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	2020	2021	2022	2023	2024
Total	407	458	471	483	490
Coal/Lignite	20	19	19	19	19
Gas	43	40	40	37	36
Nuclear	4	4	4	4	4
Gas Turbine/Jet Engine	92	109	122	134	142
Reciprocating Engine		42	42	42	42
Hydro	8	8	8	8	8
Fluidized Bed	5	5	5	5	3
Combined Cycle (Block)	18	18	18	18	18
Combined Cycle GT	149	149	149	151	153
Combined Cycle ST	61	61	61	62	62
Other	7	3	3	1	3
Total Thermal MW Reporting	77,395	78,549	79,562	79,983	82,747
Total Thermal GWh Reporting	300,223	298,155	312,787	323,091	335,956
Wind (>200 MW)	61	64	70	72	74
Wind (100<MW<200)	77	76	81	82	87
Wind (< 100 MW)	110	118	110	112	119
Number of Wind Turbines	15,349	15,282	15,865	15,951	16,654
Total Wind MW Reporting	29,796	31,651	33,683	34,052	35,977
Total Wind GWH Reporting	79,847	82,557	92,891	94,915	98,096
Solar (>200 MW)					14
Solar (100<MW<200)					12
Solar (< 100 MW)					52
Number of Inverters Turbines					9,056
Total Solar MW Reporting					15,662
Total Solar GWH Reporting					22,760

Table A.1 – 2020-2024 GADS, GADS-Wind, and GADS-Solar Units Reporting

B. Analysis of Planned versus Actual Seasonal Operating Reserves

For the summer of 2024, peak hourly demand was 85,544 MW on August 20, 2024, approximately 3,210 MW higher than the 50/50 demand scenario estimate of 82,333 MW from ERCOT's August 2024 Monthly Outlook for Resource Adequacy (MORA). Actual reserve margin was approximately 6.6 percent. Sufficient operating reserves were maintained during the summer peak hours.

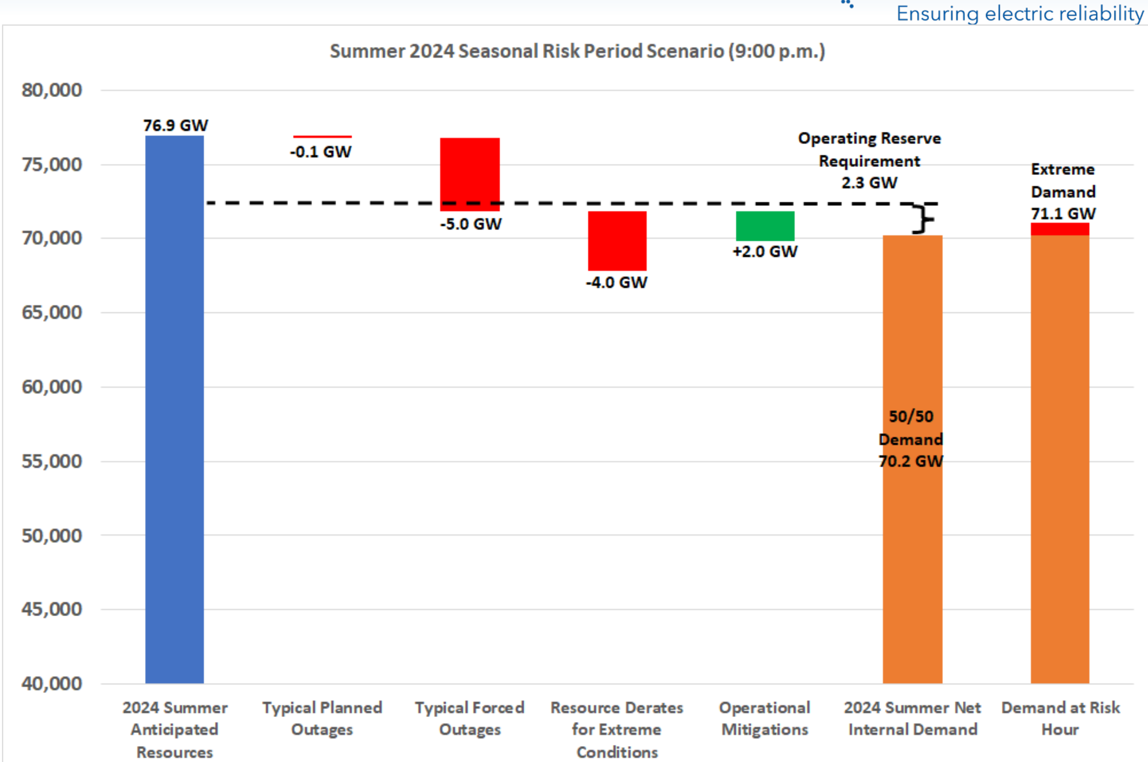


Figure A.1 – Summer 2024 Risk Scenarios

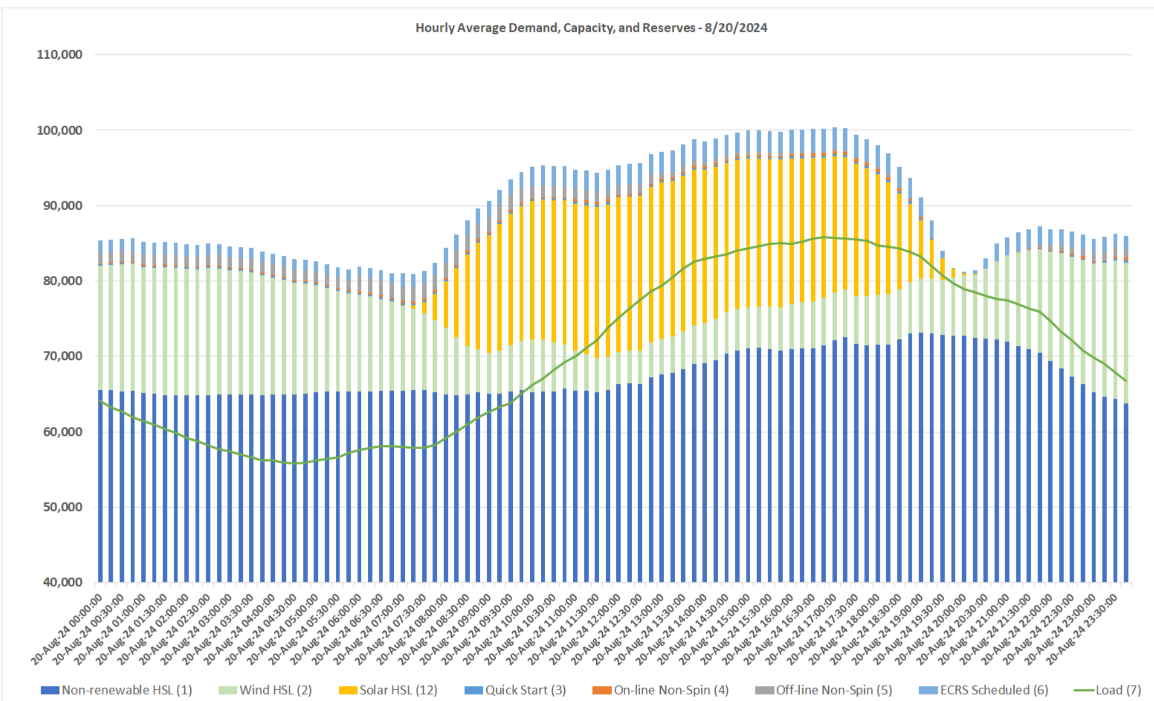


Figure A.2 – August 20, 2024, Capacity, Demand, and Reserves

The August 2024 ERCOT MORA estimated typical thermal maintenance outages of 92 MW and typical forced outages of 5,550 MW with an extreme case of 10,054 MW. Combined actual planned and forced thermal outages for summer 2024 ranged from a low of 4,174 MW to a maximum of 15,724 MW.

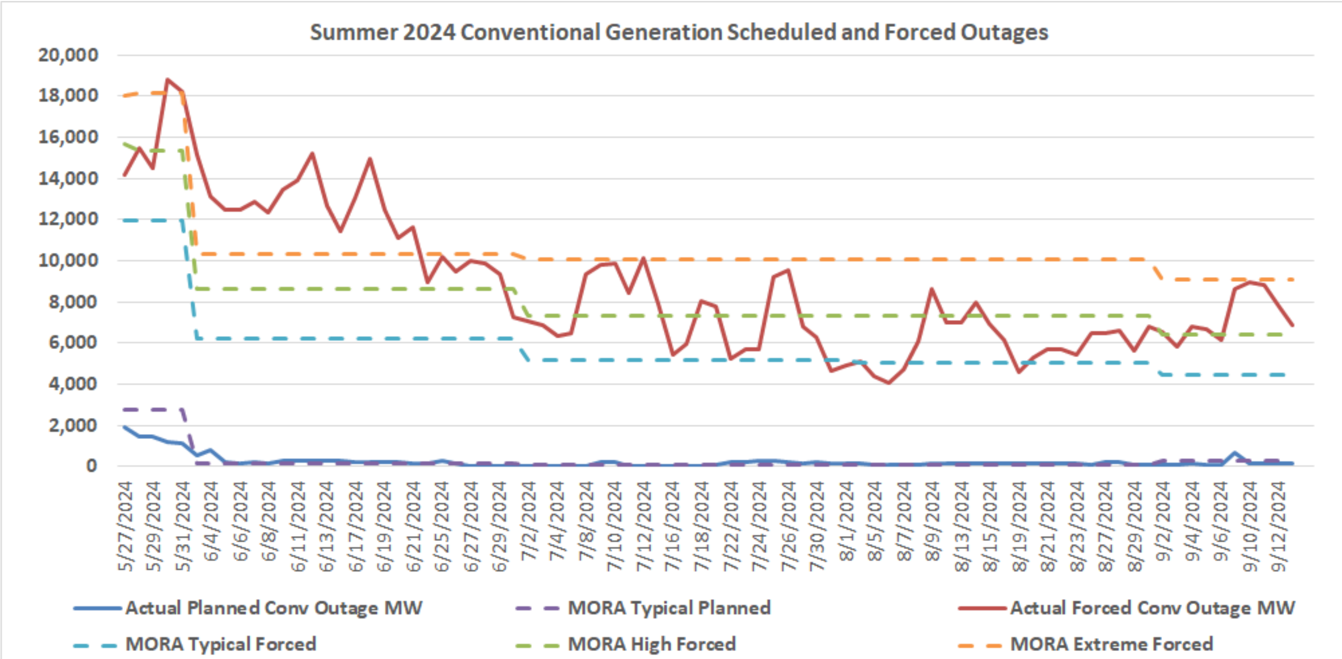


Figure A.3 – Summer 2024 Generation Scheduled and Forced Outages

For winter 2023-2024, peak hourly demand was 78,138 MW on January 16, 2024, approximately 1,846 MW less the typical load scenario estimate of 67,398 MW from the winter monthly assessment of resource adequacy (MORA), and approximately 11,823 MW less than the high load estimate. Actual reserve margin was approximately 13.8 percent. Sufficient operating reserves were maintained during the winter peak hours.

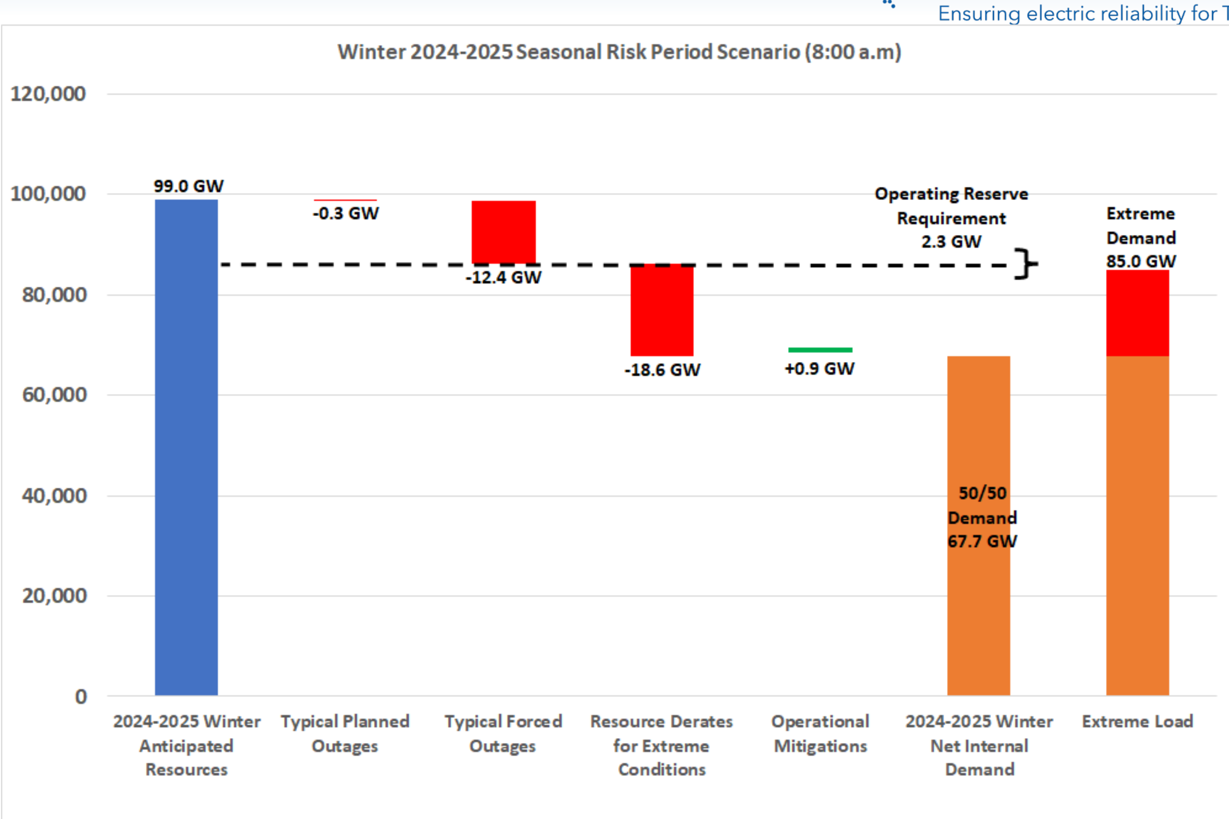


Figure A.4 – Winter 2024-2025 Risk Scenarios

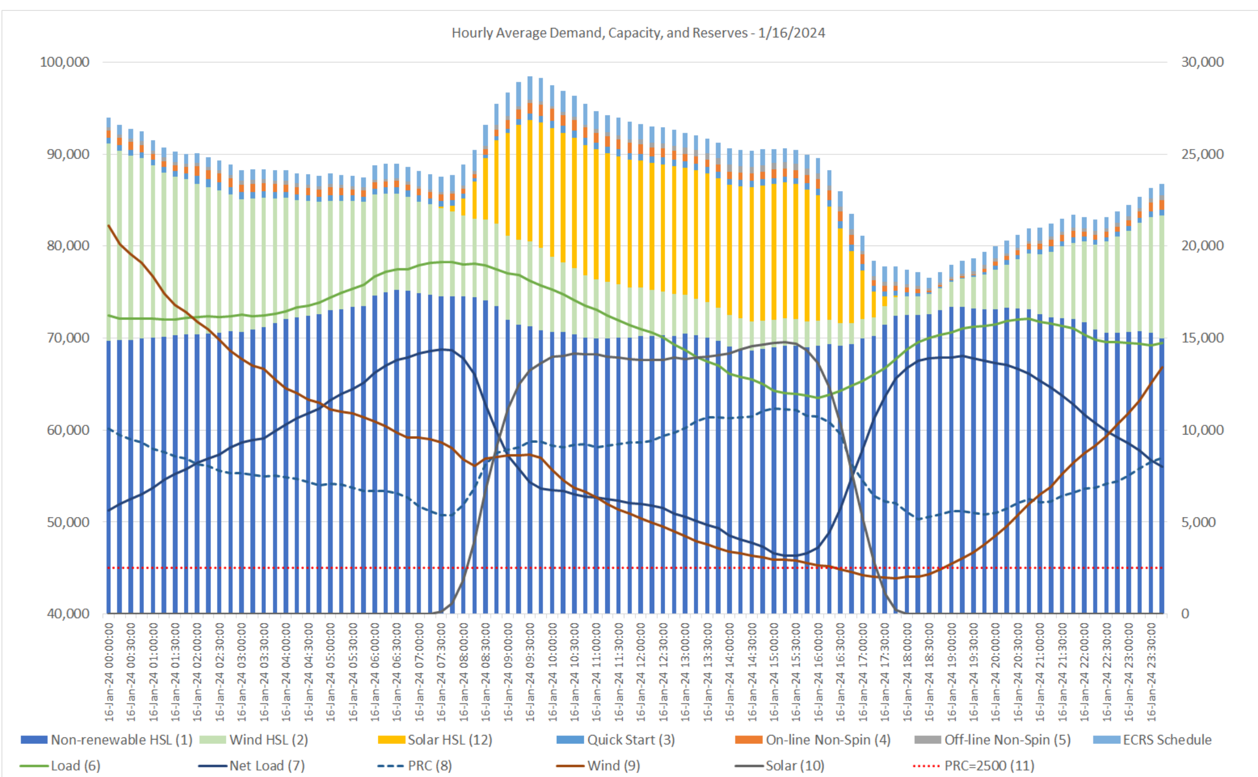


Figure A.5 – January 16, 2024, Capacity, Demand, and Reserves

The ERCOT MORA for winter 2023-2024 estimated typical thermal maintenance outages of 1,437, 407, and 1,069 MW for December, January, and February, respectively. Typical forced outages of 9,389, 7,861, and 7,510 for December, January, and February, respectively. An extreme forced outage scenario of 18,900 MW was used. Combined actual planned and forced outages for the winter ranged from a low of 4,449 MW to a maximum of 20,318 MW.

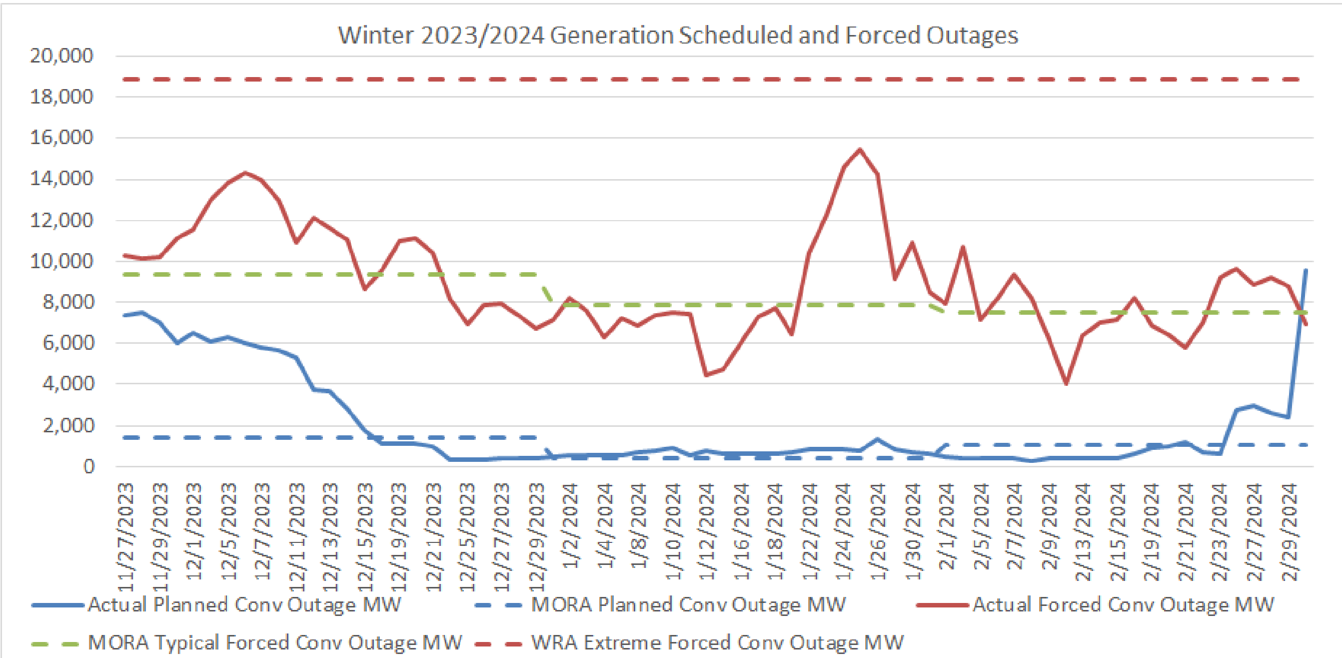


Figure A.6 – Winter 2023-2024 Generation Scheduled and Forced Outages

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.

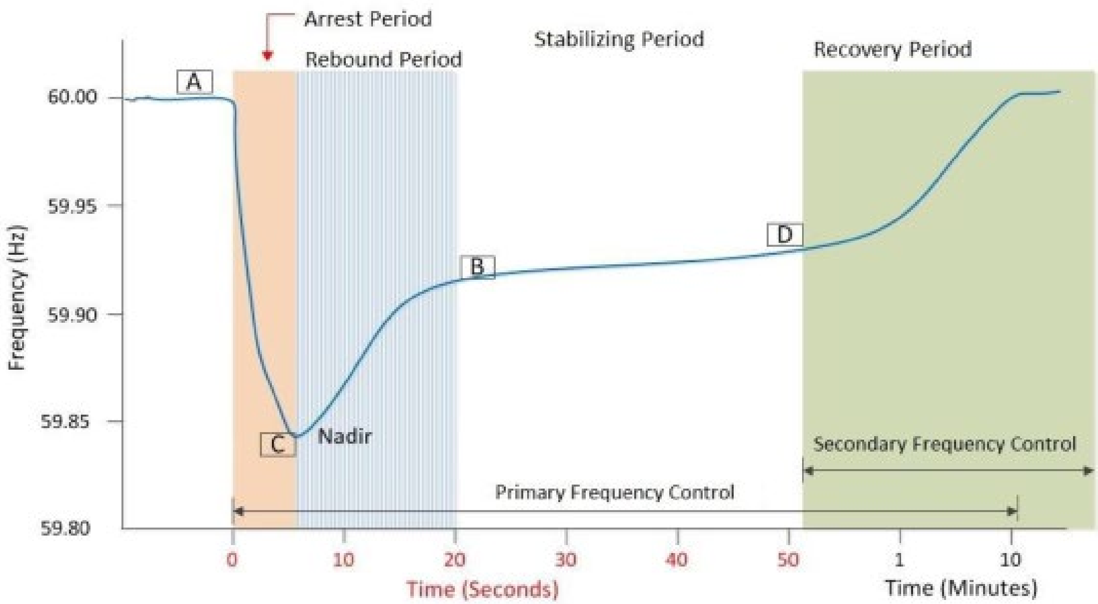


Figure A.7 – Typical Frequency Disturbance

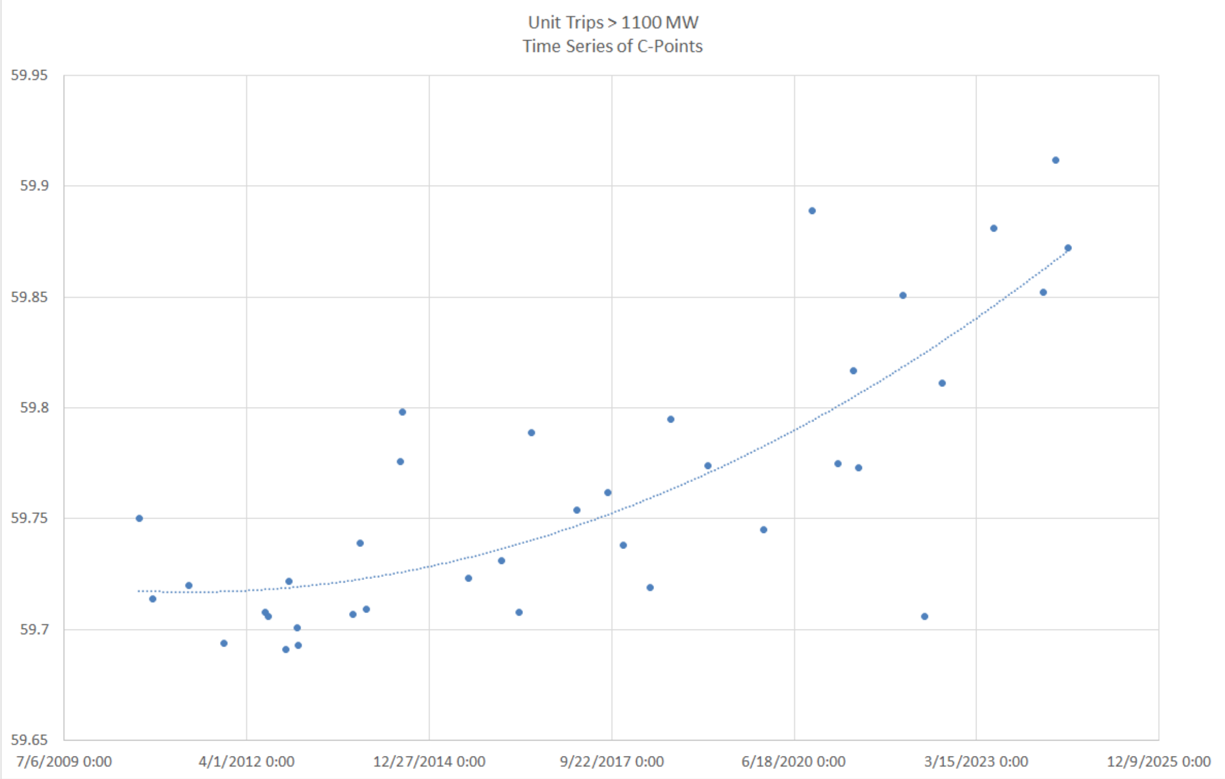
Each of the periods of the frequency disturbance is analyzed by different metrics and performance indicators. Two of the key performance indicators are based on requirements in the BAL-002 and BAL-003 Standards. These are recovery of the Area Control Error (ACE) within 15 minutes following a Reportable 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 2023-2024. The graph corroborates the time-based graph and shows how nadir frequencies are improving over time versus the normalized MW values.



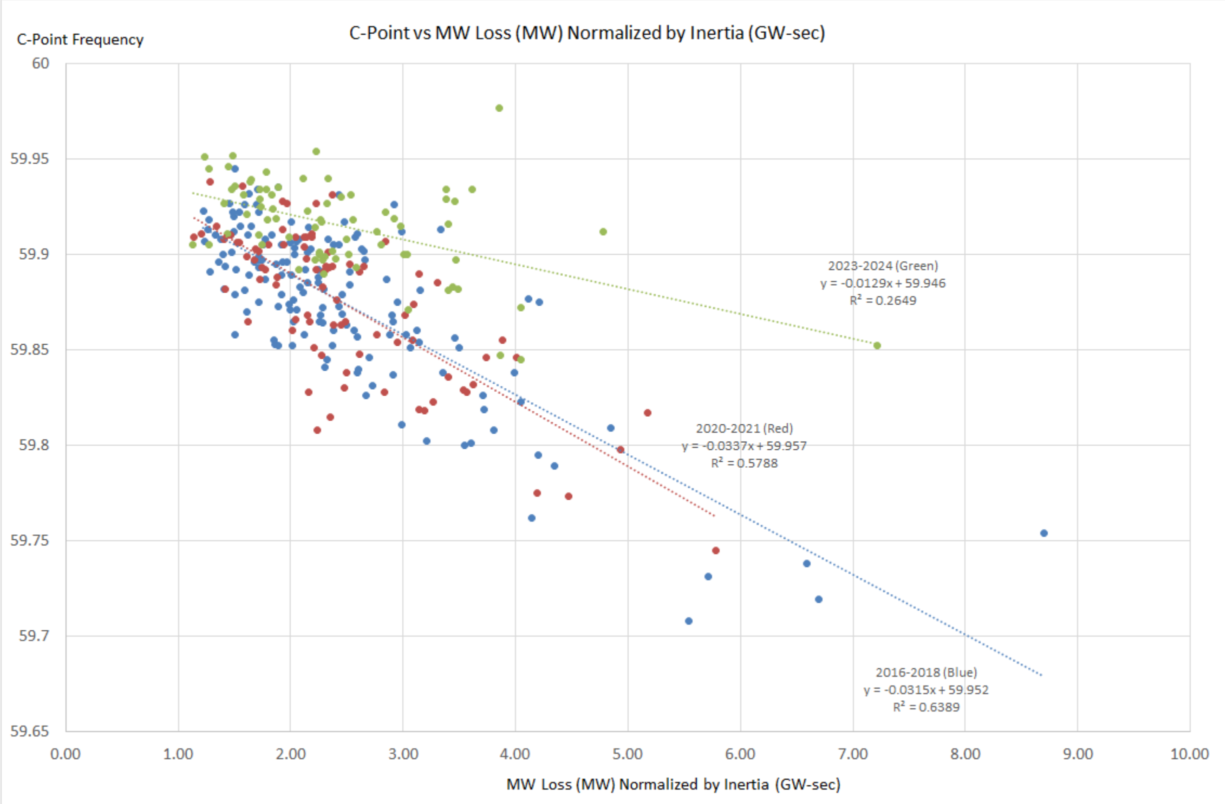


Figure A.8 – Frequency Disturbance Nadir versus Time and Gen Loss MW/Inertia

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 2023-2024. The slightly steeper slopes of the regression lines for 2020-2021 and 2023-2024 indicates that RoCoF rates are gradually increasing due to changes in inertia levels.

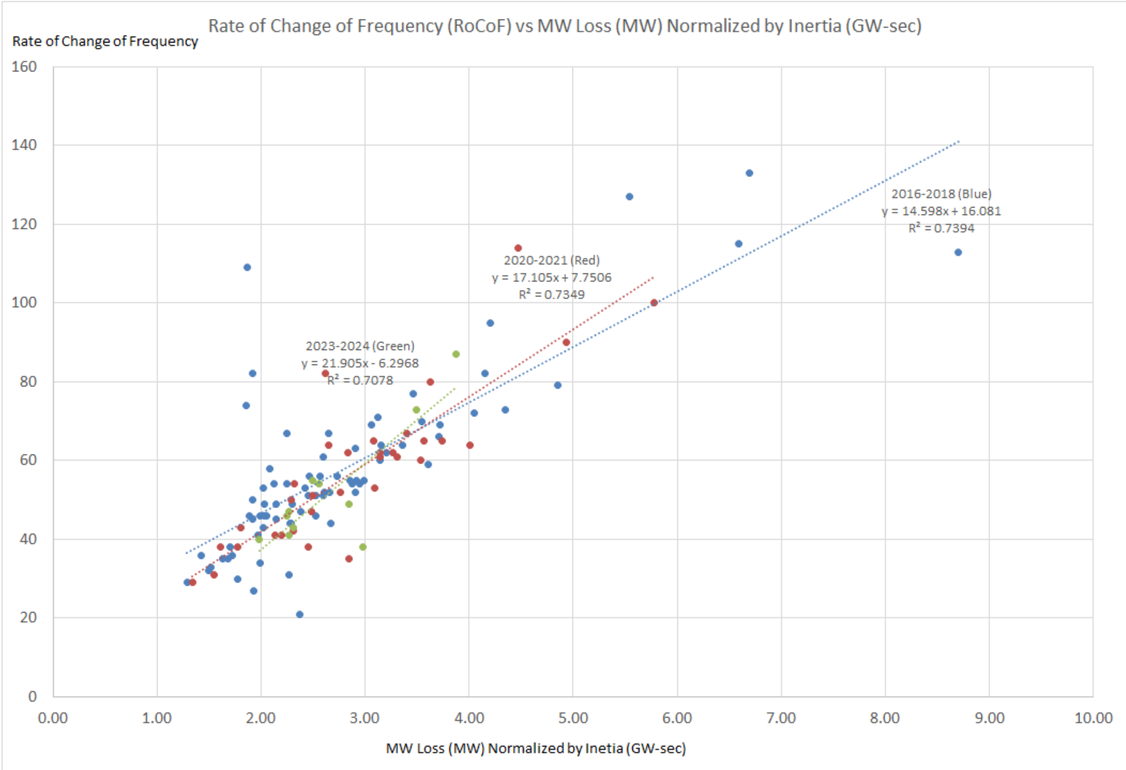


Figure A.9 – Rate of Change of Frequency versus Normalized Generation Loss

Figure A.10 shows the trend in primary frequency response for the Region. In 2024, the average frequency response was 1,552 MW per 0.1 Hz and the median frequency response was 1,499 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.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
FME Count	25	30	29	26	23	19	19	16	7	6

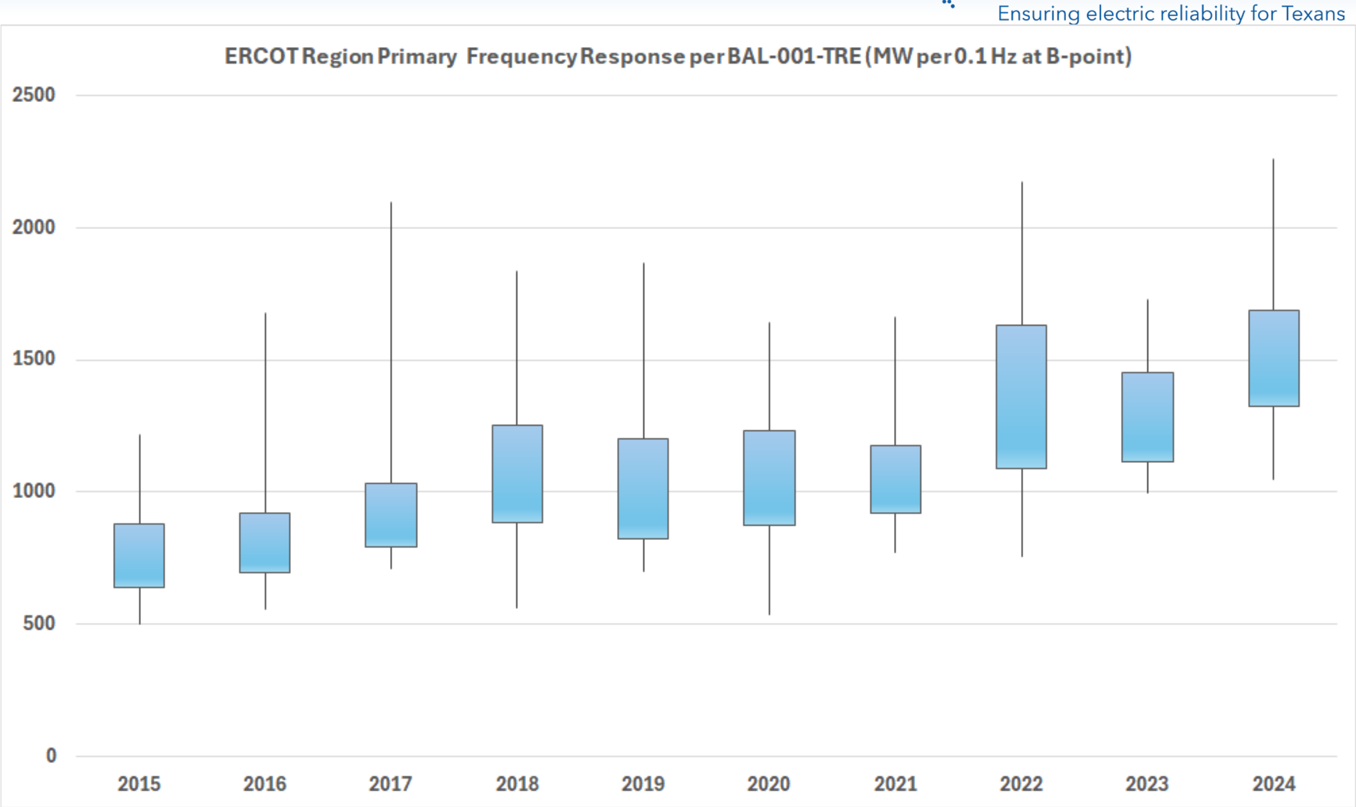


Figure A.10 – Primary (B-Point) Frequency Response Trend for ERCOT Region

Figure A.11 shows the trend in frequency response in the inertial response zone between the A and C points in the Region. In 2024, the average frequency response was 915 MW per 0.1 Hz and the median frequency response was 775 MW per 0.1 Hz as calculated per Regional Standard BAL-001-TRE-2 for the events that were evaluated during the period. 2024 results continued the improving trend versus prior years and the long-term trend continues to show a gradually increase inertial response.

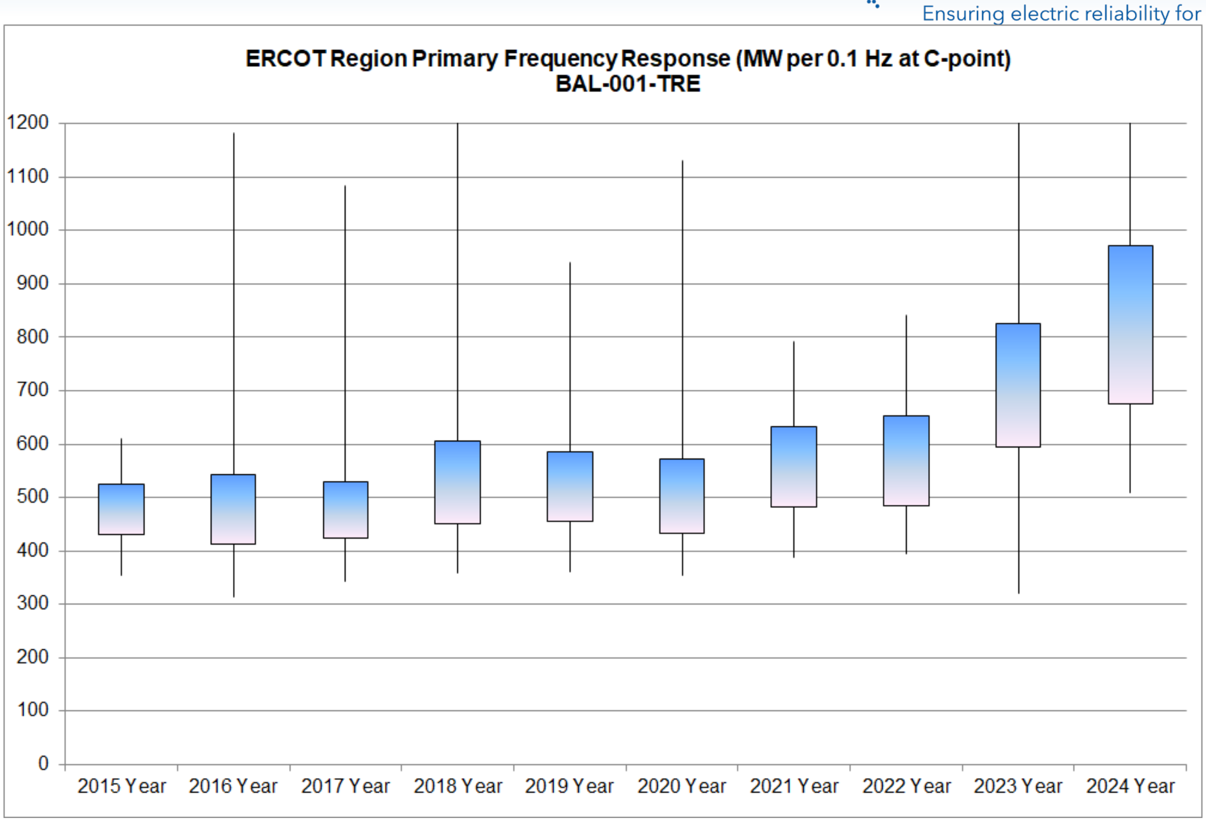


Figure A.11 – Annual Inertial (C-Point) Frequency Response Trend for ERCOT Region

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 6.6 minutes in 2024. The median recovery time from generation loss events was 6.1 minutes in 2024, the same as 2023.

