2020 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	2016	2017	2018	2019	2020
Total	409	415	407	402	407
Coal/Lignite	29	29	26	21	20
Gas	51	48	45	43	43
Nuclear	4	4	4	4	4
Gas Turbine/Jet Engine	89	85	87	90	92
Hydro	8	8	8	8	8
Fluidized Bed	6	6	5	5	5
Combined Cycle (Block)	27	18	18	18	18
Combined Cycle GT	140	151	149	149	149
Combined Cycle ST	58	62	61	61	61
Other	1	3	3	3	7
Wind (>200 MW)			47	55	62
Wind (100<MW<200)			35	73	82
Wind (< 100 MW)			58	80	114
Number of Wind Turbines			9,466	14,132	16,404

Table A.1 – 2016-2020 GADS and GADS-Wind Units Reporting

The following figure uses GADS data to plot fleet capacity by age and fuel type. It shows two important characteristics of the fossil fuel fleet: (1) there is an age bubble around 38–43 years driven by coal and some gas units; and (2) there is a significant age bubble around 15–20 years comprised almost exclusively of combined cycle units. The majority of the wind fleet is less than five years old.

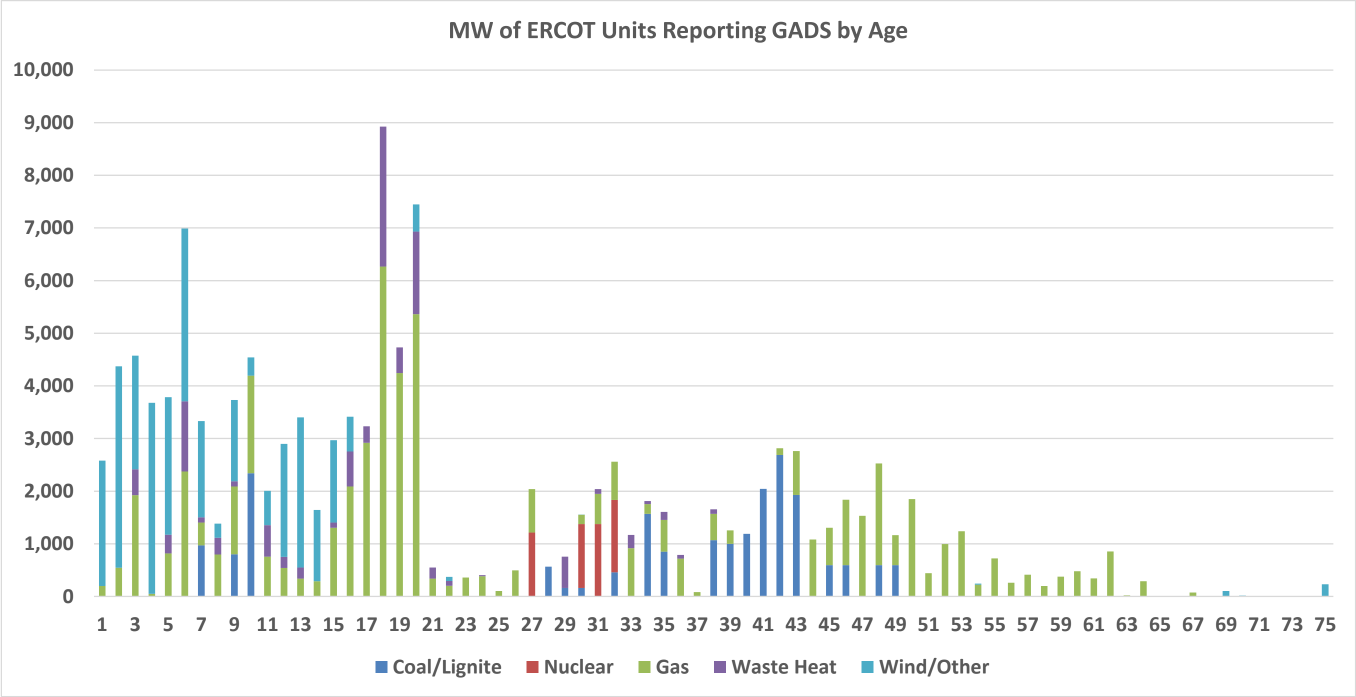


Figure A.1 – GADS Fossil Generation in ERCOT by Age and Fuel Type

B. Analysis of Planned versus Actual Seasonal Operating Reserves

For the Summer of 2020, peak demand was 74,166 MW, approximately 1,000 MW below the typical scenario estimate of 75,200 MW from the Summer Seasonal Assessment of Resource Adequacy (SARA). Actual reserve margin was approximately 5.8 percent. Sufficient operating reserves were maintained during the summer peak hours.

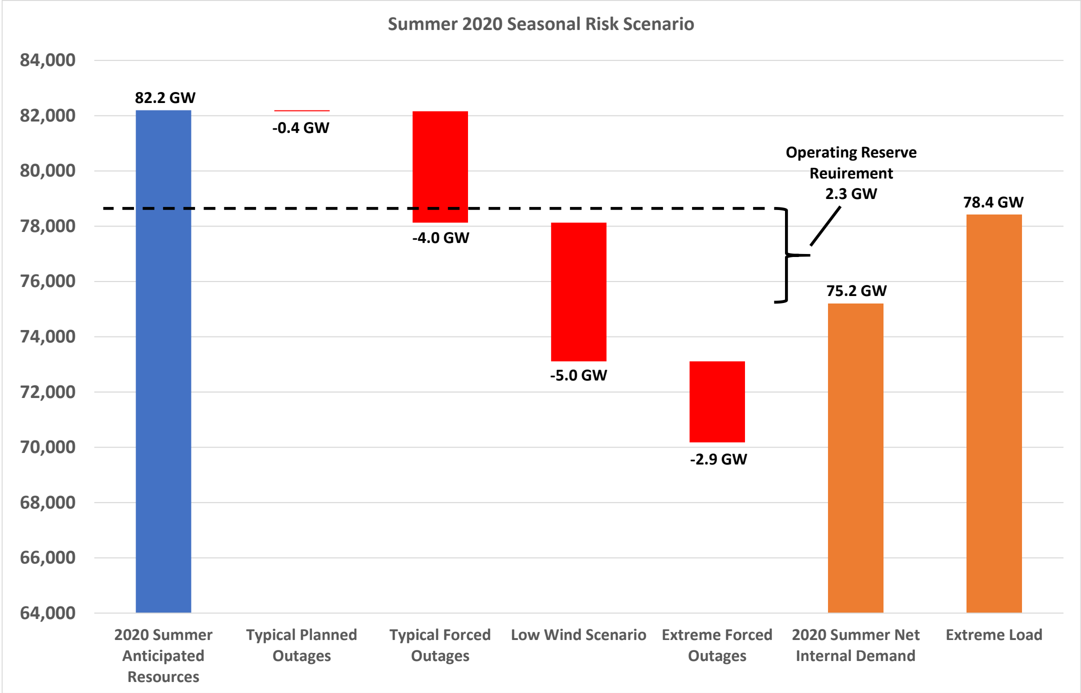


Figure A.2 – Summer 2020 Risk Scenarios

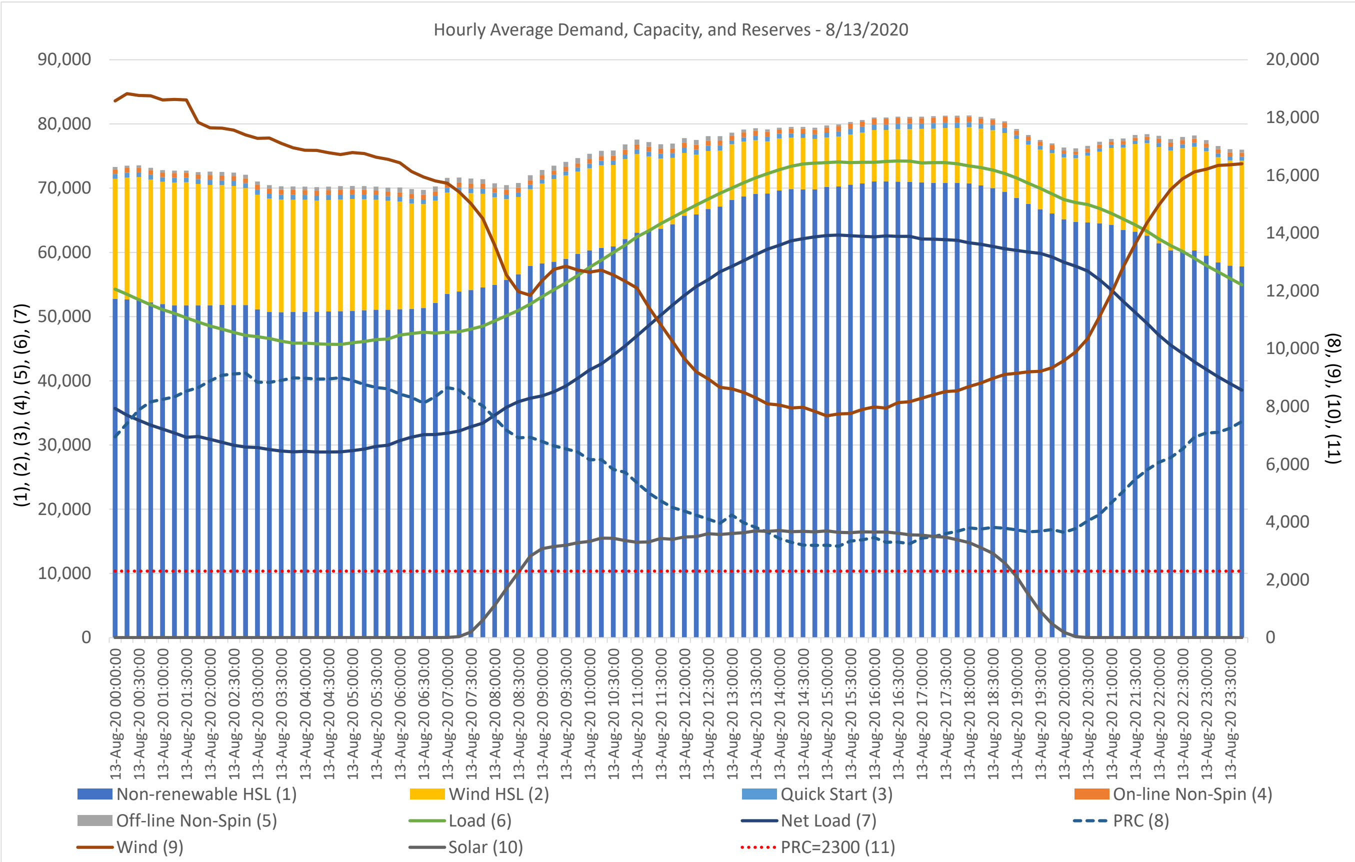


Figure A.3 – August 13, 2020 Capacity, Demand, and Reserves

The final ERCOT SARA for Summer 2020 (released May 2020) estimated typical maintenance outages of 381 MW and typical forced outages of 3,845 MW with an extreme case of 6,510 MW. Combined actual planned and forced outages for the Summer 2020 ranged from a low of 3,236 MW to a maximum of 9,820 MW. Only seven days during the summer period were less than the typical outage rate estimated for the SARA.

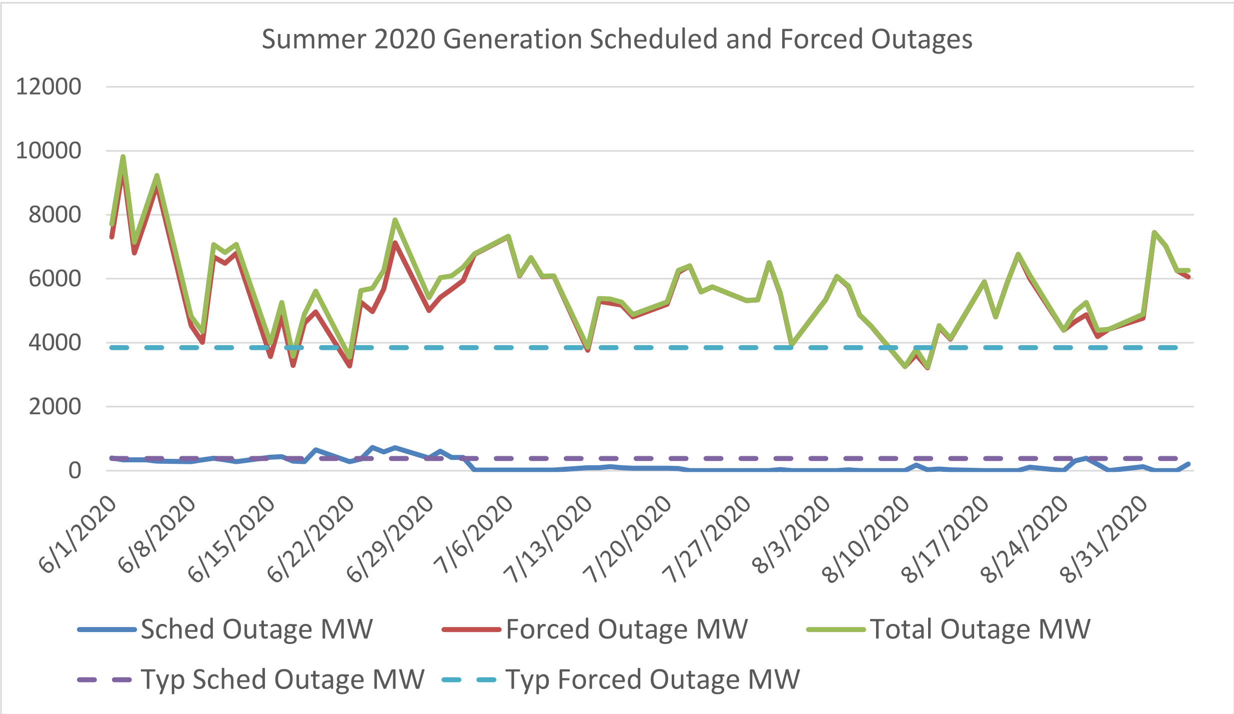


Figure A.4 – Summer 2020 Generation Scheduled and Forced Outages

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.

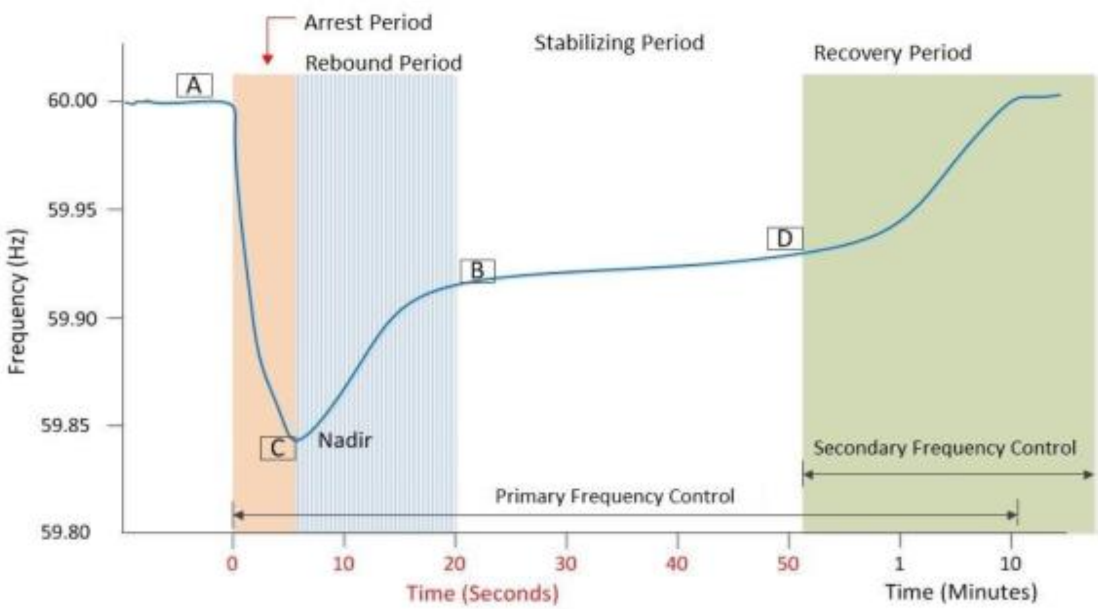


Figure A.5 – Typical Frequency Disturbance

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.

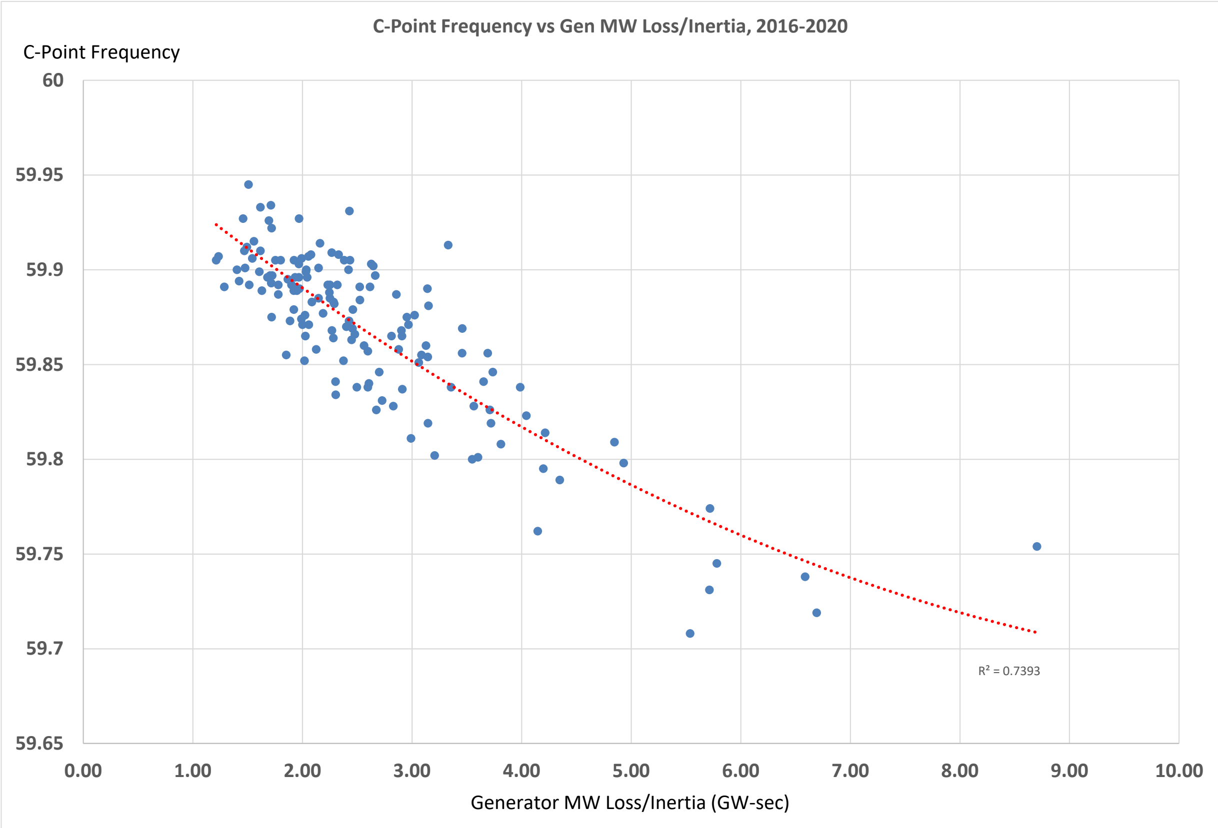


Figure A.6 – Frequency Disturbance Nadir versus Gen Loss MW/Inertia, 2016-2020

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.

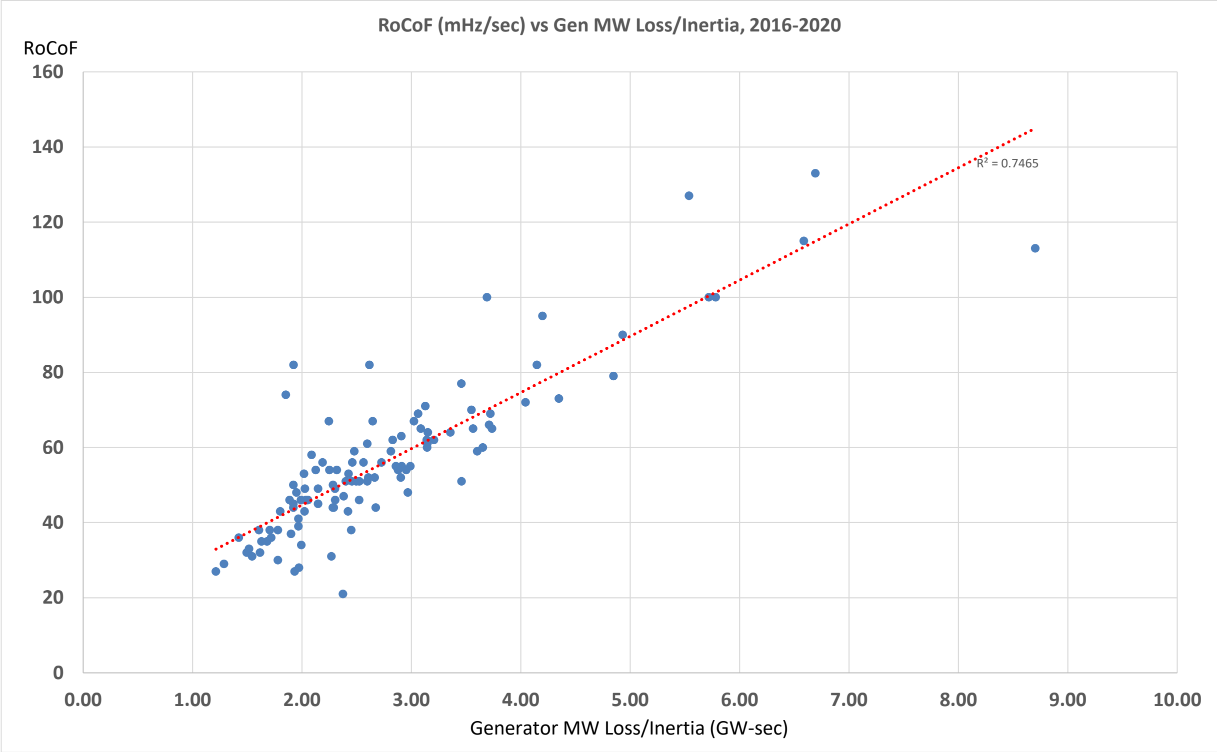


Figure A.7 – Rate of Change of Frequency versus Normalized Generation Loss, 2016-2020

The following figure shows the trend in primary frequency response for the ERCOT region. In 2020, the average frequency response was 752 MW per 0.1 Hz and the median frequency response was 674 MW per 0.1 Hz as calculated per NERC Standard BAL-003 for the events that were evaluated during the period. The following graph shows the annualized primary frequency response trend per NERC Reliability Standard BAL-003. The green lines on the figure indicate Interconnection Frequency Response Obligation (IFRO) as calculated according to NERC Standard BAL-003.

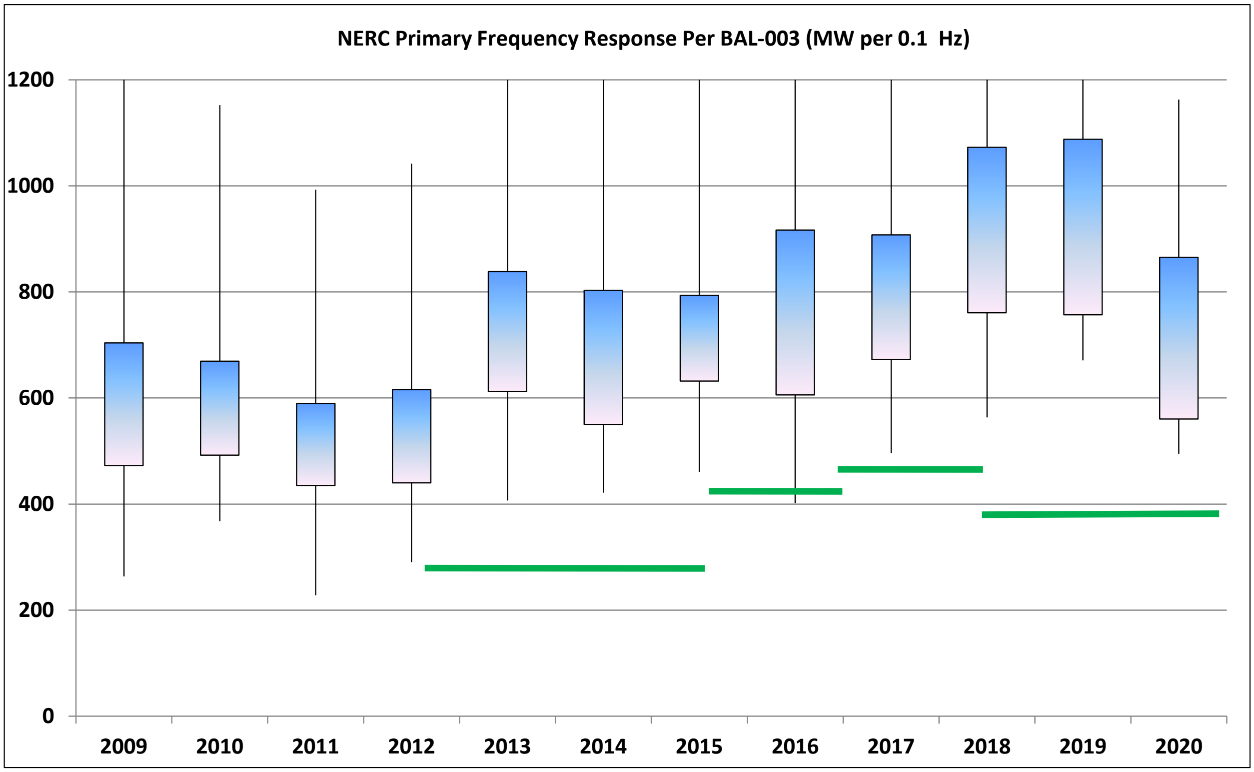


Figure A.8 – Annual Primary Frequency Response Trend for ERCOT Region

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 7.1 minutes in 2019 versus 5.8 minutes for calendar year 2019. The average event recovery time (see Figure 14) continues to show a long-term gradual upward trend since 2012.

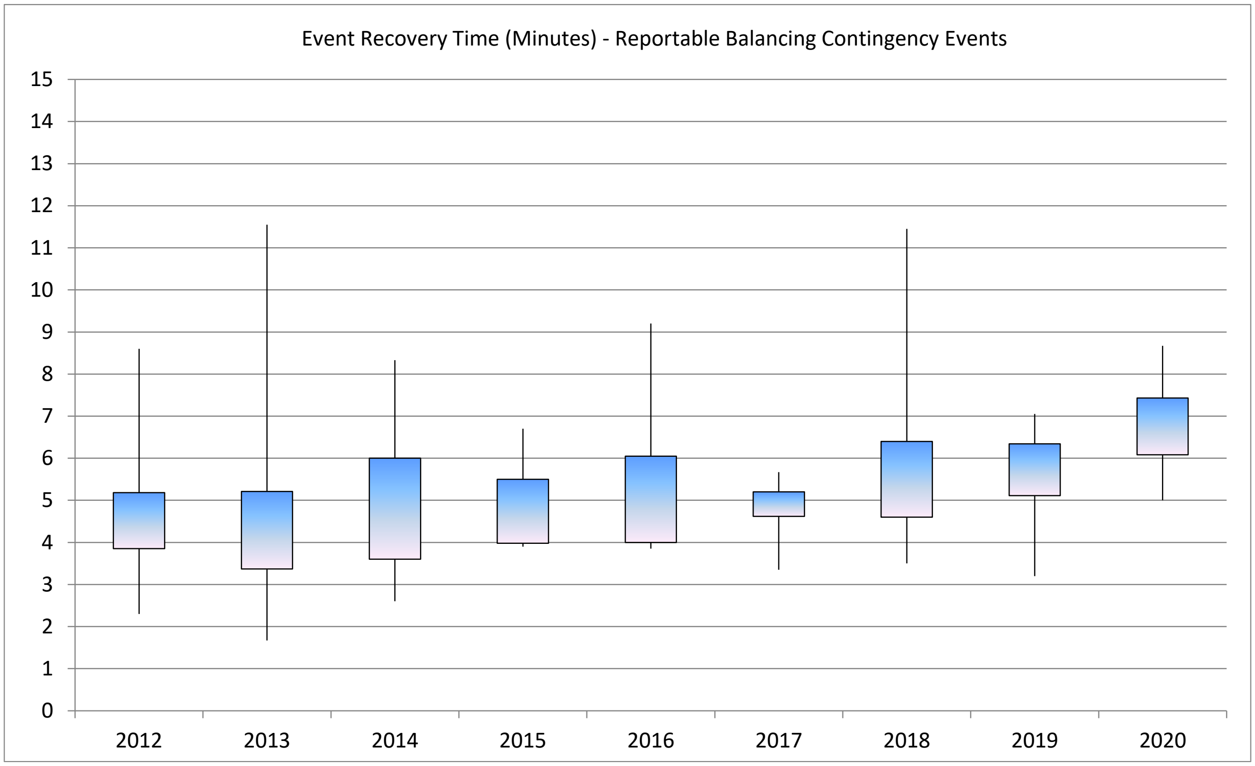


Figure A.9 – Event Recovery Time 2012-2020

E. 2020 Fossil-fueled Generator Performance Metrics

ERCOT fossil generation reporting in GADS produced a gross total of 300,223 GWH in 2020.

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 is provided in the following table.

