Appendix A – Resource Adequacy Detailed Analysis

A. Generator Performance Background (from NERC GADS and GADS-Wind)

For this analysis, generation performance data is based on required reports submitted in the Generation Availability Data System (GADS) and GADS-Wind systems under NERC Section 1600 of the Rules of Procedure. The number of generators reporting ERCOT GADS and GADS-Wind data is shown in the following tables.

Units Reporting	2021	2022	2023	2024	2025
Total	458	471	483	490	505
Coal/Lignite	19	19	19	19	19
Gas	40	40	37	36	36
Nuclear	4	4	4	4	4
Gas Turbine/Jet Engine	109	122	134	142	146
Reciprocating Engine	42	42	42	42	52
Hydro	8	8	8	8	12
Fluidized Bed	5	5	5	3	3
Combined Cycle (Block)	18	18	18	18	17
Combined Cycle GT	149	149	151	153	152
Combined Cycle ST	61	61	62	62	61
Other	3	3	1	3	3
Total Thermal MW Reporting	78,549	79,562	79,983	82,747	83,118
Total Thermal GWh Reporting	298,155	312,787	323,091	335,956	329,948
Wind Subgroups (>200 MW)	64	70	72	74	69
Wind Subgroups (100<MW<200)	76	81	82	87	86
Wind Subgroups (< 100 MW)	118	110	112	119	128
Number of Wind Turbines	15,282	15,865	15,951	16,654	15,509
Total Wind MW Reporting	31,651	33,683	34,052	35,977	35,040
Total Wind GWH Reporting	82,557	92,891	94,915	98,096	103,597
Solar Subgroups (>200 MW)				14	16
Solar Subgroups (100<MW<200)				12	16
Solar Subgroups (< 100 MW)				52	117
Number of Inverters				9,056	12,609
Total Solar MW Reporting				15,662	25,821
Total Solar GWH Reporting				22,760	43,459

Table A.1 – 2021-2025 GADS, GADS-Wind, and GADS-Solar Units Reporting

B. Analysis of Planned versus Actual Seasonal Operating Reserves

For the summer of 2025, peak hourly demand was 83,876 MW on August 18, 2025, approximately 2,476 MW higher than the 50/50 demand scenario estimate of 81.4 GW and 1,845 MW lower than the 90/10 demand scenario estimate from ERCOT's August 2025 Monthly Outlook for Resource reserves were maintained during the summer peak hours.

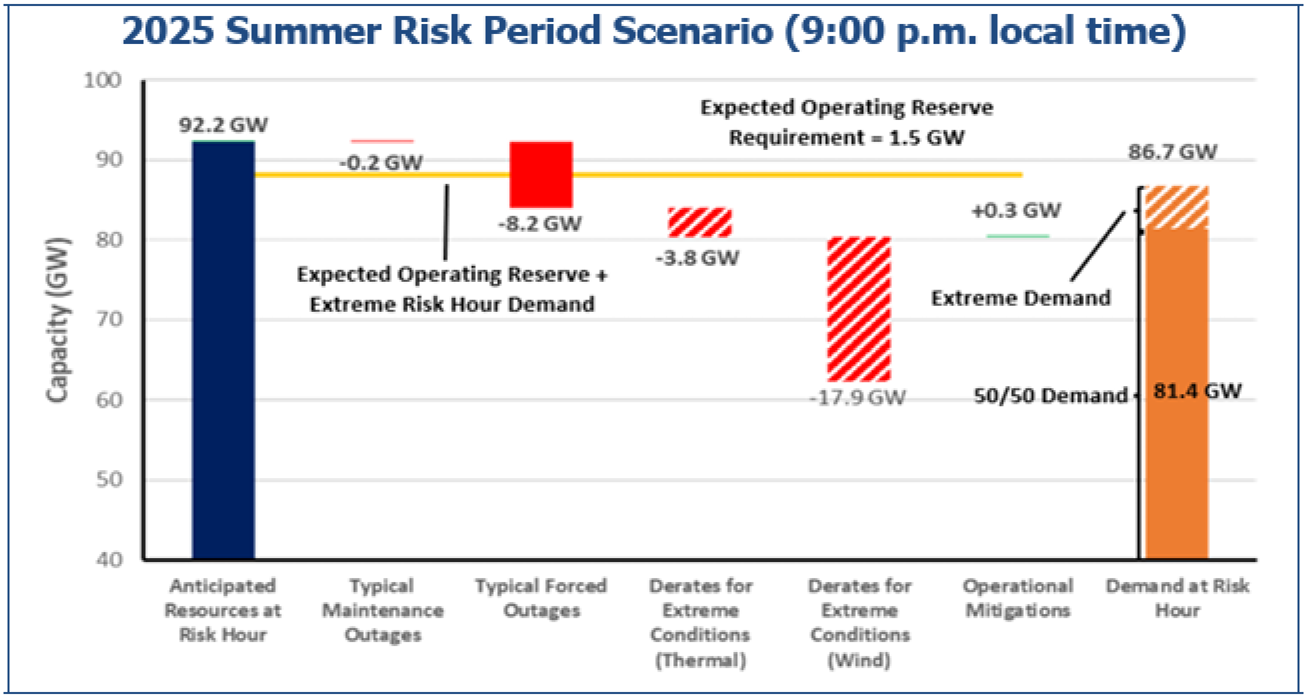


Figure A.1 – Summer 2025 Risk Scenarios

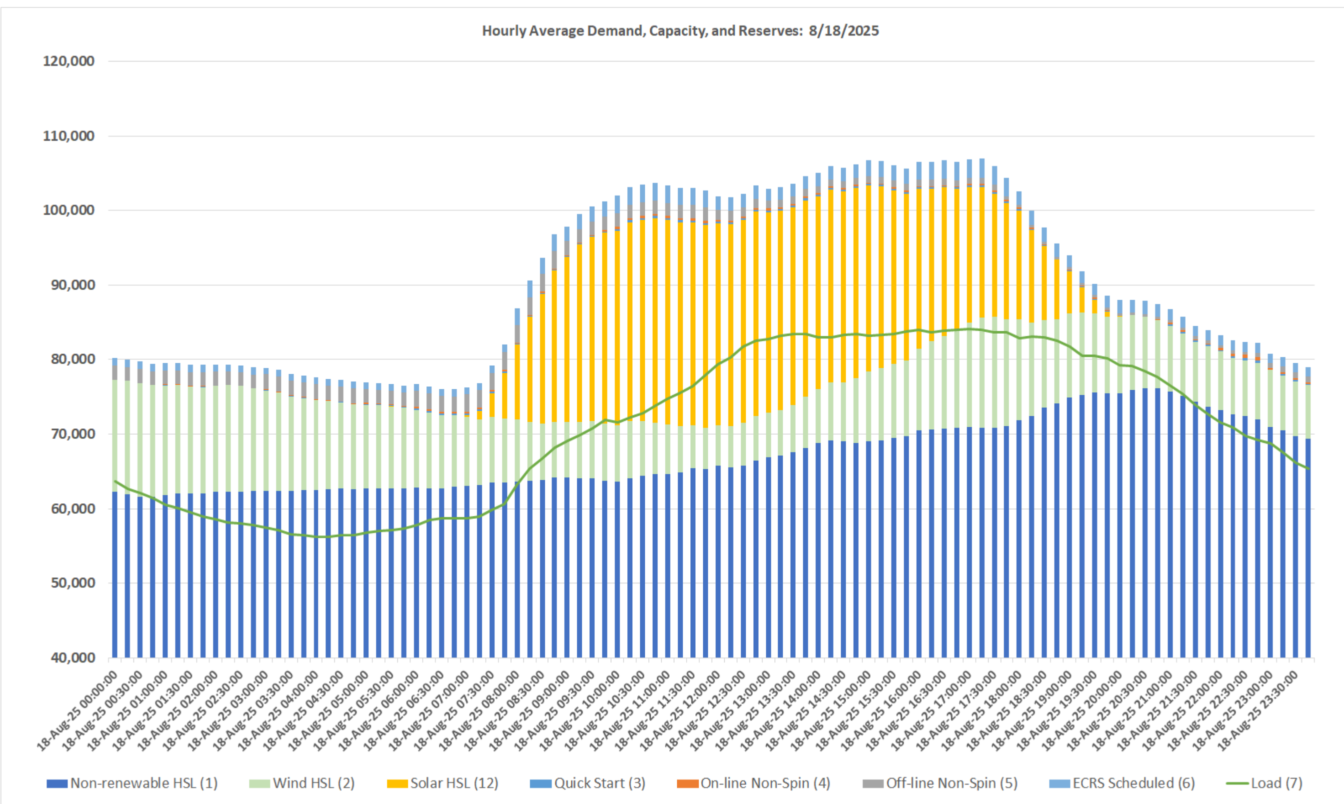


Figure A.2 – August 18, 2025, Capacity, Demand, and Reserves

The August 2025 ERCOT MORA estimated typical thermal maintenance outages of 131 MW and typical forced outages of 5,469 MW with an extreme case of 10,083 MW. Combined actual planned and forced thermal outages for summer 2025 ranged from a low of 8,472, MW to a maximum of 19,699 MW.

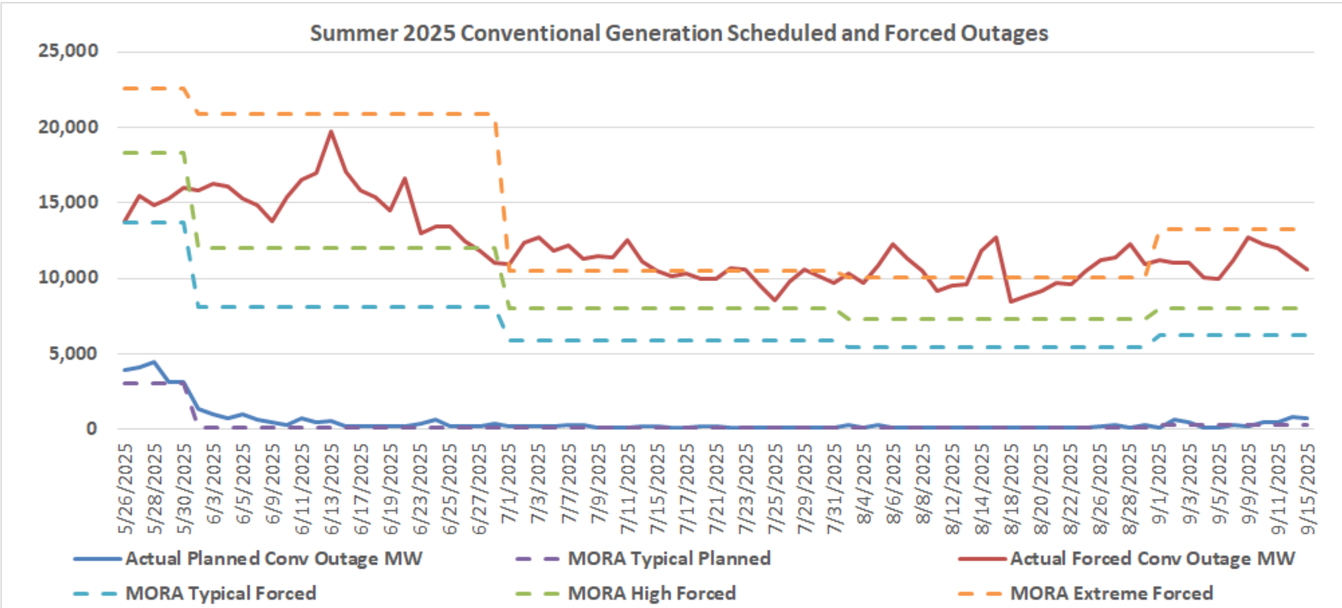


Figure A.3 – Summer 2025 Generation Scheduled and Forced Outages

For winter 2024-2025, peak hourly demand was 80,376 MW on February 20, 2025, approximately 2,493 MW higher than the typical load scenario estimate of 77,883 MW from the winter monthly assessment of resource adequacy (MORA), and approximately 10,834 MW less than the extreme load estimate. Actual reserve margin was approximately 9.9 percent. Sufficient operating reserves were maintained during the winter peak hours.

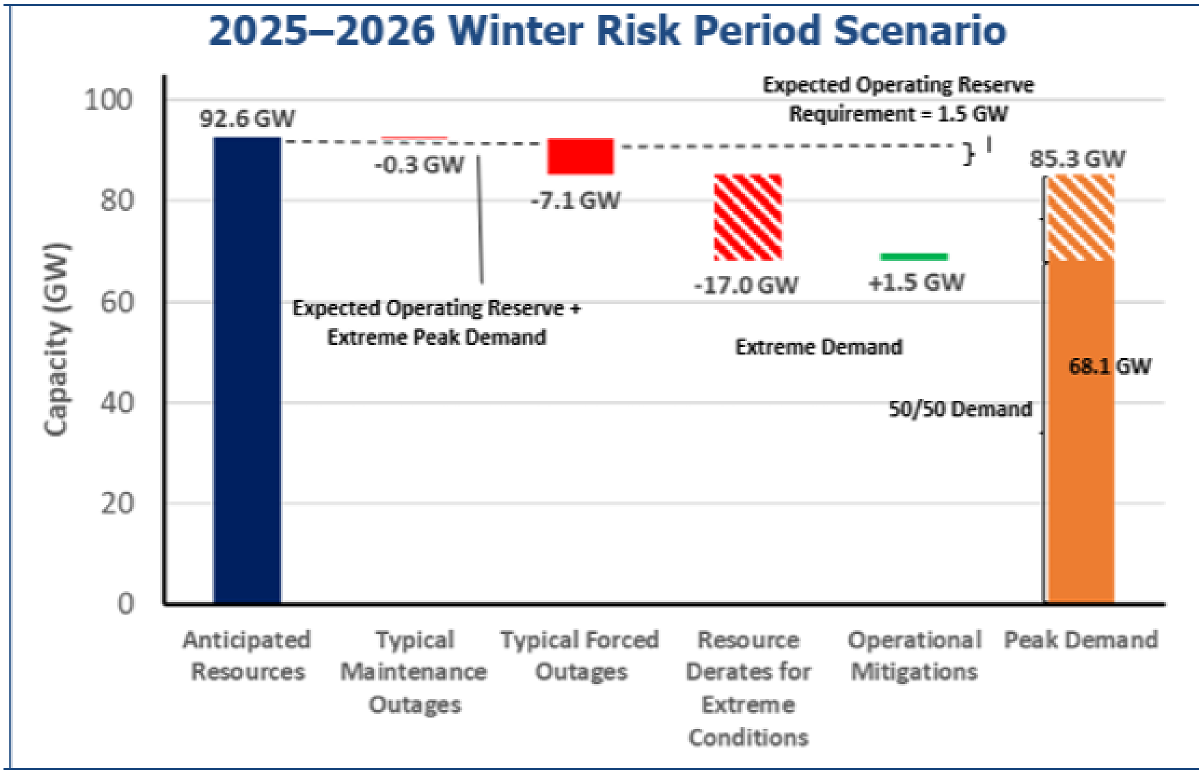


Figure A.4 – Winter 2025-2026 Risk Scenarios

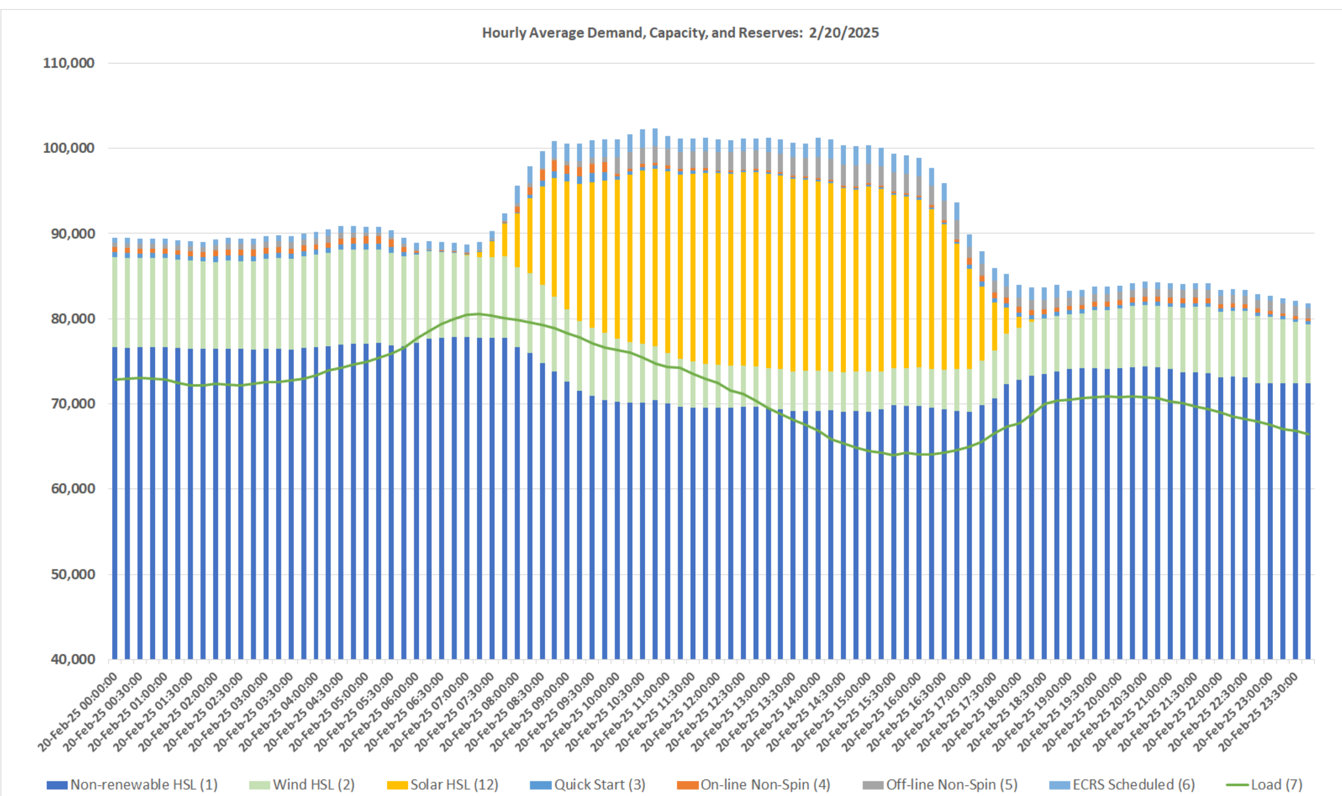


Figure A.5 – February 20, 2025, Capacity, Demand, and Reserves

The ERCOT MORA for winter 2024-2025 estimated typical thermal maintenance outages of 331 and 789 MW for January and February, respectively. Typical estimated forced outages were 16,259 and 12,457 for January and February, respectively. An extreme forced outage scenario of 23,256 MW was used. Combined actual planned and forced outages for the winter ranged from a low of 5,622 MW to a maximum of 15,921 MW.

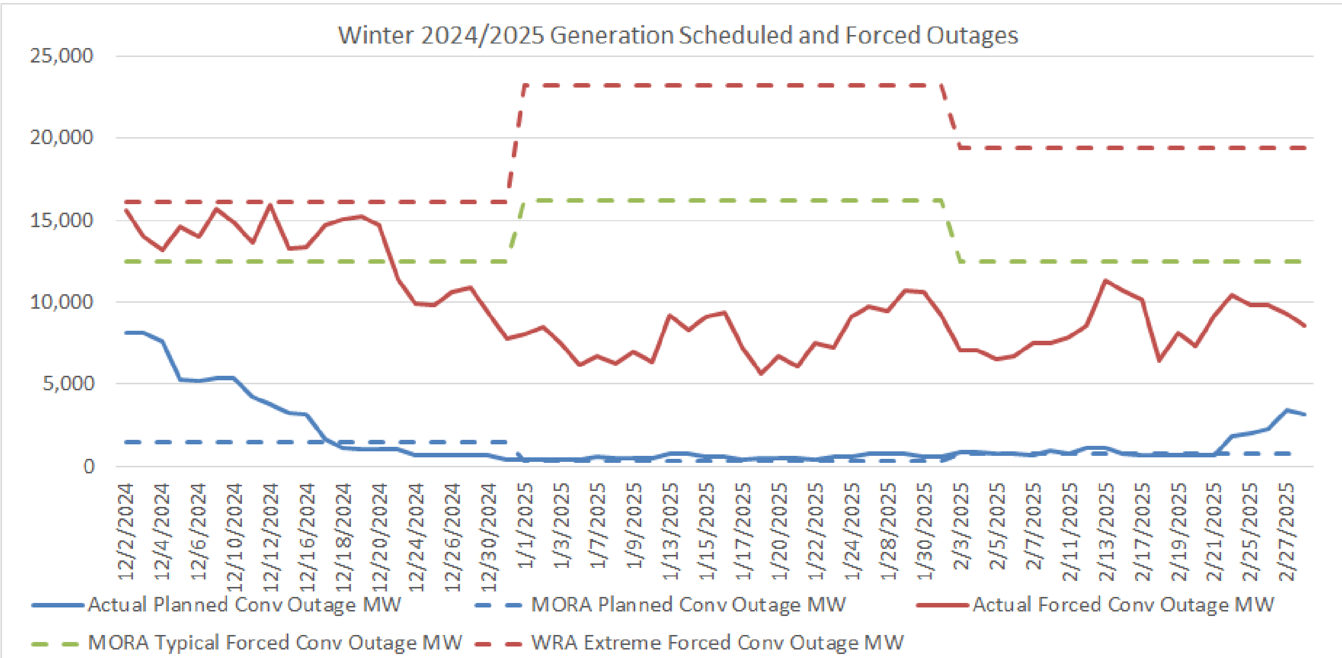


Figure A.6 – Winter 2024-2025 Generation Scheduled and Forced Outages

C. Primary Frequency Response

Primary frequency response is defined as the immediate proportional increase or decrease in real power output provided by generating units/generating facilities and the natural real power dampening response provided by load in response to system Frequency Deviations. This response is in the direction that stabilizes frequency. Figure A.7 shows a typical frequency disturbance broken down into four periods.

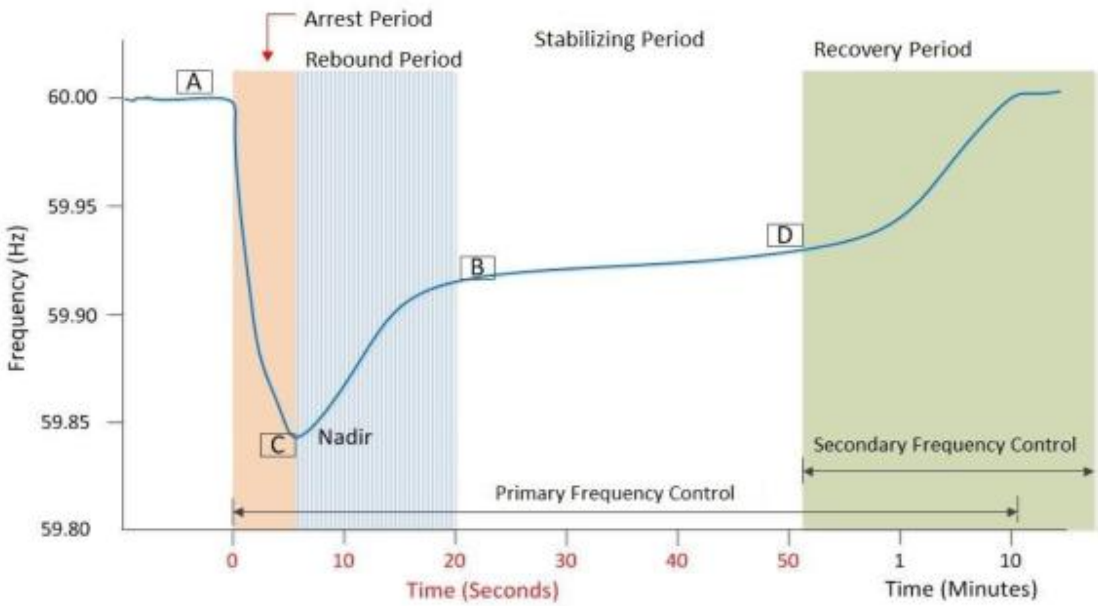


Figure A.7 – Typical Frequency Disturbance

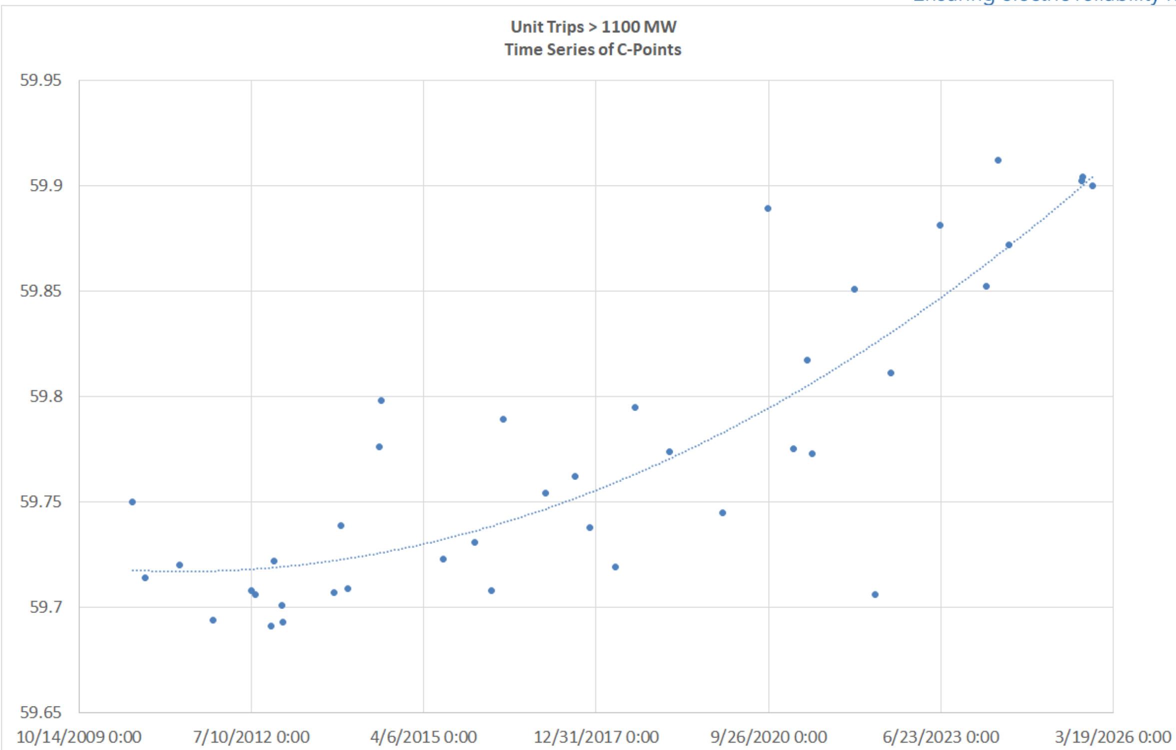
Each of the periods of the frequency disturbance is analyzed by different metrics and performance indicators. Two of the key performance indicators are based on requirements in the BAL-002 and BAL-003 Standards. These are recovery of the Area Control Error (ACE) within 15 minutes following a Reportable Balancing Contingency Event and maintaining the Interconnection frequency response at or above the Interconnection Frequency Response Obligation (IFRO).

Period	Time Frame	Reliability Requirement	Metric(s)
Arrest Period	T0 to T+6 seconds	Arrest C-point at or above 59.3 Hz for loss of 2750 MW (BAL-003)	- RoCoF/MW Loss - T0 to Tc - Nadir Frequency Margin
Rebound/Stabilizing Period	T+6 to T+60 seconds	Achieve Interconnection frequency response at or above IFRO (412 MW per 0.1 Hz) (BAL-003)	- Primary Frequency Response
Recovery Period	T+1 to T+15 minutes	Recover ACE within 15 minutes (BAL-002)	- Event recovery time

Table A.2 – Frequency Event Requirements and Metrics

Rotating turbine generators and motors synchronously interconnected to the system store kinetic energy during contingency events that is released to the system (also called inertial response). Inertial response provides an important contribution in the initial moments following a generation or load trip event and determines the initial rate of change of frequency (RoCoF). Kinetic energy will automatically be extracted from the rotating synchronized machines on the interconnection in response to a sudden loss of generation, causing them to slow down and frequency to decline. The amount of inertia depends on the number and size of generators and motors synchronized to the system, and it determines the rate of frequency decline. Greater inertia reduces the rate of change of frequency, giving more time for primary frequency response to fully deploy and arrest frequency decay above under-frequency load shed set points. Therefore, with potential wide variations in inertia conditions with increasing use of IBRs, there is a need to monitor and trend inertia and RoCoF.

The nadir, or C-Point frequency, is an indicator of the system imbalance created by the unit trip and is a combination of synchronous inertial response and governor response. Normalizing the unit MW loss by inertia can provide insight into how the nadir can vary under different inertia conditions for the same MW loss value. Figure A.8 shows the two graphs. The first graph is a time-based trend showing how nadir frequencies for large unit trips (> 1100 MW) are improving (increasing) over time. The second graph shows the nadir frequencies plotted against the generation MW loss value normalized for inertia and shows the inverse relationship between historic performance for how the nadir was affected by different MW loss and inertia conditions. The second graph shows a comparison of three periods: 2016-2018, 2020-2021, and 2023-2025. The graph corroborates the time-based graph and shows how nadir frequencies are improving over time versus the normalized MW values.



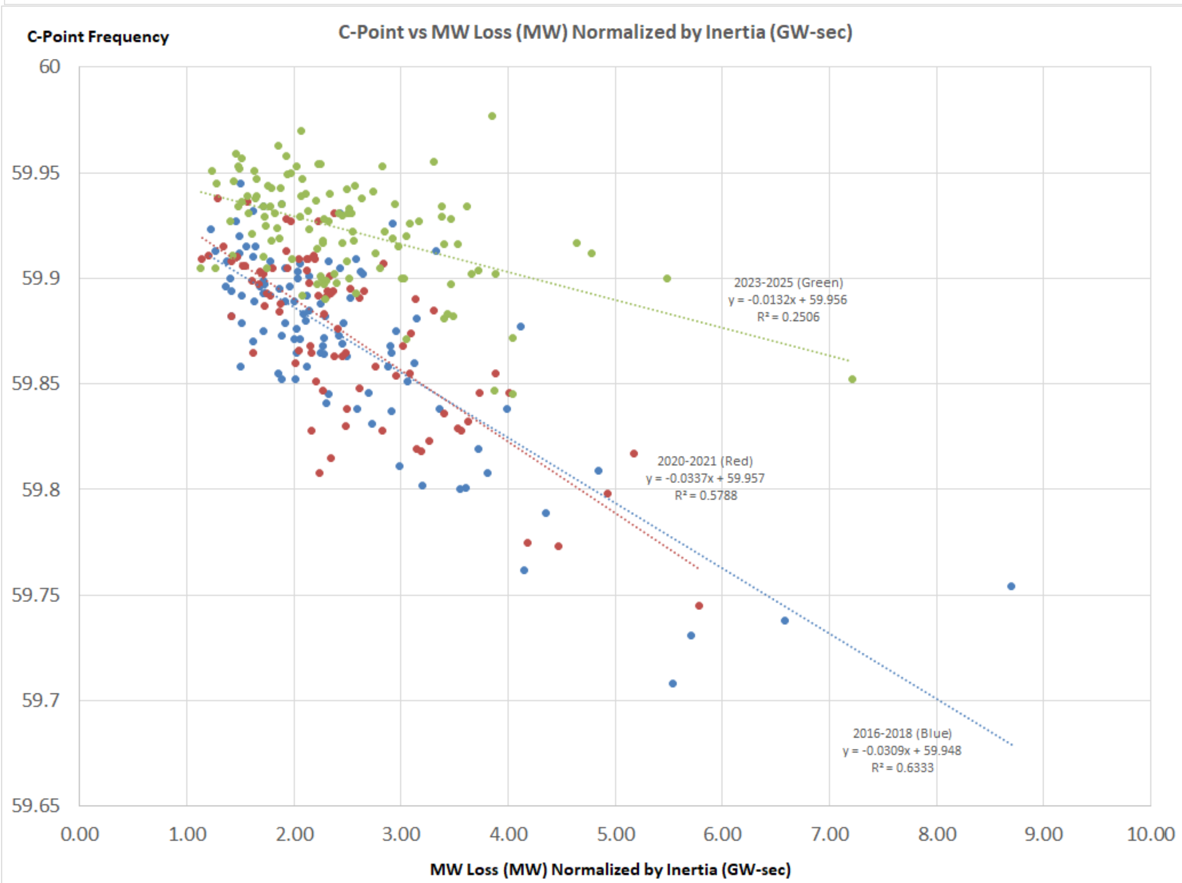


Figure A.8 – Frequency Disturbance Nadir versus Time and Gen Loss MW/Inertia

The RoCoF during the initial frequency decline in the first 0.5 sec is driven by system inertia; therefore, it is prudent to use the same analysis technique to plot the RoCoF against the generation MW loss normalized by system inertia. Figure A.9 shows this relationship, with a straight-line approximation. The graph shows a comparison of three periods: 2016-2018, 2020-2021, and 2023-2025. The slopes of the regression lines for the three periods indicate there are minimal changes in the RoCoF rates over time.

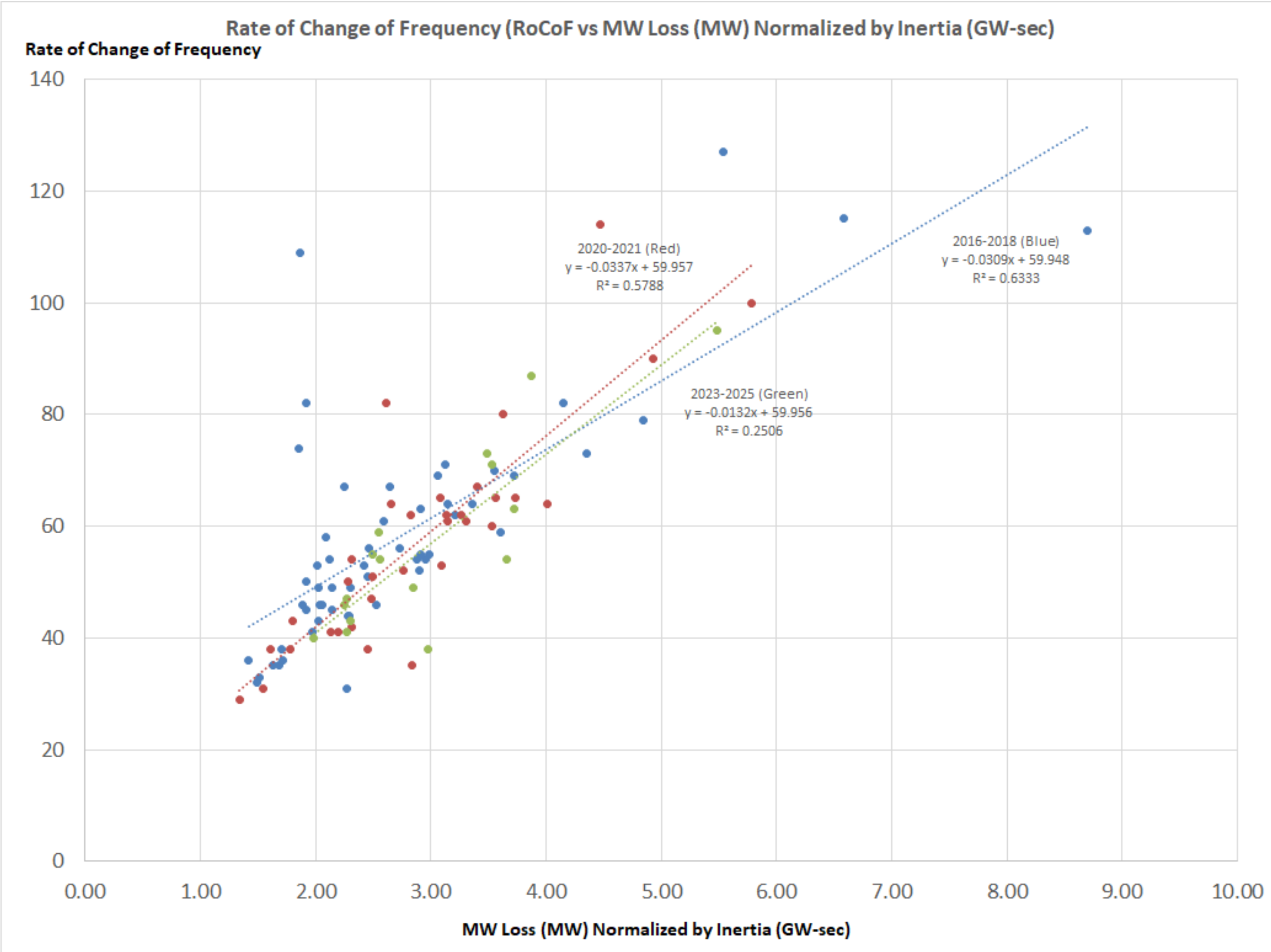


Figure A.9 – Rate of Change of Frequency versus Normalized Generation Loss

Figure A.10 shows the trend in primary frequency response for the Region. In 2025, the average frequency response was 2,127 MW per 0.1 Hz and the median frequency response was 2,140 MW per 0.1 Hz as calculated per BAL-001-TRE for the events that were evaluated during the period.

At the same time, the number of measurable events has declined due to the retirement of large coal units and the increasing integration of renewables and batteries.

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
FME Count	30	29	26	23	19	19	16	7	6	6

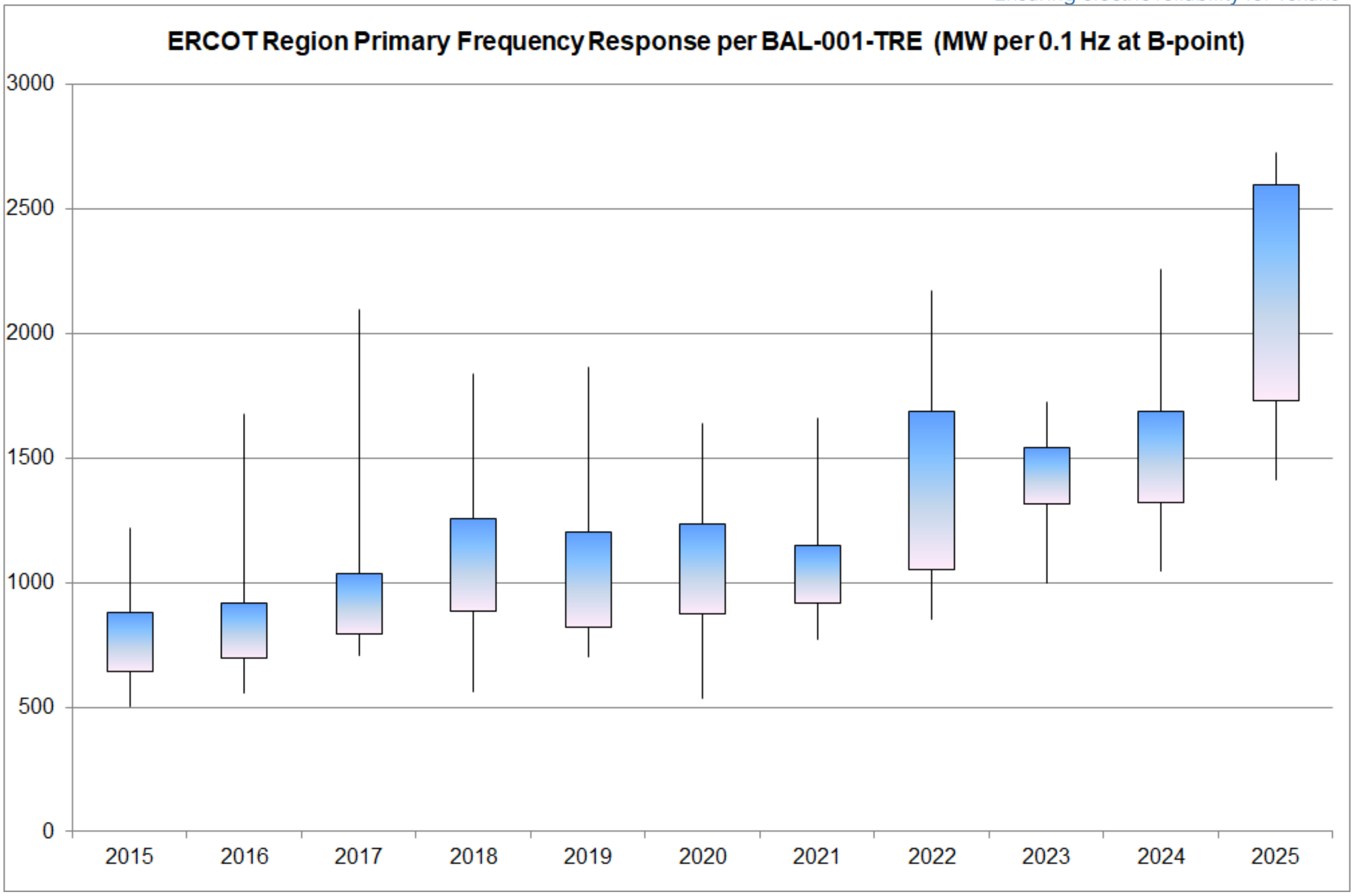


Figure A.10 – Primary (B-Point) Frequency Response Trend for ERCOT Region

Figure A.11 shows the trend in frequency response in the inertial response zone between the A and C points in the Region. In 2025, the average frequency response was 1,043 MW per 0.1 Hz and the median frequency response was 971 MW per 0.1 Hz as calculated per Regional Standard BAL-001-TRE-2 for the events that were evaluated during the period. 2025 results continued the improving trend versus prior years and the long-term trend continues to show a gradually increase inertial response.