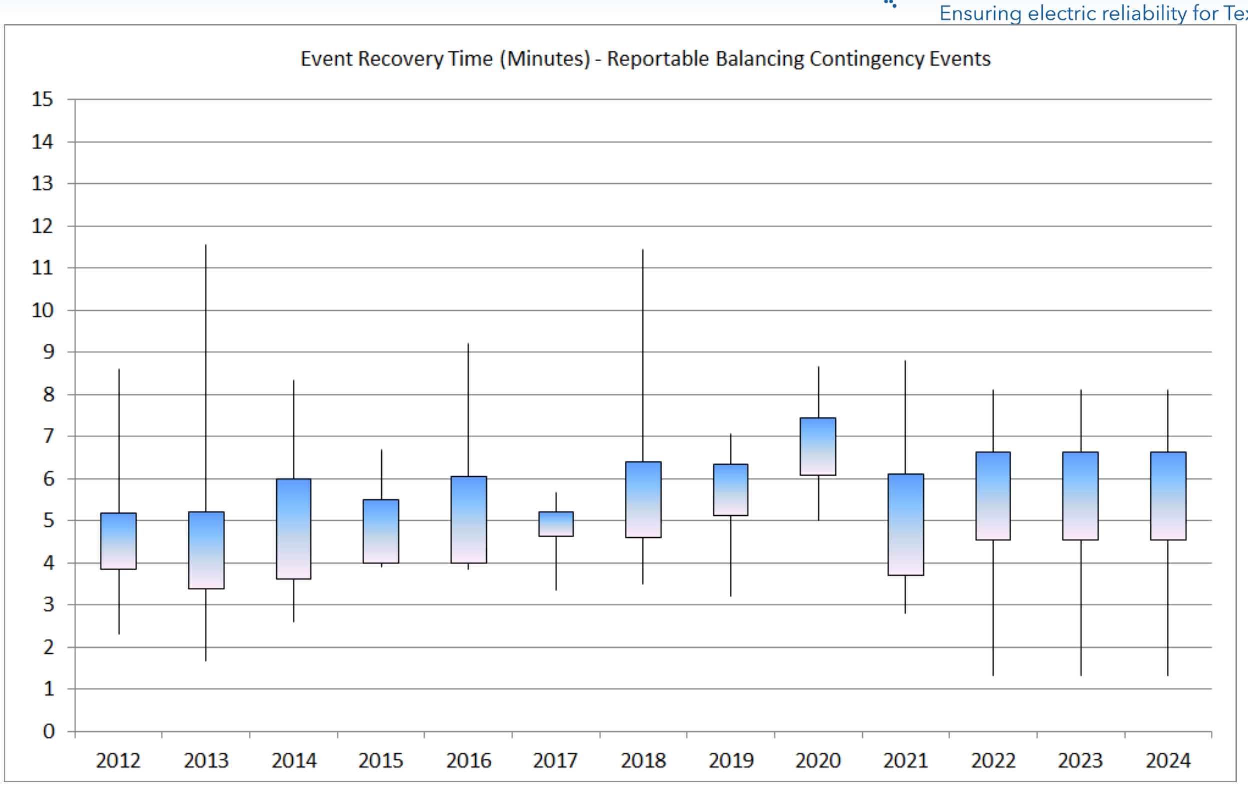


Figure A.12 – Event Recovery Time 2012-2024

E. 2024 Fossil-fueled Generator Performance Metrics

ERCOT fossil generation reporting in GADS produced a net total of 302,666 GWh in 2024 (65.6 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 2020-2024 is provided in the following table.

ERCOT Region GADS Data Metric	2020	2021	2022	2023	2024	5-Yr Avg
	Unweighted	Unweighted	Unweighted	Unweighted	Unweighted	Unweighted
# Units Reporting	407	458	471	483	490	462
Total Unit-Months	4880	5478	5514	5721	5817	5391
Net Capacity Factor (NCF)	44.5%	44.4%	46.5%	47.4%	46.8%	46.4%
Service Factor (SF)	48.8%	45.7%	45.8%	46.2%	45.7%	46.8%
Equivalent Availability Factor (EAF)	84.1%	83.8%	84.1%	84.5%	822%	83.8%
Scheduled Outage Factor (SOF)	9.5%	9.4%	9.1%	8.5%	9.9%	9.3%
Forced Outage Factor (FOF)	3.9%	4.3%	4.5%	4.2%	4.5%	4.3%
EFOR	8.4%	10.1%	10.4%	9.8%	10.1%	9.7%

Equivalent Forced Outage Rate Demand (EFORd)	6.1%	5.9%	6.7%	6.8%	6.7%	6.4%

Table A.3 – ERCOT Generation Performance Metrics 2020 through 2024

- 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 2024 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	142	18	153	62
Total Unit-Months	228	432	1626	207	1836	744
Net Capacity Factor (NCF)	48.2%	18.0%	10.8%	52.6%	59.5%	52.5%
Service Factor (SF)	76.8%	31.6%	12.5%	64.9%	68.8%	72.1%
Equivalent Availability Factor (EAF)	76.9%	69.3%	88.3%	77.9%	80.2%	81.0%
Scheduled Outage Factor (SOF)	10.6%	20.0%	5.8%	5.9%	12.6%	11.4%
Forced Outage Factor (FOF)	5.7%	6.1%	3.2%	4.1%	3.7%	4.7%
EFOR	11.8%	24.2%	20.6%	7.3%	5.2%	7.9%
EFORd	7.0%	17.1%	6.2%	5.1%	4.6%	5.8%

Table A.4 – ERCOT Generation Performance Metrics by Fuel Type for 2024

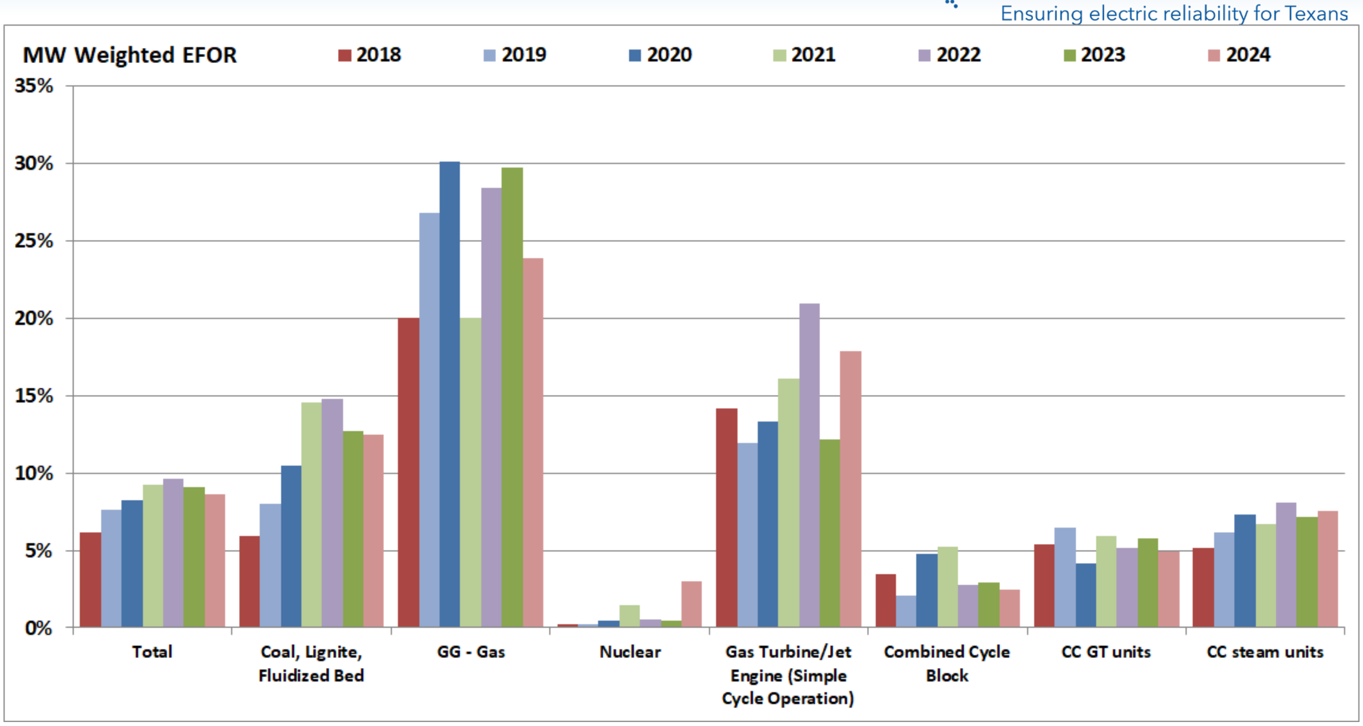


Figure A.13 – MW-Weighted EFOR Metric by Fuel Type and Year

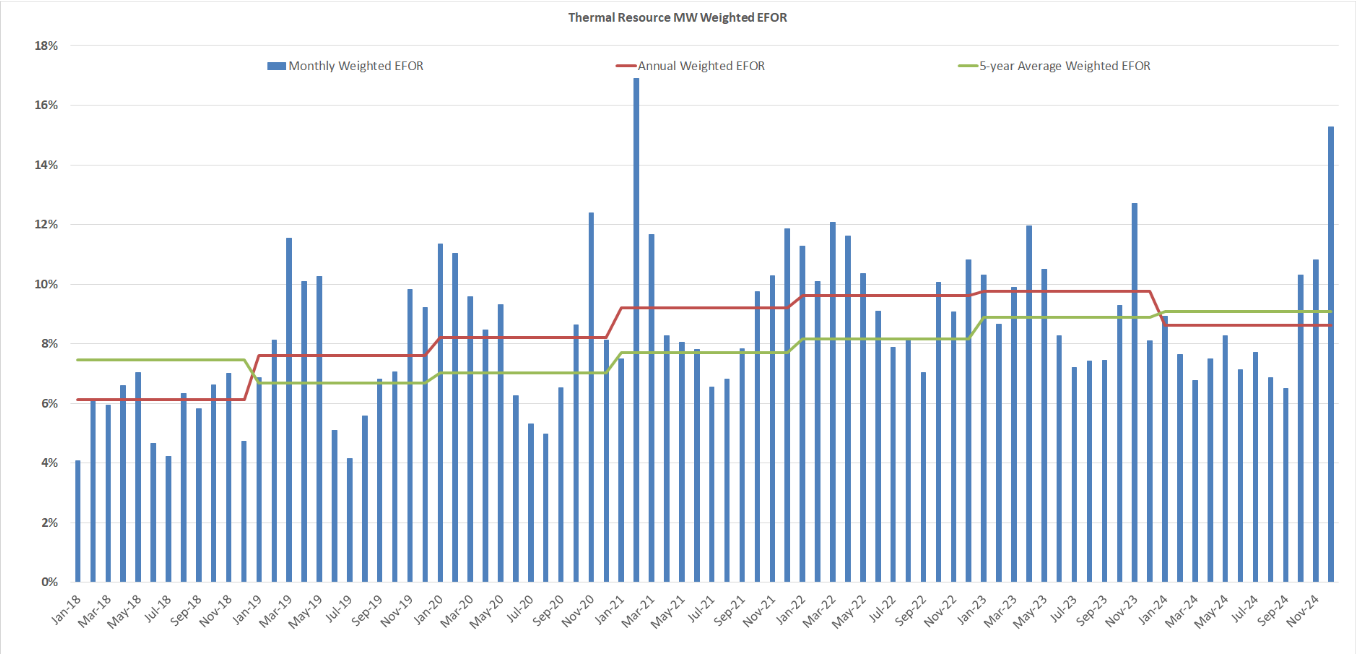


Figure A.14 – Time Trend for MW-Weighted EFOR

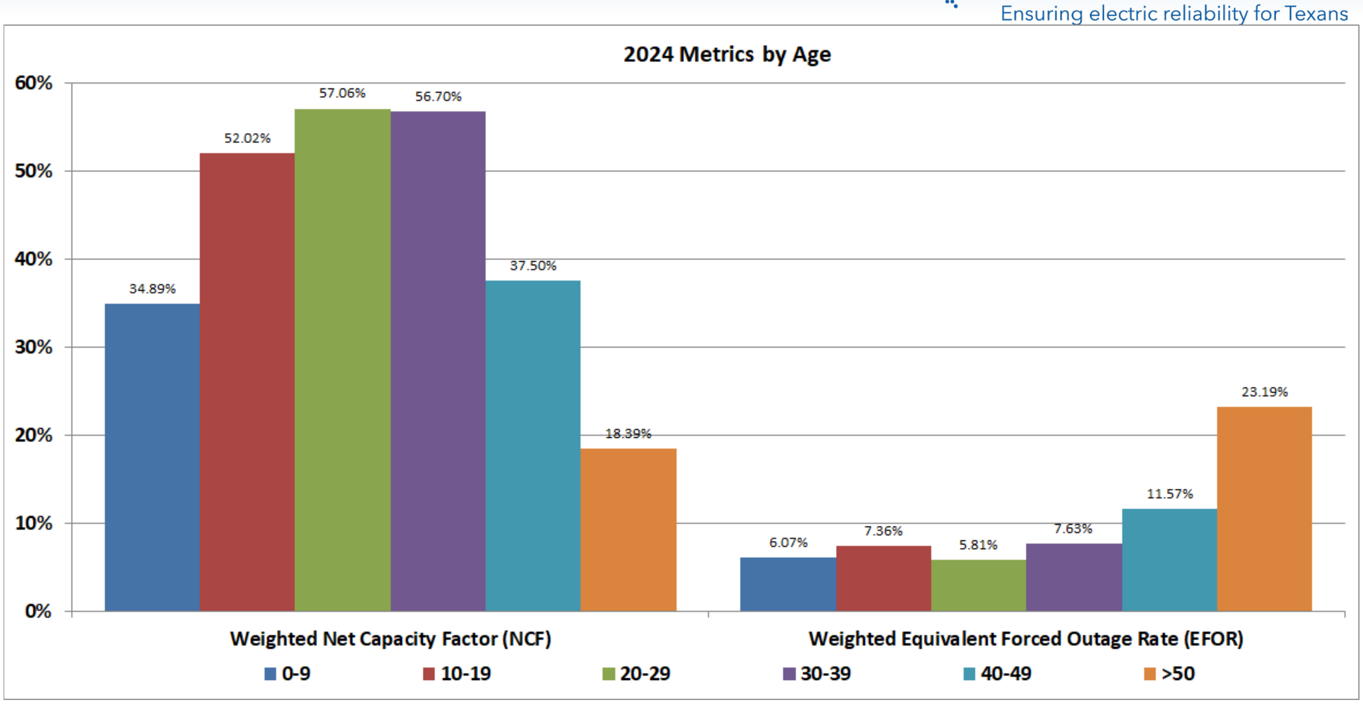


Figure A.15 – 2024 GADS Metrics by Unit Age (Years)

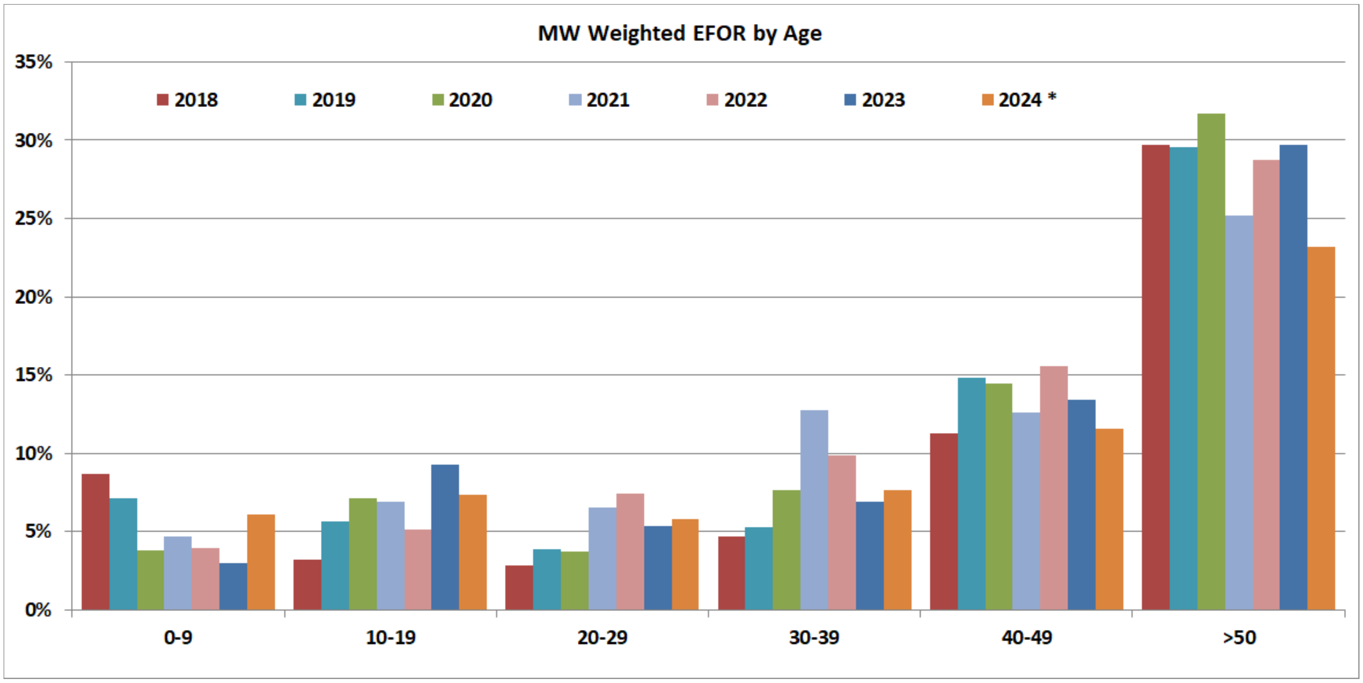


Figure A.16 – 2018-2024 GADS EFOR by Unit Age (Years)

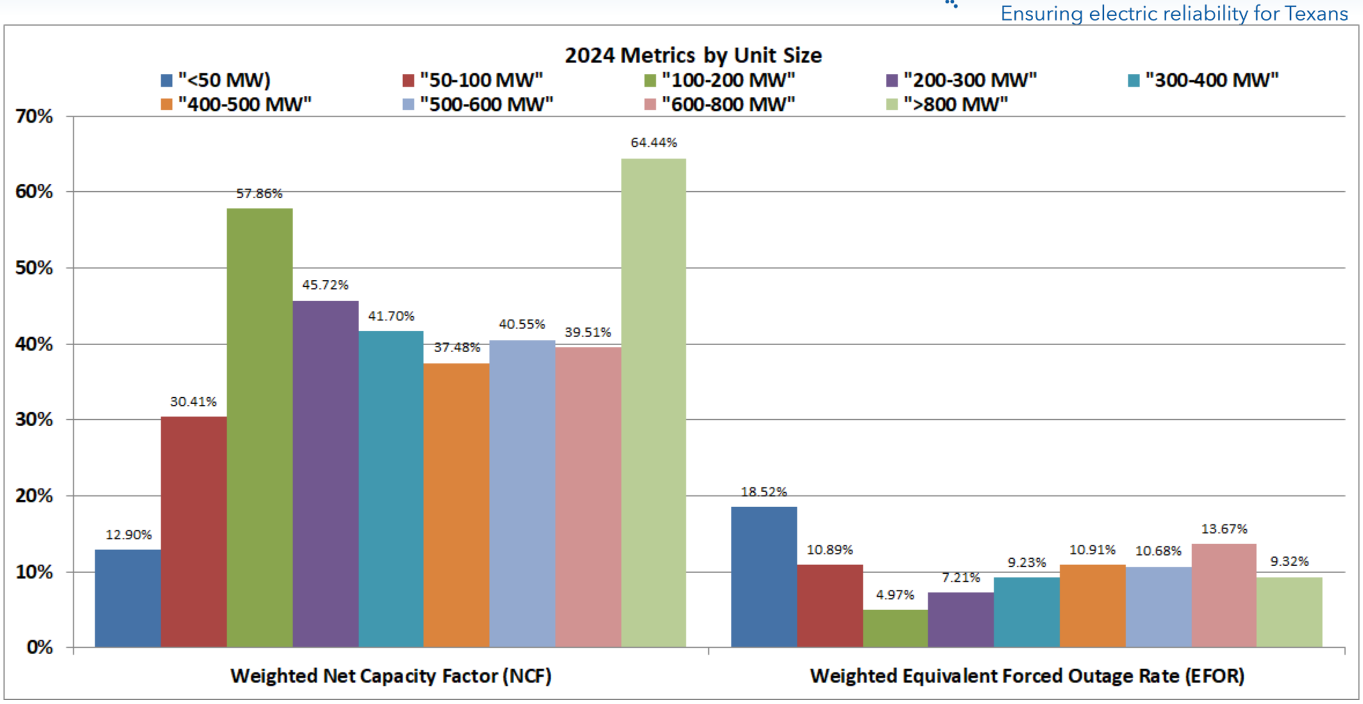


Figure A.17 – 2024 GADS Metrics by Unit Size

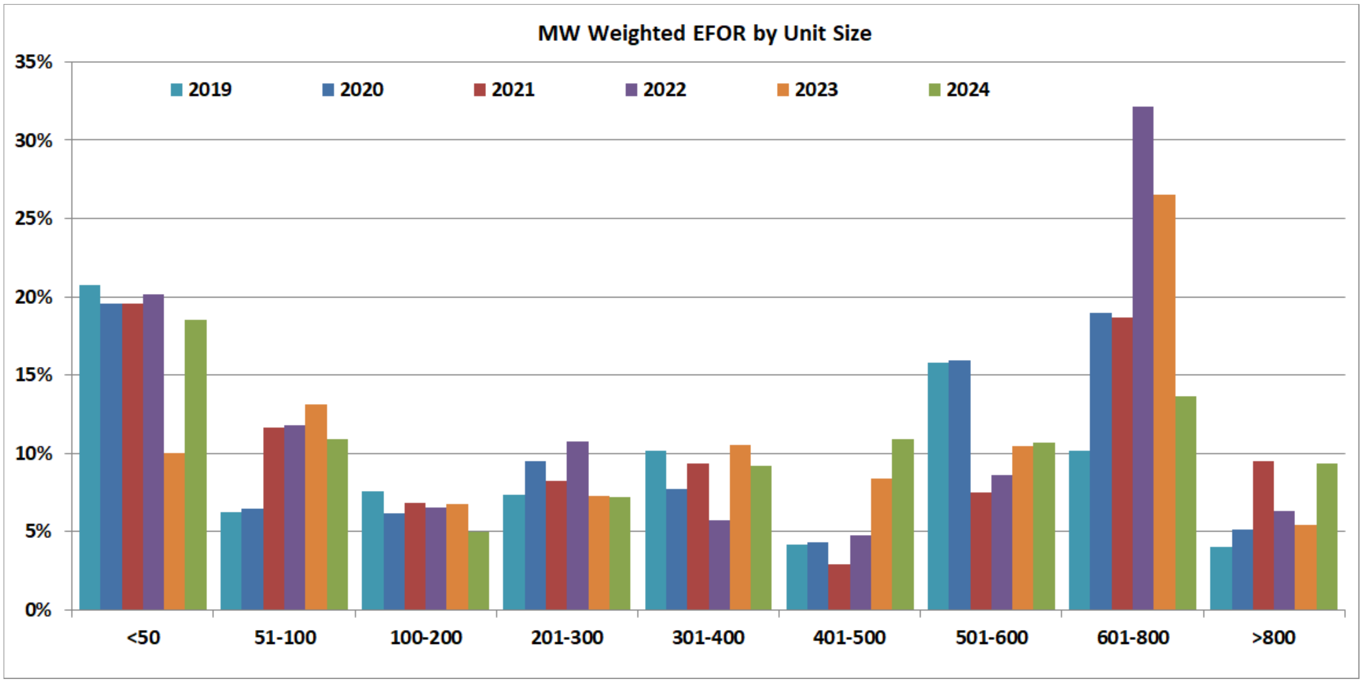


Figure A.18 – 2019-2024 GADS EFOR by Unit Size

2024 Fossil-fueled Generator Outages and De-rates

Table A.5 provides a summary of immediate de-rates and forced outages for conventional generation from January 2024 through December 2024. The 2,299 immediate forced outage events are approximately 8 percent lower than the number of forced outage events in 2023, with an average capacity of 173 MW per event.

2024	Immediate De-rates	Immediate Forced Outages
Number of Events	2,350	2,548
Total Duration (hrs)	194,902	143,594
Total Capacity (MW)	245,684	465,047
Avg Duration per Event (hrs)	82.9	56.4
Avg Capacity per Event (MW)	104.5	182.5

Table A.5 – Generator Immediate De-rate and Forced Outage Data (Jan. – Dec. 2024)

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	238	18908.0	91687.6	79.4	385.2
Balance of Plant	541	30559.7	120225.4	56.5	222.2
Steam Turbine/Generator	1407	75609.4	199313.3	53.7	141.7
Heat Recovery Steam Generator	84	7037.8	12522.1	83.8	149.1
Pollution Control Equipment	66	1380.5	6175.8	20.9	93.6
External	121	6783.2	18705.1	56.1	154.6
Regulatory, Safety, Environmental	32	1926.7	3843.5	60.2	120.1
Personnel/ Procedure Errors	54	383.9	12254.1	7.1	226.9
Other	5	1004	320	200.9	64.0

Table A.6 – 2024 Major Category Cause of Immediate Forced Outage Events from GADS

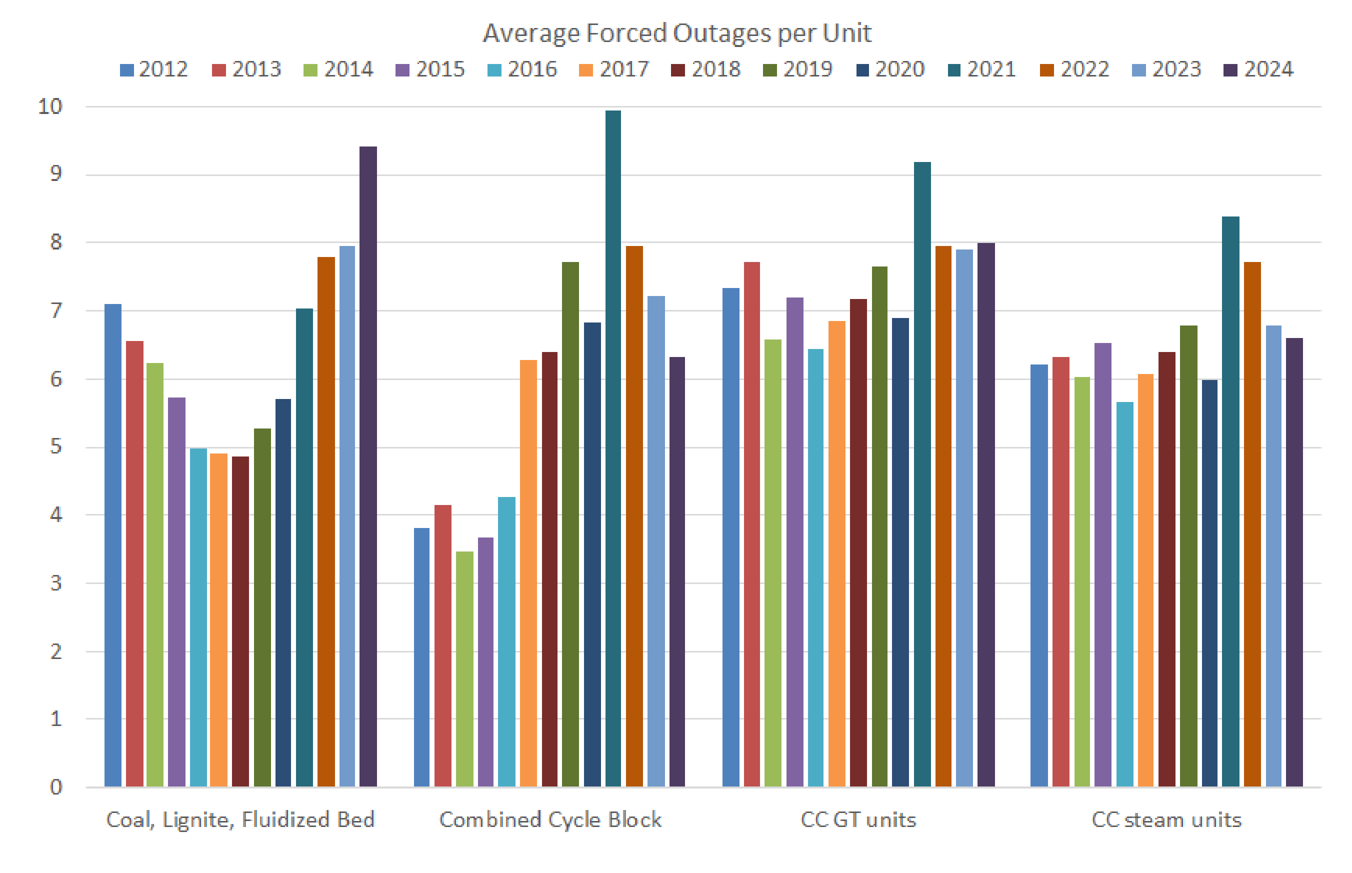


Figure A.19 – 2024 Average Forced Outages per Unit

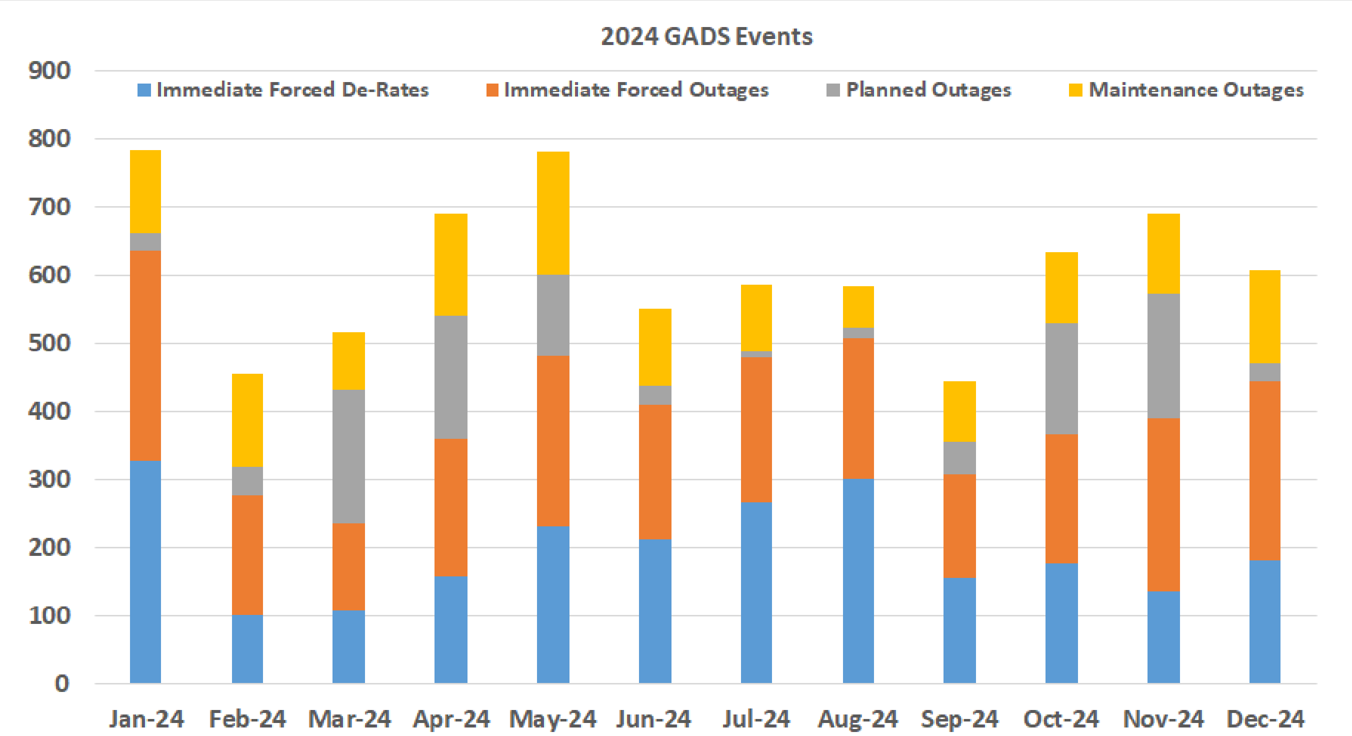


Figure A.20 –2024 Count of Generation Events by Month

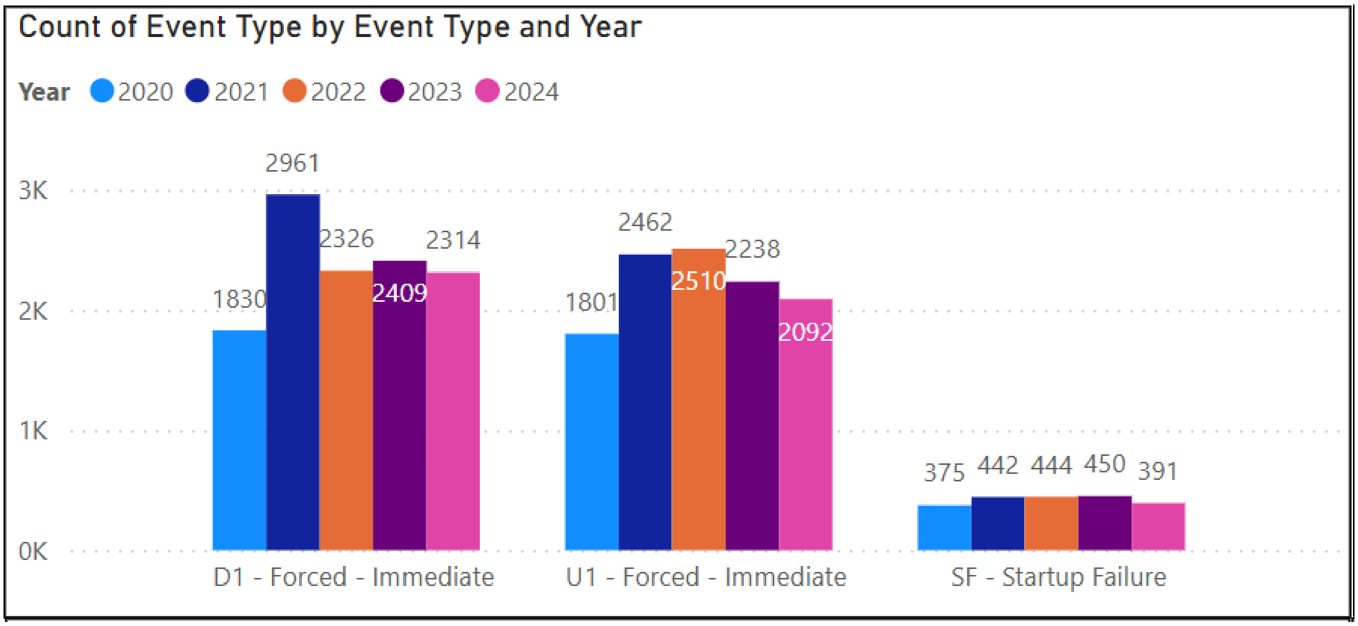


Figure A.21 – 2020-2024 Count of Events by Year

F. 2024 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 2024, 342 wind facilities in the Region and sub-groups submitted a total of 3,011 unit-months of data in GADS-Wind. Net wind generation reported was 94,547 GWh, or 84.6 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 2020-2023 is provided in the following table.

Metric: ERCOT Region GADS-Wind Data	2021		2022		2023		2024	
	Resource	Equipment	Resource	Equipment	Resource	Equipment	Resource	Equipment
Net Capacity Factor (PRNCF and PENCF)	34.6%	38.1%	36.1%	39.4%	34.1%	37.3%	34.4%	37.4%
Equivalent Forced Outage Rate (PREFOR and PEEFOR)	16.6%	6.9%	17.1%	7.8%	17.1%	8.0%	16.2%	7.3%
Equivalent Scheduled Outage Rate	1.4%	1.3%	1.6%	1.4%	1.4%	1.3%	1.9%	1.7%

(RESOR and PEESOR)								
Equivalent Availability Factor (REAF and PEEAF)	82.9%	90.2%	82.2%	88.9%	82.4%	88.9%	82.9%	89.3%

Table A.7 – ERCOT Wind Generation Performance Metrics, 2021-2024

- 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 2024 included 1,576 component outage reports totaling 154,769 turbine-hours of forced, planned, and maintenance outage duration, with an estimated production loss of 2,417.4 GWh.