ERCOT Region GADS Data Metric	2016 Unweighted	2017 Unweighted	2018 Unweighted	2019 Unweighted	2020 Unweighted	5-Yr Avg Unweighted
# Units Reporting	409	415	407	402	407	408
Total Unit-Months	4908	4860	4768	4803	4880	4844
Net Capacity Factor (NCF)	44.2%	43.3%	46.7%	46.8%	44.5%	45.1%
Service Factor (SF)	48.4%	46.1%	50.9%	51.7%	48.8%	49.2%
Equivalent Availability Factor (EAF)	87.0%	85.3%	85.2%	86.1%	84.1%	85.5%
Scheduled Outage Factor (SOF)	8.2%	8.3%	8.7%	9.3%	9.5%	8.8%
Forced Outage Factor (FOF)	2.9%	4.1%	3.9%	4.2%	3.9%	3.8%
EFOR	6.7%	9.6%	7.9%	8.3%	8.4%	8.2%
Equivalent Forced Outage Rate Demand (EFORd)	5.0%	6.6%	5.7%	6.1%	5.9%	5.9%

Table A.3 – ERCOT Generation Performance Metrics 2016 through 2020

- 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 Unweighted	Gas Unweighted	Jet Engine Unweighted	CC Block Unweighted	CC GT Unweighted	CC ST Unweighted
# Units Reporting	20	43	92	18	149	61
Total Unit-Months	240	492	1100	216	1788	732
Net Capacity Factor (NCF)	54.3%	9.0%	13.5%	47.5%	54.7%	43.9%
Service Factor (SF)	78.5%	22.9%	16.2%	50.7%	65.9%	67.5%
Equivalent Availability Factor (EAF)	88.1%	74.1%	88.4%	80.3%	83.9%	83.6%
Scheduled Outage Factor (SOF)	6.0%	15.4%	7.5%	6.4%	11.2%	9.3%
Forced Outage Factor (FOF)	5.8%	7.0%	3.4%	4.4%	2.5%	5.0%
EFOR	9.7%	29.6%	18.4%	8.4%	3.8%	8.7%
EFORd	6.8%	19.6%	8.1%	5.5%	3.2%	6.2%

Table A.4 – ERCOT Generation Performance Metrics by Fuel Type for 2020

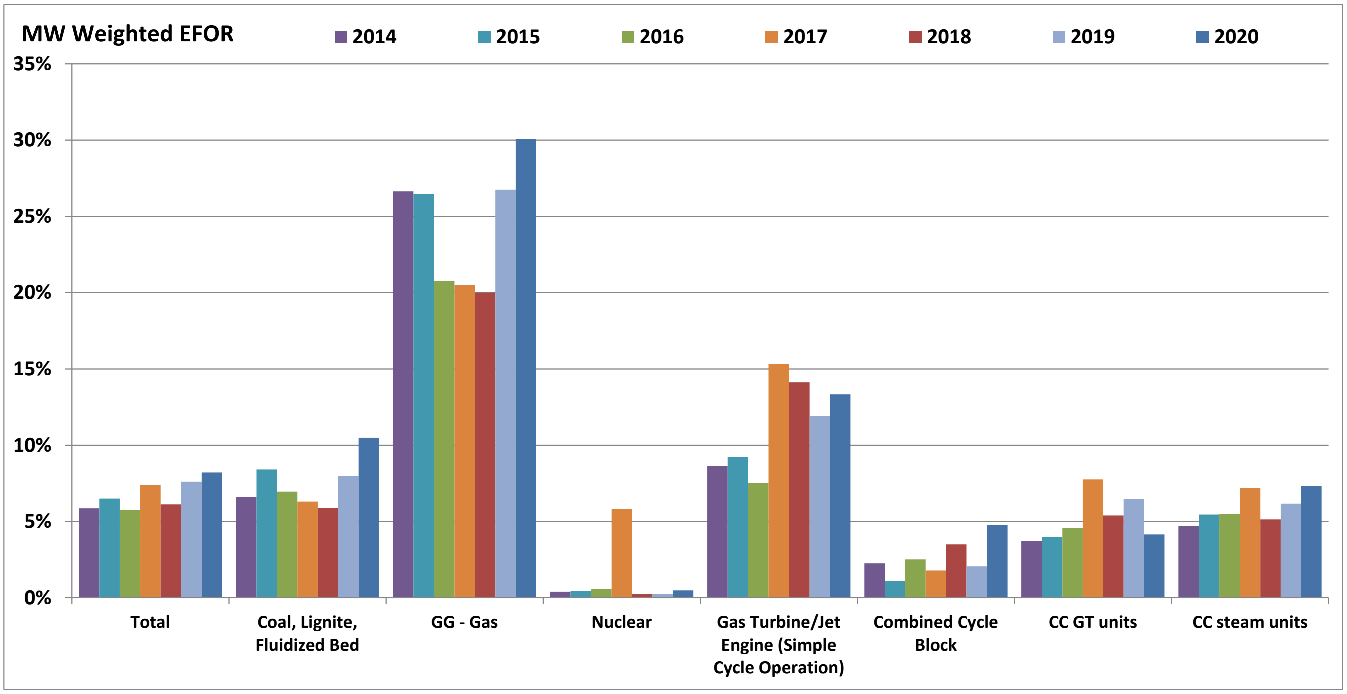


Figure A.10 – MW-Weighted EFOR Metric by Fuel Type and Year

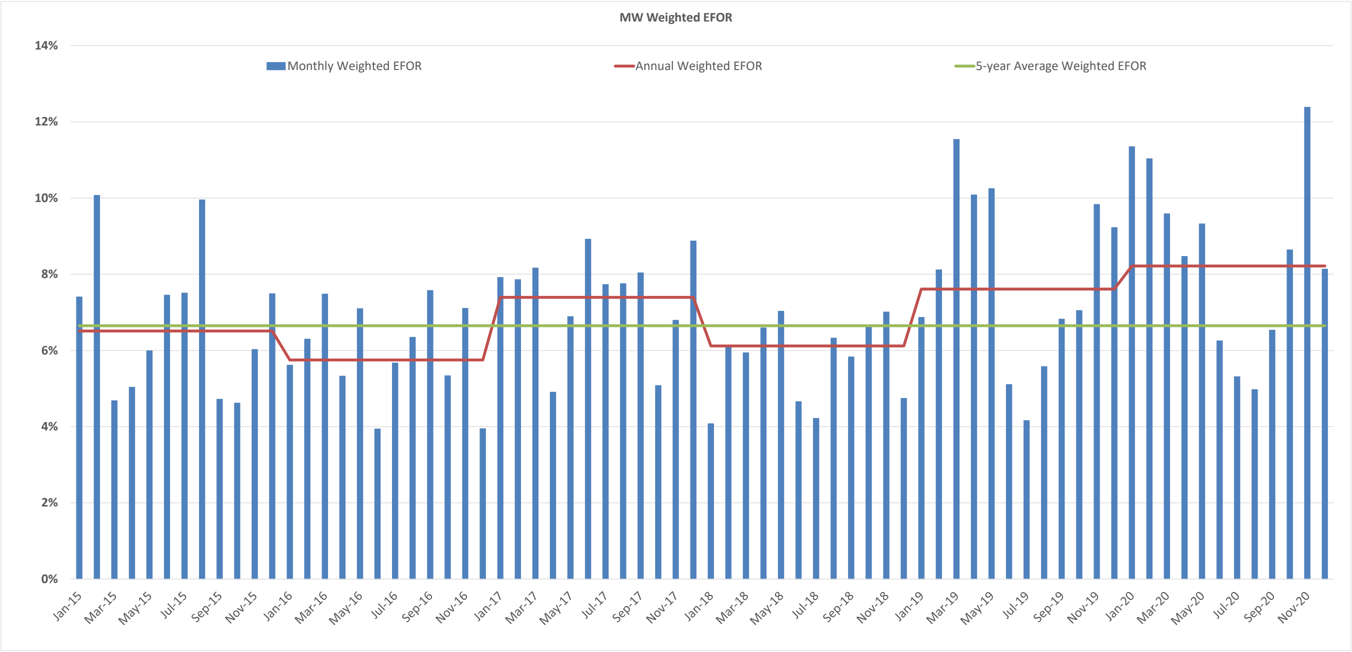


Figure A.11 – Time Trend for MW-Weighted EFOR

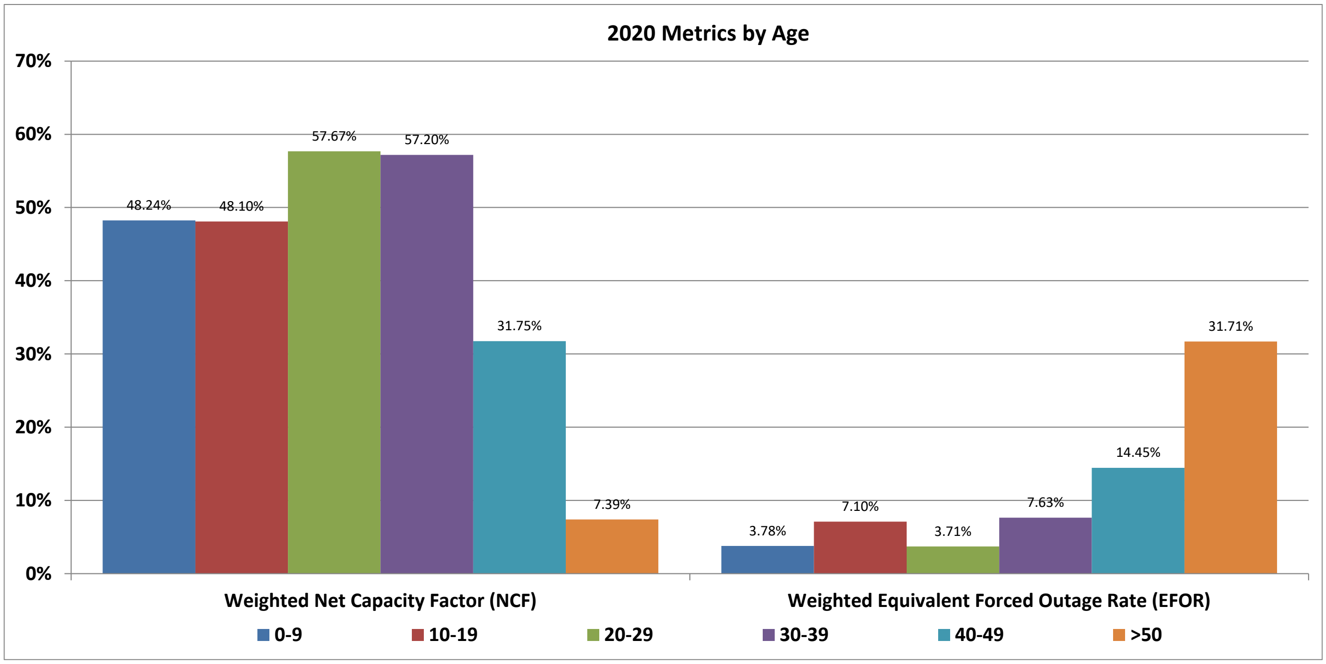


Figure A.12 – 2020 GADS Metrics by Age

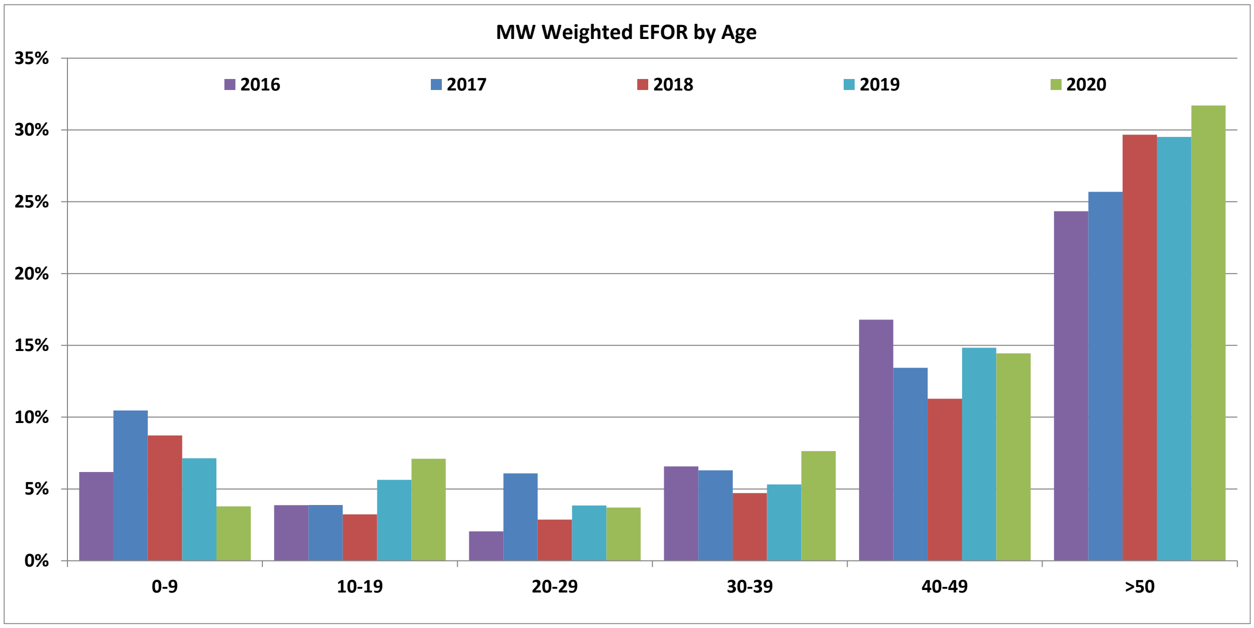


Figure A.13 – 2016-2020 GADS EFOR by Age

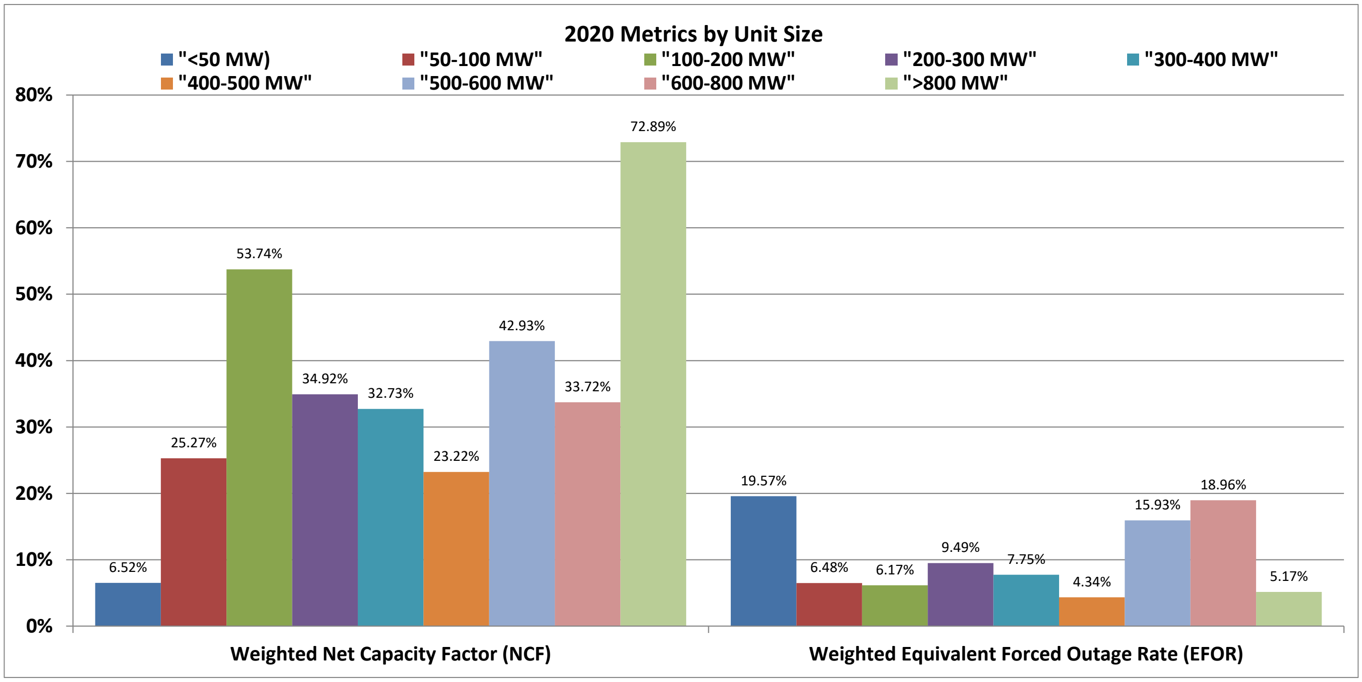


Figure A.14 – 2020 GADS Metrics by Unit Size

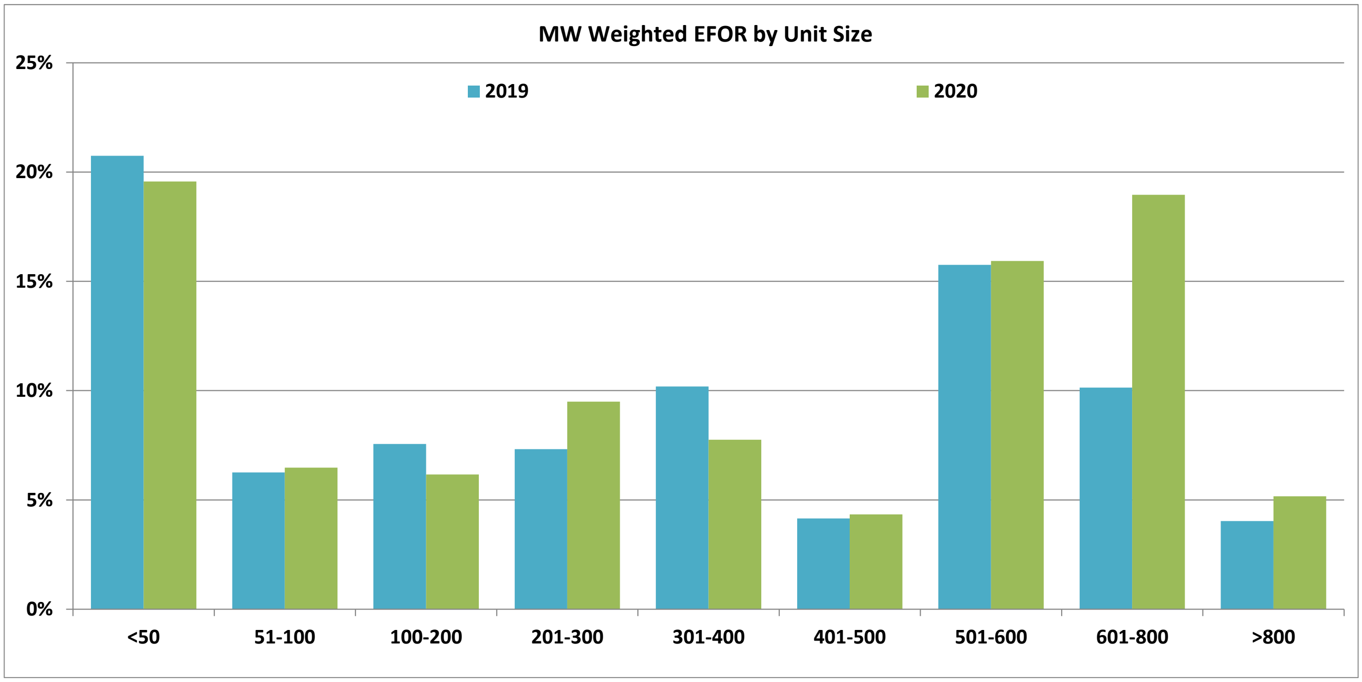


Figure A.15 – 2019-2020 GADS EFOR by Unit Size

<u>2020 Fossil-fueled Generator Outages and De-rates</u>

Table 5 provides a summary of immediate de-rates and forced outages for conventional generation from January 2020 through December 2020. The 1,946 immediate forced outage events are about eight percent less than 2019, with a median capacity of 171 MW per event nearly identical to last year's, as were the top three systems affected.

	Immediate De-Rates	Immediate Forced Outages
Number of Events	1,901	1,946
Total Duration (hrs)	177,251.6	118,397.1
Total Capacity (MW)	215,051.2	388,327.9
Avg Duration per Event (hrs)	93.2	60.8
Median Duration per Event (hrs)	4.8	4.7
Avg Capacity per Event (MW)	113.1	199.6
Median Capacity per Event (MW)	85.0	170.0

Table A.5 – Generator Immediate De-rate and Forced Outage Data (Jan. – Dec. 2020)

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	195	15,762.8	69,806.9	80.8	358.0
Balance of Plant	332			64.5	226.8
Steam Turbine/Generator	1073	21,417.8	75,285.9	61.0	175.6
Heat Recovery Steam Generator	71	65,412.9	188,419.0	57.6	206.1
Pollution Control Equipment	32	4,086.8	14,631.1	11.6	126.8
External	142	370.0	4,057.6	32.1	124.8
Regulatory, Safety, Environmental	45	4,562.9	17,723.8	51.0	101.2
Personnel/ Procedure Errors	52	2,296.6	4,554.9	19.4	263.0
Other	4	1,006.9	13,677.7	870.1	42.7

Table A.6 – 2020 Major Category Cause of Immediate Forced Outage Events from GADS

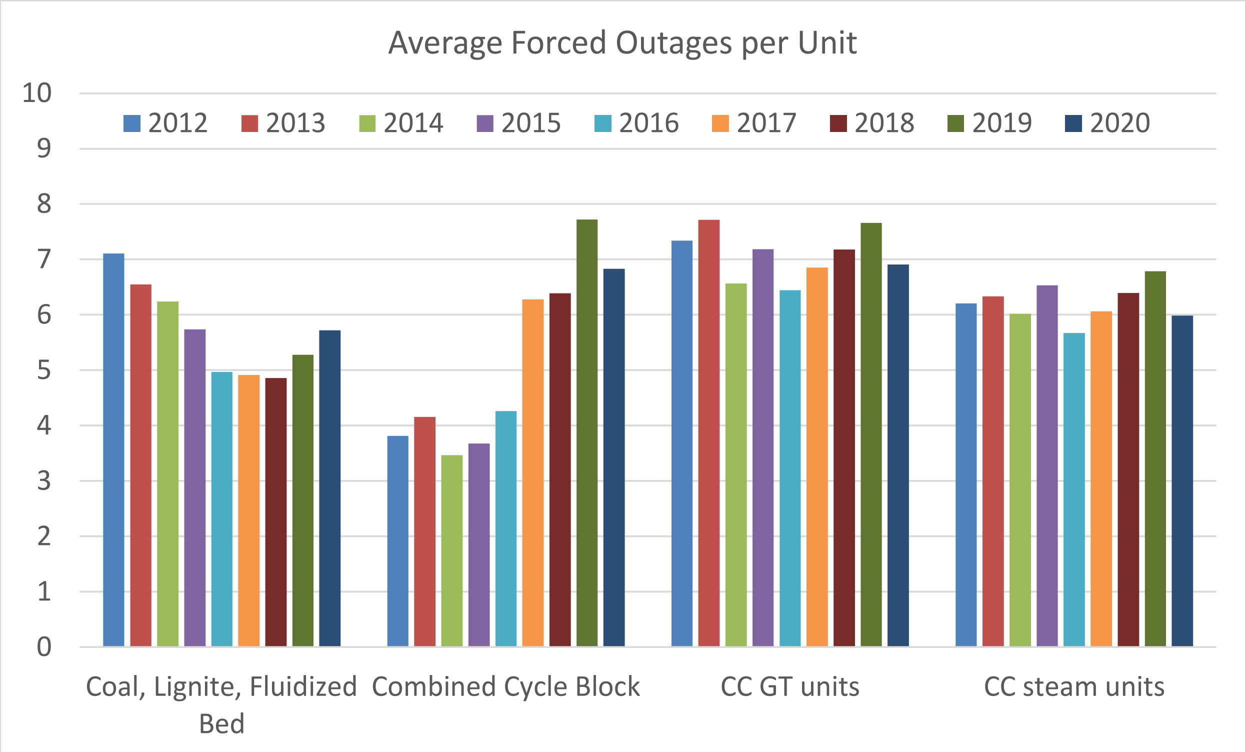


Figure A.16 – 2020 Average Forced Outages per Unit

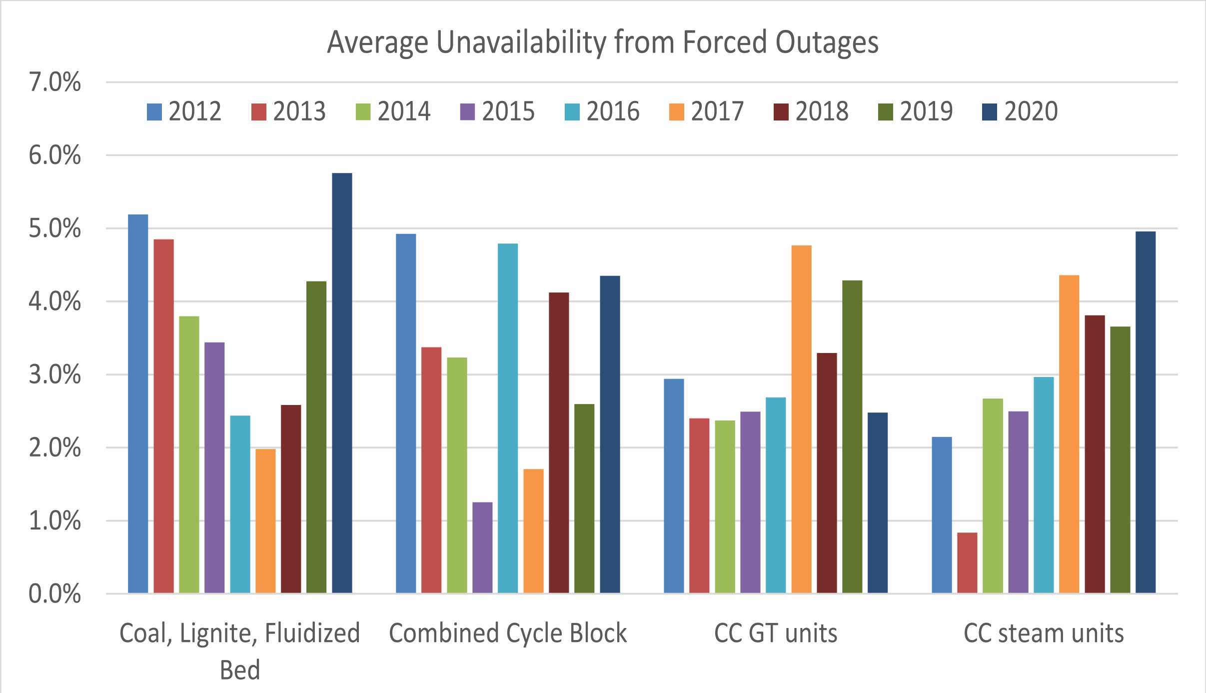


Figure A.17 – 2020 Average Unavailability from Forced Outages per Unit

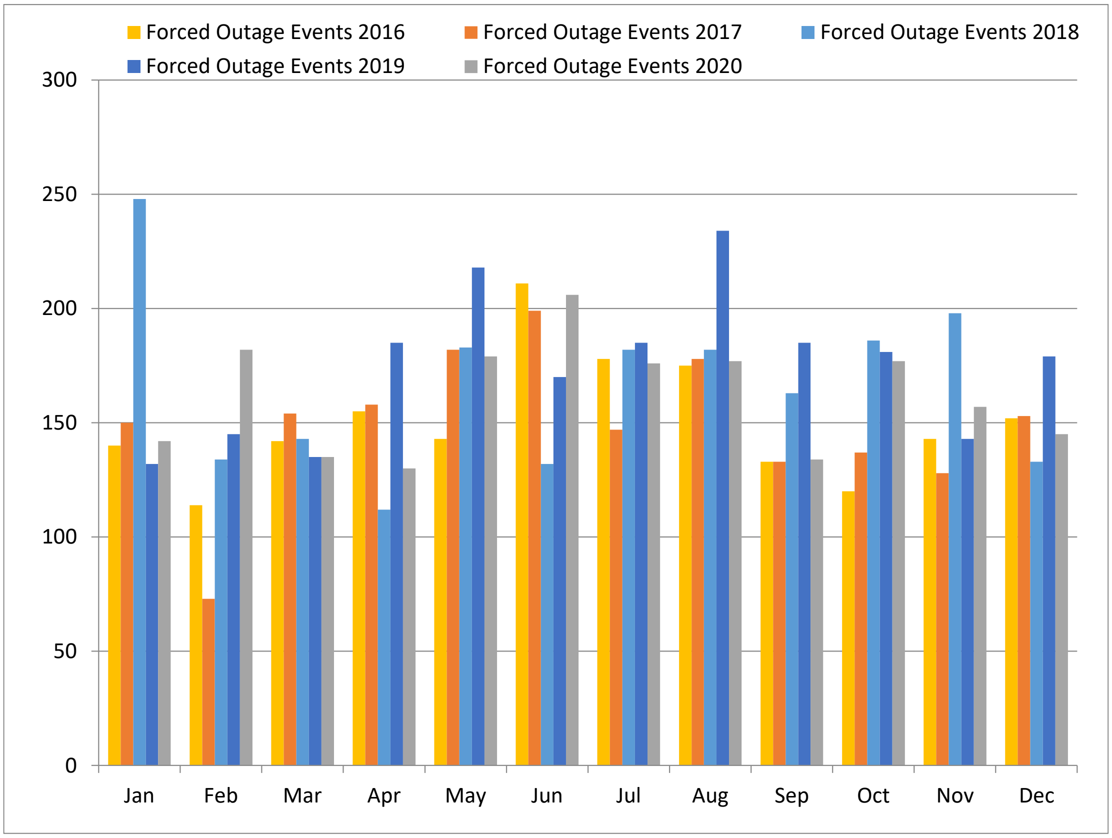


Figure A.18 – 2016-2020 Count of Immediate Forced Outage Events by Month

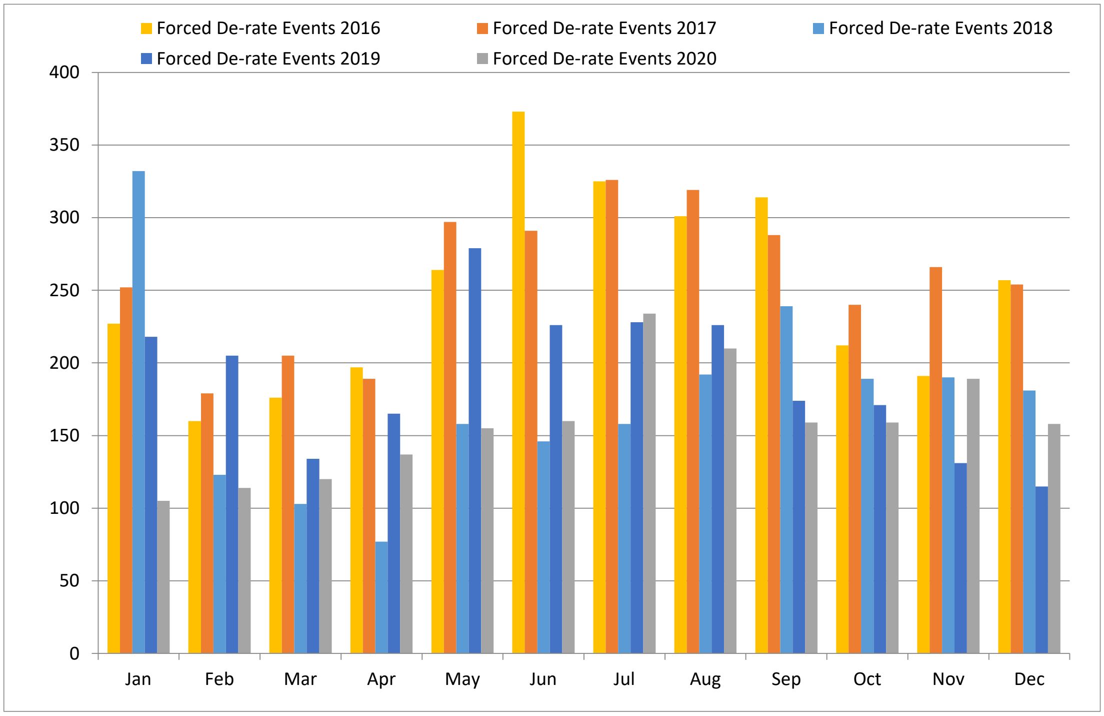


Figure A.19 – 2016-2020 Count of Immediate Forced De-rate Events by Month

F. 2020 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 2020, 258 ERCOT wind facilities and sub-groups submitted a total of 2,405 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	
	Resource	Equipment	Resource	Equipment
Net Capacity Factor (PRNCF and PENCF)	37.5%	39.7%	36.6%	39.6%
Equivalent Forced Outage Rate (PREFOR and PEEFOR)	12.1%	5.8%	14.7%	6.5%
Equivalent Scheduled Outage Rate (RESOR and PEESOR)	1.6%	1.5%	1.4%	1.3%
Equivalent Availability Factor (REAF and PEEAF)	87.0%	91.8%	84.7%	91.0%

Table A.7 – ERCOT Wind Generation Performance Metrics, 2020

- 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.
- 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.
- Pooled Equipment Equivalent Availability Factor (PEEAF): Percent of time the WTG equipment was available.

GADS-Wind turbine outage data for 2020 included 6,763 component outage reports totaling 828,812 turbine-hours of forced, planned, and maintenance outage duration.