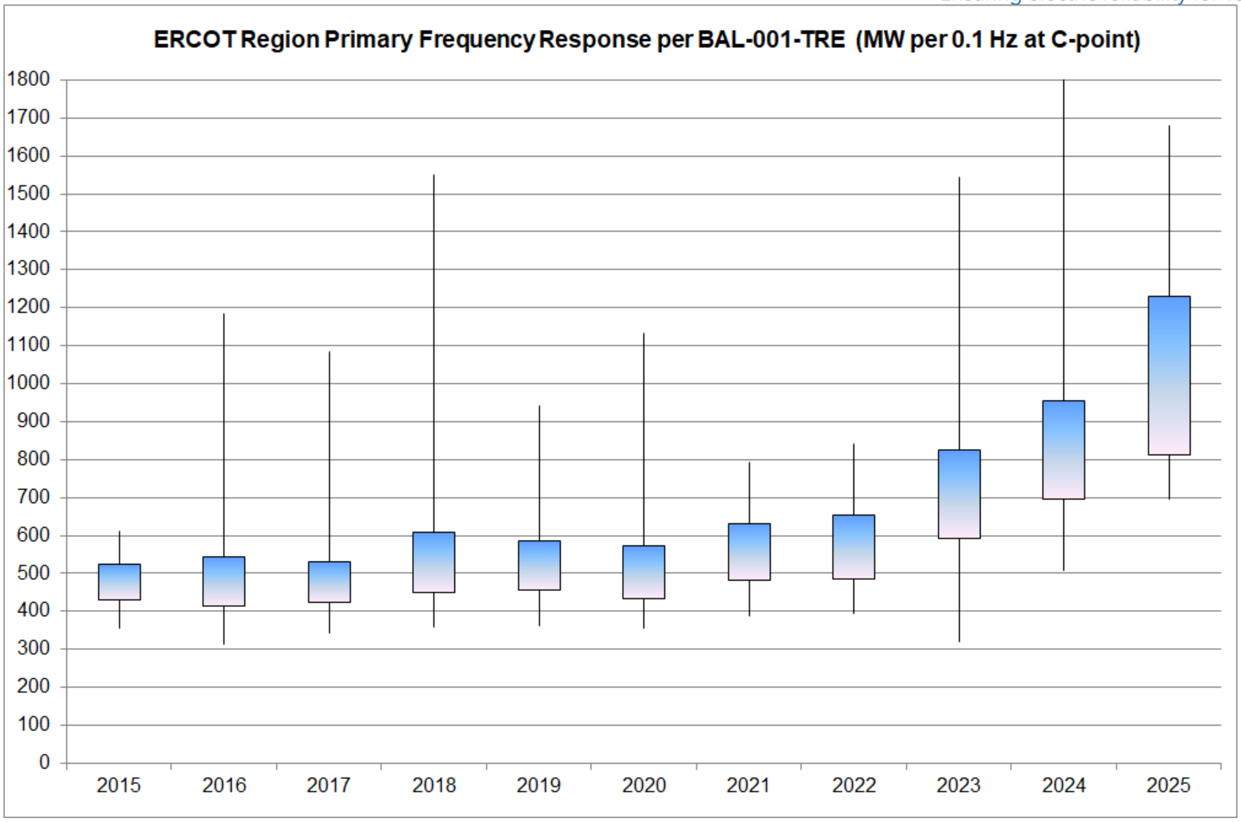


Figure A.11 – Annual Inertial (C-Point) Frequency Response Trend for ERCOT Region

D. Secondary Frequency Response

NERC Reliability Standards require a maximum ACE recovery time of 15 minutes for reportable disturbances. Average recovery time from generation loss events was 5.0 minutes in 2025. The median recovery time from generation loss events was 4.5 minutes in 2025.

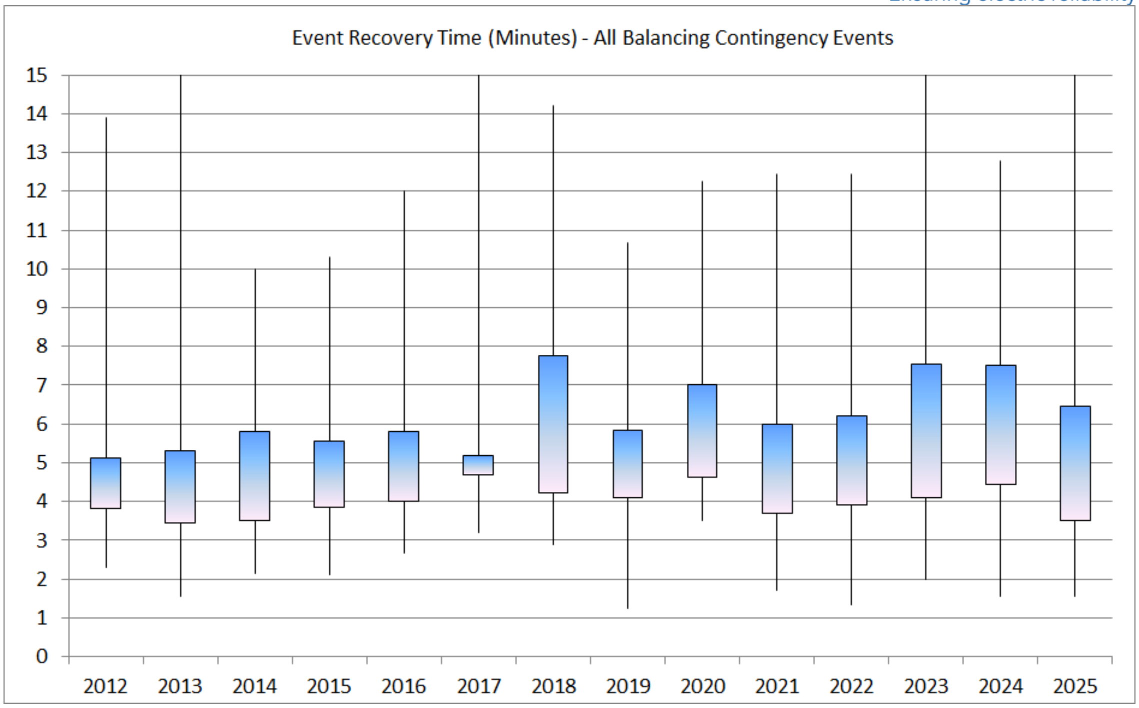


Figure A.12 – Event Recovery Time 2012-2025

E. 2025 Fossil-fueled Generator Performance Metrics

ERCOT fossil generation reporting in GADS produced a net total of 329,948 GWh in 2025 (67.5 percent of total generation)

GADS provides various metrics to compare unit performance. Two of these methods are unweighted (time-based) and weighted (based on unit MW size). A summary of key unweighted performance metrics for the ERCOT generation fleet for 2021-2025 is provided in the following table.

ERCOT Region GADS Data Metric	2021	2022	2023	2024	2025	5-Yr Avg
	Unweighted	Unweighted	Unweighted	Unweighted	Unweighted	Unweighted
# Units Reporting	458	471	483	490	507	482
Total Unit-Months	5478	5514	5721	5817	6004	5707
Net Capacity Factor (NCF)	44.4%	46.5%	47.4%	46.8%	47.5%	46.5%
Service Factor (SF)	45.7%	45.8%	46.2%	45.7%	45.1%	45.7%
Equivalent Availability Factor (EAF)	83.8%	84.1%	84.5%	82.2%	81.5%	83.2%
Scheduled Outage Factor (SOF)	9.4%	9.1%	8.5%	9.9%	9.5%	9.3%
Forced Outage Factor (FOF)	4.3%	4.5%	4.2%	4.5%	5.7%	4.6%
EFOR	10.1%	10.4%	9.8%	10.1%	12.7%	10.6%
Equivalent Forced Outage Rate Demand (EFORd)	5.9%	6.7%	6.8%	6.7%	8.2%	6.9%

Table A.3 – ERCOT Generation Performance Metrics 2021 through 2025

- Net Capacity Factor: Percent of maximum net energy produced for the period
- Service Factor: Percent of time on-line
- Equivalent Availability Factor: Percent of time available without outages or de-rates
- Scheduled Outage Factor: Percent of time on scheduled outage or de-rate
- Forced Outage Factor: Percent of time on forced outage or de-rate
- Equivalent Forced Outage Rate: Probability of being on a forced outage or de-rate
- Equivalent Forced Outage Rate Demand: Probability that units will not meet generating requirements for demand periods due to forced outages or de-rates.

The following table shows the same metrics for 2025 by fuel type.

ERCOT Region GADS Data Metric	Coal/Lignite	Gas	Jet Engine	CC Block	CC GT	CC ST
	Unweighted	Unweighted	Unweighted	Unweighted	Unweighted	Unweighted
# Units Reporting	19	36	145	17	152	62
Total Unit-Months	228	432	1740	204	1824	732
Net Capacity Factor (NCF)	52.2%	16.1%	10.6%	56.6%	58.9%	50.9%
Service Factor (SF)	72.6%	32.1%	11.4%	68.1%	69.5%	72.1%
Equivalent Availability Factor (EAF)	69.5%	67.3%	84.4%	86.3%	79.8%	80.7%
Scheduled Outage Factor (SOF)	10.8%	18.0%	6.4%	6.7%	10.8%	11.0%
Forced Outage Factor (FOF)	15.1%	10.5%	5.9%	4.6%	5.6%	4.2%
EFOR	21.4%	29.7%	35.6%	7.4%	7.6%	8.7%
EFORd	17.1%	20.0%	12.1%	5.5%	6.7%	5.5%

Table A.4 – ERCOT Generation Performance Metrics by Fuel Type for 2025

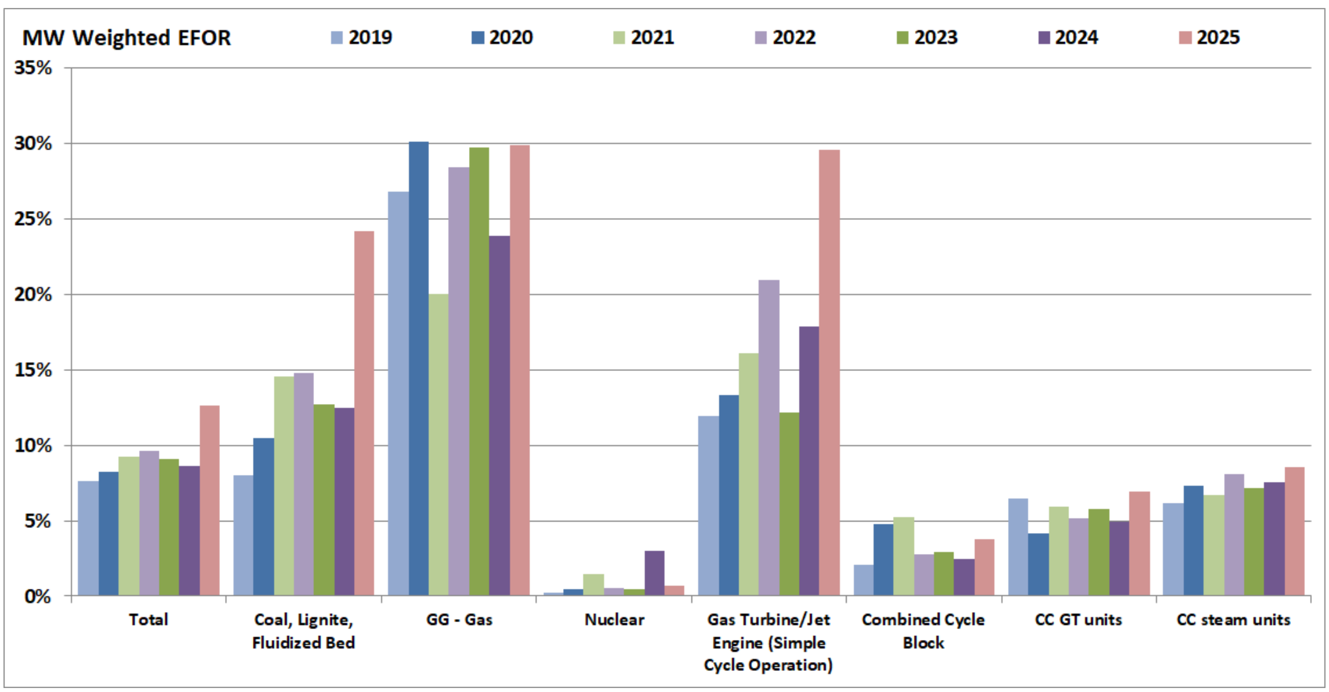


Figure A.13 – MW-Weighted EFOR Metric by Fuel Type and Year

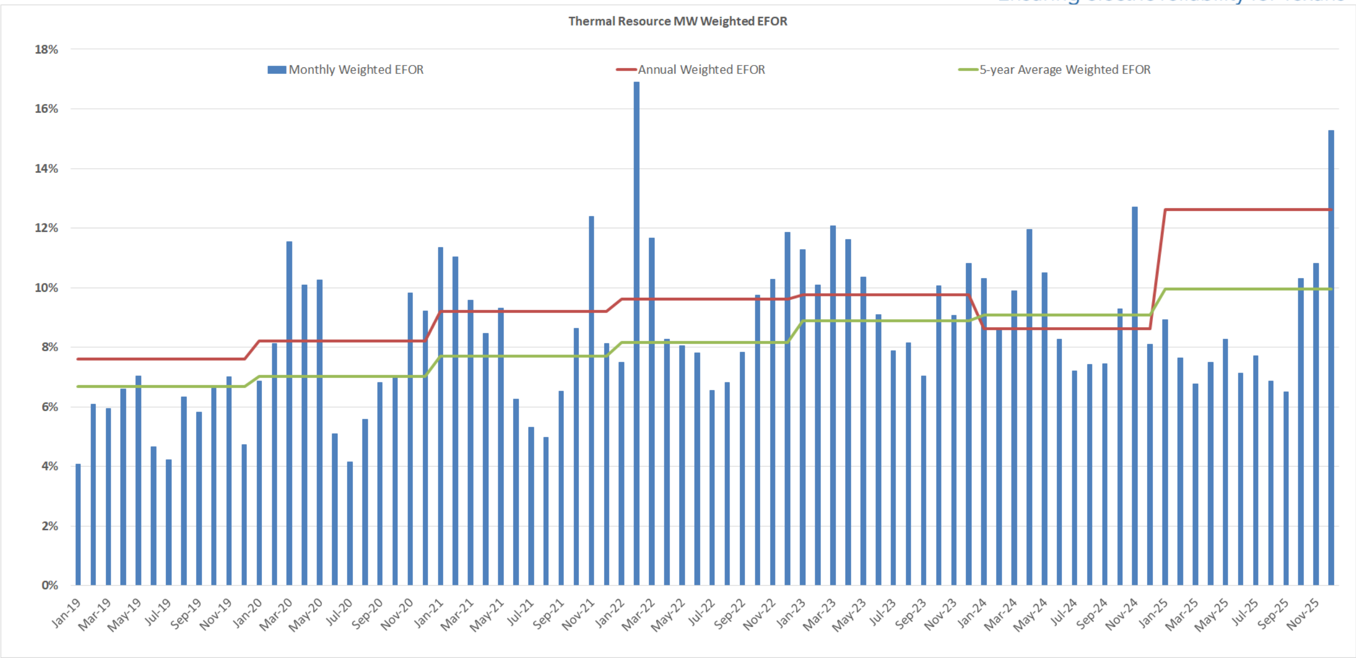


Figure A.14 – Time Trend for MW-Weighted EFOR

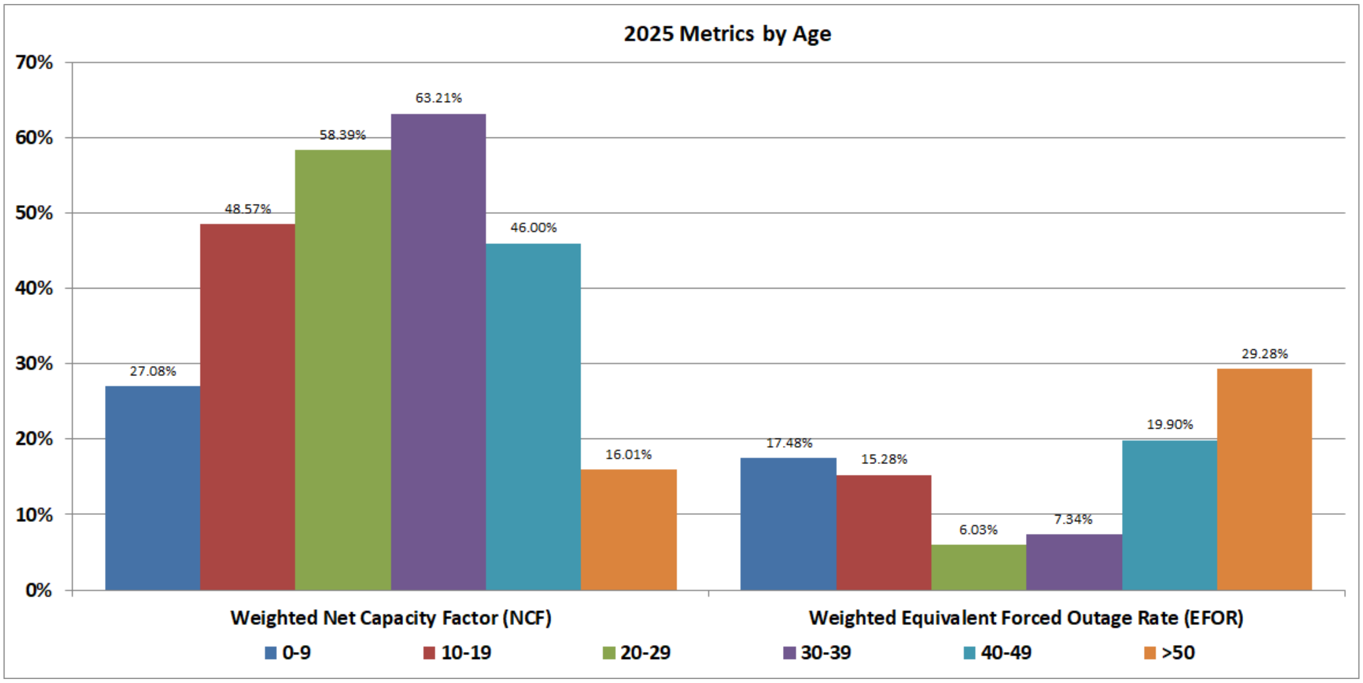


Figure A.15 – 2025 GADS Metrics by Unit Age (Years)

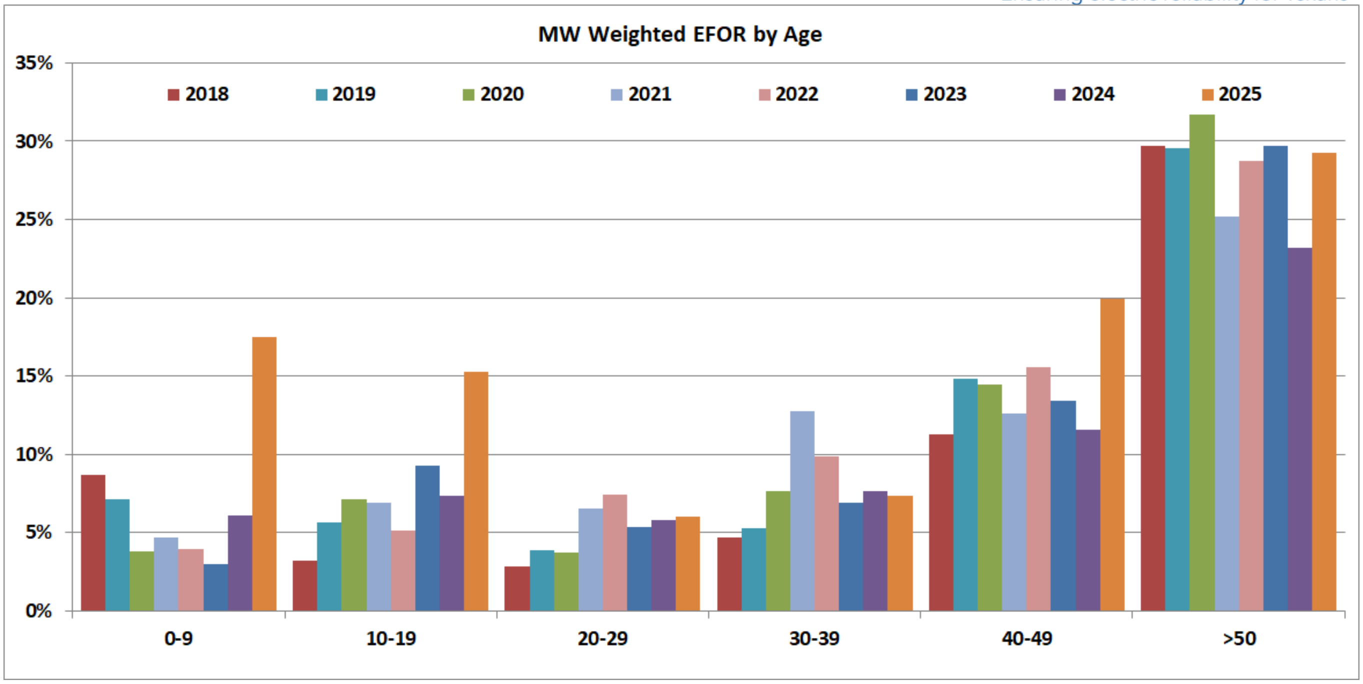


Figure A.16 – 2018-2025 GADS EFOR by Unit Age (Years)

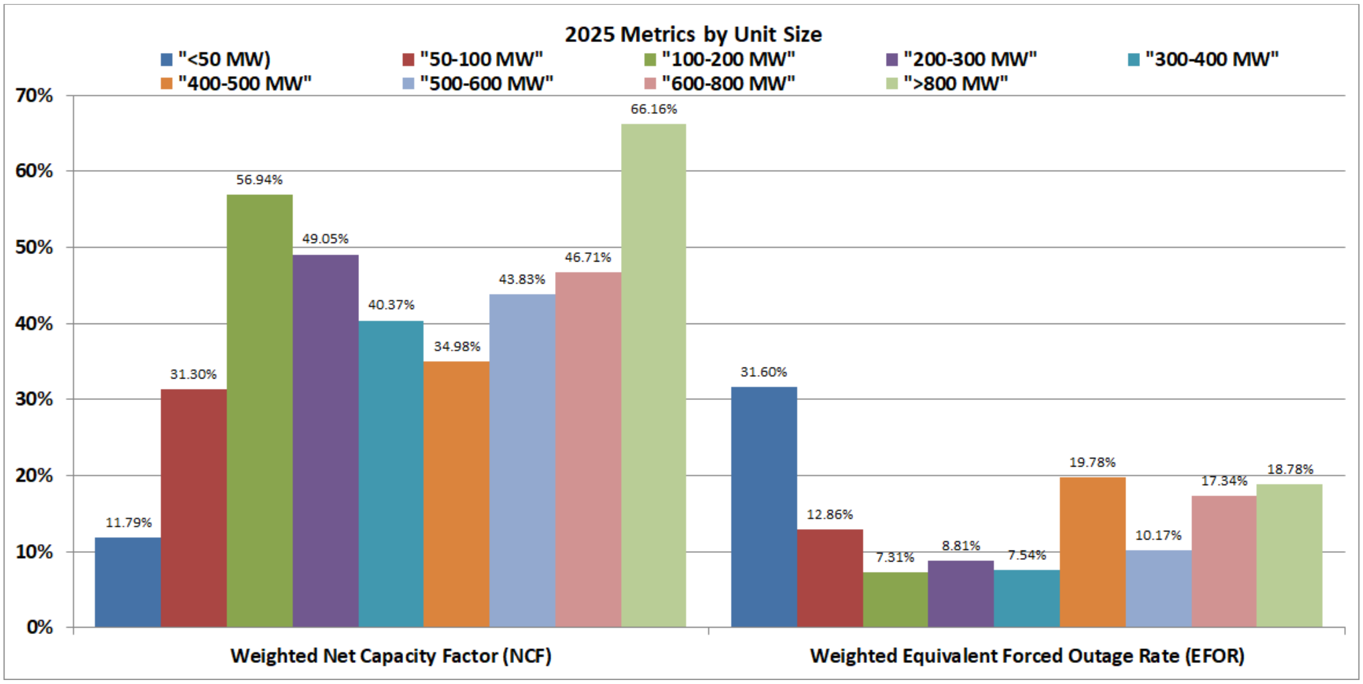


Figure A.17 – 2025 GADS Metrics by Unit Size

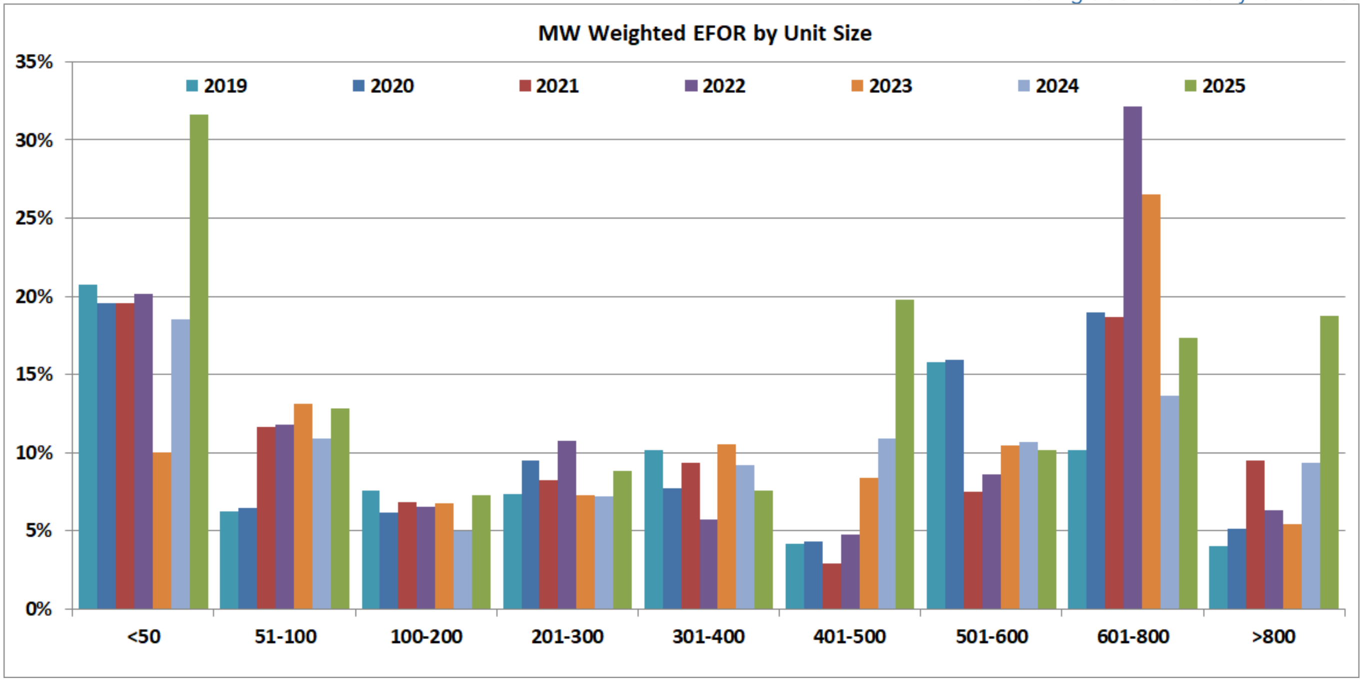


Figure A.18 – 2019-2025 GADS EFOR by Unit Size

<u>2025 Fossil-fueled Generator Outages and De-rates</u>

Table A.5 provides a summary of immediate de-rates and forced outages for conventional generation from January 2025 through December 2025. The 3,336 immediate forced outage events are approximately 30 percent higher than the number of forced outage events in 2024, with an average capacity of 167 MW per event.

2025	Immediate De-rates	Immediate Forced Outages
Number of Events	2,784	3,336
Total Duration (hrs)	221,294	233,906
Total Capacity (MW)	294,293	556,116
Avg Duration per Event (hrs)	79.5	70.1
Avg Capacity per Event (MW)	105.7	166.7

Table A.5 – Generator Immediate De-rate and Forced Outage Data (Jan. – Dec. 2025)

The cause of the immediate forced outage events can also be further broken down into major categories based on the GADS data.

Major System	Number of Forced Outage Events	Total Duration (hours)	Total Capacity (MW)	Avg Duration per Event (hours)	Avg Capacity per Event (MW)
Boiler System	282	21535.9	111948.8	76.4	397.0
Balance of Plant	546	33339.9	113092.0	61.1	207.1
Steam Turbine/Generator	1622	132388.2	235412.7	81.6	145.1
Heat Recovery Steam Generator	100	8435.4	17376.1	84.4	173.8

Pollution Control Equipment	65	1653.5	8166.1	25.4	125.6
External	572	19136.5	51756.2	33.5	90.5
Regulatory, Safety, Environmental	45	3286.9	5786.5	73.0	128.6
Personnel/ Procedure Errors	31	262.4	7644.3	8.5	246.6
Other	73	13868	4934	190.0	67.6

Table A.6 – 2025 Major Category Cause of Immediate Forced Outage Events from GADS

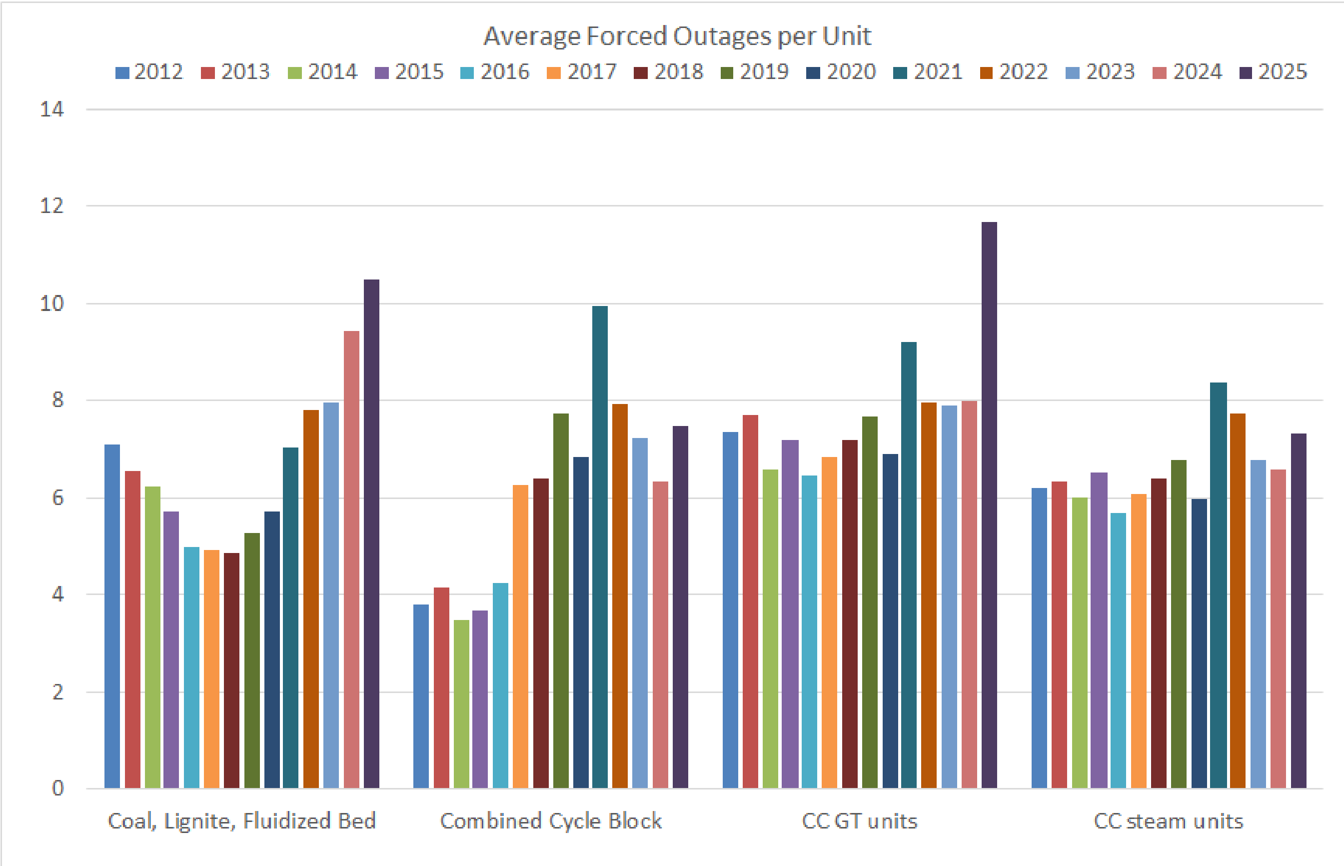


Figure A.19 – 2025 Average Forced Outages per Unit

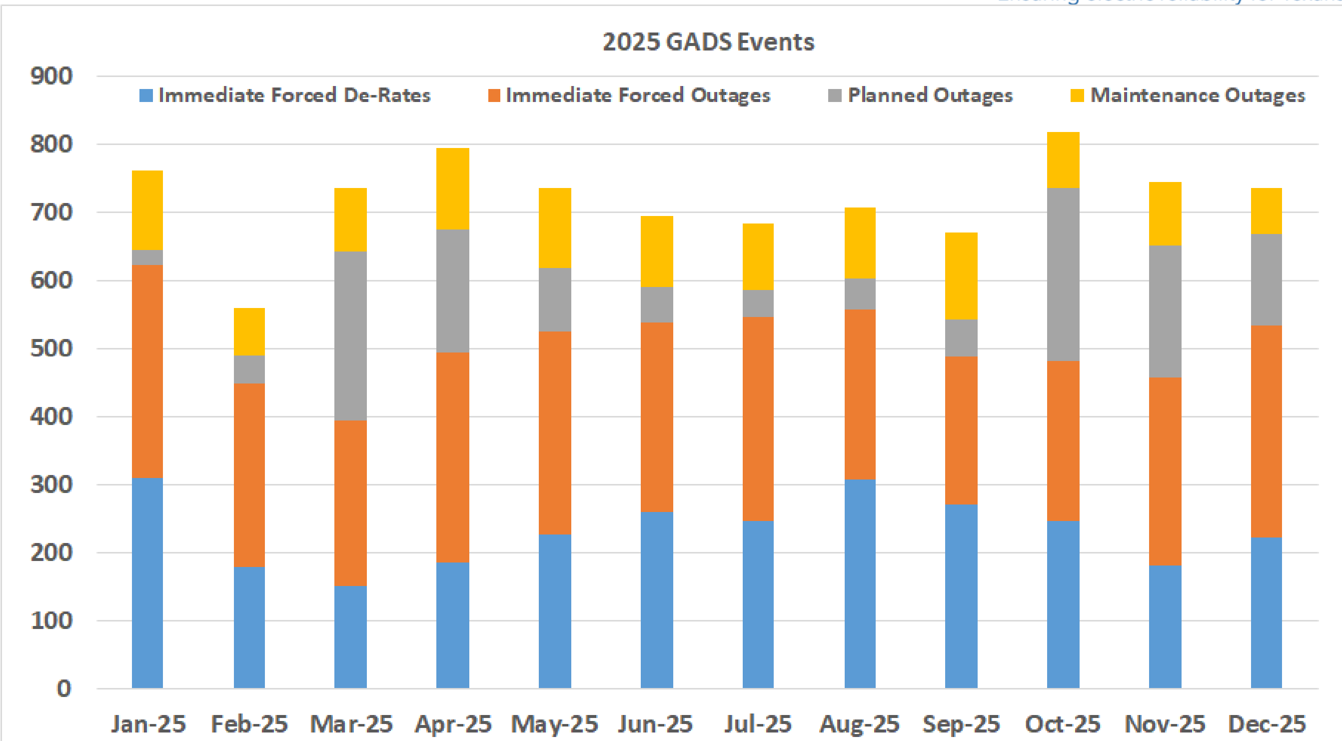


Figure A.20 –2025 Count of Generation Events by Month

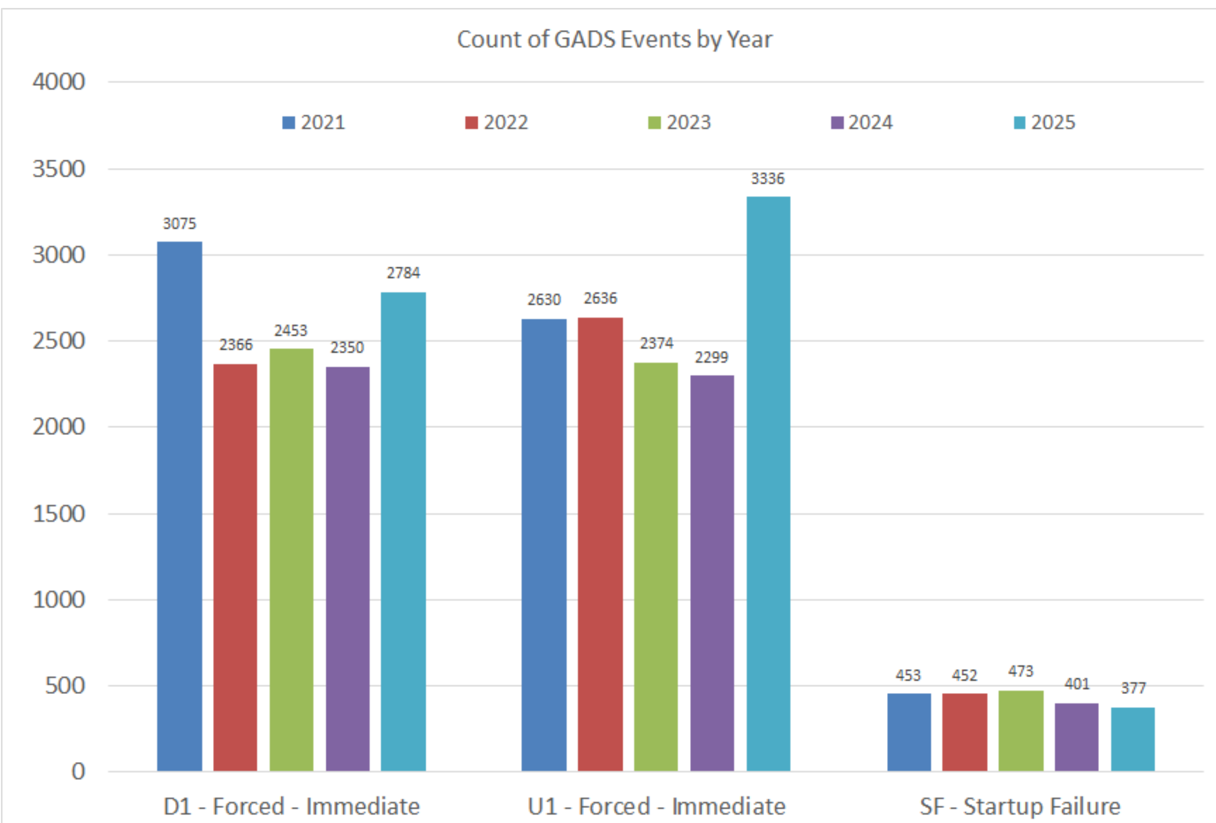


Figure A.21 – 2021-2025 Count of Events by Year

F. 2025 Renewable Generator Performance Metrics

Wind facilities greater than 200 MW began mandatory reporting in GADS-Wind in 2018. Wind facilities greater than 100 MW began mandatory reporting in GADS-Wind in 2019. All units began mandatory reporting in 2020. GADS-Wind provides similar metrics as GADS to compare unit-level and fleet-level performance. Two of these methods provide resource-level and equipment-level performance rates. In 2025, 283 wind sub-groups in the Region submitted a total of 3,312 unit-months of data in GADS-Wind. Net wind generation reported was 103,597 GWh, or 90.1 percent of the total wind generation for the year. Pooled equipment metrics provide a mechanism to look at sub-group performance of turbines of similar capacity. A summary of key performance metrics based on resource versus pooled equipment values for wind generators in the Region for 2022-2025 is provided in the following table.

Metric: ERCOT Region GADS-Wind Data	2022		2023		2024		2025	
	Resource	Equipment	Resource	Equipment	Resource	Equipment	Resource	Equipment
Net Capacity Factor (PRNCF and PENCF)	36.1%	39.4%	34.1%	37.3%	34.4%	37.4%	34.6%	47.1%
Equivalent Forced Outage Rate (PREFOR and PEEFOR)	17.1%	7.8%	17.1%	8.0%	16.2%	7.3%	17.7%	9.2%
Equivalent Scheduled Outage Rate (RESOR and PEESOR)	1.6%	1.4%	1.4%	1.3%	1.9%	1.7%	2.1%	1.9%
Equivalent Availability Factor (REAF and PEEAF)	82.2%	88.9%	82.4%	88.9%	82.9%	89.3%	81.5%	86.6%

Table A.7 – ERCOT Wind Generation Performance Metrics, 2022-2025

- Pooled Resource Equivalent Forced Outage Rate (PREFOR): Probability of forced plant downtime when needed for load.
- Resource Equivalent Scheduled Outage Rate (RESOR): Probability of maintenance or planned plant downtime when needed for load.
- Resource Equivalent Availability Factor (REAF): Percent of time the plant was available.
- Pooled Resource Net Capacity Factor (PRNCF): Percent of actual plant generation versus capacity.
- Pooled Equipment Equivalent Forced Outage Rate (PEEFOR): Probability of forced WTG equipment downtime when needed for load.
- Pooled Equipment Equivalent Scheduled Outage Rate (PEESOR): Probability of maintenance or planned WTG equipment downtime when needed for load.
- Pooled Equipment Net Capacity Factor (PENCF): Percent of actual WTG equipment generation while on-line versus capacity.
- Pooled Equipment Equivalent Availability Factor (PEEAF): Percent of time the WTG equipment was available.

GADS-Wind turbine outage data reporting for 2025 included 6,476 component outage reports totaling 520,086 turbine-hours of forced, planned, and maintenance outage duration, with an estimated production loss of 2,695.8 GWh.

