2021 ASSESSMENT OF RELIABILITY PERFORMANCE

Appendices

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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. A number of generators reporting ERCOT GADS and GADS-Wind data is shown in the following tables.

Units Reporting	2017	2018	2019	2020	2021
Total	415	407	402	407	458
Coal/Lignite	29	26	21	20	19
Gas	48	45	43	43	40
Nuclear	4	4	4	4	4
Gas Turbine/Jet Engine	85	87	90	92	109
Reciprocating Engine					42
Hydro	8	8	8	8	8
Fluidized Bed	6	5	5	5	5
Combined Cycle (Block)	18	18	18	18	18
Combined Cycle GT	151	149	149	149	149
Combined Cycle ST	62	61	61	61	61
Other	3	3	3	7	3
Total Thermal MW Reporting	81,757	78,898	77,388	77,395	78,549
Total Thermal GWH Reporting	308,676	320,376	315,746	300,223	298,139
Wind (>200 MW)		47	55	61	64
Wind (100<MW<200)		35	72	77	76
Wind (< 100 MW)		58	82	110	118
Number of Wind Turbines		9,466	13,735	15,349	15,282
Total Wind MW Reporting		17,955	26,451	29,796	31,651

Table A.1 – 2017-2021 GADS and GADS-Wind Units Reporting

B. Analysis of Planned versus Actual Seasonal Operating Reserves

For the summer of 2021, peak demand was 73,476 MW, approximately 3,600 MW below the typical scenario estimate of 77,100 MW from ERCOT's summer Seasonal Assessment of Resource Adequacy (SARA). Actual reserve margin was approximately 6.1 percent. Sufficient operating reserves were maintained during the summer peak hours.

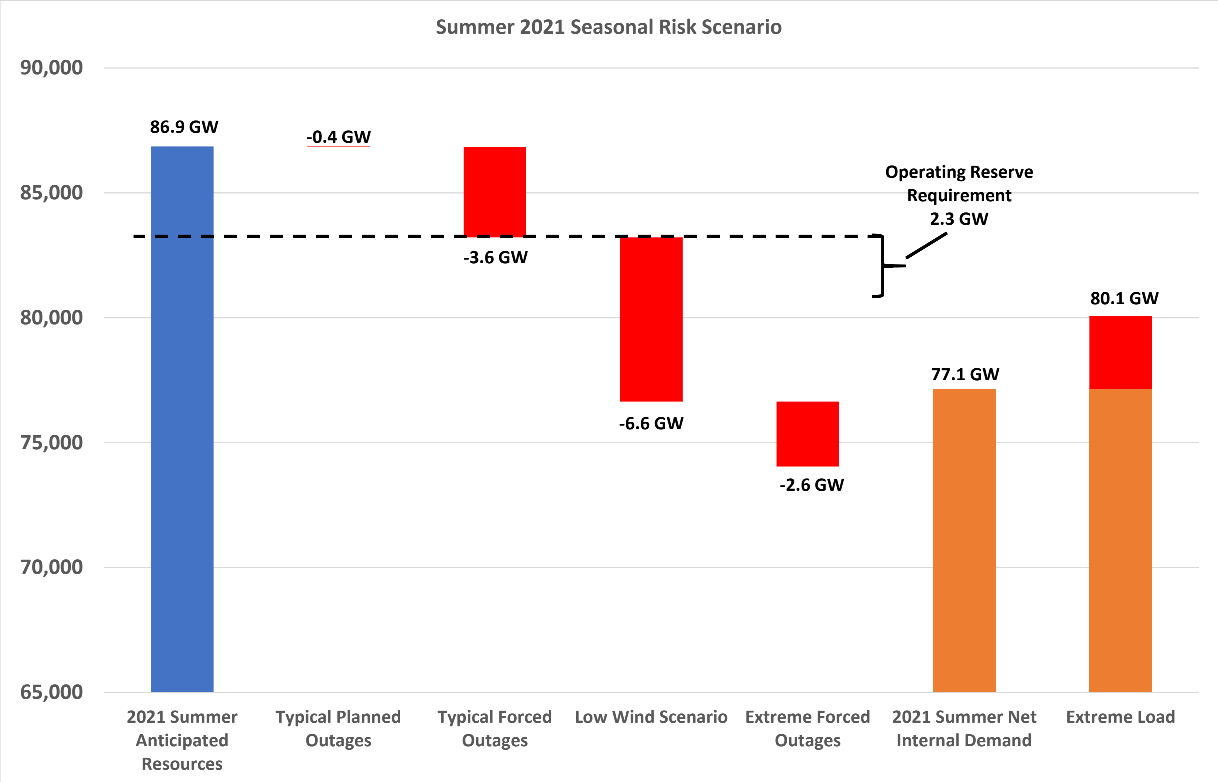


Figure A.1 – Summer 2021 Risk Scenarios

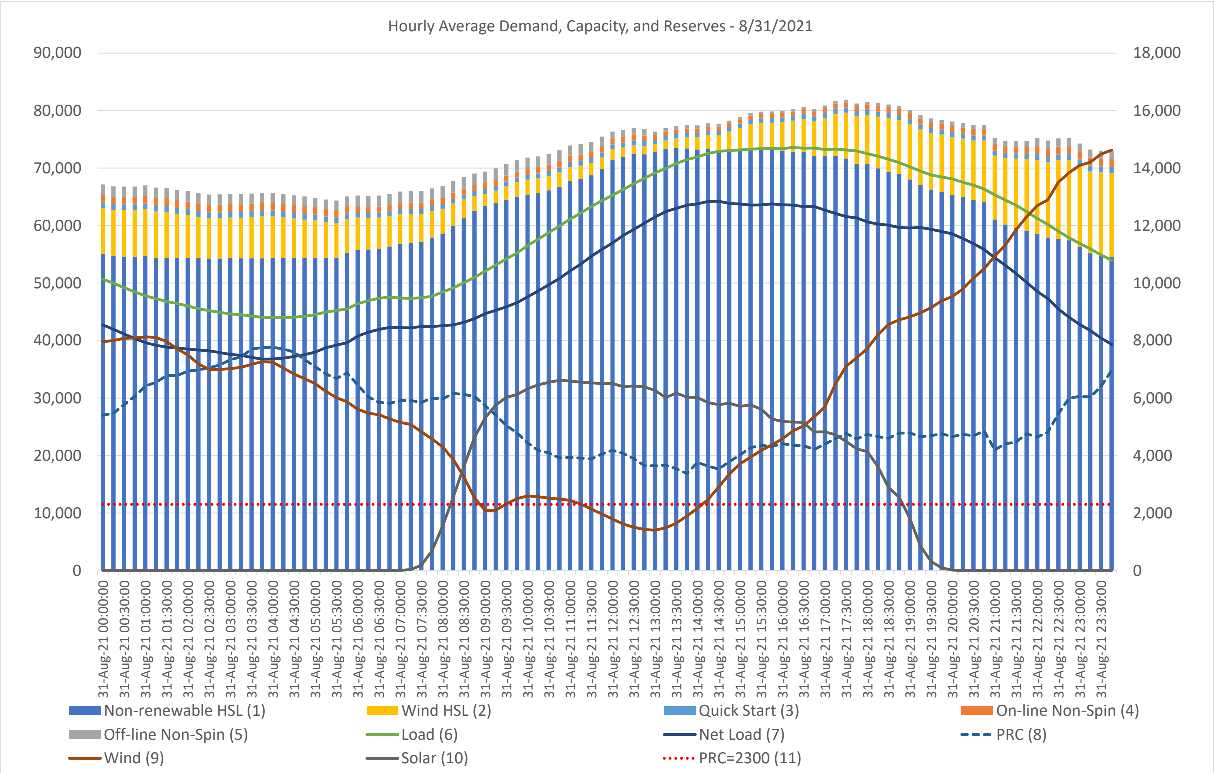


Figure A.2 – August 31, 2021, Capacity, Demand, and Reserves

The final ERCOT SARA for summer 2021 estimated typical thermal maintenance outages of 25 MW and typical forced outages of 3,617 MW with an extreme case of 6,218 MW. Combined actual planned and forced outages for the summer 2021 ranged from a low of 5,897 MW to a maximum of 12,823 MW.

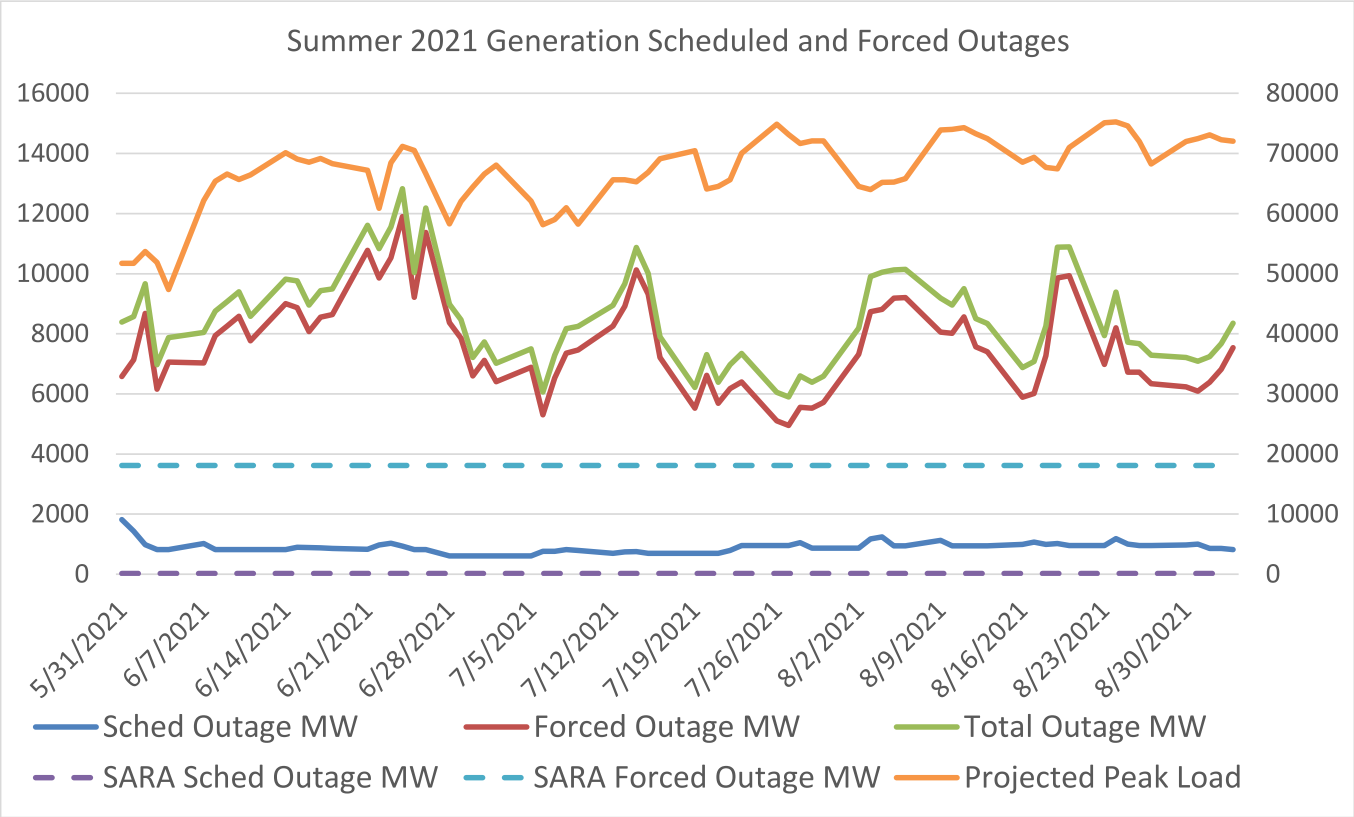


Figure A.3 – Summer 2021 Generation Scheduled and Forced Outages

For the winter of 2021, peak demand was 69,216 MW, approximately 1,400 MW above the extreme scenario estimate of 67,800 MW from the winter SARA. Adequate reserve margins were not maintained during Winter Storm Uri due to the loss of multiple resources and load shed.

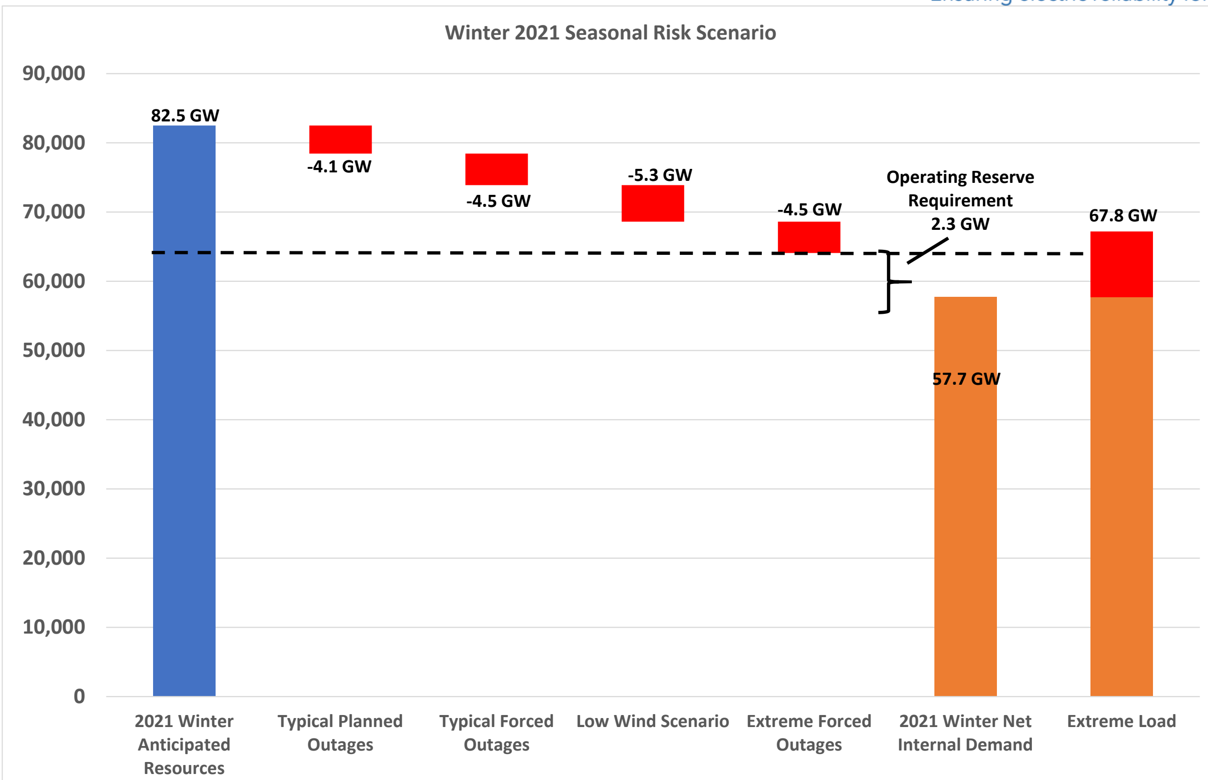


Figure A.4 – Winter 2021 Risk Scenarios

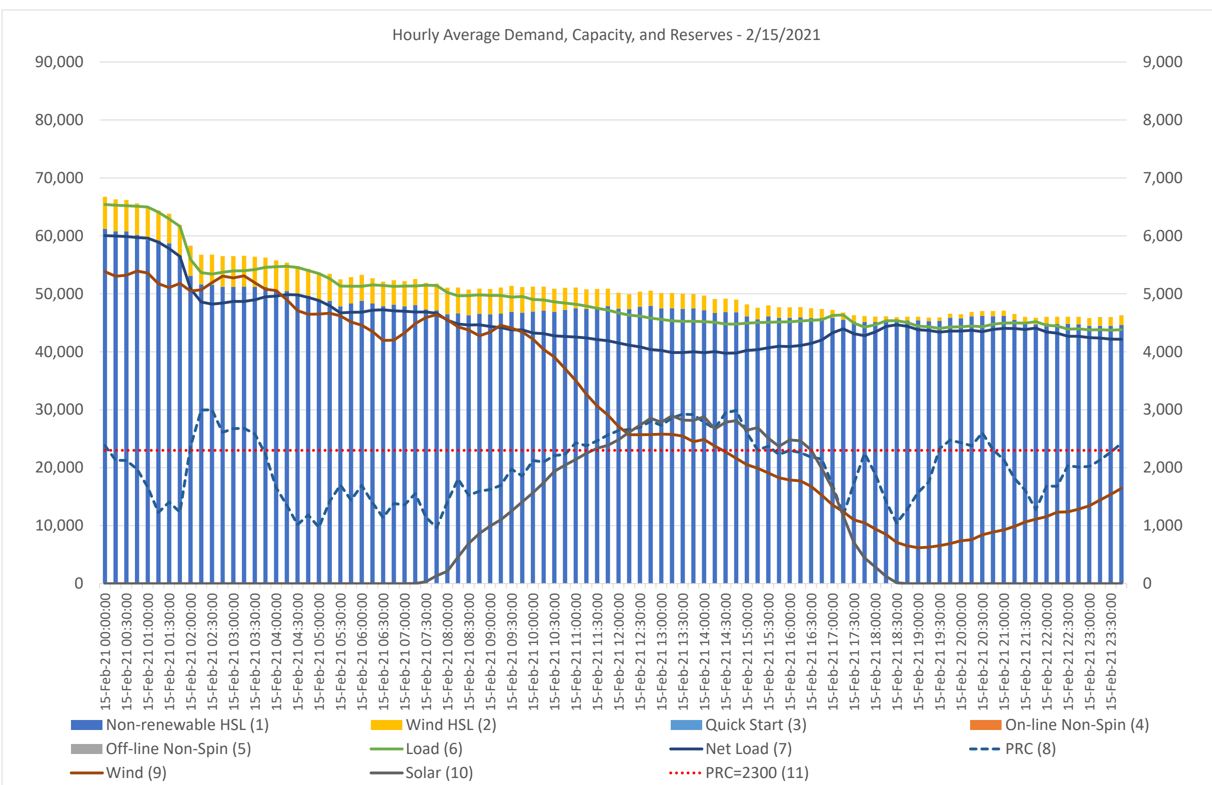


Figure A.5 – February 15, 2021, Capacity, Demand, and Reserves

The final ERCOT SARA for winter 2021 estimated typical thermal maintenance outages of 4,074 MW and typical forced outages of 4,542 MW with an extreme case of 9,082 MW. Combined actual planned and forced outages for the winter ranged from a low of 4,867 MW to a maximum of 38,424 MW.

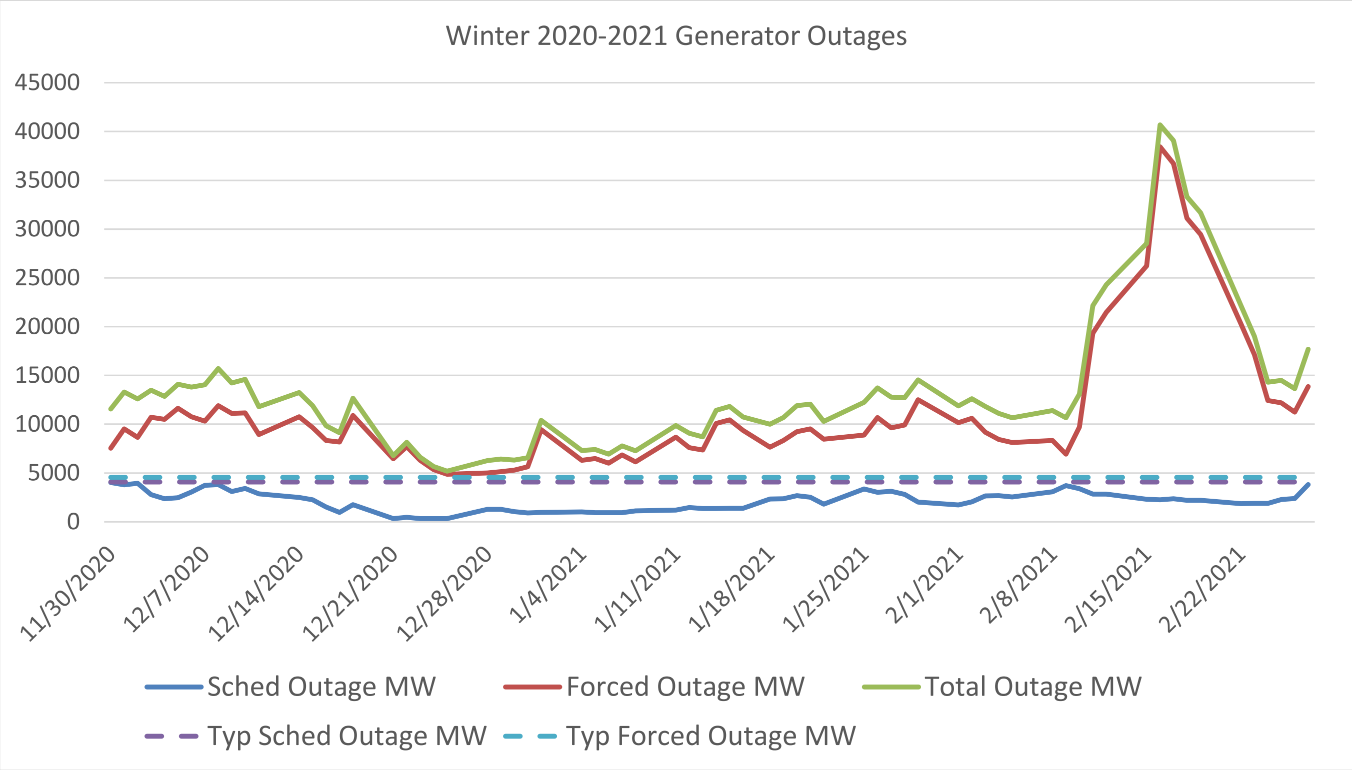


Figure A.6 – Winter 2021 Generation Scheduled and Forced Outages

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. The following figure shows a typical frequency disturbance broken down into several periods.

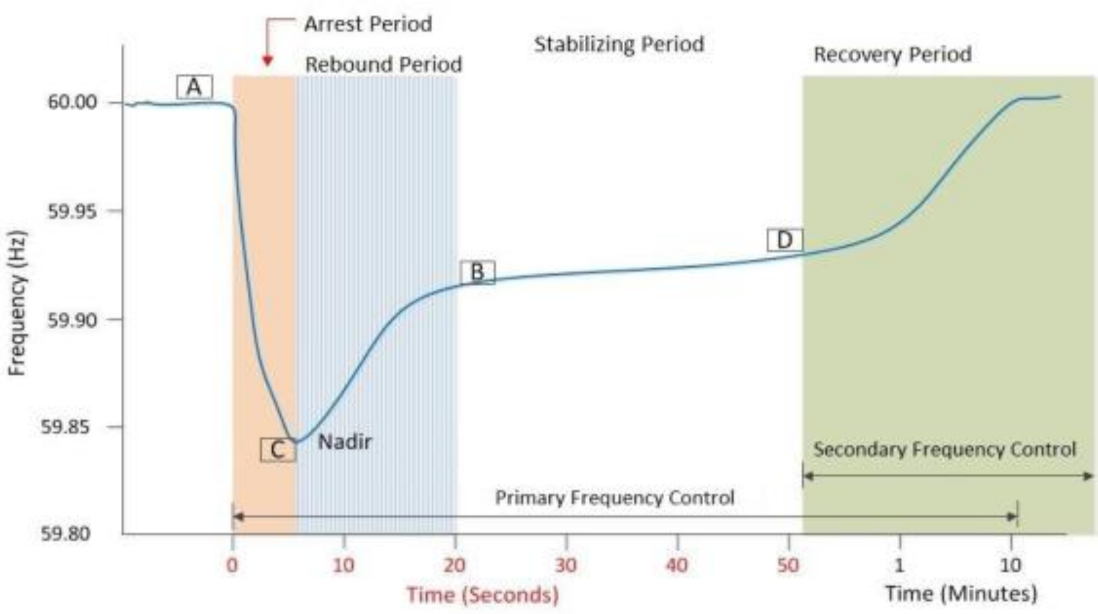


Figure A.7 – Typical Frequency Disturbance

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 (381 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). In response to a sudden loss of generation, kinetic energy will automatically be extracted from the rotating synchronized machines on the Interconnection, 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 inverter-based generation resources, there is a need to monitor and trend inertia and initial rate of change of frequency.

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. The figure below shows the nadir plotted against the generation MW loss value normalized for inertia and shows the inverse relationship for how historic performance for how the nadir was affected by different MW loss and inertia conditions.

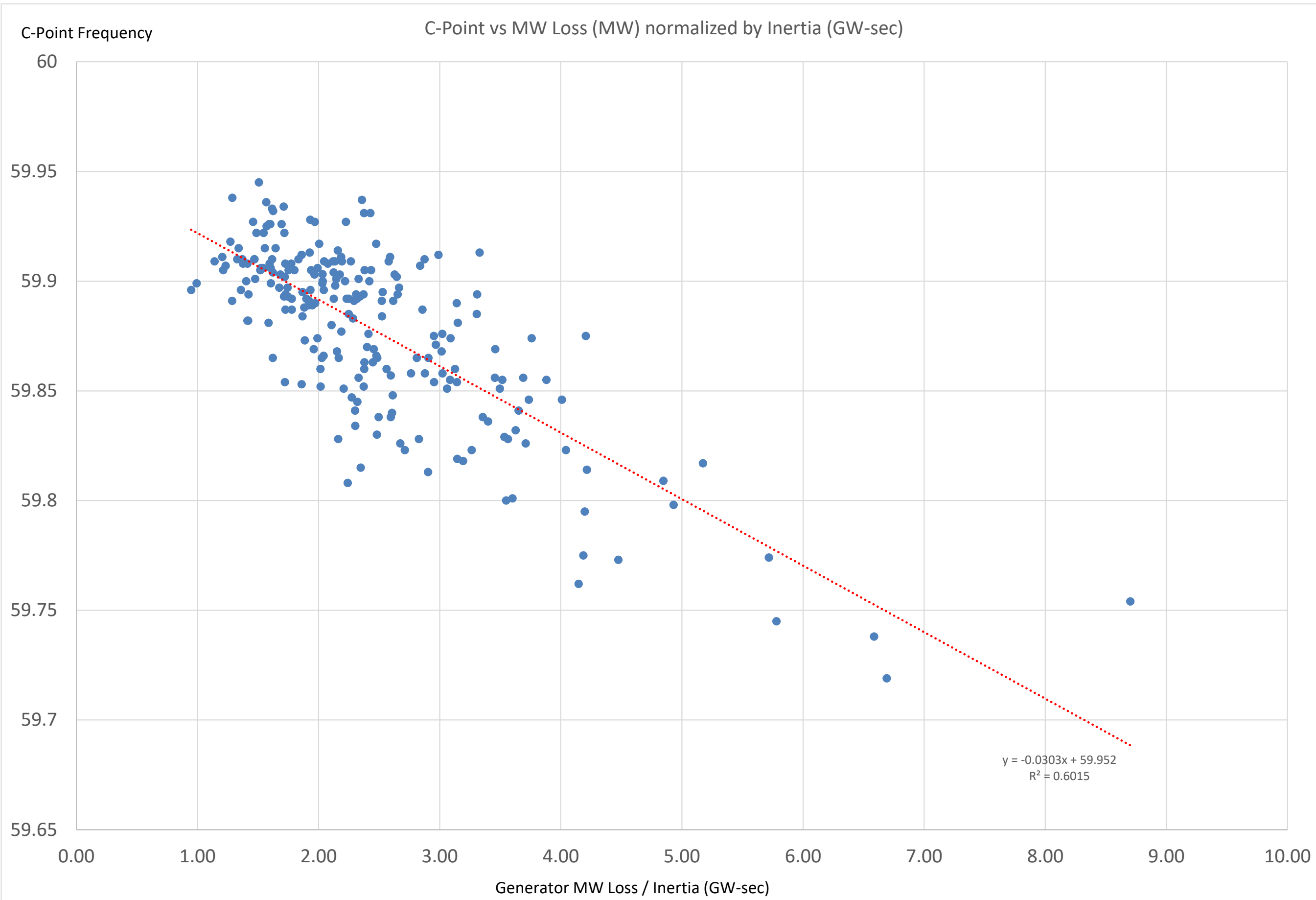


Figure A.8 – Frequency Disturbance Nadir versus Gen Loss MW/Inertia, 2017-2021

The RoCoF during the initial frequency decline in the first 0.5 sec is largely 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. The figure below shows this relationship, with a straight line approximation.

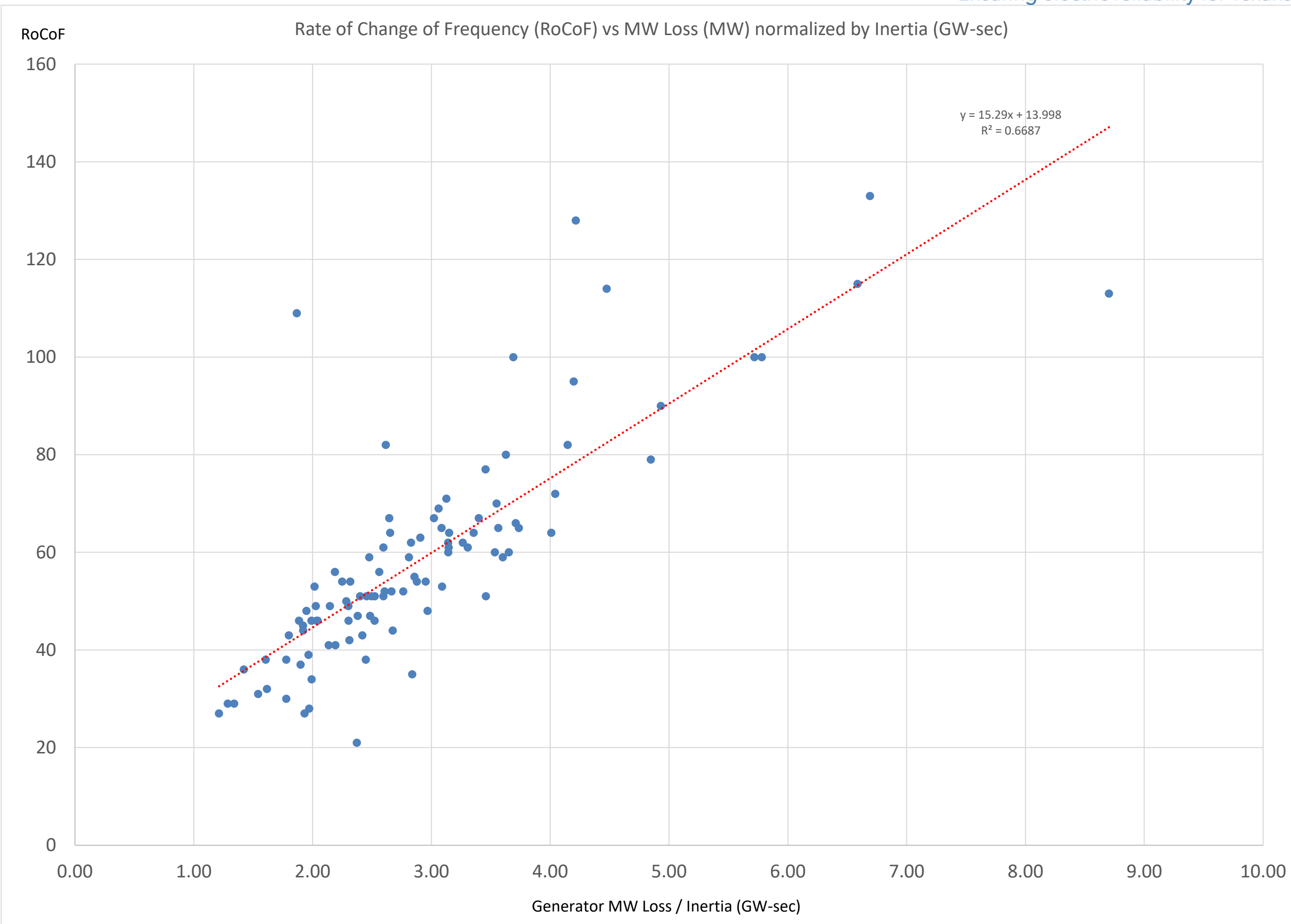


Figure A.9 – Rate of Change of Frequency versus Normalized Generation Loss, 2017-2021

The following figure shows the trend in primary frequency response for the ERCOT region. In 2021, the average frequency response was 1,074 MW per 0.1 Hz and the median frequency response was 1,081 MW per 0.1 Hz as calculated per BAL-001-TRE for the events that were evaluated during the period.

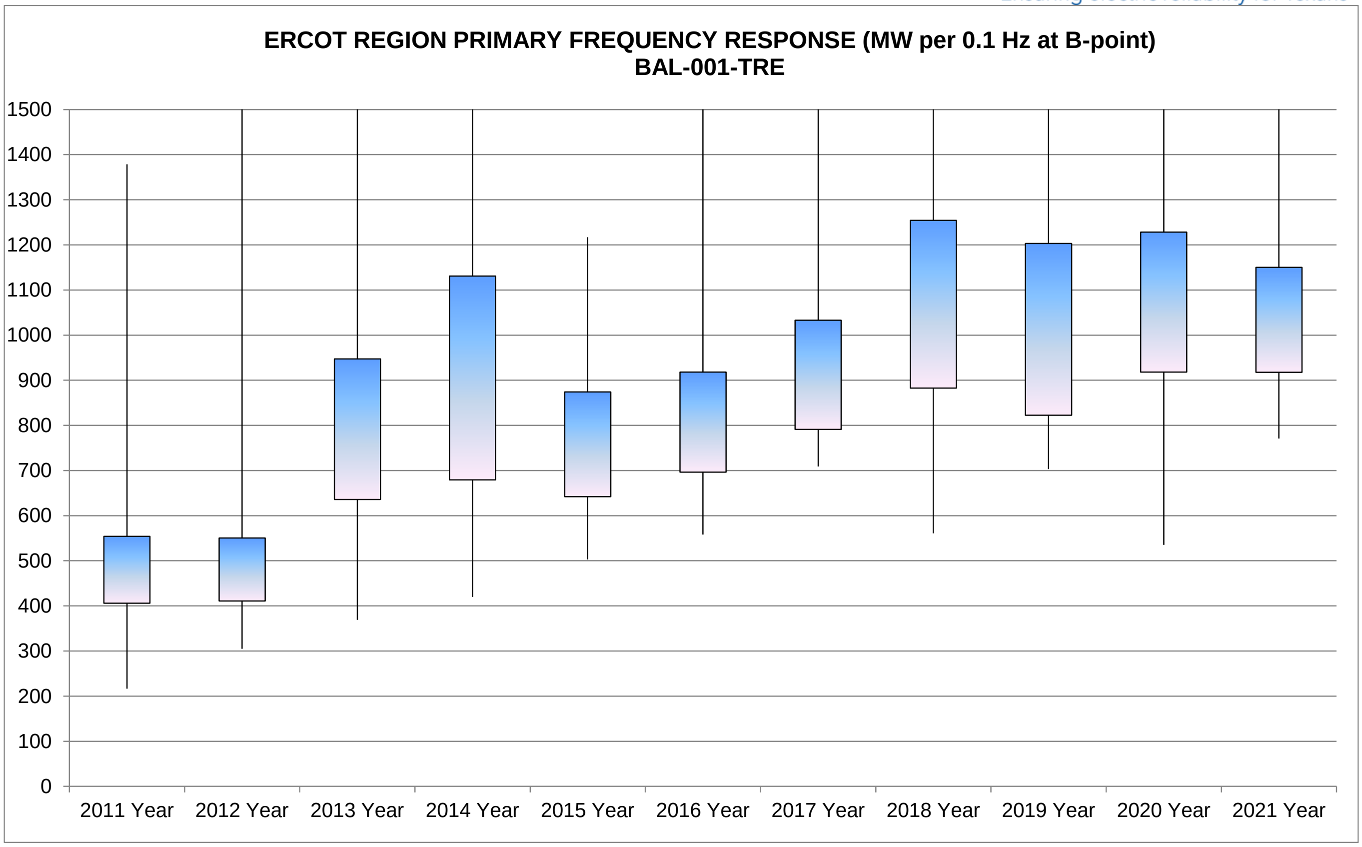


Figure A.10 – Annual Primary (B-Point) Frequency Response Trend for ERCOT Region

The following figure shows the trend in frequency response in the inertial response zone between the A and C points for the ERCOT region. In 2021, the average frequency response was 530 MW per 0.1 Hz and the median frequency response was 521 MW per 0.1 Hz as calculated per BAL-001-TRE for the events that were evaluated during the period.