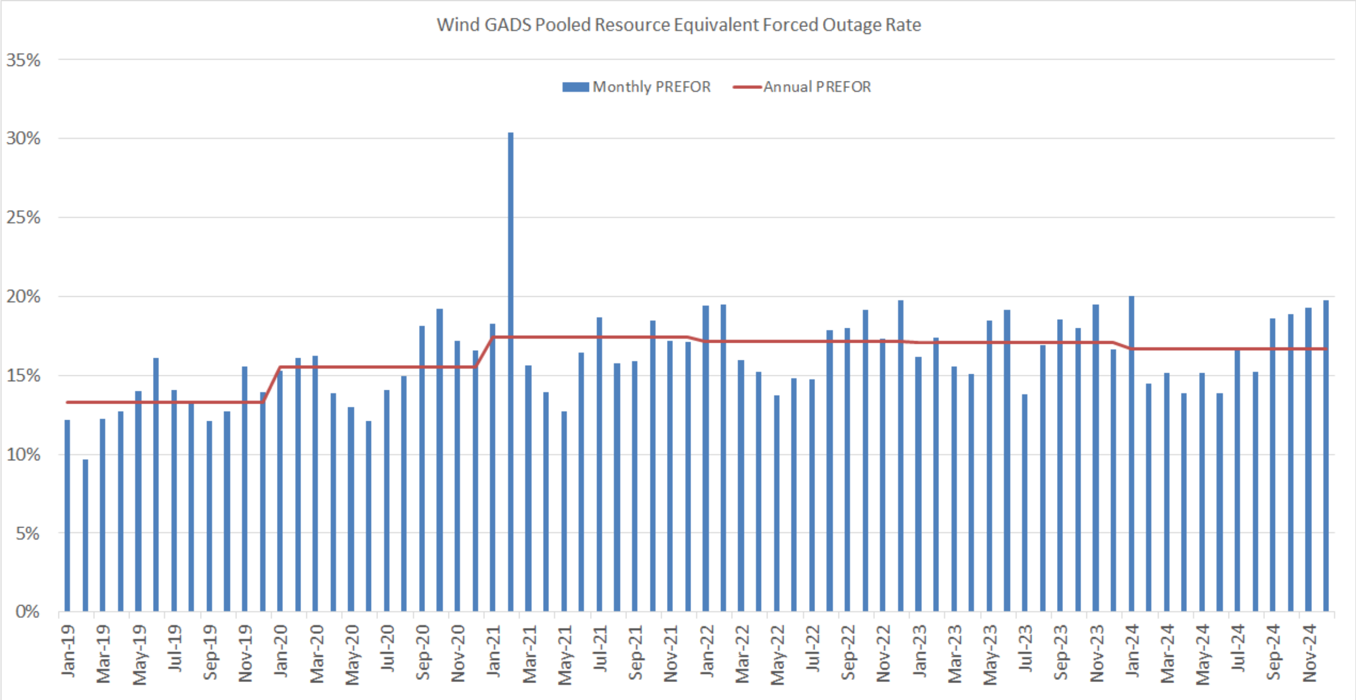


Figure A.22 – GADS-Wind Time Trend for MW-Weighted EFOR

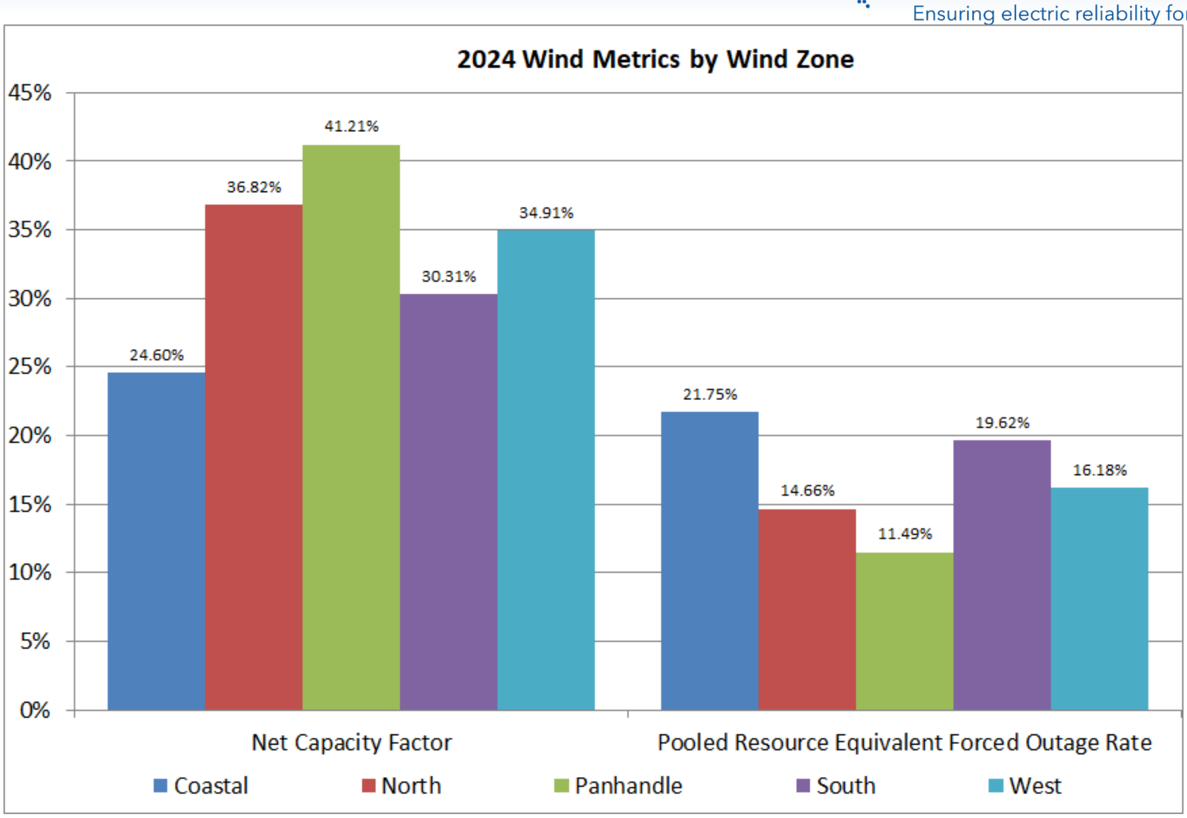


Figure A.23 – 2024 GADS-Wind Metrics by Wind Zone

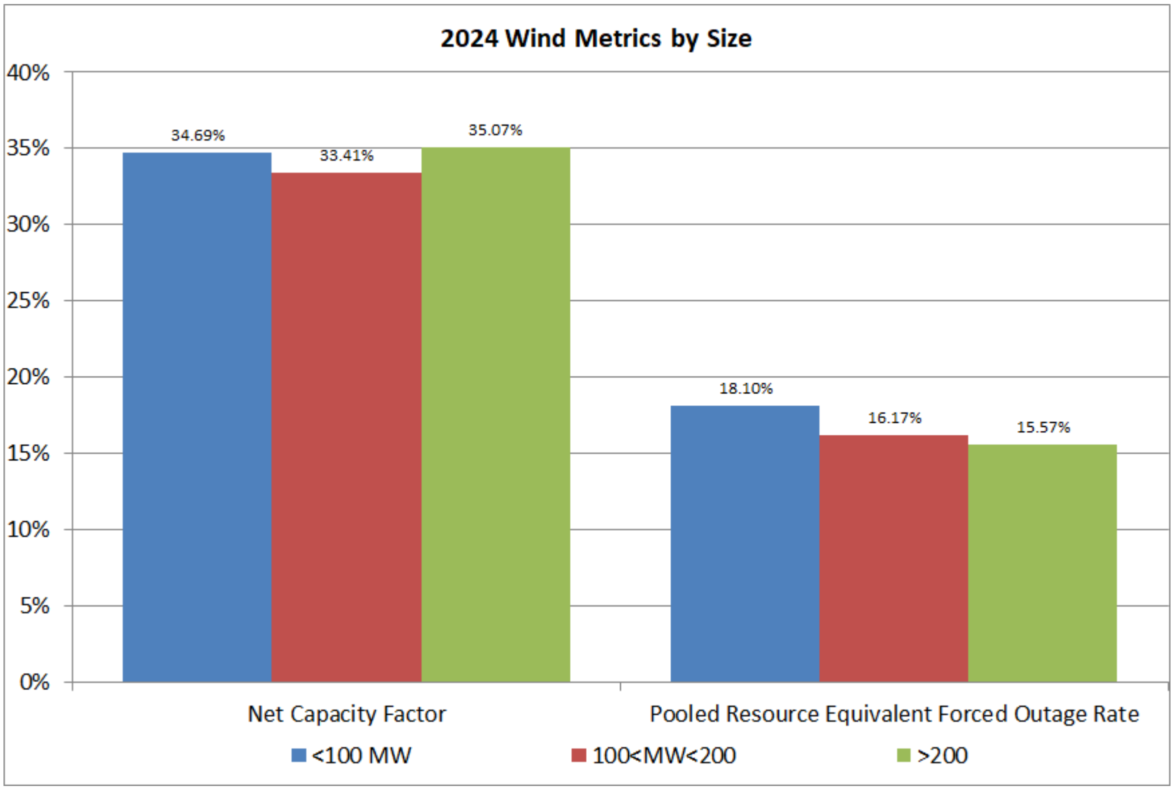


Figure A.24 – 2024 GADS-Wind Metrics by Unit Size

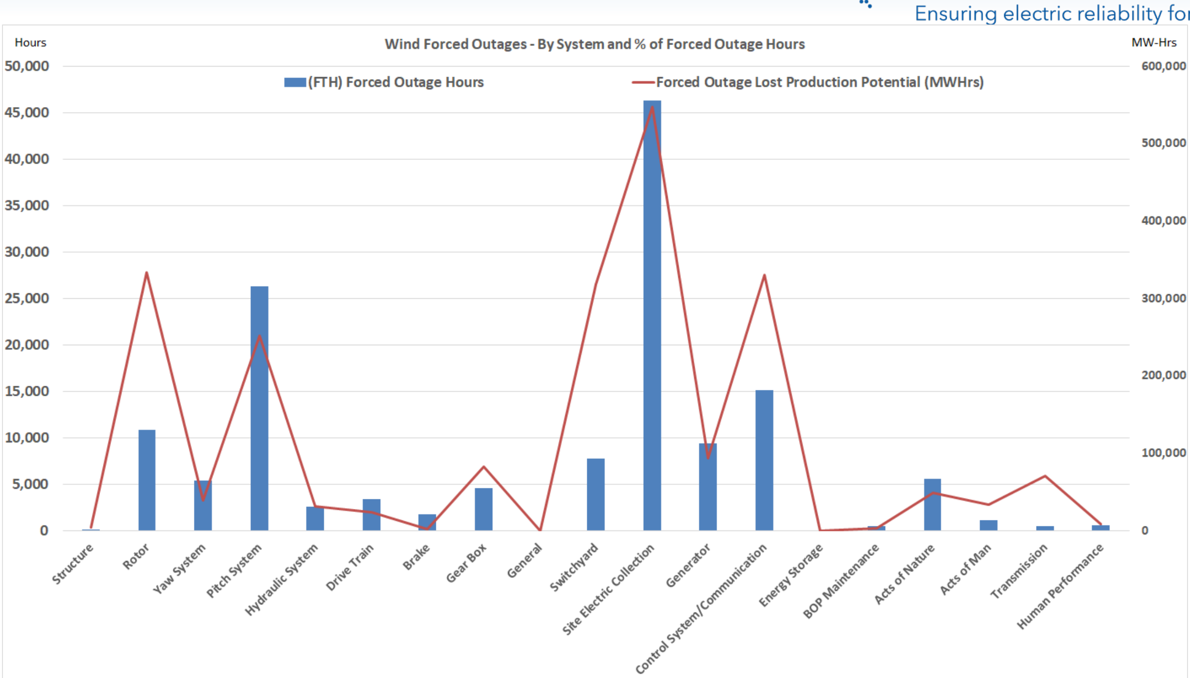


Figure A.25 – 2024 GADS-Wind Turbine Outage Hours and Production Loss by System

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 2024, 81 solar facilities in the Region and sub-groups submitted a total of 744 unit-months of data in GADS-Solar. Net solar generation reported was 22,759.8 GWh, or 47.2 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 2024 is provided in the following table.

Metric: ERCOT Region GADS-Solar Data	2024
Net Capacity Factor (RNCF)	17.6%
Resource Generating Factor (RGF)	42.6%
Resource Forced Outage Rate (RFOR)	10.0%
Equipment Forced Outage Rate (EFOR)	4.4%
Resource Scheduled Outage Rate (RSOR)	0.3%
Performance Index (PI)	79.5%
Resource Availability Factor (RAF)	95.0%

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

- 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 2024 included 2,206 component outage reports totaling 22,643 inverter-hours of forced, planned, and maintenance outage duration, with an estimated production loss of 16,248.6 GWh.

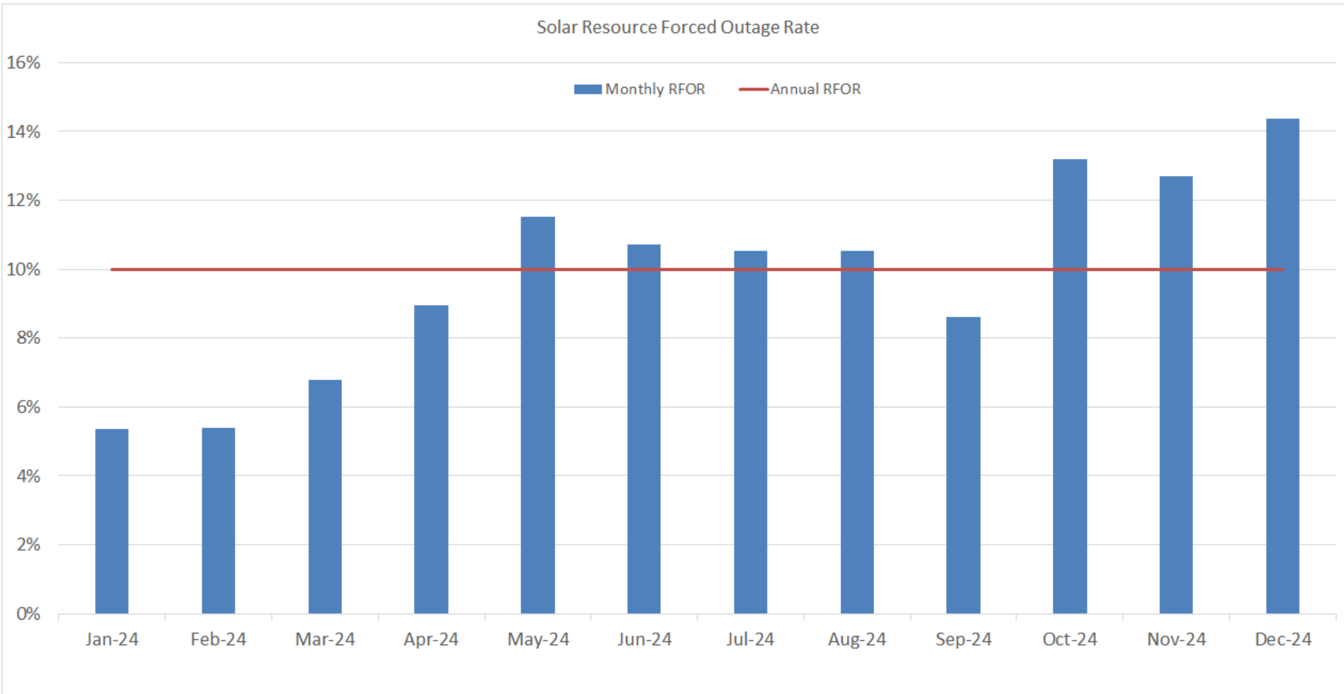


Figure A.26 – GADS-Solar Time Trend for RFOR

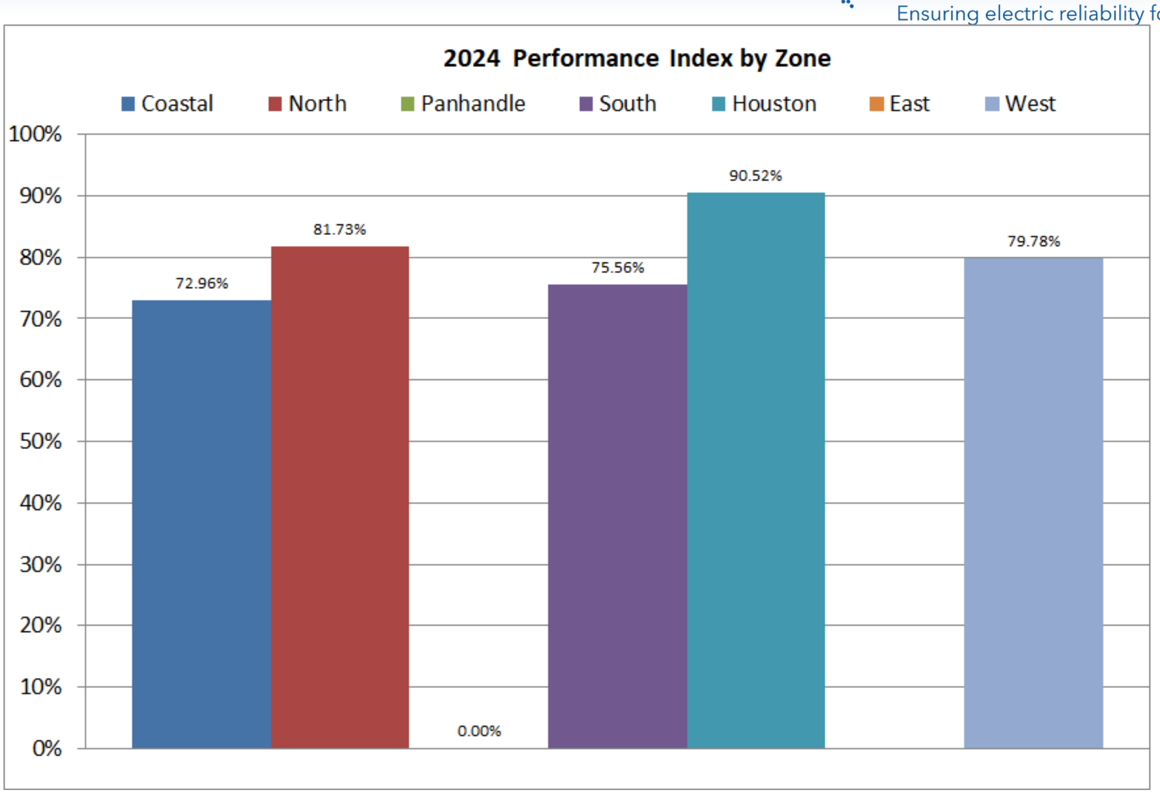


Figure A.27 – 2024 GADS-Solar Performance Index by Zone

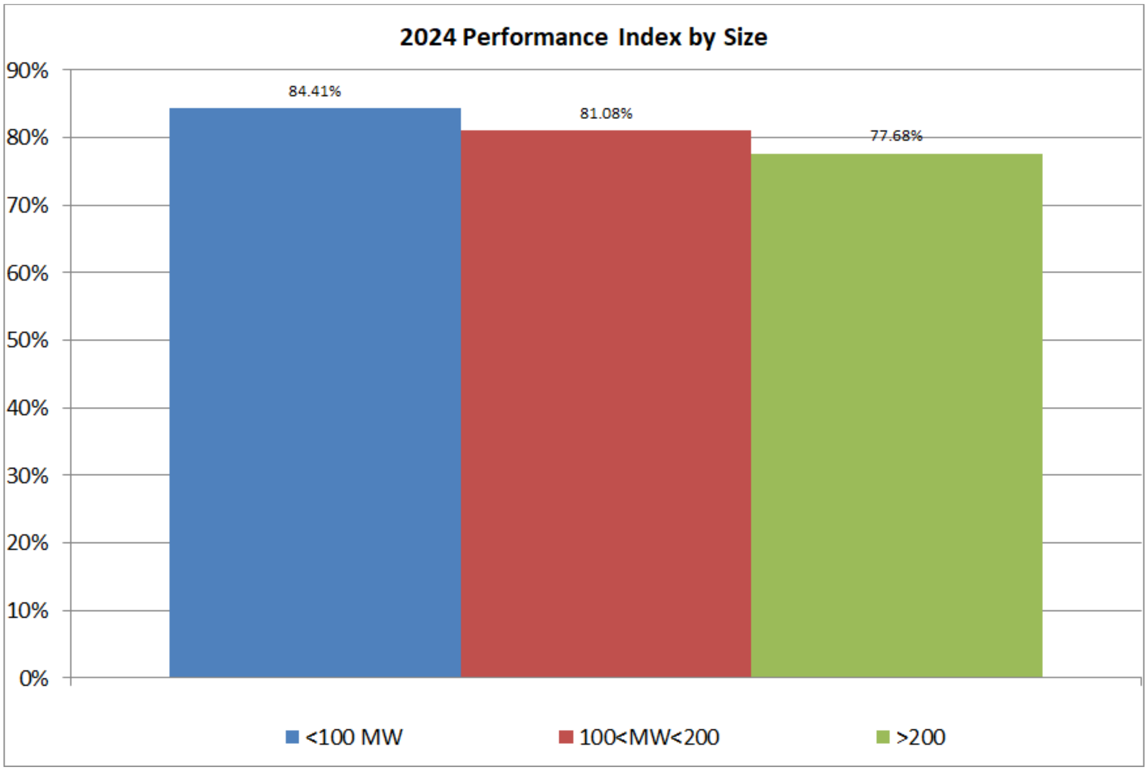


Figure A.28 – 2024 GADS-Solar Performance Index by Unit Size

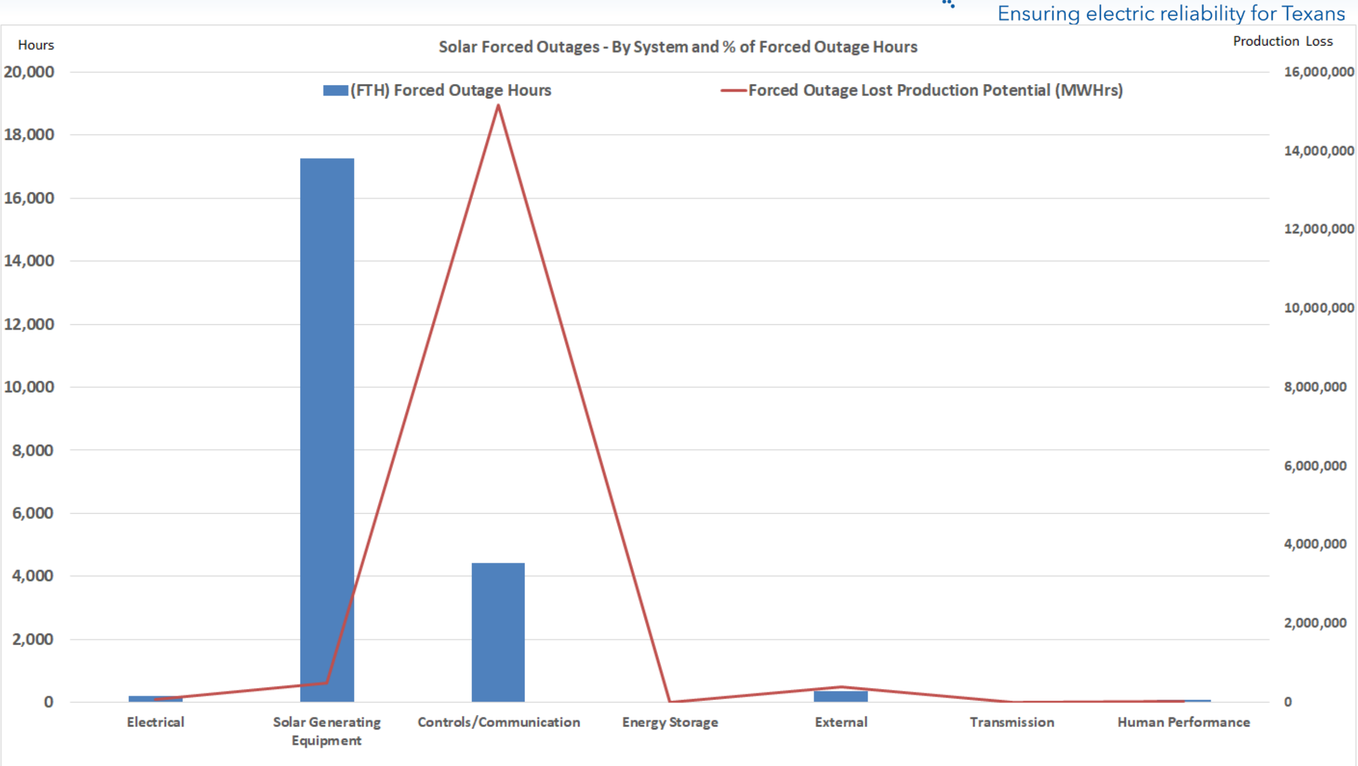


Figure A.29 – 2024 GADS-Solar Inverter Outage Hours and Production Loss by System

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.

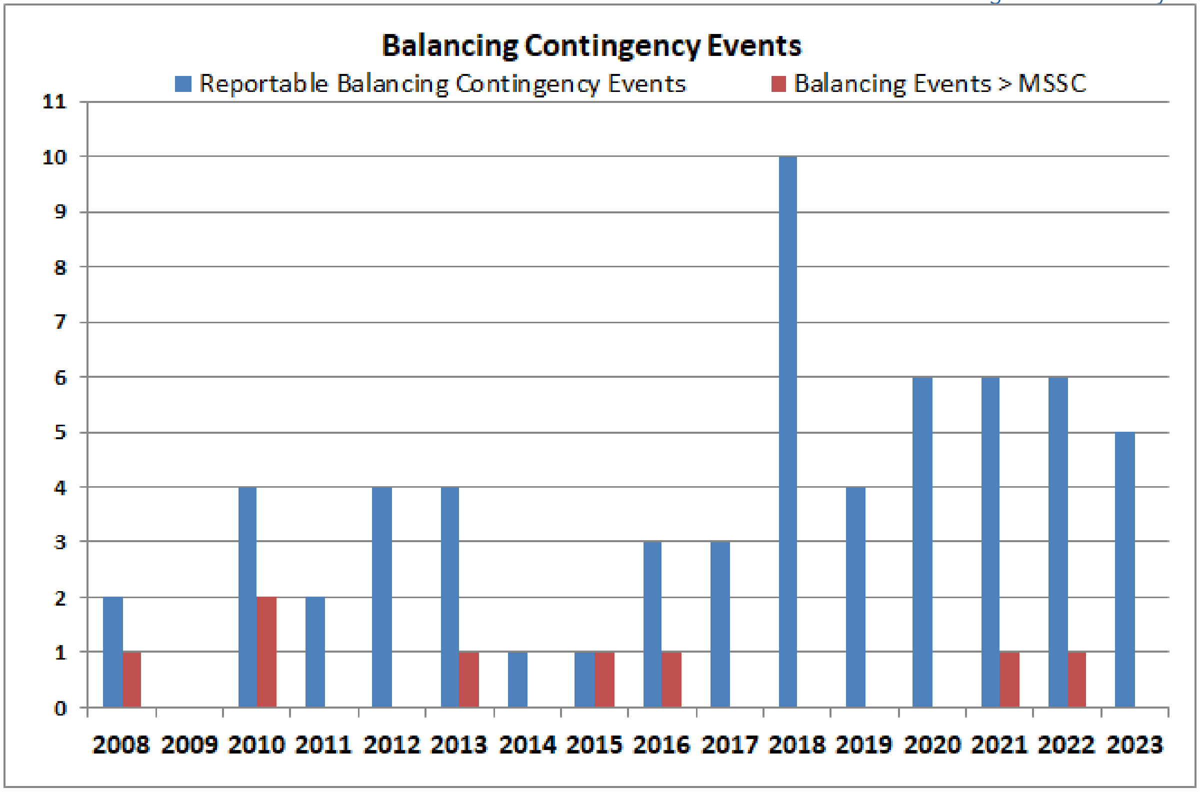


Figure A.30 – Reportable Balancing Contingency Events by Year

H. Fuel Constraints

There was a decrease in the unavailable generation capacity due to natural gas fuel curtailments in 2024 compared to 2023.

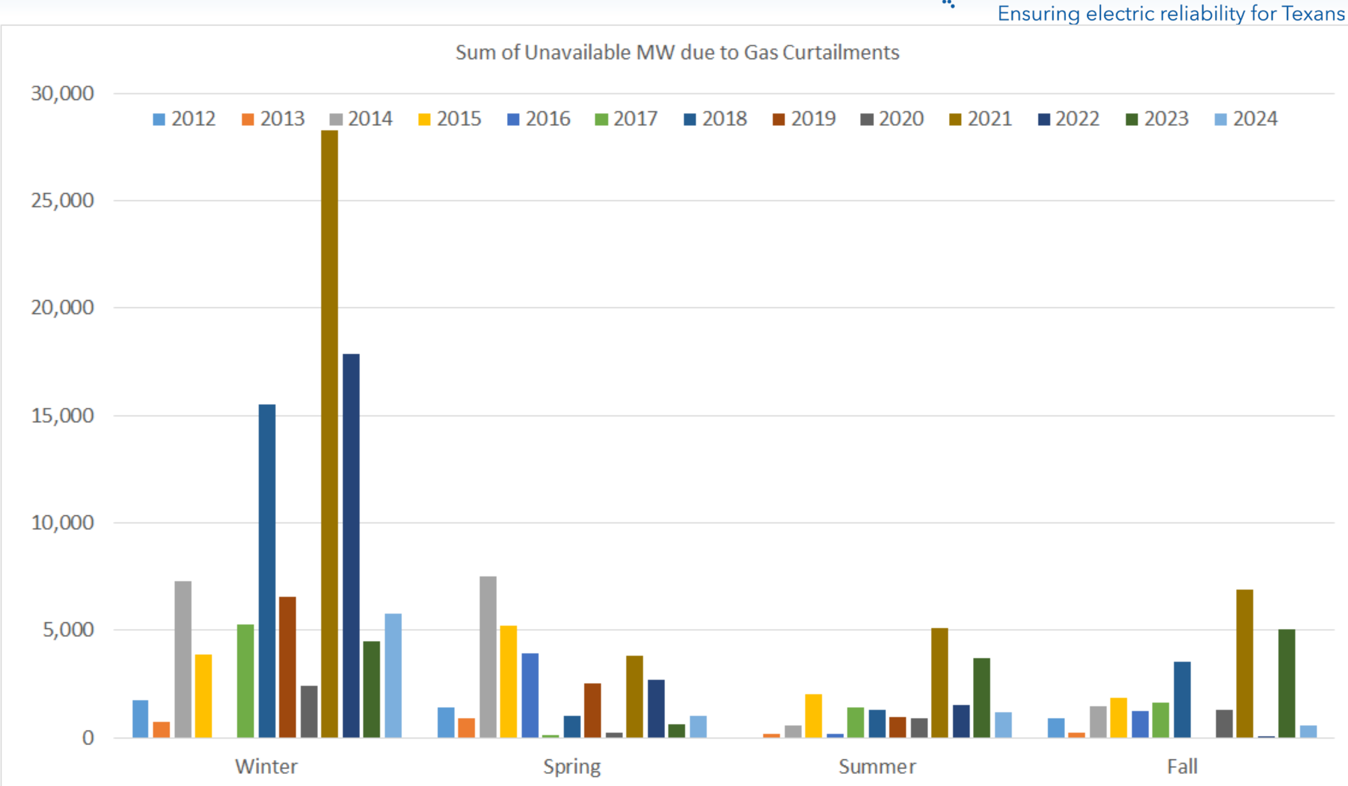


Figure A.31 – Cumulative Unavailable MW Due to Natural Gas Curtailments By Season

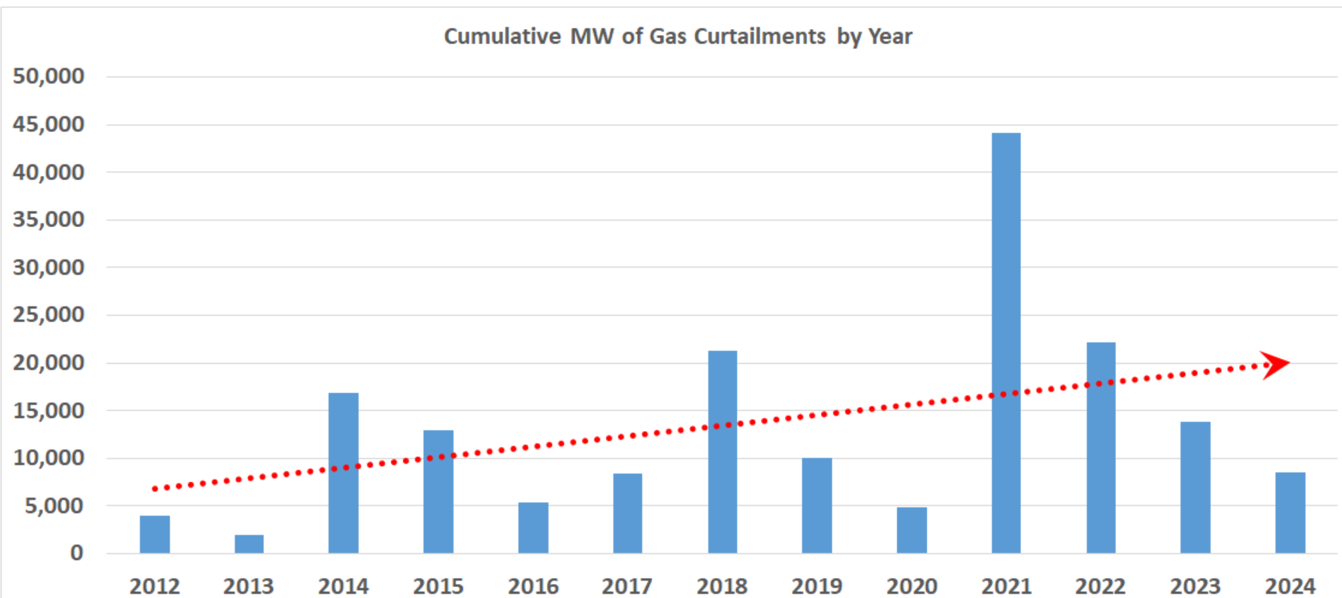


Figure A.32 – Cumulative Unavailable MW Due to Natural Gas Curtailments by Year

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)
2014	394	13,976.1	
2015	408	14,605.0	206
2016	438	15,460.4	213
2017	456	15,886.3	217
2018	490	16,322.9	221
2019	514	17,357.7	223
2020	567	18,221.4	242
2021	604	18,808.3	252
2022	719	20,737.5	252
2023	764	20,943.3	259
2024	804	21,448.3	300

Table B.1 – 2014-2024 End of Year Circuit Data

	Automatic		Non-Automatic Operational	
Outage Information	Count	Duration (hours)	Count	Duration (hours)
2010	195	1,090.0	24	1,167.9
2011	276	1,908.6	66	7,096.1
2012	226	682.6	45	4,264.6
2013	197	1,935.6	32	7,877.4
2014	276	2,917.3	69	6,001.3
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
5-Yr Average	467	12,734.5	156	21,292.2

Table B.2 – 2010-2024 345 kV Circuit and Transformer Outage Data

[1] Outage count and duration for 2015-2024 includes 345 kV transformers which began reporting in 2015

B. Event Analysis

The following noteworthy events occurred in 2024:

- Loss of multiple elements on May 16, 2024: A Derecho event with straight line winds approaching 100 mph impacted the region, causing multiple transmission line outages and over 800,000 customer outages.
- Loss of multiple elements on May 22, 2024: A tornado caused the loss of multiple transmission lines and two combined cycle generation facilities.
- Hurricane Beryl impacted the ERCOT region between July 8 and July 10, 2024, affecting over two million customers.
- CrowdStrike event impacted multiple entities on July 19, 2024.
- Loss of multiple elements on July 24, 2024: A shunt reactor failure caused the loss of a 345kV bus at a nuclear generation plant.
- One reported ransomware event.

Historical Disturbance Data: In 2024, the number of qualified events (Category 1 or higher) was similar to 2023, however, the number of unqualified events decreased sharply when compared to 2023, primarily due to a reduction in the number of large generation unit trips. The total events in 2024 remained near 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]	2020	2021	2022	2023	2024	5-Yr Avg
Non-Qualified	84	74	70	115	79	85
1	8	14	11	6	7	9
2	0	0	1	0	0	0
3	0	0	1	0	0	0
4 and 5	0	1	0	0	0	0
Total	92	89	83	121	86	94

Table B.3 – Summary of Event Analyses

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

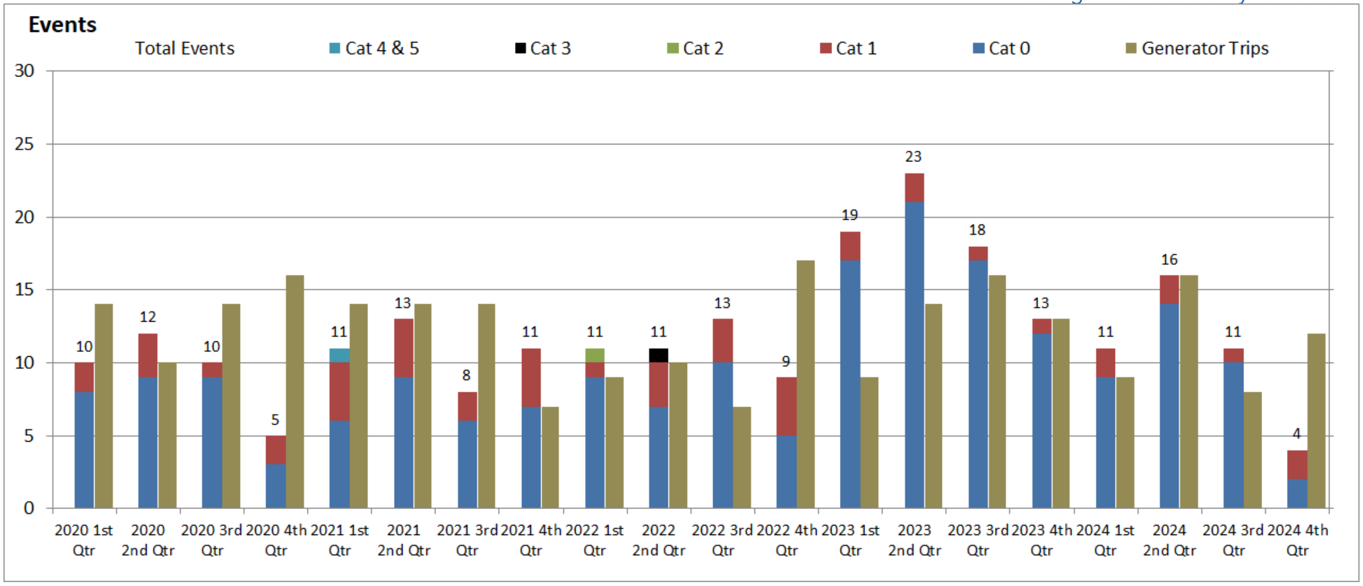


Figure B.1 – Events Reported by Quarter

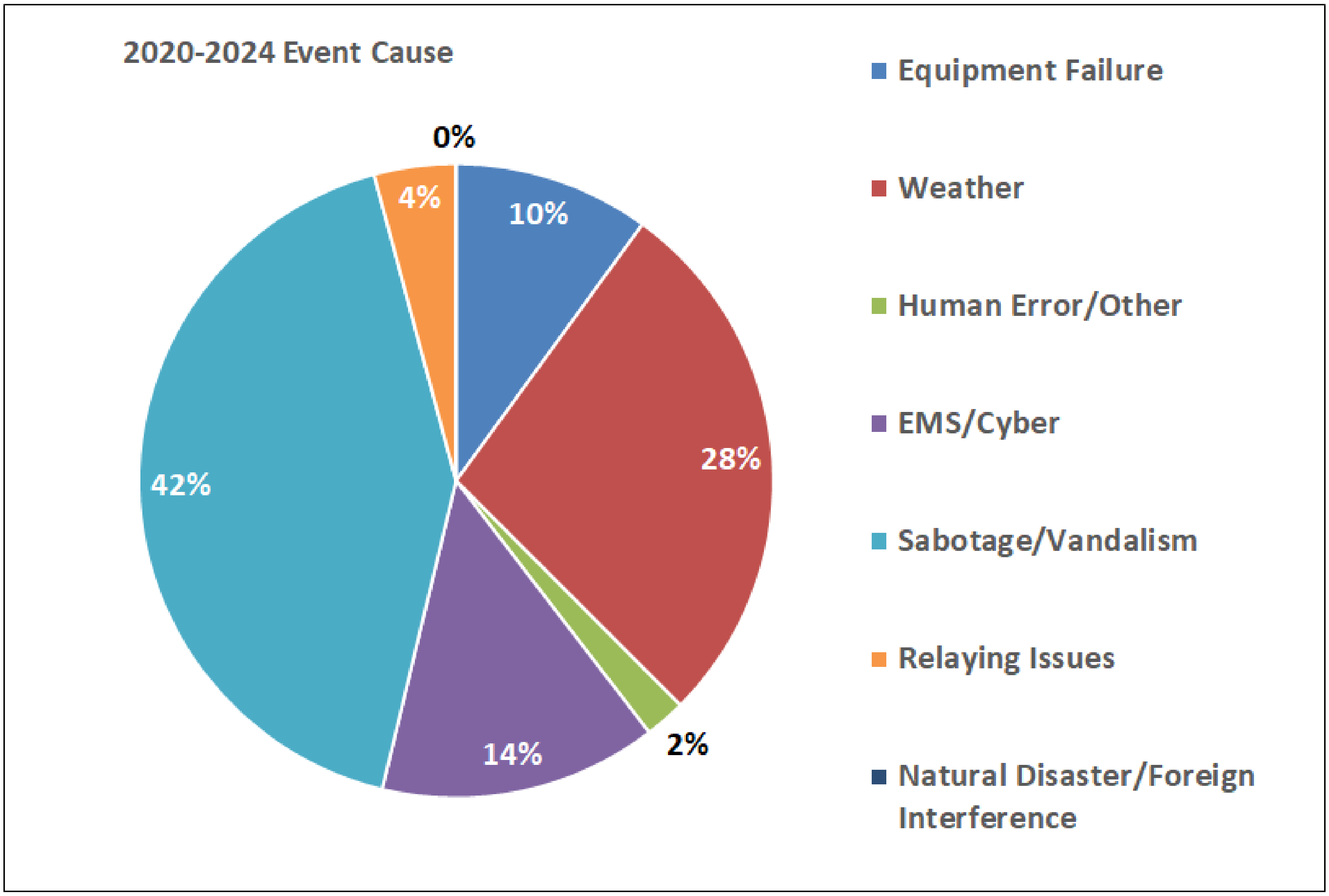


Figure B.2 – 2020-2024 Event Cause Summary

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, although the 138 kV circuit outage rates have increased for two consecutive years in 2024 to its highest level in the last five years.