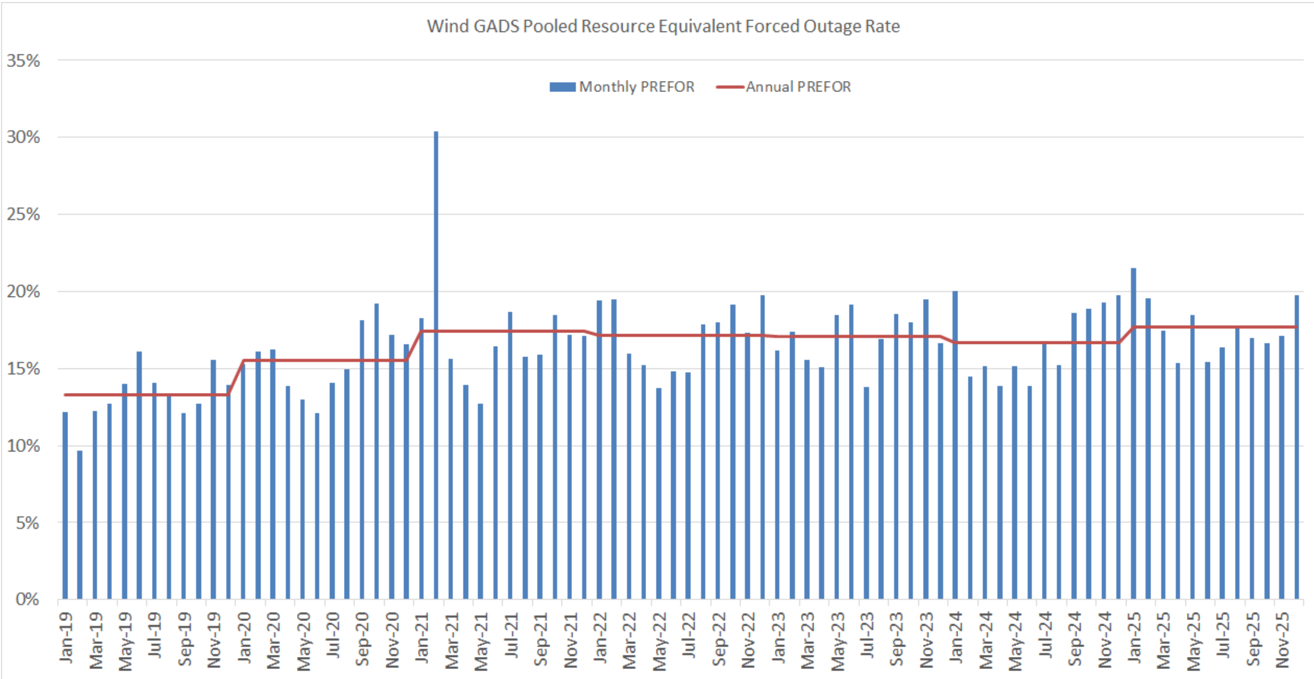


Figure A.22 – GADS-Wind Time Trend for MW-Weighted EFOR

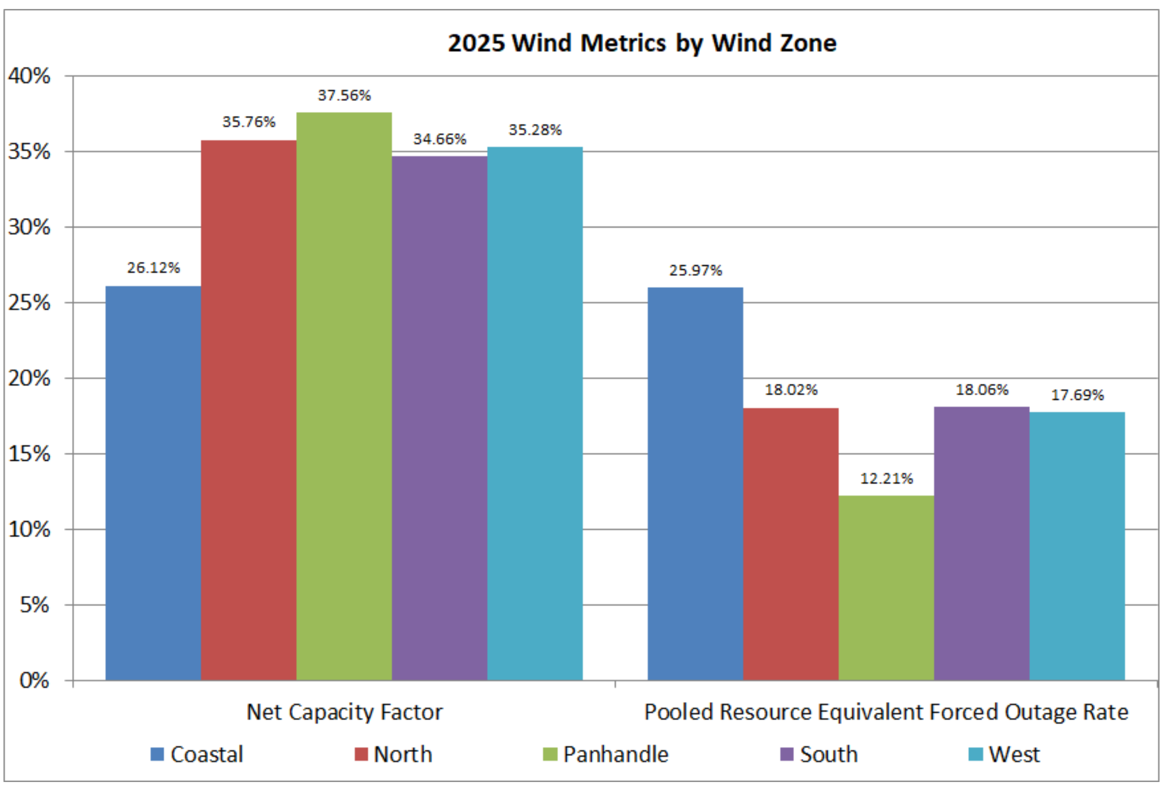


Figure A.23 – 2025 GADS-Wind Metrics by Wind Zone

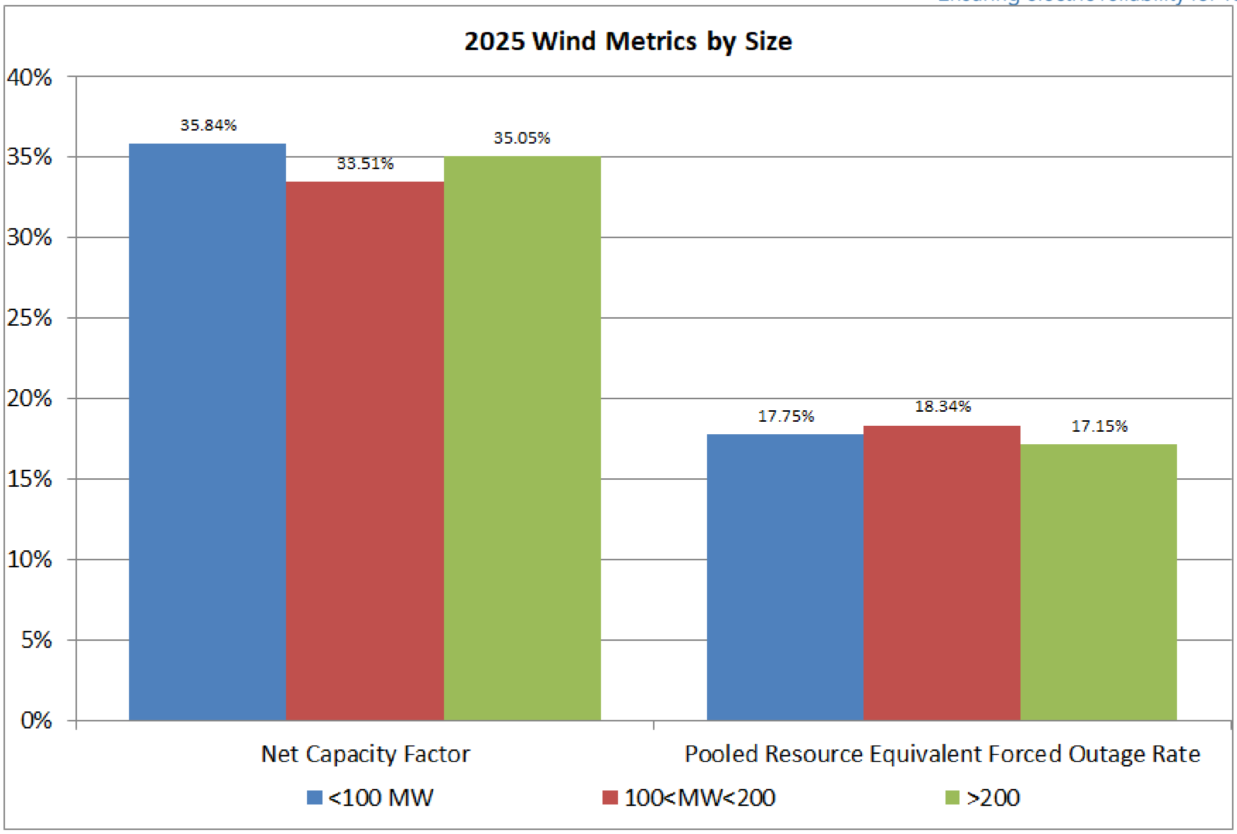


Figure A.24 – 2025 GADS-Wind Metrics by Unit Size

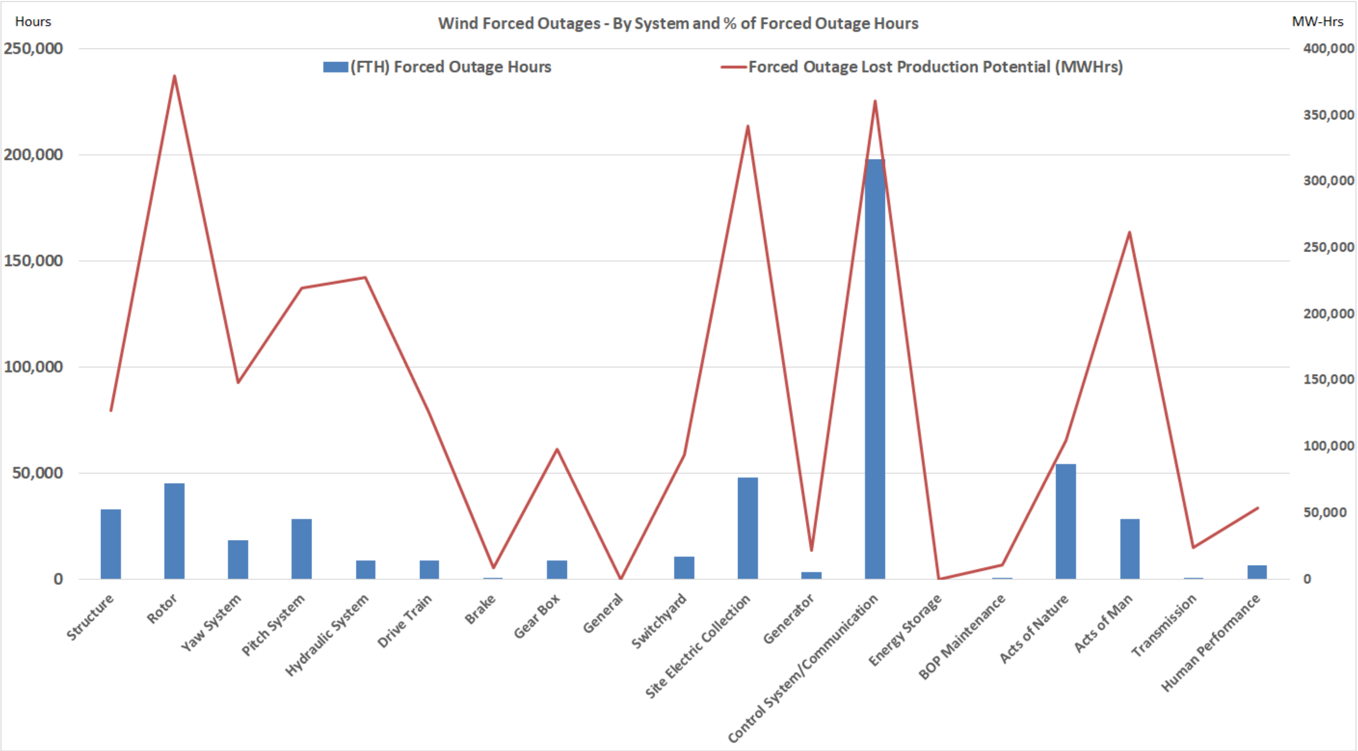


Figure A.25 – 2025 GADS-Wind Turbine Outage Hours and Production Loss by System

Solar facilities greater than 100 MW began mandatory reporting in GADS-Solar in 2024. Solar facilities greater than 20 MW will begin mandatory reporting in GADS-Solar in 2025. GADS-Solar provides similar metrics as GADS to compare unit-level and fleet-level performance. In 2025, 132 solar sub-groups submitted a total of 1,355 unit-months of data in GADS-Solar. Net solar generation reported was 43,459 GWh, or 64.1 percent of the total solar generation for the year. Resource-level metrics look at the resource as a whole. A summary of key performance metrics for the ERCOT solar generators for 2025 is provided in the following table.

Metric: ERCOT Region GADS-Solar Data (Daylight hours)	2024	2025
Net Capacity Factor (RNCF)	25.1%	31.6%
Resource Generating Factor (RGF)	87.1%	86.3%
Resource Forced Outage Rate (RFOR)	10.0%	11.1%
Equipment Forced Outage Rate (EFOR)	4.5%	5.4%
Resource Scheduled Outage Rate (RSOR)	0.7%	0.1%
Performance Index (PI)	79.5%	85.2%
Resource Availability Factor (RAF)	89.7%	89.1%

Table A.8 – ERCOT Solar Generation Performance Metrics, 2024-2025

- Resource Forced Outage Rate (RFOR): Probability of forced plant downtime when needed for load.
- Resource Generating Factor (RGF): Percentage of the period in which the plant was online and in a generating state.
- Equipment Forced Outage Rate (EFOR): Probability of forced equipment downtime when needed for load.
- Resource Scheduled Outage Rate (RSOR): Probability of maintenance or planned plant downtime when needed for load.
- Resource Net Capacity Factor (RNCF): Percent of actual plant generation versus capacity.
- Performance Index (PI): Percentage of generation that was produced compared to expected generation.
- Resource Availability Factor (RAF): Percentage of the period in which the plant was available.

GADS-Solar inverter outage data reporting for 2025 included 2,946 component outage reports totaling 638,274 inverter-hours of forced, planned, and maintenance outage duration, with an estimated production loss of 949.8 GWh.

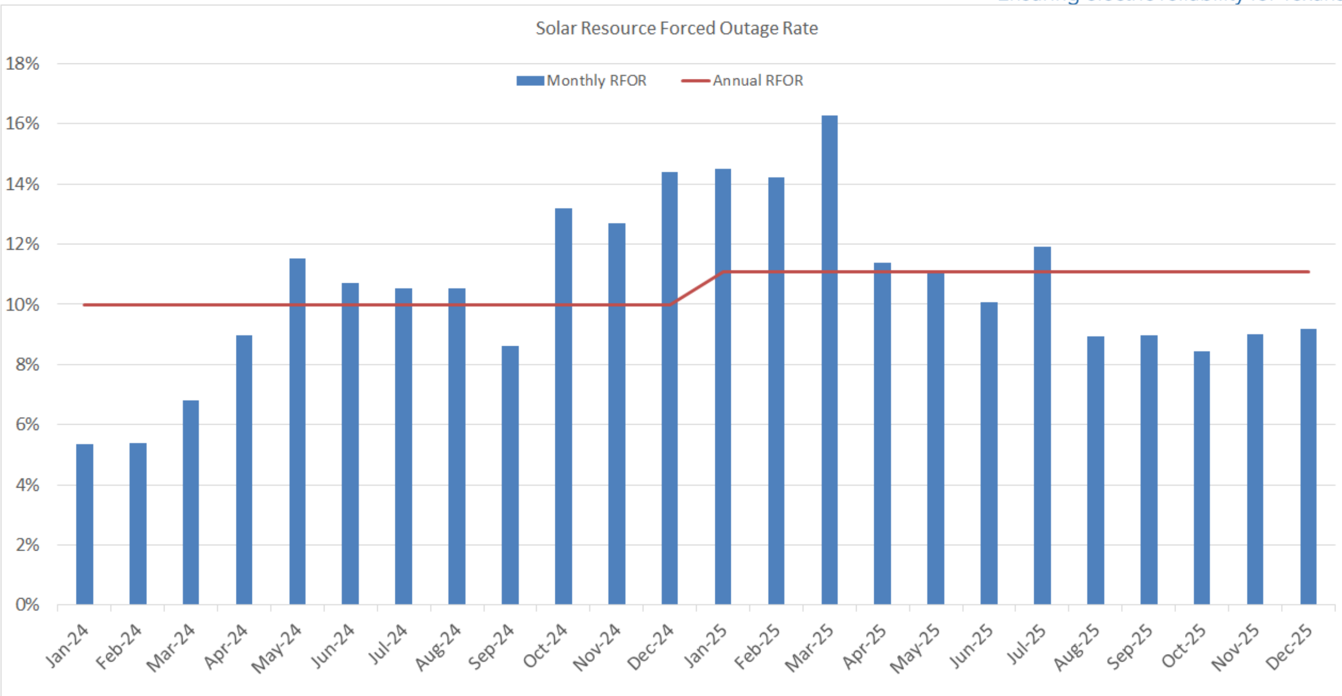


Figure A.26 – GADS-Solar Time Trend for RFOR

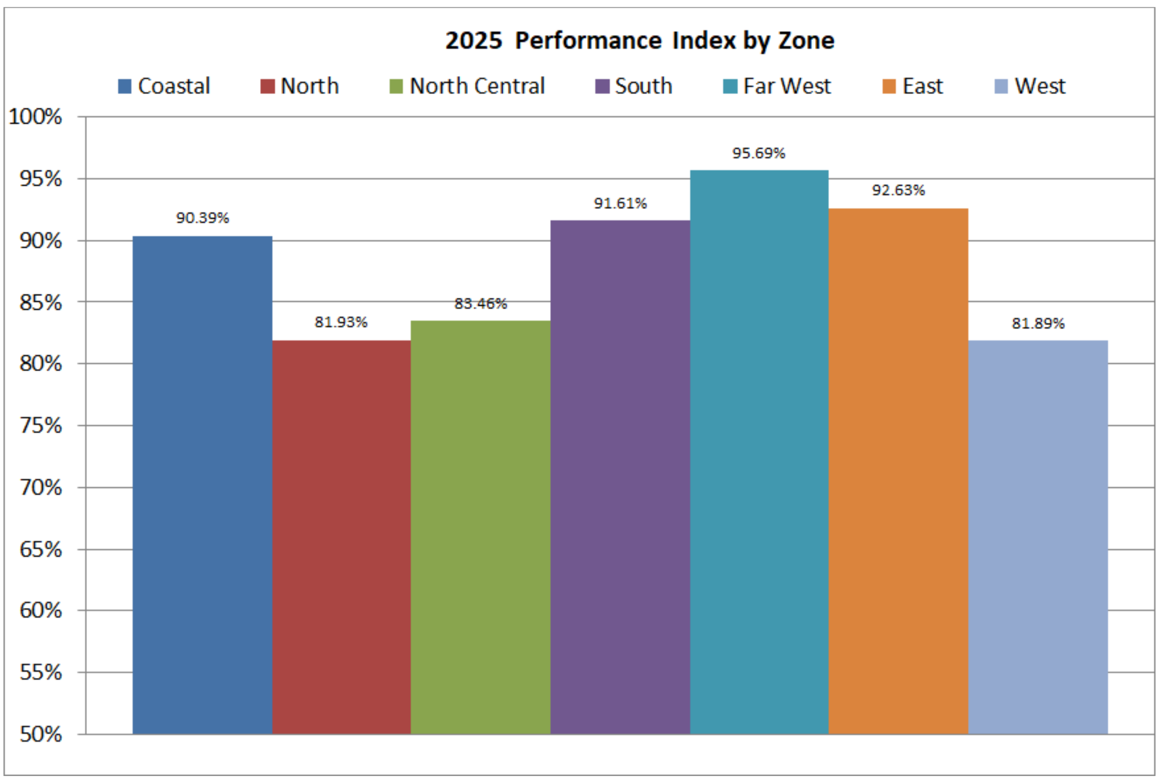


Figure A.27 – 2025 GADS-Solar Performance Index by Zone

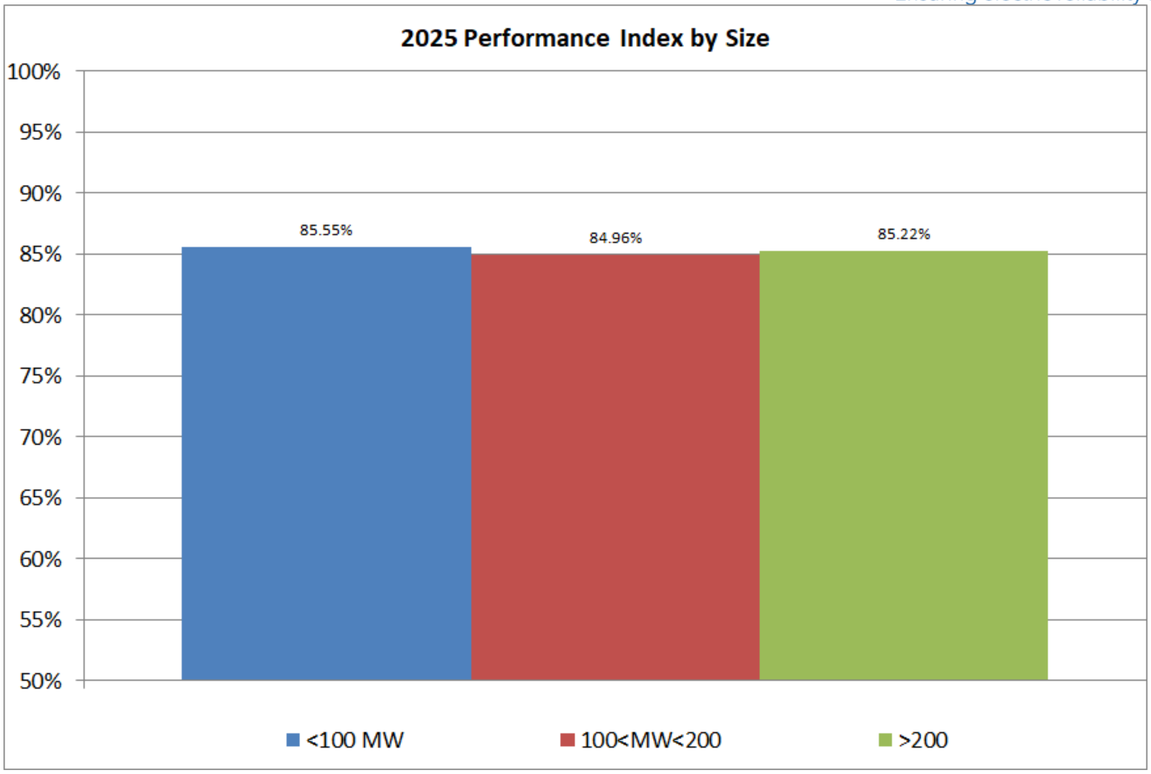


Figure A.28 – 2025 GADS-Solar Performance Index by Unit Size

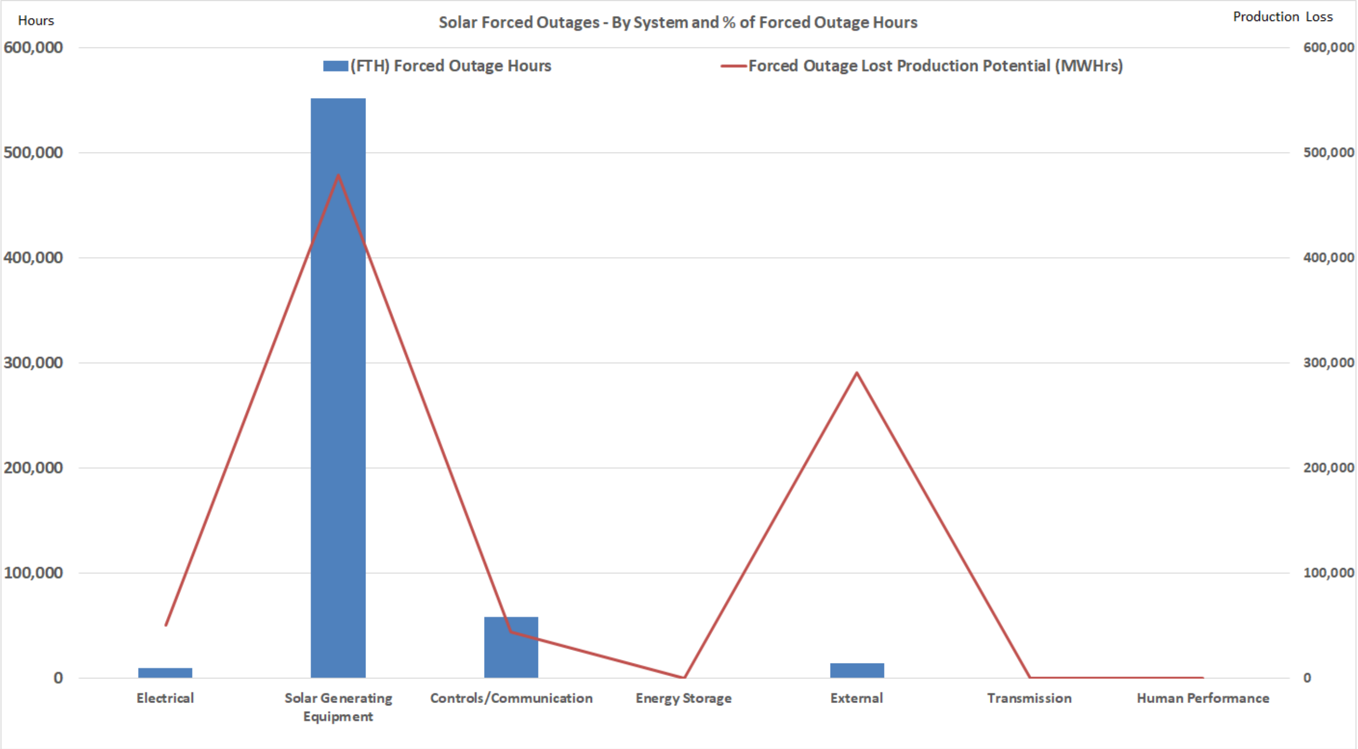


Figure A.29 – 2025 GADS-Solar Inverter Outage Hours and Production Loss by System

Battery/Energy Storage facilities (BESS) that are co-located with wind or solar facilities began mandatory reporting in GADS in 2024. GADS metrics for BESS facilities have not yet been developed. In 2025, 23 co-located BESS facilities 1,984 MW capacity) submitted a total of 248 unit-months of data in GADS. Net generation reported for 2025 was 895.6 GWh of charge generation and 832.0 GWH of discharge generation. A summary of key data for the ERCOT co-located BESS facilities for 2025 is provided in the following table.

Metric: ERCOT Region GADS Battery Data	2024	2025
Charge Generation (GWH)	129.3	895.6
Discharge Generation (GWH)	141.9	832.0
Charging Hours	37,039	73,768
Discharging Hours	22,913	60,250
Planned Outage Hours	1,664.0	656.2
Forced Outage Hours	1,710.7	4,424.8
Maintenance Outage Hours	370.6	156.0

Table A.9 – ERCOT Co-located Battery Data, 2024-2025

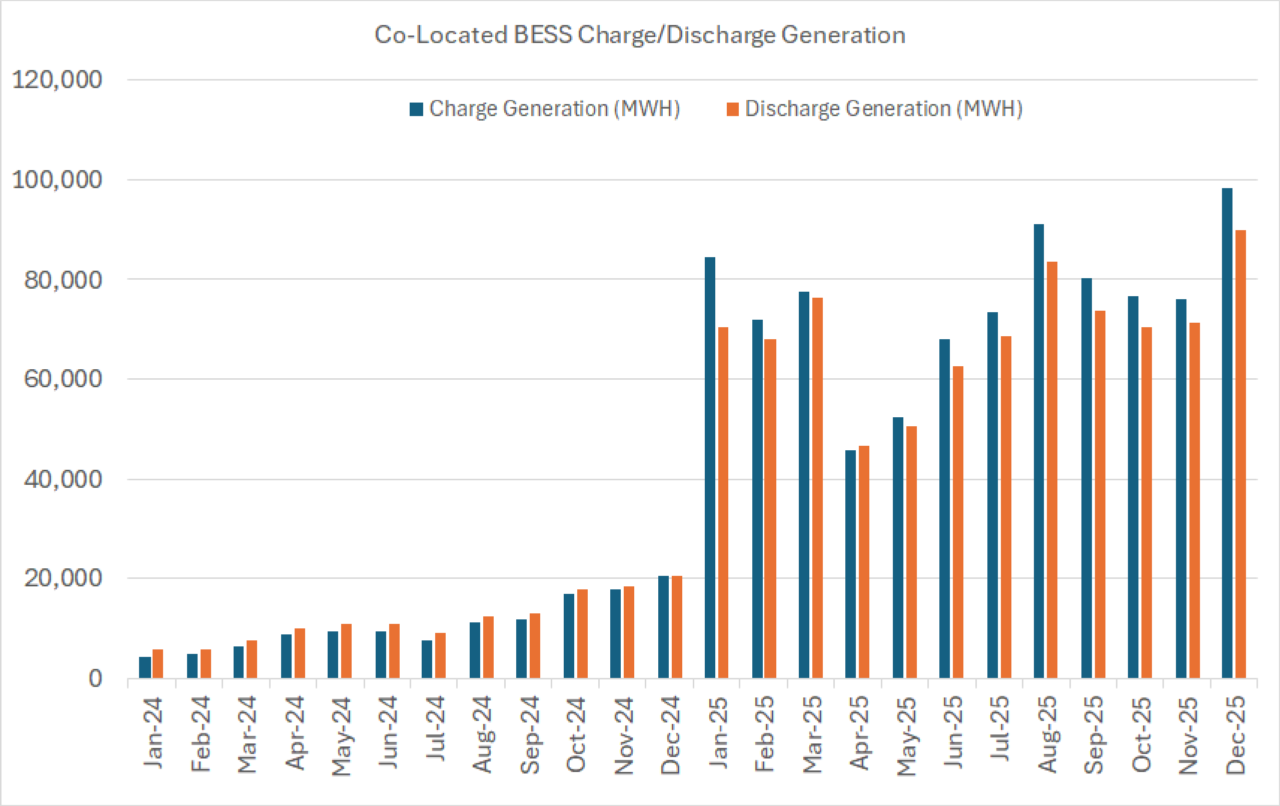


Figure A.30 – Co-Located BESS Charge/Discharge Generation

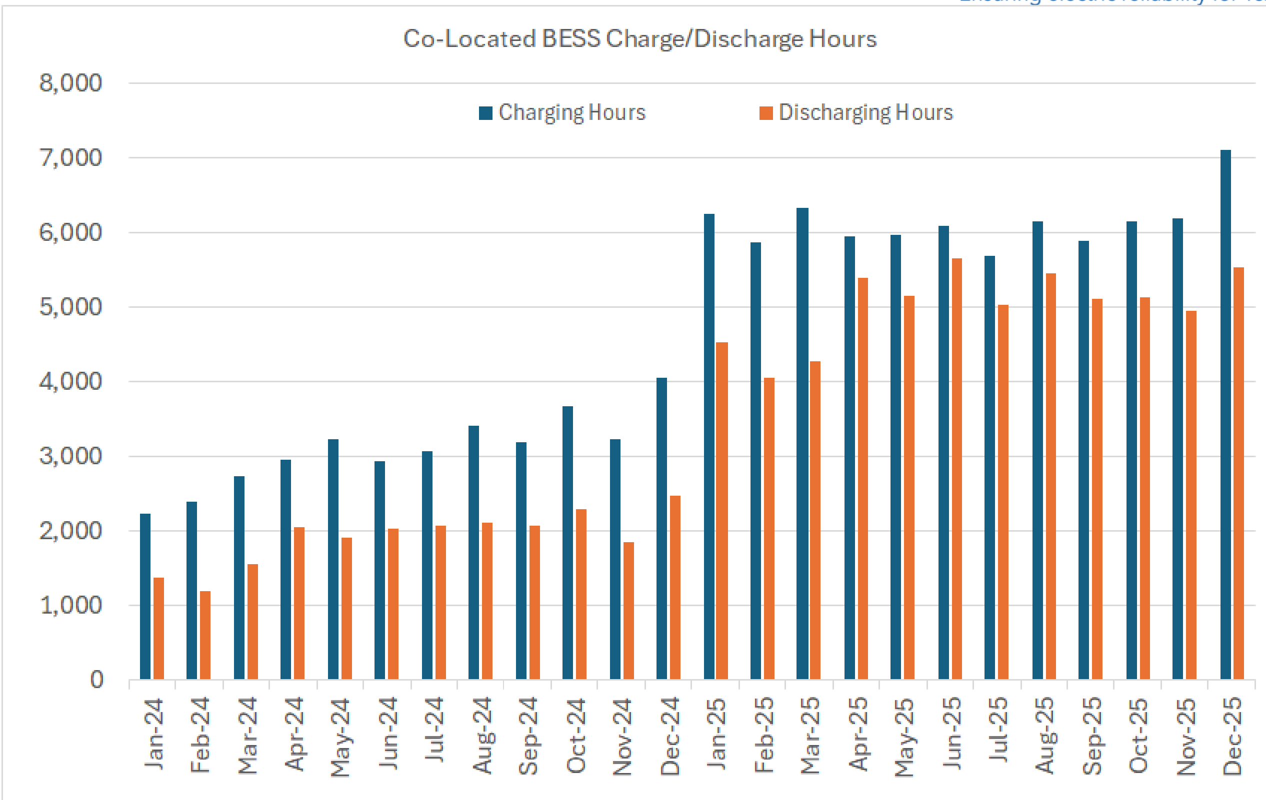


Figure A.31 – Co-Located BESS Charge/Discharge Hours

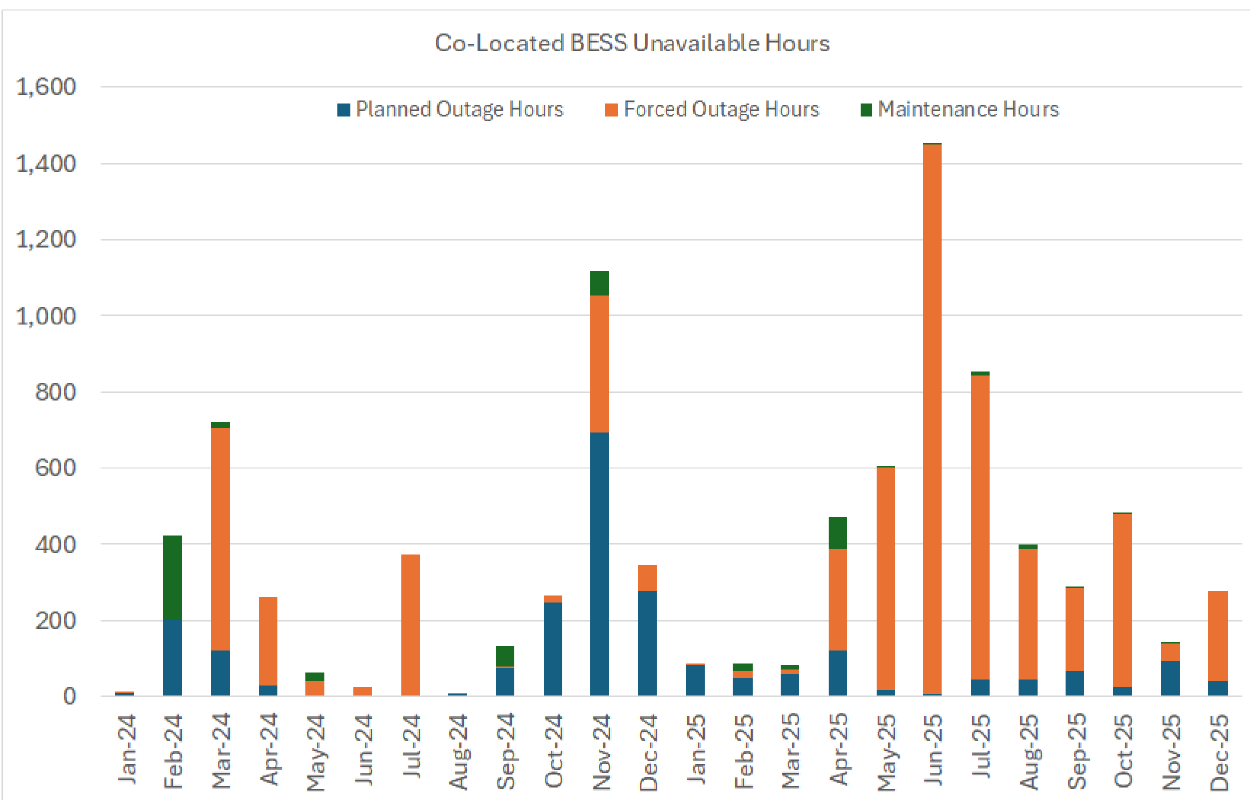


Figure A.32 – Co-Located BESS Unavailable Hours

G. Balancing Contingency Event Performance

Texas RE tracks the number of Balancing Contingency Events and recovery time within the Region to provide any potential adverse reliability indications. Per the NERC BAL-002-2 Disturbance Control Standard, a Reportable Disturbance is defined as any event which causes a change in Area Control Error greater than or equal to 800 MW. Note that the BAL-002 definition for a Reportable Balancing Contingency Event changed from 1,100 MW to 800 MW for ERCOT in January 2018 when BAL-002-2 went into effect.

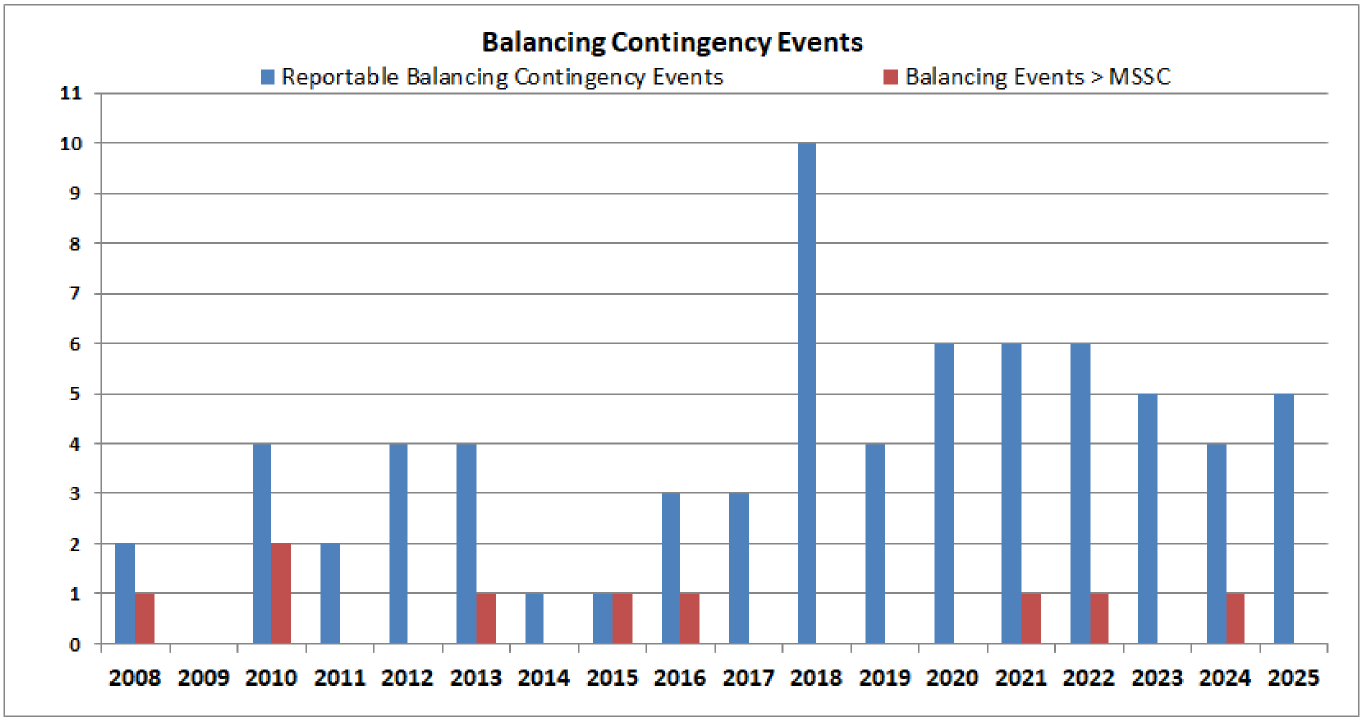


Figure A.33 – Reportable Balancing Contingency Events by Year

H. Fuel Constraints

There was a significant increase in the unavailable generation capacity due to natural gas fuel curtailments in 2025 compared to 2024, primarily in the spring, summer and fall.