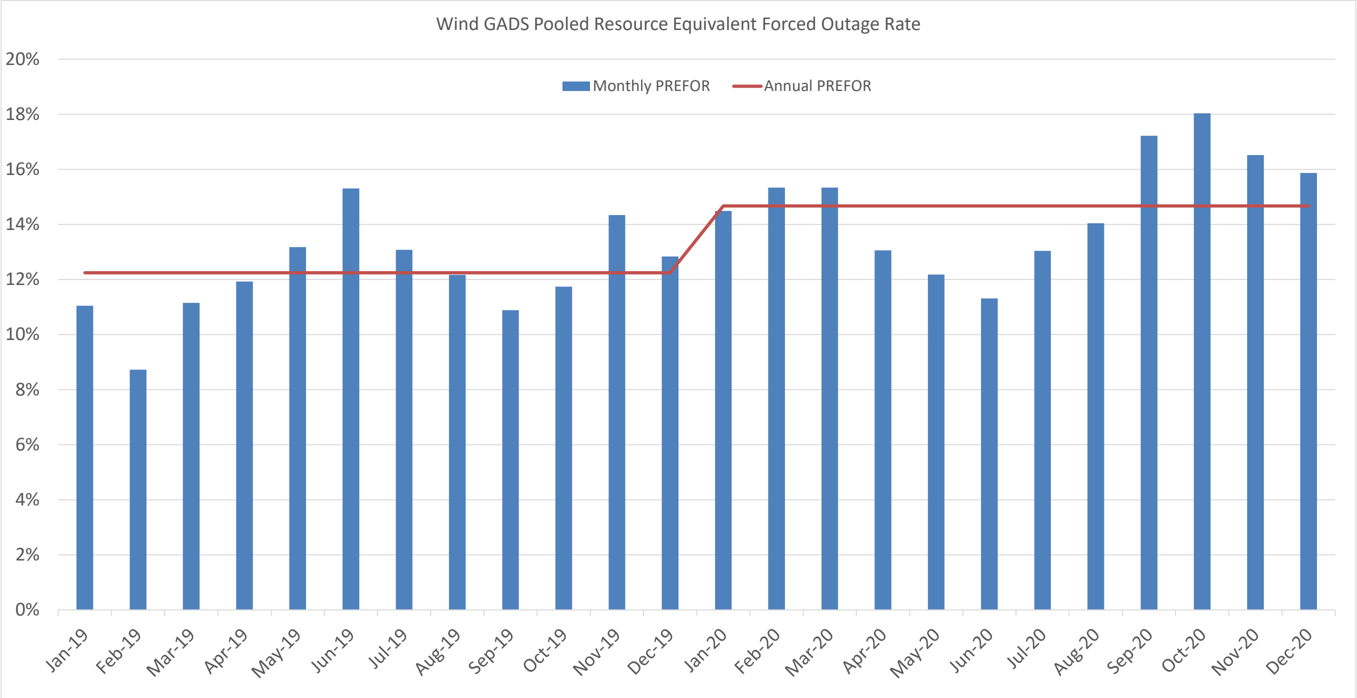


Figure A.20 – GADS-Wind Time Trend for MW-Weighted EFOR

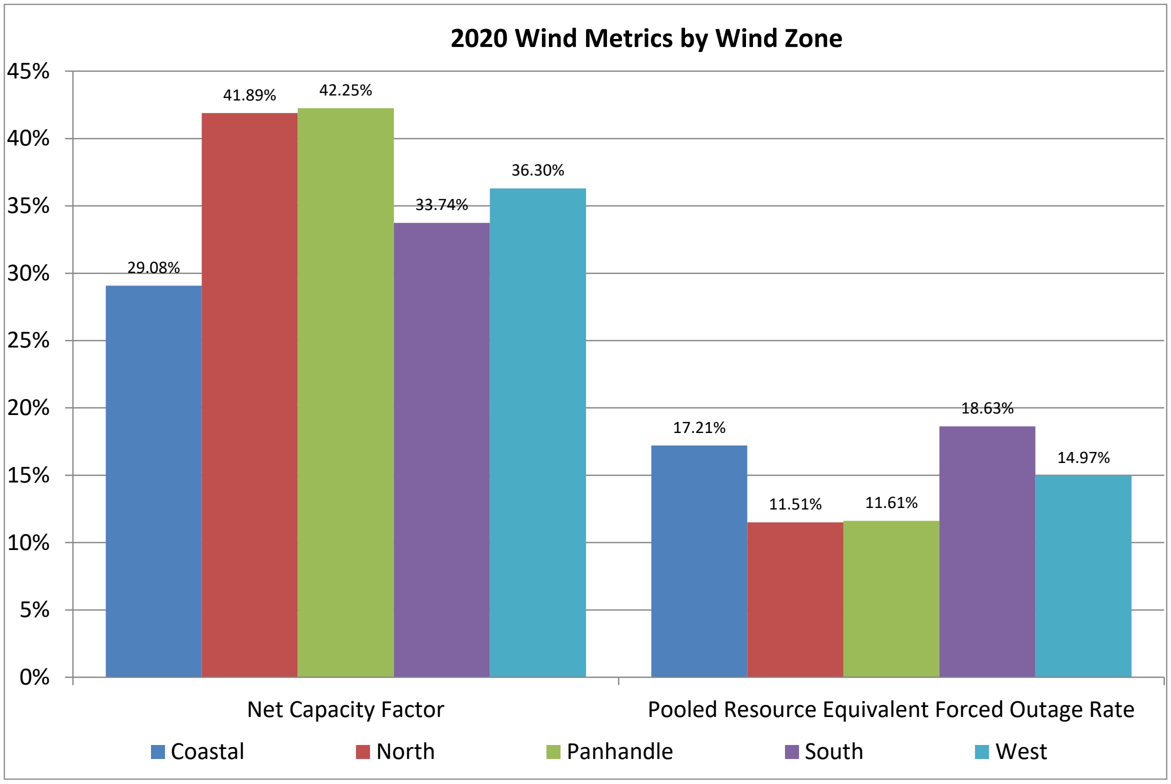


Figure A.21 – 2020 GADS-Wind Metrics by Wind Zone

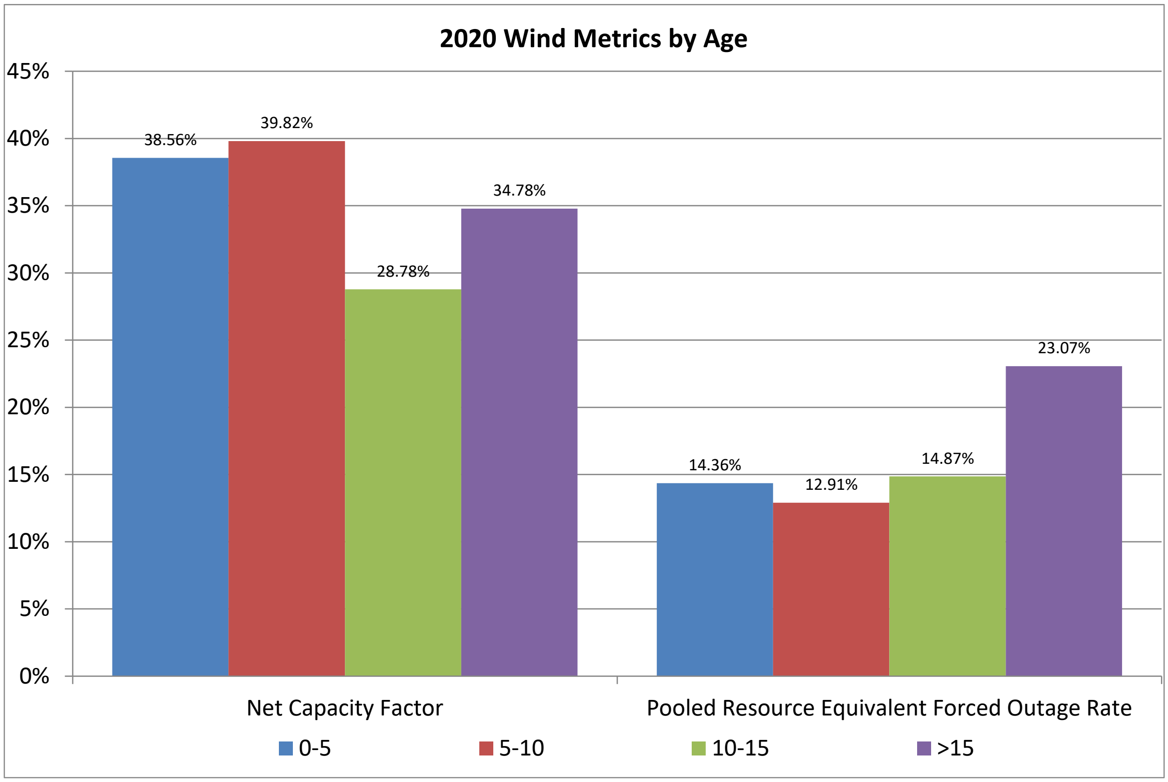


Figure A.22 – 2020 GADS-Wind Metrics by Age

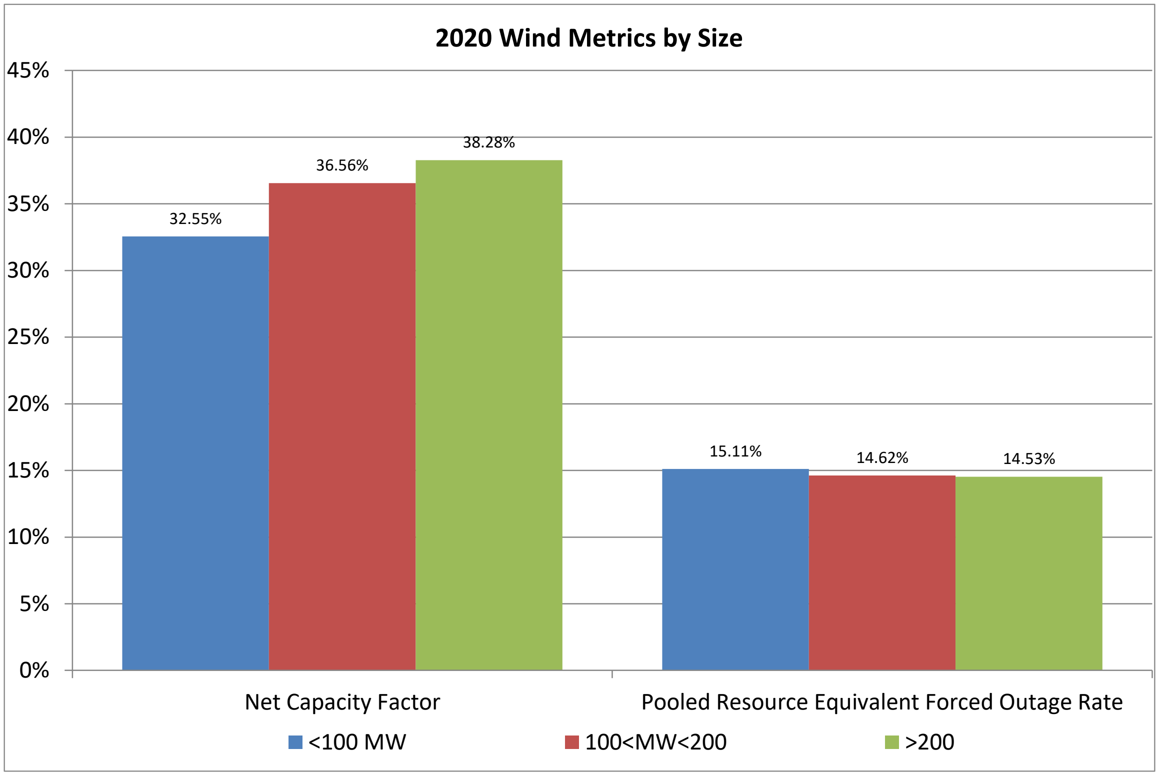


Figure A.23 – 2020 GADS-Wind Metrics by Unit Size

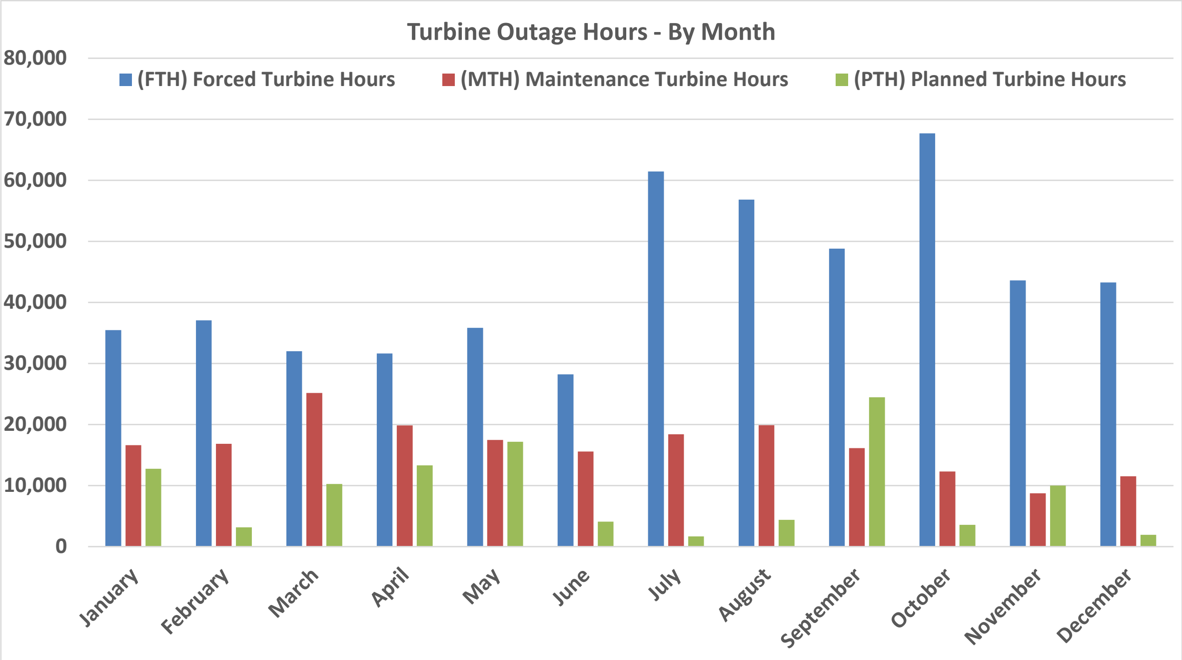


Figure A.24 – 2020 GADS-Wind Turbine Outage Hours by Month

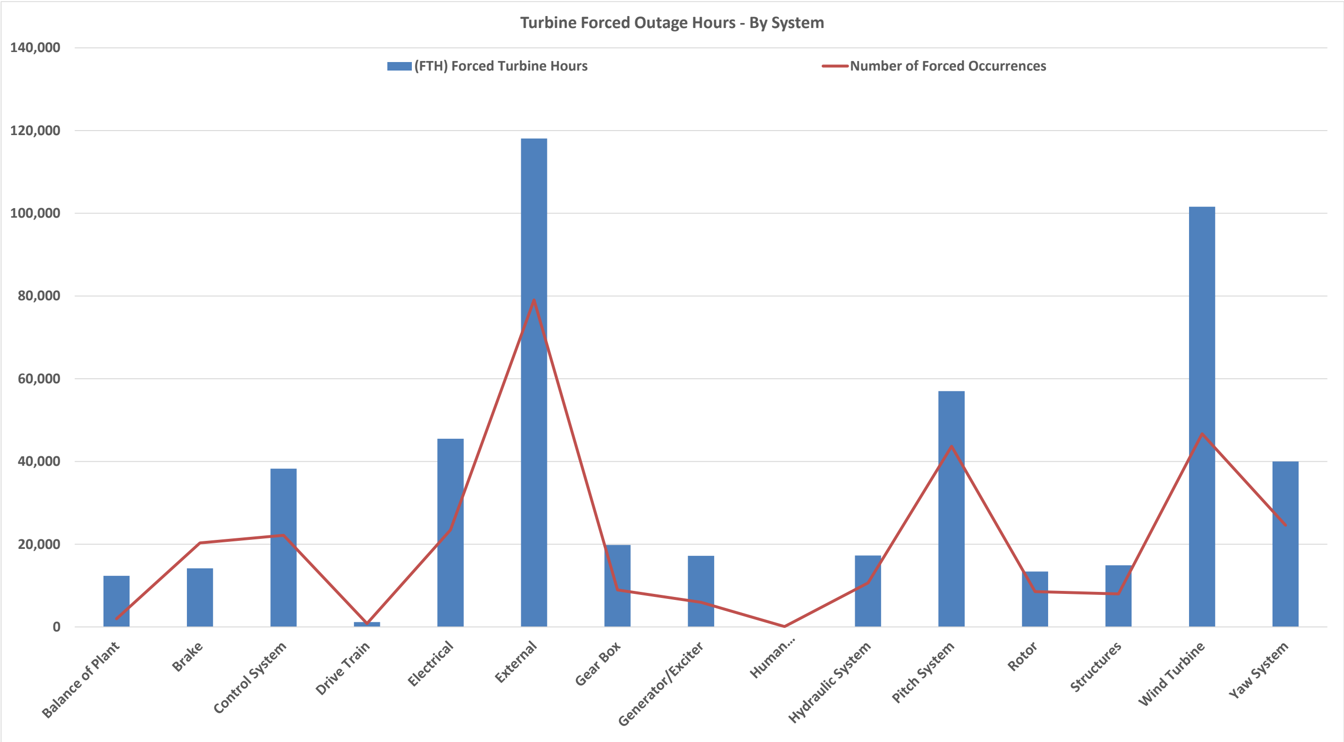


Figure A.25 – 2020 GADS-Wind Turbine Forced Outage Hours by System

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.

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.

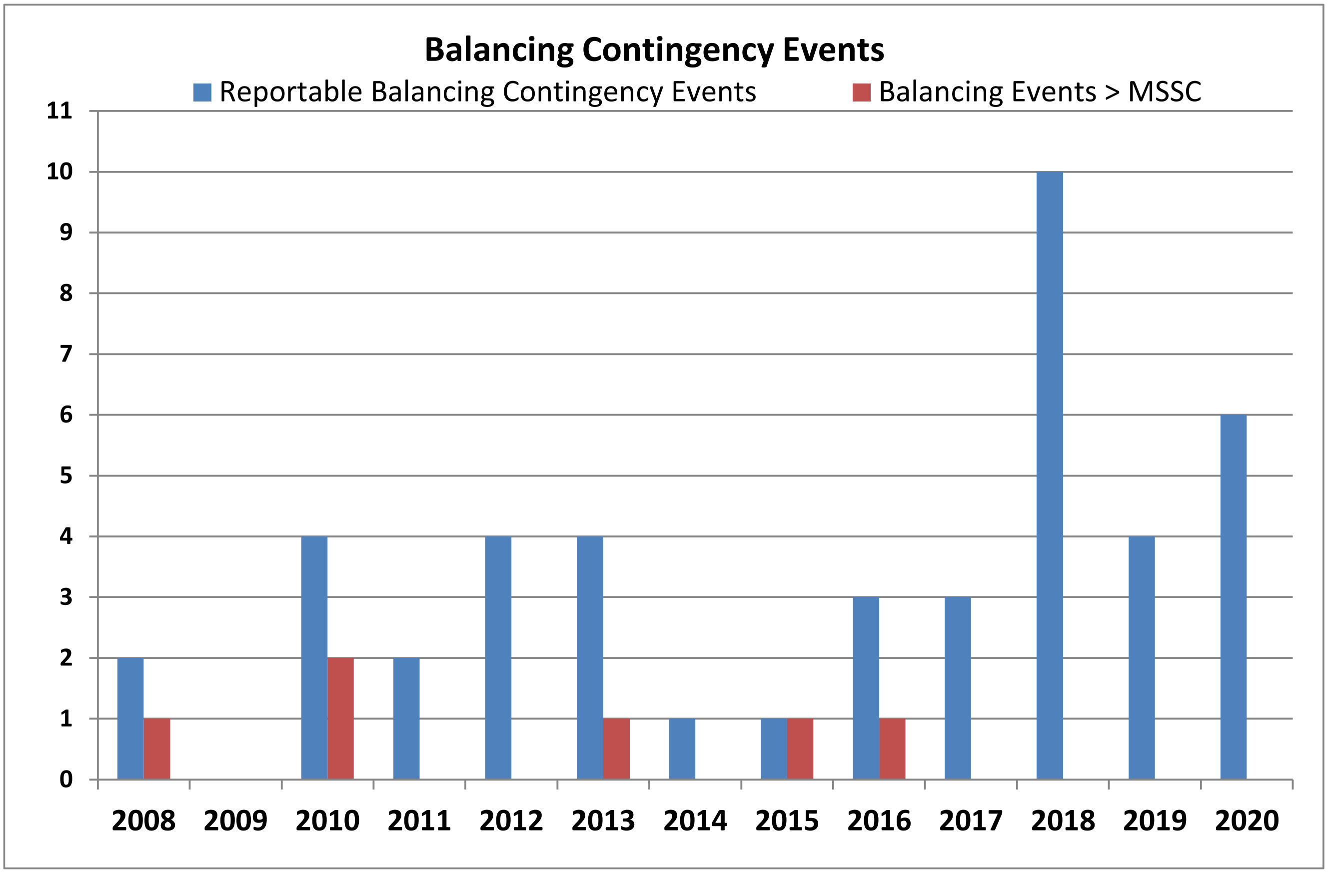


Figure A.26 – Reportable Balancing Contingency Events by Year

H. Fuel Constraints

There was a significant decrease in the unavailable generation capacity due to natural gas fuel curtailments in 2020 (compared to 2019 and 2018) due to the much milder winter.

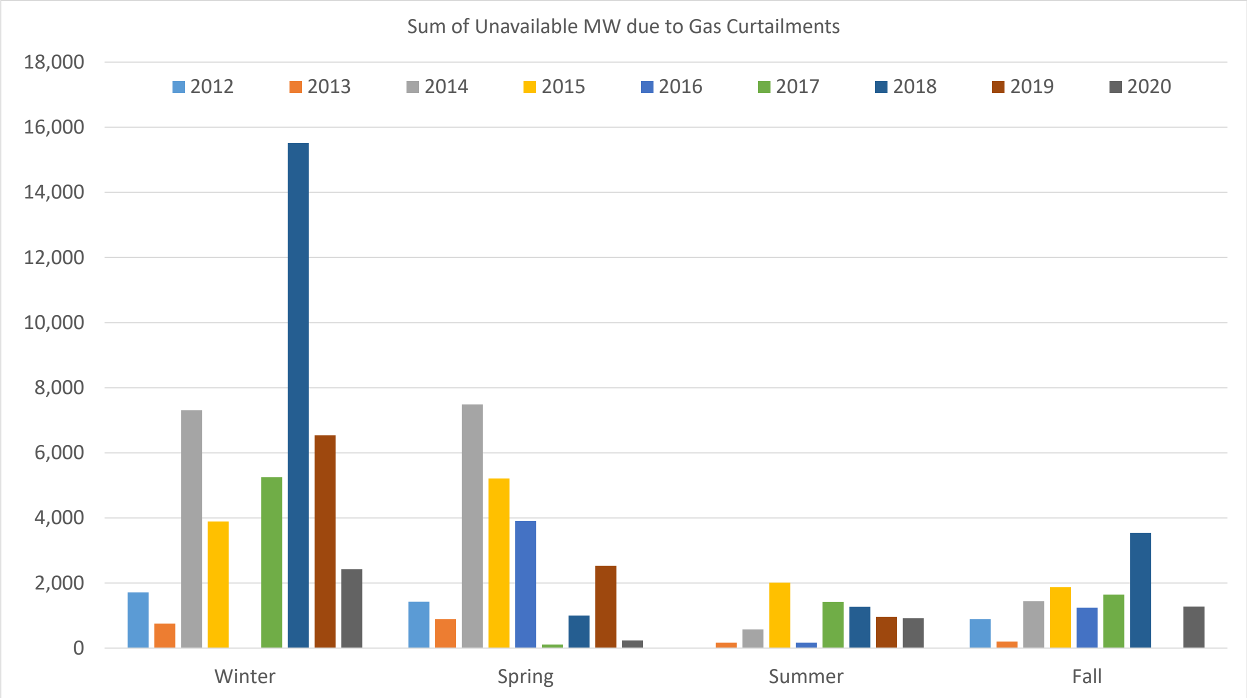


Figure A.27 – Cumulative Unavailable MW Due to Natural Gas Curtailments By Season

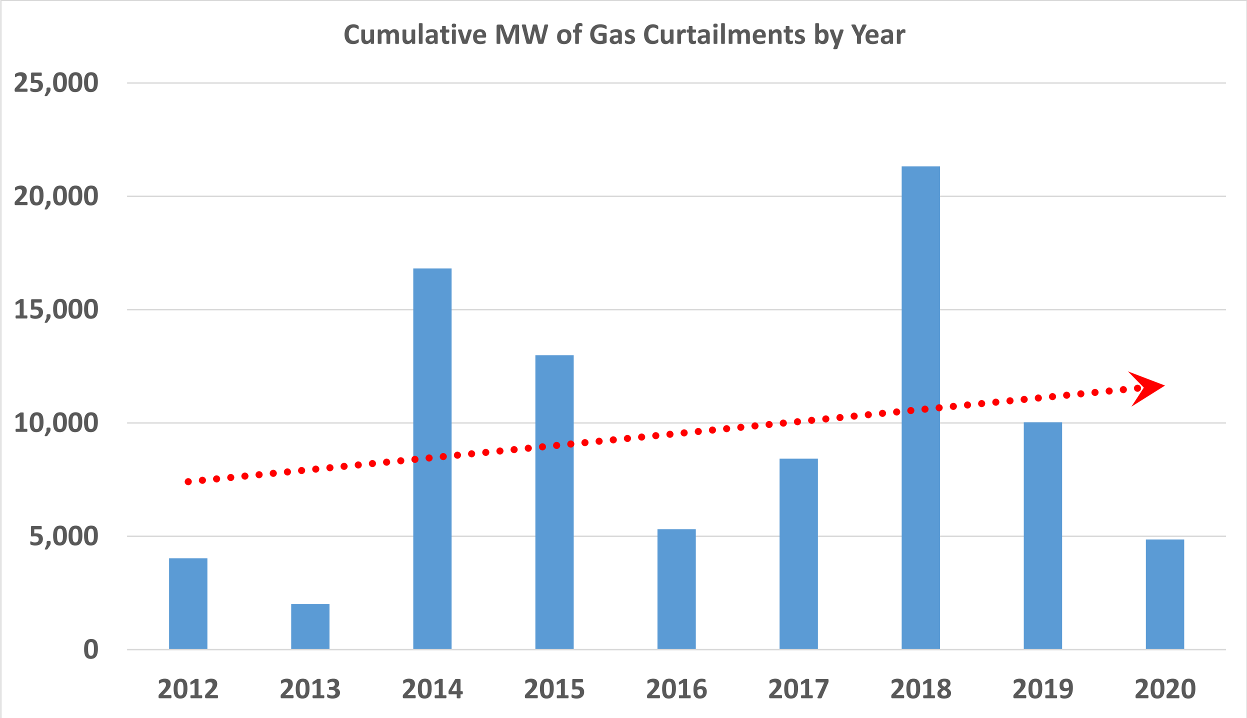


Figure A.28 – Cumulative Unavailable MW Due to Natural Gas Curtailments By Year

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 that 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.

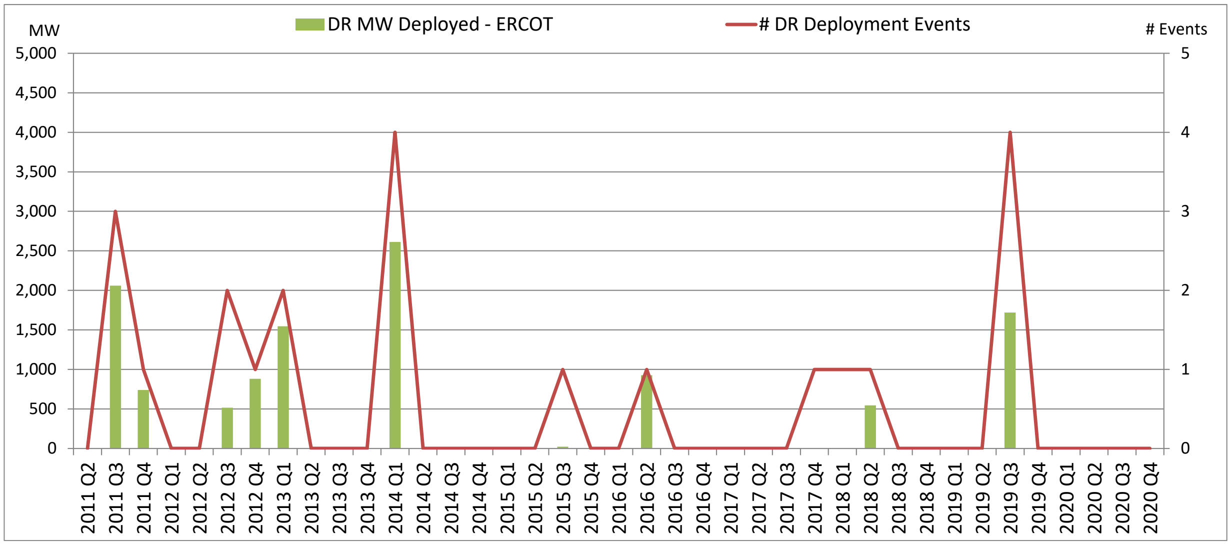


Figure A.29 – History of Demand Response Deployed by ERCOT

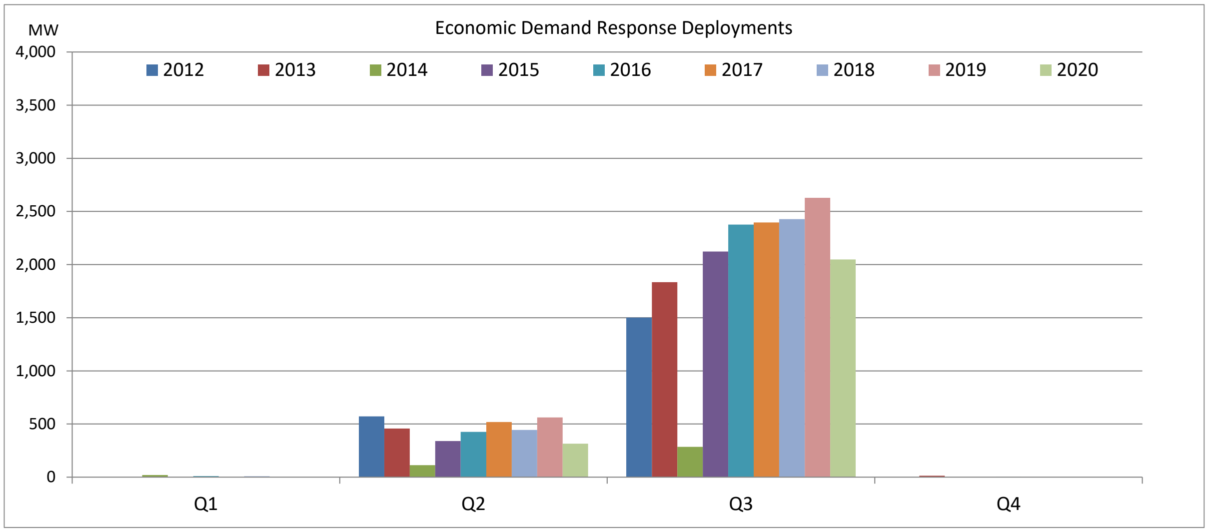


Figure A.30 – Cumulative MW of Economic Demand Response Deployments

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

Table B.1 – 2010-2020 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
5-Yr Average	440	12,245.1	61	10,082.2

Table B.2 – 2010-2020 345 kV Circuit and Transformer Outage Data

B. Event Analysis

[1] Outage count and duration for 2015-2020 includes 345 kV transformers which began reporting in 2015

The following significant events occurred in 2020.

(1) Multiple wind unit loss event on March 18, 2020: A lightning strike caused a multi-phase fault on a 138 kV transmission line. Multiple wind units generating 690 MW tripped off-line as a result of the low voltage conditions created by the fault.

(2) Multiple wind and solar unit loss on April 22, 2020: A fault occurred on a 138 kV transmission line, causing the loss of 408 MW of wind and solar generation due to the low voltage conditions created by the fault.

(3) Hurricane Hannah July 25, 2020: Hurricane Hannah hit south Texas and the lower Rio Grande Valley, causing the loss of three 345 kV lines, nineteen 138 kV lines, ten 69 kV lines and a maximum of approximately 280,000 customers out of service.

(4) Remedial Action Scheme (RAS) misoperation on August 18, 2020: A RAS misoperated during testing of SCADA communications, combined with incorrect logic programmed in the RAS controller, causing the loss of six 138 kV lines and 205 MW of load.

(5) Loss of multiple wind and solar Units October 14, 2020: A fault occurred on a substation bus due to a failed surge arrestor. The breaker failure scheme misoperated due to incorrect logic settings, resulting in the loss of multiple 69 kV lines, 96 MW of wind and solar generation, and 18 MW of load.

(6) Panhandle outage October 28, 2020: An ice storm hit the Panhandle causing the loss of 48 345 kV transmission lines and 206 MW of generation, separating the Panhandle area from ERCOT.

Historical Disturbance Data: In 2020, the number of events reported increased slightly when compared to average number of events between 2016 through 2019.

Event Category[2]	2016	2017	2018	2019	2020	5-Yr Avg
Non-Qualified	65	52	78	73	84	70
1	5	11	13	11	8	10
2	0	0	0	0	0	0
3	2	0	0	0	0	0
4 and 5	0	1	0	0	0	0
Total	72	64	91	84	92	81

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

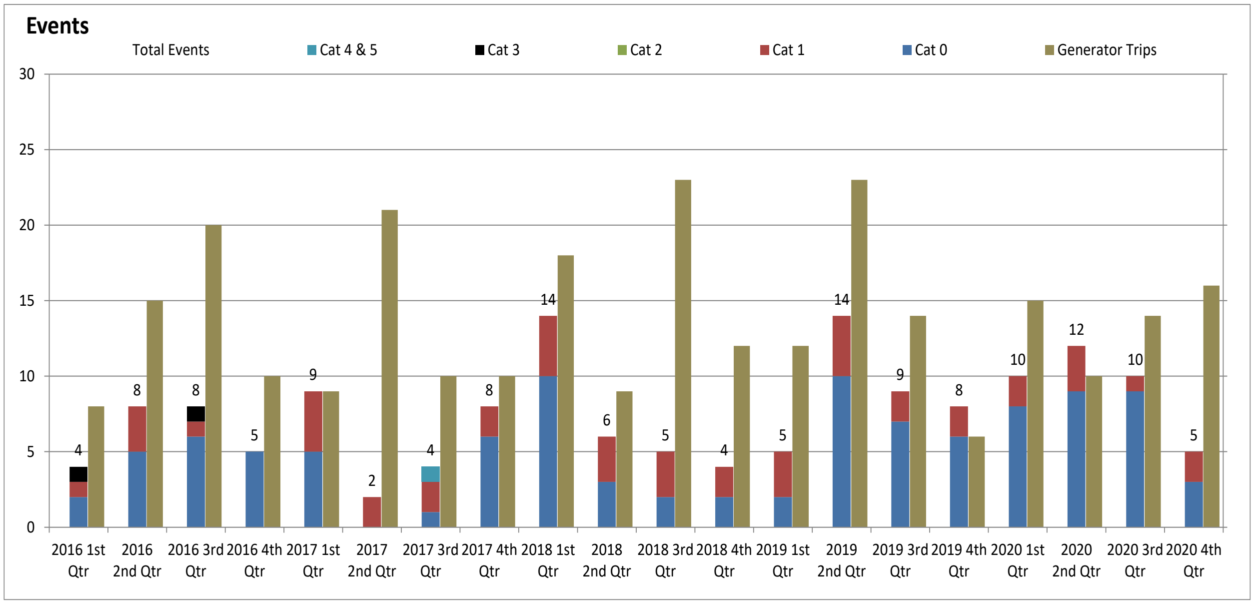


Figure B.1 – Events Reported by Quarter

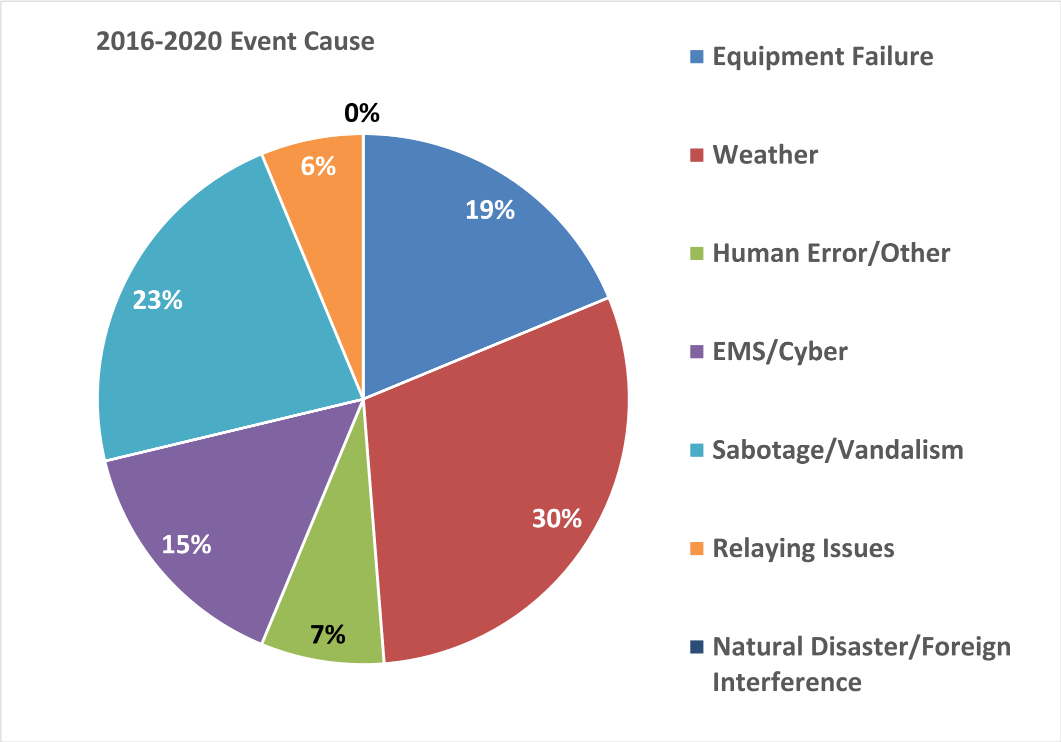


Figure B.2 – 2016-2020 Event Cause Summary

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.