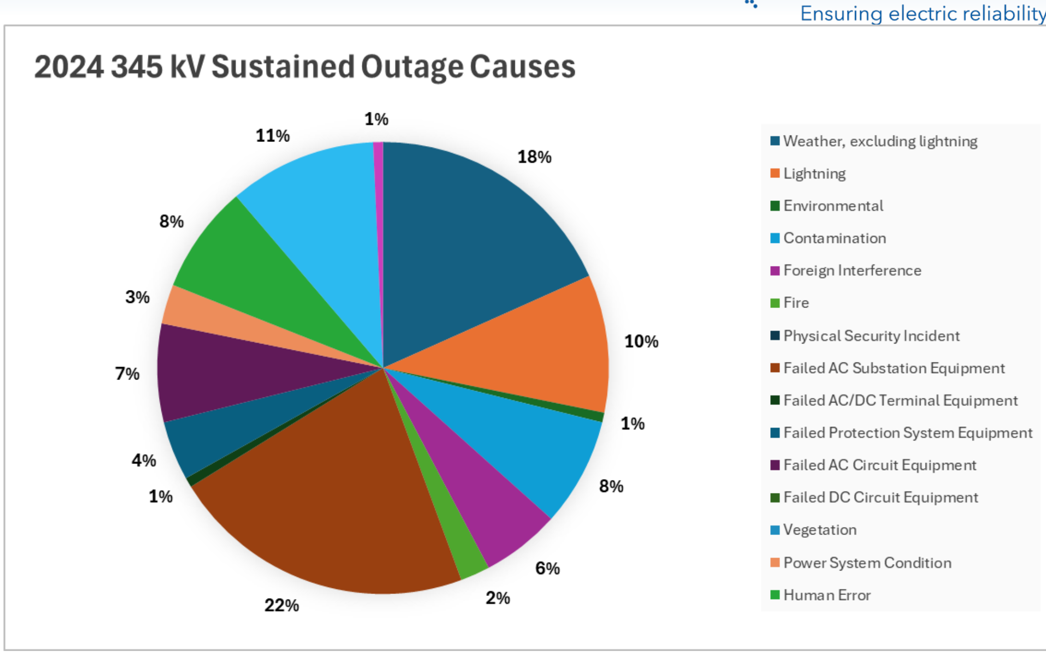
Voltage Class Name	Metric	2020	2021	2022	2023	2024	5-Yr Avg
AC Circuit 300-399 kV	Automatic Outages per Circuit	0.82	0.80	0.62	0.56	0.55	0.67
AC Circuit 300-399 kV	Automatic Outages per 100 miles	2.45	2.52	2.04	2.00	2.07	2.22
AC Circuit 100-199 kV	Sustained Automatic Outages per Circuit	0.19	0.29	0.25	0.30	0.32	0.27
AC Circuit 100-199 kV	Sustained Automatic Outages per 100 miles	1.61	2.50	2.25	2.74	2.95	2.41
Transformer 300-399 kV	Automatic Outages per Element	0.10	0.13	0.08	0.12	0.09	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 2024 were weather (excluding lightning), lightning, unknown, and failed circuit equipment, representing 61 percent of the total sustained outages. Failed transmission circuit equipment and failed substation equipment accounted for 66 percent of the outage duration.

For 138 kV transmission circuits, predominant causes for sustained outages in 2024 were weather (excluding lightning), lightning, foreign interference, unknown, and failed circuit equipment, representing 75 percent of the total sustained outages. Failed transmission circuit equipment, failed substation equipment, and foreign interference accounted for 77 percent of the outage duration.



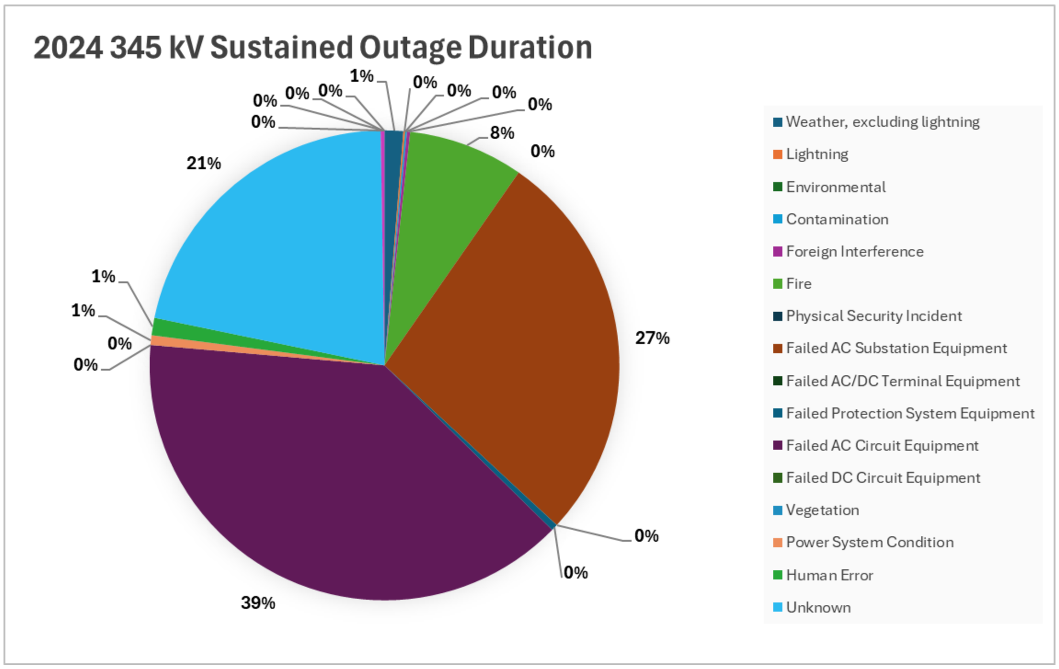


Figure B.3 – 2023 345 kV AC Circuit Sustained Outage Cause versus Duration

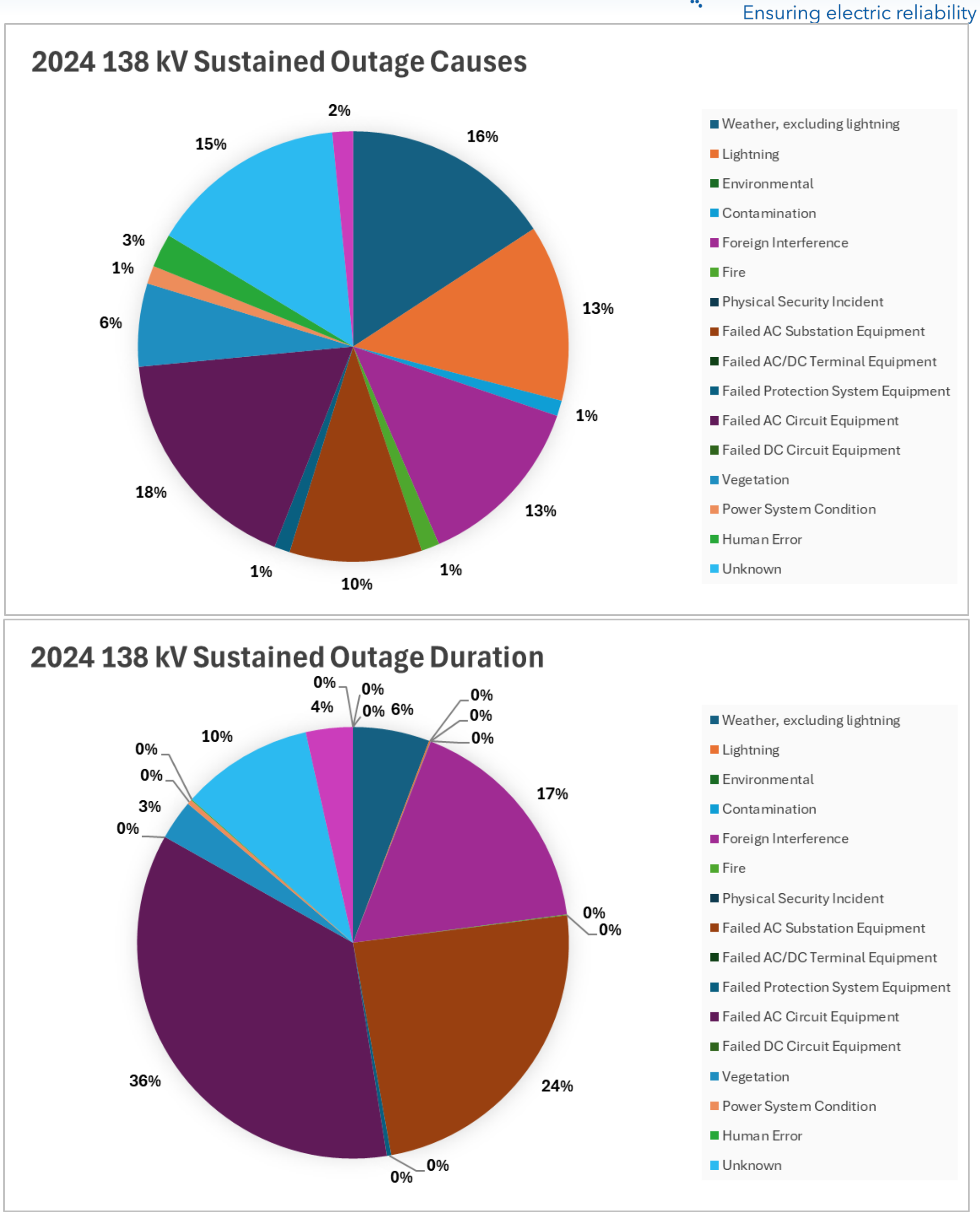


Figure B.4 – 2023 138 kV AC Circuit Sustained Outage Cause versus Duration

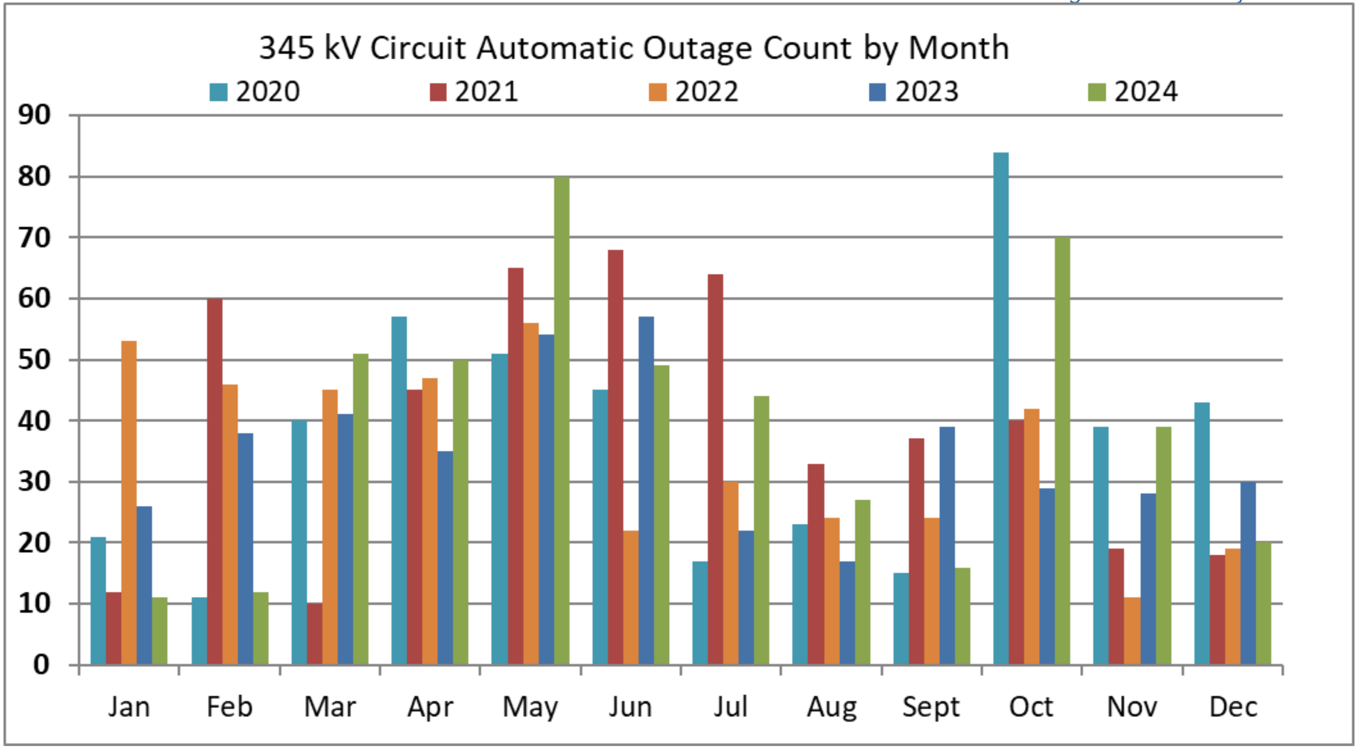


Figure B.5 – 345 kV Circuit Automatic Outages by Month

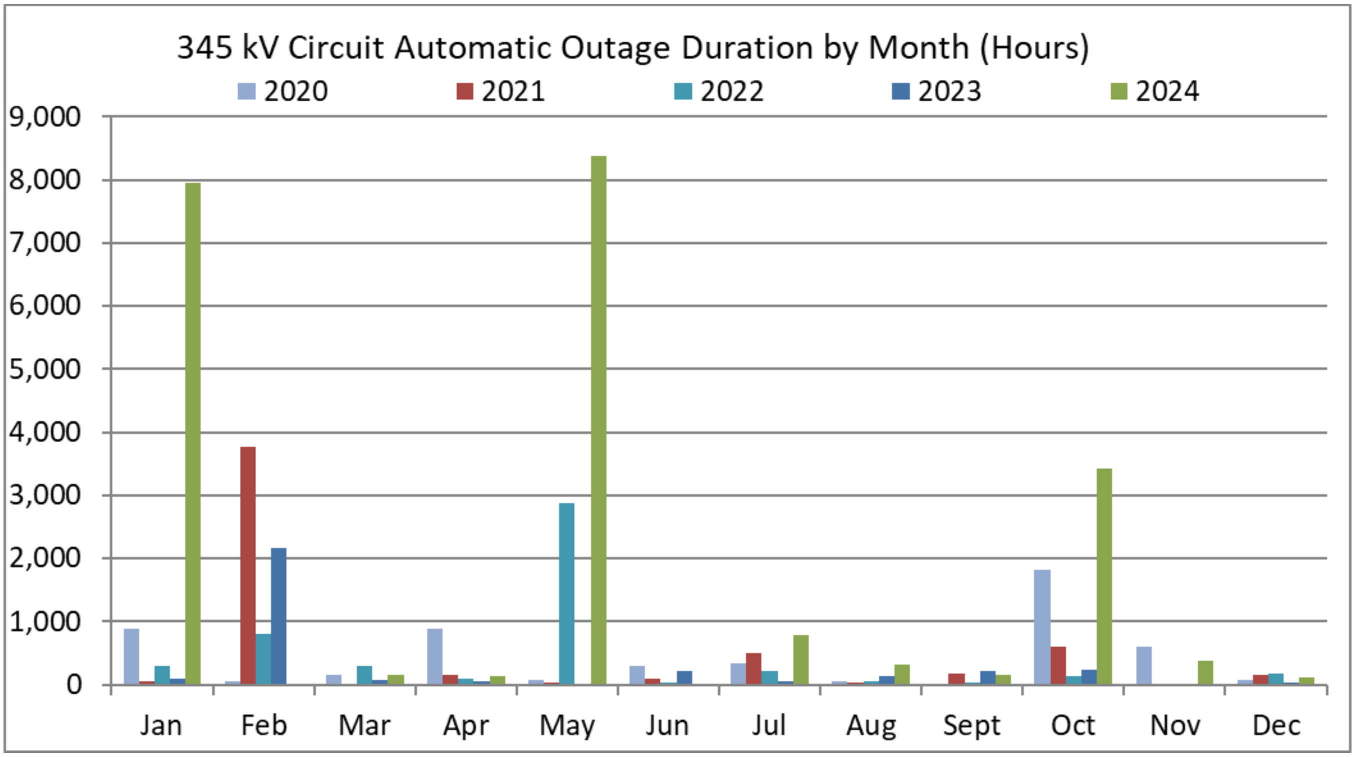


Figure B.6 – Multi-Year Comparison of TADS Outages and Duration by Month (> 200 kV)

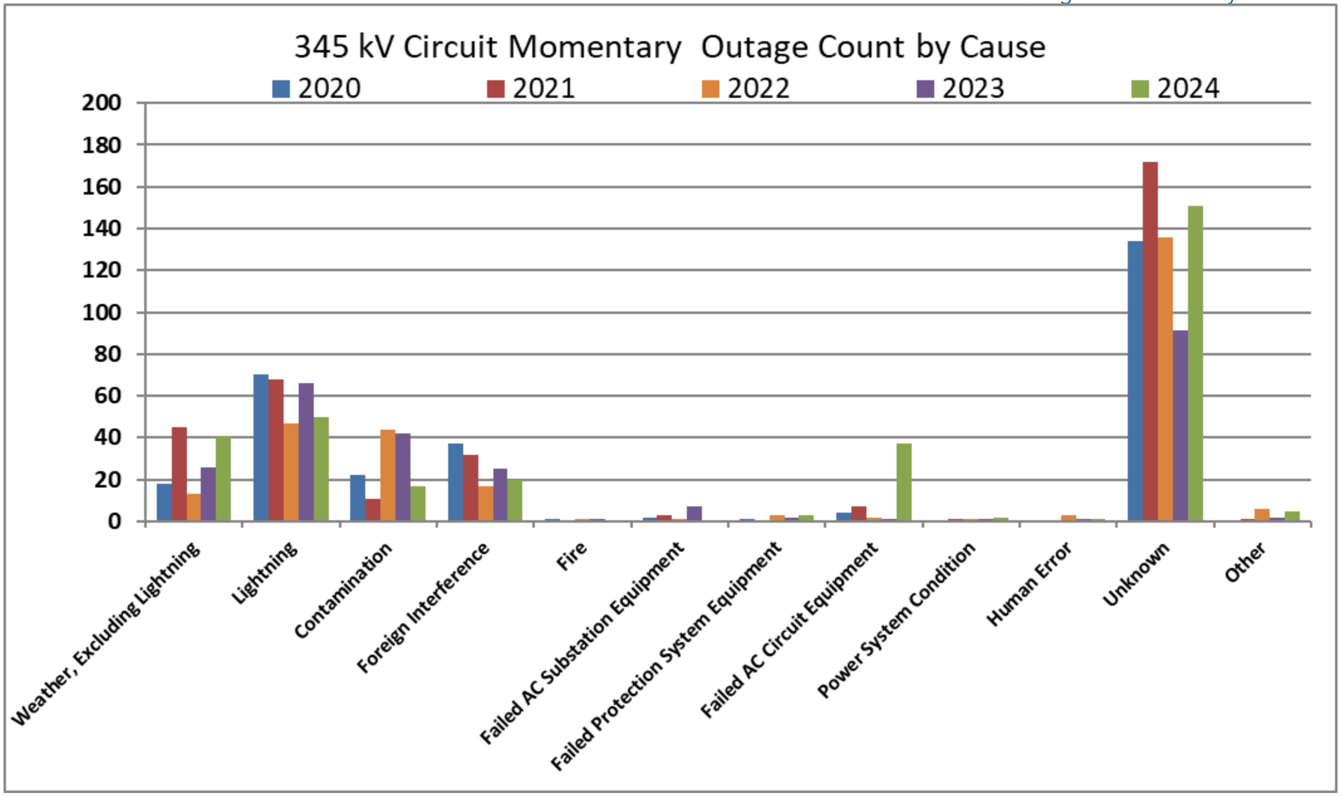


Figure B.7 – 345 kV Circuit Momentary Outage Count by Cause

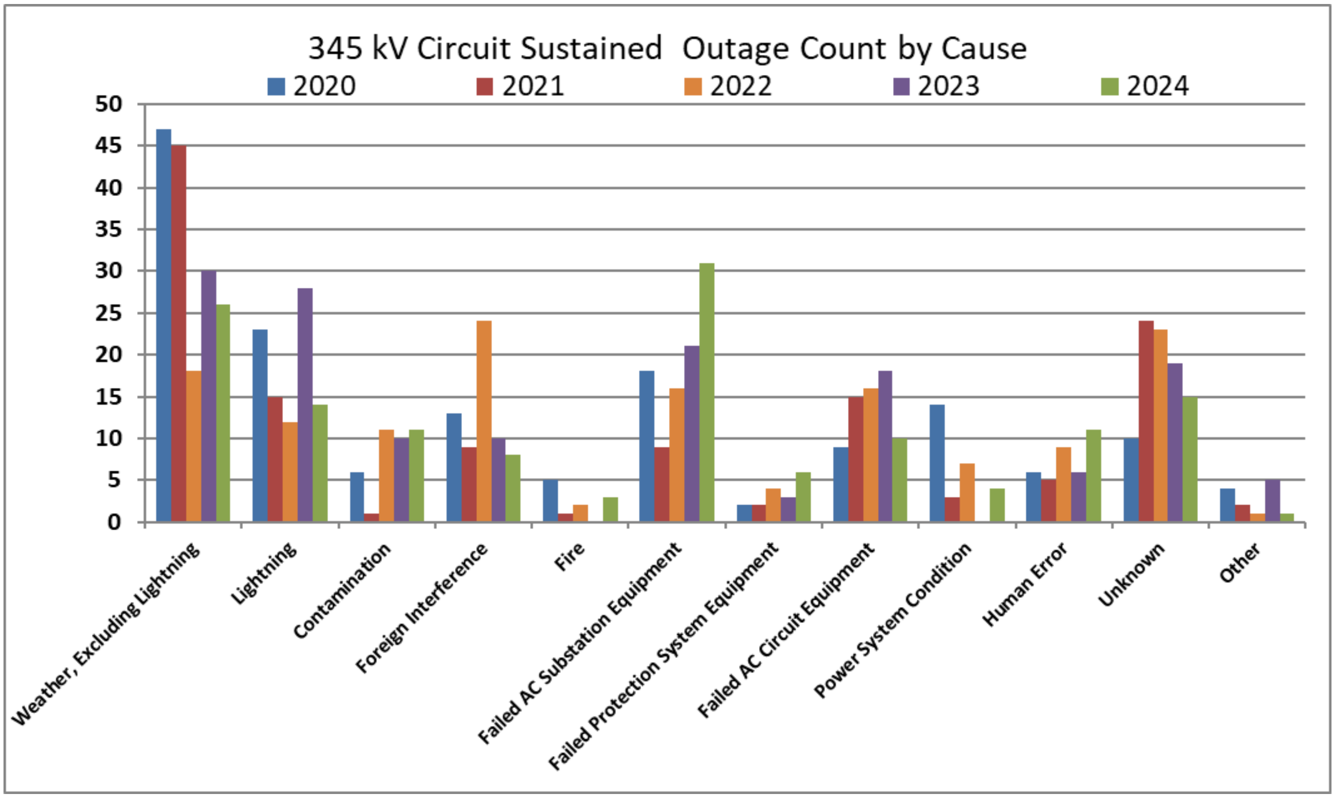


Figure B.8 – 345 kV Circuit Sustained Outage Count by Cause

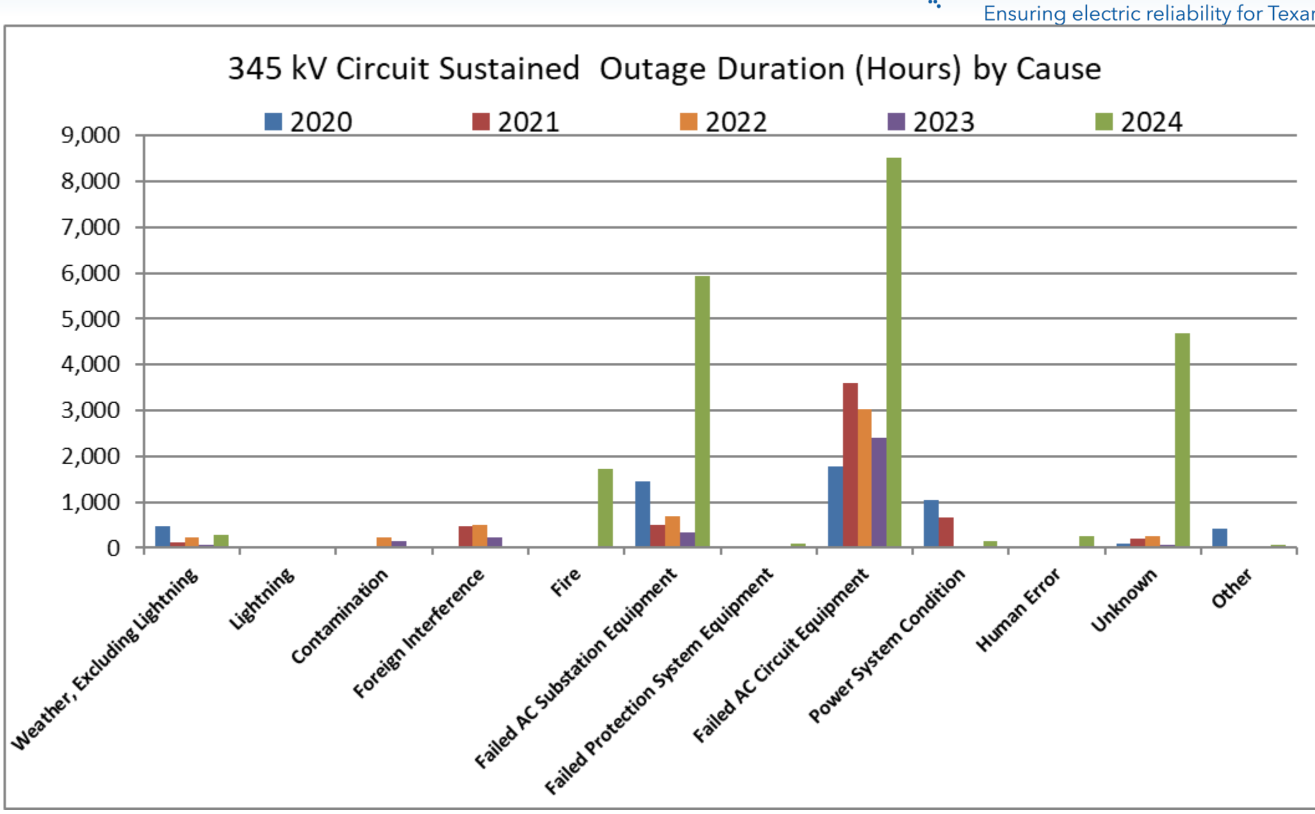


Figure B.9 – 345 kV Circuit Sustained Outage Duration (Hours) by Cause

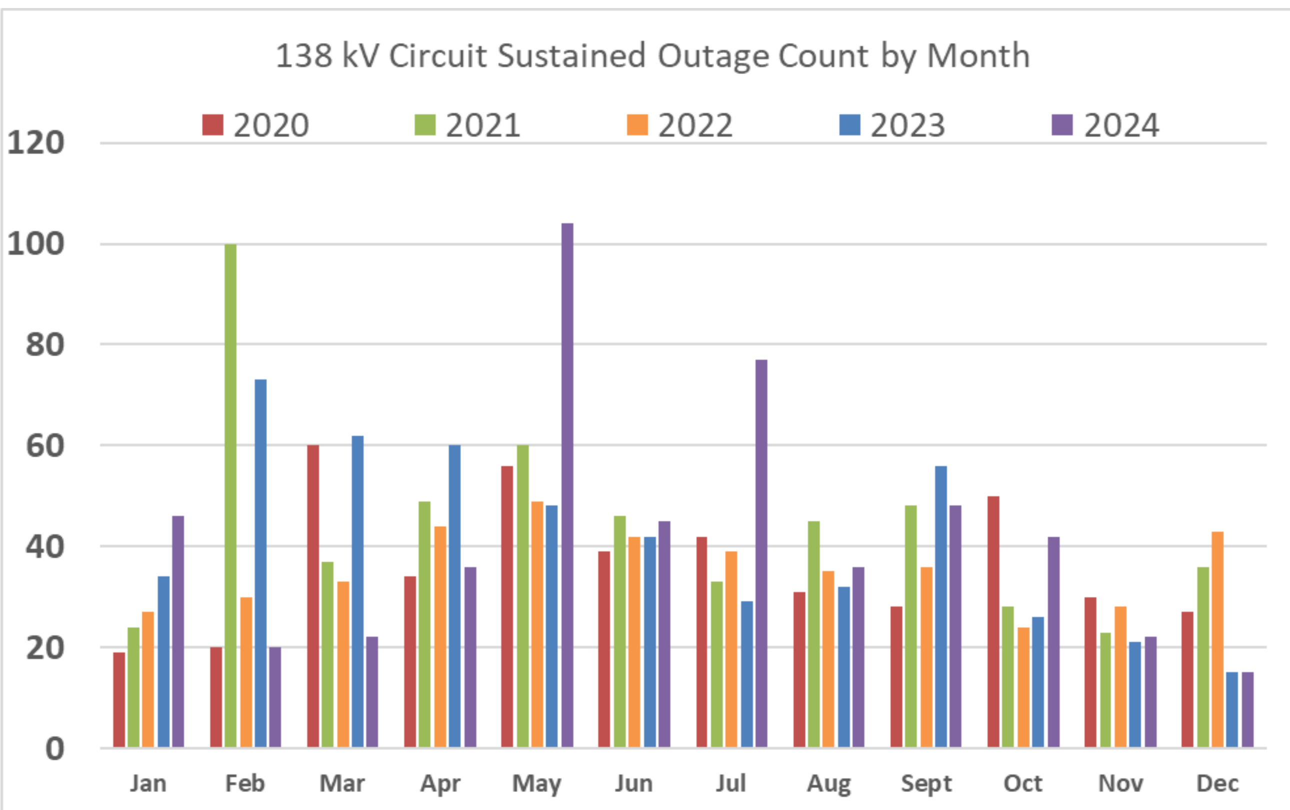


Figure B.10 – 138 kV Circuit Sustained Outage Count by Month

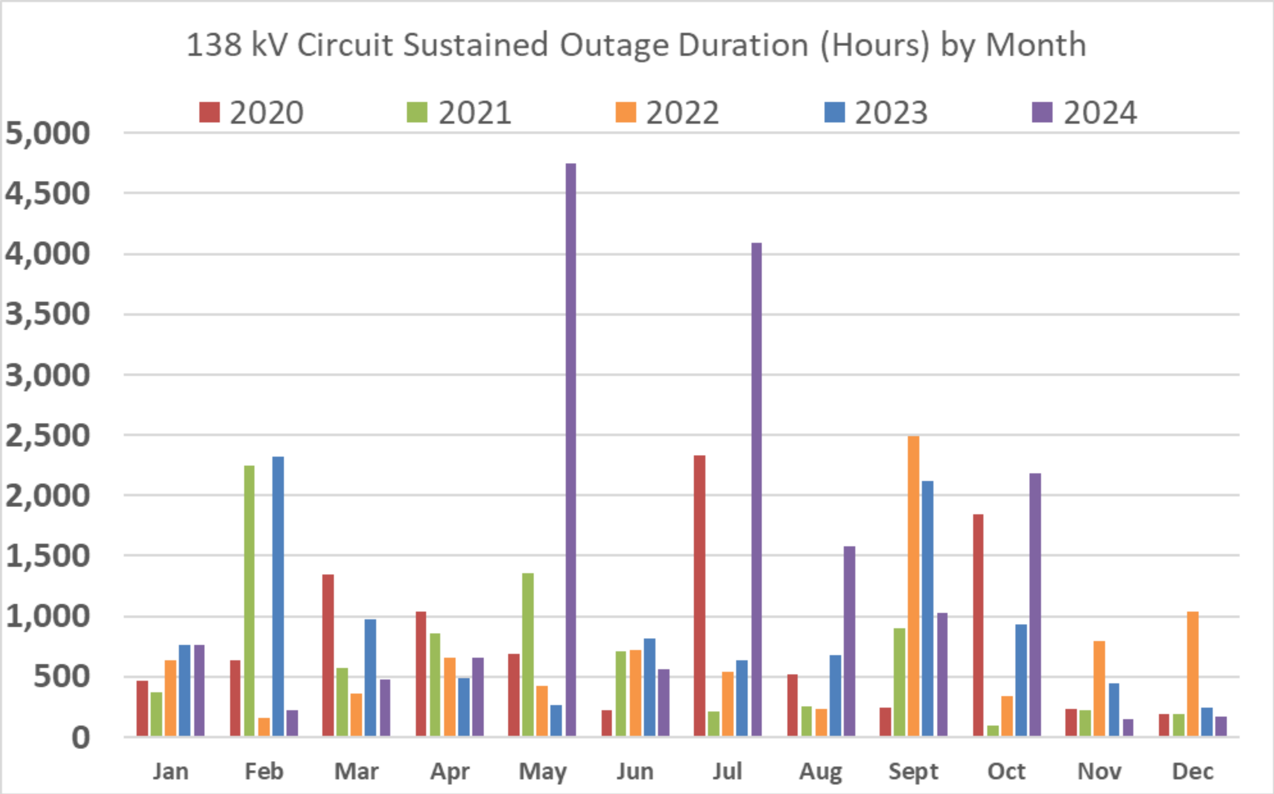


Figure B.11 – 138 kV Circuit Sustained Outage Duration (Hours) by Month

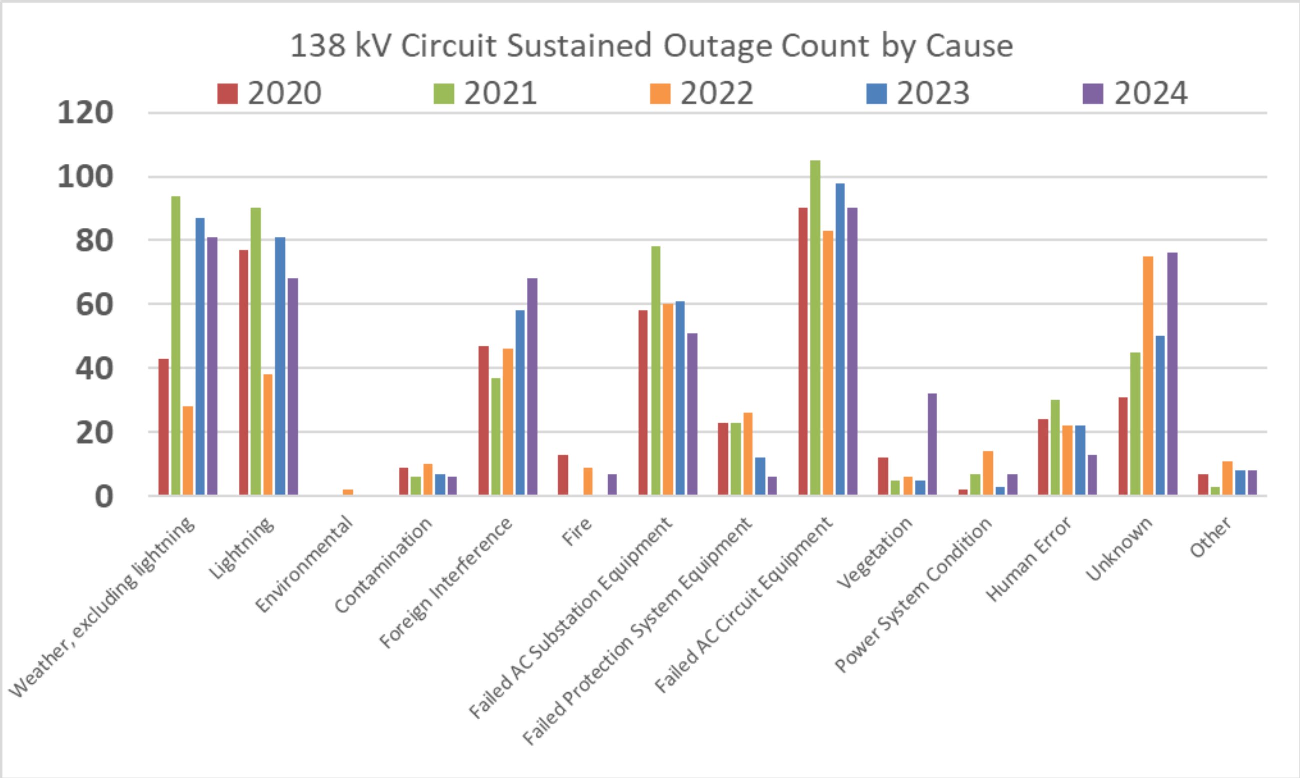


Figure B.12 – 138 kV Circuit Sustained Outage Count by Cause

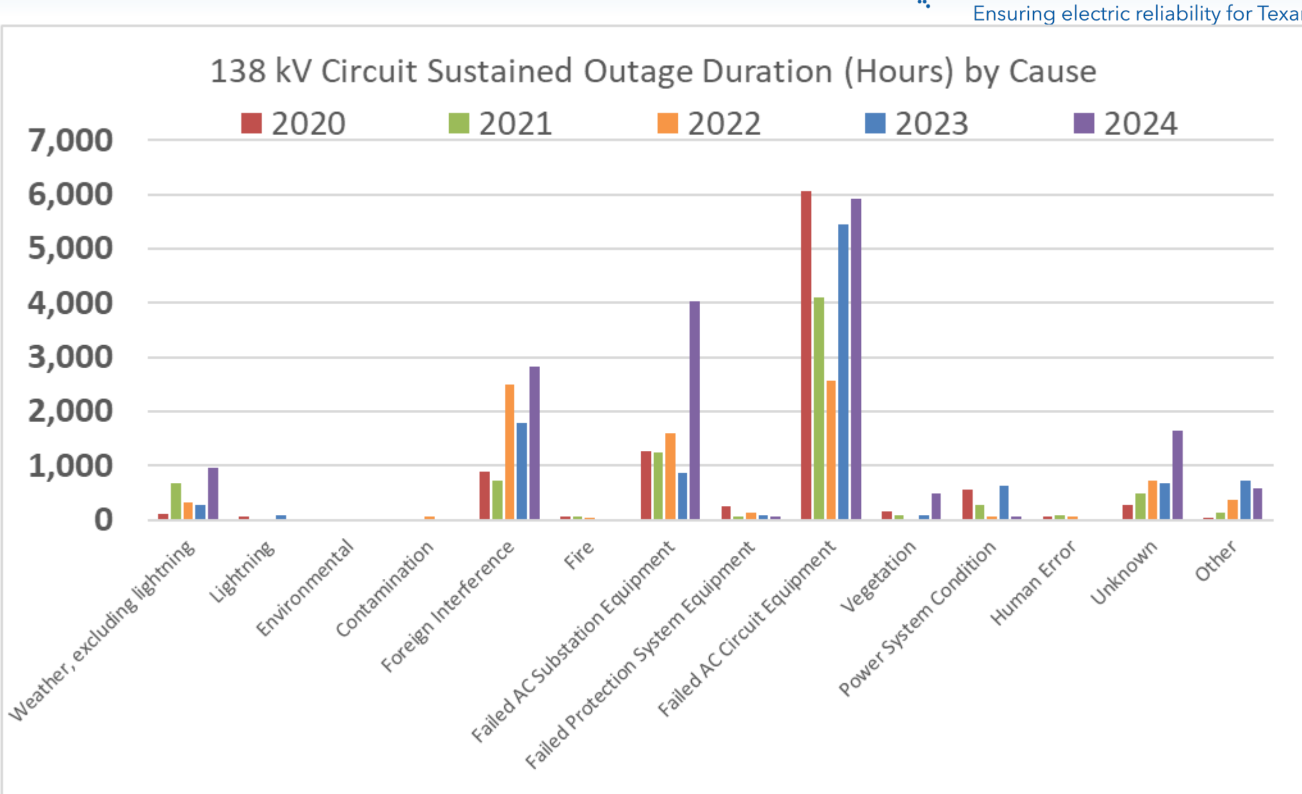


Figure B.13 – 138 kV Circuit Sustained Outage Duration by Cause

<u>Extreme Event Periods</u>

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 2017-2024. 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

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

Table B.6 – Extreme Generation Event Day Analyses

D. Multiple Element Outages

For 345 kV equipment in 2024, 26 of the 469 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 5.5 percent of all outages and 41.0 percent of sustained outage duration for the 345 kV system.