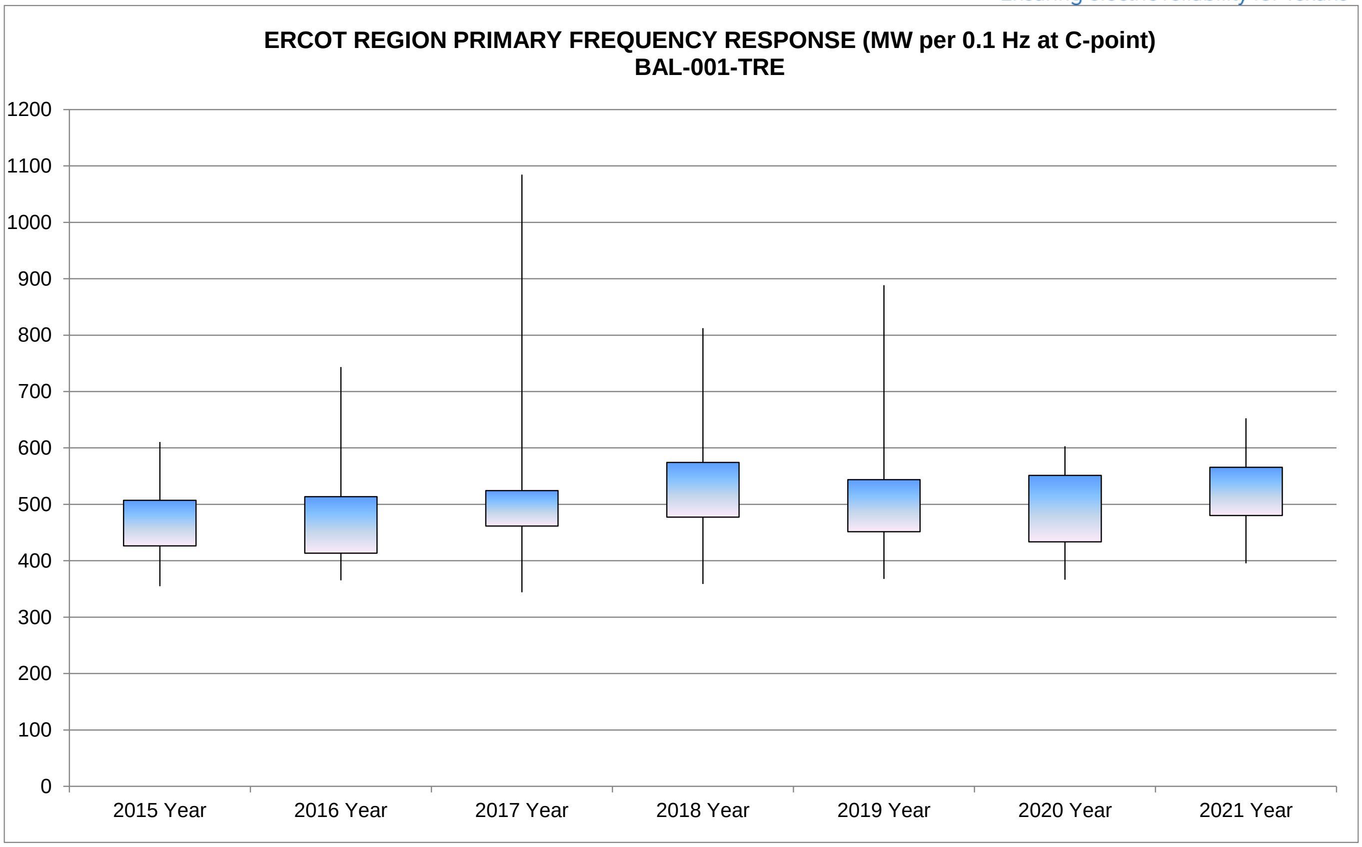


Figure A.11 – Annual Inertial (C-Point) Frequency Response Trend for ERCOT Region

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 5.3 minutes in 2021.The average event recovery time (see Figure A.9) shows a drop in average recovery time in 2021 compared to previous years.

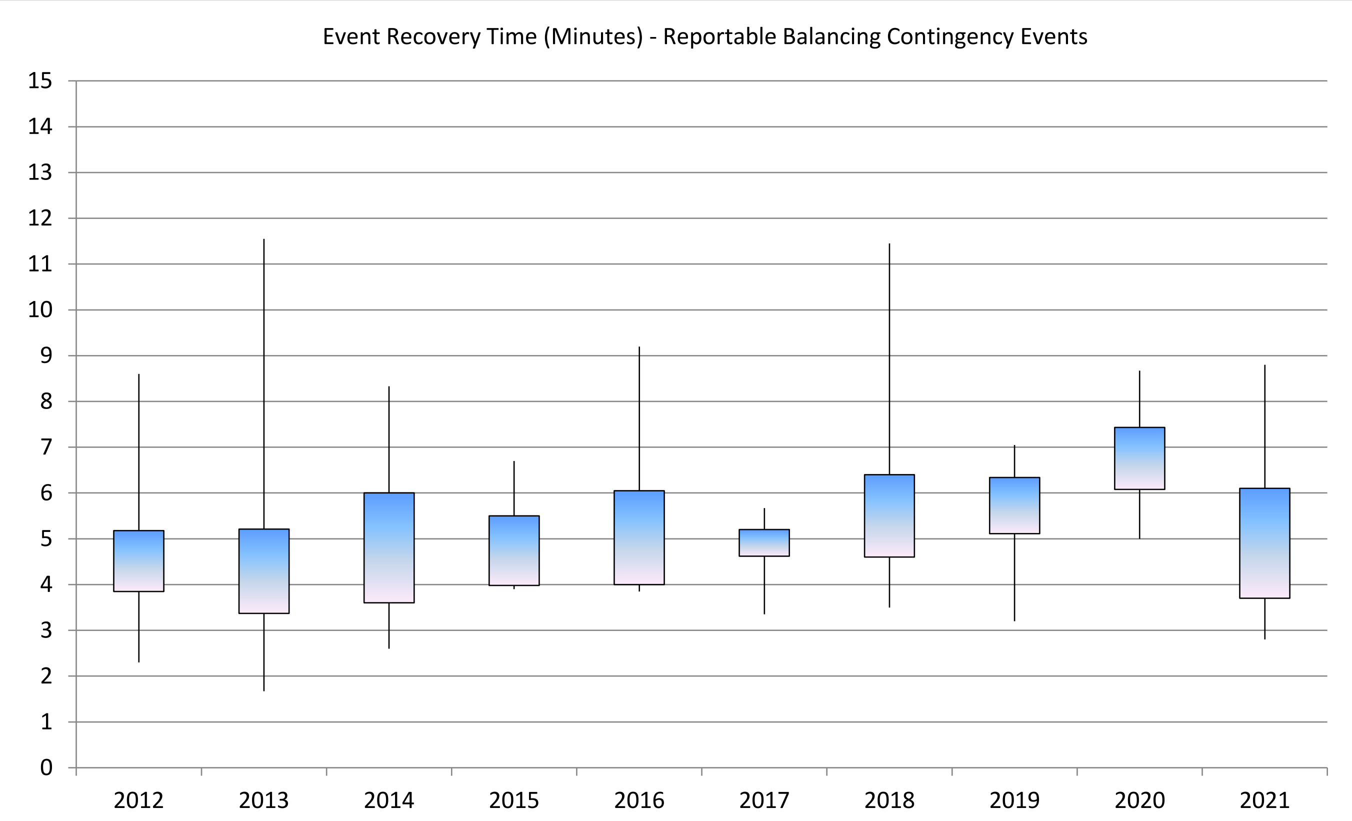


Figure A.12 – Event Recovery Time 2012-2021

E. 2021 Fossil-fueled Generator Performance Metrics

ERCOT fossil generation reporting in GADS produced a gross total of 307,337 GWH in 2021 (78% 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 is provided in the following table.

ERCOT Region GADS Data Metric	2017	2018	2019	2020	2021	5-Yr Avg
	Unweighted	Unweighted	Unweighted	Unweighted	Unweighted	Unweighted
# Units Reporting	415	407	402	407	458	418
Total Unit-Months	4860	4768	4803	4880	5478	4958
Net Capacity Factor (NCF)	43.3%	46.7%	46.8%	44.5%	44.4%	45.1%
Service Factor (SF)	46.1%	50.9%	51.7%	48.8%	45.7%	48.6%
Equivalent Availability Factor (EAF)	85.3%	85.2%	86.1%	84.1%	83.8%	84.5%
Scheduled Outage Factor (SOF)	8.3%	8.7%	9.3%	9.5%	9.4%	9.1%
Forced Outage Factor (FOF)	4.1%	3.9%	4.2%	3.9%	4.3%	4.1%
EFOR	9.6%	7.9%	8.3%	8.4%	10.1%	8.9%

Equivalent Forced Outage Rate Demand (EFORd)	6.6%	5.7%	6.1%	5.9%	6.7%	6.5%

Table A.3 – ERCOT Generation Performance Metrics 2017 through 2021

- 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 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	40	109	18	149	61
Total Unit-Months	228	480	1290	216	1788	732
Net Capacity Factor (NCF)	62.5%	12.0%	12.7%	44.2%	51.2%	41.3%
Service Factor (SF)	80.9%	28.6%	15.6%	50.5%	62.7%	63.1%
Equivalent Availability Factor (EAF)	76.8%	72.4%	88.8%	76.8%	82.3%	82.0%
Scheduled Outage Factor (SOF)	9.0%	16.8%	6.6%	9.8%	11.2%	11.2%
Forced Outage Factor (FOF)	8.9%	7.3%	3.8%	4.6%	4.0%	3.7%
EFOR	15.0%	26.7%	21.1%	10.2%	6.2%	7.7%
EFORd	9.9%	17.7%	9.6%	6.6%	5.1%	5.2%

Table A.4 – ERCOT Generation Performance Metrics by Fuel Type for 2021

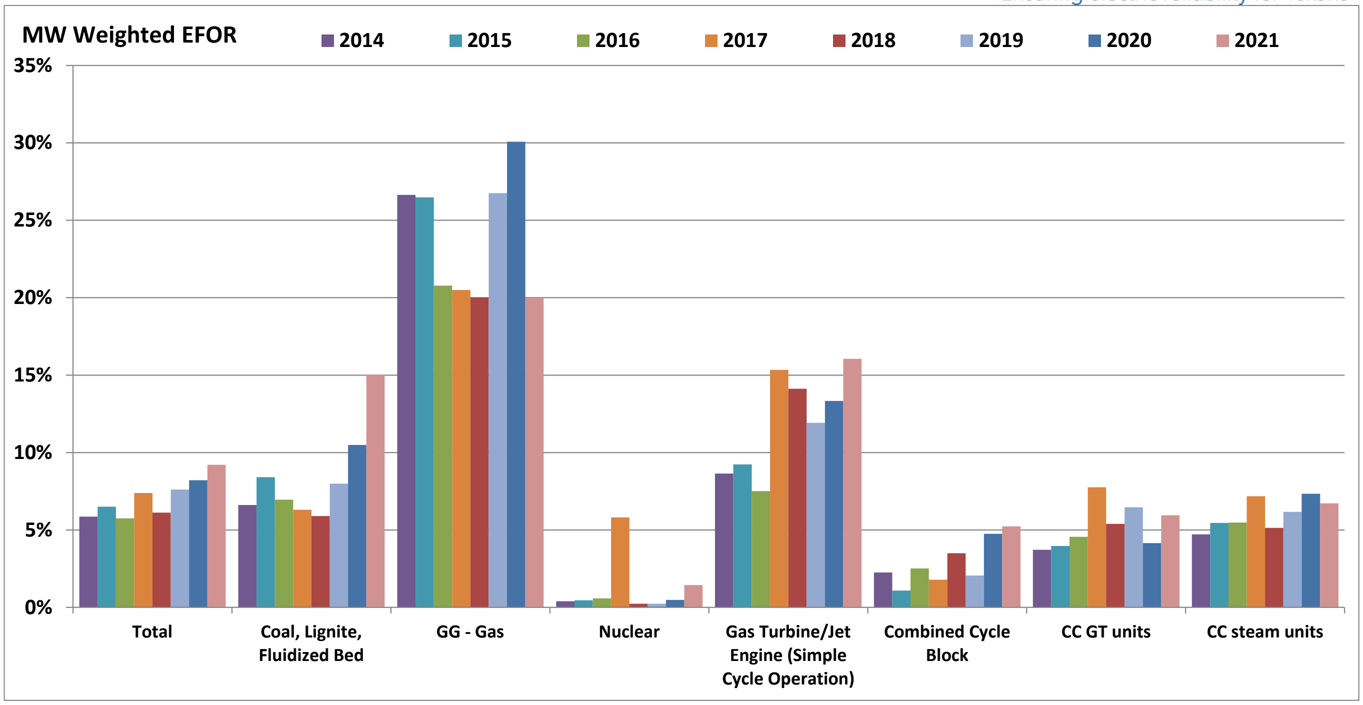


Figure A.13 – MW-Weighted EFOR Metric by Fuel Type and Year

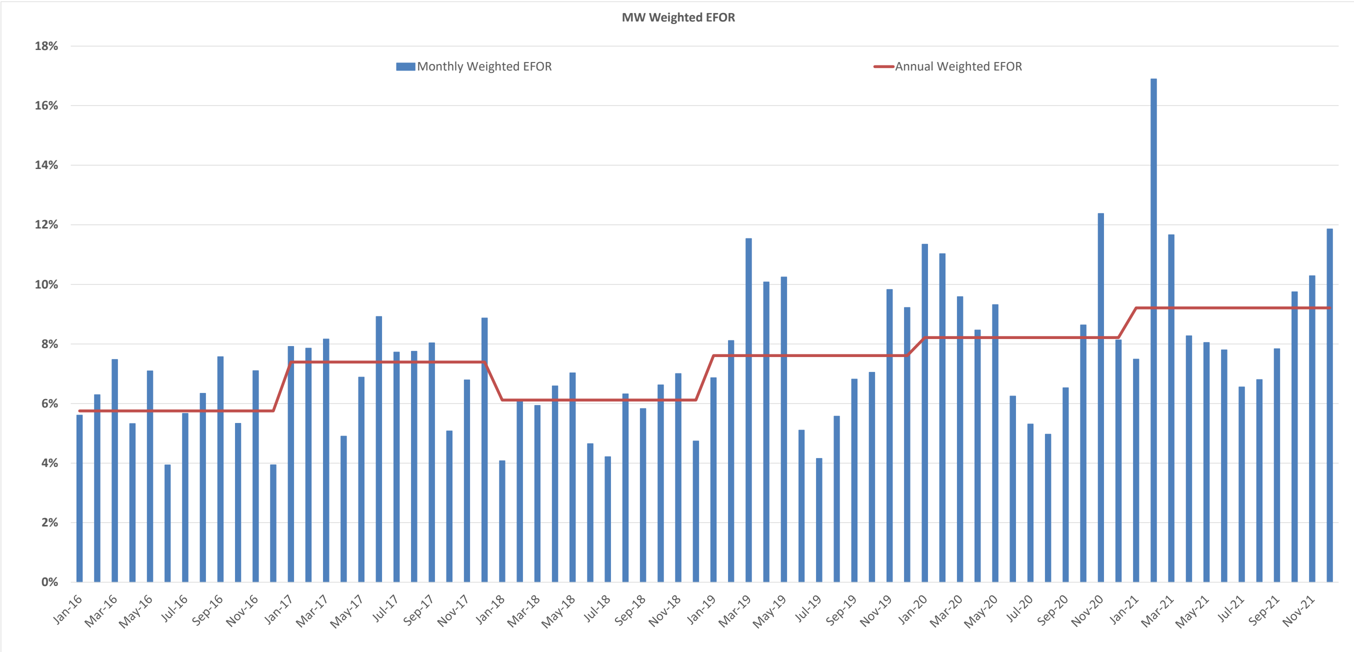


Figure A.14 – Time Trend for MW-Weighted EFOR

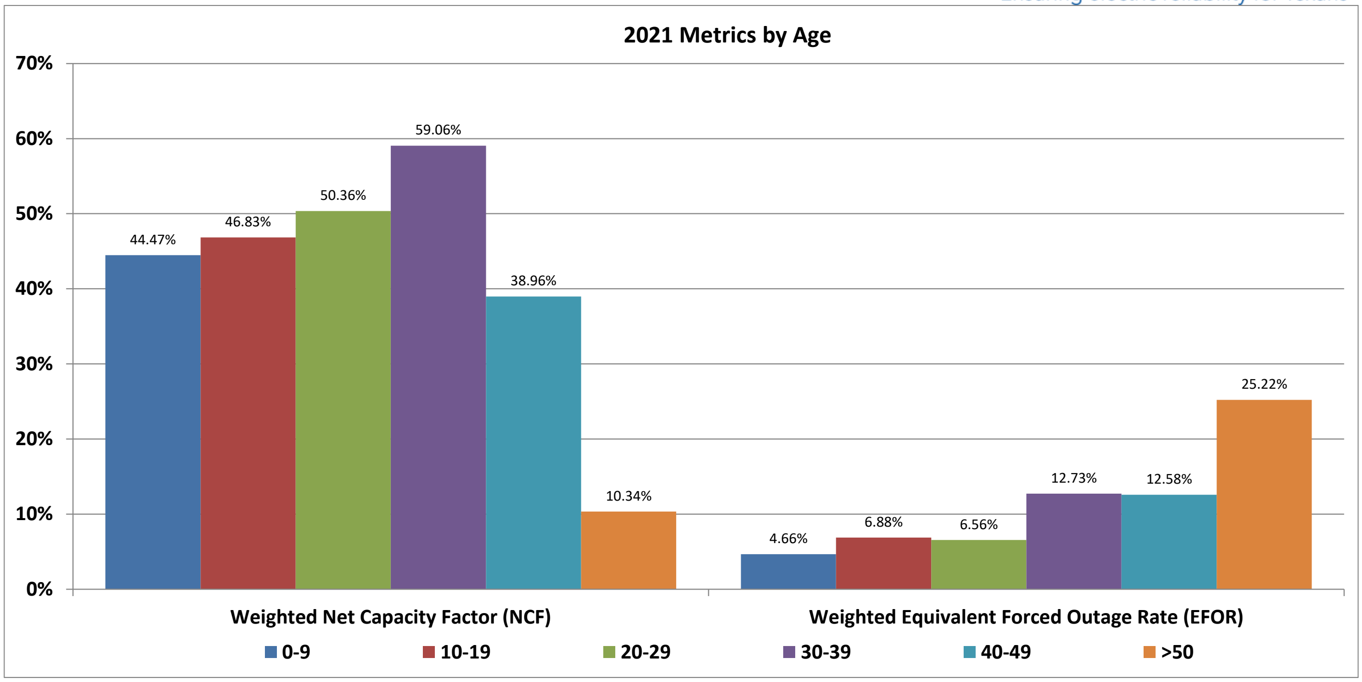


Figure A.15 – 2021 GADS Metrics by Age

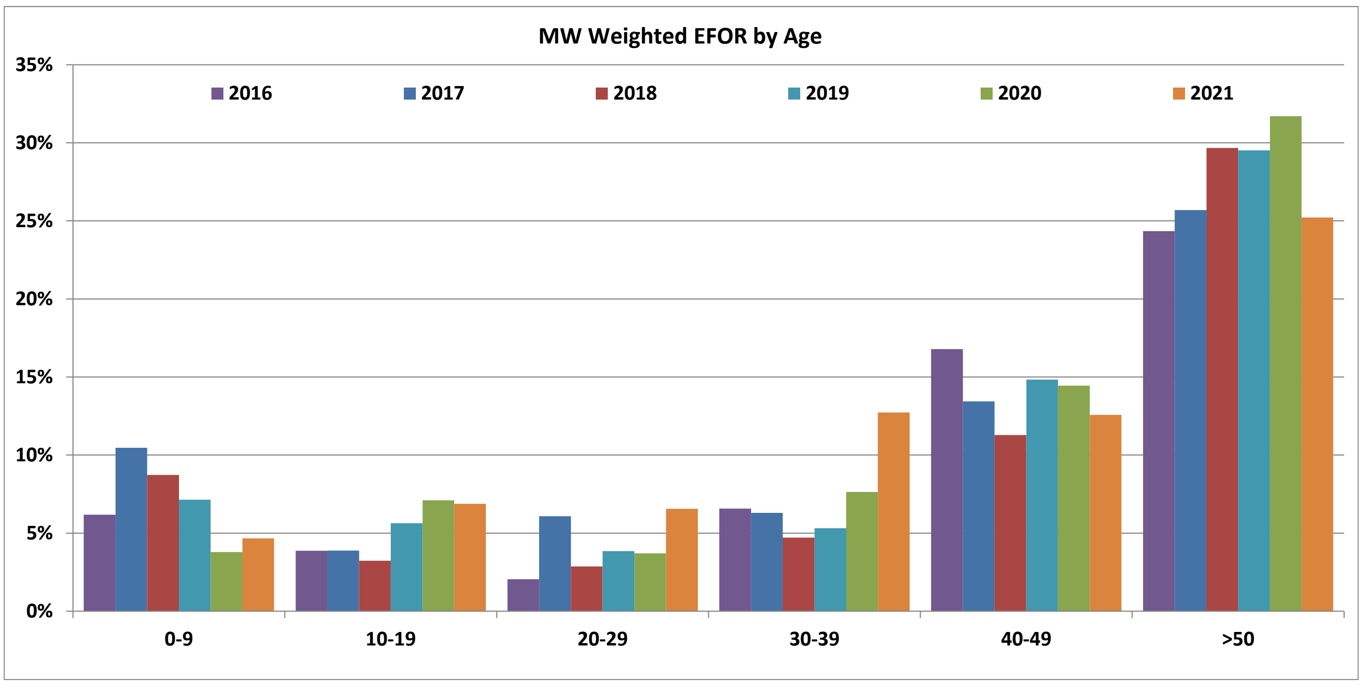


Figure A.16 – 2016-2021 GADS EFOR by Age

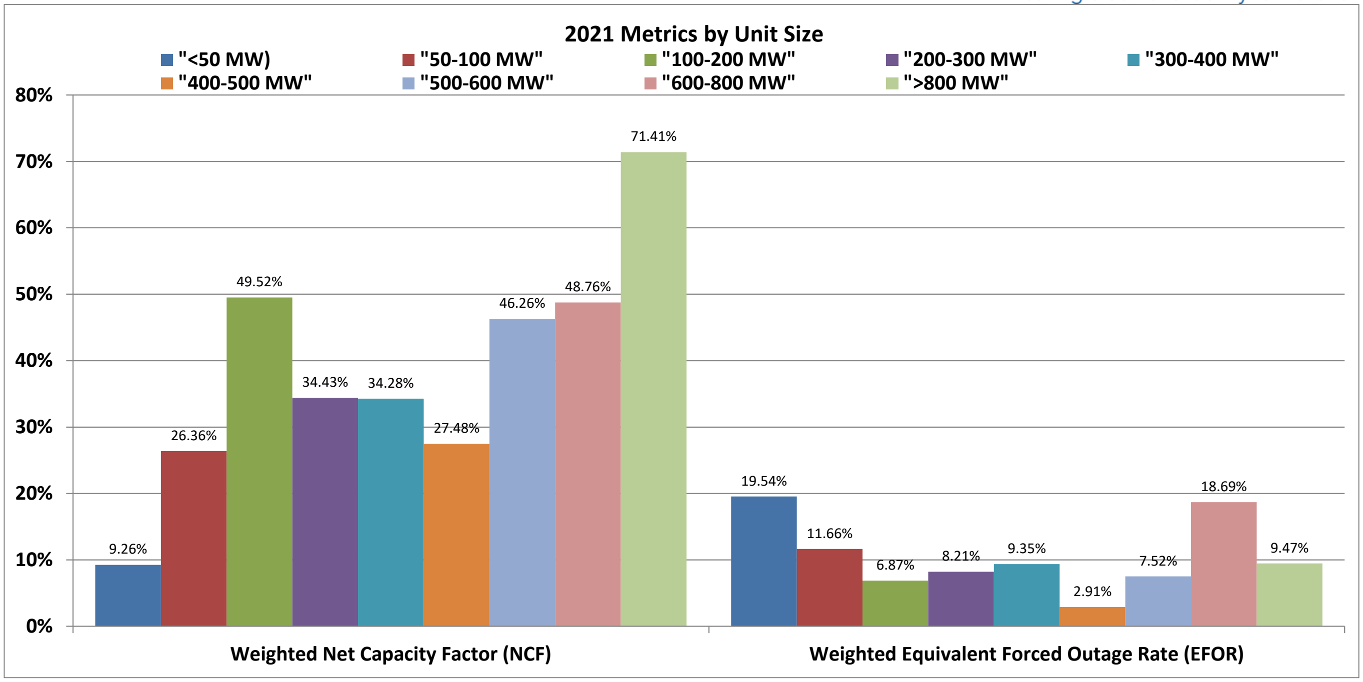


Figure A.17 – 2021 GADS Metrics by Unit Size

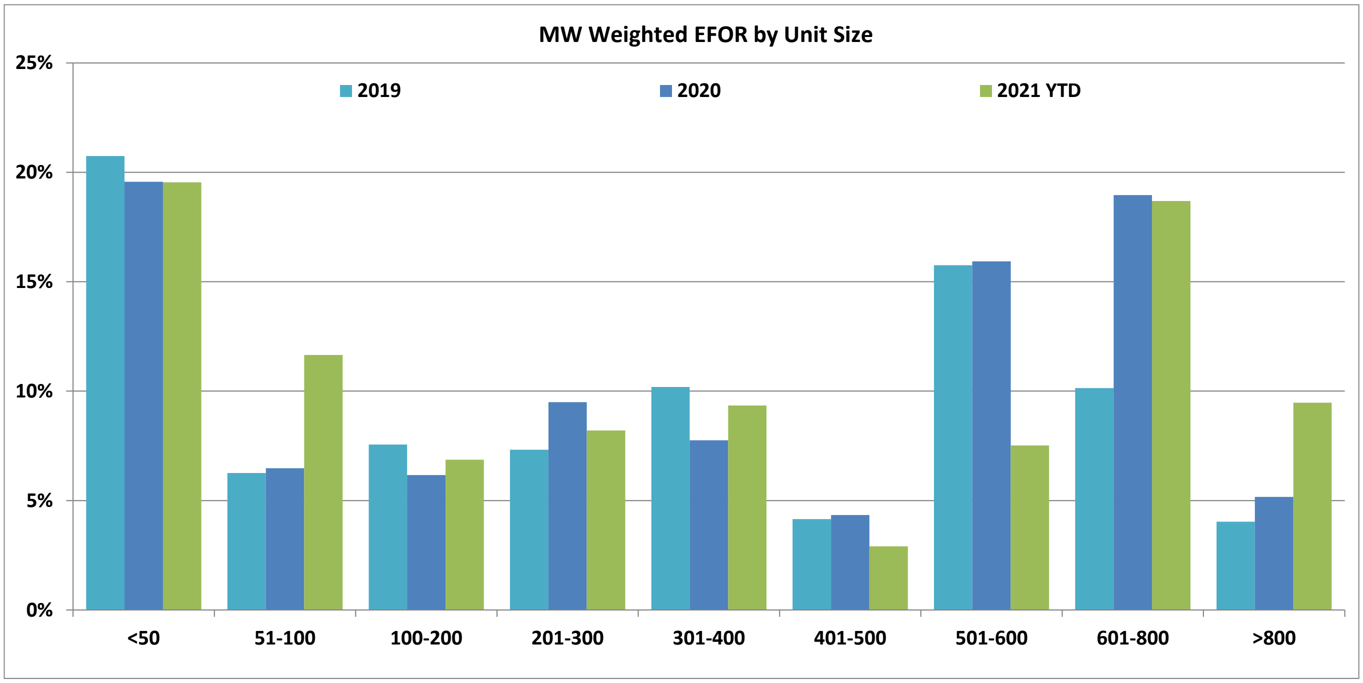


Figure A.18 – 2019-2021 GADS EFOR by Unit Size

2021 Fossil-fueled Generator Outages and De-rates

Table 5 provides a summary of immediate de-rates and forced outages for conventional generation from January 2021 through December 2021. The 2,630 immediate forced outage events are about 35 percent higher than 2020, with a median capacity of 170 MW per event nearly identical to last year's, as were the top three systems affected.

2021	Immediate De-Rates	Immediate Forced Outages
Number of Events	3,074	2,630
Total Duration (hrs)	242,922.6	153,360.5
Total Capacity (MW)	334,163.8	487,129.6
Avg Duration per Event (hrs)	79.0	58.3
Median Duration per Event (hrs)	4.2	4.8
Avg Capacity per Event (MW)	108.7	185.2
Median Capacity per Event (MW)	81.0	170.0

Table A.5 – Generator Immediate De-rate and Forced Outage Data (Jan. – Dec. 2021)

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	311	19,128.2	93,565.0	61.5	300.9
Balance of Plant	420	28,295.7	86,615.9	67.4	206.2
Steam Turbine/Generator	1265	64,298.7	197,796.7	50.8	156.4
Heat Recovery Steam Generator	92	4,296.0	17,357.5	46.7	188.7
Pollution Control Equipment	32	1,445.5	4,943.9	45.2	154.5
External	298	23,270.8	42,933.8	78.1	144.1
Regulatory, Safety, Environmental	17	206.1	2,594.0	12.1	152.6
Personnel/ Procedure Errors	81	509.3	11,554.7	6.3	142.7
Other	114	11,910	29,768	104.5	261.1

Table A.6 – 2021 Major Category Cause of Immediate Forced Outage Events from GADS

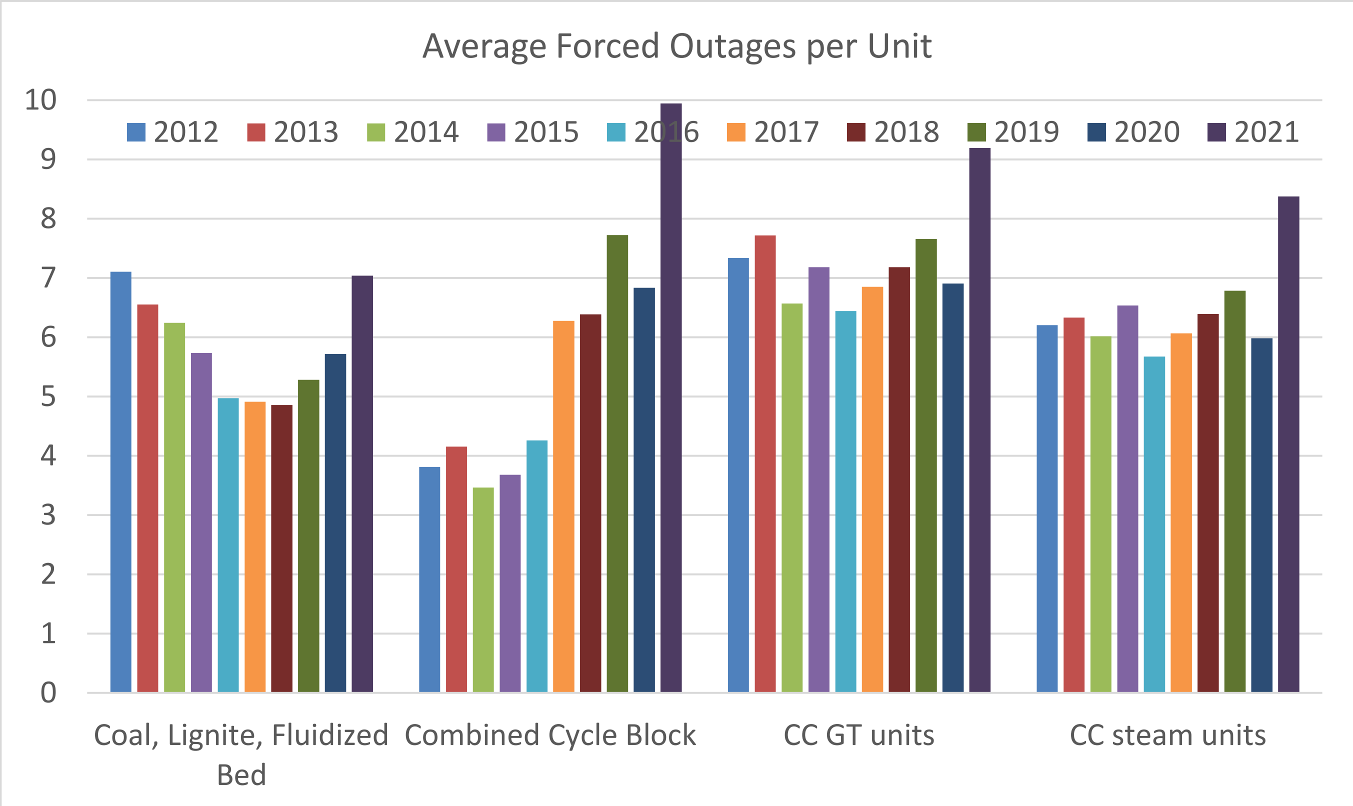


Figure A.19 – 2021 Average Forced Outages per Unit

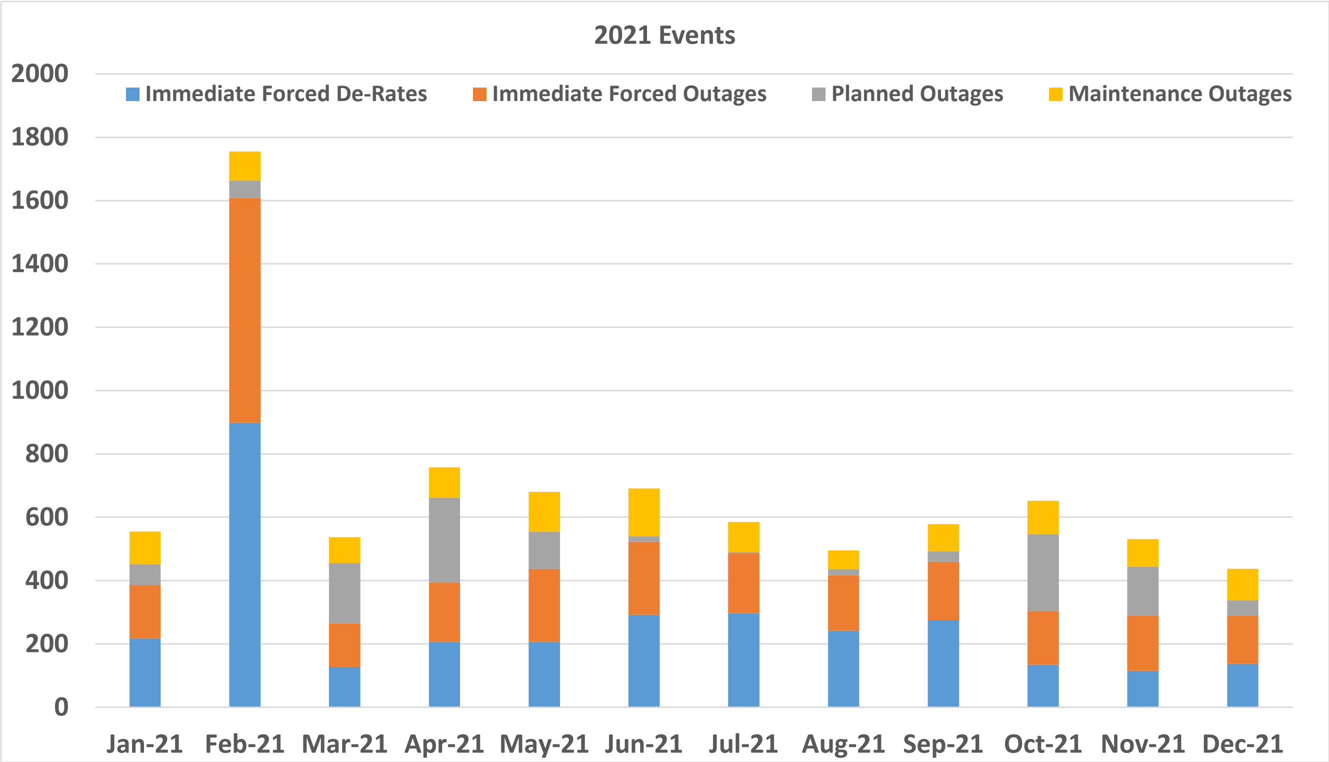


Figure A.20 –2021 Count of Generation Events by Month

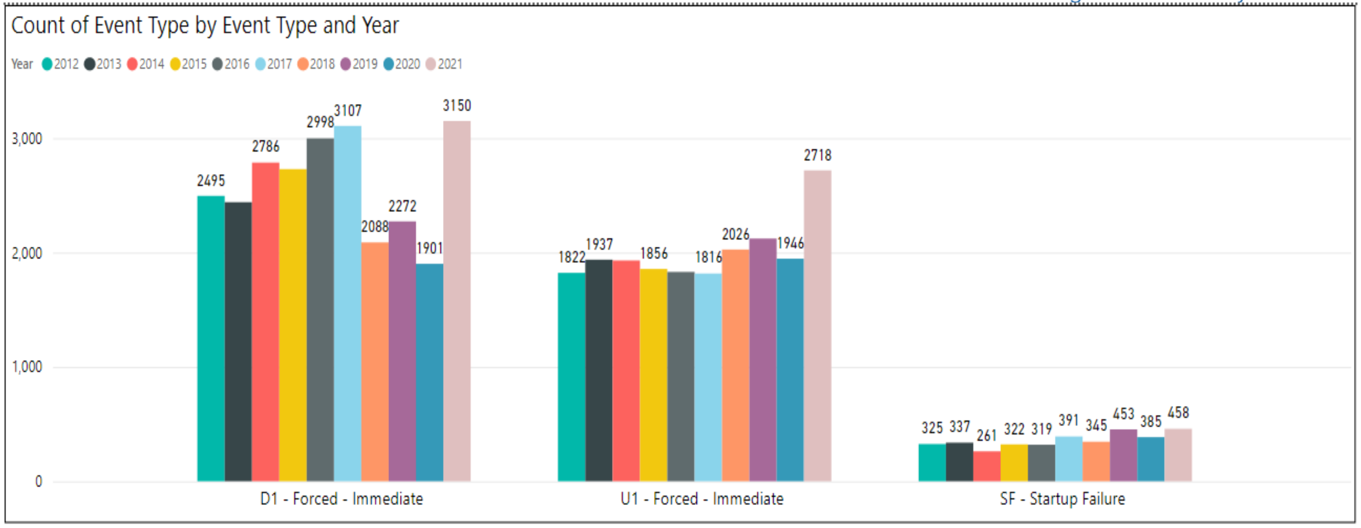


Figure A.21 – 2012-2022 Count of Events by Year

F. 2021 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 2021, 259 ERCOT wind facilities and sub-groups submitted a total of 2,231 unit-months of data in GADS-Wind. Resource-level metrics look at the resource as a whole. 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 the ERCOT wind generators for 2020 is provided in the following table.

Metric	ERCOT Region GADS-Wind Data 2019		ERCOT Region GADS-Wind Data 2020		ERCOT Region GADS-Wind Data 2021	
	Resource	Equipment	Resource	Equipment	Resource	Equipment
Net Capacity Factor (PRNCF and PENCF)	37.5%	39.7%	36.6%	39.6%	34.2%	37.6%
Equivalent Forced Outage Rate (PREFOR and PEEFOR)	12.1%	5.8%	14.7%	6.5%	16.1%	7.2%
Equivalent Scheduled Outage Rate (RESOR and PEESOR)	1.6%	1.5%	1.4%	1.3%	1.5%	1.3%
Equivalent Availability Factor (REAF and PEEAF)	87.0%	91.8%	84.7%	91.0%	83.4%	89.9%

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

- 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 voluntary turbine outage data reporting for 2021 included 6,744 component outage reports totaling 862,716 turbine-hours of forced, planned, and maintenance outage duration.