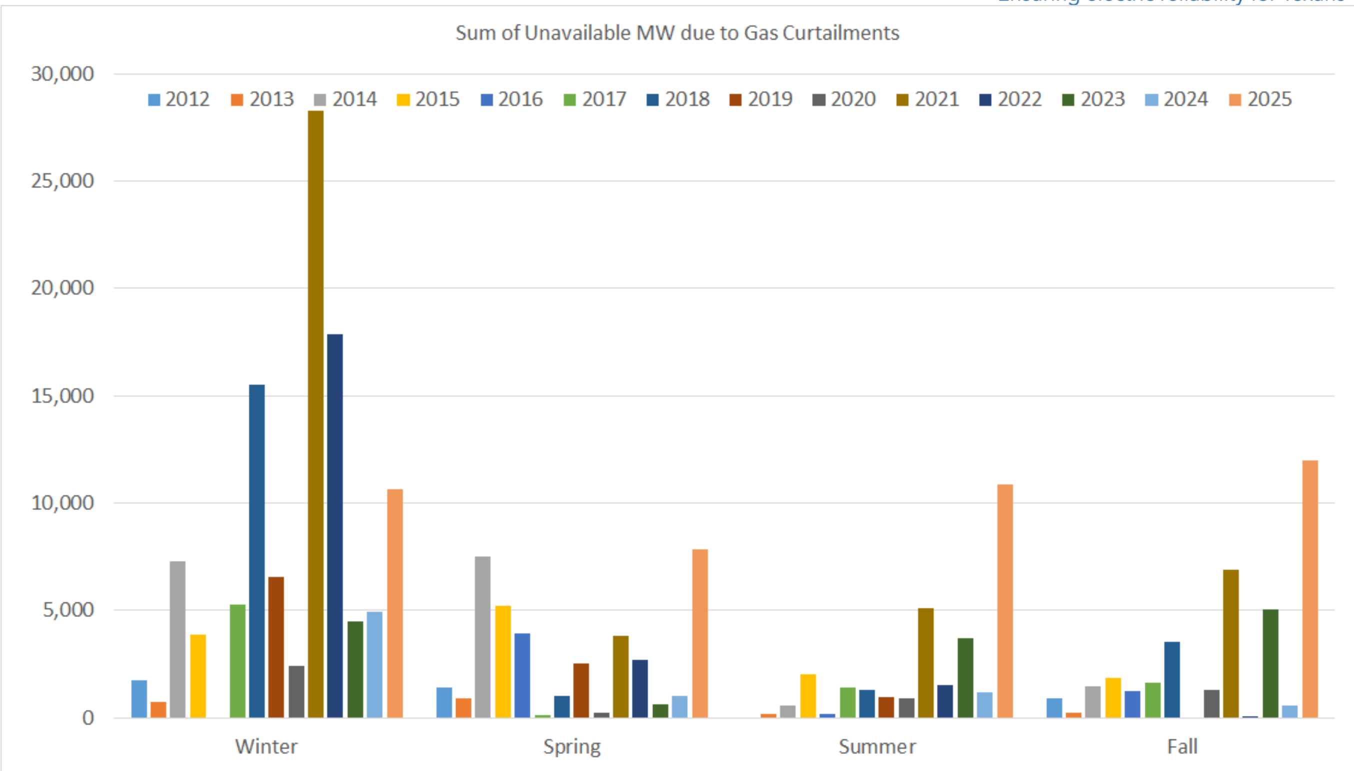


Figure A.34 – Cumulative Unavailable MW Due to Natural Gas Curtailments By Season

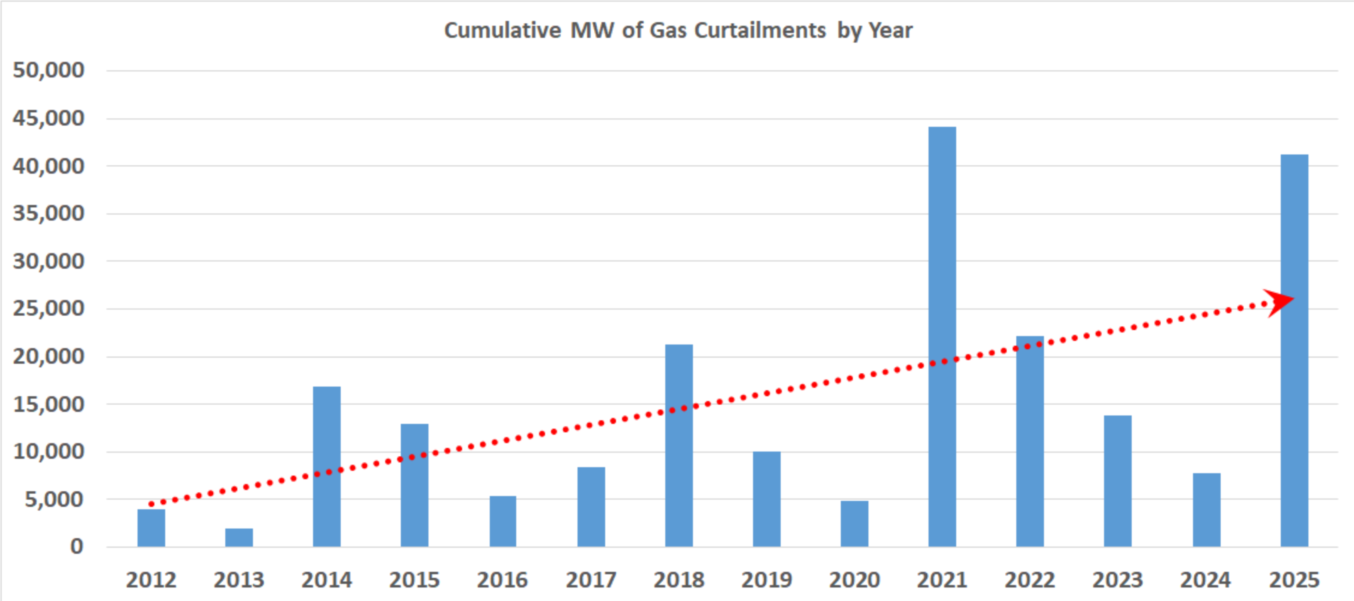


Figure A.35 – Cumulative Unavailable MW Due to Natural Gas Curtailments by Year

Appendix B – System Resilience Detailed Analysis

A. Transmission Inventory Data (from NERC TADS)

For this analysis, transmission performance data is based on required reports submitted in the Transmission Availability Data System (TADS) under NERC Section 1600 of the Rules of Procedure. A summary of the aggregated ERCOT TADS elements, circuit miles, and outage data is shown in the following tables.

Year	Circuits (300-399 kV)	Circuit Miles (300-399 kV)	Transformers (300-399 kV)
2015	413	14,832.02	206
2016	456	15,928.06	245
2017	476	16,434.39	252
2018	501	16,327,85	258
2019	524	17,333.63	263
2020	580	18,152.37	283
2021	633	18,872.23	294
2022	719	20,263.98	301
2023	776	20,915.80	303
2024	818	21,643.80	303
2025	840	21,943.95	305

Table B.1 – 2015-2025 End of Year Circuit Data

	Automatic		Non-Automatic Operational	
Outage Information	**Count**	**Duration (hours)**	**Count**	**Duration (hours)**
2015[1]	477	10,806.9	44	2,821.8
2016	436	6,446.1	43	3,645.6
2017	438	18,657.8	18	345.9
2018	334	22,619.0	27	3,472.9
2019	523	7,398.8	82	14,591.1
2020	471	6,103.8	137	28,351.5
2021	505	17,804.4	167	29,794.5
2022	441	9,155.3	195	14,128.9
2023	447	8,796.8	173	20,230.8
2024	469	21,812.5	109	13,955.5
2025	424	31,896.1	45	1,118.7
5-Yr Average	457	17,893.0	138	15,845.7

Table B.2 – 2015-2025 345 kV Circuit and Transformer Outage Data

B. Event Analysis

[1] Outage count and duration for 2015-2025 includes 345 kV transformers which began reporting in 2015

The following noteworthy events occurred in 2025:

- Three loss of multiple element events that involved failed equipment or protection system misoperations.
- Five loss of ability to remotely control or monitor events
- Seven physical security events, including equipment damaged by gunfire..

Historical Disturbance Data: In 2025, the number of qualified events (Category 1 or higher) was similar to 2024. The number of unqualified events continued to decrease when compared to 2023, primarily due to a reduction in the number of large generation unit trips. The total events in 2025 was well below the long-term average number of events from 2020 through 2024, with 2023 being an outlier due to a large number of reported physical security events that occurred.

Event Category[2]	2021	2022	2023	2024	2025	5-Yr Avg
Non-Qualified	74	70	115	79	70	82
1	14	11	6	7	6	9
2	0	1	0	0	0	0
3	0	1	0	0	0	0
4 and 5	1	0	0	0	0	0
Total	89	83	121	86	76	91

Table B.3 – Summary of Event Analyses

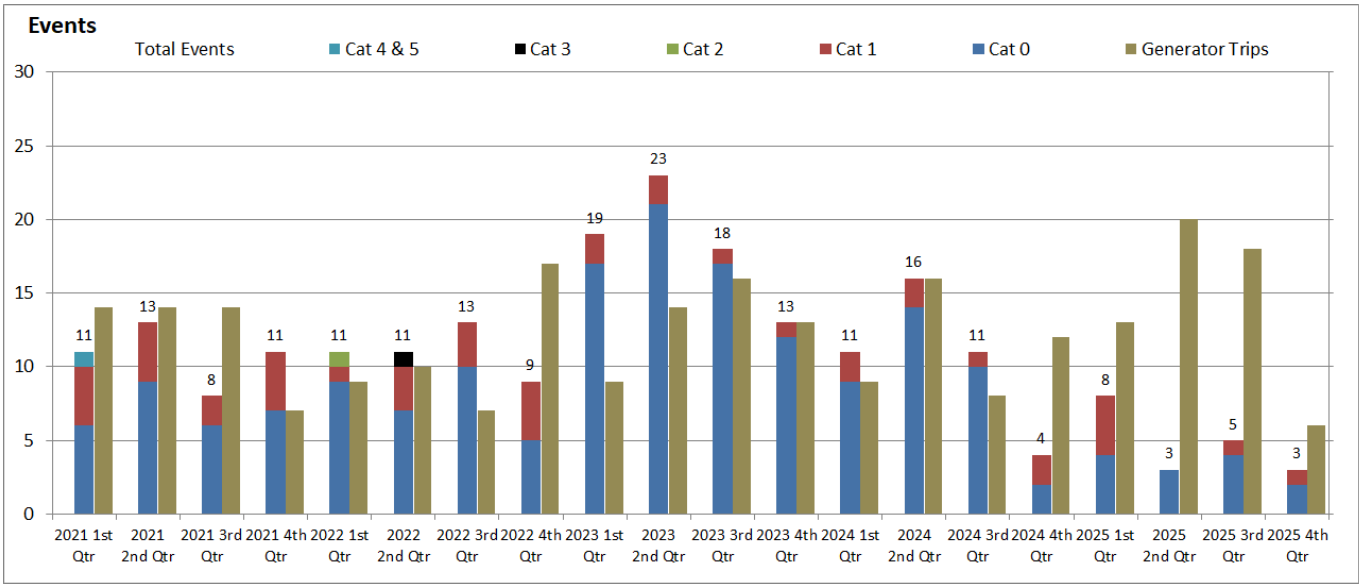


Figure B.1 – Events Reported by Quarter

[2] Link to NERC Events Analysis Process with category definitions: [ERO Event Analysis Process - Version 5]

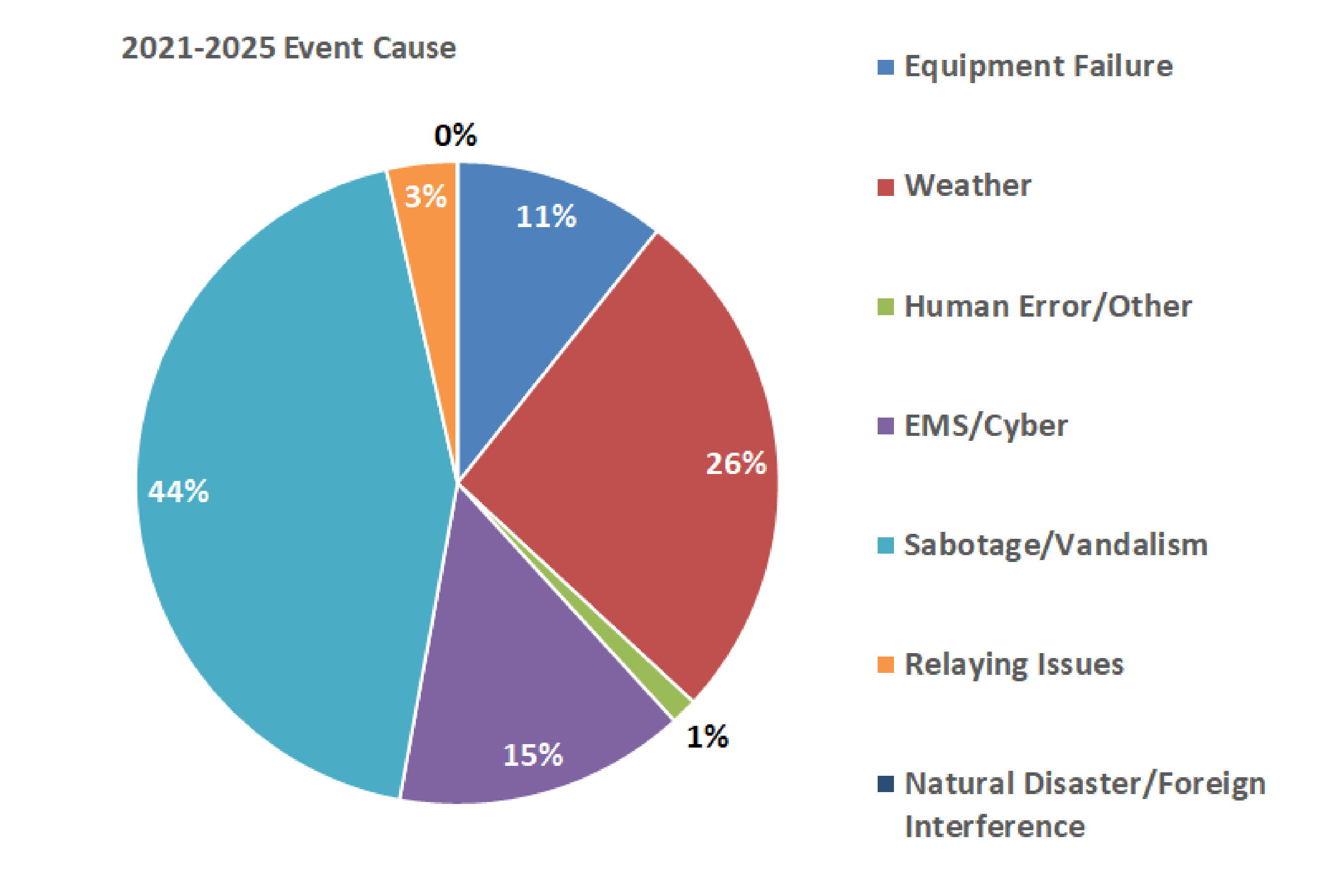


Figure B.2 – 2021-2025 Event Cause Summary

C. Transmission Circuit Outage Data

Long-term trends are indicating stable trends in outage rates per circuit and per 100 miles of line for the 345 kV and 138 kV systems. The outage rates in 2025 were at their lowest level in the last five years.

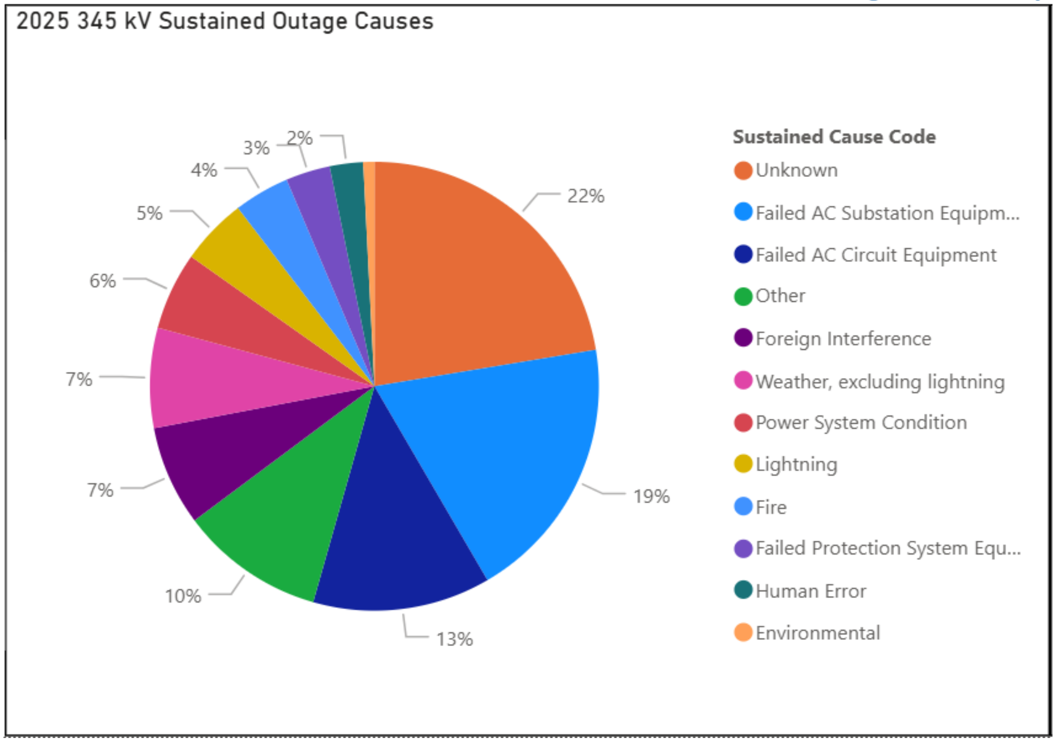
Voltage Class Name	Metric	2021	2022	2023	2024	2025	5-Yr Avg
AC Circuit 300-399 kV	Automatic Outages per Circuit	0.80	0.60	0.55	0.55	0.48	0.64
AC Circuit 300-399 kV	Automatic Outages per 100 miles	2.53	2.04	2.00	2.07	1.83	2.09
AC Circuit 100-199 kV	Sustained Automatic Outages per Circuit	0.22	0.17	0.18	0.18	0.12	0.17
AC Circuit 100-199 kV	Sustained Automatic Outages per 100 miles	1.94	1.52	1.68	1.68	1.13	1.59
Transformer 300-399 kV	Automatic Outages per Element	0.14	0.09	0.12	0.09	0.08	0.10

Table B.4 – TADS Circuit and Automatic Outage Historical Data for ERCOT Region

Automatic Outage Data

For 345 kV transmission circuits, predominant causes for sustained outages in 2025 were unknown, failed AC substation equipment, and failed AC circuit equipment, representing 54 percent of the total sustained outages. A single fire-related outage accounted for 85 percent of the outage duration.

For 138 kV transmission circuits, predominant causes for sustained outages in 2025 were failed AC circuit equipment, failed AC substation equipment, and unknown, representing 59 percent of the total sustained outages. Failed transmission circuit equipment, failed substation equipment, and foreign interference accounted for 84 percent of the outage duration.



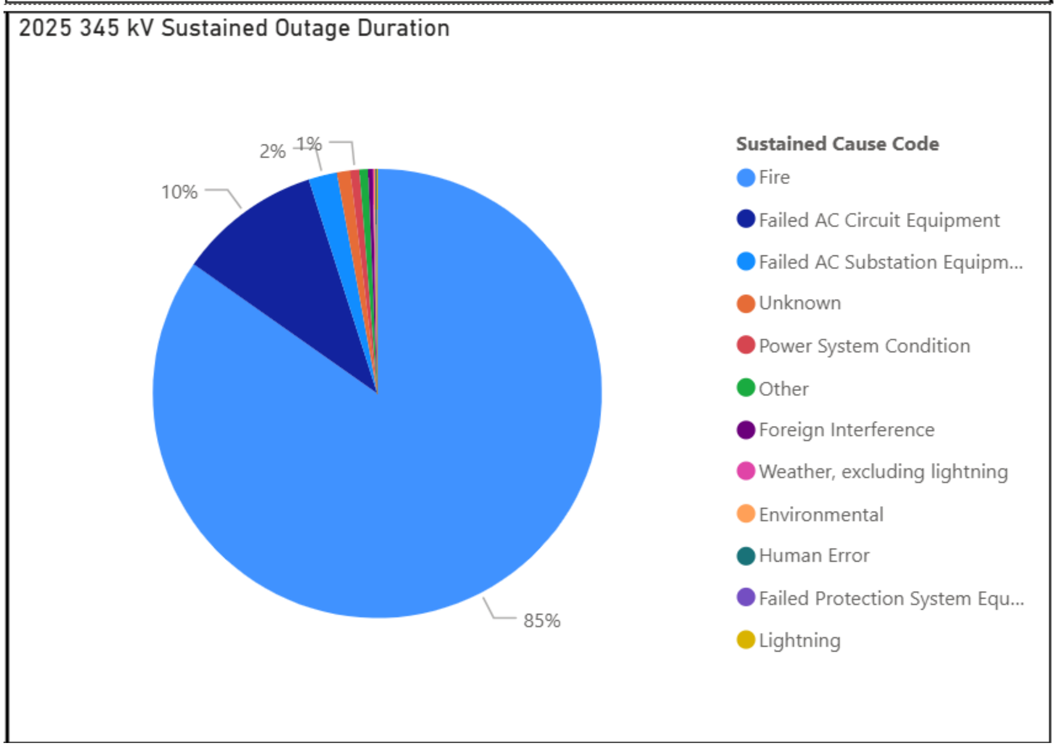
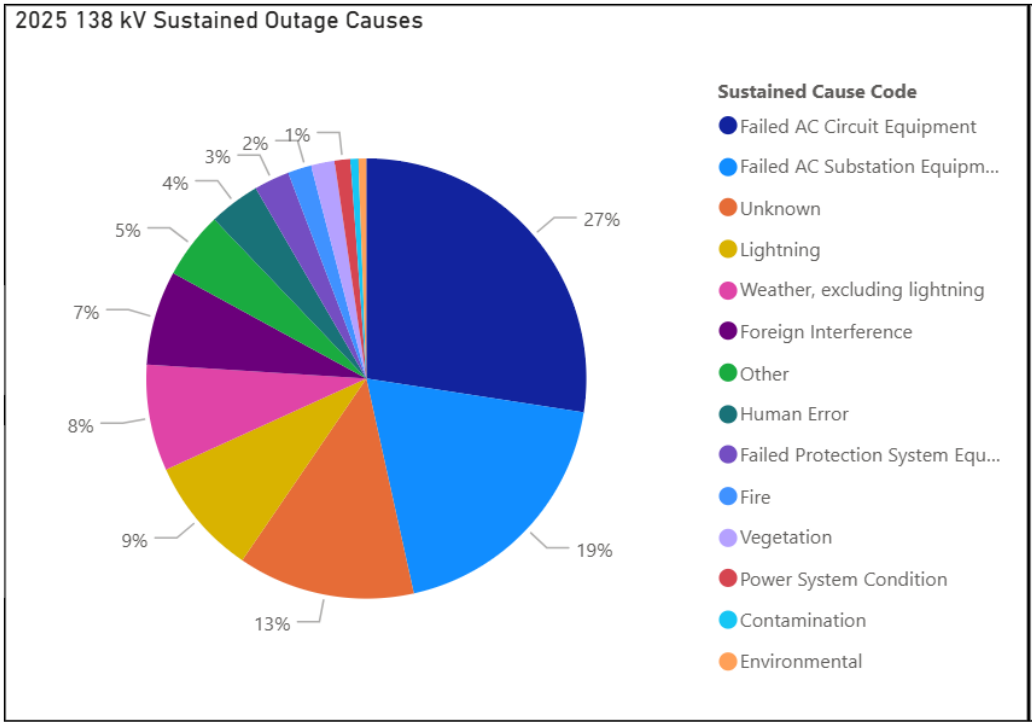


Figure B.3 – 2025 345 kV AC Circuit Sustained Outage Cause versus Duration



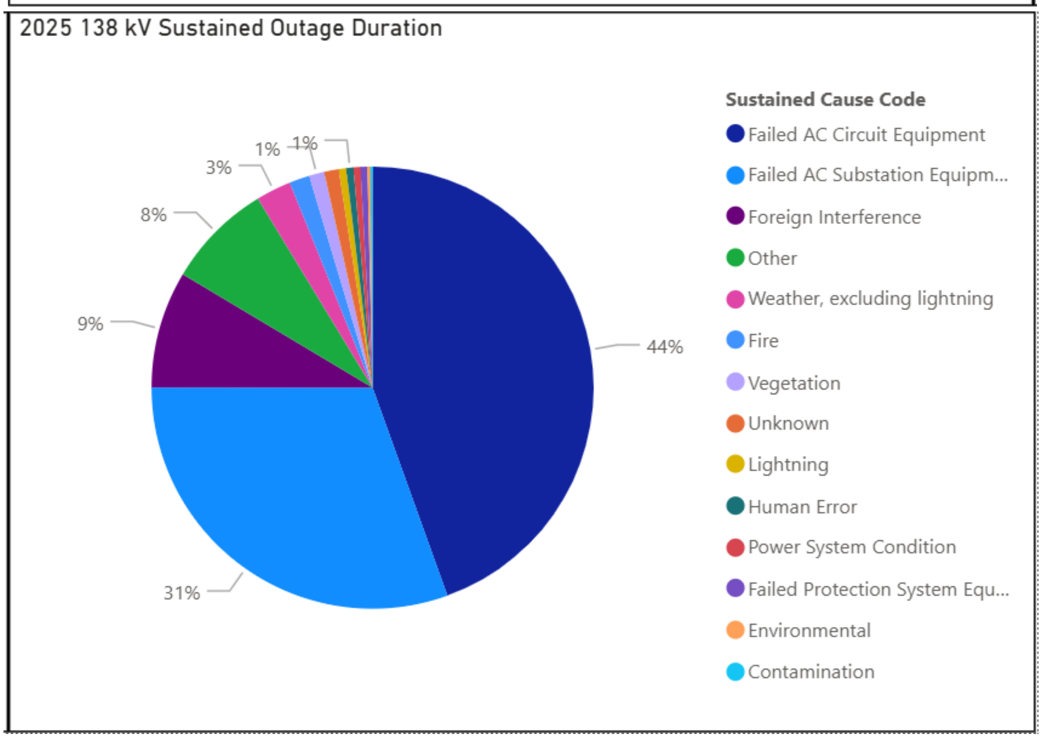


Figure B.4 – 2025 138 kV AC Circuit Sustained Outage Cause versus Duration

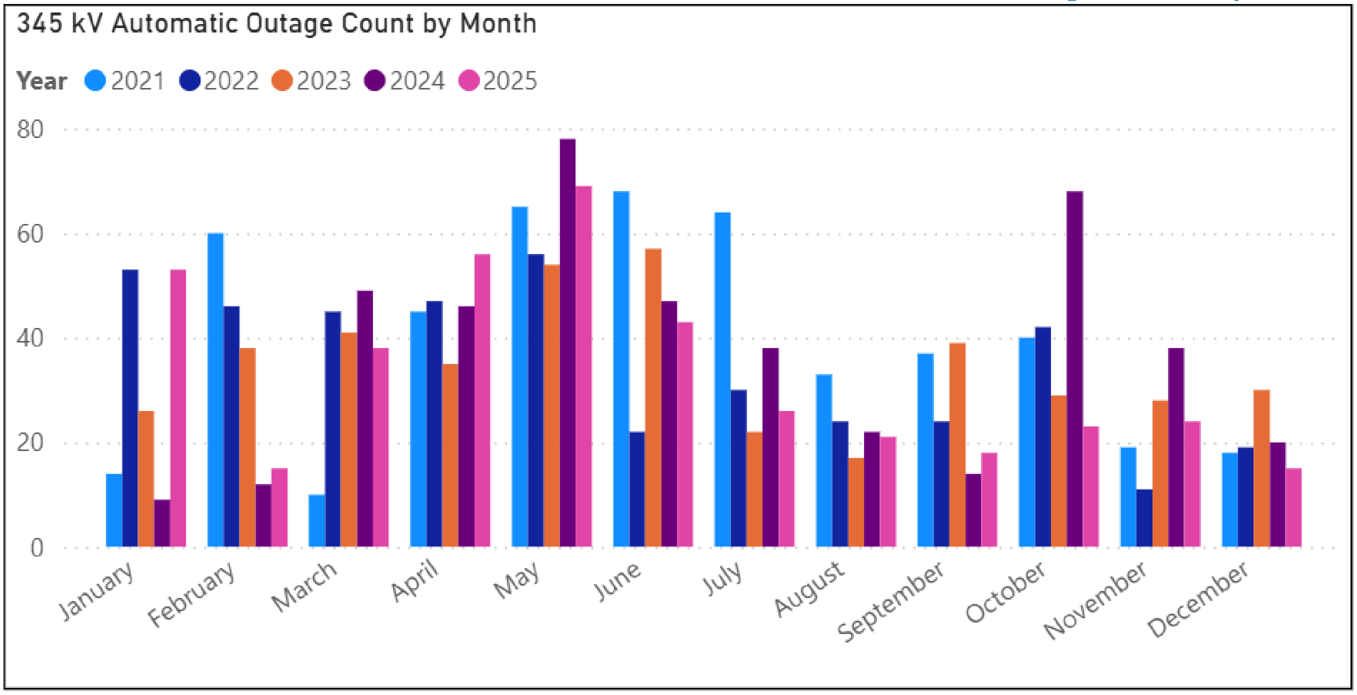


Figure B.5 – 345 kV Circuit Automatic Outages by Month

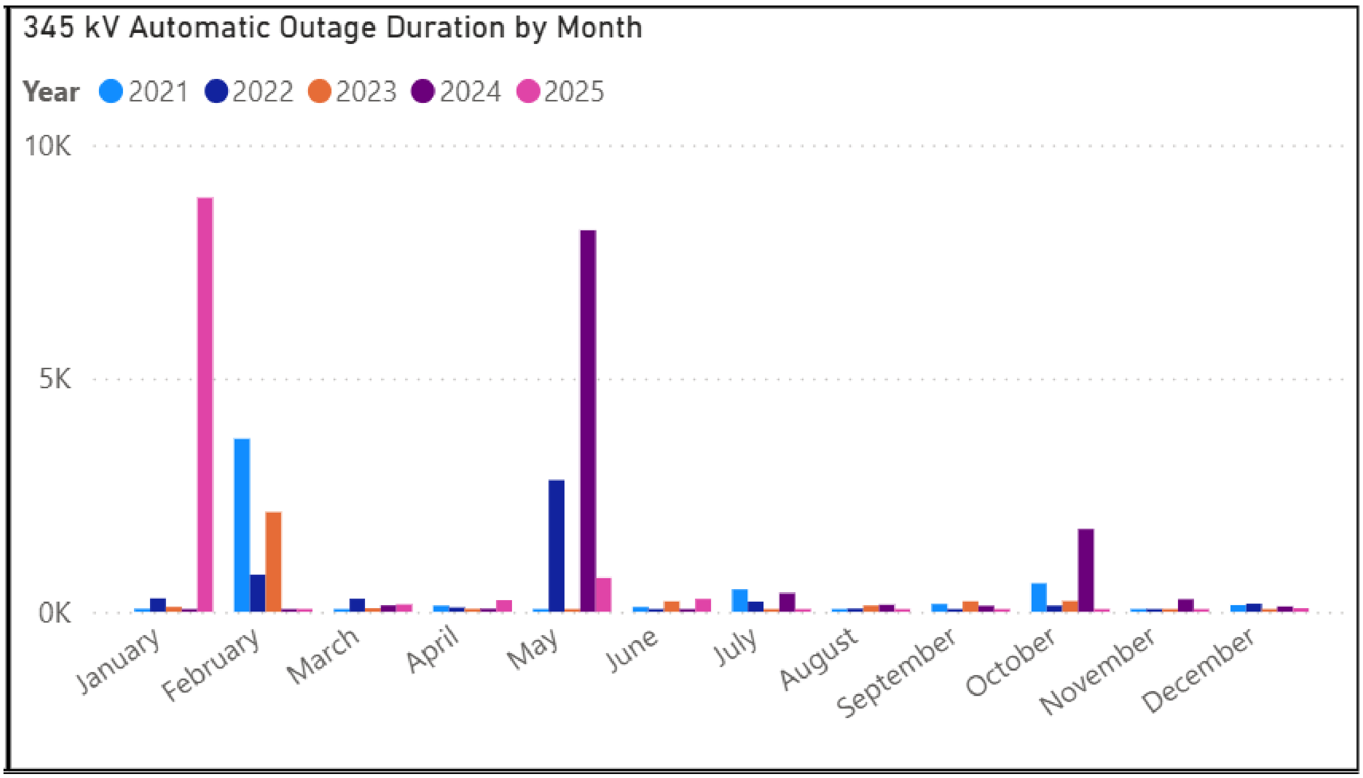


Figure B.6 – Multi-Year Comparison of TADS Outages and Duration by Month (> 200 kV)