For 138 kV equipment in 2024, 73 of the 513 reported automatic sustained outage events involved two or more circuit elements. Dependent Mode and Common Mode outages represented 14.2 percent of all sustained outages and 13.2 percent of sustained outage duration.

Over the five-year period from 2020-2024, multiple element outages represented 21.7 percent of sustained outages and 31.7 percent of the sustained outage duration for the 345 kV system.

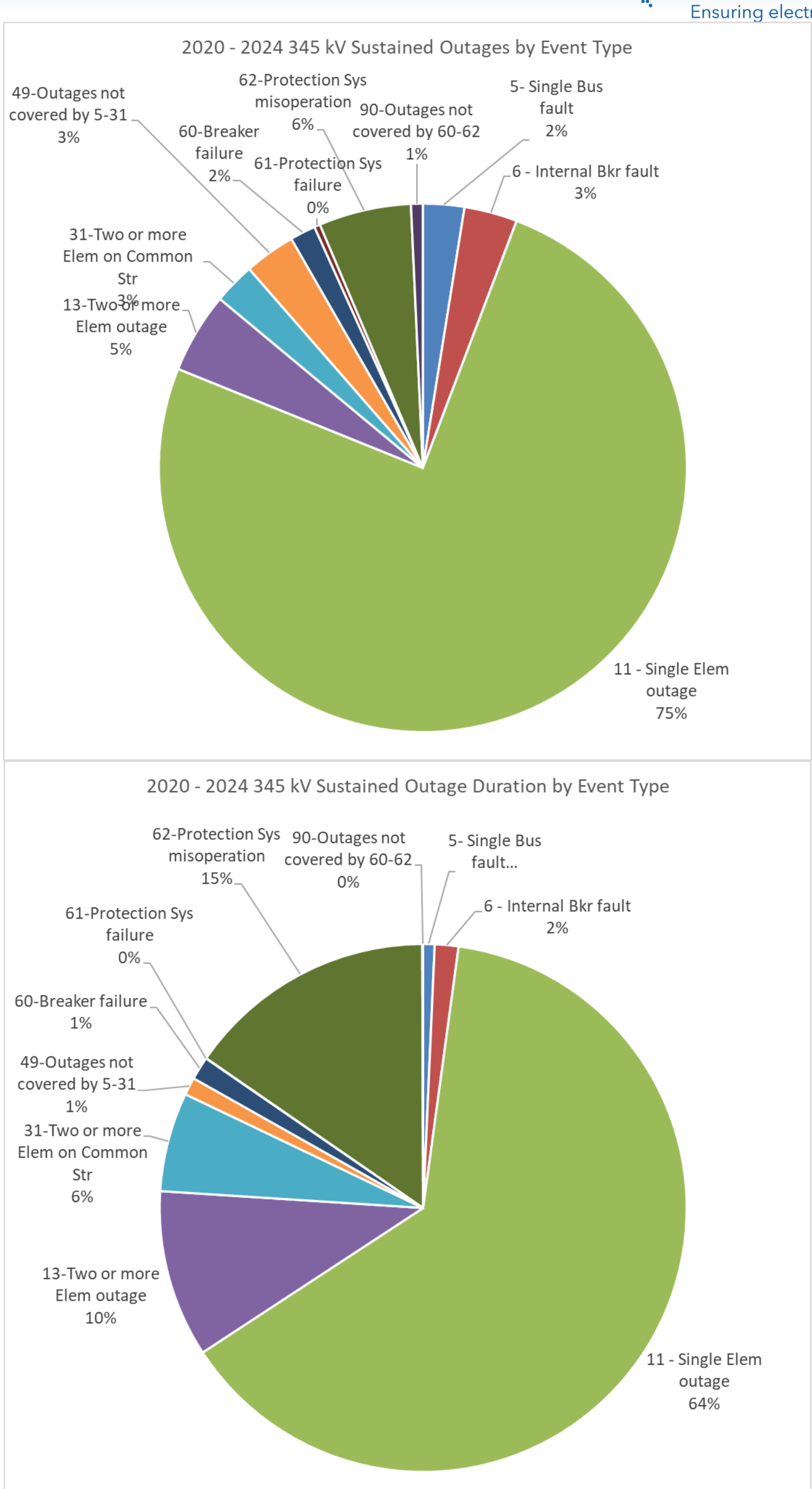


Figure B.14 – 2020-2024 345 kV Sustained Outages by Event Type

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 2024, there were nine 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).

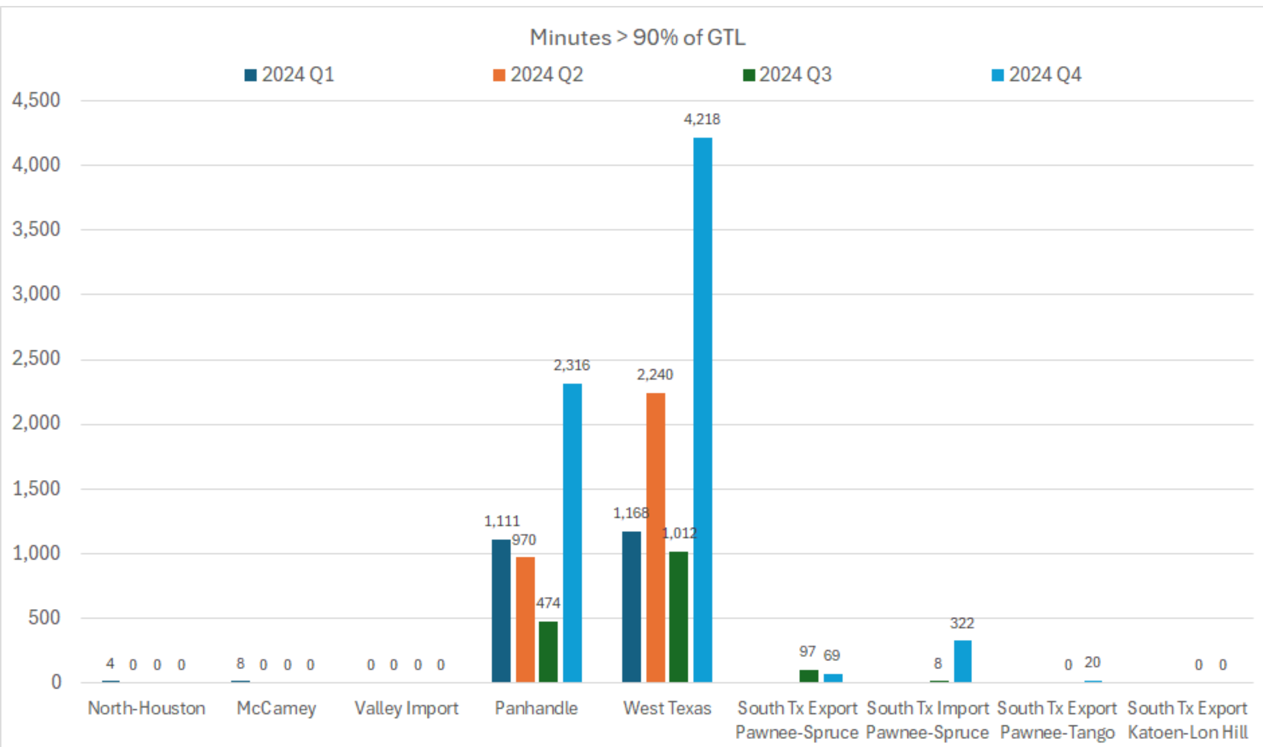


Figure B.15 – Interface Operation Minutes Greater Than 90 Percent of GTL

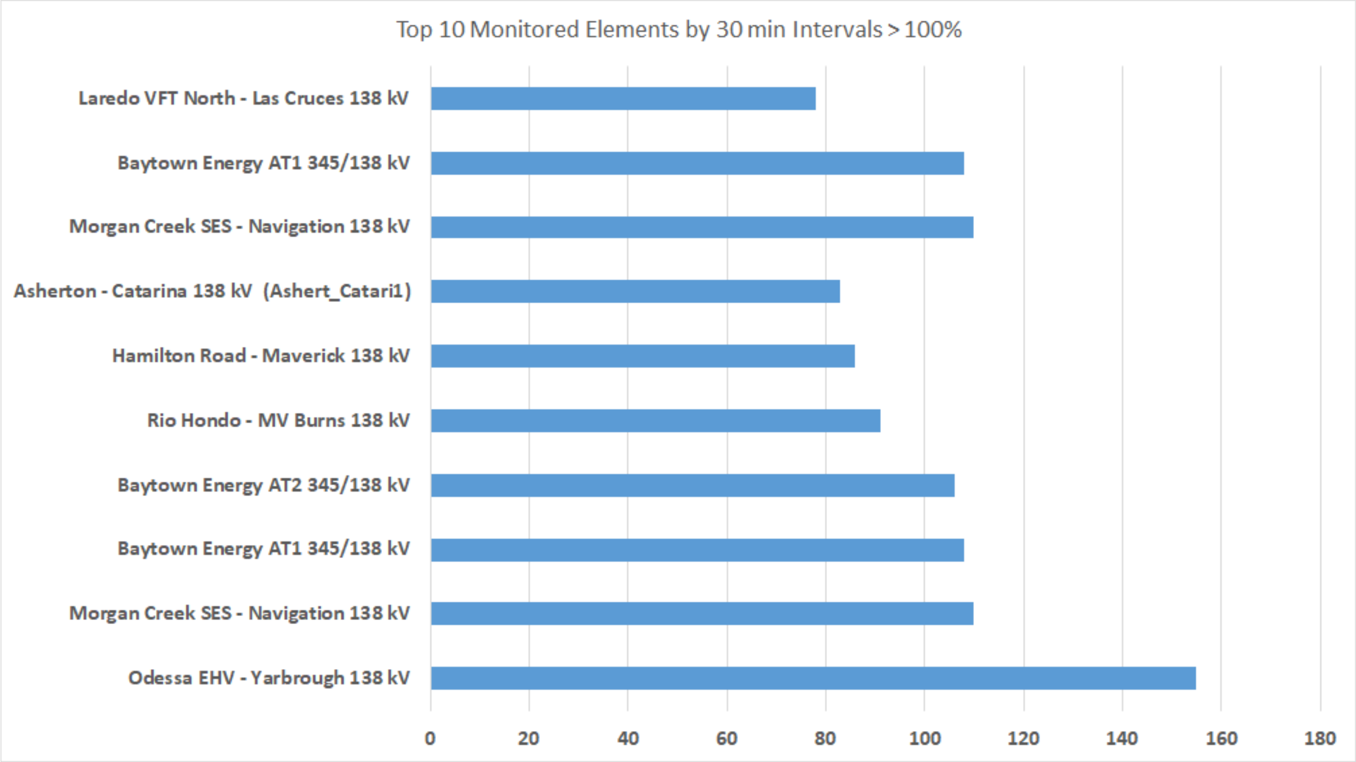


Figure B.16 – 2024 Top Constraints by Duration

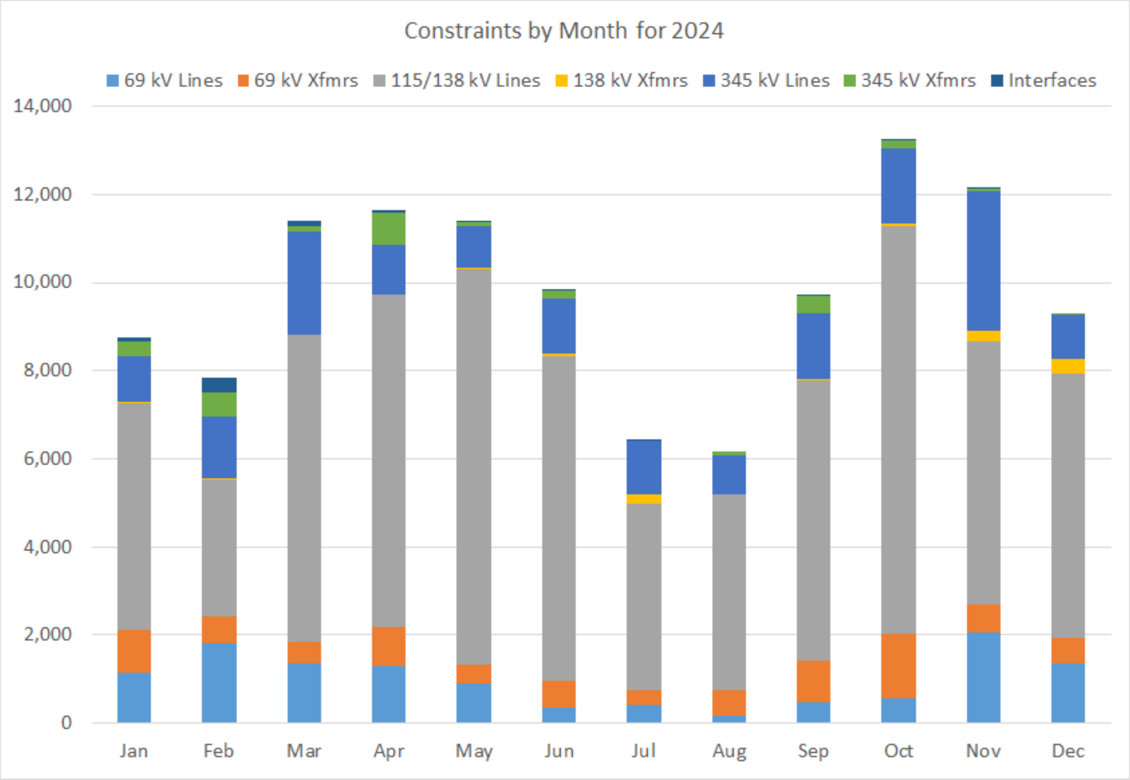


Figure B.17 – Constraints by Month for 2024

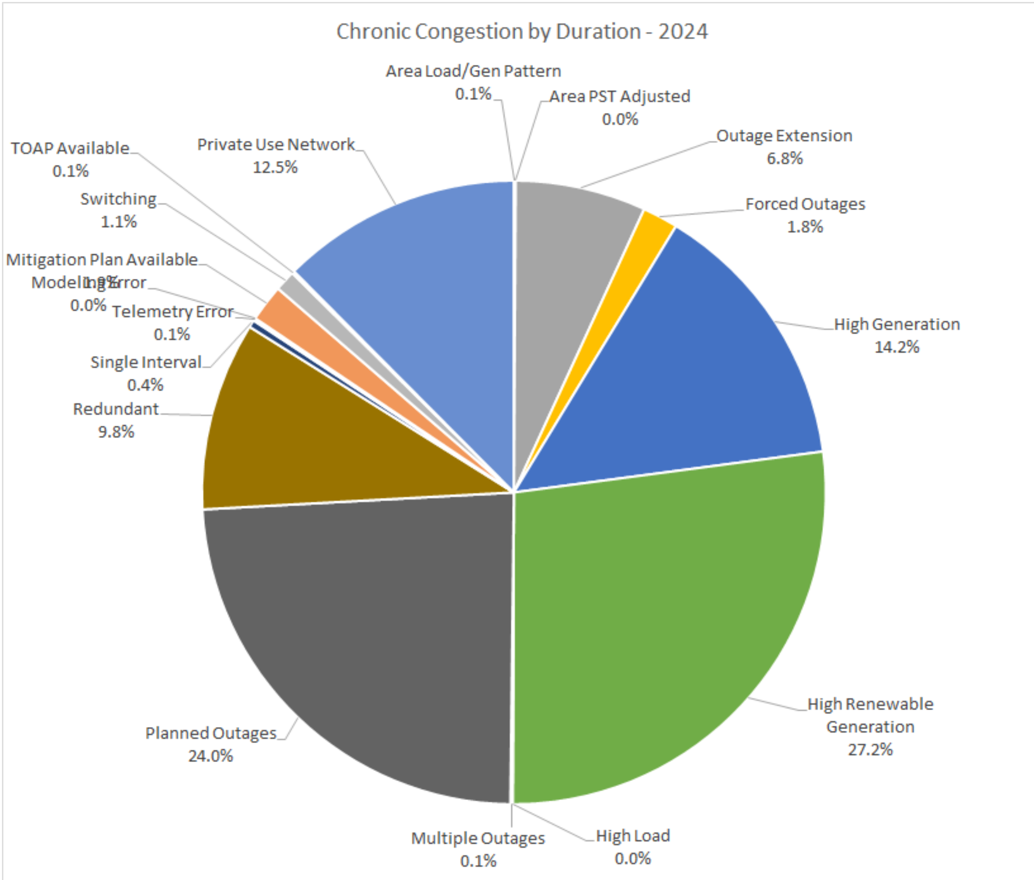


Figure B.18 – 2024 Chronic Constraint Causes by Duration

F. Reliability Unit Commitments

HRUC commitments saw a decrease in 2024 compared to 2023. RUC commitments totaled 72 units for 1,923 commitment hours. The primary reason for HRUC commitments was capacity, which accounted for approximately 45 percent of all HRUC hours in 2024.

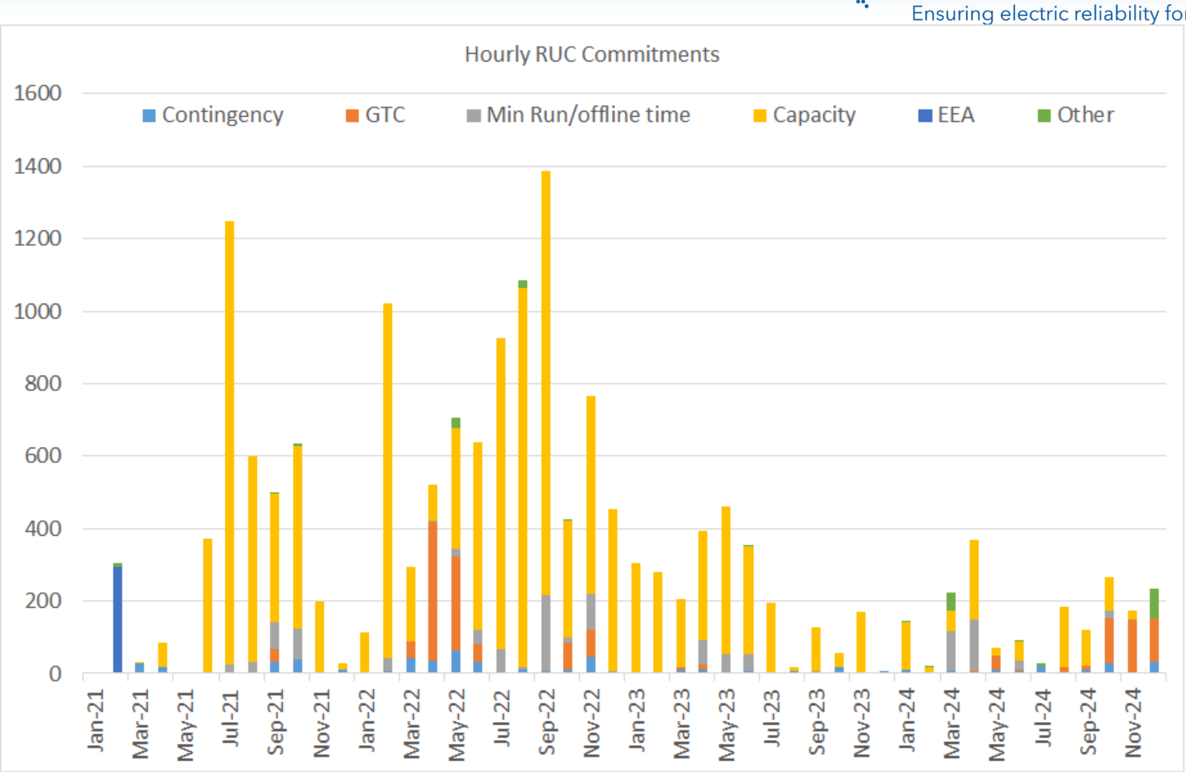


Figure B.19 – Hourly Reliability Unit Commitments by Month and Cause

Appendix C – Grid Transformation Detailed Analysis

A. Unit Additions and Retirements

Retirements and Mothball Status – 109 MW

Unit	Date	Status	MW	Fuel Type
Signal Mountain M2	1/1/2024	Indefinite Mothball	7	Wind
Chisholm Grid BES	11/1/2024	Temporary Mothball	102	Other

New Resources Approved for Commercial Operation – 11,959 MW

Unit	Date	MW	Fuel Type
Jade Solar	01/02/2024	326.6	Solar
Andromeda Solar	01/03/2024	326.6	Solar
Galloway 2 Solar	01/04/2024	113.9	Solar
Spanish Crown	01/05/2024	103.1	Solar
Val Verde BESS	01/24/2024	9.95	Other
Mineral Wells East BESS	02/16/2024	9.95	Other
Lufkin South BESS	02/21/2024	9.95	Other
Lufkin South BESS	02/21/2024	9.95	Other
Hamilton BESS	02/22/2024	9.95	Other
Judkins BESS	02/22/2024	9.95	Other
Pauline BESS	02/22/2024	9.95	Other
Golinda Solar	02/27/2024	103.1	Solar
Garden City East BESS	02/29/2024	9.95	Other
Horizon Solar	03/05/2024	203.5	Solar
Diboll Bess	03/05/2024	9.95	Other
Appaloosa Run Wind	03/06/2024	175.0	Wind
Mustang Creek Storage	03/08/2024	70.5	Other
Cameron Storage	03/26/2024	18.0	Other
St. Gall I Energy Storage	03/26/2024	102.6	Other
Lacy Creek wind	04/02/2024	301.3	Wind
Goodnight Wind	04/08/2024	258.1	Wind
LIBRA BESS	04/09/2024	206.2	Other
Anchor Wind IV	04/15/2024	19.32	Wind
Anchor Wind	04/15/2024	98.9	Wind
Vortex Wind	04/15/2024	350.0	Wind
Anchor Wind II	04/15/2024	128.7	Wind
Pisgah Ridge Solar	04/17/2024	253.85	Solar
Longbow Solar	04/17/2024	78.15	Solar
Sun Valley Solar	04/19/2024	252.0	Solar
BLUE SUMMIT I REPOWER	04/19/2024	4.4	Wind
Apogee Wind	04/19/2024	393.24	Wind
Sparta Solar	04/24/2024	252.35	Solar
Zier Solar	04/26/2024	162.99	Solar
Zier Storage	04/26/2024	40.41	Other
Texas Solar Nova	04/30/2024	253.5	Solar
Hopkins Solar	05/02/2024	253.1	Solar
Five Wells BESS	06/04/2024	220.8	Other

Anemoi Energy Storage	06/11/2024	205.0	Other
Ebony Energy Storage	06/12/2024	203.5	Other
Farmersville West BESS 1	06/18/2024	9.9	Other
Mainland BESS	06/21/2024	9.9	Other
Pyron Wind Repower	06/27/2024	19.9	Wind
Rowland Solar II	06/28/2024	202.8	Solar
Weil Tract BESS	07/02/2024	9.9	Other
Frye Solar	07/03/2024	502.0	Solar
Continental BESS	07/31/2024	9.8	Other
Giga Texas Energy Storage	08/09/2024	131.05	Other
Aureola Solar	08/12/2024	203.0	Solar
Halo Solar	08/12/2024	254.0	Solar
BoCo BESS	08/12/2024	155.48	Other
Callisto I Energy Center	08/15/2024	206.4	Other
SunRay	08/20/2024	203.5	Solar
Hollywood Solar	09/06/2024	353.41	Solar
Pavo BESS	09/06/2024	175.8	Other
Falfurrias BESS	09/09/2024	9.9	Other
Limousin Oak Storage	09/11/2024	104.62	Other
Remy Jade Power Station	09/13/2024	306.0	Gas
Dickens BESS	09/16/2024	200.8	Other
Sheep Creek Storage	09/17/2024	142.1	Other
Mandorla Solar	09/19/2024	254.0	Solar
Coral Storage	09/24/2024	99.0	Other
Coral Solar	09/24/2024	151.6	Solar
Pavlov BESS	10/01/2024	9.90	Other
SANDLAKE BESS	10/01/2024	9.99	Other
Sheep Creek Wind	10/01/2024	153.0	Wind
Hydra BESS	10/04/2024	200.8	Other
Paleo BESS	10/04/2024	200.8	Other
TECO GTG2	10/08/2024	50.00	Gas
River Bend	10/09/2024	101.64	Other
Hummingbird Storage	10/11/2024	103.80	Other
Fence Post BESS	10/16/2024	72.23	Battery
Moore Field BESS 2	10/18/2024	9.80	Other
Stampede BESS	10/25/2024	72.38	Battery
Cisco BESS	10/29/2024	9.90	Other
Al Pastor BESS	11/01/2024	103.1	Other
Connolly Storage	11/01/2024	125.36	Other
Gregory BESS	11/07/2024	9.9	Other
Regis Palacios BESS	11/19/2024	9.9	Other
Telview BESS	12/04/2024	9.96	Other
Remy Jade II Unit 7 Unit 8 Power Station	12/11/2024	102.0	Gas
Crockett BESS1	12/13/2024	9.95	Other
Montgomery Ranch Wind	12/13/2024	200.2	Wind
Beachwood II Power Station	12/13/2024	102.0	Gas
Century BESS	12/18/2024	9.88	Other
Liggett Switch BESS	12/19/2024	9.88	Other
Russek Street BESS	12/20/2024	9.9	Other

True North Solar	12/20/2024	238.8	Solar
Wigeon Whistle BESS	12/20/2024	122.9	Other
Holy ESS	12/30/2024	209.32	Other
Estonian Storage	12/31/2024	101.6	Other
Tierra Bonita Solar	12/31/2024	306.9	Solar

Table C.1 – 2024 Unit Additions and Retirements

B. Fuel Mix Analysis

Wind generation reporting in GADS-Wind produced a net total of 94,547 GWh in 2024, or 84.6 percent of the total ERCOT wind generation for 2024. Wind generation, as a percentage of total ERCOT energy produced was 24.2 percent in 2024, compared to 24.3 percent in 2023. In 2024, hourly wind generation reached a maximum of 27,667 MW on June 17, 2024, at 10:00 p.m., and hourly renewable generation served a maximum of 74.9 percent of system demand on March 29, 2024, at HE13.

Utility-scale solar generation within the region continued its significant growth in 2024. The amount of energy provided by solar generation was 10.4 percent in 2024 compared to 7.3 percent in 2023, an increase of 48 percent versus 2023.

Wind energy curtailments totaled 5,327 GWh in 2024, which was an increase of 12.4 percent from 2023. Solar energy curtailments totaled 3,036 GWh in 2024, which was an increase of 57.1 percent from 2023.

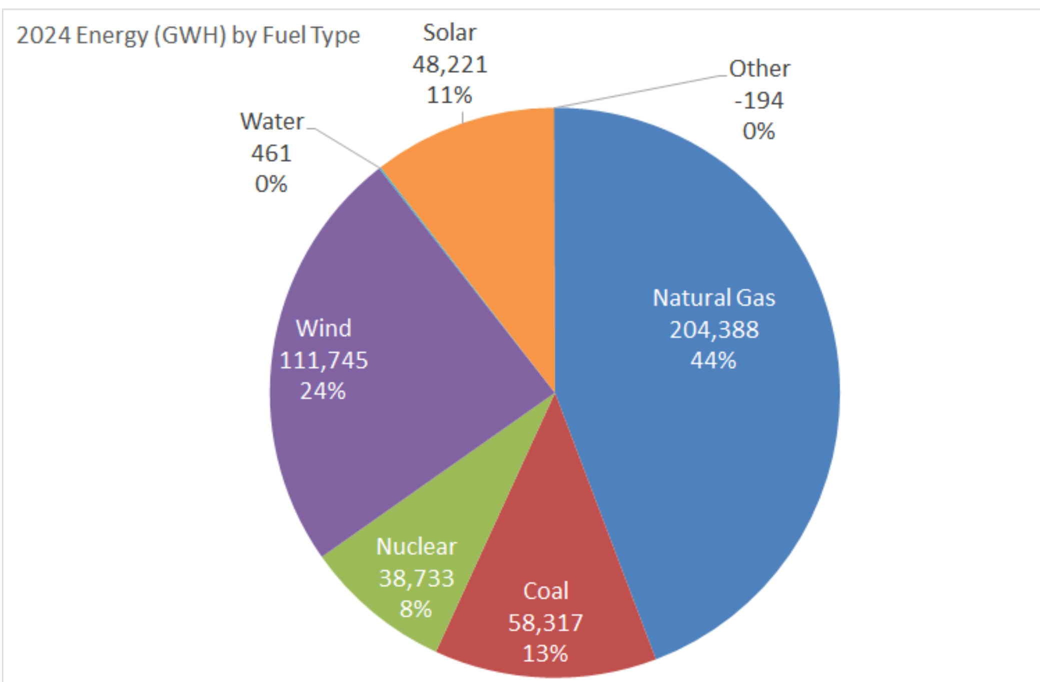


Figure C.1 – 2024 Energy by Fuel Type

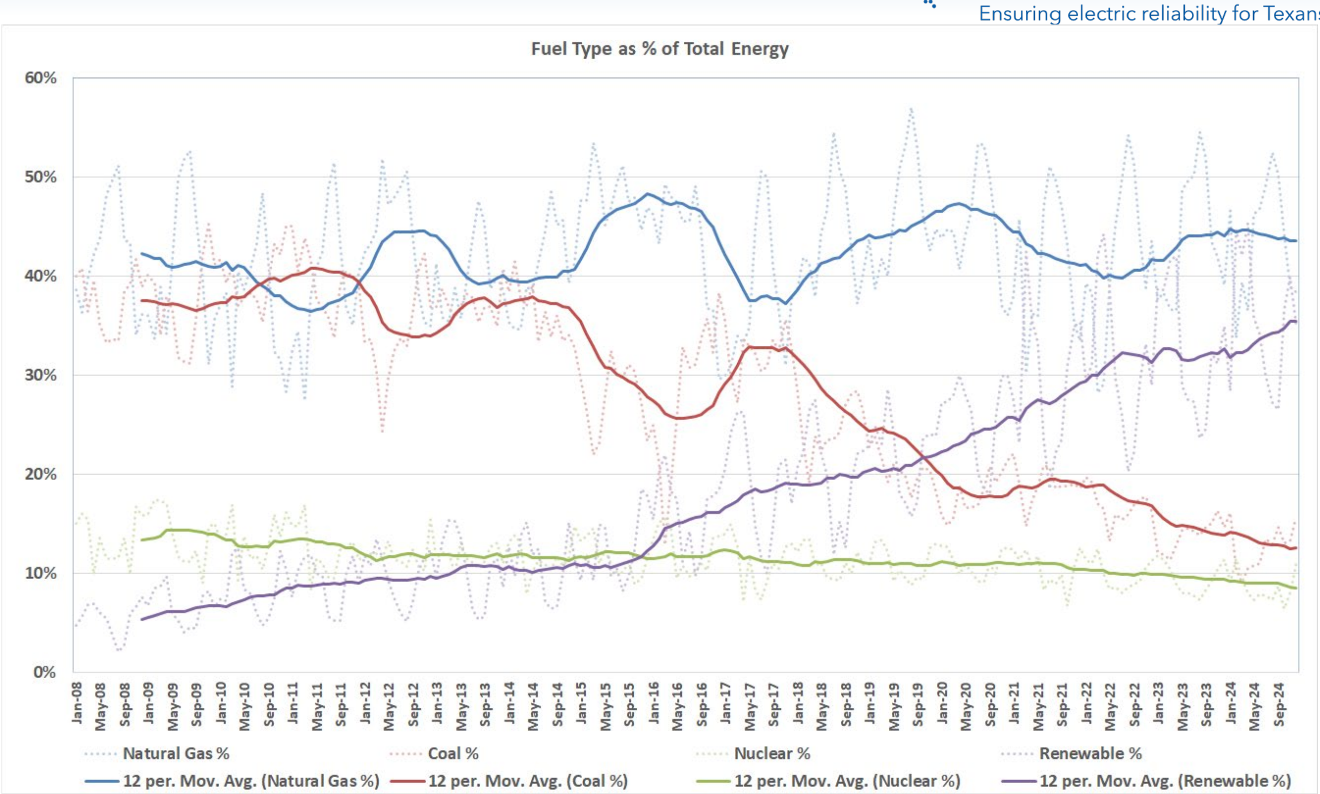


Figure C.2 – Energy by Fuel Type Trend

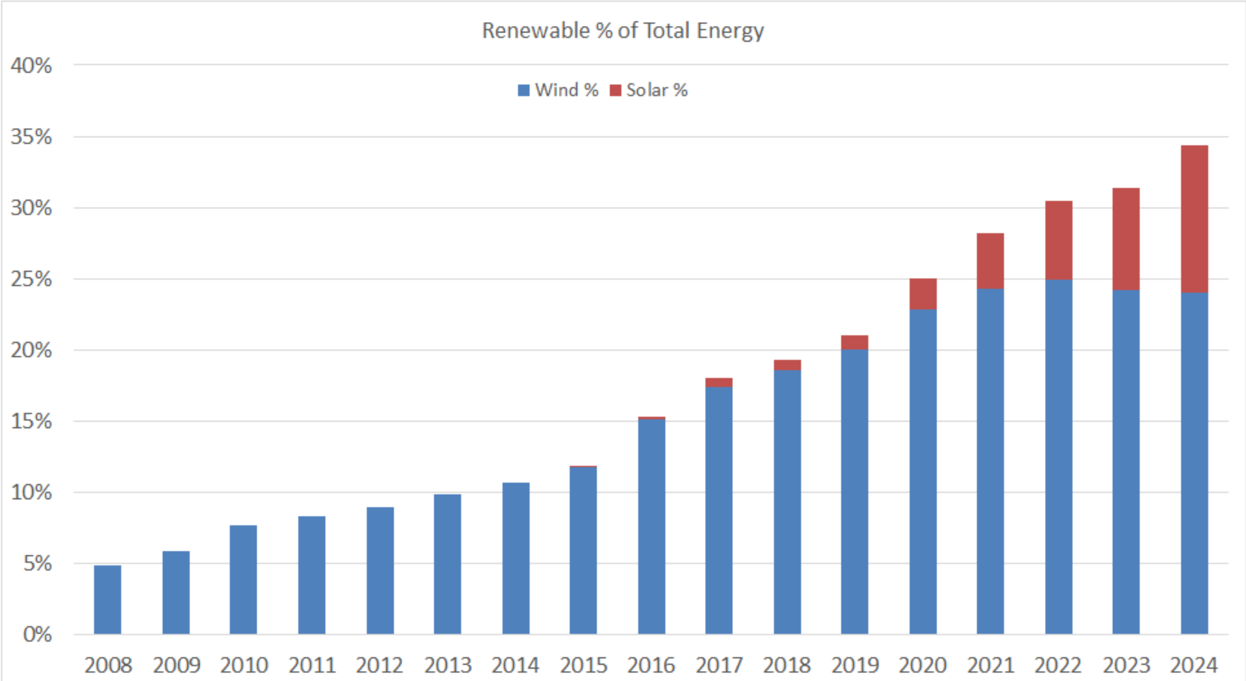


Figure C.3 – Renewable Energy Percentage of Total Load Time Trend

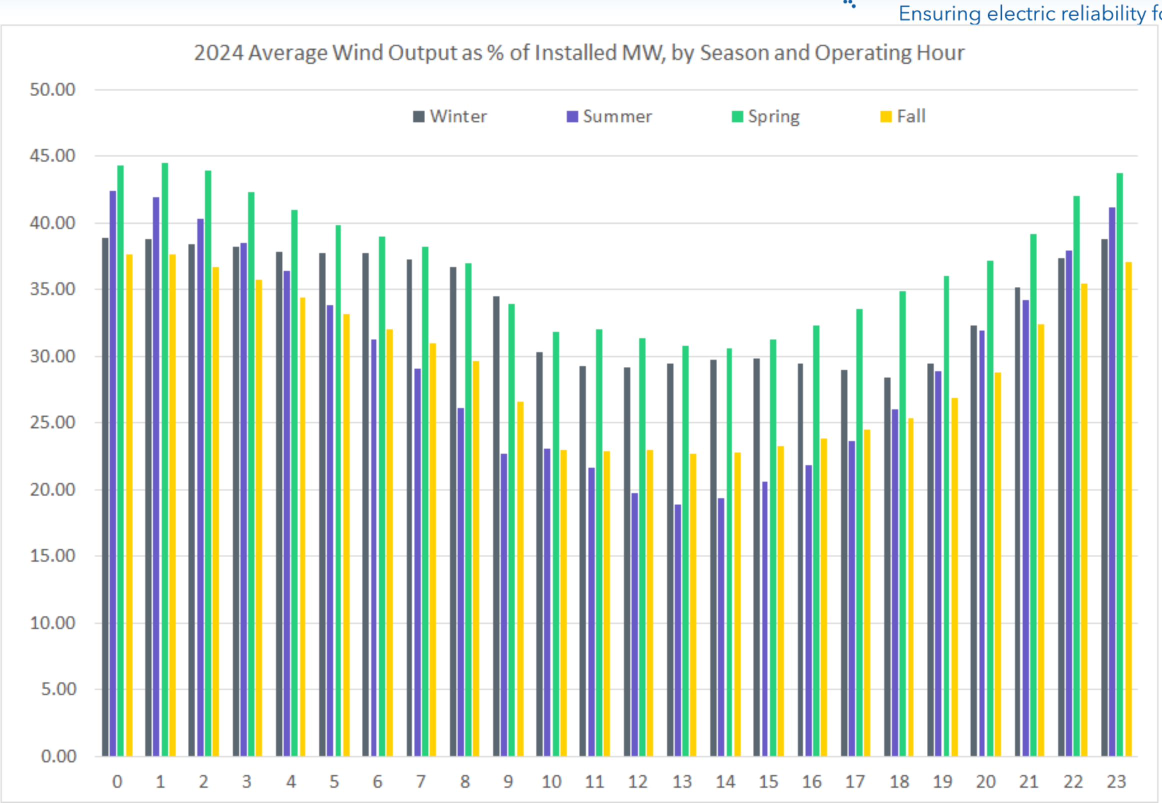


Figure C.4 – Average Wind Output as a Percentage of Installed Wind MW by Season/ Hour