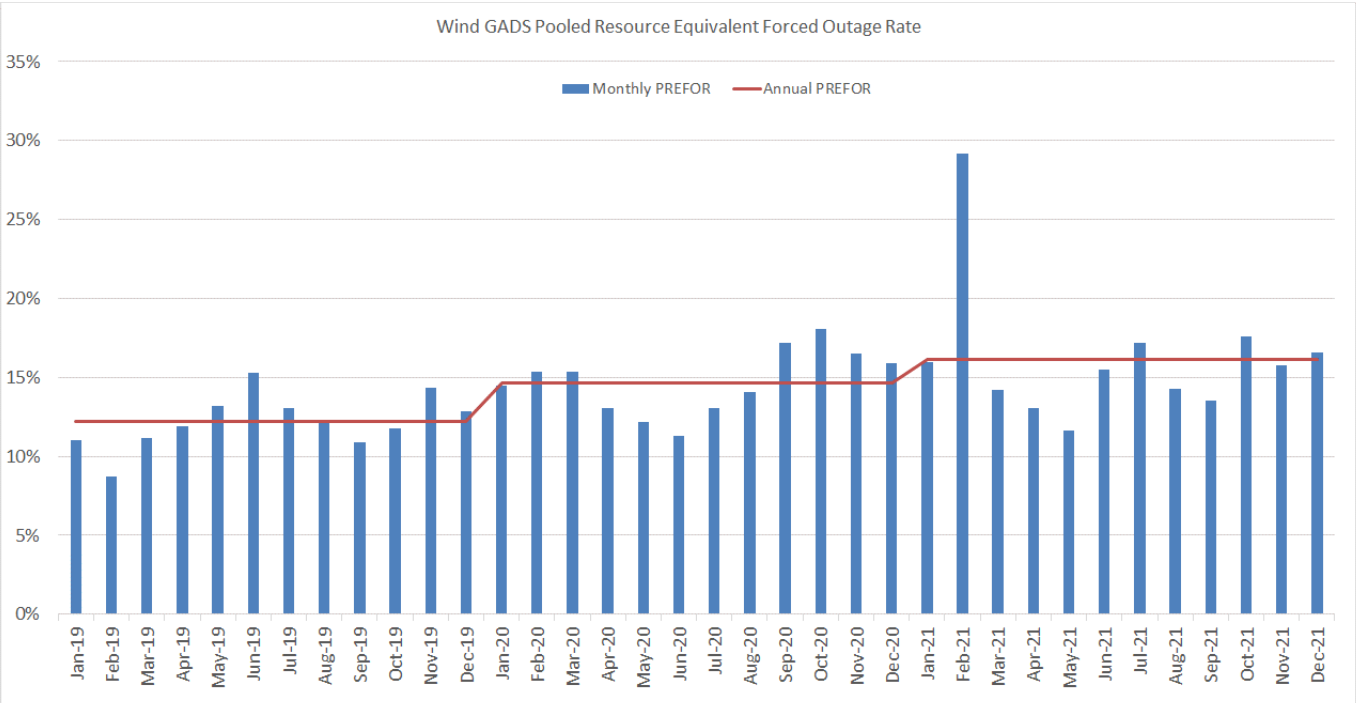


Figure A.22 – GADS-Wind Time Trend for MW-Weighted EFOR

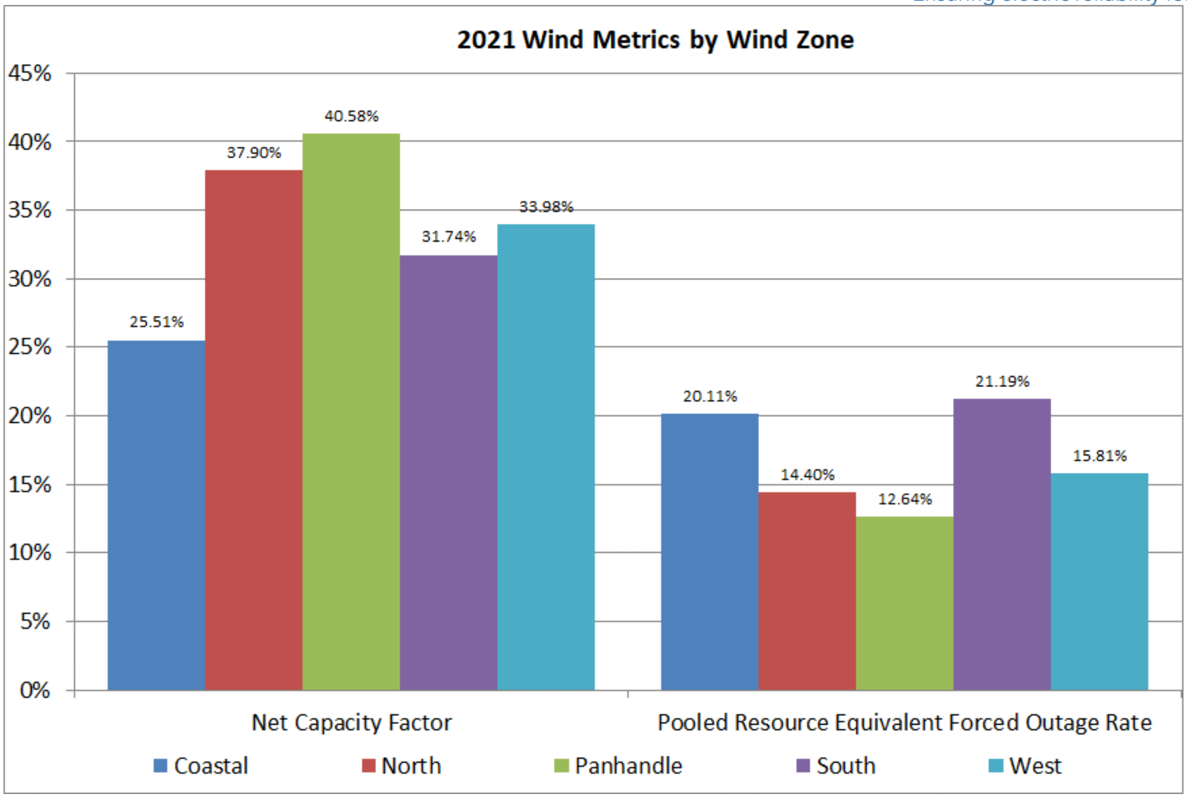


Figure A.23 – 2021 GADS-Wind Metrics by Wind Zone

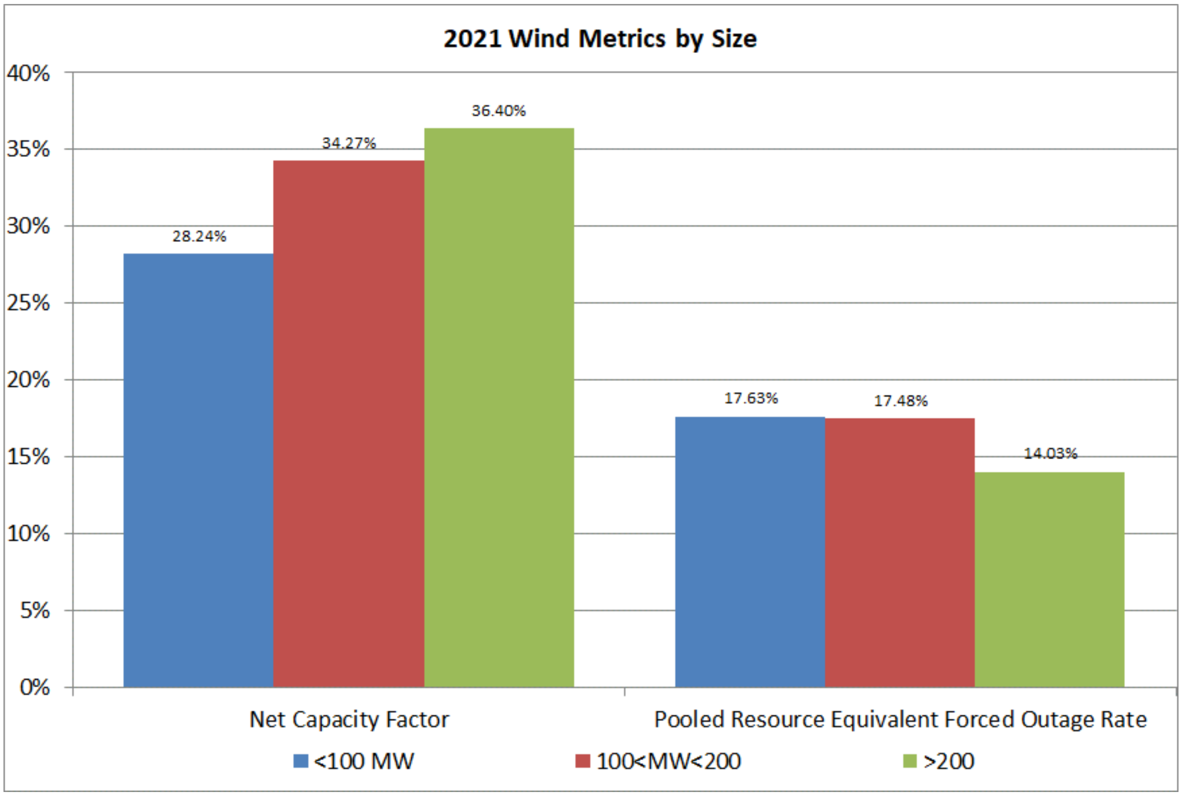


Figure A.24 – 2021 GADS-Wind Metrics by Unit Size

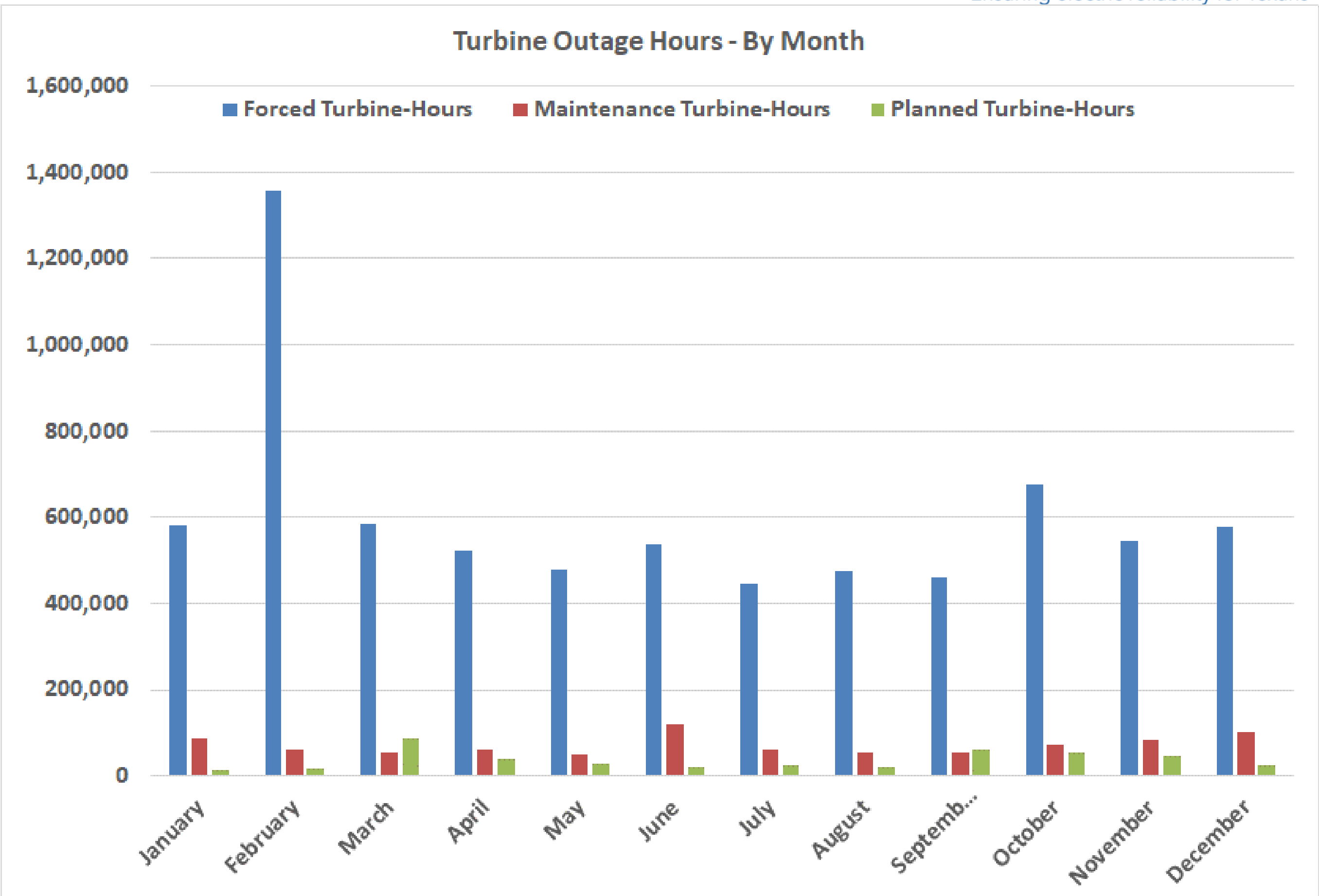


Figure A.25 – 2021 GADS-Wind Turbine Outage Hours by Month

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.

As part of the Event Analysis process, Texas RE investigates the cause and relative effect on reliability of Balancing Contingency events within the region. Balancing Contingency events greater than the MSSC (1,375 MW) typically do not create a significant reliability problem for the ERCOT region since ERCOT carries contingency reserves greater than the MSSC; however, these events warrant special consideration for review of system frequency response and recovery.

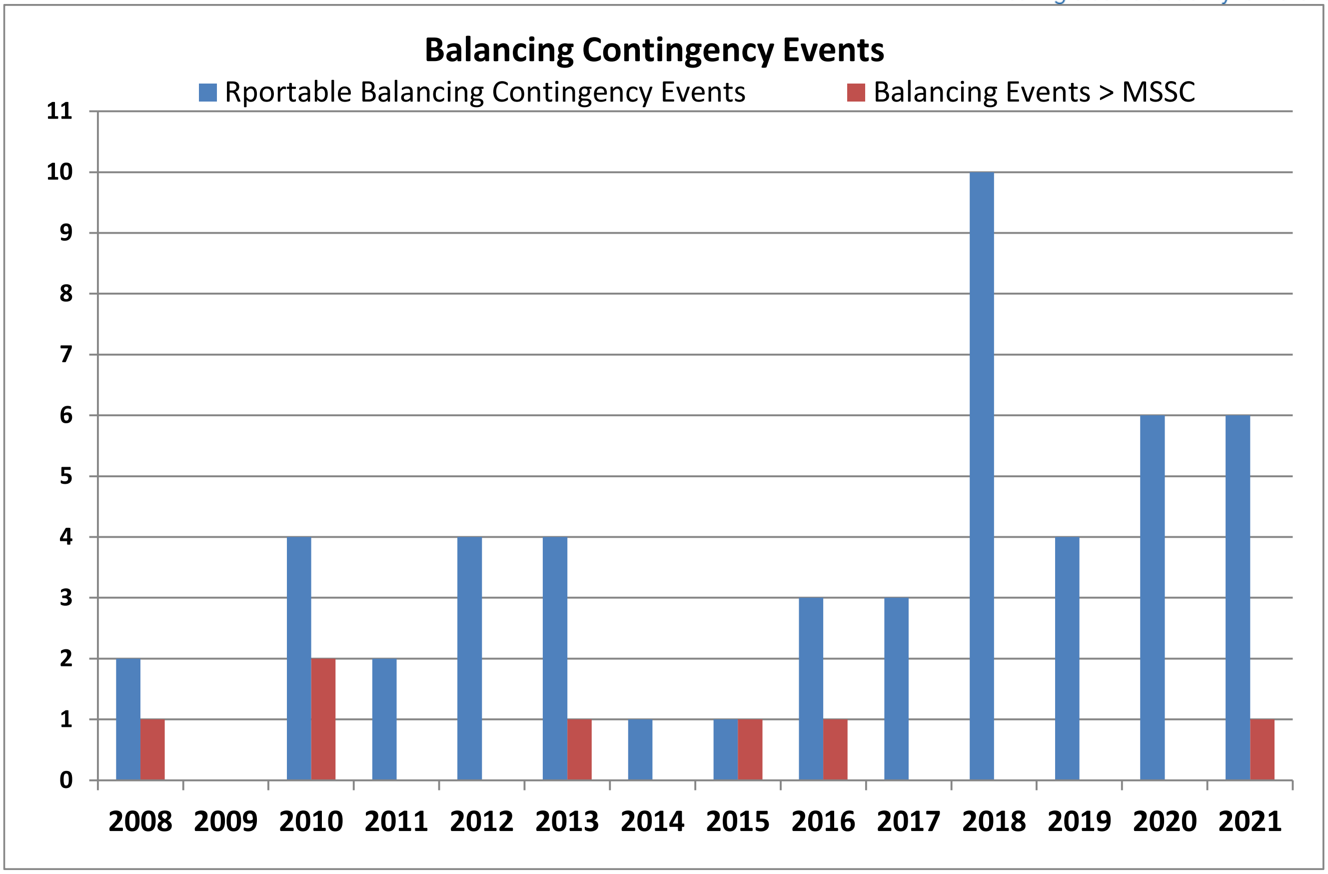


Figure A.26 – Reportable Balancing Contingency Events by Year

H. Fuel Constraints

There was a significant increase in the unavailable generation capacity due to natural gas fuel curtailments in 2021.

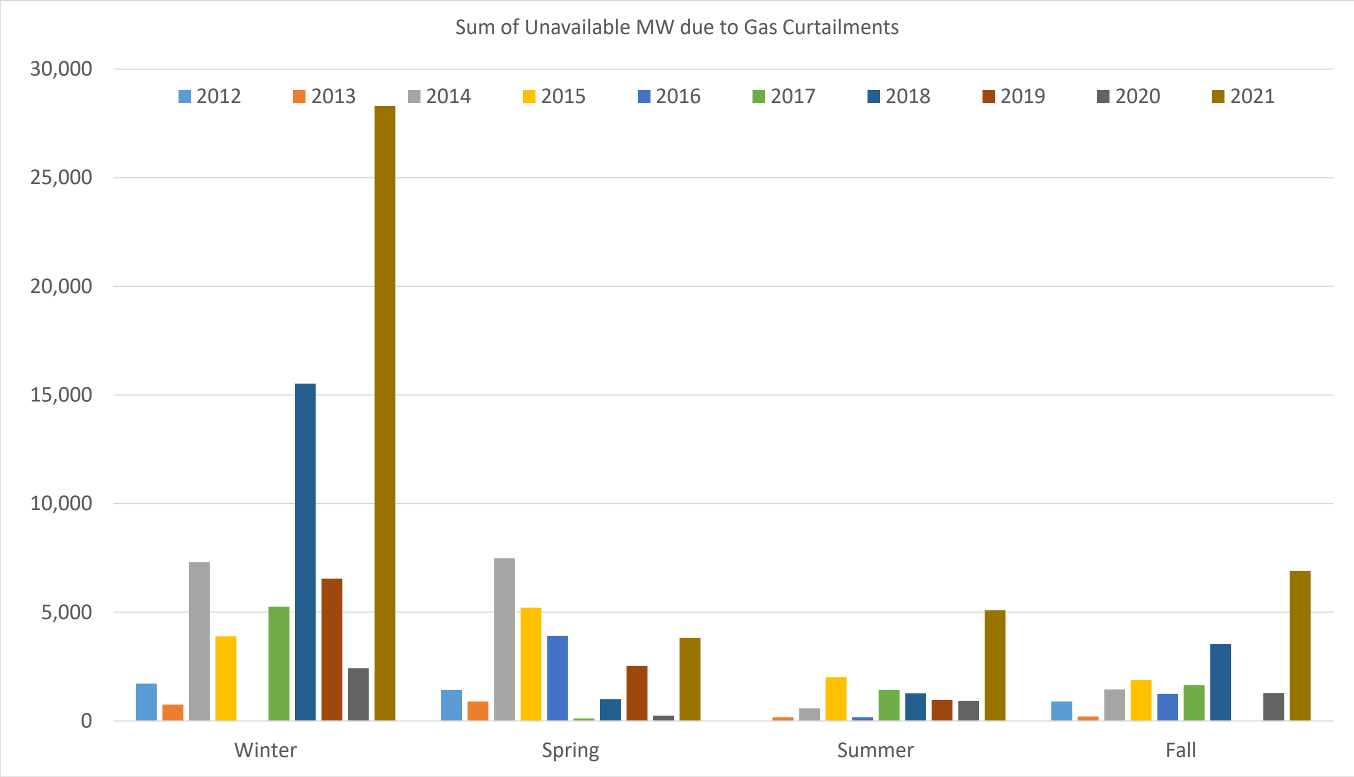


Figure A.27 – Cumulative Unavailable MW Due to Natural Gas Curtailments By Season

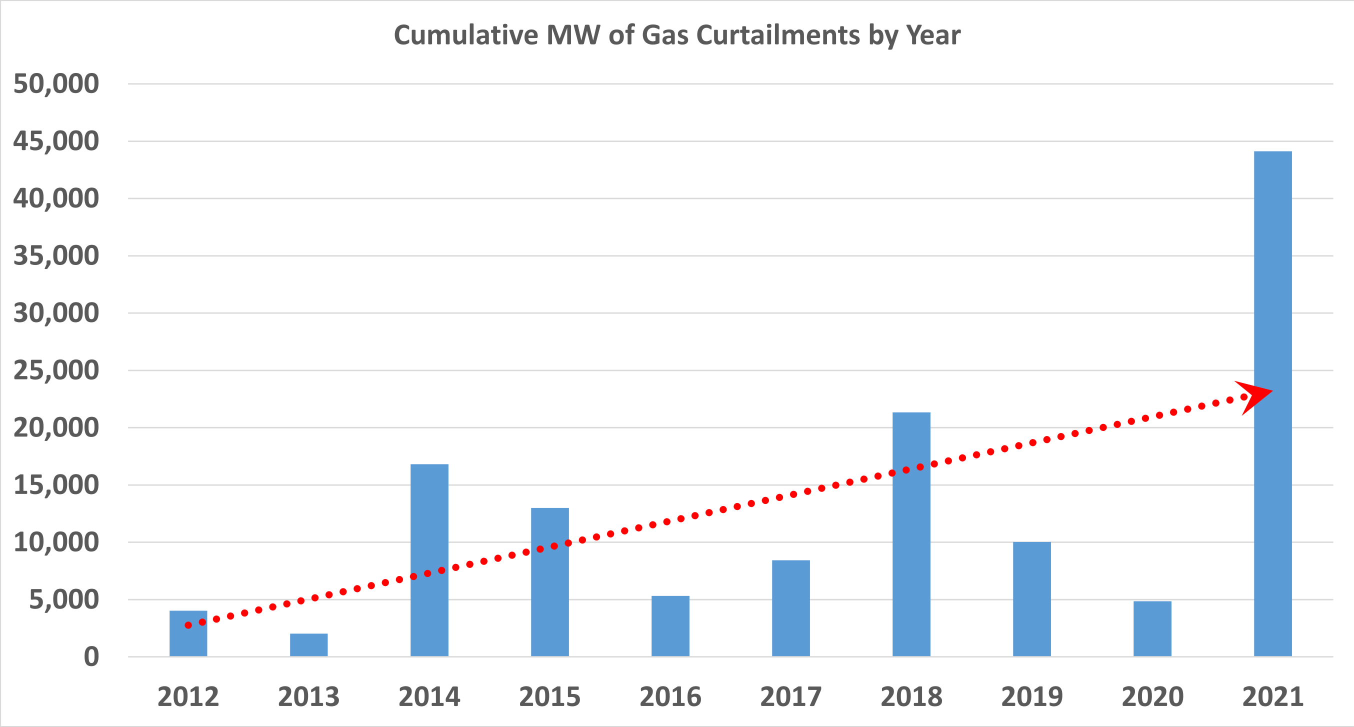


Figure A.28 – Cumulative Unavailable MW Due to Natural Gas Curtailments By Year

I. Demand Response

Three types of demand response are employed in the ERCOT region.

1. Load Resources (LR) providing Responsive Reserve Service (RRS) that are automatically interrupted by underfrequency relays when system frequency decreases to 59.7 Hz or below. These resources can also be manually deployed within 10 minutes by ERCOT in response to energy emergencies.
2. Emergency Response Service (ERS) is a service designed to be deployed by ERCOT as an operational tool under an EEA. ERS is designed to decrease the likelihood of ERCOT operating reserve depletion and the need for ERCOT to direct firm Load shedding. Two types of ERS are procured, ERS-10 (ERS with a 10 minute ramp period) and ERS-30 (ERS with a 30 minute ramp period).
3. Economic demand response is employed by non-opt-in entities (NOIEs), such as municipalities, for economic purposes in the form of commercial-industrial programs, smart thermostat programs, peak shaving programs, etc.

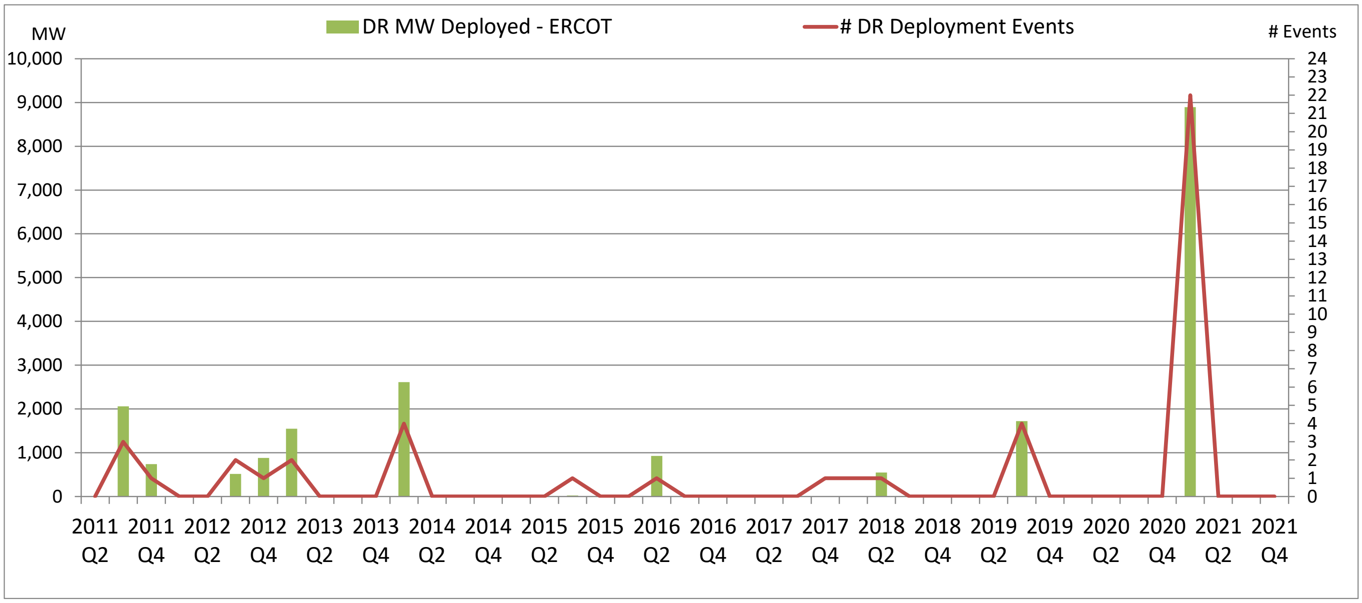


Figure A.29 – History of Demand Response Deployed by ERCOT

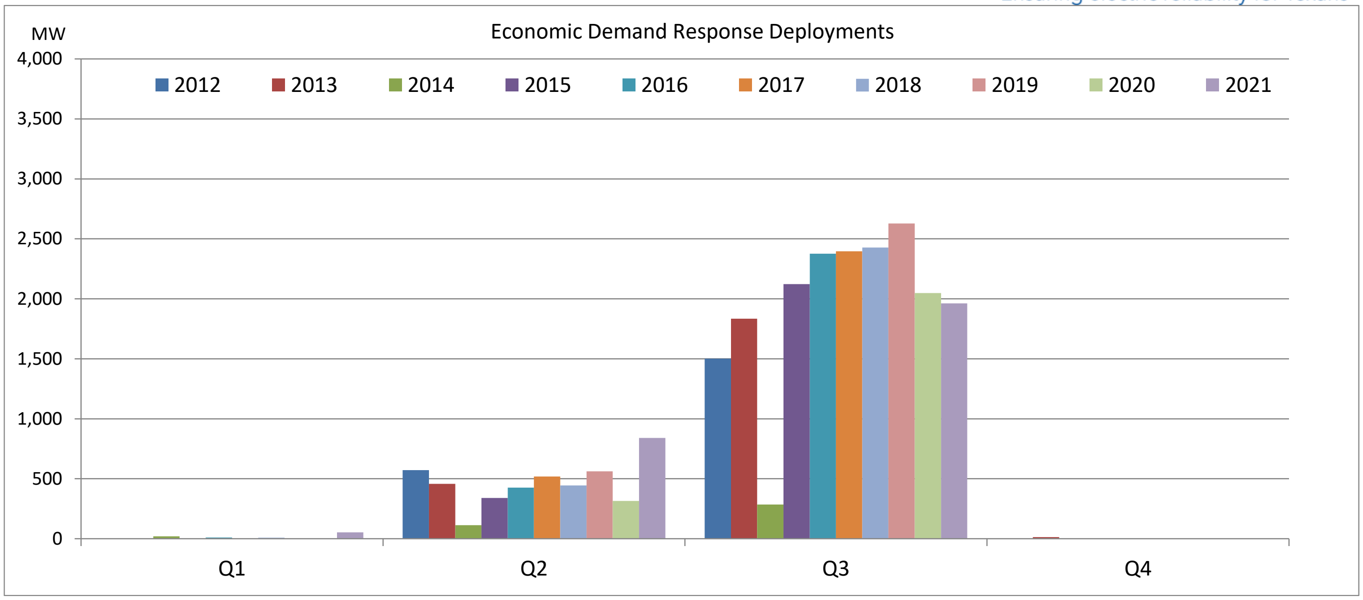


Figure A.30 – Cumulative MW of Economic Demand Response Deployments

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)
2010	287	9384.7	
2011	307	9679.1	
2012	313	9884.0	
2013	370	13,071.6	
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

Table B.1 – 2010-2021 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	7398.8	82	14,591.1
2020	471	6103.8	137	28,351.5
2021	505	17,804.4	167	29,794.5
5-Yr Average	454	14,516.8	86	15,311.2

Table B.2 – 2010-2021 345 kV Circuit and Transformer Outage Data

B. Event Analysis

[1] Outage count and duration for 2015-2021 includes 345 kV transformers which began reporting in 2015

The following significant events occurred in 2021:

- Winter Storm Uri on February 8-20, 2021: A severe winter storm caused the loss of over 40,000 MW of generation capacity, resulting in a maximum of 20,000 MW of firm load shed.
- Multiple wind and solar unit loss on May 9, 2021: A fault occurred on a 345 kV transmission bus, causing the loss of over 1,100 MW of wind and solar generation due to the low voltage conditions created by the fault.
- Multiple solar unit loss on June 26, 2021: A fault occurred on a 345 kV transmission line, causing the loss of 697 MW of wind and solar generation due to the low voltage conditions created by the fault.
- Loss of multiple elements on February 1, 2021: A fault occurred on a 138 kV transmission line combined with protective relay misoperations, causing the loss of two 138 kV busses.
- Loss of multiple elements on August 2, 2021: A fault occurred on a 138 kV transmission line combined with protective relay misoperations, causing the loss of three 138 kV lines and two power transformers.
- Loss of multiple elements on October 10, 2021: A fault occurred on a non-BES 12 kV transformer combined with protective relay misoperations, causing the loss of a 138 kV bus and multiple 138 kV lines.
- Loss of multiple elements on December 21, 2021: A fault occurred on a 138 kV transmission line combined with protective relay misoperations, causing the loss of a 138 kV bus and multiple tapped substation loads.
- Loss of multiple elements on December 24, 2021: A fault occurred on a 345 kV autotransformer combined with protective relay misoperations, causing the loss of a 345 kV bus.

  Historical Disturbance Data: In 2021, the number of events reported remained steady when compared to the average number of events from 2017 through 2020.

Event Category[2]	2017	2018	2019	2020	2021	5-Yr Avg
Non-Qualified	52	78	73	84	74	72
1	11	13	11	8	14	11
2	0	0	0	0	0	0
3	0	0	0	0	0	0
4 and 5	1	0	0	0	1	0
Total	64	91	84	92	89	84

Table B.3 – Summary of Event Analyses

[2] Link to NERC Events Analysis Process with category definitions:
https://www.nerc.com/pa/rrm/ea/ERO_EAP_Documents%20DL/ERO_EAP_v4.0_final.pdf

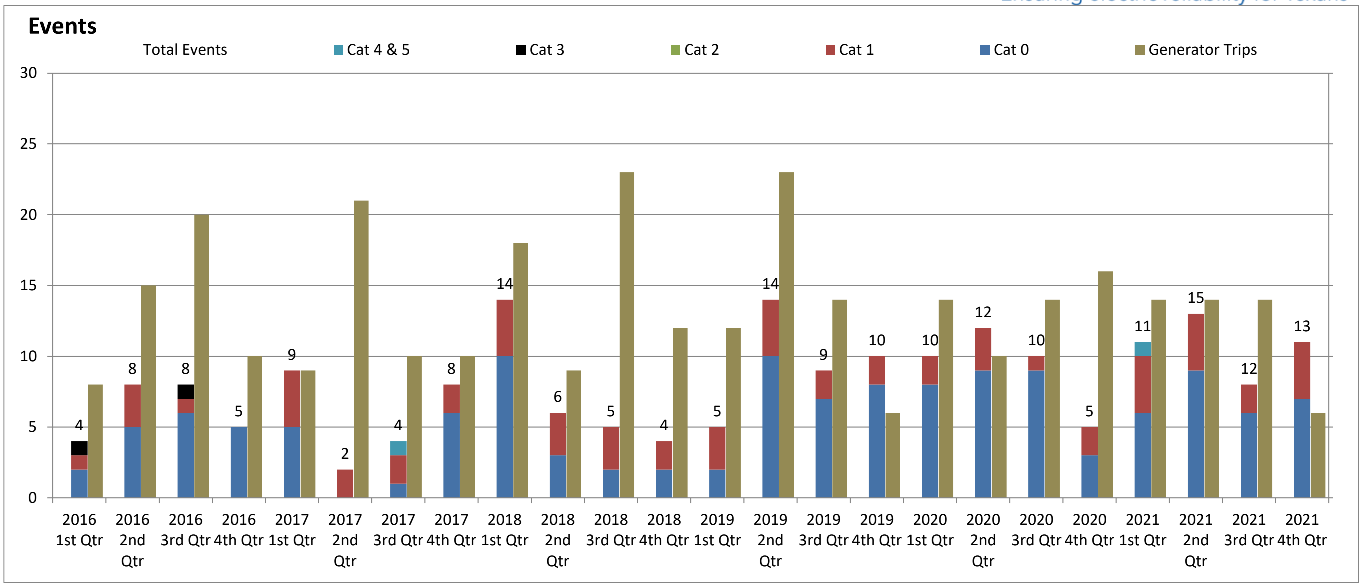


Figure B.1 – Events Reported by Quarter

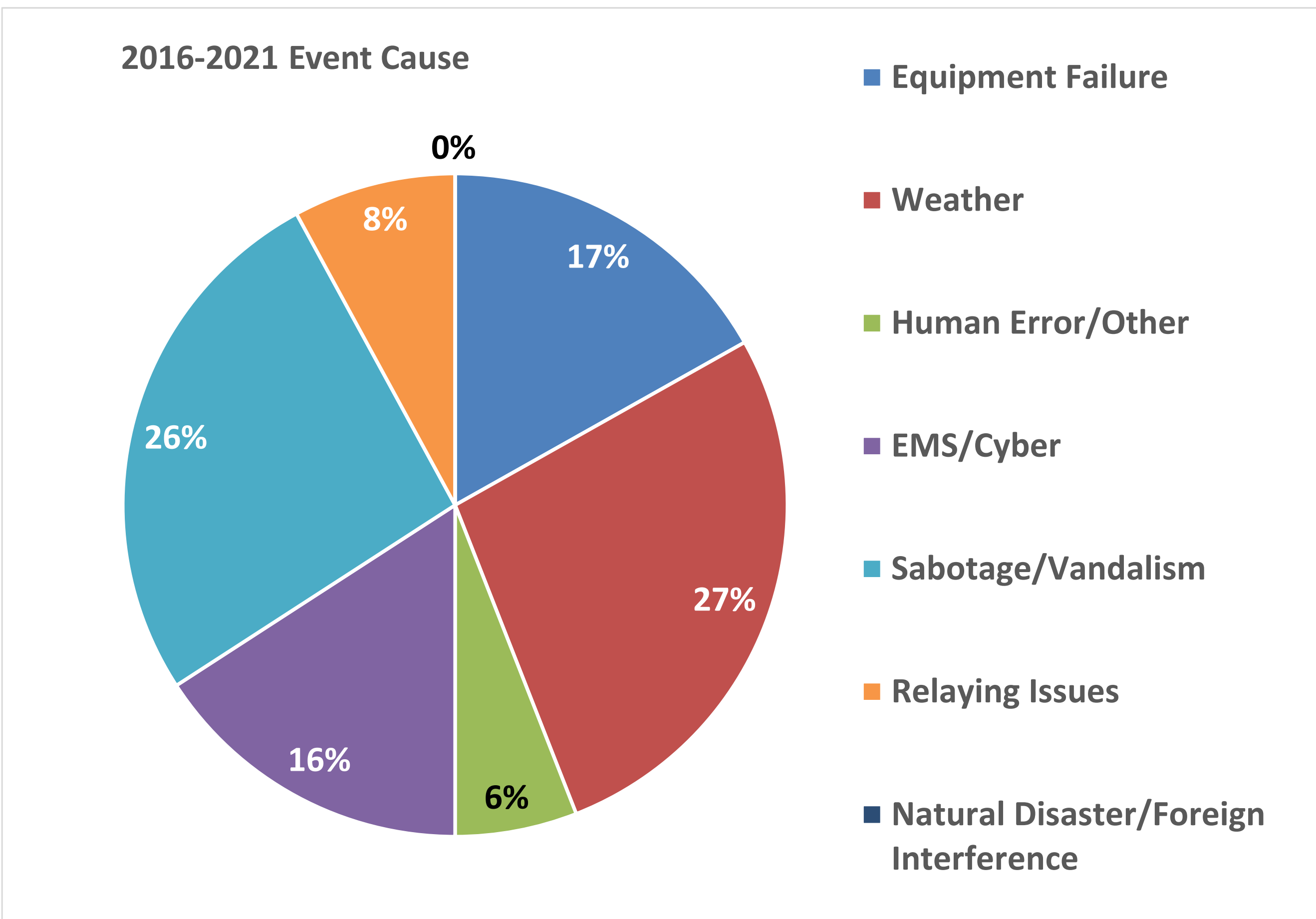


Figure B.2 – 2016-2021 Event Cause Summary

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.

