NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

State of Reliability 2018

June 2018

RELIABILITY | ACCOUNTABILITY



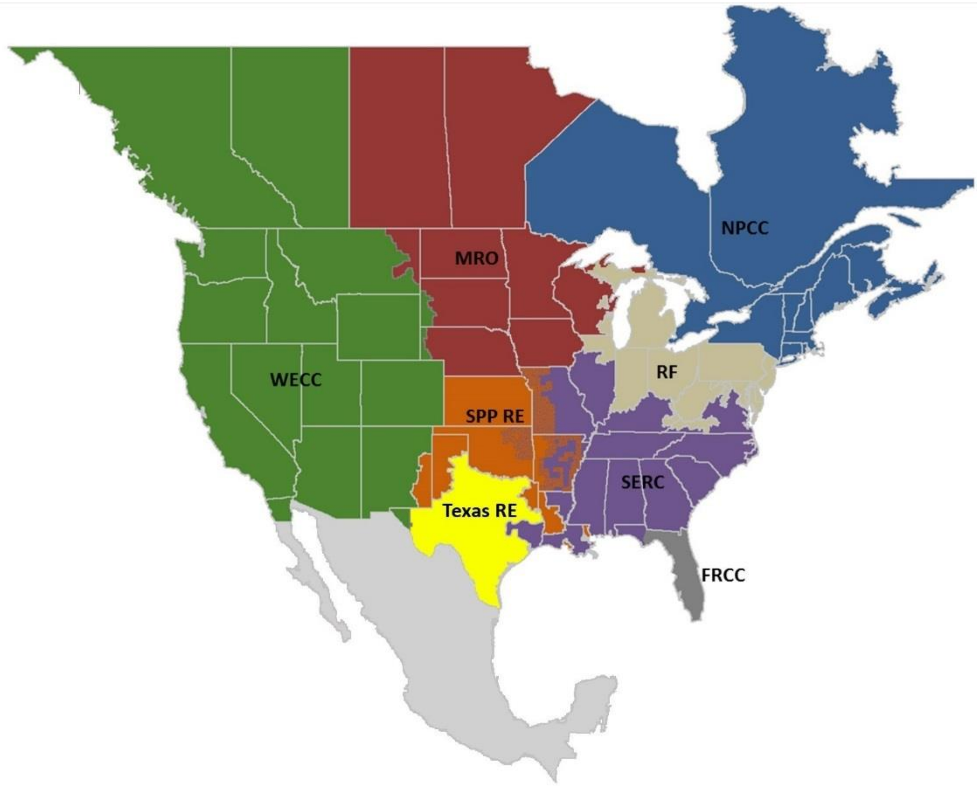

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Table of Contents

Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the eight Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

The North American BPS is divided into eight RE boundaries as shown in the map and corresponding table below. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

NERC, as the ERO of North America, assures the effective and efficient reduction of reliability and security risks for the North American BPS. Annual and seasonal risk assessments that look to the future and special reports on emergent risks serve to identify and mitigate potential risks. Additionally, analyses of past BPS performance serve to document BPS adequacy and to identify positive or negative performance trends. NERC's annual *State of Reliability* report is one such analysis of past performance that informs regulators, policymakers, and executives at a high level while providing granular technical details (typically in appendices) for those interested in the underlying data and detailed analytics.

The *State of Reliability 2018* is NERC's independent assessment developed by its Performance Analysis staff with support from the Performance Analysis Subcommittee (PAS). The *State of Reliability 2018* focuses on BPS performance during 2017 as measured by a predetermined set of reliability indicators (metrics).[1] Based on the metrics, the BPS provided an adequate level of reliability (ALR)[2] during 2017. The only metric indicating cause for concern is Metric M-1: Planning Reserve Margin,[3] which is actually a forward-looking metric previously reported in NERC's *2018 Summer Reliability Assessment*.[4] In addition to identifying reliability risks, NERC highlights significant work by industry to improve reliability. Analysis of the 2017 events and data drives six key findings.

Details in **Chapter 5**

Key Finding 1: BPS Showed Improved Resilience during the NERC Category 5 Events

Hurricanes Harvey and Irma resulted in NERC Category 5 Events, the highest severity level within the Event Analysis (EA) Process. While wind and water damage were record setting, the restoration efforts and subsequent recovery times were improved from historical benchmarks.

Hurricane Harvey inflicted massive disruptions on the electric power system in south Texas, damaging 85 substations, over 850 transmission line structures, and causing 225 transmission line outages. Extensive flooding and storm debris challenged the recovery process. Use of amphibious vehicles, unmanned aerial vehicles (drones), and airboats to perform damage assessments allowed utilities to preplan prior to areas becoming accessible, expediting recovery efforts.

Similarly, Irma caused more electric outages than any storm in Florida history. In one utility's service territory alone, a total of 4.45 million customers lost power contrasted with the previous high of 3.24 million from Hurricane Wilma

[1] The delay in performance metrics reporting results from the time necessary for quarterly data collection, submission to NERC, and validation.
[2] The following is the definition of "Adequate Level of Reliability":
http://www.nerc.com/pa/Stand/Resources/Documents/Adequate_Level_of_Reliability_Definition_(Informational_Filing).pdf
[3] Chapter 3 presents **Table 3.1**, which summarizes the results of each of the original 16 reliability metrics for 2017. Supporting information for the complete set of metrics is included in **Appendix F**, including Metric M-1: Planning Reserve Margin. Metric M-4: Interconnection Frequency Response is the exception and is included in **Appendix E**.
[4] The *Summer Reliability Assessment 2018* can be found at the following location:
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_05252018_Final.pdf
An excerpt of the first Key Finding on page six states, "The majority of assessment areas maintain sufficient resources to meet and exceed their Planning Reference Margin Levels for this summer. However, certain areas face additional operating challenges from either a resource shortfall or a diminishing resource surplus. Texas RE-ERCOT projects an Anticipated Reserve Margin of 10.9 percent. This Reserve Margin equates to a capacity shortfall of 2,000 MW based on the Reference Margin Level of 13.75 percent." This metric is a forward-looking metric and is a candidate for retirement from future State of Reliability reports.

in 2005. System hardening between the storms increased resiliency and reduced restoration time from 18 days for Wilma to 10 days for Irma.[5]

Recommendations	
1-1:	**Emphasize Participation in Mutual Assistance Programs:** Mutual assistance agreements provided essential personnel, equipment, and material following Hurricanes Harvey and Irma. NERC should encourage participation with assistance from government and non-governmental authorities where applicable.
1-2:	**Expand Use of Drones**: Coordination with government and first responders is critical for successful drone use. NERC, in collaboration with the industry, should publish a lesson learned to guide more effective drone use and inform government regulatory agencies that increased drone use can increase grid reliability.
1-3:	**NERC Should Amplify Information Sharing:** NERC should publish event reports for both hurricanes and expand its outreach to include multimedia products and public presentations, including continuing collaborative efforts with the North American Generator Forum (NAGF), the North American Transmission Forum (NATF), and others to share reliability information and seek new venues for increased sharing.

Details in **Chapter 5**

Key Finding 2: Inverter Disconnects during Transmission Disturbances Present an Emerging Risk

A number of events have resulted in the wide-spread loss of BPS-connected inverter-based resources for different reasons. NERC initiated the Inverter-Based Resource Performance Task Force (IRPTF), which studied inverter performance under a variety of circumstances and informed industry on potential risks and their mitigation in 2017 and will continue to do so as long as the need exists.

On August 16, 2016, a 500 kV line fault (during the Blue Cut Fire in San Luis Obispo County, California) resulted in a reduction of 1,000 MW of BPS-connected solar photovoltaic (PV) resources in CAISO.[6, 7] On October 9, 2017, a 220 kV and a 500 kV line (during the Canyon 2 Fire east of Los Angeles, California) each experienced phase-to-phase faults with normal clearing that resulted in the reduction of over 900 MW of solar PV across a wide area of the Southern California Edison footprint. The majority of these inverter-based resources tripped off-line due to sub-cycle transient overvoltages and instantaneous protective action at the inverters to disconnect them from the grid. A significant amount of inverters also entered momentary cessation during and following the fault events. The events were analyzed and an ERO event report was published.[8] NERC, NATF, NAGF, the Utility Variable-Generation Integration Group,[9] and EPRI are conducting webinars to inform industry on desired performance outcomes and inverter settings to achieve them.

---

[5] Florida Power & Light's public presentation to the DOE Electricity Advisory Committee regarding Hurricane Irma can be found at the following location: https://www.energy.gov/sites/prod/files/2018/02/f49/2_Emergency%20Response%20and%20Resilience%20Panel%20-%20Tom%20Gwaltney%2C%20FPL.pdf. See slide 4 for relative hurricane restoration times.

[6] See the Blue Cut Fire disturbance report at the following location: https://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf.

[7] See Level 2 NERC Alert, *Loss of Resources during Transmission Disturbances due to Inverter Settings* at the following location: https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20Loss%20of%20Solar%20Resources%20during%20Transmission%20Disturbance.pdf.

[8] See the Canyon 2 Fire disturbance report at the following location: https://www.nerc.com/pa/rrm/ea/October%209%202017%20Canyon%202%20Fire%20Disturbance%20Report/900%20MW%20Solar%20Photovoltaic%20Resource%20Interruption%20Disturbance%20Report.pdf

[9] Utility Variable-Generation Integration Group changed its name to Energy Systems Integration Group in March 2018.

Recommendations	
2-1:	**Alert Industry of Emerging Potential Risks to Reliability as Identified:** NERC developed a second Level II alert (industry recommendation) in May 2018 to further analyze inverter information and evaluate the extent of conditions associated with emerging issues.
2-2:	**Publish a Reliability Guideline Regarding Inverter-Based Resources:** In coordination with the IRPTF, NAGF, vendors, and manufacturers, NERC should publish a reliability guideline to capture inverter-based resources' different performance characteristics, including coverage of planning, design, and coordination necessary for their reliable integration into the BPS.
2-3:	**Include Vendors and Manufacturers in Analyses when Possible**: As the grid continues to rapidly transform, NERC must continue to track and trend occurrences and events to identify, analyze, and provide recommendations for risk mitigation. NERC must also augment collaboration with the technical committees by including vendors and manufacturers in the technical analysis of equipment performance and specifications.

Details in **Chapter 6**

Key Finding 3: No Loss-Of-Load Due to Cyber or Physical Security Events despite Continually Evolving Threats

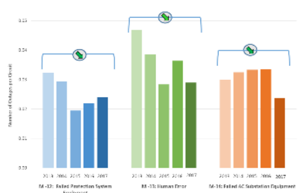
In 2017, there were no reported cyber or physical security incidents that resulted in a loss of load. Nonetheless, grid security, particularly cyber security, is an area where NERC and the industry must continually improve defenses as threats continue to rapidly evolve.

While there were no NERC-reportable cyber security incidents during 2017 and therefore none that caused a loss of load, this does not necessarily suggest that the risk of a cyber security incident is low as the number of cyber security vulnerabilities are increasing.[10] Registered entities report physical security events to the E-ISAC as required by the NERC EOP-004-3 Event Reporting Reliability Standard. Key Finding 3 is a result of the total number of physical security reportable events[11] that occurred in 2017 and identifies how many have resulted in a loss of load. This finding does not include physical events affecting distribution-level equipment (i.e., non-Bulk Electric System (BES) equipment). Both mandatory and voluntary reporting indicate that distribution-level events are more frequent than those affecting BES equipment.

Recommendations	
3-1:	**Enhance Security Posture:** The industry should continue to drive improvements in its security posture through technological hardening, growing a culture of security, and effective information exchange between entities, the E-ISAC, and trusted partner organizations.
3-2:	**Maturation of Security Standards:** The ERO Enterprise should continue to drive positive security outcomes by continual improvement of the Critical Infrastructure Protection (CIP) Standards and by effective execution of the compliance monitoring and enforcement program. Particular attention should be given to the next steps in assessing and responding to the recognized complexity of supply chain risks.
3-3:	**Expand the Use of Systems such as the Cybersecurity Risk Information Sharing Program:** The E-ISAC should identify and evaluate opportunities to lower the cost of participation to include more entities, explore Department of Energy (DOE) funding for broader participation of defense critical electric infrastructure

[10] ERO Reliability Risk Priorities, RISC Recommendations to the NERC Board of Trustees, November 2016, p. 9. Risk Mapping chart depicts Cyber Security Risk as having high potential impact and relative likelihood of BPS-wide occurrence.
[11] Reportable events are defined in Reliability Standard EOP-004-3 Event Reporting, Attachment 1.

Recommendations
utilities, and support American Public Power Association (APPA) and National Rural Electric Cooperative Association (NRECA) member participation.
3-4: **Expand Data Input from Cross-Sector Public and Private Resources:** The E-ISAC should include other data sources, such as the Federal Bureau of Investigation (FBI), SANS Institute, Verizon, etc., as inputs for increasing awareness of the broader security landscape surrounding critical infrastructures. The E-ISAC should improve notification capabilities while reviewing and developing specific and purpose-built user community requirements.
3-5: **Strengthen Situational Awareness Capabilities:** NERC should also create, maintain, and support additional collaborative efforts to strengthen situational awareness for cyber and physical security while providing timely and coordinated information to industry. In addition, industry should continue to review its planning and operational practices to mitigate potential vulnerabilities to the BPS.[12] Timely and complete implementation of the E-ISAC strategic plan will substantially increase its tools and analytically capabilities in this area and will increase the ability to share this information with the industry.



Details in **Chapter 3**

Key Finding 4: Transmission Outages Caused by Failed Protection System Equipment, AC Substation Equipment, or Human Error All Show a Decreasing Trend for the Last Five Years

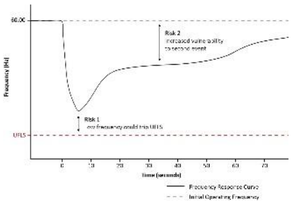
These three areas have historically been major causes of transmission outages. Each has trended downward for the last five years; however, these areas remain major contributors to transmission outage severity and will remain areas of focus.

Transmission outage rates are trending lower while the overall correlation with outage severity has remained similar to past years. Transmission line sustained outages caused by Failed AC Circuit Equipment and Failed AC Substation Equipment (e.g., breakers, transformers) have remained top contributors to BPS transmission outage severity.

Recommendations
4-1: **Continue Emphasis on Human Performance (HP) Training:** NERC should continue to focus on HP training and education through conferences and workshops that increase knowledge and provide information to further mitigate risk scenarios related to transmission and generation outages.
4-2: **Expand Coordination and Collaboration:** NERC should increase collaboration with the NAGF, NATF, and other groups to expand education, outreach, and training to improve awareness of HP challenges for both industry and policy makers.
4-3: **Initiate Focused Collection and Assessment:** Industry should investigate the value of increased granularity of data collection for transmission outages caused by Failed AC Circuit Equipment, Failed AC Substation Equipment, and HP. NERC has published addendum documents[13] for the Event Analysis Program that elicit more event information for the aforementioned transmission outage types and will prepare detailed Failure Mode and Mechanism documents to guide industry analysis of such events.

[12] See Reliability Standard EOP-004-3 Event Reporting at the following location: https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-004-3.pdf.

[13] See Reference Materials for Event Analysis at the following location: https://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx



Details in **Chapter 2**

Key Finding 5: Frequency Response Performance Trends, while Remaining Acceptable, Are Showing Varied Results by Interconnection.

Individual Interconnection performance is separated into performance during the arresting period and during the stabilizing period. Three of the four Interconnections trended "improving" during the arresting period, and two of the four trended "improving" during the stabilizing period. No Interconnection experienced frequency response performance below its interconnection frequency response obligation (IFRO).

Frequency response arrests and stabilizes frequency during system disturbances. NERC closely monitors the M-4 Interconnection frequency response metric (IFRO in the stabilizing period) as the rapidly changing resource mix must continue to provide sufficient amounts of frequency response;[14] this is an essential reliability service (ERS). NERC also emphasizes the importance of maintaining margin between the lowest frequency (nadir) of a loss of generation event (during the arresting period) and the respective Interconnection's underfrequency load shed (UFLS) setpoint. UFLS provides a vital BPS safety net; however, BPS operation should occur in such a way to avoid unnecessary UFLS activation.[15] Activation de-energizes prioritized load to protect the BPS as a whole, also protecting the highest priority distribution loads of police, fire, and hospital facilities.

Individual Interconnection performance is separated into performance during the arresting period and during the stabilizing period:

Arresting Period: Over the 2013–2017 operating years, the Eastern Interconnection (EI), the Texas Interconnection (TI), and the Québec Interconnection (QI) each had a statistically significant and improving frequency response trend during the arresting period. The Western Interconnection (WI) trend was neither statistically improving nor declining.

Stabilizing Period: Frequency response over the 2013–2017 operating years indicated that the WI and TI trends experienced statistically significant improvement during the stabilizing period. The EI and QI trends neither statistically improved nor declined. Interconnection performance differences impact decisions on resource characteristics vital to maintain the reliability of BPS.

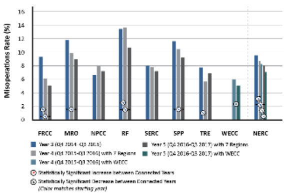
Recommendations[16]	
5-1:	**Enhance Performance Analysis**: NERC should intensify efforts and analytical capability to measure the effects of the changing resource mix on frequency response and voltage support, including any effects related to distributed energy resources.
5-2:	**Ensure Frequency Response Capabilities for New Generation Resources:** Regulators and markets should continue to support modifications and improvements to generator interconnection agreements. NERC should consider methods that promote improved margins between the nadir and the UFLS setpoint. NERC should also continue to provide protection against multiple frequency events.

[14] The *Essential Reliability Services Task Force Measures Framework Report* can be found at the following location: http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf

[15] Reliability Standard PRC-006-3 — Automatic Underfrequency Load Shedding can be found at the following location: https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-006-3.pdf. In this standard's purpose statement, UFLS is characterized as providing "last resort system preservation measures."

[16] **Chapter 2** includes detailed recommendations that do not rise to the level of inclusion in the Executive Summary. These recommendations are specifically worded to provide guidance and consistency for related work in the *State of Reliability 2018*, in NERC's planned July 1 BAL-003 Informational Frequency Response filing in response to FERC Order 794, and for the ongoing work of the BAL-003 Standard Drafting Team.

Recommendations[16]
5-3: **Expand Coordination and Outreach:** NERC should collaborate with the NAGF and others to increase frequency response awareness and capabilities. NERC should also expand education, outreach, and training to improve awareness of frequency response challenges for all levels of industry and policy makers.



Details in **Chapter 3**

Key Finding 6: Protection Systems Misoperations Rates, while Remaining High Priority, Have Declined for the Fifth Consecutive Year.

The overall NERC misoperation rate is lower in 2017 than 2016 (7.1 percent down from 8.3 percent), continuing a five-year trend of declining rates across North America. The three largest causes of misoperations in 2017 remained the same as in 2016: Incorrect Settings/Logic/Design Errors, Relay Failure/Malfunctions, and Communication Failures.

Protection system misoperations exacerbate the impact of transmission outages, thereby increasing their severity. While the misoperation rate for some REs increased in 2017, the overall NERC 2017 misoperation rate is lower than 2016.[17] For the second year, the WECC Region's operation count was collected, enabling the WECC misoperation rate to be developed in 2017 (calculated to be 4.6 percent for 2017). Inclusion of the WECC rate lowers the 2017 NERC rate to 7.1 percent.

Recommendations
6-1: **Continued Focus Merited, Alignment of Definitions Required:** Protection system misoperation should remain an area of focus, as it continues to be one of the largest contributors to the severity of transmission outages. NERC should publish detailed data reporting instructions (DRI) for misoperations to create better alignment of entity understanding and more consistent submissions of misoperation data.
6-2: **Expand Outreach Efforts:** Regional Entities should continue and expand efforts on education, outreach, and training with industry and stakeholders to reduce protection system misoperations. NERC should also continue to support the sharing of good industry practices and lessons learned to continue the downward trend.
6-3: **Leverage Complementary Work:** NERC should continue collaboration with the NATF, vendors, manufacturers, and others to understand, mitigate, and reduce the protection system misoperation rate and impact on the BES.
Foundational support for these findings and recommendations comprises the chapter content of the *State of Reliability 2018*. Specifics, analytics, and associated granular detail of the data makes up the content of the related appendices.

[17] The *State of Reliability 2017* stated the 2016 rate as 8.3 percent including WECC and 8.7 percent excluding WECC since that was the first year that WECC operations were reported to support a regional misoperation rate. *State of Reliability 2018* is the first report to include WECC for all NERC-level comparisons. Also, further analysis resulted in a correction to the 2016 NERC level misoperation rate without WECC, increasing it by 0.1 percent from 8.7 to 8.8 percent, which does not significantly impact the resulting conclusions on protection system performance.

Chapter 1: Availability Data Systems Assessment

This chapter provides an overview of BPS performance as indicated by the analyses of the Transmission Availability Data System (TADS), the Generation Availability Data System (GADS), and the Demand Availability Data System (DADS). These analyses, which are based on 2013–2017 data, provide a basis to evaluate 2017 performance relative to the previous years and performance trends over the last five years.

Overview

The following is a summary of 2013–2017 performance of transmission, generation, and demand response:

- **Transmission System:** Overall, 2017 performance of the transmission system was steady over the five years and has improved as compared with 2016.
- **Generation System:** While the 2017 annual megawatt-weighted equivalent forced outage rate (WEFOR) is slightly above the five-year average, the trend over the five years shows improving reliability for the generator fleet.
- **Demand Response:** The 2013–2017 trend of demand response realization is improving.

Daily performance of transmission and generation systems is statistically analyzed in **Appendix A**.

Highlights of TADS Analysis

TADS inventory and outage data are used to study the initiating cause codes (ICCs) and sustained cause codes (SCCs) of the transmission outages. This analysis can shed light on prominent and underlying causes affecting the overall performance of the BPS. A complete analysis of TADS data is presented in **Appendix B**.

NERC performed five focused analytical studies of TADS data from the 2013–2017 period. The following are the five studies:

1. 200 kV+ TADS ac circuit events (momentary and sustained) from 2013–2017 analyzed by ICC
2. 200 kV+ ac circuit common or dependent-mode (CDM) events, which resulted in multiple transmission element outages from 2013–2017 analyzed by ICC
3. 200 kV+ TADS ac circuit events (momentary and sustained) by Region from 2013–2017 analyzed by ICC
4. 100 kV+ TADS ac circuit and transformer sustained events from 2015–2017 analyzed by ICC
5. 100 kV+ TADS ac circuit sustained 2015–2017 outages analyzed by SCC and by pair ICC-SCC

The results of these studies are summarized with the following observations:

- **Controllable Cause Codes:** The overall number of events with a controllable ICC has reduced from 2016–2017. Excepting Vegetation, the individual cause codes also experienced a reduction in the number of events.
- **Failed AC Circuit Equipment and Failed AC Substation Equipment[18] Cause Codes:** Failed AC Circuit Equipment initiates and sustains more outages than any other cause code. When accounting for duration, sustained outages with the ICC-SCC Failed AC Circuit Equipment and ICC-SCC Failed AC Substation Equipment have notably higher contribution to the total transmission outage severity than any other ICC-SCC group for

[18] NATF's supplemental analyses indicate that, for the 2014–2016 period, the largest contributors to sustained outages for overhead ac circuits coded as Failed AC Substation Equipment are breakers (declining) and arresters (steady). To address these causes, NATF is collaborating with EPRI on an initiative to explore the failure mode for certain types of equipment. The EPRI Industry-Wide Transmission and Substation Performance Database is currently being used to gather information on transformers and arresters with plans to include breakers in the future.

the three years in the study. Additional analyses into the causation of this are being planned with the TADS Working Group (TADSWG).

- **Misoperation Cause Code:** ICC Misoperation initiates the largest number of events with multiple outages (CDM events) than any other cause code. Also, this group is a top contributor to the total transmission outage severity (TOS) of the CDM events.

- **Unknown Cause Code:**[19] While still a top contributor, the ICC Unknown has continued to initiate fewer TADS events. The number of Unknown momentary and sustained events of 200 kV+ ac circuits had a statistically significant decrease, and the number of sustained events of 100 kV+ ac circuits initiated by Unknown also reduced.

- **Fire ICC:** In 2017, the number of events initiated by Fire was the largest number of events in the five years studied. These events were mostly initiated by wildfires that were prevalent in the WI throughout 2017.

Figure 1.1 and **Figure 1.2** provide a graphic summary of Studies 1 and 4, respectively.

Figure 1.1 represents an analysis of the TOS risk of the 2013–2017 TADS for the 200 kV+ ac circuits and provides a comparison with analogous results for 2012–2016.[20] A marker (bubble) represents a group of transmission outage events with a common ICC represented by a number.[21] The size/area of the marker represents the frequency of events initiated by the ICC and is proportional to the number of events initiated by a given cause. The x-axis is the magnitude of the correlation of a given ICC with the TOS. The y-axis represents the expected TOS of an event when it occurs. The color of the marker indicates if there is a correlation of the TOS with the given ICC (statistically significant positive correlation: red, statistically significant negative correlation: green, or no significant correlation: blue). For example, the location and color of the Misoperation bubble in **Figure 1.1** indicate that TADS events with an ICC of Misoperation have the highest expected TOS that is statistically significantly greater than the average TOS of all TADS events of 200 kV+ ac circuits while the events with ICC Misoperation are not very frequent as reflected by the average size of the bubble. The second biggest marker corresponds to the ICC Lightning that has no significant correlation with the TOS but shows a high relative transmission risk because of the high probability of events initiated by Lightning. The other two biggest ICC groups, Unknown and Weather (Excluding Lightning), have a statistically significant negative correlation with the TOS.

The bright colors correspond to groups of events in the 2013–2017 data, the faded colors correspond to the groups of events in the 2012–2016 data. Change in size or position of a bubble with the same number (delineating ICC) may indicate improved or declined performance. For three groups of events—initiated by Fire (3), Contamination (4), and Foreign Interference (13)—the average TOS did not reduce. Dry conditions in California drove at least the Fire category to slightly higher TOS. All other bubbles moved lower, showing a reduction in TOS of events initiated by a given cause. The overall average TOS of the 2013–2017 events were reduced compared with the 2012–2016 events. There were no significant changes in the size of the bubbles; some bubbles moved right (e.g., Contamination (4)) or left (e.g., Weather, Excluding Lightning (12)), pointing to increased or decreased correlation, respectively, of the group with the TOS.

[19] Per NATF's supplemental analyses, outages coded as "Unknown" continue to decrease overall with over 80 percent of those outages being investigated and/or patrolled in attempts to discover the actual cause. The overall decrease in "Unknown" outages can be attributed, at least in part, to this improvement in Transmission Owner/Operator investigative processes as well as NERC and Region actions on related recommendations from previous *State of Reliability* reports (**Chapter 7**).

[20] The detailed results of the analysis of the 2012–2016 TADS data are provided in the *State of Reliability 2017*.

[21] The three smallest groups of automatic events of the 200 kV+ ac circuits with ICCs Vegetation; Vandalism, Terrorism, and Malicious Acts; and Environmental comprise "Combined Smaller ICC groups" to reach a sufficient sample size for reliable statistical inference.

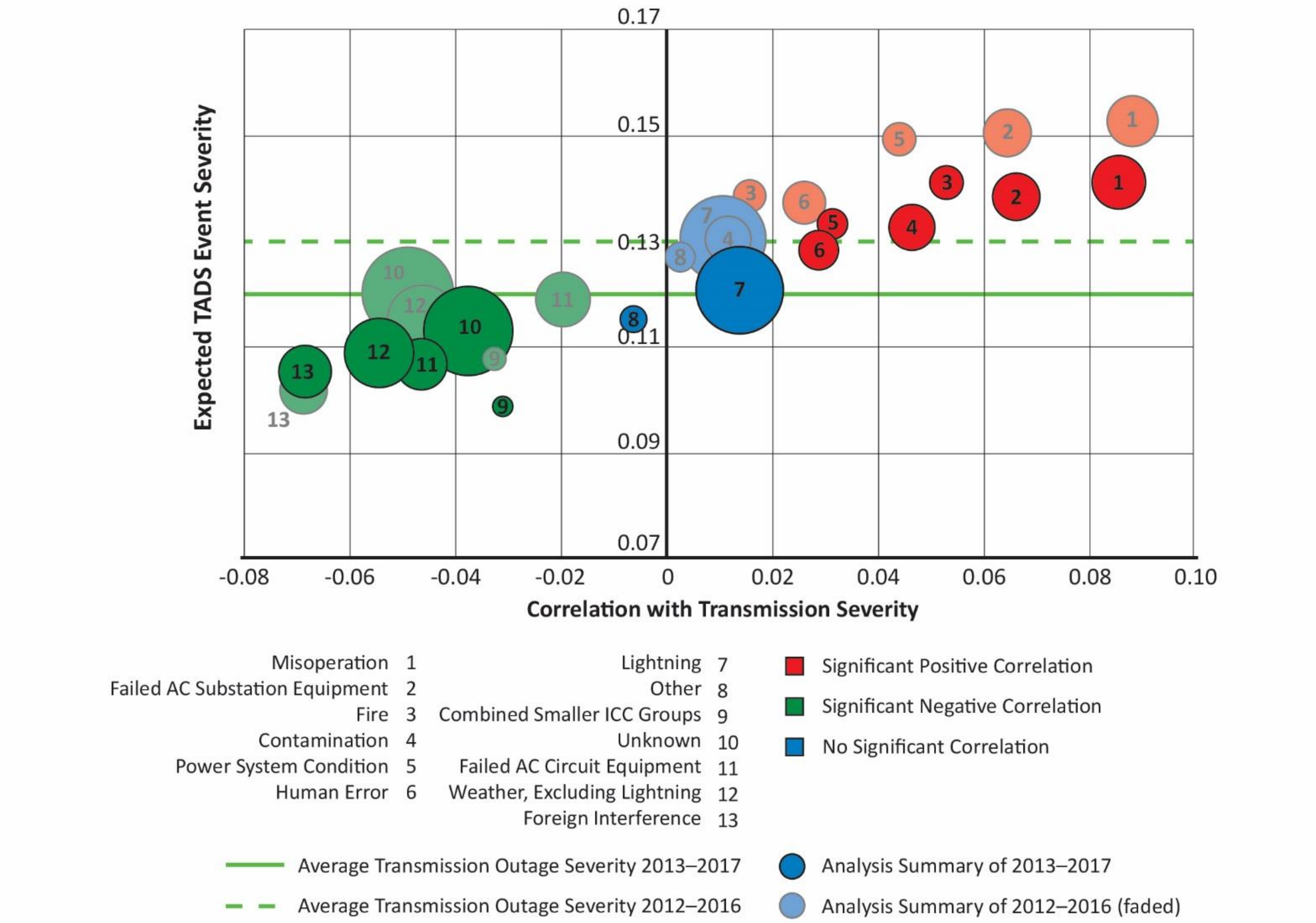


Figure 1.1: Risk Profile of TADS 200 kV+ AC Circuit Events by ICC for the 2012–2016 Data versus the 2013–2017 Data

Figure 1.2 represents an analysis of the TOS risk of the 2015–2017 ICC study of sustained events of 100 kV+ ac circuits and transformers in the same format except that there is no comparison with the previous years since the data collection below 200 kV started only in 2015. The same two ICC groups as in Figure 1.1, Lightning and Other, are shown by blue markers indicating that events initiated by these two causes have no significant correlation with the TOS. In other words, Lightning and Other have about average TOS. Combined Smaller ICC Groups,[22] Fire, and Power System Condition initiate sustained ac circuit and transformer events with the highest TOS; however, these events happen very infrequently as reflected by small sizes of markers for these ICCs. In contrast, the biggest marker for Weather (Excluding Lightning) indicates the highest frequency of weather-initiated events. This leads to the highest relative risk of this group despite a lower TOS of its events.

[22] The three smallest groups of sustained events of the 100 kV+ ac circuits and transformers with ICCs Contamination; Vandalism, Terrorism, and Malicious Acts; and Environmental comprise "Combined Smaller ICC groups" to reach a sufficient sample size for reliable statistical inference.

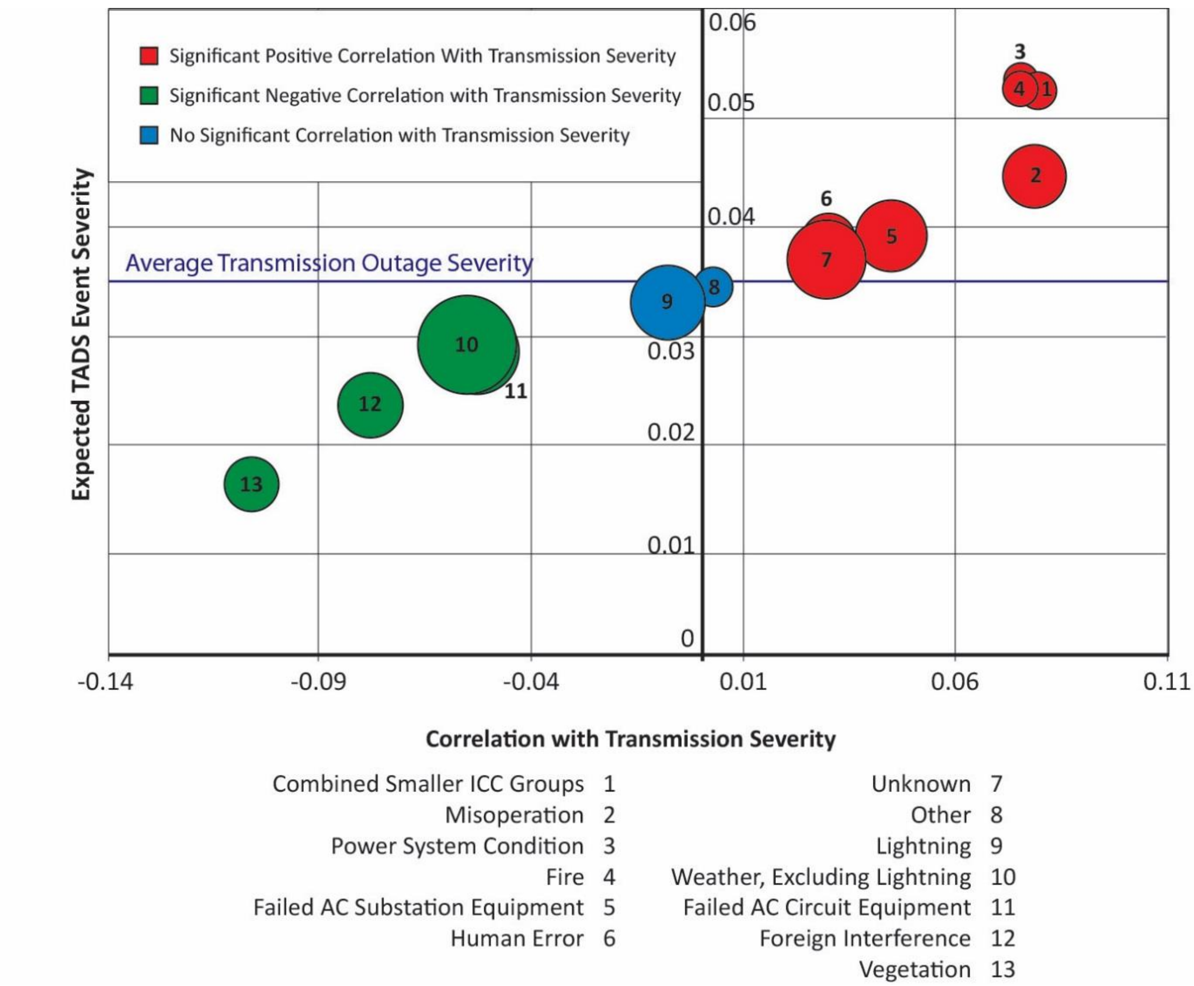


Figure 1.2: Risk Profile of the 2015–2017 Sustained Events of 100 kV+ AC Circuits and Transformers by ICC

Highlights of GADS Analysis

GADS contains information that can be used to compute reliability measures, such as megawatt-WEFOR. WEFOR is a metric measuring the probability that a unit will not be available to deliver its full capacity at any given time due to forced outages and derates.

Figure 1.3 presents the monthly WEFOR across the NERC footprint for the five-year period of 2013–2017.[23] The horizontal steps show the annual WEFOR compared to the monthly WEFOR; the solid horizontal bar in **Figure C.2** shows the mean outage rate over each year. The mean outage rate over the analysis period is seven percent. The WEFOR has been fairly consistent and has a statistical distribution that is nearly an exact standard distribution. While the 2017 annual WEFOR is slightly above the five-year average, the trend over the five years shows improving reliability.

[23] The reporting year covers January 1 through December 31.

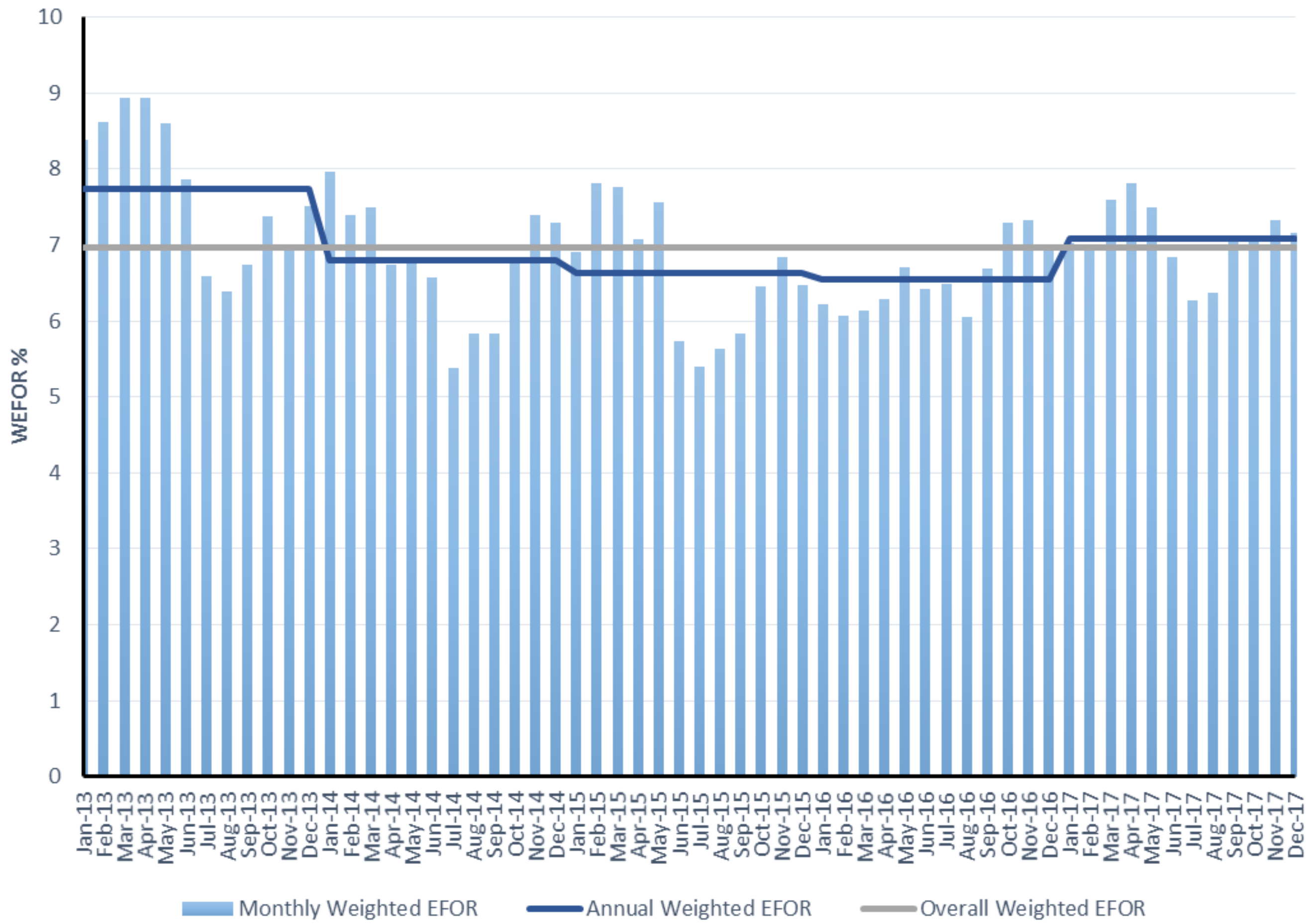


Figure 1.3: Monthly Megawatt Capacity-Weighted EFOR 2013–2017

Another analysis focuses on the seasonality of the Net TWh of potential production lost. Thus, both the amount of capacity affected and the duration of the forced outages are captured by season in **Table 1.1**.

Table 1.1: Net TWh of Potential Production Lost Due to Forced Outages, by Calendar Year 2013–2017

NERC	Total Annual TWh	Summer TWh-Months	Winter TWh-Months	Spring/Fall TWh-Months
2013	313.7	84.8	132.9	96.0
2014	278.6	73.6	97.4	107.6
2015	258.5	79.9	89.9	88.7
2016	257.0	89.1	74.5	93.4
2017	285.7	84.6	100.3	100.7

Based on the latest five years of available data for conventional generating units that are 20 MW and larger, the following observations can be made (as seen in **Table 1.1**):

- Outages from severe storms in the last quarter of 2012, such as Superstorm Sandy, continued through the first quarter of 2013 and are responsible for the increase in production lost in Winter 2013.[24]
- The shoulder months of spring/fall in 2014, 2016, and 2017 have higher Net MWh attributed to forced outages than the corresponding summer or winter periods.

Additional analyses of GADS data for calendar years 2013–2017 is presented in **Appendix C**.

Highlights of DADS Analysis

In 2017, the DADS Working Group (DADSWG) continued efforts to improve data collection and reporting through outreach and development of training materials. Future DADSWG efforts are focused on improving data collection, updating existing materials, developing additional guidance documents, maintaining data quality, and providing observations of possible demand response contributions to reliability. Demand response can support reliability during forecast or actual reserve shortages, reliability events, or assisting with frequency control. Of greatest significance is the improving realization rate for demand response activations.

An analysis of DADS data from 2013 through 2017 provides the following observations:

- Over the 2013–2017 period, the total registered capacity of demand response increased slightly year-over-year in the summer reporting period (two percent to 10 percent as reflected in **Figure D.1**). Over the five-year period, summer and winter enrolled demand response capacity have increased by 17 percent and 20 percent, respectively.
- Changes in enrollment due to regulatory policies in some areas have resulted in an eight percent increase in summer enrollment and redistribution of existing demand response resources to other service types, such as Non-Spinning Reserves and Emergency.
- The amount and types of demand response dispatched by season and year illustrate how much weather can affect the deployment of demand response (see **Figure D.5** and **Figure D.6**).
- The variability of which demand response is deployed may be a function of demand response program design rather than an indication of extensive reliability issues within a Region.
- The effectiveness of demand response to support reliability is illustrated by a comparison of the cumulative dispatched MW to the average realized reduction MW each season and year. Overall, the five-year performance trend for demand response is improving and shows an 88 percent realization rate. The summer performance is 83.8 percent for the five-year period and the winter performance is 99.7 percent (see **Figure D.7** and **Figure D.8**).

Additional analysis of the DADS data is presented in **Appendix D**.

[24] For this GADS analysis, the season of a forced outage is associated with the season in which the start date of the event was reported in that year; therefore, when an event continues into the next year, a new event record is created in January, resulting in the event impacts being categorized as occurring in the winter of the following year as well.

Chapter 2: Frequency Response

This chapter and **Appendix E** are comprised of an explanation of BPS Interconnection frequency response: its necessity and process as well as details of calculation and results of metric M-4, which was established to track and trend frequency response. **Appendix E** also provides introductory information on frequency measures established by the Essential Reliability Services Task Force. Frequency response and metric M-4 merit a separate chapter from the reliability metrics covered in **Chapter 3** and **Appendix F** for two reasons: The first is the potential impact on frequency response performance due to a changing resource mix and increase in renewable resources. The second is the enhanced scope of analysis to include the ability of the Interconnection to arrest the initial frequency decline immediately following the loss of a generation resource that results in a low frequency event.

Metric M-4 Interconnection Frequency Response

Metric M-4 has two components of primary interest: performance of the Interconnection to arrest the frequency decline after a loss of generation event to prevent activation of UFLS and performance of the Interconnection to stabilize quickly at a high enough frequency to successfully respond to a second frequency event should one occur.[25,26] The EI, QI, and TI showed statistically significant improvement in the arresting period time-trend from 2013 through 2017. The WI was statistically unchanged. The TI and WI exhibited statistically significant improvement during the stabilizing period from 2013 through 2017. The EI and QI were statistically unchanged in their performance during the stabilizing period from 2013 through 2017.

Background

Primary frequency response is essential for maintaining the reliability of the BPS. Frequency maintained within predefined limits is a key ALR performance outcome. Frequency response is necessary to support BPS reliability during loss of generation resource or loss of load disturbances that result in frequency deviations; this is critical during system restoration efforts where frequency fluctuations must be controlled during load pick up and connection of additional resources. Frequency response and frequency control are often used synonymously and involve the ability of the BPS to support frequency following a disturbance.

Frequency response is comprised of the actions provided by the Interconnection to arrest and stabilize frequency in response to frequency deviations. Frequency response is provided from automatic generator governor response, load response (typically from induction motors), and facilities that provide an immediate change in output when frequency changes are detected by local device-level control systems. The purpose of the M-4 metric is to determine frequency response trends for each Interconnection so that adequate primary frequency control is provided to arrest and stabilize frequency during frequency excursions of a predefined magnitude. Frequency response is bidirectional and Interconnection resources should respond to loss of resource events that result in low frequency to avoid tripping the first stage of UFLS[27] as well as loss of load events that result in high frequency that could trip connected generation (over-frequency generation protection relays and turbine over-speed control action) from the BPS to prevent from damaging equipment.

---

[25] IFRO mitigates the second of these: stabilization at high enough frequency for a second successful event. NERC began to be additionally concerned with the margin between the lowest frequency (nadir) and the UFLS set point in the *State of Reliability 2016* report. The nadir margin concern has grown to now be at least equal with that of the IFRO.

[26] For full graphic representation and explanation of (loss of generation) frequency events, see **Figure E.1**.

[27] BES owners of UFLS-enrolled load support the concept and implementation of intentional loss of prioritized load to preserve the BPS backbone and to protect essential loads, such as police and fire stations and hospitals. However, despite rigorous design, implementation, and testing, full awareness exists that UFLS exposes these loads to inadvertent de-energization when HP errors occur. To avoid this and other HP associated reliability risks, NERC and NATF conduct their annual Improving Human Performance on the Grid conference in late March. This and other quality HP conferences and training mitigate these risks.

The performance trends discussed in this report for the operating years 2013–2017 should be considered within the context of longer term trends analyzed and discussed in the *Frequency Response Initiative Report* from 2012.[28] A downward trend in frequency response over a number of years raised concerns that credible contingencies could result in frequency excursions that encroach on the first step of an Interconnection's UFLS. While recent initiatives have made progress in arresting the decline in measured frequency response, the growing complexities of primary frequency response due to changes in the resource mix and increased penetration of inverter based variable resources, such as wind and solar, keep this a concern.

In 2017, the NERC Standards Committee (SC) received two standard authorization requests (SARs) proposing revisions to the BAL-003-1.1 Reliability Standard. Several issues highlighted in these two SARs were anticipated and raised in more detail in the *NERC 2015* and *2016 Frequency Response Annual Analysis* reports.[29, 30] The SC appointed a standard authorization request (SAR) standard drafting team to develop one combined SAR. Upon SC endorsement of the combined SAR, the standard drafting team will consider modifications to the BAL-003-1.1 Reliability Standard to address the issues identified in the SAR through the standard development process. This effort is ongoing as of the date of this report.

Interconnection Performance Summary

The following summary includes the observations and results of statistical analysis for each Interconnection.[31] Individual Interconnection performance is separated into performance during the arresting period and during the stabilizing period. Note that frequency response metrics (i.e., IFRO and Interconnection Frequency Response Performance Measure (IFRM)) are typically negative numbers expressed in MW/0.1 Hz, because the change in MW output should be in the opposite direction as the change in frequency. For this report, frequency response is expressed as an absolute value. The statistical analysis and data supporting these findings can be found in **Appendix E** along with additional statistical techniques and discussion of ERS measures.

Table 2.1 provides a summary of the Interconnection performance statistics discussed above.

Table 2.1: Interconnection Performance Summary Statistics

Interconnection	2017 OY Largest Resource Loss		2017 OY Lowest A-B IFRM Performance		2013–2017 OY Arresting Period Performance Trend	2013–2017 OY Stabilizing Period Performance Trend
	MW Loss	UFLS Margin (Hz)	MW Loss	UFLS Margin (Hz)		
Eastern	1,661	0.453	511	0.472	Improving	No Change
Texas	1,219	0.433	369	0.603	Improving	Improving
Quebec	954	0.873	314	1.199	Improving	No Change
Western	2,776	0.210	383	0.450	No Change	Improving

[28] The *2012 Frequency Response Initiative Report* can be found at the following location: http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

[29] The *2015 Frequency Response Annual Analysis* report can be found at the following location: https://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Related%20Files/2015_FRAA_Report_Final.pdf

[30] The *2016 Frequency Response Annual Analysis* report can be found at the following location: https://www.nerc.com/comm/OC/Documents/2016_FRAA_Report_2016-09-30.pdf

[31] In the 2016 operating year, a change in selection criteria was implemented that included frequency events with a smaller MW loss if the event resulted in a sufficient frequency deviation. Note that this change resulted in a larger sample of events for all Interconnections as compared to previous years and is meant to capture frequency response performance over a wider range of operating conditions (e.g., those that might occur during light load conditions when less generation is online and therefore the inertia and governor response of the Interconnections might be reduced). Due to this change, results of any detected statistically significant time trend or statistically significant difference in year-over-year performance can be partially due to the criteria modification.

Eastern Interconnection

In the 2017 operating year, the largest resource loss for an M-4 event in the EI was 1,661 MW (versus a resource contingency criterion (RCC) of 4,500 MW) that resulted in a Point C frequency nadir of 59.953 Hz and UFLS margin of 0.453 Hz from a Value A starting frequency of 59.999 Hz. The event occurred in July 2017 during hour ending (HE) 13:00 EDT.

The lowest A-B IFRM performance for an M-4 event was 1,043 MW/0.1 Hz (versus an IFRO of 1,015) due to a resource loss of 511 MW resulting in a Point C frequency nadir of 59.972 Hz and UFLS margin of 0.472 Hz from a Value A starting frequency of 60.014 Hz. The event occurred in November 2017 during HE 04:00 EST.

Arresting Period Performance: The EI has seen increasing margins between Point C frequency nadirs and UFLS each of the five years evaluated in this report, suggesting that there is reduced risk during the arresting period of frequency events. In 2017, the smallest margin between the Point C nadir and UFLS was 0.435 Hz with no events lower than 0.400 Hz during the 2013–2017 operating years.

Note: statistical analysis indicates that, over the 2013–2017 operating years, the EI had an improving frequency response trend during the arresting period that was highly statistically significant.

Stabilizing Period Performance: The mean Value B in 2017 of 59.963 Hz was higher than all previous years, which suggests that there are improvements during the stabilizing period. However, the mean frequency response was lower in 2017 than all previous years since 2013. Of concern, variability increased again in 2017 with lower lows and higher highs and a larger standard deviation than all previous years. The EI had no years where its IFRM was below its IFRO.

Note: statistical analysis indicates that the EI frequency response time trend during the stabilizing period over the 2013–2017 operating years was neither improving nor declining.[32]

Texas Interconnection

In the 2017 operating year, the largest resource loss for an M-4 event in the TI was 1,219 MW (versus an RCC of 2,750 MW) that resulted in a Point C frequency nadir of 59.733 Hz and UFLS margin of 0.433 Hz from a Value A starting frequency of 60.005 Hz. The event occurred in November 2017 during HE 21:00 CST.

The lowest A-B IFRM performance for an M-4 event was 491 MW/0.1 Hz (versus an IFRO of 381) due to a resource loss of 369 MW resulting in a Point C frequency of 59.903 Hz and UFLS margin of 0.603 Hz from a starting frequency of 60.011 Hz. The event occurred in April 2017 during HE 08:00 CDT.

Arresting Period Performance: The TI has seen increasing margins between Point C frequency nadirs and UFLS (as measured by the mean) each of the five years evaluated in this report, suggesting that there is reduced risk during the arresting period of frequency events. However, the lowest Point C to UFLS margin for each of those operating years shows no clear trend. In 2017, the smallest margin between the Point C nadir and UFLS was 0.433 Hz with no events lower than 0.400 Hz during the 2013 to 2017 operating years.

Note: statistical analysis indicates that, over the 2013–2017, operating years the TI had an improving frequency response trend during the arresting period that was highly statistically significant.

Stabilizing Period Performance: The mean Value B in 2017, of 59.930 Hz, was higher than all previous years, which suggests that there are improvements and reduced risk during the stabilizing period. Frequency response variability

[32] A statistical test is performed to determine if the time trend-line is increasing or decreasing. A statistically significant trend means that the slope, positive or negative, is unlikely to have occurred by chance. The complete statistical analysis can be found in **Appendix E**.

also decreased in 2017 compared to 2016 with a smaller standard deviation suggesting improved predictability of performance. In 2017, the minimum individual event performance of 491 MW/0.1 Hz was the highest seen during all years evaluated in this report.

Note: statistical analysis indicates that the TI frequency response time trend during the stabilizing period, has improved over the 2013–2017 operating years.

Québec Interconnection

In the 2017 operating year, the largest resource loss for an M-4 event in the QI was 954 MW (versus an RCC of 1,700 MW) that resulted in a Point C frequency nadir of 59.373 Hz and UFLS margin of 0.873 Hz from a Value A starting frequency of 59.947 Hz. The event occurred in August 2017 during HE 21:00 EDT.

The lowest A-B IFRM performance for an M-4 event was 221 MW/0.1 Hz (versus an IFRO of 179) due to a resource loss of 314 MW, resulting in a Point C frequency of 59.699 Hz and UFLS margin of 1.199 Hz from a starting frequency of 60.063 Hz. The event occurred in June 2017 during HE 23:00 EDT.

Arresting Period Performance: In 2017 the QI saw the largest margin between Point C frequency nadir and UFLS than all previous years evaluated in this report, suggesting that there is reduced risk during the arresting period of frequency events. However, in 2017 the mean resource MW loss was the smallest and mean Value A starting frequency was the highest of all previous years, which should be considered when evaluating the improved UFLS margin. On an annual basis, the QI continues to exhibit the largest margins between Point C frequency nadir and UFLS of all Interconnections with the exception of 2013.

Note: statistical analysis indicates that, over the 2013–2017 operating years, the QI had an improving frequency response trend during the arresting period that was highly statistically significant.

Stabilizing Period Performance: The mean Value B in 2017 of 59.895 Hz was higher than all previous years, which suggests that there are improvements and reduced risk during the stabilizing period. However, the mean B-C margin of 0.304 Hz was the smallest of all years except 2015. Performance variability during the stabilizing period also increased in 2017 with lower lows and higher highs and larger standard deviation than all previous years.

Note: statistical analysis indicates that the QI frequency response time trend over the 2013–2017 operating years was neither statistically improving nor declining.

Western Interconnection

In the 2017 operating year, the largest M-4 event in the WI was 2,776 MW (versus an RCC of 2,626 MW), which was the result of a Pacific Northwest remedial action scheme[33] (RAS) with a Point C of 59.710 Hz and UFLS margin of 0.210 Hz from a Value A starting frequency of 60.019 Hz. The event occurred in April 2017 during the HE 23:00 PDT.

The lowest A-B IFRM performance for an M-4 event was 870 MW/0.1 Hz (versus an IFRO of 858) due to a resource loss of 383 MW resulting in a Point C frequency of 59.950 Hz and UFLS margin of 0.450 Hz from a starting frequency of 60.022 Hz. The event occurred in April 2017 during HE 20:00 PDT.

[33] It should be noted that this event was the activation of one the Pacific Northwest RAS identified and studied in the *2013 Frequency Response Annual Analysis* (see footnote 34). These RAS events may cause a larger MW loss than the elected RCC, but their net impact to the Interconnection frequency is less than that of the RCC due to the difference in transmission system losses caused by the difference in distance from the lost resources to major load centers.

Arresting Period Performance: In 2017, the WI experienced an event where the Point C nadir was 59.697 Hz, resulting in a Point C to UFLS margin of 0.197 Hz, the smallest margin since a 0.171 Hz event in 2014. The resource MW loss for these two events were 2,685 MW and 2,826 MW, respectively, more than double the mean resource MW loss for each year and close to the RCC of 2,626 MW defined in the *2016 Frequency Response Annual Analysis*[34] and used to calculate 2017 IFROs.

Note: over the 2013–2017 operating years, statistical analysis indicates that the WI frequency response trend was neither statistically improving nor declining during the arresting period,

Stabilizing Period Performance: The mean frequency response in 2017 of 1,836 MW / 0.1 Hz was the highest of all years evaluated in this report, albeit with increased variability and larger standard deviation. The WI had no events in 2017 where its IFRM was below its IFRO, including the event noted above where the Point C nadir to UFLS margin was less than 0.200 Hz.

Note: statistical analysis indicates that the WI mean frequency response time trend over the 2013-2017 operating years saw a statistically significant improvement.

Summary of Findings and Recommendations[35]

Finding 1: The largest M-4 frequency events, based on size of the resource loss, varied significantly between Interconnections during the 2017 operating year. The largest resource loss in the EI was 1,661 MW, which is 37 percent of the RCC. When compared to their respective Interconnection's RCCs, the TI, QI, and WI experienced events during the 2017 operating year where the resources losses were 44 percent, 56 percent, and 106 percent of their RCCs, respectively. The magnitude of the resource loss has a direct impact on Interconnection performance calculation as measured by IFRMs and Point C to UFLS margins.

Recommendation 1: NERC should, in coordination with NERC technical committees and staff, review and evaluate historic resource loss events and the method used to determine the appropriate RCC for each Interconnection.

Finding 2: The size of the resource loss has a significant impact on Interconnection performance as measured by IFRM. The resulting IFRM is not necessarily an accurate indicator of risk. For example, in the 2017 operating year, the lowest A-B IFRM performance for each Interconnection occurred when the resource loss was well below the largest resource loss and the Point Cs were well above UFLS set points.

Recommendation 2: NERC should, in coordination with NERC technical committees and staff, evaluate the effectiveness of IFRM and IFRO as the preferred indicators of risk to BPS reliability. This could include consideration of alternate methods for establishing Interconnection performance parameters necessary to mitigate risk during both the arresting and stabilizing periods of frequency events that may include, but not be limited to, consideration of frequency responsive reserves and the impact of changing trends in Interconnection-wide inertia.

Finding 3: The risk of poor frequency response performance during the arresting period is higher in comparison to the stabilizing period due to the risk of activating UFLS that results in the loss of Interconnection load and possible instability. The EI, TI, and QI experienced statistically significant improving performance trends during the arresting period through the 2013 to 2017 operating years. The corresponding WI performance trend was statistically neither

[34] The *2016 Frequency Response Annual Analysis* can be found at the following location: https://www.nerc.com/comm/OC/Documents/2016_FRAA_Report_2016-09-30.pdf

[35] These findings and recommendations do not rise to a level to bring forward into the **Executive Summary**. They are specifically worded to provide guidance and consistency for related work in the *State of Reliability 2018*, in NERC's planned July 1, BAL-003 Informational Frequency Response filing in response to FERC Order 794, and for the ongoing work of the BAL-003 Standard Drafting Team.

improving nor declining. While the monitoring of statistical performance trends (during the arresting period) is helpful, it is important to pay attention to individual event performance due to the risk of activating UFLS for a single event.

Recommendation 3: NERC should, in collaboration with the Resources Subcommittee (RS) and the NAGF, develop methods that promote improved performance during the arresting period and minimize the risk of activating UFLS for any single event.

Finding 4: The TI and WI experienced improving performance trends during the stabilizing period that were statistically significant through the 2013 to 2017 operating years. The corresponding trends for the EI and QI were neither statistically improving nor declining over the same period.

Recommendation 4: NERC should, in collaboration with the RS and NAGF, continue the outreach to maximize the number of generators in the existing generation fleet that are capable of providing primary frequency response and pursue the addition of a frequency bias in all outer loop controls for both conventional generation and inverter-based resources to prevent withdrawal or squelching of primary frequency response.

Finding 5: All Interconnections except TI experienced increased variability in frequency response performance during the stabilizing period of frequency events. This could be due in part to increased variability in the size of the resource losses; limited Balancing Authority (BA) monitoring of frequency responsive reserves in real-time could also be a contributor.

Recommendation 5: NERC, in collaboration with the NERC RS, should explore methods that result in reduced variability and increased predictability of frequency response performance that could include, but not be limited to, BA monitoring of frequency responsive reserves in real time and identification of impediments to doing so.

Chapter 3: Reliability Indicator Trends

This chapter provides a summary of the reliability indicators and follows with a section on select metrics determined to best communicate the *State of Reliability 2018*, including its most challenging and improving trends and those supporting the key findings detailed in the **Executive Summary**. Other metrics and any supporting material can be found in **Appendix F**. However, one metric (metric M-4, Interconnection Frequency Response) is discussed instead in **Chapter 2** with details explored in the **Metric M-4: Interconnection Frequency Response** section of **Appendix E**.

NERC reliability indicators tie the performance of the BPS to a set of reliability performance objectives included in the approved 2012 ALR definition.[36] This set of seven NERC reliability performance objectives are mapped to the current reliability indicators[37] and are then evaluated to determine whether the BPS meets the ALR definition and whether overall reliability is improving or declining. **Table 3.1** provides a summary of the trends over the past five years by providing a performance rating of improving, declining, stable, or inconclusive based on analysis of available data.

Summary

When reviewing the reliability indicators it is important to note the following:

- **Table 3.1** lists each reliability indicator with its metric trend rating(s). Additional information for each metric can be found later in this chapter (in **Chapter 2** for Metric M-4) and in **Appendix F**.
- The PAS annually reviews the reliability indicators to identify gaps in performance or data collection. Over time, PAS has implemented changes, added new indicators, and retired some indicators to keep the others relevant. An example of a recent change would be the alignment of M-12 through M-16 to the BES definition. Future developments may include the adoption of ERS Working Group (ERSWG) measures[38] with near-term focus on Measure 7: Reactive Capability on the System. PAS has solicited voluntary industry data submission to support the measure, and the Systems Analysis and Modeling Subcommittee (SAMS) is using this data to evaluate the measure's value.
- Metrics are evaluated over different periods of time. This can be attributed to the period established with the approved metric definition, the duration for what data are available, or other data limitations. For example, M-4 Interconnection Frequency Response has a period defined as "1999 or when data are first available," and M-12 has a time frame defined as "a rolling five-year average."
- Metrics may be defined to be NERC-wide, for a specific Region, or on Interconnection-level basis.
- The ALR defines the state of the BES to meet performance objectives. Reliability performance and trends of individual metrics should be evaluated within the context of the entire set of metrics.
- It is important to retain the anonymity of individual reporting entities when compiling the data necessary to evaluate metric performance. Details presented in this report are aggregated to maintain the anonymity of individual reporting organizations.

---

[36] Definition of "Adequate Level of Reliability" is as follows:
http://www.nerc.com/comm/Other/Adequate%20Level%20of%20Reliability%20Task%20Force%20%20ALRTF%20DL/Final%20Documents%20Posted%20for%20Stakeholders%20and%20Board%20of%20Trustee%20Review/2013_03_26_ALR_Definition_clean.pdf

[37] The current reliability indicators can be found at the following location:
http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2014_SOR_Final.pdf

[38] The ERSWG Framework Measures report can be found at the following location:
http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf

Table 3.1: Metric Trends		
Metric	**Description**	**Trend Rating**
M-1	Planning Reserve Margin	Stable except for TI **Appendix F**
M-2	BPS Transmission-Related Events Resulting in Loss of Load (modified in early 2014)	Improving
M-3	System Voltage Performance (discontinued in 2014)	Retired—**Appendix F**
M-4	Interconnection Frequency Response	Arresting Phase—EI, QI, and TI improving; WI no change Stabilizing Phase—TI and WI improving; EI and QI unchanged See **Chapter 2**
M-5	Activation of Underfrequency Load Shedding (discontinued in 2014)	Retired
M-6	Average Percent Non-recovery Disturbance Control Standard Events	Improving—**Appendix F**
M-7	Disturbance Control Events Greater than Most Severe Single Contingency	Stable–**Appendix F**
M-8	Interconnection Reliability Operating Limit/System Operating Limit (IROL/SOL) Exceedances (modified in 2013)	EI—Improving—**Appendix F**
		ERCOT—Stable—**Appendix F**
		WI—Stable—**Appendix F**
		QI—Retired—**Appendix F**
M-9	Correct Protection System Operations	Improving
M-10	Transmission Constraint Mitigation (discontinued in 2016)	Retired
M-11	Energy Emergency Alerts (modified in 2013)	Inconclusive–events up; load loss down **Appendix F**
M-12	Automatic AC Transmission Outages Initiated by Failed Protection System Equipment (modified in late 2014)	Circuits—Improving
		Transformers—Improving
M-13	Automatic AC Transmission Outages Initiated by Human Error (modified in late 2014)	Circuits—Improving for 200 kV+; Inconclusive for 100 kV+
		Transformers—Improving
M-14	Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment (modified in late 2014)	Circuits—Stable
		Transformer—Improving
M-15	Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment (modified in late 2014; normalized by line length)	Inconclusive
M-16	Element Availability Percentage (APC) and Unavailability Percentage (modified in 2013)	Circuits—Inconclusive
		Transformers—Improving

M-2 BPS Transmission-Related Events Resulting in Loss of Load

Background

This metric measures BPS transmission-related events that result in the loss of load, excluding weather-related outages. The underlying data that is used for this metric is important for operators and planners in assessing how effective their design and operating criteria are. All other metrics support M-2.