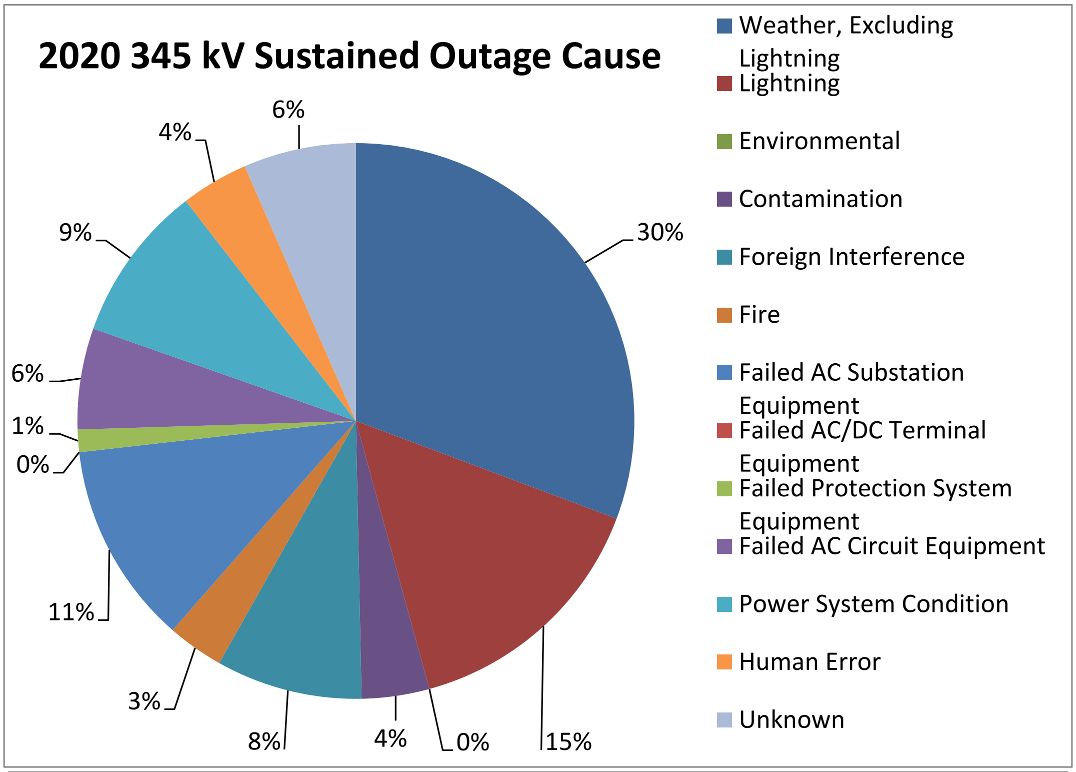
Voltage Class Name	Metric	2016	2017	2018	2019	2020	5-Yr Avg
AC Circuit 300-399 kV	Automatic Outages per Circuit	0.99	0.95	0.66	1.02	0.82	0.89
AC Circuit 300-399 kV	Automatic Outages per 100 miles	2.78	2.68	1.98	2.97	2.45	2.57
AC Circuit 100-199 kV	Sustained Automatic Outages per Circuit	0.19	0.22	0.22	0.19	0.19	0.20
AC Circuit 100-199 kV	Sustained Automatic Outages per 100 miles	1.55	1.90	1.87	1.65	1.61	1.72
Transformer 300-399 kV	Automatic Outages per Element	0.11	0.14	0.13	0.16	0.10	0.13

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 2020 were weather (excluding lightning), lightning, and failed substation equipment, representing 56 percent of the total sustained outages. Failed transmission circuit equipment accounted for 34 percent of the outage duration.

For 138 kV transmission circuits, predominant causes for sustained outages in 2020 were lightning, failed substation equipment, and failed circuit equipment, representing 52 percent of the total sustained outages. Failed substation/transmission circuit equipment dominated the sustained outage duration, accounting for 75 percent of the outage duration.



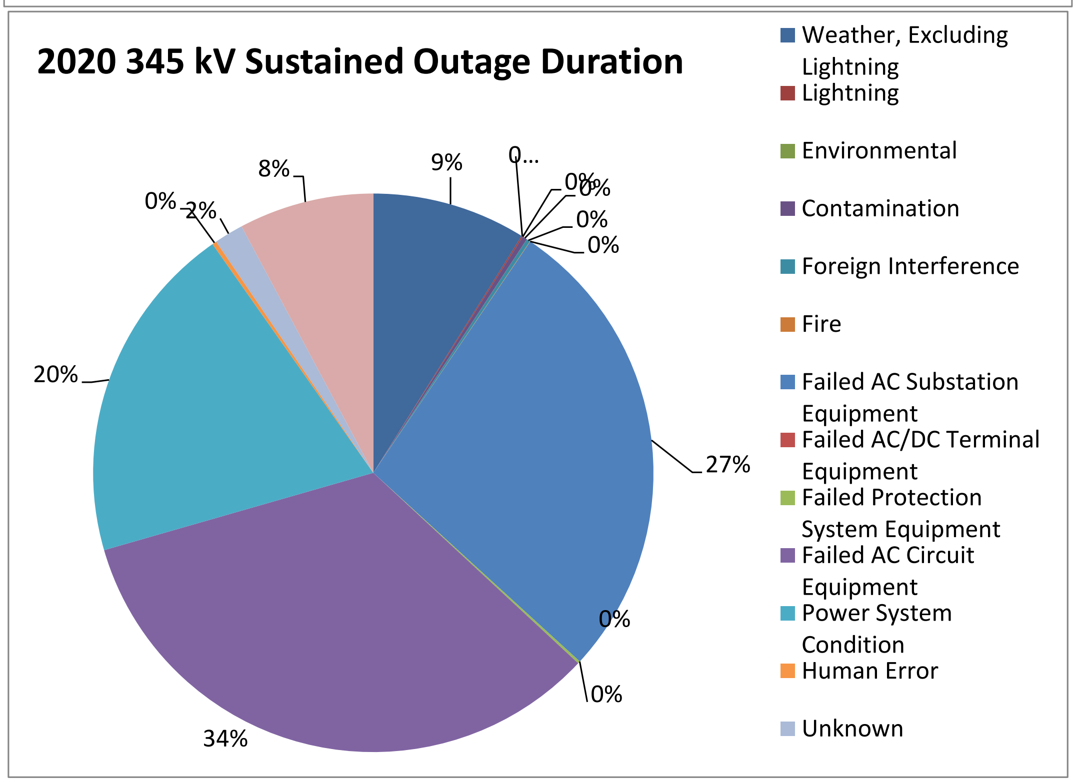


Figure B.3 – 2020 345 kV Sustained Outage Cause versus Duration

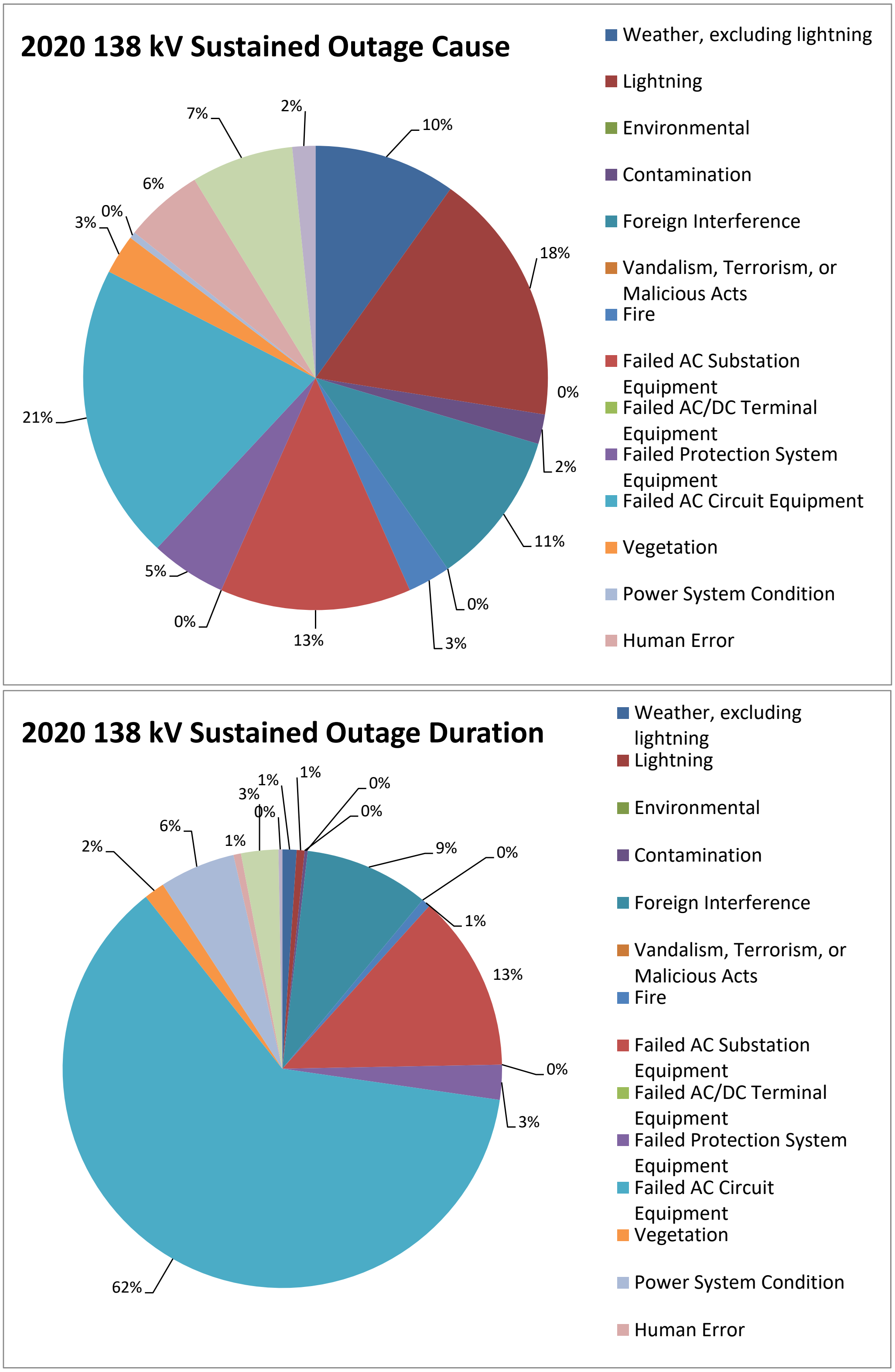


Figure B.4 – 2020 138 kV Sustained Outage Cause versus Duration

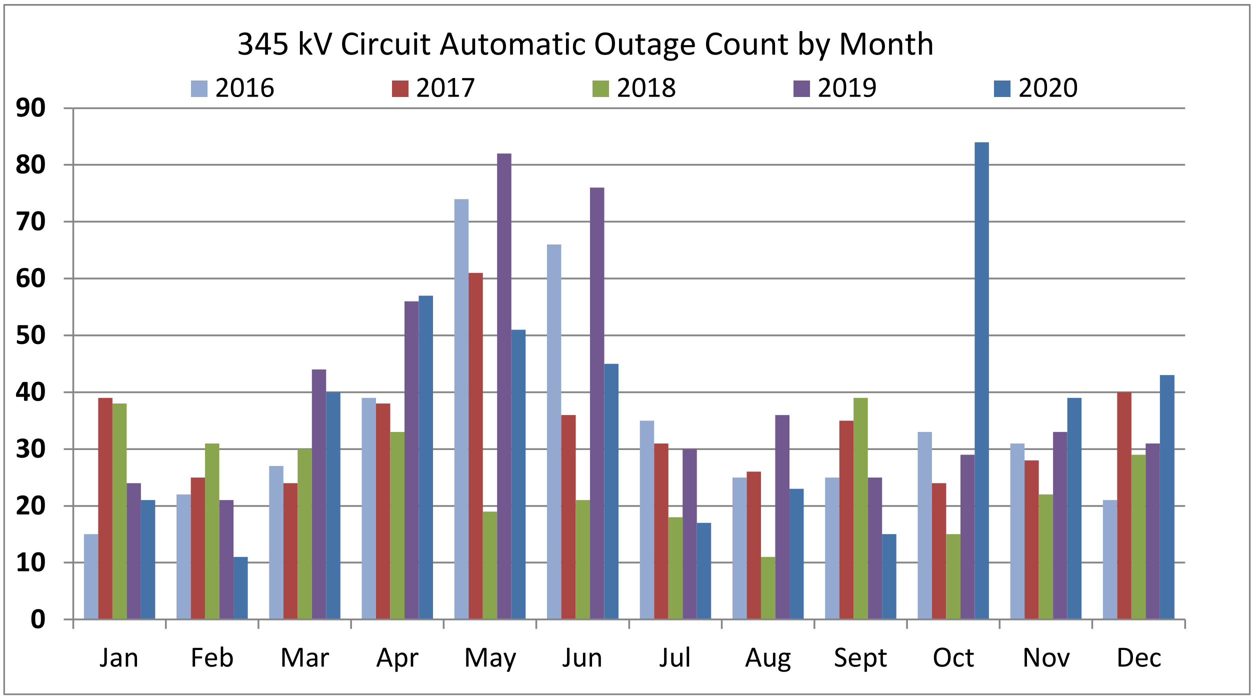


Figure B.5 – 345 kV Circuit Automatic Outages by Month

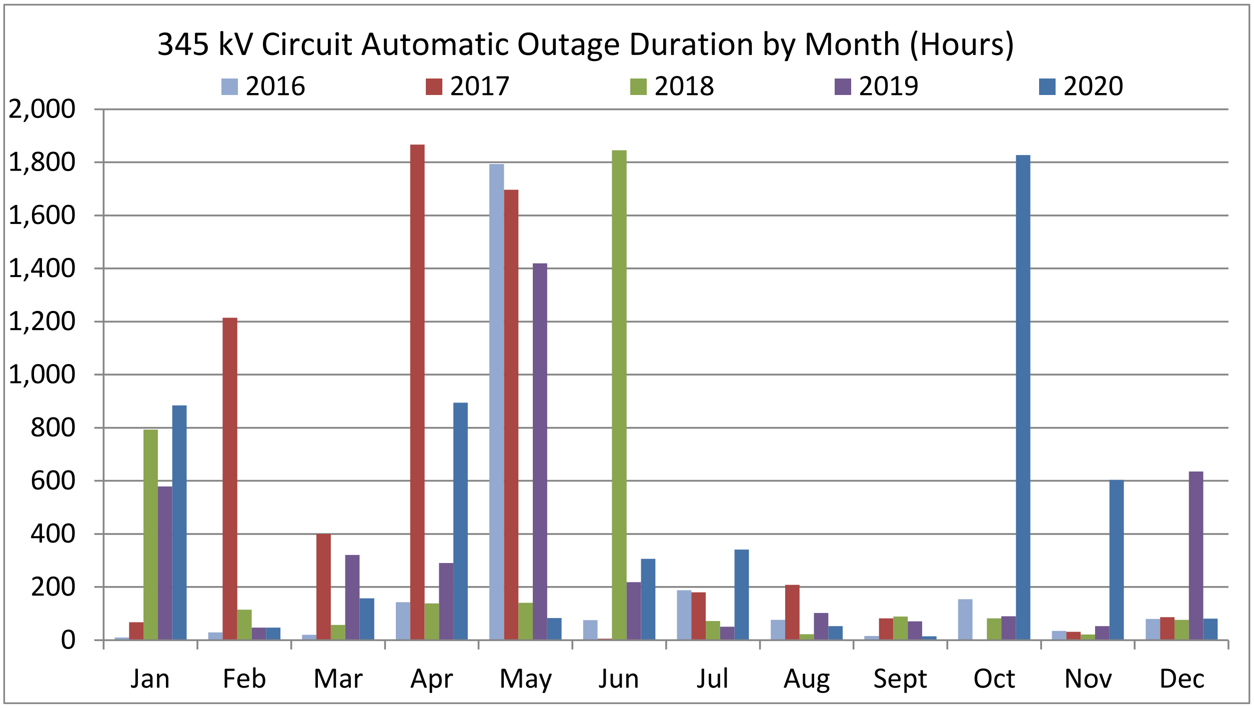


Figure B.6 – Multi-Year Comparison of TADS Outages and Duration by Month (> 200 kV)