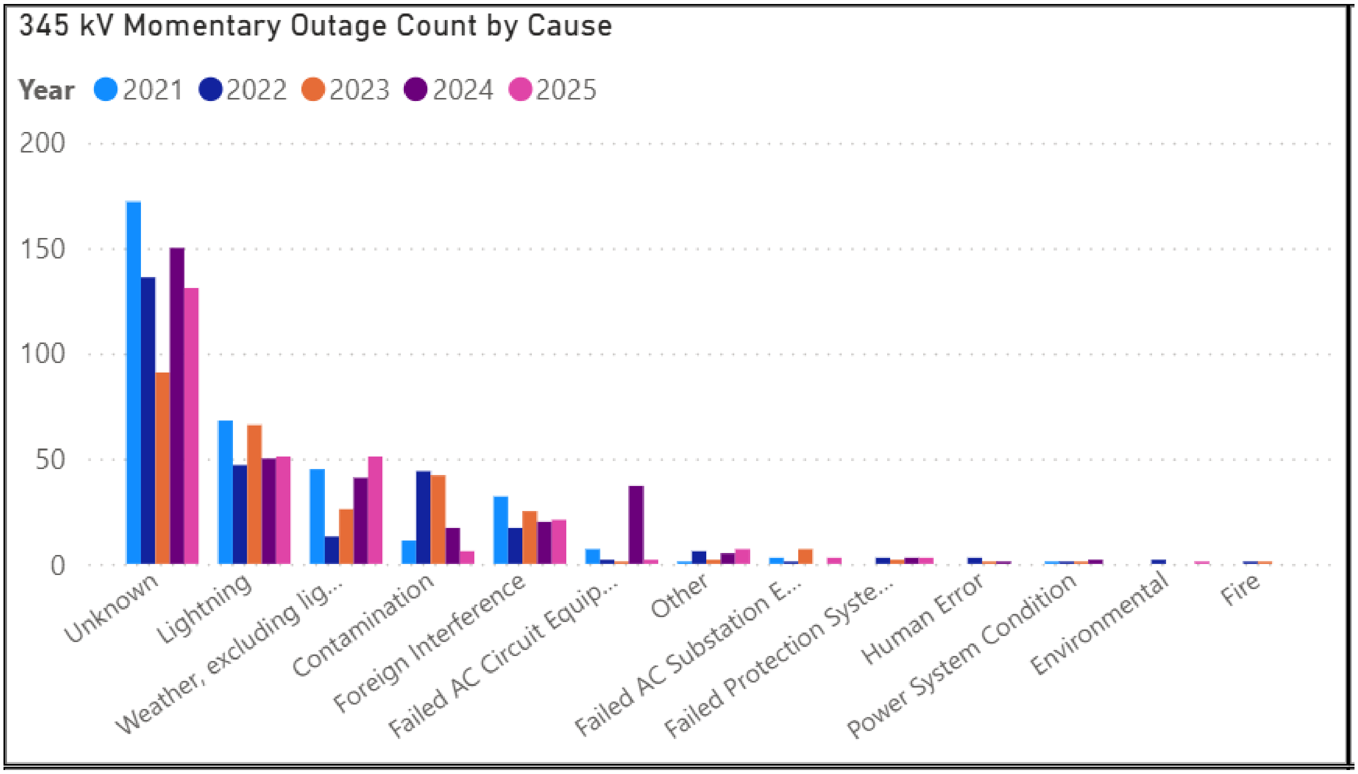


Figure B.7 – 345 kV Circuit Momentary Outage Count by Cause

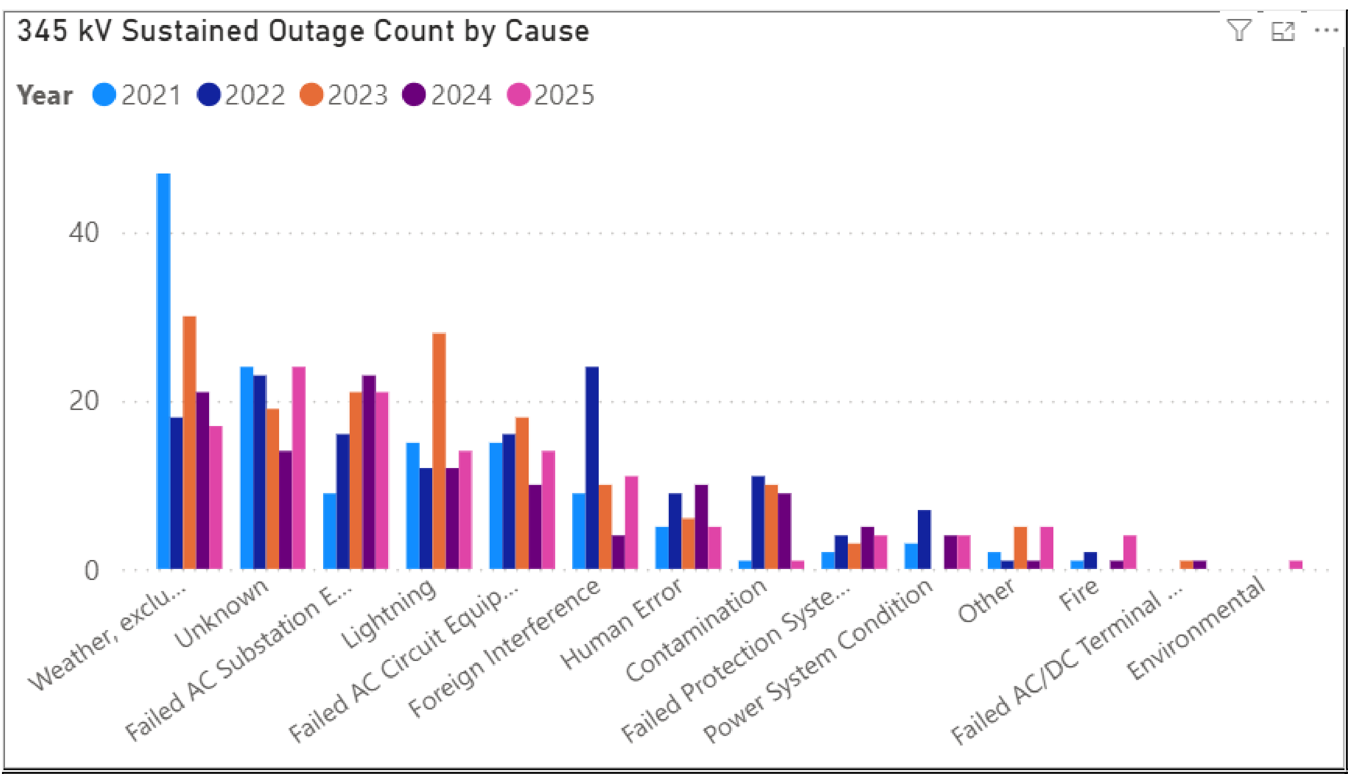


Figure B.8 – 345 kV Circuit Sustained Outage Count by Cause

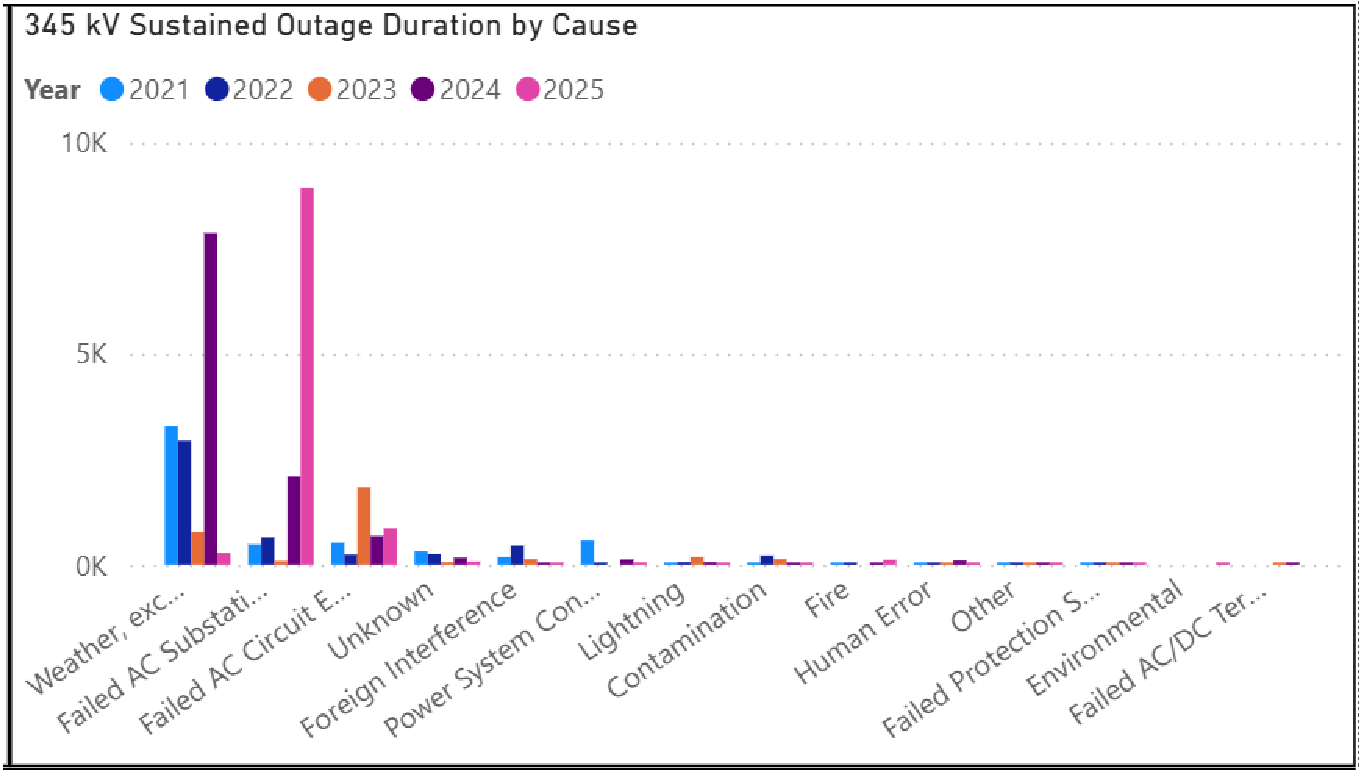


Figure B.9 – 345 kV Circuit Sustained Outage Duration (Hours) by Cause

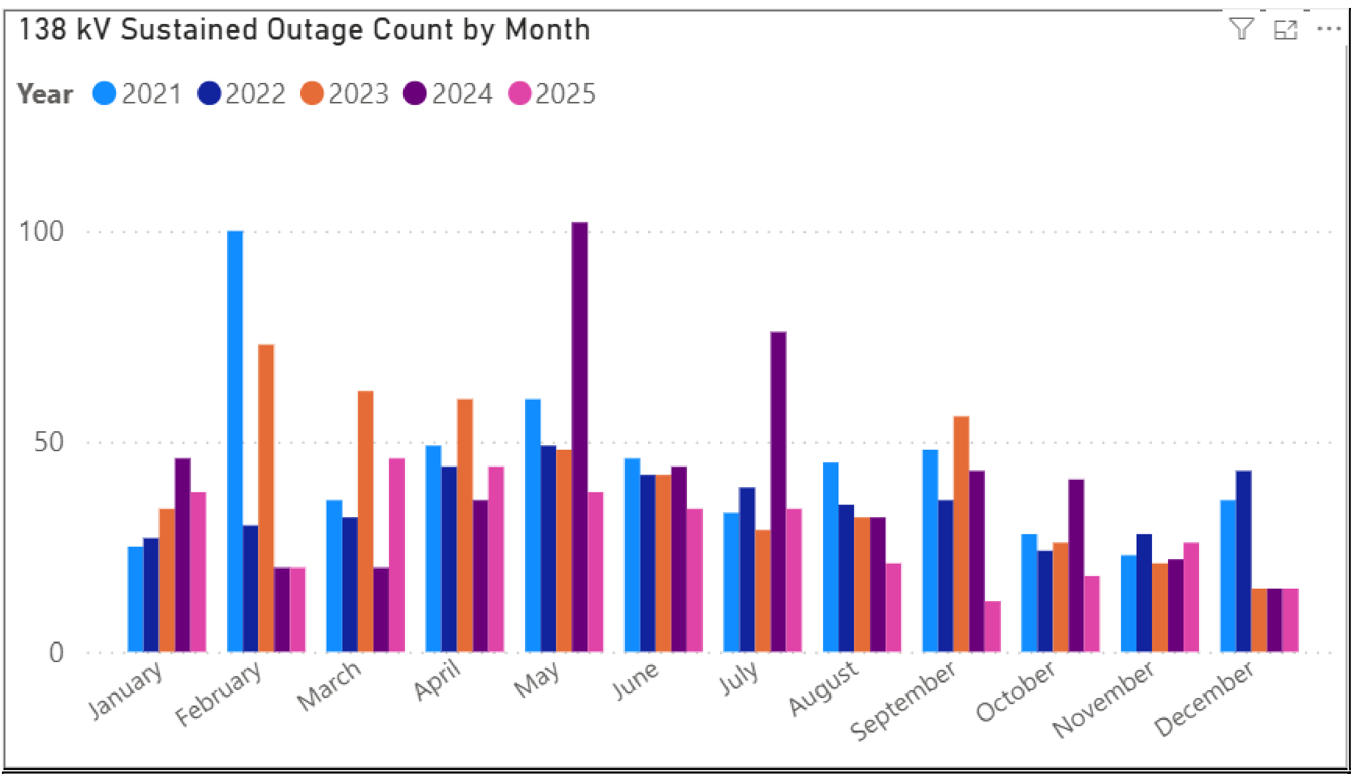


Figure B.10 – 138 kV Circuit Sustained Outage Count by Month

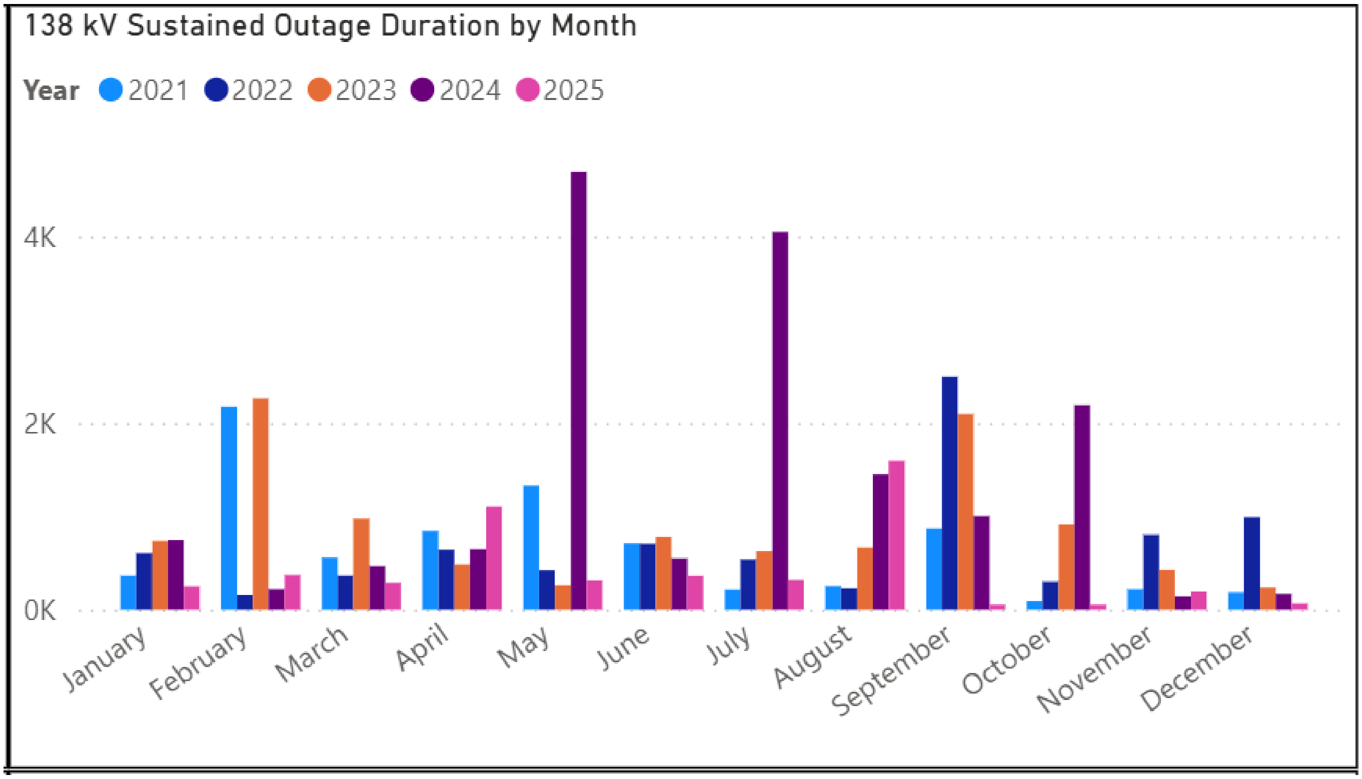


Figure B.11 – 138 kV Circuit Sustained Outage Duration (Hours) by Month

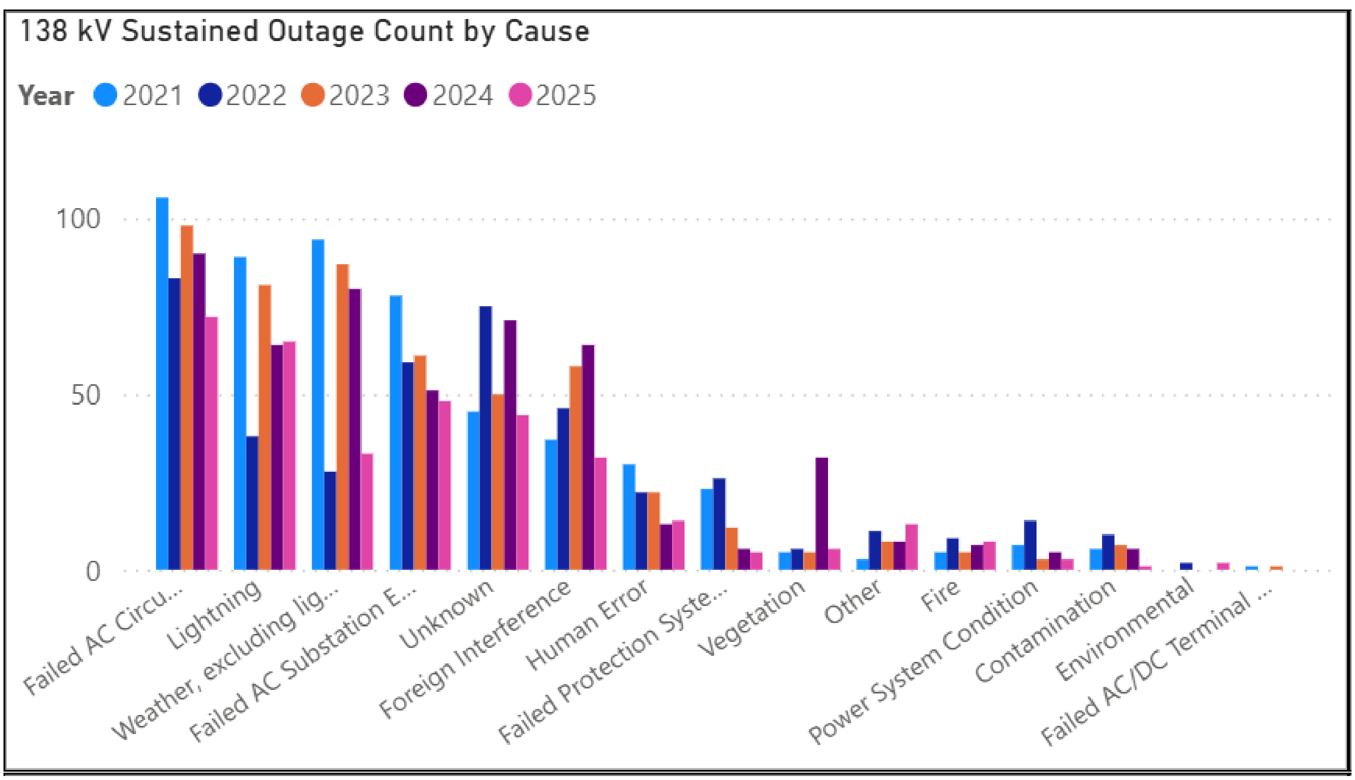


Figure B.12 – 138 kV Circuit Sustained Outage Count by Cause

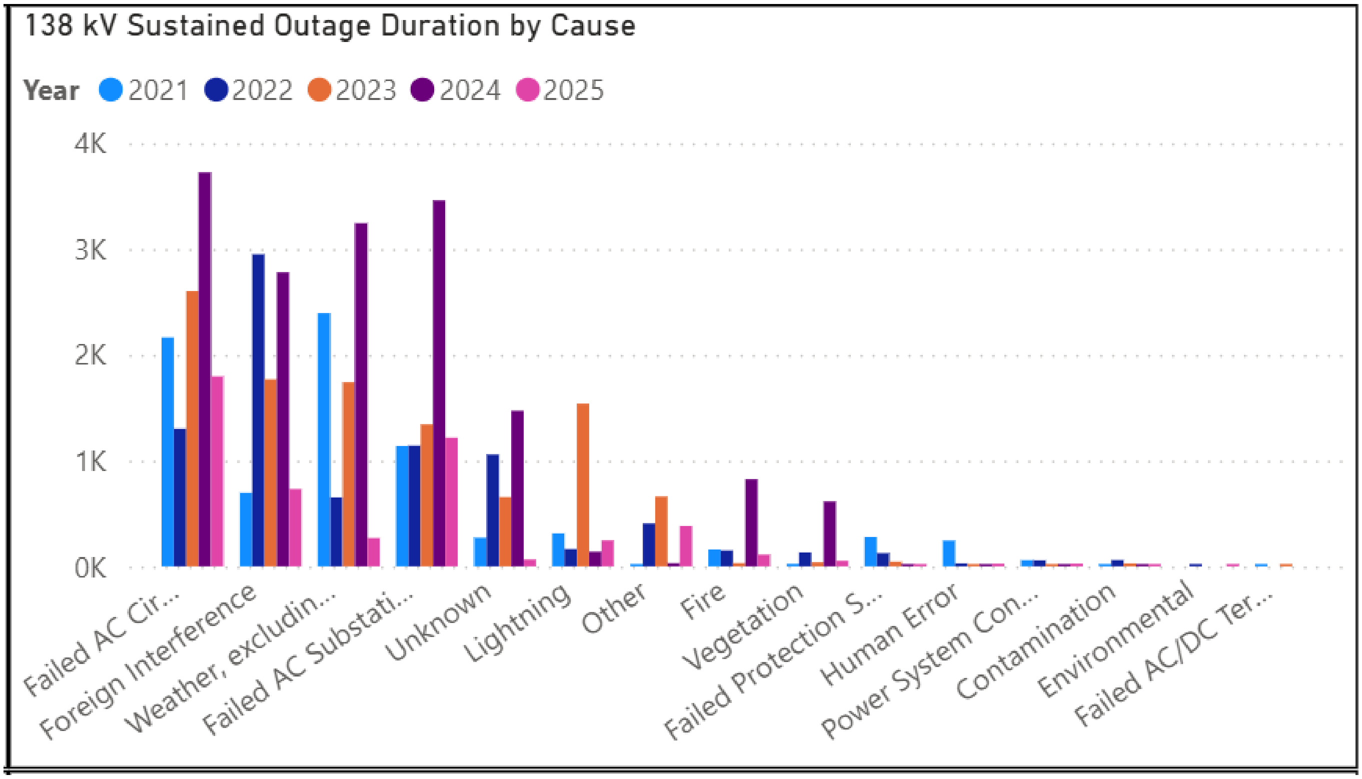


Figure B.13 – 138 kV Circuit Sustained Outage Duration by Cause

Extreme Event Periods

For transmission, "extreme days" are based on the most impactful days as determined by the number of transmission line and transformer outages as well as duration of outages. For generation, "extreme days" are based on the most impactful days as determined by the number of generation immediate forced outages, de-rates, as well as the cumulative MW impact of the outages. The following tables shows a comparison of the extreme transmission event days and extreme generation event days for 2017-2025. Extreme outage days for both generation and transmission in 2021 occurred during Winter Storm Uri.

Date	Number of Sustained Transmission Outage Events on Extreme Day	Leading Causes for Extreme Day	Average Sustained Forced Outage Duration on Extreme Day	Longest Sustained Forced Outage on Extreme Day	Average Sustained Forced Outage Duration for Year	Longest Sustained Forced Outage Duration for Year
8/26/2017	40	Weather	80 hours	257 hours	54 hours	7,594 hours
1/16/2018	50	Weather	10 Hours	72 hours	53 hours	6,403 hours
5/18/2019	19	Weather	85 hours	332 hours	31 hours	1,657 hours
10/28/2020	50	Weather	18 hours	63 hours	7 hours	99 hours
2/14/2021	43	Weather	64 hours	817 hours	20 hours	7,589 hours
3/21/2022	24	Weather	15 hours	146 hours	29 hours	1,971 hours
2/2/2023	44	Weather	18 hours	97 hours	28 hours	2,214 hours
7/8/2024	68	Weather	24 hours	122 hours	28 hours	4,356 hours
3/4/2025	29	Weather	4 hours	44 hours	36 hours	8760 hours

Table B.5 – Extreme Transmission Event Day Analyses

Date	Number of Generation Outage Events on Extreme Day	Leading Causes for Extreme Day	Cumulative Outage Duration on Extreme Day	Cumulative MW Impact on Extreme Day	Cumulative GWh Impact on Extreme Day
8/27/2017	41	Weather	22,798 hours	10,107 MW	2,917.5 GWH
1/16/2018	84	Balance of Plant/Fuel	2,891 hours	11,893 MW	517.8 GWh
5/11/2019	36	Turbine Generator	1,626 hours	6,449 MW	282.5 GWh
7/1/2020	44	Auxiliary systems	3,352 hours	8,251 MW	247.9 GWh
2/15/2021	187	Weather	6,937 hours	35,241 MW	1,204.1 GWh
12/23/2022	164	Weather	2,180 hours	23,163 MW	321.8 GWh
1/30/2023	65	Turbine Generator/Fuel	2,745 hours	9,327 MW	332.4 GWH
1/15/2024	92	Fuel, Weather	916 hours	10,200 MW	89.6 GWH
1/6/2025	74	Fuel, Weather	4,687 hours	9,884 MW	283.2 GWH

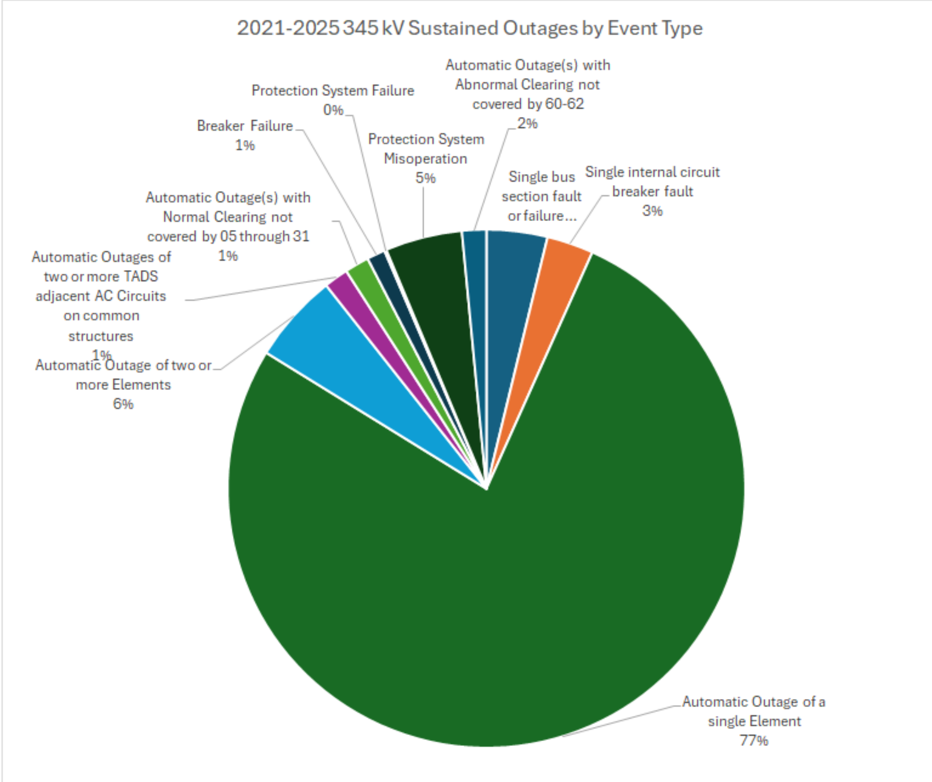
Table B.6 – Extreme Generation Event Day Analyses

D. Multiple Element Outages

For 345 kV equipment in 2025, 37 of the 424 reported automatic outage events involved two or more circuit elements. Dependent Mode outages (defined as an automatic outage of an element that occurred as a result of another outage) and Common Mode outages (defined as two or more automatic outages with the same initiating cause and occurring nearly simultaneously) represented 8.7 percent of all outages and 68.7 percent of sustained outage duration for the 345 kV system.

For 138 kV equipment in 2025, 80 of the 348 reported automatic sustained outage events involved two or more circuit elements. Dependent Mode and Common Mode outages represented 23.0 percent of all sustained outages and 24.7 percent of sustained outage duration.

Over the five-year period from 2021-2025, multiple element outages represented 19.0 percent of sustained outages and 46.9 percent of the sustained outage duration for the 345 kV system.



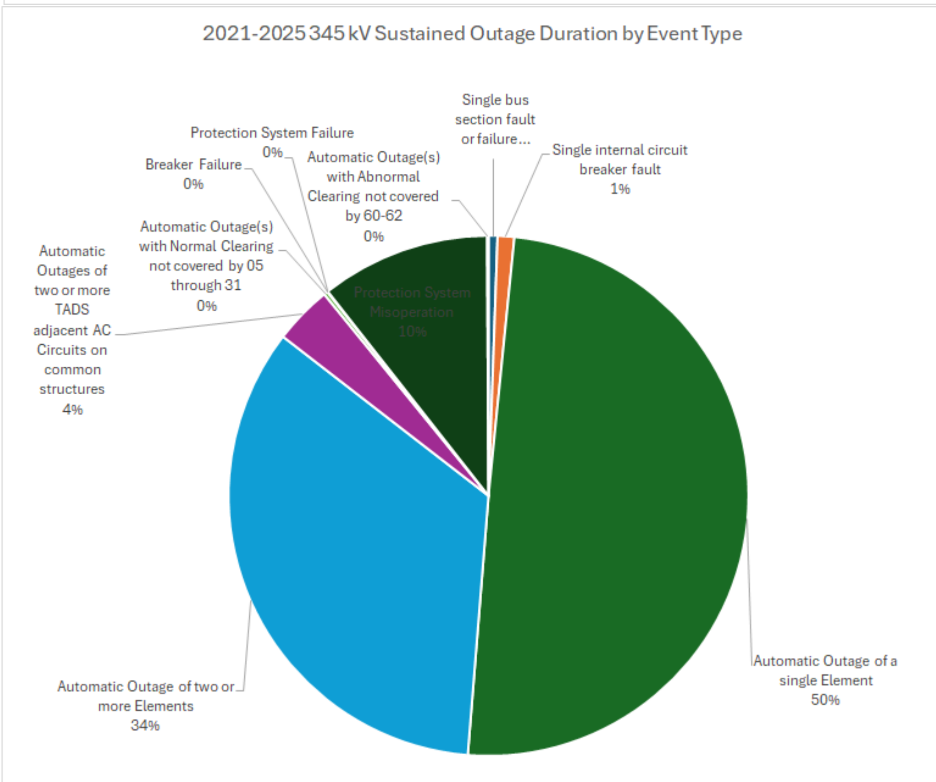


Figure B.14 – 2021-2025 345 kV Sustained Outages by Event Type

E. System Operating Limit Performance

A System Operating Limit (SOL) is the value (such as MW, Mvar, amperes, frequency, or voltage) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (applicable pre- and post-Contingency equipment or Facility Ratings)
- Transient stability ratings (applicable pre- and post-Contingency stability limits)
- Voltage stability ratings (applicable pre- and post-Contingency voltage stability)
- System voltage limits (applicable pre- and post-Contingency voltage limits)

An Interconnection Reliability Operating Limit (IROL) is an SOL that, if violated, could lead to instability, uncontrolled separation, or Cascading outages. At the end of 2025, there were eleven IROLs in the Region, based on ERCOT's System Operating Limit methodology.

Voltage stability limits, transient and control stability limits, and stability issues for interfaces are monitored and managed using Generic Transmission Limits (GTLs).

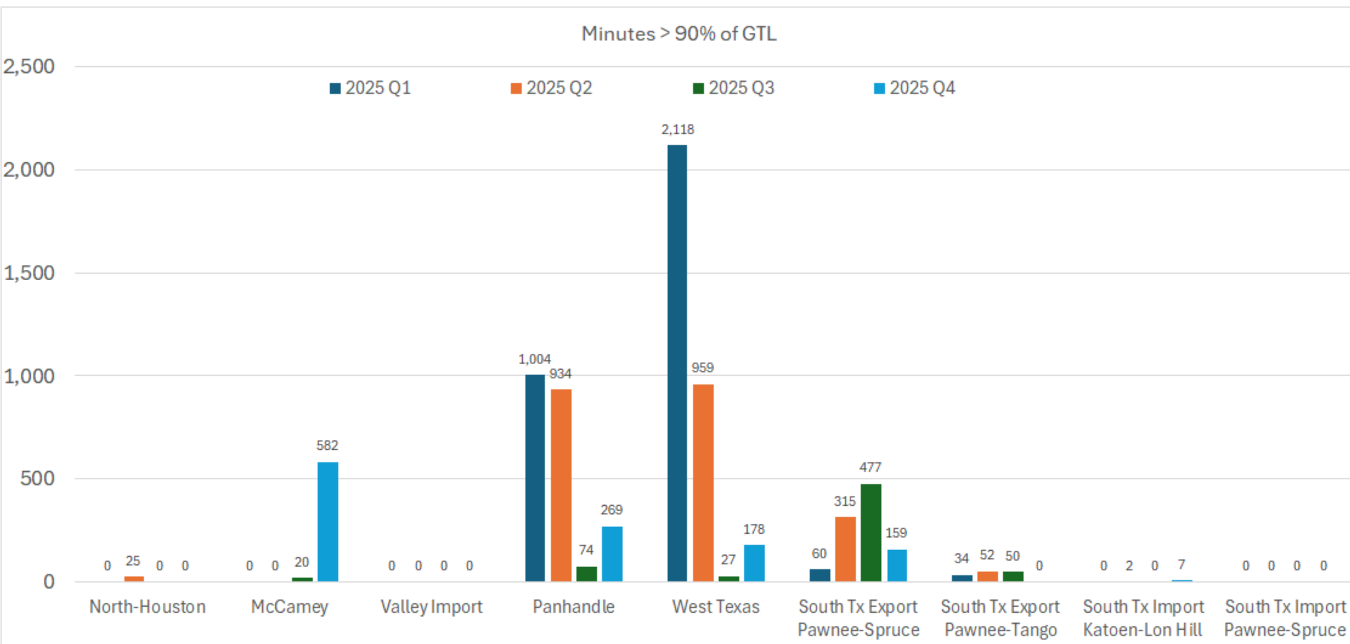


Figure B.15 – Interface Operation Minutes Greater Than 90 Percent of GTL

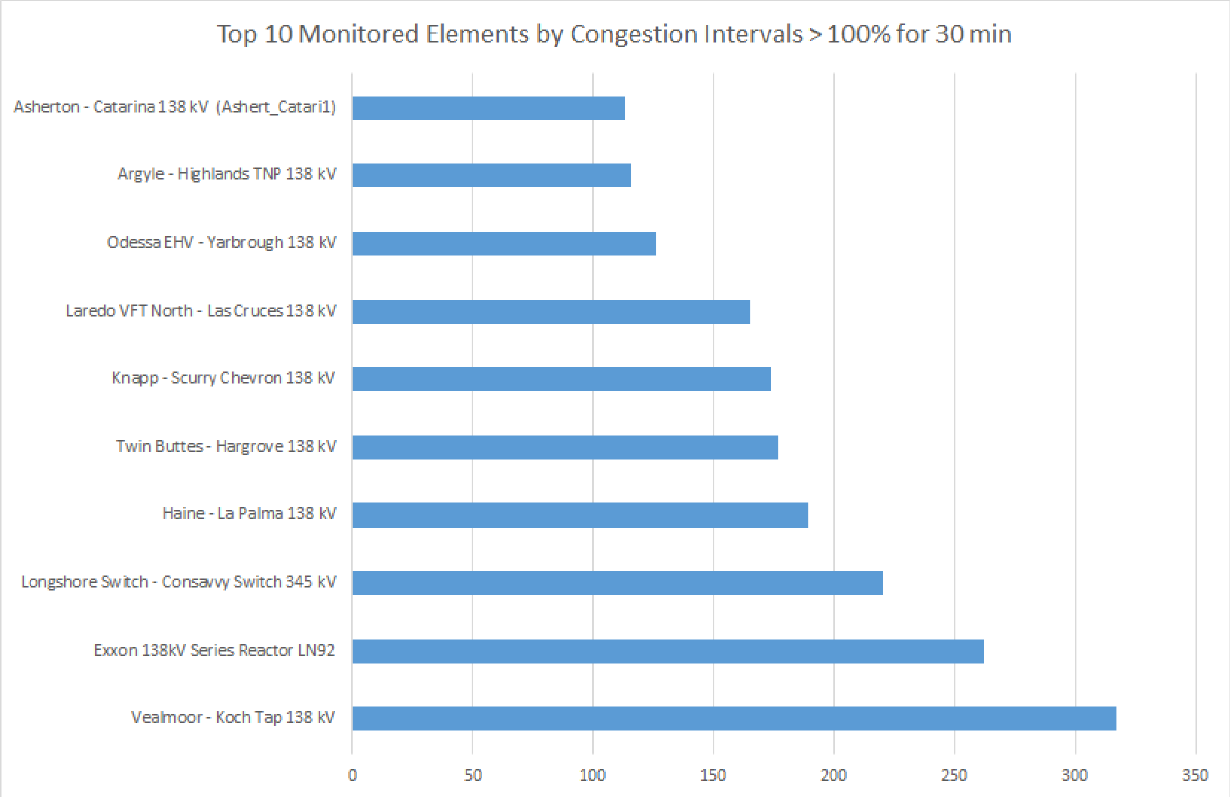


Figure B.16 – 2025 Top Constraints by Duration

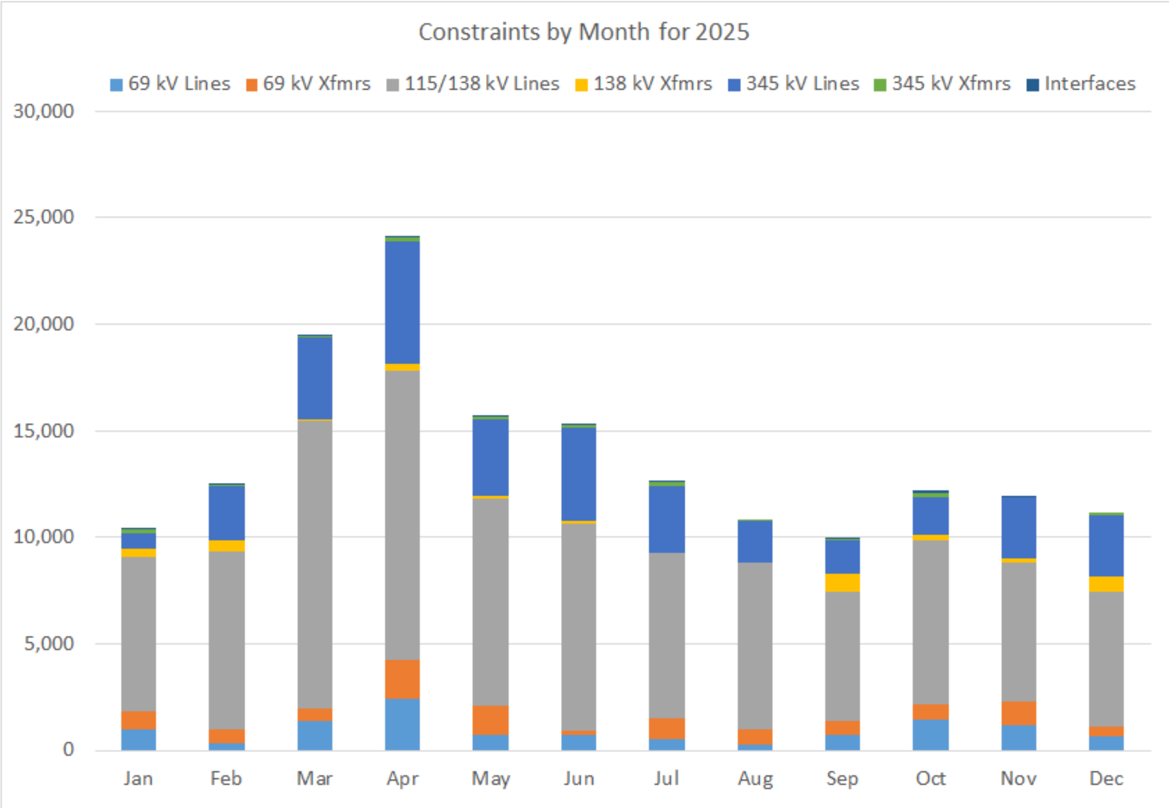


Figure B.17 – Constraints by Month for 2025

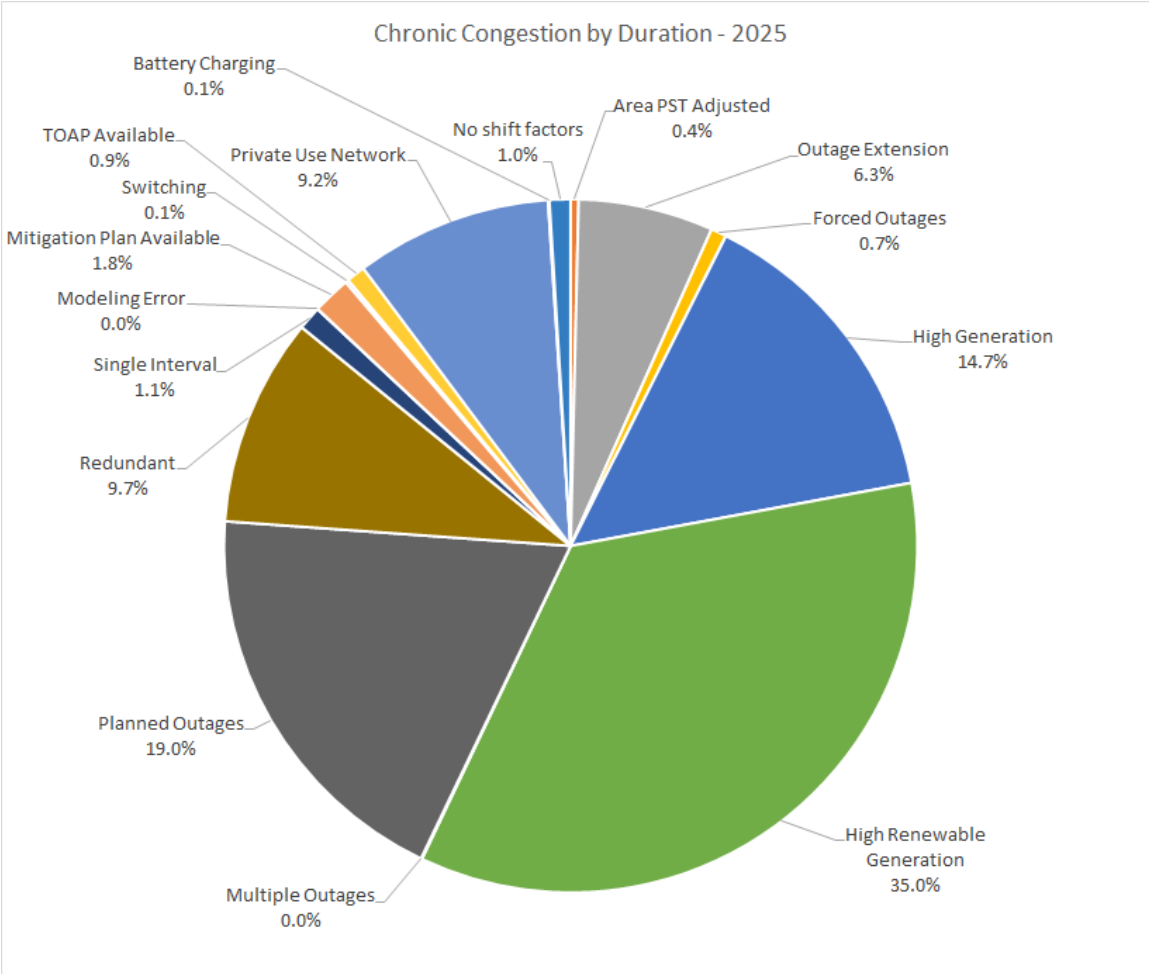


Figure B.18 – 2025 Chronic Constraint Causes by Duration

F. Reliability Unit Commitments

HRUC commitments saw a marked increase in 2025 compared to 2024. RUC commitments totaled 97 units for 5,320 commitment hours. The primary reason for HRUC commitments was constraint management on GTCs, which accounted for approximately 74 percent of all HRUC hours in 2025.

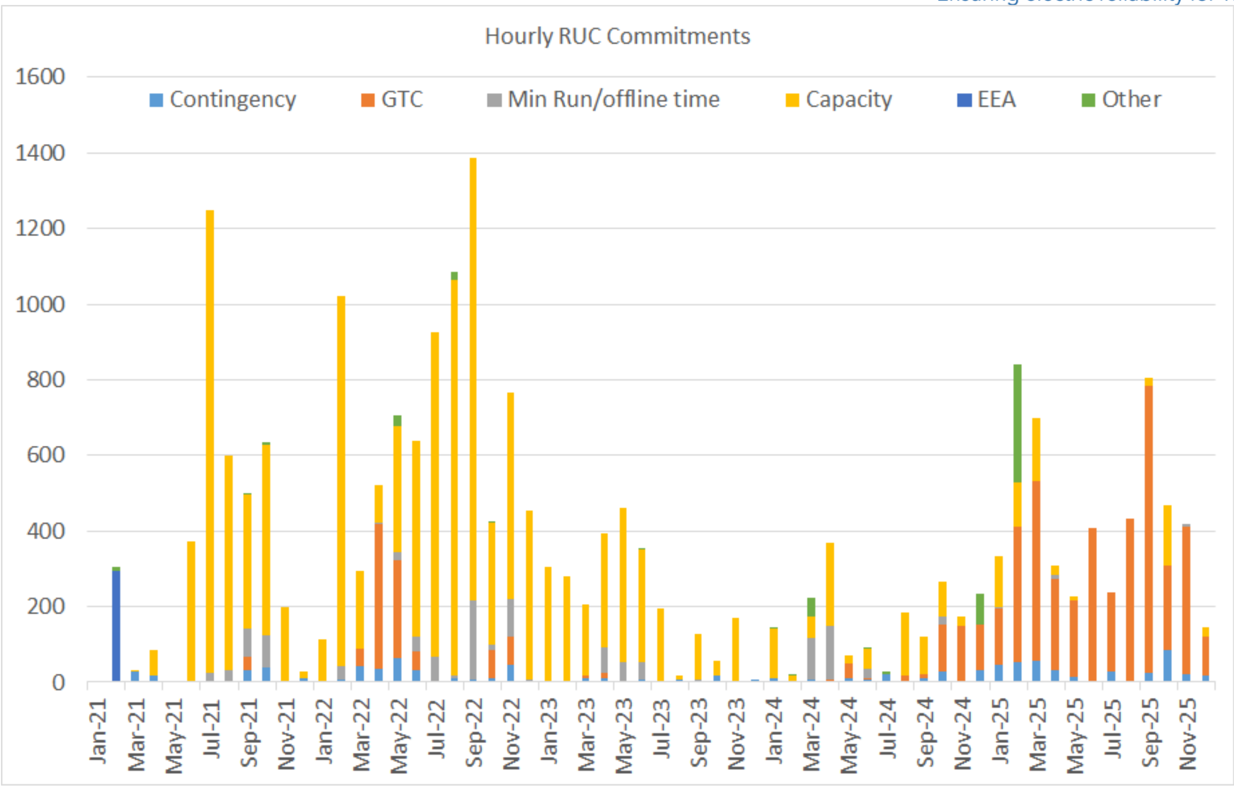


Figure B.19 – Hourly Reliability Unit Commitments by Month and Cause

Appendix C – Grid Transformation Detailed Analysis

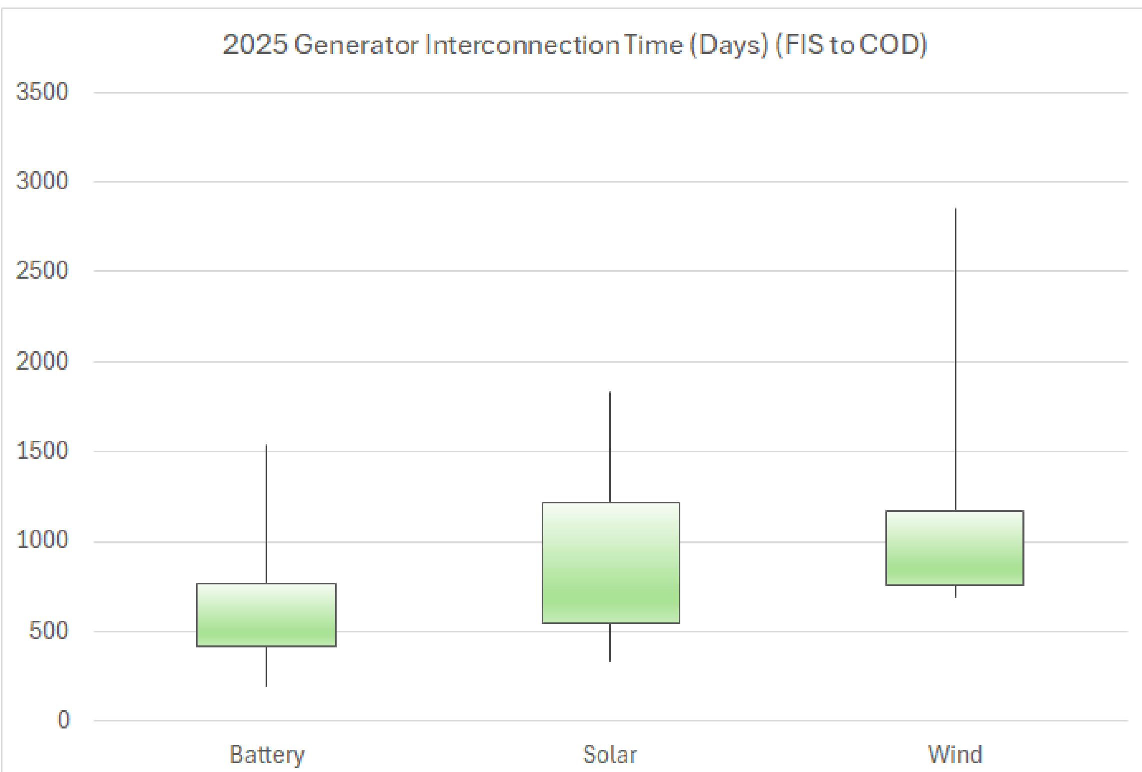
A. Unit Additions and Retirements

Retirements and Mothball Status – 1,117 MW

Unit	Date	Status	MW	Fuel Type
Air Liquide BYU G8	1/16/2025	Indefinite Mothball	4	Gas
Braunig VHB1	3/31/2025	Indefinite Mothball	217	Gas
Braunig VHB2	3/31/2025	Indefinite Mothball	230	Gas
Braunig VHB3	3/2/2025	Indefinite Mothball	412	Gas
Goat Wind	2/1/2026	Temporary Mothball	150	Wind
Hoefs Road BESS	3/1/2025	Retire	2.2	Battery
Chisholm Grid BES	10/16/2025	Temporary Mothball	102	Other

New Resources Approved for Commercial Operation – 14,583 MW

Fuel Type	Total MW	Average # Days to Connect (from FIS to COD)	Median # Days to Connect (from FIS to COD)	Minimum # Days to Connect (from FIS to COD)	Maximum # Days to Connect (from FIS to COD)
Battery	6,291	625	479	200	1,535
Solar	5,998	845	714	330	1,829
Fuel Oil	439	75	75	34	115
Wind	1,463	1,119	844	692	2,858
Gas	188	619	619	619	619



Unit	Start	COD	Days from Start to COD	MW	Fuel Type
Tortolas BESS	7/30/2021	1/6/2025	1256	50.3	Battery
7V Solar	10/21/2022	1/30/2025	832	240.63	Solar
Porter Solar	4/28/2023	1/21/2025	634	245.83	Solar
Ebony Energy Storage Repowering	10/26/2023	1/13/2025	445	5	Battery
Pioneer DJ Wind	3/28/2023	2/28/2025	703	140.32	Wind
Fence Post Solar	11/1/2023	2/13/2025	470	237.31	Solar
Great Kiskadee Storage	10/24/2023	2/14/2025	479	103.05	Battery
Myrtle Storage	1/31/2023	2/28/2025	759	151.2	Battery
Five Wells Solar	3/9/2023	3/7/2025	729	322.82	Solar
Shamrock Wind SLF	4/27/2023	3/19/2025	692	223.92	Wind
Anemoi Energy Storage Repowering	10/23/2023	3/20/2025	514	5	Battery
Burksol BESS	2/29/2024	3/31/2025	396	103.27	Battery
Danish Fields Storage	7/24/2023	4/30/2025	646	152.43	Battery
Rodeo Ranch Energy Storage Repowering	7/28/2022	4/18/2025	995	10	Battery
Big Elm Solar	7/25/2023	4/30/2025	645	201.02	Solar
PHOTON BESS1 SLF	4/10/2023	5/13/2025	764	152.74	Battery
Young Wind	5/28/2021	5/14/2025	1447	499.14	Wind
Desert Willow BESS	3/9/2024	5/12/2025	429	154.4	Battery
Angelo Solar	5/1/2023	5/6/2025	736	195.41	Solar
Cross Trails Storage	7/30/2024	5/21/2025	295	58.29	Battery
Dogfish BESS	7/31/2024	5/22/2025	295	78.2	Battery
Crawfish	7/28/2022	5/21/2025	1028	163.2	Wind
Longbow BESS	9/6/2023	5/14/2025	616	180.8	Battery
Eliza Storage	10/30/2023	6/17/2025	596	100.4	Battery
PHOTON BESS2 SLF	4/10/2023	6/16/2025	798	152.74	Battery
Ash Creek Solar	4/16/2024	6/11/2025	421	417.74	Solar
Fort Duncan BESS	7/29/2024	6/25/2025	331	101.52	Battery
Bright Arrow Solar	4/19/2022	6/30/2025	1168	305.07	Solar
Jarvis BESS	4/15/2024	6/12/2025	423	308.4	Battery
Mercury Solar SLF	10/14/2021	6/26/2025	1351	206.11	Solar
Mercury II Solar SLF	10/14/2021	6/26/2025	1351	206.11	Solar
Angelo Storage	5/1/2023	6/30/2025	791	102.97	Battery
Bright Arrow Storage	8/1/2022	6/30/2025	1064	103.56	Battery
Orange Grove Solar	7/23/2024	6/18/2025	330	130.6	Solar
Anole BESS	4/3/2024	7/22/2025	475	247.1	Battery
XE Murat [Adlong] Solar	12/6/2021	7/3/2025	1305	60.36	Solar

Plainview Solar	10/26/2020	7/22/2025	1730	514	Solar
Estonian Solar	6/29/2020	7/2/2025	1829	202.5	Solar
Padua Grid BESS	1/22/2024	7/28/2025	553	51.1	Battery
Signal Solar	9/1/2023	7/31/2025	699	51.79	Solar
Chillingham Storage	7/22/2021	7/23/2025	1462	153.93	Battery
Swift Air Solar	2/13/2024	8/7/2025	541	146.5	Solar
Lower Rio BESS	4/29/2024	8/12/2025	470	60.37	Battery
Bocanova Power	7/24/2024	8/28/2025	400	150.46	Battery
Outpost Solar	2/1/2024	8/20/2025	566	517.3	Solar
Jungmann Solar	4/25/2024	8/22/2025	484	40.21	Solar
Roadrunner Crossing Wind II SLF	5/1/2023	8/4/2025	826	126.72	Wind
Peregrine Solar	7/29/2024	8/5/2025	372	301.3	Solar
Antlia BESS	5/2/2024	8/12/2025	467	72.38	Battery
Sand Bluff Wind Repower	4/18/2022	8/15/2025	1215	0.5	Wind
Shamrock Energy Storage (SLF)	4/30/2024	8/19/2025	476	0	Battery
Roadrunner Crossing Wind SLF	4/26/2023	8/4/2025	831	128	Wind
TImmerman Power Plant	12/4/2023	8/14/2025	619	188.4	Gas
Avila BESS	7/22/2024	9/9/2025	414	164.28	Battery
Carina BESS	7/6/2021	9/18/2025	1535	154.11	Battery
Cachi BESS	7/31/2024	9/8/2025	404	205.46	Battery
Wolf Ridge Repower	5/1/2023	9/3/2025	856	9	Wind
Gransolar Texas One	1/24/2022	9/12/2025	1327	50.8	Solar
Z5 Southton DGR	8/1/2025	9/19/2025	49	29	Fuel Oil
X1 MEDINA BASE DGR	8/1/2025	9/4/2025	34	29	Fuel Oil
Markum Solar	11/28/2023	9/9/2025	651	161.54	Solar
Jaguar BESS	7/30/2024	9/9/2025	406	157.15	Battery
P2 HIGHLAND HILLS DGR	8/1/2025	9/30/2025	60	66	Fuel Oil
St. Gall II Energy Storage	10/22/2024	9/24/2025	337	100.24	Battery
Jade Storage SLF	3/29/2024	9/29/2025	549	0	Battery
Evelyn Battery Energy Storage System	7/29/2024	9/22/2025	420	221.3	Battery
Tidwell Prairie Storage 1	10/18/2024	10/23/2025	370	204	Battery
V4 Palo Alto DGR	8/1/2025	10/21/2025	81	33	Fuel Oil
Inertia BESS	7/25/2022	10/1/2025	1164	13	Battery
Walstrom BESS	3/7/2024	10/6/2025	578	205.31	Battery
Tyson Nick Solar	7/29/2024	10/6/2025	434	90.5	Solar
A4 Pearsall DGR	8/1/2025	10/10/2025	70	58	Fuel Oil
Texas Solar Nova 2	5/19/2022	10/3/2025	1233	201.14	Solar

Andromeda Storage SLF	7/30/2024	10/6/2025	433	0	Battery
Q1 Valley Road DGR	8/1/2025	10/15/2025	75	29	Fuel Oil
Hornet Solar	10/6/2021	10/20/2025	1475	602.37	Battery
K2 Nacogdoches DGR	8/1/2025	10/30/2025	90	58	Fuel Oil
Z0 BECK ROAD DGR	8/1/2025	11/6/2025	97	60	Fuel Oil
Tanzanite Storage	12/14/2023	11/12/2025	699	265.8	Battery
V2 Brooks Field DGR	8/1/2025	11/24/2025	115	76.5	Fuel Oil
Stampede Solar	11/1/2023	11/20/2025	750	256.34	Solar
Hart Wind	11/13/2023	11/12/2025	730	163.4	Wind
Parliament Solar	4/25/2024	11/26/2025	580	484.56	Solar
Stillhouse Solar	10/31/2024	11/4/2025	369	210.8	Battery
Blevins Storage	6/24/2024	11/26/2025	520	181.33	Battery
Cottonwood Bayou Storage	3/25/2024	12/11/2025	626	153.03	Battery
Corazon Storage	10/31/2024	12/24/2025	419	204.8	Battery
Capricorn IV repower	2/6/2018	12/4/2025	2858	9	Wind
Morrow Lake Solar	11/1/2023	12/31/2025	791	201.1	Solar
Black Springs BESS	8/17/2023	12/23/2025	859	120.68	Battery
Jaguar BESS_1	6/5/2025	12/22/2025	200	157.1	Battery
Lucky Bluff BESS SLF	10/23/2024	12/24/2025	427	100.8	Battery
XE Murat [Adlong] Storage	5/2/2023	12/30/2025	973	60.14	Battery

Table C.1 – 2025 Unit Additions and Retirements

B. Fuel Mix Analysis

Wind generation reporting in GADS-Wind produced a net total of 103,597 GWh in 2025, or 90.1 percent of the total ERCOT wind generation for 2025. Wind generation, as a percentage of total ERCOT energy produced was 23.3 percent in 2025, compared to 24.1 percent in 2024. In 2025, hourly wind generation reached a maximum of 28,264 MW on March 3, 2025, at 10:00 p.m.