Consistent with the revised metric approved by the OC and PC in March 2014, an "event" is an unplanned disturbance that produces an abnormal system condition due to equipment failures/system operational actions (either intentional or unintentional) that result in the loss of firm system demands. This is identified by using the subset of data provided in accordance with Reliability Standard EOP-004-3.[39] The reporting Criteria for such events, beginning with data for events occurring in 2013, are as follows:[40]

1. The loss of firm load for 15 minutes or more:
    a. 300 MW or more for entities with previous year's demand of 3,000 MW or more
    b. 200 MW or more for all other entities
2. A BES emergency that requires manual firm load shedding of 100 MW or more
3. A BES emergency that resulted in automatic firm load shedding of 100 MW or more via automatic undervoltage or underfrequency load shedding schemes or special protection systems (SPSs)/RASs[41]
4. A transmission loss event with an unexpected loss within an entity's area, contrary to design, of three or more BES elements caused by a common disturbance (excluding successful automatic reclosing), resulting in a firm load loss of 50 MW or more

PAS reviewed this M-2 metric in 2013 and made changes to its criteria to increase consistency with EOP-004-3 criteria for reporting transmission-related events that result in loss of load. The criteria presented above were approved for implementation in the first quarter of 2014. Changes in the annual measurement between 2012 and 2013 therefore reflect the addition of Criteria 4, which has been applied to the data since 2013. For the first part of the analysis below, shown in **Figure 3.1** and **Figure 3.2**, historical data back to 2002 was used and the new Criteria 4 was not included to allow trending of the other aspects of the metric over time. **Figure 3.3** includes all of the criteria, consequently it was only evaluated for 2013–2016; the time period for which data collection associated with the new criteria was available. The performance trend is continuing to improve.

Assessment

Figure 3.1 shows the number of BPS transmission-related events that resulted in the loss of firm load from 2002–2017. On average, just under eight events were experienced per year. The BPS experienced one transmission load loss events in 2017. This continues a mixed, but nonetheless improved, trend since 2012 in the number of events.

Figure 3.2 indicates that the top three years in terms of load loss remain 2003, 2008, and 2011 due to the major loss-of-load events that occurred. In 2003 and 2011, one event accounted for over two-thirds of the total load loss, while in 2008, a single event accounted for over one-third of the total load loss.

---

[39] Reliability Standard EOP-004-3 can be found at the following location: https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-004-3.pdf

[40] ALR 1-4 Reporting Criteria can be found at the following location: http://www.nerc.com/comm/PC/Performance%20Analysis%20Subcommittee%20PAS%202013/ALR1-4_Revised.pdf

[41] The Glossary of Terms Used in NERC Reliability Standards can be found at the following: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf. This document defines SPS as a Special Protection Scheme and an RAS as a Remedial Action Scheme. The document provides a wealth of related information.

Load loss excluding Criteria 4 is less for 2017 than for any year since 2002 inclusive. Load loss over the last four years remains below the median value. This also continues a mixed, but improved, trend since 2011 in the total annual load loss from these events.

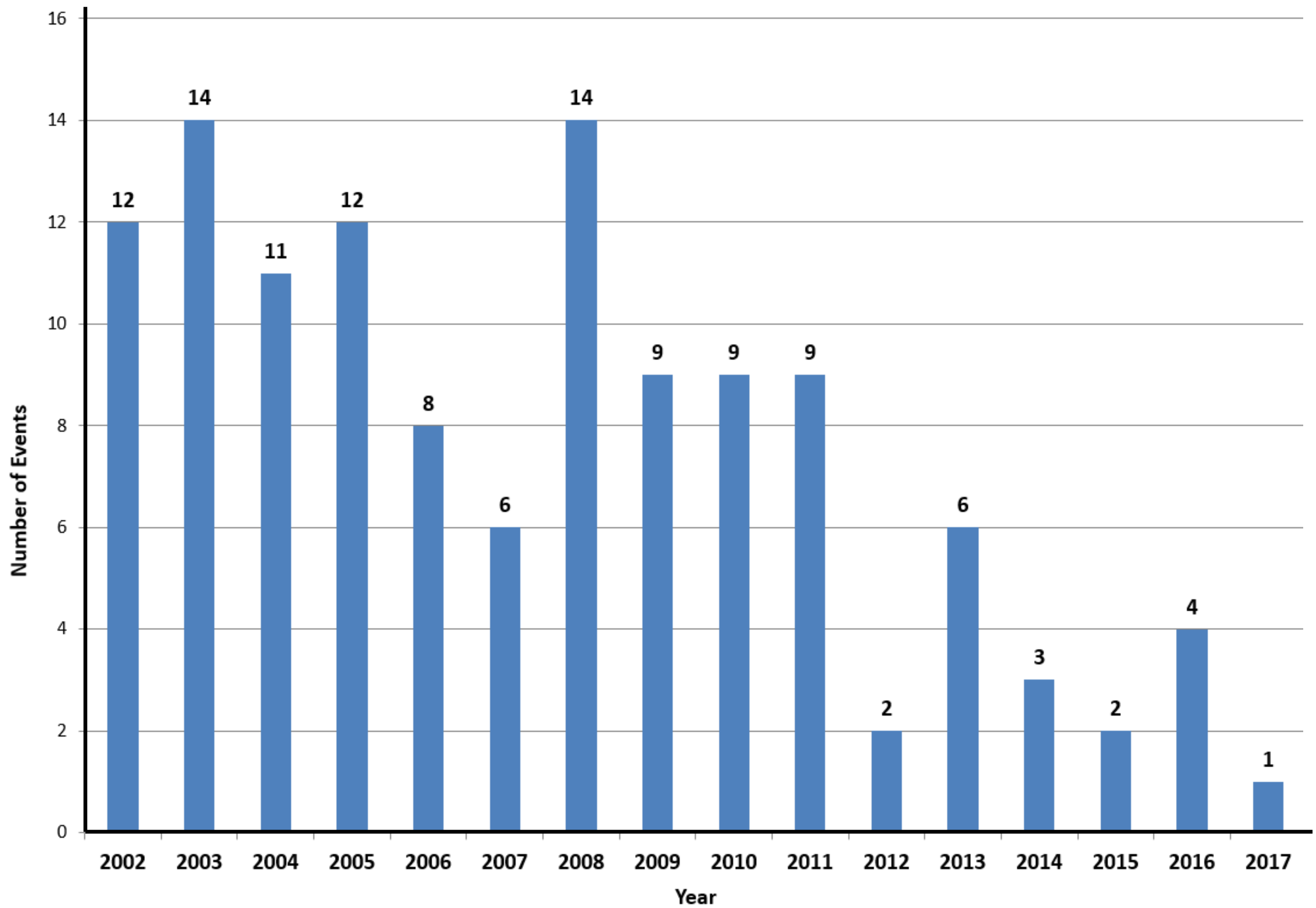


Figure 3.1: M-2 BPS Transmission Related Event Resulting in Load Loss (Excluding Criteria 4)

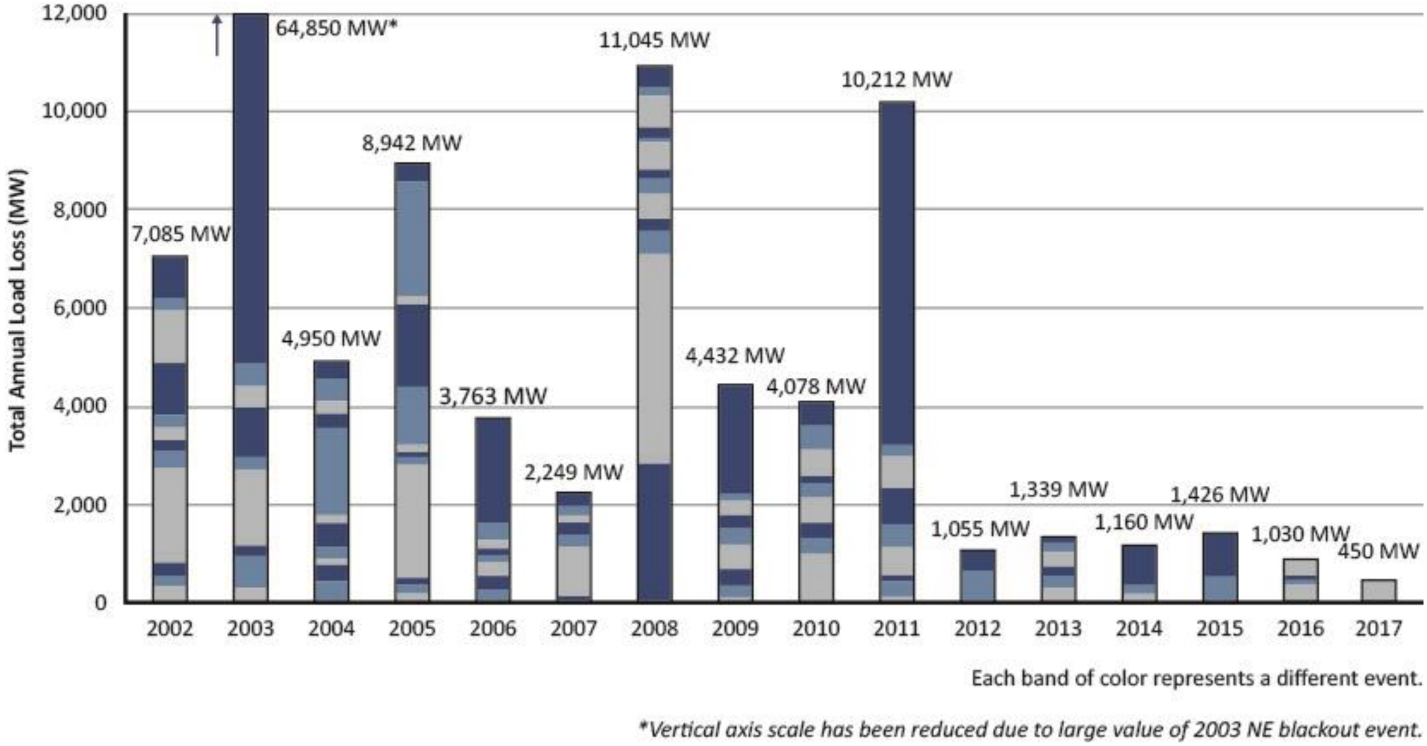


Figure 3.2: M-2 BPS Transmission-Related Events Resulting in Load Loss (Excluding Criteria 4)

Figure 3.3 shows the number of events resulting in firm load loss of 50 MW or greater from 2013–2017 and their durations. The metric was modified in 2013 to include Criteria 4 events. There were six events during 2017 (one under Criteria 4. See **Figure 3.2**) with load loss of ≥ 50MW. For 2017 the largest number of load loss events was between one and 2.99 hours.

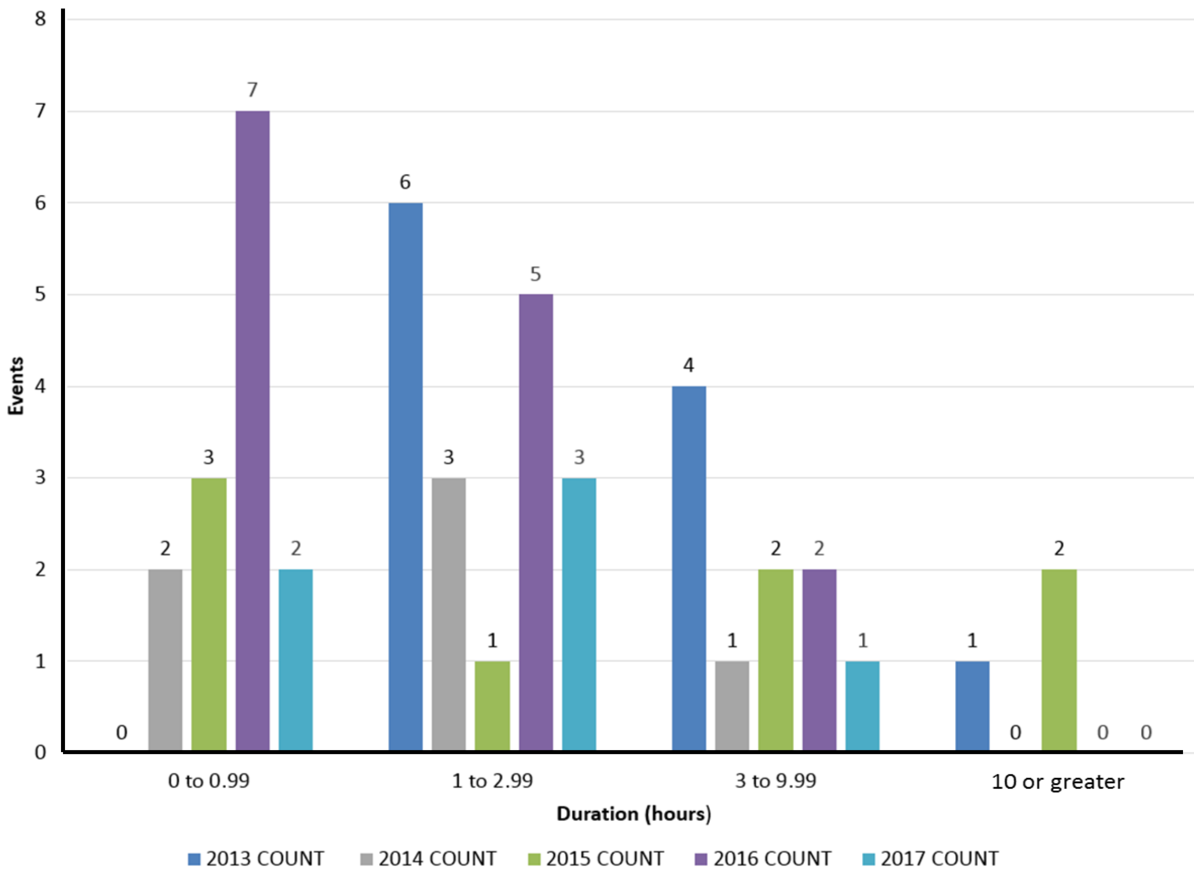


Figure 3.3: Outage Duration vs. Events

M-9 Correct Protection System Operations

Background

The correct protection system operations metric provides the performance of protection systems (both generator and transmission) on the BPS. The metric is the ratio of correct protection system operations to total system protection system operations.

Protection system misoperations have been identified as a major area of concern, as stated in previous State of Reliability reports, because misoperations exacerbate event impacts for the BPS. Improvements to data collection that the System Protection Control Subcommittee (SPCS) proposed were implemented as a result;[42] NERC coordinates with each Region as well as these groups to continue the focus on improvements. Both correct operations and misoperations are including in the information below.

Assessment

The analysis of the misoperation and operation data, summarized in **Figure 3.4**, **Figure 3.6**, **Figure 3.7**, and **Table 3.2**, leads to a conclusion about an improving performance of M-9 from Q4 2012 through Q3 2017.

Figure 3.4 shows the total correct operations rate for NERC through the first three reporting quarters of 2017.

[42] SPCS proposed improvements to data collection can be found at the following location: http://www.nerc.com/comm/PC/Protection%20System%20Misoperations%20Task%20Force%20PSMTF%202/PSMTF_Report.pdf

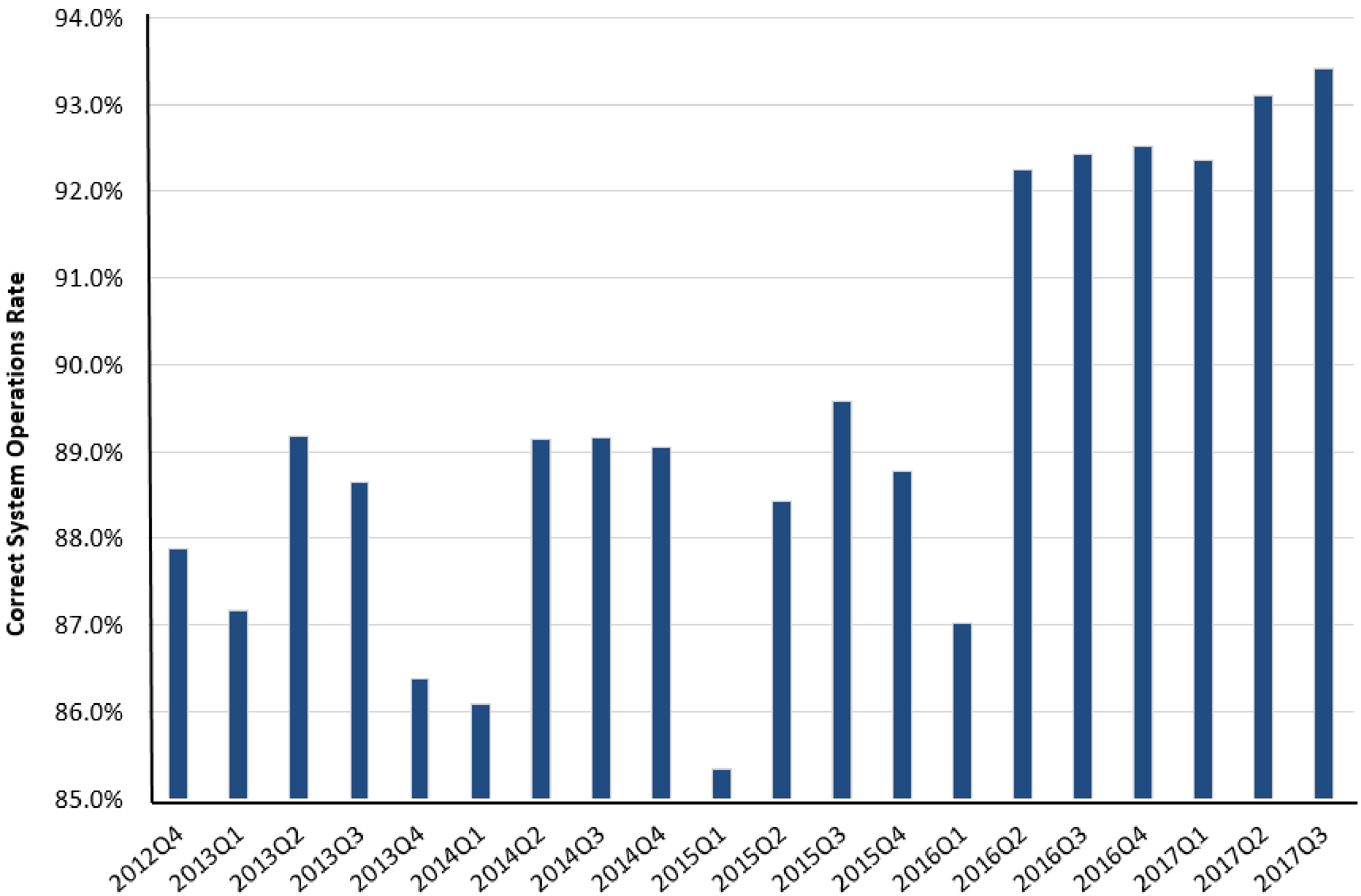


Figure 3.4: Correct Protection System Operations Rate

Figure 3.5 shows the Regional misoperation rates for the five-year data combined (from Q4 2012 through Q3 2017). NPCC's rate was calculated based on the Q1 2013 through Q3 2017 data. WECC's rate was calculated based on the Q2 2016 through Q3 2017 data.[43]

[43] WECC's operation data submission started in Q2 2016.

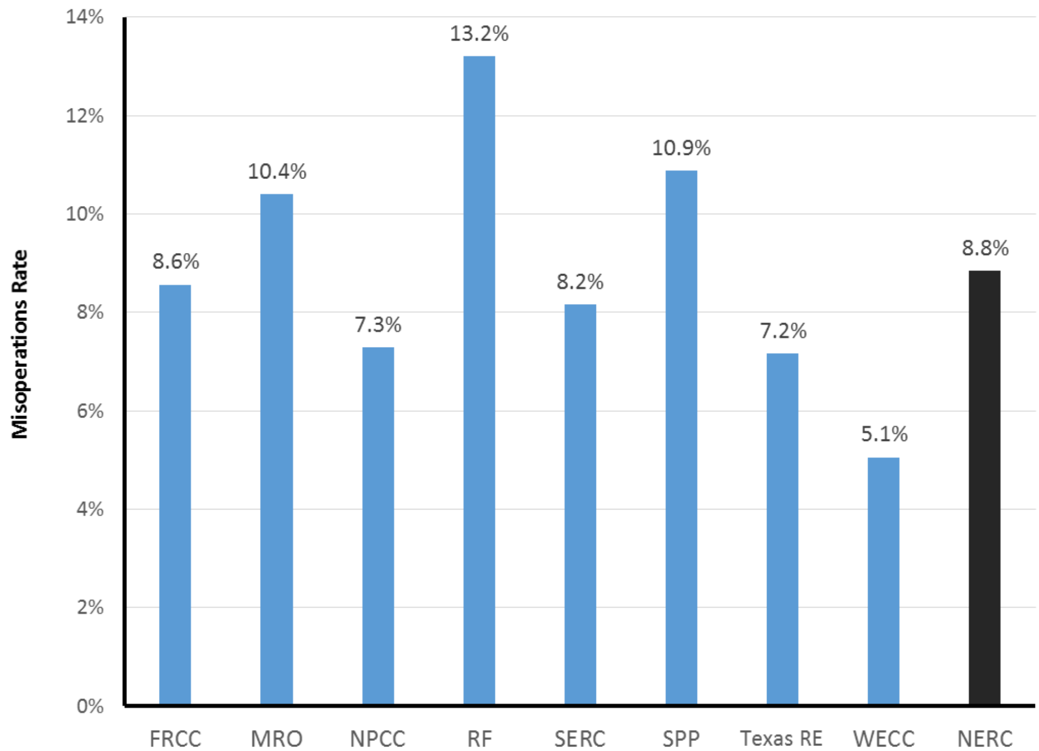


Figure 3.5: Five-Year Misoperation Rate by Region (Q4 2012 through Q3 2017)

Year-Over-Year Changes by Region

Changes from the first four quarters (Q4 2012 through Q3 2013, Year 1) to the second four quarters (Q4 2013 through Q3 2014, Year 2) to the third four quarters (Q4 2014 through Q3 2015, Year 3) to the fourth four quarters (Q4 2015 through Q3 2016, Year 4) to the fifth four quarters (Q4 2016 through Q3 2017, Year 5) were studied to compare time periods with similar composition of seasons.[44] The changes by Region are shown in **Figure 3.6**. In **Figure 3.6**, Regions are listed alphabetically from left to right. Tests[45] on misoperation rates found the statistically significant year-to-year changes shown in **Figure 3.6** by arrows. Red arrows signify increased rates (a declining performance), and green arrows signify decreased rates (an improving performance).

[44] Year-over-year changes in historical rates shown in this report reflect improvements in data quality resulting from the standardization and automation of the collection of protection system operations and misoperations data in 2016.

[45] Large sample test on population proportions at the 0.05 significance level

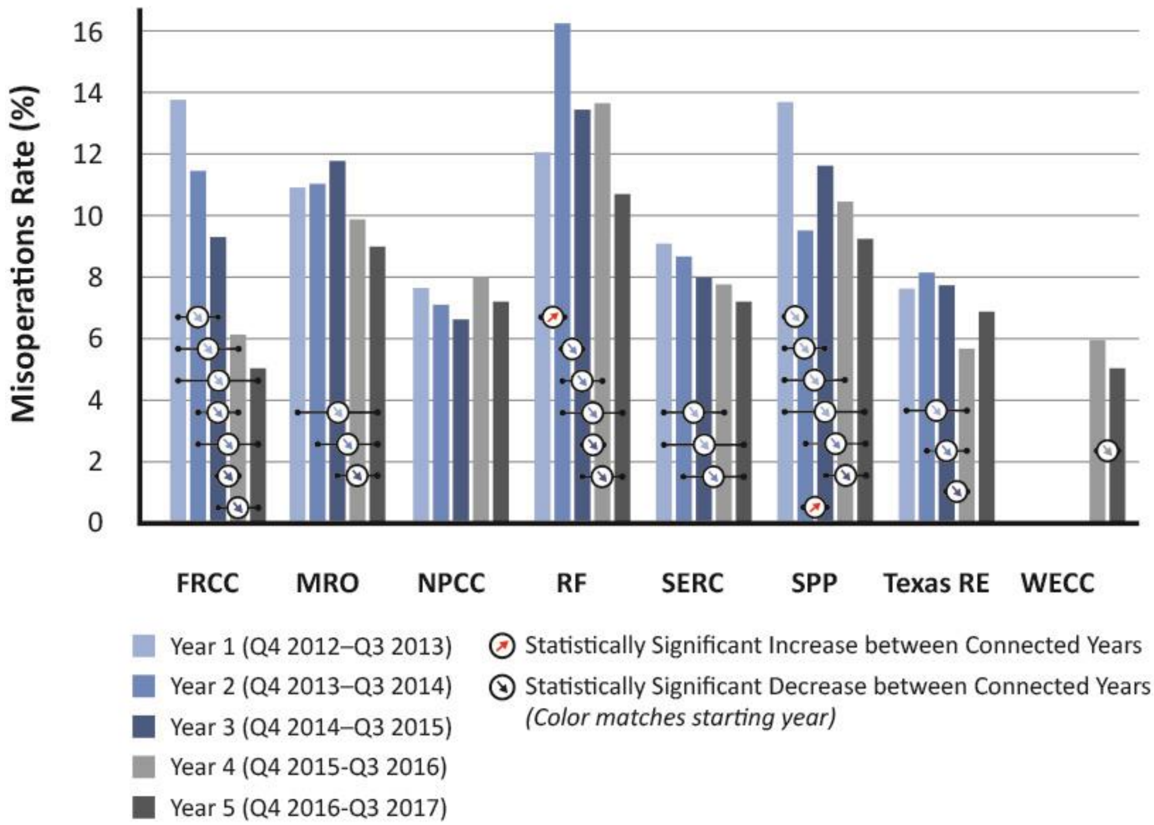


Figure 3.6: Year-Over-Year Changes in Misoperation Rate by Region

The annual changes in NERC's misoperation rate are shown in **Figure 3.7**. For Year 4, the misoperation rate is calculated in two ways: for seven Regions (excluding WECC), and for all eight Regions (WECC misoperation and operation counts included for Q2 and Q3 2016). For Year 5, the misoperation rate is calculated in two ways: for seven Regions (excluding WECC) and for all eight Regions including WECC.

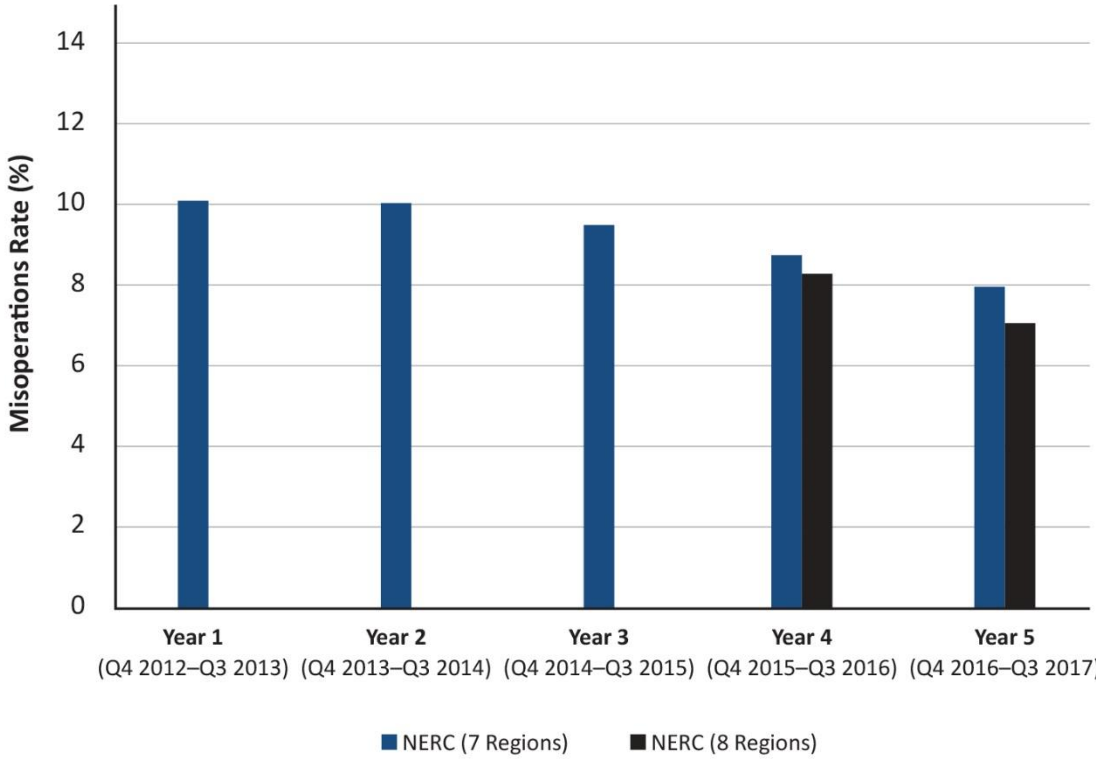


Figure 3.7: Year-Over-Year Changes in NERC's Misoperation Rate

Tests[46] on misoperation rates found the following statistically significant year-to-year changes:

- **NERC (Seven Regions):** decreases from Year 1 to Years 4 and 5, from Year 2 to Years 4 and 5, from Year 3 to Years 4 and 5, and from Year 4 to Year 5.
- **NERC (Eight Regions):** decrease from Year 4 to Year 5.

Table 3.2 lists the regional misoperation rates that are shown graphically in **Figure 3.6** and **Figure 3.7**.

Table 3.2: Misoperation Rate by Region and NERC by Year

Region	Year 1 (Q4 2012 through Q3 2013)	Year 2 (Q4 2013 through Q3 2014)	Year 3 (Q4 2014 through Q3 2015)	Year 4 (Q4 2015 through Q3 2016, Seven Regions)	Year 4 (Q4 2015 through Q3 2016, Last Two Quarters with WECC)	Year 5 (Q4 2016 through Q3 2017, Seven Regions)	Year 5 (Q4 2016 through Q3 2017, Eight Regions)
FRCC	13.7%	11.4%	9.3%	6.1%	6.1%	5.4%	5.4%
MRO	10.9%	11.0%	11.8%	9.9%	9.9%	8.8%	8.8%
NPCC (Q1 2013 to Q3 2017)	7.6%	7.1%	6.6%	8.0%	8.0%	7.2%	7.2%

[46] Large sample test on population proportions at the 0.05 significance level

Table 3.2: Misoperation Rate by Region and NERC by Year							
Region	**Year 1 (Q4 2012 through Q3 2013)**	**Year 2 (Q4 2013 through Q3 2014)**	**Year 3 (Q4 2014 through Q3 2015)**	**Year 4 (Q4 2015 through Q3 2016, Seven Regions)**	**Year 4 (Q4 2015 through Q3 2016, Last Two Quarters with WECC)**	**Year 5 (Q4 2016 through Q3 2017, Seven Regions)**	**Year 5 (Q4 2016 through Q3 2017, Eight Regions)**
RF	12.1%	16.2%	13.4%	13.8%	13.8%	10.7%	10.7%
SERC	9.1%	8.7%	8.0%	7.8%	7.8%	7.2%	7.2%
SPP	13.7%	9.5%	11.6%	10.4%	10.4%	9.3%	9.3%
Texas RE	7.6%	8.2%	7.8%	5.7%	5.7%	7.0%	7.0%
WECC (Q2 2016 to Q3 2017)					6.0%		4.6%
NERC	**10.2%**	**10.1%**	**9.5%**	**8.8%**	**8.3%**	**8.0%**	**7.1%**

Figure 3.8 shows the regional analysis for the aggregate of the top three causes of misoperations: Incorrect Settings/Logic/Design Errors, Relay Failures/Malfunctions, and Communication Failures over the five years. Tests[47] on misoperation rates, for the top three causes, were conducted to determine the statistically significant year-to-year changes. Red arrows signify increased rates and the other arrows signify decreased rates.

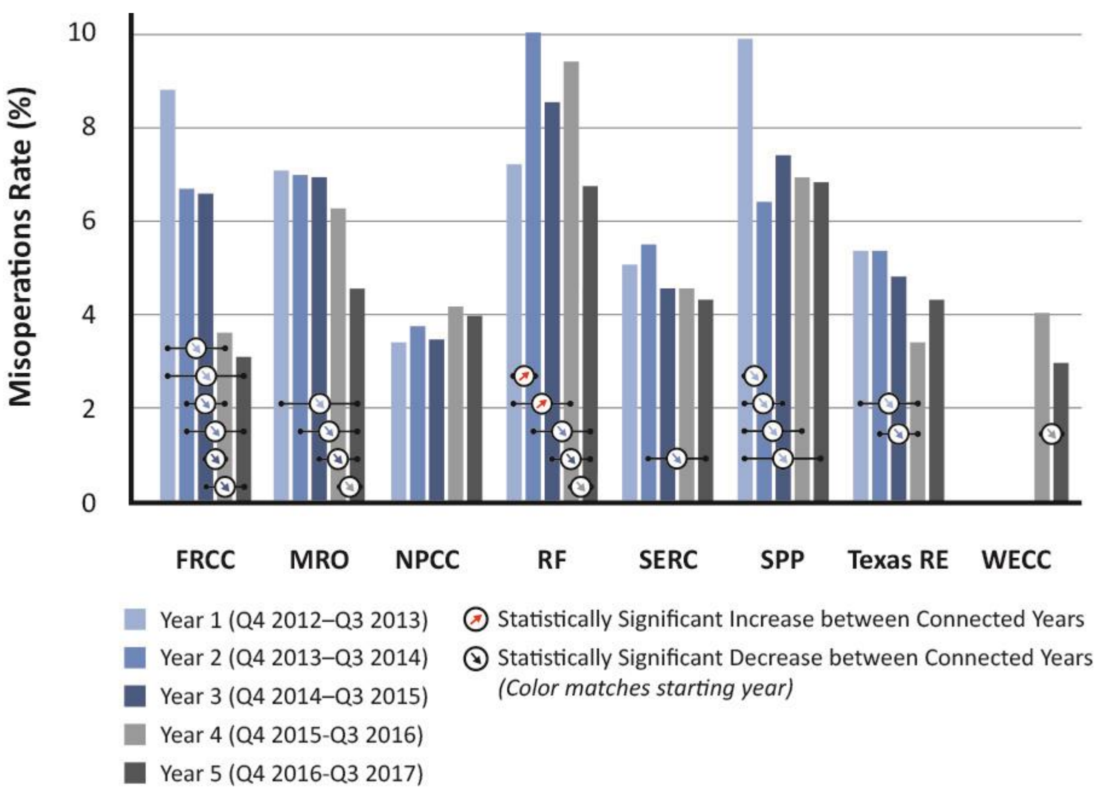


Figure 3.8: Year-Over-Year Changes in Misoperation Rate for Top Three Causes Combined by Region

[47] Large sample test on population proportions at the 0.05 significance level

The annual changes in NERC's misoperation rate for the top three causes of misoperations combined are shown in **Figure 3.9**. For Years 4 and Year 5, the misoperation rate is calculated two ways: for seven Regions (excluding WECC) and for all eight Regions (WECC misoperation and operation counts included beginning Q2 of 2016).

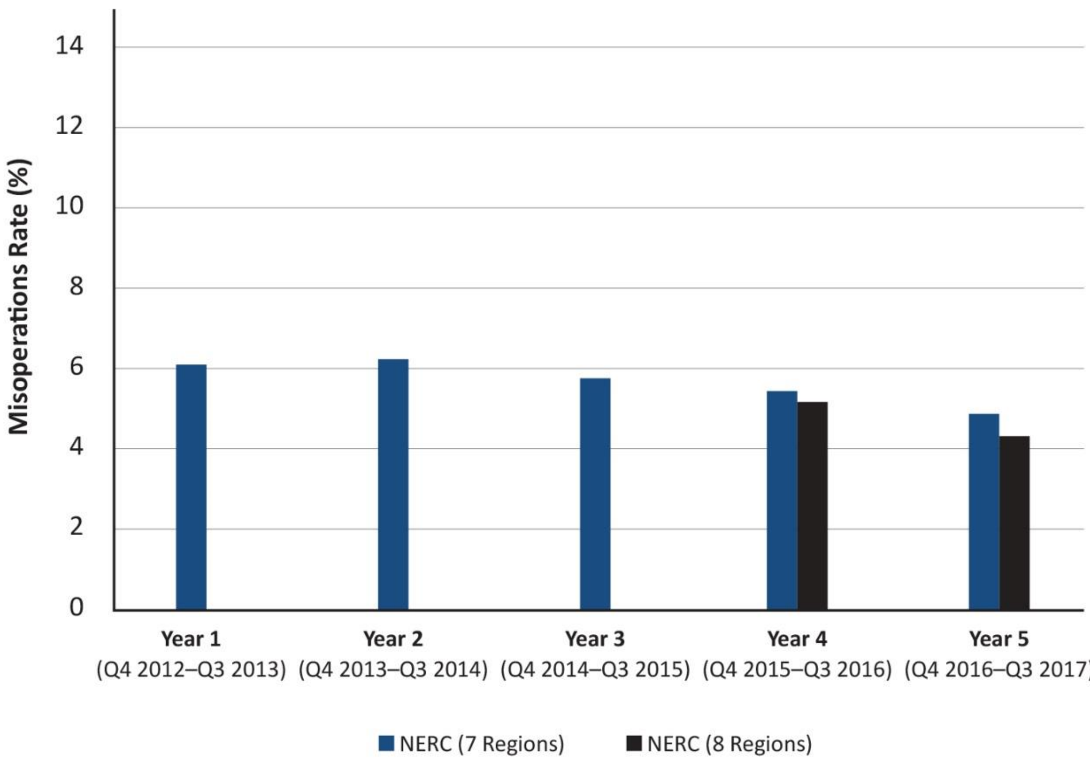


Figure 3.9: Year-Over-Year Changes in NERC's Misoperation Rate for Top Three Causes Combined

Tests[48] on misoperation rates found the following statistically significant year-to-year changes:

- **NERC (Seven Regions):** decreases from Year 1 to Years 4 and 5, from Year 2 to Years 4 and 5, from Year 3 to Years 4 and 5, and from Year 4 to Year 5.
- **NERC (Eight Regions):** decrease from Year 4 to Year 5.

Actions to Address Misoperations

To increase awareness and transparency, NERC and the REs will continue to conduct industry webinars on protection systems and document success stories on how Generator Owners (GOs) and Transmission Owners (TOs) are achieving high levels of protection system performance. The quarterly protection system misoperation trends of NERC and the REs can be viewed on NERC's website.[49] Summaries of the REs' actions to address misoperations can be found in **Appendix E**.

NERC introduced the Misoperations Information Data Analysis System (MIDAS) in 2016, a data collection site for misoperations. In 2017, NERC replaced the data collection site with an application that allows the users to review, create, or update existing records with improved data validation and reporting through a secure portal integrated with NERC's ERO User Management System. NERC collaborates closely with the Regions to impart best practices and improve data collection.

48 Large sample test on population proportions at the 0.05 significance level
49 http://www.nerc.com/pa/RAPA/ri/Pages/ProtectionSystemMisoperations.aspx

The ERO Enterprise determined from EA data and from industry expertise that a sustained focus on education regarding the instantaneous ground overcurrent protection function and on improving relay system commissioning tests were actionable and could have a significant effect. The relay ground function accounted for 11 misoperations in 2014, causing events that were analyzed due to voluntary entity reporting and cooperation. That was reduced to six event-related misoperations in 2015 and further reduced to one event-related operation in 2016. Similarly, one Region experienced a statistical improvement in relay misoperations from 2013–2014 and maintained this performance through 2016. This performance followed regional efforts that targeted a reduction of communication failures.

Based on the statistically significant increase in the total correct operation rate and the reduction in NERC's misoperation rate from 8.7 percent in 2016 to 8.0 percent in 2017, the performance trend for this metric is considered to be improving. Further statistical analysis can be found in **Appendix E**.

M-12 through M-14 Automatic AC Transmission Outages

Background

These metrics measure the impacts of Failed Protection System, Human Error, and Failed AC Substation Equipment respectively as factors in the performance of the ac transmission system. The metrics use the TADS data and definitions. The metrics were enhanced in 2014 and 2015 to be consistent with the collection of BES data in TADS, to align with the definition of the BES, and include some equipment to 100 kV.[50] With the revisions, the metrics include any BES ac transmission element outages that were initiated by the following:

- **M-12:** TADS ICC of Failed Protection System Equipment
- **M-13:** TADS ICC of Human Error
- **M-14:** TADS ICC of Failed AC Substation Equipment

Each metric is calculated for ac circuits and transformers separately in submetrics as follows:

- **Submetric 1:** The continued normalized count (on a per circuit basis) of 200 kV+ ac transmission element outages (i.e., TADS momentary and sustained automatic outages) that were initiated by Failed Protection System Equipment, Human Error, or Failed AC Substation Equipment.
- **Submetric 2:** Beginning January 1, 2015, the normalized count (on a per circuit basis) of 100 kV+ ac transmission element outages (i.e., TADS sustained automatic outages) that were initiated by Failed Protection System Equipment, Human Error, or Failed AC Substation Equipment.

Assessment M-12 through M-14 AC Circuit Outages

Overall, the performance of M-12 through M-14 ac circuit outages is improving.[51] A five-year time trend for 2013–2017 is decreasing (improving) for all submetrics except M-13 Sub-metric 2 (Human Error), which is found to be inconsistent.

Figure 3.10 presents changes for Sub-metric 1 of M-12 to M-14: the annual frequencies of automatic outages per 200 kV+ ac circuit for the time period 2013–2017. The green arrows indicate overall improving (i.e., decreasing) time trend for the five years determined from the statistical analysis as described below:

[50] The BES definition can be found at the following location: http://www.nerc.com/pa/RAPA/Pages/BES.aspx

[51] For the statistical assessments, the occurrences of automatic outages are assumed to follow the Poisson distribution (see R. Billinton and R. N. Allan. Reliability Evaluation of Power Systems. Second Edition. Plenum Press, New York, 1996, and references therein).

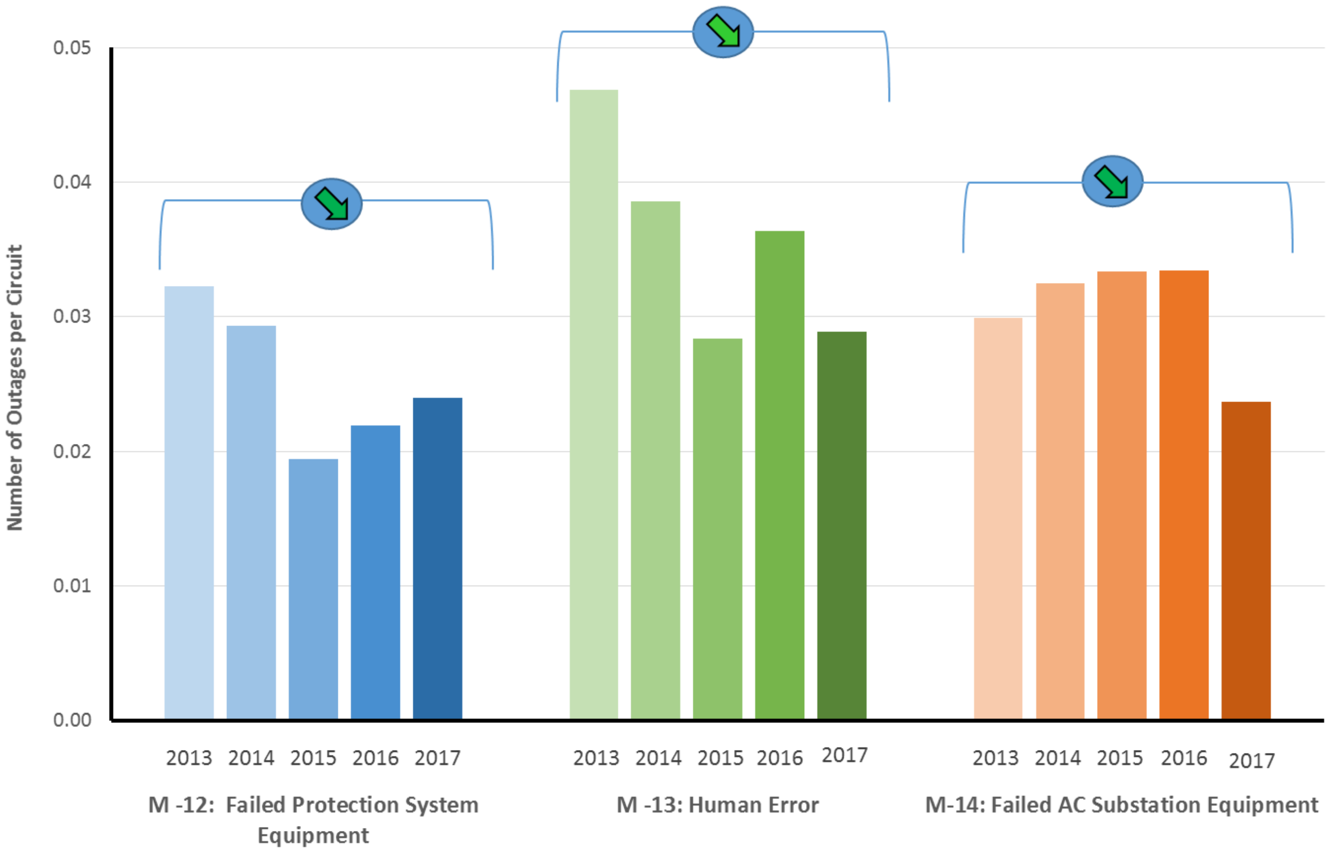


Figure 3.10: 200 kV+ AC Circuit Outages Initiated by Failed Protection System Equipment, Human Error, and Failed AC Substation Equipment (M-12 through M-14, Sub-Metric 1)

The calculated annual outage frequencies, per ac circuit, were tested to identify significant year-to-year changes of the reliability metric. Below is a summary of Submetric 1 performance for the five years:

- **M-12:** Failed Protection System Equipment initiated outages:
  - There was no statistically significant decrease from 2014–2015.
  - There were no significant changes from 2013–2014, from 2015–2016, or from 2016–2017.
  - The 2017 outage frequency is significantly lower than in 2013 and 2014 and not statistically significantly higher than in 2015 and 2016.
- **M-13:** Human Error initiated outages:
  - There was a year-to-year decrease with no statistically significant change from 2013–2014.
  - There were statistically significant decreases from 2014–2015 and from 2016–2017.
  - There was a statistically significant increase from 2015–2016.
  - The 2017 outage frequency is significantly lower than in 2013, 2014, and 2016 and statistically similar to 2015.
- **M-14:** Failed AC Substation Equipment initiated outages:
  - There were no statistically significant changes from 2013–2014, from 2014–2015, or from 2015–2016.
  - There was a statistically significant decrease from 2016–2017.

- The 2017 outage frequency is significantly lower than in each year from 2013–2016.

Figure 3.11 presents changes for Submetric 2 of M-12 to M-14: the annual frequencies of sustained automatic outages per 100 kV+ ac circuit for the time period 2015–2017. The green arrows indicate overall improving (i.e., decreasing) time trend for the three years determined from the statistical analysis as described below. No arrow indicates an inconsistent time trend.

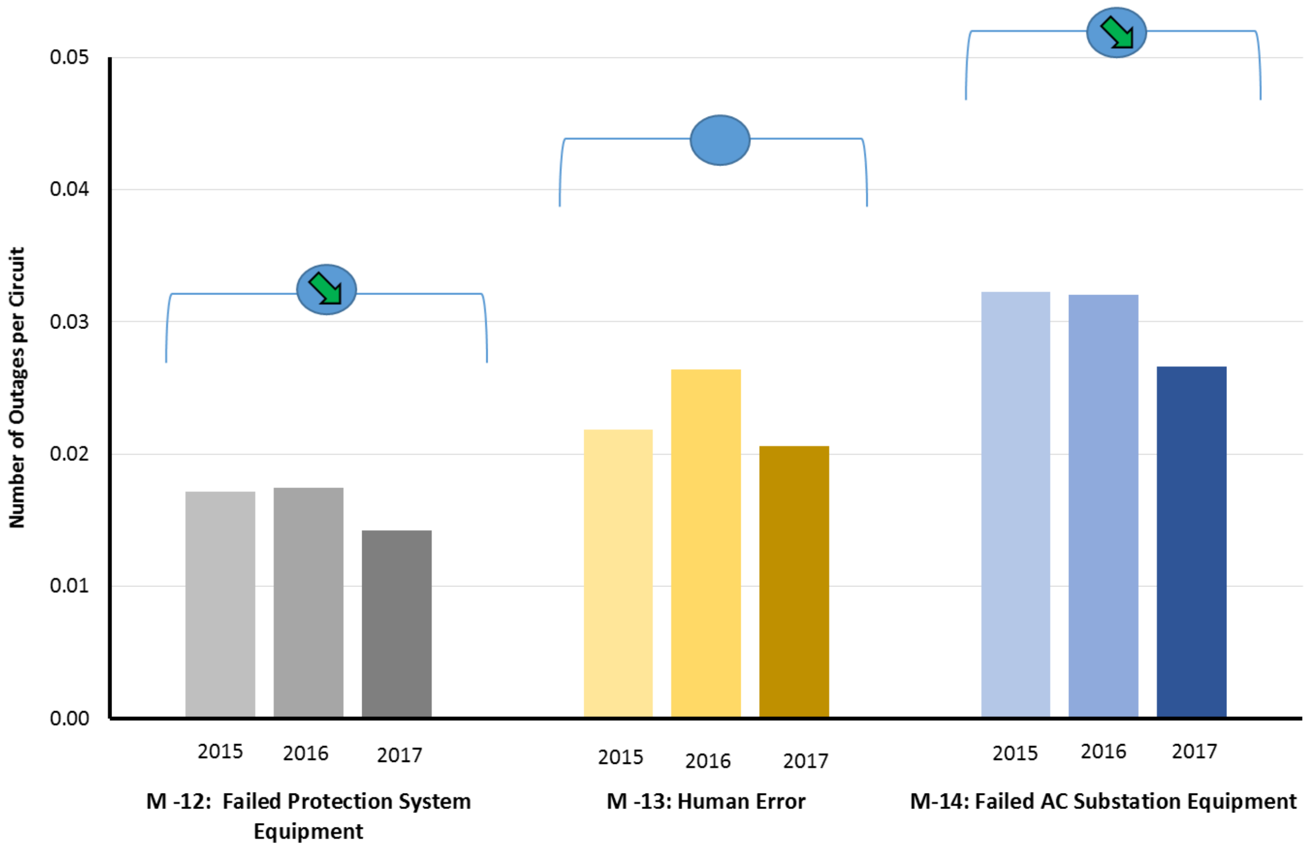


Figure 3.11: 100 kV+ AC Circuit Outages Initiated by Failed Protection System Equipment, Human Error, and Failed AC Substation Equipment (M-12 through M-14, Sub-Metric 2)

The calculated annual outage frequencies per ac circuit were tested to identify significant year-to-year changes of the reliability metric. Below is a summary of Submetric 2 performance for the three years:

- **M-12:** Failed Protection System Equipment initiated outages:
  - There was no significant changes from 2015–2016.
  - The 2017 outage frequency is significantly lower than in 2015–2016.
- **M-13:** Human Error initiated outages:
  - There was a statistically significant increase from 2015–2016.
  - There was a statistically significant decrease from 2016–2017.
  - The 2017 outage frequency is significantly lower than in 2016 and statistically similar to 2015.
- M-14: Failed AC Substation Equipment initiated outages:
  - There was no significant change from 2015–2016.

- There was a statistically significant decrease from 2016–2017.
- The 2017 outage frequency is significantly lower than in 2015–2016.

Assessment M-12 through M-14 Transformer Outages

Overall, the performance of M-12 through M-14 transformer outages is improving. A five-year time trend for 2013–2017 is decreasing (improving) for all submetrics except M-12 Submetric 2 (Failed Protection System Equipment) with no changes in performance.

Figure 3.12 presents changes for Submetric 1 of M-12 to M-14: the annual frequencies of automatic outages per 200 kV+ transformers for the time period 2013–2017. The green arrows indicate overall improving (i.e., decreasing) time trend for the five years determined from the statistical analysis as described below.

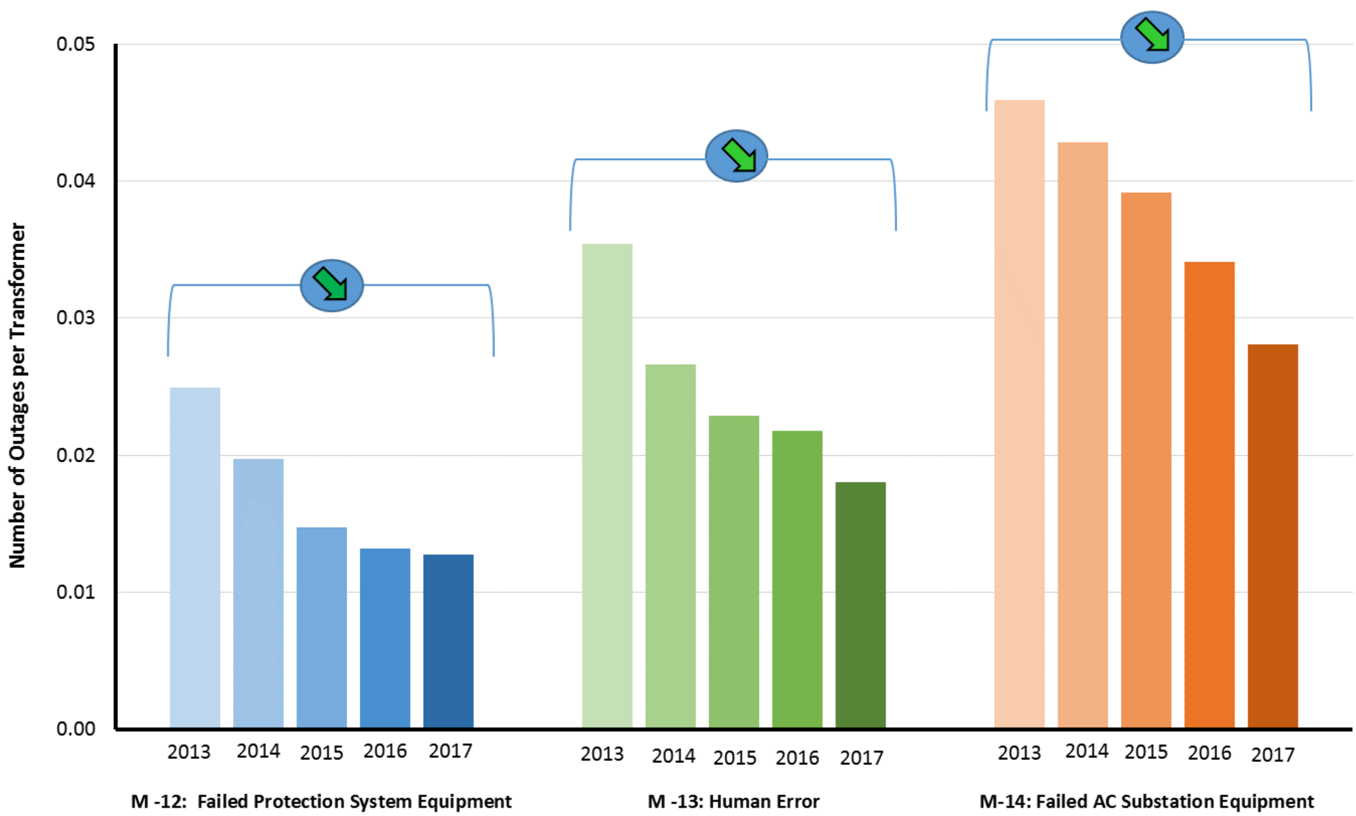


Figure 3.12: 200 kV+ Transformer Outages Initiated by Failed Protection System Equipment, Human Error, and Failed AC Substation Equipment (M-12 through M-14, Sub-Metric 1)

The calculated annual outage frequencies, per transformer, were tested to identify significant year-to-year changes of the reliability metric. Below is a summary of Submetric 1 performance for the five years:

- **M-12:** Failed Protection System Equipment initiated outages:
  - There were year-to-year decreases from 2013–2016 with no statistically significant changes for any pair of consecutive years.
  - There was no change from 2016–2017.
  - The 2017 outage frequency is significantly lower than in 2013 and statistically similar to 2015–2016.
- **M-13:** Human Error initiated outages:

- There were annual decreases from 2013–2017.
- There was a statistically significant decrease from 2013–2015.
- The 2017 outage frequency is lower than in each year from 2013–2016 and statistically significantly lower than in 2013 and 2014.

- **M-14:** Failed AC Substation Equipment initiated outages:
  - There were year-to-year decreases from 2013–2017 with no significant changes between any two consecutive years.
  - The 2017 outage frequency is lower than in any other year and statistically significantly lower than in 2013–2015.

Figure 3.13 presents changes for Submetric 2 of M-12 to M-14: the annual frequencies of sustained automatic outages per 100 kV+ transformer for the time period 2015–2017. The green arrows indicate overall improving (i.e., decreasing) time trend for the three years determined from the statistical analysis as described below. A white arrow indicates no change in performance for the three years.

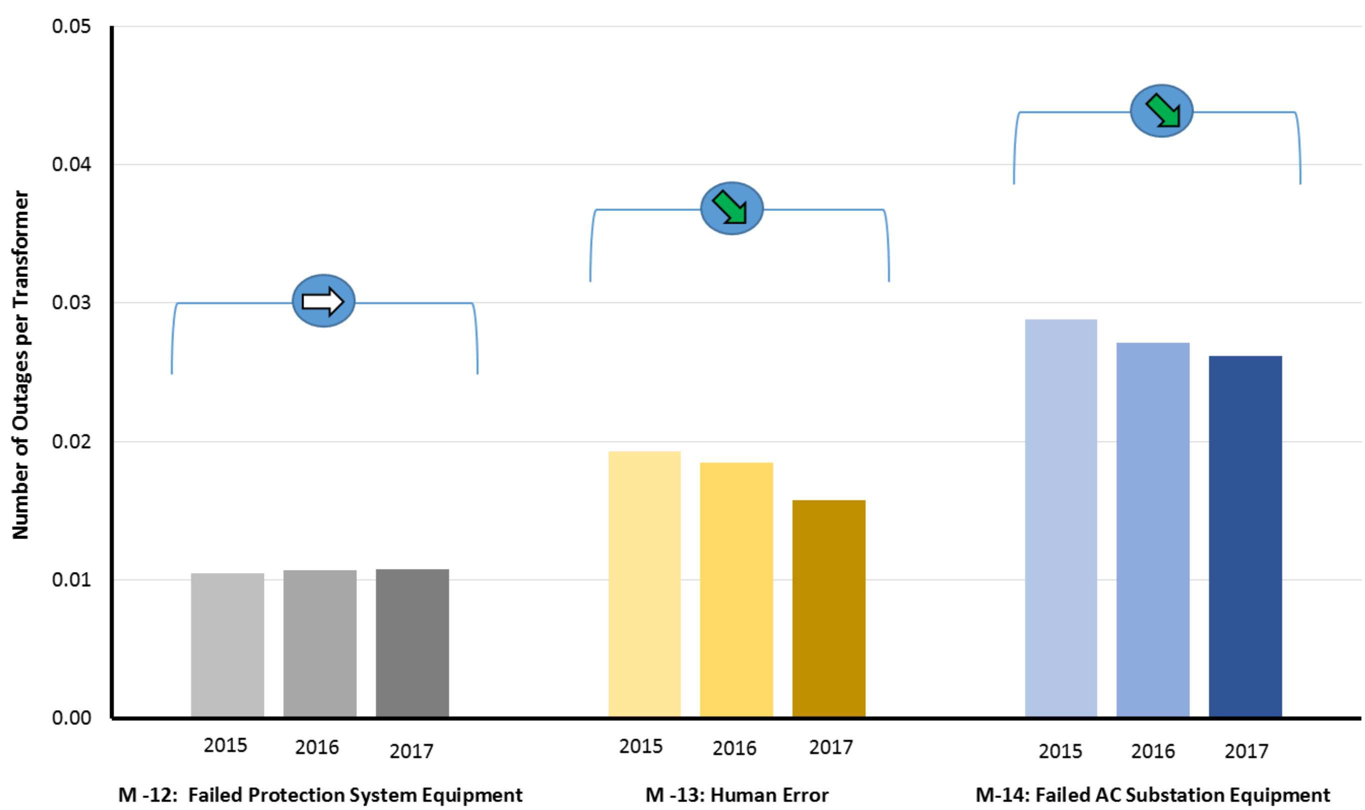


Figure 3.13: 100 kV+ Transformer Outages Initiated by Failed Protection System Equipment, Human Error, and Failed AC Substation Equipment (M-12 through M-14, Sub-Metric 2)

The calculated annual outage frequencies per transformer were tested to identify significant year-to-year changes of the reliability metric. Below is a summary of Submetric 2 performance for the three years:

- **M-12:** Failed Protection System Equipment initiated outages:
  - There were no significant changes by year.

- **M-13:** Human Error initiated outages:
  - There was a decrease from 2015–2016 and from 2016–2017.
  - There were no significant changes by year.
  - The 2017 outage frequency is lower than in 2015–2016.
- **M-14:** Failed AC Substation Equipment initiated outages:
  - There was a decrease from 2015–2016 and from 2016–2017.
  - There were no significant changes by year.
  - The 2017 outage frequency is lower than in 2015–2016.

M-15 Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment

Background

This metric measures the impact of Failed AC Circuit Equipment as one of many factors in the performance of ac transmission systems. Metric M-15 follows the same methodology described for M-12 through M-14 except that it uses a normalization based on a line length and is defined for ac circuits only. As with M-12 through M-14, the sub-metrics are calculated as follows:

- **Submetric 1:** The continued normalized count (on a per 100 circuit-mile basis) of 200 kV+ ac transmission circuit outages (i.e., TADS momentary and sustained automatic outages) initiated by Failed AC Circuit Equipment
- **Submetric 2:** Beginning January 1, 2015, the normalized count (on a 100 per circuit-mile basis) of 100 kV+ ac transmission circuit outages (i.e., TADS sustained automatic outages) initiated by Failed AC Circuit Equipment

Assessment

M-15 performance was inconsistent for both submetrics as demonstrated in **Figure 3.14** and **Figure 3.15**. The observed changes in the calculated frequencies cannot be statistically analyzed due to a mile-based normalization (these numbers do not represent observations in a statistical sample) and can be only compared numerically.

Figure 3.14 shows changes in M-15 Submetric 1, the annual frequency of automatic outages per hundred miles for ac circuits of 200 kV+ for the time period 2013–2017.

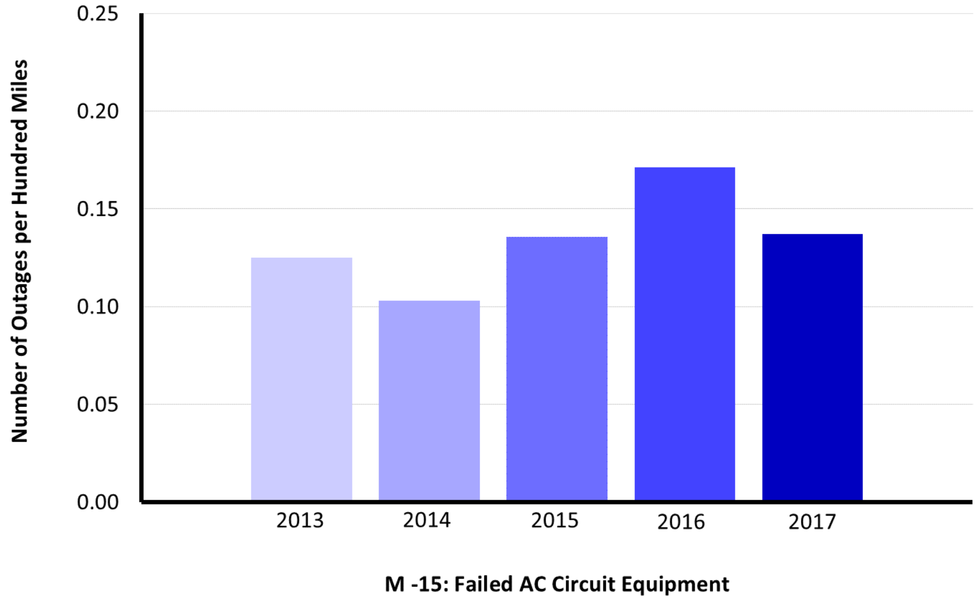


Figure 3.14: 200 kV+ AC Circuit Outages Initiated by Failed AC Circuit Equipment (M-15)

Figure 3.15 shows changes in M-15 Submetric 2, the annual frequency of sustained automatic outages per hundred miles for ac circuits of 100 kV+ for the time period 2015–2017.

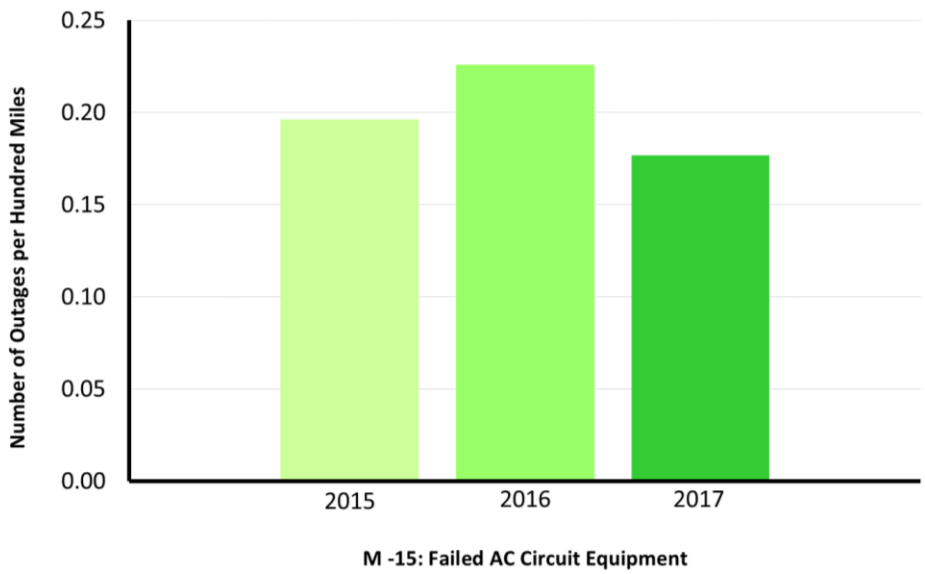


Figure 3.15: 100 kV+ AC Circuit Outages Initiated by Failed AC Circuit Equipment (M-15)

M-16 Element Availability Percentage and Unavailability Percentage

Background

The availability percentage and unavailability percentage metric determines the percentage of BES ac transmission elements that are available or unavailable when outages due to automatic and non-automatic events are considered.