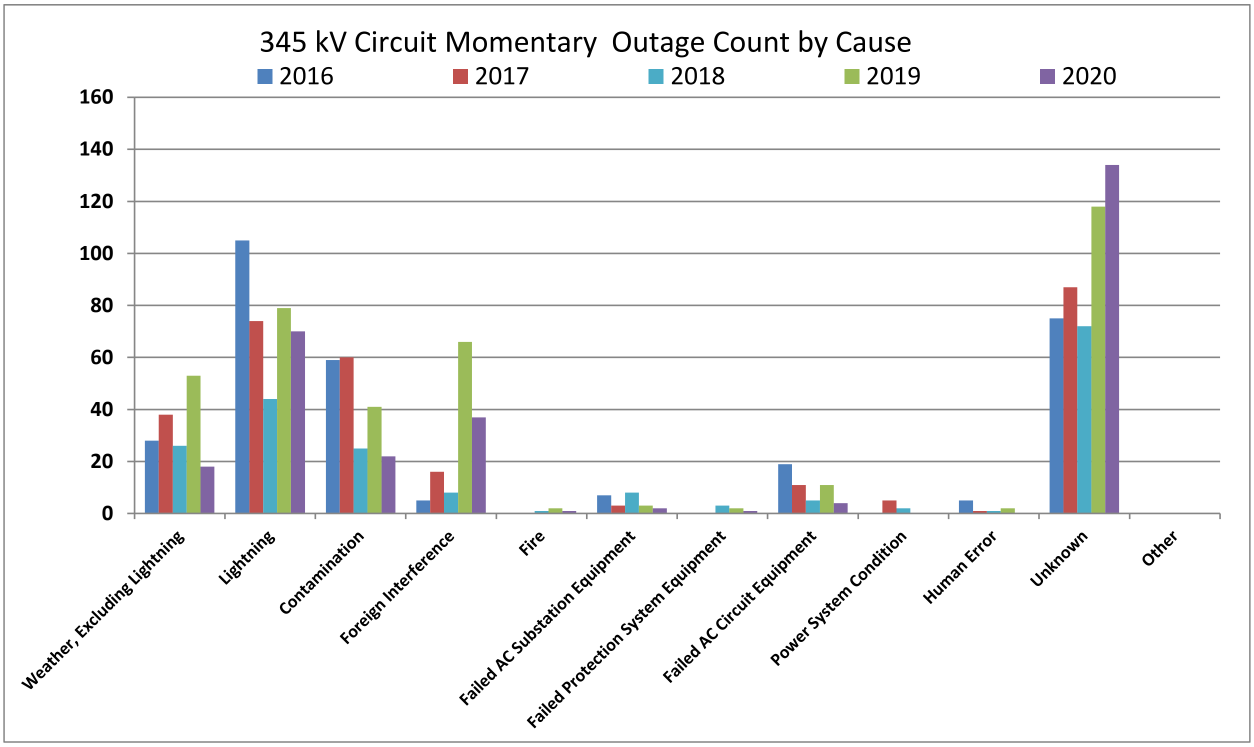


Figure B.7 – 345 kV Circuit Momentary Outage Count by Cause

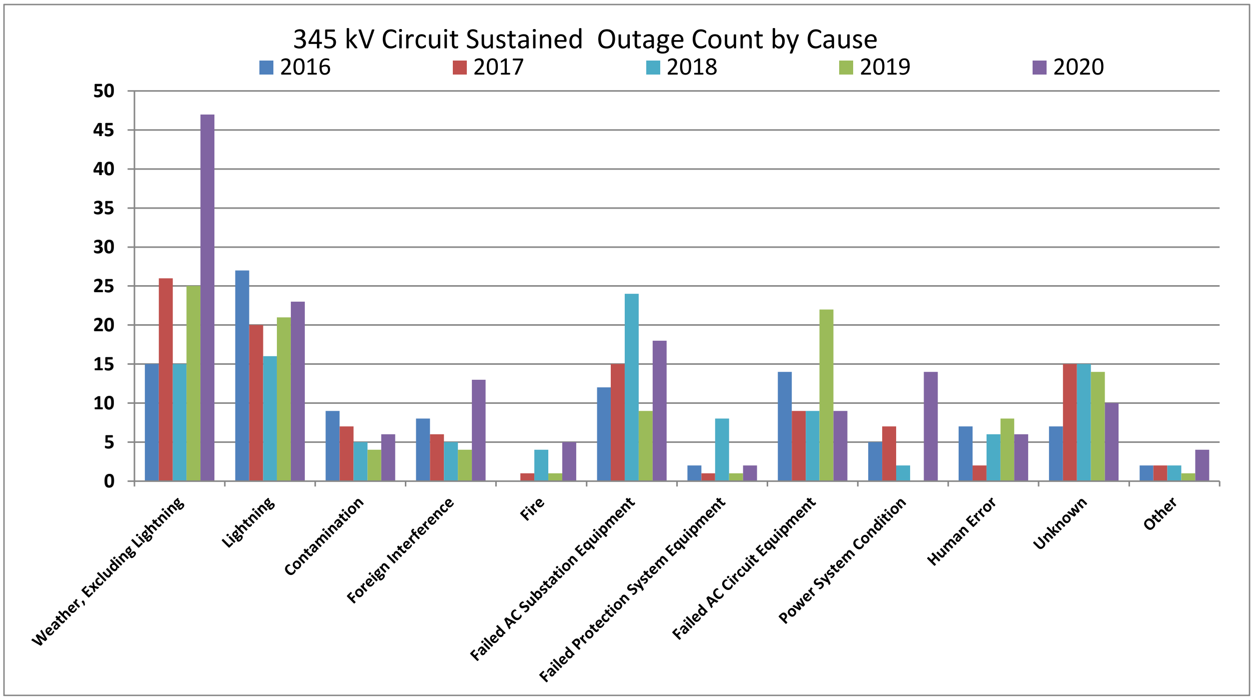


Figure B.8 – 345 kV Circuit Sustained Outage Count by Cause

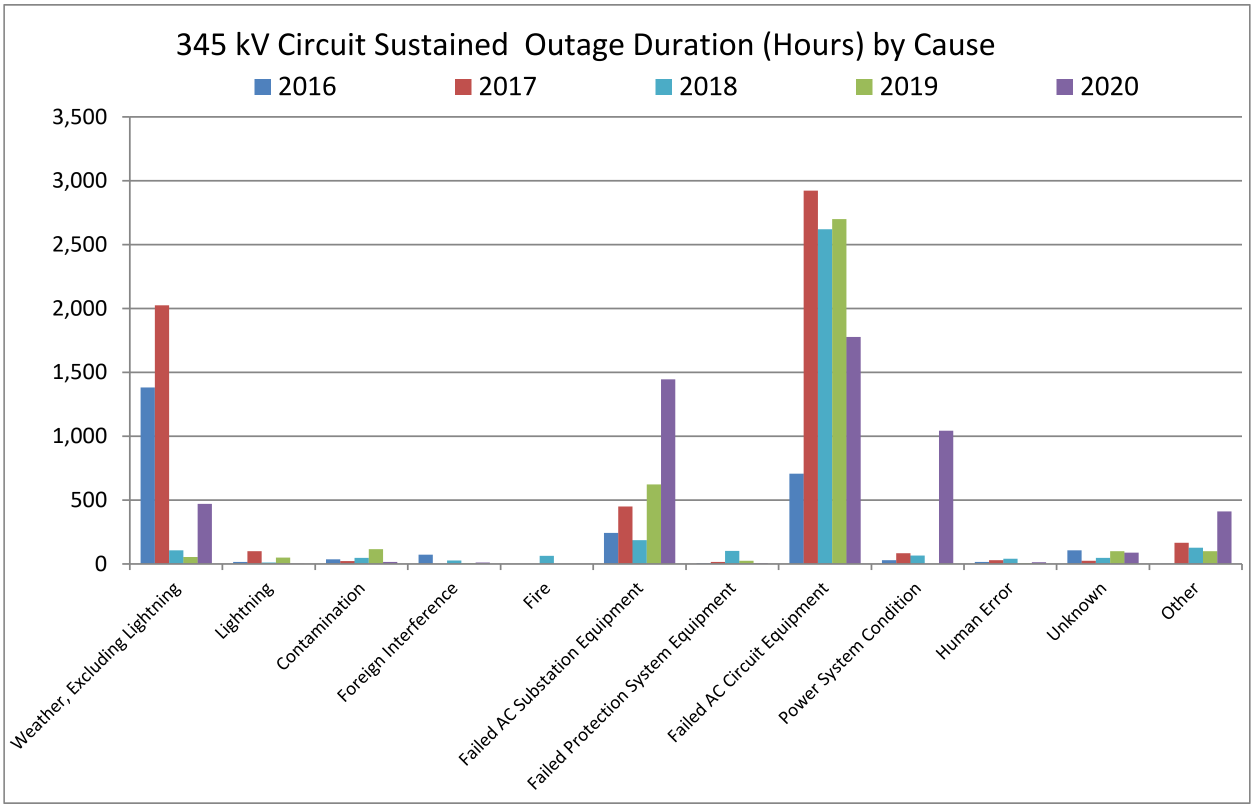


Figure B.9 – 345 kV Circuit Sustained Outage Duration (Hours) by Cause

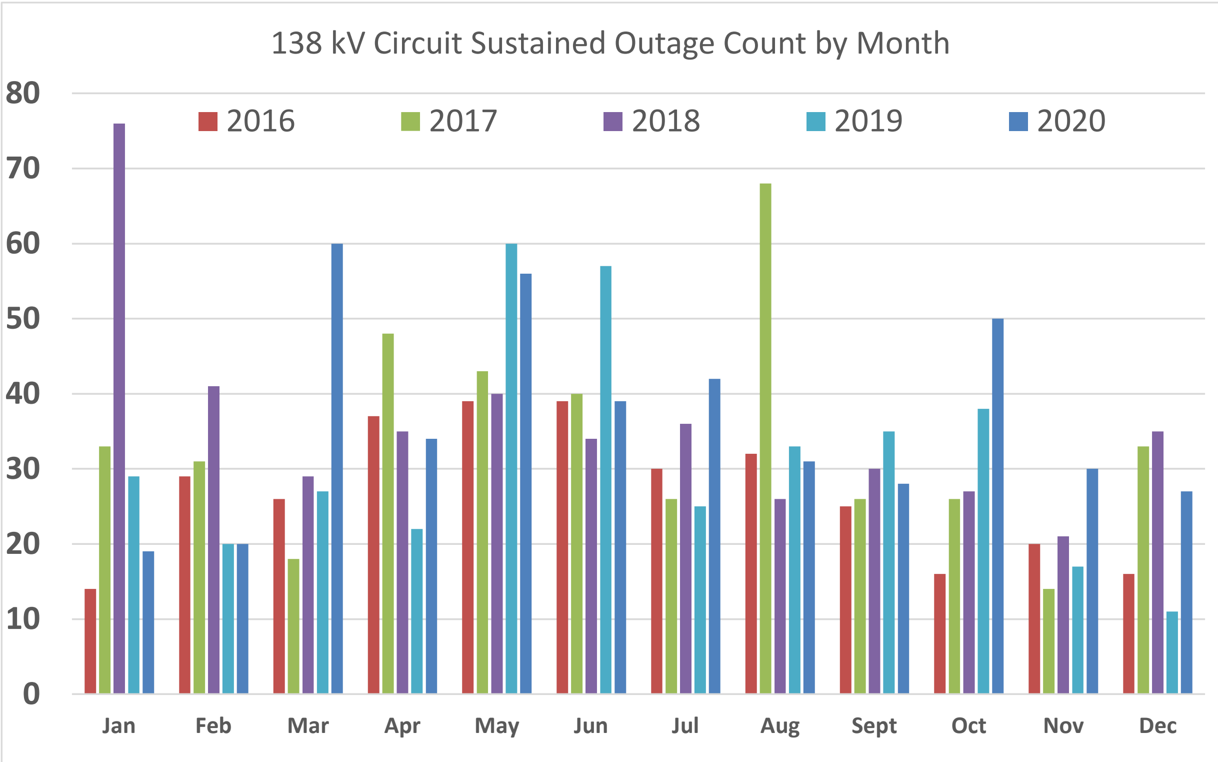


Figure B.10 – 138 kV Circuit Sustained Outage Counts by Month

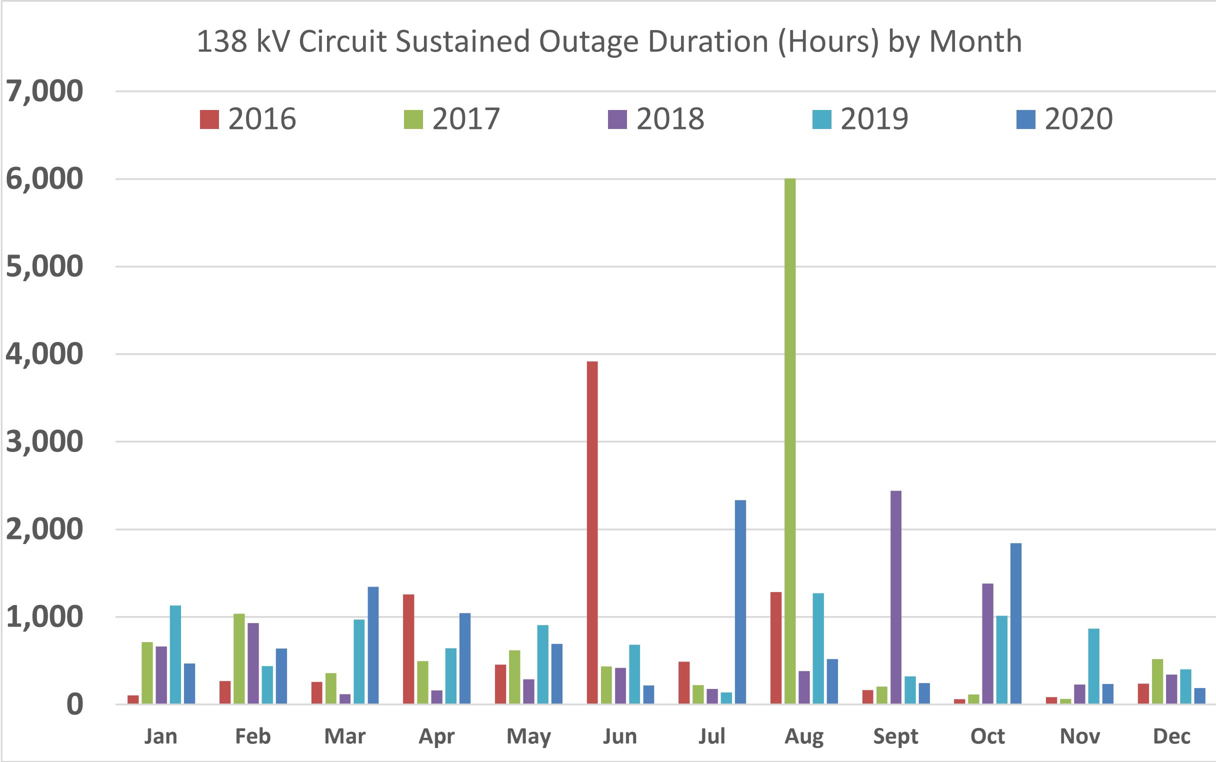


Figure B.11 – 138 kV Circuit Sustained Outage Duration (Hours) by Month

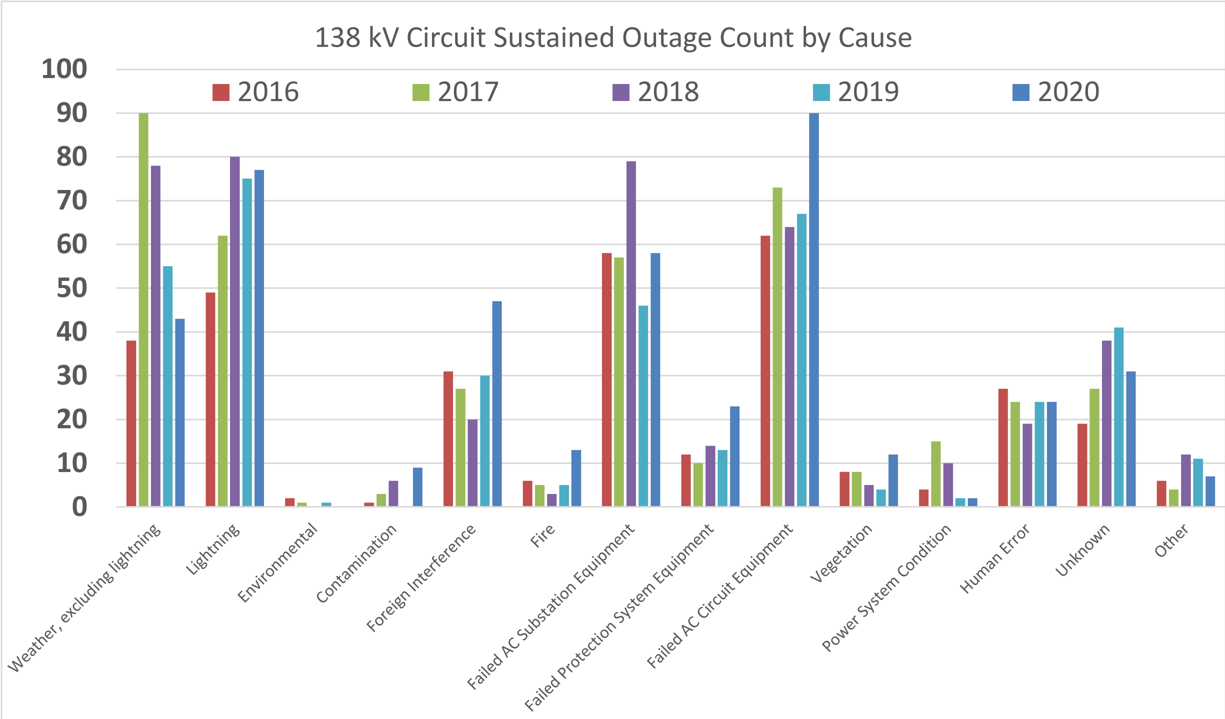


Figure B.12 – 138 kV Circuit Sustained Outage Count by Cause

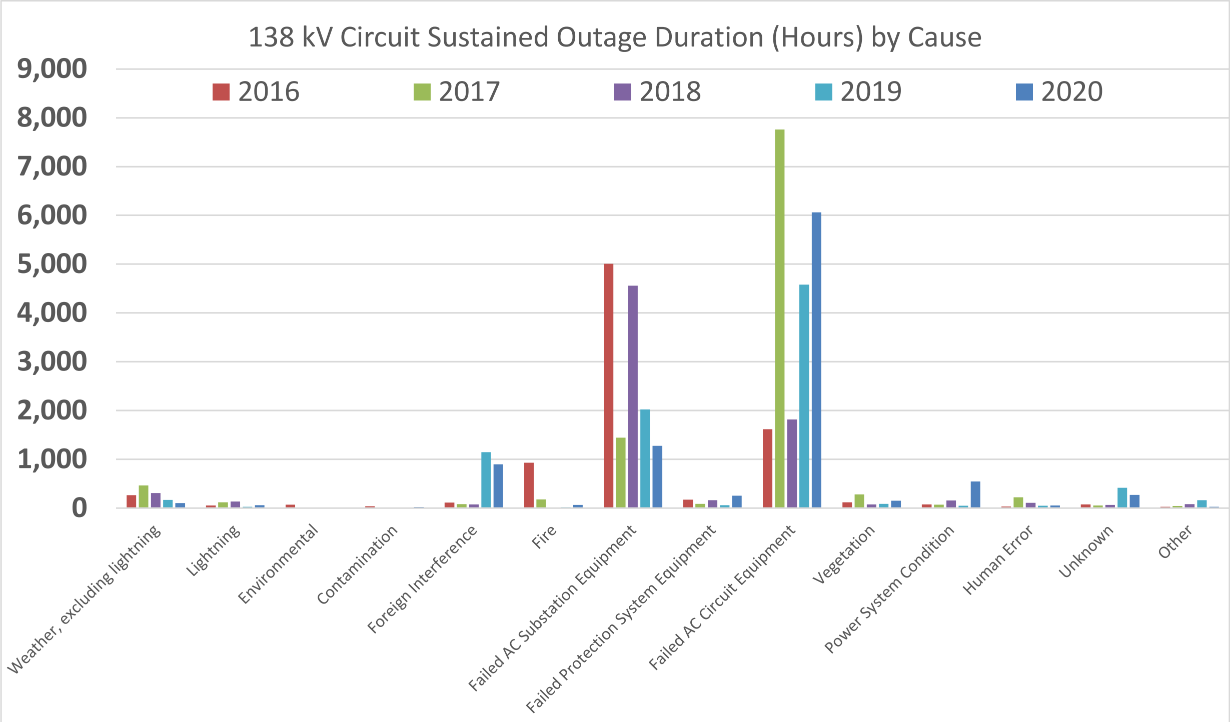


Figure B.13 – 138 kV Circuit Sustained Outage Duration by Cause

<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 2017-2020.

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

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

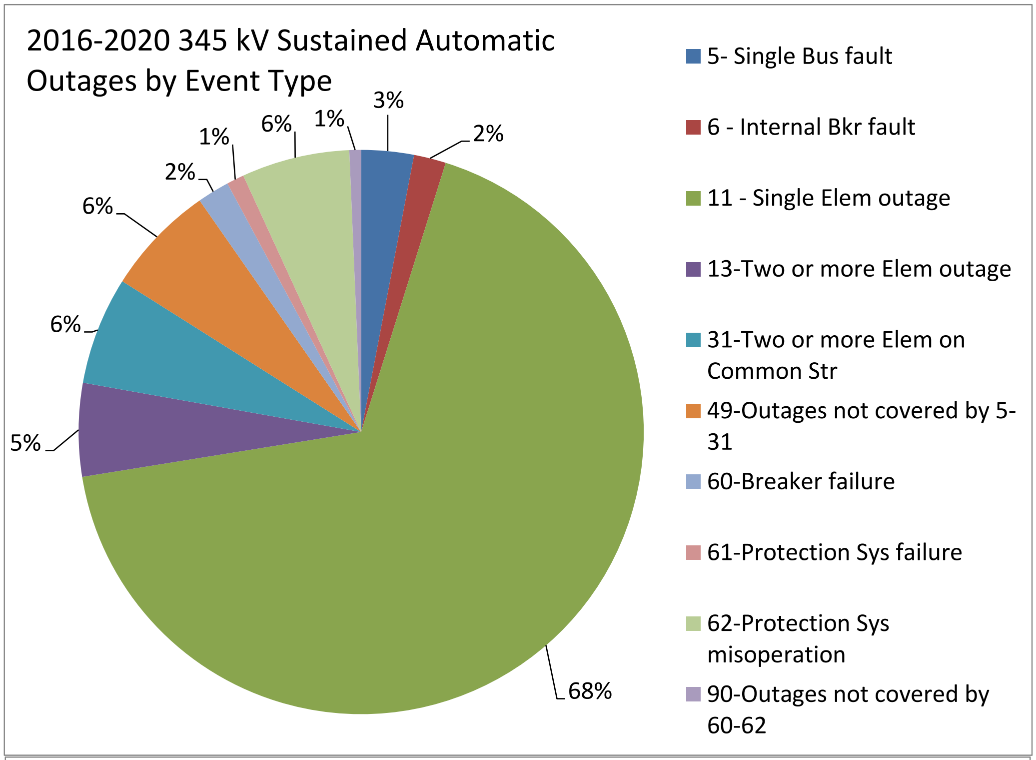
Table B.6 – Extreme Generation Event Day Analyses

D. Multiple Element Outages

For 345 kV circuits in 2020, 58 of the 446 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 13 percent of all outages and 45 percent of sustained outage duration for the 345 kV system.

For 138 kV circuits in 2020, 149 of the 436 reported automatic sustained outage events involved two or more circuit elements. Dependent Mode and Common Mode outages represented 34 percent of all sustained outages and 36 percent of sustained outage duration.

Over the five year period from 2016-2020, multiple element outages represented 30 percent of sustained outages and 55 percent of the sustained outage duration for the 345 kV system.



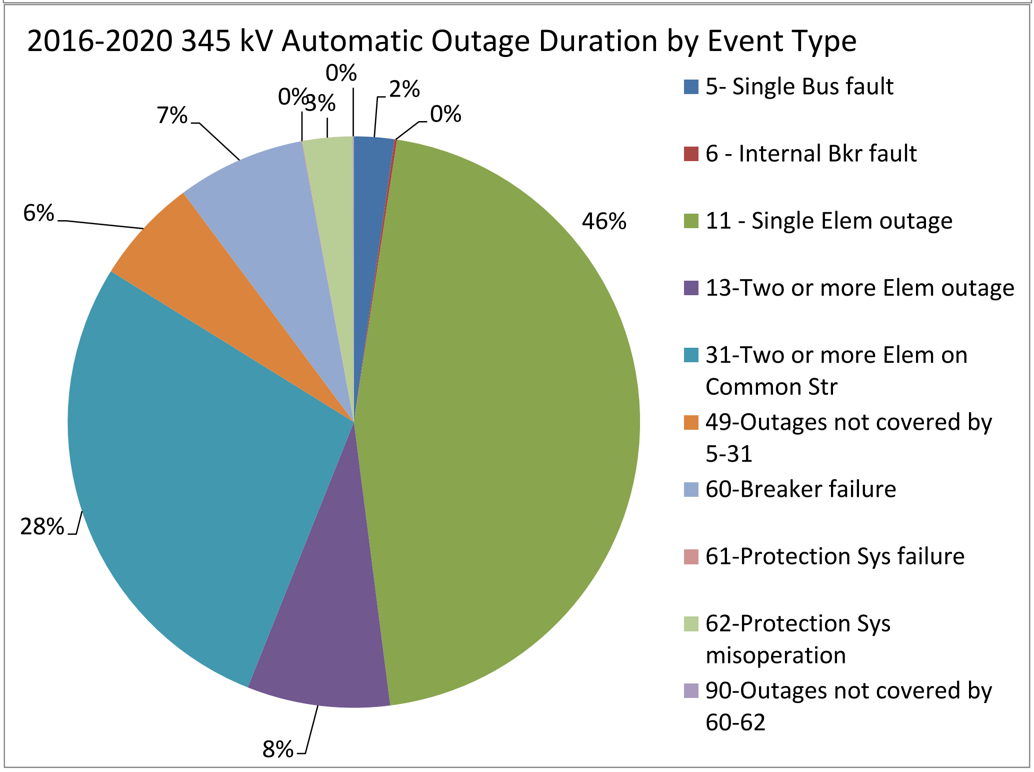


Figure B.14 – 2016-2020 345 kV Sustained Outages by Event Type

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. As of October 1, 2020, the number of IROLs in the ERCOT Interconnection increased from one to five, based on changes in 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).

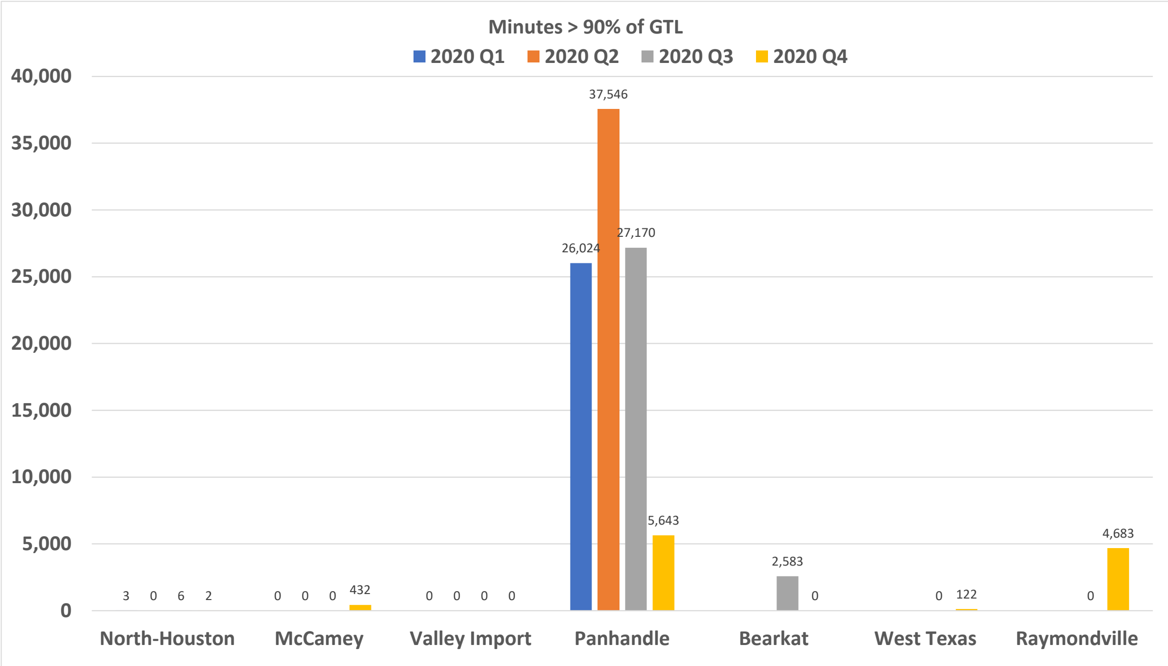


Figure B.15 – Interface Operation Minutes Greater Than 90 Percent of GTL

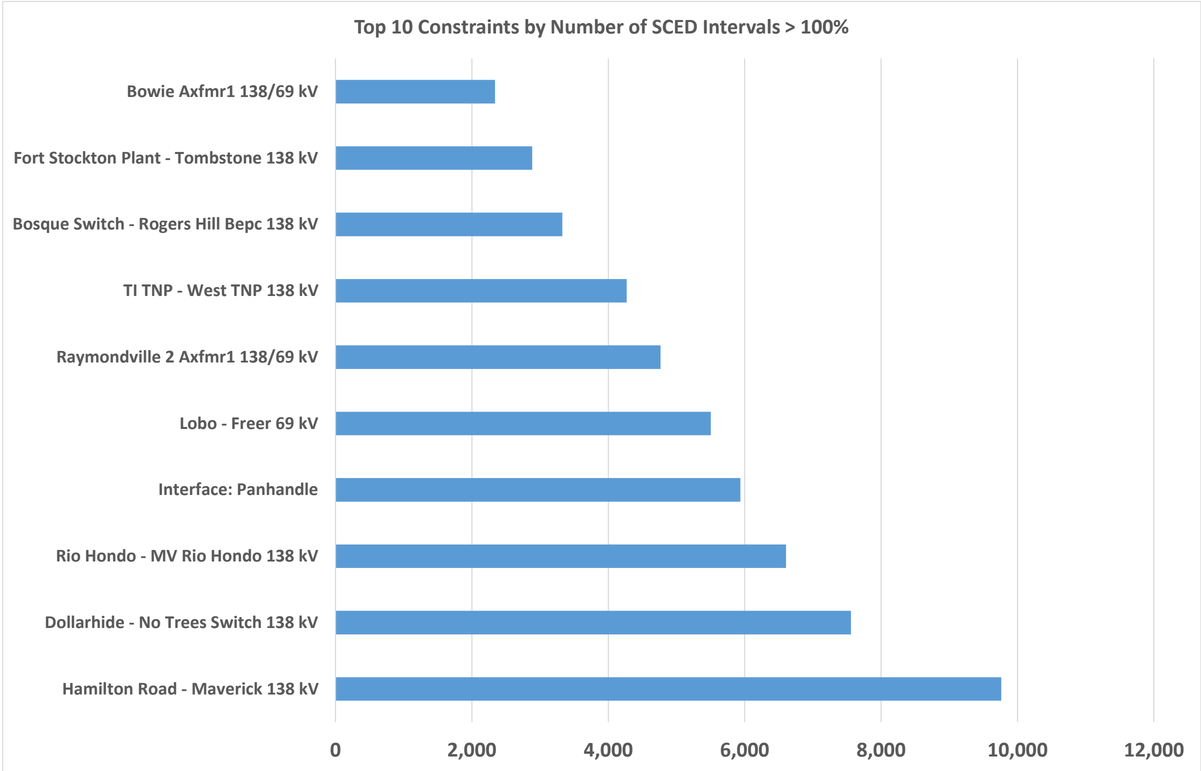


Figure B.16 – 2020 Top Constraints by Duration

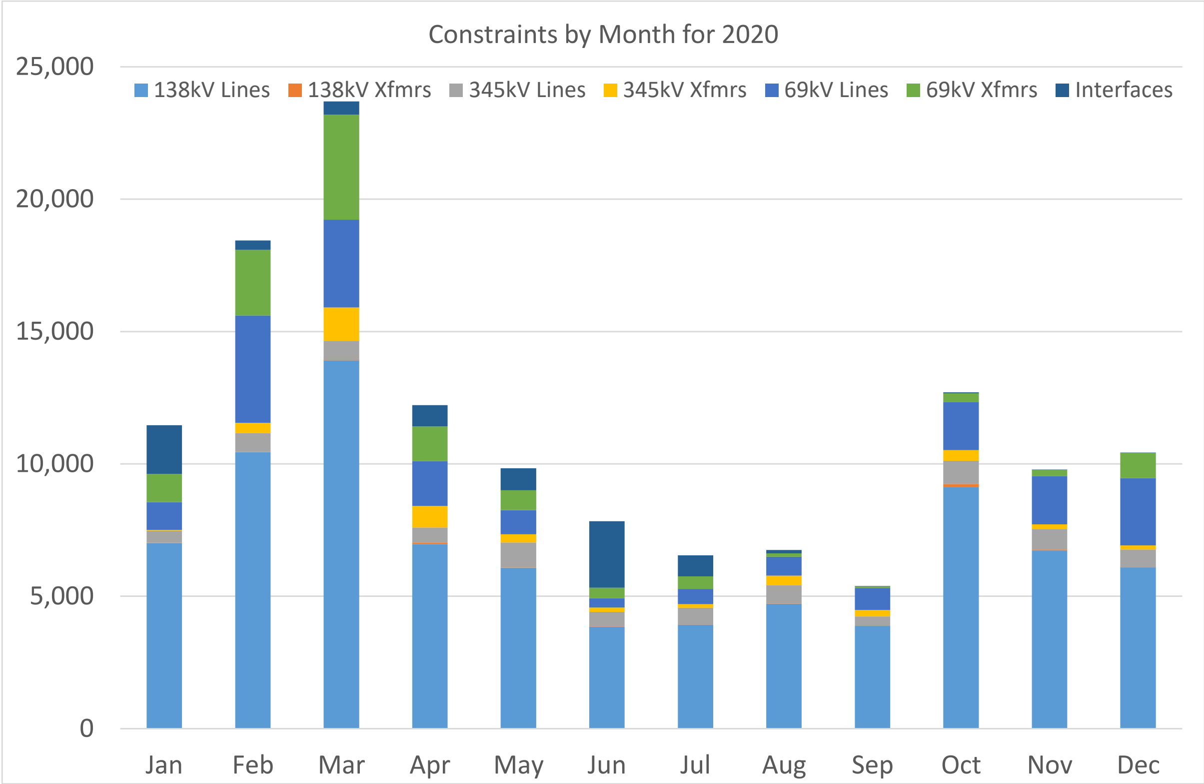


Figure B.17 – Constraints by Month for 2020

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.

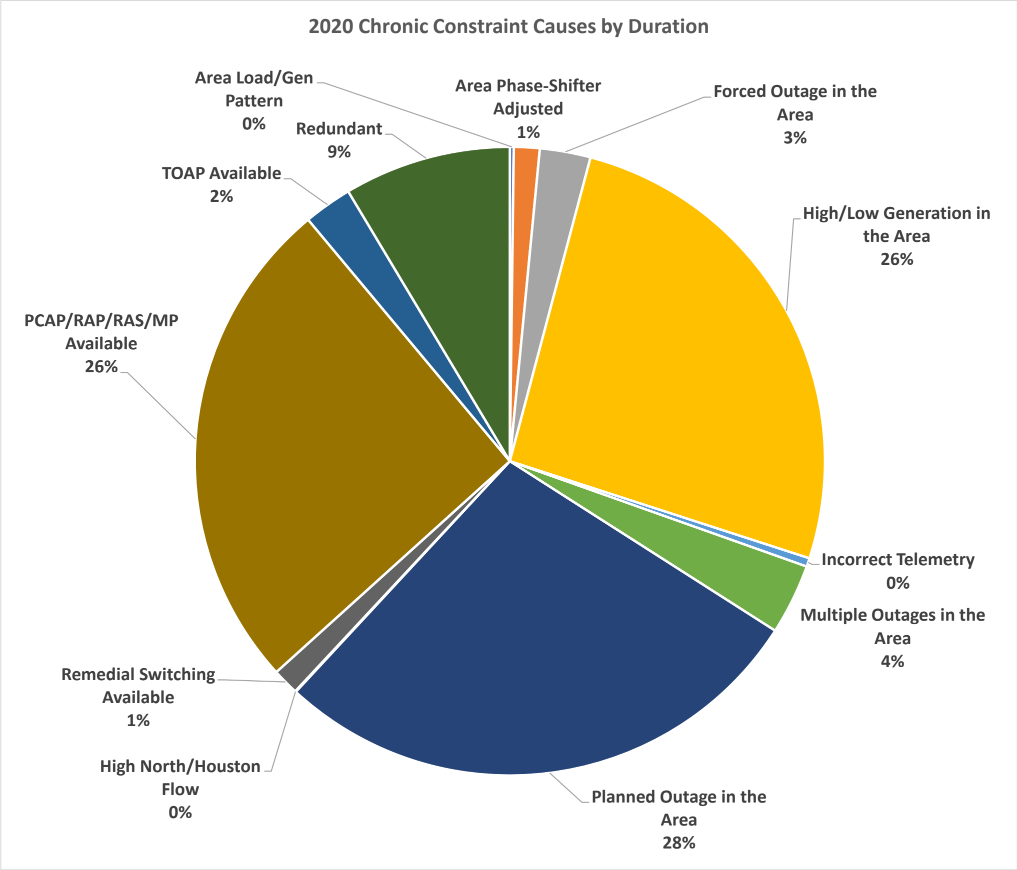


Figure B.18 – 2020 Chronic Constraint Causes by Duration

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 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 totaled 13 units for 234 commitment hours. The primary reason for HRUC commitments was to relieve local congestion or constraints on the transmission system, which accounted for approximately 94 percent of all HRUC hours.

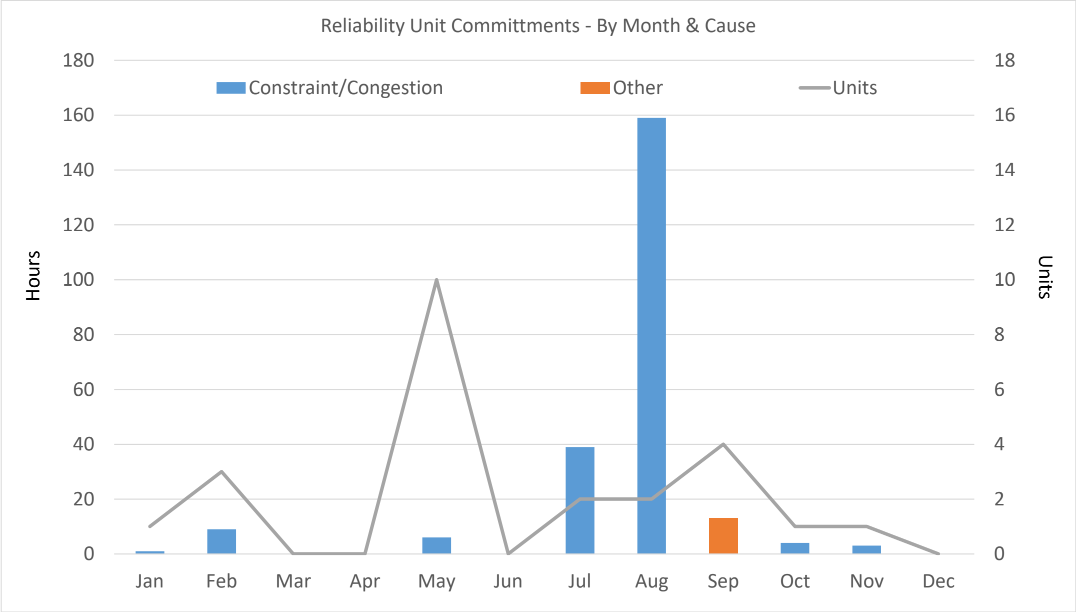


Figure B.19 – 2020 Hourly Reliability Unit Commitments by Month and Cause

Appendix C – Changing Resource Mix Detailed Analysis

A. Unit Additions and Retirements

Retirements and Mothball Status – 1,141 MW

Unit	Date	Status	MW	Fuel Type
Oklaunion	10/1/2020	Retired	650	Coal
Nacogdoches	10/16/2020	Seasonal Mothball	105	Wood
Decker G1	10/30/2020	Retired	315	Gas
Petra Nova	12/20/2020	Mothballed	71	Gas

New Resources Approved for Commercial Operation – 3,135 MW

Unit	Date	MW	Fuel Type
City Vict	2/6/2020	100	Gas
Gopher Creek Wind	3/9/2020	158	Wind
Wilson Ranch Wind	4/17/2020	199.5	Wind
Blue Summit II	4/6/2020	102	Wind
Bobcat Bluff Repower	4/17/2020	12	Wind
Blue Summit III	5/19/2020	200	Wind
Ranchero Wind	5/4/2020	300	Wind
Queen Solar Phase I	5/4/2020	200	Solar
Holstein Solar	5/28/2020	200.5	Solar
Prospero Solar	6/30/2020	300	Solar
Rio Nogales Upgrade	6/9/2020	19	Gas
Peyton Creek Wind	6/4/2020	151	Wind
Lapetus Solar	6/24/2020	100	Solar
Oberon Solar	7/13/2020	180	Solar
Hudson	7/17/2020	96	Gas
Fowler Ranch	8/28/2020	152.5	Solar
Queen Solar Phase II	8/28/2020	200	Solar
Rambler Solar	10/1/2020	200	Solar
Palmas Altas Wind	11/12/2020	145	Wind
Kellam Solar	12/24/2020	60	Solar
Rippey Solar	12/30/2020	60	Solar

Table C.1 – 2020 Unit Additions and Retirements

B. Fuel Mix Analysis

Wind generation reporting in GADS-Wind produced a net total of 78,540 GWH in 2020, or 90.2 percent of the total ERCOT wind generation for 2020. Wind generation, as a percentage of total ERCOT energy produced, increased to 22.8 percent in 2020, up from 20.0 percent in 2019. In 2020, hourly wind generation reached a maximum of 22,099 MW on December 30, 2020, at 11:00 a.m., and hourly wind generation served a maximum of 59.1 percent of system demand on May 2, 2020, at 2:00 a.m.

Utility-scale solar generation within the region continued its significant growth in 2020. The amount of energy provided by solar generation increased 108 percent versus 2019.

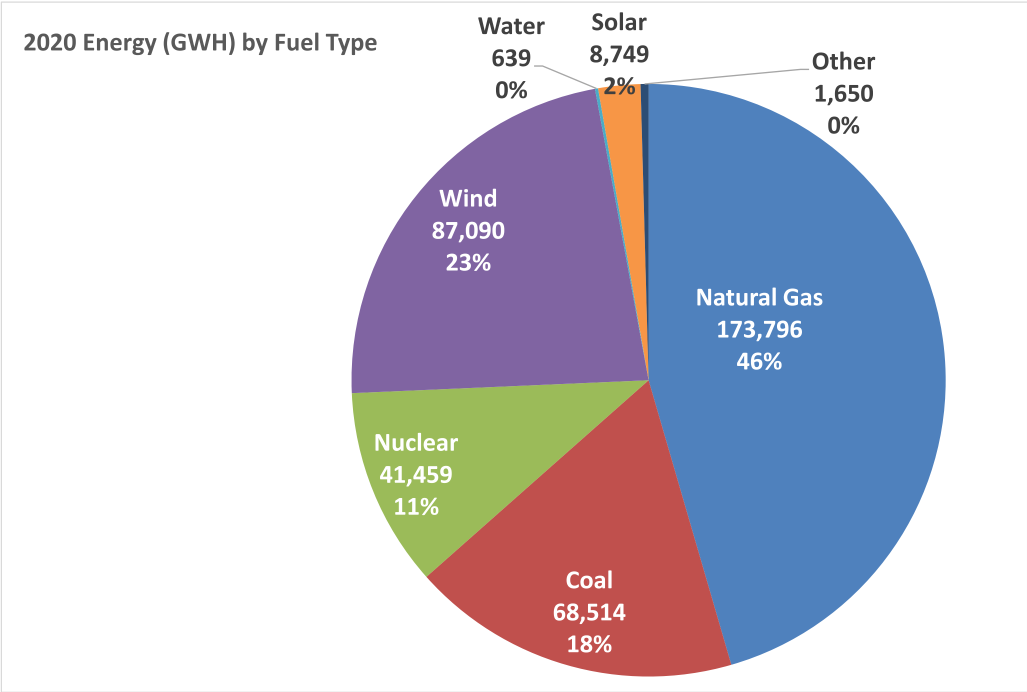


Figure C.1 – 2020 Energy by Fuel Type

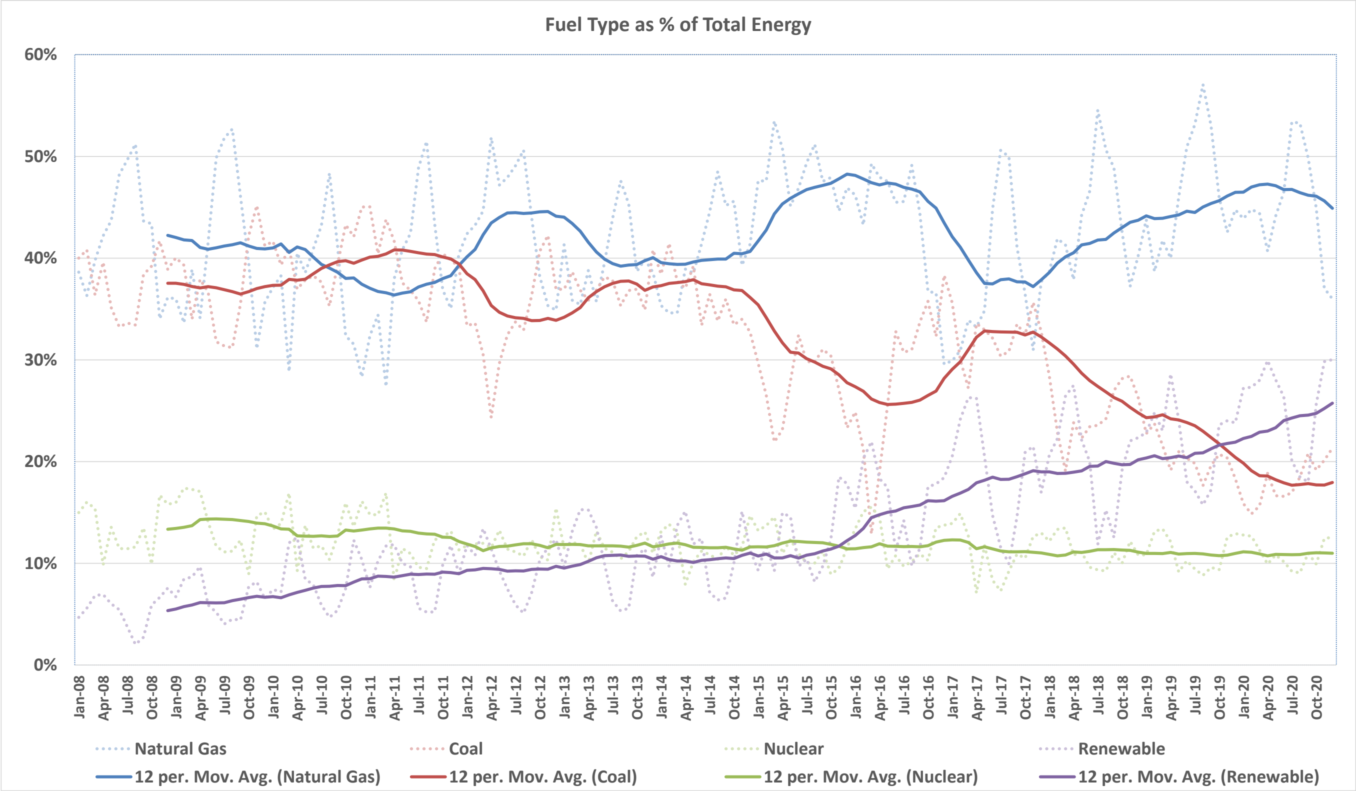


Figure C.2 – Energy by Fuel Type Trend

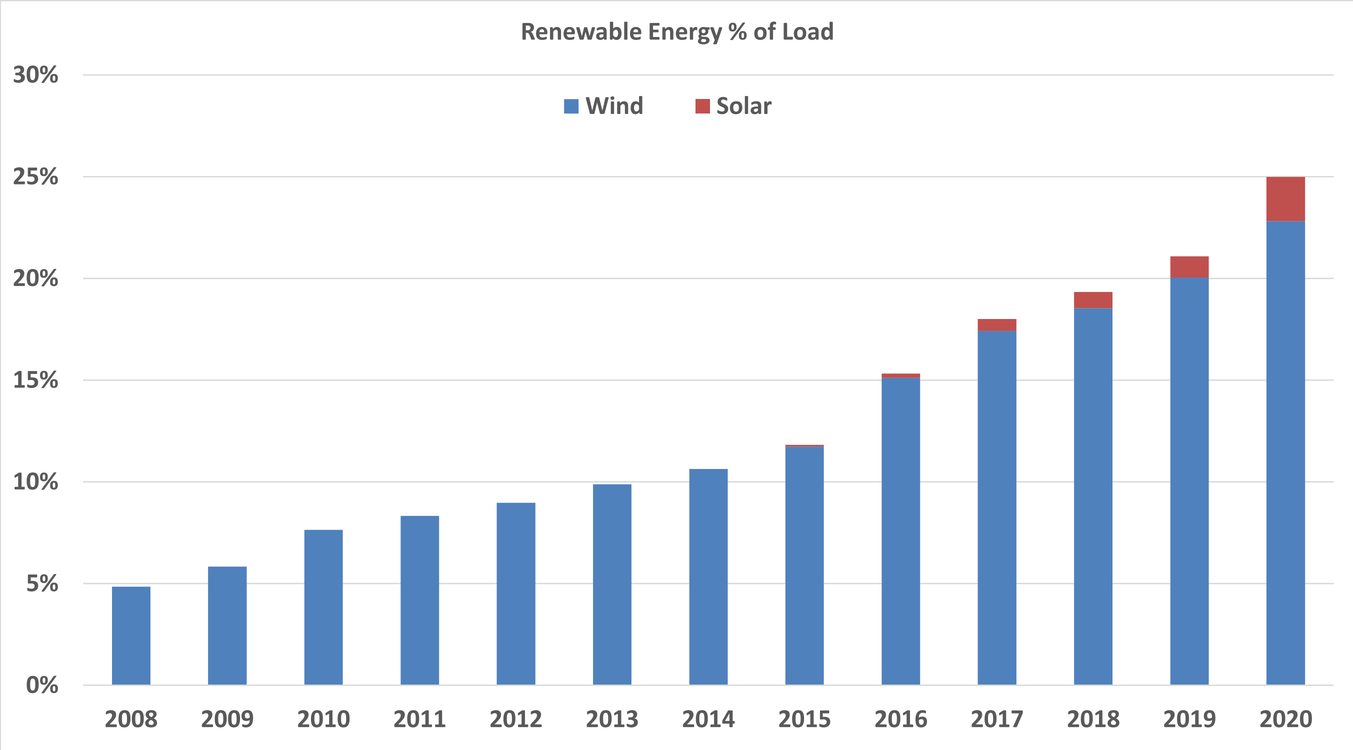


Figure C.3 – Renewable Energy Percentage of Total Load Time Trend

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 2020 was 131.1 GW-s, on May 20, 2020 at 1:00 a.m., when the IRR penetration level was 57.0 percent and system load was 31,505 MW (net load of 13,541 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%