Utility-scale solar generation within the region continued its significant growth in 2025. Solar generation reporting in GADS-Solar produced a net total of 43,459 GWh in 2025, or 64.4 percent of the total ERCOT solar generation for 2025. The amount of energy provided by solar generation was 13.7 percent in 2025 compared to 10.3 percent in 2024, an increase of 41 percent versus 2024. In 2025, hourly solar generation reached a maximum of 29,503 MW on September 9, 2025, at 12:00 p.m.

Wind energy curtailments totaled 5,704 GWh in 2025, which was an increase of 7.1 percent from 2024. Solar energy curtailments totaled 4,072 GWh in 2025, which was an increase of 34.1 percent from 2024.

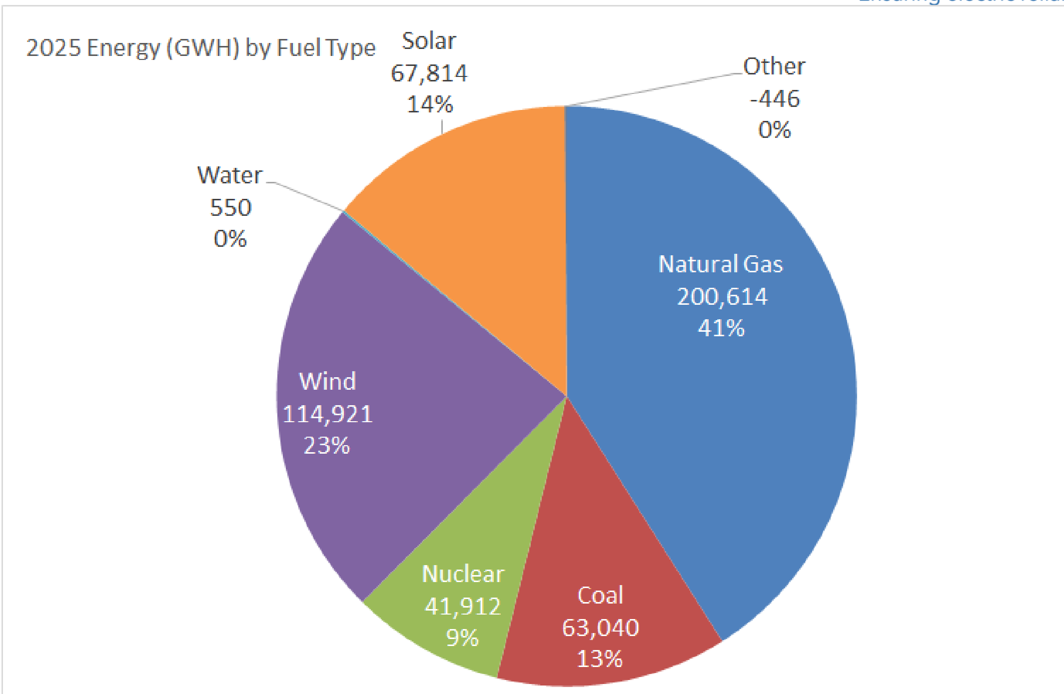


Figure C.1 – 2025 Energy by Fuel Type

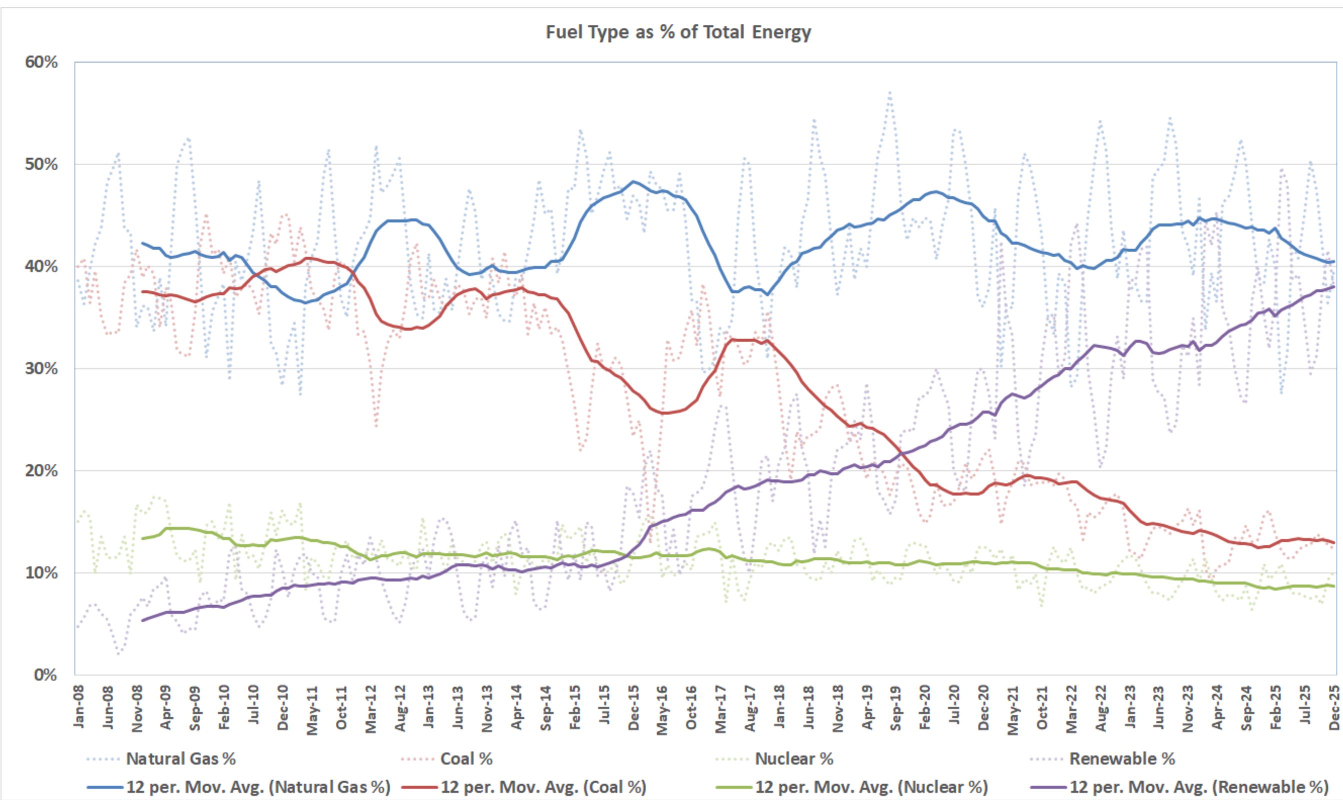


Figure C.2 – Energy by Fuel Type Trend

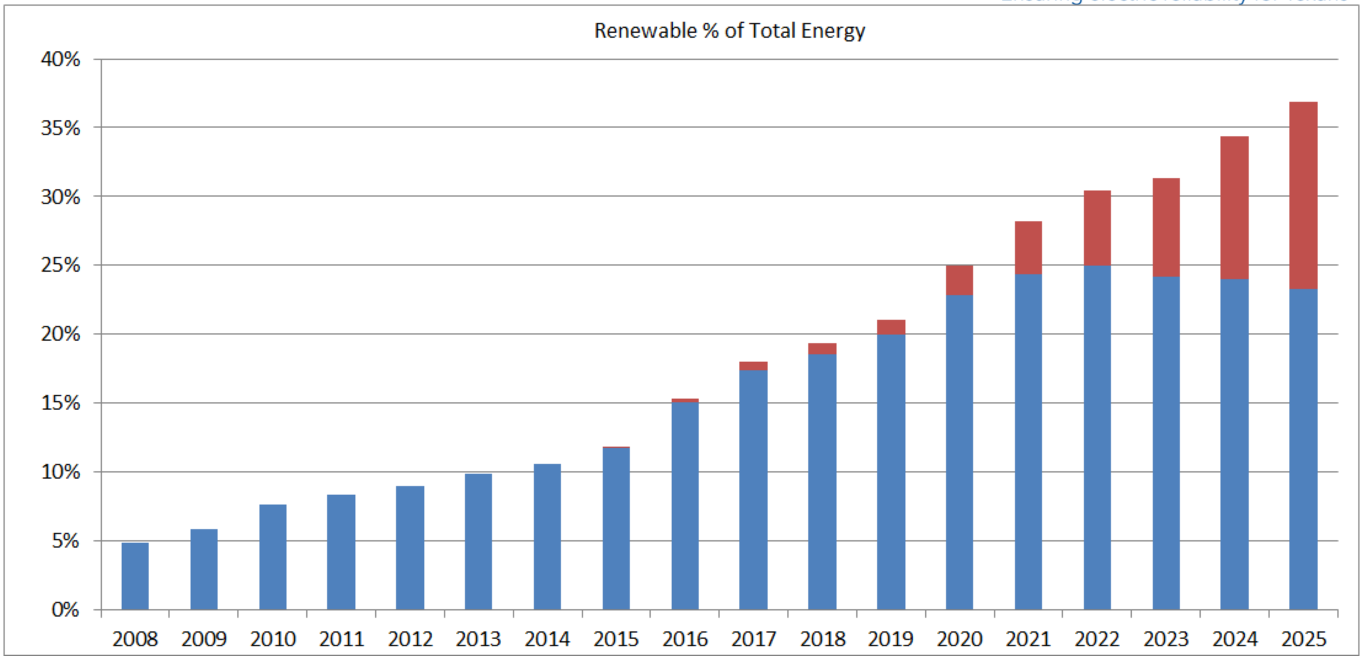


Figure C.3 – Renewable Energy Percentage of Total Load Time Trend

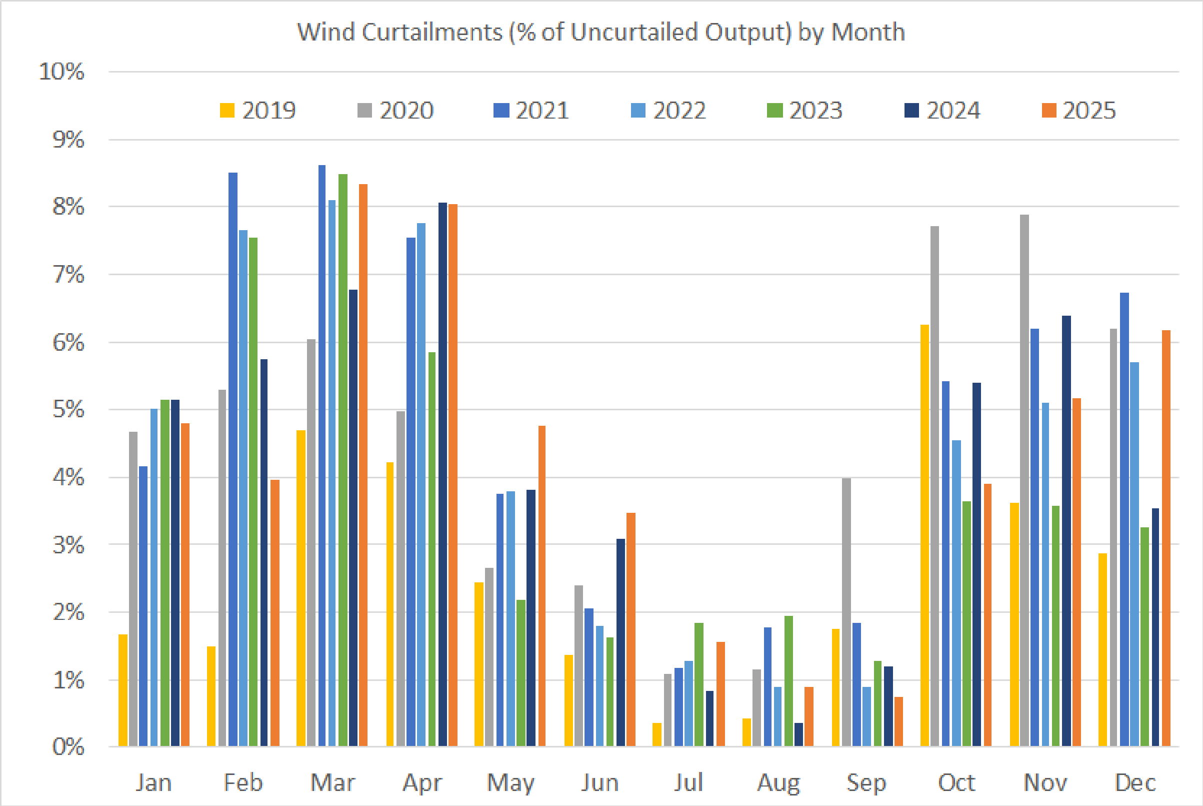


Figure C.4 – Wind Curtailments as a Percentage of Uncurtailed Output by Month

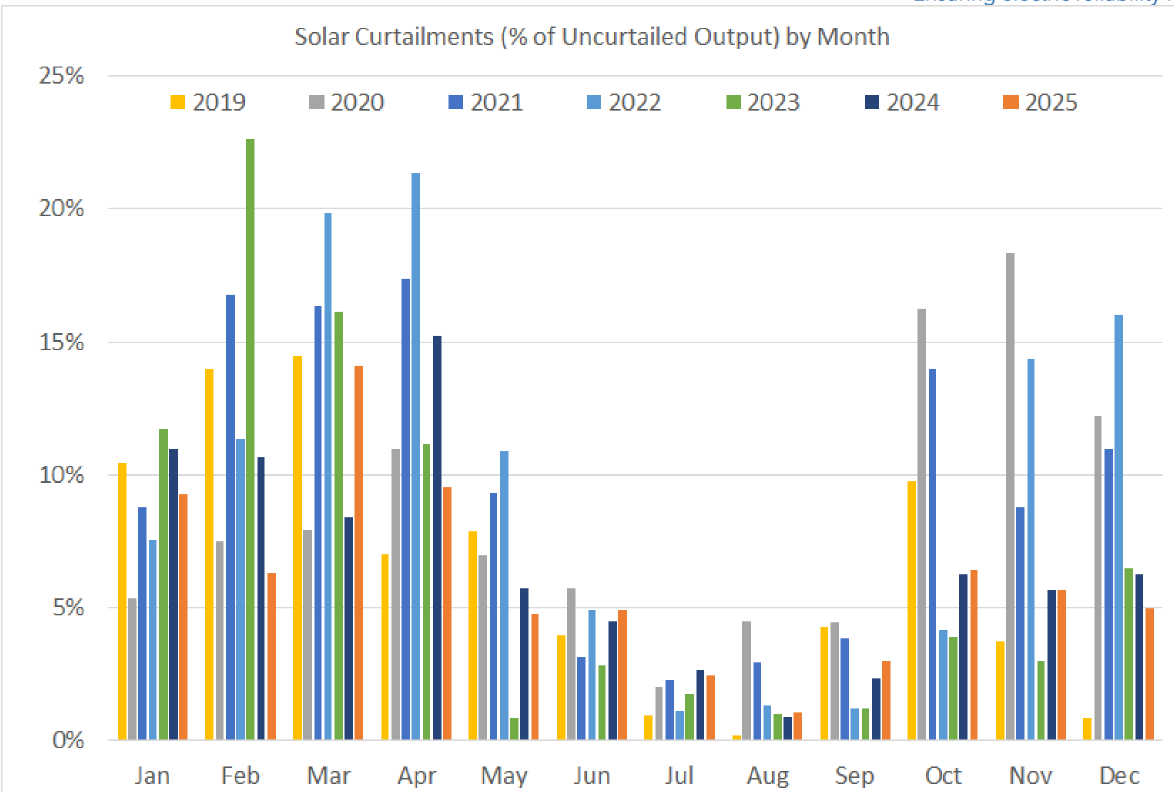


Figure C.5 – Solar Curtailments as a Percentage of Uncurtailed Output by Month

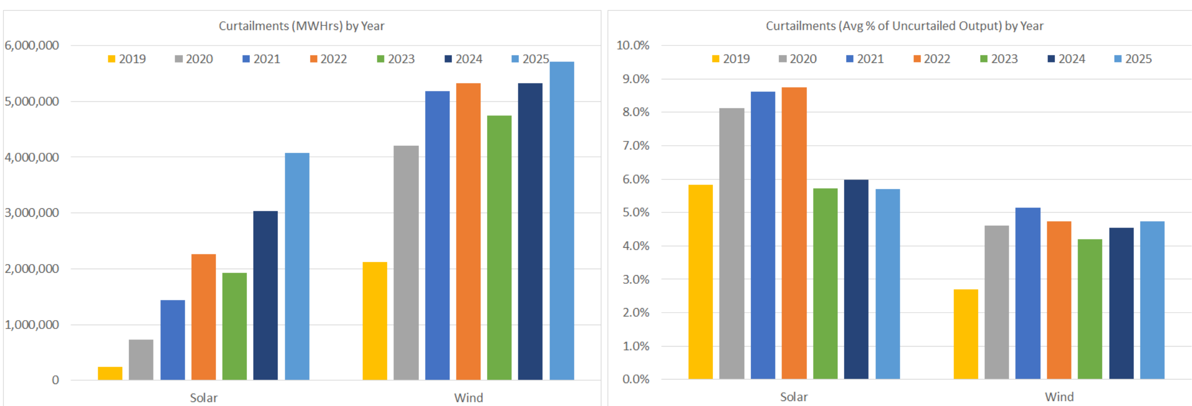


Figure C.6 – Wind/Solar Curtailments MWh and Percentage by Year

C. Synchronous Inertia

ERCOT calculated that the critical inertia level for the Interconnection is approximately 94 Gigawatt-seconds (GWs). ERCOT uses a critical inertia level of 100 GWs for its operating procedures and in particular its forward projections for ancillary services procurement of responsive reserves in the day-ahead market.

The minimum hourly inertia level in 2025 was 118.3 GWs, on March 18, 2025, at HE12, when the IRR penetration level was 74.9 percent and system load was 48,973 MW (net load of 12,290 MW).

Year	Minimum Inertia (GWs)	Load (MW)	Net Load (MW)	IRR %	# Hours < 150 GWs
2015	130.3	27,798	20,569	26.1%	189
2016	138.4	26,839	14,797	44.9%	42
2017	130.0	28,443	13,178	53.7%	174
2018	128.8	28,412	13,452	52.7%	41
2019	134.6	29,426	14,645	50.2%	79
2020	131.1	31,505	13,541	57.0%	149
2021	116.6	31,904	10,905	65.8%	580
2022	115.0	33,365	11,445	65.7%	492
2023	124.3	35,799	13,817	61.4%	165
2024	129.9	37,297	11,912	68.1%	120
2025	118.3	48,973	12,290	74.9%	203

Table C.2 – Minimum Inertia for 2015-2025

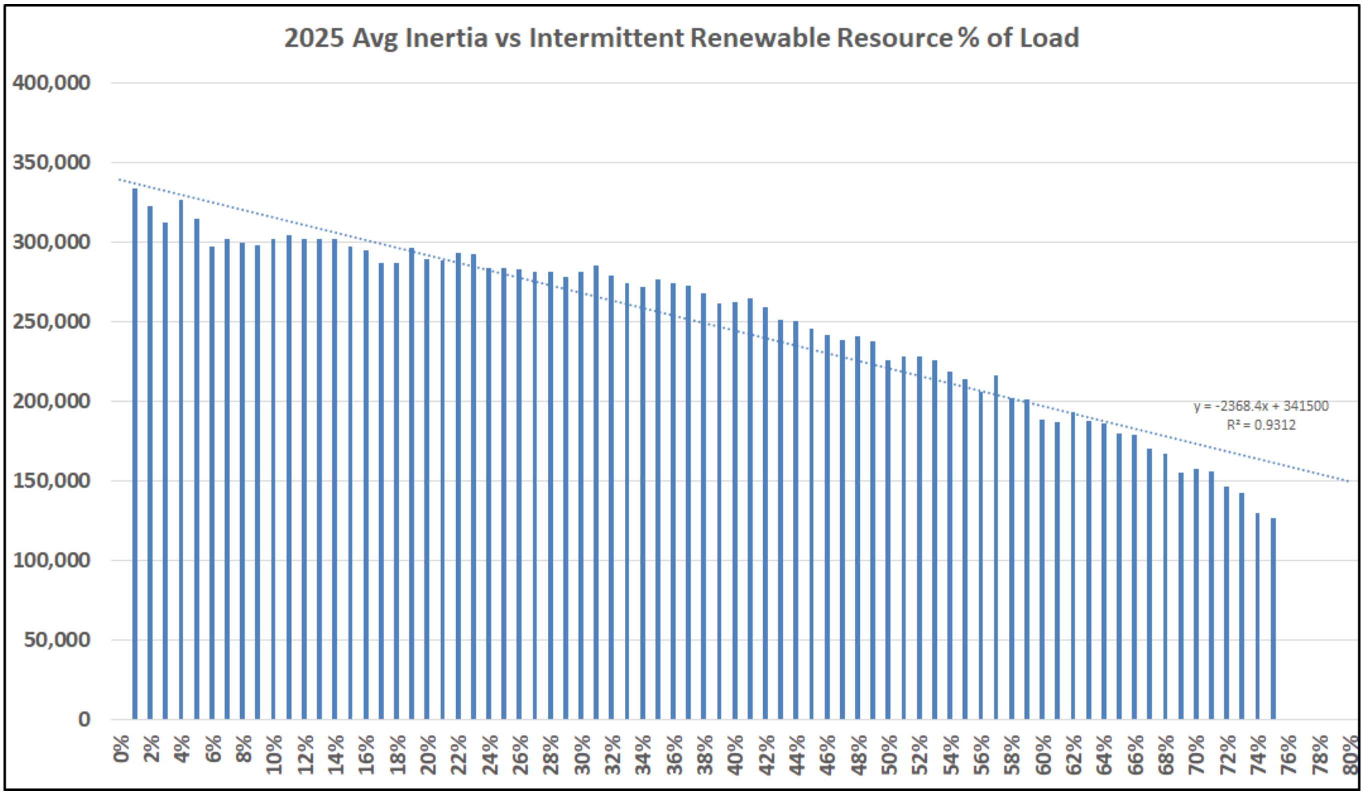


Figure C.7 – 2025 Average Inertia versus Renewable Percentage of Load

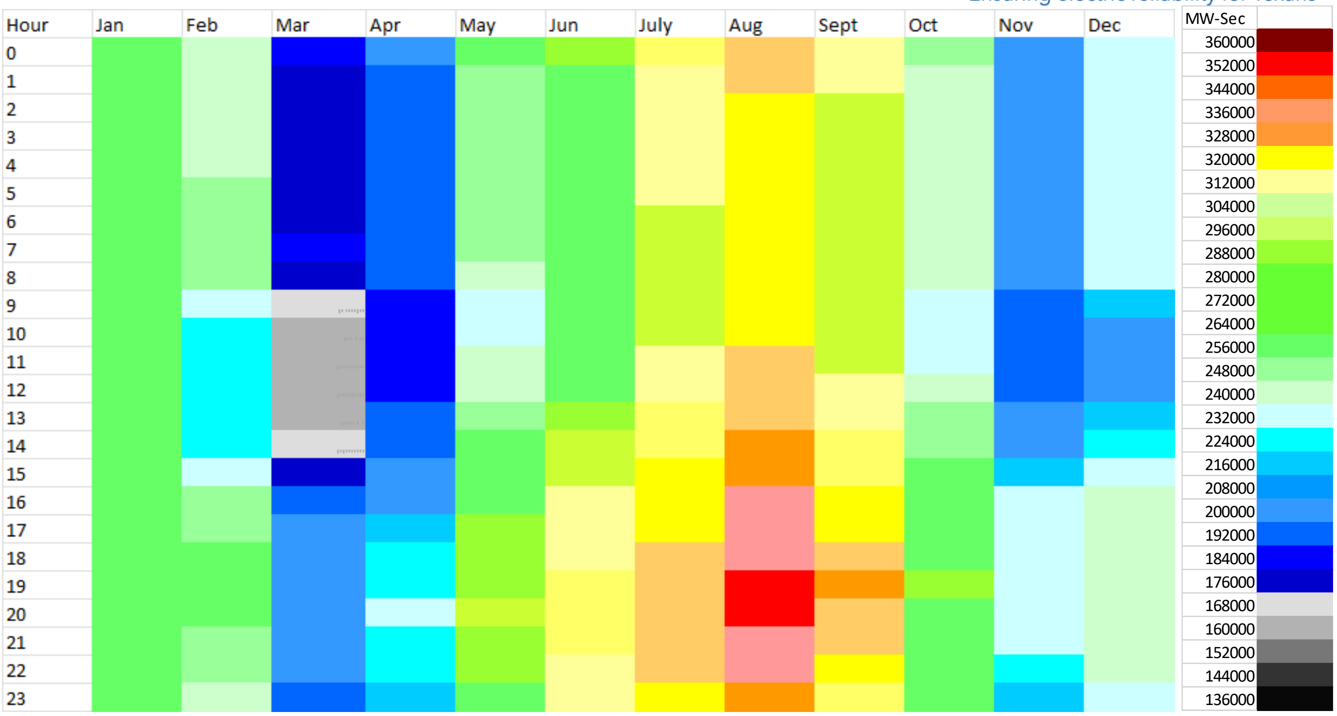


Figure C.8 – 2025 Average Inertia by Month and Operating Hour

Riskier low inertia hours are represented by the dark blue and grey colors.

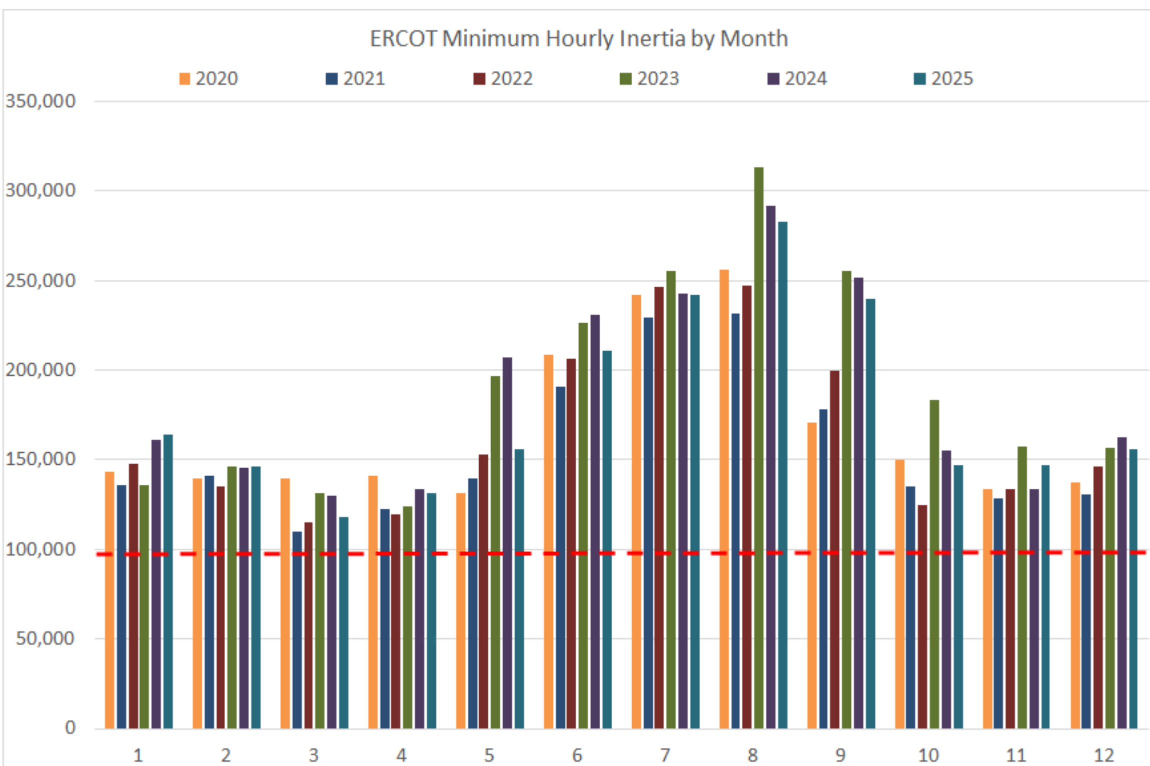


Figure C.9 – 2020-2025 Minimum Hourly Inertia by Month

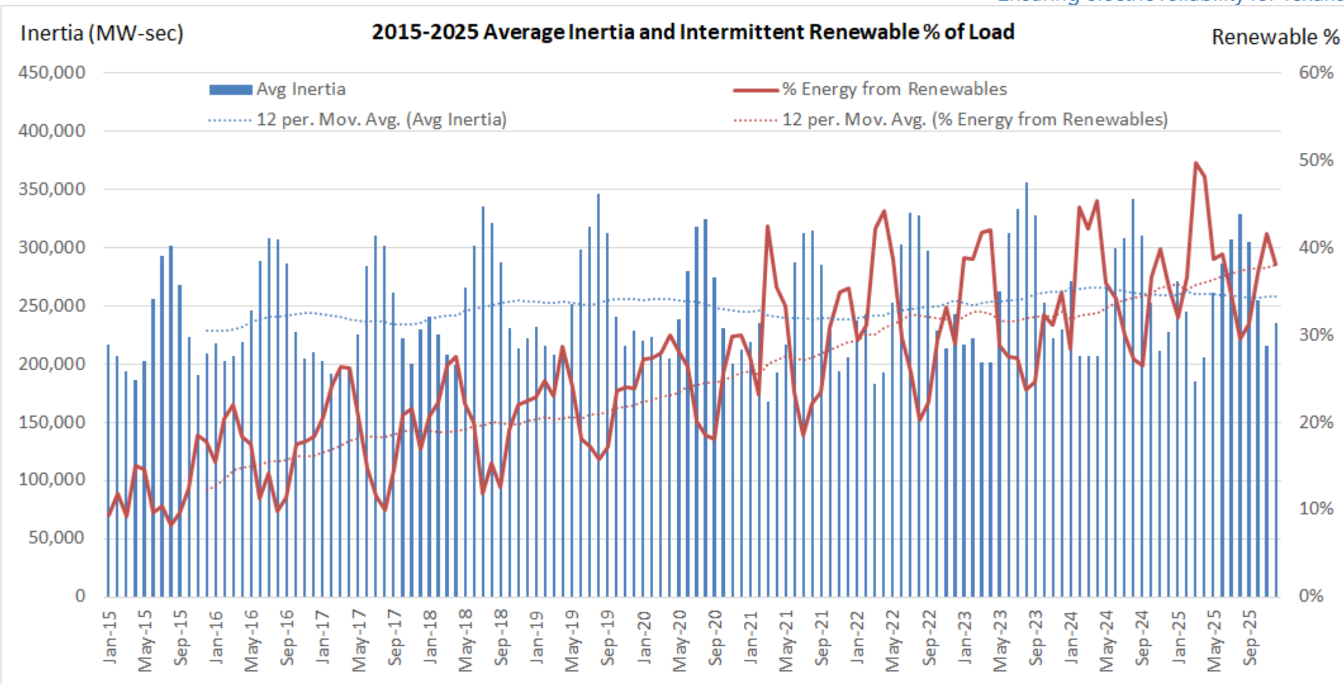


Figure C.10 – 2015-2025 Time Trend of Average Inertia and Renewable Energy Percentage

D. Net Demand Ramping Variability

Changes in the amount of non-dispatchable resources, system constraints, load behaviors, and the generation mix can affect the ramp rates needed to keep the system in balance. Conventional resources must have sufficient ramping capability to maintain the generation-load balance when intermittent renewables have large up or down ramps. ERCOT calculates the system ramp capability in real-time to ensure that this ramping variability can be met. If insufficient ramping capability is not available, ERCOT will bring additional quick start resources online.

Ramping Variability	Load	Wind Gen	Solar Gen	Net Load
Maximum One-Hour Increase	7,158 MW	6,058 MW	16,215 MW	15,862 MW
Maximum One-Hour Decrease	-5,030 MW	-6,004 MW	-14,834	-14,796 MW

Table C.3 – Maximum and Minimum Load, Wind, Solar, and Net-Load Ramps for 2025

There continues to be a long-term increasing trend in the maximum one-hour up ramps for net load and solar. Figure C.11 shows a comparison of the maximum one-hour load, net load, and wind ramps for 2025 compared to previous years.

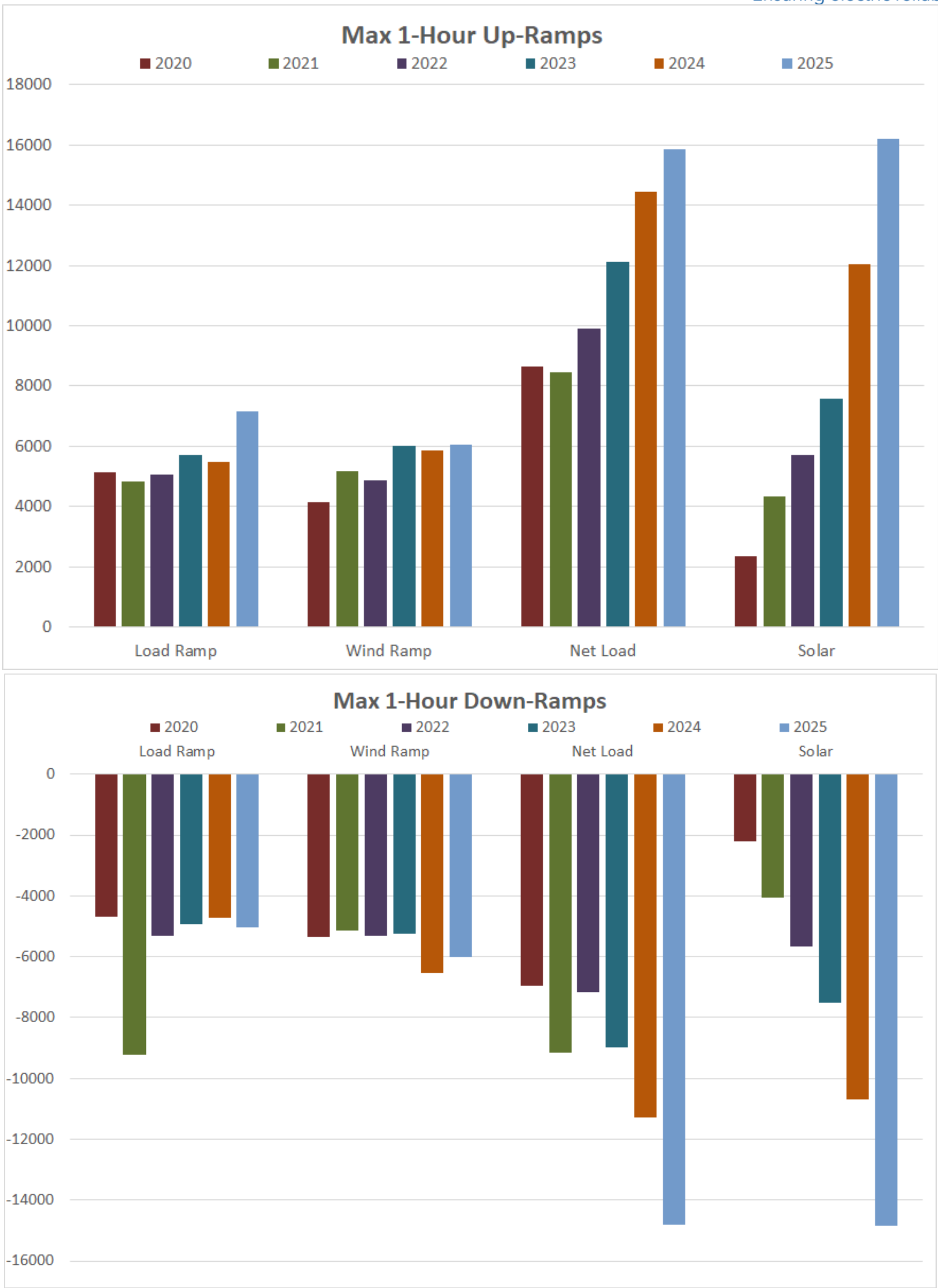


Figure C.11 – Maximum One-Hour Ramps for 2020-2025

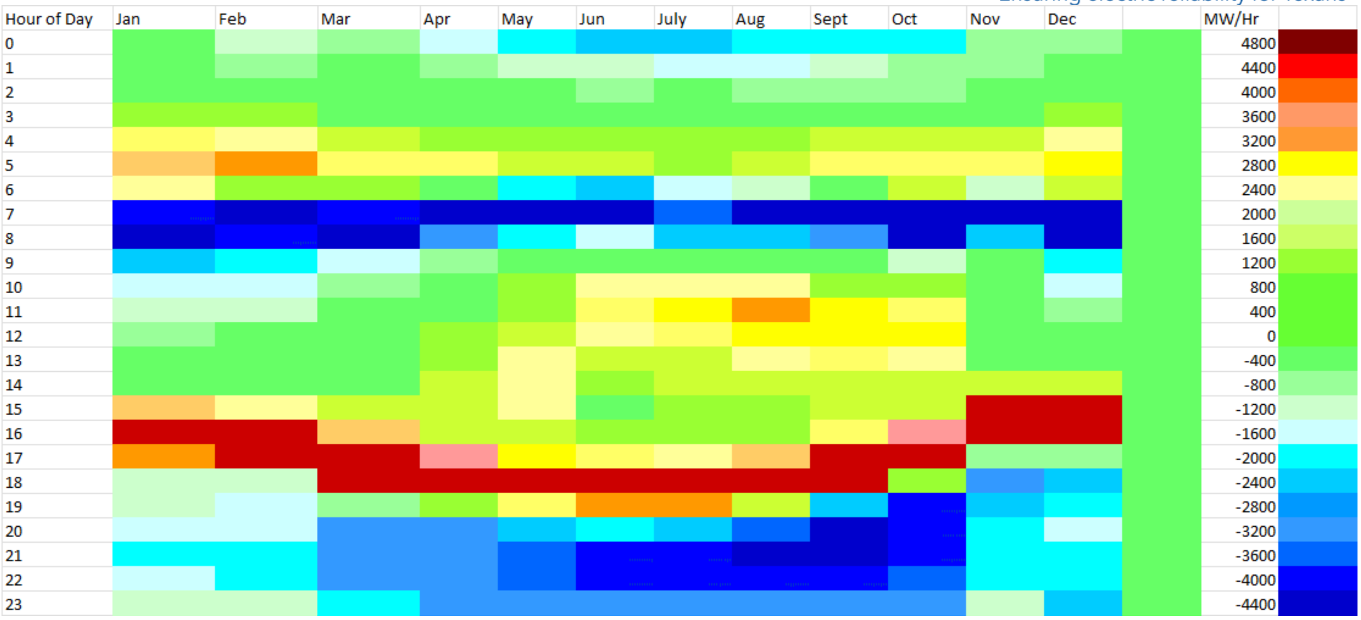


Figure C.12 – 2025 Heat Map of Net Load Ramp by Month and Operating Hour

High net load down ramp hours tend to result in high frequency and deployment of down regulation. High net load up ramp hours present a greater risk since they tend to result in low frequency and deployment of up regulation, ECRS, and non-spinning reserves.