Originally, there were two metrics: one to calculate availability and one to calculate unavailability. These were combined into one metric in 2013. This metric continues to focus on availability of elements at 200 kV+ because non-automatic (operational) outages, included in the calculation of unavailability, are not collected for TADS elements below 200 kV. Therefore, the reporting voltage levels for this metric did not change.

Assessment

The performance trend of M-16 for ac circuits is steady (all year-to-year changes are below 0.1 percent), and the trend is found to be improving for transformers.

For both transmission element types (ac circuits and transformers) only charts for unavailability are shown because annual unavailability can be broken down by outage type (unlike availability). A part of unavailability due to planned outages cannot be calculated due to the 2015 changes in TADS data collection and is nether shown nor analyzed.

Figure 3.16 presents 200 kV+ ac circuit unavailability as a percentage for the time period 2013–2017.

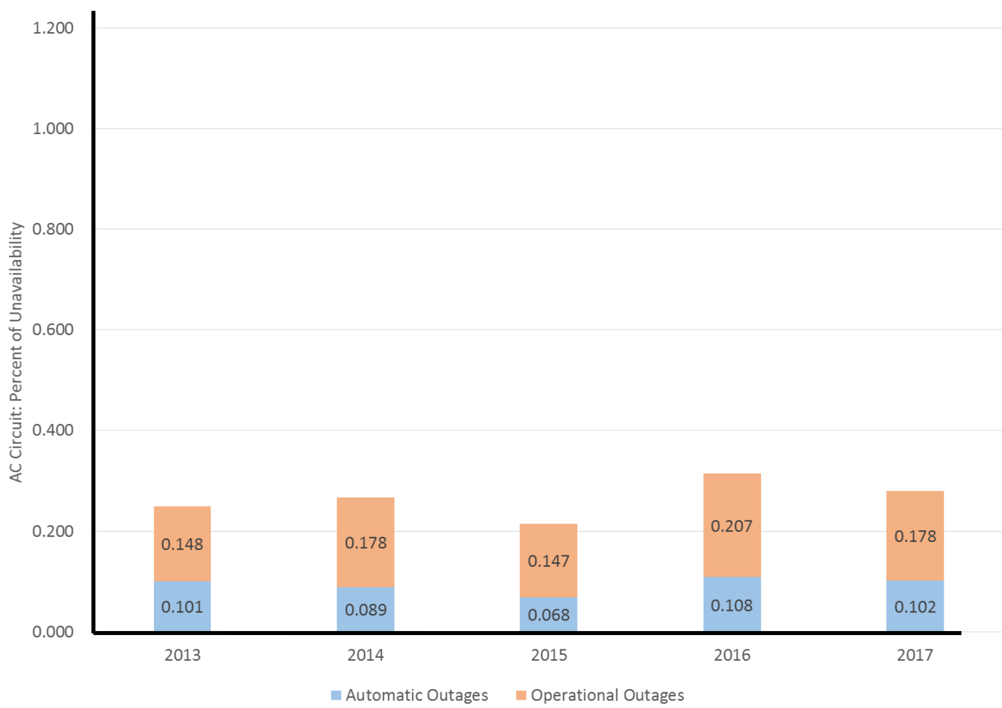


Figure 3.16: 200 kV+ AC Circuit Unavailability by Year and Outage Type

The 2017 ac circuit combined unavailability due to operational and automatic outages was the second largest from 2013–2017. Overall, over the five years, the ac circuit unavailability remained steady with range of changes at 0.1 percent (between 0.22 percent in 2015 and 0.32 in 2016).

Figure 3.17 presents 200 kV+ TADS transformer unavailability as a percentage for the time period 2013–2017.

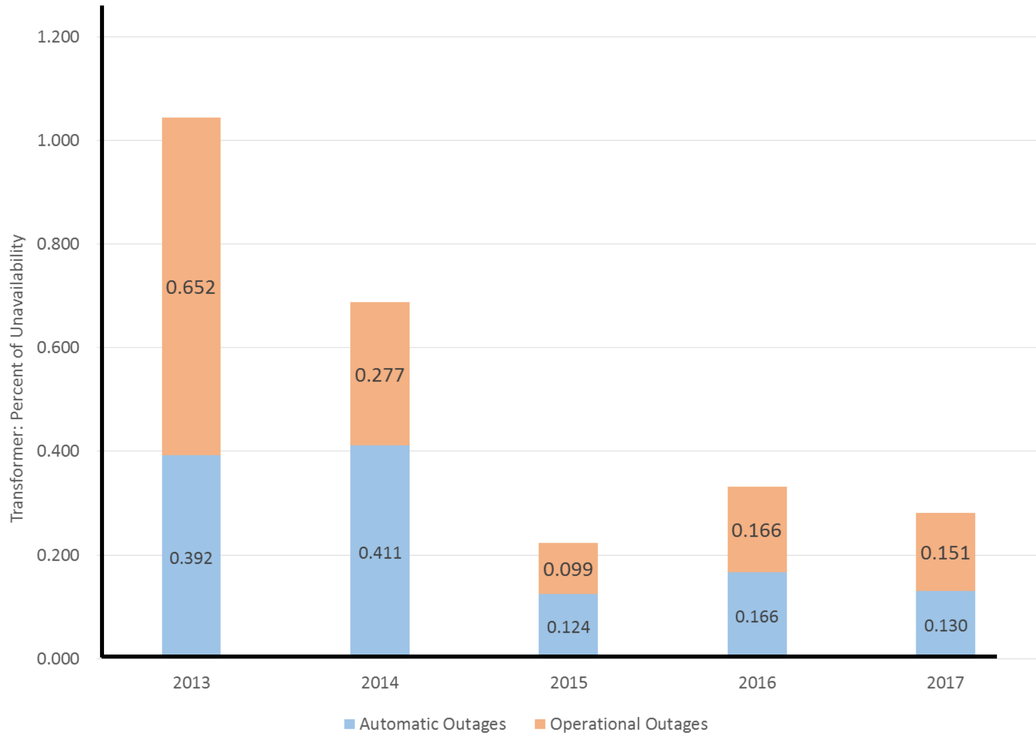


Figure 3.17: 200 kV+ Transformer Unavailability by Year and Outage Type

Transformer unavailability due to operational and automatic outages in 2017 was the second lowest from 2013 to 2017 with an overall improving trend from 2013–2017. It is worth noting that a sizable change in transformer inventory occurred in 2015 due to changes in TADS reporting and that additional year-over-year data will help to confirm the observed improving trend.

Chapter 4: Enforcement Metrics for Risk and Reliability Impact

This chapter provides compliance-based metric results for 2017 by using data through the end of March 2018. The *ERO Enterprise Compliance Monitoring and Enforcement Program Annual Report*[52] *(CMEP 2017)* is the authoritative source document for this data and supplies this information with full background narrative and graphics. The annual enforcement document refers to Serious Risk Violations and Noncompliance with Impact. For purposes of this report, they are referred to as Compliance Process 1 and Compliance Process 2 metrics, respectively. These track compliance violation risk and compliance violation impact.

Analysis reveals a decreasing trend in the 12-month rolling average of Compliance Process 1 serious risk violations from 2012 through the end of 2018, Q1. However, it is important to remember that there is time required to fully understand serious risk violations and reach disposition, which may include the filing of a full notice of penalty. In the future, there may be additional serious risk violations added to the count of this metric as reported violations are fully analyzed and reach disposition.

Analysis of violations with impact Compliance Process 2 finds that the rate for the same time period remains constant at a relatively low level. Again, as not all reported noncompliances have reached final disposition, this metric also remains subject to change.

As with many BPS reliability issues, annual analysis of enforcement metrics has sometimes highlighted HP as a key issue. The *CMEP 2016*[53] report targeted this with additional analysis.[54] HP analysis was not repeated for *CMEP 2017*, but determination of underlying root causes for HP issues[55] is always emphasized during analysis of individual violations.

---

[52] See https://www.nerc.com/pa/comp/Reports%20DL/2017%20NERC%20Compliance%20Monitoring%20Enforcement%20Program.pdf for the 2017 edition.

[53] https://www.nerc.com/pa/comp/Reports%20DL/2016%20NERC%20Compliance%20Monitoring%20Enforcement%20Program.pdf

[54] http://www.nerc.com/pa/comp/CE/Compliance%20Violation%20Statistics/Analysis%20of%20Serious%20Risk%20Violations%20with%20an%20Impact.pdf

[55] HP emerges as an issue in multiple aspects of BPS performance. NERC and NATF jointly conduct the annual Improving Human Performance on the Grid conference in Atlanta in late March, and Regions and various industry groups also conduct high quality HP conferences and training to address this need.

Chapter 5: Event Analysis

This chapter focuses on three significant outcomes from event analysis in 2017: reliability and resiliency aspects of two hurricanes (Harvey and Irma), an update on inverter-based resource performance, and the solar eclipse. **Appendix G** highlights other significant events analysis activity and provides details on, for example, the 179 events in 2017 that analysis confirmed to be low level Category 1.

Each of the hurricanes comprised a NERC Category 5 event, the highest severity within the EA Process[56], which should not be confused with their Category 4 Hurricane classifications.[57] Harvey evokes perhaps the surprising description by some as a "water event" rather than a "wind event," not necessarily a distinction expected to be drawn for a hurricane. It presented unexpected challenges to service restoration and required restoration and recovery techniques that were never used before in the Houston area. Irma highlights resiliency impacts that can be achieved by hardening the system before challenges arise. For example, customer electric outages for FP&L exceeded those of its highest number for a prior hurricane by greater than 1.2 million (4.454 million versus 3.241 million), yet it accomplished restoration in 10 days as opposed to 18 days for the prior storm.[58] One key finding from these events was the importance of deploying drones as an effective way to identify field conditions and required restoration activities.

This chapter also updates the *State of Reliability 2017* risk resulting from unexpected and undesired inverter performance. The risk is the loss of significant amounts of generation during certain system conditions when BPS reliability may depend on their output. Collaborative regulatory and industry actions proved successful in 2017 to address trips due to inappropriate frequency calculations. However, a subsequent incident occurred, revealing new risks regarding cessation of current injection into the system for specific voltage rather than frequency excursions. A team is developing mitigation approaches for these and any other emergent issues.

Pertaining to the total solar eclipse of 2017, effective mitigation plans prevented it from threatening reliability of the BPS and ensured that it unfolded as a non-event.

Weather (Hurricanes—Wind and Water Events)

Hurricane Harvey

Hurricanes typically evoke thoughts of damaging winds and water with neither predominant and the size of the storm surge at the forefront of any discussion of flooding. Hurricane Harvey[59] broke that pattern. Although Harvey made landfall on the Texas coast as a Category 4 Hurricane, one weather media authority's website first highlights that, "Harvey was a catastrophic flood disaster in southeast Texas"[60] and only later mentions its 130 mph winds. It is clear that a key characteristic that should be emphasized about any hurricane is whether it was a typical wind and water event or primarily one over the other. The delineation is vital to understanding restoration and recovery challenges and performance: Harvey comprised a water and wind event on the Texas coast with a record breaking storm surge and developed into a water event further inland, particularly for the Houston area.[61] The storm inflicted massive

---

[56] The EA Process can be found at the following location: https://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx

[57] The NOAA hurricane classifications can be found at the following location: https://www.nhc.noaa.gov/aboutsshws.php

[58] FP&L's Grid Hardening and Hurricane Response can be found at the following location: https://www.energy.gov/sites/prod/files/2018/02/f49/2_Emergency%20Response%20and%20Resilience%20Panel%20-%20Tom%20Gwaltney%2C%20FPL.pdf (See slide 4.)

[59] The August 2017 *Hurricane Harvey Event Analysis Report* can be found at the following location: https://www.nerc.com/pa/rrm/ea/Pages/August-2017-Hurricane-Harvey-Event-Analysis-Report.aspx

[60] A recap of Hurricane Harvey can be found at the following location: https://weather.com/storms/hurricane/news/tropical-storm-harvey-forecast-texas-louisiana-arkansas

[61] The Hurricane Harvey Response and Restoration presentation can be found at the following location: https://www.energy.gov/sites/prod/files/2018/02/f49/2_Emergency%20Response%20and%20Resilience%20Panel%20-%20Steve%20Greenley%2C%20CenterPoint%20Energy.pdf (See slide 5.)

disruptions on the electric power system in the Corpus Christi, Houston/Galveston, and Beaumont/Port Arthur areas; damaging 85 substations, over 850 transmission line structures, and over 6,000 distribution poles. It caused 225 transmission line outages until it stalled and degraded into a tropical storm, causing excessive rain (40–50 inches) in parts of southeastern Texas and flooding large areas of Houston and inland as far as Austin.

Following a hurricane, utility and contract restoration crews normally provide rapid response to damaged areas, but following Harvey, unanticipated continued flooding did not allow access into many areas. For example, the water continued to rise in the greater Houston area as the massive inland rainfall flowed toward the Gulf of Mexico. The extensive and extended presence of flooding and storm debris challenged the recovery process. Utilities met the challenges in novel ways for some areas while relying on mutual assistance agreements. A staple of Florida and Texas coastal restorations, airboats arrived for the first time in the Houston area to aid in assessing damage in its flooded areas. Amphibious vehicles proved quite valuable also.

However, drones provided the greatest versatility. Utilities mobilized drones, some of which mutual assistance agreements supplied, to perform damage assessments on inaccessible substations as well as transmission and distribution lines. The drones used infrared capability to identify which equipment needed further inspection and which could be trusted without it. Drones greatly accelerated and enhanced real-time situational awareness and assessments using their information enabled efficient dispatch of restoration crews to accessible locations. Drones later proved a notable resiliency asset following Hurricane Irma, and the unusual flooding following Harvey emphasized the range of challenges for which they provide exceptional value. CenterPoint alone used 15 drones to track 500 locations in its electrical system following Harvey. As a natural gas and electric utility, CenterPoint responded to 8,246 natural gas emergency orders and performed 1.27 million total electric restorations for Harvey. As a final note on drone versatility, one method, among several, that CenterPoint used in response to the breach of an 18 inch natural gas pipeline under the Neches River was to mount a remote methane leak detector to a drone to monitor resultant river methane levels.

Texas RE and FRCC are leading the development with NERC of a lessons learned document to provide insights into how drones might be even more effectively used in future restorations, including identification of policies and regulations that might change.[62] Close coordination with government agencies and first responders is critical for successful drone use. The document is expected to publish in 2018.

Hurricane Irma

Hurricane Irma's impacts on Florida present a case study in resilience. Following the 2005 hurricane season (which included Hurricane Wilma), the Florida Legislature, Florida Public Service Commission (FPSC), and state utilities, including FP&L, first explored and then implemented a very deliberate hardening of the state electrical infrastructure.[63] Irma gave FP&L the opportunity to prove the worth of the 1.5 billion dollars it invested in strengthening its transmission and distribution system in preparation for the next big storm with FPSC approval.

Irma caused more electric outages than any prior storm. In its immediate aftermath, it caused an estimated 8.96 million customers in five states, Puerto Rico, and the U.S. Virgin Islands to lose electric service at some point, compared with Superstorm Sandy's 8.66 million customers in 2012.[64] In FP&L's service territory alone, 4.45 million

[62] TOs and TOPs make the case that their use increases reliability and resiliency even for routine inspections outside of emergency operations.
[63] https://www.energy.gov/sites/prod/files/2017/01/f34/Evaluating%20Proposed%20Investments%20in%20Power%20System%20Reliability%20and%20Resilience%20Preliminary%20Results%20from%20Interviews%20with%20Public%20Utility%20Commission%20Staff.pdf. See **Appendix E** for information on the State of Florida's hurricane preparation and response.
[64] Information regarding power outages during Hurricane Irma can be found at the following location: https://blog.ucsusa.org/julie-mcnamara/hurricane-irma-power-outage

customers lost power, contrasted with the previous high of 3.24 million during Hurricane Wilma. Importantly though, the utility evidenced increased resiliency as it cut total restoration time from 18 days for Wilma to 10 days for Irma.[65]

Inverter-Based Generation Update

State of Reliability 2017 reported that an unplanned loss of approximately 1,200 MW of solar inverter-based resources occurred in August 2016 in the WI. A joint NERC/WECC task force analyzed that event and produced a report,[66] resulting in a NERC alert Level 2: recommendation to industry issued on June 20, 2017. The analysis revealed two major issues with solar PV inverter-based resources. First, a specific manufacturer's inverters were susceptible to erroneous frequency tripping during transmission faults. The manufacturer devised a solution, and the recommendation advised registered entities to contact the inverter manufacturer and implement the changes. Second, manufacturers' inverters employ an operating characteristic in general during abnormal grid voltages referred to as momentary cessation. During cessation, the inverter ceases to inject current into or draw current from the grid. The recommendation advised registered entities with inverters that they must use momentary cessation during abnormal voltages to configure them to restore output after no greater delay than five seconds from the initiation of cessation.

The analysis identified the need for further studies to determine impacts of momentary cessation on reliability as well as other inverter issues that impact the stability of the Interconnections. The NERC OC and PC created a joint task force, the IRPTF in June 2017, to perform that work. The task force is producing a guideline for inverter-based resource performance to support BPS reliability.[67]

Another incident occurred in the WI in October 2017. The NERC report[68] on that disturbance was published in February 2018, and it revealed new inverter-based resource performance issues that are being addressed with a follow up to the first alert: Recommendation to Industry (Loss of Solar Resources during Transmission Disturbances – II).[69] This Recommendation advises entities to do the following:

- Ensure inverters will not trip on transient overvoltage (specific thresholds and guidance are under development).
- Eliminate inverter use of momentary cessation if possible.
- Inject reactive current as necessary to mitigate cases of low voltage.
- In cases for which momentary cessation cannot be eliminated do the following:
  - Reduce the momentary cessation low voltage threshold to the lowest value possible.
  - Reduce the recovery delay to the smallest time period possible.
  - Increase the active power ramp rate to at least 100 percent per second (i.e., return to pre-disturbance active current injection within one second).

[65] A comparison of Hurricane Irma to historical storms can be found at the following location: https://www.energy.gov/sites/prod/files/2018/02/f49/2_Emergency%20Response%20and%20Resilience%20Panel%20-%20Tom%20Gwaltney%2C%20FPL.pdf (See slide 4)

[66] The *1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance* report can be found at the following location: https://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf.

[67] The IRPTF can be found at the following location: https://www.nerc.com/comm/PC/Pages/Inverter-Based-Resource-Performance-Task-Force.aspx

[68] The *900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance* report can be found at the following location: https://www.nerc.com/pa/rrm/ea/Pages/October-9-2017-Canyon-2-Fire-Disturbance-Report.aspx.

[69] The alert can be found at the following location: https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC_Alert_Loss_of_Solar_Resources_during_Transmission_Disturbance-II_2018.pdf

- Coordinate facility and inverter controls to not impede restoration from momentary cessation.

Solar Eclipse

While most of the United States awaited the total eclipse of the sun on August 21, 2017, the electric industry implemented measures to ensure it would not cause electrical outages due to the sudden loss of solar resources. In anticipation of this event, NERC produced a white paper[70] in April 2017 that indicated there would be no projected impacts to the BPS while the industry similarly anticipated that this event would not cause problems. Industry did plan for reduction in solar resources during the event and no issues developed. Entities, including PJM[71] and CAISO,[72] took this opportunity to compare results of the actual event with their study projections.

Adverse weather and inverter performance challenged BPS reliability in 2017, but the weather provided evidence of increased BPS resilience and pointed to potential improvements for future restorations. The inverter issues are driving greater collaborative understanding and improved inverter compatibility with the BPS. Key Findings 1 and 2 and associated recommendations in the **Executive Summary** derive from these events.

[70] The white paper can be found at the following location: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Solar_Eclipse_2017_Final_4-25-17.pdf
[71] The PJM Solar Output During August 21, 2017 Total Solar Eclipse can be found at the following location: https://www.pjm.com/-/media/committees-groups/committees/oc/20170912/20170912-item-15-oc-eclipse-updated-20170831.ashx
[72] The CAISO Performance of ISOs System during August 21, 2017 Eclipse can be found at the following location: https://www.caiso.com/Documents/Performance-ISOSystemsDuringSolarEclipse.pdf

Chapter 6: BES Security Measures

This chapter provides cyber and physical security performance metrics. It further presents metrics on data sharing and a metric on global cyber vulnerabilities. Each metric is followed by contextual information to aid in understanding and application. All information presented resides in the public domain.

The E-ISAC and Security Metrics Working Group—formerly the Bulk Electric System Security Metrics Working Group—have reviewed the metrics and identified trends where possible, recognizing that these results are based on only three years of data. The metrics provide a global and industry-level view of how security risks are evolving and indicate the extent to which the electricity industry is successfully managing these risks. This chapter also provides an overview of a roadmap prepared by the SMWG for the development of additional security metrics in future.

A word of caution: NERC and the E-ISAC consistently maintain accurate public data, which is supported by the E-ISAC's access to protected, confidential data. Other external data sources outside the control of the E-ISAC or NERC to which NERC and the E-ISAC's public data may be compared could be based upon less rigorous data collection by third parties; therefore, direct and quantitative comparisons of the data presented in this report to such third party external data sources may not be complete.

Cyber Security

Security Metric: Reportable Cyber Security Incidents

No reportable cyber security incidents[73] occurred in the last three years, so therefore there are none that caused a loss of load. This does not suggest that the risk of a cyber security incident is low as the number of cyber security vulnerabilities continues to increase (see **Security Metric: Global Cyber Vulnerabilities**). Additional observed and potential risks are detailed in the E-ISAC cyber security data and findings available to those with access to the E-ISAC portal.[74]

Responsible entities must report cyber security incidents to the E-ISAC as required by the NERC Reliability Standard CIP-008-5 Incident Reporting and Response Planning.[75] This metric reports the total number of reportable cyber security incidents that occur over time and identifies how many of these incidents have resulted in a loss of load. It is important to note that any loss of load, whether directly caused by an adversary or intentionally shed as part of the real-time response, will meet the threshold for inclusion in this metric. For example, if load was shed as a result of a loss of situational awareness caused by a cyber incident affecting an entity's energy management system, the incident would be counted even though the cyber incident did not directly cause the loss of load. This metric provides the number of reportable cyber security incidents and an indication of the resilience of the BES to operate reliably and continue to serve load.

Recent Cyber Security Developments

Notice of Proposed Rulemaking

In December 2017, the Federal Energy Regulatory Commission (FERC) issued a notice of proposed rulemaking to direct NERC to broaden CIP-008 to include mandatory reporting of cyber security incidents that compromise, or attempt to compromise, an entity's Electronic Security Perimeter or associated Electronic Access Control or

[73] Ref. NERC Glossary of Terms: "A Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity."

[74] The E-ISAC portal can be found at the following location: https://www.eisac.com/

[75] The Reliability Standard, CIP-008-5 – Cyber Security – Incident Reporting and Response Planning, can be found at the following location: https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=CIP-008-5&title=Cyber%20Security%20-%20Incident%20Reporting%20and%20Response%20Planning&jurisdiction=United%20Stateshttps://

Monitoring Systems (EACMS). FERC proposes that incident reports be sent to ICS-CERT (in addition to the E-ISAC) and that NERC file an annual, public and anonymized summary with FERC. NERC submitted comments in February 2018, supporting the Commission's proposal to broaden reporting requirements but seeking flexibility to gather data without overburdening entities. Whatever additional data may become available from the outcome of these proceedings will undoubtedly influence the collection, reporting, and maturation of future cybersecurity-related measures in future State of Reliability reports and other publications.

E-ISAC Cyber Security Findings

The E-ISAC continues to share relevant cyber security information with its members via the E-ISAC portal. In 2017, the portal included 226 posted cyber bulletins. Over 30 percent of the total number of cyber reports involved phishing incidents. Other important trends and analysis that the E-ISAC conducted this year focused on reconnaissance, exploitation, and compromise activities. The E-ISAC observed some activity that leveraged ransomware and other activities that used compromised credentials and technology native to the target environment. The E-ISAC also monitored several non-industry specific campaigns, including WannaCry and NotPetya ransomware activity.

In 2017, members observed several instances of Server Message Block (SMB) protocol[76] credential harvesting. The E-ISAC believes exploitation of SMB misconfigurations may continue to be used as an effective adversary technique to collect and ultimately compromise credentials.

Phishing

Phishing emails attempt to deceive individuals into providing sensitive information, such as credentials or financial account access (through fraudulent emails masquerading as legitimate communications). Phishing is typically used to gain an initial foothold into a network in support of other activities. Spear phishing[77] and whaling[78] accounted for approximately 15 percent of phishing emails reported to the E-ISAC. Towards the end of 2017, reports pointed to an increase in phishing activity originating from trusted businesses that may have been compromised. The E-ISAC also received a significant increase in spear phishing reports with credential harvesting objectives in 2017. The E-ISAC believes that this is coordinated activity that is targeting the electricity industry, which is consistent with the findings in *Joint Analysis Report* (*JAR*), *JAR-17-20114,*[79] discussed later.

Malware Targeting Electricity Industry Assets in Ukraine

In June, the E-ISAC released information on modular malware samples that may have been involved in the December 2016 attack on Ukraine's electricity assets. The reports[80] include details of the malware's capabilities.[81] The information was shared with the E-ISAC by industrial control security company Dragos Inc. This information was amplified in a Level 1 (advisory) NERC alert on June 13, 2017, entitled "Modular Malware Targeting Electricity Industry Assets in Ukraine.[82]

The malware is a modular framework that can be tailored to meet desired objectives against specific equipment in the target environment. The malware sample analyzed included capabilities against ABB and possibly Siemens

---

[76] SMB protocol allows applications, such as Microsoft Word to read and write to file shares and retrieve files and resources on a remote server.
[77] Spear phishing is a subset of phishing activity that targets specific individuals in an organization with tailored content to improve success rates.
[78] Whaling is a subset of phishing activity targeting wealthy or powerful individuals, such as CEOs (i.e., "big fish.")
[79] The Joint Analysis Report can be found at the following location: https://www.us-cert.gov/sites/default/files/publications/JAR_16-20296A_GRIZZLY%20STEPPE-2016-1229.pdf
[80] For more information, authorized users can go to the E-ISAC portal at the following location: https://www.eisac.com/portal-home/document-detail?id=64317
[81] For more information, authorized users can go to the E-ISAC portal at the following location: https://www.eisac.com/portal-home/document-detail?id=64319
[82] The NERC Alert can be found at the following location: http://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERCAlert_A-2017-06-13-01_Modular-Electric-Industry-Malware.pdf

equipment. The malware's framework design likely allows for the targeting of other vendors or communication protocols.

The E-ISAC and SANS Industrial Control System Team released a joint product summarizing analysis of the modular malware framework associated with the 2016 attack on Ukraine's power system. The report consolidated open source information, clarified important details surrounding the attack, offered lessons learned, and recommended approaches to help the ICS community search for and repel similar attacks.

The threat level protocol (TLP): AMBER version[83] of the Defense Use Case contains considerations specifically for electricity industry asset owners and operators. A TLP: WHITE version[84] was also released without the industry-specific considerations.

Advanced Persistent Threat Actor Targeting the Electricity Industry and Other Critical Sectors

In June, the E-ISAC released a Level 1 (advisory) NERC alert to inform NERC registered entities of a campaign targeting several critical sectors, including the electricity industry.

The FBI and Department of Homeland Security (DHS) released the *JAR-17-20114* on advanced persistent threat (APT) actors targeting energy, nuclear, and critical manufacturing industry companies, including electricity industry members in the United States. APT actors have attempted to collect and compromise energy industry credentials. The credential harvesting campaign used website water-holing and spear phishing to trigger external authentication attempts via SMB. The remote authentication attempts caused credentials to be exposed outside the protected network, and they were likely compromised.

According to the JAR, the compromised credentials may have been used to access the victim's environment. Once inside the environment, the APT actors used native network management and monitoring tools to collect additional information, including additional authentication information and possibly establish persistence.

In July, the FBI and DHS released an update to *JAR-17-20114* that expanded the list of targeted entities to include government organizations as well as water and aviation sectors members. The update also provided additional indicators of compromise and more details into the tactics, techniques, and procedures used by the threat actors.

Dragonfly

In September 2017, Symantec published a report[85] tying activity similar to activity reported in NERC Alert 2017-06-30-01[86] to an APT group called "Dragonfly" (i.e., Energetic Bear, Koala, and Iron Liberty). The E-ISAC, Symantec, and other security researchers agree that the activity reported indicates high interest in electricity industry companies and that the actors have a high level of sophistication.

[83] For more information, authorized users can go to the E-ISAC portal at the following location: https://www.eisac.com/portal-home/document-detail?id=64398

[84] For more information, authorized users can go to the E-ISAC portal at the following location: https://www.eisac.com/portal-home/document-detail?id=64412

[85] The Symantec report can be found at the following location: https://www.symantec.com/connect/blogs/dragonfly-western-energy-sector-targeted-sophisticated-attack-group

[86] For more information, authorized users can go to the E-ISAC portal at the following location: https://www.eisac.com/portal-home/article-detail?id=66010

Level 2 Recommendation NERC Alert based on DHS Issuance of Binding Operational Directive 17-01

On October 5, 2017, the E-ISAC released a Level 2 (Recommendation) NERC alert to inform NERC registered entities of supply chain risks in relation to a directive to executive branch agencies by DHS and to request information to assess the extent of exposure of the BPS.

To implement a stronger supply chain risk management security posture, on September 13, 2017, DHS issued *Binding Operational Directive 17-01,*[87] which notified all executive branch agencies, "to take actions related to the use or presence of information security products, solutions, and services supplied directly or indirectly by AO Kaspersky Lab or related entities." This document[88] describes the directive and the reasoning behind it and offers recommendations and additional information on supply chain risks to the North American BPS.

Large Botnets

In September 2017, CheckPoint[89] and Netlab360[90] reported that more than one million devices may be part of a botnet larger than the Mirai[91] botnet. The new botnet has been named "IoTroop" or "IoT_reaper."

The E-ISAC has previously reported on risks associated with Internet of Things devices, including the 2016 release of a Level 2 (recommendation) NERC alert[92] to registered entities.

Malware Targeting Safety Instrumented Systems

Dragos Inc. and FireEye identified a new malware that targets safety instrumented systems (SIS) devices in November 2017. Dragos directly shared analysis and threat information on this malware with the E-ISAC. The malware can disable the SIS protection, leaving critical industrial control systems vulnerable to failure without the safety trip from the SIS.

The E-ISAC has not received any reports of the malware targeting SIS systems being found on systems within NERC's footprint.

2018 Cyber Security Outlook

As the E-ISAC looks to 2018, advanced persistent threat actors will almost certainly continue to specifically target the electricity industry. Some tactics and trends are anticipated:

- **Continued and More Sophisticated Phishing Activity**: The E-ISAC expects an increase in sophisticated phishing activity against ERO members. Recent phishing activity has focused on the technique of directing victims to a malicious site in order to harvest their credentials.
- **Compromise of Trusted Business Partners**: The E-ISAC expects an increase of phishing activity originating from trusted business partners that have been compromised (e.g., construction contractors, business support vendors, service providers). The E-ISAC expects sharing levels to increase as smaller business partners may make easier targets of compromise from their smaller security budgets. Small businesses make for attractive initial targets because a phishing email from a trusted source may be more likely to be opened.
- **Cryptocurrency Mining**: As long as the value of cryptocurrency continues to remain high, the E-ISAC expects illegitimate cryptocurrency mining activity to be consistent or increase. The activity may not be targeted

[87] The Binding Operational Directive can be found at the following location: https://cyber.dhs.gov/bod/17-01/

[88] For more information, authorized users can go to the E-ISAC portal at the following location: https://www.eisac.com/portal-home/article-detail?id=66141

[89] The CheckPoint report can be found at the following location: https://research.checkpoint.com/new-iot-botnet-storm-coming/

[90] The Netlab360 report can be found at the following location: http://blog.netlab.360.com/iot_reaper-a-rappid-spreading-new-iot-botnet-en/

[91] For more information, authorized users can go to the E-ISAC portal at the following location: https://www.eisac.com/

[92] For more information, authorized users can go to the E-ISAC portal at the following location: https://www.eisac.com/portal-home/cyber-bulletin-detail?id=68561

malicious activity but can nonetheless consume members' computing resources and increase their electricity consumption.

Physical Security

Security Metric: Reportable Physical Security Events

Since 2015, one physical security event occurred that caused a loss of load as reflected in **Figure 6.1**.

This near-zero result does not suggest that the risk of a physical security event causing a loss of load is low as the number of reportable events has not declined over the past two years. Although this metric does not include physical security events affecting equipment at the distribution level (i.e., non-BES equipment), NERC receives information through both mandatory and voluntary reporting that indicates distribution-level events are more frequent than those affecting BES equipment. Some observed and potential risks are detailed in the E-ISAC physical security data and findings available to those with access to the E-ISAC portal.

Responsible entities must report physical security events to the E-ISAC as required by the *NERC EOP-004-3 Event Reporting Reliability Standard.*[93] This metric reports the total number of physical security reportable events[94] that occur over time and identifies how many of these events have resulted in a loss of load. It is important to note that any loss of load, whether directly caused by an adversary or intentionally shed as part of the real-time response, will meet the threshold for inclusion in this metric. For example, if load was shed as a result of safety concerns due to a break-in at a substation, the event is counted even though no equipment damage directly caused the loss of load. The metric provides the number of physical security reportable events and an indication of the resilience of the BES to operate reliably and continue to serve load.

Note: This metric does not include physical security events reported to the E-ISAC that do not meet the reporting threshold as defined by the *NERC EOP-004-3 Reliability Standard*, such as physical threats and damage to substation perimeter fencing. Also, this metric does not include physical security events that affect equipment at the distribution level (i.e., non-BES equipment).

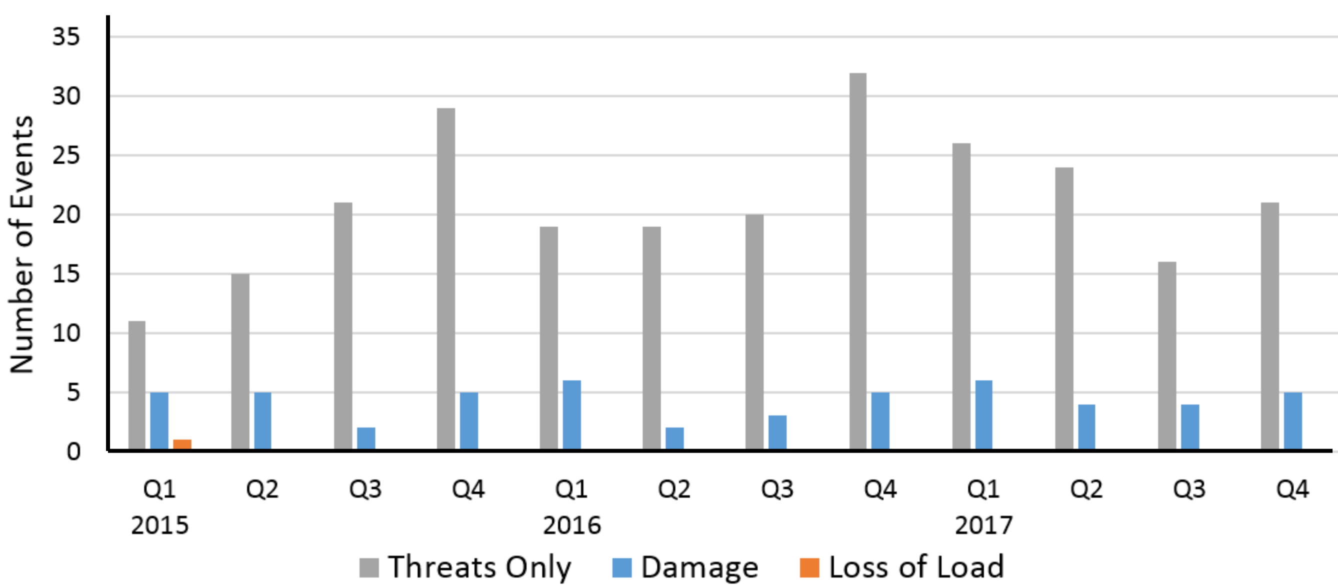


Figure 6.1: Reportable Physical Security Events

[93] Reliability Standard EOP-004-3 Event Reporting can be found at the following location: https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-004-3.pdf

[94] Reportable Events are defined in Reliability Standard EOP-004-3 Event Reporting.

Metric Contextual Information: Recent Physical Security Developments

E-ISAC Physical Security Findings

The E-ISAC physical security analysts capture, analyze, and disseminate physical security incidents reported by electricity industry members to fellow E-ISAC members, law enforcement, and government agencies. The information is disseminated in a nonattributed format and is valuable in ongoing situational awareness, detection, and prevention of similar incidents. The physical security analysts also provide reporting and analysis regarding sector-relevant global incidents.

Sources of the physical reports were voluntary incident shares, RCIS messages, OE-417s, and EOP-004s. Members shared over 57 percent of the incidents directly to the E-ISAC, or further context was provided to the E-ISAC after the incident was fully investigated.

There was a considerable increase in direct shares during 2017 by members to the E-ISAC compared to 2016. These direct shares were often phone calls during incident response, emails sharing details (e.g., pictures and law enforcement engagement), or members voluntarily posting incidents to the E-ISAC portal. The E-ISAC conducted over 10 outreach events, including quarterly Critical Infrastructure Protection Committee briefings, visits to regional security meetings, quarterly teleconference participation, and ad-hoc requests. The physical security analysts' outreach efforts and timely bulletins to industry were pivotal in creating a trusted environment for voluntary sharing, and the E-ISAC benefited from regular correspondence from security managers throughout the Regions.

Reporting Trends

The physical security analysts reviewed the incidents from all segments of the industry by month, ERO Region, and event type. The analysts reviewed events by overall type by using the following categories: Gunfire, Intrusion, Surveillance, Suspicious Activity, Theft, Threat, and Vandalism. For incidents that fell into multiple categories, the E-ISAC categorized them based on the intent of the action. See **Figure 6.2**.

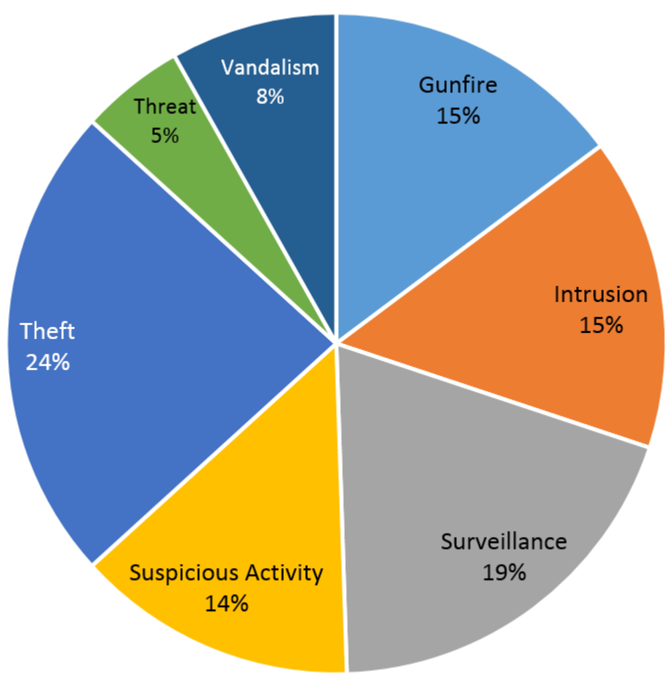


Figure 6.2: Breakdown of Physical Security Incidents for 2017

In 2017, theft related incidents accounted for 24 percent of incidents. These thefts were predominantly copper related but also included equipment like vehicles, tools, and uniforms.

Figure 6.3 shows the price of copper over the course of 2017 (left) and tracks the frequency of copper theft events shared with the E-ISAC (right). While the price of copper has increased by almost 20 percent over the past 12 months, there is no correlation in the price increase and an increase in copper theft incidents. The fluctuation in incident frequency is more likely attributed to seasonal temperature changes as individuals looking to steal copper are less likely to do so during the colder and hotter months. It might conversely align with periods of increased construction activities and greater access to materials. Also, as states enact legislation and regulation on metal recycling and resale, the market for stolen copper will diminish.

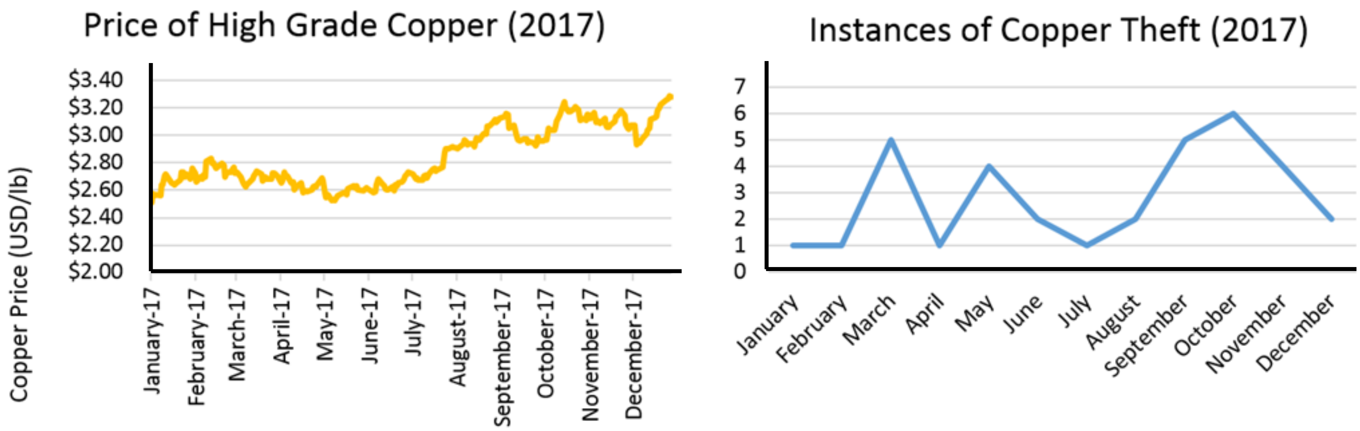


Figure 6.3: 2017 Copper Theft Prices and Reported Incidents

Surveillance accounted for 19 percent of incidents. Methods of surveillance included drones, photography, and video footage. While these incidents may seem trivial, this activity could lead to follow-on activity, such as theft or even a coordinated attack. In 2017, the E-ISAC called for increased vigilance of surveillance activity during monthly calls and outreach events, which may have led to an increase in sharing.

Gunfire related incidents accounted for 15 percent of events. A majority of these came from damage discovered during routine inspection. Many members provided the E-ISAC with photographs of the damage that provided helpful context surrounding the incidents. In the fourth quarter of 2017, the E-ISAC observed a slight increase in gunfire damage to wind farms.

2018 Physical Security Outlook

After a review of 2017 data, government reports, and industry whitepapers and discussions, the E-ISAC has made some security predictions for 2018. The E-ISAC assesses that there will be an increase in theft, especially in areas more negatively impacted by socio-economic issues. This theft may be copper, equipment, or tools. The E-ISAC advises members to track copper prices, engage with law enforcement and metal recyclers, and continue to share incidents with the E-ISAC. The E-ISAC anticipates a rise in incidents involving suspicious activity, such as targeted phone scams and individuals probing security personnel for facility information or response thresholds. While intent is always challenging to assess, the possibility exists that, intermingled in this continued low-level threat activity, there could be probing attacks to gauge defenses and response actions in preparation for follow-on attacks from individuals or groups with a broad range of ideological motivations. Employee education programs regarding topics like protecting sensitive information and incident sharing procedures may help to counteract these tactics.

Information Sharing

Security Metric: Industry-Sourced Information Sharing

The E-ISAC continues to share relevant cyber security information with its members via the E-ISAC portal. This metric reports the total number of incident bulletins (i.e., cyber bulletins and physical bulletins) published by the E-ISAC based on information voluntarily submitted by the E-ISAC member organizations as shown in **Figure 6.4**.[95] The E-ISAC member organizations include NERC registered entities and others in the electricity sector, including distribution utilities (i.e., it is not limited to the BPS). Incident bulletins describe physical and cyber security incidents and provide timely, relevant, and actionable information of broad interest to the electricity sector. Given today's complex and rapidly changing threat environment, it is important that electricity sector entities share their own security-related intelligence, as it may help identify emerging trends or provide an early warning to others. This metric provides an indication of the extent to which the E-ISAC member organizations are willing and able to share information related to cyber and physical security incidents they experience. As the E-ISAC member organizations increase the extent that they share their own information, all member organizations will be able to increase their own awareness and ability to respond quickly and effectively. This should enhance the resilience of the BPS to new and evolving threats and vulnerabilities. The modest but steady increase in the number of bulletins published by the E-ISAC suggests that member organizations are sharing security-related information.

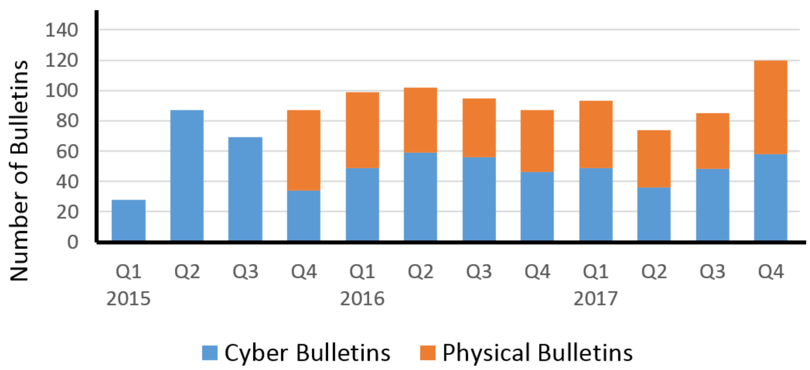


Figure 6.4: Industry-Sourced Information Sharing

Metric Contextual Information: Recent Trends in Information Sharing

E-ISAC Information Sharing

In 2017, the E-ISAC portal included 226 posted cyber bulletins. Of these, a total of 191 (ref. security Metric 3) included information that members either provided to the E-ISAC or posted themselves, and a total of 31 of the bulletins included information based on Cyber Security Risk Information Sharing Program (CRISP) data. In 2017, the E-ISAC portal included 181 physical bulletins that included information that members either provided to the E-ISAC or posted themselves (ref. security Metric 3). The E-ISAC also posted several bulletins based on information obtained from government and trusted open source partners.

CRISP Reporting

Security Metric: CRISP Statistics

CRISP uses many different sources of threat reporting to identify potential indicators of compromise. In 2017, a total of 25 percent of investigations opened in CRISP were based on information initially shared by CRISP participants; this

[95] In September 2015, the E-ISAC launched its new portal. Watchlist Entries are now called Cyber Bulletins. The category Physical Bulletins is on the portal to share physical security information. Prior to 2015 Q4, physical security reports were shared through the E-ISAC Weekly Report but not through Watchlist Entries.

is an increase from five percent in 2016 as participants have become more comfortable sharing indicators. The E-ISAC anticipates this number to increase in the future.

CRISP is a public-private partnership cofounded by the DOE and NERC and managed by the E-ISAC that facilitates the exchange of detailed cyber security information among industry, the E-ISAC, DOE, and Pacific Northwest National Laboratory. The program facilitates information sharing and enables owners and operators to better protect their networks from sophisticated cyber threats.

The purpose of CRISP is to collaborate with energy sector partners to facilitate the timely bi-directional sharing of unclassified and classified threat information. CRISP information helps support development of situational awareness tools to enhance the sector's ability to identify, prioritize, and coordinate the protection of its critical infrastructure and key resources.

CRISP participant companies serve approximately 75 percent of electricity customers in the United States. The quantity, quality, and timeliness of the CRISP information exchange allows the industry to better protect itself against cyber threats and to make the BPS more secure.

CRISP reports increased information sharing that resulted in enhanced security awareness of CRISP participants and the rest of the electricity industry. Additionally, anonymized CRISP information shared with the intelligence community led to the discovery of previously unknown compromised computer networks. **Table 6.1** details the reporting statistics from 2017.

In 2017, CRISP analysts generated 121 all-site reports on a variety of threats:

- **Reconnaissance**: Cautious and methodical actors conduct reconnaissance by using a wide variety of techniques and tactics, including port scanning, ICS/SCADA identification, enumeration, and social engineering.
- **Credential Harvesting**: This includes phishing emails, watering holes, open source research, and database exploitation to collect user identification and password credentials to access a target system or masquerade as a legitimate user.
- **Ransomware**: This includes malware that encrypts systems, disks, or specific files/types and requires a ransom payment for the decryption key. High profile ransomware campaigns include WannaCry and NotPetya.
- **Watering Hole**: This includes attacks that leverage the false sense of security provided by a high volume of traffic to legitimate sites. While performing normal functions at a seemingly innocuous site, victims are exposed to malicious code capable of harvesting credentials, redirecting users to malicious sites, or collecting sensitive user information.
- **High-Value Threat Actors**: High value threat actors typically employ multiple techniques and phases of attacks in a cyclical pattern to gain unauthorized entry to networks. Campaigns seen in 2017 include GRIZZLY STEPPE, HIDDEN COBRA, and Operation CloudHopper[96]/Chessmaster.[97]

[96] Information on Operation CloudHopper can be found at the following location:
http://baesystemsai.blogspot.com/2017/04/apt10-operation-cloud-hopper_3.html
[97] Information on Chessmaster can be found at the following location:
https://blog.trendmicro.com/trendlabs-security-intelligence/chessmaster-cyber-espionage-campaign/

Table 6.1: CRISP 2017 Reporting Statistics	
Product	**2017 Total**
Cases Opened	1,817
Analyst Generated Reports	235
Site Annexes	442
Automated Reports	187,403

Cases Opened: The CRISP analysis team opens a case each time an indicator of compromise is queried against CRISP data. Even if no activity was observed against CRISP data, historical cases provide trending and tactics used by threat actors.

Analyst Generated Reports: If indicators of compromise are observed in CRISP network traffic, the CRISP team works with the DOE to declassify indicators to disseminate to CRISP participants.

Site Annexes: An individual site annex is provided to each CRISP participant where the indicators were observed. A site annex consists of individual CRISP participant data that provides cyber defenders information on when the activity occurred and which system(s) may be communicating with the identified suspicious activity.

Automated Reports: Due to the sheer volume of network data, CRISP has developed automated analytical tools. These tools identify unique relationships between network traffic and CRISP participants. CRISP participants can access the automated analytical tools and their unique site reports through the Cyber Analytics Services Access interface. They can also use the Cyber Analytics Services Access application programming interface to integrate into existing processed at local sites.

Global Vulnerabilities

Security Metric: Global Cyber Vulnerabilities

This metric reports the number of global cyber security vulnerabilities considered to be high severity (as reflected in Figure 6.5) based on data published by the National Institute of Standards and Technology. The National Institute of Standards and Technology defines high severity vulnerabilities as those with a common vulnerability scoring system[98] of seven or higher. The term "global" is an important distinction as this metric is not limited to information technology typically used by electricity sector entities. The year-over-year increase in global cyber security vulnerabilities compared with global cyber security incidents indicates that vulnerabilities are increasingly being successfully exploited and reinforces the need for organizations to continue to enhance their cyber security capabilities.

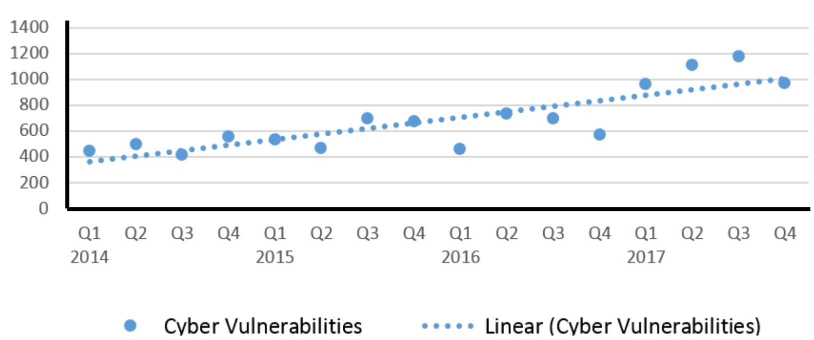


Figure 6.5: Global Cyber Vulnerabilities

[98] Ref. NIST: http://nvd.nist.gov/cvss.cfm

Continued Security Metrics Maturation

For this report, the E-ISAC and Security Metrics Working Group have taken a combined approach to assessing the security of the BPS as it relates to overall reliability. Collecting and assessing the inherently quantitative metrics used by the SMWG in recent years is now accompanied with a qualitative narrative to explain the "so what" factor of the metrics, highlight important findings, and provide context that may otherwise be obscured in a simple chart or number. Underlying all this is the clear goal to use these metrics and narrative to project into a future time and less understood topics to make an assessment about the future state of security of the BPS.

Principles for Future Work

To guide the continued refinement of how security is measured and assessed, five principles were identified and agreed upon by the different groups working in this space:

- Measuring and assessing security requires a shared, clear, and complete lexicon whose use is broadly understood and consistently enforced.
- Metrics, measures, and assessments are different and related:
  - Metrics are the result of counting things (vulnerabilities, incidents, etc.) and are usually quantitative.
  - Measures provide the "so what" to the metrics as a qualitative narrative supported by the metrics.
  - Assessments are a projection of the measures into future time and less understood topics.
- Sometimes measures, but usually assessments, require assumptions to be made, replacing assumptions with fact as more information becomes available is a standing high priority.
- Using consistent frameworks for both the cyber and physical domains, with different metrics but philosophically similar measures, will improve process efficiency as well as external comprehension.
- Stakeholders involved in these efforts must be diligent in maintaining the appropriate distinctions between different uses[99] of measures even when the data sources underlying the metrics overlap.

Throughout 2018, the E-ISAC, System Security Metrics Working Group (SMWG), and ERO Enterprise staff will continue to refine how security is measured. One of the most promising areas under development is the application of sociotechnical probabilistic risk assessment[100] to mathematically combine calibrated subject matter expert assessments of the likelihood of contributing elements of a certain security outcome to assess the time-bounded likelihood of the realization of a specific harm. Integral to this technique is the ability to similarly estimate the efficacy of various mitigation strategies to inform risk management.

[99] In recent years, these different uses could generally be divided into categories for the actual security outcomes seen on the BPS, performance objectives for the E-ISAC as supported by industry, and ERO Enterprise corporate metrics (which intermingled aspects from the first two categories).

[100] While not explicitly named "socio-technical probabilistic risk assessment" by them, this is the concept and techniques described by Douglas W. Hubbard and Richard Seiersen in their 2016 book *How to Measure Anything in Cybersecurity Risk.*

Chapter 7: Actions to Address Recommendations in Prior State of Reliability Report

The *State of Reliability* report identifies key findings, and many of these findings contain recommended actions for NERC or the larger ERO Enterprise, PAS, and other subcommittees and working groups. **Table 7.1** shows the number of past recommendations and includes whether the item was completed as of the *State of Reliability 2017* report, whether the item was ongoing in 2017 but has since been closed out as a completed recommendation, or whether the item is still an ongoing recommendation. Actions completed through the 2017 report are considered archived, and details about their completion are available in this chapter of the report.[101]

Table 7.1: Recommendation Status Summary

Key Finding Action Status	2011	2012	2013	2014	2015	2016	2017	Total
Completed Status Through 2017 Report	4	6	7	5	9	3	0	34
Completed During 2017	0	0	0	0	1	2	3	6
Ongoing as of 2018 Report	0	0	0	0	2	2	1	5
Total Actions from All Reports	**4**	**6**	**7**	**5**	**12**	**7**	**4**	**45**

Table 7.1 shows that, over the six years of reports, 45 recommendations have been developed. Actions to address those specific items have been completed for 40 recommendations. These actions are understood to have improved the reliability of the BPS. In this report, additional key findings and recommendations are identified and will be reported in future State of Reliability reports.

Table 7.2 outlines actions that have addressed the recommendations completed during 2016, and **Table 7.3** outlines recommendations where actions are currently ongoing and will be included in future reports.

Table 7.2: Completed Recommendations for 2017

Item Reference	Finding SOR Report Year	Key Finding SOR Reference	Recommendations	Actions Taken to Date
1	2015[102]	Page 32 Paragraph 1	The ERSWG has recommended a measure that was approved by the OC and PC for data collection and testing. This may support development of new voltage and reactive support metrics going forward.	The ERSTF Measures Framework Report[103] contained a proposed measure 7, which was assigned to PAS to develop the necessary data collection processes to allow a test of measure 7 as a potential future voltage and reactive metric.

[101] Prior *State of Reliability* reports can be found at the following location: https://www.nerc.com/pa/RAPA/PA/Pages/default.aspx http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2015%20State%20of%20Reliability.pdf

[102] The *State of Reliability 2015* can be found at the following location: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2015%20State%20of%20Reliability.pdf

[103] The *Essential Reliability Services Task Force Measures Framework Report* can be found at the following location: https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf

Table 7.2: Completed Recommendations for 2017				
Item Reference	**Finding SOR Report Year**	**Key Finding SOR Reference**	**Recommendations**	**Actions Taken to Date**
				During 2016, PAS developed and conducted a voluntary data collection and released the data for analysis to the SAMS. During 2017, SAMS determined that this was not a feasible measure. The PC accepted that recommendation and no further work will be performed relative to measure 7.
2	2016[104]	Page 1 Key Finding 2	NERC should consider performing daily severity risk index (SRI) calculations on a regional basis to investigate the feasibility of correlating performance with regional weather data.	NERC and PAS are examining Interconnection-level daily SRI calculations prior to developing possible daily SRI calculations on the regional level. PAS determined in 2017 that SRI daily calculations are not feasible at the regional level. This report contains a pilot at the Interconnection level using WECC.
3	2016	Page 1 Key Finding 3	NERC should provide focus on HP training and education through conferences and workshops that increase knowledge of possible risk scenarios.	NERC continues to host HP workshops to enhance awareness of the HP impact on system risk. NERC and NATF continue to conduct the annual Improving Human Performance on the Grid conference in Atlanta in late March, and Regions have also conducted HP conferences/training. While this will continue as an ongoing activity, this action is closed for purposes of the report.
4	2017[105]	Page 1 Key Finding 1	As NERC continues to track and trend events and provide recommendations for risk mitigation, NERC should include vendors and manufacturers in analyses when possible.	In analyzing events related to inverter based generation events, NERC and WECC have included inverter vendors and manufacturers soon after determination that issues existed.

[104] The *State of Reliability 2016* can be found at the following location: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2016_SOR_Report_Final_v1.pdf

[105] The *State of Reliability 2017* can be found at the following location: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf

Table 7.2: Completed Recommendations for 2017				
Item Reference	**Finding SOR Report Year**	**Key Finding SOR Reference**	**Recommendations**	**Actions Taken to Date**
5	2017	Page 2 Key Finding 2	Continue with regional efforts on education and outreach to continue reduction of protection system misoperations.	In addition to annual RF and SPP misoperation conferences, WECC has established a strong leadership position with its Misoperation Summit webinar series. NERC is additionally working with the Regions and with industry through the PC and SPCS to get a comprehensive misoperation DRI developed.
6	2017	Page 5 Key Finding 5	Increase awareness of HP issues with industry and policymakers	HP emerges as an issue in multiple aspects of BPS performance, including TADS transmission outages. NERC and NATF jointly conduct the annual Improving Human Performance on the Grid conference in Atlanta in late March, and Regions and various industry groups also conduct high quality HP conferences and training to address this need. This report has cited the HP conferences for years, but this year is attempting to link significant BPS reliability impacts that drive the need for increasing HP efforts with the educational venues. For purposes of this report, this item is closed.

Table 7.3: Ongoing Recommendations				
Item Reference	**Finding SOR Report Year**	**Key Finding SOR Reference**	**Recommendations**	**Actions Taken to Date**
1	2015[106]	Page 31 Paragraph 2	The collected data (transmission related events resulting in load loss) does not indicate whether load loss during an event occurred as designed. Data collection will be refined in the future for this metric to allow enable data grouping into categories, such as separating load loss as	NERC, PAS, and the TADSWG are currently evaluating data collection and methods that may be enhanced to provide increased awareness of year-over-year trends when load loss occurs during transmission events. These efforts may include collaboration with IEEE and industry forums. This is included in PAS annual reliability metrics review process.

[106] The *State of Reliability 2015* can be found at the following location: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2015%20State%20of%20Reliability.pdf

Table 7.3: Ongoing Recommendations				
Item Reference	**Finding SOR Report Year**	**Key Finding SOR Reference**	**Recommendations**	**Actions Taken to Date**
			designed from unexpected firm load loss. Also, differentiating between load losses as a direct consequence of an outage compared to load loss as a result of an operator-controlled action to mitigate an IROL/SOL exceedance should be considered.	
2	2015	Page 43 Paragraph 4	Since monitoring the changes that occurred in 2014 versus prior years, the time range categories for IROL exceedances may need to be reviewed. Based on this anticipated result (that monitoring granularity has increased, which may result in a variance over history), the parameters for reporting on Time Range 1 should be examined to ensure that the correct information is being captured.	The TADSWG is currently evaluating data collection and methods that may be enhanced to provide increased awareness of year-over-year trends when load loss occurs during transmission events. Also, the Methods for Establishing IROLs Task Force is currently reviewing consistency of IROL exceedance criteria and may be recommending changes to the IROL exceedance metric.
3	2016[107]	Page 2 Key Finding 5	NERC should provide leadership in collaborative efforts to improve system model validation, particularly dynamic models, including the use of synchrophasor and other advanced technology.	Several modeling improvement initiatives have begun. The Synchronized Measurement Subcommittee and the Power Plant Modeling and Verification Task Force have been created to implement and monitor several modeling initiatives. There have also been a number of reliability guidelines and technical reference documents prepared to enhance modeling efforts.
4	2016	Page 2 Key Finding 6	The ERO should lead efforts to monitor the impacts of resource mix changes with concentration on the following: • ERS measures for frequency and voltage support that have been developed and adopted	The ERSWG continues to develop implementation plans for various ERS measures.

[107] The *State of Reliability 2016* can be found at the following location: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2016_SOR_Report_Final_v1.pdf

Table 7.3: Ongoing Recommendations				
Item Reference	**Finding SOR Report Year**	**Key Finding SOR Reference**	**Recommendations**	**Actions Taken to Date**
			• Methods to increase the population and capability of resources providing frequency response, especially under the scenario that conventional generation continues to be replaced with variable energy resources • Reliability of reactive power generators, such as static var compensators (SVCs), FACTS devices, and synchronous condensers when applied to replace the voltage support function of retiring conventional generators, such as low-voltage ride-through • Protection for these devices as well as compatibility and coordination with other BPS protection and controls	
5	2017[108]	Page 3 Key Finding 3	Increase awareness of frequency response challenges.	NERC has in the last three years (including in this report) emphasized that there is a frequency response nadir to UFLS set point margin risk in the arresting phase as well as the requirement to meet IFRO in the stabilizing phase. NERC has also established a standard drafting team to explore and accomplish improvements to BAL-003.1.1 in response to the receipt of

[108] The State of Reliability 2017 can be found at the following location: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf

Table 7.3: Ongoing Recommendations				
Item Reference	**Finding SOR Report Year**	**Key Finding SOR Reference**	**Recommendations**	**Actions Taken to Date**
				SARs. This work will continue through 2018 at minimum. NERC and the NAGF are also jointly addressing the need for increased awareness of the challenges.

Appendix A: Statistical Analysis of Daily Transmission and Generation Performance

Assessment of Daily Transmission Performance and Daily Generation Performance

Analyses in the following sections show a stable daily transmission system performance and an improved daily generation performance in 2017 based on the analysis of the 2013–2017 TADS and GADS data, respectively.

Daily Transmission Loss (DTL) and Daily Generation Loss (DGL)

The DTL is defined by **Equation A.1**.

$$DTL = \frac{\sum(Equivalent\ MVA\ of\ TADS\ elements\ with\ sustained\ automatic\ outages\ initiated\ on\ a\ given\ day)}{\sum(Equivalent\ MVA\ of\ elements\ in\ TADS\ inventory)} \cdot 1000$$

Equation A.1

In **Equation A.1:**

- TADS elements are ac circuits, dc circuits, and transformers reportable in TADS.[109]
- Sustained automatic outages have a duration of one minute or greater.

Defined by Equation A.1: DTL is a share of the total megavolt ampere (MVA) of the BPS transmission system lost on a given day due to sustained automatic outages.[110] **Table A.1** and **Table A.2** list equivalent MVA values for TADS elements by the voltage class reportable in TADS.

Table A.1: Equivalent MVA Values of AC Circuits and Transformers

Voltage Class	AC Circuits	Transformers
100–199 kV	200	100
200–299 kV	700	259
300–399 kV	1,300	518
400–599 kV	2,000	1,034
600–799 kV	3,000	1,441

Table A.2: Equivalent MVA Values of DC Circuits

Voltage Class	DC Circuits
100–199 kV	545
200–299 kV	140
400–400 kV	1,033
500–599 kV	818

[109] From 2008–2015, TADS collected the inventory and outage data on transmission elements with voltages 200 kV and above. In 2015, TADS data collection changed to include inventory and outage data for all BPS transmission elements in NERC footprint. This change led to a larger inventory (below 200 kV) and resulted in more outage data collected.
[110] The ratio is multiplied by 1,000 for convenience to avoid working with and presenting very small numbers.

The DGL is defined by **Equation A.2**:

$$DGL = \frac{\sum(MW\ rating\ of\ generators\ with\ unplanned\ outages\ that\ started\ on\ a\ given\ day)}{\sum(MW\ rating\ of\ all\ available\ generators)} \cdot 1000$$

Equation A.2

In **Equation A.2**:

- Only conventional generation reported in the GADS is includable generation.
- A monthly capacity value is used as a denominator.

Defined by Equation A.2: DGL is a share of the total MW rating of conventional generation reportable in GADS lost on a given day due to unplanned (forced) outages.[111]

Daily Transmission Performance

DTL Statistics and Time Trend

Analysis of a daily BPS transmission system performance is based on the DTL values calculated for the years 2013–2017 by **Equation A.1**. **Table A.3** shows the descriptive statistics of the five-year DTL data.