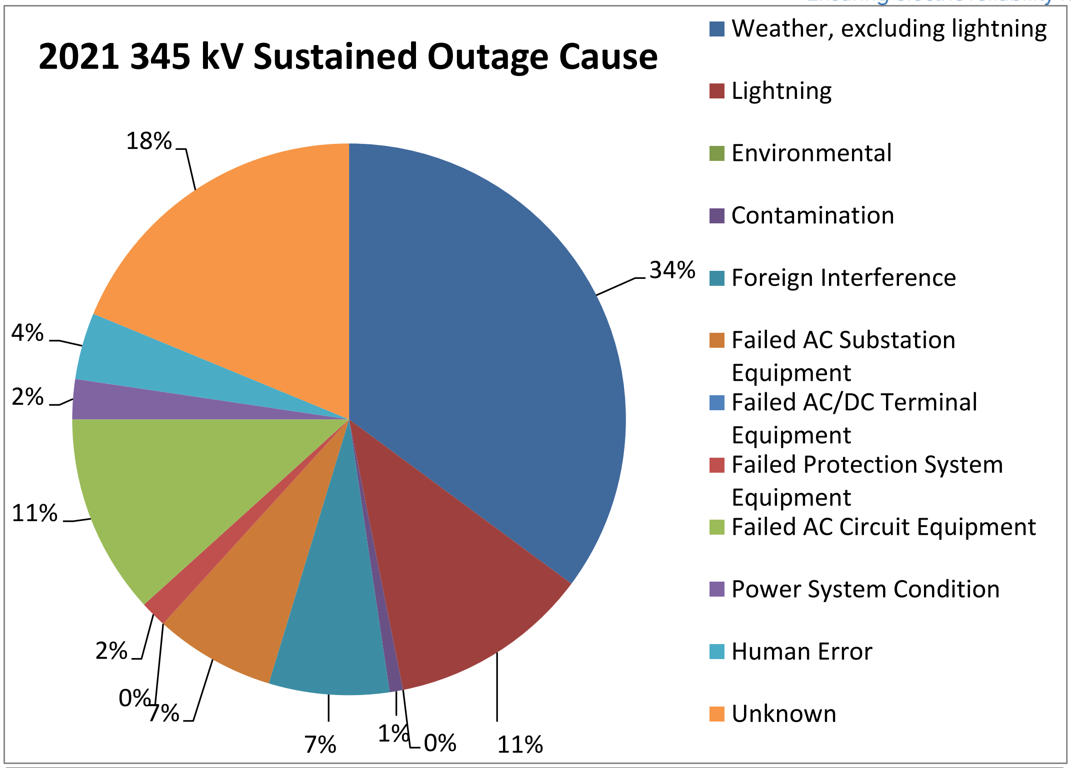
Voltage Class Name	Metric	2017	2018	2019	2020	2021	5-Yr Avg
AC Circuit 300-399 kV	Automatic Outages per Circuit	0.95	0.66	1.02	0.82	0.80	0.85
AC Circuit 300-399 kV	Automatic Outages per 100 miles	2.68	1.98	2.97	2.45	2.52	2.52
AC Circuit 100-199 kV	Sustained Automatic Outages per Circuit	0.22	0.22	0.19	0.19	0.29	0.22
AC Circuit 100-199 kV	Sustained Automatic Outages per 100 miles	1.90	1.87	1.65	1.61	2.50	1.91
Transformer 300-399 kV	Automatic Outages per Element	0.14	0.13	0.16	0.10	0.13	0.13

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

<u>Automatic Outage Data</u>

For 345 kV transmission circuits, predominant causes for sustained outages in 2021 were weather (excluding lightning), unknown, and failed circuit equipment, representing 63 percent of the total sustained outages. Failed transmission circuit equipment accounted for 64 percent of the outage duration.

For 138 kV transmission circuits, predominant causes for sustained outages in 2021 were weather, lightning, failed circuit equipment, and failed substation equipment, representing 70 percent of the total sustained outages. Failed substation/transmission circuit equipment dominated the sustained outage duration, accounting for 67 percent of the outage duration.



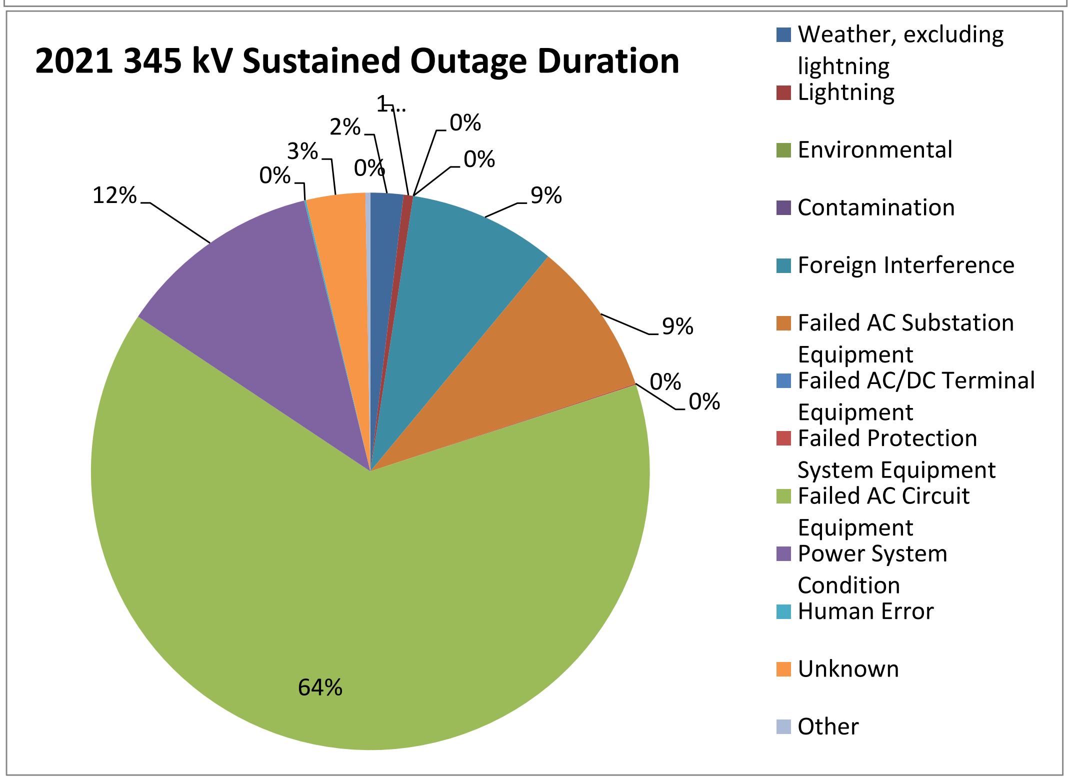


Figure B.3 – 2021 345 kV Sustained Outage Cause versus Duration

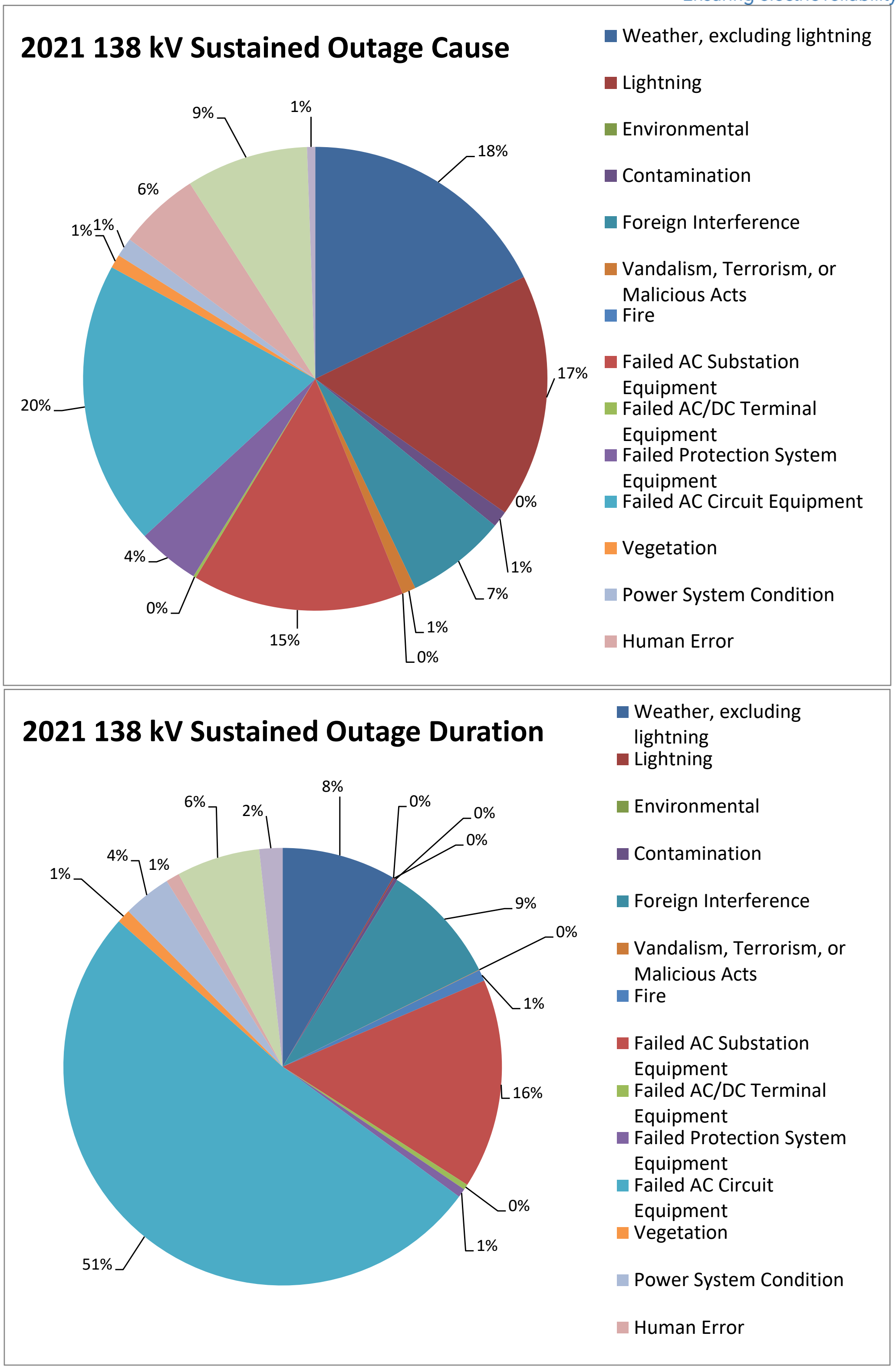


Figure B.4 – 2021 138 kV Sustained Outage Cause versus Duration

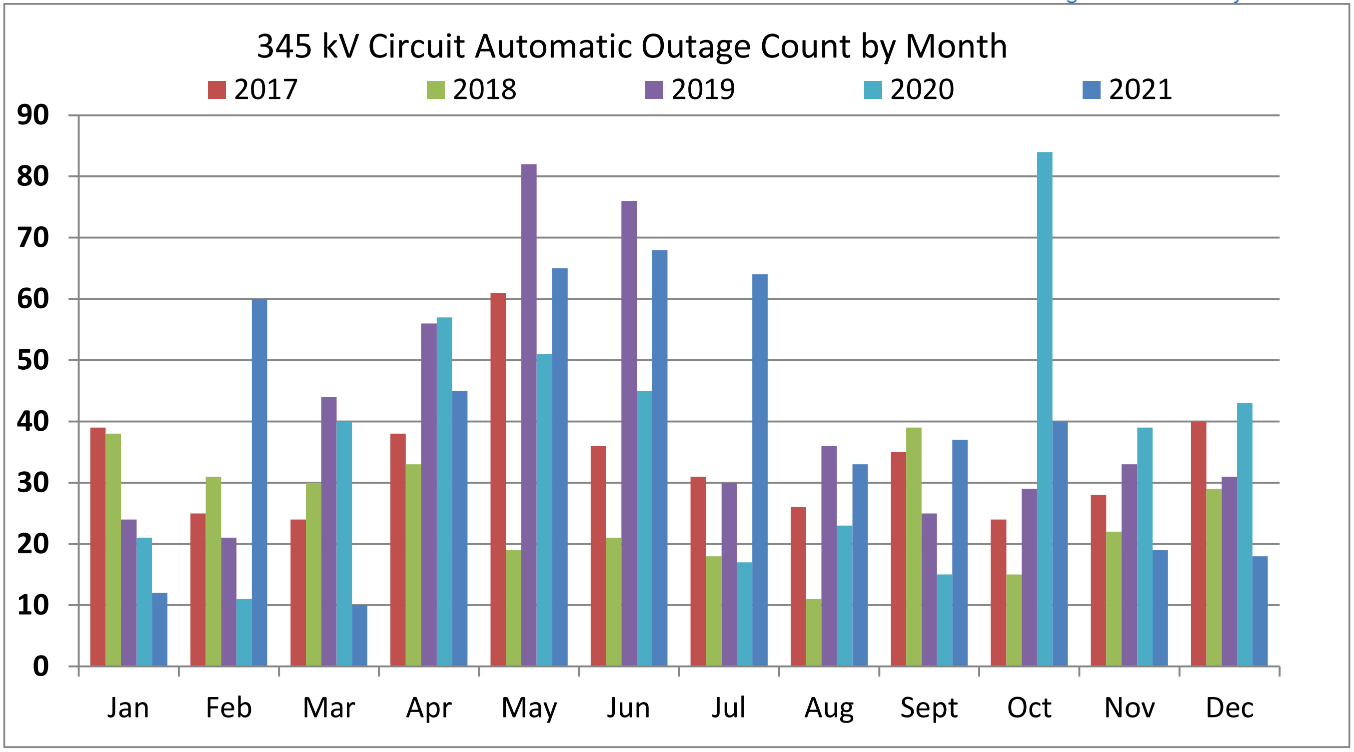


Figure B.5 – 345 kV Circuit Automatic Outages by Month

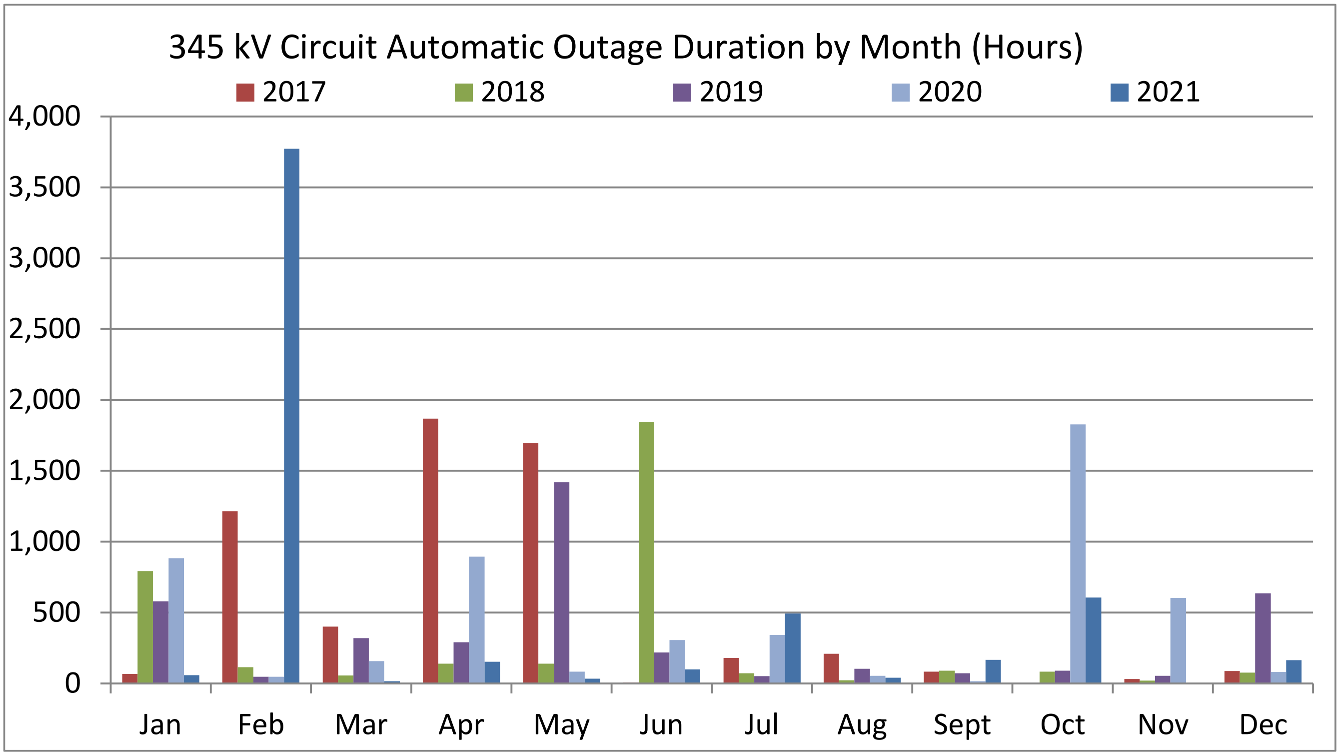


Figure B.6 – Multi-Year Comparison of TADS Outages and Duration by Month (> 200 kV)

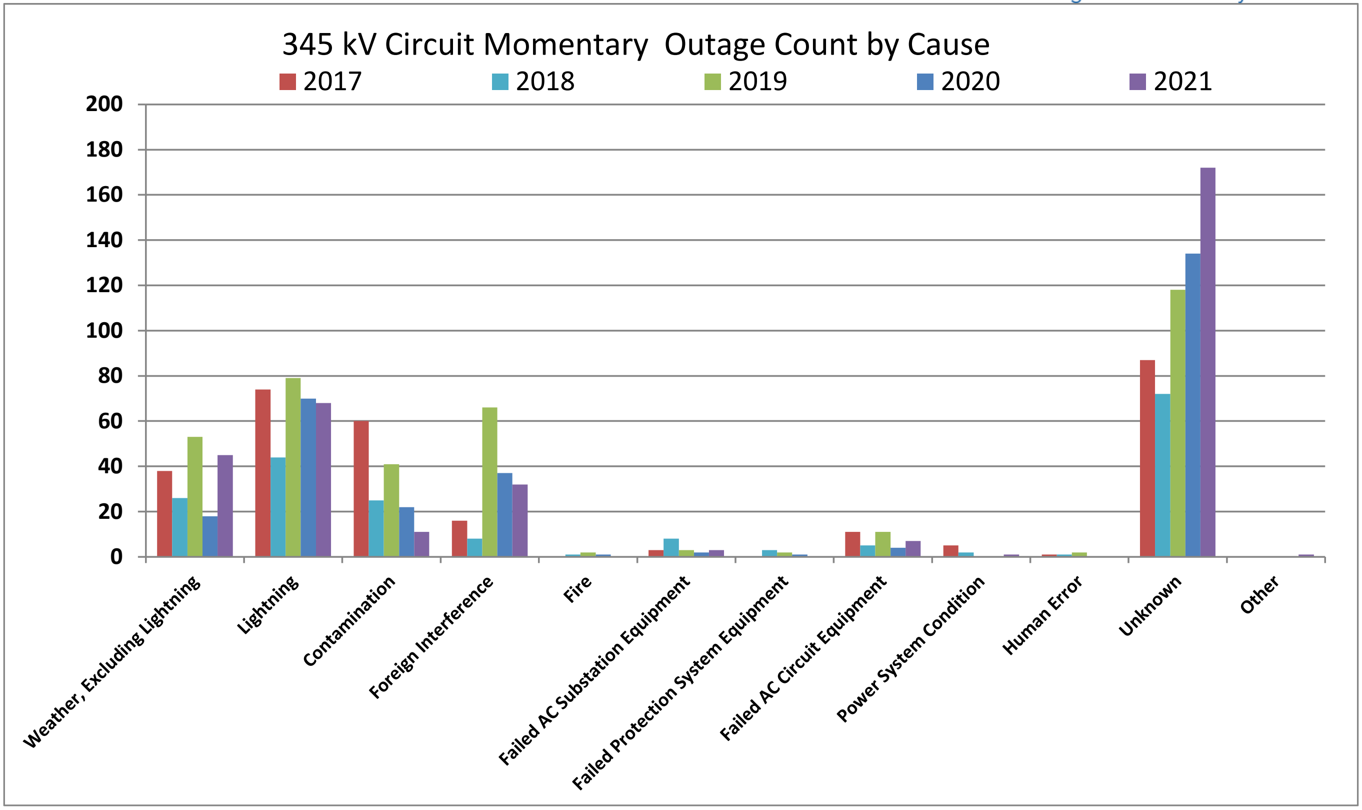


Figure B.7 – 345 kV Circuit Momentary Outage Count by Cause

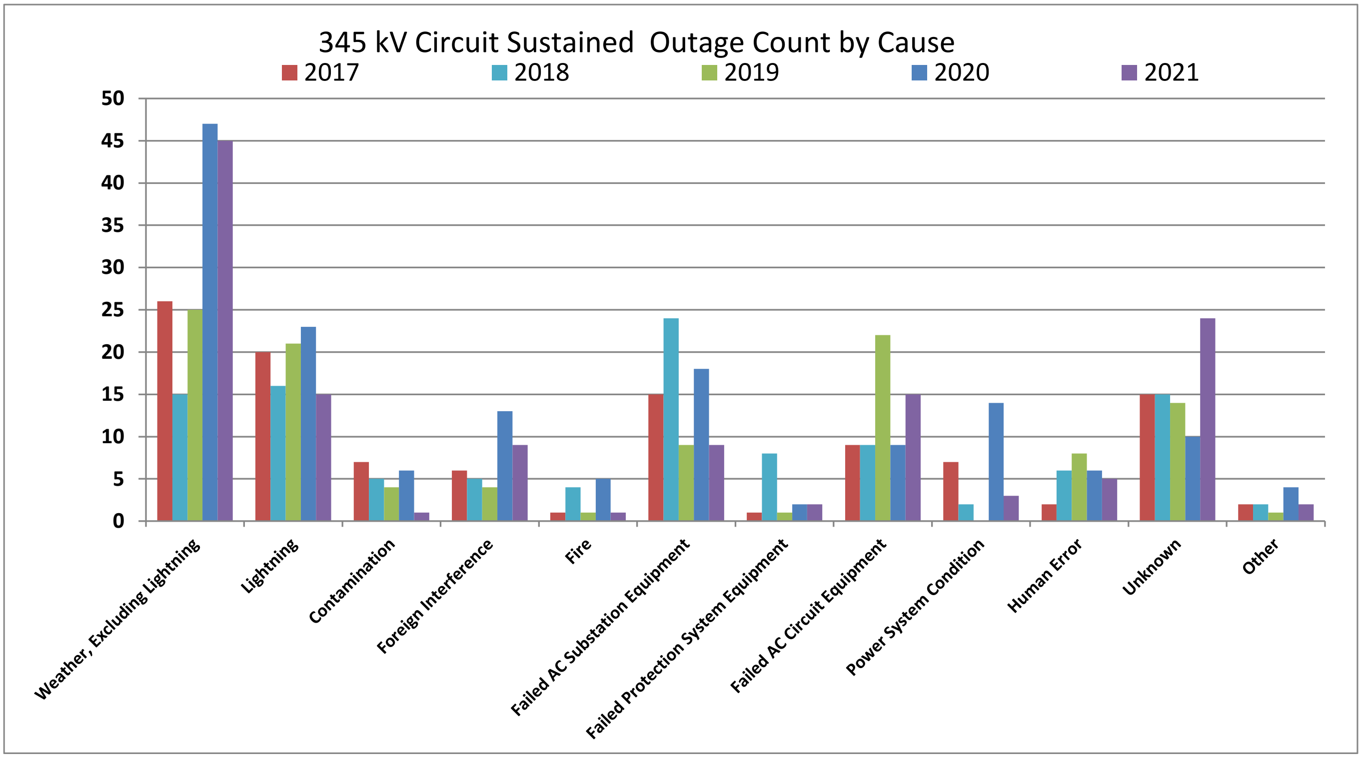


Figure B.8 – 345 kV Circuit Sustained Outage Count by Cause

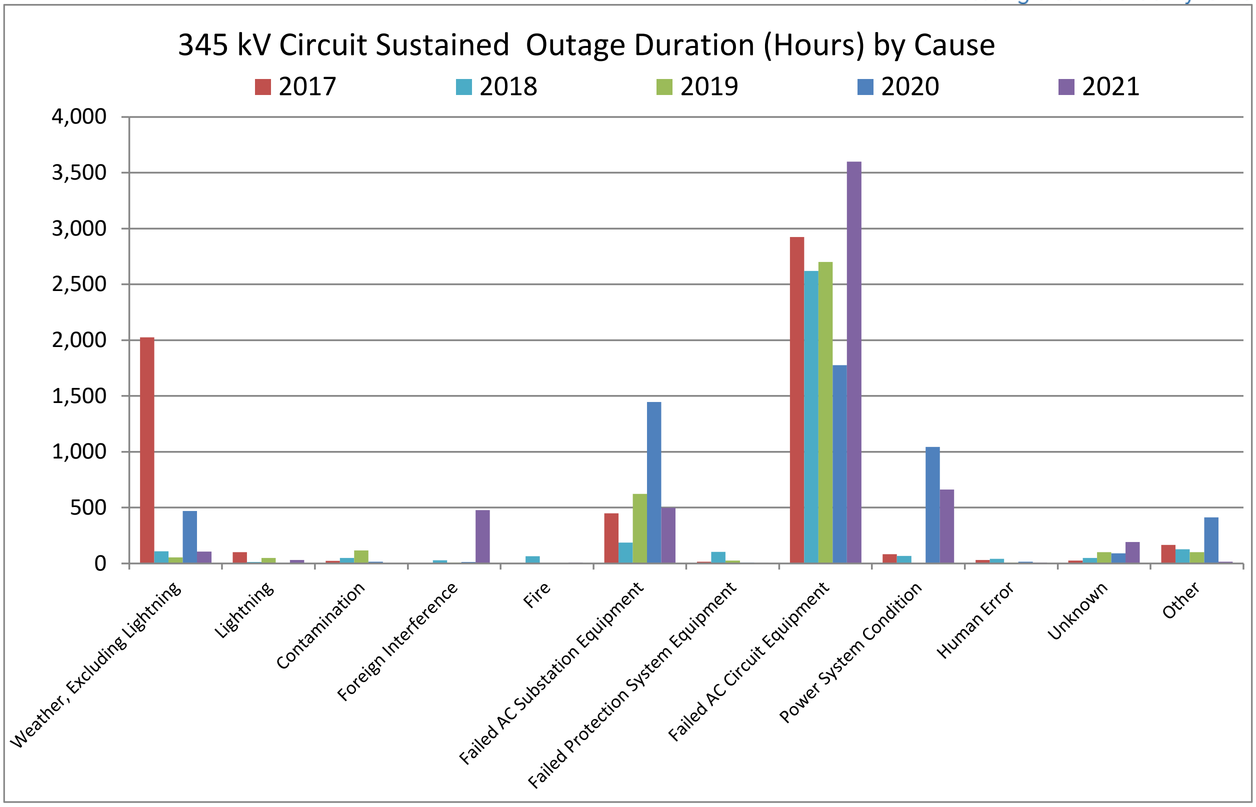


Figure B.9 – 345 kV Circuit Sustained Outage Duration (Hours) by Cause

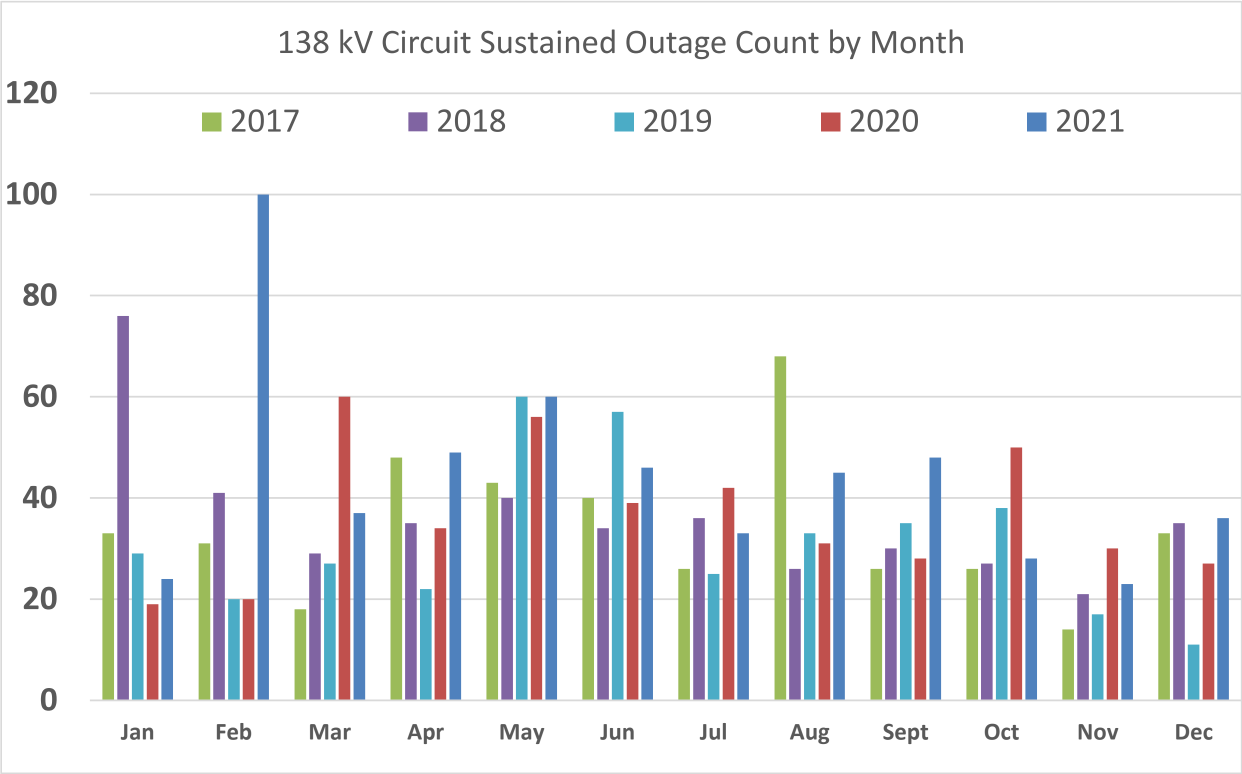


Figure B.10 – 138 kV Circuit Sustained Outage Counts by Month

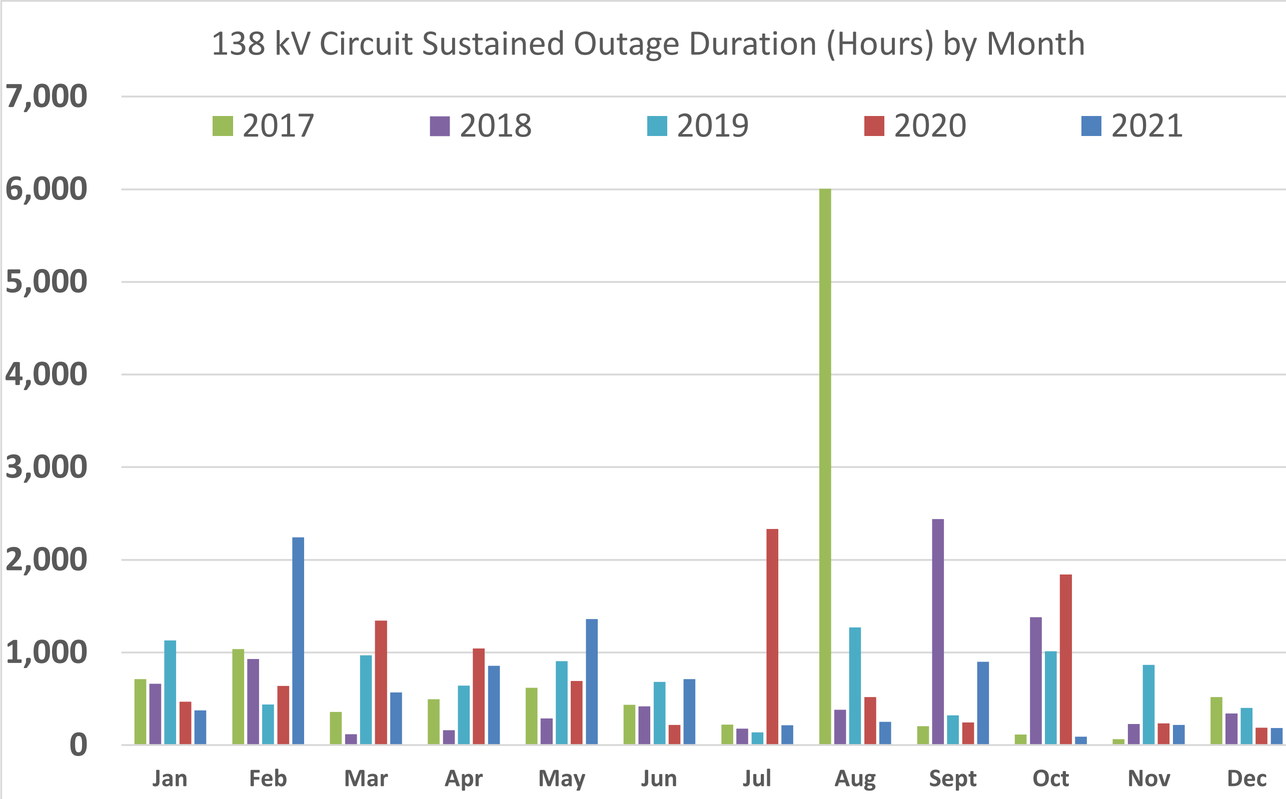


Figure B.11 – 138 kV Circuit Sustained Outage Duration (Hours) by Month

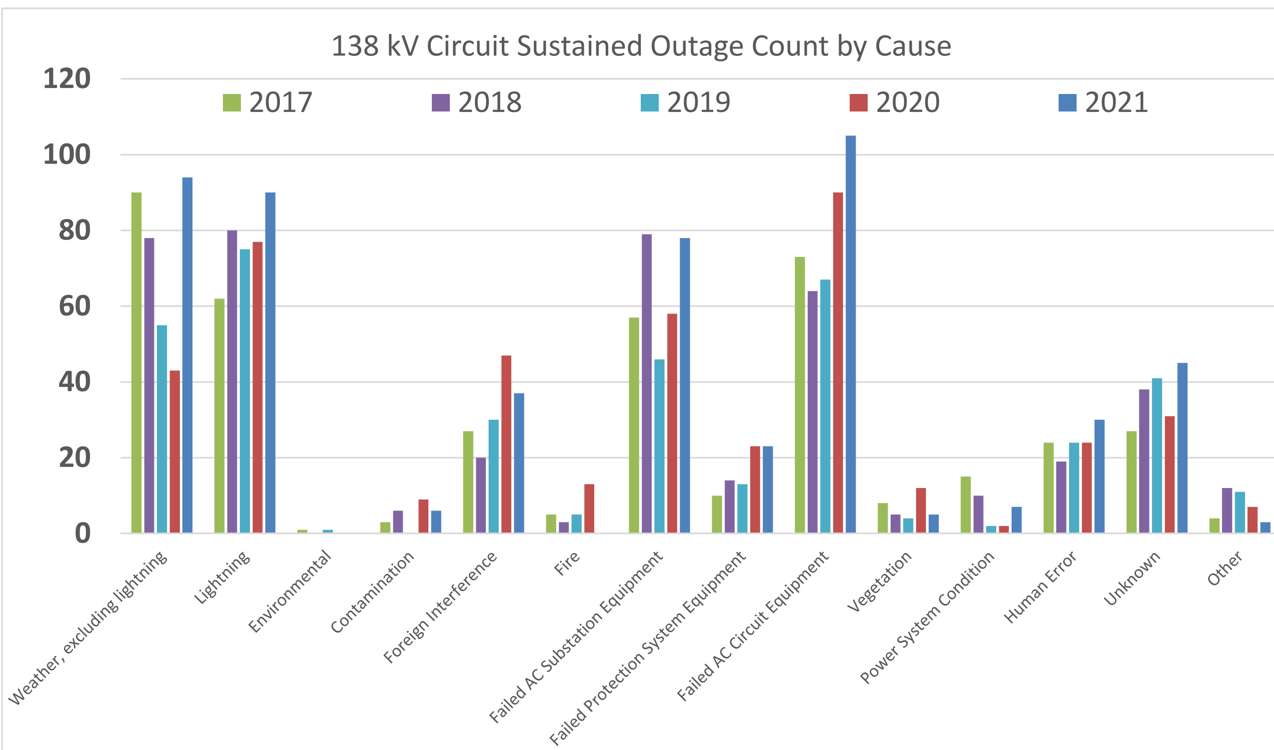


Figure B.12 – 138 kV Circuit Sustained Outage Count by Cause

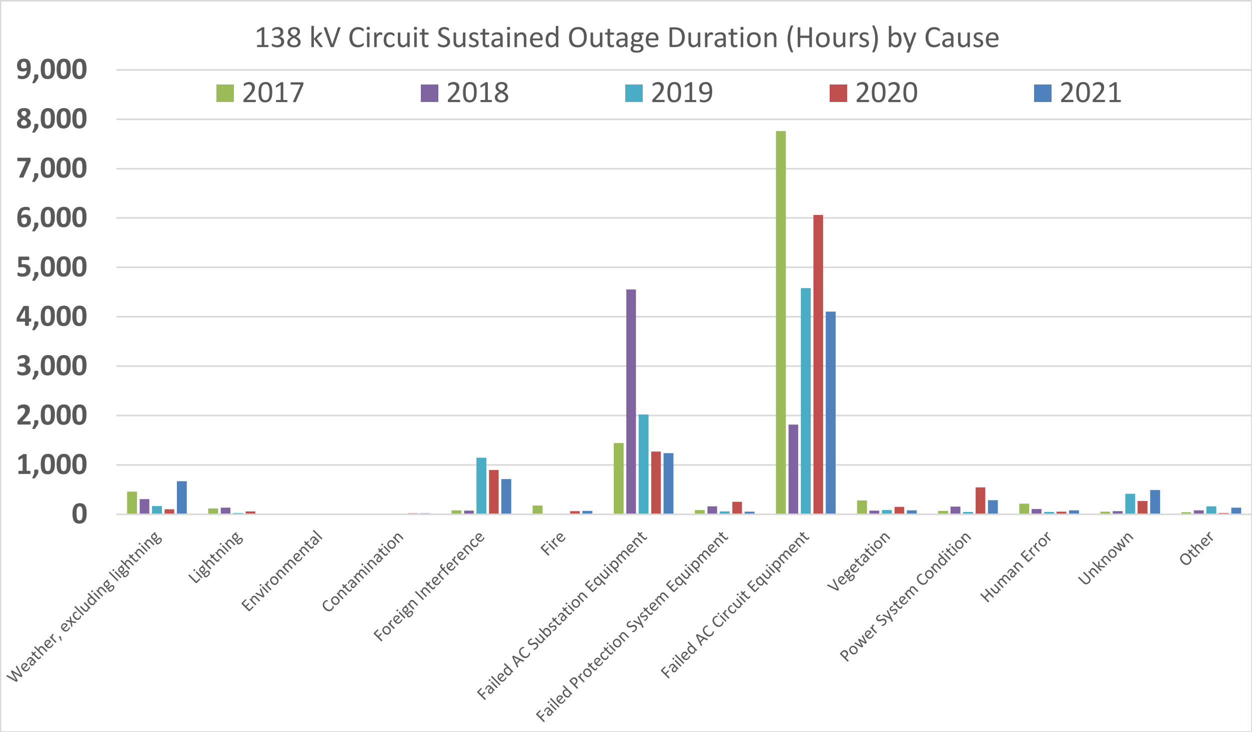


Figure B.13 – 138 kV Circuit Sustained Outage Duration by Cause

<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 2017-2021. 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 Outage Duration on Extreme Day	Longest Sustained Outage on Extreme Day	Average Sustained Outage Duration for Year	Longest Sustained 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	7589 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	1204.1 GWH

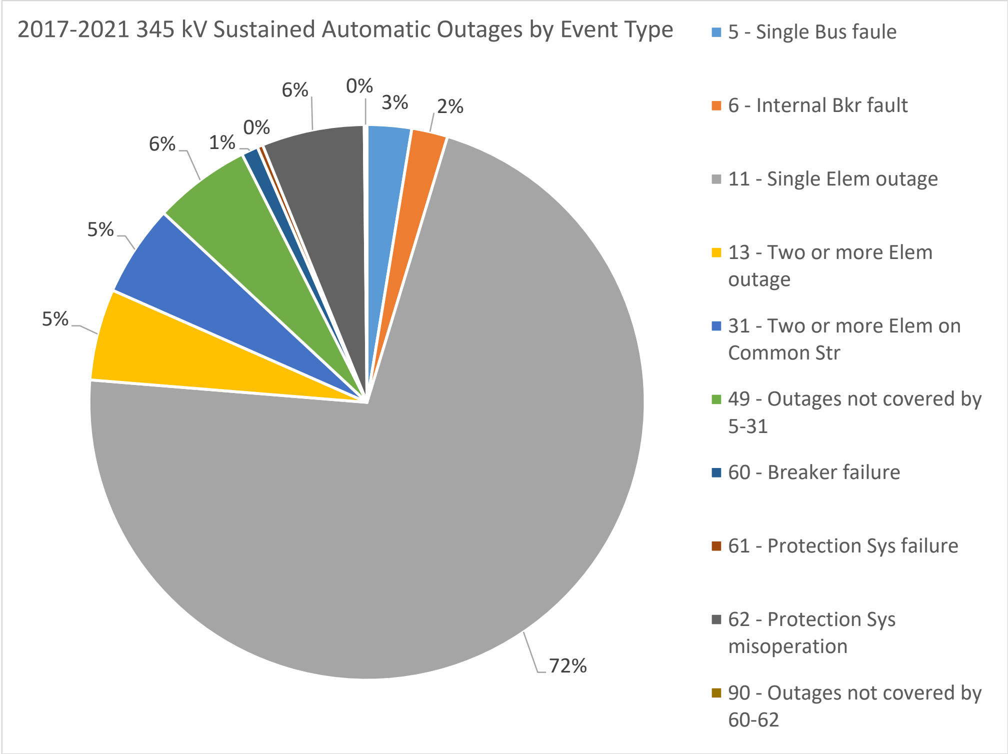
Table B.6 – Extreme Generation Event Day Analyses

D. Multiple Element Outages

For 345 kV circuits in 2021, 25 of the 471 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 five percent of all outages and five percent of sustained outage duration for the 345 kV system.