Appendix D – Human Performance Detailed Analysis

A. Outages Initiated by Human Error

Outage rates caused by human error for 138 kV circuit outages, and transformers were stable or showed a decrease in 2025 compared to prior years. Outage rates caused by human error for Protection System Misoperations increased in 2025 compared to 2024 but remained within the long-term trend averages.

Element Type	Metric	2021	2022	2023	2024	2025	5-Yr Avg
AC Circuit 300-399 kV	Outages per Element Initiated by Human Error	0.8%	1.7%	0.9%	1.4%	0.6%	1.1%
AC Circuit 100-199 kV	Outages per Element Initiated by Human Error	1.2%	0.9%	0.8%	0.5%	0.5%	0.8%
Transformer 300-399 kV	Outages per Element Initiated by Human Error	0.0%	1.2%	1.2%	0.3%	0.3%	0.6%
Generator	Immediate Forced Outages Initiated by Human Error	3.2%	1.9%	1.7%	2.3%	0.8%	1.9%
Protection Systems	Misoperation Rate Caused by Human Error	2.0%	3.2%	2.3%	1.9%	3.0%	2.4%

Table D.1 – Outages Rates Caused by Human Error

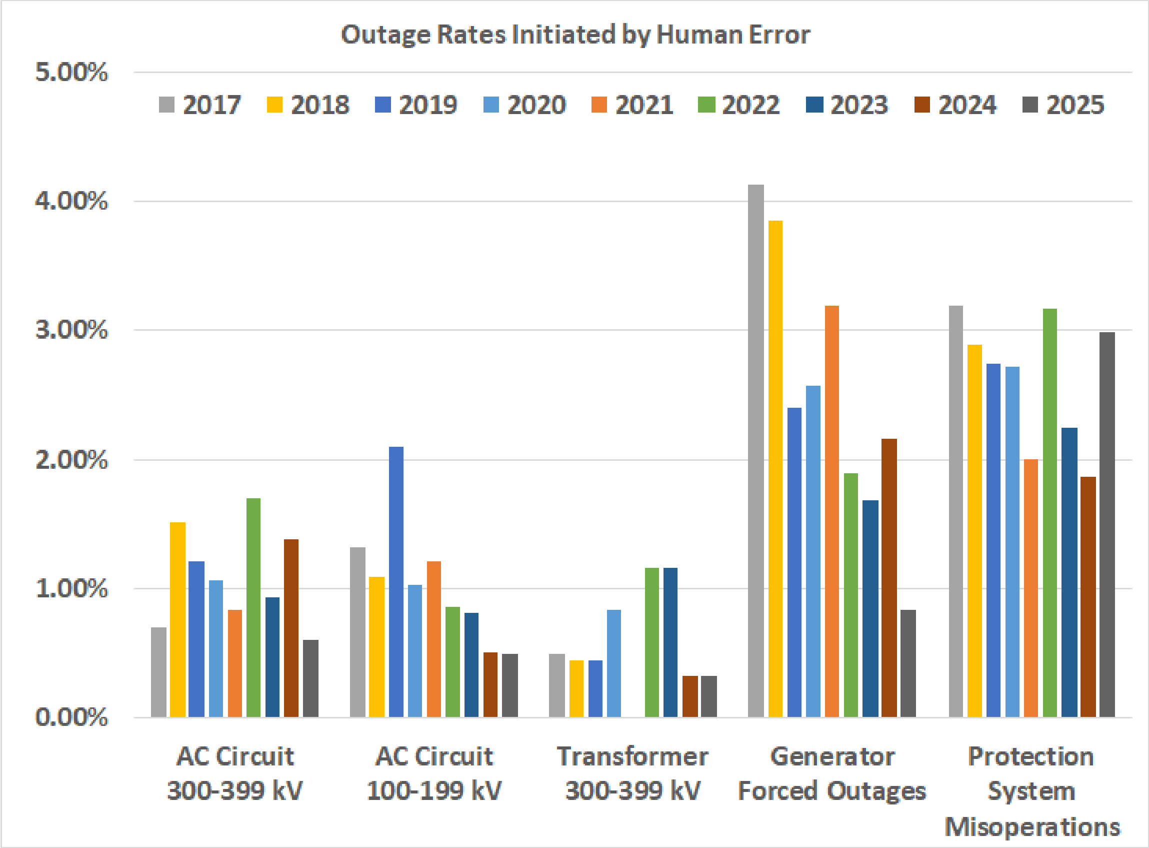


Figure D.1 – Outage Rates Caused by Human Error

Since 2017, there have been 656 generation immediate forced outages, de-rates, and startup failures caused by human error in the Region. The breakdown and impact of the causes is shown below.

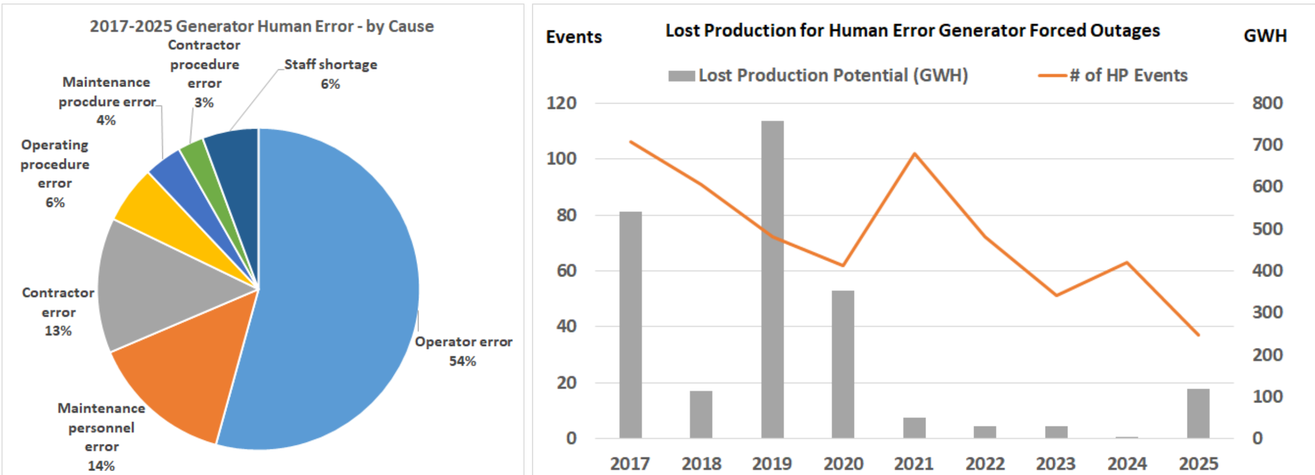


Figure D.2 – Generator Forced Outage Human Errors

B. Human Performance in System Events

The NERC Cause Code process provides a systematic approach to assigning cause code(s) after an event on the BPS is analyzed. Appropriate use of this method after event analysis will result in effective labeling, collection, and trending of causes. It will also lead to the proper application of risk management procedures to develop and implement appropriate corrective and preventative actions.

Human performance remains the primary causal factor in Misoperations, primarily due to incorrect settings and/or as-left errors.

Since 2020, 51 events in ERCOT have been analyzed using this cause code process, with 403 root cause and contributing cause codes assigned. Approximately 56 percent of the assigned root and contributing cause codes are related to potential human performance issues (shown in red below in Figure D.3).

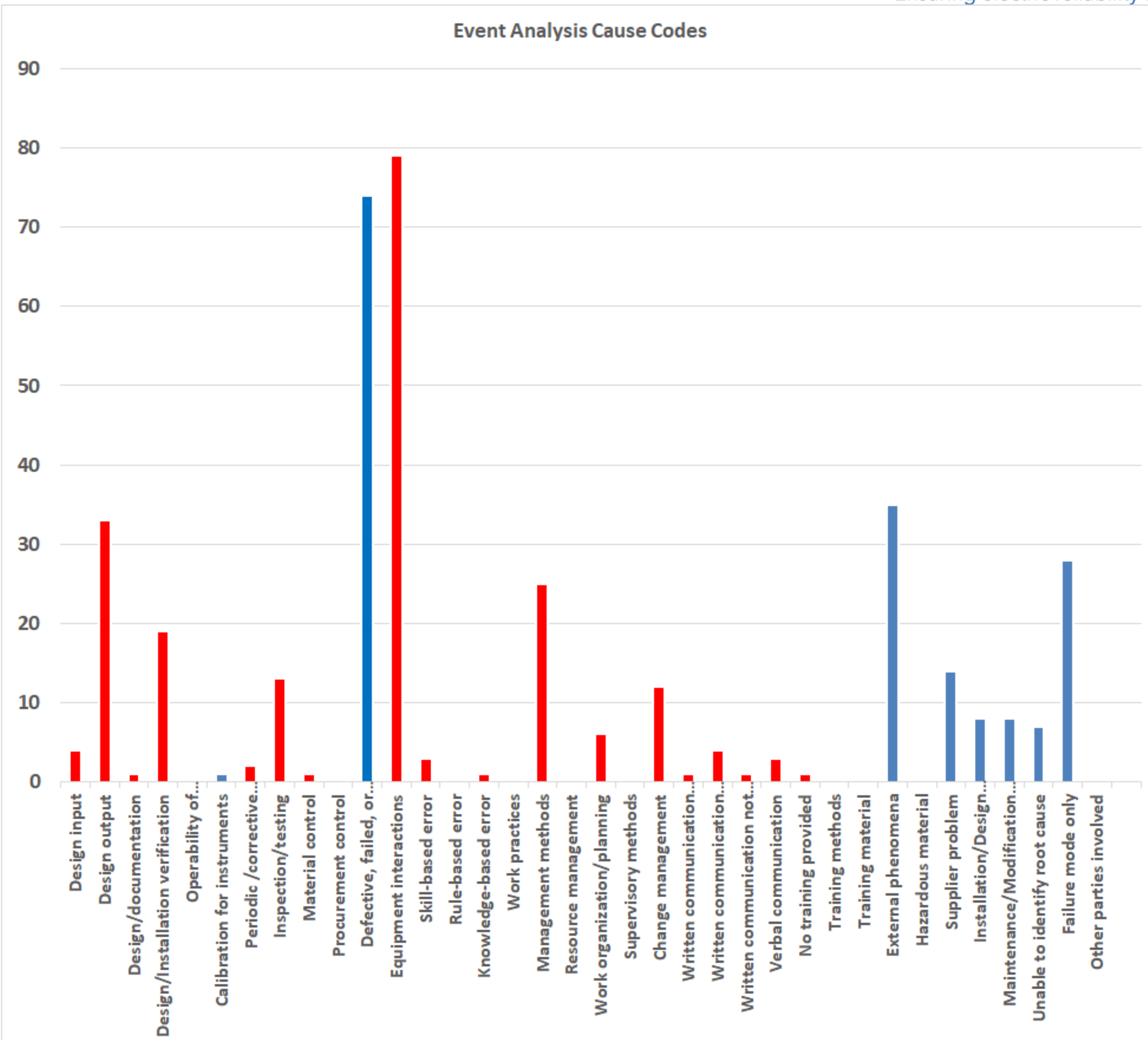


Figure D.3 – Event Analysis Human Performance Cause Coding

Appendix E – Bulk Power System Planning Analysis

A. Net Energy for Load

In 2025, total annual energy usage was 488,406 GWh, an increase of 6.4 percent from 2024. Peak hourly demand was 83,717 MW on August 18, 2025. The West Load Zone continues to see the largest load energy usage increase, with a 12.2 percent increase in 2025 compared to 2024.

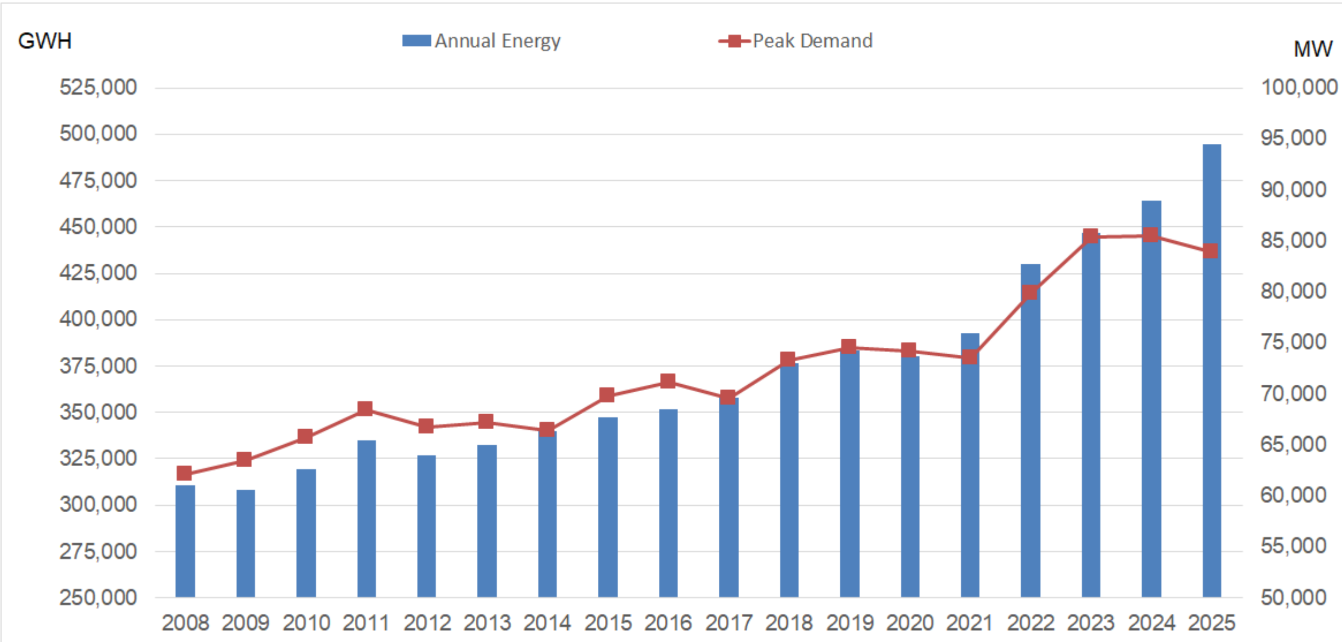


Figure E.1 – Annual Energy and Peak Demand

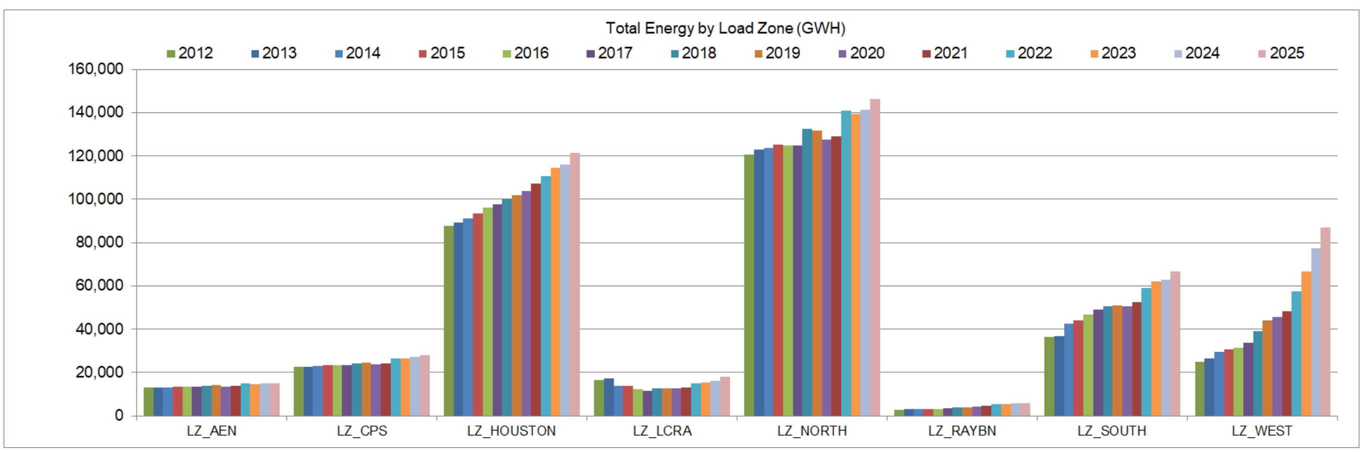


Figure E.2 – Energy by Load Zone

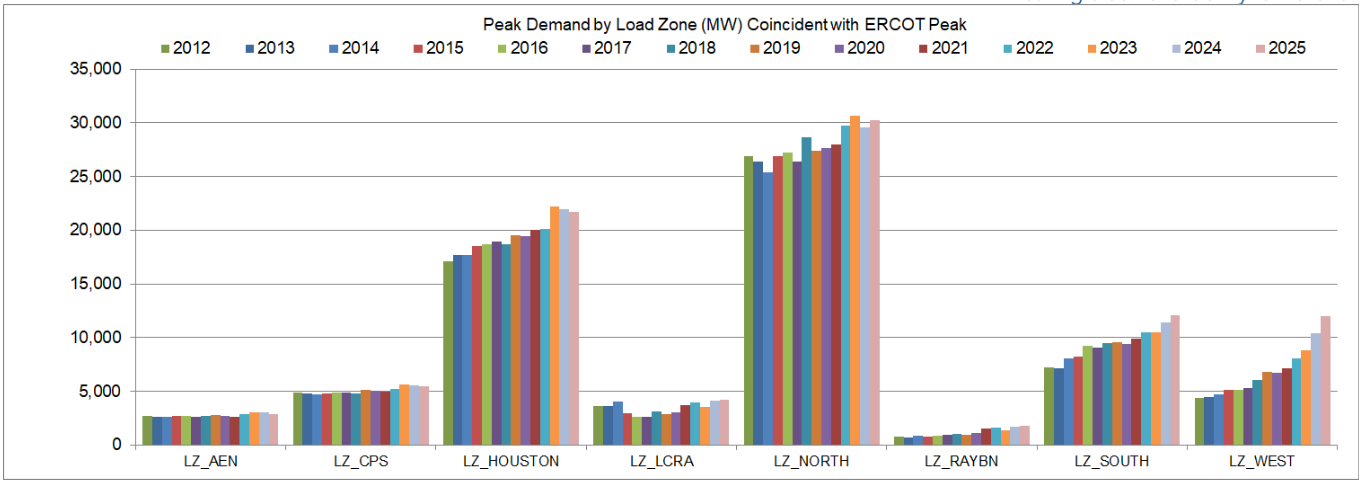


Figure E.3 – Peak Demand by Load Zone

The Far West and North weather zones continued to show large year-over-year percentage increases in energy usage increase in 2025 compared to 2024. The Far West had a 12.7 percent increase in 2025 compared to 2024 while the North weather zone had a 16.0 percent increase.

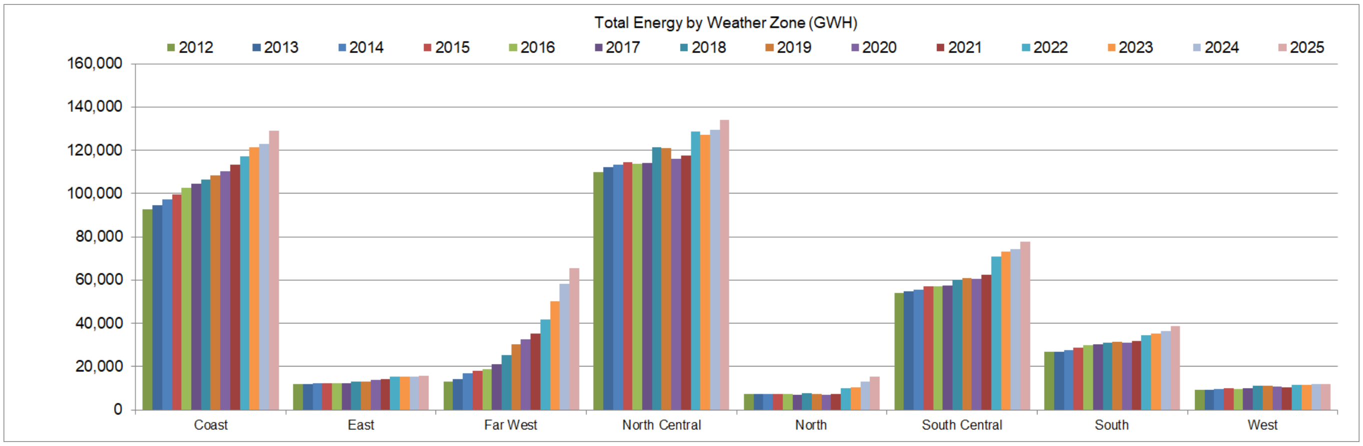


Figure E.4 – Energy by Weather Zone

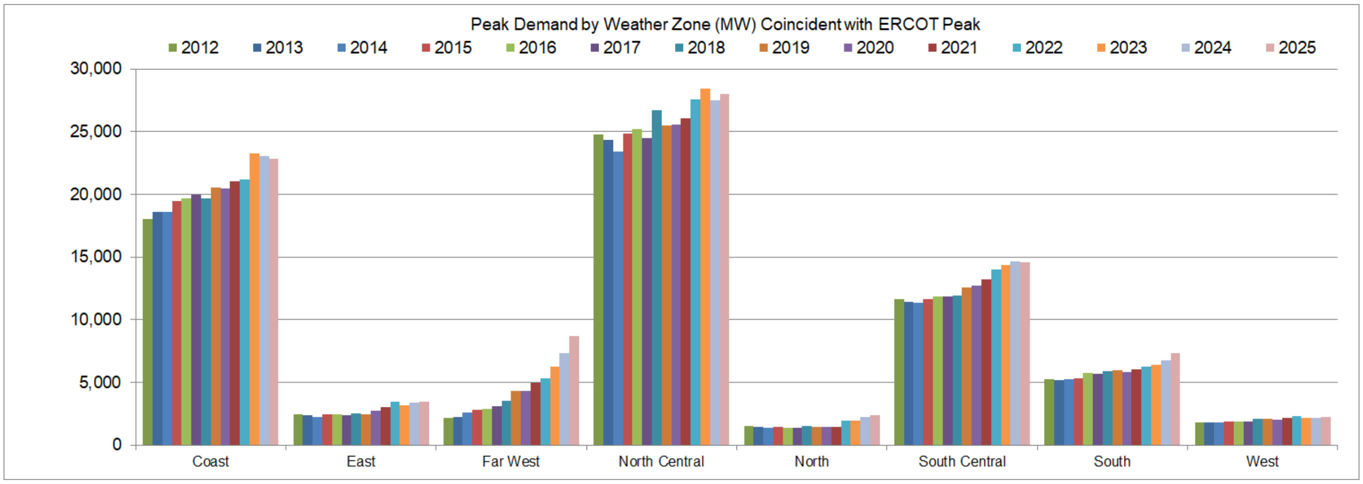


Figure E.5 – Peak Demand by Weather Zone

Overall energy growth rate has averaged 5.4 percent per year and demand growth rate has averaged 2.8 percent per year since 2021.

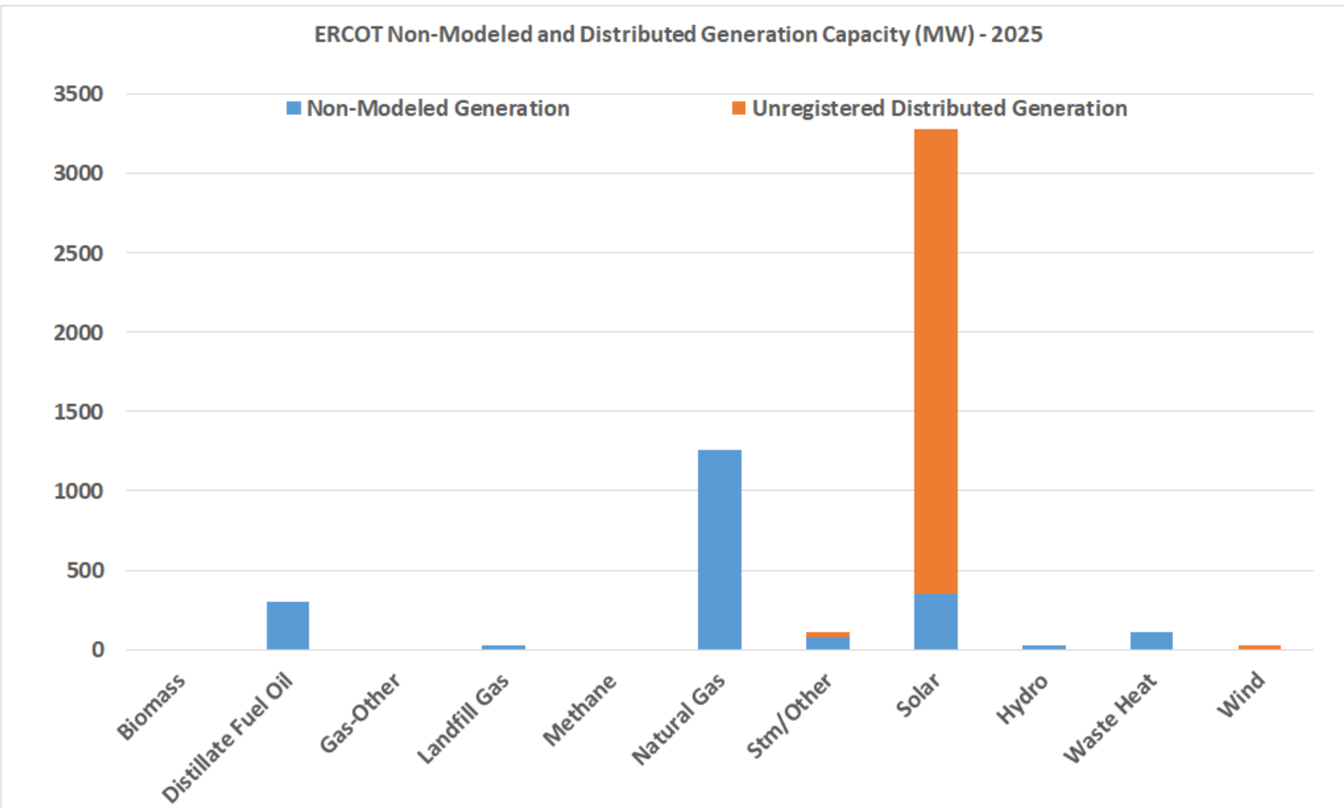
B. Distributed Energy Resources and Non-Modeled Generation

Distributed Energy Resources (DER) include any non-BES resource located solely within the boundary of the distribution utility, such as:

- Distribution and behind-the-meter generation
- Energy storage facilities
- Microgrids
- Cogeneration
- Stand-by or back-up generation

Currently under ERCOT Protocols, distributed generation resources greater than 1 MW must register with ERCOT and provide resource registration data. Increasing amounts of DER will change how the distribution system interacts with the BPS by transforming the distribution system into an active energy source.

At the end of 2025, ERCOT had approximately 2,142 MW of non-modeled generation capacity and 2,998 MW of unregistered distributed generation resources (DGR) that has provided data for mapping capacity to their modeled loads.



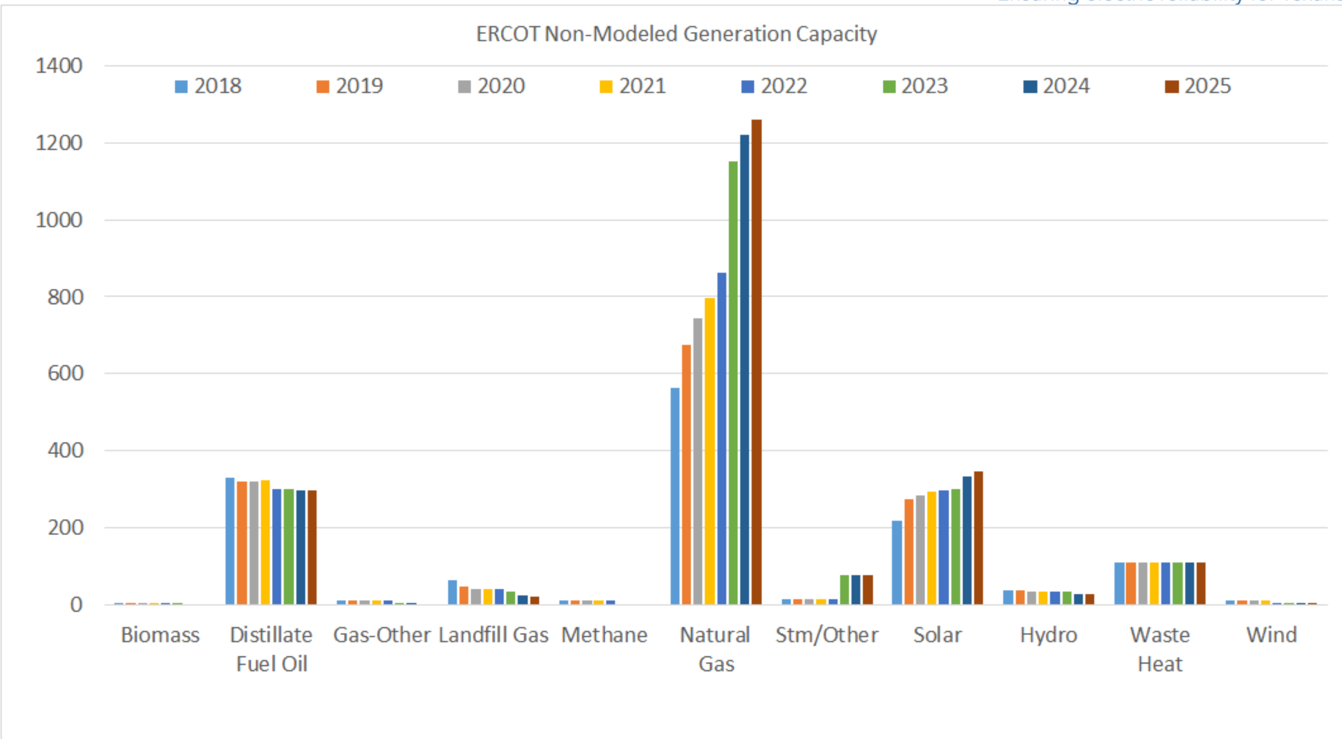


Figure E.8 – Non-Modeled Generation Capacity by Fuel Type

Appendix F – Loss of Situational Awareness Analysis

A. Loss of EMS and Loss of SCADA Events

Loss of Energy Management System (EMS) and System Control and Data Acquisition (SCADA) events continue to be a focus area for NERC and the Regions. Category 1 events include loss of operator ability to remotely monitor and control BES elements, loss of communications from SCADA Remote Terminal Units (RTU), unavailability of Inter-Control Center Communications Protocol (ICCP) links, loss of the ability to remotely monitor and control generating units via Automatic Generation Control (AGC), and unacceptable State Estimator or Contingency Analysis solutions for more than 30 minutes.

Notable loss of SCADA or EMS events reviewed in 2025 include the following:

- A TOP experienced a loss of monitoring and control when the building UPS failed to restore critical loads during a power outage.
- A TOP experienced a loss of monitoring and control during a planned SCADA system failover test.
- A TOP experienced a loss of monitoring and control due to a hardware failure of a network switch.
- A TOP experienced an intermittent loss of monitoring and control due to a corrupted database file.
- A TOP experienced a loss of monitoring and control during a scheduled patch and SCADA database rebuild.

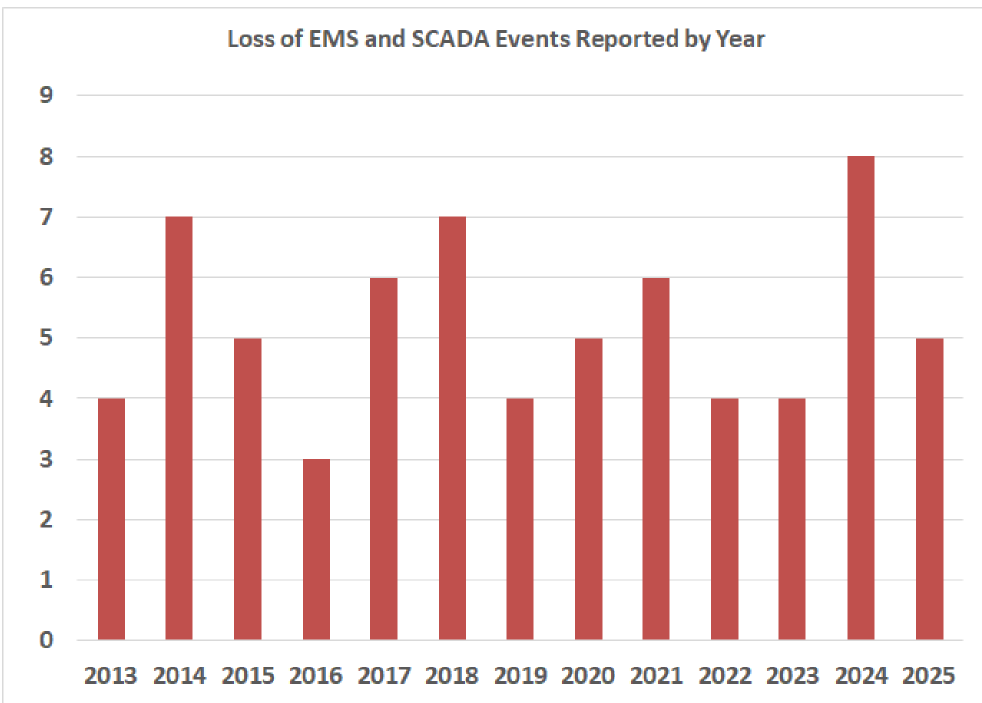


Figure F.1 – Loss of EMS and SCADA Events by Year

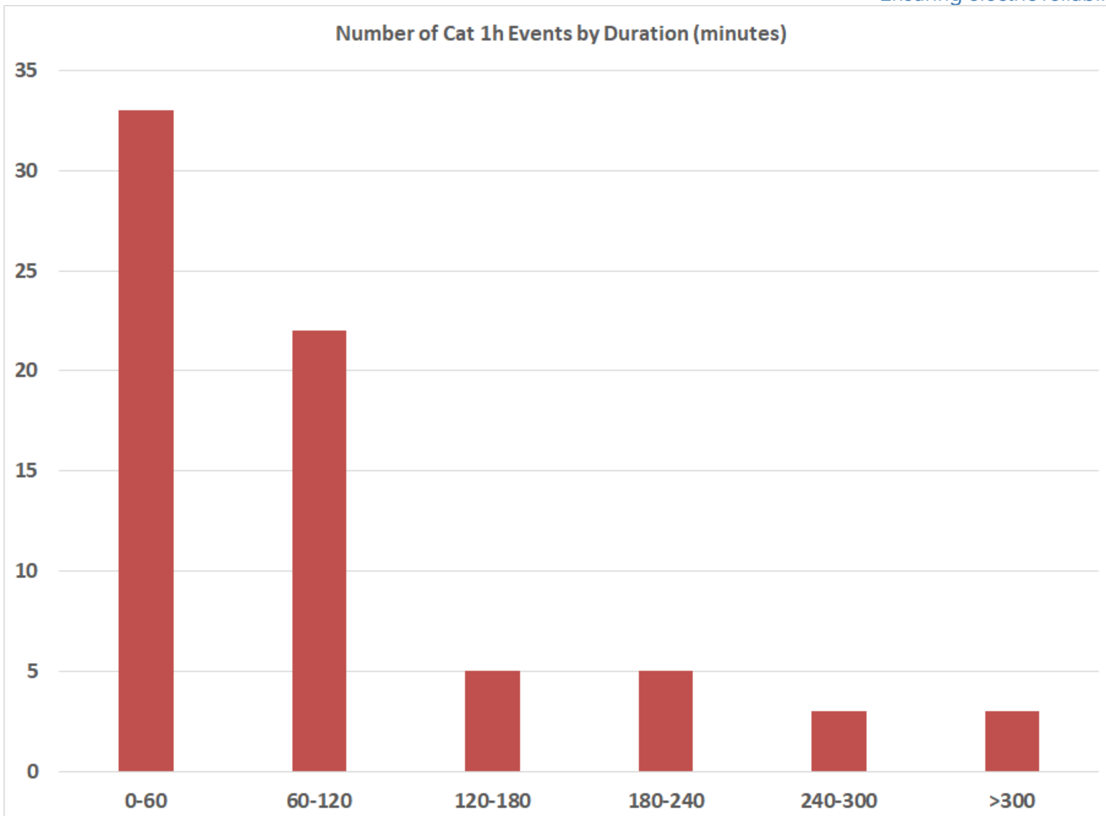


Figure F.2 – Loss of EMS and SCADA Events by Duration Since 2011

B. State Estimator Convergence

ERCOT's goal for State Estimator convergence is 97 percent or higher. In 2025, the convergence rate was 99.98 percent.

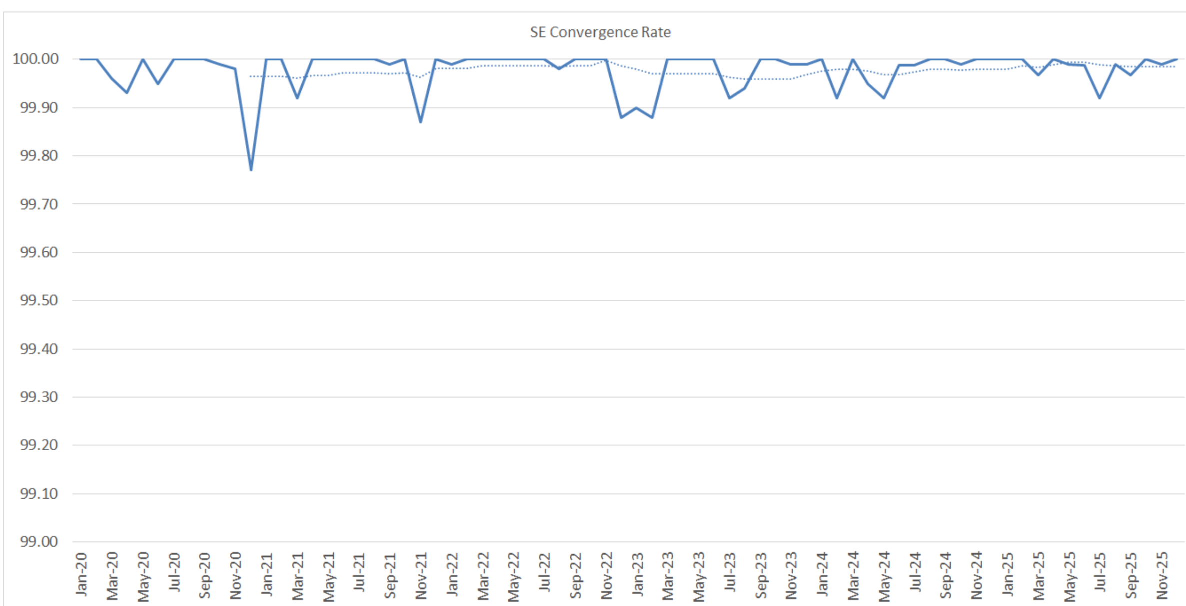


Figure F.3 – State Estimator Convergence Rate

C. Telemetry Availability Metrics

ERCOT telemetry performance criteria states that 92 percent of all telemetry provided to ERCOT must achieve a quarterly availability of 80 percent. Figure F.4 shows the telemetry availability metric per the ERCOT telemetry standard. For 2025, the total number of telemetry points failing the availability metric averaged 8,380 each month, or 4.44 percent of the total system telemetry points.

