Guide Section 3.1.7, *Steady State Transmission Planning Load Forecast*. The Coastal Weather Zone load level was updated to represent weather-related damages and to reflect post-hurricane load recovery based on historical data. Table 6 shows the final weather zone load levels used in the hurricane scenario. The values do not include self-serve load.

⁵https://www.ercot.com/files/docs/2024/08/12/ANL%20Potential%20Severe%20Weather%20Event%20Study_08132024RPG%20meeting.pdf.

Table 6: Load by Weather Zone for the Hurricane Scenario

East (MW)	Coast (MW)	North (MW)	North Central (MW)	Southern (MW)	South Central (MW)	West (MW)	Far West (MW)	Total (MW)
3,476	23,236	5,501	32,449	7,724	18,225	3,489	14,821	108,920

2.1.3.2 Generation Dispatch Assumptions

Renewable generation dispatch was set based on the *December 2023 CDR Report's* wind and solar summer peak capacity factors.

Battery dispatch was set based on the methodology described in note [3] on the “Peak v High Net Load Hour 2024” tab of the *December 2023 CDR Report*.

The capacity factors used for renewable generation and battery energy storage are shown in Table 7.

Table 7: Renewable and Battery Capacity Factors for Hurricane Scenario

Wind-Coastal	Wind-Panhandle	Wind-Other	Solar	Battery
60%	29%	22%	76%	20%

2.1.3.3 Outages

Argonne National Laboratory's *2024 Hurricane Study for ERCOT* was used to determine the weather-related equipment outages. The outages in the report had various estimated repair times, these times can be seen in Table 8 below.

Table 8: Repair Time by Equipment Type and Damage Level⁶

Asset	Equipment	Slight/Minor	Moderate	Substantial / Severe	Complete
Generator	Gas Turbine	2 days	4 days	18 days	6 weeks
Generator	Coal Fired Power Plant	3 days	6 days	25 days	8 weeks
Generator	Wind Turbine Farm	1 – 5 days	3 – 15 days	5 – 7 weeks	2 – 6 months
Generator	Solar PV Farm	1 – 5 days	1 week	6 – 8 weeks	5 – 6 months
Generator	Nuclear Power Plant	1 – 2 weeks	2 – 3 weeks	3 – 4 weeks	> 1 year
Bus	Substation (Bus)	1 day	3 days	7 days	1 month

⁶ The information was provided in the Argonne National Laboratory *2024 Hurricane Study for ERCOT* report.

To study the greatest impact to reliability and resiliency, ERCOT chose to study the timeframe during the recovery period that had the greatest number of simultaneous outages along with the highest load in the ERCOT Region impacted by the storm. As a result, only outages on equipment reported as being substantially, severely, or completely damaged and expected to be out for significant amount of time were considered, Table 9 shows the total number of transmission element outages applied by voltage level and Table 10 shows the total amount of load and generation capacity lost due to damages.

Table 9: Number of Transmission Outages Applied

345 kV	138 kV	69 kV	345/138 kV	Total
2	141	6	4	153

Table 10: Total Amount of Load and Generation Capacity Lost

Load (MW)	Capacity (MW)
2,240	4,468

As a comparison to the recent 2024 Hurricane Beryl, Table 11 shows the total number of transmission outages experienced during Beryl and the total number of outages on equipment with any damage level reported for the hurricane studied in the 2024 GRRA. Of the outages listed, Beryl only had two 138-kV line outages during the same recovery period as the hurricane studied in the 2024 GRRA.

Table 11: Beryl Vs. GRRA Hurricane Total Transmission Outage Count

Hurricane	345 kV	138 kV	69 kV	138/69 kV	345/138 kV	Total
GRRA	10	199	15	1	9	234
Beryl	5	80	42	0	0	127

2.2. Study Methodology and Criteria

Consistent with the criteria proposed by PGRR117, the 2024 GRRA evaluated the post-contingency performance of the ERCOT System under the extreme weather scenarios for the following contingency events:

- P0, P1, and P2.1 contingencies as defined in the NERC Reliability Standard; and
- Common tower outages as defined in the ERCOT Planning Guide Section 4.1.1.1, Planning Assumptions.