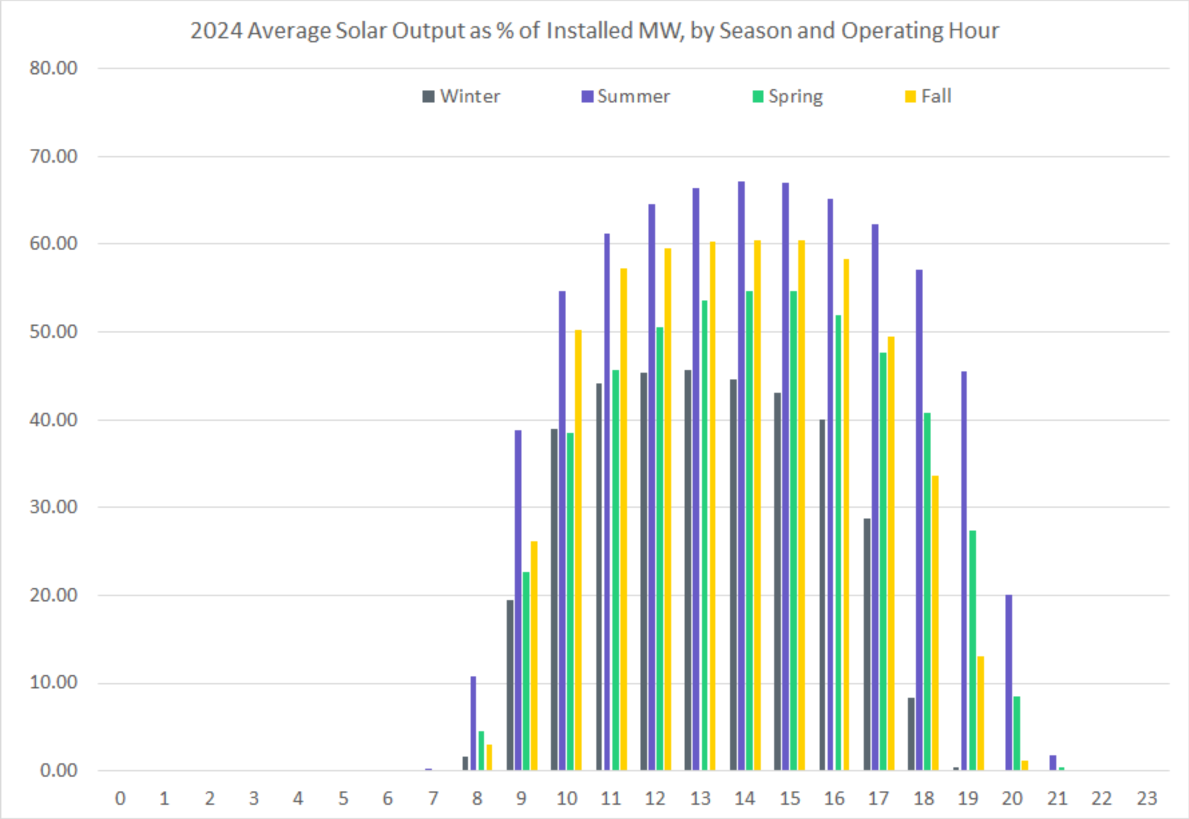


Figure C.5 – Average Solar Output as a Percentage of Installed Solar MW by Season/ Hour

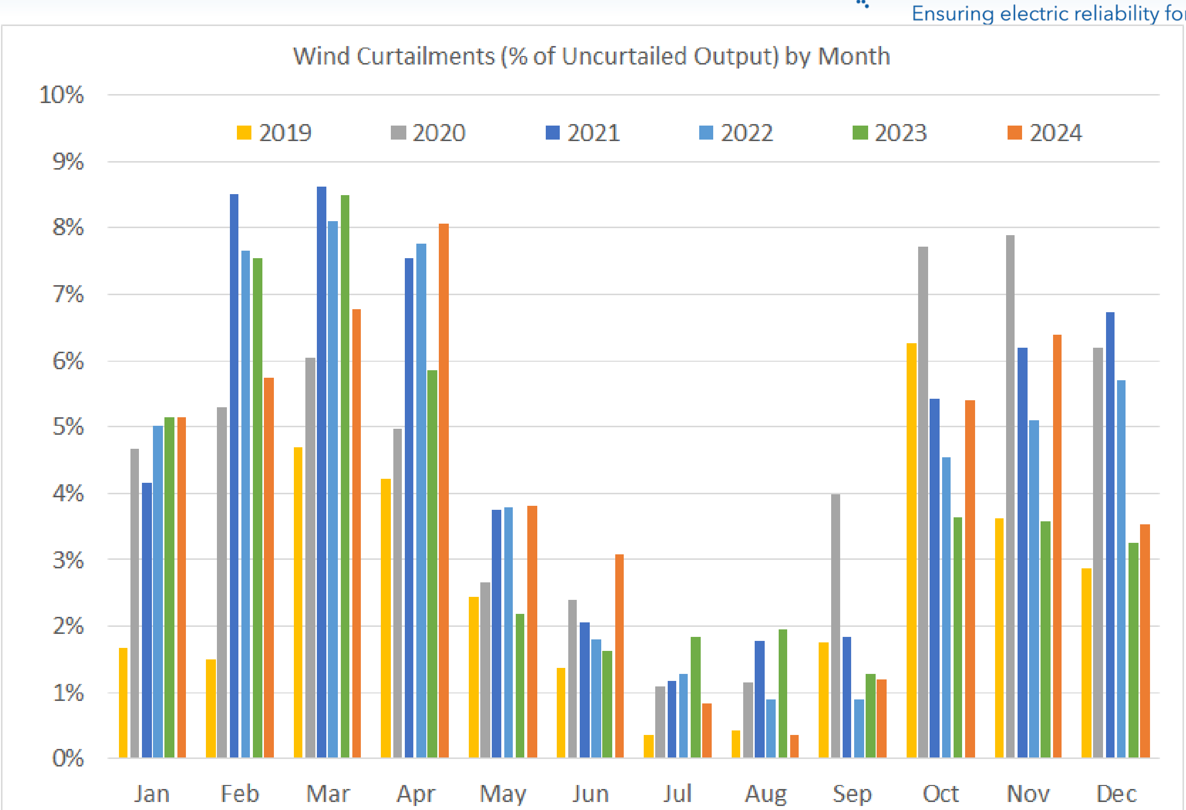


Figure C.6 – Wind Curtailments as a Percentage of Uncurtailed Output by Month

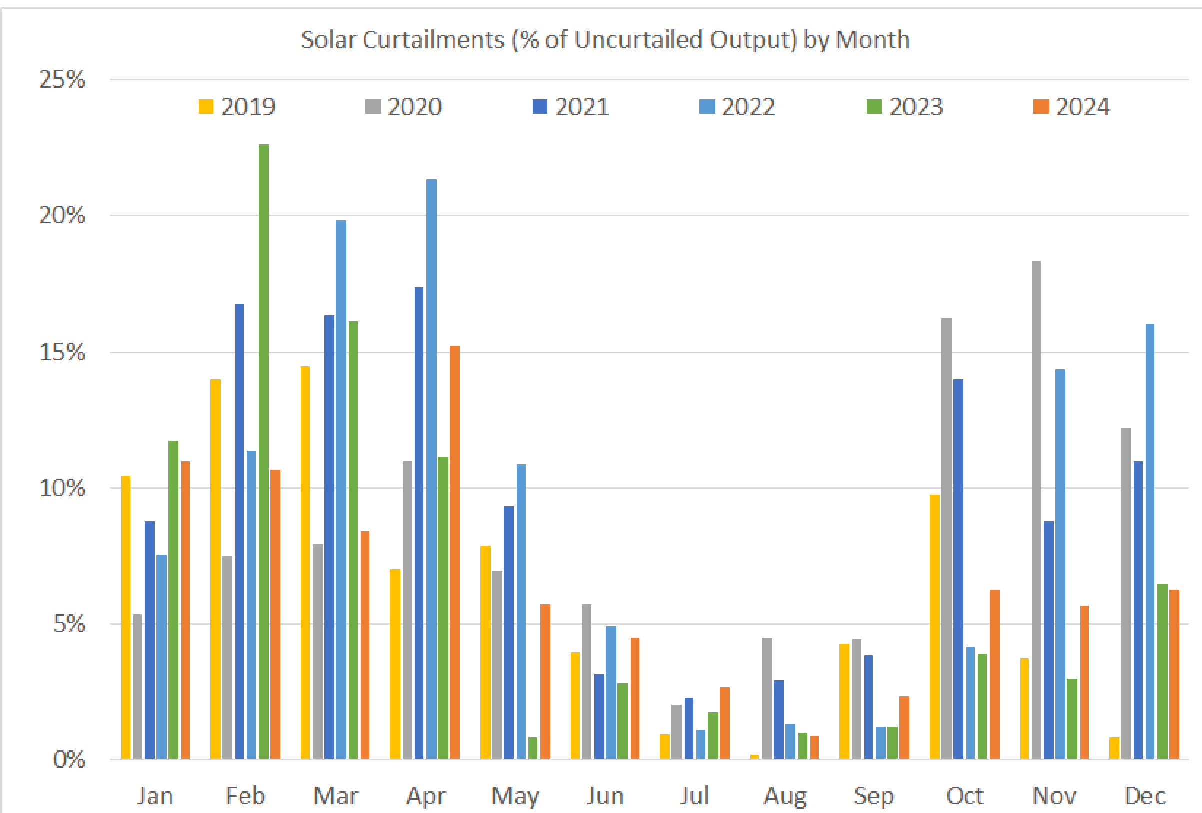


Figure C.7 – Solar Curtailments as a Percentage of Uncurtailed Output by Month

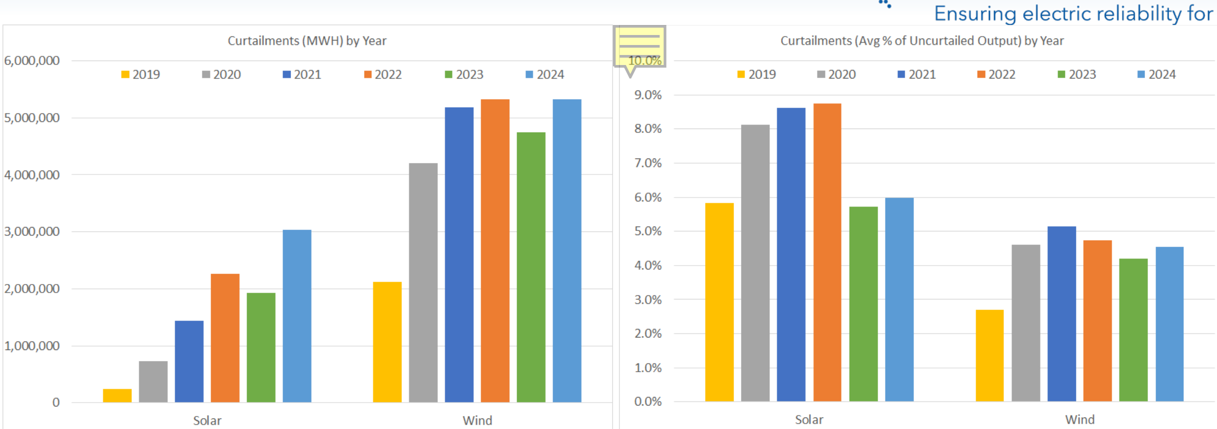


Figure C.8 – Wind/Solar Curtailments MWh and Percentage by Year

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 2024 was 129.96 GWs, on March 24, 2024, at HE04, when the IRR penetration level was 68.1 percent and system load was 37,297 MW (net load of 11,912 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

Table C.2 – Minimum Inertia for 2015-2024

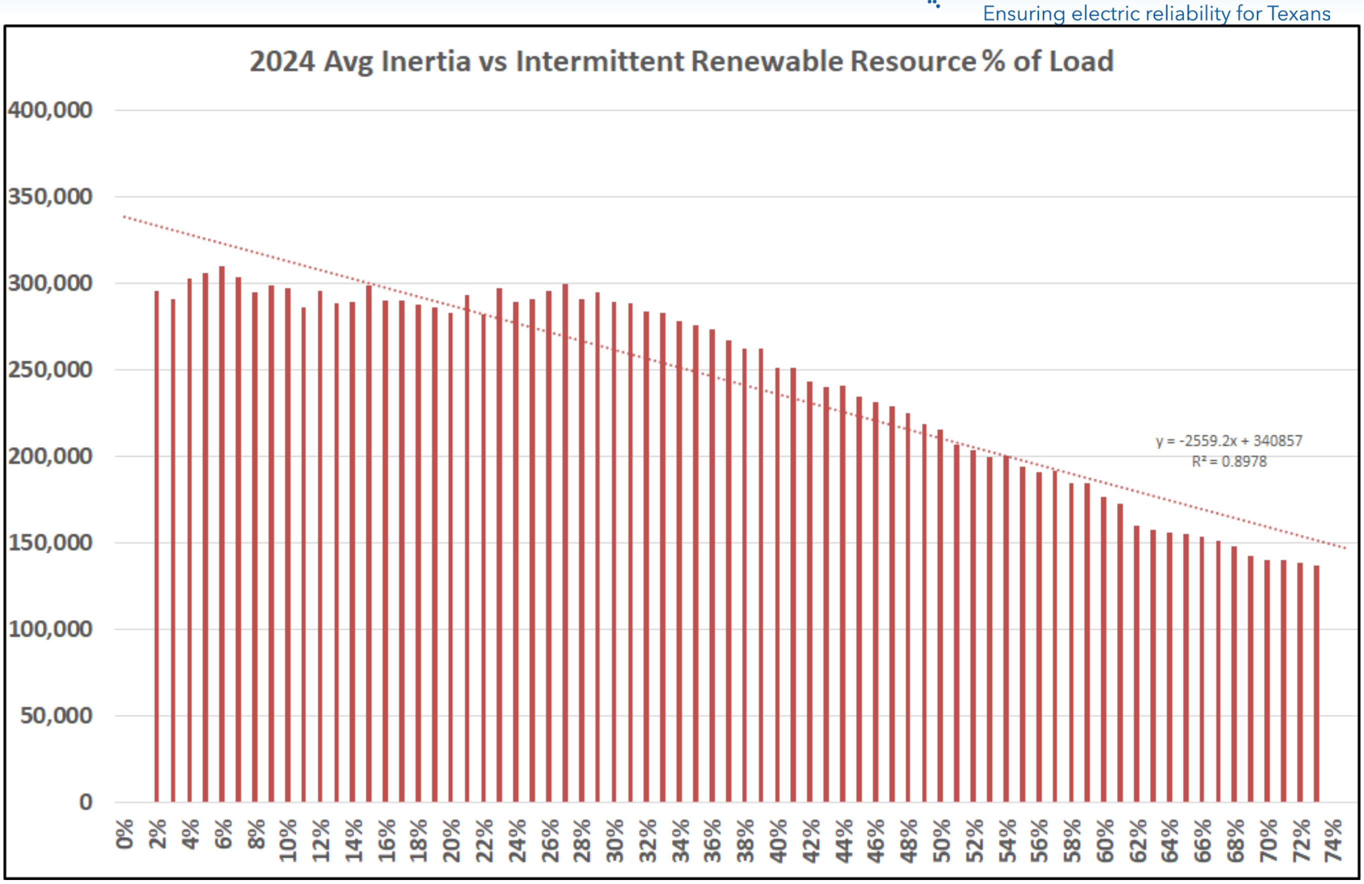


Figure C.9 – 2024 Average Inertia versus Renewable Percentage of Load

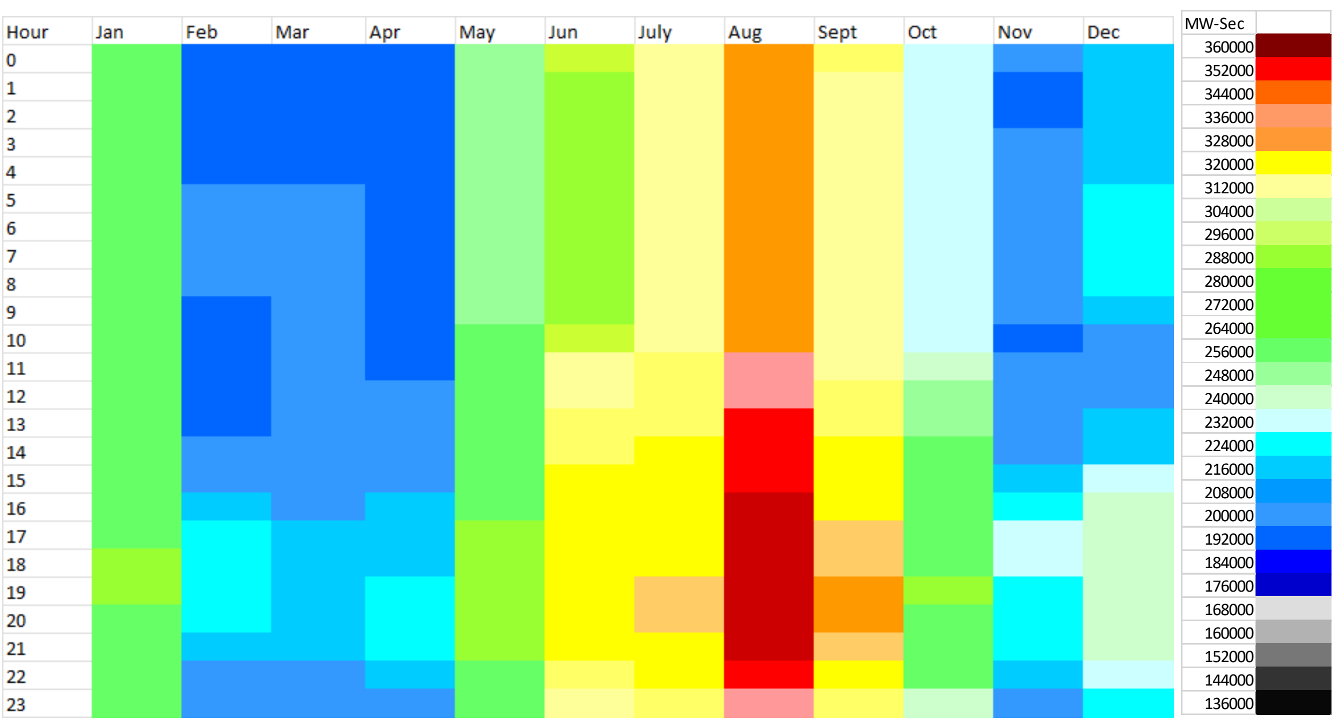


Figure C.10 – 2024 Average Inertia by Month and Operating Hour

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

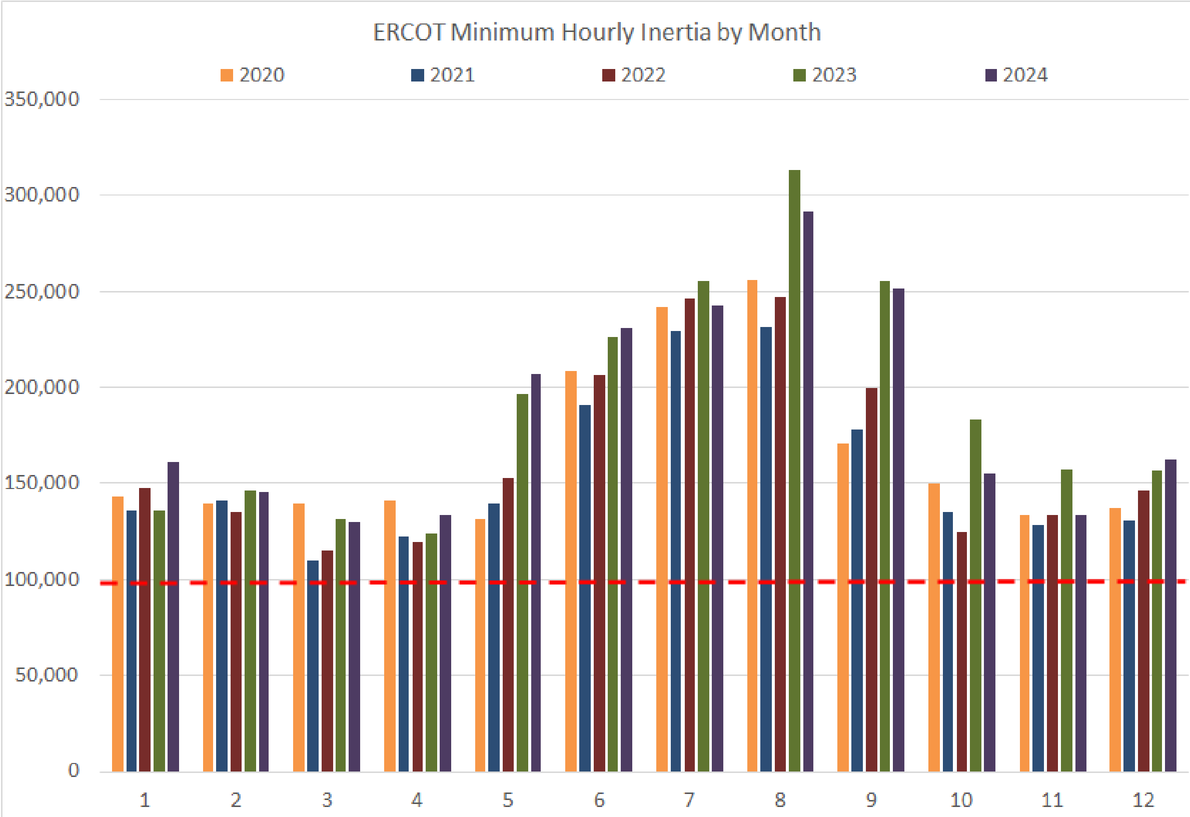


Figure C.11 – 2020-2024 Minimum Hourly Inertia by Month

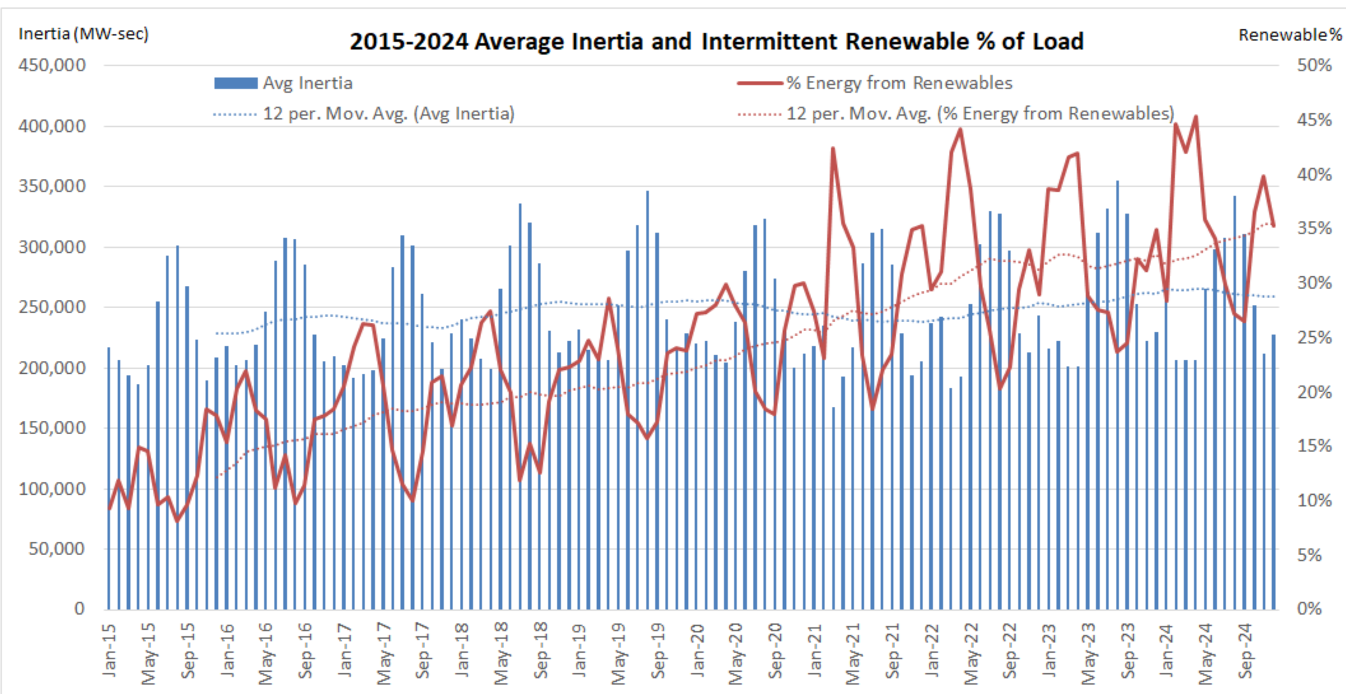


Figure C.12 – 2015-2024 Time Trend of Average Inertia and Renewable Energy Percentage

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	5,487 MW	5,868 MW	12,053 MW	14,432 MW
Maximum One-Hour Decrease	-4,730 MW	-6,521 MW	-10,697 MW	-11,301 MW

Table C.3 – Maximum and Minimum Load, Wind, Solar, and Net-Load Ramps for 2024

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 2024 compared to previous years.

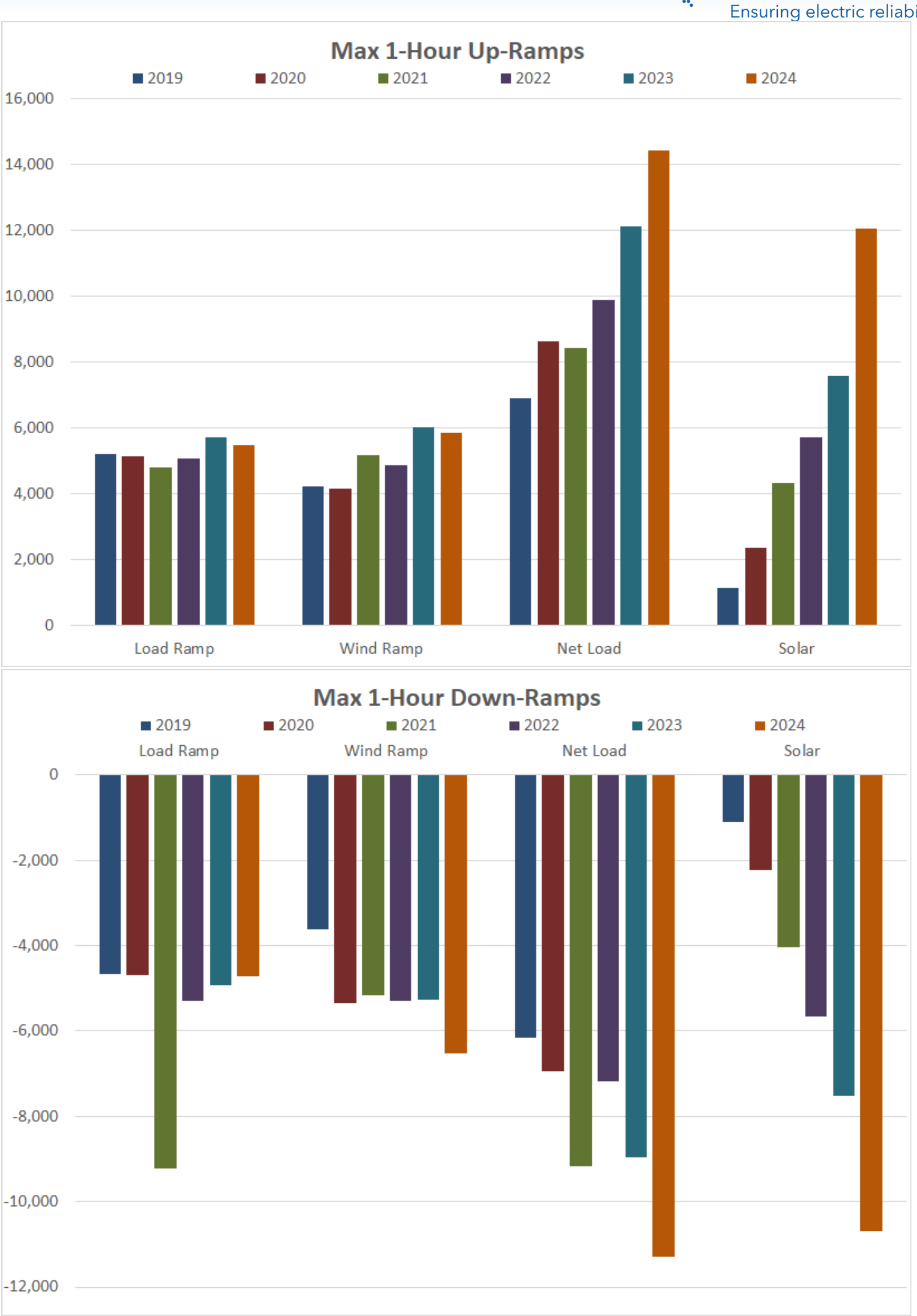


Figure C.13 – Maximum One-Hour Ramps for 2019-2024

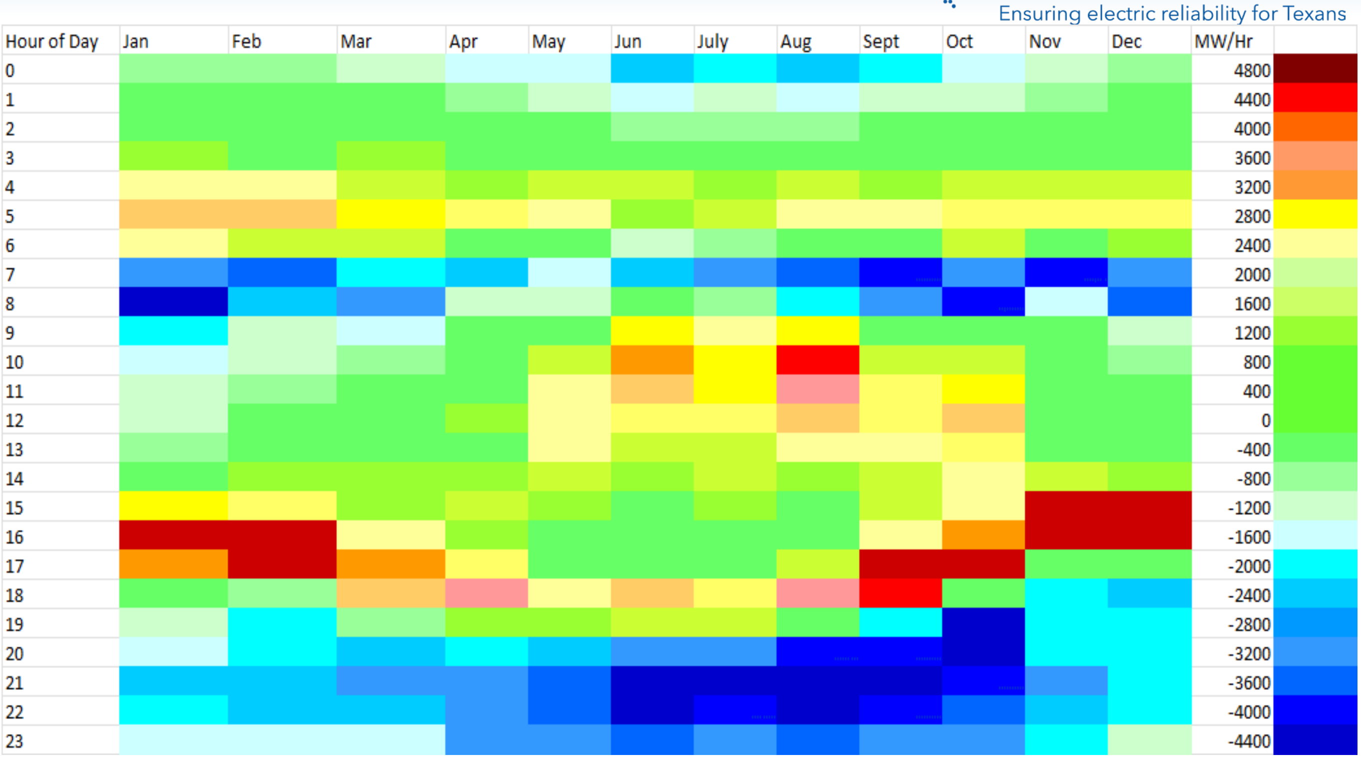


Figure C.14 – 2024 Heat Map of Net Load Ramp by Month and Operating Hour

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 Protection System Misoperations, 138 kV circuit outages, and transformers showed a decrease in 2024 compared to prior years. Outage rates caused by human error for generators and 345 kV circuit outages increased in 2024 compared to 2023 but remained within the long-term trend averages.

Element Type	Metric	2020	2021	2022	2023	2024	5-Yr Avg
AC Circuit 300-399 kV	Outages per Element Initiated by Human Error	1.1%	0.8%	1.7%	0.9%	1.4%	1.2%
AC Circuit 100-199 kV	Outages per Element Initiated by Human Error	1.0%	1.2%	0.9%	0.8%	0.5%	0.9%
Transformer 300-399 kV	Outages per Element Initiated by Human Error	0.8%	0.0%	1.2%	1.2%	0.3%	0.7%
Generator	Immediate Forced Outages Initiated by Human Error	2.6%	3.2%	1.9%	1.7%	2.3%	2.3%
Protection Systems	Misoperation Rate Caused by Human Error	2.7%	2.0%	3.2%	2.3%	1.9%	2.4%

Table D.1 – Outages Rates Caused by Human Error

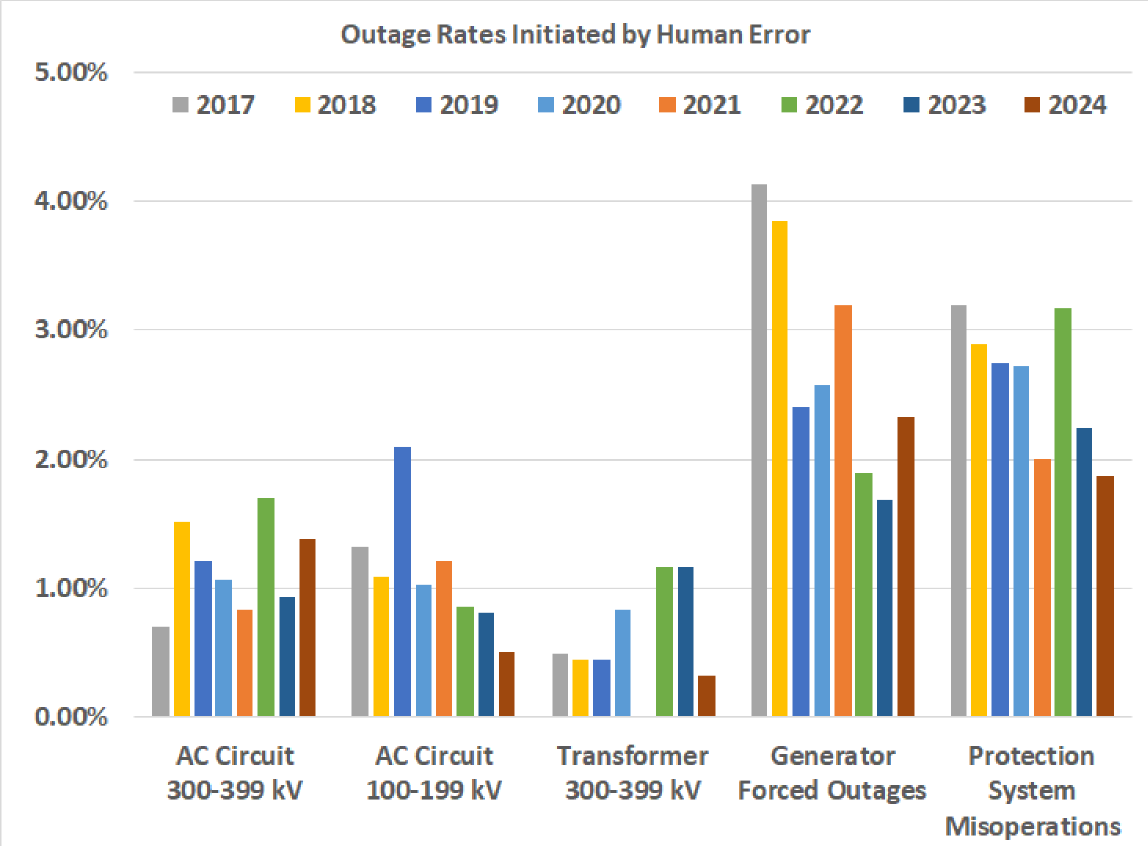


Figure D.1 – Outage Rates Caused by Human Error

Since 2017, there have been 617 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.

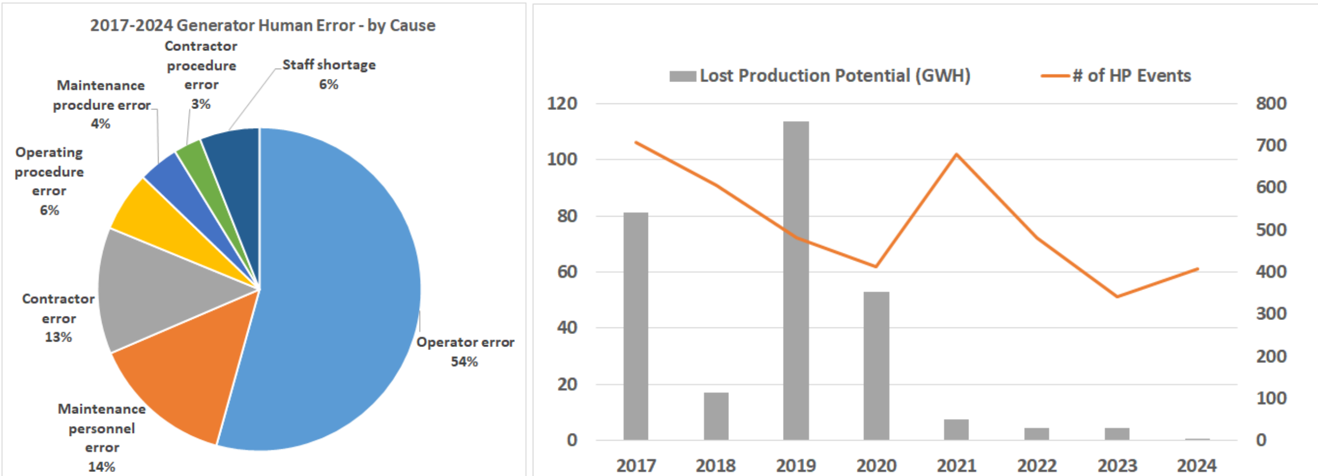


Figure D.2 – Generator Forced Outage Human Errors

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, 45 events in ERCOT have been analyzed using this cause code process, with 418 root cause and contributing cause codes assigned. Approximately 54 percent of the assigned root and contributing cause codes are related to potential human performance issues (shown in red below in Figure D.3).