Table C.2 – Minimum Inertia for 2015-2020

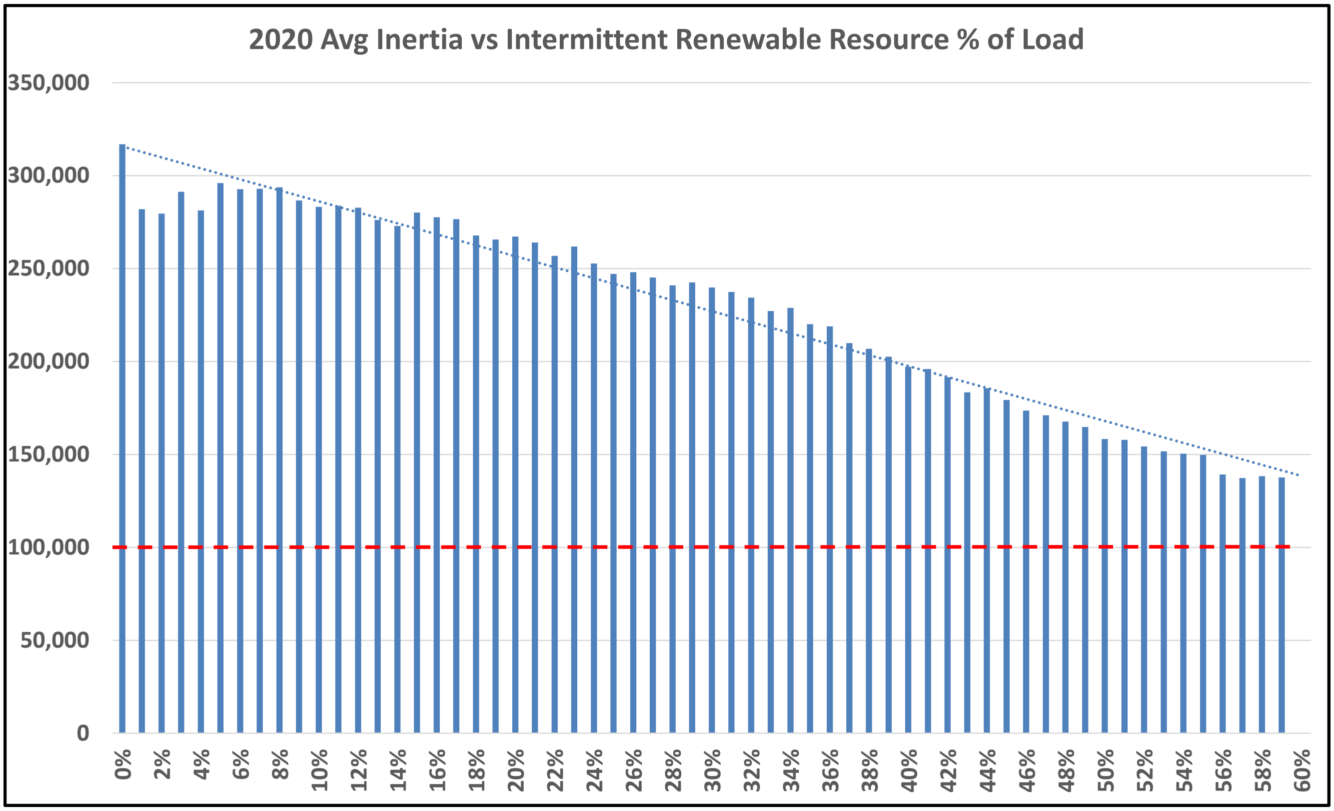


Figure C.4 – 2020 Average Inertia versus Renewable Percentage of Load

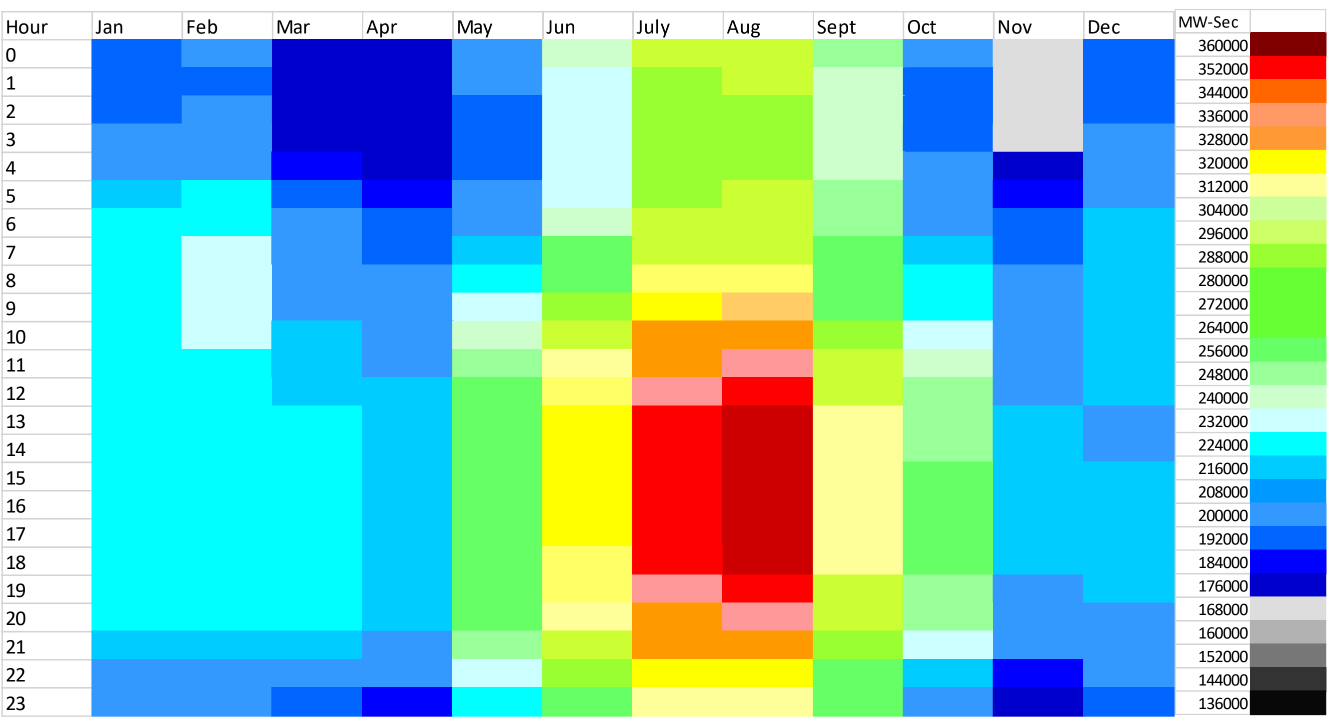


Figure C.5 – 2020 Average Inertia by Month and Operating Hour

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	5,150 MW	4,152 MW	2,352	8,636
Maximum One-Hour Decrease	-4,695 MW	-5,353 MW	-2,222	-6,940
Maximum Three-Hour Increase	13,634 MW	7,085 MW	3,242 MW	15,444 MW
Maximum Three-Hour Decrease	-11,748 MW	-8,125 MW	-2,925 MW	-16,110 MW

Table C.3 – Maximum and Minimum Load, Wind, Solar, and Net-Load Ramps for 2020

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 2020 compared to previous years.

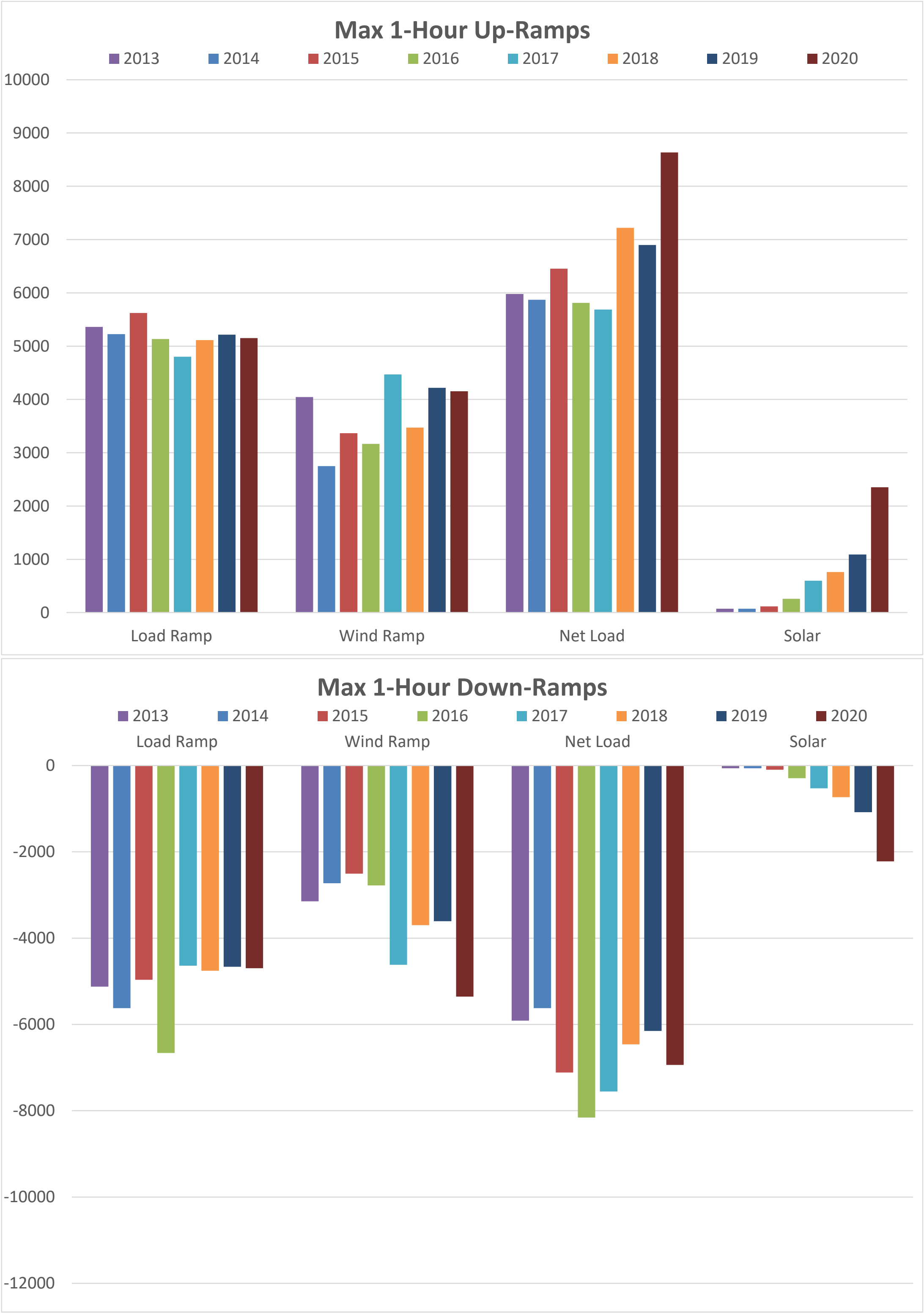


Figure C.6 – Maximum One-Hour Ramps for 2013-2020

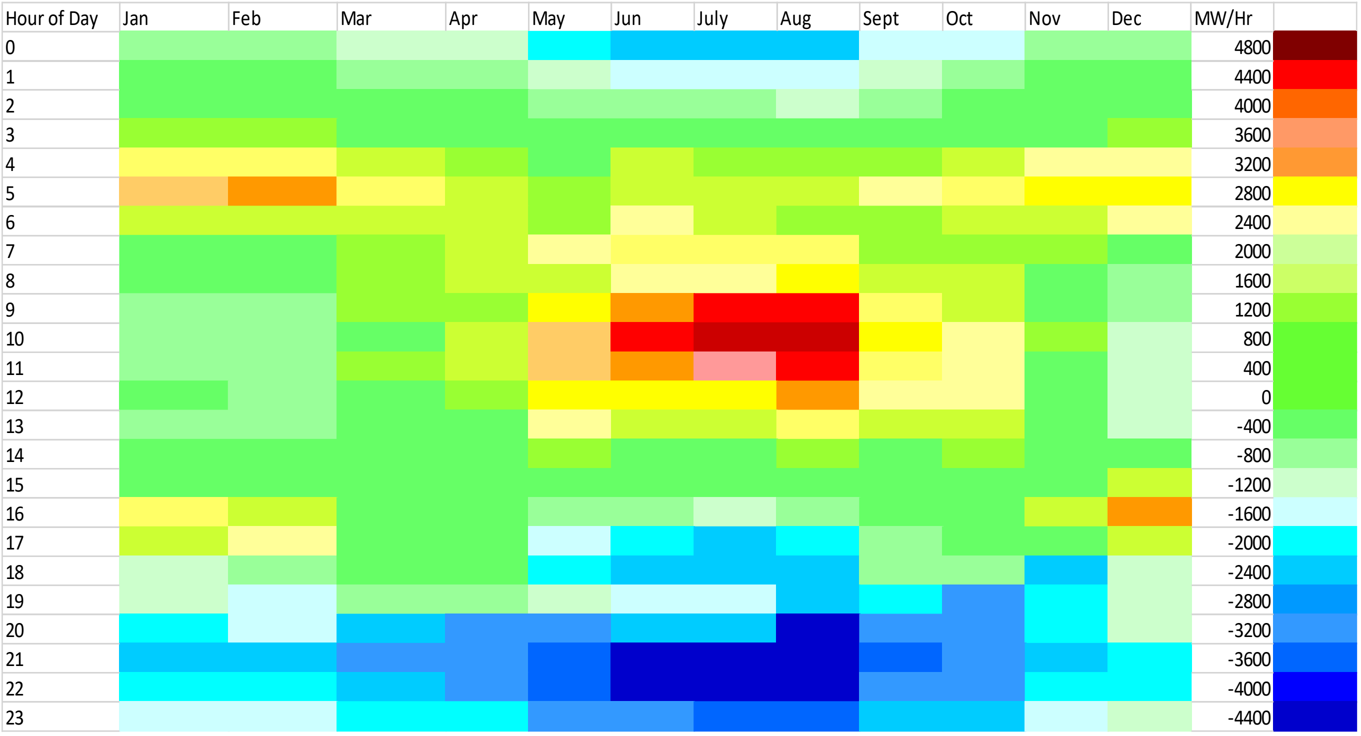


Figure C.7 – 2020 Heat Map of Net Load Ramp by Month and Operating Hour

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	2016	2017	2018	2019	2020	5-Yr Avg
AC Circuit 300-399 kV	Outages per Element Initiated by Human Error	2.9%	0.7%	1.5%	1.2%	1.1%	1.5%
AC Circuit 100-199 kV	Outages per Element Initiated by Human Error	1.6%	1.3%	1.1%	2.1%	1.0%	1.4%
Transformer 300-399 kV	Outages per Element Initiated by Human Error	1.0%	0.5%	0.5%	0.5%	0.8%	0.7%
Generator	Immediate Forced Outages Initiated by Human Error	3.9%	4.2%	3.9%	2.4%	2.6%	3.4%
Protection Systems	Misoperation Rate Caused by Human Error	2.9%	3.2%	2.9%	2.7%	2.7%	2.9%

Table D.1 – Outages Rates Caused by Human Error

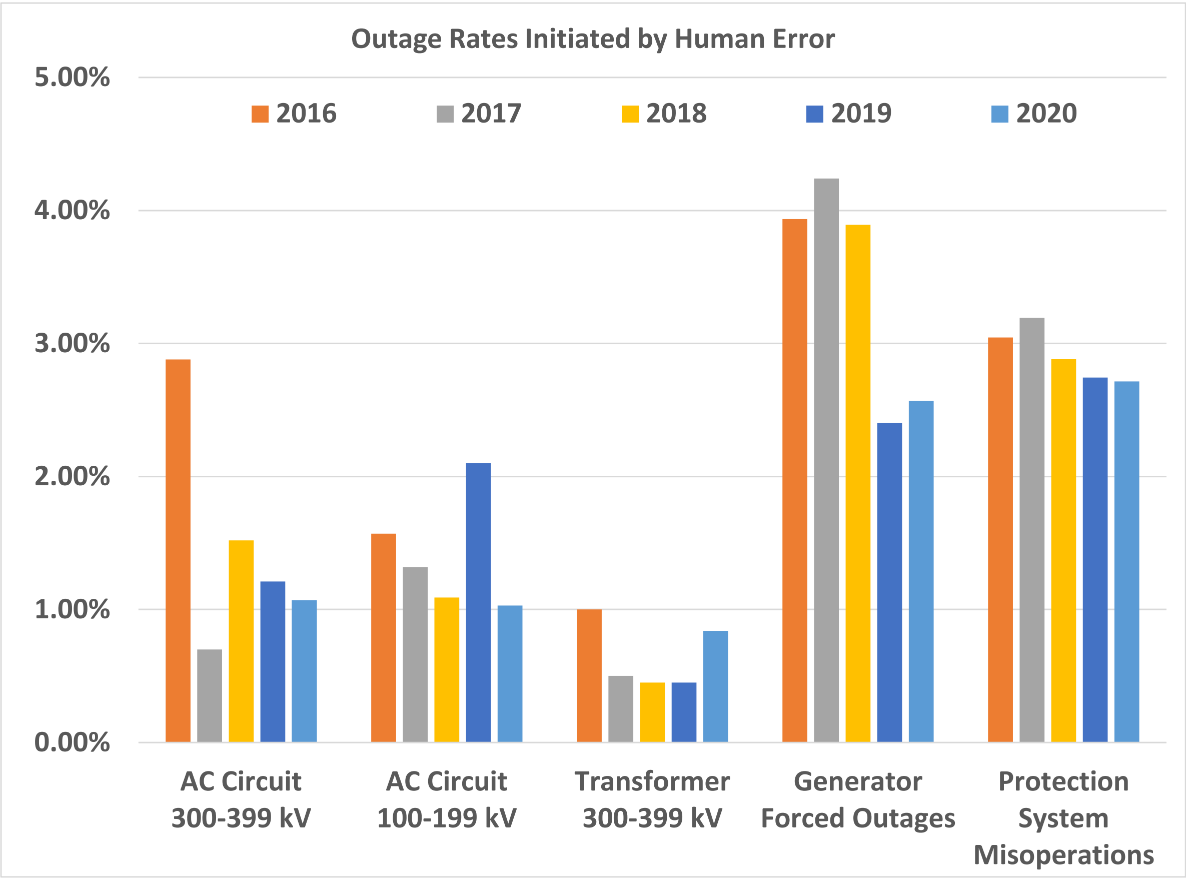


Figure D.1 – Outage Rates Caused by Human Error

Since 2016, there have been 430 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.

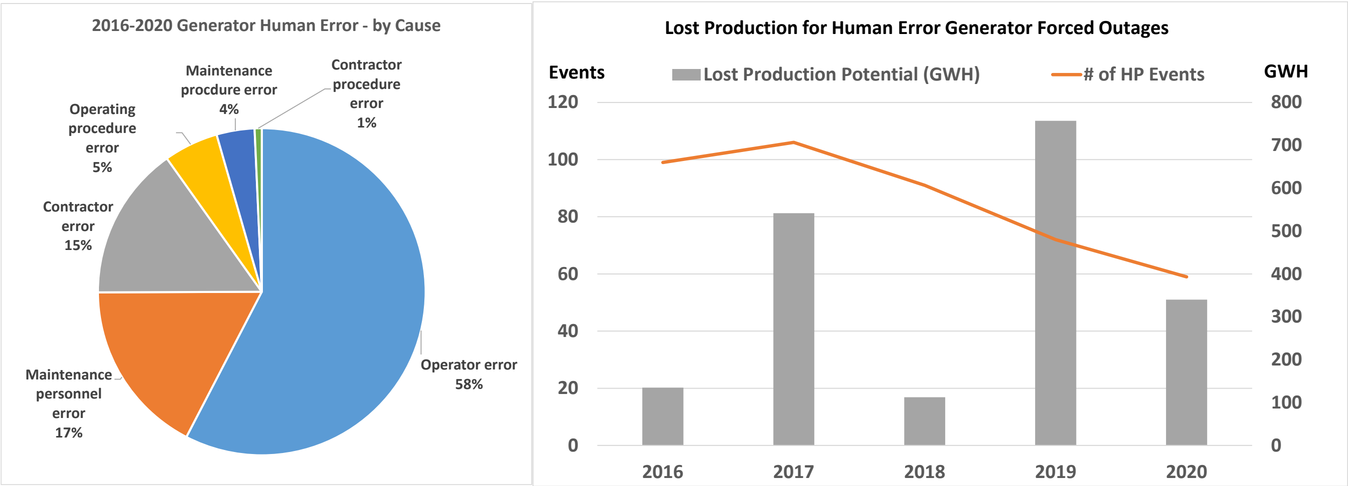


Figure D.2 – Generator Forced Outage Human Errors

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 2016, 47 events in ERCOT have been analyzed using this cause code process, with 326 root cause and contributing cause codes assigned. Approximately 51 percent of the assigned root and contributing cause codes are related to potential human performance issues (shown in red).

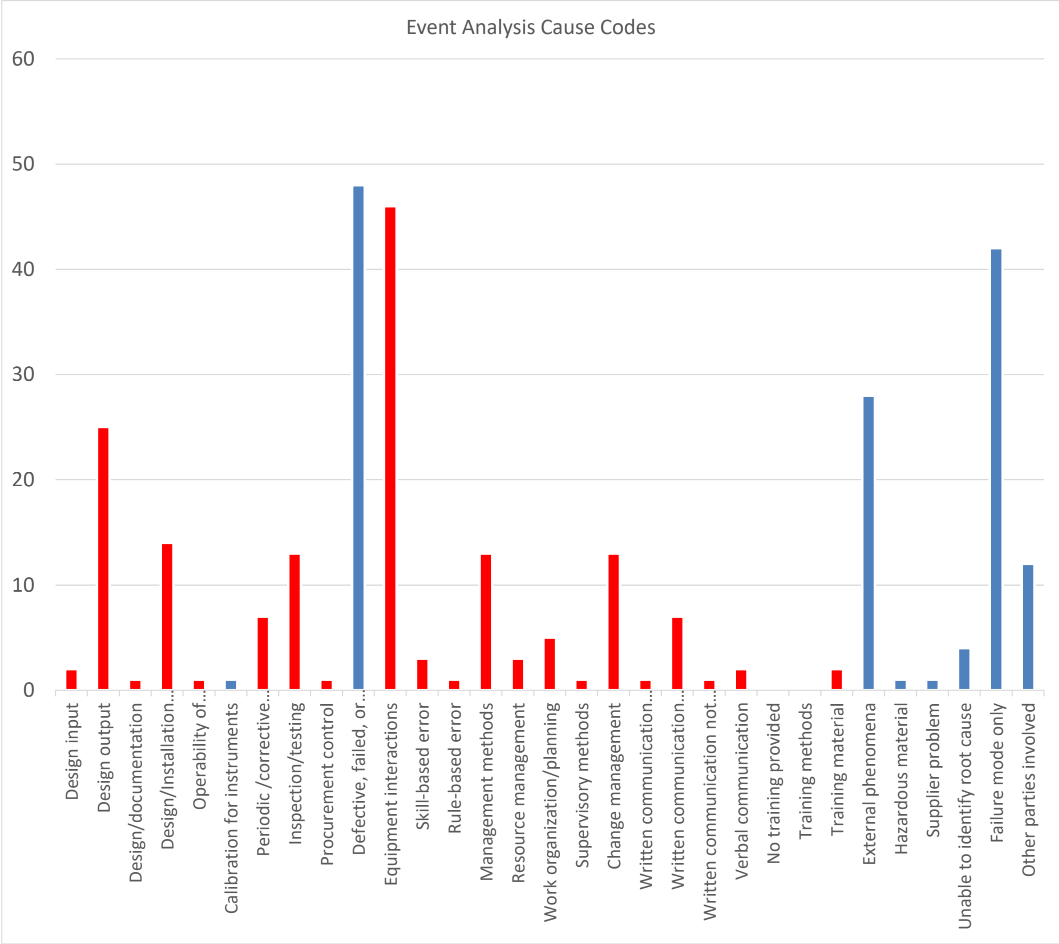


Figure D.3 – Event Analysis Human Performance Cause Coding

Appendix E – Bulk Power System Planning Analysis

A. Net Energy for Load

In 2020, total annual energy usage was 381.9 GWH, a decrease of 0.5 percent from 2019. Peak hourly demand was 74,166 MW on August 13, 2020. The West Load Zone has seen the largest load energy usage increase (7.7 percent per year since 2016).

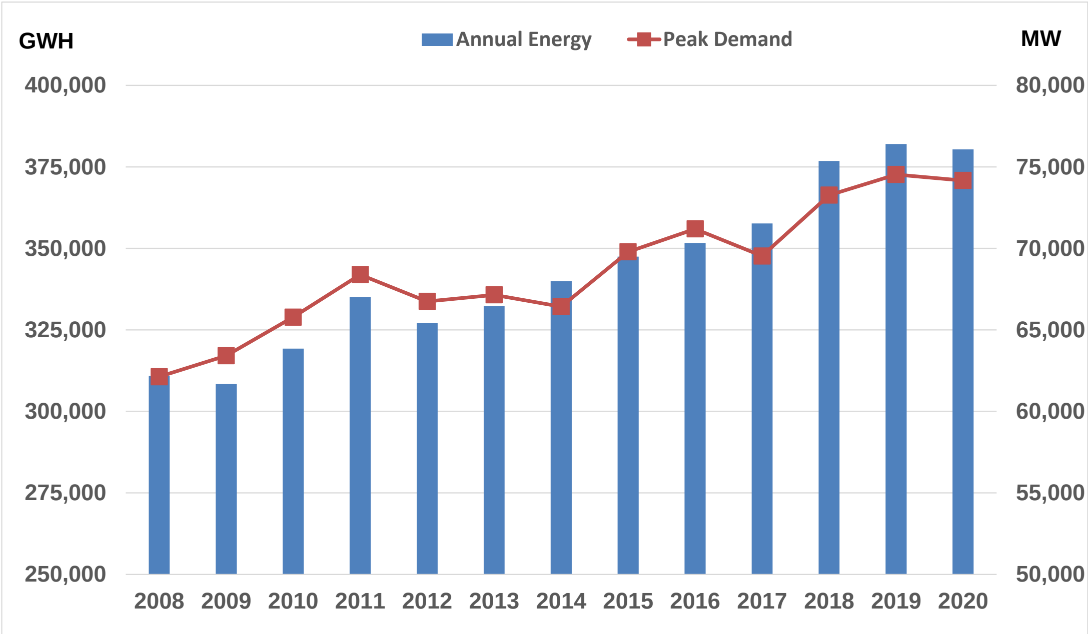


Figure E.1 – Annual Energy and Peak Demand

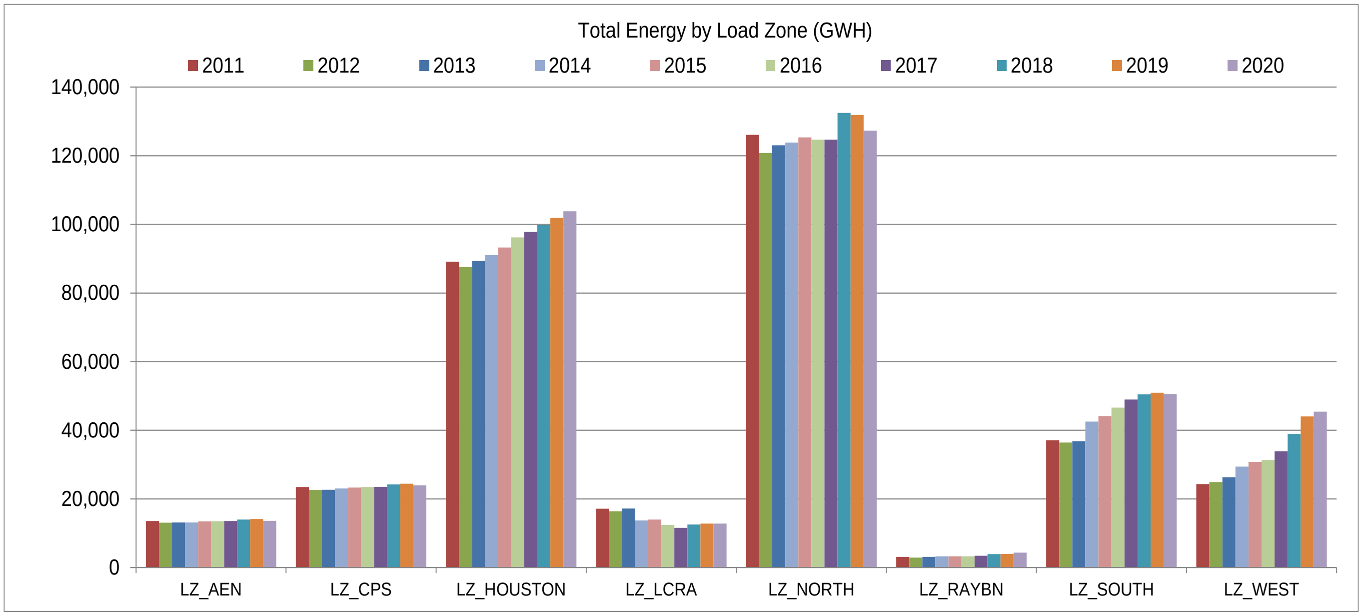


Figure E.2 – Energy by Load Zone

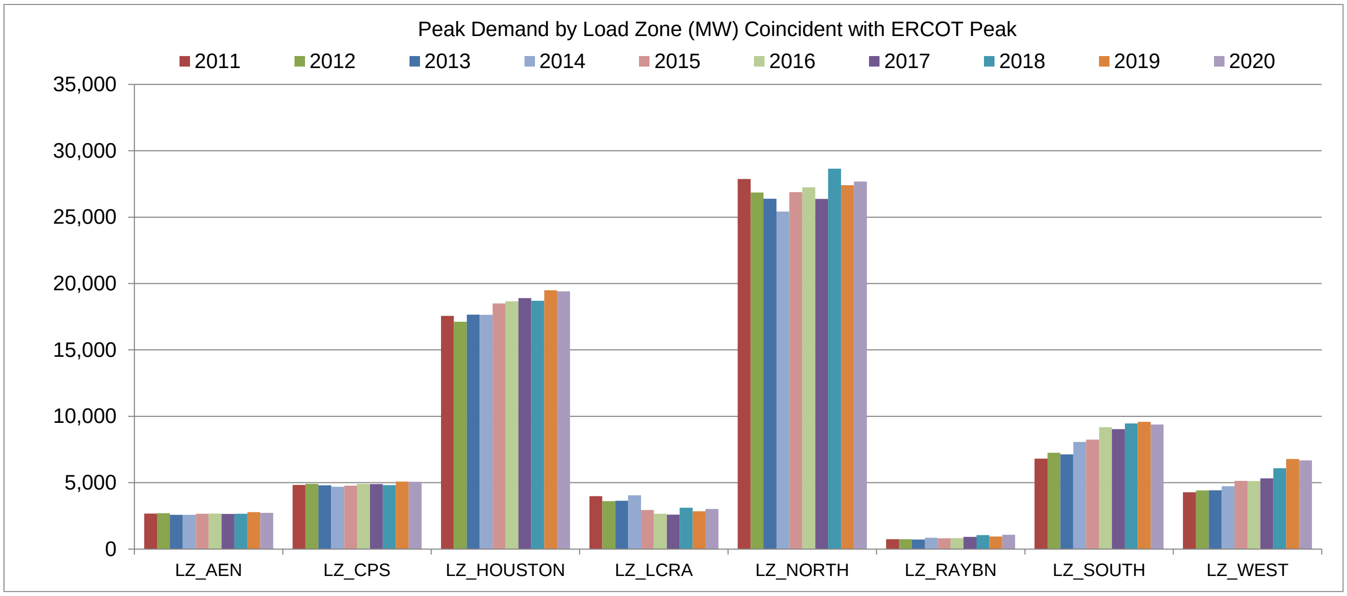


Figure E.3 – Peak Demand by Load Zone

The weather zone with the largest load energy usage increase was the Far West (11.5 percent per year since 2016).