ERCOT then performed cascading analysis and load loss analysis to identify transmission projects that were necessary to:

- Prevent cascading, instability, or uncontrolled islanding; and/or

- Reduce the impact of outages on customers.

2.2.1 Cascading Analysis

Cascading analysis was performed to identify events that had a potential to create cascading conditions. The cascading analysis included a full AC contingency analysis that solved load flow, monitored system elements, tripped system elements exceeding the equipment's tripping threshold, and monitored loss of load. Equipment trip settings were defined as the lower of 125% of their emergency rating or the relay loadability limits as provided by TSPs. If such ratings were not available from the TSPs, or the ratings were lower than the emergency rating of the equipment, a default limit of 125% of the equipment's emergency rating was used. Under Voltage Load Shed (UVLS) from TSPs and generator over and under voltage trip settings from Resource Registration data were modeled where applicable. Default values were used if generator over or under voltage trip settings were unavailable. The default values were determined as follows:

- For renewable generators: 0.9 pu and 1.1 pu for under-voltage and over-voltage trip settings, respectively
- For all other generators: post-contingency voltage limits

This process was repeated for several iterations (cascade levels) by removing transmission elements which exceeded their trip settings until either there were no more transmission elements outside of their thresholds or until the load flow did not converge.

Transmission projects were identified for any studied planning event that resulted in potential cascading.

2.2.2 Load Loss Analysis

Besides preventing cascading, instability, or uncontrolled islanding from occurring, the 2024 GRRA also performed analyses to identify transmission projects that will help reduce the impact of outages on customers. The analyses consisted of the following two parts:

1. Identified load losses as a direct outcome of the transmission outages caused by the extreme weather conditions (consequential load loss).
2. Identified load losses that were required to maintain system reliability but were not the direct result of transmission outages caused by the extreme weather conditions (non-consequential load loss).

The 2024 GRRA focused on transmission projects that can address non-consequential load losses greater than or equal to 100 MW and solutions that can reduce the consequential load losses.

3. Study Findings

3.1. Study Findings from the Extreme Winter Peak Scenario

The extreme winter peak scenario was designed to reflect a weather condition similar to the 2021 Winter Storm Uri event. The load forecast for year 2029 from the February 2021 winter weather scenario in the ERCOT 2024 LTLF published in January 2024 was used as the base forecast for the 2024 GRRRA extreme winter peak scenario. The base load forecast was then updated to incorporate the Permian Basin load forecast and the large load additions adopted by the 2023 Regional Transmission Plan (RTP).

Generation outages caused by the extreme winter weather conditions were incorporated into the scenario and the impacts of the weatherization rules were accounted for. Transmission outages were not modeled because historical data analysis revealed no significant transmission outages during the winter event.

Since this assessment was not intended to resolve resource adequacy issues caused by the extreme weather event, system load was reduced to make up for the generation deficit created by generation outages as described in Section 2.1.2.4 of this report.

The weather pattern in 2021 had some unique characteristics. The 2029 load forecast based on the 2021 weather pattern showed that ERCOT's annual peak will be in February and most of the weather zones except for the Coast and North weather zones will have their peak load in February as well. The South Central Weather Zone is impacted the most with the forecasted 2029 winter peak load under the 2021 weather condition being almost 5,000 MW higher than the forecasted summer peak for the same year. The North Central Weather Zone also shows a significantly higher load forecast for winter than summer with a magnitude of just under 3,000 MW. Temperature data for the three largest load centers (Dallas-Fort Worth (DFW), Austin, and Houston) during the 2021 Winter Storm Uri event provides insight into this shift in peak demand. The temperature data for these three load centers are shown in Figure 1 below.⁷ Austin (South Central Weather Zone) and DFW (North Central Weather Zone) had a significantly higher number of consecutive hours below or at freezing and experienced lower temperatures overall during the event than Houston (Coast Weather Zone).