For 138 kV circuits in 2021, 165 of the 529 reported automatic sustained outage events involved two or more circuit elements. Dependent Mode and Common Mode outages represented 31 percent of all sustained outages and 19 percent of sustained outage duration.

Over the five year period from 2017-2021, multiple element outages represented 27 percent of sustained outages and 48 percent of the sustained outage duration for the 345 kV system.



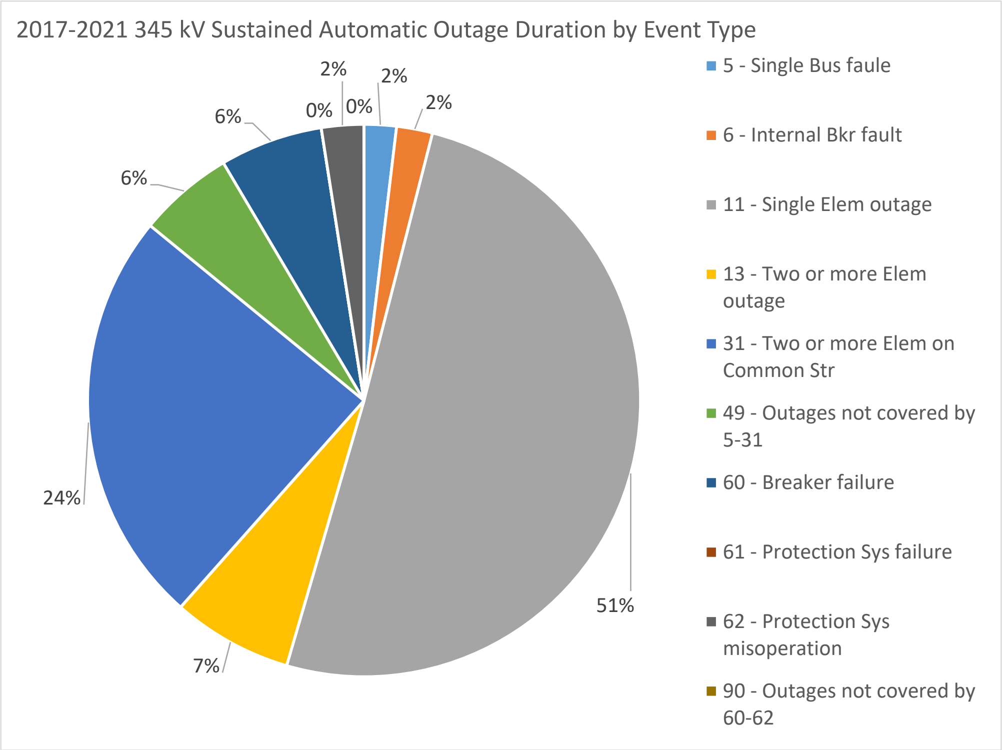


Figure B.14 – 2017-2021 345 kV Sustained Outages by Event Type

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. There are currently five IROLs in the ERCOT Interconnection, based on ERCOT's System Operating Limit methodology.

Voltage stability limits, transient and control stability limits, and stability issues for interfaces or in areas with low weight short circuit ratios are monitored and managed using Generic Transmission Limits (GTLs).

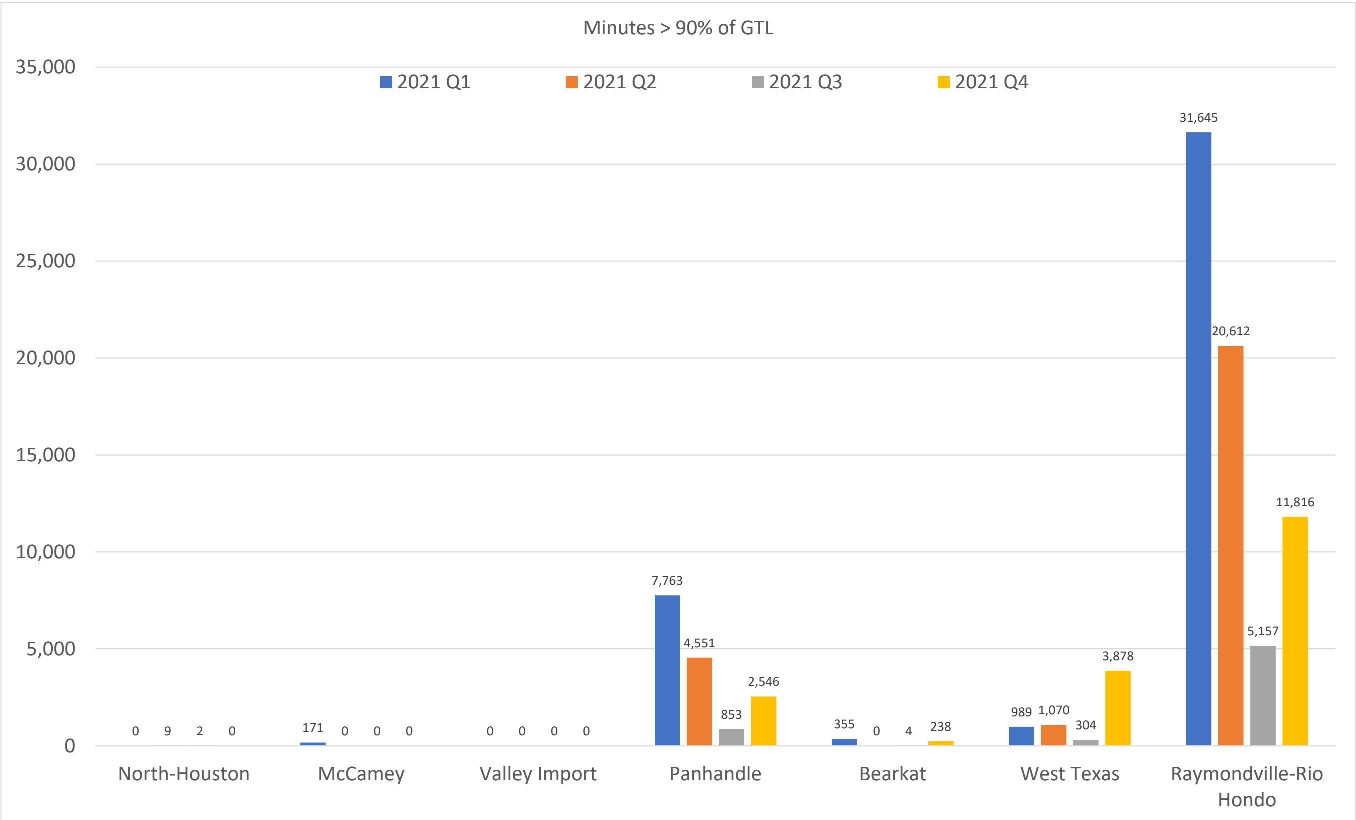


Figure B.15 – Interface Operation Minutes Greater Than 90 Percent of GTL

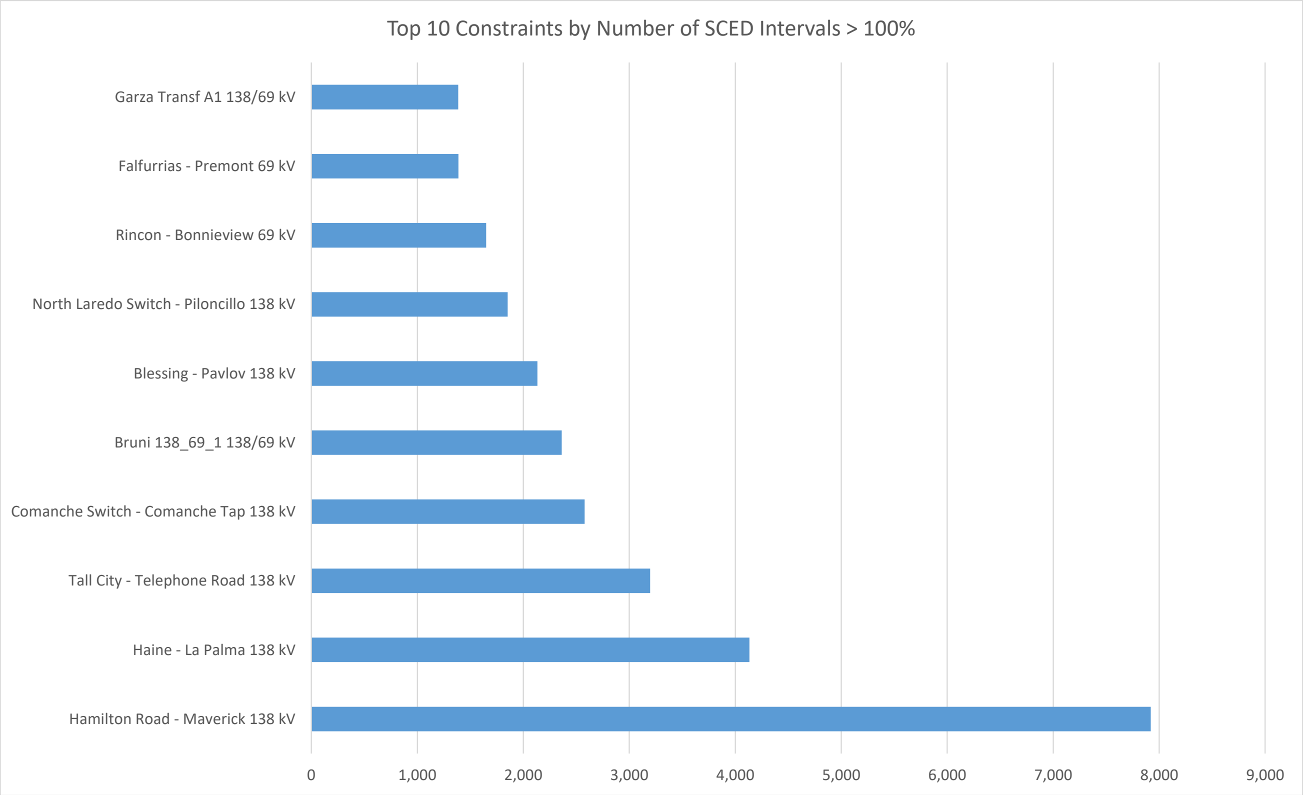


Figure B.16 – 2021 Top Constraints by Duration

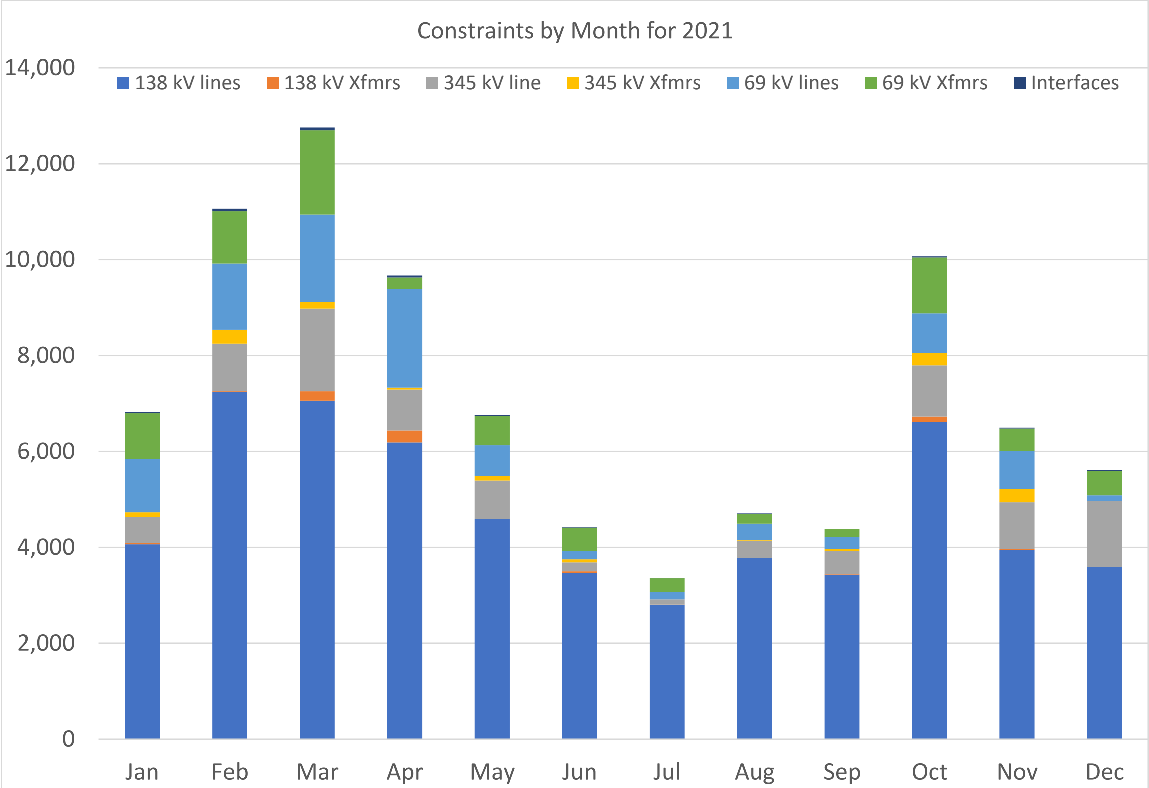


Figure B.17 – Constraints by Month for 2021

ERCOT also posts a Chronic Congestion Summary report each month. This report provides the following:

(1) All security violations that were 125 percent or greater of the Emergency Rating for a single SCED interval or greater than 100 percent of the Emergency Rating for a duration of 30 minutes or more during the prior reporting month and the number of occurrences and congestion cost associated with each of the constraints causing the security violations on a rolling 12-month basis.
(2) Operating conditions on the ERCOT System that contributed to each security violation reported in paragraph (1) above.

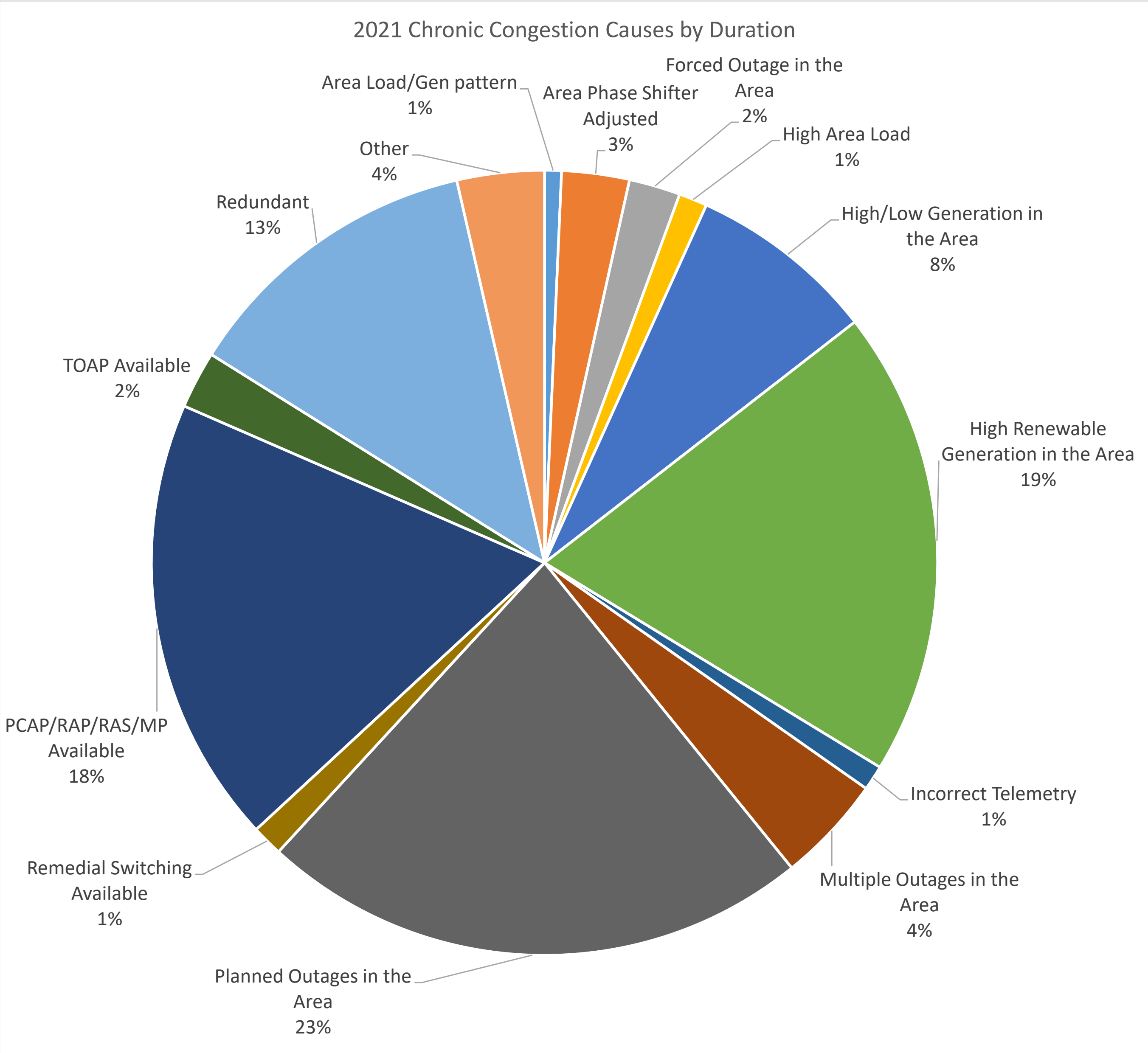


Figure B.18 – 2021 Chronic Constraint Causes by Duration

F. Reliability Unit Commitments

The Reliability Unit Commitment (RUC) process ensures that there is adequate Resource capacity and Ancillary Services capacity committed in the proper locations to serve ERCOT's forecasted load. Day-ahead RUC (DRUC) commitments are made for the next operating day. Hour-ahead (HRUC) commitments are made for a specific operating hour(s) after the DRUC process is completed.

HRUC commitments saw a dramatic increase in 2021 due to a change in ERCOT's methodology. RUC commitments totaled 88 units for 400 commitment hours. The primary reason for HRUC commitments was capacity, which accounted for approximately 83 percent of all HRUC hours.

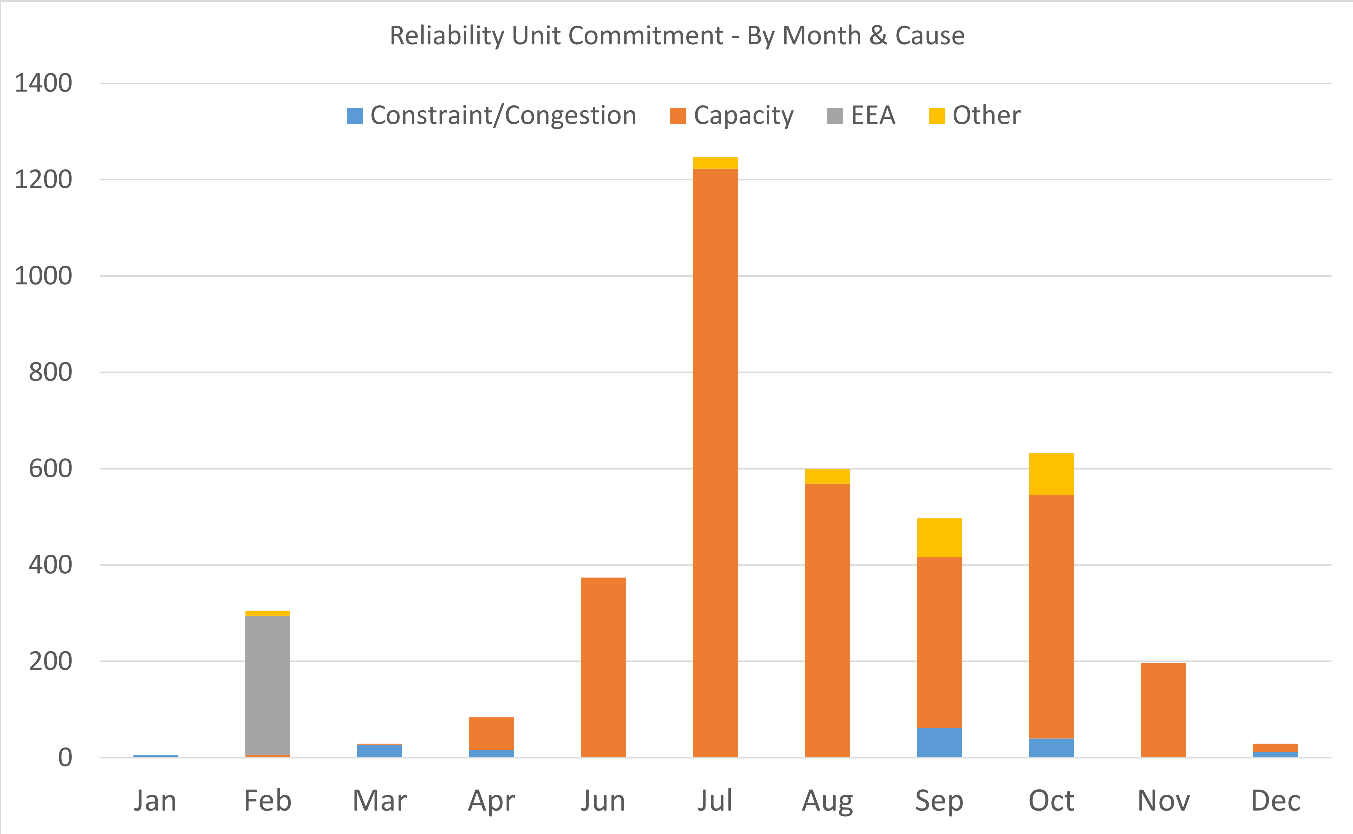


Figure B.19 – 2021 Hourly Reliability Unit Commitments by Month and Cause

Appendix C – Grid Transformation Detailed Analysis

A. Unit Additions and Retirements

Retirements and Mothball Status – 569 MW

Unit	Date	Status	MW	Fuel Type
Olinger 1	4/5/2022	Retired	78	Gas
Decker G2	3/31/2022	Retired	420	Gas
Petra Nova	6/26/2021	Mothballed	71	Gas

New Resources Approved for Commercial Operation – 9,317 MW

Unit	Date	MW	Fuel Type
Greasewood Solar	2/9/2021	255	Solar
Oxy Solar	2/24/2021	16.2	Solar
PES1	3/30/2021	306	Gas
Amadeus Wind	4/5/2021	250.1	Wind
STP Unit 1 Repower	4/15/2021	13	Nuclear
BlueBell Solar II	4/28/2021	113	Solar
Vera Wind V110	05/26/2021	34	Wind
Gulf Wind 1 repower	05/06/2021	0	Wind
Rio Nogales CT2 repower	05/06/2021	13	Gas
RTS2 Wind	05/14/2021	179.91	Wind
Vera Wind	05/26/2021	208.8	Wind
Juno Solar Phase 1	05/26/2021	166.12	Solar
Aviator Wind	06/22/2021	525	Wind
Espiritu Wind	06/10/2021	25.2	Wind
Gambit Batt	06/14/2021	102.4	Other
Taygete Solar	06/14/2021	255.07	Solar
Chalupa Wind	06/10/2021	174	Wind
Shaffer Wind	06/08/2021	226	Wind
East Raymond Wind (El Rayo)	06/11/2021	202	Wind
Eunice Storage	07/14/2021	40.26	Other
High Lonesome Wind	07/01/2021	449.5	Wind
High Lonesome Wind Phase II	07/01/2021	50.6	Wind
Hidalgo II Wind	07/30/2021	51	Wind
Coniglio Solar	08/09/2021	125.68	Solar
Impact Solar	08/20/2021	198.55	Solar
Juno Solar (Phase II)	08/09/2021	147.09	Solar
East Blackland Solar	08/12/2021	144	Solar
Phoenix Solar	09/01/2021	82.3	Solar
Eunice Solar	09/24/2021	426.7	Solar
Prospero Solar II	09/23/2021	250	Solar
Barrow Ranch Wind	09/07/2021	160	Wind
Chisholm Grid	10/01/2021	101.7	Other
West Raymond (Trueno) Wind	10/26/2021	239.8	Wind
Wagyu Solar	10/04/2021	120	Solar
North Fork Energy Storage	10/22/2021	100.49	Other
Lily Storage	10/08/2021	51.74	Other

Oveja Wind	10/20/2021	300	Wind
RE Maplewood 2a Solar	10/11/2021	222	Solar
Griffin Trail Wind	10/28/2021	225.6	Wind
RE Maplewood 2b Solar	10/11/2021	28	Solar
Galloway Solar	10/27/2021	250	Solar
Lily Solar	10/08/2021	147.63	Solar
Topaz Power Plant	10/14/2021	510	Gas
Corazon Solar	10/11/2021	202.64	Solar
Bat Cave Energy Storage	10/22/2021	100.49	Other
Titan Solar	11/22/2021	270	Solar
Azure Sky Solar	11/15/2021	228.4	Solar
PES 2 Power Station	11/11/2021	102	Gas
Long Draw Solar	12/14/2021	226.73	Solar
Misae Solar	12/20/2021	240.8	Solar
Aragorn Solar	12/22/2021	187.2	Solar
Venado Wind	12/06/2021	201.6	Wind
Spencer 4	10/11/2021	61	Gas (return from mothball)
Spencer 5	10/11/2021	65	Gas (return from mothball)
Nacogdoches	10/15/2021	105	Wood (return from mothball)
Wharton County	2/4/2022	94	Gas (return from retirement)

Table C.1 – 2021 Unit Additions and Retirements

B. Fuel Mix Analysis

Wind generation reporting in GADS-Wind produced a net total of 74,865 GWH in 2021, or 78.4 percent of the total ERCOT wind generation for 2021. Wind generation, as a percentage of total ERCOT energy produced, increased to 24.3 percent in 2021, up from 22.8 percent in 2020. In 2021, hourly wind generation reached a maximum of 24,463 MW on December 23, 2021, at 8:00 p.m., and hourly wind generation served a maximum of 65.8 percent of system demand on March 22, 2021, at HE01

Utility-scale solar generation within the region continued its significant growth in 2021. The amount of energy provided by solar generation increased 84 percent versus 2020.

Wind energy curtailments totaled 5,182.3 GW-Hrs in 2021. Solar energy curtailments totaled 1,434.8 GW-Hrs in 2021.

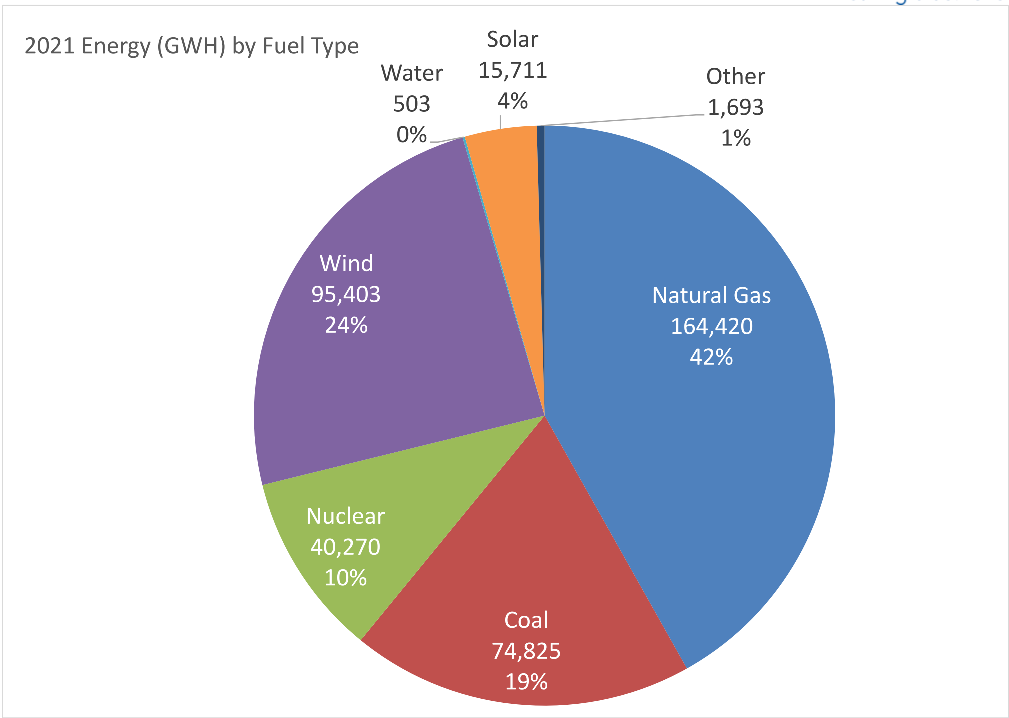


Figure C.1 – 2021 Energy by Fuel Type

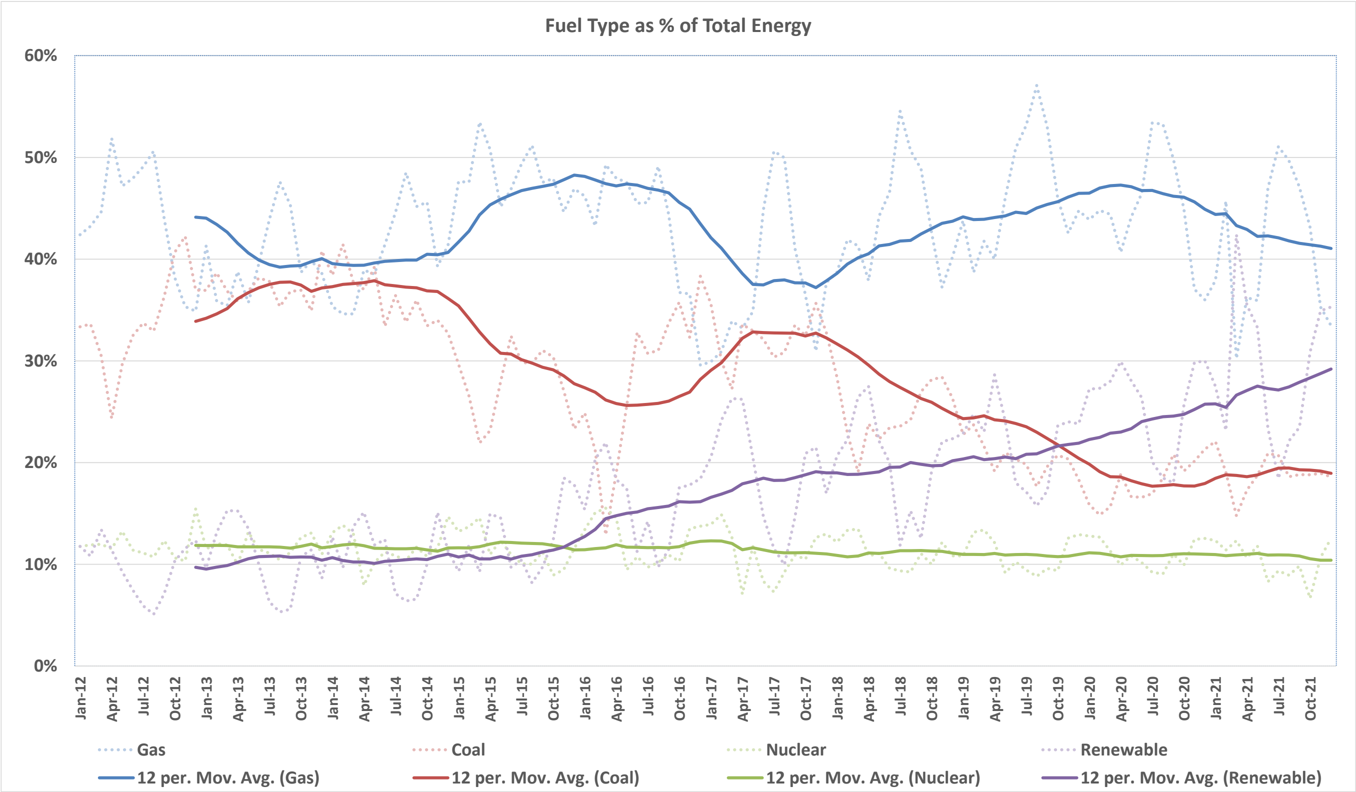


Figure C.2 – Energy by Fuel Type Trend

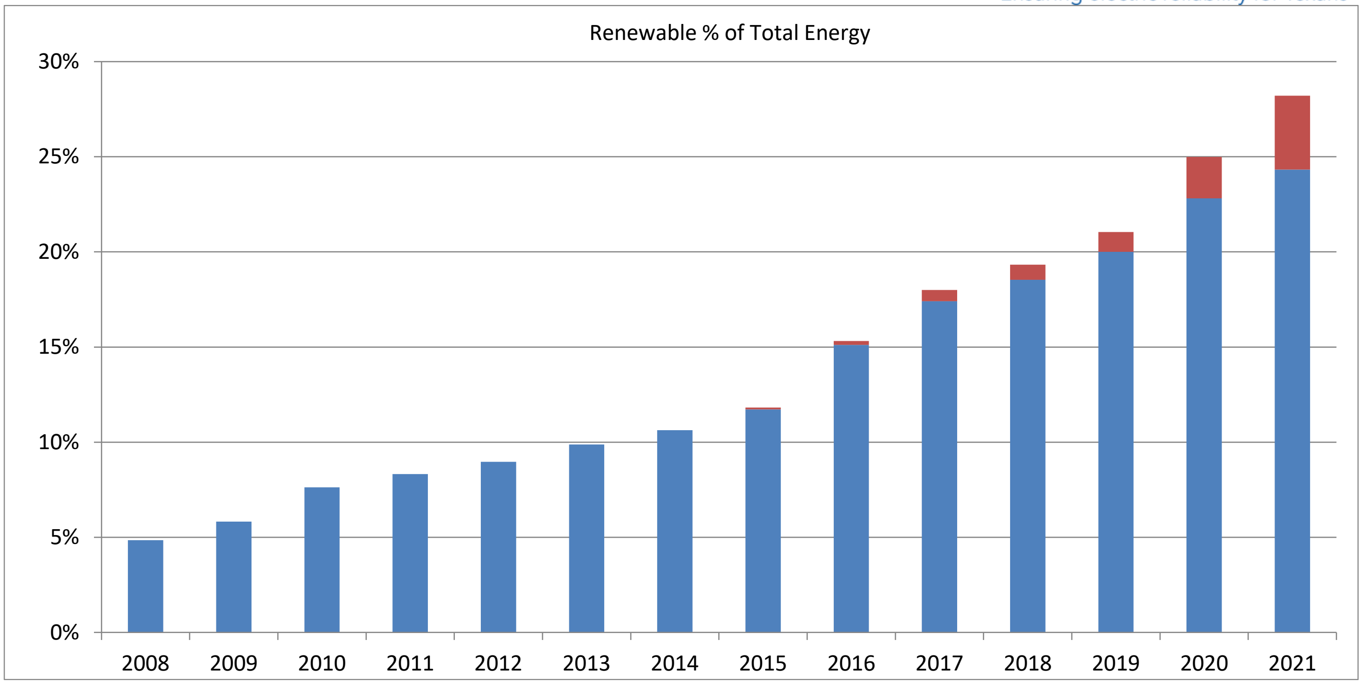


Figure C.3 – Renewable Energy Percentage of Total Load Time Trend

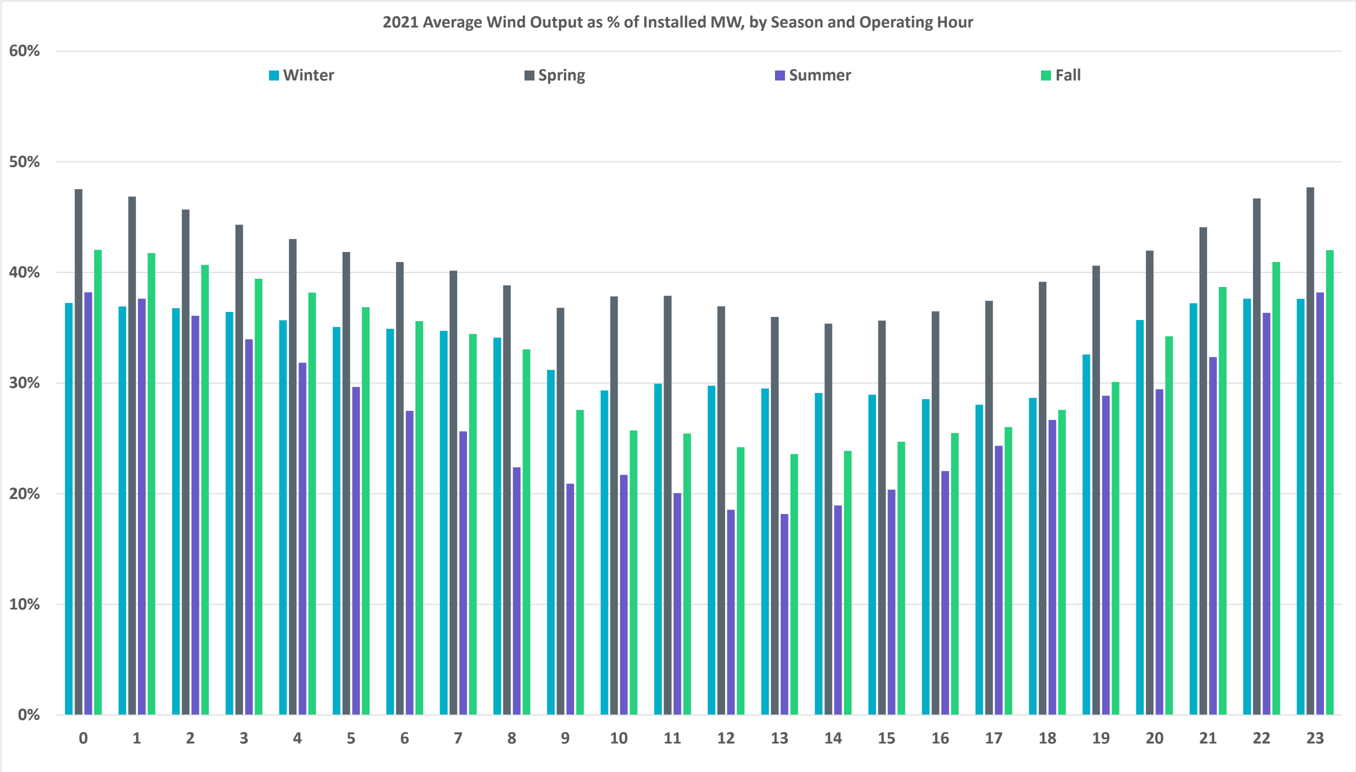


Figure C.4 – Average Wind Output as a Percentage of Installed Wind MW by Season/ Hour