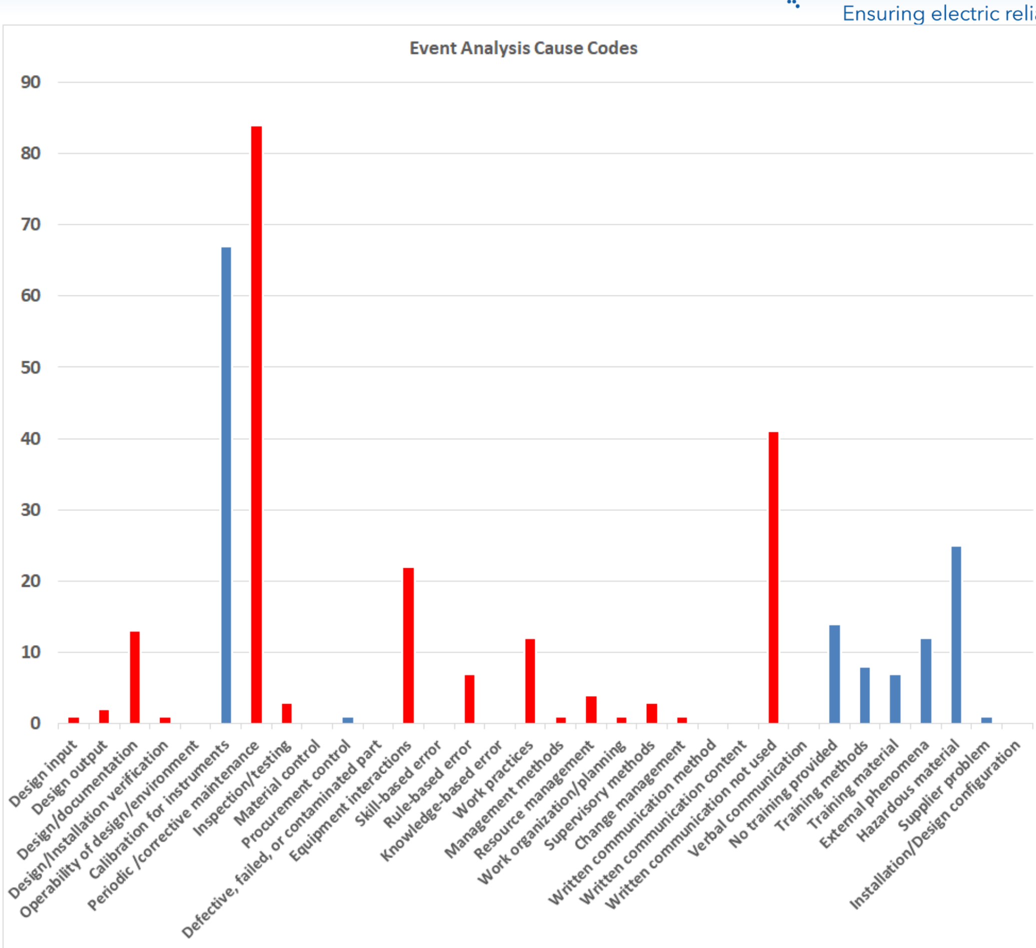


Figure D.3 – Event Analysis Human Performance Cause Coding

Appendix E – Bulk Power System Planning Analysis

A. Net Energy for Load

In 2024, total annual energy usage was 461,577 GWh, an increase of 3.3 percent from 2023. Peak hourly demand was 85,544 MW on August 20, 2024. The West Load Zone continues to see the largest load energy usage increase, with a 15.9 percent increase in 2024 compared to 2023.

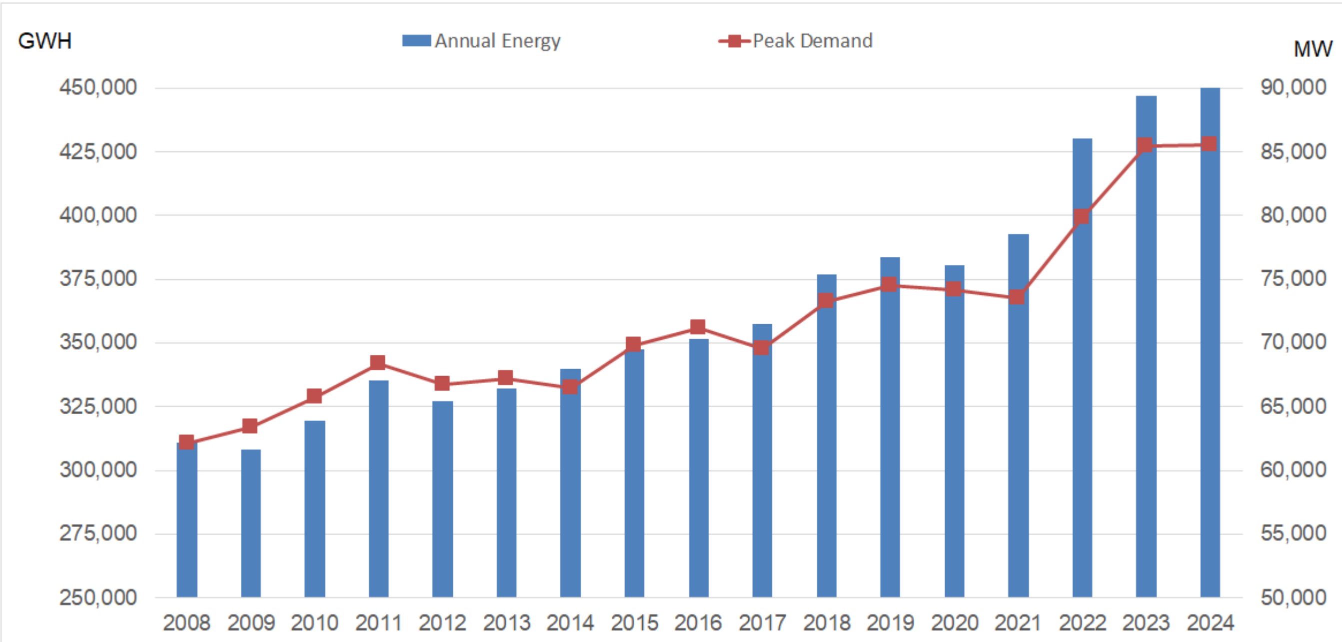


Figure E.1 – Annual Energy and Peak Demand

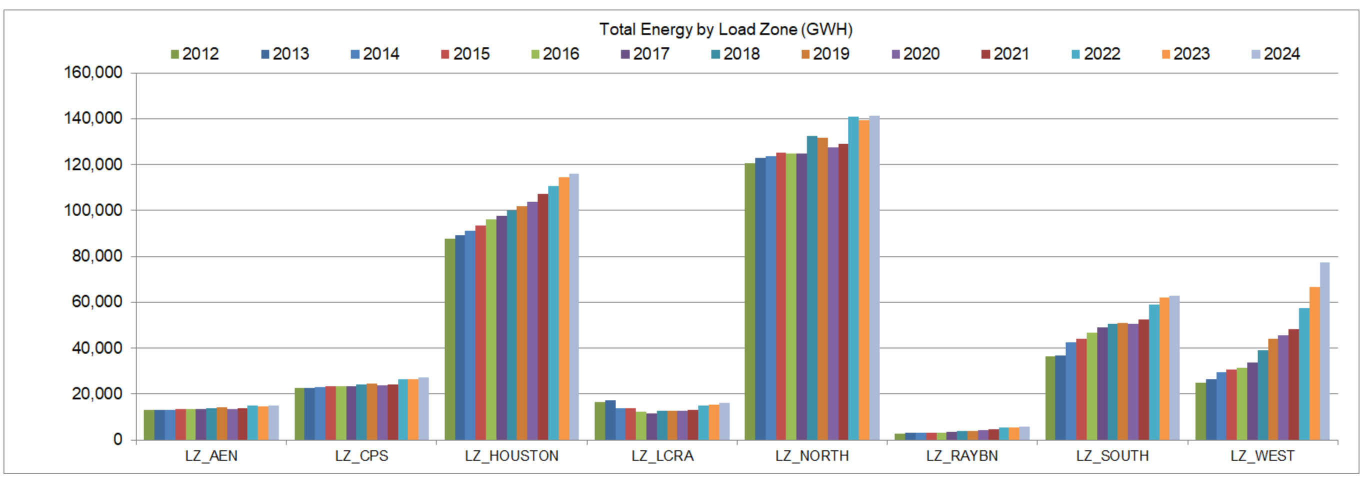


Figure E.2 – Energy by Load Zone

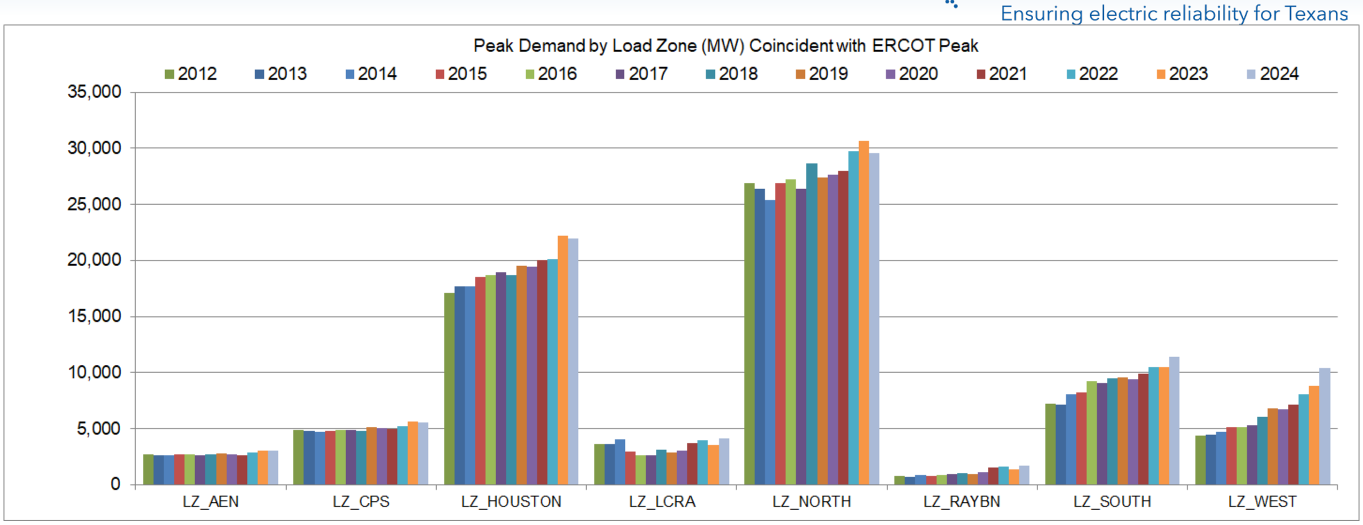


Figure E.3 – Peak Demand by Load Zone

The Far West and North weather zones showed large year-over-year percentage increased in energy usage increase in 2024 compared to 2023. The Far West had a 15.8 percent increase in 2024 compared to 2023 while the North weather zone had a 24.3 percent increase.

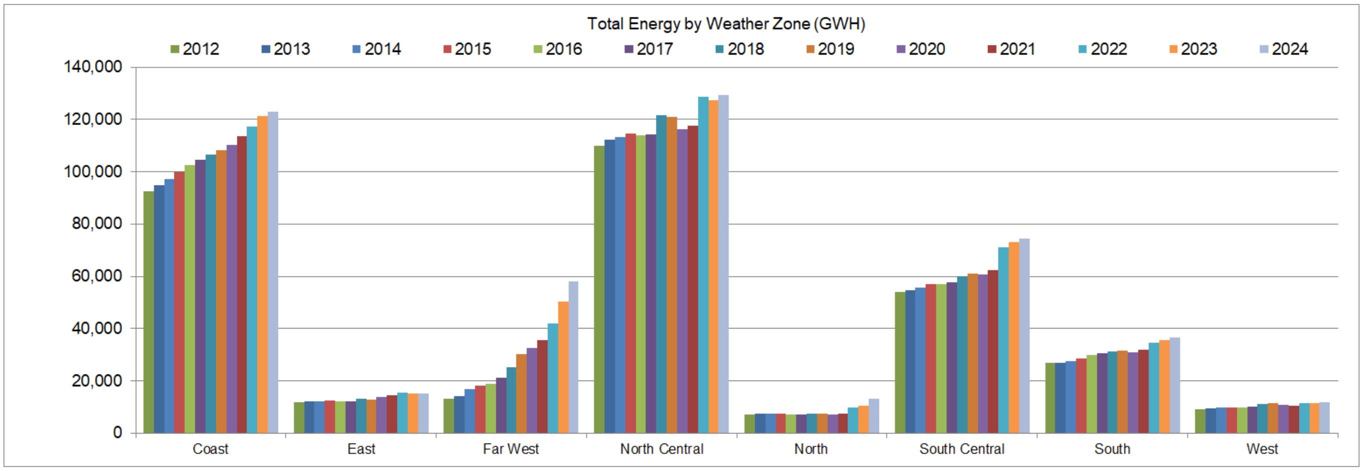


Figure E.4 – Energy by Weather Zone

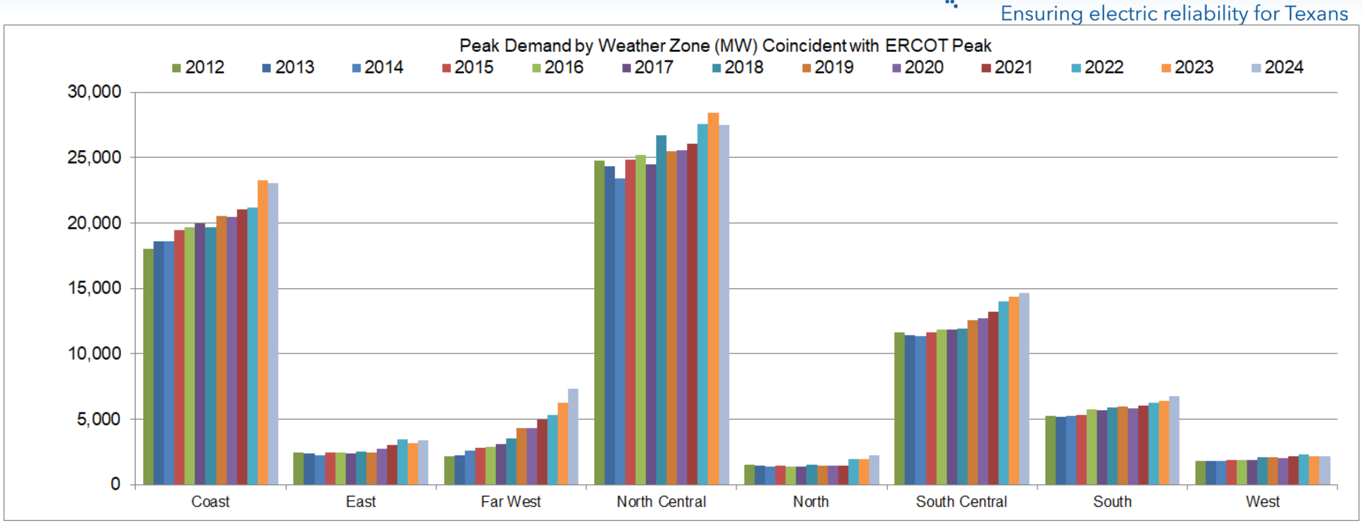


Figure E.5 – Peak Demand by Weather Zone

Overall energy growth rate has averaged 3.9 percent per year and demand growth rate has averaged 2.9 percent per year since 2020.

B. Reserve Margin

NERC develops and publishes its Long-Term Reliability Assessment (LTRA) each December to independently assess each region in an effort to identify trends, emerging issues, and potential risks during the 10-year horizon. A key component of the LTRA is an evaluation of the peak demand and planning reserve margins, which are based on average weather conditions and the forecasted economic growth conditions at the time of the assessment. In the LTRA, NERC uses a reference planning reserve margin of 13.75 percent, based on a one event in 10-year loss of load probability.

ERCOT publishes its Capacity, Demand and Reserves (CDR) report twice each year, in December and May. The purpose of the CDR is to provide updates to the planning reserve margins based on current load forecasts and resource availability.

While both of these reports are focused on the long-term planning reserve margins, the results will differ due to multiple factors such as data collection dates and forecasting of load.

The 2024 LTRA and the December 2024 CDR both show the forward-looking impacts on large load growth for the interconnection. In particular, with the inclusion of TSP Officer Letter Loads, the CDR shows the potential for negative reserve margins in 2027-2029, depending on the scenario.

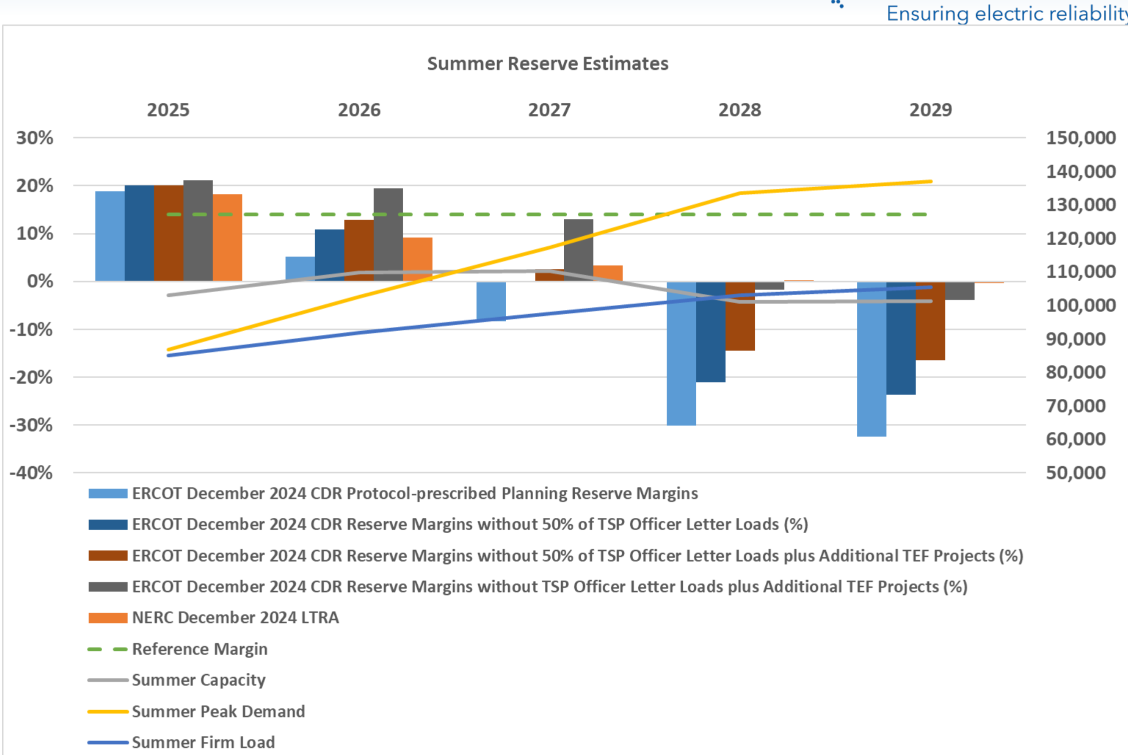


Figure E.6 – Summer Peak Reserve Margins

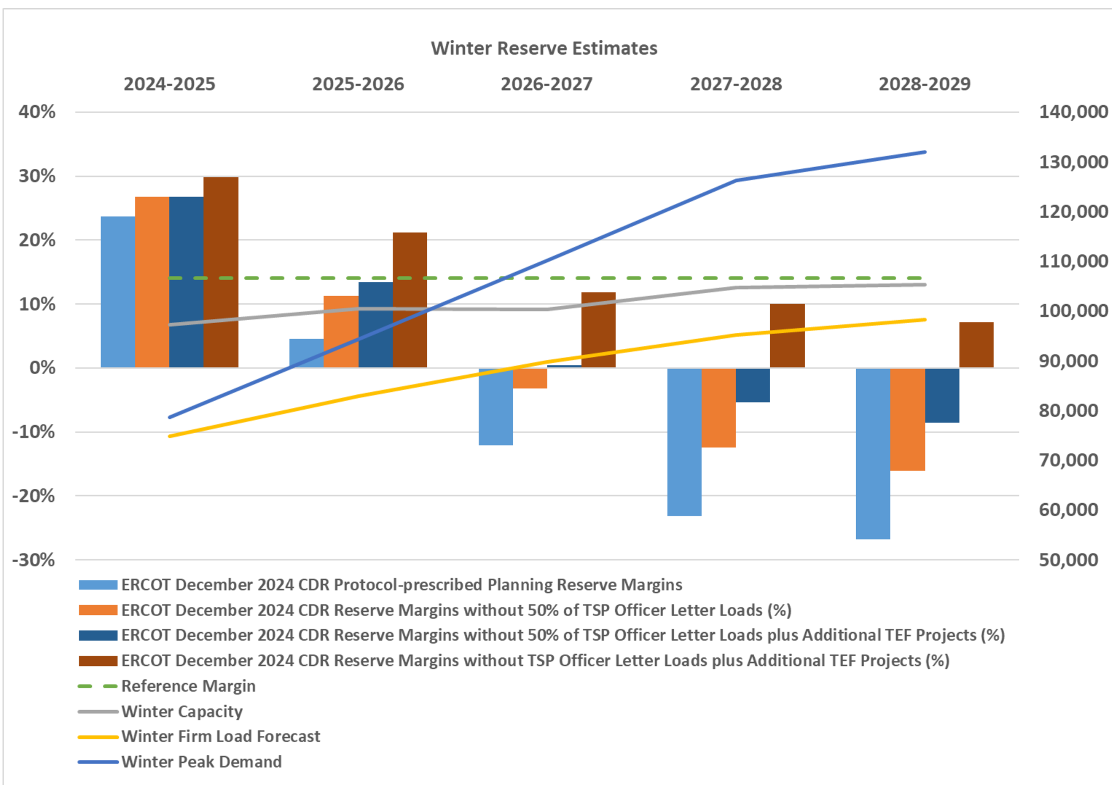


Figure E.7 – Winter Peak Reserve Margins

C. 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:

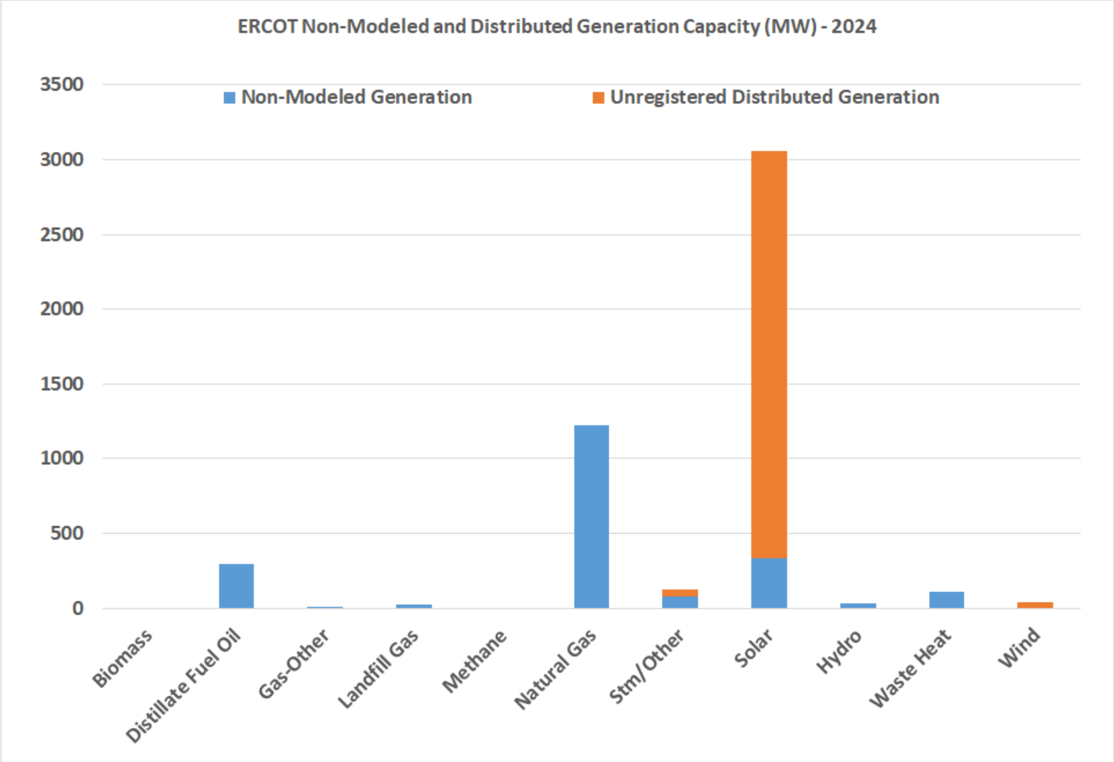
- Distribution and behind-the-meter generation
- Energy storage facilities
- Microgrids
- Cogeneration
- Stand-by or back-up generation

Increasing amounts of DER will change how the distribution system interacts with the BPS by transforming the distribution system into an active energy source.

DER modeling processes are described through ERCOT working groups and these facilities are explicitly included in the Steady State Working Group (SSWG) and Dynamics Working Group (DWG) cases. Standards development projects are in progress at NERC to incorporate DER into relevant reliability standards.

Currently under ERCOT Protocols, distributed generation resources greater than 1 MW must register with ERCOT and provide resource registration data per Protocol 16.5(5) and Planning Guide 6.8.2. Additionally, P.U.C. SUBST. R. 25.211(n) requires every electric utility to file (by March 30 of each year) a distributed generation interconnection report with the commission for the preceding calendar year that identifies each distributed generation facility interconnected with the utility's distribution system, including ownership, capacity, and whether it is a renewable energy resource.

At the end of 2024, ERCOT had approximately 2,095 MW of non-modeled generation capacity and 2,805 MW of unregistered distributed generation resources (DGR) that has provided data for mapping capacity to their modeled loads.



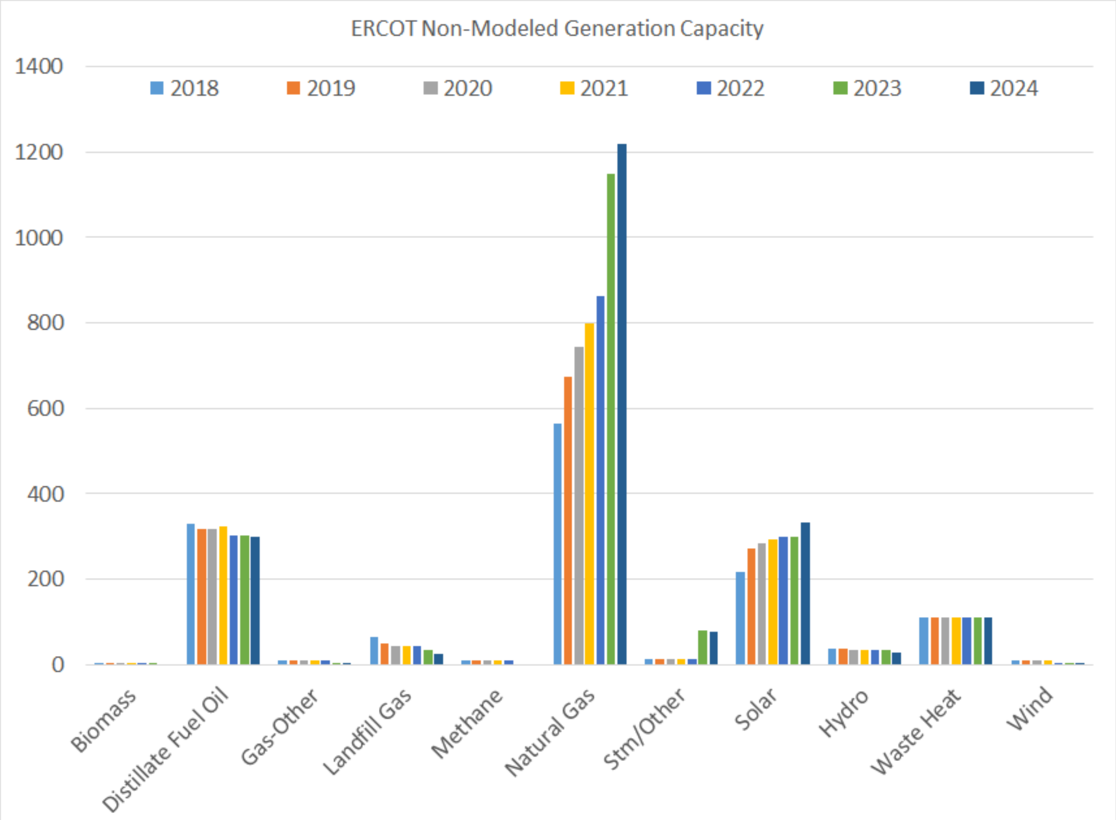


Figure E.8 – Non-Modeled Generation Capacity by Fuel Type

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 2024 include the following:

- A GOP experienced a complete loss of monitoring and control due to a core switch failure.
- A TOP experienced a complete loss of monitoring and control due to a software failure of the primary SCADA communications server. The software failure was caused by an independent health monitor script on the EMS system.
- A TOP experienced a partial loss of visibility when the EMS database application failed during a system backup.
- A GOP experienced control room issues during the CrowdStrike global outage.
- A GOP experience multiple interruptions of ICCP and SCADA during a scheduled maintenance activity to install new SCADA servers.
- A TOP experienced a loss of monitoring and control when a scheduled EMS site failover was unsuccessful.
- A TOP experienced a complete loss of monitoring and control during a scheduled annual failover test when the backup PCI failed.

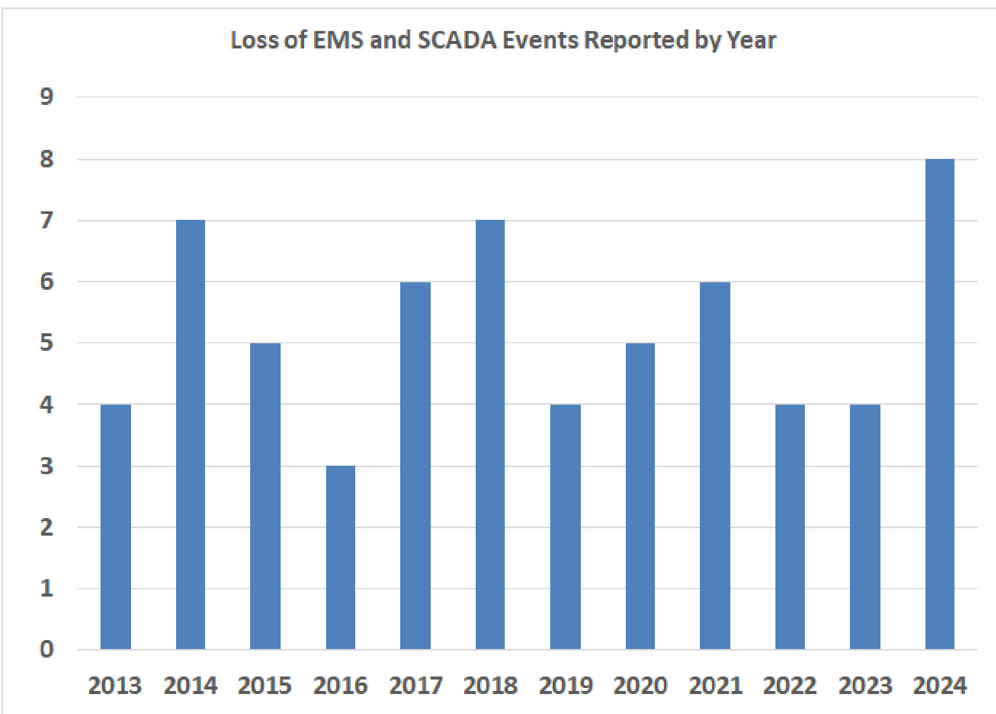


Figure F.1 – Loss of EMS and SCADA Events by Year

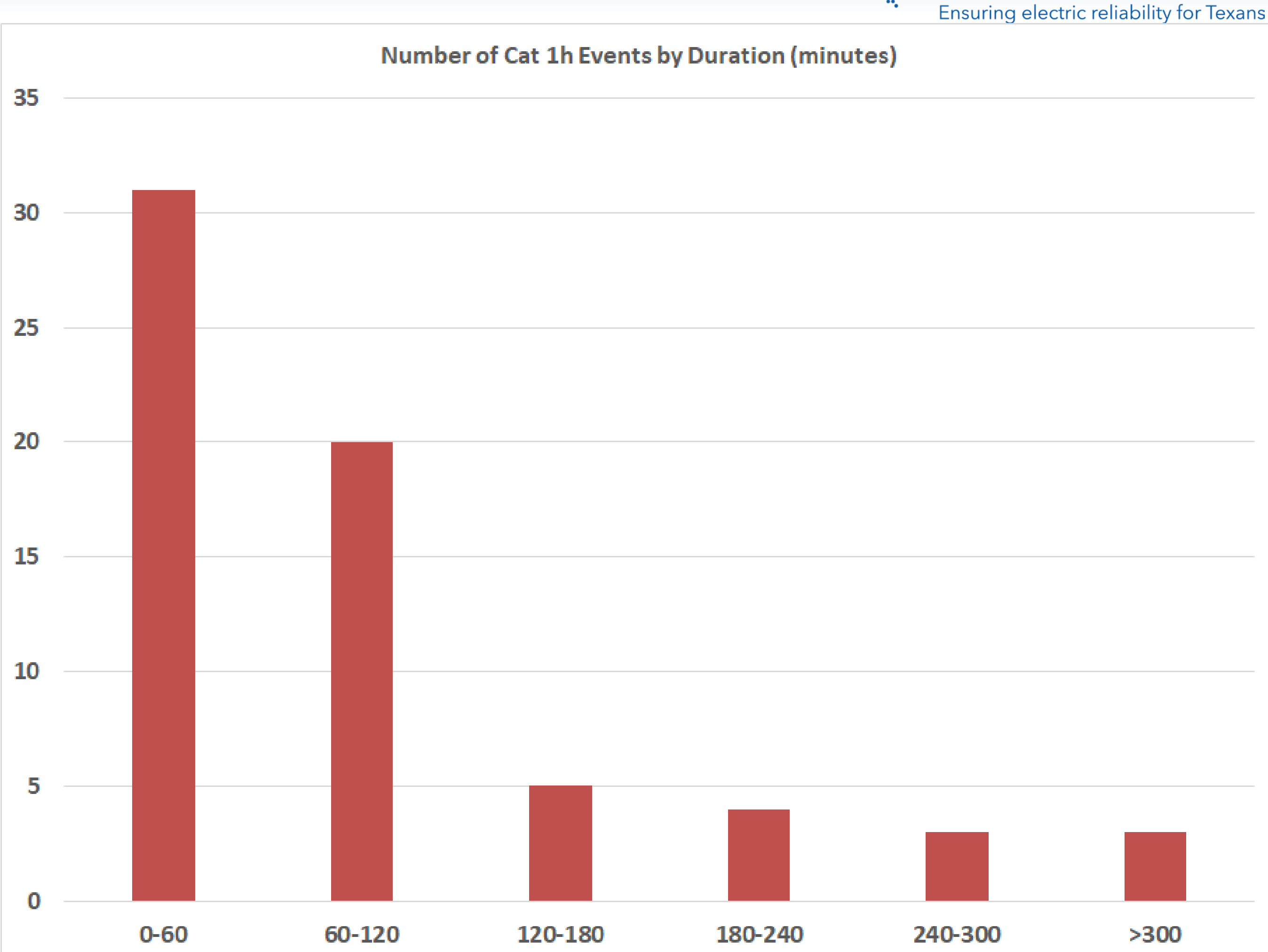


Figure F.2 – Loss of EMS and SCADA Events by Duration Since 2011

B. State Estimator Convergence

ERCOT's goal for State Estimator convergence is 97 percent or higher. In 2024, the convergence rate was 99.98 percent.

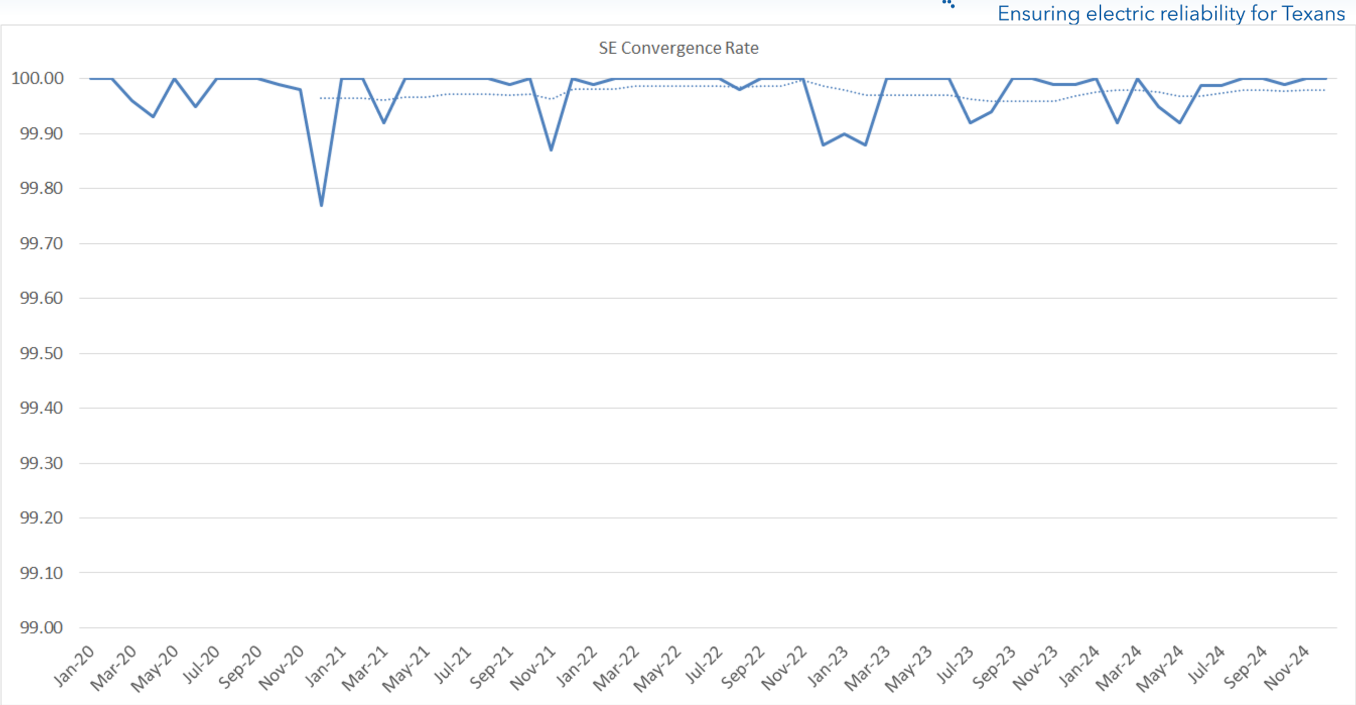


Figure F.3 – State Estimator Convergence Rate

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 2024, the total number of telemetry points failing the availability metric averaged 6,375 each month, or 3.96 percent of the total system telemetry points.