⁷ https://www.ercot.com/files/docs/2021/03/03/Texas_Legislature_Hearings_2-25-2021.pdf.

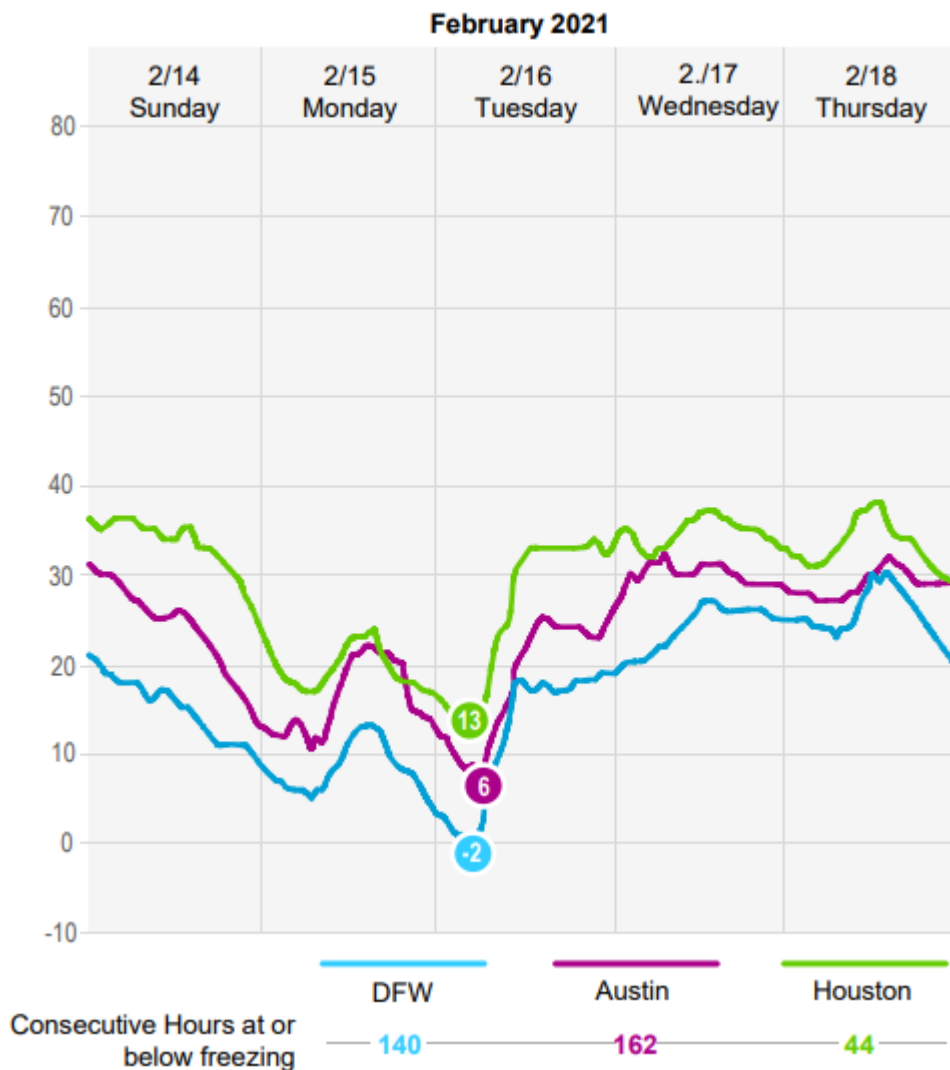


Figure 1: Winter Storm Uri Temperatures in the Austin, DFW, and Houston Areas

North Central and South Central weather zones were found to have greater need for imports due to their high load forecasts and significant generation capacity losses based on assumptions adopted by the extreme winter peak scenario.