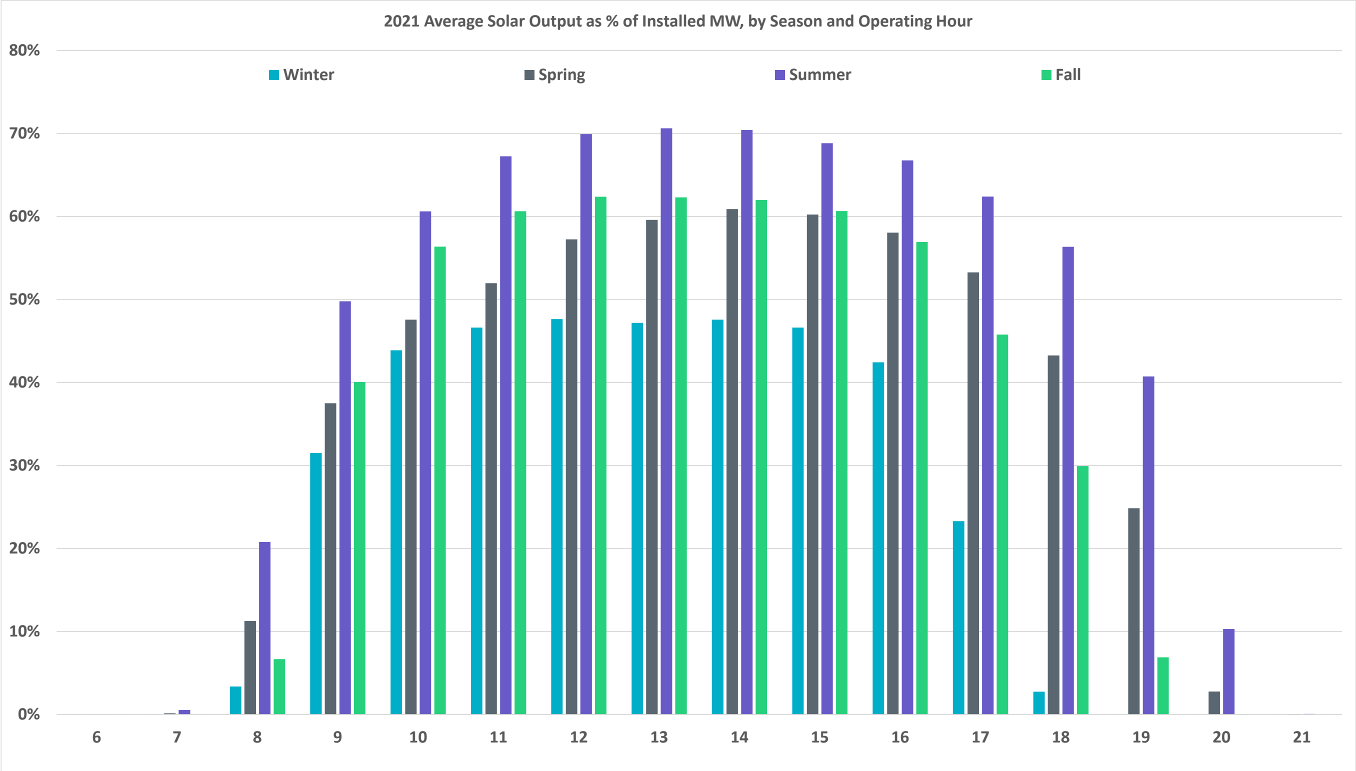


Figure C.5 – Average Solar Output as a Percentage of Installed Solar MW by Season/ Hour

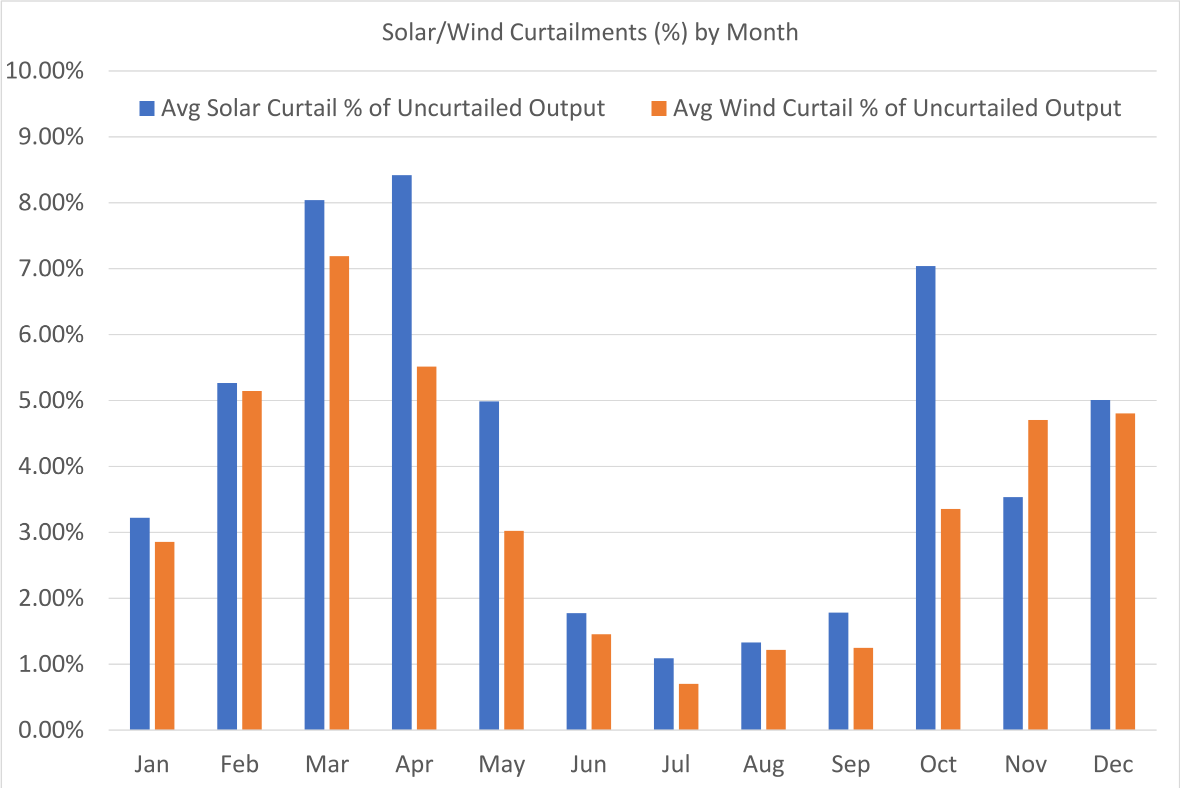


Figure C.6 – Solar and Wind Curtailments as a Percentage of Uncurtailed Output

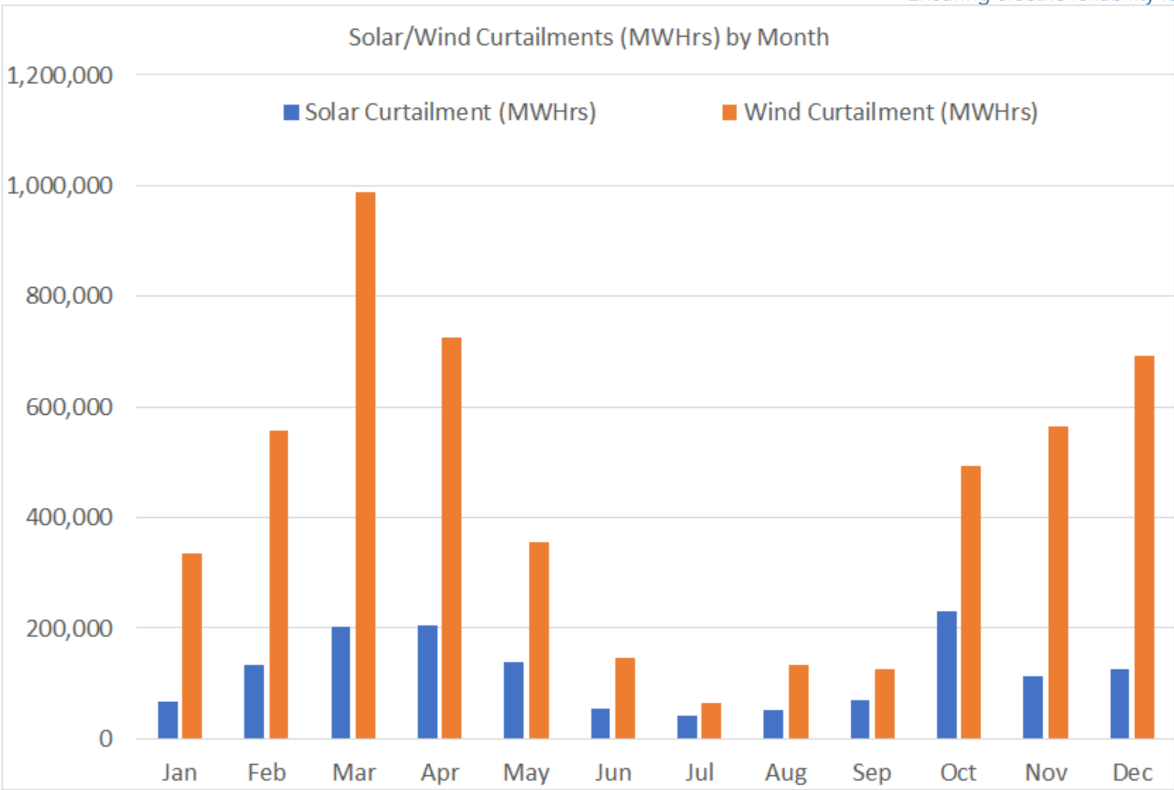


Figure C.7 – Solar and Wind Curtailments in MWHrs by Month

C. Synchronous Inertia

ERCOT calculated that the critical inertia level for the Interconnection is approximately 94 Gigawatt-seconds (GW-s). ERCOT uses a critical inertia level of 100 GW-s 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 2021 was 109.6 GWs, on March 22, 2021, at HE01, when the IRR penetration level was 65.8 percent and system load was 31,904 MW (net load of 10,905 MW).

Year	Minimum Inertia (GW-s)	Load (MW)	Net Load (MW)	IRR %
2015	130.3	27,798	20,569	26.1%
2016	138.4	26,839	14,797	44.9%
2017	130.0	28,443	13,178	53.7%
2018	128.8	28,412	13,452	52.7%
2019	134.6	29,426	14,645	50.2%
2020	131.1	31,505	13,541	57.0%
2021	109.6	31,904	10,905	65.8%

Table C.2 – Minimum Inertia for 2015-2021

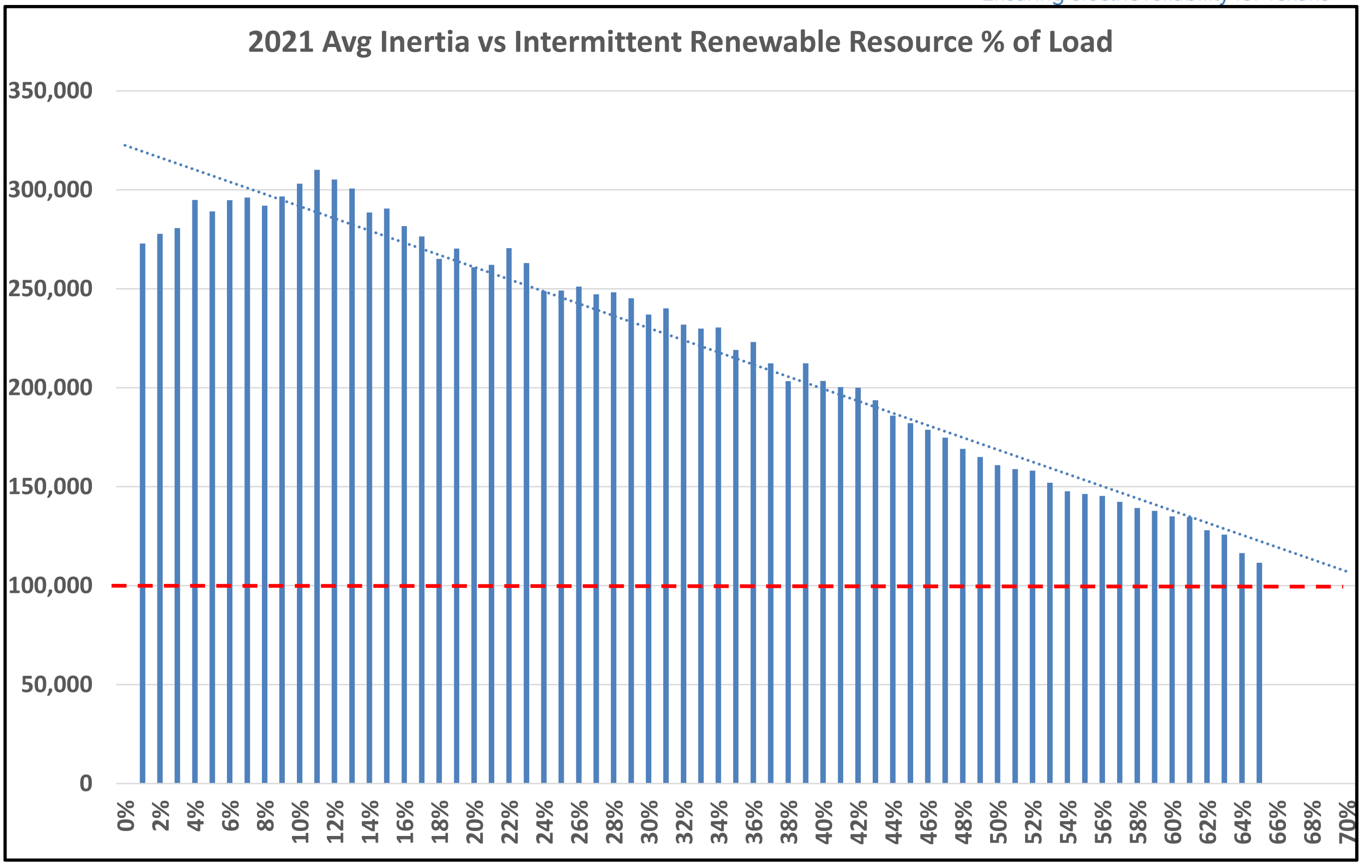


Figure C.8 – 2021 Average Inertia versus Renewable Percentage of Load

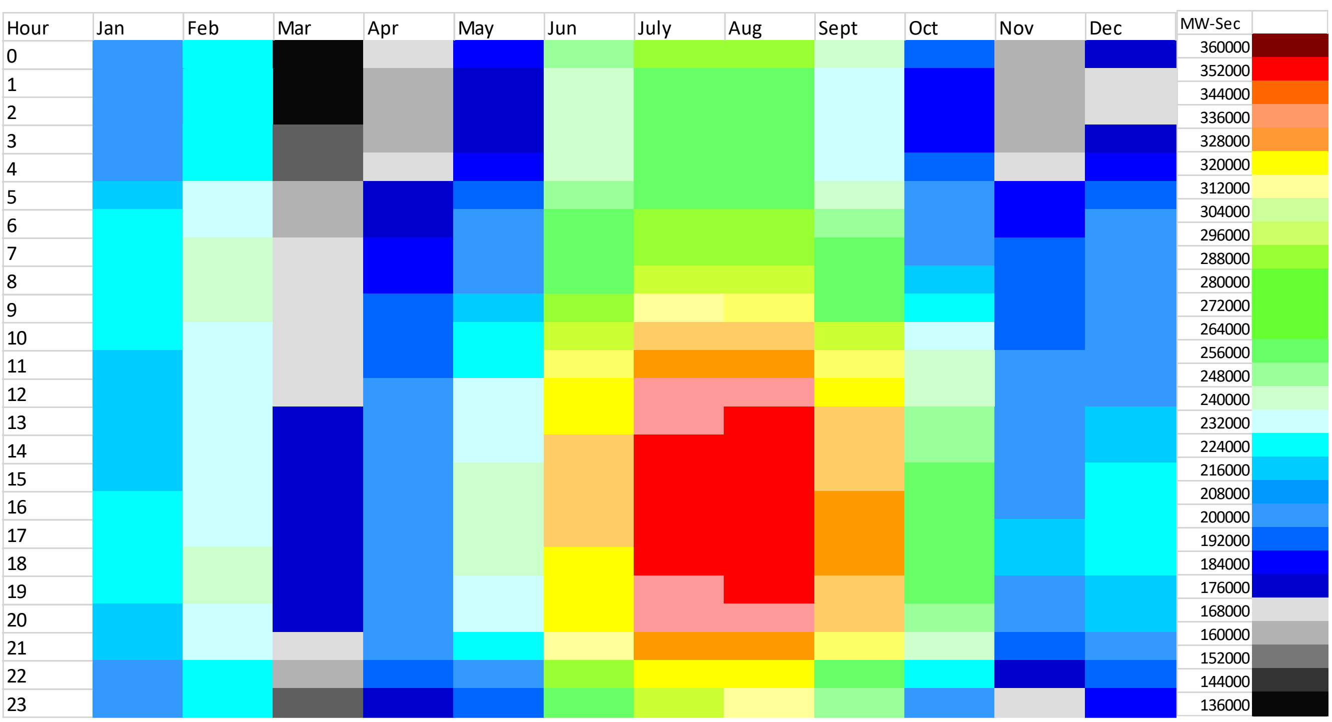


Figure C.9 – 2021 Average Inertia by Month and Operating Hour

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 on line.

Ramping Variability	Load	Wind Gen	Solar Gen	Net Load
Maximum One-Hour Increase	4,813 MW	5,173 MW	4,325	8,446
Maximum One-Hour Decrease	-9,218 MW	-5,153 MW	-4,043	-9,167

Table C.3 – Maximum and Minimum Load, Wind, Solar, and Net-Load Ramps for 2021

There is a long-term increasing trend in the maximum one-hour up ramps for net load and solar. The following figure shows a comparison of the maximum one-hour load, net load, and wind ramps for 2021 compared to previous years.

Figure C.10 – Maximum One-Hour Ramps for 2017-2021

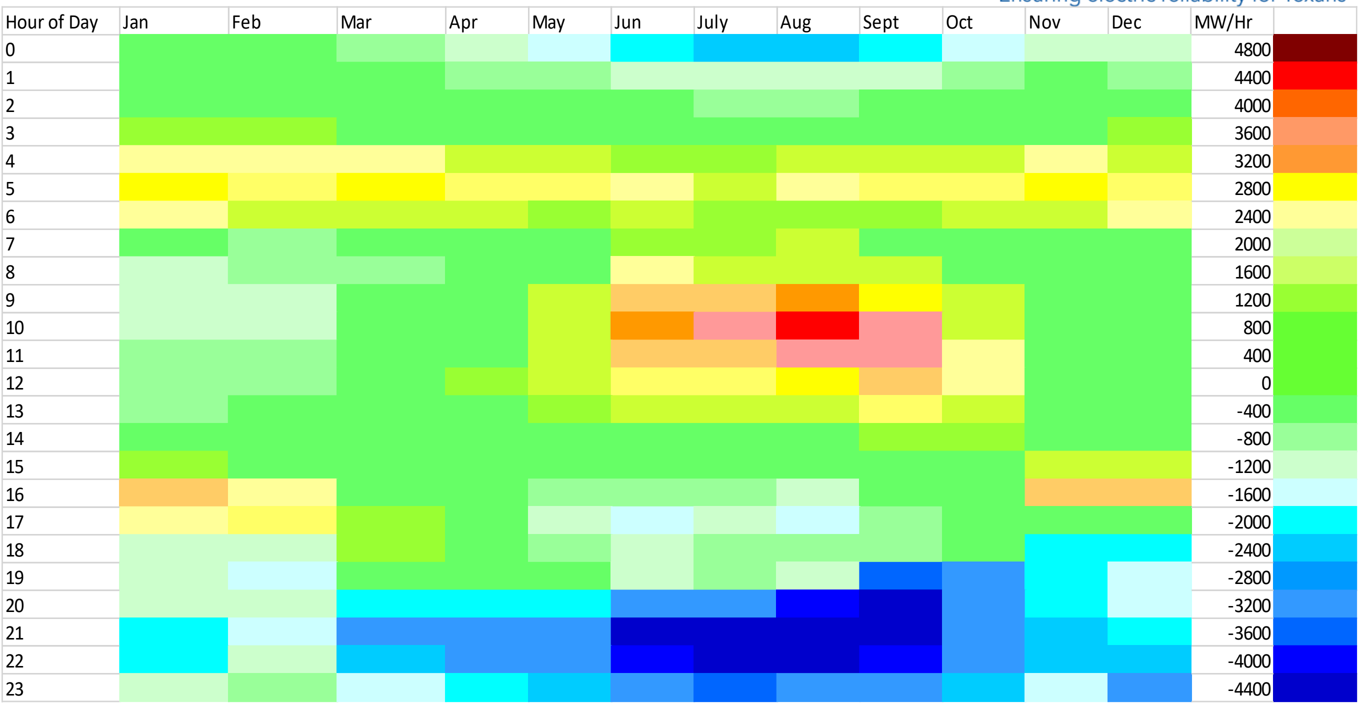


Figure C.11 – 2021 Heat Map of Net Load Ramp by Month and Operating Hour

Appendix D – Human Performance Detailed Analysis

A. Outages Initiated by Human Error

Outage rates for Protection System Misoperations and 345 kV circuit outages caused by human error are showing an improving, downward trend.

Element Type	Metric	2017	2018	2019	2020	2021	5-Yr Avg
AC Circuit 300-399 kV	Outages per Element Initiated by Human Error	0.7%	1.5%	1.2%	1.1%	0.8%	1.1%
AC Circuit 100-199 kV	Outages per Element Initiated by Human Error	1.3%	1.1%	2.1%	1.0%	1.2%	1.4%
Transformer 300-399 kV	Outages per Element Initiated by Human Error	0.5%	0.5%	0.5%	0.8%	0.0%	0.5%
Generator	Immediate Forced Outages Initiated by Human Error	4.2%	3.9%	2.4%	2.6%	3.2%	3.3%
Protection Systems	Misoperation Rate Caused by Human Error	3.2%	2.9%	2.7%	2.7%	2.0%	2.7%

Table D.1 – Outages Rates Caused by Human Error

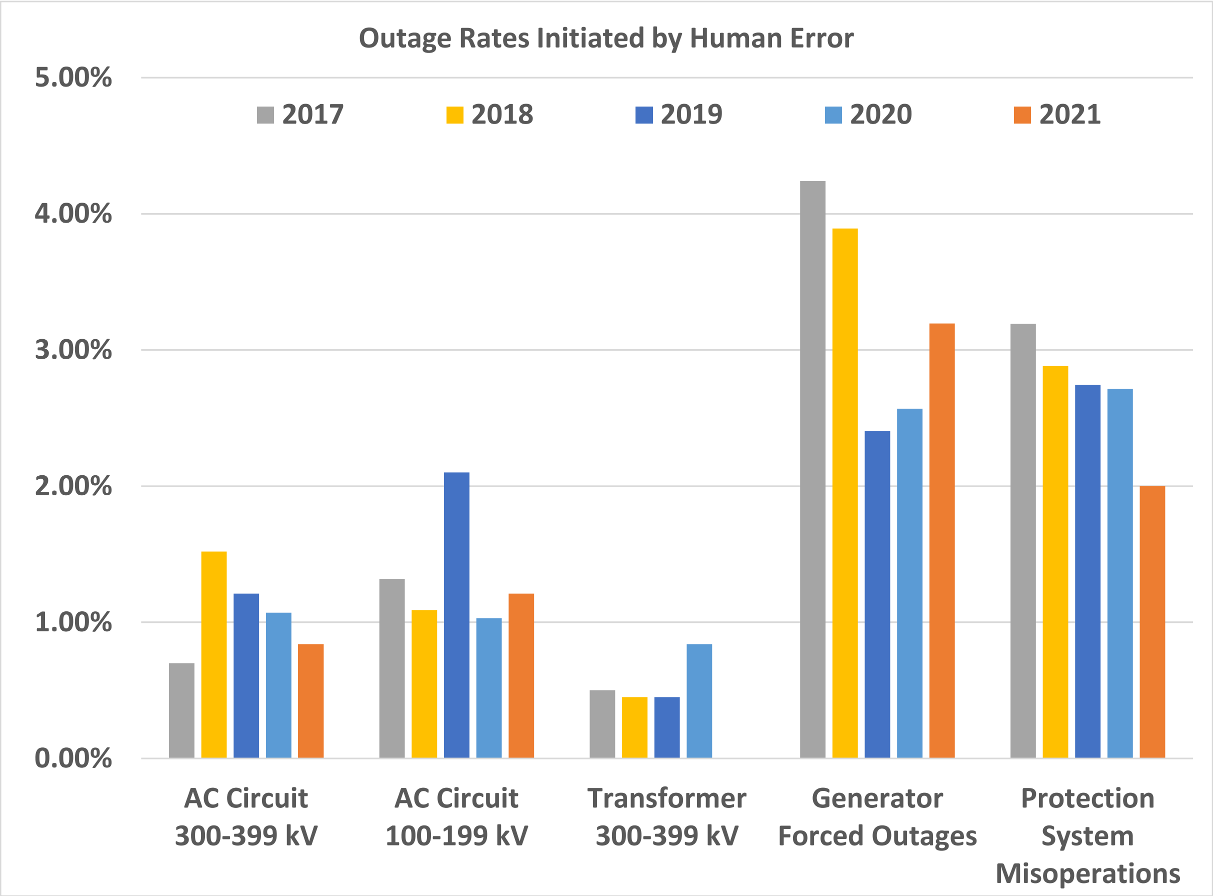
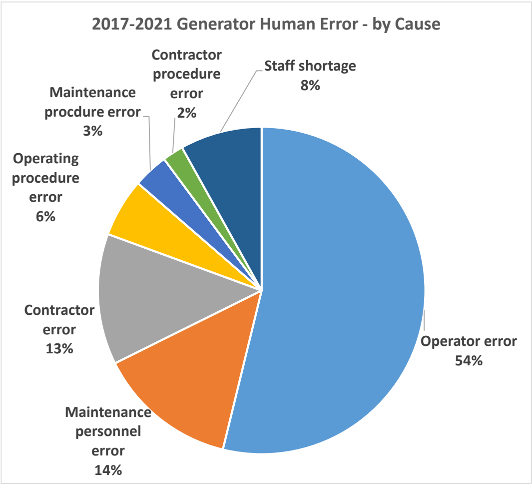


Figure D.1 – Outage Rates Caused by Human Error

Since 2017, there have been 433 generation immediate forced outages, de-rates, and startup failures caused by human error in ERCOT. The breakdown and impact of the causes is shown below.



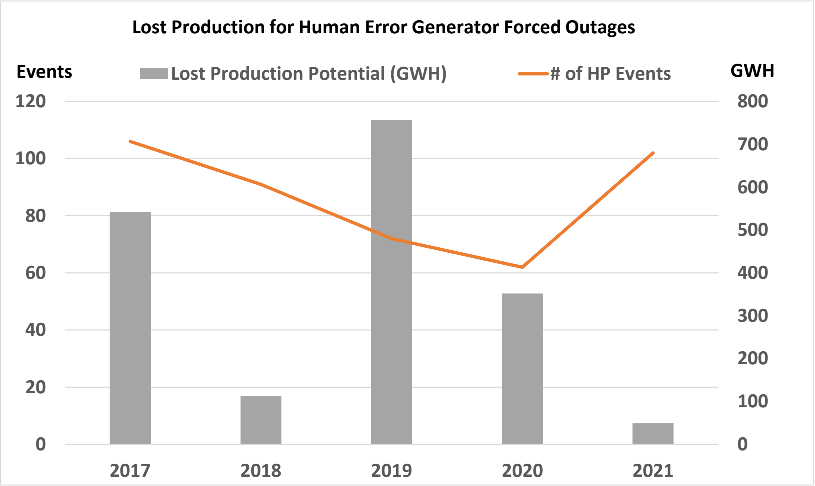


Figure D.2 – Generator Forced Outage Human Errors

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 will lead to the proper application of risk management procedures to develop and implement appropriate corrective and proactive actions.

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

Since 2017, 59 events in ERCOT have been analyzed using this cause code process, with 326 root cause and contributing cause codes assigned. Approximately 52 percent of the assigned root and contributing cause codes are related to potential human performance issues (shown in red below in Figure D.3).

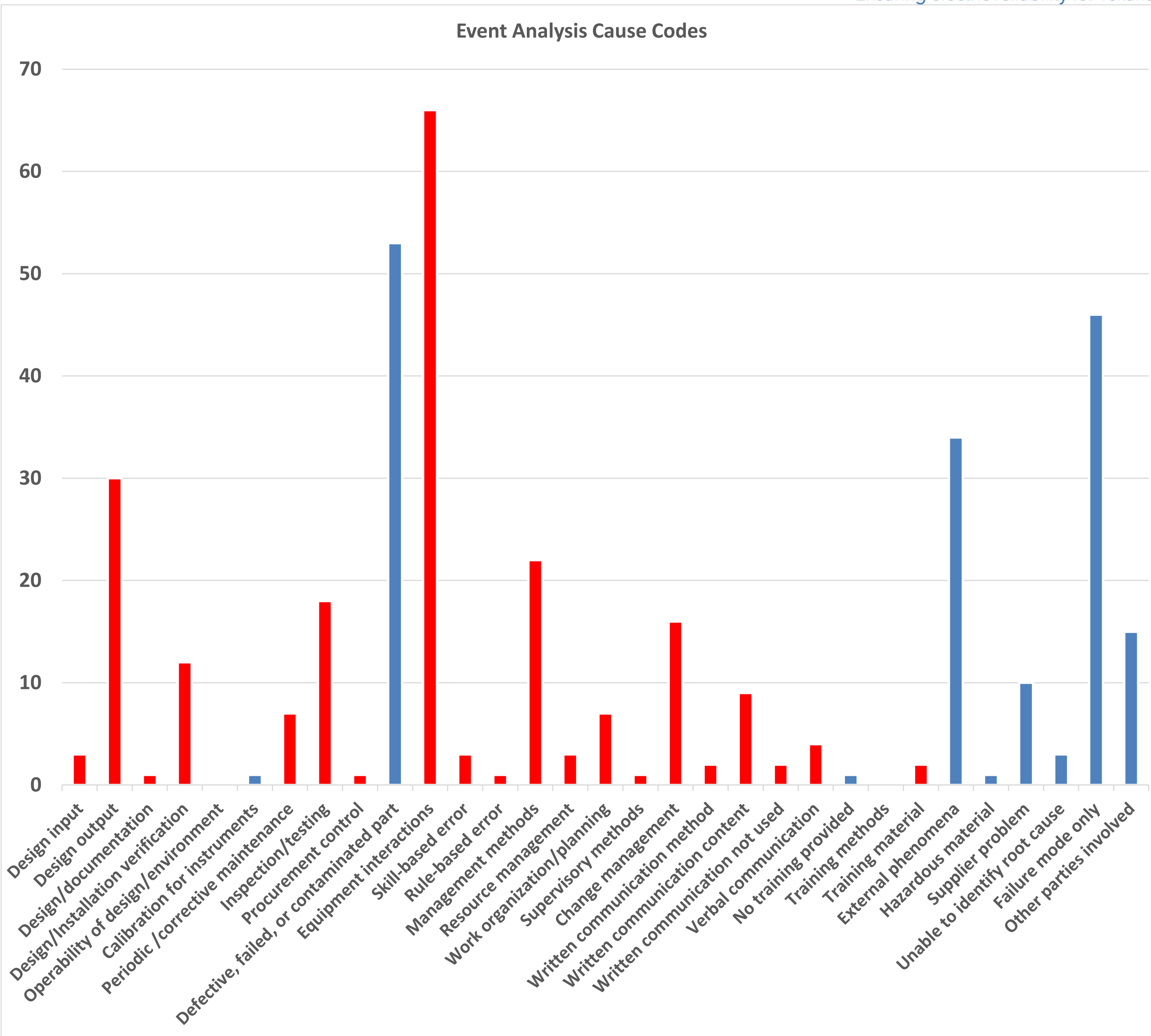


Figure D.3 – Event Analysis Human Performance Cause Coding

Appendix E – Bulk Power System Planning Analysis

A. Net Energy for Load

In 2021, total annual energy usage was 392.5 GWH, an increase of 3.2 percent from 2020. Peak hourly demand was 73,476 MW on August 31, 2021. The West Load Zone has seen the largest load energy usage increase (8.6 percent per year since 2017).