Table A.3: Descriptive Statistics of DTL (2013–2017)

Days	Mean	Standard Deviation	Minimum	Maximum	Median
1.826	0.81	0.59	0.00	8.41	0.69

Table A.3 informs that, on average, about 0.08 percent of the total MVA has been lost daily due to sustained outages of TADS elements over these five years. For half of the days, the transmission loss was below 0.069 percent and for another half it was above 0.069 percent; the maximum DTL was more than ten times the average with 0.84 percent of the total MVA lost (July 4, 2013). On that day, 29 sustained outages were reported in TADS; a total of 24 of these (22 outages of ac circuits and two dc circuit outages) were caused by wildfires in Canada (NPCC), and the remaining five outages were spread across the continent and not related.

In **Figure A.1**, the daily performance of the DTL is shown over the five-year history. The daily values follow prominent seasonal pattern, which is analyzed in detail in the next section. Also, clearly visible are upper outliers—days with multiple sustained outages of the transmission system.

[111] The ratio is multiplied by 1,000 for convenience to avoid working with and presenting very small numbers.

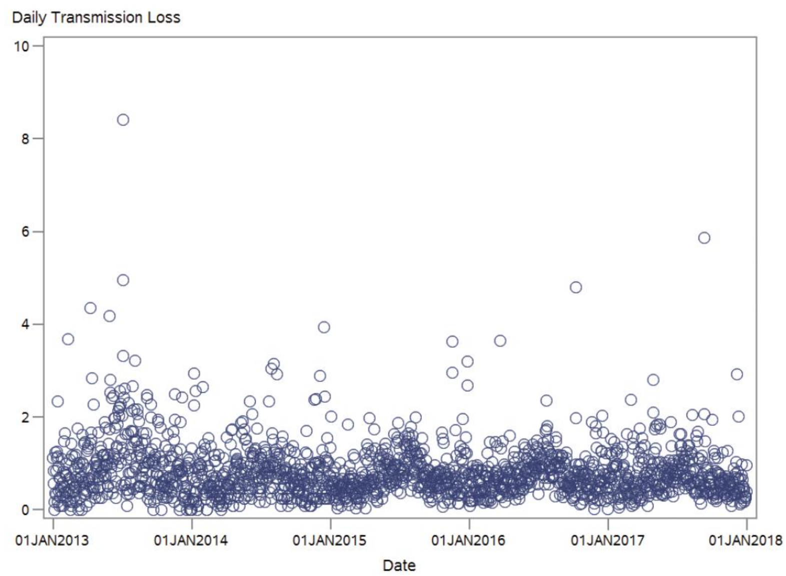


Figure A.1: Scatter Plot of DTL (2013–2017)

Because of TADS data collection changes in 2015, a time trend-line is calculated and significance of its slope is tested for the DTL data limited for the years 2015–2017. The scatter plot of the 2015–2017 DTL is shown in **Figure A.2** data along with a time trend-line.

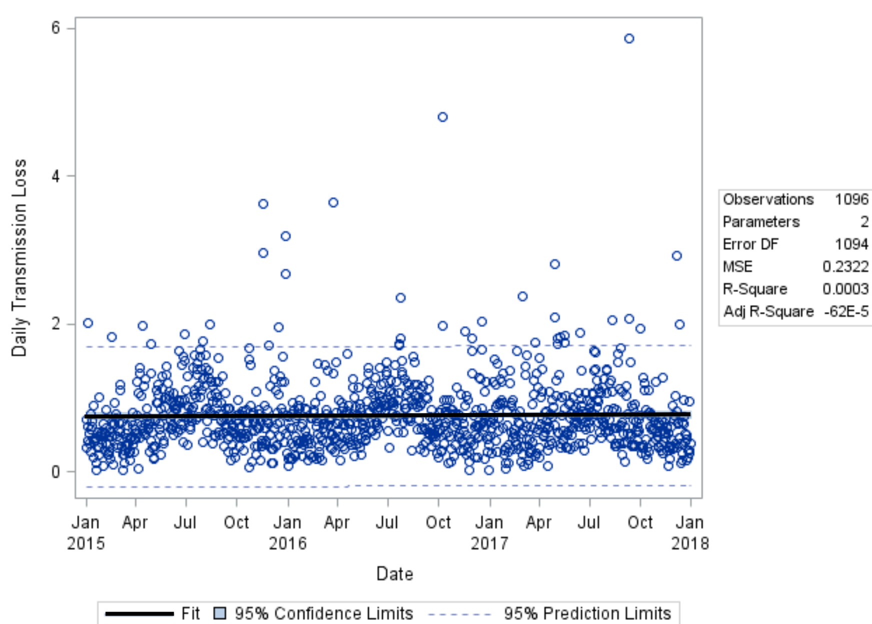


Figure A.2: Scatter Plot of DTL with Time Trend Line (2015–2017)

The time trend line has a positive slope that is not statistically significant (p-value=0.57). This result indicates that it is very likely that the positive slope was observed by mere chance and, on average, the daily transmission system performance was stable from 2015–2017.

Seasonal Analysis of Transmission Performance

Figure A.1 and **Figure A.2** reveal a prominent seasonality of the DTL. Further analysis of the seasonal performance confirms and quantifies differences in DTL by season.[112] **Table A.4** shows the DTL descriptive statistics by season based on the 2013–2017 data.

Table A.4: Descriptive Statistics of DTL by Season

Season	N	Mean	Standard Deviation	Minimum	Maximum	Median
Winter	451	0.68	0.54	0.00	3.93	0.56
Spring	305	0.72	0.53	0.00	4.34	0.62
Summer	765	0.95	0.63	0.00	8.41	0.85
Fall	305	0.70	0.53	0.00	4.80	0.60

Seasonal differences in DTL are further illustrated in the boxplot of **Figure A.3**.

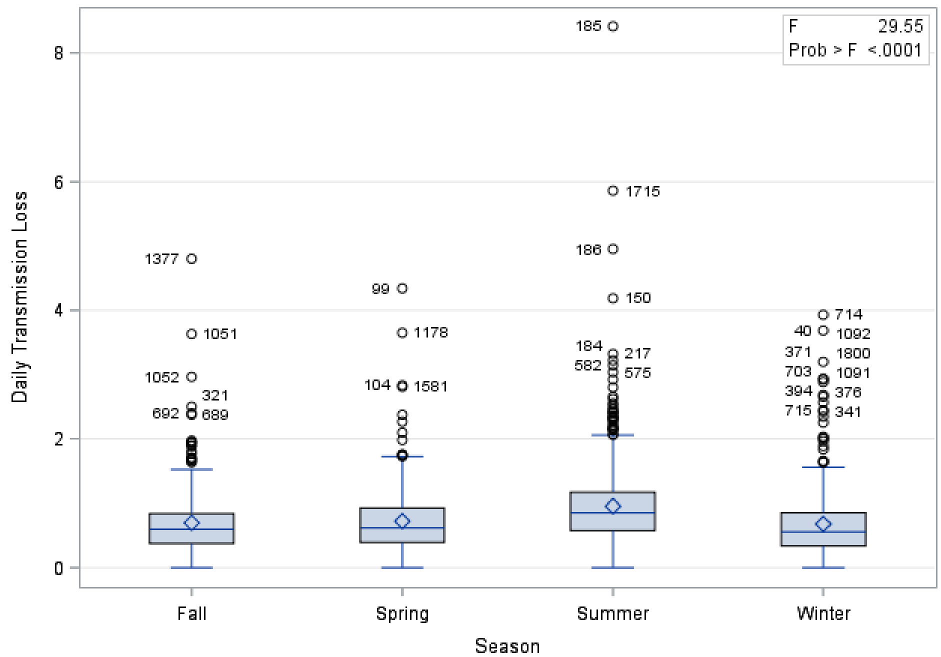


Figure A.3: Boxplot of DTL by Season 2013–2017

Statistical tests[113] indicate statistically significant differences among seasonal distributions of the DTL. **Figure A.4** shows the mean DTL by season ordered from highest (for summer) to lowest (for winter) and summarizes results of Duncan's grouping test for the seasonal means. Each bar connects seasons with similar (not statistically significantly different) mean DTL values. Thus, differences in spring, fall, and winter DTL (connected by a red bar) are not significant, and, on average, these seasons have similar daily transmission losses. Summer DTL is the highest and statistically significantly different from the other seasons.

---

112 For seasonal analysis of TADS and GADS data in Appendix A, winter includes the months of January, February, and December of the same calendar year. Summer includes May through September; all other months are categorized as spring/fall.

113 ANOVA with Fisher's Least Significant Difference test and Duncan grouping test at the significance level of 0.05.

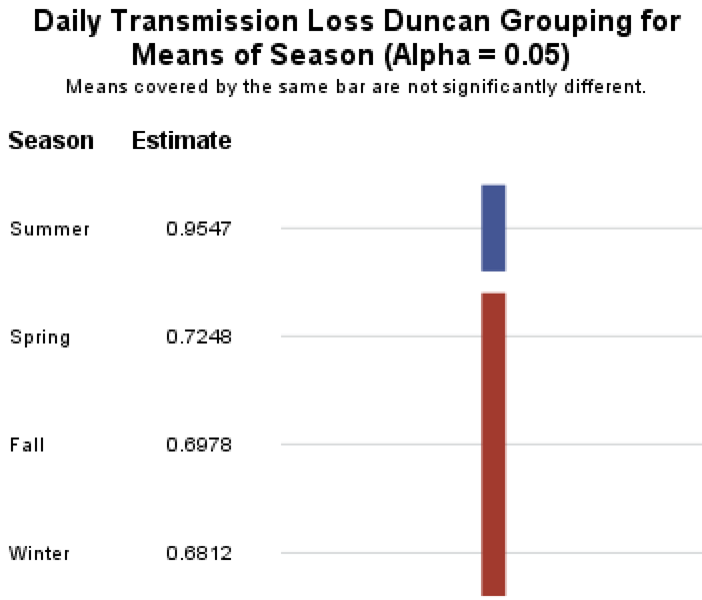


Figure A.4: Average DTL by Season and Seasonal Grouping by Mean DTL (2013–2017)

2017 Transmission Performance versus Historical Seasonal Bounds

The detected seasonal differences in the transmission system performance motivated the analysis of daily 2017 transmission performance based on seasonal bounds for typical daily values.

Figure A.5 shows a daily plot of the DTL score for 2017 (shown in blue) against bounds of typical seasonal performance that is calculated by using 2013–2016 (historical) daily data. On a daily basis, a general normal range of performance exists. This normal range is defined as the 90-percent confidence interval of historical seasonal values and is visible as a band between the fifth percentile of seasonal values (orange line) and the ninety-fifth percentile of seasonal values (grey line). For each season, the historical median and mean are also shown. Similarity of parameters of the distribution of the winter, spring, and fall DTL is further visible in **Figure A.5**.

Days of stress rise above the seasonal daily control limits. **Figure A.5** shows that the BPS transmission performance in 2017, as measured by the DTL, had eight stress days that exceeded corresponding historical seasonal bounds. This indicates a stable overall performance comparatively to the previous four years since for a year similar to the historical years 18 or 19 stress day would be expected. However, the six most extreme days in 2017 exceeded any seasonal control bounds.

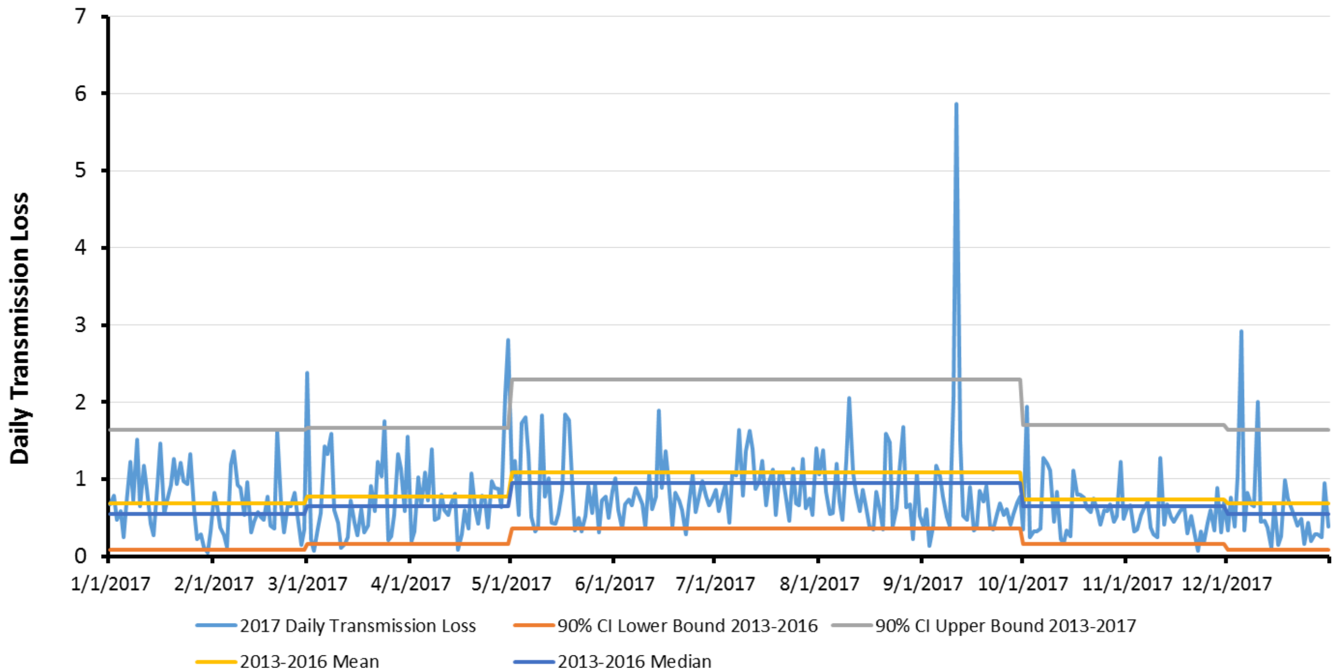


Figure A.5: 2017 DTL with the 2013–2016 90-Percent Confidence Interval by Season

On two of these extreme days, September 10 and 11, a total of 325 sustained outages started (seven transformer outages and 318 ac circuit outages), 194 of which happened in Florida and were caused by Hurricane Irma (with the TADS ICC Weather, Excluding Lightning). The majority of the 55 sustained outages that started on another extreme day, December 5, 2017, were initiated by wildfires in WECC (with the TADS ICC Fire). The two extreme days on April 29 and 30 had 146 sustained outages (six transformer outages and 140 ac circuit outages) spread across North America (all Regions except NPCC and FRCC) with 26 of these outages caused by Weather, Excluding Lightning, and remaining outages initiated by different causes. On these two days, a total of 69 tornadoes were reported in SPP, SERC, and Texas RE by the National Weather Service as well as multiple hails and winds spread in SPP, SERC, Texas RE, MRO, and RF. On the last extreme day, March 1, there were 48 sustained outages (five transformer outages and 43 ac circuit outages) started, with 21 of them reported by SERC and 16 by RF. A total of 26 of these 48 outages were initiated by Weather, Excluding Lightning. On this day, the National Weather Service reports about 16 tornadoes, 11 hail occurrences, and 616 wind occurrences concentrated in RF and SERC.

It is noteworthy that Hurricane Harvey is not one of the extreme transmission days of 2017. On August 26, 2017, a total of 56 sustained outages were reported in TADS, and 40 of them occurred in Texas and were caused by Harvey (with TADS ICCs Weather, Excluding Lightning, and Failed AC Circuit Equipment); however, most of the outages involved the 100–199 kV ac circuits[114] and their contribution to the daily transmission loss was relatively small (see Equation A.1 and **Table A.1**).

Daily Transmission Performance by Year

The descriptive statistics of the annual distributions of the daily transmission loss values are listed in **Table A.5**.

[114] The 100–199 kV ac circuits account for about 80 percent of the Texas RE ac circuit inventory in TADS. The relatively low (seventeenth) rank of August 26 (Hurricane Harvey) highlights the fact that a Regional inventory's voltage mix is a factor that magnifies or decreases an impact of Regional transmission outage events to the DTL values because of the NERC-wide normalization in Equation A.1. This observation indicates that similar regional/Interconnection analysis could be beneficial supplement to the analysis of the North American BPS.

Table A.5: Descriptive Statistics of DTL by Year						
Year	**N**	**Mean**	**Standard Deviation**	**Minimum**	**Maximum**	**Median**
2013	365	0.99	0.83	0.00	8.41	0.84
2014	365	0.77	0.57	0.00	3.93	0.68
2015	365	0.76	0.47	0.03	3.63	0.67
2016	366	0.75	0.46	0.01	4.80	0.69
2017	365	0.75	0.52	0.05	5.86	0.65

The year-over-year differences in transmission performance are further illustrated in the boxplot of **Figure A.6**.

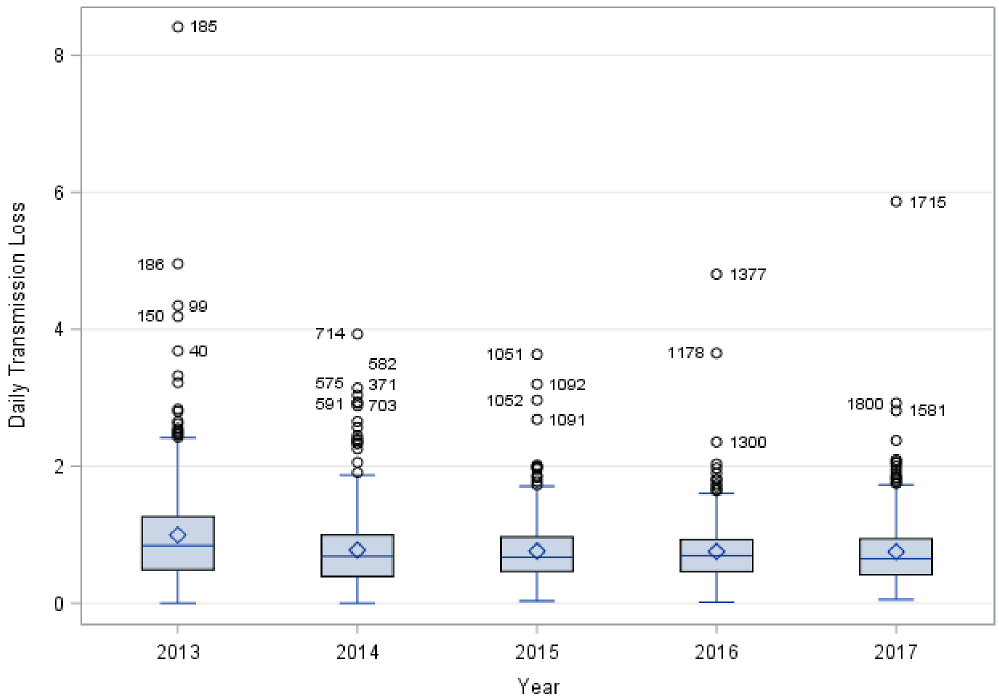


Figure A.6: Boxplot of DTL by Year (2013–2017)

Table A.5 and **Figure A.6** show that the 2017 transmission performance was the best as measured by the mean and median, but the variability of values as measured by the standard deviation was relatively high.

Because of TADS data collection changes in 2015, statistical tests on significance of differences in annual DTL distributions were performed only for the annual datasets for the years 2015–2017. Statistical tests[115] found no statistically significant difference among these annual distributions (with a remarkable p-value=0.96 for ANOVA). This result provides just other confirmation of a stable performance of the BPS transmission system in 2017.

[115] ANOVA with Fisher's Least Significant Difference test and Duncan grouping test at the significance level of 0.05.

Daily Generation Performance

DGL Statistics and Time Trend

Analysis of a daily BPS generation system performance is based on the DGL values calculated for the years 2013–2017 by **Equation A.2**. Table A.6 shows the descriptive statistics of the five-year DGL data.

Table A.6: Descriptive Statistics of DGL (2013–2017)					
Days	Mean	Standard Deviation	Minimum	Maximum	Median
1,826	10.97	4.03	2.68	74.18	10.49

Table A.6 informs that, on average, about 1.1 percent of the total MW rating of conventional generators has been lost daily due to unplanned outages. The maximum DGL was almost seven times greater than the average with 7.4 percent of the total MW rating lost on that day, January 7, 2014, the peak day of the polar vortex.[116]

Figure A.7 illustrates the daily performance of the DGL over the five-year history. The scatter plot, of the values, is shown along with a time trend-line. The daily values follow prominent seasonal pattern, which is analyzed in detail in the next section. Also clearly visible are upper outliers—days with extreme generation losses.

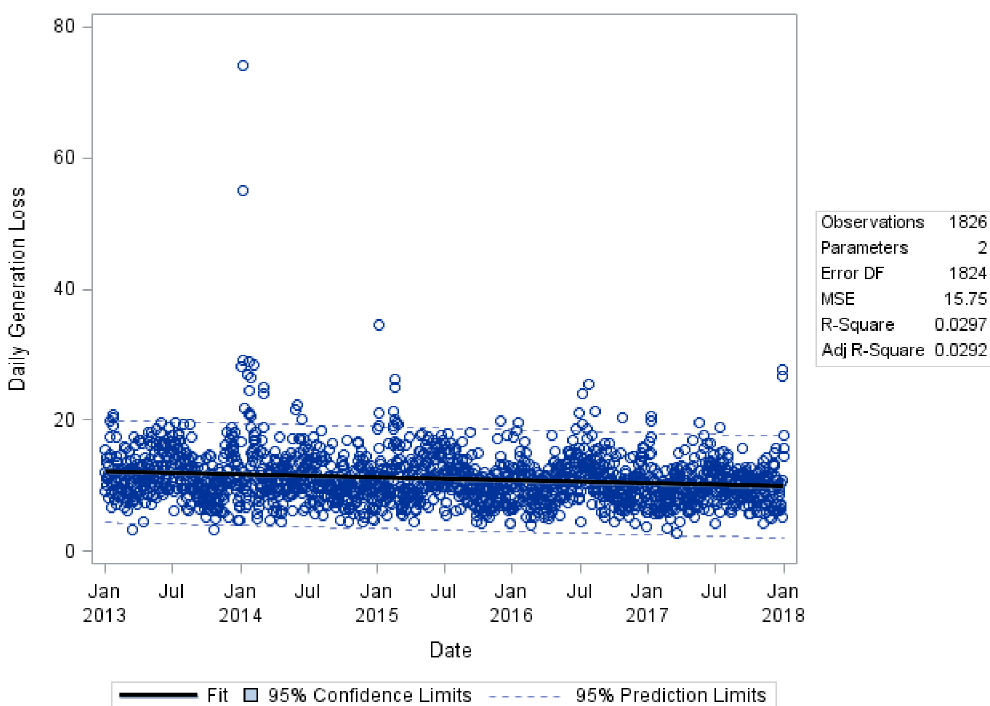


Figure A.7: Scatter Plot of DGL with Time Trend Line (2013–2017)

The DGL trend line has a negative slope that is highly statistically significant (p-value<0.0001). This result indicates that it is extremely unlikely that the negative slope was observed by mere chance and confirms that, on average, the daily generation system performance was improving from 2013–2017.

[116] NERC's 2014 Polar Vortex Review is can be found at the following location: https://www.nerc.com/pa/rrm/Pages/January-2014-Polar-Vortex-Review.aspx

Seasonal Analysis of Generation Performance

Figure A.7 reveals a prominent seasonality of the DGL. Further analysis of the seasonal performance confirms and quantifies differences in DGL by season.[117] **Table A.7** shows the DGL descriptive statistics by season based on the 2013–2017 data.

Table A.7: Descriptive Statistics of DGL by Season

Season	N	Mean	Standard Deviation	Minimum	Maximum	Median
Winter	451	11.67	5.81	3.54	74.18	10.58
Spring	305	10.23	3.16	2.68	25.07	9.95
Summer	765	11.45	3.20	4.29	25.58	11.06
Fall	305	9.46	2.76	3.26	20.27	9.45

Seasonal differences in DGL are further illustrated in the boxplot of **Figure A.8**.

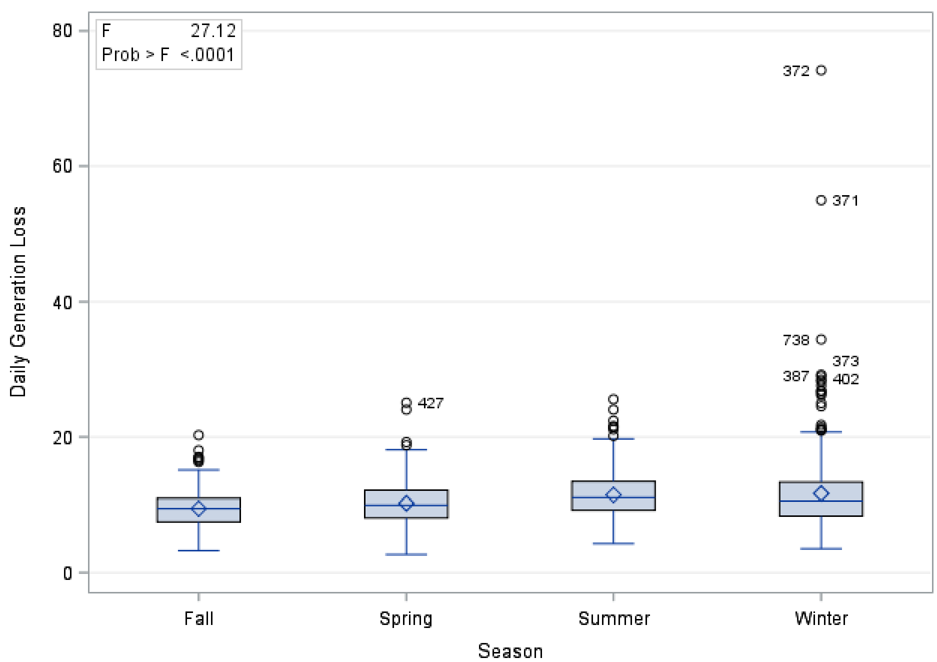


Figure A.8: Boxplot of DGL by Season 2013–2017

Statistical tests[118] indicate statistically significant differences among seasonal distributions of the DGL. **Figure A.9** shows the mean DGL by season ordered from highest (for summer) to lowest (for fall) and summarizes results of Duncan's grouping test for the seasonal means. Each bar connects seasons with similar (not statistically significantly different) mean DGL values. Thus, differences in summer and winter DGL (connected by a blue bar) are not significant, and, on average, these seasons have similar daily generation losses; however, winter generation performance is more volatile as indicated by the largest seasonal standard deviation and illustrated by multiple outliers in **Figure A.8**. Fall DGL is statistically the lowest, and the spring performance is the second best.

[117] For seasonal analysis of TADS and GADS data in Appendix A, winter includes the months of January, February, and December of the same calendar year. Summer includes May through September; all other months are categorized as spring/fall.

[118] ANOVA with Fisher's Least Significant Difference test and Duncan grouping test at the significance level of 0.05.

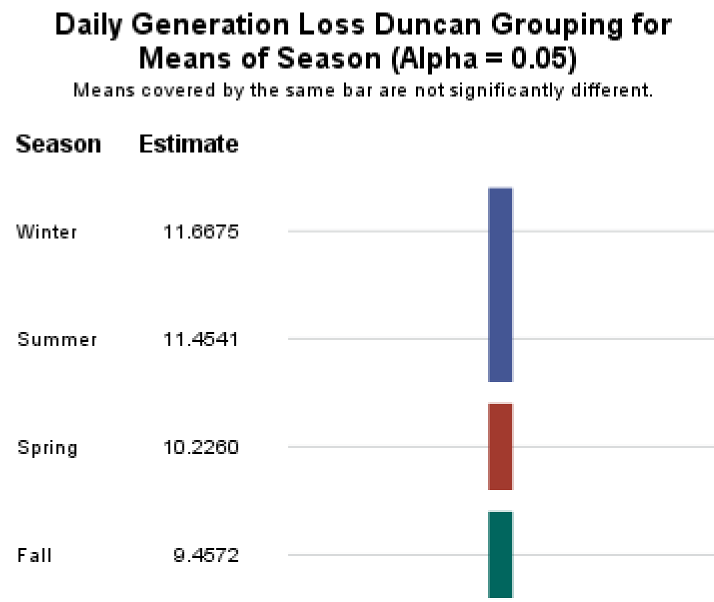


Figure A.9: Average DGL by Season and Seasonal Grouping by Mean DGL (2013–2017)

2017 Generation Performance vs. Historical Seasonal Bounds

The detected seasonal differences motivated the analysis of the daily 2017 generation performance based on seasonal bounds for typical daily values.

Figure A.10 shows a daily plot of the DGL score for 2017 (shown in blue) against bounds of typical seasonal performance calculated using 2013–2016 (historical) daily data. On a daily basis, a general normal range of performance exists. This normal range is defined as the 90-percent confidence interval of historical seasonal values and is visible as a band between the fifth percentile of seasonal values (orange line) and the ninety-fifth percentile of seasonal values (grey line). For each season, the historical median and mean are also shown.

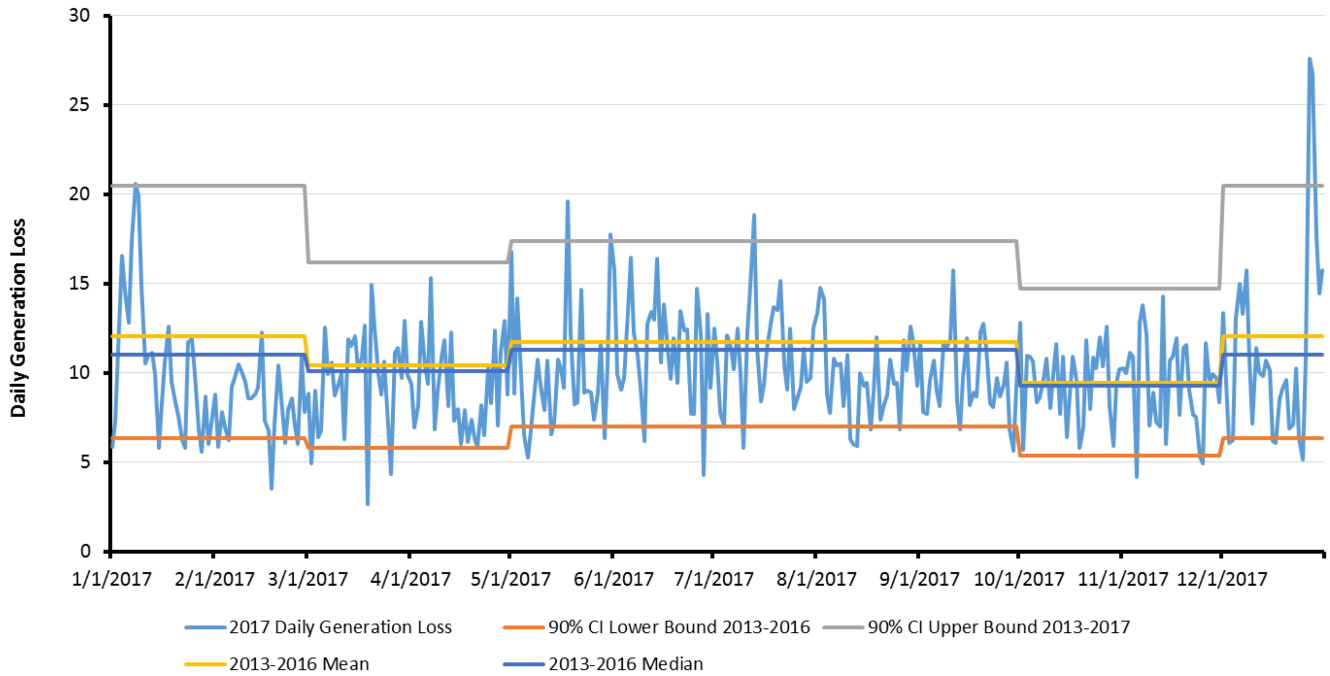


Figure A.10: 2017 Daily Generation Loss with the 2013–2016 90-Percent Confidence Interval by Season

Days of stress rise above the seasonal daily control limits. **Figure A.10** shows that the BPS generation performance in 2017, as measured by the DGL, had only six stress days which exceeded historical seasonal bounds (for a year similar to the historical years the expected number of the stress days is 18.25). Additionally, a total of 38 days were below the corresponding historical lower seasonal bounds. These results show an improved seasonal generation performance in 2017 as compared to the previous four years.

Of the six stress days, there were three extreme winter days that exceeded any seasonal control bound. Forced outages due to weather-related causes were clustered in groups of Regions. The following is in rank order from greatest amount of capacity reporting forced outages: 68.1 percent (48,632 MW) of the capacity reporting forced outages over the three extreme winter days was located in SERC, RF, and NPCC; 28.3 percent (20,178 MW) of the capacity reporting forced outages was located in WECC, MRO, Texas RE, and SPP RE, with the remaining 3.5 percent (2,565 MW) reported by units in FRCC.

Daily Generation Performance by Year

The descriptive statistics of the annual distributions of the daily generation loss values are listed in **Table A.8**.

Table A.8: Descriptive Statistics of DGL by Year

Year	N	Mean	Standard Deviation	Minimum	Maximum	Median
2013	365	11.58	3.40	3.26	20.92	11.16
2014	365	11.60	5.73	4.35	74.18	10.61
2015	365	10.99	3.77	4.14	34.41	10.49
2016	366	10.67	3.33	3.77	25.58	10.52
2017	365	9.99	3.14	2.68	27.61	9.71

The year-over-year differences in transmission performance and a 2017 improved performance are further illustrated in the boxplot of **Figure A.11**.

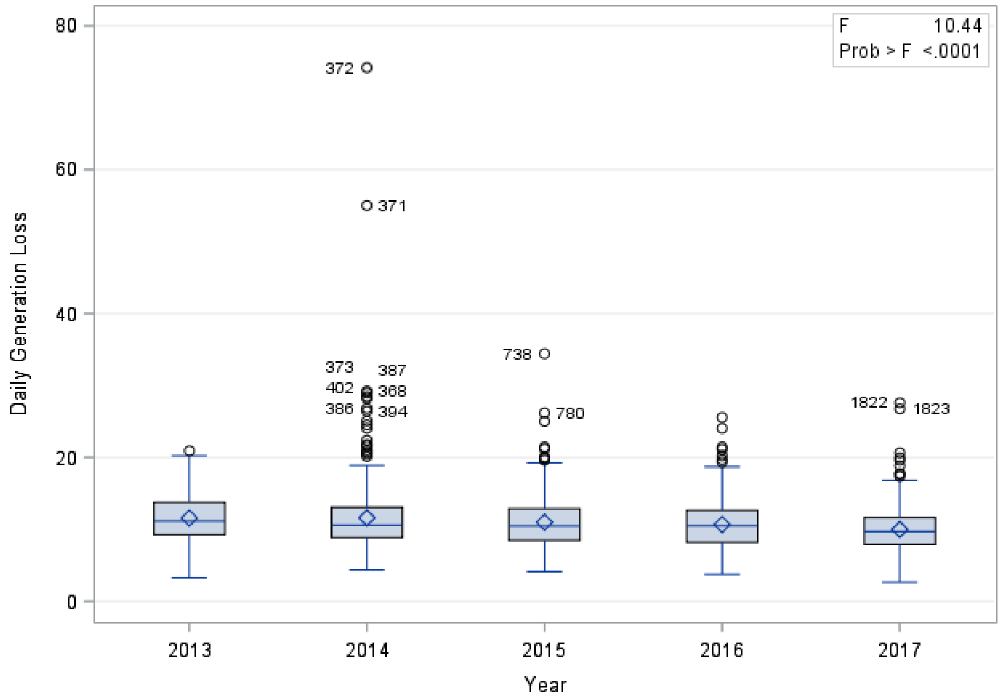


Figure A.11: Boxplot of Daily Generation Loss by Year (2013–2017)

Table A.8 and **Figure A.11** indicate that the 2017 generation performance was the best as measured by the mean and median as well as smaller variability of values as measured by the standard deviation.

Statistical tests[119] found statistically significant differences among annual distributions of the DGL. **Figure A.12** shows the mean DGL by year ordered from highest (in 2014) to lowest (in 2017) and summarizes results of Duncan's grouping test for the annual means. Each bar connects years with similar (not statistically significantly different) mean DGL values. Thus, differences in 2014 and 2013 DGL (connected by a blue bar) are not significant, and, on average, these years had similar daily generation losses. The 2017 DGL was statistically significantly lower than for the previous four years.

[119] ANOVA with Fisher's Least Significant Difference test and Duncan grouping test at the significance level of 0.05.

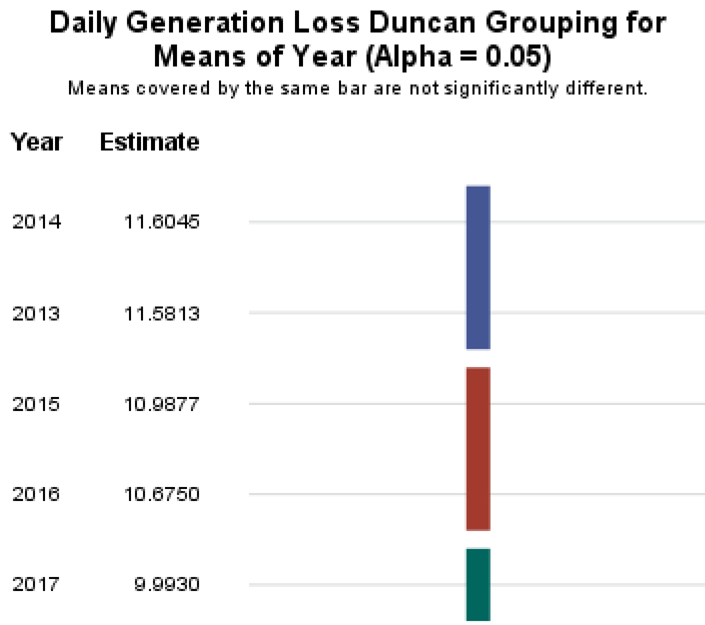


Figure A.12: Average DGL by Year and Grouping by Mean DGL (2013–2017)

The results provided in the previous four sections of this appendix lead to the conclusion that BPS generation performance improved significantly in 2017.

Appendix B: Statistical Analysis of Transmission Data

This appendix provides an analysis of TADS outage events based on their TADS outage initiating or sustained cause(s) with an impact of an event defined as its transmission outage severity given by **Equation B.1**.

Study Method

The following four sections provide a description of the data analysis methodology used in this appendix to rank transmission outage causes by risk to the transmission system and track TADS data changes by year. The final section in this appendix provides TADS event statistics by year.

Defining BPS Impact from Transmission Risk

The impact of a TADS event to BPS reliability is called the TOS of the event. A TADS event TOS is defined by either **Equations B.1** or **Equation B.2**, depending on the element types included. The equations are aligned to the definition of transmission component of the SRI. **Equation B.1** is used for TADS studies involving ac circuit outage events; **Equation B.2** is applied to TADS studies involving both ac circuit and transformer outage events. The severity of a transmission outage is calculated based on its estimated contribution of power flow capacity through TADS transmission element based on voltage class. The average power flow MVA values or equivalent MVA values are shown in **Table B.1**. These equivalent MVA values are also applied to the denominator of the TOS equation to normalize the function. For normalization, the denominator in **Equation B.1** is defined as the sum of the equivalent MVA's of TADS ac circuit inventory for the same year as the event; similarly, the denominator in **Equation B.2** is defined as the sum of the equivalent MVA's of TADS ac circuit and transformer inventory for the same year as the event. This allows comparison of TADS events across years while taking into account the changing number of ac circuits and transformers within the BPS.

$$Transmission\ Outage\ Severity\ (TADS\ AC\ circuit\ outage\ event) = \frac{\sum(Equivalent\ MVA\ of\ AC\ Circuits\ with\ automatic\ outages\ in\ this\ event)}{\sum(Equivalent\ MVA\ of\ ALL\ AC\ Circuits\ in\ TADS\ inventory)} \cdot 1000$$

Equation B.1

$$Transmission\ Outage\ Severity\ (TADS\ AC\ circuit\ or\ Transformer\ outage\ event) = \frac{\sum(Equivalent\ MVA\ of\ AC\ Circuits\ and\ Transformers\ with\ sustained\ automatic\ outages\ in\ this\ event)}{\sum(Equivalent\ MVA\ of\ ALL\ AC\ Circuits\ and\ Transformers\ in\ TADS\ inventory)} \cdot 1000$$

Equation B.2

Table B.1: Equivalent MVA Values of TADS Elements

Voltage Class	AC Circuits	Transformers
100–199 kV	200	100
200–299 kV	700	259
300–399 kV	1,300	518
400–599 kV	2,000	1,034
600–799 kV	3,000	1,441

Impact of the TADS Data Collection Changes

Beginning in 2015, the reporting changed through the NERC Rules of Procedure 1600 Data Request so that TADS data collection would align with the implementation of the FERC approved BES definition.[120] Two additional voltage classes were amended, namely, less than 100 kV and 100–199 kV.

TADS provides information to classify automatic outages as momentary or sustained.[121] A momentary outage is defined as an automatic outage with an outage duration of less than one minute. If the circuit recloses and trips again within less than a minute of the initial outage, it is only considered one outage. The circuit would need to remain in service for longer than one minute between the breaker operations to be considered two outages. A Sustained Outage[122] is defined as an automatic outage with an outage duration of a minute or greater.

Changes to TADS data collection had an impact on existing metrics and provides for expanded analysis. **Table B.2** illustrates the ac circuit data collected at the various voltage classes available to support outage metrics. For example, discontinuation of the non-automatic planned outage data no longer supports a total outage availability (or unavailability) metric. Sustained outages are the only common outages collected at all voltage classes above and below 200 kV.

Table B.2: TADS BES Outage Data Collection by AC Voltage Class (Effective Jan 1, 2015)

AC Voltage Class	Automatic Outages		NonAutomatic Outages	
	Sustained	Momentary	Planned	Operational
Below 100 kV	Yes	No	No	No
100–199 kV	Yes	No	No	No
200–299 kV	Yes	Yes	No	Yes
300–399 kV	Yes	Yes	No	Yes
400–599 kV	Yes	Yes	No	Yes
600–799 kV	Yes	Yes	No	Yes

Legend	
Yes	Outage data collected for this type of outage and voltage class
No	Outage data not collected for this type of outage and voltage class

In this Appendix, the following TADS study cases were analyzed by ICC or SCC:

1. TADS sustained and momentary events for 200 kV+ ac circuits (2013–2017) analyzed by ICC
2. TADS common or dependent mode (CDM) events for 200 kV+ ac circuits (2013–2017) analyzed by ICC
3. RE transmission analysis of momentary and sustained events of 200 kV+ ac circuits (2013–2017) by ICC
4. TADS sustained events of 100 kV+ ac circuits and transformers[123] (2015–2017) analyzed by ICC

[120] The FERC approved BES definition can be found at the following location: http://www.nerc.com/pa/RAPA/Pages/BES.aspx
[121] TADS information on automatic outages can be found at the following location: http://www.nerc.com/pa/RAPA/tads/Pages/default.aspx.
[122] The TADS definition of Sustained Outage is different from the NERC *Glossary of Terms* used in *Reliability Standards* definition of Sustained Outage that is presently only used in FAC-003-1. The glossary defines a Sustained Outage as follows: "The de-energized-energized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure." The definition is inadequate for TADS reporting for two reasons. First, it has no time limit that would distinguish a sustained outage from a momentary outage. Second, for a circuit with no automatic reclosing, the outage would not be "counted" if the TO has a successful manual reclosing under the glossary definition.
[123] Transformer voltages are determined based on the element's secondary voltage.

5. Sustained cause code and ICC-SCC study for sustained outages of 100 kV+ ac circuits (2015–2017).

The less than 200 kV sustained automatic outage data set was not included in Study 1–3 to allow for a valid year-over-year comparative analysis of the 200 kV+ data set for the years 2013–2017. In studies 1–3 and 5, the TOS of TADS events is calculated by using **Equation B.1**. In Study 4 it is calculated by using **Equation B.2**.

Determining Initiating Causes and Modification Method

TADS collects automatic outages[124] and operational outages.[125] A TADS event is a transmission incident that results in the automatic outage (sustained or momentary) of one or more elements. TADS events are categorized by ICC. These ICCs facilitate the study of cause-effect relationships between each event's ICC and event severity. The procedure illustrated in **Figure B.1** is used to determine a TADS event's ICCs. The procedure that defines ICCs for a TADS event allows ICC assignment to a majority of transmission outage events recorded in TADS.

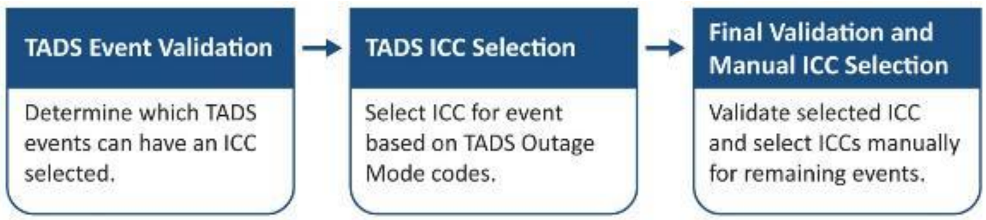


Figure B.1: TADS Event Initiating Cause Code Selection Procedure

The *State of Reliability 2013–2017* reports included analysis based on an augmented data set that defined changes in ICCs to further distinguish normal clearing events from abnormal clearing events. Two TADS ICCs are impacted: Human Error and Failed Protection System Equipment.

- TADS Human Error ICC is subdivided by type codes, which first became available in 2012. Using the type codes in the consequent *State of Reliability* reports, data for two specific type codes related to protection system misoperations have been removed from the Human Error ICC and added to the Failed Protection System Equipment ICC. Those type codes are 61, dependability[126] (failure to operate), and 62, security[127] (unintended operation).
- TADS Failed Protection System Equipment ICC, plus the Human Error type code 61 and 62 data, are added together in a new or augmented ICC labeled "Misoperation" in each *State of Reliability* report.

Note: in this appendix, references to ICC mean the augmented ICC as described above.

Determining Relative Risk

The process of the statistical analysis (performed to identify top causes to transmission risk) is demonstrated in **Figure B.2** Steps 1–4; after preliminary steps of assigning ICC's to TADS events, described in the previous section, and

[124] This is an outage that results from the automatic operation of a switching device, causing an element to change from an in-service state to a not in-service state. Single-pole tripping, followed by successful ac single-pole (phase) reclosing, is not an automatic outage.

[125] This is a nonautomatic outage for the purpose of avoiding an emergency (i.e., risk to human life, damage to equipment, damage to property) or to maintain the system within operational limits and that cannot be deferred. This includes nonautomatic outages resulting from manual switching errors.

[126] Event Type 61 Dependability (failure to operate): one or more automatic outages with delayed fault clearing due to failure of a single protection system (primary or secondary backup) under either of these conditions:

- Failure to initiate the isolation of a faulted power system element as designed or within its designed operating time
- In the absence of a fault, failure to operate as intended within its designed operating time

[127] Event Type 62 Security (unintended operation): one or more automatic outages caused by improper operation (e.g., overtrip) of a protection system resulting in isolating one or more TADS elements it is not intended to isolate, either during a fault or in the absence of a fault.

calculation of a TOS for every event by using **Equation B.1** or **Equation B.2,** NERC staff proceeded to determine relative risks of ICCs and ranked them by contribution to the total TOS of TADS events.

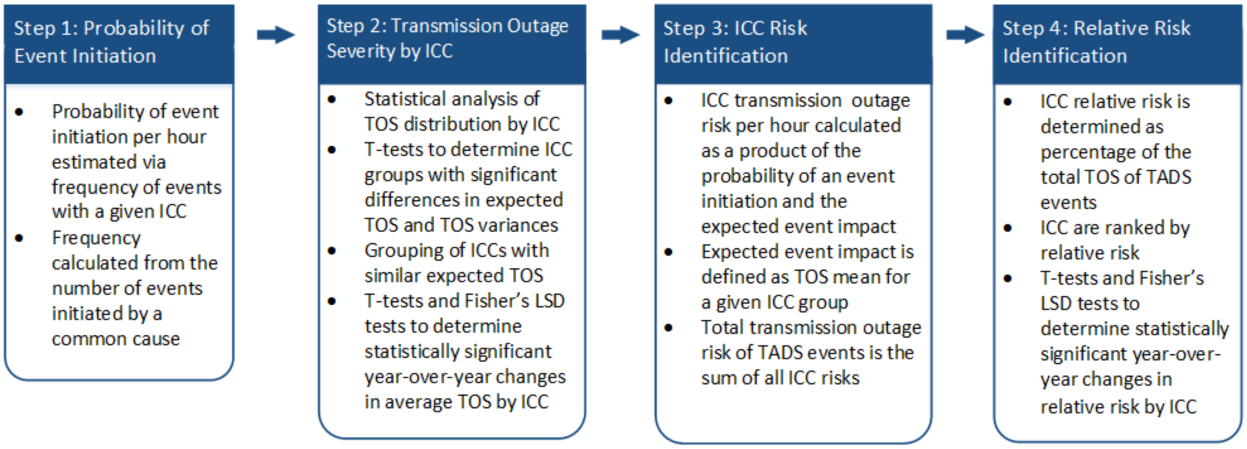


Figure B.2: Transmission Outage Risk Identification Method

First, the probability that an event from a given group initiates during a given hour was estimated from the frequency of the events of each type without taking into account the event duration. Then, distributions of TOS were examined for all TADS events and separately for events with a given ICC. A series of t-tests[128] were performed to compare the expected TOS of a given ICC with the expected outage severity of the rest of the events at significance level of 0.05. Then the Fisher's Least Significant Difference[129] method was applied to determine statistically significant[130] differences in the expected TOS for all pairs of ICCs. Next, Duncan's grouping test[131] found clusters of ICC groups with similar expected TOS values.

Statistically significant differences in the expected TOS for each ICC group were analyzed for each year of data. This showed if the average TOS for a given ICC group had changed over time.

The relative risk was calculated for each ICC group. The impact of an outage event was defined as the expected TOS associated with a particular ICC group. The risk per hour of a given ICC was calculated as the product of the probability per hour and the expected severity (impact) of an event from this group. The relative risk was then defined as the percentage of the risk associated with each ICC out of the total (combined for all ICC events) risk per hour.

TADS Event Statistics by Year

Table B.3 provides the information about the number of transmission outage events analyzed in Appendix B. There are 18,693 momentary and sustained 200 kV+ ac circuit events included in the analysis done for Studies 1–3 (shown in the following sections). These studies include a five-year range of data from 2013–2017. There are 19,548 sustained 100 kV+ ac circuit and/or transformer events analyzed for Studies 4 and 5 (shown in the following sections). As momentary outage data are not available for 100–199 kV circuits, these studies only include the impact of sustained outages. It should also be noted that the number of ac circuit and transformer events does not equate to the sum of the two individual values combined due to events including both ac circuits and transformers.

[128] For t-test, see D. C. Montgomery and G. C. Runger, Applied Statistics and Probability for Engineers. Fifth Edition. 2011. John Wiley & Sons. Pp. 361–369.

[129] For Fisher's Least Significance Difference (LSD) method or test, see D. C. Montgomery and G. C. Runger, Applied Statistics and Probability for Engineers. Fifth Edition. 2011. John Wiley & Sons. Pp. 524–526.

[130] At significance level of 0.05

[131] D. B. Duncan. Multiple Range and Multiple F-tests. *Biometrics,* V.11, No.1, March 1955, pp.1–42.

Table B.3: TADS Automatic Outage Event Summary (2013–2017)						
Summary	**2013**	**2014**	**2015**	**2016**	**2017**	**2013–2017**
Number of Momentary and Sustained 200 kV+ AC Circuit TADS Events	3,762	3,434	3,772	3,935	3,790	18,693
Number of Sustained 100 kV+ AC Circuit TADS Events	N/A	N/A	6,155	6,105	6,370	18,630
Number of Sustained 100 kV+ Transformer TADS Events	N/A	N/A	445	459	502	1,406
Number of Sustained 100 kV+ AC Circuit and Transformer TADS Events*	N/A	N/A	6,456	6,404	6,688	19,548
* Value does not equal sum of 100 kV+ ac circuit plus 100 kV+ transformer events due to overlap in element involvement.						

Study 1: TADS Sustained and Momentary Events for 200 kV+ AC Circuits

Events with Common ICC by Year and Estimates of Event Probability

Table B.4 lists annual counts and hourly event probability of 200 kV+ ac circuit automatic outage events by ICC and for all ICC combined. From 2013–2017, a total of 18,693 events were reported, including 8,457 momentary (45 percent of total) events and 10,236 (55 percent of total) sustained events. In Study 1–3 momentary and sustained events are analyzed together.

Almost all TADS ICC groups have sufficient number of events to be used in a statistical year-to-year analysis.[132] Only three ICCs (Vegetation; Vandalism, Terrorism, or Malicious Acts; and Environmental) do not have sufficient size for reliable statistical inferences. Therefore, these ICC groups are combined into a new group, named "Combined Smaller ICC Groups" that can be statistically compared to every other group and also studied with respect to annual changes of TOS.

For TADS events initiated by a common cause, the probability of observing the initiation of an event during a given hour (listed in the last column of **Table B.4**.) is estimated by using the corresponding historical event occurrences reported in TADS.[133] The reciprocal of the overall event initiation frequency of 0.427 per hour indicates that in NERC's defined BES system of 200 kV+ ac circuits the automatic outage event started, on average, every 2 hours and 20 minutes.

Table B.4: TADS 200 kV+ AC Circuit Events and Hourly Event Probability by ICC (2013–2017)							
Initiating Cause Code	**2013**	**2014**	**2015**	**2016**	**2017**	**2013–2017**	**Event Initiation Probability/Hour**
Unknown	771	766	888	777	732	3,934	0.090
Lightning	830	681	817	730	664	3,722	0.085
Weather, Excluding Lightning	444	447	536	638	655	2,720	0.062
Failed AC Circuit Equipment	252	223	272	358	300	1,405	0.032

[132] A size of the dataset should be sufficient to apply the Central Limit Theorem for the annual sample means (40 or more observations).

[133] Probability is estimated using event occurrence frequency of each ICC type without taking into account the event duration. Namely, the event occurrence probability is the total number of occurrences for a given type of event observed during the historical data period divided by the total number of hours in the same period. Therefore, the sum of the estimated probabilities over all ICCs is equal to the estimated probability of any event during a given hour.

Table B.4: TADS 200 kV+ AC Circuit Events and Hourly Event Probability by ICC (2013–2017)							
Initiating Cause Code	**2013**	**2014**	**2015**	**2016**	**2017**	**2013–2017**	**Event Initiation Probability/Hour**
Misoperation	303	319	223	251	232	1,328	0.030
Foreign Interference	191	222	260	254	220	1,147	0.026
Contamination	163	149	163	290	276	1,041	0.024
Failed AC Substation Equipment	197	226	232	208	162	1,025	0.023
Human Error (w/o Type 61 OR Type 62)	213	150	140	151	126	780	0.018
Fire	154	42	66	72	196	530	0.012
Power System Condition	107	85	57	82	105	436	0.010
Other	84	75	82	78	59	378	0.009
Combined Smaller ICC Groups	53	49	36	46	63	247	0.006
Vegetation	36	39	30	33	45	183	0.004
Vandalism, Terrorism, or Malicious Acts	9	8	2	7	7	33	0.001
Environmental	8	2	4	6	11	31	0.001
All Events	**3,762**	**3,434**	**3,772**	**3,935**	**3,790**	**18,693**	**0.427**

The six largest ICC groups combined amount to 76 percent of TADS events for the most recent five years. ICC Unknown is the biggest group of events with 21 percent of the events from 2013–2017.

This increased number of events with the Fire ICC in 2013 and 2017 were caused by high numbers of wildfires and largely should not be attributed to causes that are directly preventable by utilities.

In 2017, there was a significant decrease in the number of events for a majority of ICC groups (Unknown, Lightning, Failed AC Circuit Equipment, Misoperation, etc.,) reflected in an overall decrease in the number of outage events (a decrease of four percent from 2016 to 2017). In contrast, ICC groups Fire, Combined smaller ICC groups, and Power System Condition significantly increased from 2016 to 2017.

The number of events initiated by Vegetation increased from 33 in 2016 to 45 events in 2017.[134]

TOS by ICC

Using the TOS measure and TADS event ICCs, NERC staff statistically analyzed the most recent five years of TADS data (2013–2017).[135] The distribution of TOS was studied separately for events with a given ICC and the complete dataset for the five years combined.

[134] In response to ineffective vegetation management, as identified as a major cause of the August 14, 2003, blackout, NERC developed and has since updated a vegetation management Reliability Standard (FAC-003-4 is the latest versions). TADS contains all transmission outages of the BPS elements caused by vegetation. FAC-003-4 has a different sustained outage definition than TADS, concerns a smaller voltage level population, and deals only with limited and specific outages such as those caused by vegetation "fall-ins." Confusion between the two data sets should be avoided.

[135] All statistical tests in Study 1 are performed at the significance level alpha = 0.05.

The average TOS of the 2013–2017 automatic outage events of the 200 kV+ ac circuits is 0.12, the median TOS is 0.07, and a sample deviation is 0.07. The largest TOS of 2.75 was observed on August 5, 2013, in a NPCC event initiated by Lightning with outages on nine 600–799 kV ac circuits.

Next, statistical tests are performed to determine statistically significant differences in the average TOS between ICC groups. The TOS averages (means) by ICC are shown in **Figure B.3**. A series of the t-tests reveals that each of groups of events initiated by Fire, Misoperation, Failed AC Substation Equipment, Power System Condition, Contamination, and Human Error has statistically greater expected outage severity than other events.[136] This means that, when an event initiated by one of these causes occurs it is expected to have a greater impact and a higher risk to the transmission system. The tests on homogeneity of variances find statistically greater variances (and the standard deviations) for the same ICC groups except Contamination as compared with other events. The greater variance can signify additional risk since it implies more frequent occurrences of events with high TOS.

Further t-tests indicate that each of the ICC groups Foreign Interference, Combined Smaller ICC groups, Failed AC Circuit Equipment, Weather (Excluding Lightning), and Unknown has statistically smaller expected outage severity than other events.[137] Finally, events initiated by Lightning and Other do not have a significant difference in outage severity with other events, and therefore are expected to have an average dataset TOS when happen.[138]

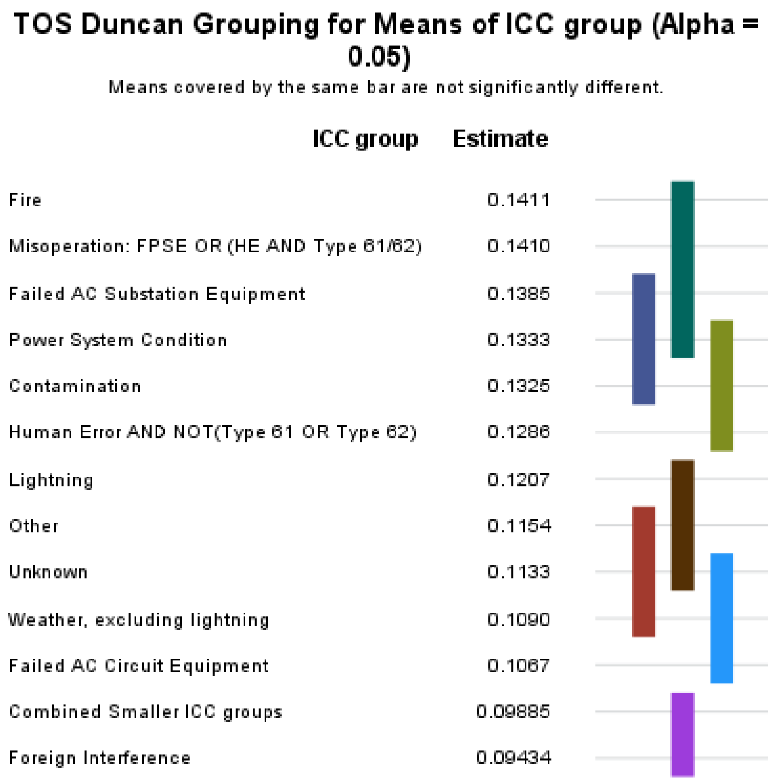


Figure B.3: TOS of 200 kV+ AC Circuit Outage Events by ICC and ICC grouping by Expected TOS (2013–2017)

[136] Additionally, a test on significance of correlation, which is equivalent to a polled t-test, confirms that these ICCs have a statistically significant positive correlation with TOS.
[137] Additionally, a test on significance of correlation, which is equivalent to a polled t-test, confirms that these ICCs have a statistically significant negative correlation with TOS.
[138] Additionally, a test on significance of correlation, which is equivalent to a polled t-test, confirms that ICCs Lightning and Other have no significant correlation with TOS.

Figure B.3 shows the mean TOS by ICC ordered from highest to lowest and summarizes results of Duncan's grouping test for the TOS means. Each bar connects ICC groups with similar (not statistically significantly different) expected TOS. For example, differences in TOS between events initiated by Lightning, Other, and Unknown, connected by a brown bar, are not significant, meaning that individual impacts of events from these groups (the expected TOS) are similar.

Average TOS by ICC: Annual Changes

Year-over-year changes in calculated TOS for 200 kV+ ac circuit events by ICC are reviewed next. **Figure B.4** shows changes in the average TOS for each ICC for the 2013–2017 dataset. The groups of ICC events are listed from left to right by descending average TOS for the five years combined (the average TOS are listed in **Figure B.3**). The largest average TOS over the five-year period was observed for events initiated by Fire, mostly due to the very high average TOS in the year 2013. The unusually high severity of Fire events can be contributed to a particular string of events that occurred in Canada, putting a number of high voltage elements out of service repeatedly.

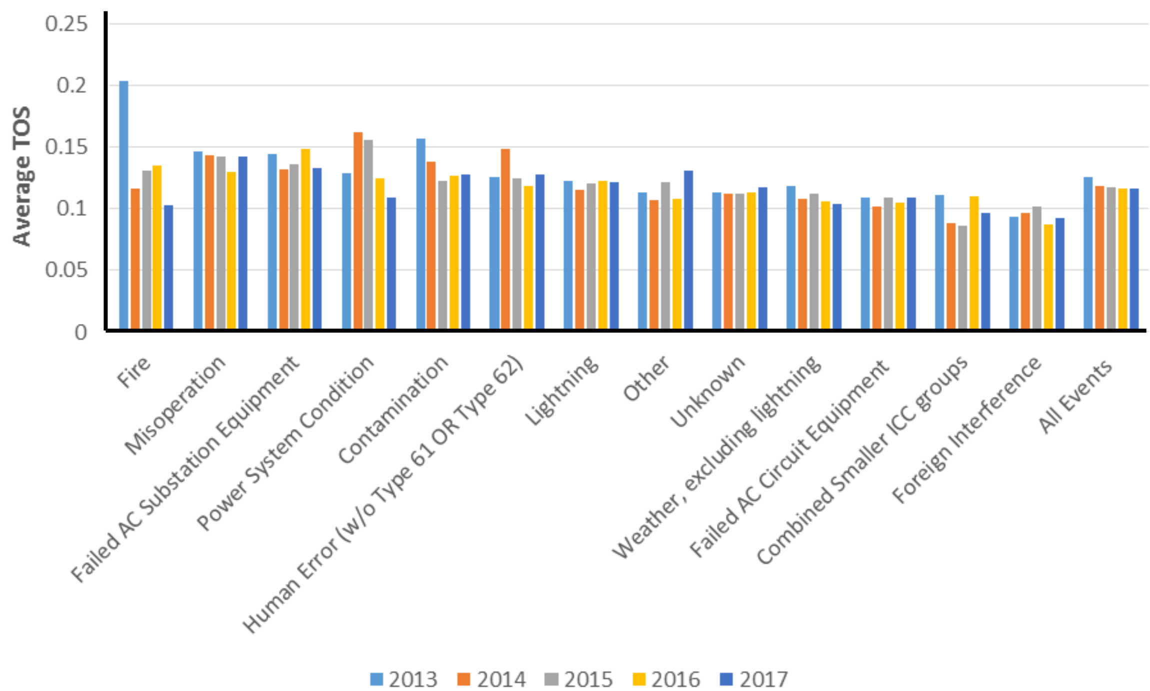


Figure B.4: Average TOS of 200 kV+ AC Circuit Events by ICC and Year (2013–2017)

A series of Fisher's Least Significant Difference tests allowed to identify statistically significant year-over-year changes in TOS by ICC and for all event combined. In 2017, the average TOS statistically significantly decreased for ICCs:

- **Fire:**[139] compared with 2013, 2015, 2016
- **Power System Condition:** compared with 2014 and 2015
- **Contamination:** compared with 2013
- **Weather, Excluding Lightning:** compared with 2013 and 2015
- **Foreign Interference:** compared with 2015

In 2017 the average TOS statistically significantly increased for ICCs:

[139] Although the number of Fire initiated events was higher in 2017 than in previous years, the severity of the individual events was much lower, causing the overall TOS due to Fire events to be the lowest within the studied data set.

- **Other:** compared with 2014
- **Unknown:** compared with 2014 and 2015

There were no significant changes for other ICC groups in 2017. For all events combined, the average TOS in 2013 was statistically greater than in 2014–2017, and for 2014–2017 the TOS had, on average, no significant changes.

TOS Risk and Relative Risk of 200 kV+ AC Circuit Outage Events by ICC

The risk of each ICC group can be defined as the total TOS associated with this group. Its relative risk is equal to the percentage of the group TOS in the 2013–2017 database. The risk of a given ICC per hour can be defined as the product of the probability that an event with this ICC initiates during an hour and the expected TOS (impact) of an event from this group.[140]

Relative risk of the 2013–2017 TADS 200 kV+ ac circuit events by ICC is listed in **Table B.5** in decreasing order. Lightning and Unknown are two ICCs with the largest relative risk of more than 20 percent of the total five-year TOS each. Events initiated by Lightning have a small expected individual TOS but they happened more frequently than events with other ICCs. Similarly, ICC Unknown initiates events with an average expected TOS but very frequently. Fire has a low rank with respect to relative risk despite having the largest average TOS of an individual event due to small number of events with this ICC, and, respectively, their low probability.