The simulation showed elevated stress on the 345-kV pathways from Coast to Central Texas and the 345-kV pathways from South Dallas to Central Texas under the studied planning event due to forecasted load and assumed generation losses. The reliability violations did not cause any potential cascading risks or instability, but non-consequential load losses were needed to maintain system reliability. Transmission solutions were identified to mitigate any planning event that needed 100 MW or more of non-consequential load losses to reduce the impact of outages on customers. The majority of transmission solutions identified by the 2024 GRRA were also identified in the 2024 RTP, which focused on addressing the challenges associated with the unprecedented amount of large loads seeking interconnection to the ERCOT System. The noteworthy transmission solutions identified for the extreme winter peak scenario are summarized below:

- Knob Creek Switch (3413) to Salado Switch (3699) 345-kV line upgrade
- Bell East (3687) to Salado (3699) 345-kV line addition
- Lake Creek SES (3409) to Temple Pecan Creek (3412) 345-kV line upgrades
- Old Hickory (5323) 345-kV Substation and 345-kV line additions
- Shaula (5380) to Elm Creek (5133) to Cachena (5068) 345-kV line upgrades
- Hillje (44200) to Bottom Grass POI (888870) 345-kV line upgrade

These noteworthy transmission solutions were also identified in the 2024 RTP 345-kV plan. The 2024 RTP 765-kV plan, however, was able to avoid some of these 345-kV solutions with the incorporation of the 765-kV additions. Since the 2024 RTP 765-kV plan was still under development at the time the 2024 GRRA was performed, the 765-kV additions were not studied in the 2024 GRRA. Nonetheless, the 765-kV addition is expected to decrease the number of 345-kV mitigations identified in the extreme winter peak scenario given that both the 2024 GRRA and 2024 RTP identified similar stress on the import pathways to Central Texas.

The detailed project list can be found in Appendix B.

3.2. Study Findings from the Hurricane Scenario

Tropical storms and hurricanes occur annually in the Gulf of Mexico and cost Texas many billions of dollars in damages. Preventing cascading, instability, or uncontrolled islanding, and reducing the impact of outages on customers are all crucial for the resiliency of the ERCOT System. ERCOT engaged Argonne National Laboratory in late 2023 to perform a hurricane impact study. The study analyzed the impacts of nine historical hurricanes and three worst-case scenario hurricanes on the ERCOT electric system. The 2024 GRRA created the hurricane scenario based on the study results from the worst-case Houston hurricane scenario. The Houston scenario was based on the Great Galveston Storm of 1900, which is the deadliest natural disaster in the United States history. The original storm intensity was increased from Category 4 to 5 and the storm track was shifted about 15 miles north to create the Houston scenario. The Houston scenario was simulated with the following storm characteristics:

- Wind speed (mph): 160
- Barometric pressure (mbar): 915
- Storm surge (ft): 22+