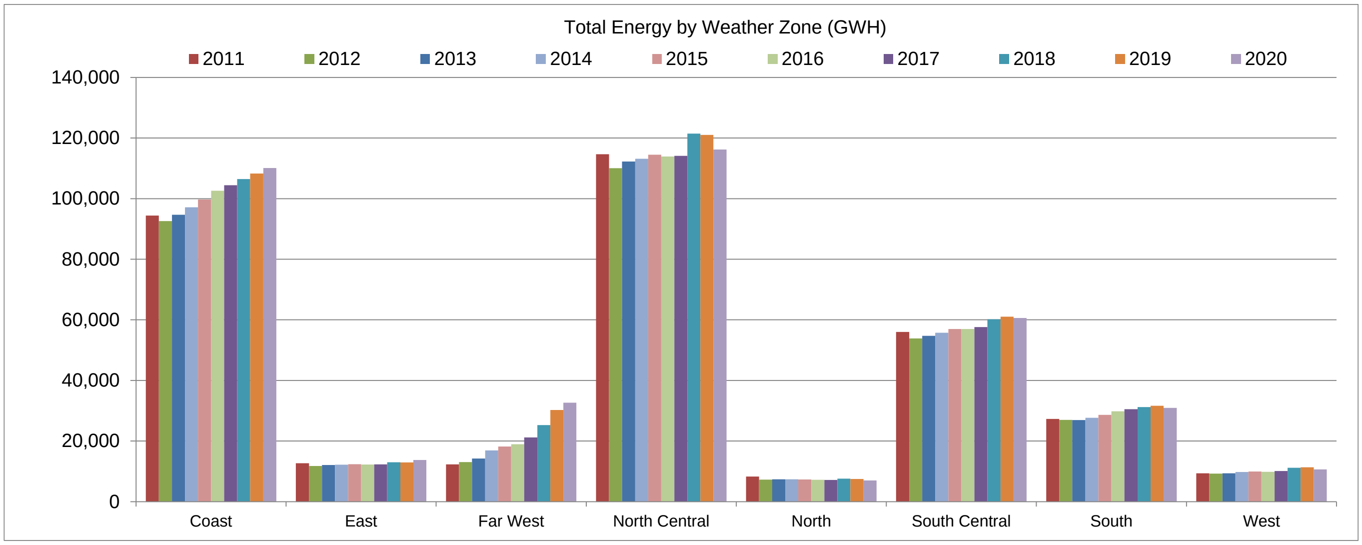


Figure E.4 – Energy by Weather Zone

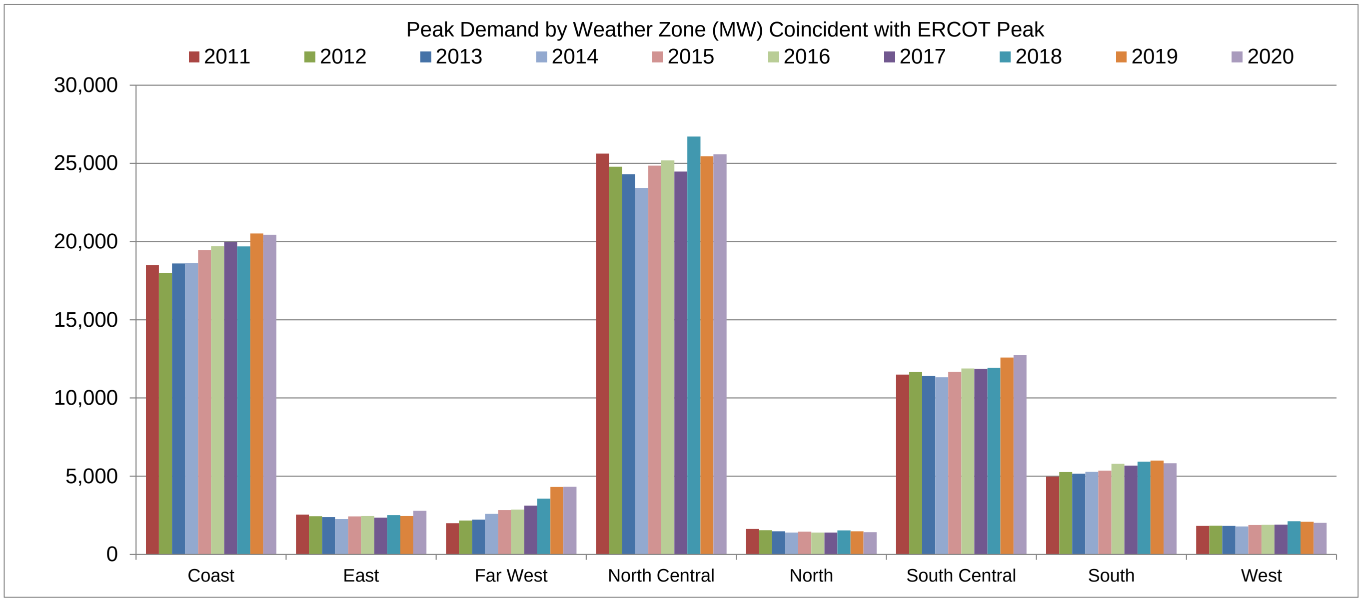


Figure E.5 – Peak Demand by Weather Zone

Overall energy growth rate has averaged 1.6 percent per year and demand growth rate has averaged 1.2 percent per year since 2016.

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 and Demand Report (CDR) 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.

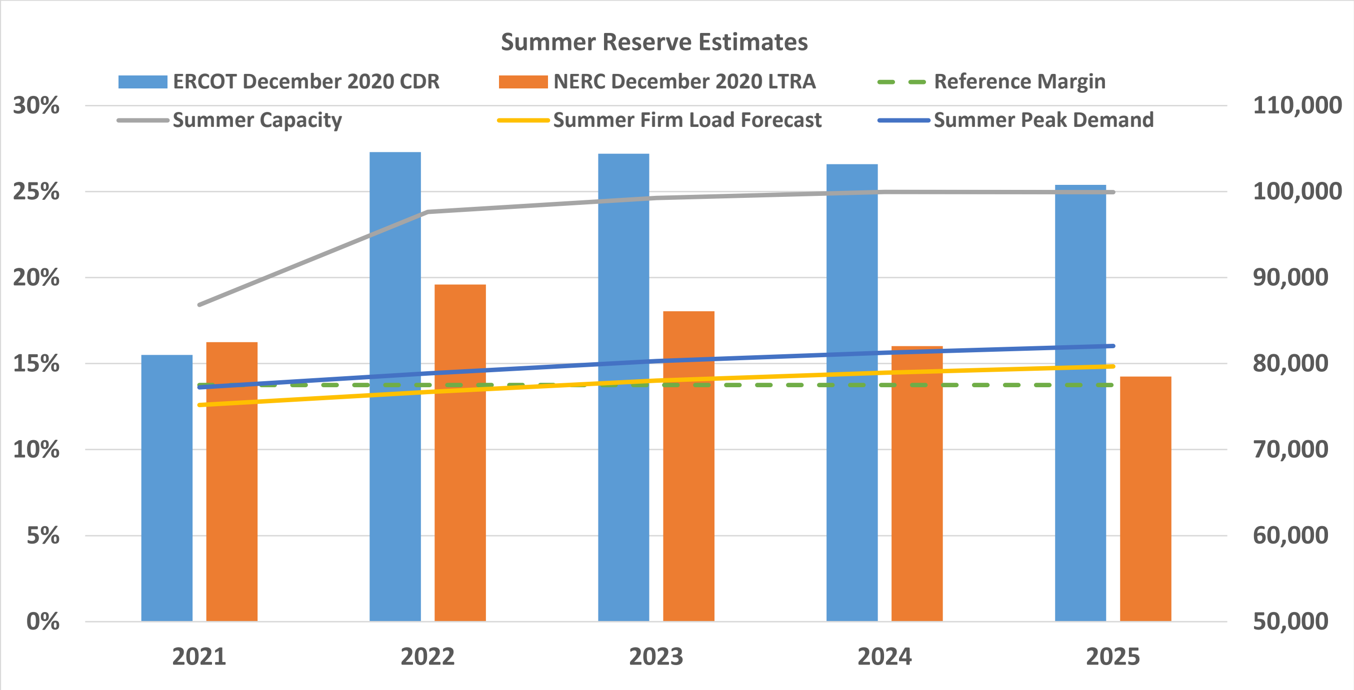


Figure E.6 – Summer Peak Reserve Margins

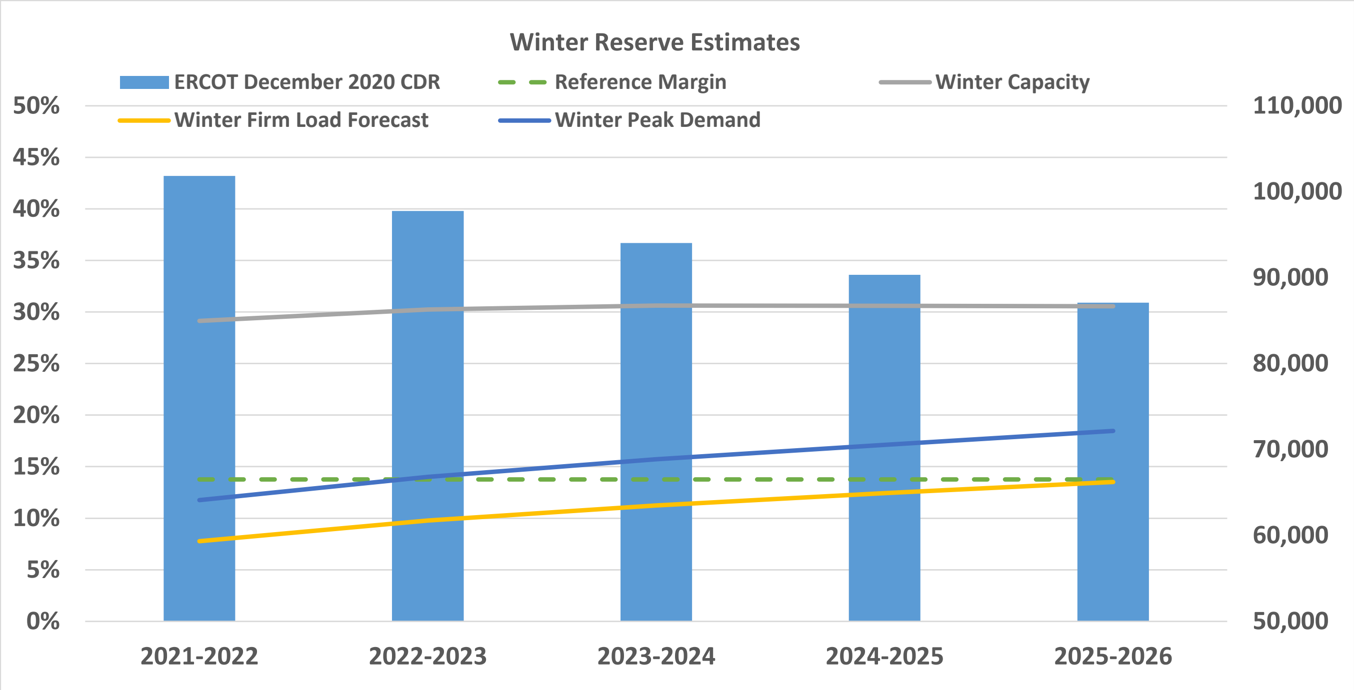


Figure E.7 – Winter Peak Reserve Margins

C. Energy Emergency Alerts

There were no Energy Emergency Alerts issued in 2020. The figure below shows the historical EEA data.

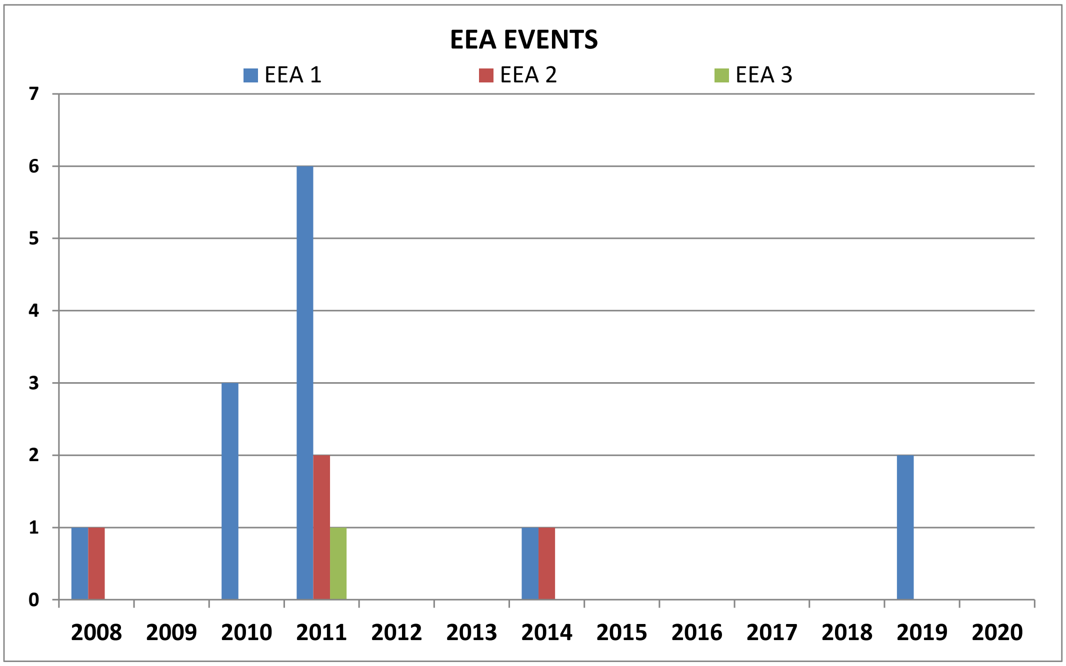


Figure E.8 – Energy Emergency Alerts by Year

D. Distributed Energy Resources and Non-Modeled Generation

DERs 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.

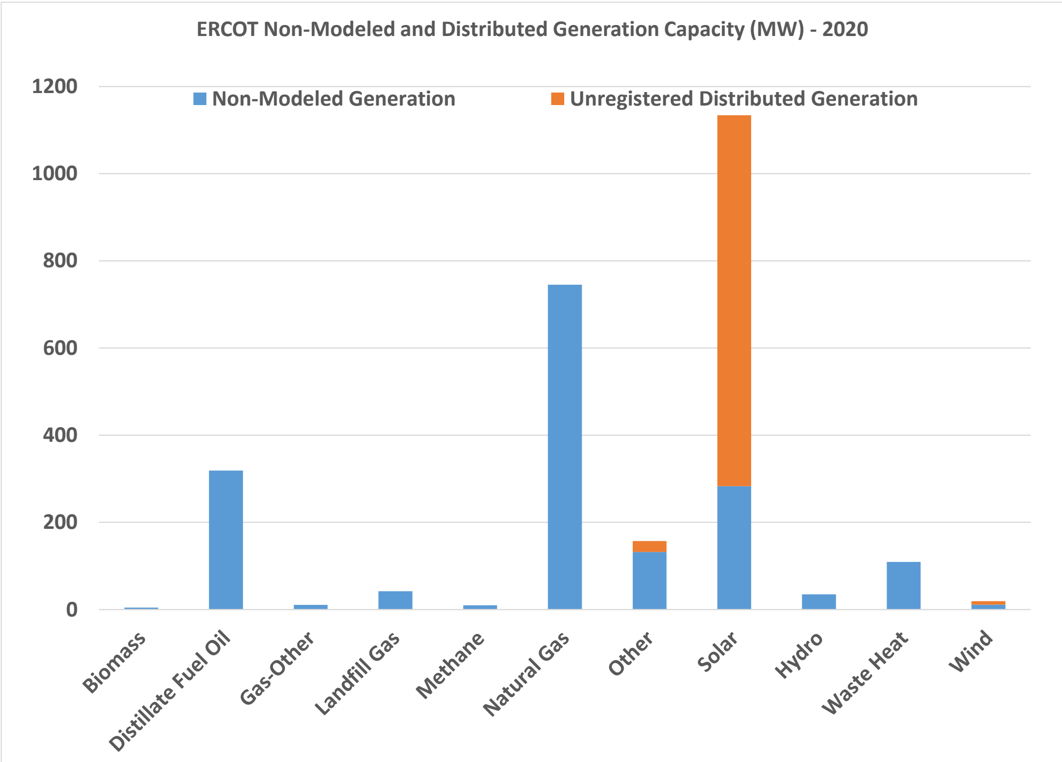
Issues with DERs include:

- 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 2020, ERCOT had approximately 1,701 MW of non-modeled generation capacity and 884 MW of distributed generation resources (DGR) that has provided data for mapping capacity to their modeled loads.



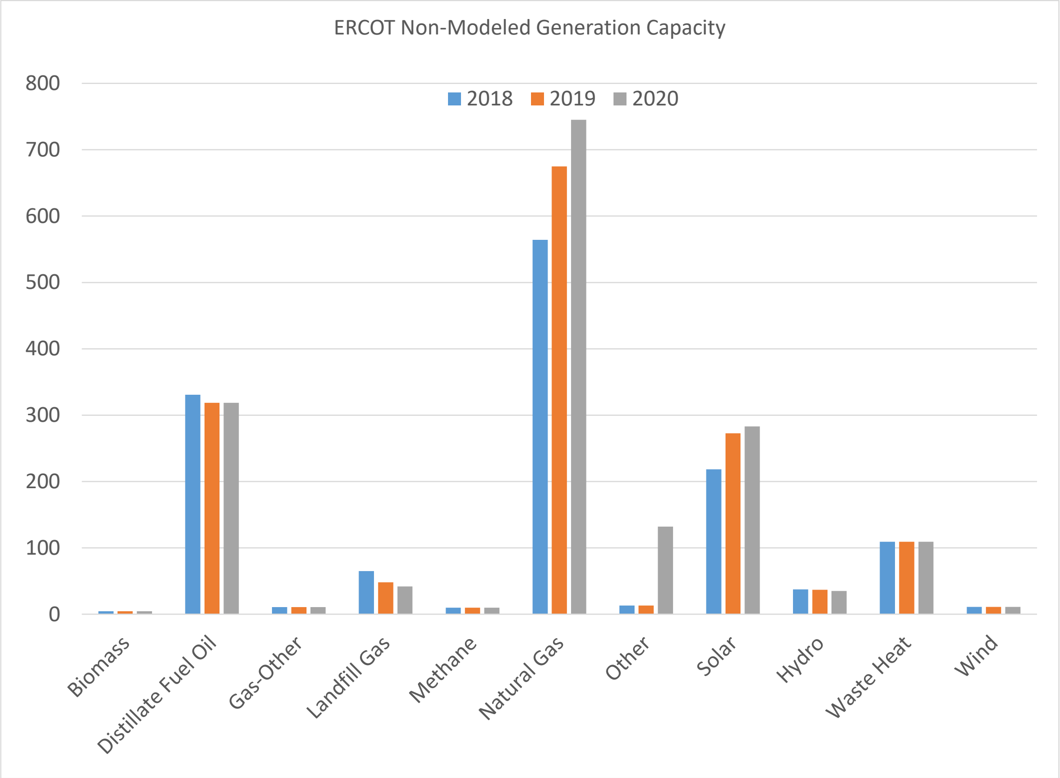


Figure E.9 – Non-Modeled Generation Capacity by Fuel Type

Appendix F – Loss of Situational Awareness Analysis

A. Loss of EMS and Loss of SCADA Events

Loss of EMS/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 2020 include the following:

- A Transmission Operator (TOP) had a loss of SCADA when a patch installed by the SCADA vendor caused a compatibility issue and mismatched database between the Quality Assurance System and the Production System.
- A TOP lost their control system and visibility due to a failed firewall module.
- A QSE experienced a cyber attack on its corporate network.
- A TOP lost connectivity at its backup control center due to a third-party phone vendor's loss of two circuits between the data center and the backup control center.
- A QSE experienced a denial of service when an attacker repeatedly attempted to gain access to its corporate network.

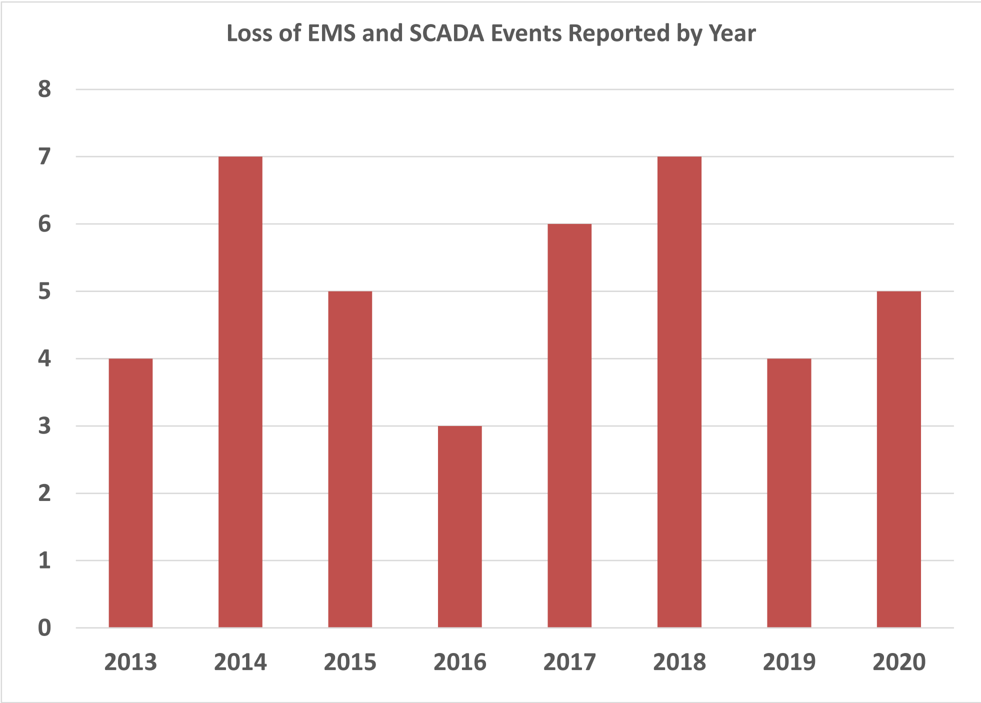


Figure F.1 – Loss of EMS and SCADA Events by Year

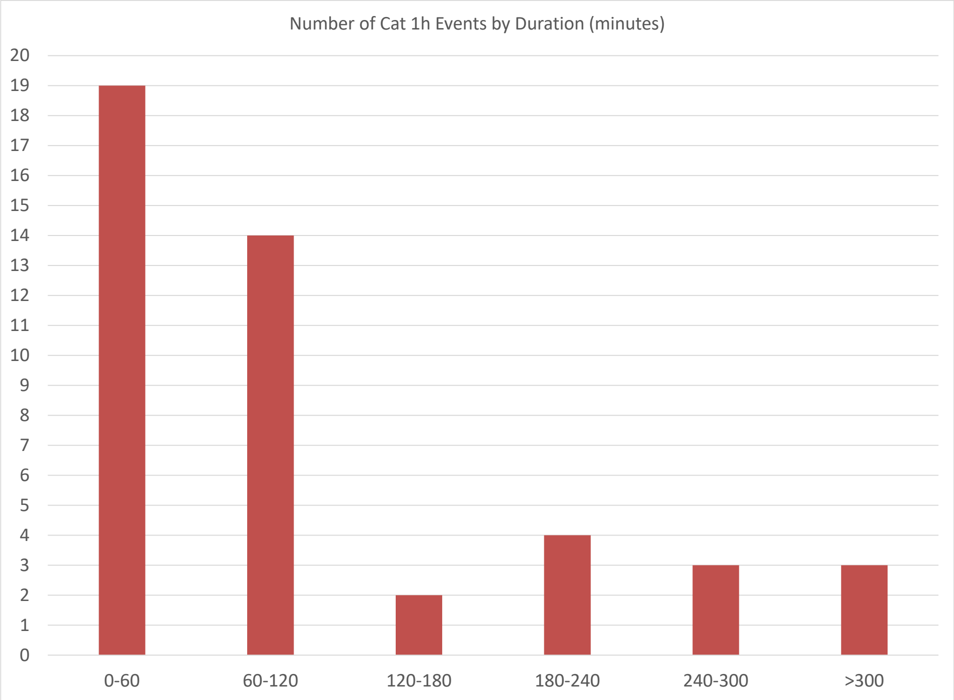


Figure F.2 – Loss of EMS and SCADA Events by Duration

B. State Estimator Convergence

ERCOT's goal for State Estimator convergence is 97 percent or higher. In 2019, the convergence rate was 99.97 percent.

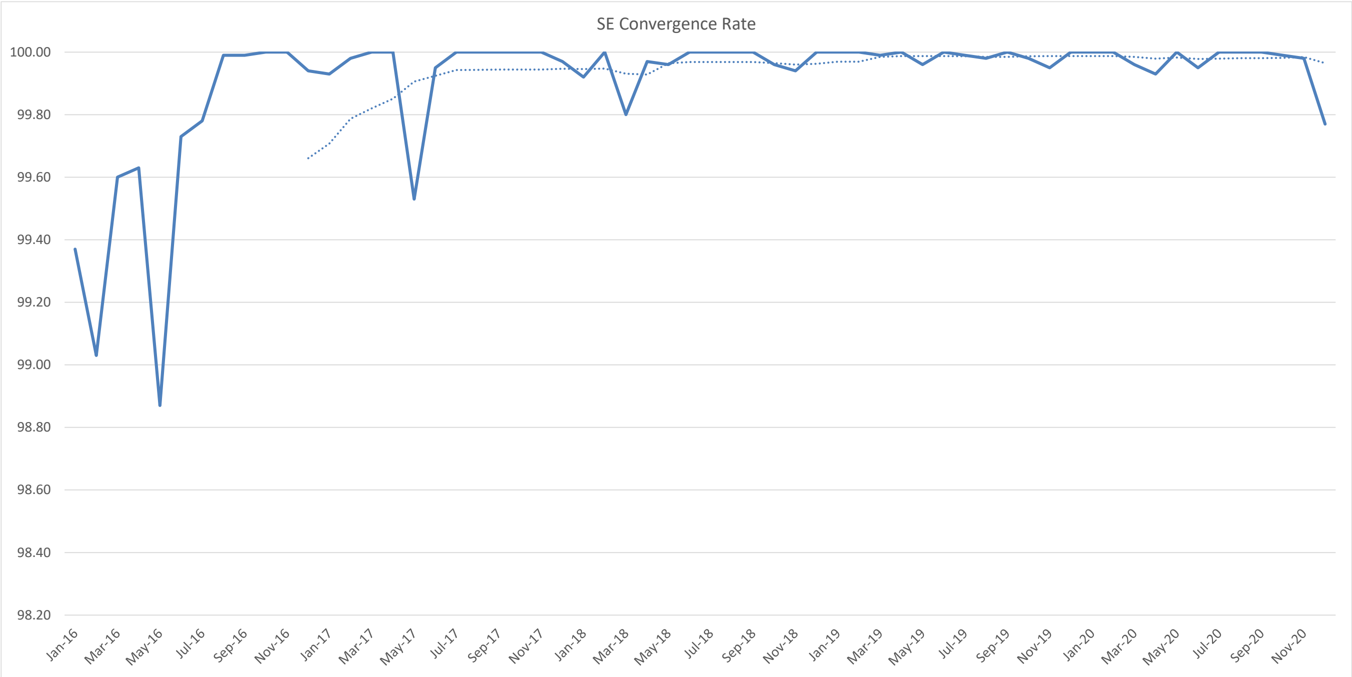


Figure F.3 – State Estimator Convergence Rate

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 2020, the total number of telemetry points failing the availability metric averaged 4,674 each month, or 3.9 percent of the total system telemetry points.

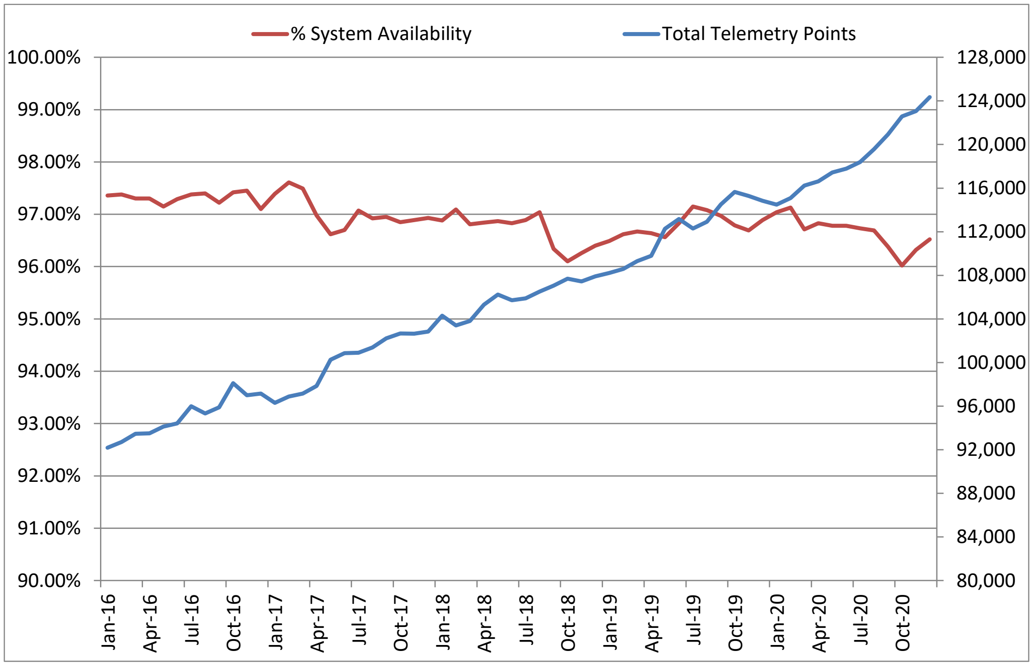


Figure F.4 – ERCOT Telemetry System Availability

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 100kV is <10 percent of emergency rating or < 10MW (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.