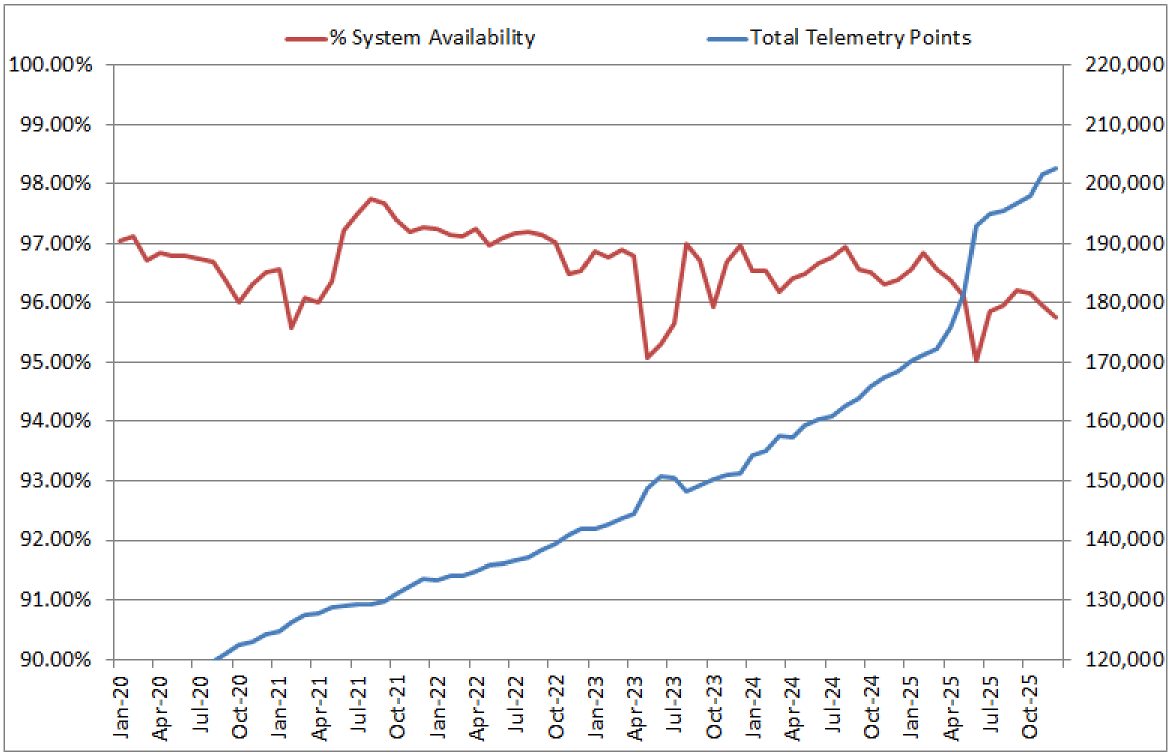


Figure F.4 – ERCOT Telemetry System Availability

D. Telemetry Accuracy Metrics

ERCOT uses several processes to verify the accuracy of telemetry when compared to State Estimator solutions. These include:

1. Residual difference between telemetered value and State Estimator value on Transmission Elements over 100 kV is <10 percent of emergency rating or < 10 MW (whichever is greater) on 99.5 percent of all samples during a month period.
2. Residual difference between telemetered value and State Estimator value on congested Transmission Elements over 100 kV is <3 percent of emergency rating or < 10 MW (whichever is greater) on at least 95 percent of all samples during a month period. Congested elements are those transmission elements causing 80 percent of congestion in the latest year for which data is available.
3. The sum of flows into any telemetered bus is less than the greater of five MW or five percent of the largest Normal line rating at each bus.
4. The telemetered bus voltage minus state estimator voltage shall be within the greater of two percent or the accuracy of the telemetered voltage measurement involved for at least 95 percent of samples measured.

The following figures show the historic performance for these metrics.

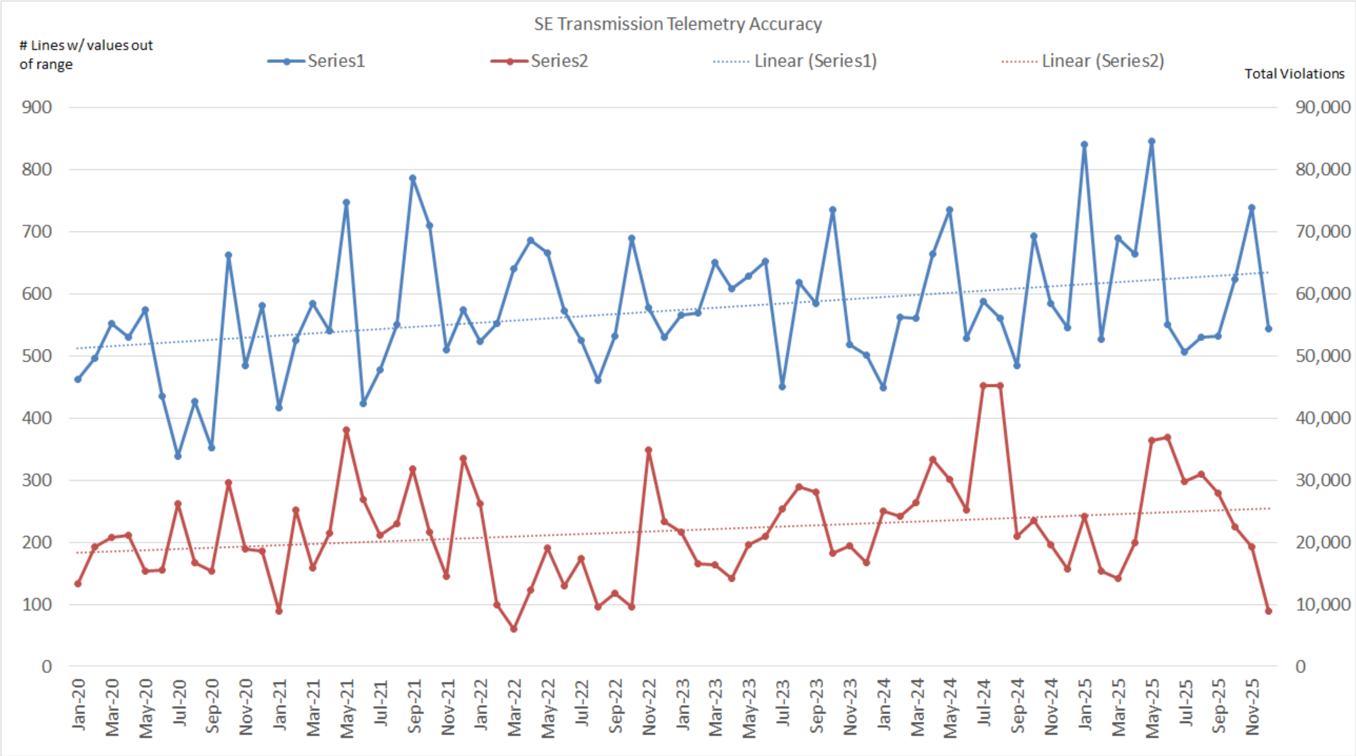


Figure F.5 – State Estimator versus Transmission Telemetry Accuracy

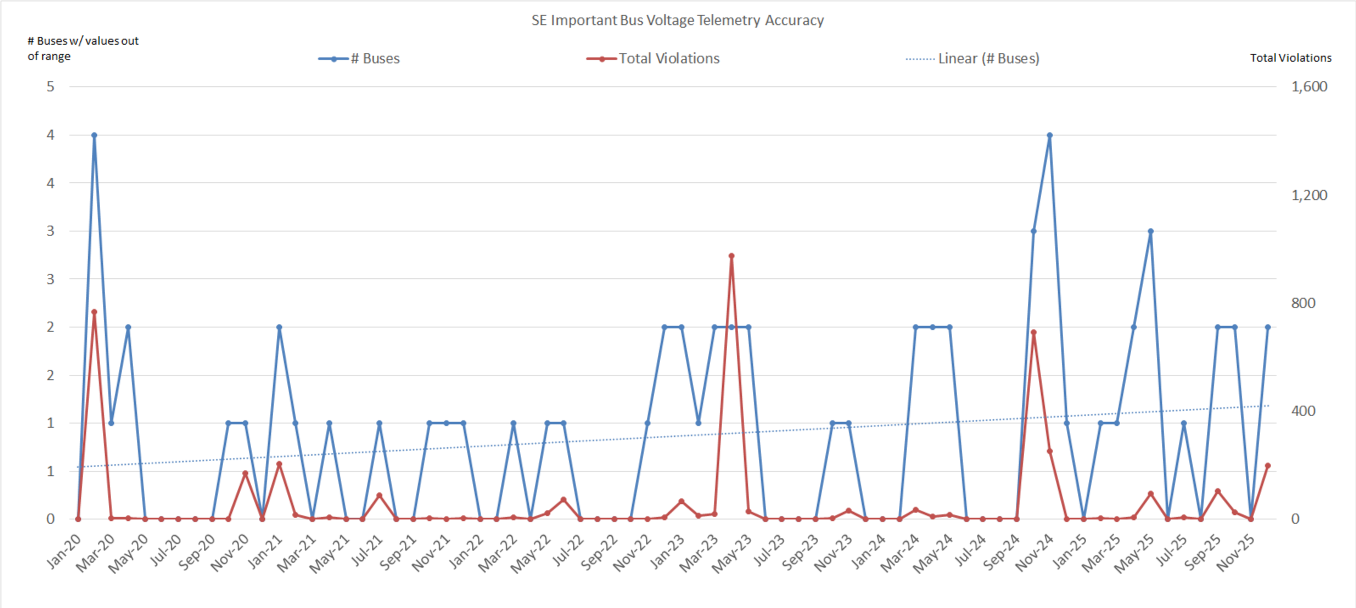


Figure F.6 – Bus Voltage Telemetry Accuracy

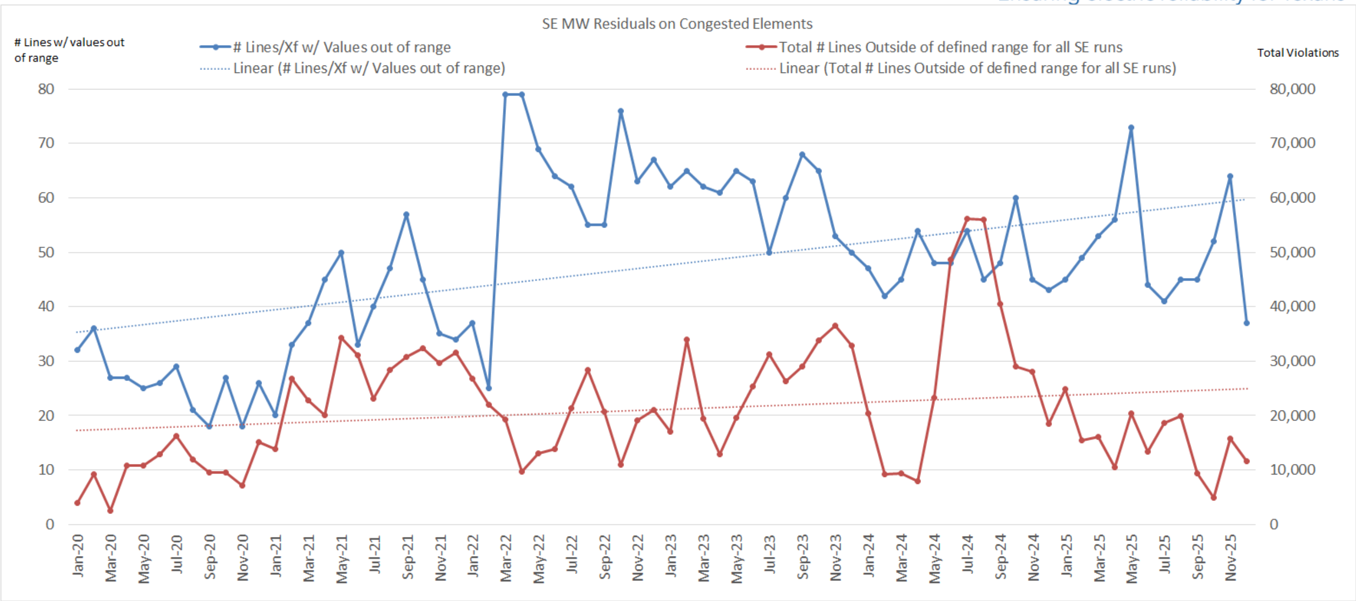


Figure F.7 – State Estimator vs Congested Element Telemetry Accuracy

Appendix G – Protection System Detailed Analysis

A. Protection System Misoperations

Since January 2021, the overall transmission system Protection System Misoperation rate has increased slightly, from 5.2 percent in 2021 to 6.0 percent in 2025. The five-year average Misoperation rate from 2021-2025 was 5.5 percent.

138 kV	2021	2022	2023	2024	2025	5-Yr Avg
Number of Misoperations	102	95	66	75	83	84
Number of Events	1805	1296	1472	1664	1717	1591
Percentage of Misoperations	5.7%	7.3%	4.5%	4.5%	4.8%	5.3%
345 kV	**2021**	**2022**	**2023**	**2024**	**2025**	**5-Yr Avg**
Number of Misoperations	33	42	33	36	67	42
Number of Events	718	612	603	647	762	668
Percentage of Misoperations	4.6%	6.9%	5.5%	5.5%	8.8%	6.3%
< 100 kV	**2021**	**2022**	**2023**	**2024**	**2025**	**5-Yr Avg**
Number of Misoperations	0	11	3	1	2	3
Number of Events	76	81	108	150	62	95
Percentage of Misoperations	0.0%	13.6%	2.8%	0.7%	3.2%	3.1%

Table G.1 – Protection System Misoperation Data

In 2025, three main categories account for 60 percent of the total Misoperations: incorrect settings/logic/design (25 percent), AC systems (18 percent), and unknown (17 percent).

Misoperations due to incorrect settings, As-left personnel errors, and relay failures remained flat or stable in 2025 compared to 2024.

Misoperations due to AC systems, Communications systems, and Unknown showed significant increases in 2025 compared to 2024.

Entities have completed corrective actions on approximately 70 percent of Misoperations that occurred in 2025.

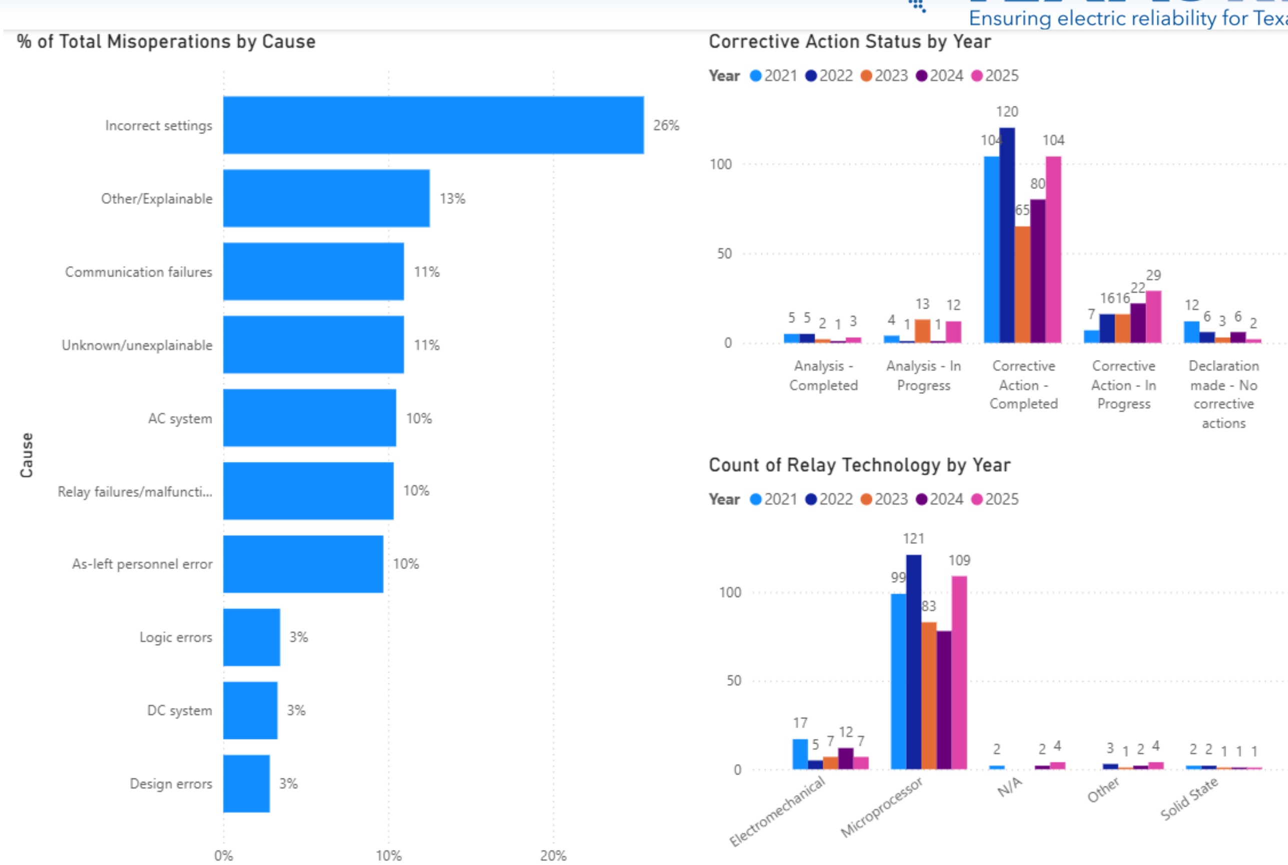


Figure G.1 – Protection System Misoperation Count 2021-2025

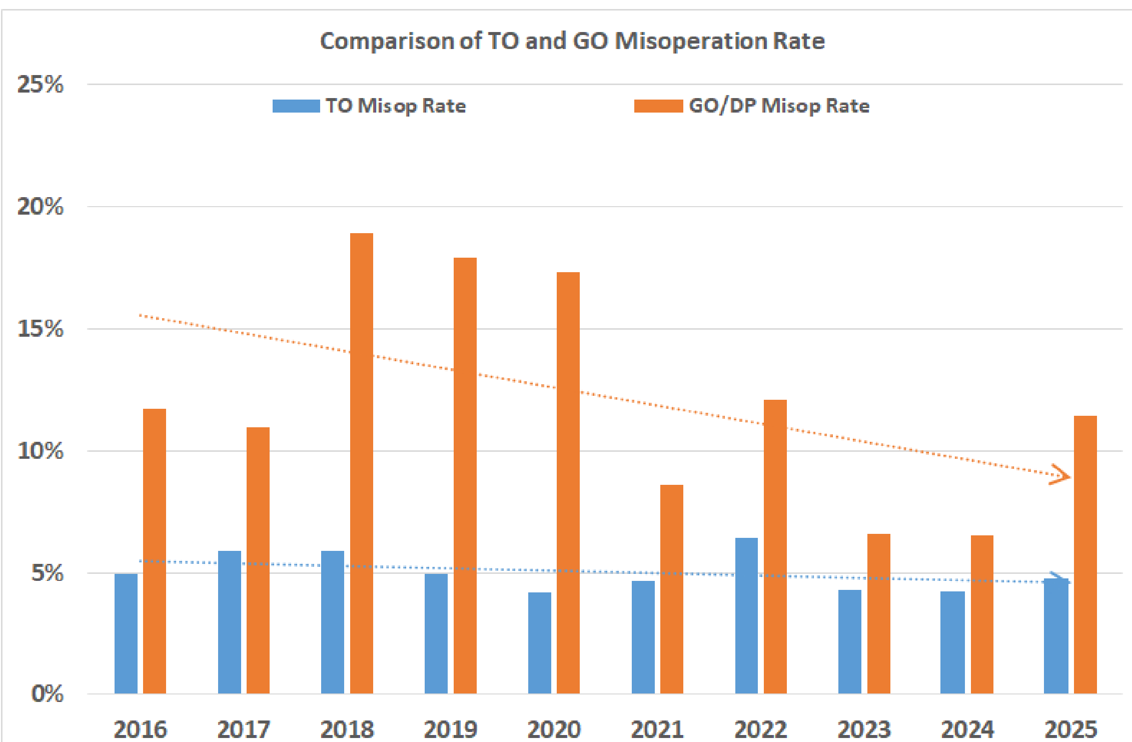


Figure G.2 – Protection System Misoperation Rate by Entity Type

B. Transmission Outages Initiated by Failed Protection System Equipment

From TADS data, the outage rate per element initiated by failed Protection System equipment for 345 kV transmission circuits, 138 kV circuits, and 345 kV transformers decreased or remained stable.

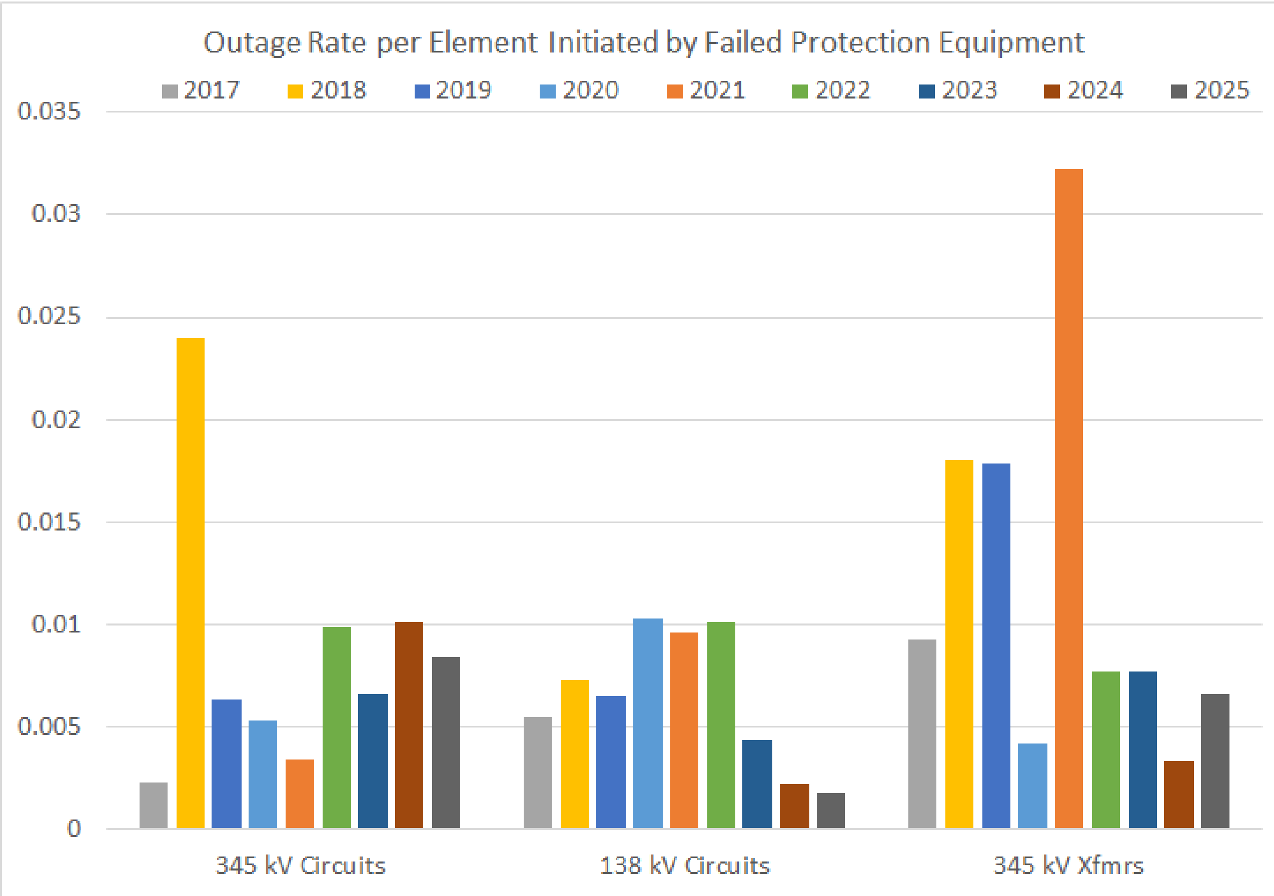


Figure G.3 – Outage Rates Caused by Failed Protection Equipment

Appendix H – Frequency Control Detailed Analysis

A. CPS1 Performance

Control Performance Standard 1 (CPS1): 177.2 for calendar year 2025 versus 175.5 for calendar year 2024.

NERC Reliability Standard BAL-001-2 requires each Balancing Authority (BA) to operate such that the 12-month rolling average of the clock-minute ACE divided by the clock-minute average BA Frequency Bias times the corresponding clock-minute average frequency error, Control Performance Standard 1 (CPS1), is less than a specific limit. The NERC CPS1 Standard requires rolling 12-month average performance of at least 100 percent. Figure H.1 shows the ERCOT region CPS1 trend since January 2018. For 2025, the annualized CPS1 score was 177.2.

Of note in 2025, ERCOT made two significant tuning adjustments in the 4th quarter that improved overall CPS1 values as well as RMS-1.

1. In October, ERCOT made an adjustment to Regulation Instruction (Load Frequency Control LFC) which allowed LFC to react more quickly to frequency changes.
2. In December, ERCOT adjusted the solar forecast threshold to better account for installed solar capacity and ramping capability during ramping hours, which in turn reduced regulation exhaustion.

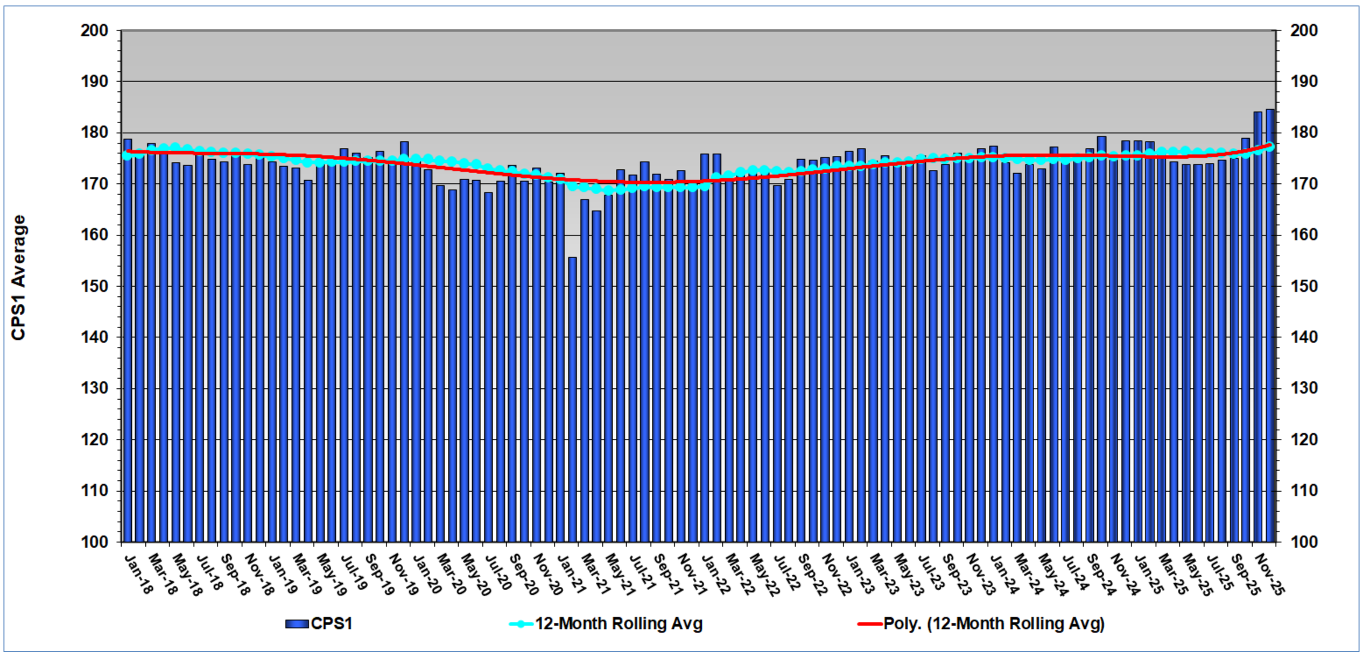


Figure H.1 – CPS1 Average January 2018 to December 2025

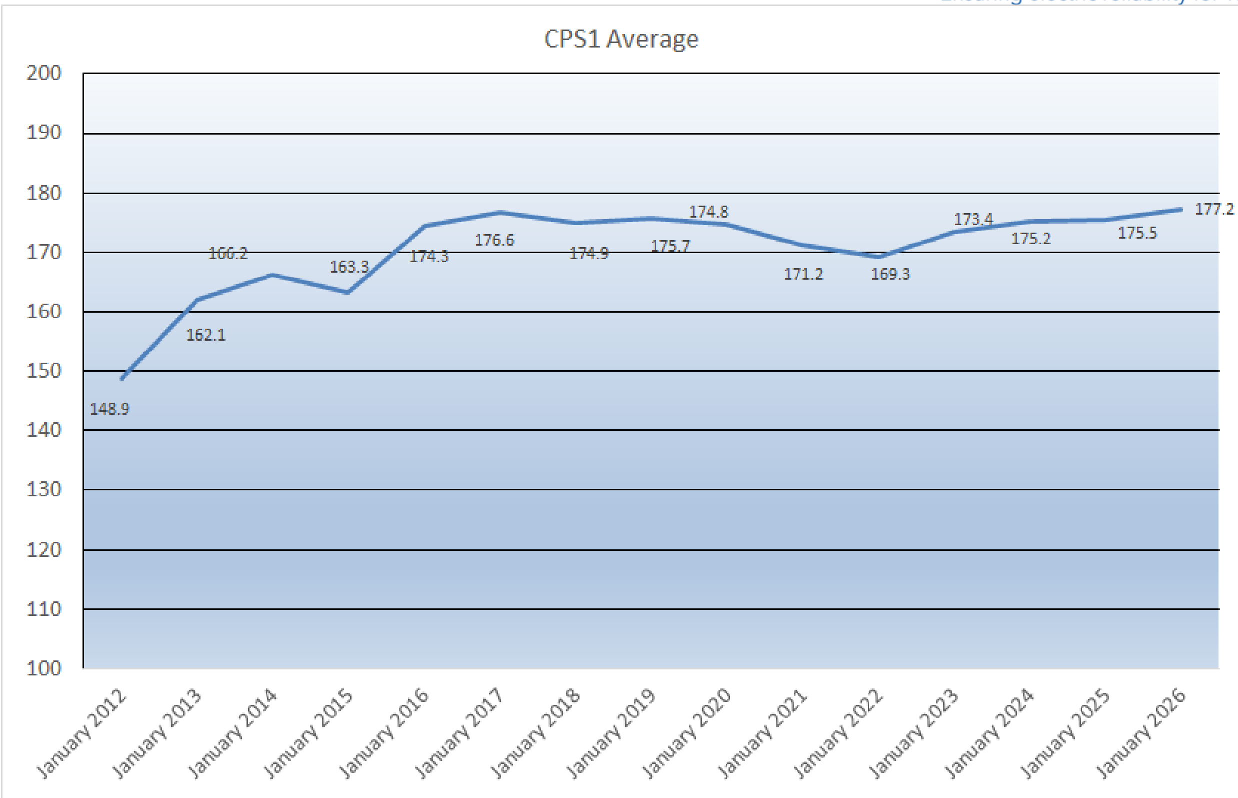


Figure H.2 – ERCOT CPS1 Annual Trend since January 2012

Figure H.3 shows bell curves of the ERCOT frequency profile, comparing 2018 through 2025. The shape of the bell curve in 2025 was identical to 2024.

The blue dashed lines on the figure represent the Epsilon-1 (ε1) value of 0.030 Hz which is used for calculation of the CPS-1 score. The red dashed lines represent governor deadband settings of 0.017 Hz. The purple dashed lines represent three times the ε1 value which is used for Balancing Authority Ace Limit (BAAL) exceedances per NERC Standard BAL-001-2.

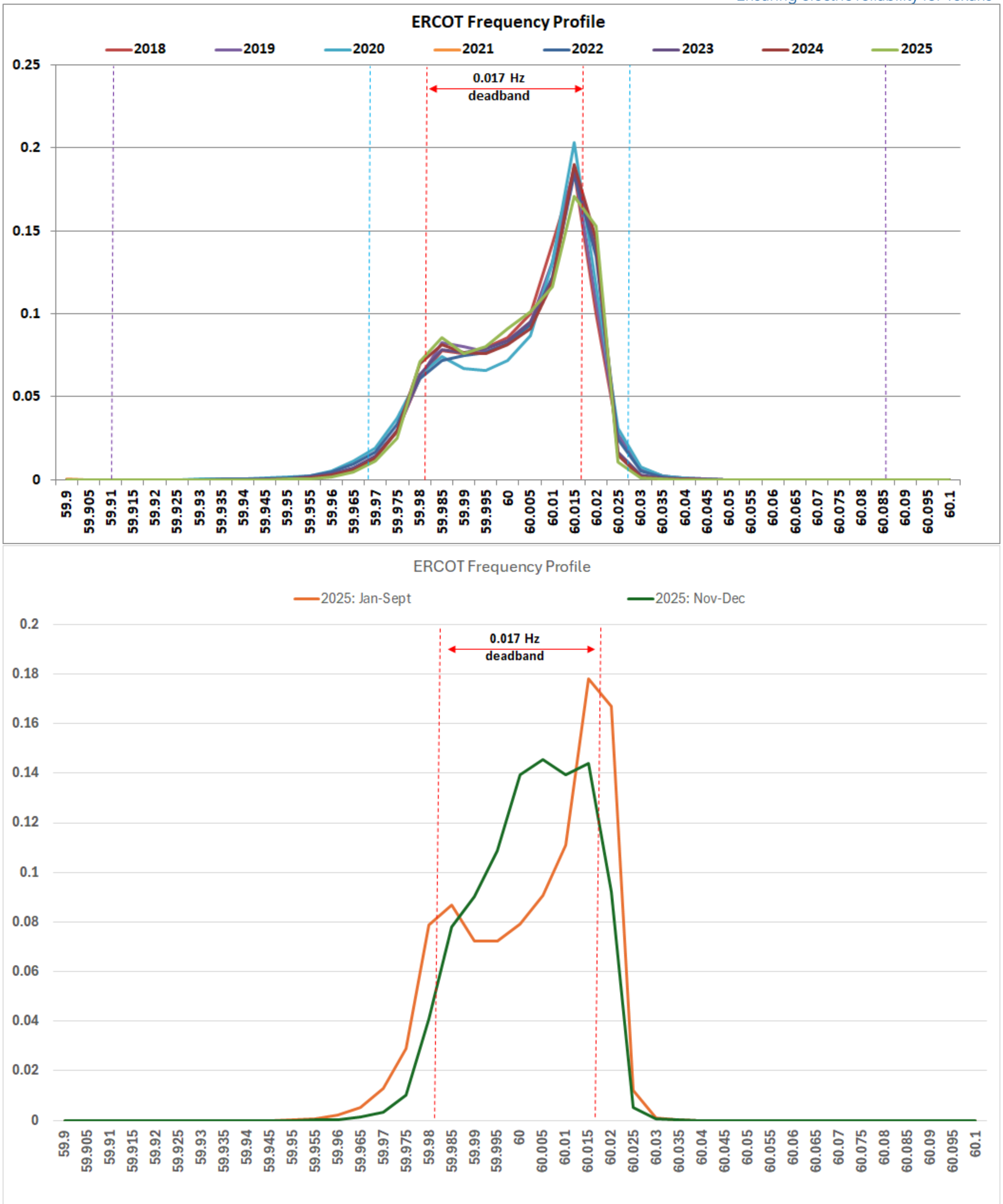


Figure H.3 – Frequency Profile Comparison

Figure H.4 shows the 2025 CPS1 scores by month compared to previous years. The February 2021 CPS1 score shows a sharp reduction compared to other months due to the impact of Winter Storm Uri.

The daily RMS1 figure shows the average root-mean-square of the frequency error based on one-minute frequency data. The long-term trend continues to show excellent control of frequency error. The red dashed line on the figure shows the 17 mHz governor deadband required by BAL-001-TRE in relation to the daily RMS1.

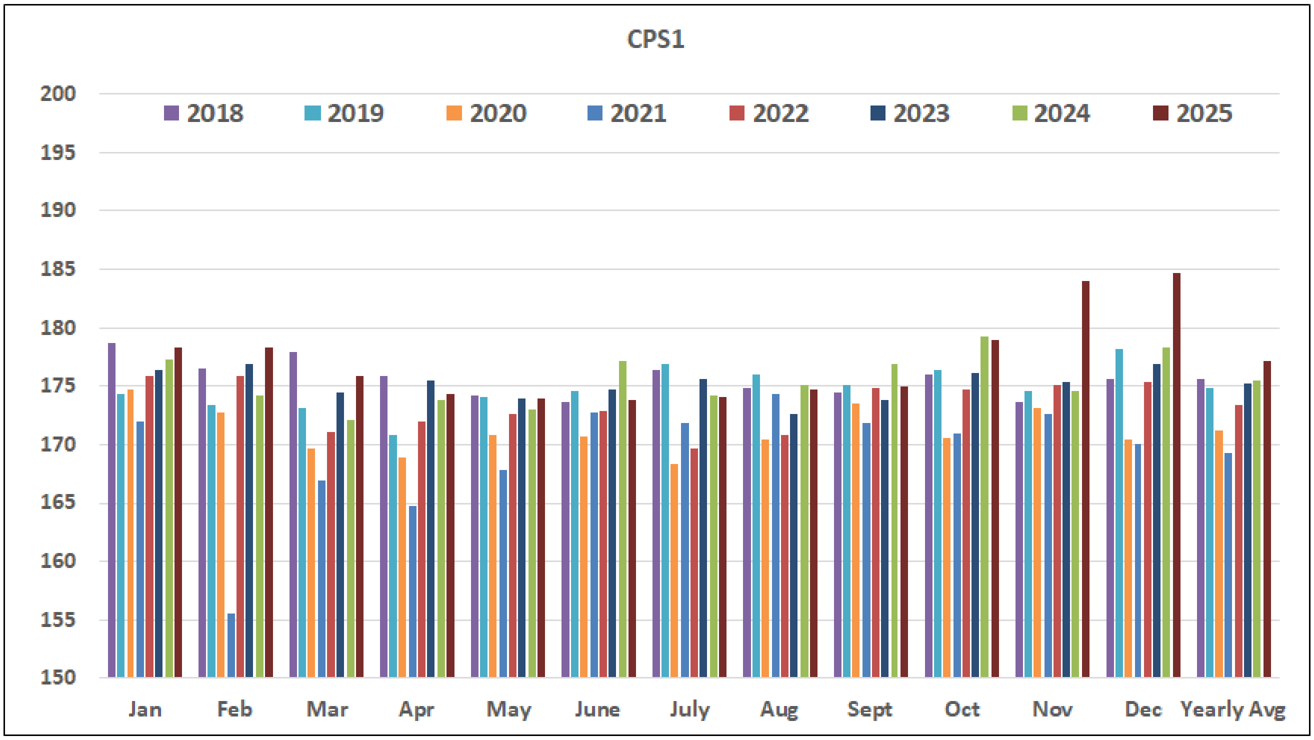


Figure H.4 – CPS1 Score by Month for 2018 through 2025

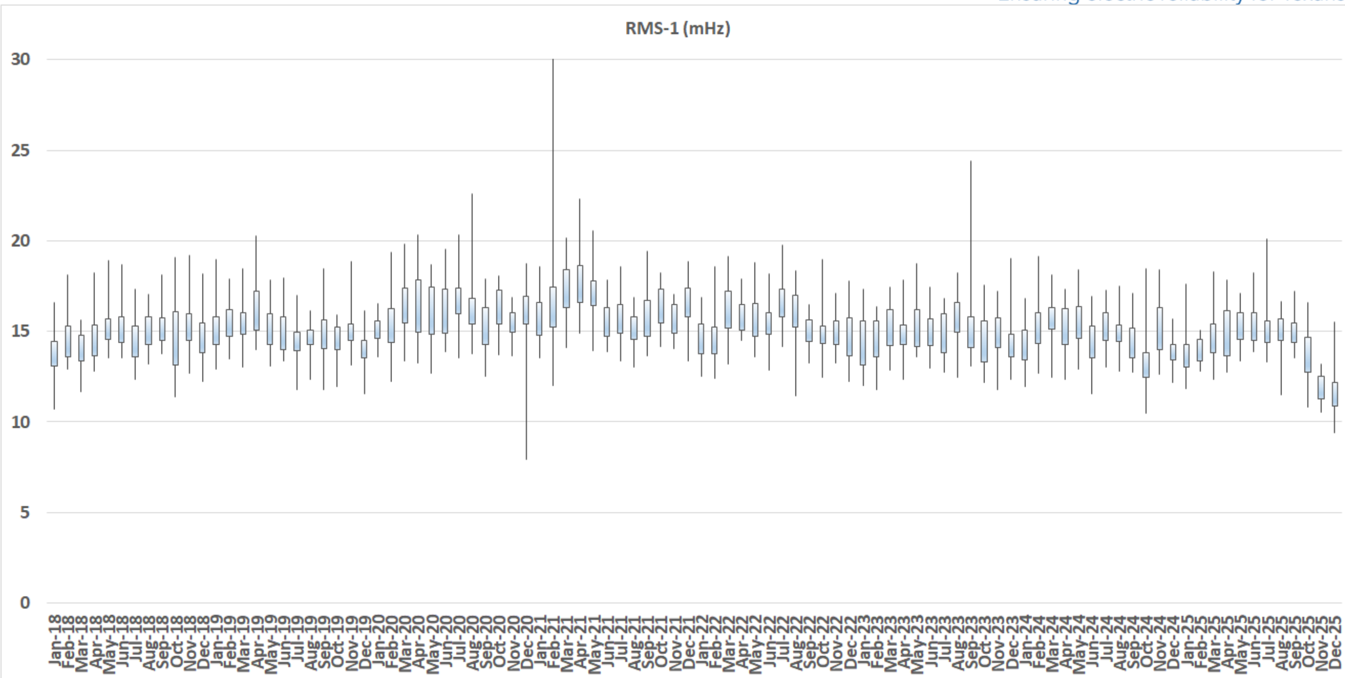


Figure H.5 – Daily RMS1 for 2018 through 2025

B. Time Error Correction Performance

In 2025, there were no manual Time Error Corrections. In December 2016, ERCOT added an ACE Integral term to the Generation-To-Be-Dispatched (GTBD) calculation. This term corrected longer-term errors in generation basepoint deviation rather than depending on regulation. Since implementation of the ACE Integral into the GTBD, ERCOT is controlling frequency to zero average time error.

C. Balancing Authority ACE Limit (BAAL) Performance

The Frequency Trigger Limits (FTL) are ranges for the BAAL high and low values per NERC Standard BAL-001-2 which became enforceable in July 2016. The FTL-Low value is calculated as 60 Hz – 3 x Epsilon-1 (ε1) value of 0.030 Hz, or 59.910 Hz for the ERCOT region. The FTL-High value is calculated as 60 Hz + 3 x Epsilon-1 (ε1) value, or 60.090 Hz for the ERCOT region.

The following table shows the total one-minute intervals where frequency was above the FTL-High alarm level or below the FTL-Low alarm level.

In 2021, 54 of the 79 BAAL exceedance minutes were associated with Winter Storm Uri. In 2023, 18 of the 20 BAAL exceedance minutes were associated with the Energy Emergency Alert (EEA) level 2 event on September 6, 2023.

High/Low Frequency	2021 Total Minutes	2022 Total Minutes	2023 Total Minutes	2024 Total Minutes	2025 Total Minutes	Five-year Avg
Low (<59.91 Hz)	78	1	20	5	0	21
High (>60.09 Hz)	1	0	0	0	0	0

Table H.1 – BAAL Exceedance Performance