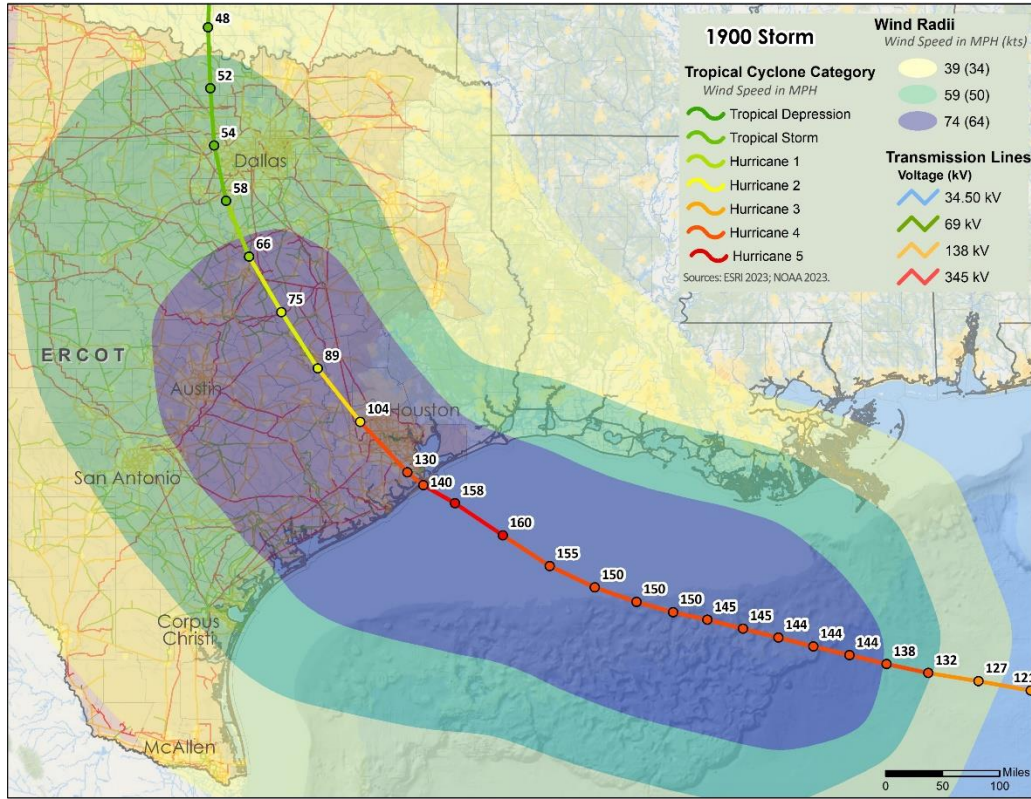


Figure 2: Worst-Case Houston Hurricane Scenario

The Argonne National Laboratory simulation results showed that the Houston hurricane scenario was expected to cause significant generation and substation outages due to storm surge. The most impacted area was the region around Galveston and Texas City. While some damages could be repaired in days, others could take weeks, months, or years to repair.

The recovery of the electric system post hurricane may experience a few stages:

- Most transmission and distribution damages have not been repaired yet and area load is low due to service interruption from damages and evacuation (a few days after hurricane).
- Slight/minor and moderate damages have been repaired and electric services are mostly restored (a week or more after hurricane).
- All damages have been repaired and the electric system is back to normal operation.

The 2024 GRRRA focused on the time period when slight/minor and moderate damages have been repaired and electric services are mostly restored. The study results showed that there were potential cascading risks under certain studied planning event. Transmission solutions were identified to mitigate the cascading risks. In addition, a list of substations was identified as crucial to reduce the impacts of outages on customers including due to the direct impact of the hurricane. Hardening of those substations are beneficial if they are not hardened yet. The noteworthy transmission solutions identified for the hurricane scenario are summarized below:

- PH Robinson, Fairmont, Webster Substation Hardening
- Galveston Island Substations Hardening

The detailed study results can be found in Appendix B.

ERCOT also reviewed the system condition where most transmission and distribution damages have not been repaired yet and area load is low due to service interruption from damages and evacuation. Historical data analysis showed that the load in the affected area typically follows a slow recovery process post hurricane and it may be as low as 30% of the peak load level after the slight/minor damages were repaired. It might be attributed to the needed repair time for the damages in the distribution system. The system may experience high voltages that makes operating the system more challenging during this period. While the hardening of the transmission system is critical to ensure system resiliency under hurricane conditions, hardening of the distribution system is equally important to reduce the impact of outages on customers and mitigate operational challenges due to high voltage. Dynamic reactive power support devices would help manage the high voltage issues experienced during this period, but the hardening of the distribution system would fundamentally improve system resiliency.

As illustrated in Table 8, *Repair Time by Equipment Type and Damage Level*, in Section 2.1.3.3, the severe or substantial damages of generators take weeks or months longer than transmission damages to repair, this may result in resource adequacy issues in the Houston area during this recovery period following the hurricane. This particular recovery period was not included in the 2024 GRRRA. The 765-kV plan considered in the 2024 RTP was not available for inclusion in the 2024 GRRRA, but 765-kV connections to the Houston area may help mitigate issues during this recovery period following the hurricane.

Appendices

Index	Description	Document	Access
A	Input assumptions for the 2024 GRRR reliability analysis	Appendix_A_2024_GRRR_Input_Assumptions.xlsx	Public
B	2024 GRRR resiliency projects	Appendix_B_2024_GRRR_Resiliency_Projects.xlsx	Public