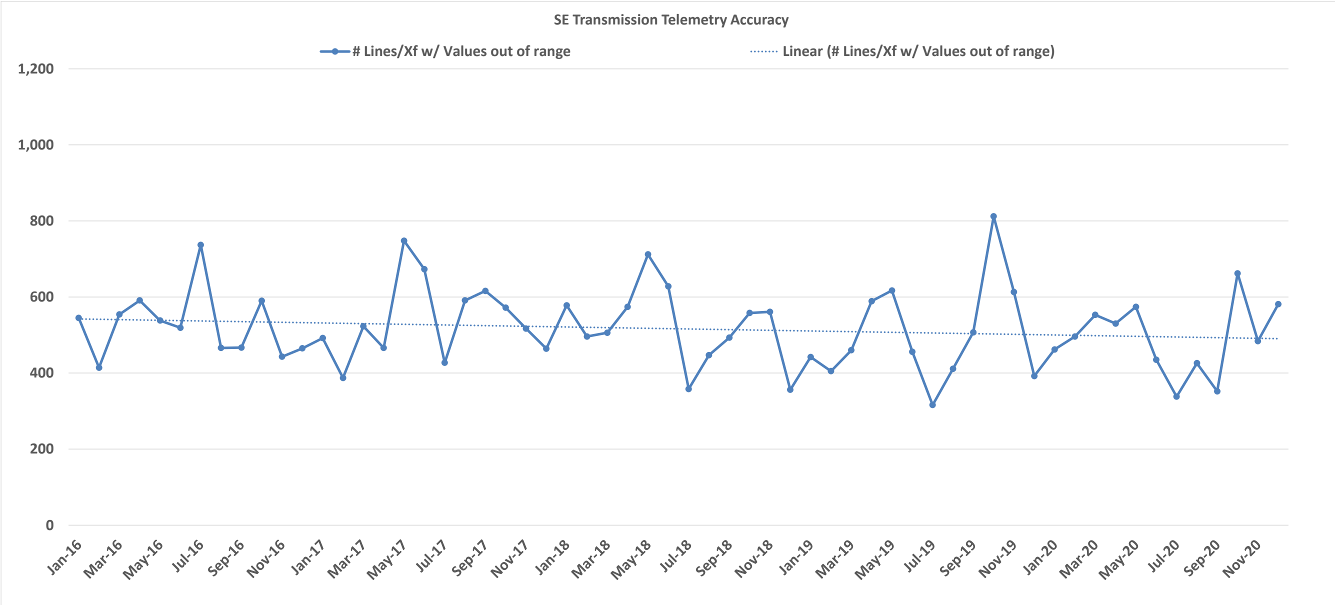


Figure F.5 – State Estimator versus Telemetry Accuracy

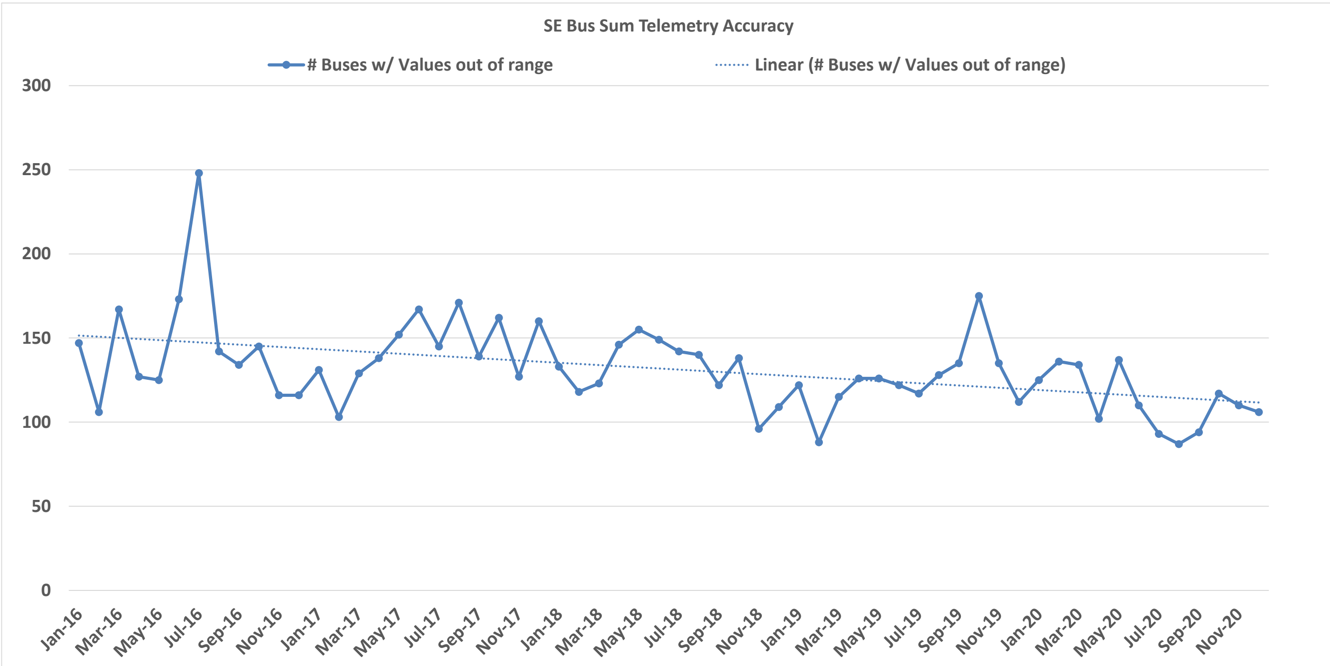


Figure F.6 – Bus Summation Telemetry Accuracy

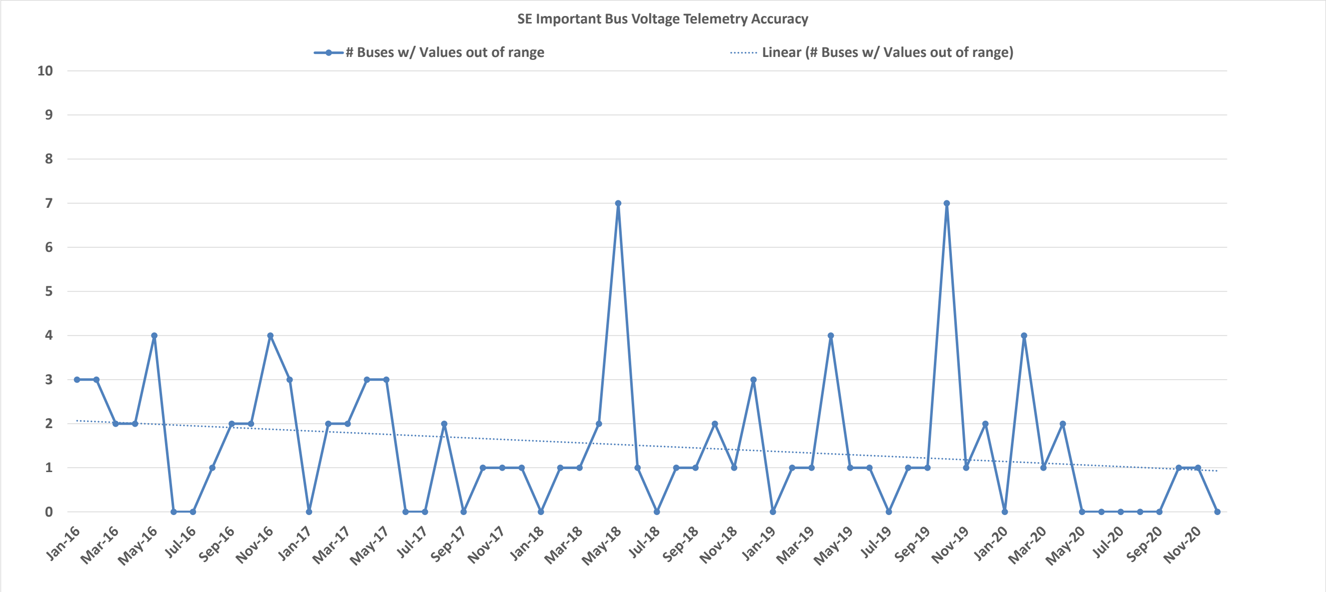


Figure F.7 – Bus Voltage Telemetry Accuracy

Appendix G – Protection System Detailed Analysis

A. Protection System Misoperations

Since January 2016, the overall transmission system Protection System Misoperation rate is stable, from 5.4 percent in 2015 to 5.8 percent in 2020. The five-year misoperation rate from 2016-2020 was 6.3 percent, compared to the NERC rate of 7.4 percent.

138 kV	2016	2017	2018	2019	2020	5-Yr Avg
Number of Misoperations	97	120	101	115	68	100
Number of Events	1815	1676	1639	1852	1293	1655
Percentage of Misoperations	5.3%	7.2%	6.2%	6.3%	5.3%	6.0%
345 kV	**2016**	**2017**	**2018**	**2019**	**2020**	**5-Yr Avg**
Number of Misoperations	32	30	48	40	41	38
Number of Events	584	606	548	715	622	615
Percentage of Misoperations	5.5%	4.9%	8.8%	5.6%	6.6%	6.2%
< 100 kV	**2016**	**2017**	**2018**	**2019**	**2020**	**5-Yr Avg**
Number of Misoperations	3	0	5	1	1	2
Number of Events	74	76	44	55	62	68
Percentage of Misoperations	4.0%	0.0%	11.4%	1.9%	1.6%	2.6%

Table G.1 – Protection System Misoperation Data

In 2020, three main categories account for 68 percent of the total misoperations: incorrect settings/logic/design (36 percent), other (22 percent), and as-left personnel error (10 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 communications failures and as-left personnel errors are also showing a positive downward trend.

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

Entities have completed corrective actions on approximately 87 percent of misoperations.

Transmission owner misoperation rates are showing a downward improving trend, while generator owners are showing a long-term negative trend.

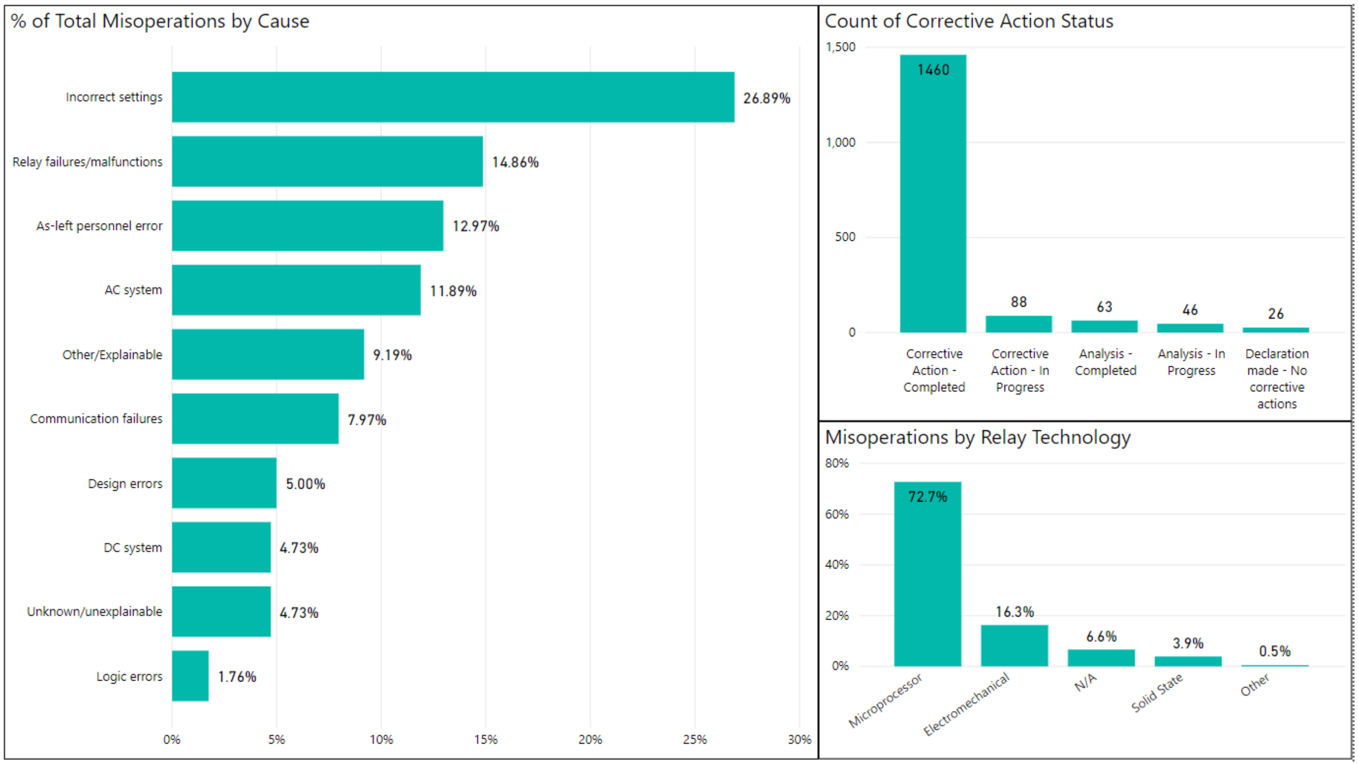


Figure G.1 – Protection System Misoperation Count 2011-2020

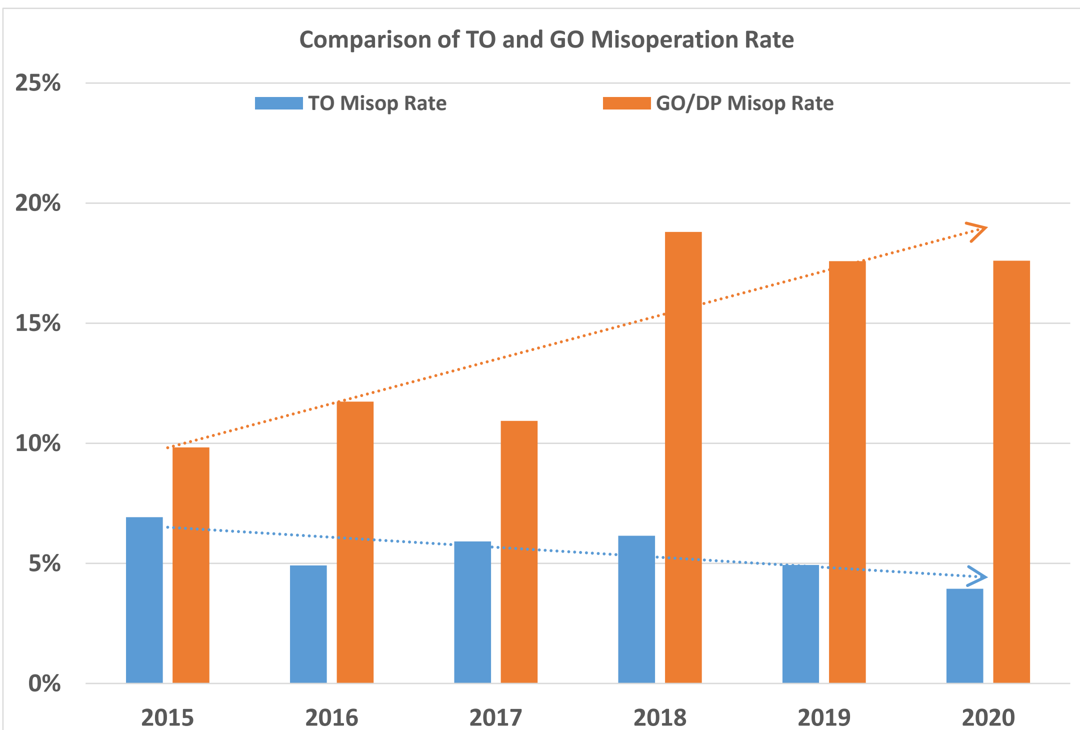


Figure G.2 – Protection System Misoperation Rate by Entity Type

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 remained stable. The outage rates per element initiated by failed protection system equipment for 138 kV circuits showed an upward trend, while the outage rate for 345 kV transformers showed a significant decrease.

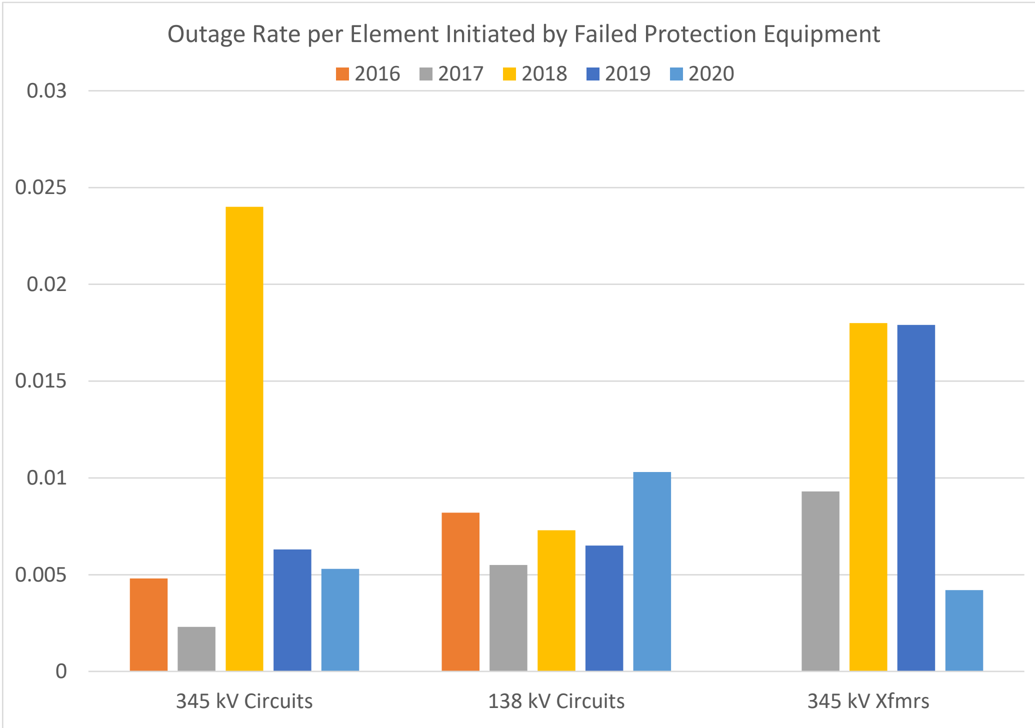


Figure G.3 – Outage Rates Caused by Failed Protection Equipment

Appendix H – Frequency Control Detailed Analysis

A. CPS1 Performance

Control Performance Standard 1 (CPS1): 171.2 for calendar year 2020 versus 174.8 for calendar year 2019.

NERC Reliability Standard BAL-001-2 requires each BA to operate such that the 12-month rolling average of the clock-minute Area Control Error (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 2015. For 2020, the annualized CPS1 score was 171.2.

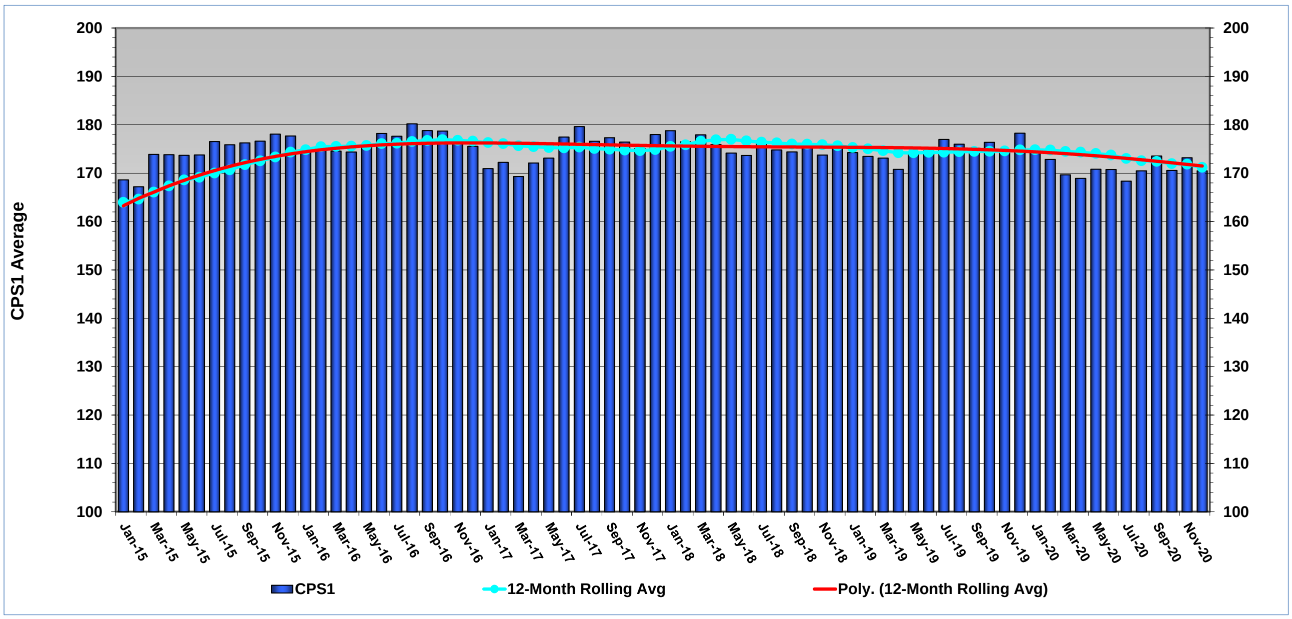


Figure H.1 – CPS1 Average January 2015 to December 2020

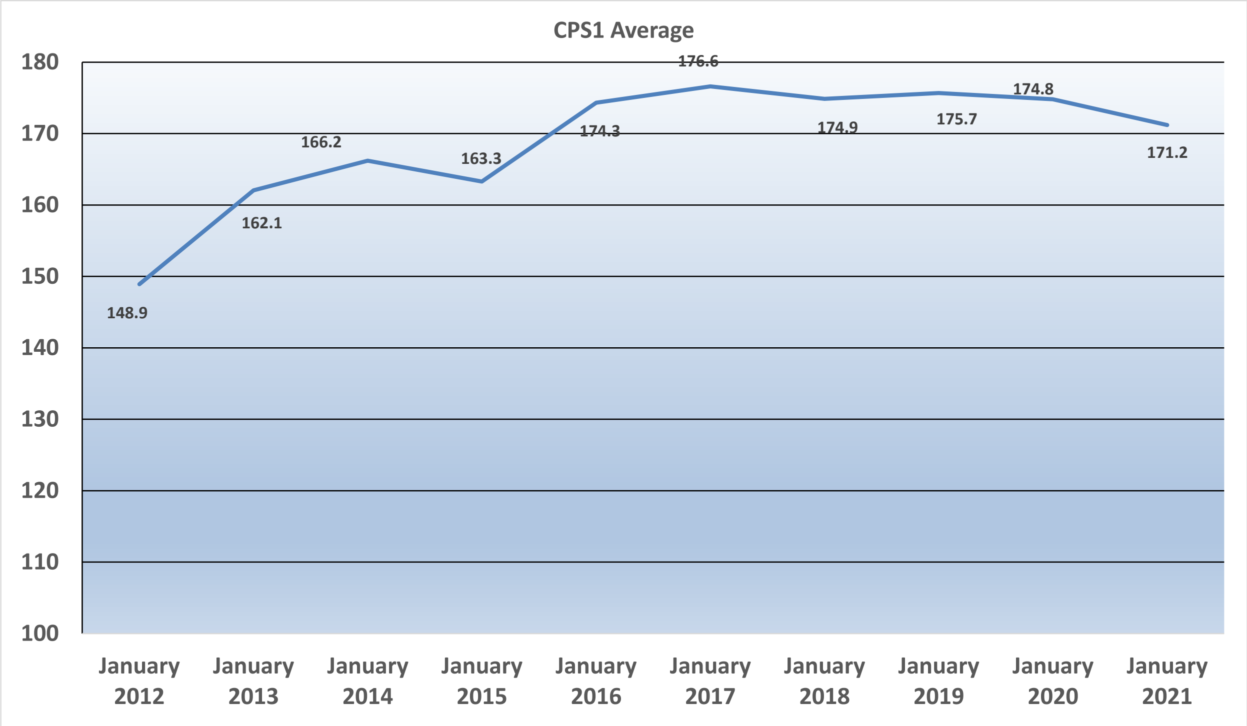


Figure H.2 – ERCOT CPS1 Annual Trend since January 2012

Figure C.3 shows bell curves of the ERCOT frequency profile, comparing 2015 through 2020. The shape of the bell curve in 2020 was virtually identical to 2017-2019.

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 BAAL exceedances per NERC Standard BAL-001-2.

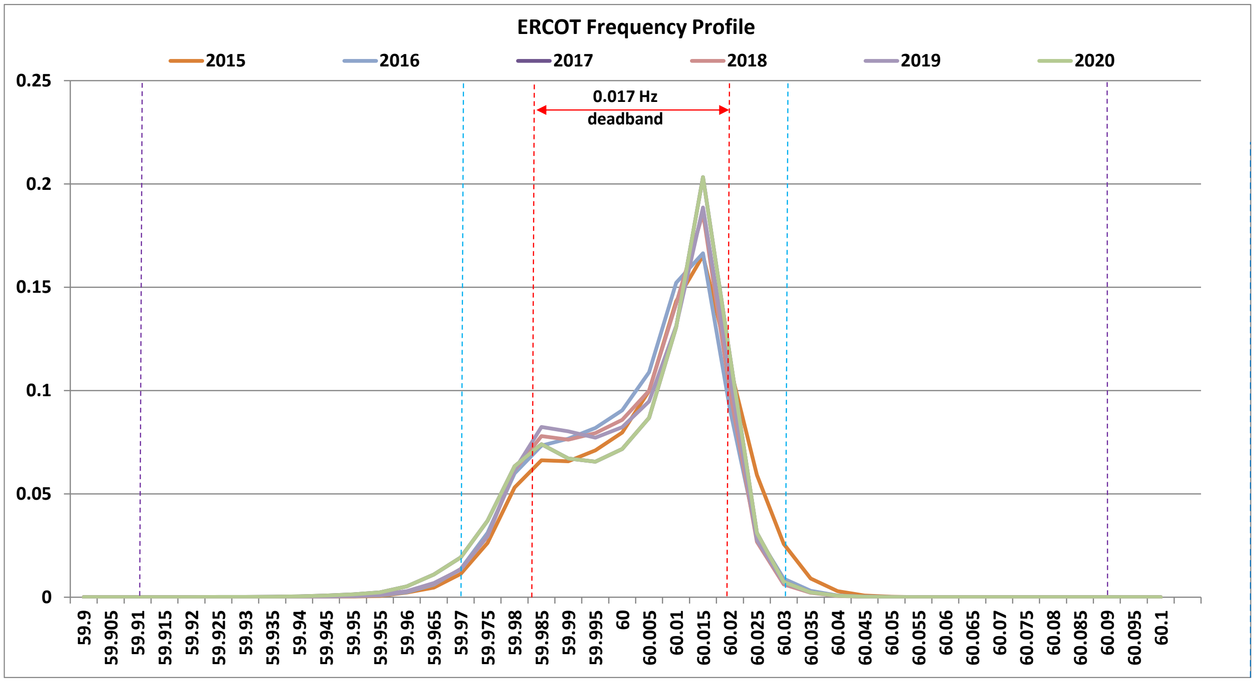


Figure H.3 – Frequency Profile Comparison

The following figure shows the 2020 CPS1 scores by operating hour compared to previous years.

The CPS1 score by operating hour continues to indicate possible issues for hour-ending (HE) 06:00 and HE 07:00. These issues are related to the load ramps during these hours and procedures used by generation resource entities during unit startup and shutdown. Additional CPS1 impacts are indicated in HE 15:00 through HE 20:00. This is primarily due to increasing solar down ramp rates during these hours.

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.

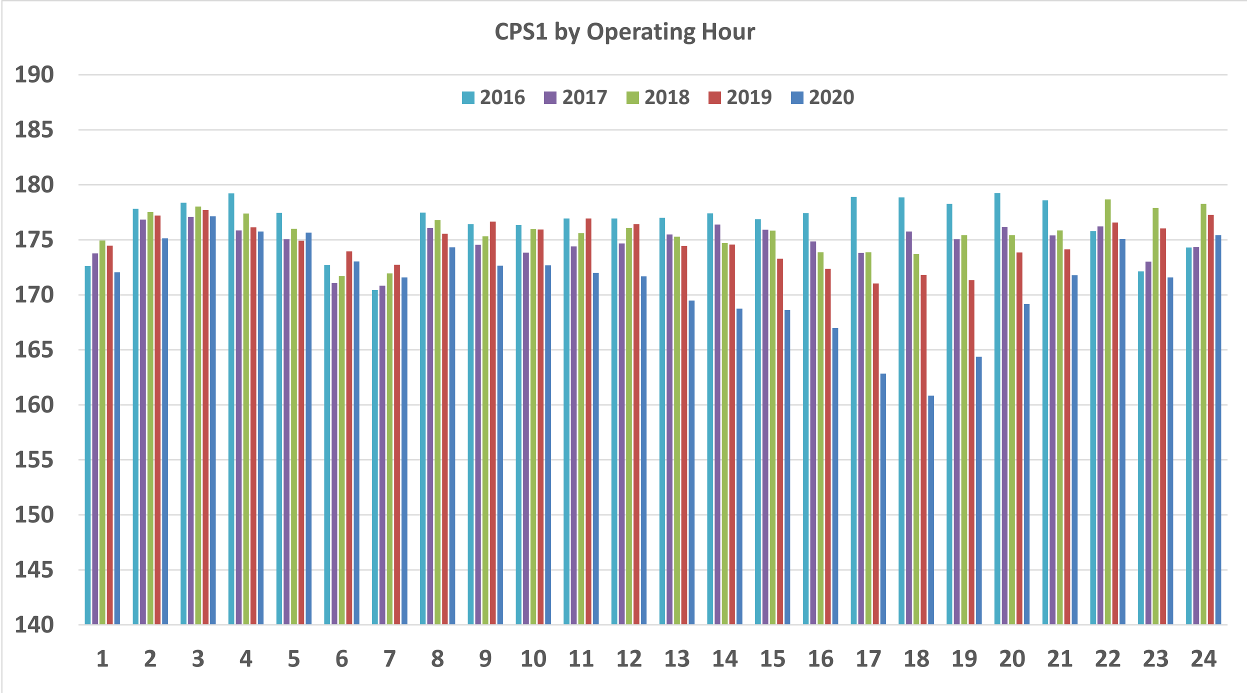


Figure H.4 – CPS1 Score by Operating Hour for 2016 through 2020

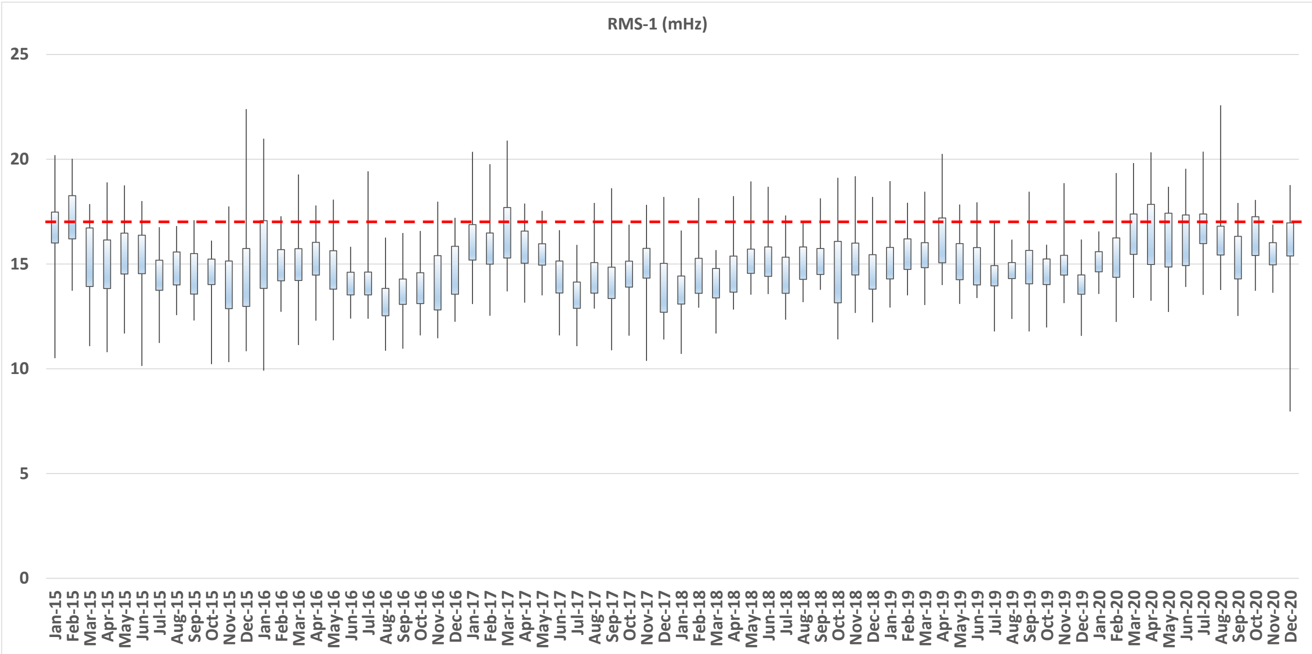


Figure H.5 – Daily RMS1 for 2015 through 2020

B. Time Error Correction Performance

In 2020, 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 Balancing Authority ACE Limit 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.

All low BAAL exceedance minutes in 2020 were associated with large generation unit trips.

High/Low Frequency	2016 Total Minutes	2017 Total Minutes	2018 Total Minutes	2019 Total Minutes	2020 Total Minutes	Five-year Avg
Low (<59.91 Hz)	26	18	17	16	29	21
High (>60.09 Hz)	0	0	0	0	0	0

Table H.1 – Frequency Trigger Limit Performance