Table B.5: Relative Risk of TADS AC Circuit 200 kV+ Events by ICC (2013–2017)

Group of TADS events	Probability that an Event from a Group Starts during a Given Hour	Expected Impact (Expected TOS of an Event)	Risk Associated with a Group per Hour	Relative Risk by Group
All TADS events 200 kV+	0.427	0.119	0.051	100.0%
Lightning	0.085	0.121	0.010	20.2%
Unknown	0.090	0.113	0.010	20.1%
Weather, Excluding Lightning	0.062	0.109	0.007	13.4%
Misoperation	0.030	0.141	0.004	8.4%
Failed AC Circuit Equipment	0.032	0.107	0.0034	6.8%
Failed AC Substation Equipment	0.023	0.139	0.0032	6.4%
Contamination	0.024	0.132	0.0031	6.2%
Foreign Interference	0.026	0.094	0.0025	4.9%
Human Error (w/o Type 61 OR Type 62)	0.018	0.129	0.0023	4.5%
Fire	0.012	0.141	0.0017	3.4%
Power System Condition	0.010	0.133	0.0013	2.6%
Other	0.009	0.115	0.0010	2.0%
Combined Smaller ICC groups	0.006	0.099	0.0006	1.1%

[140] The probability that an event from a given ICC group initiates during a given hour is listed in **Table B.4**, and the expected TOS by ICC are shown in **Figure B.3**. For any ICC group, the relative risk per hour is the same as the relative risk for a year (or any other time period) if estimated from the same dataset.

Figure B.5 shows year-over-year changes in the relative risk of TADS events by ICC. The groups of ICC events are listed from left to right by descending relative risk for years 2013–2017 combined. The top contributor to transmission risk, Lightning, had a decrease in relative risk in 2016 due to a decrease in the number (and the frequency) of events as reflected in **Table B.4**. The relative risk of Unknown slightly increased from 2016 to 2017 because of an increase in the average TOS of this group but it still remained below the 2015 and 2016 levels. In contract, Weather, Excluding Lightning, had consecutive year-to-year increases from 2013–2017.

The relative risk of Misoperation stayed essentially flat over 2015–2017 after significant decrease from 2014 to 2015. Also, there was a significant decrease in the relative risk for the ICC Failed AC Circuit Equipment due to significant reduction in the frequency of these events in 2017.

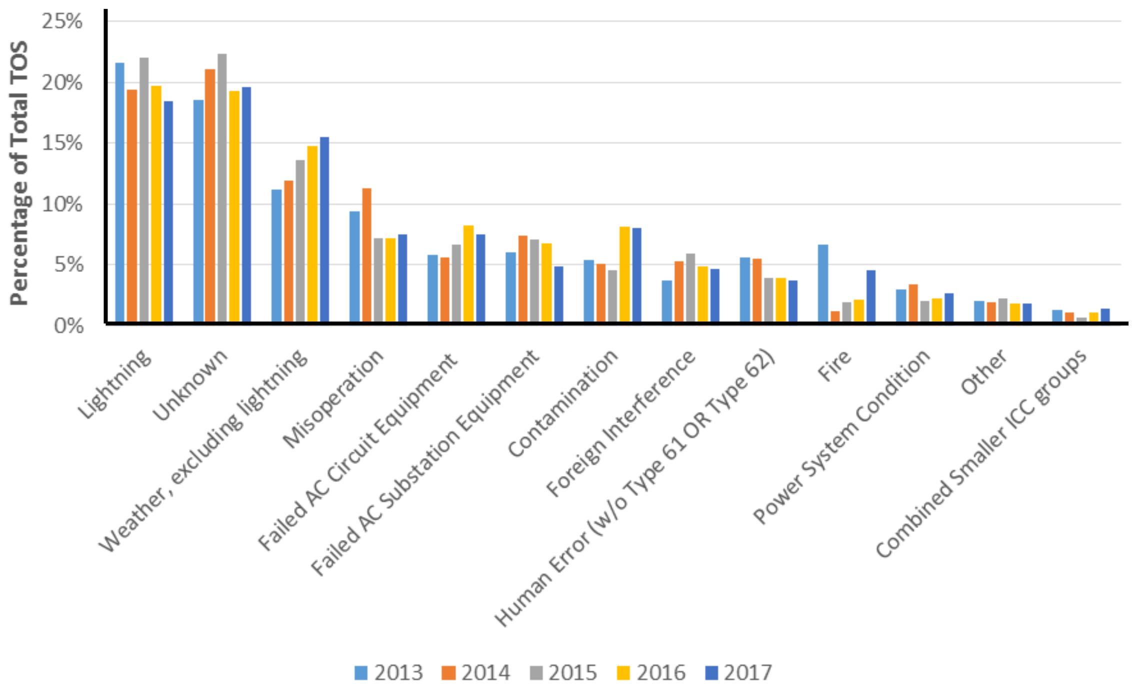


Figure B.5: Relative TOS Risk 200 kV+ AC Circuit Outage Events by ICC and Year (2013–2017)

Study 2: TADS Sustained and Momentary CDM Events for 200 kV+ AC Circuits

CDM Event ICC Analysis (2013–2017)

TADS provides information to classify outages as Single Mode or CDM events. A Single-Mode event is defined as a TADS event with a single-element outage. CDM events result in multiple transmission element outages where all outages have one of the mode codes (other than Single Mode) as described in **Table B.6**. Typically, these TADS events have a higher TOS than TADS events with a Single-Mode outage. It is important to monitor and investigate CDM events due to their increased risk to system reliability.

Table B.6: Outage Mode Codes	
Outage Mode Code	**Automatic Outage Description**
Single Mode	A single-element outage that occurs independently of another automatic outage

Table B.6: Outage Mode Codes	
Outage Mode Code	**Automatic Outage Description**
Dependent Mode Initiating	A single-element outage that initiates at least one subsequent element automatic outage
Dependent Mode	An automatic outage of an element that occurred as a result of an initiating outage, whether the initiating outage was an element outage or a non-element outage
Common Mode	One of at least two automatic outages with the same ICC where the outages are not consequences of each other and occur nearly simultaneously
Common Mode Initiating	A common-mode outage that initiates one or more subsequent automatic outages

Table B.7 lists numbers of CDM events of 200 kV+ ac circuits by ICC for 2013–2017. There was a total of 2,581 CDM events. The reciprocal of the probability of 0.059 CDM events per hour indicates that in NERC's defined BES system of 200 kV+ ac circuits a CDM event started, on average, every 16 hours and 59 minutes. CDM events comprise 13.8 percent of all TADS 200 kV+ ac circuit events from 2013–2017. The largest group of CDM events was initiated by Misoperations followed by Failed AC Substation Equipment (18 and 15 percent of the CDM events, respectively).

Table B.7 also provides the population percentage of CDM events in the different ICC groups. These percentages vary greatly—from 3.9 percent of CDM events among events initiated by Contamination to 38.8 percent of events initiated by Failed AC Substation Equipment.

Table B.7: CDM Events 200 kV+ AC Circuits and Hourly Event Probability by ICC (2013–2017)				
Initiating Cause Code	**CDM Events**	**ALL TADS Events 200 kV+**	**CDM as Percent of ALL**	**CDM Event Initiation Probability/Hour**
Misoperation	471	1,328	35.5%	0.011
Failed AC Substation Equipment	398	1,025	38.8%	0.009
Lightning	369	3,722	9.9%	0.008
Unknown	244	3,934	6.2%	0.006
Weather, Excluding Lightning	225	2,720	8.3%	0.005
Human Error (w/o Type 61 OR Type 62)	182	780	23.3%	0.004
Failed AC Circuit Equipment	163	1,405	11.6%	0.004
Power System Condition	162	436	37.2%	0.004
Foreign Interference	116	1,147	10.1%	0.003
Other	115	378	30.4%	0.003
Fire	75	530	14.2%	0.002
Contamination	41	1,041	3.9%	0.001
Combined Smaller ICC groups	20	247	8.1%	0.0005
Vegetation	8	183	4.4%	0.0002
Environmental	7	31	22.6%	0.0002
Vandalism, Terrorism, or Malicious Acts	5	33	15.2%	0.0001
TADS events	**2,581**	**18,693**	**13.8%**	**0.059**

Annual datasets of CDM events do not have enough observations to track statistically significant year-over-year changes in TOS. Upon combining the three smallest ICC groups (Vegetation; Environmental; and Vandalism, Terrorism, or Malicious Acts) into a new group (Combined Smaller ICC groups), the five-year ICC groups are used for the comparative statistical analysis.[141]

The distribution of TOS of CDM events was studied by ICC and for all CDM event combined. The average TOS of the 2013–2017 CDM events of the 200 kV+ ac circuits is 0.17, the median TOS is 0.13, and a sample deviation is 0.14. These parameters are greater than for all 200 kV+ ac circuit events (0.12, 0.07, and 0.07, respectively), which is not surprising since CDM events involve multiple outages.

Next, statistical tests are performed to determine statistically significant differences in the average TOS between ICC groups of CDM events. The average (mean) TOS by ICC are shown in **Figure B.6**. A series of the t-tests confirms that the group of CDM events initiated by Contamination has statistically greater expected TOS than other events.[142] This means that when a CDM event initiated Contamination occurs, this event is expected to have a greater impact and a higher risk to the transmission system. The tests on homogeneity of variances highlights statistically greater variances (and the standard deviations) for ICCs Contamination, Human Error, and Power System Condition as compared with other CDM events. The greater variance can signify additional risk since it implies more frequent occurrences of events with high TOS.

Further t-tests indicate that ICC groups Foreign Interference, Other, and Failed AC Circuit Equipment have statistically smaller expected outage severity than other CDM events.[143] Finally, events initiated by the remaining nine ICC groups of CDM events do not have a significant difference in TOS with other CDM events; therefore, are expected to have average TOS when happen.[144]

[141] All statistical tests in Study 2 are performed at the significance level 0.05.

[142] Additionally, a test on significance of correlation, which is equivalent to a polled t-test, determines that ICCs Contamination and Human Error have a statistically significant positive correlation with TOS.

[143] Additionally, a test on significance of correlation, which is equivalent to a polled t-test, determines that ICCs Foreign Interference and Other have a statistically significant negative correlation with TOS.

[144] Additionally, a test on significance of correlation, which is equivalent to a polled t-test, finds no ICC except Contamination, Human Error, Foreign Interference, and Other that has a significant correlation with TOS.

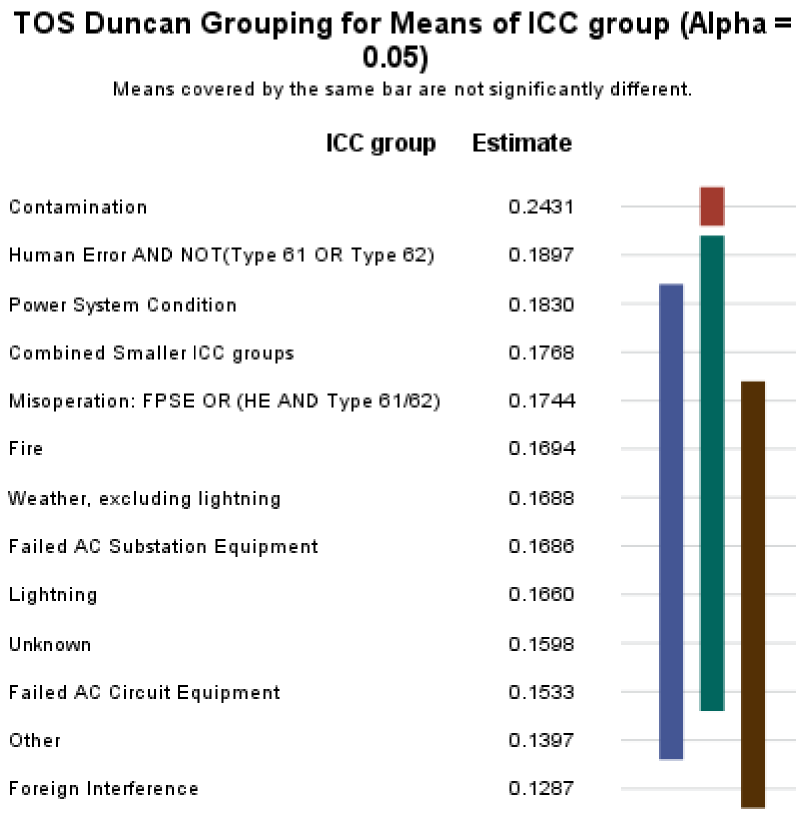


Figure B.6: TOS of 200 kV+ AC Circuit CDM Outage Events by ICC and ICC grouping by Expected TOS (2013–2017)

Figure B.6 shows the mean TOS by ICC order from highest to lowest and summarizes results of Duncan's grouping test for the TOS means of CDM events. Each bar connects ICC groups with similar (not statistically significantly different) expected TOS. For example, differences in TOS between events initiated by Misoperation, Fire, Weather (Excluding Lightning), Failed AC Substation Equipment, Lightning, Unknown, Failed AC Circuit Equipment, Other, and Foreign Interference, connected by a brown bar, are not significant, meaning that individual impacts of events from these groups (the expected TOS) are similar. Something noteworthy is that the results of t-test and Duncan's test reflect less TOS variability between ICC groups for CDM events than for all even. This is partially due to the smaller size of CDM groups.

Finally, the transmission risk and relative risk by ICC group for CDM events were calculated and ranked. Table B.8 provides a breakdown of relative risk of CDM events by ICC group.

Table B.8: Relative Risk of 200 kV+ AC Circuit CDM Events by ICC (2013–2017)

Group of TADS events	Probability that an Event from a Group Starts during a Given Hour	Expected Impact (Expected TOS of an Event)	Risk Associated with a Group per Hour	Relative Risk by Group
All TADS 200 kV+	0.427	0.119	0.051	100.0%
CDM Events	0.059	0.168	0.010	19.6%
Misoperation	0.011	0.174	0.002	3.7%

Table B.8: Relative Risk of 200 kV+ AC Circuit CDM Events by ICC (2013–2017)				
Group of TADS events	**Probability that an Event from a Group Starts during a Given Hour**	**Expected Impact (Expected TOS of an Event)**	**Risk Associated with a Group per Hour**	**Relative Risk by Group**
Failed AC Substation Equipment	0.009	0.169	0.002	3.0%
Lightning	0.008	0.166	0.001	2.8%
Unknown	0.006	0.160	0.001	1.8%
Weather, Excluding Lightning	0.005	0.169	0.001	1.7%
Human Error (w/o Type 61 OR Type 62)	0.004	0.190	0.001	1.6%
Power System Condition	0.004	0.183	0.001	1.3%
Failed AC Circuit Equipment	0.004	0.153	0.001	1.1%
Other	0.003	0.140	0.0004	0.7%
Foreign Interference	0.003	0.129	0.0003	0.7%
Fire	0.002	0.169	0.0003	0.6%
Contamination	0.001	0.243	0.0002	0.4%
Combined Smaller ICC groups	0.0005	0.177	0.0001	0.2%

Overall, TADS CDM events contribute almost 20 percent of the total TOS of the 200 kV+ ac circuits from 2013–2017 with top ICC groups of Misoperation, Failed AC Substation Equipment, and Lightning.

Study 3: Regional Entity Transmission Analysis of 200 kV+ Momentary and Sustained Events

The following is a study of the TOS of TADS events by Region. This analysis is based on the 2013–2017 TADS data for the 200 kV+ ac circuits and utilizes the general methodology described in the previous sections. Here, a summary of this analysis is introduced and similarities and differences in transmission risk profiles by Region are examined.

Figure B.7 illustrates differences among the Regions by showing the breakdown of NERC-wide inventory, TADS ac circuit events, and TOS risk by Region. The breakdown of the number of outage events and total TOS is similar to breakdown of the NERC inventory by ac circuit counts and by ac circuit miles.

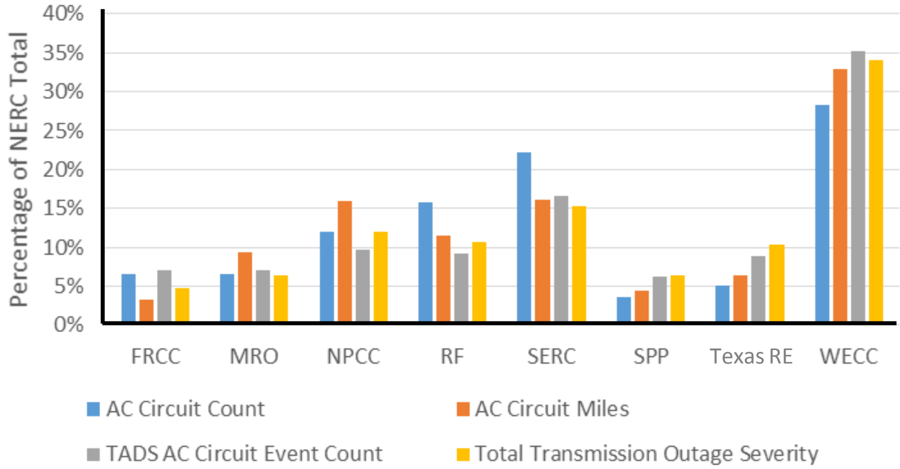


Figure B.7: NERC 200 kV+ AC Circuit Inventory, TADS Events and Breakdown by Region (2013–2017)

The TOS by ICC was studied for each Region. A comparative analysis of RE relative risks by ICC is summarized in **Figure B.8**. ICCs are listed from left to right by decreasing relative risk for NERC data.

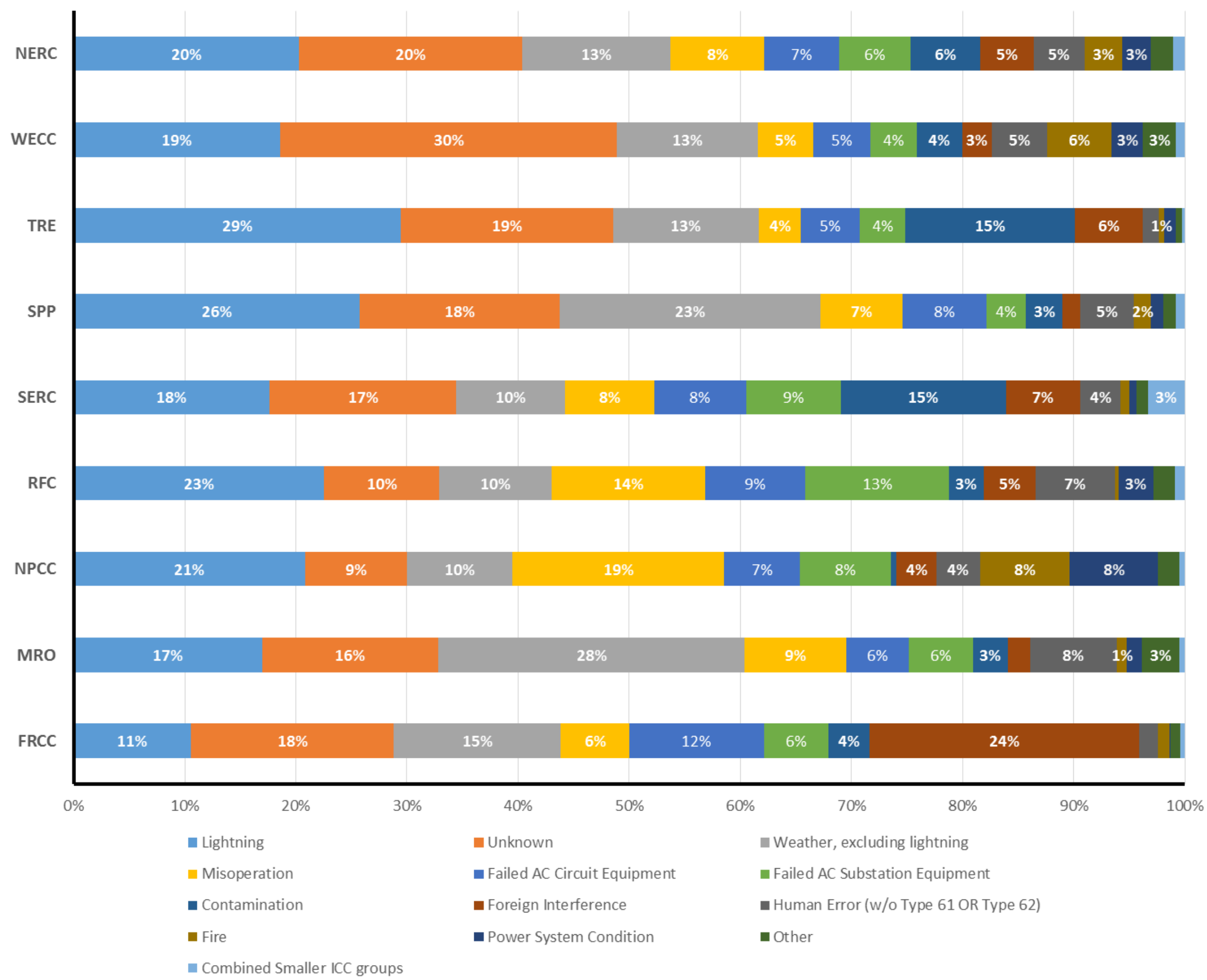


Figure B.8: Relative Transmission Risk of 200 kV+ AC Circuit Outage Events by ICC and Region (2013–2017)

The ICC contributions vary dramatically among Regions for the top NERC ICCs. For example, Misoperation has the highest relative risk in NPCC (19 percent) and the lowest in Texas RE (four percent) with other Regions' numbers being closer to the NERC average of nine percent. For Texas RE and WECC, AC Substation Equipment failures resulted in four percent of the total TOS while they contributed 13 percent in RF. A relative risk ICC Unknown varied from 30 percent in WECC to nine percent in NPCC while NERC-wide it ranked second with 20 percent of the total TOS.

FRCC has a very distinctive profile with a unique risk breakdown. FRCC's top-risk ICC is Foreign Interference, which ranks low for NERC and other Regions. On the other hand, NERC's largest contributor, ICC Lightning, contributes only 11 percent to FRCC's TOS.

Finally, **Figure B.9** shows changes in the total TOS by year for Regions and NERC. FRCC had consecutive year-to-year TOS increases from 2013–2017, MRO's TOS stayed essentially flat, NPCC in 2017 had the second highest TOS compared with 2013, RF consistently improved from 2013–2017, SERC had a stable performance in 2013–2016 and the best year in 2017, SPP and Texas RE had an increase from 2014 to 2015 and stayed stable from 2015–2017, WECC and NERC had the highest TOS in 2013, smallest in 2014, and non-significant changes from 2015–2017. NERC year-to-year TOS changes reflect changes in the number of outage events (the bottom row of **Table B.4**) as well as changes in the expected TOS of an individual event shown in **Figure B.4**.

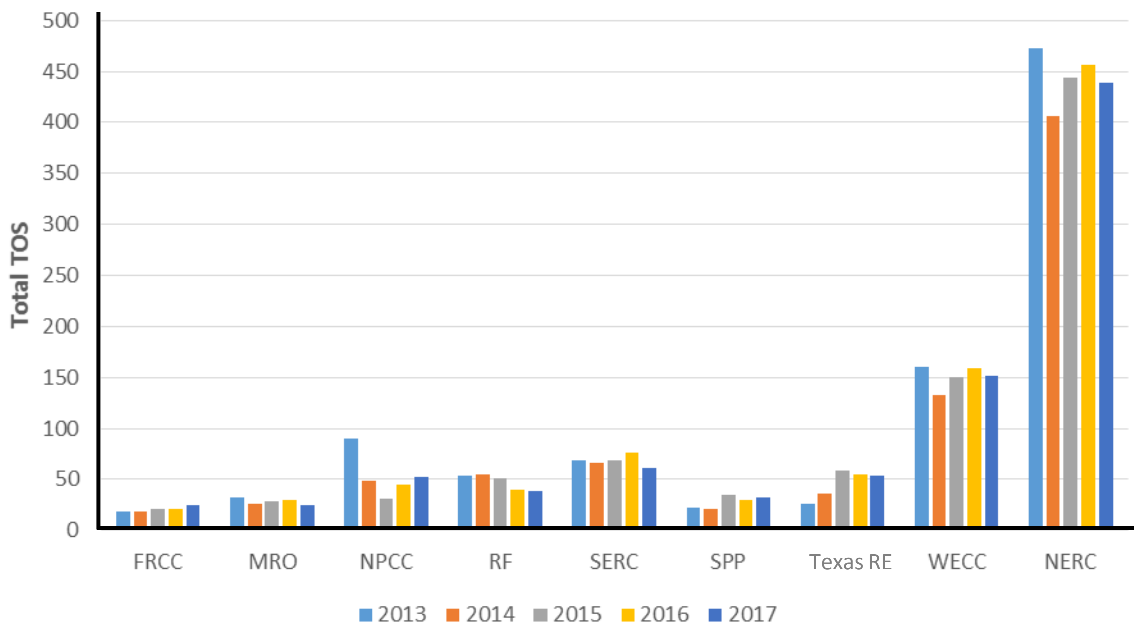


Figure B.9: Total TOS by Year by Region and NERC for 200 kV+ AC Circuit Outage Events (2013–2017)

Study 4: TADS Sustained Events of 100 kV+ AC Circuits and Transformers

Sustained Events with Common ICC by Year and Estimates of Event Probability

The addition of the BES elements below 200 kV, beginning in the year 2015, significantly increased TADS inventory, especially for ac circuits. It should be noted that only sustained automatic outages were collected by TADS for voltages less than 200 kV. The definition of Sustained Outage has been extended to a TADS event with duration of one minute or greater. This study is based on the 2015–2017 TADS data for sustained outage events of the 100 kV and above ac circuits and transformers.

Table B.9 lists annual counts and hourly sustained event probability by ICC and for all ICC combined. From 2015–2017, the total of 19,546 sustained events was reported. Almost 93 percent of events involved only ac circuit outages, about five percent involved only transformer outages, and the remaining two percent involved both ac circuit and transformer outages. In Study 4 these events are analyzed together.

Almost all TADS ICC groups have sufficient number of events to be used in a statistical year-to-year analysis.[145] Only two ICCs (Vandalism, Terrorism, or Malicious Acts; and Environmental) do not have sufficient size for reliable statistical inferences. Therefore, these ICC groups are added to ICC Contamination to create a new group, named "Combined Smaller ICC Groups Study 4," that can be statistically compared to every other group and also studied with respect to annual changes of TOS.

For sustained events initiated by a common cause, the probability of observing the initiation of an event during a given hour, listed in the last column of **Table B.9,** is estimated using the corresponding historical event occurrences reported in TADS.[146] The reciprocal of the probability of 0.743 events per hour estimates that in the defined BES system a sustained ac circuit or transformer event started, on average, every 1 hour and 21 minutes.

Table B.9: Sustained Events 100 kV+ AC Circuits and Transformers and Hourly Event Probability by ICC (2015–2017)

Initiating Cause Code	2015	2016	2017	2015–2017	Event Initiation Probability/Hour
Weather, Excluding Lightning	1,117	1,095	1,458	3,670	0.140
Failed AC Circuit Equipment	794	847	790	2,431	0.092
Unknown	906	750	722	2,378	0.090
Lightning	755	654	714	2,123	0.081
Failed AC Substation Equipment	667	639	611	1,917	0.073
Foreign Interference	494	571	515	1,580	0.060
Misoperation	481	491	469	1,441	0.055
Vegetation	333	320	378	1,031	0.039
Human Error (w/o Type 61 OR Type 62)	348	358	309	1,015	0.039
Other	211	165	165	541	0.021
Fire	118	127	218	463	0.018
Power System Condition	110	185	137	432	0.016
Combined Smaller ICC groups	122	202	200	524	0.020
Contamination	89	178	162	429	0.016
Environmental	26	11	23	60	0.002
Vandalism, Terrorism, or Malicious Acts	7	13	15	35	0.001
All Events	**6,456**	**6,404**	**6,686**	**19,546**	**0.743**

145 A size of the dataset should be sufficient to apply the Central Limit Theorem for the annual sample means (40 or more observations).

146 Probability is estimated using event occurrence frequency of each ICC type without taking into account the event duration. Namely, the event occurrence probability is the total number of occurrences for a given type of event observed during the historical data period divided by the total number of hours in the same period. Therefore, the sum of the estimated probabilities over all ICCs is equal to the estimated probability of any sustained event during a given hour.

ICC Weather, Excluding Lightning, is the largest group of sustained events. It had a significant increase of 33 percent from 2016 to 2017. Other ICCs with significant increases were Fire (72 percent) and Vegetation (18 percent). ICCs Power System Condition, Human Error, and Foreign Interference had the biggest decreases from 2016 to 2017 (26 percent, 14 percent, and 10 percent, respectively). Overall, the number of sustained events marginally decreased from 2015 to 2016 (a decrease of less than one percent) and increased by four percent from 2016 to 2017.

TOS by ICC

Using the TOS measure and sustained event ICCs, NERC staff statistically analyzed the most recent three years of TADS data (2015–2017).[147] The TOS of a sustained event is calculated by applying **Table B.1** and **Equation B.2**. The distribution of TOS was studied separately for sustained events with a given ICC and the complete dataset for the three years combined.

The average TOS of the 2015–2017 sustained outage events is 0.034, the median TOS is 0.012, and a sample deviation is 0.039. The largest TOS of 0.961 was observed in a NPCC event coded as having initiated by Misoperation (an original TADS ICC of Failed Protection System Equipment) on August 10, 2017, with outages on 18 ac circuits and six transformers. The event occurred in Northeast Ontario and resulted with the area's separation from the BES. Additional investigation is currently being performed by NERC Event Analysis.

Next, statistical tests are performed to determine statistically significant differences in the average TOS between ICC groups. The TOS averages (means) by ICC are shown in **Figure B.10** listed from highest (ICC Power System Condition) to smallest (Vegetation). A series of the t-tests determined that each of groups of events initiated by Power System Condition, Fire, Combined Smaller ICC groups, Misoperation, Failed AC Substation Equipment, Human Error, and Unknown has statistically greater expected outage severity than other events.[148] It means that when an event initiated by one of these causes occurs, it is expected to have a greater impact and a higher risk to the transmission system. The tests on homogeneity of variances find statistically greater variances (and the standard deviations) for the same ICC groups except Human Error and Unknown as compared with other events. The greater variance can signify additional risk since it implies more frequent occurrences of events with high TOS.

Further t-tests indicate that each of the ICC groups Vegetation, Foreign Interference, Weather (Excluding Lightning), and Failed AC Circuit Equipment has statistically smaller expected outage severity than other events.[149] Finally, events initiated by Other and Lightning do not have a significant difference in outage severity with other events, therefore, are expected to have an average dataset TOS when happen,[150]

[147] All statistical tests in Study 1 are performed at the significance level 0.05

[148] Additionally, a test on significance of correlation, which is equivalent to a polled t-test, confirms that these ICCs have a statistically significant positive correlation with TOS.

[149] Additionally, a test on significance of correlation, which is equivalent to a polled t-test, confirms that these ICCs have a statistically significant negative correlation with TOS.

[150] Additionally, a test on significance of correlation, which is equivalent to a polled t-test, confirms that ICCs Lightning and Other have no significant correlation with TOS.

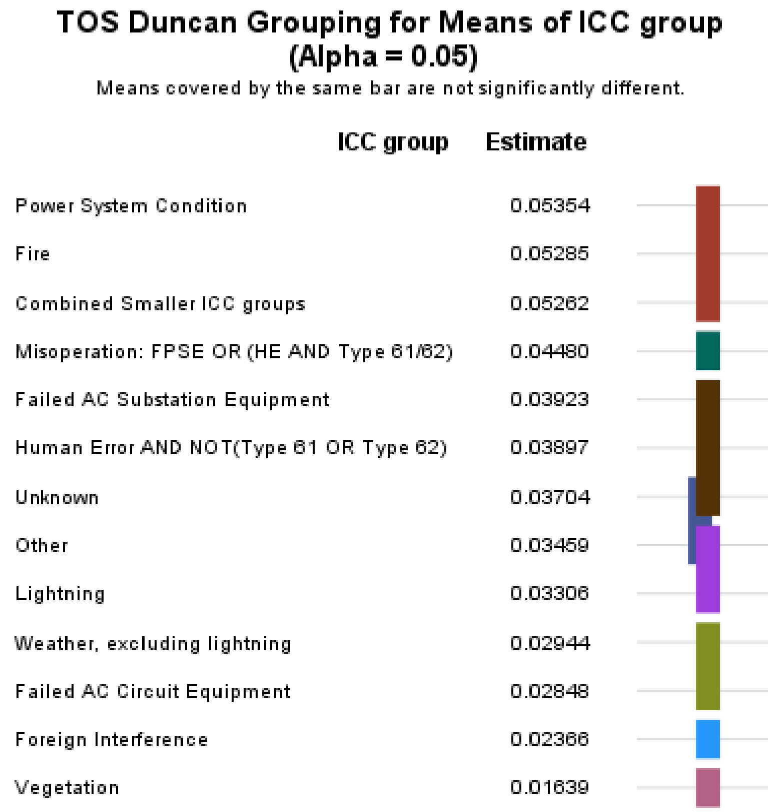


Figure B.10: TOS of 100 kV+ AC Circuit and Transformer Sustained Events by ICC and ICC grouping by Expected TOS (2015–2017)

Figure B.10 also summarizes results of Duncan's grouping test for the TOS means. Each bar connects ICC groups with similar (not statistically significantly different) expected TOS. For example, differences in TOS between events initiated by Power System Condition, Fire, and Combined Smaller ICC Groups, connected by a red bar, are not significant, meaning that individual impacts of events from these groups (the expected TOS) are similar.

Average TOS by ICC: Annual Changes

Year-over-year changes in calculated TOS for 100 kV+ sustained events by ICC are reviewed next. Figure B.11 shows changes in the average TOS for each ICC for years 2015–2017. The groups of ICC events are listed from left to right by descending average TOS for the five years combined (the average TOS are listed in Figure B.10).

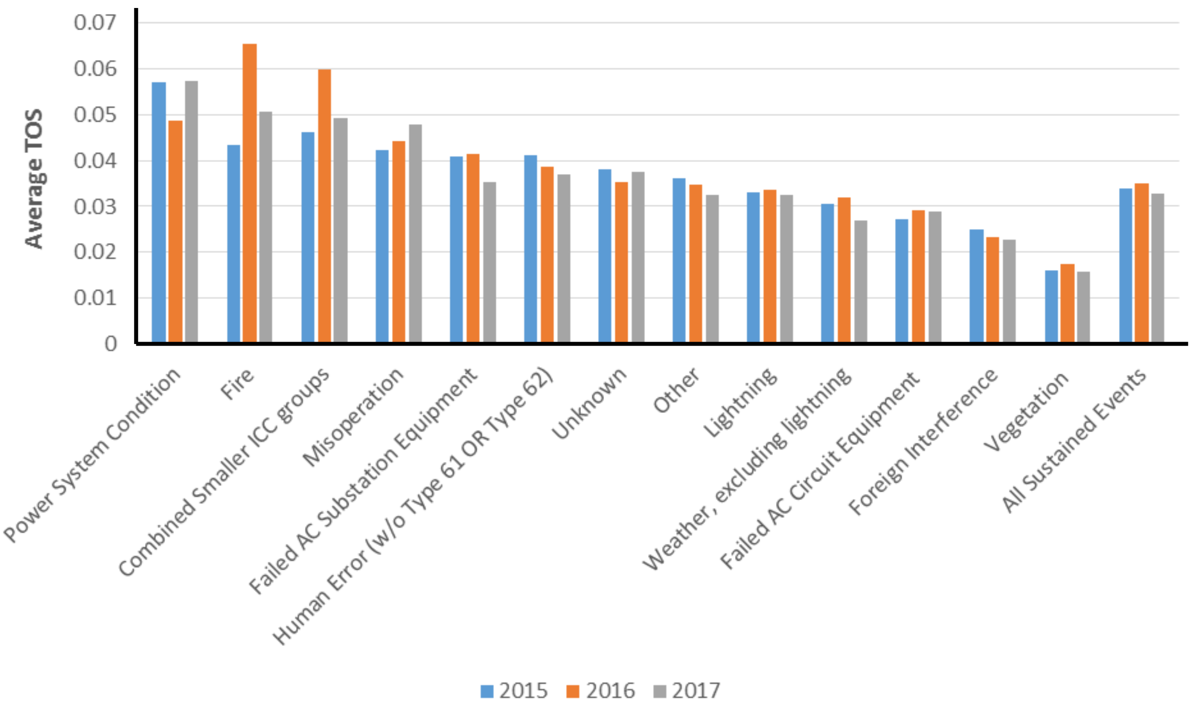


Figure B.11: Average TOS of Sustained Events of 100 kV+ AC Circuits and Transformers by ICC and Year (2015–2017)

A series of Fisher's Least Significant Difference tests allowed to identify statistically significant year-over-year changes in TOS by ICC and for all events combined. In 2017 the average TOS statistically significantly decreased for ICCs:

- **Fire:** compared with 2016
- **Combined Smaller ICC Groups:** compared with 2016
- **Failed AC Substation Equipment:** compared with 2015 and 2016
- **Weather, Excluding Lightning:** compared with 2015 and 2016

In 2017 there were no statistically significant increases in the average TOS by ICC. For all sustained events combined, the average TOS in 2017 was statistically lower than in 2016 and similar 2015.

TOS Risk and Relative Risk of 100 kV+ AC Circuit and Transformer Sustained Events by ICC

The risk of each ICC group can be defined as the total TOS associated with this group. Its relative risk is equal to the percentage of the group TOS in the 2015–2017 database. Equivalently, the risk of a given ICC per hour can be defined as the product of the probability that an event with this ICC initiates during an hour and the expected TOS (impact) of an event from this group.[151]

[151] The probability that an event from a given ICC group initiates during a given hour is listed in **Table B.9**, and the expected TOS by ICC are shown in **Figure B.9**. For any ICC group, the relative risk per hour is the same as the relative risk for a year (or any other time period) if estimated from the same dataset.

Group of TADS events	Probability that an Event from a Group Starts during a Given Hour	Expected Impact (Expected TOS of an Event)	Risk Associated with a Group per Hour	Relative Risk by Group
TADS sustained events 100 kV+	0.743	0.034	0.025	100.0%
Weather, Excluding Lightning	0.140	0.029	0.004	16.3%
Unknown	0.090	0.037	0.003	13.3%
Failed AC Substation Equipment	0.073	0.039	0.003	11.3%
Lightning	0.081	0.033	0.003	10.6%
Failed AC Circuit Equipment	0.092	0.028	0.0026	10.4%
Misoperation	0.055	0.045	0.0025	9.7%
Human Error (w/o Type 61 OR Type 62)	0.039	0.039	0.0015	6.0%
Foreign Interference	0.060	0.024	0.0014	5.6%
Combined Smaller ICC groups	0.020	0.053	0.0010	4.2%
Fire	0.018	0.053	0.0009	3.7%
Power System Condition	0.016	0.054	0.0009	3.5%
Other	0.021	0.035	0.0007	2.8%
Vegetation	0.039	0.016	0.0006	2.5%

Table B.10: Relative Risk of Sustained Events of 100 kV+ AC Circuits and Transformers by ICC (2015–2017)

Relative risk of the 2015–2017 TADS 100 kV+ ac circuit and transformer sustained events by ICC is listed in **Table B.10** in decreasing order. Weather, Excluding Lightning, Unknown, and Failed AC Substation Equipment are three ICCs with the largest relative risk. Events initiated by Weather, Excluding Lightning, have a small expected individual TOS but they happened more frequently than events with other ICCs. Despite having the three largest TOS averages, Power System Condition, Fire, and Combined Smaller ICC Groups rank low with respect to relative risk because of a small number of events with these ICCs and their low frequency.

Figure B.12 shows year-over-year changes in the relative risk of TADS sustained events by ICC. The groups of ICC events are listed from left to right by descending relative risk for years 2015–2017 combined. The top contributor to transmission risk, Weather, Excluding Lightning, had a significant increase in the total TOS from 2016 to 2017 due to a big increase in the number (and the frequency) of events as reflected in **Table B.9**. Another ICC with significant risk increase from 2016 to 2017 was Fire. Relative risk of ICCs Failed AC Substation Equipment, Combined Smaller Groups, Human Error, Power System Condition, and Foreign Interference significantly decreased from 2016 to 2017. Other ICCs did not have significant changes in 2017.

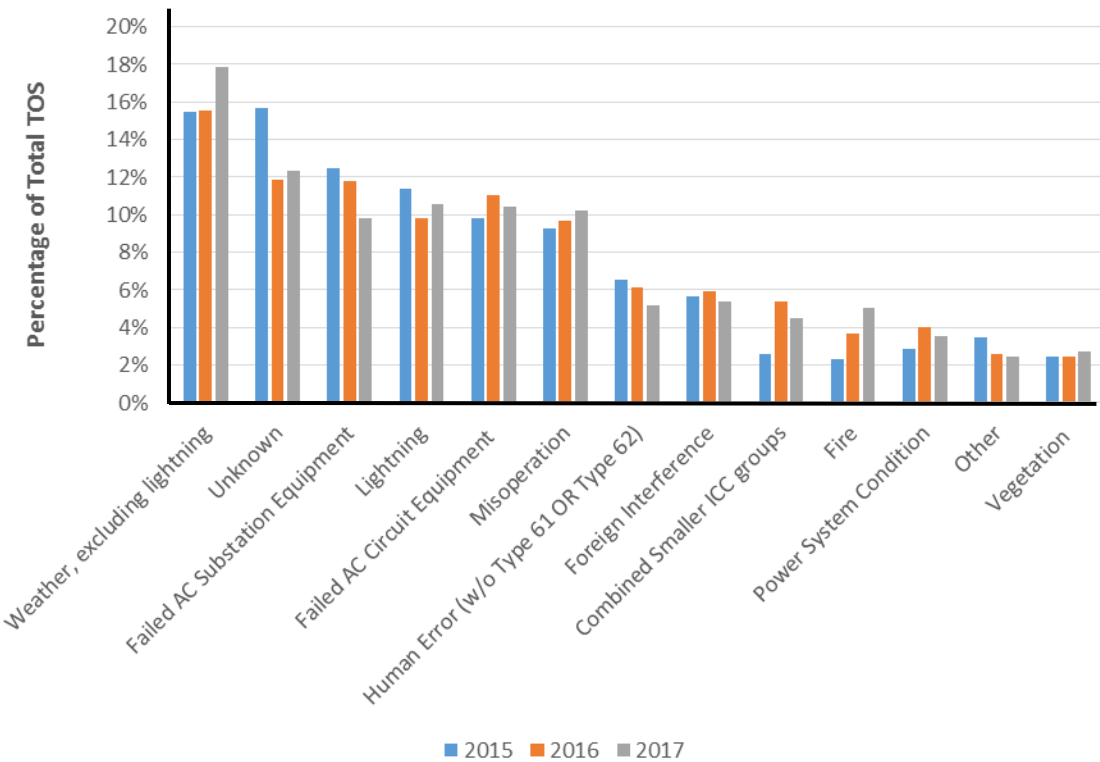


Figure B.12: Relative TOS Risk 100 kV+ AC Circuit Outage Events by ICC and Year (2015–2017)

Study 5: Sustained Cause Code and ICC-SCC Study for Sustained Outages of 100 kV+ AC Circuits

Besides an ICC, a SCC is assigned to a sustained outage. The SCC describes the cause that contributed to the longest duration of the outage. The list of TADS SCCs is the same as the list of ICCs as shown in **Table B.4**. A method of assigning a single SCC to a TADS event with multiple outages having different SCCs has not yet been developed; therefore, it is not yet possible to analyze SCCs by applying the same methodology as described in Studies 1–4 for ICCs.

In this study, the 2015–2017 sustained outages of the 100 kV+ ac circuits with a TOS calculated by **Equation B.1** are investigated by SCC. TADS outages, unlike TADS events, can be dependent; thus, they do not represent a statistical sample with independent observations. Therefore, the risk analysis for outages is limited to the TOS calculation, numerical comparison of the TOS of SCC groups, and their ranking. However, there is another important variable reported for sustained outages—the outage duration. **Table B.11** provides some statistics on the outage duration by SCC and then suggest a way to incorporate duration into analysis of the relative risk by SCC.

Table B.11 lists the number of outages, the average, the median, and the maximum outage duration by SCC and overall for the 2015–2017 sustained outages of the 100 kV+ ac circuits. SCC groups are listed in decreasing order by number of outages.

Table B.11: TADS Sustained Outages 100 kV+ AC Circuits (2015–2017)				
Sustained Cause Code	**Number of Outages**	**Average Outage Duration (Hours)**	**Median Outage Duration (Hours)**	**Maximum Duration (Days)**
Failed AC Circuit Equipment	3,664	59.9	13.0	366.0
Failed AC Substation Equipment	2,392	44.5	3.3	365.0
Weather, Excluding Lightning	2,341	20.8	1.7	245.8
Other	2,055	7.6	0.2	95.1
Unknown	1,986	8.6	0.2	83.4
Misoperation	1,714	8.5	1.0	34.5
Foreign Interference	1,457	9.9	2.3	25.6
Lightning	1,223	4.1	0.1	37.6
Vegetation	1,204	26.8	10.9	57.9
Human Error (w/o Event Type 61 or 62)	1,030	5.0	0.3	40.1
Power System Condition	814	21.9	0.8	161.0
Fire	387	25.3	1.8	52.9
Contamination	341	8.0	0.4	5.6
Environmental	73	38.2	11.9	24.2
Vandalism, Terrorism, or Malicious Acts	28	54.4	6.3	53.9
All Sustained Outages	**20,709**	**24.8**	**2.0**	**366.0**

The SCC order differs from that seen for ICC groups in Studies 1, 2, and 4 (**Table B.4**, **Table B.7**, and **Table B.9**). Outages with SCC Failed AC Circuit Equipment not only comprise the largest group, but they have also, on average, the longest durations. Another observation is that the SCC Other is the fourth biggest group that contains almost 10 percent of the 2015–2017 sustained outages compared with the low ranked ICC Other in **Table B.4**. Outages with SCC Other, on average, are shorter than overall sustained outages. The same is true for the fifth largest SCC group, Unknown.

The TOS of each outage is calculated by **Equation B.1**, then the total TOS of each SCC group is calculated, and the relative risk of a SCC is determined based on contribution of the group to the total TOS of all 2015–2017 sustained outages. The analysis is repeated for the TOS weighted with an outage duration with the purpose to take into account the outage duration and incorporate it as a factor that impacts transmission outage risk. The results of these two analyses of the relative SCC risk are compared to illustrate how outage duration affects the SCC ranking.

Since there are outages with very large durations (up to 366 days), two types of sensitivity analysis are performed for the evaluation of transmission severity weighted with outage duration: First, the SCC analysis is repeated for all outages not longer than one month (with the 121 outages or about 0.6 percent of the total dataset removed); second, the analysis is rerun with the top percent of longest outages removed (208 outages longer than 14.7 days removed).

Figure B.13 summarizes results of the four analyses of the relative transmission outage risk by SCC. SCC Environmental and SCC Vandalism, Terrorism, and Malicious Acts, the two groups with less than one percent of the relative transmission outage risk each, are not shown.

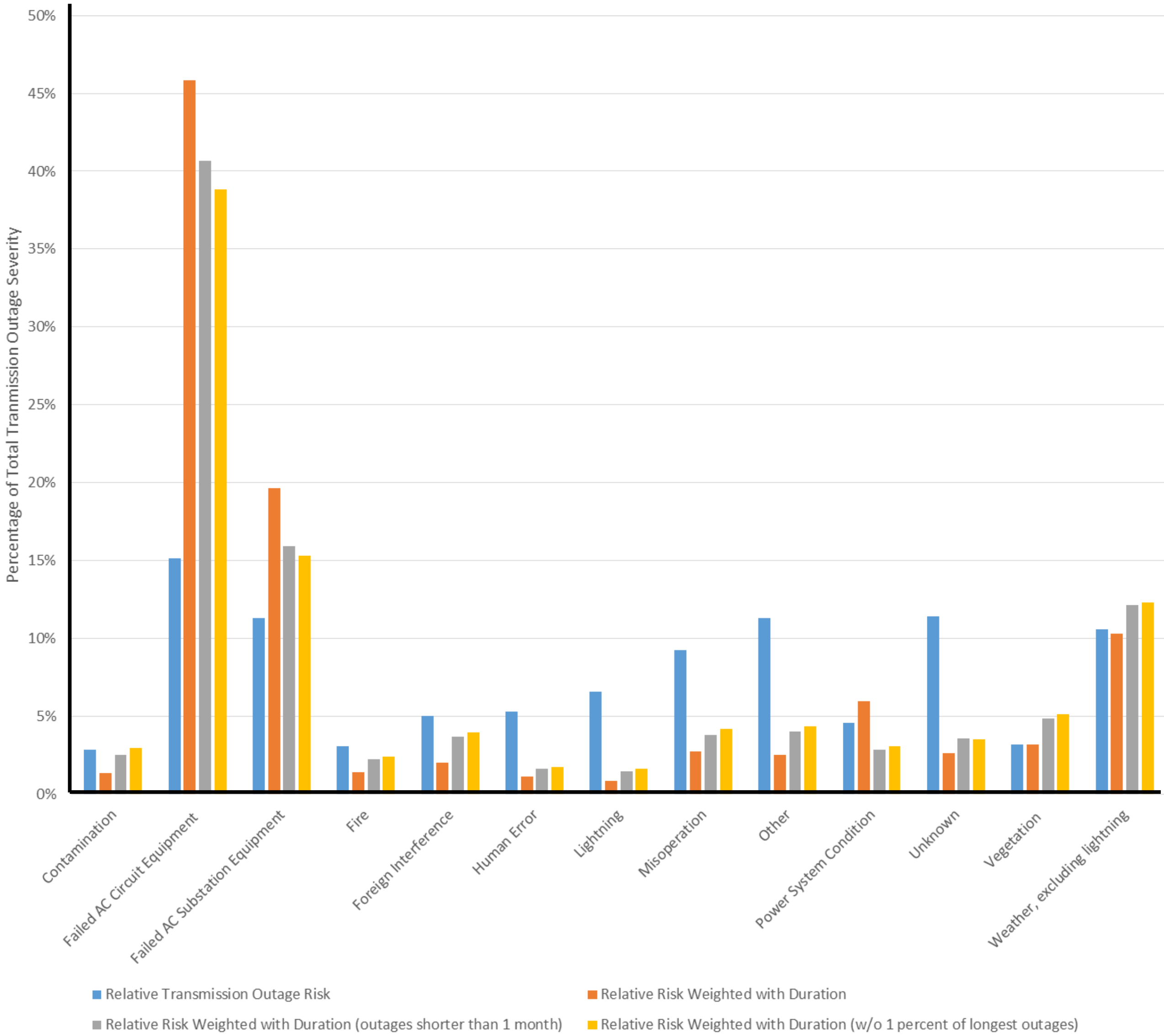


Figure B.13: Relative TOS Risk by SCC for Sustained Outages of the 100 kV+ AC Circuits (2015–2017)

Figure B.13 shows the SCC relative transmission outage risk and the SCC relative transmission outage risk weighted with duration. The largest differences are observed for the SCCs with "non-typical" average outage durations (i.e., the average outage duration significantly different from the average duration of 24.8 hours).

Events with SCC Failed AC Circuit Equipment have the highest average outage duration. The relative transmission outage risk of this SCC increases from 15 percent to 45 percent when measured by unweighted and weighted transmission outage risk, respectively (in both causes this SCC ranks the highest). Similarly, the relative transmission outage risk of SCC Failed AC Substation Equipment increases from 11 percent to 20 percent. For SCCs with shorter average durations, such as Unknown, Other, Lightning, Misoperation, Human Error, and Foreign Interference, the relative transmission outage risks are noticeably lower when weighted with outage duration (e.g., for SCC's Unknown and Other from 11 percent to three percent of the total transmission severity and for SCC Misoperation from nine percent to three percent).

Comparison of the three right-hand side bars for each SCC allows for the drawing of some observations on sensitivity analyses and evaluate effect of the longest outages on the SCC relative risk. Overall, an SCC relative risk does not change much among these three types; this fact confirms that the SCC relative transmission outage risk, weighted with duration calculations, are robust with respect to duration outliers.

Table B.12 shows the SCC rankings by relative transmission outage risk (unweighted and weighted with outage duration).

Table B.12: SCC Ranking for TADS Sustained Outages 100 kV+ AC Circuits (2015–2017)		
Sustained Cause Code	**By Relative Transmission Outage Risk**	**By Relative Transmission Outage Risk Weighted with Outage Duration**
Contamination	13	11
Environmental	14	14
Failed AC Circuit Equipment	1	1
Failed AC Substation Equipment	3	2
Fire	12	10
Foreign Interference	9	9
Human Error	8	12
Lightning	7	13
Misoperation	6	6
Other	4	8
Power System Condition	10	4
Unknown	2	7
Vandalism, Terrorism, or Malicious Acts	15	15
Vegetation	11	5
Weather, Excluding Lightning	5	3

For several SCCs, there are significant differences between their respective ranks due to differences in outage duration impact.

A summary of analysis of the sustained outages by the ICC-SCC pair is presented in **Table B.13**. The table lists the ICC-SCC groups with the total percent of all outages in each group, the percent of the total TOS for 2015–2017 comprised by the outages in each group, and the percent of the TOS weighted with outage duration calculated by the method described above in Study 5.

Table B.13: TADS Sustained Outages 100 kV+ AC Circuits by ICC-SCC (2015–2017)				
Initiating Cause Code	**Sustained Cause Code**	**Percent of Total Outages**	**Percent of Total TOS**	**Percent of Total TOS Weighted with Duration**
Failed AC Circuit Equipment	Failed AC Circuit Equipment	11.3%	9.8%	25.8%
Failed AC Substation Equipment	Failed AC Substation Equipment	9.3%	9.2%	17.2%
Weather, Excluding Lightning	Failed AC Circuit Equipment	3.1%	2.7%	14.2%
Weather, Excluding Lightning	Weather, Excluding Lightning	10.9%	10.2%	10.2%
Power System Condition	Power System Condition	2.4%	3.1%	4.3%
Misoperation	Misoperation	7.0%	8.0%	2.4%
Unknown	Unknown	8.7%	10.4%	1.8%

Table B.13: TADS Sustained Outages 100 kV+ AC Circuits by ICC-SCC (2015–2017)				
Initiating Cause Code	**Sustained Cause Code**	**Percent of Total Outages**	**Percent of Total TOS**	**Percent of Total TOS Weighted with Duration**
Foreign Interference	Foreign Interference	6.4%	4.6%	1.6%
Vegetation	Vegetation	4.5%	2.4%	1.6%
Fire	Fire	1.8%	3.0%	1.4%
Foreign Interference	Failed AC Circuit Equipment	0.6%	0.4%	1.4%
Contamination	Contamination	1.5%	2.6%	1.3%
Other	Other	2.4%	2.4%	1.2%
Human Error	Human Error	4.6%	4.8%	1.0%
Lightning	Failed AC Circuit Equipment	0.9%	0.8%	0.9%
Lightning	Lightning	5.8%	6.5%	0.8%
Lightning	Failed AC Substation Equipment	0.6%	0.5%	0.6%
Weather, Excluding Lightning	Other	1.4%	2.0%	0.4%
Lightning	Other	1.9%	1.9%	0.2%
Failed AC Substation Equipment	Other	1.9%	0.3%	0.1%
Unknown	Other	1.4%	1.7%	0.1%
Failed AC Circuit Equipment	Other	1.4%	0.3%	0.1%

Theoretically, for the 15 ICCs and 15 SCCs, 225=15*15 ICC-SCC pairs are possible. In the 2015–2017 dataset of sustained ac circuit outages, a total of 164 distinct pairs appear. In **Table B.13,** only the top 22 ICC-SCC pairs are listed with at least 0.5 percent of the total number of outages (a minimum of 121 outages out of 20,709) for the three years in each group. These 22 largest groups are listed by decreasing number of outages. Together, they represent 90 percent of outages, a total of 88 percent of the total TOS, and 89 percent of the total TOS weighted with outage duration. The top nine groups are comprised of outages with coinciding ICC and SCC. The ICC-SCC Failed AC Circuit Equipment is the largest group, followed by Weather (Excluding Lightning), Failed AC Substation Equipment, and Unknown.

Ranking with respect to the TOS is different: the ICC-SCC Unknown ranks highest with the 10.4 percent of the total TOS for 2015–2017 followed by ICC-SCC Weather (Excluding Lightning), and ICC-SCC Failed AC Circuit Equipment. The ICC-SCC Failed AC Circuit Equipment is the top ranked by the TOS weighted with outage duration with the total 25 percent of the relative outage risk. In the weighted ranking, the ICC-SCC Unknown's relative outage risk decreases to 1.8 percent due to shorter outage duration—an effect of the weighting as described in a discussion on **Figure B.13**.

In regards to Study 5, both unweighted and weighted rankings in **Table B.12** and **Table B.13** are derived and presented without making a decision about superiority of either method of the relative transmission outage risk evaluation. Each method has its advantages and disadvantages: the transmission outage risk that is based on TOS calculations without duration is simpler and allows for the analysis of all outages and events of both momentary and sustained. The transmission outage risk, based on the TOS weighted with outage duration discards momentary outages from the analysis, and while it does take into account differences in sustained outage duration, more analysis and the industry expert discussions are needed to decide whether the weighing is fair. For example, as a result of this weighting, a 300–399 kV voltage class one-hour ac circuit outage contributes to the total weighted transmission severity equally with an outage of the 100–199 kV ac circuit with duration of six hours and 30 minutes; with an outage of the 200–299 kV ac circuit with duration of one hour and 51 minutes; with an outage of the 400–599 kV ac circuit with duration of 39 minutes; and with an outage of the 600–799 kV ac circuit with duration of 26 minutes.

A summary of results of Studies 1–5 is provided in Overview of TADS Analysis in **Chapter 1**.

Appendix C: Analysis of Generator Data

Introduction

GADS, beginning in 2013, collects design, performance, and event data for conventional generating units that are 20 MW and larger. In addition, smaller units and other units outside of NERC's jurisdiction may report into GADS on a voluntary basis. The analysis for this report includes only active units with a mandatory reporting obligation that have reported performance data as of the reporting deadline for the period being analyzed. Data used in the analysis includes information reported into GADS through the end of 2017.

GADS does not include wind, solar, other renewable technology generating assets, distributed energy resources, or other small energy sources. Wind performance data reporting requirements have been developed, and a phased-in reporting process began in 2017 and continues through 2020. Reporting data requirements for solar have been initiated with a target goal of data submittal to begin by 2021.

GADS collects and stores unit operating information. By pooling individual unit information, overall generating unit availability performance and metrics are calculated. The information supports equipment reliability, availability analyses, and risk-informed decision making to industry. Reports and information resulting from the data collected through GADS are used by industry for benchmarking and analyzing electric power plants. **Table C.1** shows the number of units and average age characteristics of the population reporting into GADS and select unit types for each year.

Table C.1: Key Characteristics of GADS

Metric/year	2013	2014	2015	2016	2017
Numbering of Reporting Units	6,129	6,100	6,106	5,982	5,810
Average Age of the Fleet (Years)	34	34	35	35	34
Average Age of Coal Units (Years)	43	44	44	43	44
Average Age of Natural Gas Units (Years)	21	22	22	23	23
Average Age of Nuclear Units (Years)	35	36	36	37	38

The age of the generating fleet is considered to be a particularly relevant statistic derived from GADS, because an aging fleet could potentially see increasing outages. However, with proper maintenance and equipment replacement, older units may perform comparably to newer units. In addition, the WEFOR, reported later in this section, shows stable rates of forced outages. **Table C.1** also shows the age of conventional units remaining stable. Future reports will continue to monitor the age to see how the fleet is changing.

Figure C.1 uses GADS data to plot fleet capacity by age and fuel type. **Figure C.1** shows two characteristics of the fleet reported to GADS: an age bubble exists around 38–47 years, by a population consisting of coal and some natural gas units, and a significant age bubble around 13–21 years is comprised almost exclusively of natural gas units. The data shows a clear shift toward natural-gas-fired unit additions, and the overall age of the fleet across North America is almost 20 years younger than the age of the coal-fired base-load plants that have been the backbone of power supply for many years. This trend is projected to continue given current forecasts around price and availability of natural gas as a power generation fuel as well as regulatory impetus.

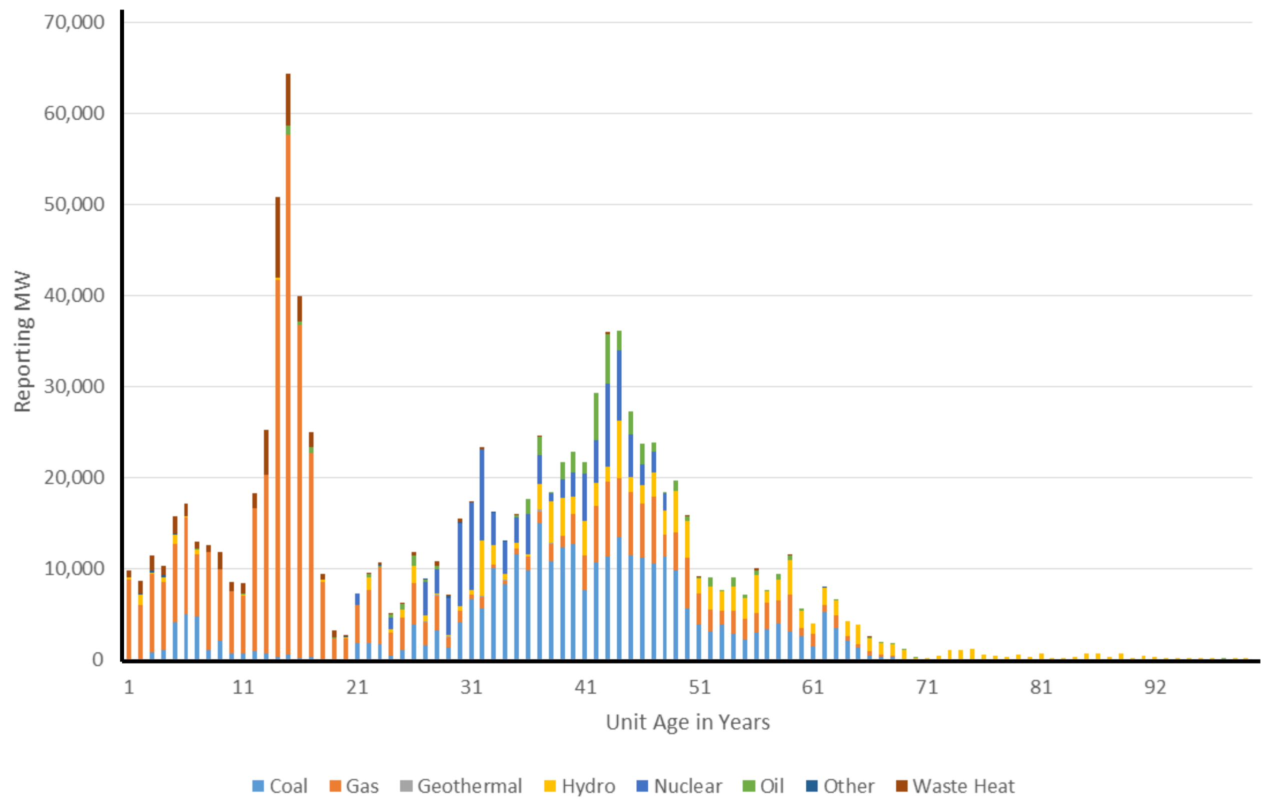


Figure C.1: Fleet Capacity by Age and Fuel Type

Generator Fleet Reliability

GADS contains information that can be used to compute reliability measures, such as WEFOR. WEFOR is a metric measuring the probability that a unit will not be available to deliver its full capacity at any given time, taking into consideration forced outages and derates.

Figure C.2 presents the monthly megawatt-weighted EFOR[152] across the NERC footprint for the five-year period of 2013–2017.[153] The horizontal steps show the annual EFOR compared to the monthly EFOR; the solid horizontal bar in **Figure C.2** shows the mean outage rate over each year. The mean outage rate over the analysis period is seven percent. The EFOR has been fairly consistent with a near-exact standard distribution.

[152] Equivalent Forced outage rate (EFOR)

[153] The reporting year covers January 1 through December 31.