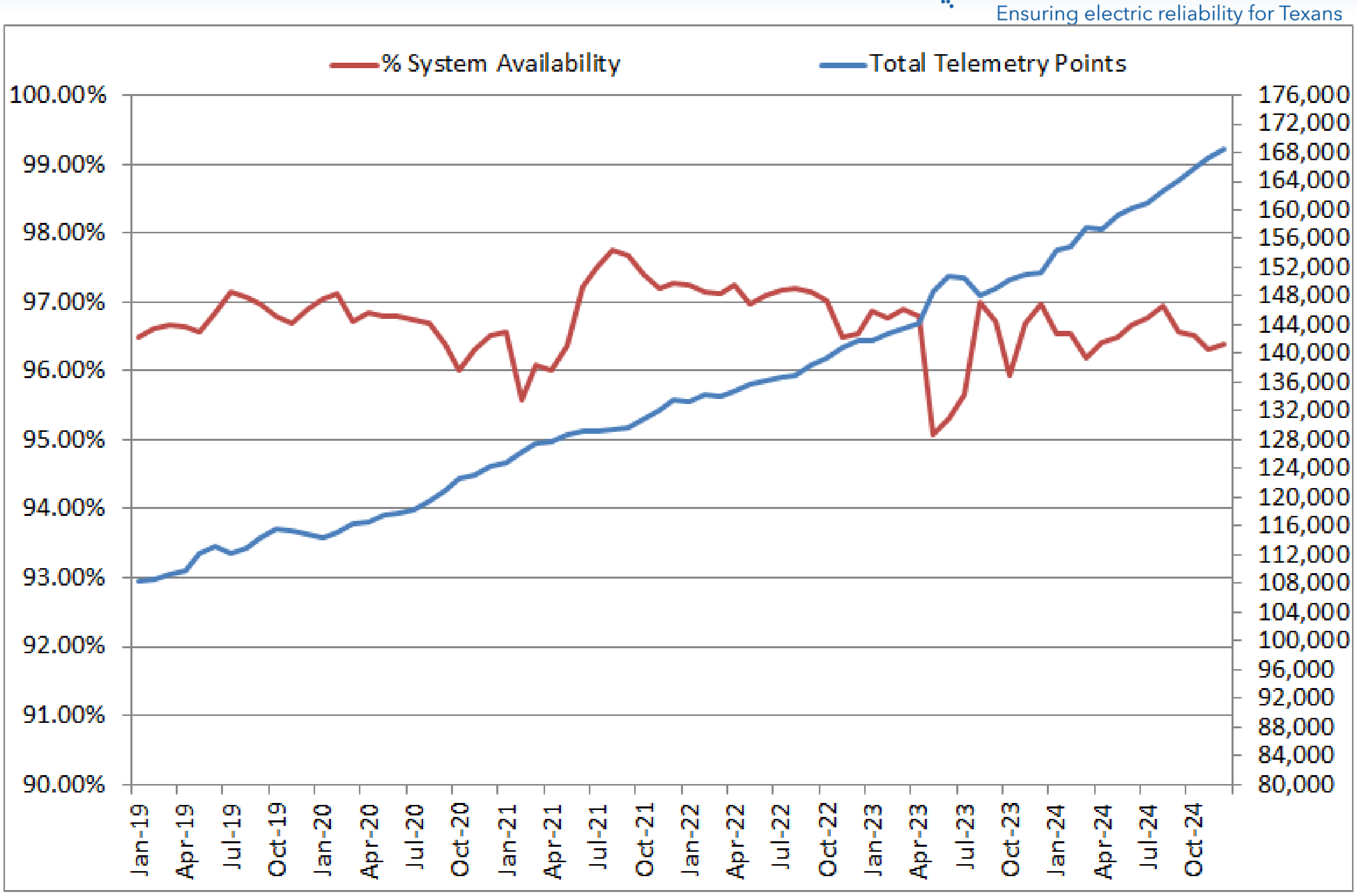


Figure F.4 – ERCOT Telemetry System Availability

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.

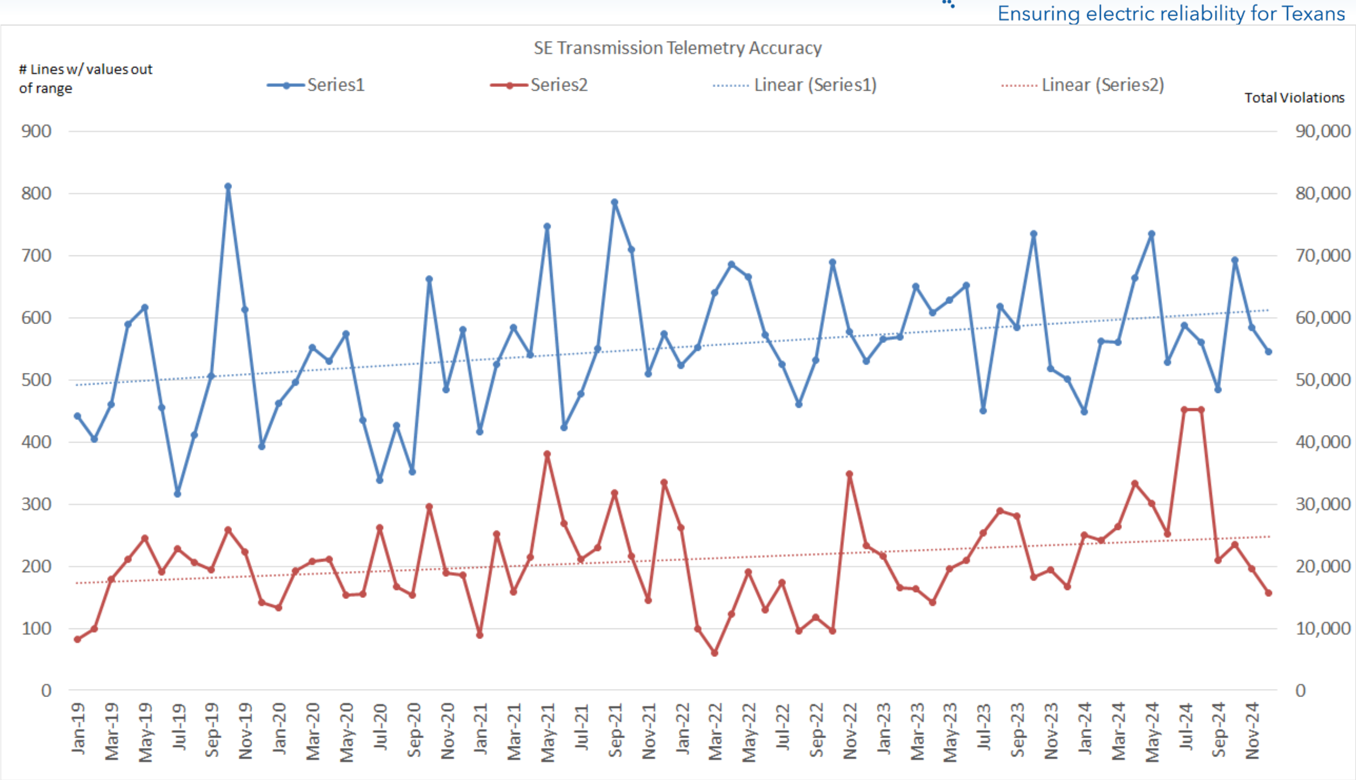


Figure F.5 – State Estimator versus Transmission Telemetry Accuracy

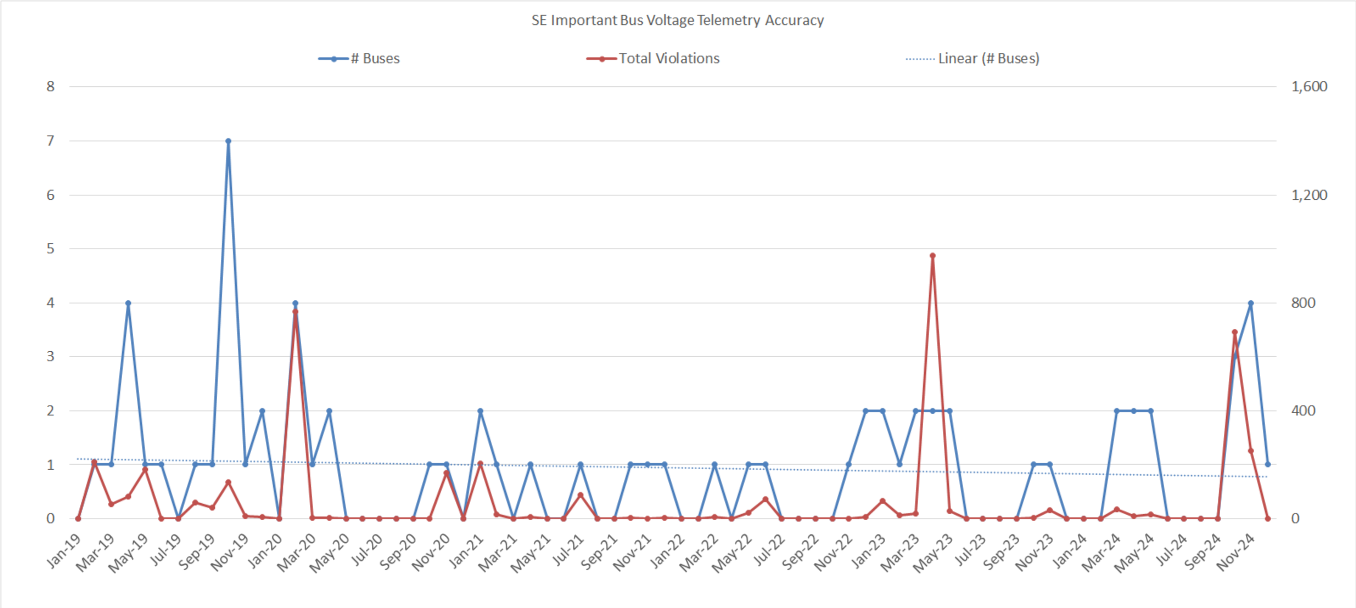


Figure F.7 – Bus Voltage Telemetry Accuracy

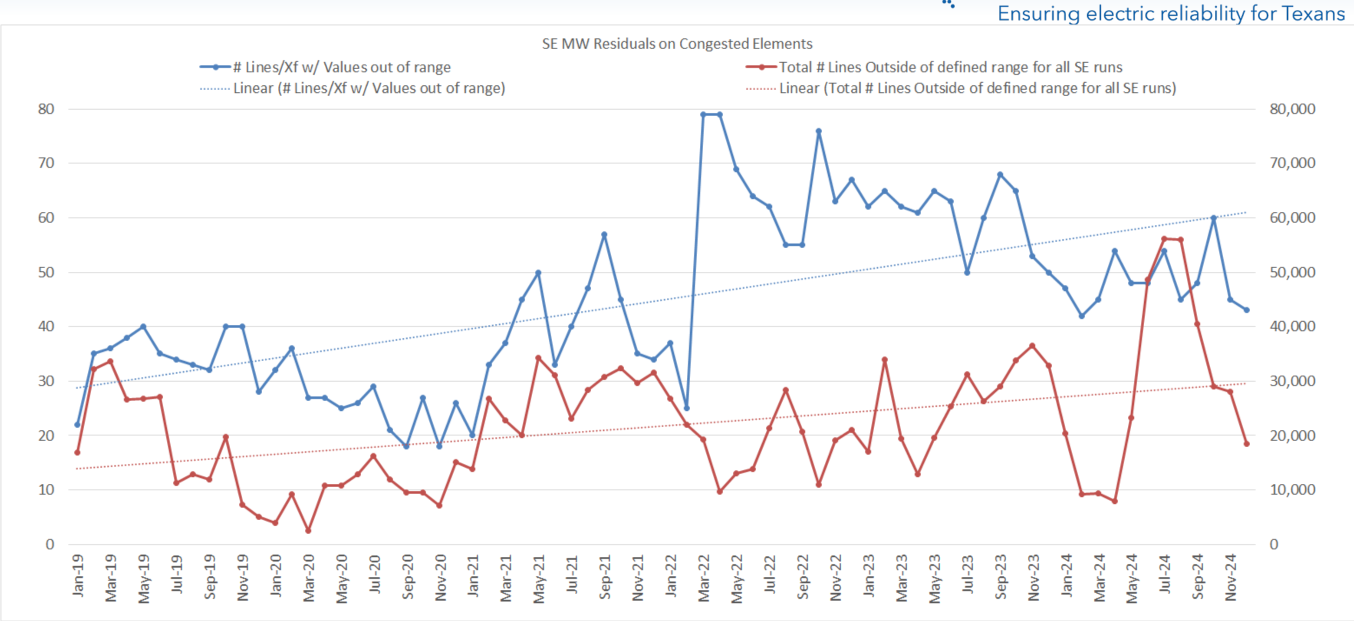


Figure F.8 – State Estimator vs Congested Element Telemetry Accuracy

Appendix G – Protection System Detailed Analysis

A. Protection System Misoperations

Since January 2020, the overall transmission system Protection System Misoperation rate has been declining slowly, from 6.0 percent in 2020 to 4.3 percent in 2024. The five-year Misoperation rate from 2020-2024 was 5.8 percent.

138 kV	2020	2021	2022	2023	2024	5-Yr Avg
Number of Misoperations	74	102	95	65	72	82
Number of Events	1301	1794	1284	1472	1664	1508
Percentage of Misoperations	5.7%	5.7%	7.4%	4.4%	4.3%	5.4%
345 kV	**2020**	**2021**	**2022**	**2023**	**2024**	**5-Yr Avg**
Number of Misoperations	42	33	42	32	33	37
Number of Events	629	714	612	602	647	642
Percentage of Misoperations	6.7%	4.6%	6.9%	5.3%	5.1%	5.8%
< 100 kV	**2020**	**2021**	**2022**	**2023**	**2024**	**5-Yr Avg**
Number of Misoperations	3	0	11	3	1	4
Number of Events	47	59	80	108	149	96
Percentage of Misoperations	6.4%	0.0%	13.8%	2.8%	0.6%	4.2%

Table G.1 – Protection System Misoperation Data

In 2024, three main categories account for 57 percent of the total Misoperations: incorrect settings/logic/design (30 percent), Other/explainable (15 percent), and unknown (12 percent).

Misoperations due to incorrect settings, AC systems, and As-left personnel errors decreased in 2024 compared to 2023 (from 42 to 32).

Misoperations due to As-left personnel errors, Other/Explainable, and Unknown showed a sharp increase in 2023 compared to 2024, however, the five-year trend is flat.

Entities have completed corrective actions on approximately 66 percent of Misoperations that occurred in 2024.

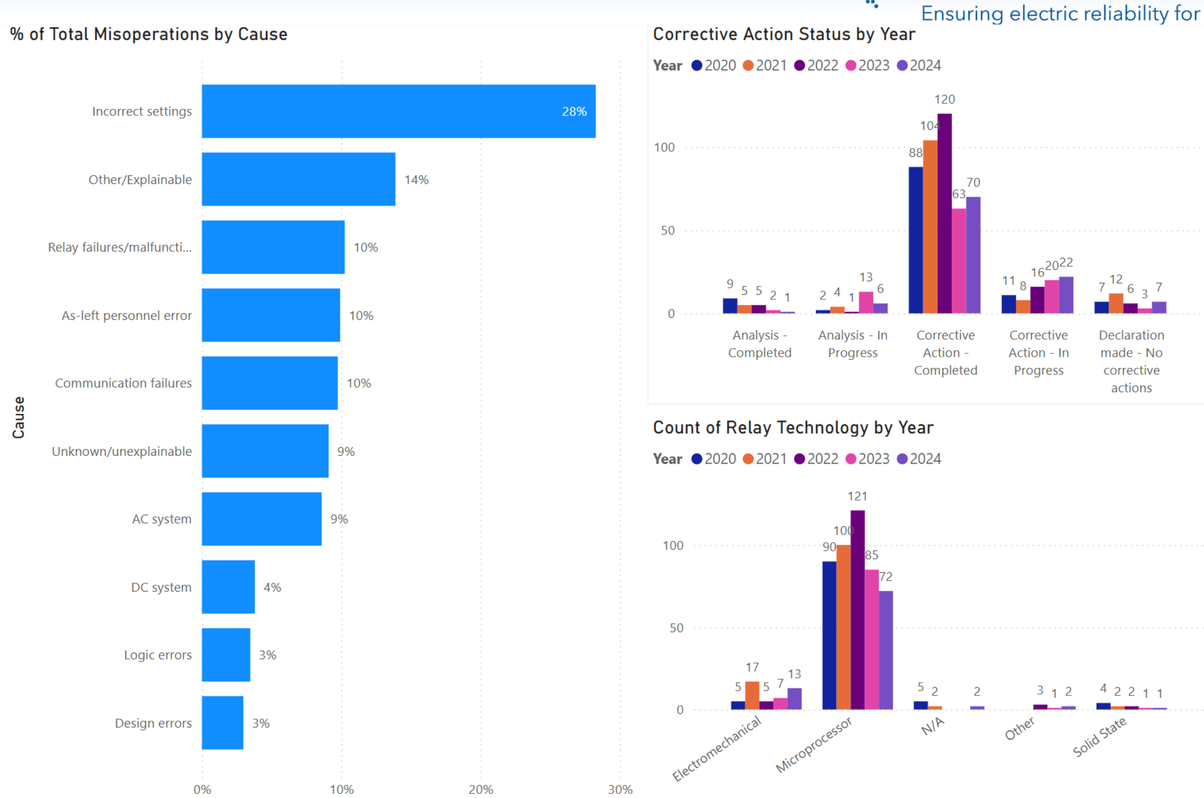


Figure G.1 – Protection System Misoperation Count 2020-2024

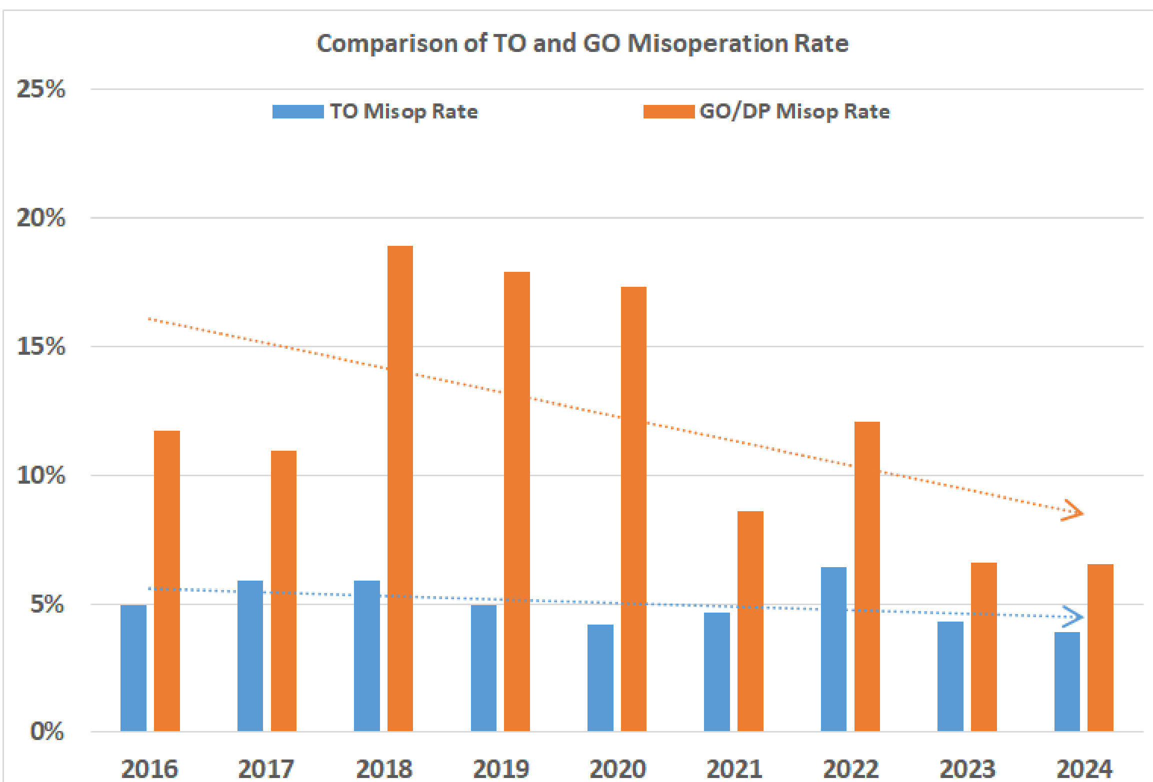


Figure G.2 – Protection System Misoperation Rate by Entity Type

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.

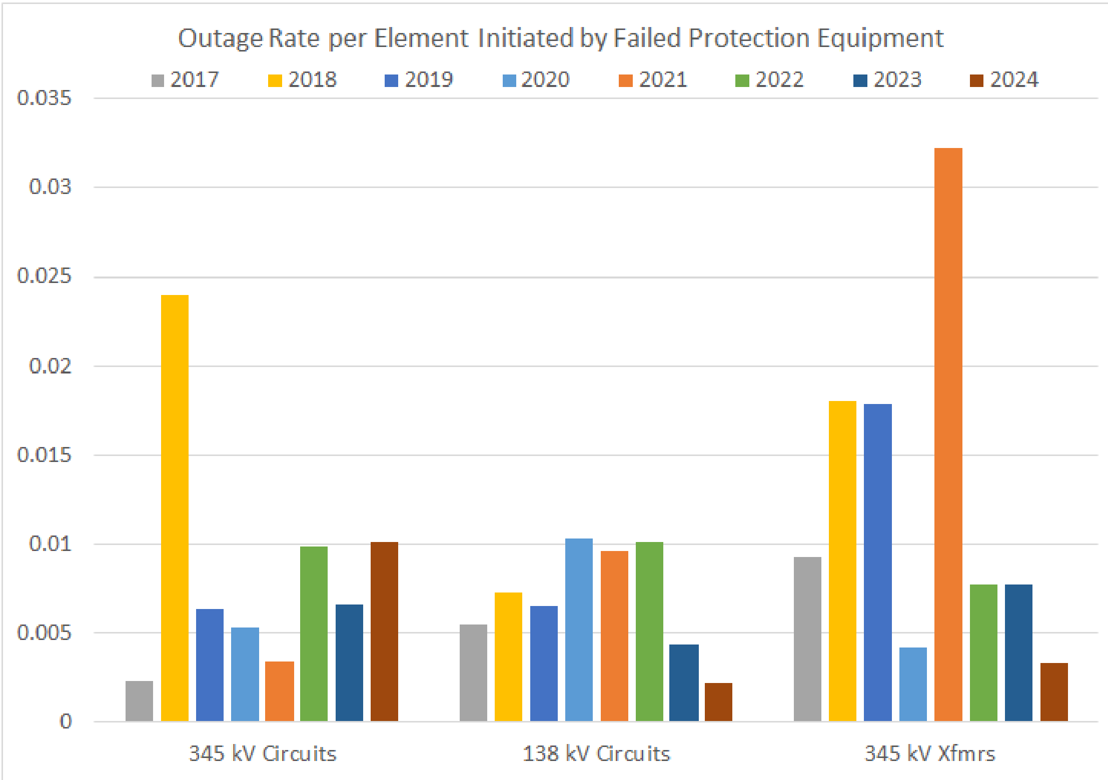


Figure G.3 – Outage Rates Caused by Failed Protection Equipment

Appendix H – Frequency Control Detailed Analysis

A. CPS1 Performance

Control Performance Standard 1 (CPS1): 175.5 for calendar year 2024 versus 175.2 for calendar year 2023.

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 2024, the annualized CPS1 score was 175.5.

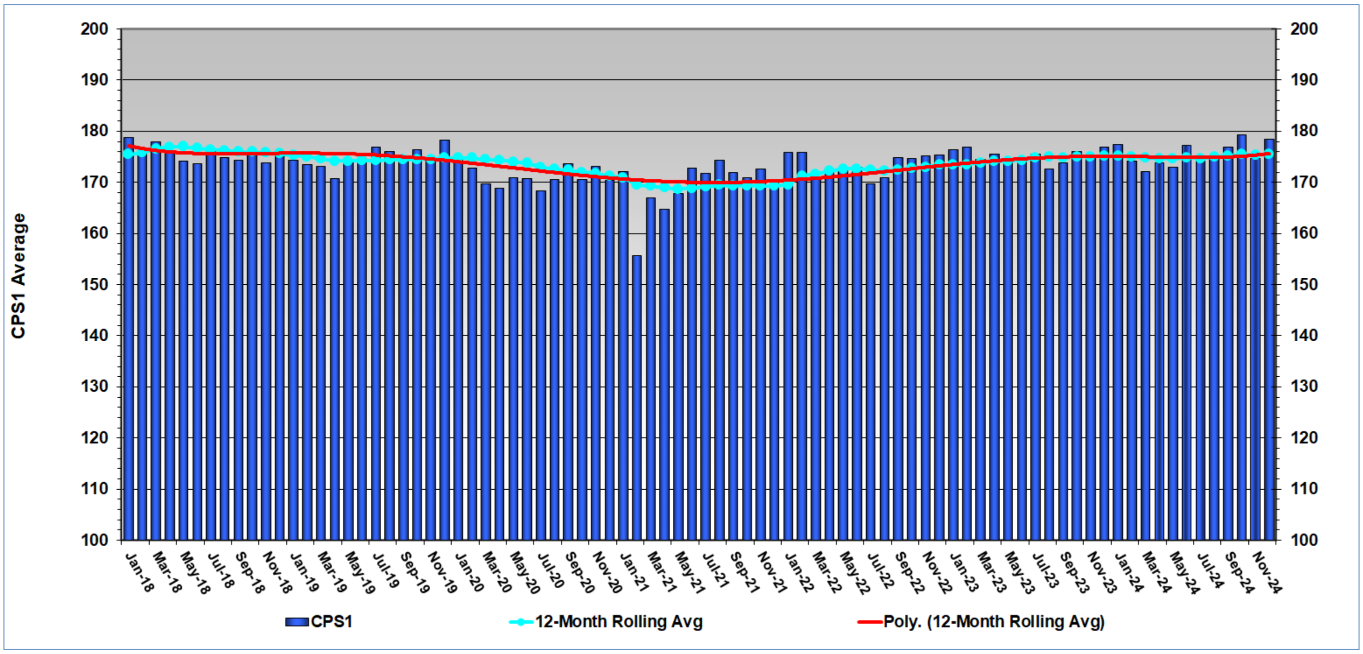


Figure H.1 – CPS1 Average January 2018 to December 2024

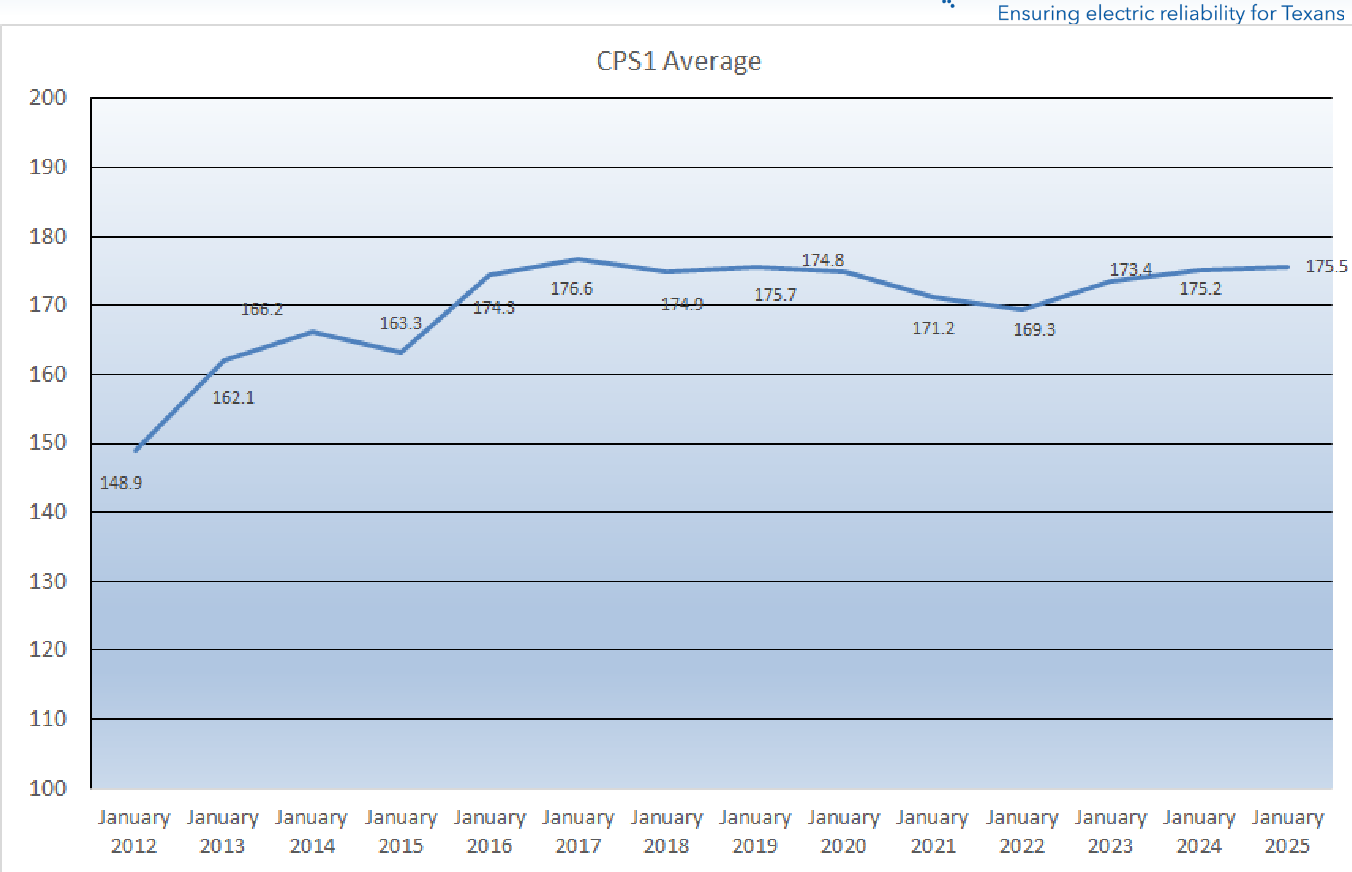


Figure H.2 – ERCOT CPS1 Annual Trend since January 2012

Figure H.3 shows bell curves of the ERCOT frequency profile, comparing 2018 through 2024. The shape of the bell curve in 2024 was identical to 2023.

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.

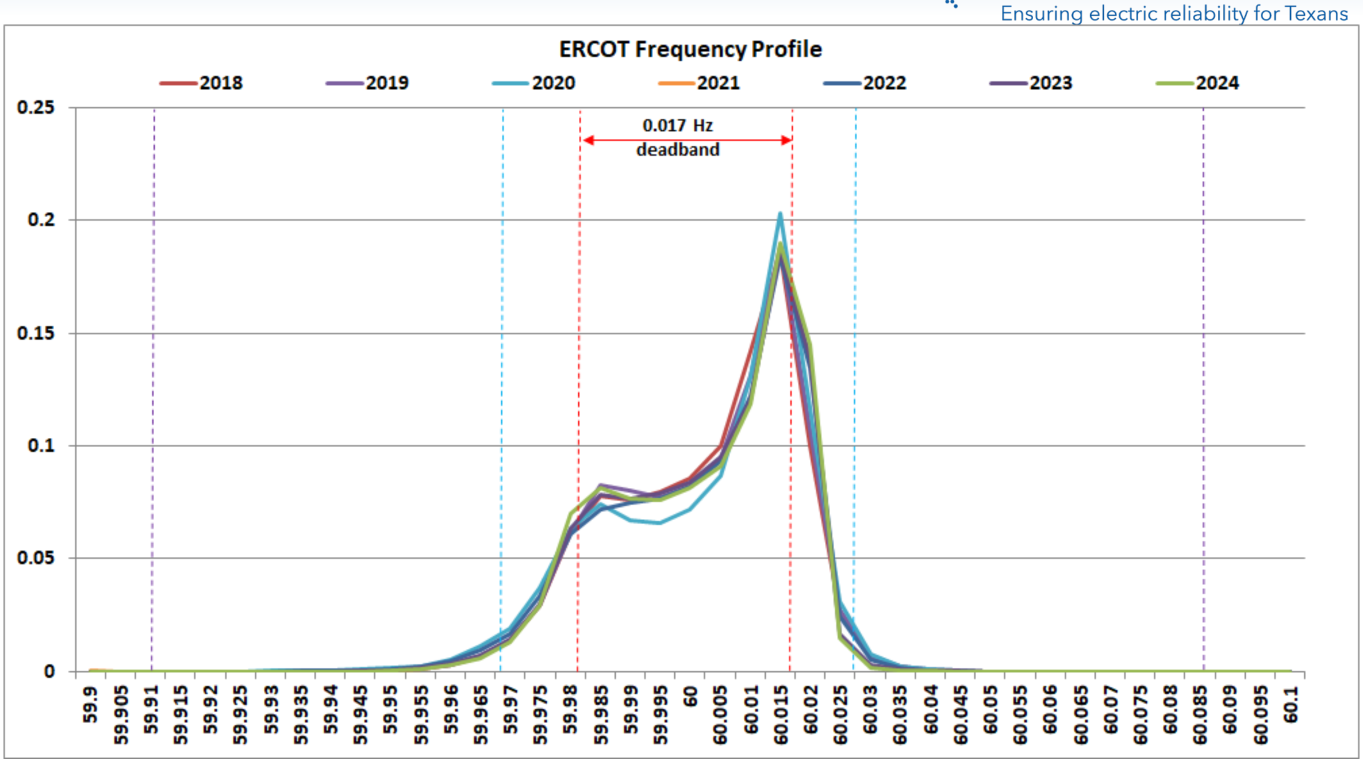


Figure H.3 – Frequency Profile Comparison

Figure H.4 shows the 2024 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.

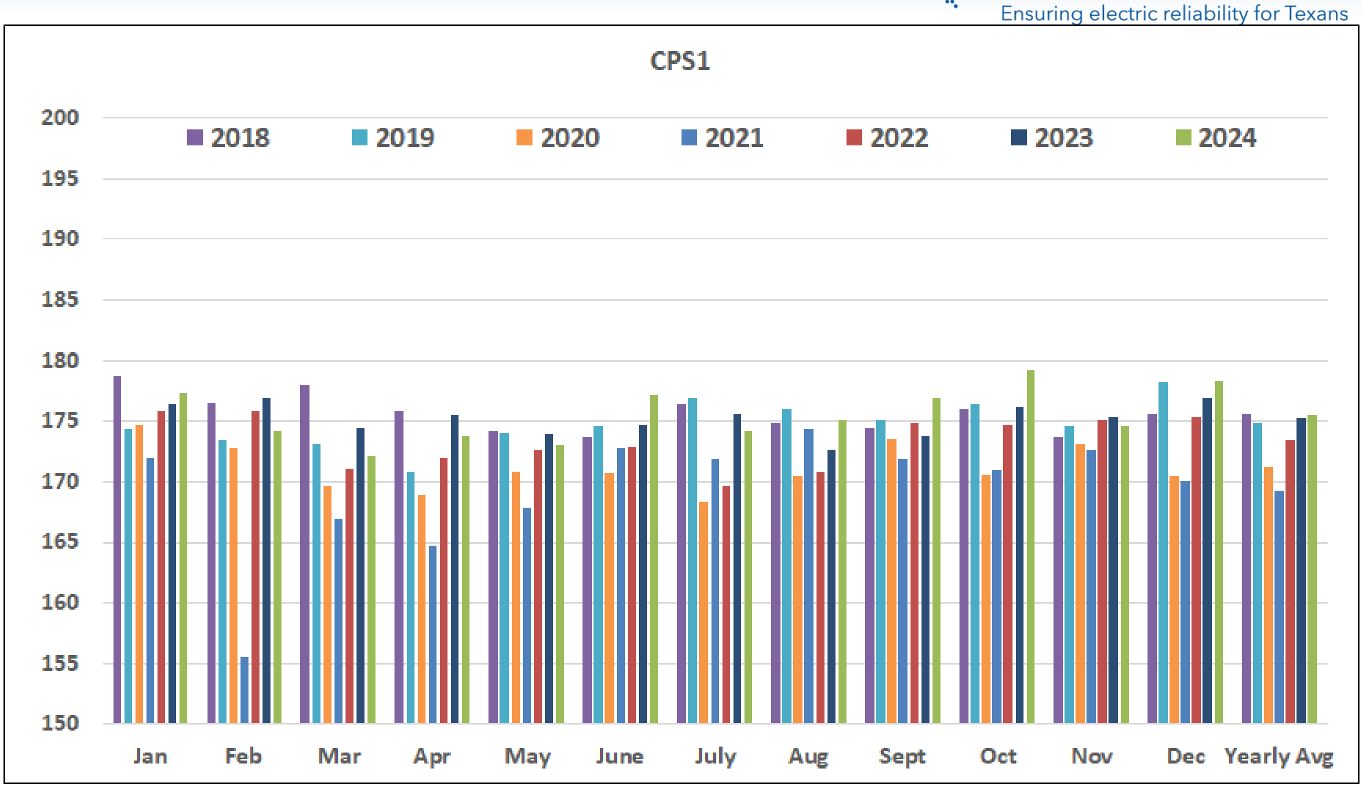


Figure H.4 – CPS1 Score by Month for 2018 through 2024

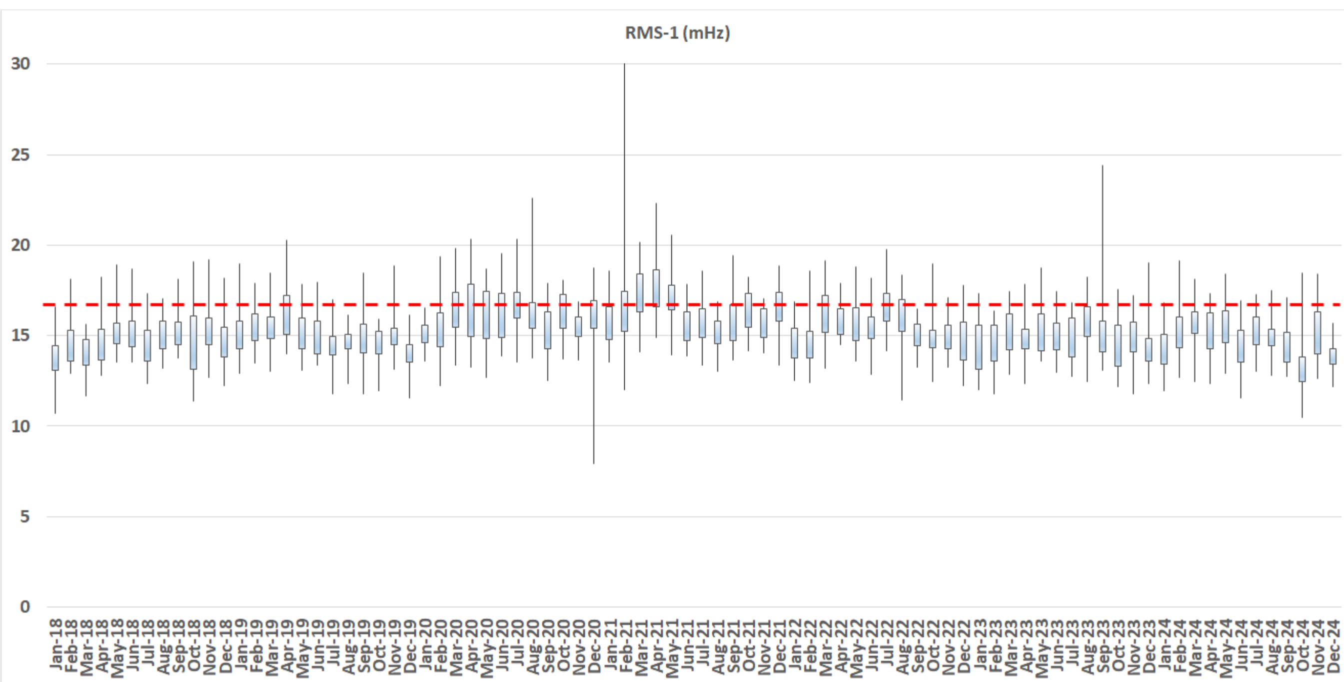


Figure H.5 – Daily RMS1 for 2018 through 2024

B. Time Error Correction Performance

In 2024, 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	2020 Total Minutes	2021 Total Minutes	2022 Total Minutes	2023 Total Minutes	2024 Total Minutes	Five-year Avg
Low (<59.91 Hz)	29	78	1	20	5	27
High (>60.09 Hz)	0	1	0	0	0	0

Table H.1 – BAAL Exceedance Performance