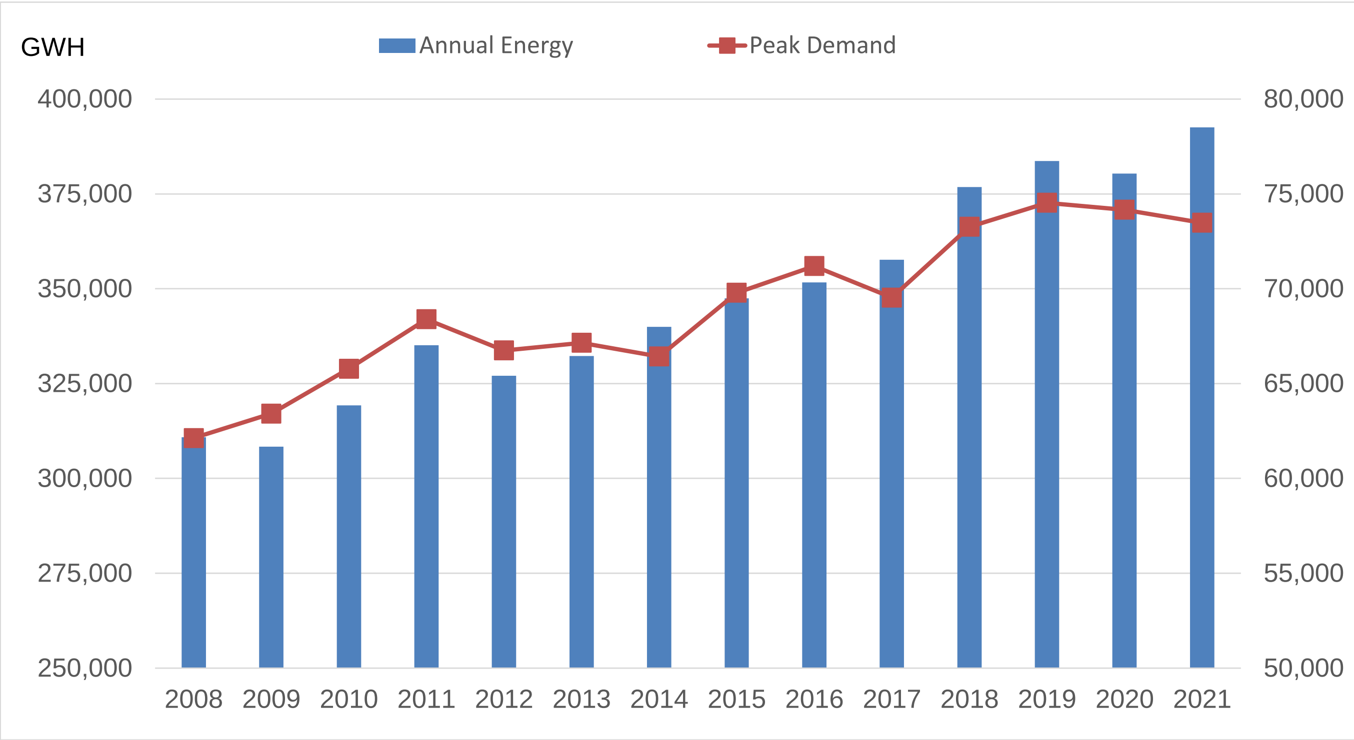


Figure E.1 – Annual Energy and Peak Demand

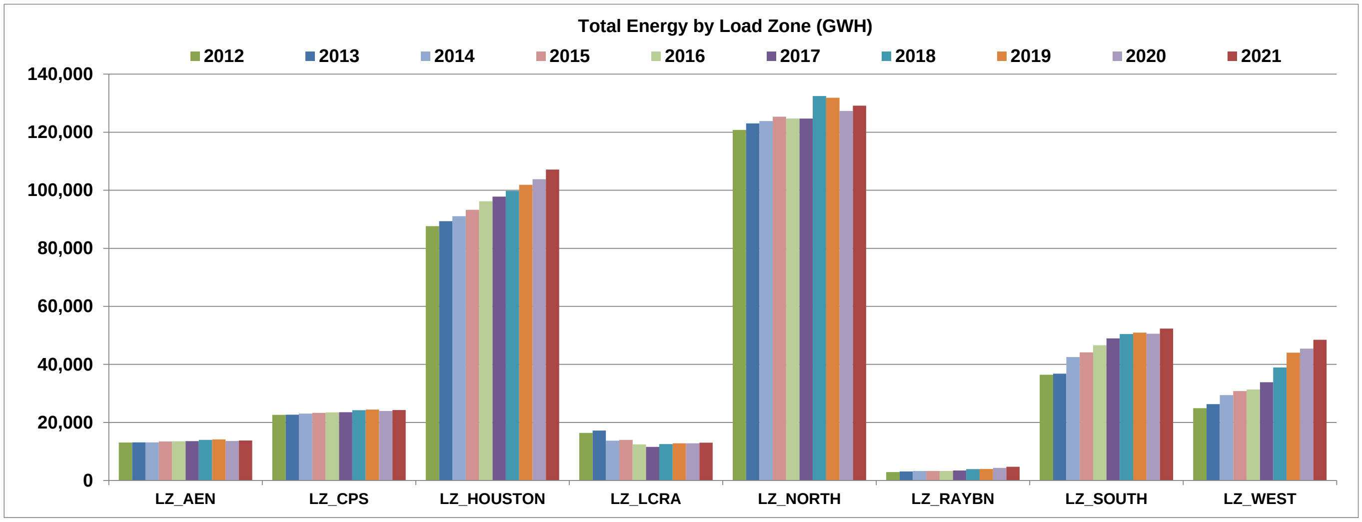


Figure E.2 – Energy by Load Zone

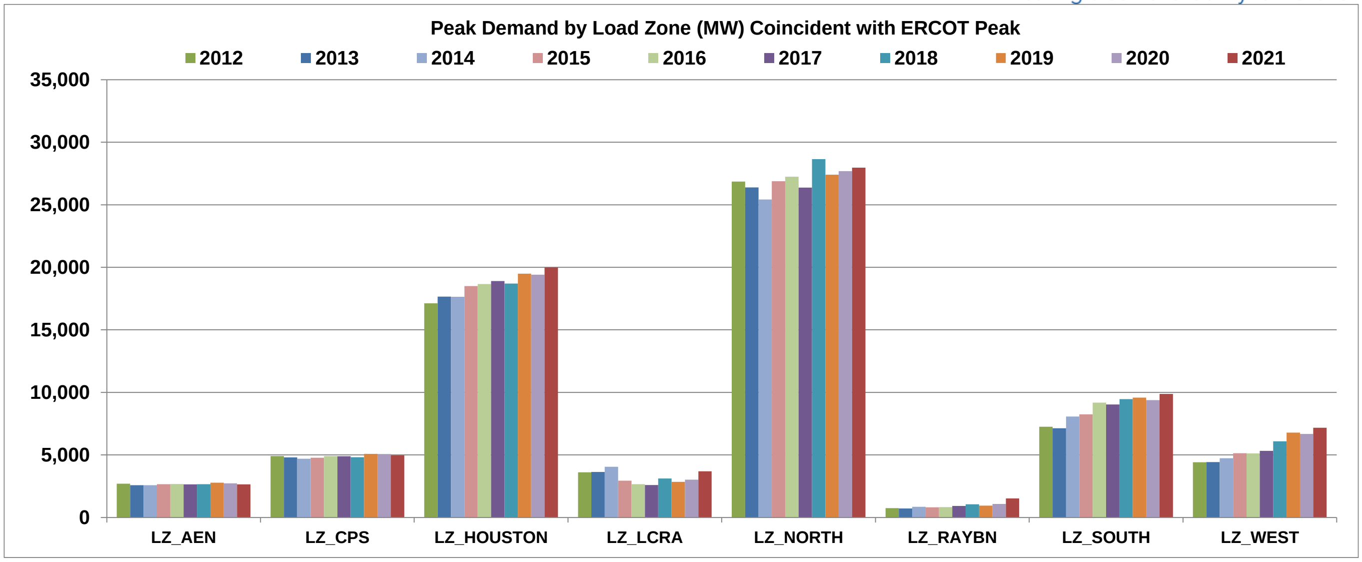


Figure E.3 – Peak Demand by Load Zone

The weather zone with the largest load energy usage increase was the Far West (13.4 percent per year since 2017).

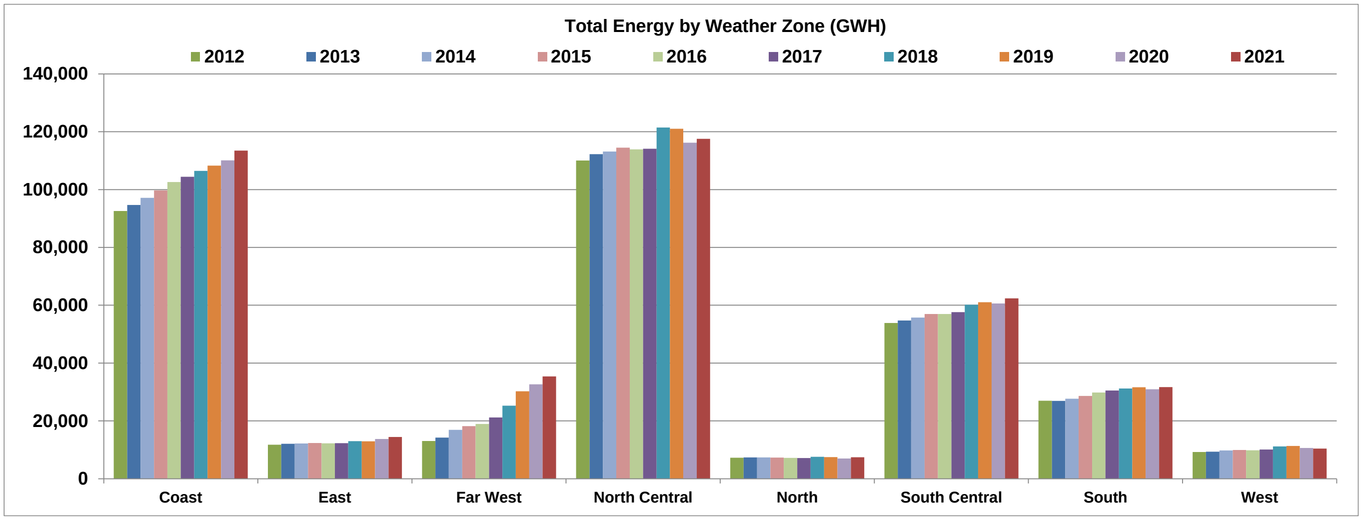


Figure E.4 – Energy by Weather Zone

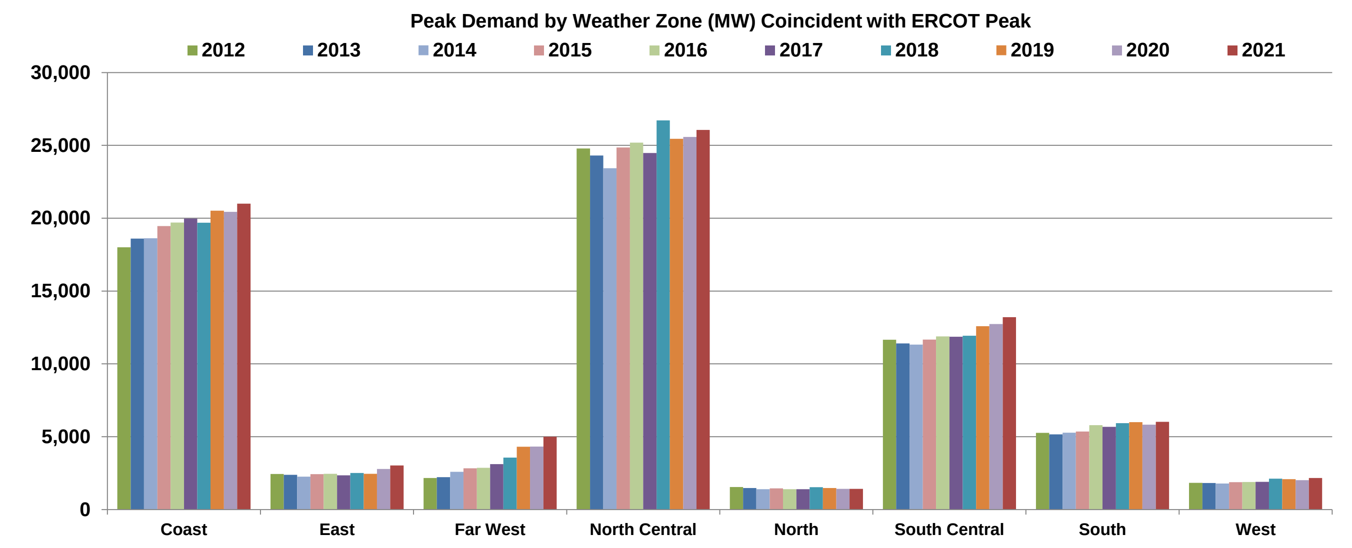


Figure E.5 – Peak Demand by Weather Zone

Overall energy growth rate has averaged 1.9 percent per year and demand growth rate has averaged 1.1 percent per year since 2017.

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.

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.

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. Both assessments show the planning reserve margin to be above the reference margin for the next five years.

ERCOT also publishes its Seasonal Assessment of Resource Adequacy (SARA) four times each year. The SARA report serves as an early indicator of the risk that ERCOT may need to call an Energy Emergency Alert Level 1 (EEA1) due to having insufficient operating reserves during seasonal peak electric demand periods. It uses a scenario approach to illustrate a range of resource adequacy outcomes based on extreme system conditions. The SARA report relies on projected resource capabilities and peak demand forecasts similar to the CDR report. However, unlike the CDR, it incorporates generator outage trends to determine the expected amount of resource capacity available for operating reserves.

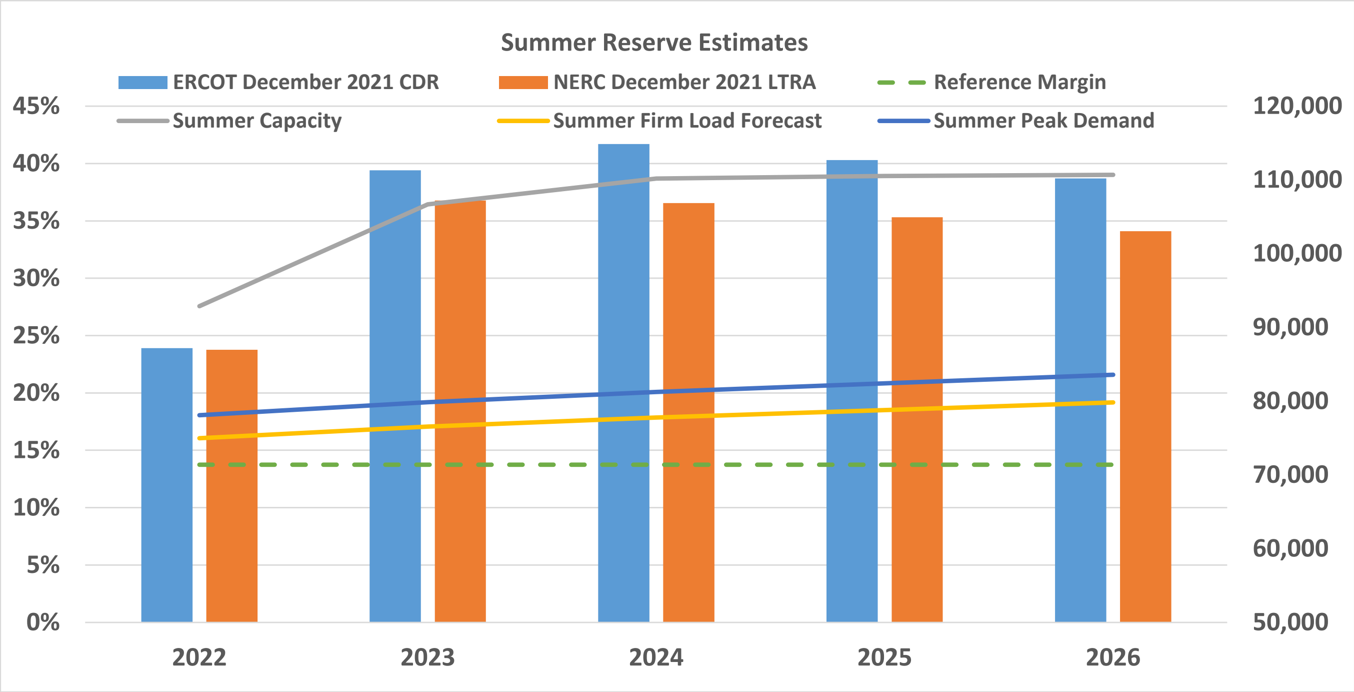


Figure E.6 – Summer Peak Reserve Margins

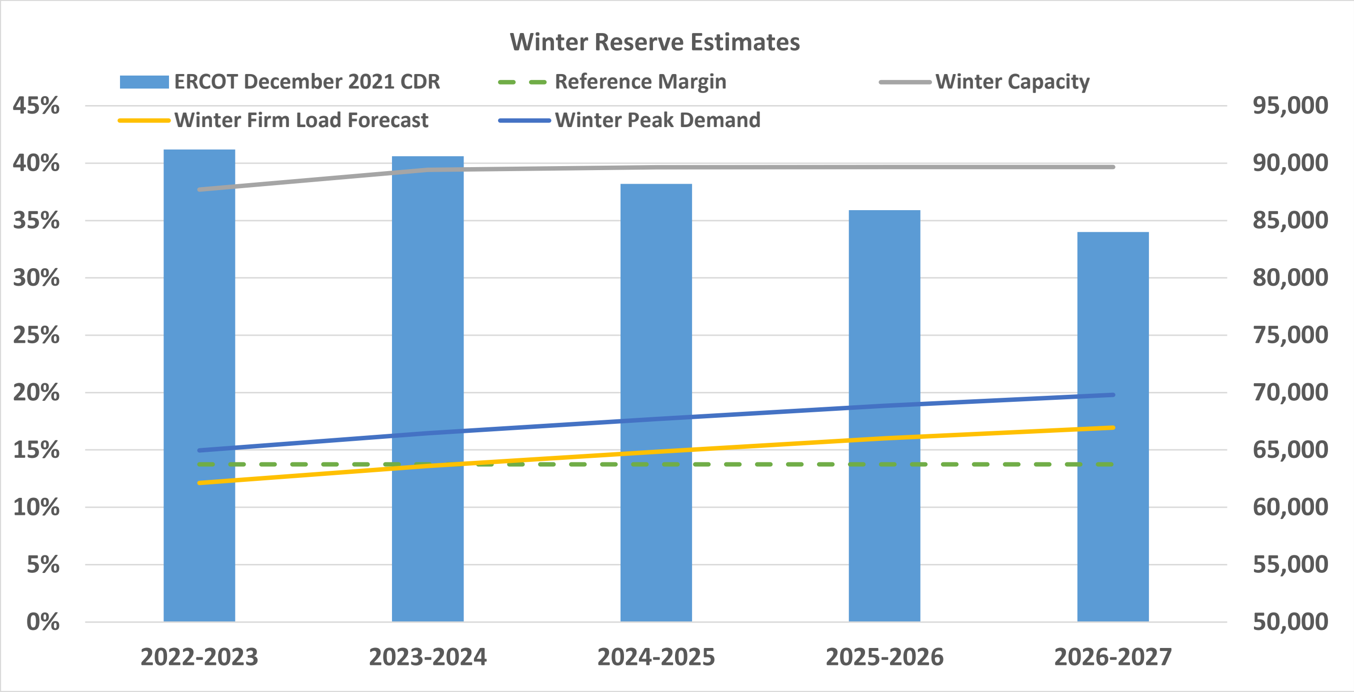


Figure E.7 – Winter Peak Reserve Margins

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

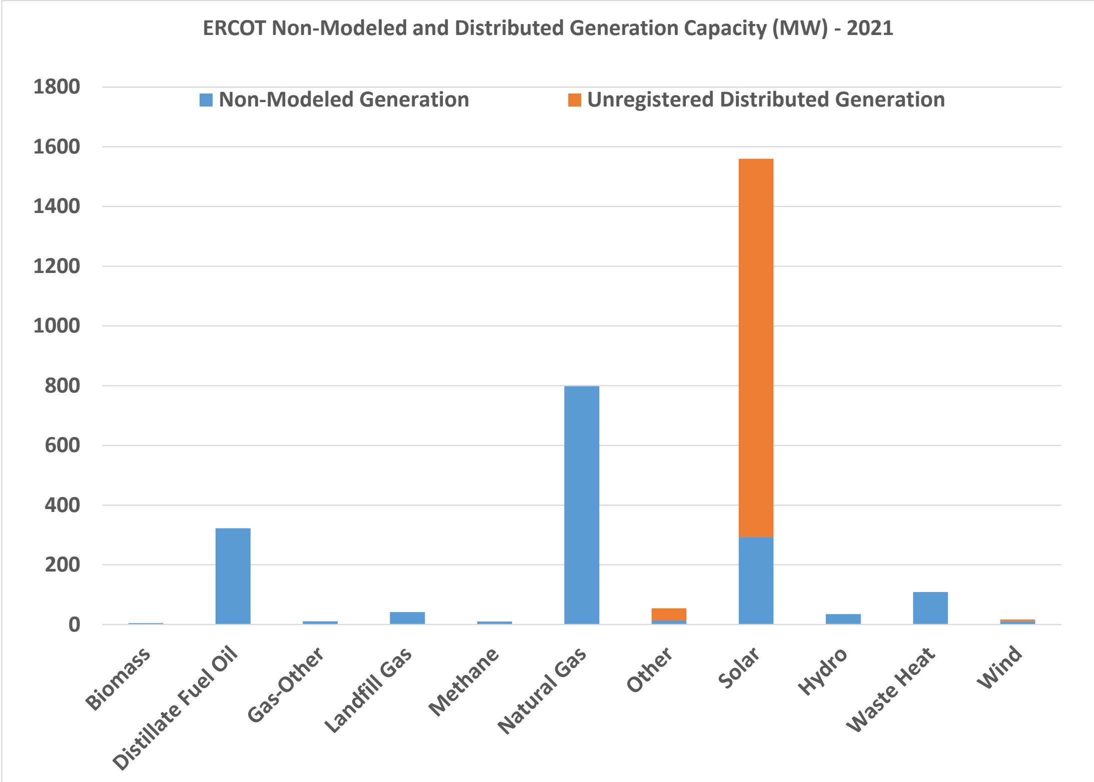
Increasing amounts of DER will change how the distribution system interacts with the BPS by transforming the distribution system into an active energy source. Currently, the aggregated effect of DER is not fully represented in BPS models or real-time operating tools. There are also differing expectations for DER performance between current Public Utility Commission of Texas (PUCT) rules and the Institute of Electrical and Electronics Engineers (IEEE) standards.

Issues with DER include:

- Modeling (both steady-state and dynamic)
- Ramping and energy-load balance
- Reactive power and voltage stability
- Frequency ride-through
- System protection and islanding protection
- Visibility and control
- Unanticipated power flows
- Load forecast errors

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 2021, ERCOT had approximately 1,650 MW of non-modeled generation capacity and 1,313 MW of unregistered distributed generation resources (DGR) that has provided data for mapping capacity to their modeled loads.



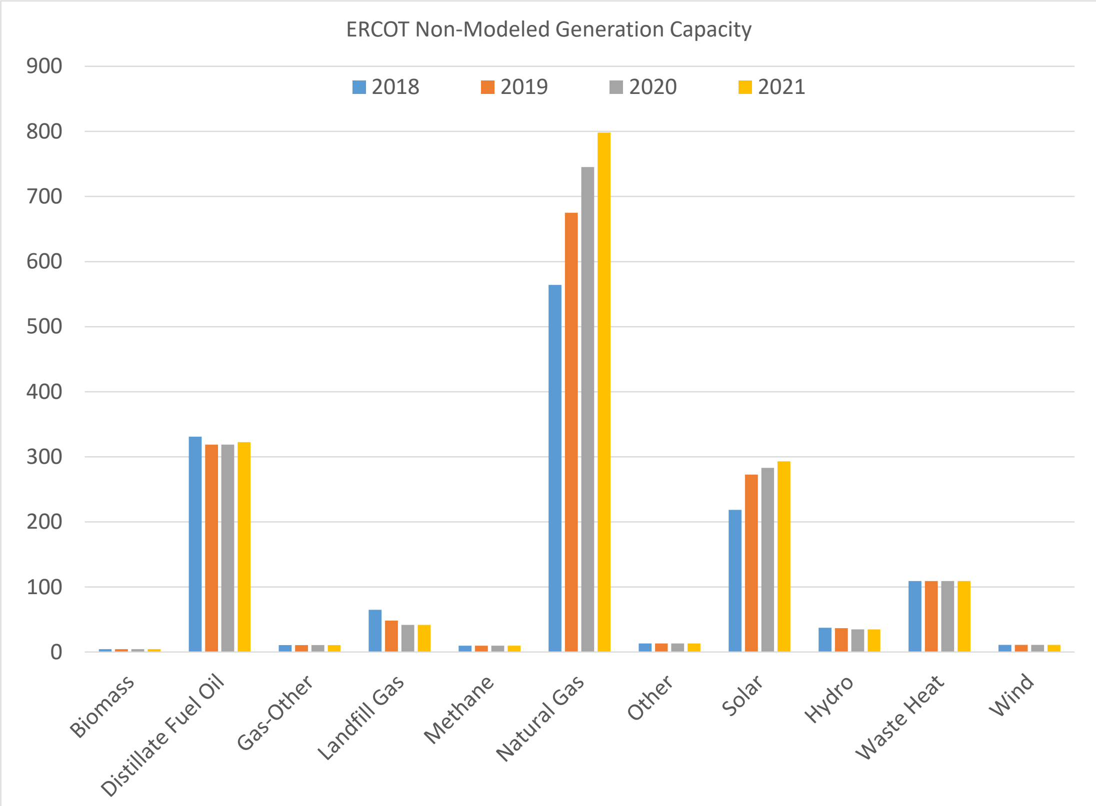


Figure E.8 – Non-Modeled Generation Capacity by Fuel Type

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 point at the NERC and regional levels. 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.

Loss of SCADA or EMS events reviewed in 2021 include the following:

- A TOP had multiple issues at their primary and backup control centers during Winter Storm Uri, including loss of external ISP services and frozen/broken water lines which flooded a portion of the backup control center.
- A TOP lost the ability to monitor and control when the Network Time Protocol (NTP) time service became disabled, causing the SCADA hosts to have the system time drift.
- A TOP lost the ability to monitor and control after a front-end processor (FEP) database upload failed due to a version mismatch between the FEP database and the software.
- A TOP lost the ability to monitor and control during a SCADA database sync rollout.
- A TOP lost the ability to monitor and control during a database upload. A documented data linking step was skipped during the SCADA model promotion process.
- A TOP lost the ability to monitor and control during a database upload when the software upload process paused, failed to execute the next step, and stopped further promotion tasks.

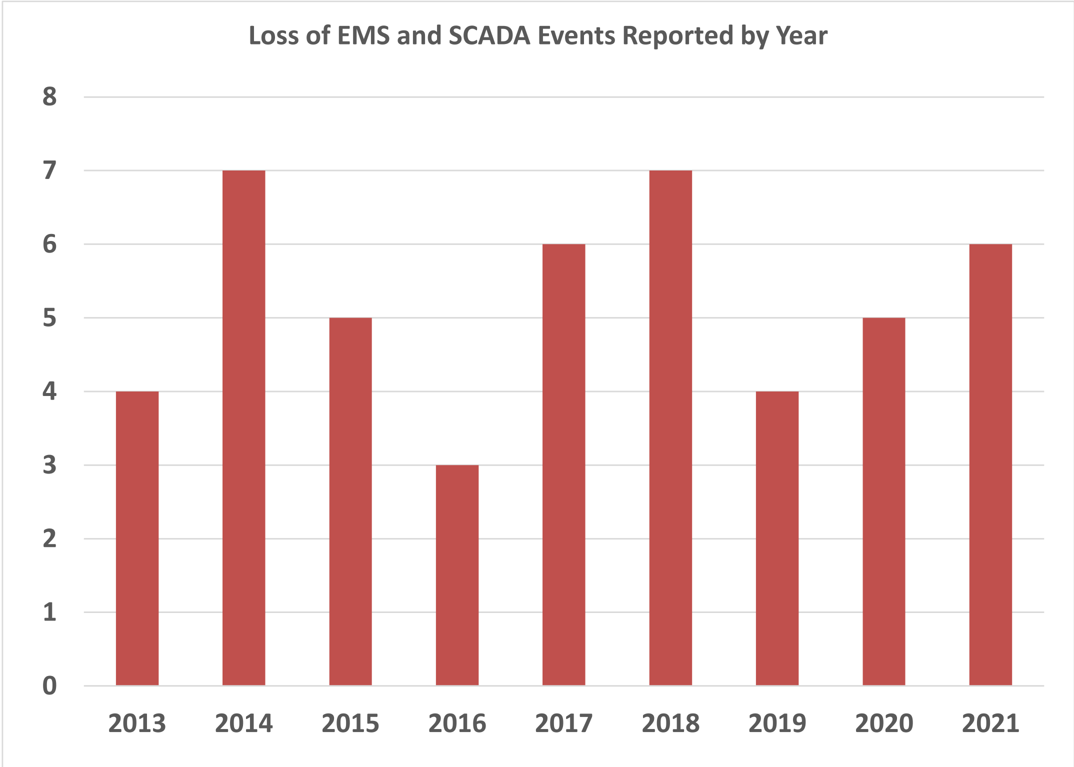


Figure F.1 – Loss of EMS and SCADA Events by Year

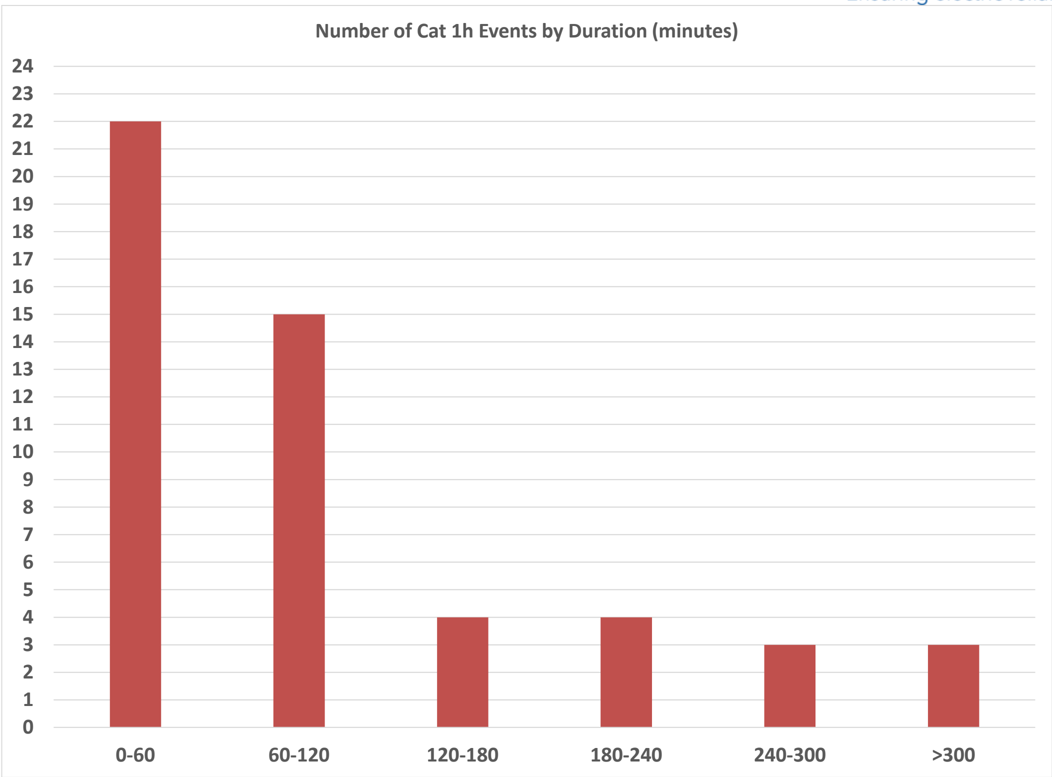


Figure F.2 – Loss of EMS and SCADA Events by Duration Since 2011

B. State Estimator Convergence

ERCOT's goal for State Estimator convergence is 97 percent or higher. In 2021, the convergence rate was 99.98 percent.

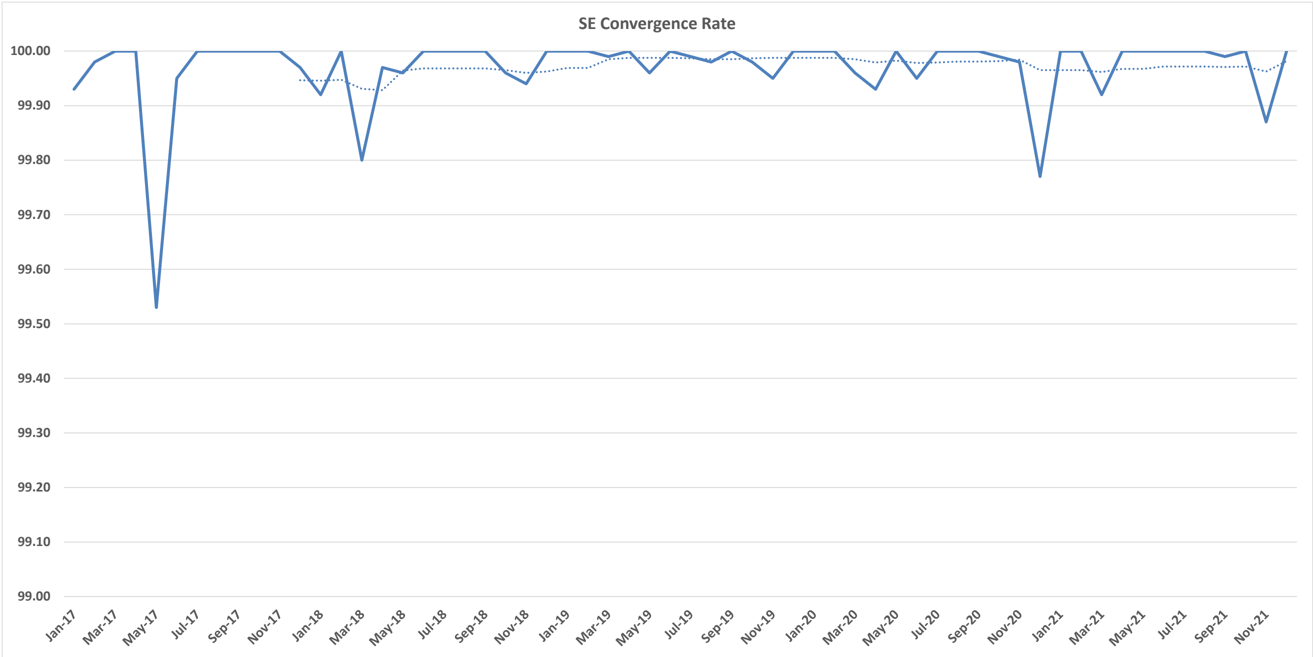


Figure F.3 – State Estimator Convergence Rate

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. The following figure shows the telemetry availability metric per the ERCOT telemetry standard. For 2021, the total number of telemetry points failing the availability metric averaged 4,621 each month, or 3.35 percent of the total system telemetry points.

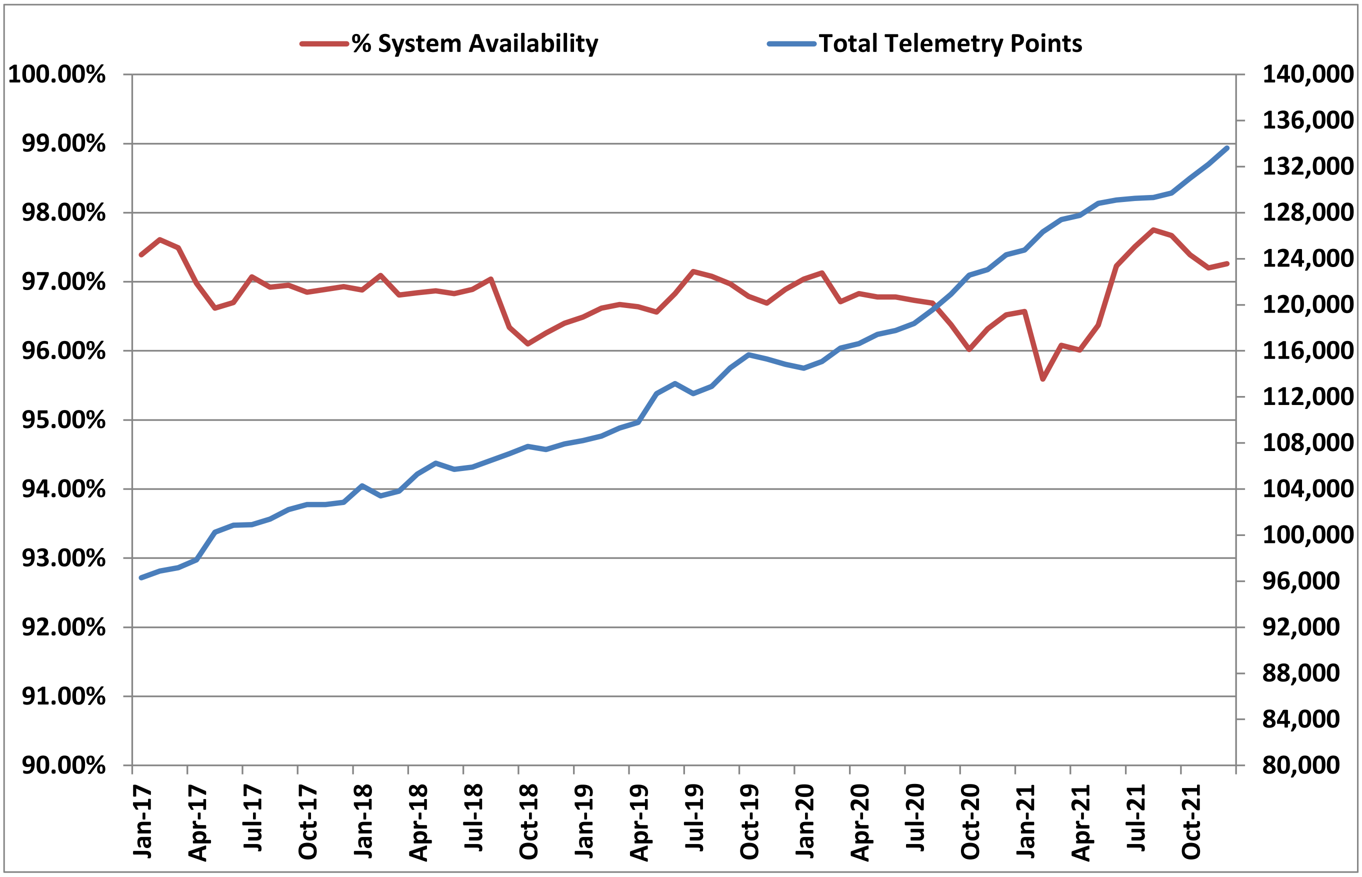


Figure F.4 – ERCOT Telemetry System Availability

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. 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.
3. 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.