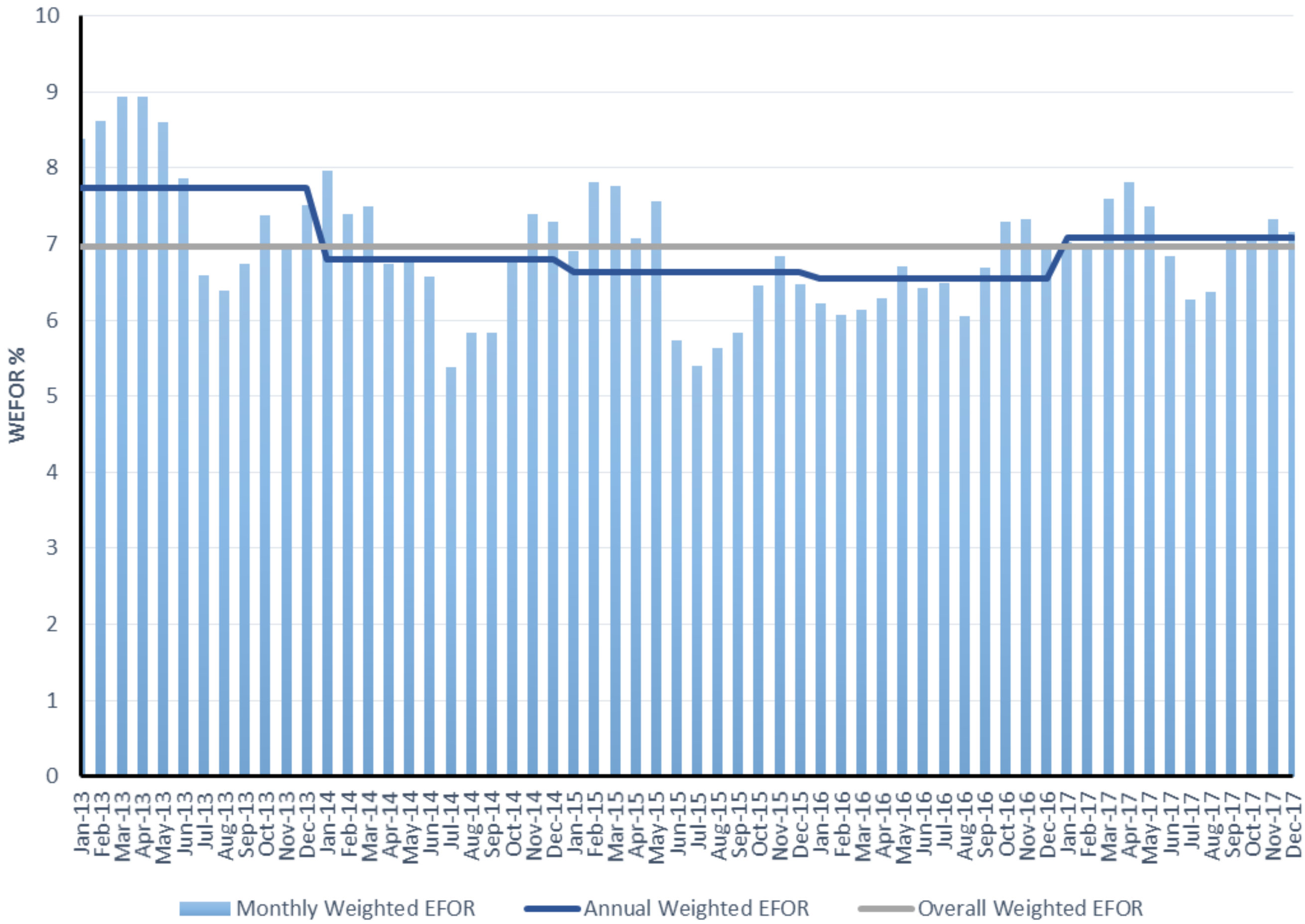


Figure C.2: Monthly MW Capacity-Weighted EFOR 2013–2017

Forced Outage Causes

To better understand the causes of forced outages of generators, the annual and top 10 forced outage causes for the summer and winter seasons were analyzed for the period of 2013–2017. This analysis is focused on forced outage causes measured in terms of net TWh of potential production lost, so both the amount of capacity affected and the duration of the outages are captured.

The levels of forced outages reported into the GADS database are presented in **Figure C.3** and **Table C.2**, providing detail on the net TWh of potential production lost due to forced outages for the period 2013–2017 by calendar year.

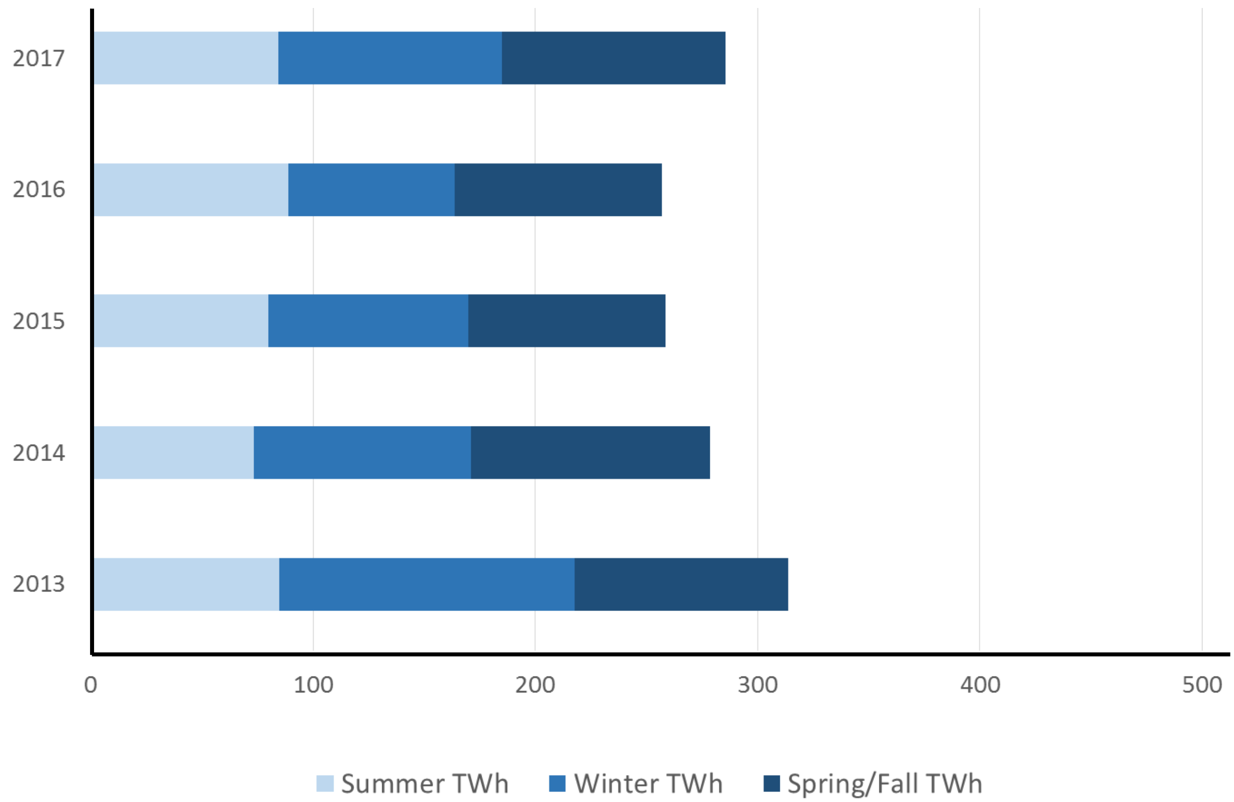


Figure C.3: Total Net TWh of Potential Production Lost Due to Forced Outages 2013–2017

Table C.2: Net TWh of Potential Production Lost Due to Forced Outages, by Calendar Year 2013–2017				
NERC	**Total Annual TWh**	**Summer TWh-Months**	**Winter TWh-Months**	**Spring/Fall TWh-Months**
2013	313.7	84.8	132.9	96.0
2014	278.6	73.6	97.4	107.6
2015	258.5	79.9	89.9	88.7
2016	257.0	89.1	74.5	93.4
2017	285.7	84.6	100.3	100.7

Based on five years of data, the following observations can be made:

- Outages from severe storms in the last quarter of 2012, such as Hurricane Sandy, continued through first quarter of 2013 and are responsible for the increased production lost in Winter 2013.[154]
- The shoulder months of Spring/Fall in 2014, 2016, and 2017 have higher forced outage net TWh than the corresponding summer or winter periods.

Further analysis into the causes of forced outages considered the impact of weather. The percentage of net TWh of potential production lost due to weather-related forced outage cause codes reported each year ranges from two

[154] Winter includes the months of December, January, and February. When analysis is performed on a calendar year basis, as for this report, these three months are included from the same calendar year. Summer includes May through September; all other months are categorized as Spring/Fall. For this analysis, the season of a forced outage is associated with the season in which the start date of the event was reported in that year; therefore, when an event continues into the next year, a new event record is created in January, resulting in the event impacts being categorized as occurring in the winter of the following year as well.

percent to four percent annually. This indicates that while weather does cause major headlines, the overall effect of weather on the fleet is minimal. The real impacts of weather-related events are localized impacts and of relatively short duration.

To gain additional insight into the drivers for the reported net TWh of potential production lost due to forced outages, the top 10 forced outage causes were examined to determine their impact on the annual total of net TWh of potential production lost. The number of events reported in the top 10 forced outage causes represent between seven percent and 12 percent of all forced outage events reported annually while contributing an average of 27 percent to the annual total megawatt hours lost. Table C.3 shows the contribution of the top 10 forced outage causes to net TWh of potential production lost on a NERC-wide basis over the period 2012–2017. With the exception of 2016, winter periods show the highest percentage of potential production lost for the top 10 forced outage causes.

Table C.3: Percentage of Top 10 Forced Outage Causes to Net TWh of Potential Production Lost over the Period 2013–2017

NERC	Total Annual TWh	Summer TWh	Winter TWh	Spring/Fall TWh
2013	32%	7%	15%	10%
2014	28%	6%	11%	11%
2015	24%	7%	9%	8%
2016	25%	8%	8%	9%
2017	24%	6%	10%	8%

The top 10 causes vary annually, and the contribution from each of the top 10 causes to the total megawatt hours lost varies as well. Table C.4 lists the top 10 forced outage causes on an annual basis in order of the most impactful cause to the least, based on annual net MWh of potential production lost due to forced outages.

Table C.4: Top 10 Cause Codes as Percentages of Annual Net MWh of Potential Production Lost due to Forced Outages

Rank	2013	2014	2015	2016	2017
1	Waterwall (Furnace wall) 6.2%	Waterwall (Furnace wall) 7.7%	Waterwall (Furnace wall) 7.0%	Waterwall (Furnace wall) 6.9%	Waterwall (Furnace wall) 5.5%
2	Main Transformer 4.1%	Lack of Fuel (interruptible supply of fuel) 3.6%	Main Transformer 5.7%	Main Transformer 4.6%	Other Exciter Problems 3.1%
3	Rotor - General 3.2%	Main Transformer 3.2%	First Reheater 2.5%	Stator Windings, Bushings, and Terminals 3.2%	Unattributed Vibration of Turbine Generator 2.4%
4	Second Superheater 3.0%	Second Superheater 2.7%	Lack of Fuel (interruptible supply of fuel) 1.7%	Other Exciter Problems 2.6%	Main Transformer 2.3%
5	Operator Error 2.8%	First Reheater 2.5%	Second Superheater 1.6%	Flood 2.1%	Buckets or Blades 2.2%

Table C.4: Top 10 Cause Codes as Percentages of Annual Net MWh of Potential Production Lost due to Forced Outages					
Rank	**2013**	**2014**	**2015**	**2016**	**2017**
6	Stator Windings, Bushings, and Terminals 2.2%	Emergency Generator Trip Devices 1.8%	First Superheater 1.5%	First Reheater 1.9%	Stator Windings, Bushings, and Terminals 2.0%
7	Stator - General 2.0%	Other Low Pressure Turbine Problems 1.7%	Boiler - Miscellaneous 1.5%	Second Superheater 1.7%	Other Miscellaneous problems 1.8%
8	Hurricane 2.0%	AC Conductors and Buses 1.6%	Generator Vibration 1.5%	Other Miscellaneous Generator Problems 1.6%	Second Superheater 1.7%
9	Rotor Windings 1.9%	First Superheater 1.6%	Other Boiler Tube Leaks 1.4%	Residual Heat Removal/Decay Heat Removal System 1.5%	Bunker Structures 1.5%
10	First Reheater 1.8%	Boiler – Miscellaneous 1.5%	Other Exciter Problems 1.4%	Other Boiler Tube Leaks 1.5%	Flood 1.4%

Several outage causes appear in the top 10 more often than others: Weather-related outages in 2012 due to Hurricane Sandy resulted in flooding impacted several units that continued to report forced outages into 2013 and 2014. Lack of Fuel occurs within the top causes in 2014 and 2015. In 2017, three new cause codes entered the top 10: Unattributed vibration of Turbine Generator, Buckets or blades, and Bunker structures. **Table C.5** lists the recurring cause codes and number of years that the cause code appears in the top 10.

Table C.5: Recurring Top 10 Cause Codes		
Code	**Description**	**Number of Years in Top 10 Causes**
1000	Waterwall (Furnace wall)	5
1050	Second Superheater	5
3620	Main Transformer	5
1060	First Reheater	4
4609	Other Exciter Problems	3
4520	Stator Windings, Bushings, and Terminals	3
1040	First Superheater	2
9131	Lack of Fuel (interruptible supply of fuel)	2
1090	Other Boiler Tube Leaks	2
1999	Boiler–Miscellaneous	2

The Second Superheater (1050), Waterwall (1000), and First Reheater (1060) are all related to tube leaks in the respective systems. Given the amount of steam generating units that make up the fleet, the magnitude of these outages would not be unusual. These are not uncommon failures that occur in normal operation.

Both the Main Transformer (3620) and Stator Windings (4520) are high on the list. These items are the result of a very low likelihood event occurring that has a high impact. Most plants do not have spares available for these assets because the likelihood of failure is very low. However, if an event does occur, it can take several months to remedy, causing the event to show very high on this cause code list.

Wind performance data reporting requirements have been developed, and a phased-in reporting process began in 2017 and continues through 2020.

- **January 1, 2017**: Voluntary reporting
- **January 1, 2018:** Mandatory reporting for plants with total installed capacity of 200 MW or larger
- **January 1, 2019:** Mandatory reporting for plants with total installed capacity of 100 MW or greater
- **January 1, 2020:** Mandatory reporting for plants with total installed capacity of 75 MW or greater

There are 357 wind generation groups/subgroups across 155 entities that are currently set up for reporting in Wind GADS. NERC, through the GADSWG, will begin to provide analysis of wind generation performance as part of this report when sufficient data are available.

2017 performance of the BPS generation system measured in daily MW rating losses due to unplanned outages of conventional generators was the best over the five most recent years.

GADSWG Future Considerations:

- GADSWG might consider requiring additional design data from the conventional generating units to help improve analytics on the generating fleet and its possible impacts to BES reliability.
- GADSWG might continue to investigate seasonal performance trends for all types of reported generation. As the generation fleet continues to shift toward natural-gas-fired units, and the overall age of the fleet reduces, new emerging trends must be examined to identify common outage concerns across fuel types.
- GADSWG might examine outage cause codes at the system level instead of the component level to see if further insight can be gained.

Appendix D: Analysis of Demand Response Data

Overview

In 2017, the DADSWG continued efforts to improve data collection and reporting through outreach and development of training materials. Future DADSWG efforts are focused on improving data collection, updating existing materials, developing additional guidance documents, maintaining data quality, and providing observations of demand response contributions to reliability.

Demand Response Programs

Demand Response Registered Program data provides important information about the individual programs that include product and service type, relationships to other entities and programs, and monthly registered capacities. BAs and Distribution Providers (DPs) that administer demand response programs that have been commercially in service for at least 12 months with 10 MW or more of enrolled capability are required to report into DADS. In accordance with two 2015 FERC orders,[155] reporting by Purchasing-Scheduling Entities and Load-Serving Entities was discontinued after the Summer 2016 reporting period.

DADS data are reported semiannually as summer and winter seasons with the summer season representing program data from April 1 through September 30 and the winter season representing program data from October 1 to March 31 of the following year. This report includes data reported through September 2017.

Registered Capacity

Figure D.1 represents the registered capacity MW for all demand response registered programs in NERC; registered capacity for summer is based on August of each year, and winter is based on January of each year. The total registered capacity during Summer 2017 shows an eight percent increase over 2016, and an increase during the winter period of two percent. Over the five-year period of 2013 to 2017, summer and winter enrolled demand response capacity increased by 17 percent and 20 percent, respectively.

It is important to note that the demand response registered capacity is considered fungible (resources and associated capacities are interchangeable). For example, an entity's reported demand response program may be an aggregation of individual resources and each year the individual resources could be from different sources and programs.

[155] Orders RR15-4-000: http://www.nerc.com/FilingsOrders/us/FERCOrdersRules/Order_RBR_ROP_20150319_RR15-4.pdf and RR-15-4-001: http://www.nerc.com/FilingsOrders/us/FERCOrdersRules/Order_RBR_ROP_10152015_RR15-4.pdf

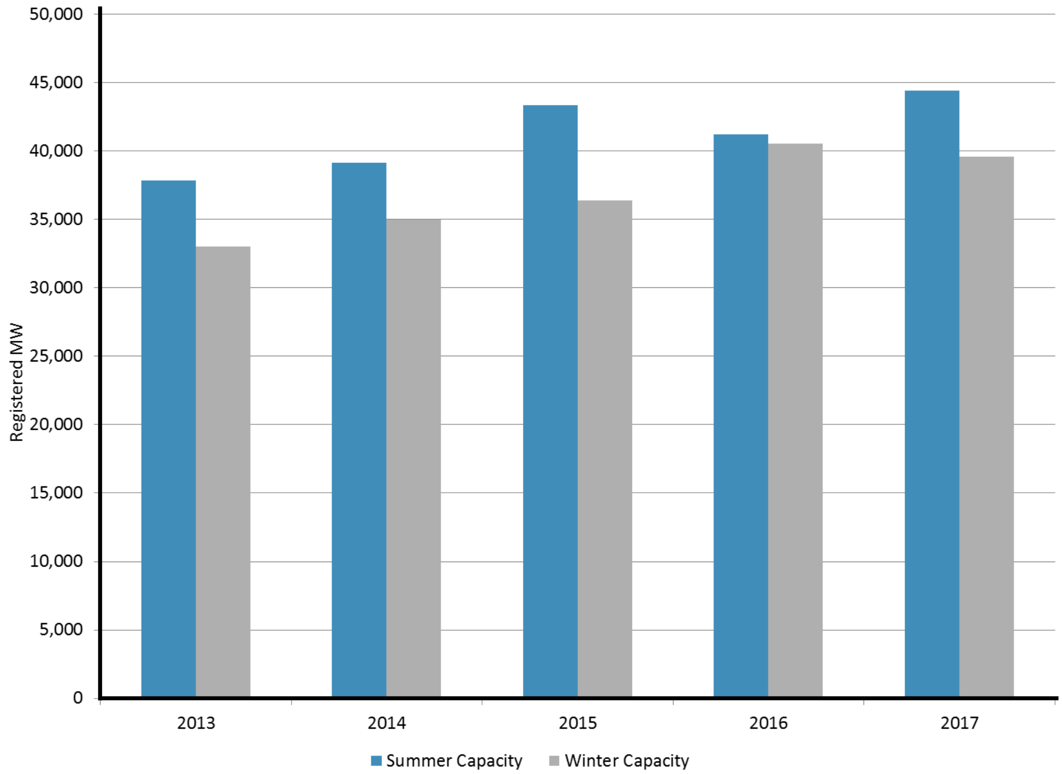


Figure D.1: Registered Demand Response Capacity MW by Season for All Registered Programs, 2013–2017

Product and Service Types

The webDADS portal collects information about demand response programs based on product type and product service type. Current product types in DADS include Energy, Capacity, and Reserves. Figure D.2 shows the registered capacity MW of demand response across NERC for Summer 2013–2017 and Winter 2013–2017 by reported product and service type.

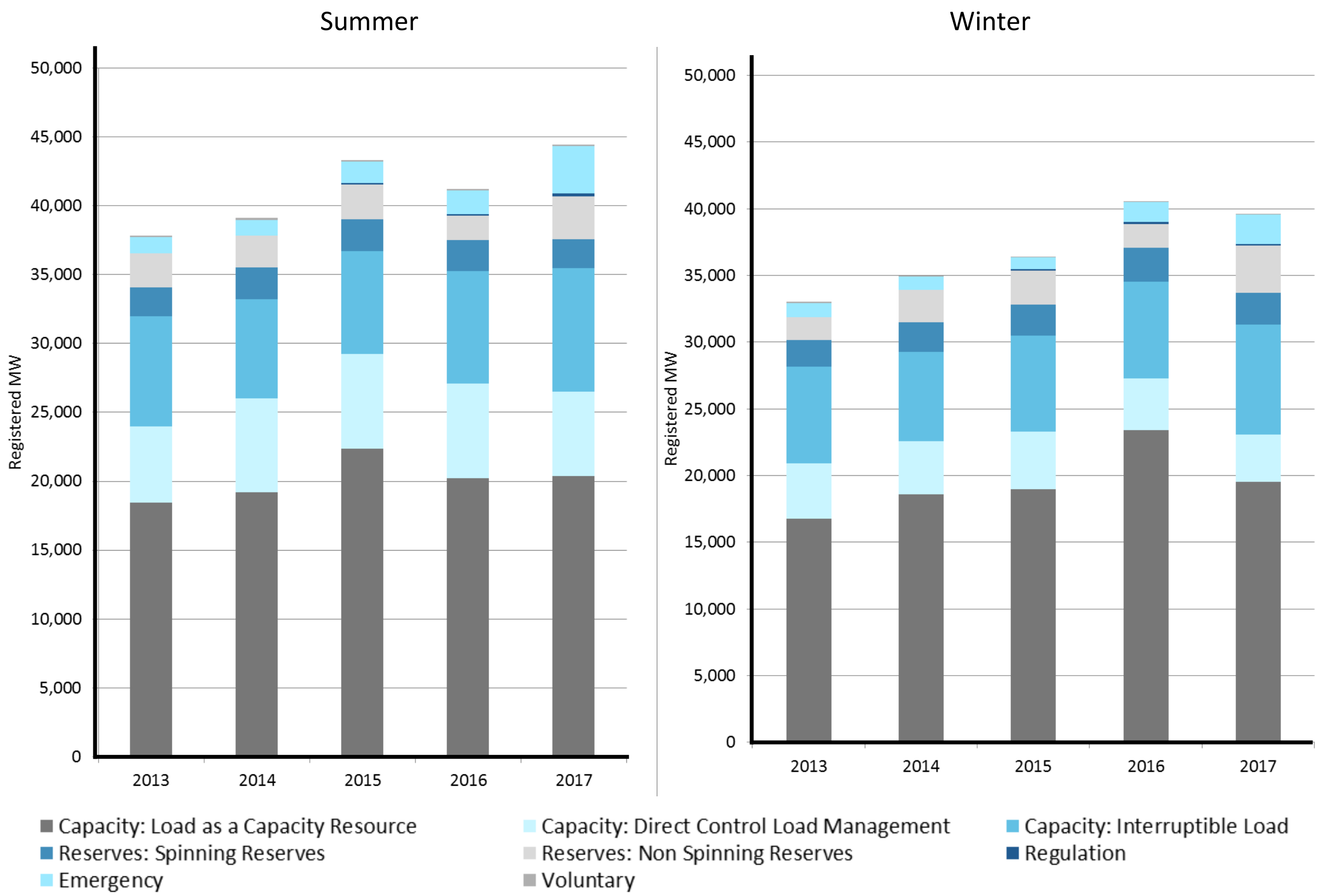


Figure D.2: Registered Demand Response Capacity MW by Service Type and Season, 2013–2017

A review of available capacity registered for each service type supports the following observations:

- Demand Response program enrollment shows growth in non-spinning reserves in both seasons.
- Load as a Capacity Resource and Interruptible Load continue to attract the highest enrollment. Some resources may also be eligible to provide in other Service Types—only unique MW are shown.
- Continued impacts to Load as a Capacity Resource are due in part to changes in 2016 environmental regulations for Emergency Engines.
- Changes in enrollment due to regulatory policies in some areas have resulted in an eight percent increase in summer enrollment and redistribution of existing demand response resources to other service types, such as Non-Spinning Reserves and Emergency.

Demand Response: Reliability Events

Demand response programs are deployed by system operators that are monitoring conditions on the grid. Demand response program rules may require advanced notification for the deployment of these resources that can be several hours ahead of when the emergency condition actually occurs. As the potential for the emergency condition approaches, many operators have more responsive demand response resources that may be deployed with as little as 10 minutes of notification to ramp and/or curtail load.

Reliability event reasons reported and summarized in DADS where demand response supports the BPS are categorized as one of three types of events: forecast or actual reserve shortage, reliability event, or frequency control.

Reserve shortage events tend to be driven by extreme weather events. For example, the following events all resulted in demand response deployment increases: the polar vortex of 2014 and extreme heat conditions on the East Coast and Northeast during 2013 and the West Coast during the summer of 2015. Reliability events can occur at almost any time, day, or month. These can typically be caused by a large number of unit trips or extreme weather that occurs during periods when the generation fleet is going through fleet maintenance periods in the fall and spring. Frequency control reliability events are a type of event that is more local and in isolated areas. For example, a large unit trip may cause a frequency disturbance, which is then arrested by the instantaneous tripping of loads using under-frequency relays installed at facilities of demand response resources.

Figure D.3 and **Figure D.4** show the number of demand response event days each month in a season from January 2013 through September 2017.[156] The black diamond in each column indicates the number of calendar days in a month when demand response was deployed for a reliability event. The stacked bars show the number of days that demand response events occurred in each NERC Region. When the stacked bar exceeds the black diamond, it is an indication that multiple Regions had demand response events on the same day within the month.

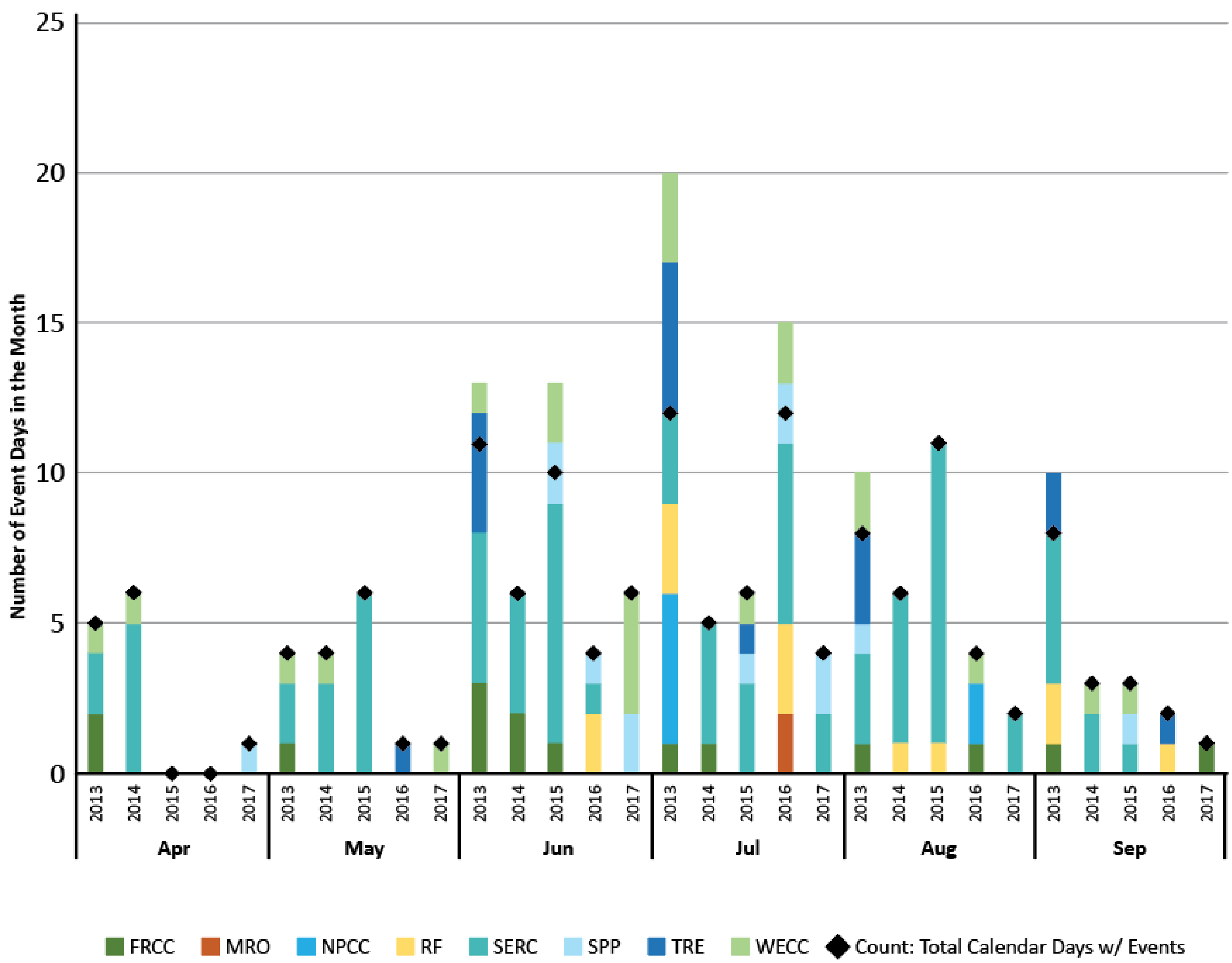


Figure D.3: Summer Demand Response Event Days by Month and Region, 2013–2017

[156] Event data for October 2017 through December 2017 are not reported until after publication of this report.

The peak number of events of demand response capacity during this five-year period occurred during the summer peak season and is especially evident during June and July of 2013. The second highest number of demand response deployments occurred during July of 2016. The frequency of deployment events in Summer 2017 was lower than the previous four years with some Regions having no demand response event days. For example, Summer 2016[157] had 23 calendar days with deployments while Summer 2017 had 15 calendar days with deployments (a 35 percent drop in the number of calendar days during which demand response was deployed). The impact of the polar vortex is also evident in the number of days and Regions that dispatched demand response in January 2014. Since 2015, winter deployments have dropped to single digits, due to warmer weather without the severity of the polar vortex events that occurred in 2014. Data for Winter 2017/2018 will not be reported until after the publication of this report.

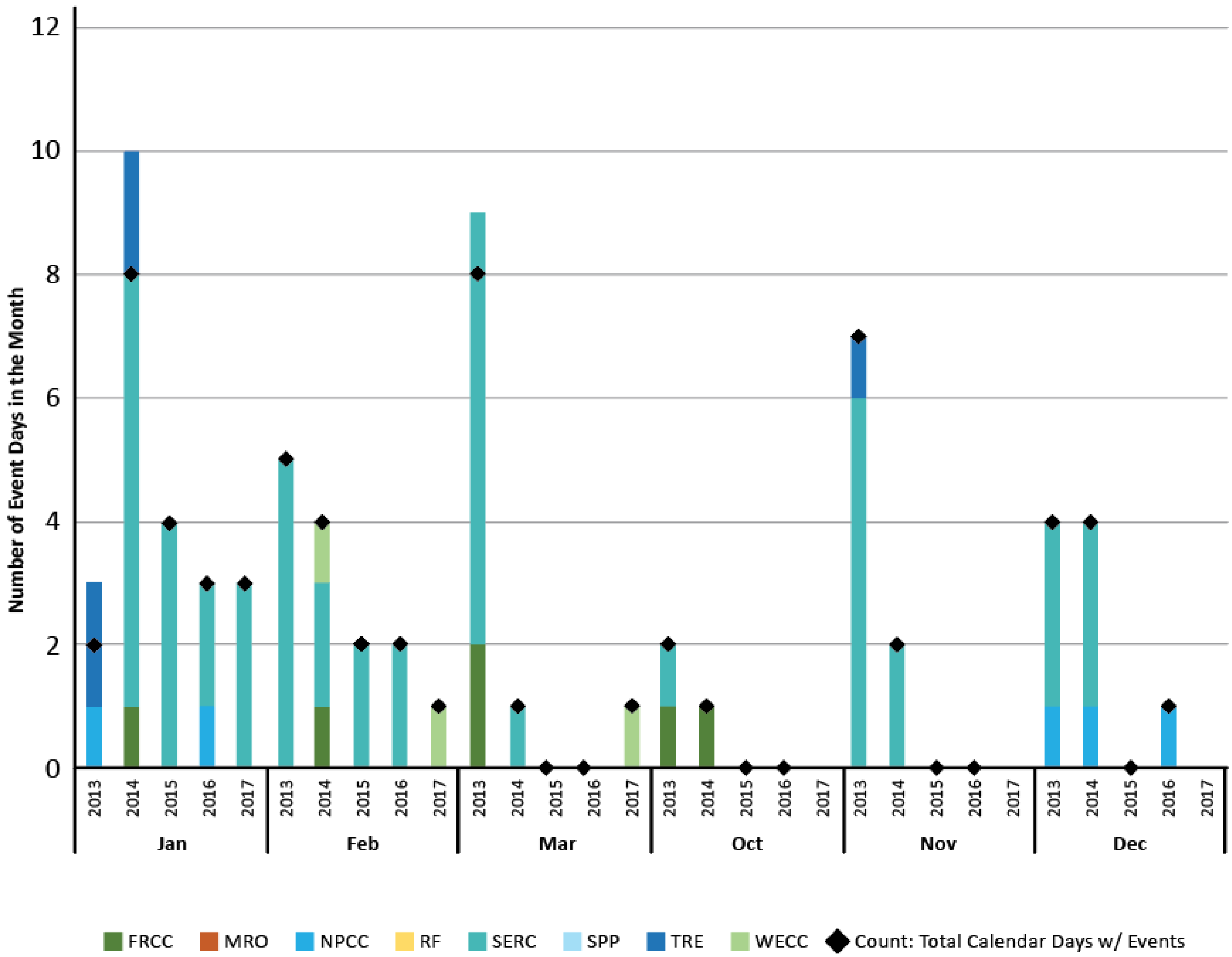


Figure D.4: Winter Demand Response Event Days by Month and Region, 2013–2017

DADS Metrics

Four metrics have been developed by the DADSWG and approved by PAS. These metrics are described in **Table D.1**.

[157] Defined as April 1–September 30.

Table D.1: DADS Metrics	
Metrics Title	**Purpose**
DADS Metric 1: Realized Demand Reduction of Event Deployment by Month	Shows the amount of demand response reduction (in MW) provided during all the reliability events deployed in a given month by time of day.
DADS Metric 2: Dispatched Demand Response MW by Service Type	Reflects the cumulative megawatts of demand reduction dispatched by service type in reliability event days per month at the NERC or Region level
DADS Metric 3: Realized Demand Response MW by Service Type	Reflects the cumulative time weighted megawatts of demand reduction realized by service type in reliability event days per month at the NERC or Region level
DADS Metric 4: Demand Response Events by Month—Dispatched vs. Realized	Allows for the creation of a demand response realization rate for reliability events to be established and trending

The DADSWG has completed analysis of Metrics 2, 3, and 4 and determined that Metrics 2 and 4 are most relevant for inclusion in this report. The working group will evaluate the DADS metrics, including the feasibility of implementing Metric 1.

DADS Metric 2: Dispatched Demand Response MW by Service Type

The amount and types of demand response dispatched by season and year illustrate how much weather can affect the deployment of demand response. **Figure D.5** and **Figure D.6** show the cumulative dispatched MW of demand response by service type for summer and winter, respectively. During Summer 2013, the cumulative amount of demand response deployed over all events was nearly 20,000 MW with over 70 percent of the demand response dispatched from load as a capacity resource and nearly equal amounts of direct load control and interruptible load. Since 2013, the summers have been much milder, resulting in few deployments and more conservative utilization of demand response primarily from direct load control and interruptible load. During Summer 2016, deployments included a marked increase in the amount of demand response dispatched to provide spinning reserves. Events during Summer 2017 were exclusively to demand response resources with interruptible load and direct control load management capabilities.

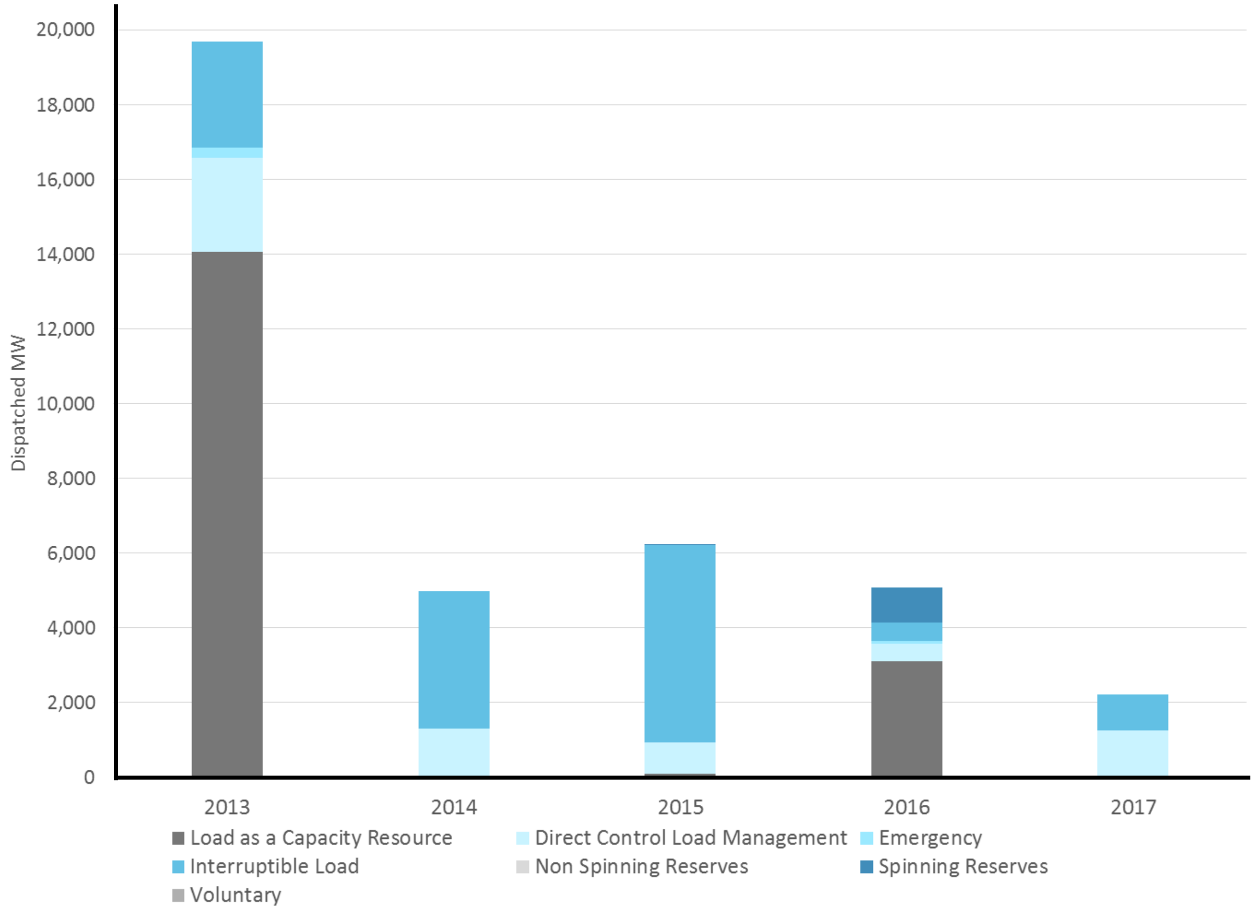


Figure D.5: Cumulative Dispatched MW by Service Type for Summer Demand Response Events, 2013–2017

Winter deployments of demand response are much less extensive as reflected in the cumulative MW dispatched each winter in the analysis period (**Figure D.6**). Deployments during the analysis period were primarily to demand response provided from interruptible load resources. During Winter 2013 and 2014, demand response providing reserves (spinning and non-spinning) accounted for almost one-third of the cumulative dispatched MW each year.

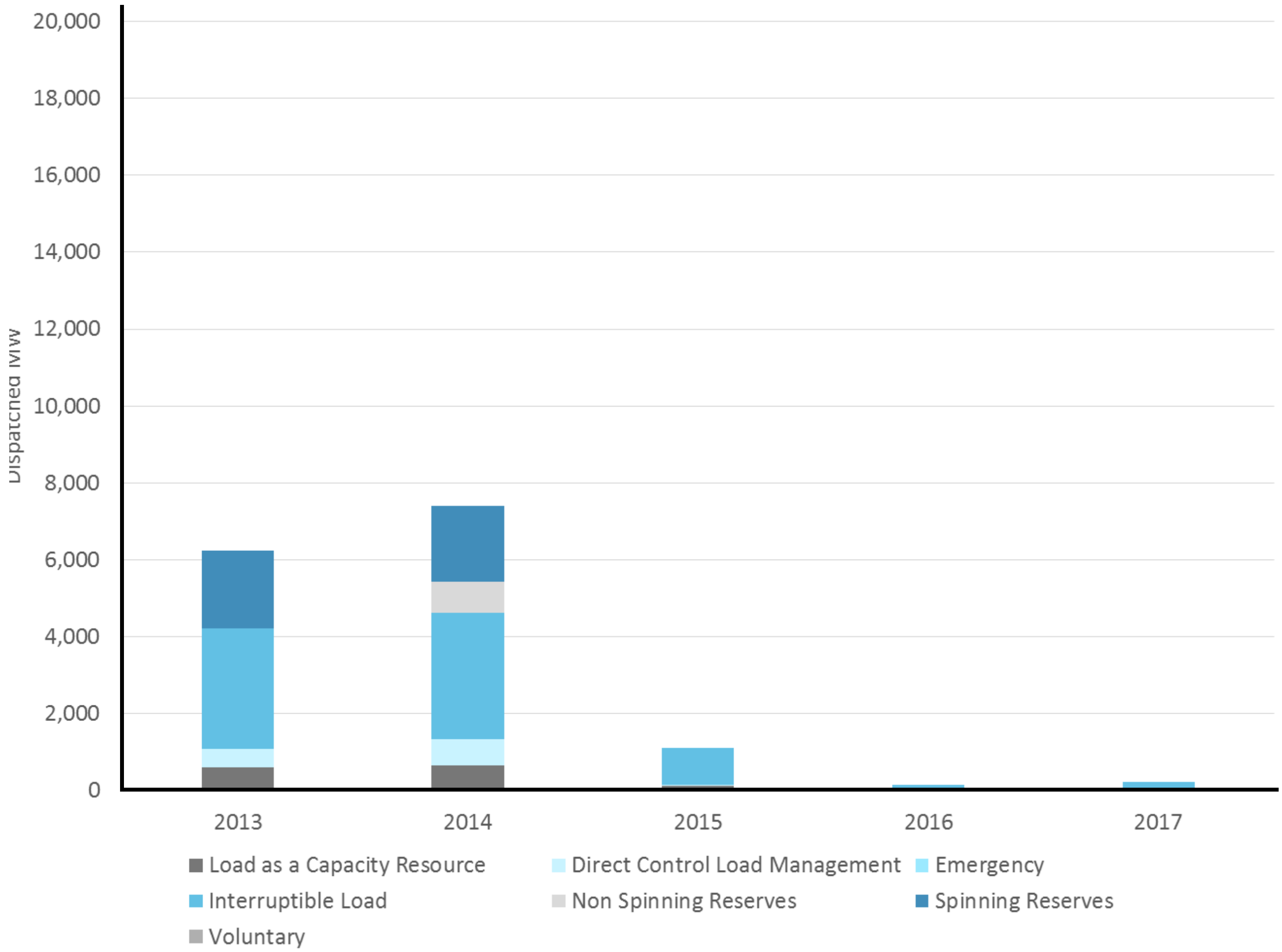


Figure D.6: Cumulative Dispatched MW by Service Type for Winter Demand Response Events, 2013–2017

DADS Metric 4: Performance—Demand Response Events by Month—Dispatched vs. Realized

The effectiveness of demand response to support reliability is illustrated by a comparison of the cumulative dispatched MW to the average realized reduction MW each season and year. Figure D.7 and Figure D.8 show the cumulative dispatched MW and corresponding performance of all demand response types deployed in a season for each year of the analysis period.

During Summer 2013, demand response performed at 82 percent of its committed capacity (Figure D.7). This includes the deployment of voluntary and emergency types of demand response, which typically performs at a much lower rate (about 15 percent of registered) than other categories of demand response. The voluntary and emergency types of demand response deployed in Summer 2013 represented 1.3 percent of all dispatched MW. When Summer 2013 performance was evaluated without the voluntary and emergency types of demand response, there was a slight increase in performance, from 82.1 percent to 82.9 percent. Performance during Summer 2014—2016 was well above 90 percent, due to the amount and types of demand response deployed. Summer 2017 showed a slight drop in performance to 89 percent.

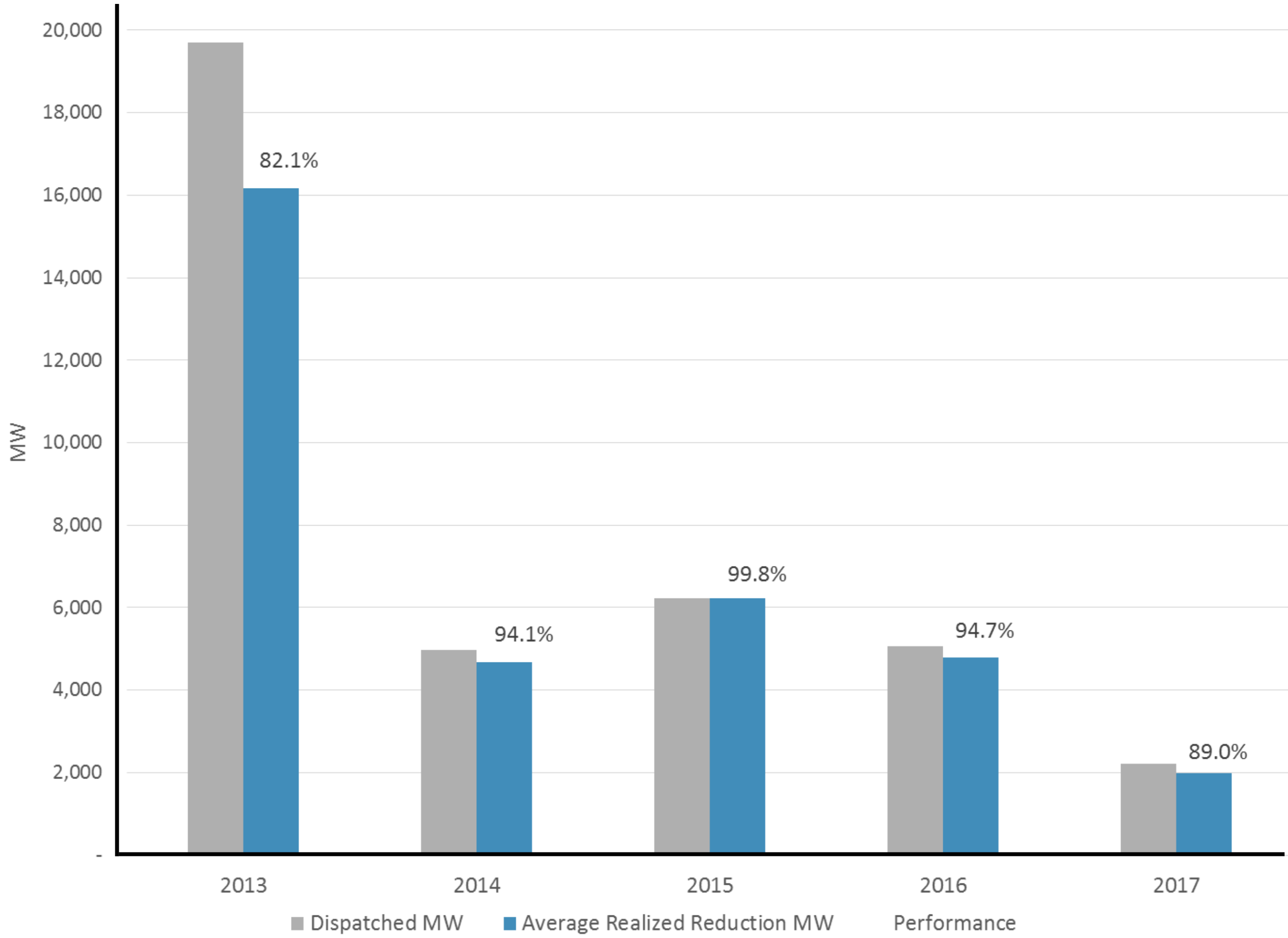


Figure D.7: Demand Response Performance for Summer Demand Response Events, 2013–2017

As previously stated, fewer MW of demand response were deployed in the winter seasons. Performance exceeded 96 percent during events in Winter 2013–2014 and 90 percent in 2015 (**Figure D.8**). Fewer than 100 MW of demand response were deployed in Winter 2016. During the Winter 2017 period, the 215 MW of demand response deployed performed above registered capability by 6.5 percent.

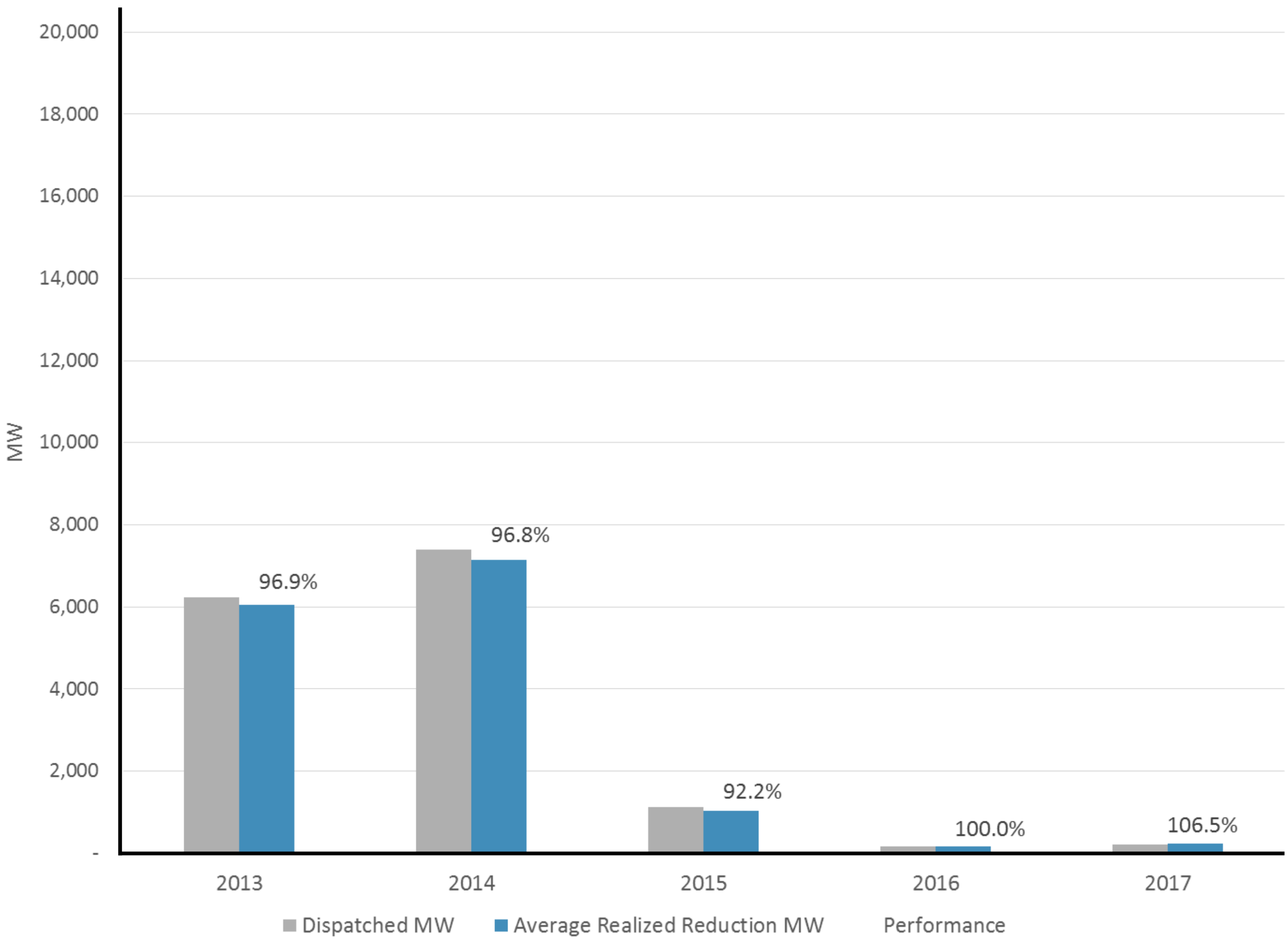


Figure D.8: Demand Response Performance for Winter Demand Response Events, 2013–2017

Looking Ahead

The DADSWG is focused on improving the quality of the demand response data collected by NERC, and this will provide a better perspective on how this type of resource is being used to support reliability. To achieve this objective, the following initiatives are planned for 2018 and beyond:

- Development of an introductory video for DADS reporting.
- Completion of training and data quality materials to improve data reporting.
- Finalization and implementation of requirements for data reporting capabilities for market-based demand response programs that support reliability.

Appendix E: Frequency Response Statistics and Essential Reliability Services

Primary frequency response is essential for maintaining the reliability of the BPS. Frequency maintained within predefined limits is a key ALR performance outcome. Frequency response is necessary to support BPS reliability during loss of generation resource or loss of load disturbances that result in frequency deviations, and it is critical during system restoration efforts where frequency fluctuations must be controlled during load pick up and connection of additional resources. Frequency response and frequency control are often used synonymously and involve the ability of the BPS to support frequency following a disturbance.

Frequency response is comprised of the actions provided by the Interconnection to arrest and stabilize frequency in response to frequency deviations. Frequency response is provided from automatic generator governor response, load response (typically from induction motors), and facilities that provide an immediate change in output when frequency changes are detected by local device-level control systems.

Metric M-4: Interconnection Frequency Response

The purpose of the M-4 metric is to determine frequency response trends for each Interconnection so that adequate primary frequency control is provided to arrest and stabilize frequency during frequency excursions of a predefined magnitude. Frequency response is bidirectional and Interconnection resources should respond to loss of resource events that result in low frequency to avoid tripping the first stage of UFLS as well as loss of load events that result in high frequency that could trip connected generation (over-frequency generation protection relays and turbine over-speed control action) from the BPS to prevent from damaging equipment.

The M-4 metric is based on methods defined in BAL-003-1.1 for developing a frequency response measure that is used to calculate an interconnection frequency response performance measure ($IFRM_{A\text{-}B}$) as the ratio of the resource or load megawatt (MW) loss that initiated the event to the difference of pre-disturbance frequency (Value A) and the stabilizing period frequency (Value B). Value A and Value B are average frequencies from t_{-16} to t_{-2} and t_{+20} to t_{+52}, respectively, as defined in NERC BAL-003-1.1. The MW loss experienced by the Interconnection that initiated the event must be determined in order to calculate M-4 frequency response performance. Measurement of frequency performance in that time period is a surrogate for the lowest frequency during the event (the nadir or Point C) based on the limitations of system control and data acquisition scan rates. Below is the equation for calculating $IFRM_{A\text{-}B}$.

$$IFRM_{A-B} = \frac{MW\ Loss}{10 * \Delta f_{A-B}}$$

Where:
MW Loss = Resource or Load Output immediately prior to the start of the event
$f_{A\text{-}B}$ = Change in frequency from Value A to Value B

The predominant reliability risk is the frequency during the arresting period (from the start of the event at T=0 to the time of the nadir) of a frequency event when the low frequency nadir (Point C) is experienced in the first few seconds of the event. Performance during the arresting period is vital to ensure that customer load is not shed nor equipment damaged due to a low frequency nadir that activates the Interconnection's UFLS devices. The arresting and stabilizing periods are illustrated in **Figure E.1**.

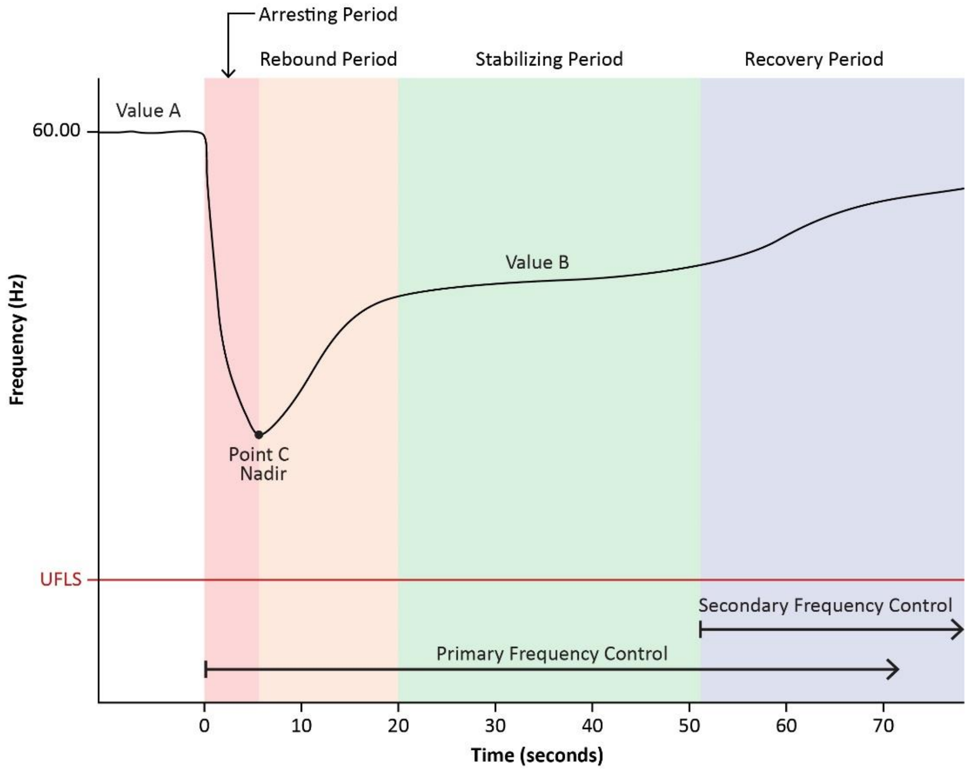


Figure E.1: Primary and Secondary Frequency Control

Figure E.1 shows the Arresting, Rebound, Stabilizing, and Recovery Periods of a frequency event following the loss of a large generation resource.

Primary Frequency Control: This is the action by the Interconnection to arrest and stabilize frequency in response to frequency deviations and has three time components; the arresting period, rebound period, and stabilizing period.

Arresting Period: This is the time from time zero (Value A) to the time of the nadir (Value C) and is the combination of system inertia, load damping, and the initial primary control response of resources acting together to limit the duration and magnitude of frequency change. It is essential that the decline in frequency is arrested during this period to prevent activation of automatic UFLS schemes in the Interconnection.

Rebound Period: This includes the effects of governor response in sensing the change in turbine speed as frequency increases or declines, causing an adjustment to the energy input of the turbine's prime mover. The Rebound Period can also be impacted by end-user customer or other loads that are capable of self-curtailment due to local frequency sensing and control during frequency deviations.

Stabilizing Period: This is the third component of primary frequency control following a disturbance when the frequency stabilizes following a frequency excursion. Value B represents the interconnected system frequency at the point immediately after the frequency stabilizes primarily due to governor action but before the contingent control area takes corrective automatic generation control action.

Secondary Frequency Control: This comes from either manual or automated dispatch of resources from a centralized control system. Secondary Control also includes initial reserve deployment for disturbances and maintains the minute-to-minute balance throughout the day: it is used to restore frequency to nominal following a disturbance and is provided by Operating Reserve, both Supplemental and Spinning.

This report provides analysis of Interconnection frequency response performance during both the arresting period and the stabilizing periods. Value A, Point C, and Value B definitions can be found in the *2012 Frequency Response Initiative Report*[158] and the BAL-003-1.1 Reliability Standard[159] as well as in this appendix.

Deteriorating performance during the arresting period of a low frequency event can result in the loss of load due to activation of automatic UFLS schemes. Deteriorating performance during the rebound and stabilizing periods can result in increased risk of a subsequent frequency event occurring from a lower starting frequency. It is important to understand that performance in the arresting and stabilizing periods are only loosely coupled; therefore, an Interconnection can realize improved performance in one period and yet have decreased performance in the other.

NERC applies statistical tests to Interconnection frequency event datasets. An operating year, for frequency event purposes, runs from December of the previous year through November of the current year. For the 2013–2017 operating years, historical frequency response was statistically analyzed to evaluate performance trends for each Interconnection. An increasing trend over time indicates that frequency response is improving in that Interconnection. It should be noted that, in the 2017 operating year, no Interconnection had an M-4 frequency event where the IFRM was below its IFRO as defined in the BAL-003-1 Reliability Standard. It is important to note that there is a difference between the measured frequency response for a given event and the amount of response that was actually available at the time of the event. Measured response varies depending on starting frequency as well as the size of the resource loss. The amount of frequency response delivered is also dependent on the amount of frequency responsive reserves available (Operating Reserves—Supplemental and Operating Reserves—Spinning) in the Interconnection, sometimes called headroom, and the magnitude of the frequency deviation outside of the governor dead band settings. Calculated frequency response provided by an Interconnection can be influenced by the magnitude of the frequency deviation; relatively small deviations can indicate rather large response due to the normalization to 0.1 MW/Hz criteria.

Events for frequency response analysis are selected by the NERC RS's Frequency Working Group utilizing pre-defined event selection criteria. The event data are used to support Reliability Standard BAL-003-1 in addition to the M-4 metric and ERS Measure 4. Frequency data for all four Interconnections are available to NERC staff through the University of Tennessee by using the Frequency Monitoring Network (FNet). The data consists of sub-second high-speed frequency values (10 samples per second) captured by FNet's frequency disturbance recorders. Data for all significant frequency events are collected (e.g., Value A, Value B, Point C, Point C', and 300 seconds of high-speed frequency data surrounding the event) and stored on a spreadsheet for use in the event detection and selection process and various analyses.

NERC staff and Interconnection representatives analyze frequency data to detect events for inclusion in the Candidate Frequency Event List. The event detection criteria is slightly broader than the criteria used to select events for M-4 and BAL-003-1.1 to ensure that all the potential events are detected as shown in **Table E.1** below.

To be considered for inclusion in the Candidate Frequency Event List, a frequency event shall satisfy either of the following:

- The delta frequency measured between Value A and Point C is greater than or equal to the designated threshold found in **Table E.1** for the Interconnection where the event occurred
- The net MW loss for the event (either generation or load) is greater than or equal to the designated threshold found in **Table E.1** for the Interconnection where the event occurred.

[158] The *2012 Frequency Response Initiative Report* can be found at the following location: https://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

[159] The BAL-003-1.1 Reliability Standard can be found at the following location: https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.1.pdf

Table E.1: M-4 Event Selection Criteria		
Interconnection	Δf_{AC} (mHz) ***or*** >= MW Loss	
Eastern	36	800
Western	70	700
Texas	80	450
Québec	300	450

In the 2016 operating year, a change in selection criteria was implemented that included frequency events with a smaller MW loss if the event resulted in a sufficient frequency deviation. Note that this change resulted in a larger sample of events for all Interconnections as compared to previous years and is meant to capture frequency response performance over a wider range of operating conditions (e.g., those that might occur during light load conditions when less generation is on-line and therefore the inertia and governor response of the Interconnections might be reduced). Due to this change, results should be considered as any detected statistically significant difference in year-over-year performance that can be partially due to the criteria modification.

Note that frequency response (i.e., IFRO and IFRM) is expressed as negative numbers expressed in MW/0.1 Hz because the change in MW output should be in the opposite direction as the change in frequency. For purposes of illustration in this report, frequency response is expressed as an absolute value.

The NERC RS has identified issues related to the ability of existing generating resources to provide sustained frequency response, including incorrect governor dead-band and droop settings and/or plant or generator control logic. The NERC RS developed and NERC OC issued *Reliability Guideline: Primary Frequency Control v1.0 Final*[160] to provide technical guidance to the industry to address these issues.

The M-4 metric and NERC BAL-003-1 Reliability Standard calculate the IFRM in the context of the stabilizing period, which is the interval of 20 to 52 seconds after the start of the event that is known as Value B. The Value B average frequency is compared to pre-disturbance frequency, known as Value A, in addition to the total resource or load MW loss to determine the IFRM.

It is also important to understand the impact of the arresting period of a frequency event where Point C is the low frequency nadir experienced in the first 12 seconds of the event. Performance during the arresting period is vital to ensure that customer load is not shed nor equipment damaged due to a low frequency nadir that exceeds the Interconnection's UFLS settings.

Figure E.2 illustrates a frequency deviation due to a loss of generation resource and the methodology for calculating frequency response in accordance with definitions in the BAL-003-1 Reliability Standard. The event starts at time t0 (00:00). Value A is the average frequency calculated from t-16 to t-2 seconds from t0, Point C is the lowest frequency point observed in the first 12 seconds after t0, and Value B is the average frequency from t+20 to t+52 seconds from t0. The difference between Value A and Value B is the change in frequency used for calculating primary frequency response. Frequency response is calculated as the ratio of the megawatts lost when a resource trips and the frequency deviation. Frequency response performance in the correct direction is expressed as a negative value since the resulting Interconnection change in megawatts should be in the opposite direction as the change in frequency. Frequency response with a more negative value indicates better response than a frequency response that is less negative or positive. For convenience of reporting and graphical representation, in this report frequency response is expressed as an absolute value. All events analyzed in this report had a response in the appropriate direction.

[160] The Primary Frequency Control Reliability Guideline can be found at the following location: http://www.nerc.com/comm/OC/Reliability%20Guideline%20DL/Primary_Frequency_Control_final.pdf

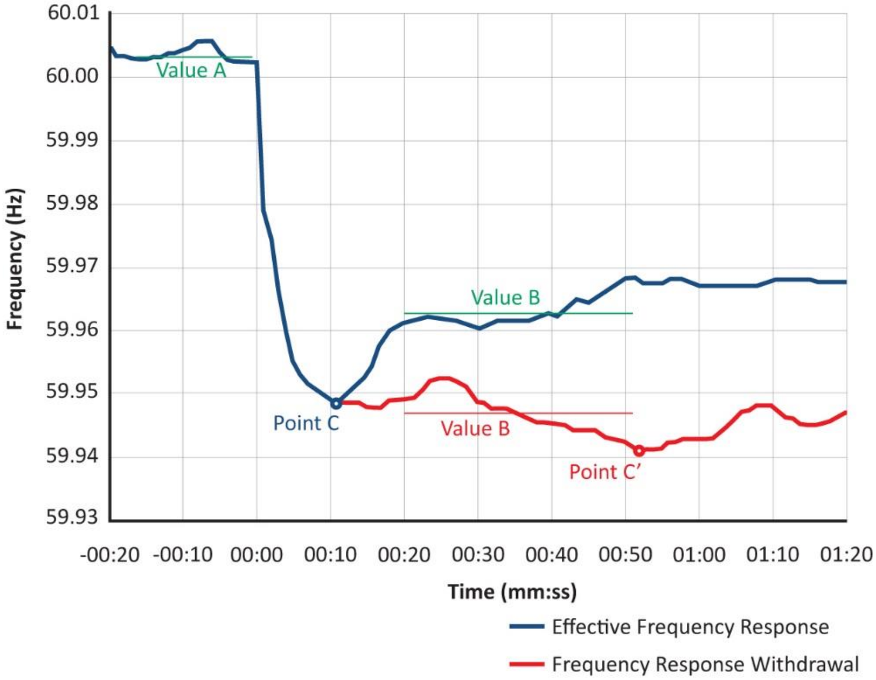


Figure E.2: Criteria for Calculating Value A and Value B

Frequency Response Arresting Period Performance

Table E.2 through **Table E.5** compare the frequency event statistics for the four Interconnections with an emphasis on performance during the arresting period as shown in **Figure E.1**. It is important to understand that frequency response is bidirectional with generating resources and loads capable of responding to frequency events that result in either high or low Interconnection frequency or loss of load or loss of generation, respectively. However, the predominate risk relevant to the arresting period of an event occurs during a low frequency event and results in the activation of UFLS relays that disconnect load from the system. As such the events analyzed in this section will be loss of resource events only and will exclude loss of load events that result in high frequency.

In the 2016 operating year, a change in selection criteria was implemented that included frequency events with a smaller MW loss if the event resulted in a sufficient frequency deviation. The purpose of this change was to increase the sample size of qualifying events in support of tests for statistical significance and to capture frequency response during a wider range of operating conditions.

Table E.2: Frequency Event Statistics for Eastern Interconnection

Operating Year	Total Low Frequency Events	Mean Resource Loss (MW)	Mean Value A (Hz)	Mean Pt C (Hz)	Mean Value B (Hz)	Mean B-C Margin (Hz)	Mean Pt C-UFLS Margin (mHz)	Lowest Pt C (Hz)	Lowest Pt C-UFLS Margin (mHz)
2013	32	1,157	60.000	59.950	59.948	-0.001	0.450	59.909	0.409
2014	34	1,212	59.995	59.947	59.948	0.001	0.447	59.910	0.410
2015	36	1,103	59.996	59.948	59.950	0.002	0.448	59.928	0.428
2016	61	938	59.999	59.956	59.959	0.003	0.456	59.930	0.430
2017	79	851	60.003	59.959	59.963	0.004	0.459	59.935	0.435

The following are observations from **Table E.2**:

- The mean Point C frequencies have increased each year since 2014.
- The lowest Point C to UFLS margin has increased each year since 2013, suggesting improvement in the arresting period.
- For all years studied the lowest Point C to UFLS margin was above 400 mHz, suggesting reduced risk during the arresting period.
- Statistical analysis indicates that, over the 2013–2017 operating years, the EI had an improving mean frequency response trend during the arresting period that was highly statistically significant (slope = 8E-06, p-value = 1.804E-08, Average Annual Increase = 2.93 mHz).

Table E.3: Frequency Event Statistics for Texas Interconnection

Operating Year	Total Low Frequency Events	Mean Resource Loss (MW)	Mean Value A (Hz)	Mean Pt C (Hz)	Mean Value B (Hz)	Mean B-C Margin (Hz)	Mean Pt C-UFLS Margin (Hz)	Lowest Pt C (Hz)	Lowest Pt C-UFLS Margin (Hz)
2013	40	721	59.997	59.836	59.896	0.061	0.536	59.732	0.432
2014	33	639	59.996	59.850	59.900	0.050	0.550	59.744	0.444
2015	34	642	59.999	59.866	59.912	0.046	0.566	59.728	0.428
2016	50	601	59.998	59.868	59.920	0.052	0.568	59.704	0.404
2017	48	568	60.002	59.876	59.930	0.054	0.576	59.733	0.433

The following are observations from **Table E.3**:

- The mean Point C frequencies and resulting Point C to UFLS margins have trended higher each year since 2013, suggesting improved overall primary frequency response in both the arresting period.
- The lowest Point C to UFLS margin was greater than 400 mHz for all years studied, suggesting reduced risk during the arresting phase of frequency events.
- Statistical analysis indicates that, over the 2013–2017 operating years, the TI had an improving mean frequency response trend during the arresting period that was highly statistically significant (slope = 3E-05, p-value = 3.02E-06, Average Annual Increase = 9.53 mHz).

Table E.4: Frequency Event Statistics for Québec Interconnection

Operating Year	Total Low Frequency Events	Mean Resource Loss (MW)	Mean Value A (Hz)	Mean Pt C (Hz)	Mean Value B (Hz)	Mean B-C Margin (Hz)	Mean Pt C-UFLS Margin (Hz)	Lowest Pt C (Hz)	Lowest Pt C-UFLS Margin (Hz)
2013	30	973	59.996	59.395	59.825	0.430	0.895	58.868	0.368
2014	24	806	60.004	59.413	59.836	0.423	0.913	58.986	0.486
2015	24	627	60.003	59.555	59.872	0.292	1.055	59.273	0.773
2016	31	740	59.998	59.487	59.859	0.372	0.977	59.019	0.519
2017	33	532	60.007	59.592	59.895	0.304	1.092	59.362	0.862

The following are observations from **Table E.4**:

- The lowest Point C to UFLS margin was greater than 400 mHz for all years except 2013 with the largest margin of 862 mHz seen in 2017, suggesting reduced risk during the arresting phase of frequency events.
- Statistical analysis indicates that, over the 2013–2017 operating years, the QI had an improving frequency response trend during the arresting period that was highly statistically significant (slope = 0.0001, p-value = 4.07E-5, Average Annual Increase = 39.4 mHz).

Table E.5: Frequency Event Statistics for Western Interconnection

Operating Year	Total Low Frequency Events	Mean Resource Loss (MW)	Mean Value A (Hz)	Mean Pt C (Hz)	Mean Value B (Hz)	Mean B-C Margin (Hz)	Mean Pt C-UFLS Margin (Hz)	Lowest Pt C (Hz)	Lowest Pt C-UFLS Margin (Hz)
2013	13	945	59.993	59.887	59.924	0.037	0.387	59.843	0.343
2014	17	1095	60.001	59.880	59.917	0.036	0.380	59.671	0.171
2015	21	846	59.998	59.903	59.934	0.032	0.403	59.845	0.345
2016	47	734	60.008	59.918	59.956	0.037	0.418	59.819	0.319
2017	38	1067	60.001	59.887	59.939	0.052	0.387	59.697	0.197

The following are observations from **Table E.5**:

- After trending higher in previous years, the mean Point C frequencies were lower in 2017, which could suggest increased risk during the arresting period of an event; this could also be due to a significant increase in mean resource loss in 2017.
- For frequency events in the 2017 operating year, the lowest Point C frequency was above the first-step UFLS setting of 59.5 Hz by 197 mHz, which is the smallest margin since a frequency event margin of 171 mHz in 2014. The resource MW loss for these two events were 2685 MW and 2826 MW, respectively, more than double the mean resource MW loss for each year and close to the Resource Contingency Protection Criteria of 2740 MW defined in the 2012 *Frequency Response Initiative Report*. This suggests increased risk during the arresting period of frequency events. It should be noted that the WI IFRM performance was above its IFRO for both events where the UFLS margins were below 200 mHz.
- Statistical analysis indicates that, over the 2013–2017 operating years, the WI mean frequency response trend during the arresting period was neither statistically improving nor declining (slope = 0.0028, p-value = 0.2663).

Frequency Response Stabilizing Period Performance

Interconnection Frequency Response: Time Trends

The time trend analysis uses the Interconnection frequency response datasets for the 2013–2017 operating years. In this section, performance of frequency response measured in the stabilizing period and its changes in time are studied by investigating relationships between frequency response data and the explanatory variable time.[161] **Figure E.3** through **Figure E.6** show the Interconnection frequency response scatter plots with a linear regression line that

[161] That is frequency response is considered to be a stochastic process frequency response (T), where T changes from December 1, 2012 to November 30, 2017, and changes of frequency response (T) are studied, quantified, and statistically analyzed. Observations of this stochastic process are assumed to be independent because the frequency events are typically separated by a significant time interval and by location.

represents changes of the mean frequency response and a quantile regression line that represents changes in the median frequency response. A significance of a linear or quantile regression is tested at the significance level of 0.05. The 95 percent confidence interval for slopes of both trend lines are shown as shaded areas. For each Interconnection, general trends for mean and median frequency response are similar, but their rates of change represented by a slope of the trend lines can be different.

It is important to note that there is a difference between the measured frequency response for a given event and the amount of response that was actually available at the time of the event. Measured response (IFRM) varies depending on starting frequency as well as the size of the resource loss. The amount of frequency response delivered is also dependent on the amount of frequency responsive reserves available in the Interconnection, sometimes called headroom, and the magnitude of the frequency deviation outside of the governor dead band settings.

Eastern Interconnection

In the EI, a linear regression line (a trend line for the mean frequency response) and a quantile regression line (a trend line for the median frequency response), shown in **Figure E.3,** both have negative slopes. However, the negative slopes are not statistically significant because the statistical test on significance of each regression fails to reject the null hypothesis about zero slope at a standard significance level (for M-4 mean p-value=0.34 and for M-4 median p-value=0.85). These results imply that it is very likely that the negative slopes may have occurred simply by chance. It leads to the inference that, on average and on median, the EI frequency response has been neither increasing nor decreasing significantly from 2013–2017.

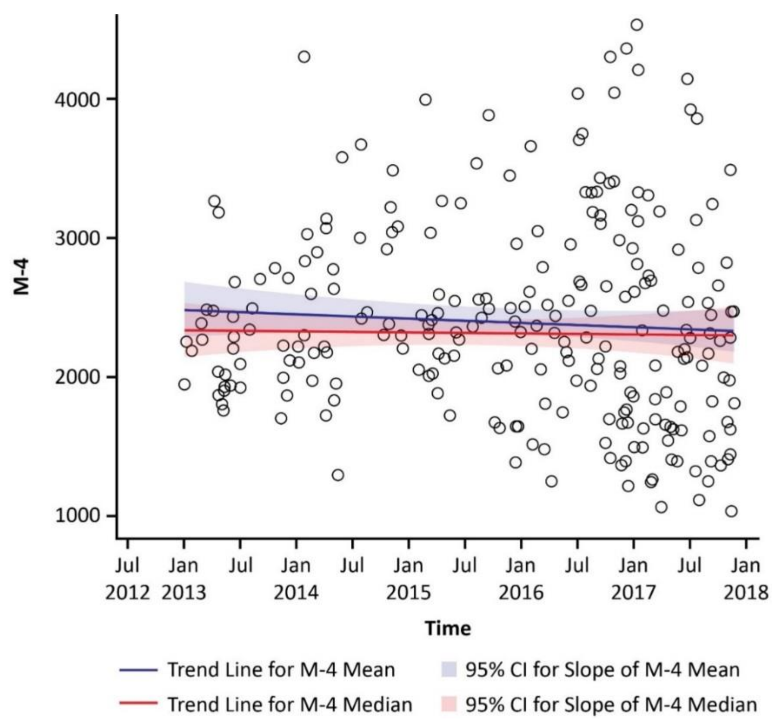


Figure E.3: Eastern Interconnection Frequency Response Scatter Plot and Time Trend Lines for Mean and Median Frequency Response 2013–2017

Texas Interconnection

In the TI, a linear regression line (a trend line for the mean frequency response) and a quantile regression line (a trend line for the median frequency response), shown in **Figure E.4**, both have positive slopes. The slope 0.0000008 of the trend line for mean is statistically significant (p-value=0.033), and it is unlikely that the increasing trend for the mean may have occurred simply by chance. On average, the TI frequency response grew from 2013–2017 at the annual rate of 25.86 MW/0.1 Hz. On the other hand, the slope of the trend line for the median is not significant because the statistical test on significance of quantile regression fails to reject the null hypothesis about zero slope at a standard significance level (p-value=0.09). It leads to the inference that from 2013–2017, the TI frequency response has been increasing as measured by the mean and has been steady as measured by the median.

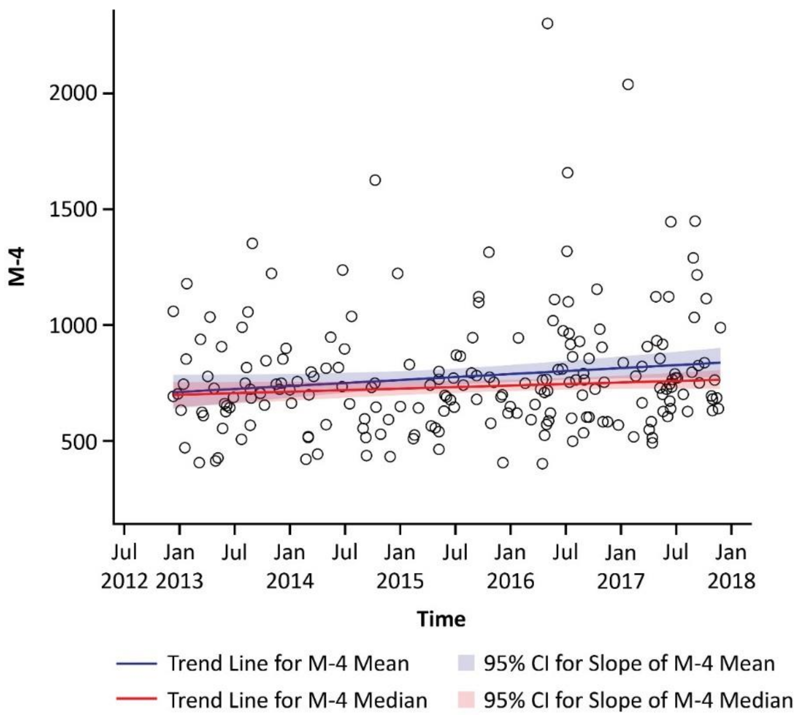


Figure E.4: Texas Interconnection Frequency Response Scatter Plot and Time Trend Lines for Mean and Median Frequency Response 2013–2017

Québec Interconnection

In the QI, a linear regression line (a trend line for the mean frequency response) and a quantile regression line (a trend line for the median frequency response), shown in **Figure E.5**, both have positive slopes. However, these positive slopes are not statistically significant because the statistical test on significance of each regression fails to reject the null hypothesis about zero slope at a standard significance level (for M-4 mean p-value=0.22 and for M-4 median p-value=0.59). These results imply that it is very likely that the increasing trends may have occurred simply by chance. It leads to the conclusion that, on average and on median, the QI frequency response has been neither increasing nor decreasing significantly from 2013–2017.

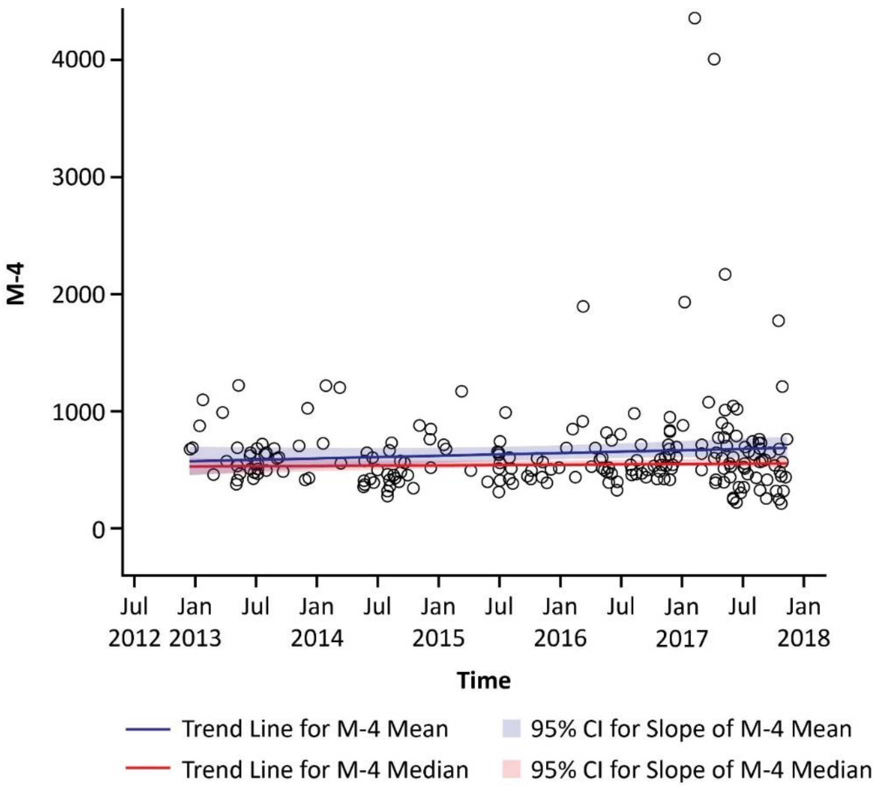


Figure E.5: Québec Interconnection Frequency Response Scatter Plot and Time Trend Lines for Mean and Median Frequency Response 2013–2017

Western Interconnection

In the WI, a linear regression line (a trend line for the mean frequency response) and a quantile regression line (a trend line for the median frequency response), shown in **Figure E.6**, both have positive slopes. The slope 0.00000425 of the trend line for mean is highly statistically significant (p-value=0.003). Even though an upper extreme outlier for the September 20, 2017 event with frequency response=6645 MW/0.1Hz affects the mean, a slope of the trend line for the mean of the dataset with this outlier removed would still be statistically significantly positive (p-value=0.006). It should be noted that the September 20 event occurred in the early morning hours on a day when significant amounts of solar PV generation resources were increasing in output; this likely being a contributing factor in the high frequency response performance for that event. These results imply that it is highly unlikely that the positive slope for the mean may have occurred simply by chance. On average, the WI frequency response grew from 2013–2017 at the annual rate of 134.0 MW/0.1 Hz. On the other hand, the statistical test on significance of quantile regression fails to reject the null hypothesis about zero slope at a standard significance level (p-value=0.08). It leads to the inference that from 2013–2017, the WI frequency response has been increasing as measured by the mean and has been neither increasing nor decreasing as measured by the median.

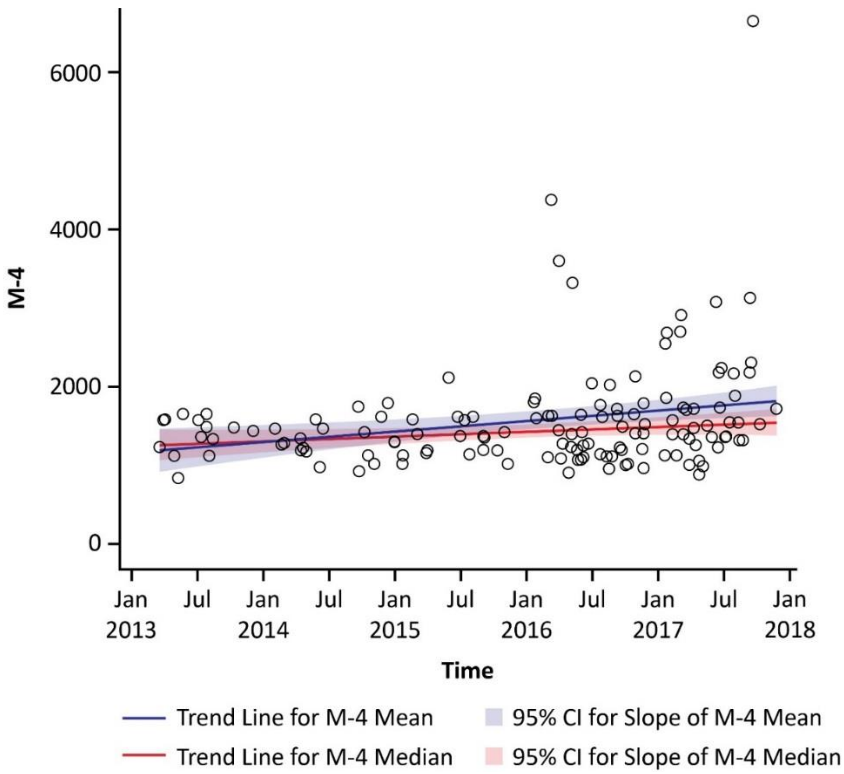


Figure E.6: Western Interconnection Frequency Response Scatter Plot and Time Trend Lines for Mean and Median Frequency Response 2013–2017

Interconnection Frequency Response: Year-Over-Year Changes

The analyses of changes by year use the Interconnection frequency response datasets for the 2013–2017 operating years. The sample statistics are listed by year in **Table E.6** through **Table E.9**. The last column lists the number of frequency response events that fell below the absolute IFRO.[162]

Figure E.7 through **Figure E.10** show the box and whisker plots of the annual distribution of the Interconnection's frequency response. The boxes enclose the interquartile range with the lower edge at the first (lower) quartile and the upper edge at the third (upper) quartile. The horizontal line drawn through a box is the second quartile or the median. The lower whisker is a line from the first quartile to the smallest data point within 1.5 interquartile ranges from the first quartile. The upper whisker is a line from the third quartile to the largest data point within 1.5 interquartile ranges from the third quartile. The data points beyond the whiskers represent outliers, or data points more than or less than 1.5 times the upper and lower quartiles, respectively. The diamonds represent the mean.

Next, to statistically compare parameters of the annual distributions of the frequency response listed in **Table E.6** to **Table E.9**, ANOVA's Fisher's Least Significant Difference test and t-test were used to analyze all pair-wise changes in the mean frequency response, the Mann-Whitney and Wilcoxon test was used to compare annual medians, and the tests on the homogeneity of variances to analyze changes in variance (thus, in the standard deviation).[163]

In the 2016 operating year, a change in selection criteria was implemented that included frequency events with a smaller MW loss if the event resulted in a sufficient frequency deviation. Note that this change resulted in a larger sample of events for all Interconnections as compared to previous years. Due to this change, results of the statistical

[162] The Information Filing to FERC can be found at the following location: http://www.nerc.com/FilingsOrders/us/NERC Filings to FERC DL/Final_Info_Filing_Freq_Resp_Annual_Report_03202015.pdf
[163] All tests at the significance level 0.05.

tests should be taken with caution as any detected statistically significant difference in year-over-year performance can be partially due to the criteria modification.

Eastern Interconnection

Table E.6 and Figure E.7 illustrate EI's year-to-year changes in the annual average and median frequency response as well as in its variability. There were no frequency events with frequency response below IFRO in 2013–2017.

Table E.6: Descriptive Statistics for Eastern Interconnection Frequency Response								
Operating Year (OY)	Number of Events	Mean Frequency Response	Standard Deviation	Median	Minimum	Maximum	IFRO for the OY	Number of Events with Frequency Response Below the IFRO
2013–2017	**244**	**2,397**	**714**	**2,300**	**1,043**	**4,536**	**N/A**	**0**
2013	32	2,239	384	2,201	1,707	3,264	1,002	0
2014	34	2,640	627	2,620	1,300	4,304	1,014	0
2015	36	2,480	577	2,372	1,636	3,997	1,014	0
2016	61	2,483	767	2,369	1,253	4,307	1,015	0
2017	81	2,257	823	2,143	1,043	4,536	1,015	0

Figure E.7 shows the box plots of the annual distribution of the Eastern frequency response.

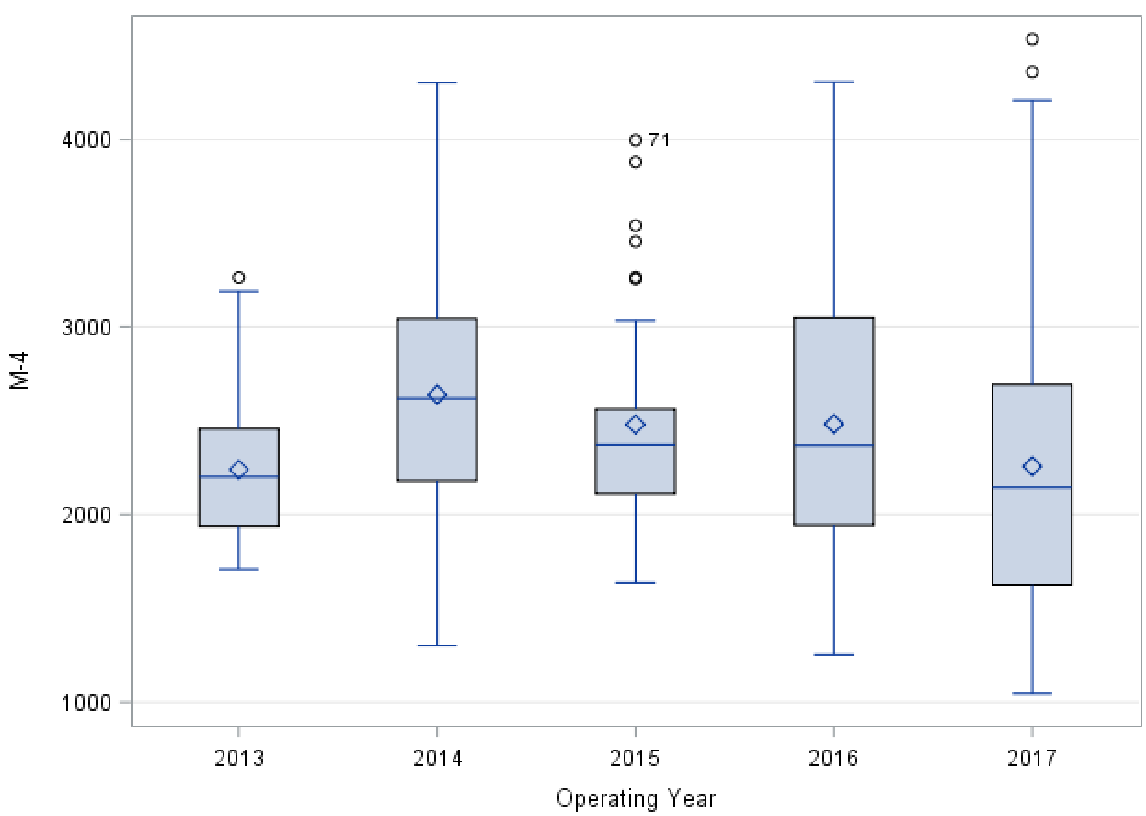


Figure E.7: Box Plots of Eastern Interconnection Frequency Response Distribution by Operating Year 2013–2017

The 2017 frequency response events comprised the largest dataset with the greatest variability over the five years. This is indicated by the standard deviation, the minimum and the maximum values, and a wider spread of values in a scatter plot shown in **Figure E.3.** The 2017 variance was statistically significantly larger than in 2013 and 2015. The mean frequency response and the median frequency response in 2017 were statistically similar to all other years except 2014, which was the best year from 2013–2017.

Texas Interconnection

Table E.7 and **Figure E.8** illustrate TI's year-to-year changes in the annual average and median frequency response as well as in its variability. Over the five years, there was one frequency event with frequency response below IFRO (in 2015).

Table E.7: Descriptive Statistics for Texas Interconnection Frequency Response

Operating Year (OY)	Number of Events	Mean Frequency Response	Standard Deviation	Median	Minimum	Maximum	IFRO for the OY	Number of Events with Frequency Response Below the IFRO
2013–2017	**206**	**782**	**263**	**733**	**404**	**2,304**	**N/A**	**1**
2013	40	752	218	705	407	1,354	286	0
2014	33	727	246	720	426	1,628	413	0
2015	34	756	197	722	469	1,316	471	1
2016	50	807	316	752	404	2,304	381	0
2017	49	835	283	764	491	2,041	381	0

Figure E.8 shows the box plots of the annual distribution of the Texas frequency response.

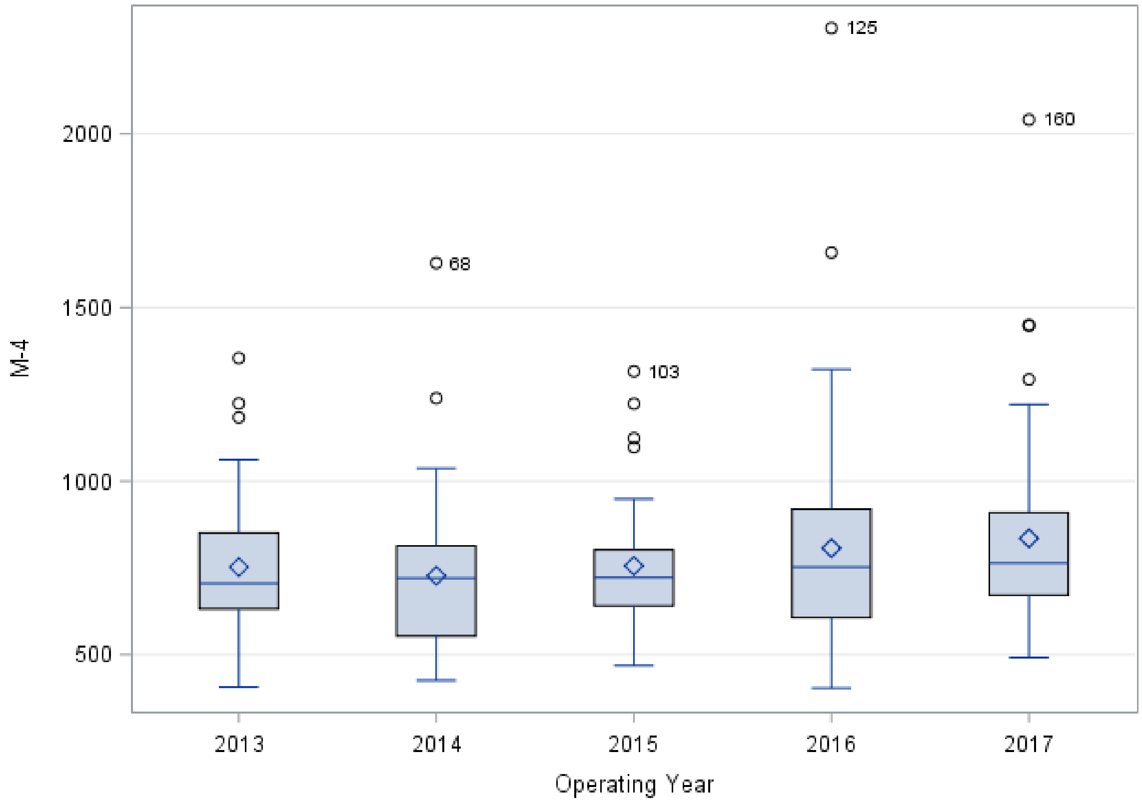


Figure E.8: Box Plots of Texas Frequency Response Distribution by Operating Year 2013–2017

There were no significant changes in the mean and the median frequency response of the annual distributions from 2013 to 2017 operating years, with the 2017 mean and median being numerically largest ones over the five years. The variances in 2016 and 2017 were two highest partly due to the extreme upper outliers seen in a box plot (Figure E.8) and in a scatter plot (Figure E.4).

Québec Interconnection

Table E.8 and Figure E.9 illustrate QI's year-to year changes in the average and median frequency response as well as in its variability. There were no frequency events with frequency response below IFRO in 2013–2017.

Table E.8: Descriptive Statistics for Québec Interconnection Frequency Response								
Operating Year (OY)	**Number of Events**	**Mean Frequency Response**	**Standard Deviation**	**Median**	**Minimum**	**Maximum**	**IFRO for the OY**	**Number of events with Frequency Response below the IFRO**
2013-2017	**217**	**648**	**435**	**558**	**221**	**4,355**	**N/A**	**0**
2013	35	624	188	596	389	1,228	179	0
2014	33	555	236	469	288	1,231	180	0
2015	29	586	190	532	320	1,167	183	0
2016	47	616	248	538	336	1,900	179	0
2017	73	748	676	599	221	4,355	179	0

Figure E.9 shows the box plots of the annual distribution of the QI frequency response.

Figure E.9: Box Plots of Québec Interconnection Frequency Response Distribution by Operating Year 2013–2017

The 2017 frequency response events comprised the largest dataset with the greatest variability over the five years. This is indicated by the standard deviation, minimum and maximum values, and a wider spread of values in a scatter plot (**Figure E.5**). The 2017 variance was statistically significantly highest over the five years. The mean frequency response and the median frequency response in 2017 were numerically largest than for all other years and statistically larger than the 2014 mean and median, respectively.

Western Interconnection

Table E.9 lists the average and median frequency response as well as in its variability. Over the five years, there were two frequency events with frequency response below IFRO (in 2013 and 2014).

Table E.9: Descriptive Statistics for Western Interconnection Frequency Response								
Operating Year (OY)	**Number of Events**	**Mean Frequency Response**	**Standard Deviation**	**Median**	**Minimum**	**Maximum**	**IFRO for the OY**	**Number of Events with Frequency Response Below the IFRO**
2013–2017	**139**	**1,556**	**697**	**1,400**	**822**	**6,645**	**N/A**	**2**
2013	13	1,374	251	1,463	822	1,645	840	1
2014	17	1,295	235	1,266	905	1,743	949	1

Table E.9: Descriptive Statistics for Western Interconnection Frequency Response								
Operating Year (OY)	Number of Events	Mean Frequency Response	Standard Deviation	Median	Minimum	Maximum	IFRO for the OY	Number of Events with Frequency Response Below the IFRO
2015	21	1,361	269	1,349	1,008	2,099	906	0
2016	47	1,545	673	1,400	902	4,368	858	0
2017	41	1,836	968	1,539	870	6,645	858	0

Figure E.10 shows the box plots of the annual distribution of the WI frequency response.

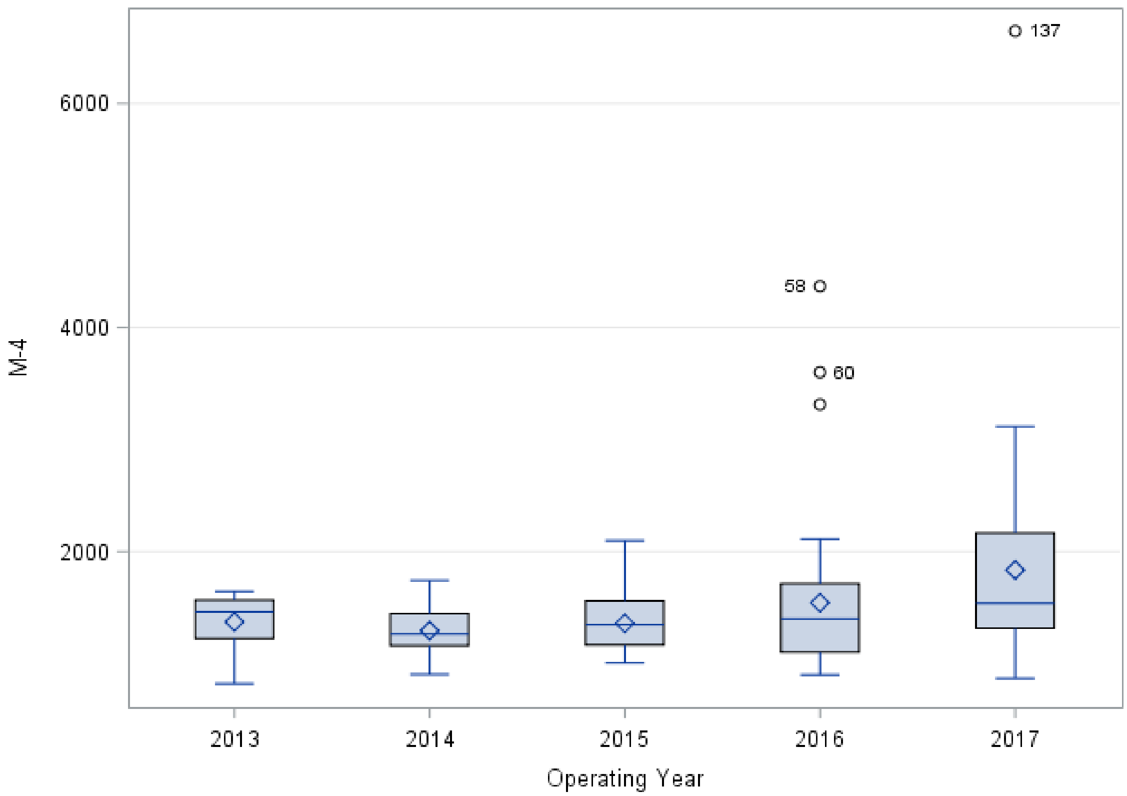


Figure E.10: Box Plots of Western Interconnection Frequency Response Distribution by Operating Year 2013–2017

The 2017 frequency response events comprised the largest dataset with the greatest variability over the five years. This is indicated by the standard deviation, the minimum and the maximum values, and a wider spread of values in a scatter plot (**Figure E.6**) and the box plots (**Figure E.10**). The 2017 variance was statistically significantly larger than in 2014, 2015, and 2016 (the 2013 data set is too small for a valid statistical inference). The mean frequency response and the median frequency response in 2017 were statistically similar to 2016 and significantly greater than in 2014 and 2015. It leads to an observation that 2017 was the best performance year from 2013–2017. It should be noted that the upper outlier event in 2017 occurred in the early morning hours on a day when significant amounts of solar photovoltaic generation resources were increasing output; this likely being a contributing factor in the high frequency response performance for that event.

Interconnection Frequency Response: Analysis of Distribution

Eastern Interconnection

Figure E.11 shows the histogram of the EI frequency response for the 2013–2017 operating years based on the 244 observations of M-4. This is a right-skewed distribution with the median of 2,300 MW/0.1 Hz, the mean of 2,397 MW/0.1 Hz, and the standard deviation of 714 MW/0.1 Hz.

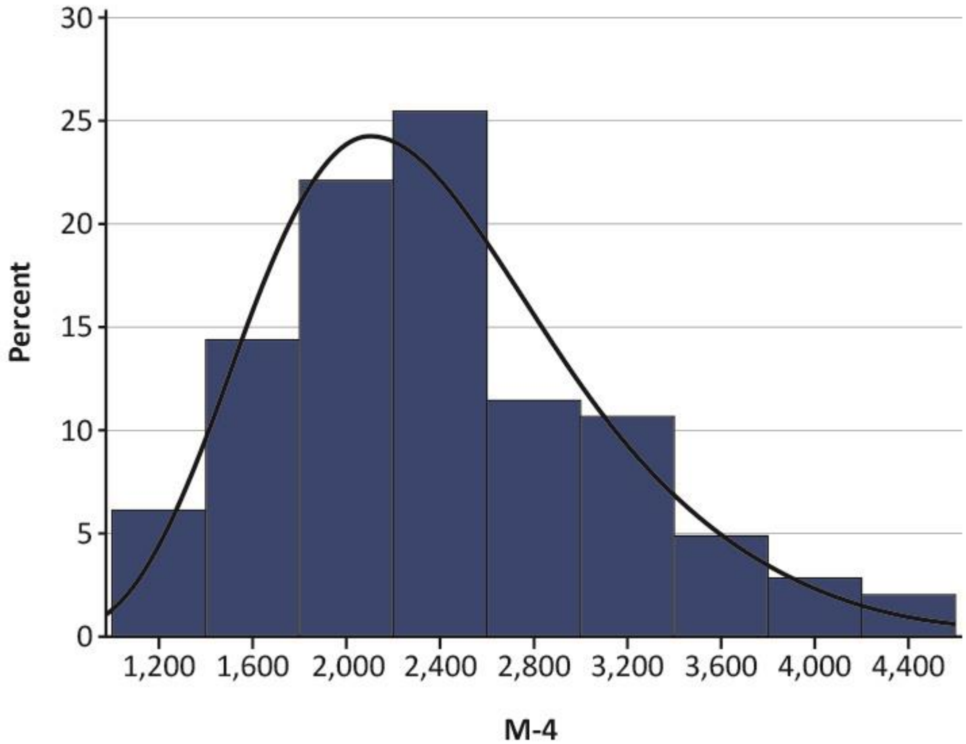


Figure E.11: Histogram of the Eastern Interconnection Frequency Response 2013–2017

The Kolmogorov-Smirnov, Cramer-von Mises, and Anderson-Darling Goodness-of-Fit tests showed that a lognormal distribution can be a very good approximation for the EI frequency response distribution for the five years (p-values are greater than 0.50, 0.25, and 0.50, respectively).

The parameters of this lognormal distribution are as follows: the threshold = -153.3, the scale = 7.8, and the shape = 0.28. The probability density function of the fitted distribution is shown in **Figure E.11** as a curve.

Texas Interconnection

Figure E.12 shows the histogram of the TI frequency response for the 2013–2017 operating years based on the 206 observations of M-4. This is a right-skewed distribution with the median of 733 MW/0.1 Hz, the mean of 782 MW/0.1 Hz, and the standard deviation of 263 MW/0.1 Hz.

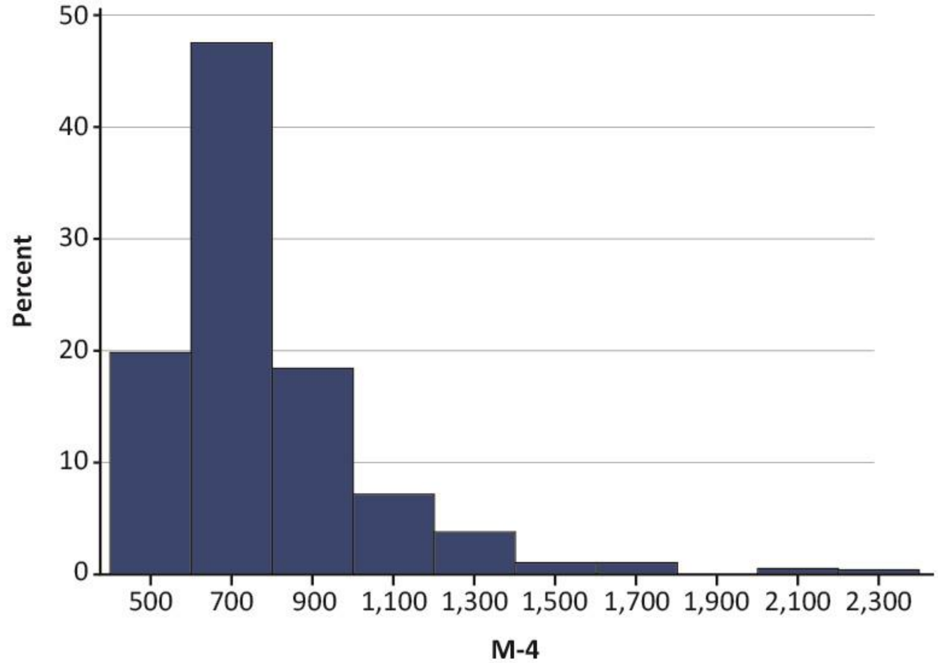


Figure E.12: Histogram of the Texas Interconnection Frequency Response 2013–2017

Kolmogorov-Smirnov, Cramer-von Mises, and Anderson-Darling Goodness-of-Fit tests were carried out for standard distributions, but they found no good fit for the Texas frequency response data. Additional Q-Q analysis showed that a poor fit to the closest lognormal distribution is due to the upper outliers in 2016 and 2017 seen in **Figure E.4** and **Figure E.8**.

Québec Interconnection

Figure E.13 shows the histogram of the QI frequency response for the 2013–2017 operating years based on the 217 observations of M-4. This is a right-skewed distribution with the median of 558 MW/0.1 Hz, the mean of 648 MW/0.1 Hz, and the standard deviation of 435 MW/0.1 Hz.

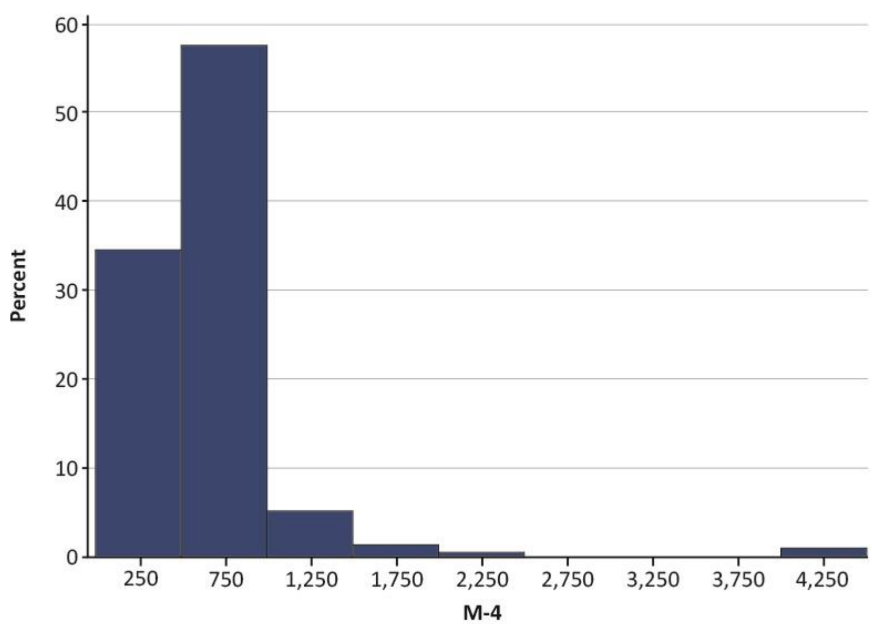


Figure E.13: Histogram of the Québec Interconnection Frequency Response 2013–2017

Kolmogorov-Smirnov, Cramer-von Mises, and Anderson-Darling Goodness-of-Fit tests were carried out for standard distributions, but they found no good fit for the Québec frequency response data. Additional Q-Q analysis showed that a poor fit to the closest lognormal distribution is due to the extreme upper outliers in 2017 seen in **Figure E.5** and **Figure E.9**.

Western Interconnection

Figure E.14 shows the histogram of the WI frequency response for the 2013–2017 operating years based on the 139 observations of M-4. This is a right-skewed distribution with the median of 1400 MW/0.1 Hz, the mean of 1556 MW/0.1 Hz, and the standard deviation of 697 MW/0.1 Hz.

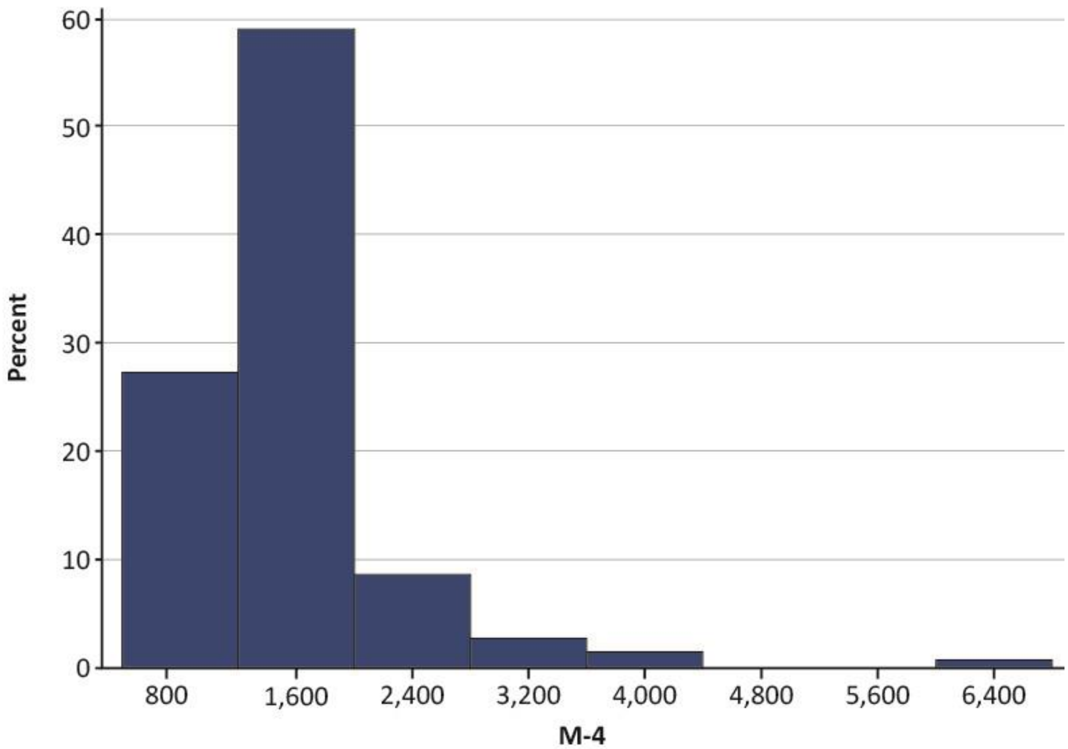


Figure E.14: Histogram of the Western Interconnection Frequency Response 2013–2017

Kolmogorov-Smirnov, Cramer-von Mises, and Anderson-Darling Goodness-of-Fit tests were carried out for standard distributions, but they found no good fit for the WI frequency response data. Additional Q-Q analysis showed that a poor fit to the closest lognormal distribution is due to the four upper outliers in 2016 and 2017 seen in **Figure E.6** and **Figure E.10**.

Explanatory Variables for Frequency Response and Multiple Regression

Explanatory Variables

The goal of this section is to evaluate and quantify how specific indicators could be tied to severity of frequency deviation events. In the *State of Reliability 2016,*[164] a set of explanatory variables that might affect the Interconnection frequency response included 10 variables. In 2017, the renewable generation is added by source for all Interconnections except the EI. The selected variables are neither exhaustive nor pair-wise uncorrelated, and some pairs are strongly correlated; however, all are included as candidates to avoid the loss of an important contributor to the frequency response variability. First, the frequency response and explanatory variables are tested for a significant

[164] The *State of Reliability 2016* can be found at the following location: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2016_SOR_Report_Final_v1.pdf

correlation (positive or negative); if a significant correlation is found, numerical estimates are provided of the explanatory variable impact to the frequency response. Then a multiple (i.e., multivariate) regression model, describing the frequency response with these explanatory variables as regressors, is built for each Interconnection. Model selection methods help ensure the removal of highly correlated regressors and run multicollinearity diagnostics (variance inflation diagnostics) for a multiple regression model selected. The explanatory variables included in this study are as follows:

Time: A moment in time (year, month, day, hour, minute, second) when a frequency response event happened. Time is measured in seconds elapsed between midnight of January 1, 1960 (the time origin for the date format in SAS), and the time of a corresponding frequency response event. This is used to determine time trends over the study period.

Winter (Indicator Function): Defined as one for frequency response events that occur from December through February, and zero otherwise.

Spring (Indicator Function): Defined as one for frequency response events that occur from March through May, and zero otherwise.

Summer (Indicator Function): Defined as one for frequency response events that occur from June through August, and zero otherwise.

Fall (Indicator Function): Defined as one for frequency response events that occur from September through November, and zero otherwise.

On-peak Hours (Indicator Function) Defined as one for frequency response events that occurred during on-peak hours, and zero otherwise. On-peak hours are designated as follows: Monday to Saturday from 0700–2200 (Central Prevailing Time for EI, TI, and QI; Pacific Prevailing Time for WI, excluding six holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

Predisturbance Frequency A: Value A as shown in **Figure E.1** (measured in Hz).

Margin = C-UFLS: Difference between an event nadir, Point C (as shown in **Figure E.1**) and the UFLS for a given Interconnection. Measured in Hz. The UFLS values are listed in **Table E.10**.

Table E.10: Underfrequency Load Shed	
Interconnection	**Highest UFLS Trip Frequency**
Eastern	59.5 Hz
Texas	59.3 Hz
Québec	58.5 Hz
Western	59.5 Hz

Interconnection Load Level: Measured in megawatts.

Interconnection Load Change by Hour: Difference between Interconnection load at the end of the hour and at the beginning of the hour during which the frequency event occurred. Measured in megawatts.

Renewable Generation by Type: Texas provided the 2012–2017 hourly data for wind generation resources. Note that wind is the only significant renewable resource in Texas with the average hourly generation of about 4,600 MW in

2015 (for comparison, solar generation is still less than 200 MW total installed capacity and hydroelectric generation is even smaller).

The QI provided the 2013–2017 hourly data for wind generation resources.

WECC provided the 2013–2016 hourly data for renewable generation output levels in the WI by generation type (Hydro, Wind, and Solar).

Data Sets: While the time trend analysis for M-4 is based on the most recent five years of the frequency response data, the multivariate analyses with the explanatory variables require large data sets and use the data for the 2012–2017 operating years when available. Some datasets (Interconnection load for the EI and the WI, Wind Load for Texas and the WI, Hydro and Solar resources) are not available for the six-year range for the 2012–2017 operating years. In such cases, the correlation between frequency response and this explanatory variable is calculated based on the available data. Even complete six-year data sets have insufficient sizes for a good explanatory and predictive model, which requires estimates of big number of parameters. An adequate model for each Interconnection can only come with an annual addition of the frequency response data sets.

Summary of Correlation Analysis

The results of the correlation and a single regression analysis by Interconnection are shown in **Table E.14**, **Table E.18**, **Table E.22,** and **Table E.26** and explained in details in the respective sections below. The explanatory variables are ranked from highest Pearson's coefficient of determination to the smallest; the coefficient indicates the explanatory power of an explanatory variable for the frequency response. Summary **Table E.11** lists the ranks of statistically significant[165] variables for frequency response in each Interconnection. In **Table E.11**, the "Positive" indicates a statistically significant positive correlation, "Negative" indicates a statistically significant negative correlation, and a dash indicates no statistically significant linear relation. For example, 4 (positive) for the EI Interconnection load means that the load ranked forth by its explanatory power (measured by the Pearson's coefficient R^2) for the EI frequency response, and there is a statistically significant[166] positive correlation between the EI Interconnection load and frequency response (the higher load the better frequency response).

Table E.11: Explanatory Variables: Ranking and Significance of Correlation

Explanatory Variable	Eastern	Texas	Québec	Western
Time	-	2 (positive)	-	2 (positive)
Winter	-	-	3 (positive)	-
Spring	3 (negative)	-	5 (positive)	-
Summer	5 (positive)		4 (negative)	-
Fall	-	-	6 (negative)	-
Predisturbance Frequency A (Hz)	1 (negative)	1 (negative)	-	1 (negative)
Margin=C-UFLS (Hz)	2 (negative)	4 (negative)	1 (positive)	-
On-Peak Hours	-	-	-	3 (positive)
Interconnection Load	4 (positive)	5 (positive)	2 (positive)	-

[165] At the significance level 0.1.
[166] At the significance level 0.1.

Table E.11: Explanatory Variables: Ranking and Significance of Correlation				
Explanatory Variable	**Eastern**	**Texas**	**Québec**	**Western**
Interconnection Load Change by Hour	-	-	-	-
Wind Load	No data	3 (positive)	-	-
Hydro Load	No data	No data	No data	-
Solar Load	No data	No data	No data	-

A statistically significant positive correlation between time and frequency response confirms an increasing trend for the mean frequency response in the TI and WI. Predisturbance Frequency has a statistically significant negative impact to frequency response in all the Interconnections except the QI—the higher A the lower frequency response. Low frequency events with a starting frequency above 60 Hz (Value A) tend to have smaller frequency response since it is less likely that frequency will drop below the governor deadband setting. Interconnection load is significantly and positively correlated with frequency response in all Interconnections except the WI. Among Interconnections with renewable generation data available, Wind load in ERC0T positively and statistically significantly affect the respective frequency response.

Seasonal differences in frequency response are found statistically significant in the EI and the QI. It is noteworthy that spring events have on average smaller frequency response than other seasons in the EI but greater frequency response than other seasons in the QI. Summer events have on average smaller frequency response than other seasons in the QI but greater frequency response than other seasons in the EI.

Margin = C-UFLS is statistically significantly correlated with frequency response in the EI, TI, and QI; however, in the QI the correlation is positive (the higher Margin the higher frequency response) while in the EI and TI the correlation is negative.

Other observations from the comparative analysis by Interconnection are as follows:

- As expected with larger datasets, the statistical significance of the results and the explanatory power of regressors improve. However, to build good explanatory and predictive models of frequency response with multiple explanatory variables more years of data and possibly additional variables are needed.
- The majority of the events occurs during on-peak hours, ranging from 61 percent of events in the WI to 68 percent in the QI.
- In the EI, a total of 47 percent of events start with Predisturbance Frequency A>60 Hz while the other Interconnections majority of events start with A>60 Hz (55 percent in TI and the WI, and 57 percent in the QI).
- In the WI 60 percent of the frequency response events occur when the Interconnection load level increases while for the other Interconnections these comprise about half of all events.

More details on the correlation analysis and multivariate models by Interconnection are provided in the following information.

Eastern Interconnection: Correlation Analysis and Multivariate Model

Descriptive statistics for the 10 explanatory variables and the EI frequency response are listed in **Table E.12** (numerical variables) and **Table E.13** (categorical variables). A statistical significance of a difference in frequency response in the last column of **Table E.13** (e.g., between frequency response of winter events and non-winter events) is drawn from the t-test.[167]

Table E.12: Numerical Explanatory Variables for Eastern Interconnection						
Variable	**N**	**Mean**	**Standard Deviation**	**Median**	**Minimum**	**Maximum**
Time	254	N/A	N/A	N/A	12/1/2012	11/30/2017
Predisturbance Frequency A (Hz)	254	60.00	0.01	60.00	59.97	60.03
Margin =C-UFLS (Hz)	254	0.45	0.01	0.45	0.41	0.49
Interconnection Load (MW)	173	345,137	66,714	331,998	222,968	512,504
Load Change by Hour (MW)	173	234	10,577	547	-33,129	28,611
Frequency Response	254	2393	701	2,291	1,043	4,536

Table E.13: Categorical Explanatory Variables for Eastern Interconnection Frequency Response						
Variable	**Total Number of Frequency Response Events**	**Number of Events with Indicator 1**	**Percent of Events with Indicator 1**	**Mean Frequency Response for Events with Indicator 1**	**Mean Frequency Response for Events with Indicator 0**	**Is Difference in Frequency Response Between 1 and 0 Statistically Significant?[168]**
Winter	254	62	24%	2,460	2,371	No
Spring	254	72	28%	2,189	2,474	Yes
Summer	254	55	22%	2,593	2,338	Yes
Fall	254	65	26%	2,386	2,395	No
On-Peak Hours	254	164	65%	2,400	2,381	No

Interconnection load and Interconnection load change by hour data are available for the 173 frequency response events that occurred from 2012–2016 calendar years. Other data are available for all 254 events.

The correlation and a single regression analysis result in the hierarchy of the explanatory variables for the EI frequency response as shown in **Table E.14**. The table lists p-values of the test on the significance of correlation between each explanatory variable and frequency response. If p-value is smaller than 0.1, the correlation is statistically significant at the 0.1 significance level. For such a variable, the value of a coefficient of determination R^2 in the last column indicates the percentage in variability of the frequency response data that can be explained by variability of this explanatory variable. Note that for categorical variables, p-value of the correlation between their indicator function, and frequency response is the same as p-value of the pooled test used to populate the last column of **Table E.13**.

[167] Pooled or Satterthwaite t-test at the significance level 0.1

[168] At the significance level 0.1

Table E.14: Correlation and Regression Analysis for Eastern Interconnection Frequency Response			
Explanatory Variable	**Correlation with Frequency Response**	**P-Value**	**R^2 (If Statistically Significant)[169]**
Predisturbance Frequency A (Hz)	-0.55	<.0001	30.7%
Margin =C-UFLS (Hz)	-0.33	<.0001	10.8%
Spring	-0.18	0.003	3.4%
Interconnection Load (MW)	0.17	0.023	3.0%
Summer	0.15	0.017	2.3%
Winter	0.05	0.390	N/A
Load Change by Hour (MW)	0.05	0.488	N/A
Time	-0.04	0.514	N/A
On-Peak Hours	0.01	0.841	N/A
Fall	-0.01	0.925	N/A

Out of the 10 explanatory variables, five have a statistically significant correlation with the EI frequency response. Predisturbance Frequency A has the strongest correlation with and the greatest explanatory power (30.7 percent) for the frequency response. Predisturbance Frequency and Margin are negatively correlated with frequency response. Thus, events with higher A tend to have smaller expected frequency response: on average, the EI frequency response decreases by 382 MW/0.1 Hz as A increases by 10 mHz. Similarly, events with larger Margin (and therefore higher nadir C) tend to have statistically significantly smaller expected frequency response: on average, frequency response decreases by 193 MW/0.1 Hz as Margin increases by 10 mHz. Note that A and Margin are not independent variables: there is a statistically significant positive correlation of 0.70 between them (p-value of the test of the significance of correlation <0.0001).

Next, Interconnection load and frequency response are positively (and statistically significantly) correlated: events happened with higher Interconnection load tend to have better response. On average, the frequency response increases by 16 MW/0.1 Hz when Interconnection load increases by 10,000 MW.

As reflected in **Table E.13** and **Table E.14**, spring events in the EI have statistically significantly lower frequency response than other events with respective average frequency responses of 2,189 MW/0.1 Hz and 2,474 MW/0.1 Hz (shown in **Table E.13**). In contrast, summer events have statistically significantly better frequency response than other events with respective average frequency responses of 2,593 MW/0.1 Hz and 2,338 MW/0.1 Hz.

The sum of the coefficients of determination in the last column of **Table E.14** (for the explanatory variables that statistically significantly correlate with frequency response) equals 50.1 percent. However, it does not mean that together variability in these five regressors explains more than a half of variability in the EI frequency response because these variables are collinear (not mutually independent)—for example, A and Margin are highly correlated, as mentioned above. The best multivariate model for the EI frequency response described below has the explanatory power (the adjusted coefficient of determination) of 33.7 percent.

[169] At the significance level 0.1

Multivariate model selection, performed by the step-wise selection and the forward selection algorithms, results in a multiple regression model that connects the 2012–2017 EI frequency response with Predisturbance Frequency A and Indicator of spring events (the other variables are not selected or are eliminated by the algorithms).[170] The model's coefficients are listed in **Table E.15**.

Table E.15: Coefficients of Multiple Model for Eastern Interconnection Frequency Response

Variable	DF	Parameter Estimate	Standard Error	t-value	p-value	Variance Inflation Value
Intercept	1	2,058,741	189,304	10.88	<.0001	0.00
Spring	1	-291.2	79.5	-3.67	0.0003	1.00006
Predisturbance Frequency A (Hz)	1	-34,271	3,155	-10.86	<.0001	1.00006

The adjusted coefficient of the multiple determination adj R^2 of the model is 33.7 percent; the model is highly statistically significant ($p<0.0001$). The random error has a zero mean and the sample deviation σ of 570 MW/0.1 Hz. Variance inflation factors for the regressors are very close to 1, which confirms an acceptable level of multicollinearity that does not affect a general applicability of the model. The parameter estimates, or the coefficients for the regressors, indicate how change in a regressor value impacts frequency response. Note that the regressors in the final model are not correlated: t-test confirms that the spring events and non-spring events have statistically similar the expected Predisturbance frequency A and the variance of A.

A summary of the Fit Diagnostics, including quantile-to-quantile and Influence diagnostics as well as residual analyses, is provided in **Figure E.15**.

170 Regressors in the final model have p-values not exceeding 0.1.

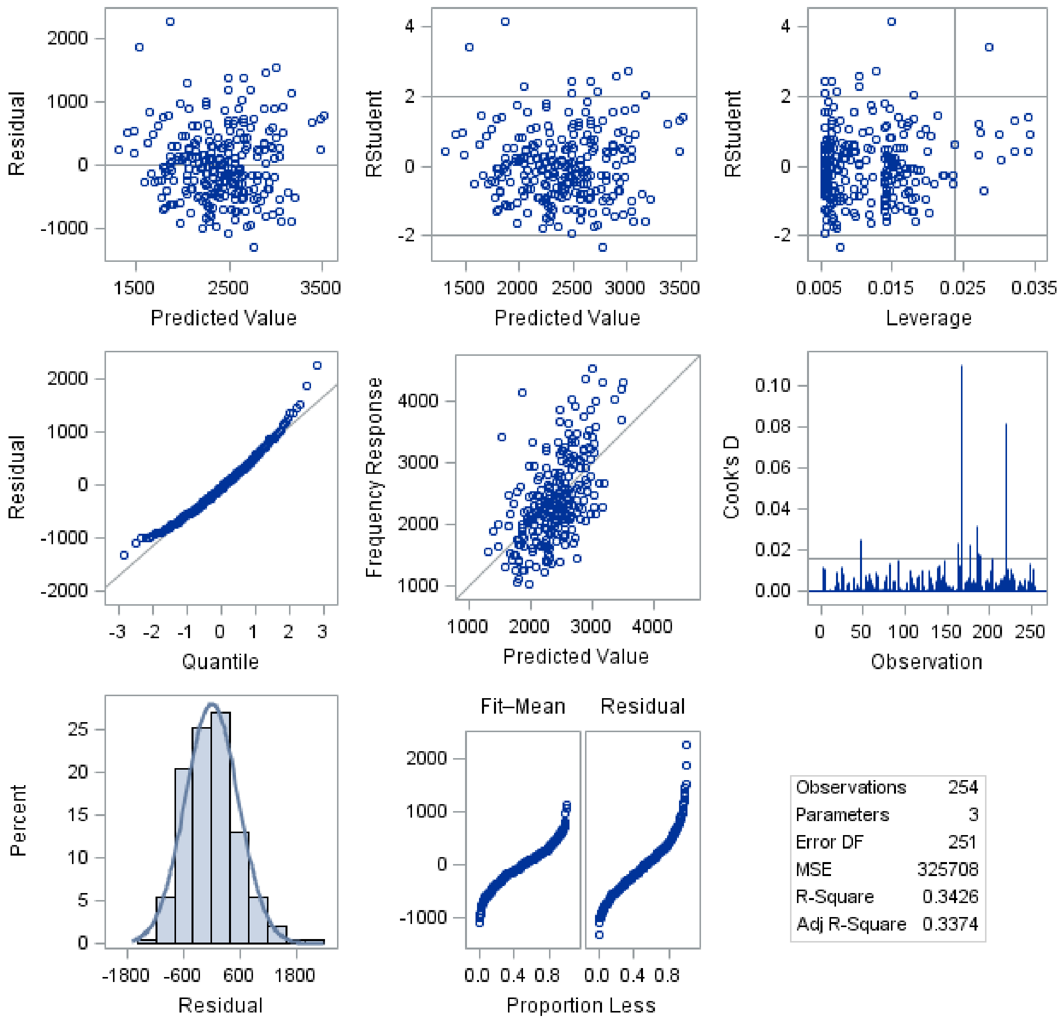


Figure E.15: Fit Diagnostics for Multiple Model of the Eastern Interconnection Frequency Response 2012–2017

Texas: Correlation Analysis and Multivariate Model

Descriptive statistics for the 11 explanatory variables and the TI frequency response are listed in Table E.16 (numerical variables) and Table E.17 (categorical variables). A statistical significance of a difference in frequency response in the last column of Table E.17 (e.g., between frequency response of winter events and non-winter events) is drawn from the t-test.[171]

Table E.16: Numerical Explanatory Variables for Texas Interconnection						
Variable	**N**	**Mean**	**Standard Deviation**	**Median**	**Minimum**	**Maximum**
Time	252	N/A	N/A	N/A	12/1/2012	11/30/2017
Predisturbance Frequency A (Hz)	252	60.00	0.02	60.00	59.94	60.03
Margin =C-UFLS (Hz)	250	0.55	0.05	0.56	0.41	0.63

[171] Pooled or Satterthwaite t-test at the significance level 0.1.