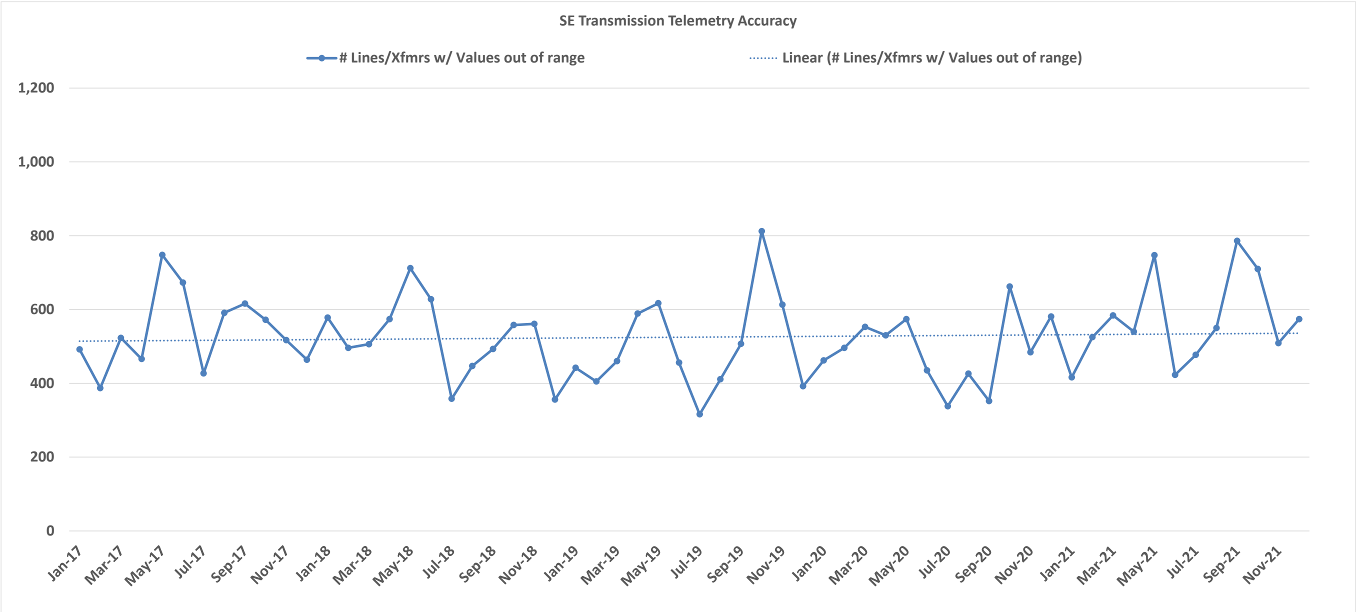


Figure F.5 – State Estimator versus Telemetry Accuracy

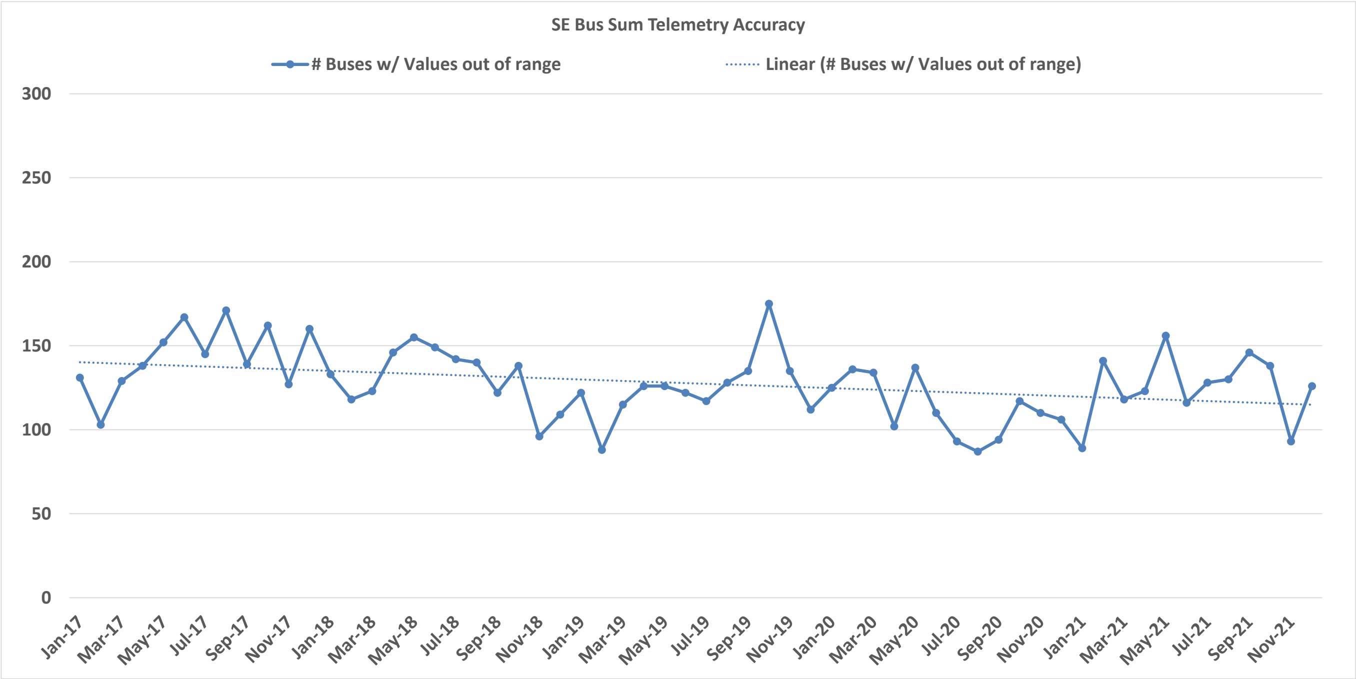


Figure F.6 – Bus Summation Telemetry Accuracy

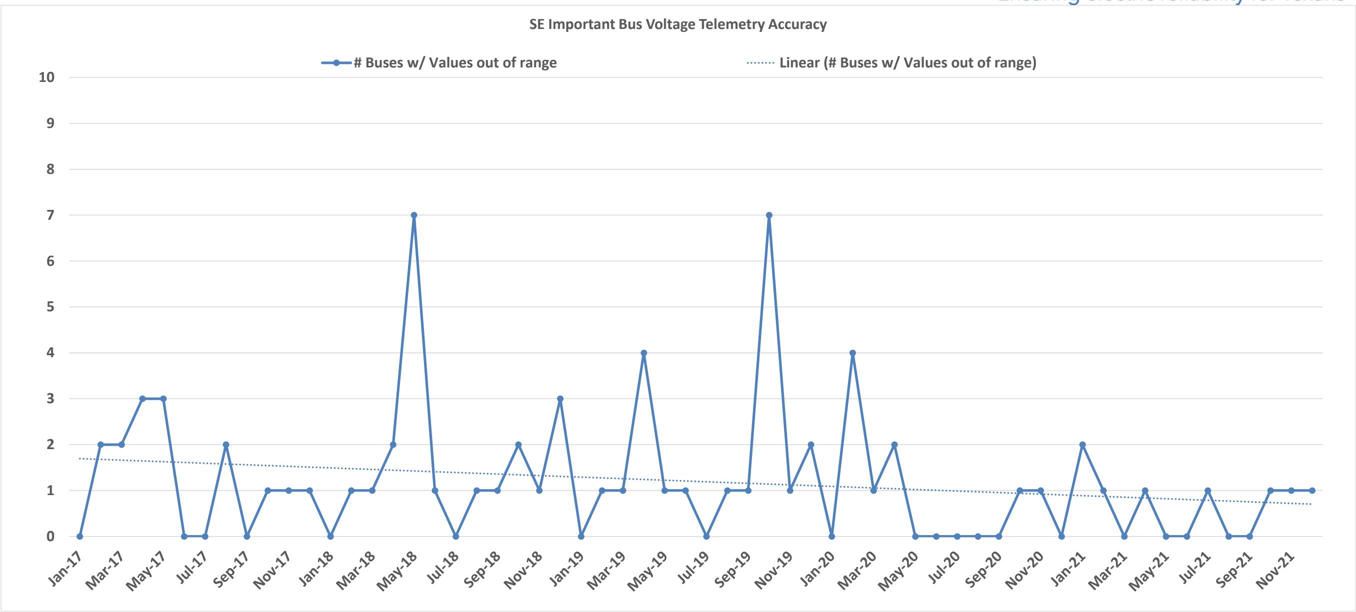


Figure F.7 – Bus Voltage Telemetry Accuracy

Appendix G – Protection System Detailed Analysis

A. Protection System Misoperations

Since January 2017, the overall transmission system Protection System Misoperation rate has improved from 6.5 percent in 2017 to 5.2 percent in 2021. The five-year misoperation rate from 2017-2021 was 6.2 percent.

138 kV	2017	2018	2019	2020	2021	5-Yr Avg
Number of Misoperations	120	101	115	72	102	102
Number of Events	1676	1639	1852	1305	1805	1655
Percentage of Misoperations	7.2%	6.2%	6.3%	5.5%	5.6%	6.2%
345 kV	**2017**	**2018**	**2019**	**2020**	**2021**	**5-Yr Avg**
Number of Misoperations	30	48	40	43	33	39
Number of Events	606	548	715	629	717	643
Percentage of Misoperations	4.9%	8.8%	5.6%	6.8%	4.6%	6.1%
< 100 kV	**2017**	**2018**	**2019**	**2020**	**2021**	**5-Yr Avg**
Number of Misoperations	0	5	1	1	0	1
Number of Events	76	44	55	62	76	63
Percentage of Misoperations	0.0%	11.4%	1.9%	1.6%	0.0	2.2%

Table G.1 – Protection System Misoperation Data

In 2021, three main categories account for 58 percent of the total misoperations: incorrect settings/logic/design (32 percent), relay failures (14 percent), and AC systems (13 percent).

There continues to be a positive downward trend in the number of misoperations occurring each year due to incorrect settings and relay failures. Misoperations due to AC systems are also showing a positive downward trend.

However, unknown errors and other/explainable errors continue to show negative upward trends.

Entities have completed corrective actions on approximately 84 percent of misoperations.

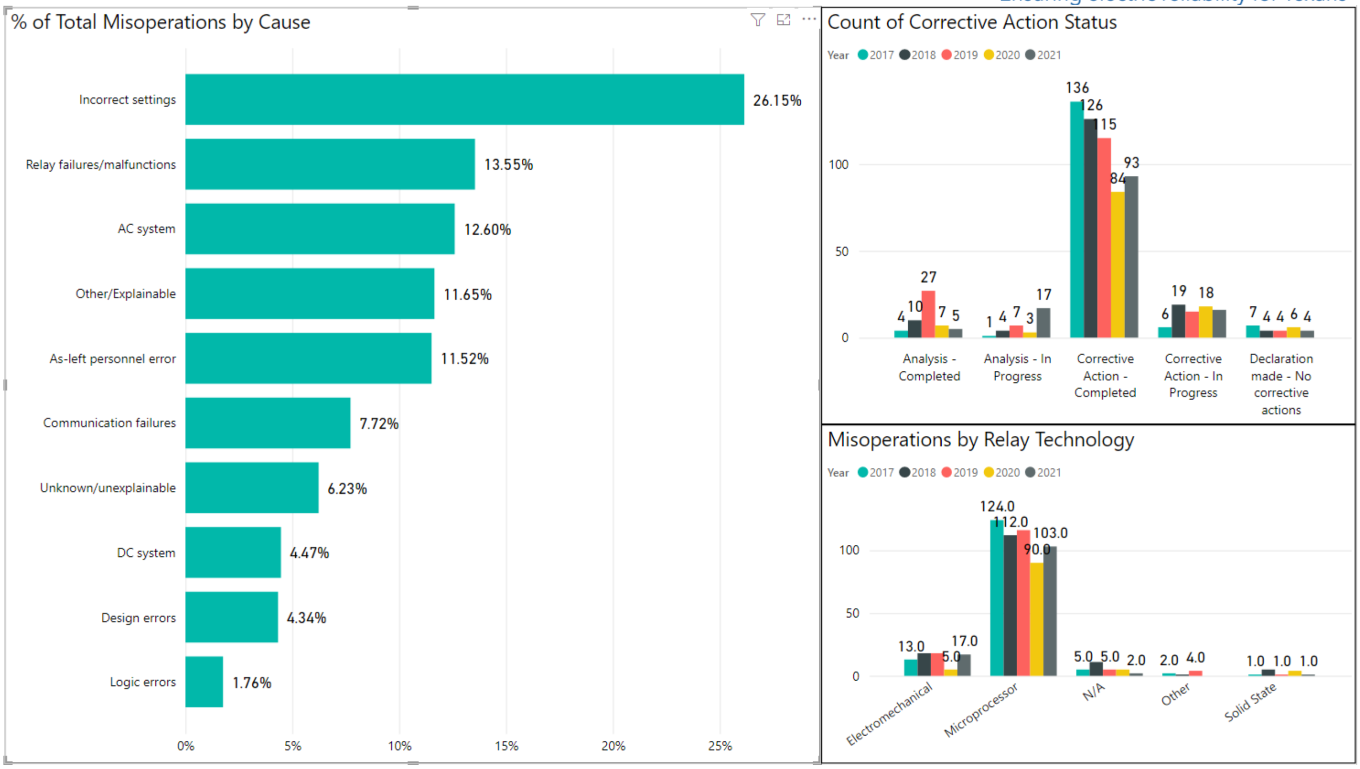


Figure G.1 – Protection System Misoperation Count 2017-2021

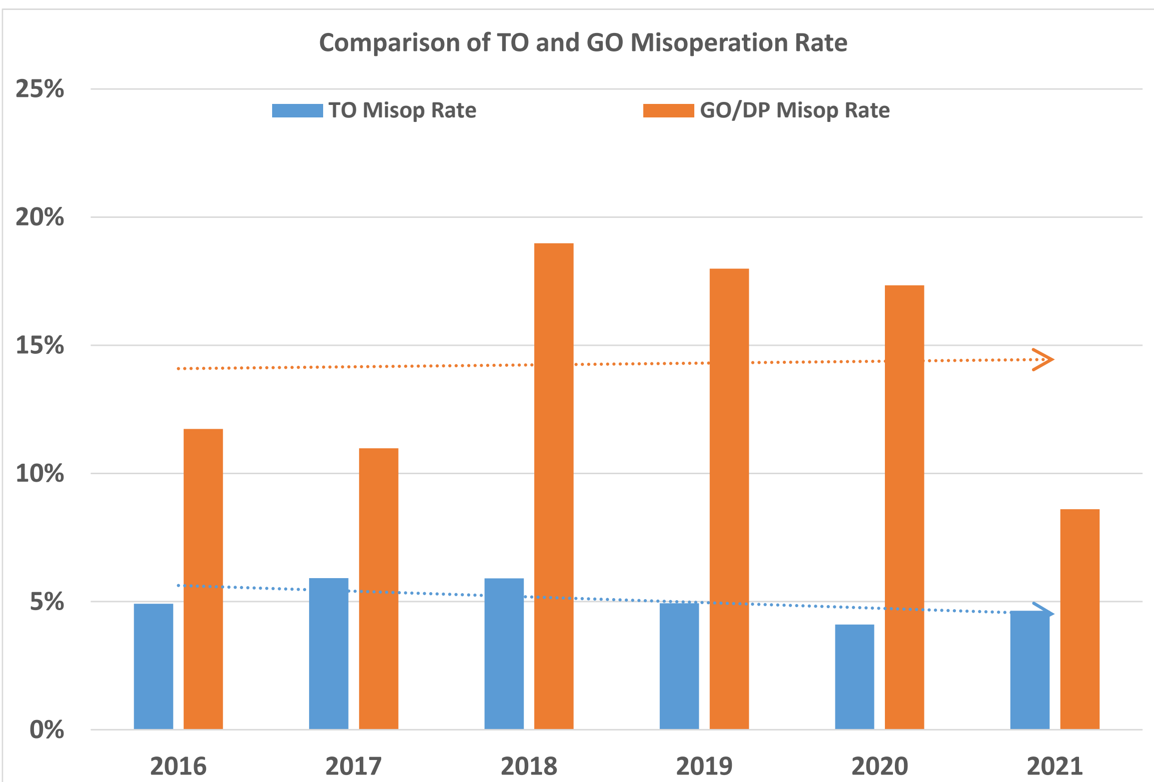


Figure G.2 – Protection System Misoperation Rate by Entity Type

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 and 138 kV circuits remained stable. The outage rates per element initiated by failed Protection System equipment for 345 kV transformers showed a significant increase.

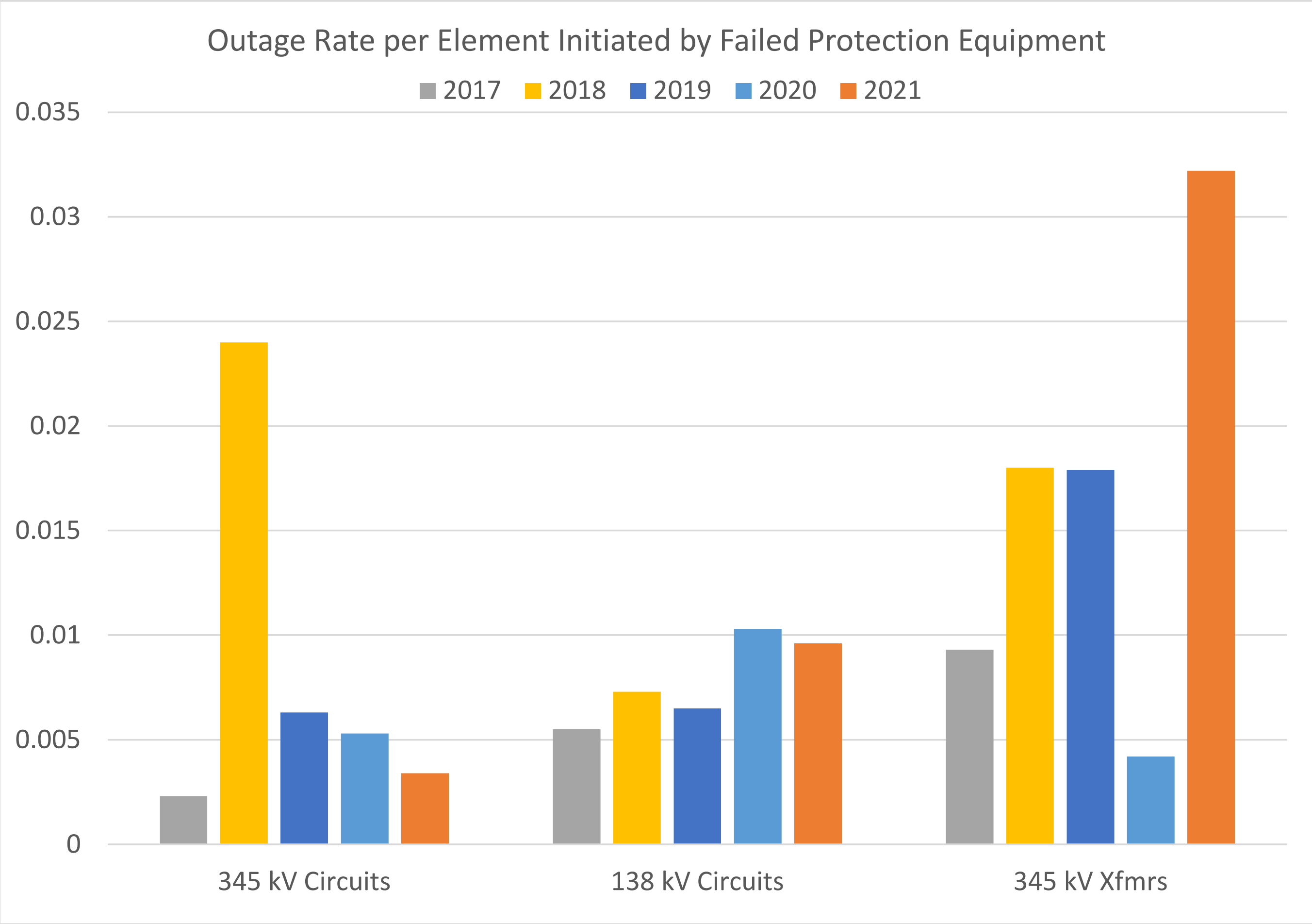


Figure G.3 – Outage Rates Caused by Failed Protection Equipment

Appendix H – Frequency Control Detailed Analysis

A. CPS1 Performance

Control Performance Standard 1 (CPS1): 169.3 for calendar year 2021 versus 171.2 for calendar year 2020.

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 is less than a specific limit. This is referred to as Control Performance Standard 1 (CPS1). The NERC CPS1 Standard requires rolling 12-month average performance of at least 100 percent. The following figure shows the ERCOT region CPS1 trend since January 2016. For 2021, the annualized CPS1 score was 169.3.

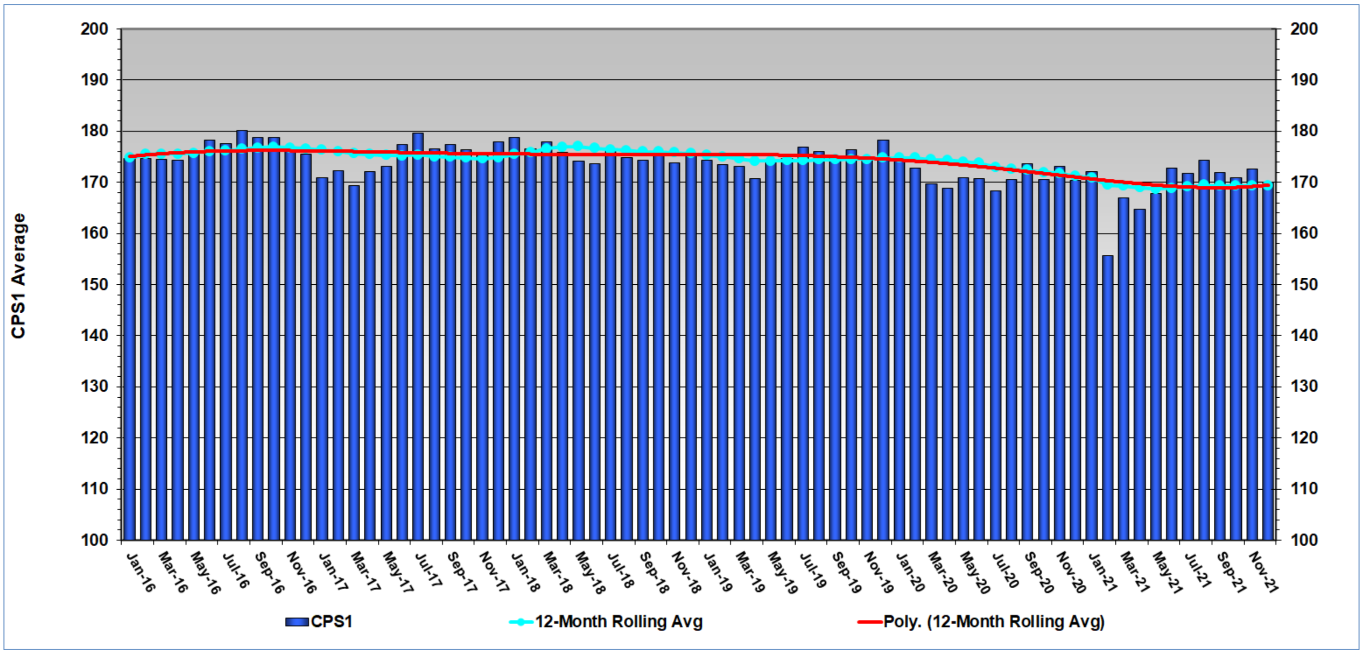


Figure H.1 – CPS1 Average January 2016 to December 2021

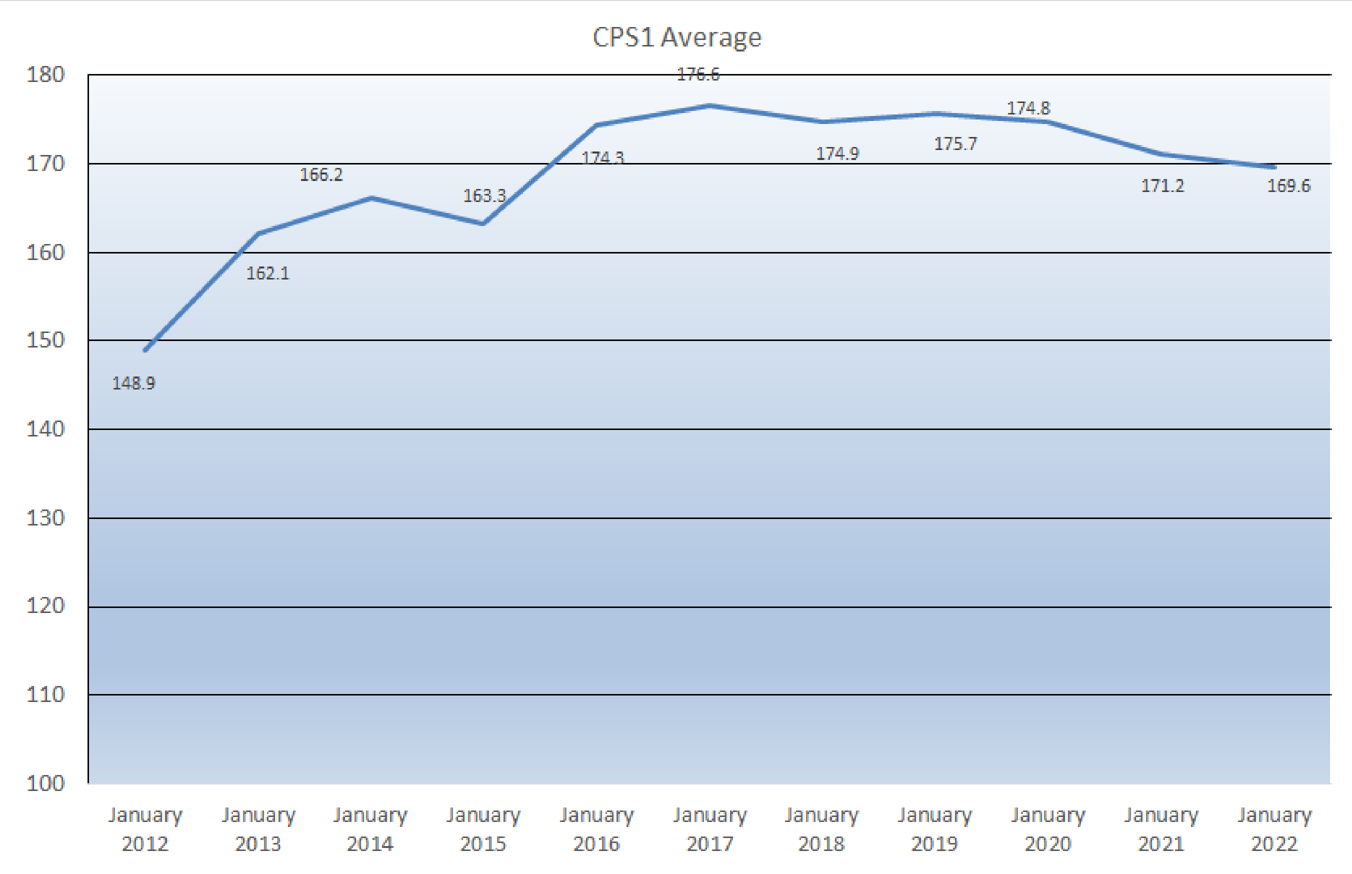


Figure H.2 – ERCOT CPS1 Annual Trend since January 2012

Figure H.3 shows bell curves of the ERCOT frequency profile, comparing 2016 through 2021. The shape of the bell curve in 2021 was virtually identical to 2020.

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.

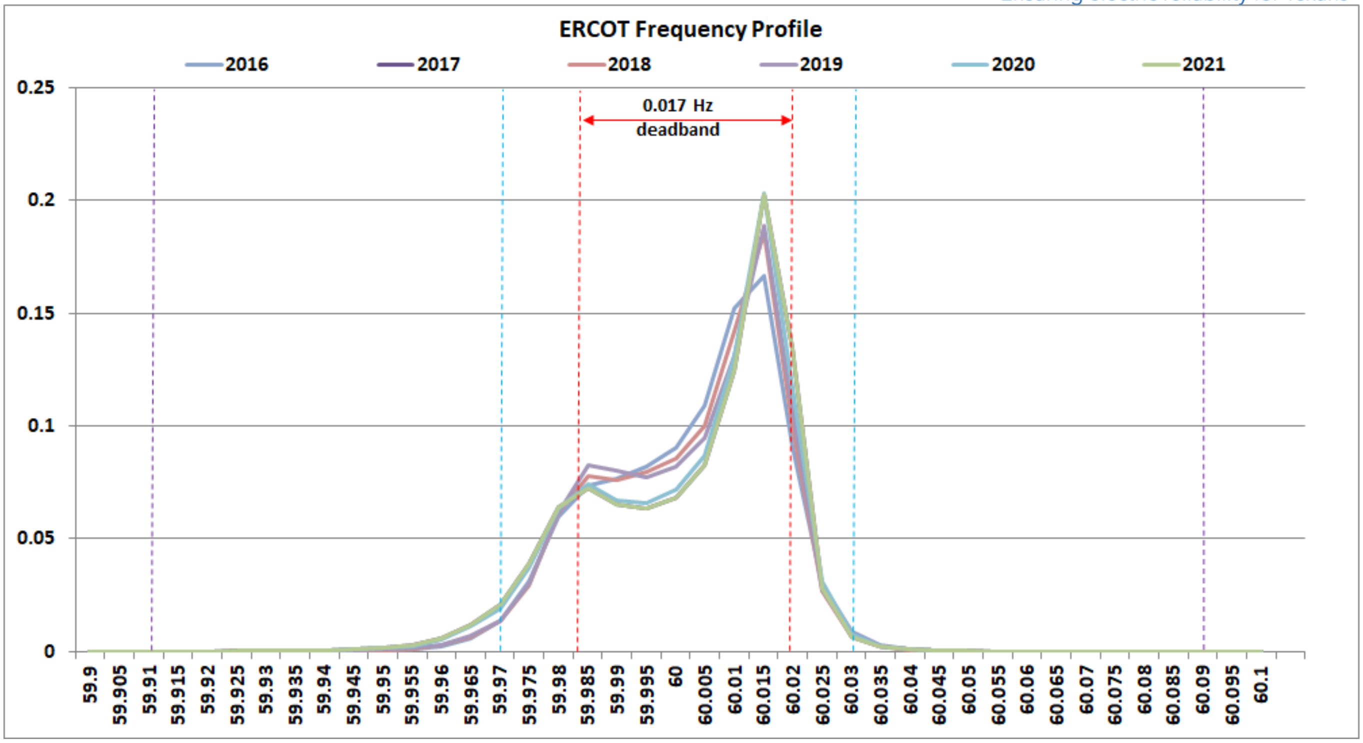


Figure H.3 – Frequency Profile Comparison

The following figure shows the 2021 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.

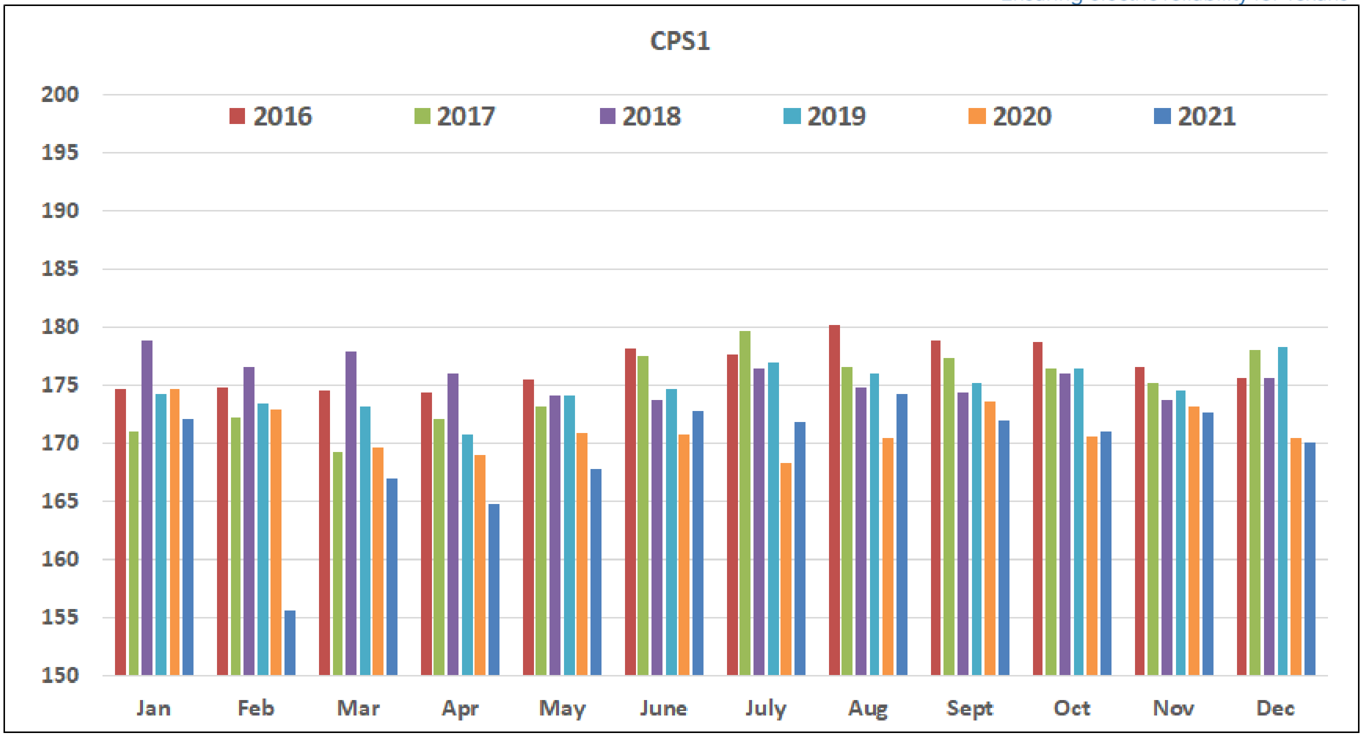


Figure H.4 – CPS1 Score by Operating Hour for 2016 through 2021

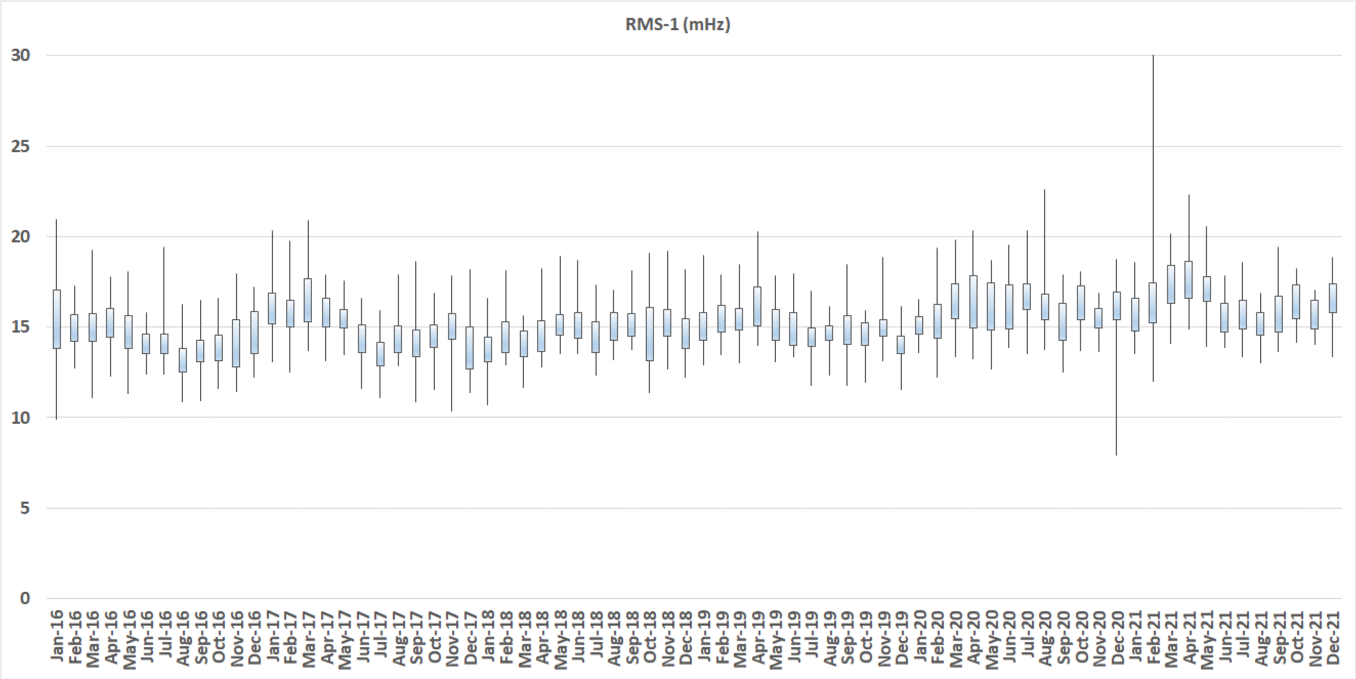


Figure H.5 – Daily RMS1 for 2016 through 2021

B. Time Error Correction Performance

In 2021, 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 (FTLs) are defined as 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 exceedances were associated with Winter Storm Uri. The remaining BAAL exceedances were associated with large unit trips.

High/Low Frequency	2017 Total Minutes	2018 Total Minutes	2019 Total Minutes	2020 Total Minutes	2021 Total Minutes	Five-year Avg
Low (<59.91 Hz)	18	17	16	29	78	32
High (>60.09 Hz)	0	0	0	0	1	1

Table H.1 – BAAL Exceedance Performance