Table E.16: Numerical Explanatory Variables for Texas Interconnection						
Variable	**N**	**Mean**	**Standard Deviation**	**Median**	**Minimum**	**Maximum**
Interconnection Load (MW)	252	42,661	10,509	40,430	23,905	67,209
Load Change by Hour (MW)	252	89	1,731	13	-4,937	4,601
Wind Resources	252	4,354	3,062	3,491	81	15,080
Frequency Response	252	742	259	701	337	2,304

Table E.17: Categorical Explanatory Variables for Texas Interconnection Frequency Response						
Variable	**Total Number of Frequency Response Events**	**Number of Events with Indicator 1**	**Percent of Events with Indicator 1**	**Mean Frequency Response for Events with Indicator 1**	**Mean Frequency Response for Events with Indicator 0**	**Is Difference in Frequency Response Between 1 and 0 Statistically Significant?[172]**
Winter	252	45	18%	690	753	No
Spring	252	70	28%	702	757	No
Summer	252	77	31%	781	724	No
Fall	252	60	24%	776	731	No
On-Peak Hours	252	164	65%	738	748	No

For all variables except Margin (loss of load events are excluded), the data are available for the 252 frequency response events that occurred from 2012–2017 operating years.

The correlation and a single-regression analysis result in the hierarchy of the explanatory variables for the TI frequency response are shown in **Table E.18**. The table lists p-values of the test on the significance of correlation between each explanatory variable and frequency response. If p-value is smaller than 0.1, the correlation is statistically significant at the 0.1 significance level. For such a variable, the value of a coefficient of determination R^2 in the last column indicates the percentage in variability of the frequency response data that can be explained by variability of this explanatory variable. Note that for categorical variables, p-value of the correlation between their indicator function and frequency response is the same as p-value of the pooled test used to populate the last column of **Table E.17**.

[172] At the significance level 0.1

Table E.18: Correlation and Regression Analysis for Texas Interconnection Frequency Response			
Explanatory Variable	**Correlation with Frequency Response**	**P-Value**	**R^2 (If Statistically Significant)[173]**
Predisturbance Frequency A (Hz)	-0.37	<.0001	13.6%
Time	0.33	<.0001	10.7%
Wind Resources	0.24	0.0001	5.8%
Margin =C-UFLS (Hz)	-0.20	0.002	3.9%
Interconnection Load (MW)	0.12	0.05	1.5%
Summer	0.10	0.107	N/A
Spring	-0.10	0.13	N/A
Winter	-0.09	0.14	N/A
Fall	0.07	0.24	N/A
Load Change by Hour (MW)	-0.03	0.63	N/A
On-Peak Hours	-0.02	0.76	N/A

Out of the 11 variables, five are statistically significantly correlated with TI's frequency response. Predisturbance Frequency A has the strongest correlation with and the greatest explanatory power (13.6 percent) for the frequency response. A and frequency response are negatively correlated (the higher A the smaller expected frequency response). On average, the frequency response decreases by 49.6 MW/0.1 Hz as A increases by 10 mHz. Similarly, events with larger Margin (and therefore higher nadir C) tend to have statistically significantly smaller frequency response; on average, frequency response decreases by 10.7 MW/0.1 Hz as Margin increases by 10 mHz. Note that A and Margin are not independent variables; there is a statistically significant positive correlation of 0.34 between them (p-value of the test of the significance of the correlation <0.0001).

Time and frequency response are positively correlated; on average, frequency response improves in time. The average rate of the frequency response increase over the 2012–2017 operating years is 3.7 MW/0.1 Hz per month.

Next, wind resources and Interconnection load both are positively correlated with frequency response; it is noteworthy that the correlation of frequency response with Wind generation is stronger than with the overall load (5.8 percent in the variability of TI frequency response in 2012–2017 can be explained by variability in its wind generation resources compared with 1.5 percent for Interconnection load). On average, a wind resources increase of 1,000 MW corresponds to a frequency response increase of 20.4 MW/0.1 Hz while an Interconnection load increase of 1,000 MW corresponds to a frequency response increase of 3.0 MW/0.1 Hz. Note that both wind generation resources and Interconnection load significantly grew over the 2012–2017 operating years.

Seasonal changes as well as On-peak hours and Load change by hour are not associated with significant changes in frequency response.

[173] At the significance level 0.1

The step-wise selection, the forward selection and the backward elimination algorithms result in a multiple regression model that connects the TI frequency response with Time, Summer, Predisturbance Frequency A, Margin, and Wind resources (the other six variables are not selected or were eliminated as regressors).[174] The coefficients of the multiple model are listed in **Table E.19**.

Table E.19: Coefficients of Multiple Model for Texas Interconnection Frequency Response

Variable	DF	Parameter Estimate	Standard Error	T-Value	p-Value	Variance Inflation Value
Intercept	1	266,282	42,467	6.27	<.0001	0.00
Time	1	0.00000191	0.00	7.49	<.0001	1.38
Summer	1	75.0	28.4	2.64	0.0087	1.07
Predisturbance Frequency A (Hz)	1	-4,468	709	-6.30	<.0001	1.15
Margin =C-UFLS (Hz)	1	-1,595	320	-4.99	<.0001	1.39
Wind Resources	1	0.010	0.005	2.12	0.035	1.18

The model's adjusted coefficient of multiple determination adj R^2 is 37.4 percent (that is the model accounts for more than 37 percent of the TI frequency response variability); the model is highly statistically significant ($p < 0.0001$). The random error has a zero mean and the sample deviation σ of 200 MW/0.1 Hz. Variance inflation factors for the regressors do not exceed four, and this confirms an acceptable level of multicollinearity that does not affect a general applicability of the model. The parameter estimates, or the coefficients for the regressors indicate, how change in a regressor value impacts frequency response.

A summary of the Fit Diagnostics, including quantile-to-quantile and Influence diagnostics as well as residual analyses, is provided in **Figure E.16**.

174 Regressors in the final model have p-values not exceeding 0.1.

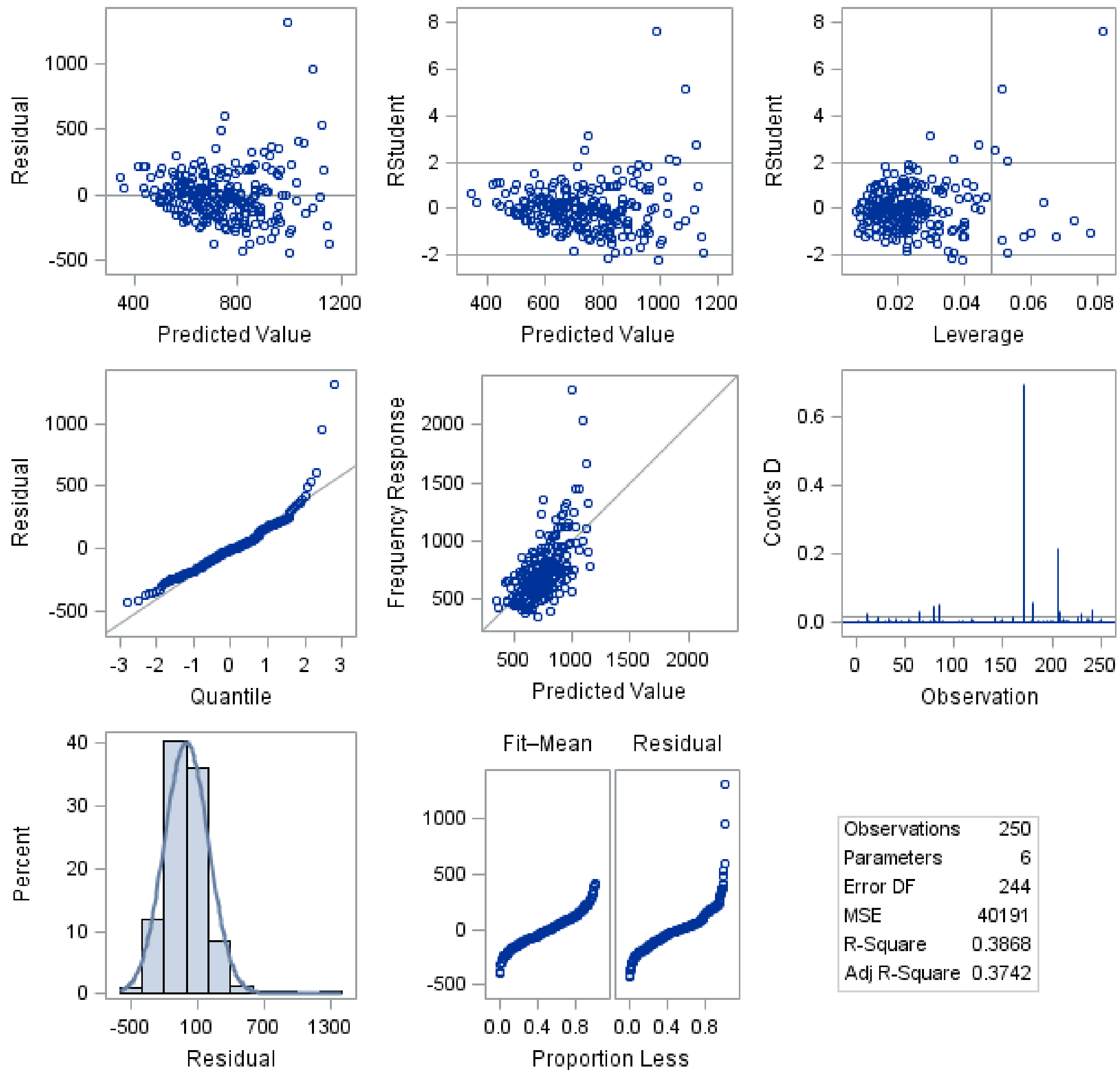


Figure E.16: Fit Diagnostics for Multiple Model of the Texas Interconnection Frequency Response 2012–2017

Québec: Correlation Analysis and Multivariate Model

Descriptive statistics for the 11 explanatory variables and the QI frequency response are listed in **Table E.20** (numerical variables) and **Table E.21** (categorical variables). A statistical significance of a difference in frequency response in the last column of **Table E.21** (e.g., between frequency response of winter events and non-winter events) is drawn from the t-test.[175]

Table E.20: Numerical Explanatory Variables for Québec Interconnection Frequency Response

Variable	N	Mean	Standard Deviation	Median	Minimum	Maximum
Time	242	N/A	N/A	N/A	1/13/2012	11/8/2017
Predisturbance Frequency A (Hz)	242	60.00	0.02	60.00	59.93	60.06

[175] Pooled or Satterthwaite t-test at the significance level 0.1.

Table E.20: Numerical Explanatory Variables for Québec Interconnection Frequency Response						
Variable	**N**	**Mean**	**Standard Deviation**	**Median**	**Minimum**	**Maximum**
Margin =C-UFLS (Hz)	161	0.98	0.19	1.03	0.29	1.25
Interconnection Load (MW)	242	20,484	4,259	19,055	13,520	35,000
Load Change by Hour (MW)	242	-27	708	-40	-2010	2,450
Wind Resources	215	962	708	857	8	3,013
Frequency Response	242	653	423	562	221	4,355

Table E.21: Categorical Explanatory Variables for Québec Interconnection Frequency Response						
Variable	**Total Number of Frequency Response Events**	**Number of Events with Indicator 1**	**Percent of Events with Indicator 1**	**Mean Frequency Response for Events with Indicator 1**	**Mean Frequency Response for Events with Indicator 0**	**Is Difference in Frequency Response Between 1 and 0 Statistically Significant?[176]**
Winter	242	30	12%	880	620	Yes
Spring	242	57	24%	771	616	Yes
Summer	242	95	39%	568	707	Yes
Fall	242	60	25%	560	683	Yes
On-Peak Hours	242	165	68%	640	681	No

The Wind generation hourly data are available for the 215 frequency response events that occurred from 2013–2017. Margin data are available for 161 events (loss of load events are excluded). Other data are available for all 242 events.

The correlation and a single-regression analysis result in the hierarchy of the explanatory variables for the QI frequency response are shown in **Table E.22.** The table lists p-values of the test on the significance of correlation between each explanatory variable and frequency response. If p-value is smaller than 0.1, the correlation is statistically significant at the 0.1 significance level. For such a variable, the value of a coefficient of determination R^2 in the last column indicates the percentage in variability of the frequency response data that can be explained by variability of this explanatory variable. Note that for categorical variables, p-value of the correlation between their indicator function and frequency response is the same as p-value of the pooled test used to populate the last column of **Table E.21**.

[176] At the significance level 0.1

Table E.22: Correlation and Regression Analysis for Québec Interconnection			
Explanatory Variable	**Correlation with Frequency Response**	**P-Value**	**R^2 (If Statistically Significant)**
Margin =C-UFLS (Hz)	0.32	<.0001	10.2%
Interconnection Load (MW)	0.26	<.0001	6.6%
Winter	0.20	0.002	4.1%
Summer	-0.16	0.01	2.6%
Spring	0.16	0.02	2.4%
Fall	-0.13	0.05	1.6%
Wind Resources	0.10	0.16	N/A
On-Peak Hours	-0.05	0.48	N/A
Time	0.04	0.49	N/A
Predisturbance Frequency A (Hz)	-0.04	0.51	N/A
Load Change by Hour (MW)	0.02	0.81	N/A

Six explanatory variables are statistically significantly correlated with frequency response. Margin has the strongest correlation and the greatest explanatory power (10.2 percent) for the frequency response. The margin is positively correlated with frequency response: on average, a margin increase of 10 mHz corresponds to a frequency response increase of 4.5 MW/0.1 Hz. Interconnection load level and frequency response are also positively correlated (i.e., the higher Interconnection load is during a frequency response event, the higher expected frequency response value of this event). On average, a load increase of 1,000 MW corresponds to a frequency response increase of 25.5 MW/0.1 Hz.

All four seasons are statistically significantly correlated with frequency response. A comparison of frequency response by season is summarized in **Table E.21**. It is noteworthy that the QI winter events have the best expected frequency response mainly due to the fact that winter is the peak usage season in the QI. More generator units are on-line; therefore, there is more inertia in the system, so it is more robust in responding to frequency changes in the winter (the highly significant positive correlation between variables winter and Interconnection load also confirms this). Another observation is that only 12 percent of the QI events have occurred in winter.

The remaining four variables do not have a statistically significant[177] linear relationship with frequency response.

The backward elimination algorithm results in a multiple regression model that connects the QI frequency response with Winter, Spring, Predisturbance Frequency, and Margin (the other variables are not selected or were eliminated).[178] The coefficients of the multiple model are listed in **Table E.23**. Note that the model is based on 161 observations with defined Margin. Because of the highly significant correlation between frequency response and Margin, exclusion of Margin from the list of candidate regressors does not lead to a better multiple model.

[177] At the significance level 0.1

[178] Regressors in the final model have p-values not exceeding 0.1.

Table E.23: Coefficients of Multiple Model for Québec Interconnection Frequency Response						
Variable	**DF**	**Parameter Estimate**	**Standard Error**	**T-Value**	**P-Value**	**Variance Inflation Value**
Intercept	1	234,613	64,215	3.65	0.000	0
Winter	1	107	64	1.69	0.094	1.059
Spring	1	99	58	1.71	0.090	1.055
Predisturbance Frequency A (Hz)	1	-3,908	1,070	-3.65	0.000	1.003
Margin =C-UFLS (Hz)	1	444	115	3.85	0.000	1.054

The model's adjusted coefficient of multiple determination adj R^2 is 19.5 percent (19.5 percent of the QI frequency response variability can be explained by the combined variability of these four parameters); the model is highly statistically significant ($p<0.0001$). The random error has a zero mean and a sample deviation σ of 239 MW/0.1 Hz. Variance inflation factors for the regressors do not exceed 1.06, which confirms an acceptable level of multicollinearity that does not affect a general applicability of the model. The parameter estimates, or the coefficients for the regressors indicate, how change in a regressor value impacts frequency response. Note that Interconnection load would not bring new information about frequency response due to a high correlation Load with Winter; therefore, this variable becomes redundant and eliminated from the model. On the other hand, Predisturbance Frequency and Margin (and, thus, A and nadir C) are not significantly correlated and both stay in the final model.

A summary of the Fit Diagnostics, including quantile-to-quantile and Influence diagnostics as well as residual analyses, is provided in **Figure E.17**.

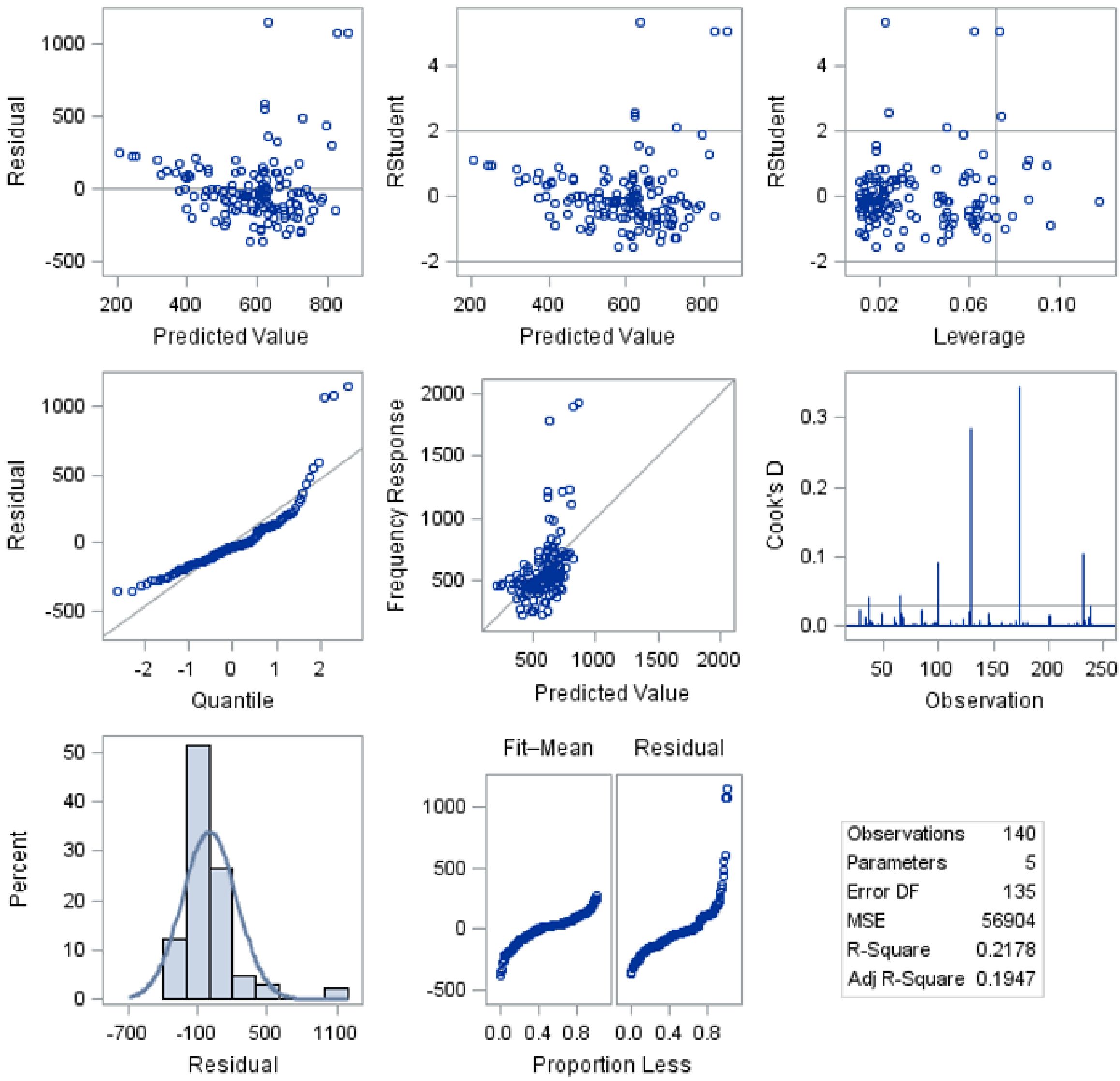


Figure E.17: Fit Diagnostics for Multiple Model of the Québec Interconnection Frequency Response 2012–2017

Western Interconnection: Correlation Analysis and Multivariate Model

Descriptive statistics for the 13 explanatory variables and the WI frequency response are listed in **Table E.24** (numerical variables) and **Table E.25** (categorical variables). A statistical significance of a difference in frequency response shown in the last column of **Table E.25** (e.g., between frequency response of winter events and non-winter events) is drawn from the t-test.[179]

Table E.24: Numerical Explanatory Variables for Western Interconnection Frequency Response

Variable	N	Mean	Standard Deviation	Median	Minimum	Maximum
Time	144	N/A	N/A	N/A	12/1/2012	11/30/2017
Predisturbance Frequency A (Hz)	144	60.00	0.02	60.00	59.96	60.05

[179] Pooled or Satterthwaite t-test at the significance level 0.1.

Table E.24: Numerical Explanatory Variables for Western Interconnection Frequency Response						
Variable	**N**	**Mean**	**Standard Deviation**	**Median**	**Minimum**	**Maximum**
Margin =C-UFLS (Hz)	141	0.40	0.05	0.41	0.17	0.46
Interconnection Load (MW)	103	95,983	18,184	91,931	65,733	151,920
Load Change by Hour (MW)	103	620	3,650	827	-10,081	6,404
Wind Resources	98	5,213	2,700	4,548	918	11,700
Hydro Resources	98	27,164	6,357	26,612	15,068	43,105
Solar Resources	98	18,440	32,746	2,001	0	106,616
Frequency Response	144	1,551	687	1,390	822	6,645

Table E.25: Categorical Explanatory Variables for Western Interconnection Frequency Response						
Variable	**Total Number of Frequency Response Events**	**Number of Events with Indicator 1**	**Percent of Events with Indicator 1**	**Mean Frequency Response for Events with Indicator 1**	**Mean Frequency Response for Events with Indicator 0**	**Is Difference in Frequency Response Between 1 and 0 Statistically Significant?**
Winter	144	24	17%	1,560	1,549	No
Spring	144	44	31%	1,516	1,566	No
Summer	144	42	29%	1,520	1,563	No
Fall	144	34	24%	1,627	1,527	No
On-Peak Hours	144	88	61%	1,632	1,423	Yes

Interconnection load and Interconnection load change by hour data are available for the 103 frequency response events that occurred during the 2012–2016 years. Renewable generation (Wind, Hydro, and Solar Load) is available by source for the 2013–2018 events. Margin data are available for 141 events (loss of load events are excluded). Other data are available for all 144 events.

The correlation and a single-regression analysis result in the hierarchy of the explanatory variables for the WI frequency response shown in **Table E.26**. The table lists p-values of the test on the significance of correlation between each explanatory variable and frequency response. If the p-value is smaller than 0.1, the correlation is statistically significant at the 0.1 significance level. For such a variable, the value of a coefficient of determination R^2 in the last column indicates the percentage in variability of the frequency response data that can be explained by variability of this explanatory variable. Note that for categorical variables, p-value of the correlation between their indicator function and frequency response is the same as p-value of the pooled test used to populate the last column of **Table E.25**.

Table E.26: Correlation and Regression Analysis for Western Interconnection for Frequency Response			
Explanatory Variable	**Correlation with Frequency Response**	**P-Value**	**R^2 (If Statistically Significant)[180]**
Predisturbance Frequency A (Hz)	-0.37	<.0001	13.8%
Time	0.24	0.004	5.8%
On-Peak Hours	0.15	0.07	2.2%
Margin =C-UFLS (Hz)	-0.11	0.19	N/A
Interconnection Load (MW)	0.11	0.28	N/A
Solar Resources	0.10	0.32	N/A
Wind Resources	-0.07	0.50	N/A
Fall	0.06	0.46	N/A
Load Change by Hour (MW)	0.06	0.54	N/A
Hydro Resources	0.05	0.60	N/A
Spring	-0.03	0.69	N/A
Summer	-0.03	0.73	N/A
Winter	0.01	0.94	N/A

Only three explanatory variables are statistically significantly correlated with frequency response. Predisturbance Frequency A has the strongest correlation with and the greatest explanatory power (13.8 percent) for the frequency response. Predisturbance Frequency A and frequency response are statistically significantly and negatively correlated; on average, frequency response decreases by 14.8 MW/0.1 Hz as A increases by 10 mHz. Time and frequency response are positively correlated; on average, frequency response improves in time. The average rate of the frequency response increase over the 2012–2017 operating years is 9.4 MW/0.1 Hz per month. On-Peak hour events have a statistically better frequency response as shown in **Table E.25**. The remaining 10 variables do not have a statistically significant[181] linear relationship with frequency response.

Even though six explanatory variables have smaller data size than the others, their exclusion from a multiple regression model do not improve the model (neither by increasing its explanatory power nor by reducing the error). Using all 13 variables as input regressors, the step-wise selection algorithm and the forward selection algorithm result in a multiple regression model that connects the WI frequency response with Interconnection load and Time, Spring, Predisturbance frequency, Margin, and Hydro resources (the other variables are not selected or were eliminated).[182] The coefficients of the multiple model are listed in **Table E.27**. Note that the model is based only on 98 observations with Hydro resources available.

[180] At the significance level 0.1
[181] At the significance level 0.1
[182] Regressors in the final model have p-values not exceeding 0.1.

Table E.27: Coefficients of Multiple Model for Western Interconnection Frequency Response						
Variable	**DF**	**Parameter Estimate**	**Standard Error**	**T-Value**	**P-Value**	**Variance Inflation Value**
Intercept	1	1,028,986	195,694	5.26	<.0001	0.00
Time	1	0.0000051	0.0000016	3.22	0.002	1.62
Spring	1	198	101	1.97	0.052	1.06
Predisturbance Frequency A (Hz)	1	-17,302	3,275	-5.28	<.0001	1.42
Margin =C-UFLS (Hz)	1	3,111	1,485	2.09	0.039	1.52
Hydro Resources	1	0.0157	0.0085	1.85	0.067	1.45

The adjusted coefficient of the determination adj R^2 of the model is 24.5 percent; the model is highly statistically significant ($p<0.0001$). The random error has a zero mean and the sample deviation σ of 440.9 MW/0.1 Hz. Variance inflation factors for the regressors do not exceed two, which confirms an acceptable level of multicollinearity that does not greatly affect a general applicability of the model even though Hydro resources and Spring are significantly (positively) correlated and so are A and Margin. The parameter estimates, or the coefficients for the regressors, indicate, how change in a regressor value impacts frequency response.

A summary of the Fit Diagnostics, including quantile-to-quantile and Influence diagnostics as well as residual analyses, is provided in **Figure E.18**.

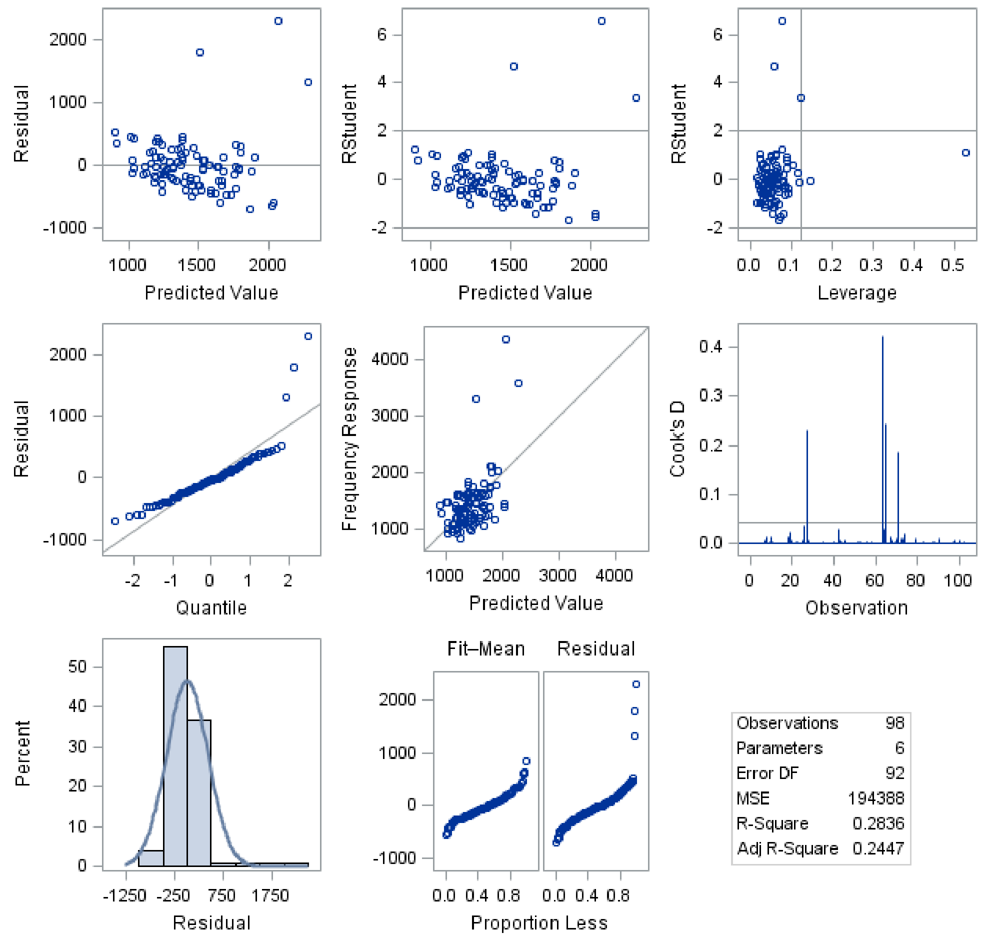


Figure E.18: Fit Diagnostics for Multiple Model of the Western Interconnection Frequency Response 2012–2017

Essential Reliability Services

Summary

Frequency support is the response of generators and loads to maintain the system frequency in the event of a system disturbance. Frequency support is provided through the combined interactions of synchronous inertia (traditionally from generators, such as natural gas, coal, hydro, and nuclear plants as well as from synchronous motors at customer locations) frequency response provided by inverters from wind farms, solar fields, and other varieties of generators and loads. Working in a coordinated way, these facilities arrest and eventually stabilize frequency. A critical issue is to stabilize the frequency before it falls below the UFLS settings or rises above the overfrequency relay trip settings on generators.

Inertia and frequency response are properties of the Interconnection, and each Interconnection has different characteristics. For example, if changes to the resource mix alter the relative amounts of synchronous inertial response or frequency response, various mitigation actions are possible. Obtaining faster primary frequency response from other generators or loads, or maintaining and improving overall frequency support can mitigate these changes.

The NERC RS monitors and identifies trends in frequency response performance as the generation mix continues to change. Measure 4 is the comprehensive frequency measure that complements metric M-4 previously discussed; it evaluates primary frequency control performance after actual disturbance events in each Interconnection tracking the initial frequency rate of change, the arresting period, and the rebound and stabilizing periods. Measures 1 and 2 evaluate components of this coordinated frequency response with Measure 1 tracking the amount of synchronous inertial response, abbreviated as SIR, and Measure 2 tracking the initial rate of change in frequency, abbreviated as RoCoF.

Measure 1: Synchronous Inertial Response

For the historical trending of the SIR, a process was established for conducting synchronous inertia calculations for each Interconnection. Calculated system inertia at any point in time depends on characteristics of online and synchronized generators that includes the units' inertial constant H, and MVA rating. The calculation procedure is to determine $H_i * MVA_i$ for each online generator *i*.

Kinetic Energy or Synchronous Inertial Response (SIR) = $\sum H_i * MVA_i$

Figure E.19 through **Figure E.22** show the monthly maximum and minimum values of SIR for each respective Interconnection.

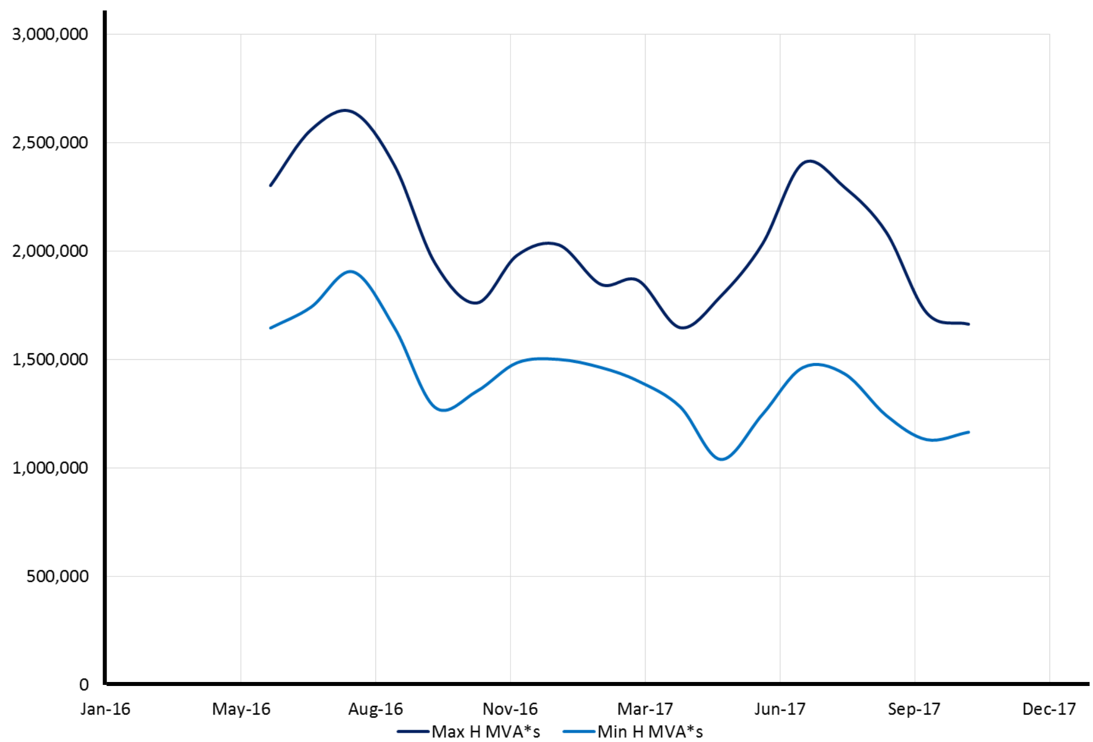


Figure E.19: Eastern Interconnection Max and Min SIR in MVA*sec vs. Month

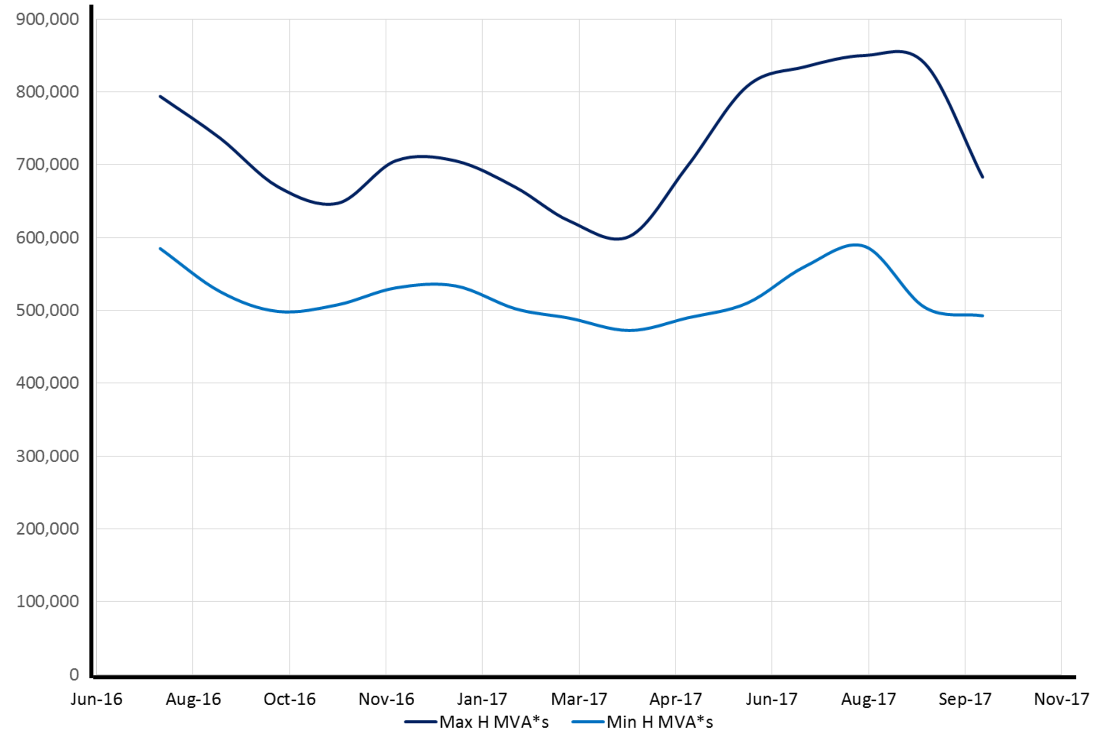


Figure E.20: Western Interconnection Max and Min SIR in MVA*sec vs. Month

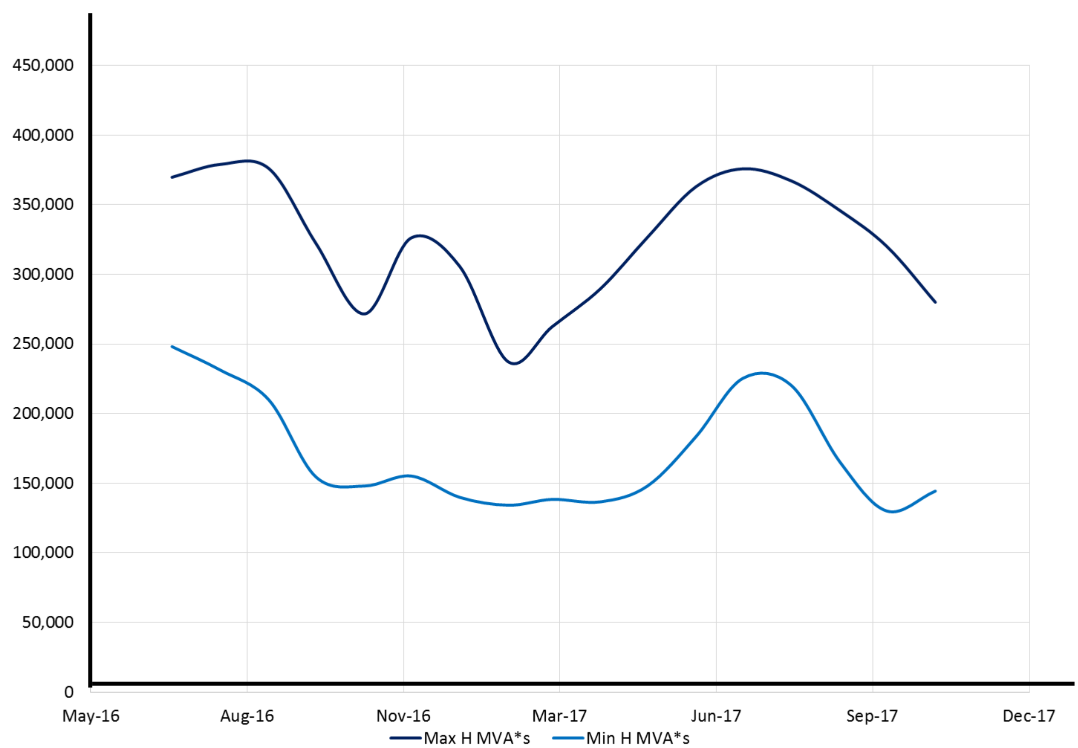


Figure E.21: Texas Interconnection Max and Min SIR in MVA*sec vs. Month

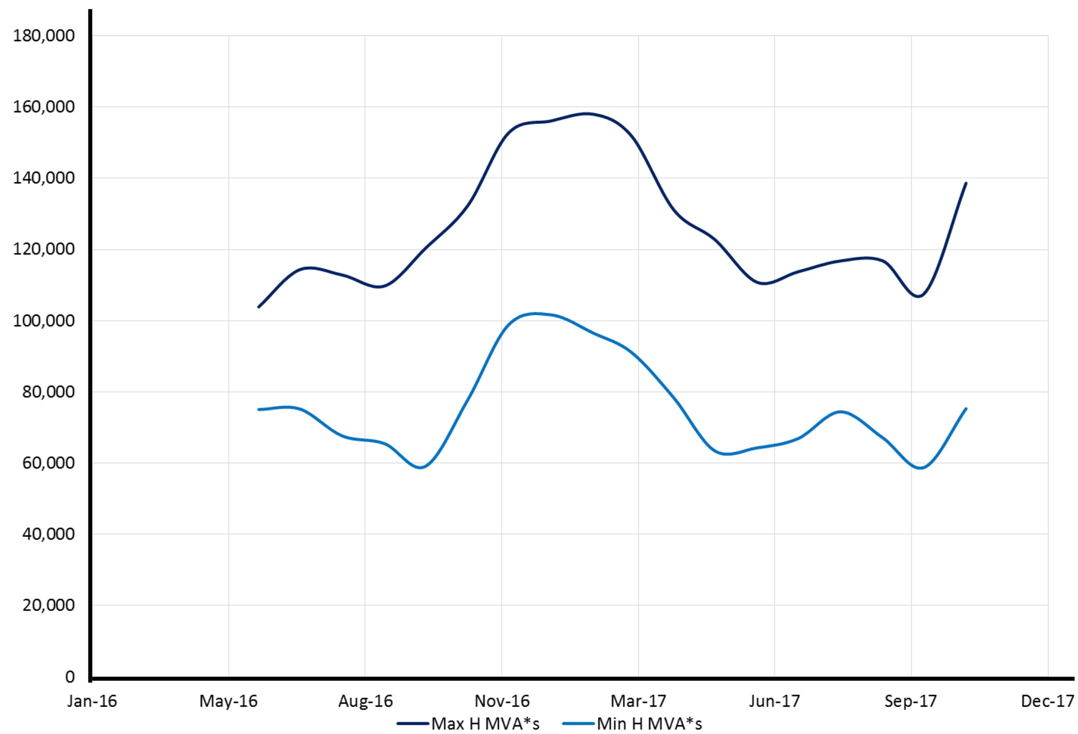


Figure E.22: Québec Interconnection Max and Min SIR in MVA*sec vs. Month

Measure 2: Initial Rate of Change of Frequency after the Largest Contingency

The initial Rate of Change of Frequency (RoCoF) after a large generator trip event is measured in Hz/s. This is an indirect measure of Interconnection inertia at the time of the event. In Measure 2 RoCoF is calculated for each Interconnection from the lowest SIR value in each year and the megawatt (MW) size of the largest contingency event for the Interconnection. RoCoF is only the initial rate of change; the rate of change over the entire frequency event (and also over other portions of the frequency event) differs widely compared to the initial RoCoF. The Resource Contingency Criteria (RCC) as defined in the BAL-003 Standard is used as the largest contingency event.

For systems where load damping constant D is not available RoCoF is calculated in mHz/sec:

$$RoCoF = \frac{60 * 1000 * \Delta P_{MW}}{2 * (KE_{min} - KE_{RCC})}$$

Where ΔP_{MW} is the largest contingency as defined by the Resource Contingency Criteria (RCC) in BAL-003, and KE_{min} is the minimum kinetic energy or synchronous inertial response for each historic year and KE_{RCC} is the Kinetic Energy of the Resource Contingency Criteria.

For systems where load damping constant D is available, the following is used to calculate frequency deviation in mHz at 0.5 seconds:

$$\Delta f_{0.5} = \frac{60 * 1000 * \Delta P_{MW}}{D * P_{load}} (1 - e^{\frac{-0.5 * D * P_{load}}{2 * (KE_{min} - KE_{RCC})}})$$

Where P_{load} is system load during SIR_{min} conditions. The corresonding 0.5 sec RoCoF is calculated in mHz/sec as

$$RoCoF = \frac{\Delta f_{0.5}}{0.5}$$

The calculations are shown for OY2017 for each Interconnection in **Table E.28**.

Table E.28: OY2017 RoCoF Statistics

Interconnection	Min H (MVA*sec)	Pload (MW)	f dev 0.5 sec (Hz) D=1.5	0.5 sec RoCoF for D=0 (mHz/s)	0.5 sec RoCoF for D=1.5 (mHz/s)	RCC (MW)
EI	1,038,756	215,222	0.0625	130	125	4,500
WI	472,507	87,712	0.0805	167	161	2,626
TI	130,014	28,444	0.3046	632	609	2,750
QI	58,760	14,260	0.4148	868	830	1,700

Measure 4 Frequency Performance after Large Contingency

Measure 4 is a comprehensive measure that tracks system frequency performance in the arresting, rebound, and stabilization periods following large contingency events that have occurred in each Interconnection. On a quarterly basis, the NERC RS selects the events and calculates a number of submeasures that comprise Measure 4. Multiple years of these values are monitored to identify trends that could be due to changes in the generation mix or other factors. The submeasures for all four Interconnections are presented on the same plots for convenience, not for comparison. When sufficient years of data become available for each Interconnection, each Interconnection will be trended only against its own historic performance.

A to C Frequency Response

A to C frequency response captures the impacts of inertial response, load response (load damping), and initial governor response (governor response is triggered immediately after frequency exceeds a pre-set deadband). However, depending on the generator technology full governor response may require up to 30 seconds to be fully deployed. This Measure is calculated as the ratio of the net megawatts lost to the difference between Point A and Point C frequency values.

Below is the equation for calculating $IFRM_{A\text{-}C}$.

$$IFRM_{A-C} = \frac{MW\ Loss}{10 * \Delta f_{A-C}}$$

Where:

MW Loss = Resource or Load Output immediately prior to the start of the event

$f_{A\text{-}C}$ = Change in frequency from Value A to Value C

Figure E.23 provides box-plots of $IFRM_{A\text{-}C}$ for operating years 2016 and 2017.

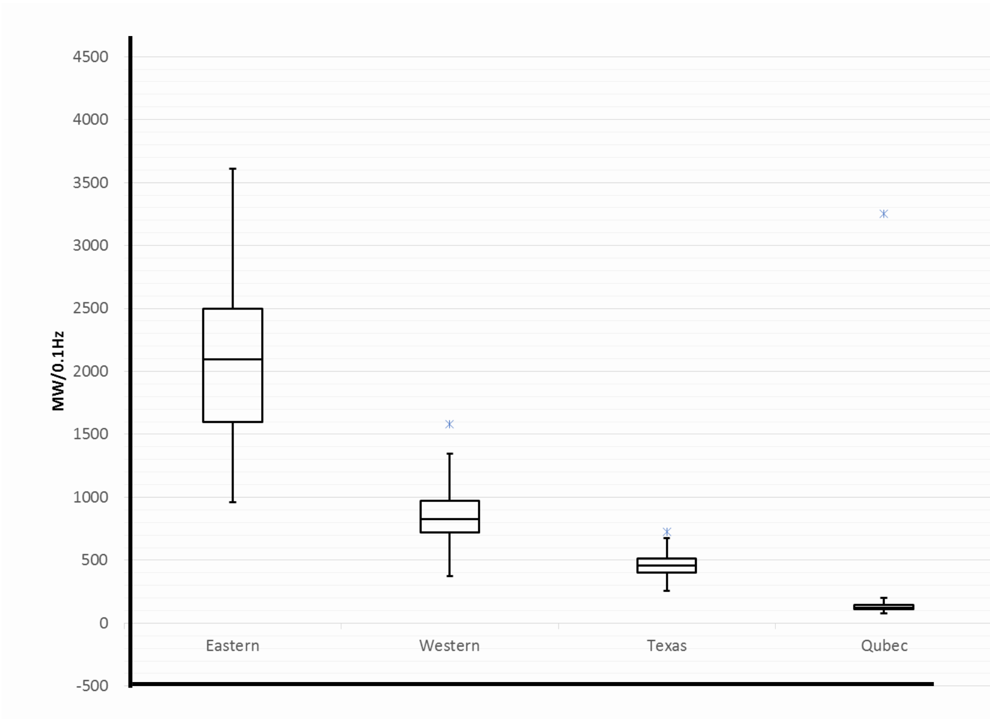


Figure E.23: IFRM A-C for OY 2016 and 2017

Cn Frequency

C_n is defined as the lowest frequency in the first 180 seconds following the beginning of the event. In the event that the low frequency nadir occurs within the Point C time interval of T_0 to T_{+12}, as is often the case in the TI, QI, and WI, Point C will equal C_n.

This measure previously used the Point C' value, which only exists if a frequency lower than Point C occurred beyond 52 seconds. Cn was adopted to insure that the low frequency nadir is captured even if it occurs prior to 52 seconds.

Time Cn to T0

Time Cn to T0 is the time in seconds that it takes to reach the lowest frequency in the first 180 seconds. **Figure E.24** provides scatter plots of these values for each Interconnection.

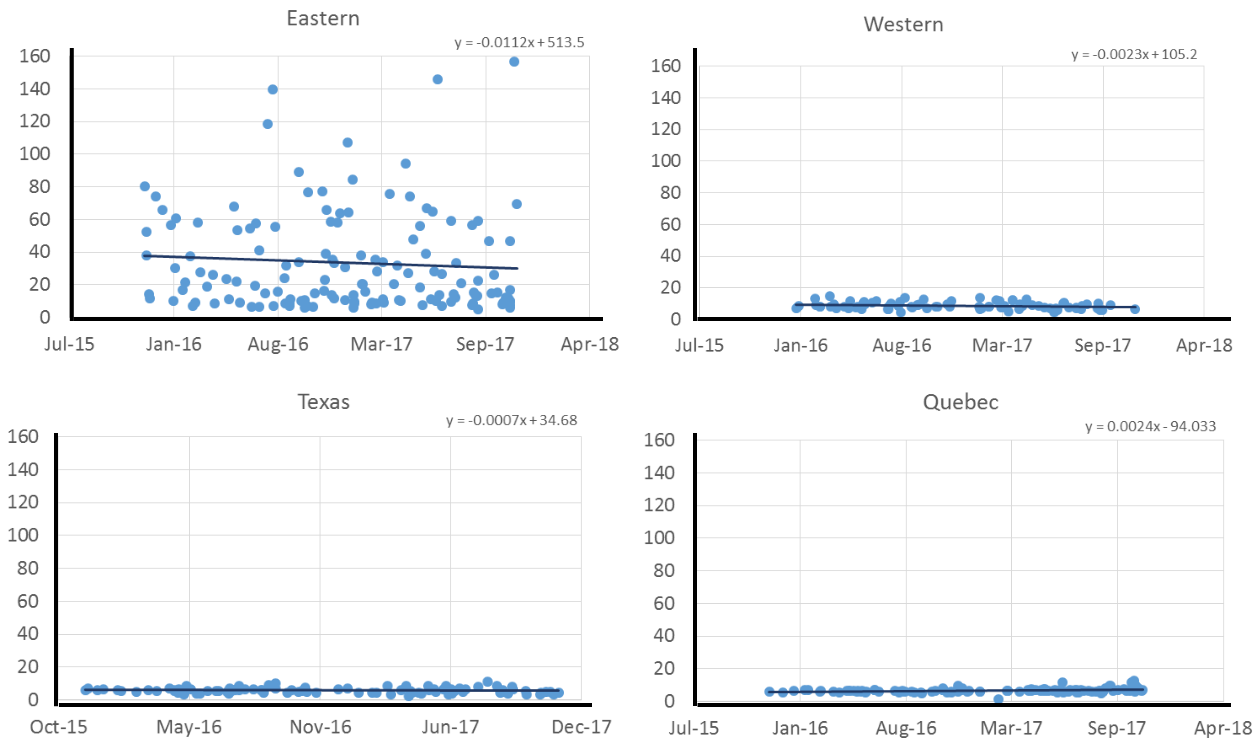


Figure E.24: TCn–T0 (sec) for OY 2016 and 2017

Appendix F: Reliability Indicator Trends

This appendix contains detailed supporting analysis for most of the reliability indicators (metrics) listed and assigned trending values as shown in **Table 3.1**. Any metric that particularly speaks to BPS reliability trend changes in 2016 is explained to some degree in **Chapter 3**. Those metrics might be completely covered in that chapter or might have more detailed analyses in this appendix. For those metrics that generally speak to reliability in any year, but did not identify trend changes in 2016, their analyses are completely contained in this appendix.

An exception is M-4: Interconnection Frequency Response. This metric is particularly important given current changes to the BPS resource mix and the fact that BAL-003-1.1 is currently open for revision and will affect M-4. **Chapter 2** and **Appendix E** provide expansive coverage of this metric.

M-1 Planning Reserve Margin

Background

This metric demonstrates the amount of generation capacity available to meet expected demand. It is a forward-looking or leading metric. PAS and RAS are collaboratively working to determine if there is a better metric for this report.

The *2018 Summer Reliability Assessment*[183] indicates, as shown in **Figure F.1**, that all Regions with the exception of Texas RE project sufficient reserve margins in the near term (five-year window).[184] Generation unit retirements that occurred in early 2018, along with reported delays in Tier 1 resource capacity by generation project developers, are expected to result in tight reserve margins for the upcoming summer. ERCOT has a variety of operational tools to help manage tight reserves and maintain system reliability. For example, control room operators can release Ancillary Services (including Load Resources that can provide various types of operating reserves depending on meeting certain qualification criteria), deploy contracted Emergency Response Service resources, instruct investor-owned utilities to call on their load management and distribution voltage reduction programs, request emergency power across the dc ties, and request support from available switchable generators currently serving non-ERCOT grids. A full description of the tools and procedures available to ERCOT, and the system conditions under which they are triggered, is provided in the ERCOT Nodal Protocols. See Chapter 6, Section 6.5.9.4, "Energy Emergency Alert."[185]

In the event that market-based solutions or other actions are not expected to be sufficient to avoid an Emergency Condition in the current or following season, the Nodal Protocols allow ERCOT to issue a procurement for generation and/or load capacity resources (An Emergency Condition is defined as "An operating condition in which the safety or reliability of the ERCOT System is compromised or threatened, as determined by ERCOT"). The process for issuing a capacity procurement is described in Nodal Protocol Chapter 6, "ERCOT Control Area Authority," Section 6.5.1.1(2).

Based on ERCOT's *Preliminary Summer Seasonal Assessment of Resource Adequacy* report,[186] released March 1, 2018, ERCOT expects that these operational tools could be needed to help maintain sufficient operating reserves given the range of resource adequacy scenarios evaluated. Note that subsequent to the release of the preliminary summer assessment report, Anticipated Resources has increased by 581 MW. This is attributable to a previously mothballed unit that is now expected to return to service in May 2018 (B. M. Davis Unit 1,300 MW), including a 226 MW planned

[183] The *2018 Summer Reliability Assessment* can be found at the following location: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_05252018_Final.pdf
[184] The reserve margins in **Figure F.1** reflect the most critical peak season for each reporting entity when reserves are lowest. This includes consideration of whether each entity is summer or winter peaking.
[185] The ERCOT Nodal Protocols can be found at the following location: http://www.ercot.com/content/wcm/current_guides/53528/06-030118_Nodal.doc
[186] ERCOT's *Preliminary Summer Seasonal Assessment of Resource Adequacy* report can be found at the following location: http://www.ercot.com/content/wcm/lists/143976/SARA-PreliminarySummer2018.pdf

natural-gas-fired resource with an expected in-service date of July 1, 2018, but which is not included in the preliminary summer assessment report due to a June 1 cut-off date used for summer assessment availability reporting and a previously unavailable 55 MW switchable generation unit that will now serve the ERCOT grid through 2019 (Antelope Unit 3).

In addition to ERCOT's actions to maintain sufficient operating reserves, higher wholesale market prices during peak demand periods are anticipated to incentivize power customers to voluntarily reduce load or increase energy output from load-serving generation facilities, such as industrial cogeneration and commercial-sector distributed generation that can inject power into the ERCOT System. Based on recent ERCOT analysis, the potential amount of this demand and generation response for the upcoming summer is significant but speculative because the ERCOT market has not experienced summer high prices subsequent to the market design changes implemented in 2012–2014. Consequently, this resource capacity is not reflected in the summer reliability assessment. ERCOT's analysis of price-driven participation from demand response and distributed generation is available in the *2017 Annual Report of Demand Response in the ERCOT Region*.[187]

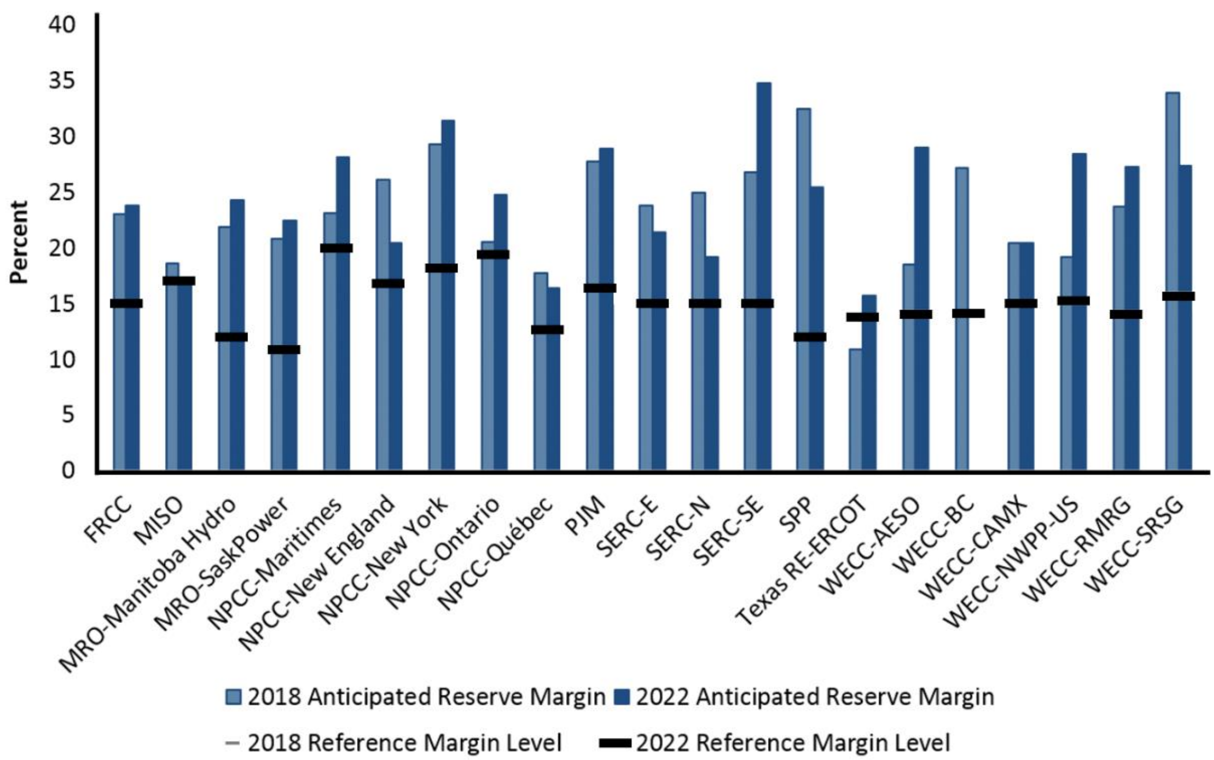


Figure F.1: M-1 Planning Reserve Margin

M-3 System Voltage Performance

Background

This metric was retired from the monitored set of metrics in 2014.

[187] The *2017 Annual Report of Demand Response in the ERCOT Region* can be found at the following location: http://www.ercot.com/content/wcm/lists/94805/2017_Annual_Report_of_Demand_Response_in_the_ERCOT_Region.docx

Future Development

Maintaining system voltage and adequate reactive control remains an important reliability performance objective that must be incorporated into the planning, design, and operation of the BES. The ERSWG developed a November 2015 framework report[188] that recommended a set of voltage measures with PAS assigned to develop data collection to support Measure 7: Reactive Capability on the System.

During 2016, PAS developed and conducted a voluntary data collection and released the data for analysis to the SAMS for analysis of Measure 7 as a potential voltage and reactive metric. During 2017, SAMS recommended to the PC that Measure 7 was not feasible, and the PC accepted the recommendation.

M-6 Disturbance Control Standard Failures

Background

This metric measures the ability of a BA or reserve sharing group (RSG) to balance resources and demand following a reportable disturbance, thereby returning the Interconnection frequency to within defined limits; this could include the deployment of contingency reserves. The relative percent recovery of a BA's or RSG's area control error provides an indication of performance for disturbances that are equal to or less than the most severe single contingency (MSSC). NERC Reliability Standard BAL-002-1[189] requires that a BA or RSG evaluate performance for all reportable disturbances and report findings to NERC on a quarterly basis.

M-7 Disturbance Control Events Greater than MSSC

Background

This metric measures the ability of a BA or RSG to balance resources and demand following reportable disturbances that are greater than their MSSC. The results will help measure how much risk the system is exposed to during extreme contingencies and how often they occur. NERC Reliability Standard BAL-002-1 requires that a BA or RSG report all disturbance control standard (DCS) events and instances of non-recovery to NERC, including events greater than MSSC.

Assessment for M-6 and M-7

Figure F.2 shows that the trend of M-6 DCS-reportable events is improved with less than half as many reportable events (M-6) in 2017 when compared to the 2016 data. **Table F.1** shows that in 2017, there was only one M-6 DCS event for which there was less than 100 percent recovery within the determined period.

Figure F.2 also shows that the number of M-7 events were slightly lower in 2017 than in 2016, although still considerably lower than in 2012, 2013, or 2014. There was one M-7 event in 2016 for which 100 percent recovery was not achieved within the required timeframe.

Based on the similar annual results over the last four years, M-6 is stable.

Based on both the improvement in 2015–2017 and relative to 2012–2014, M-7 is stable for the short term in the approved state achieved in 2015.

[188] The 2015 ERSWG Framework report can be found at the following location: http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf.

[189] Reliability Standard BAL-002-1 can be found at the following location: http://www.nerc.com/files/BAL-002-1.pdf.

Table F.1: M-6 and M-7 Event Recovery				
YEAR	M-6 100% Recovery	M-6 < 100% Recovery	M-7 100% Recovery	M-7 < 100% Recovery
2012	346	0	26	2
2013	390	3	28	2
2014	392	0	25	0
2015	370	1	12	0
2016	388	0	15	1
2017	165	1	12	1

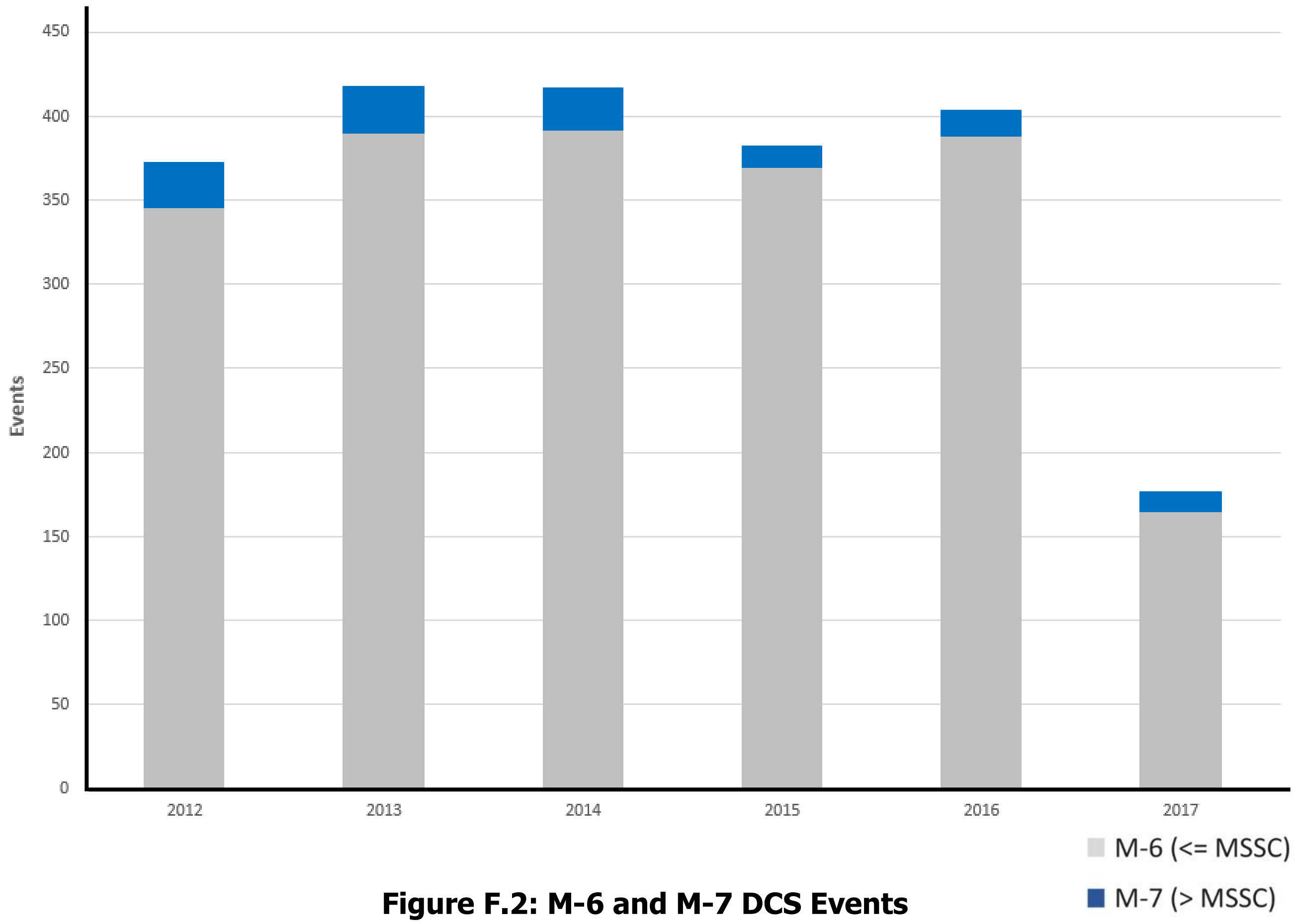


Figure F.2: M-6 and M-7 DCS Events

M-8: Interconnection Reliability Operating Limit Exceedances

Background

This metric measures the number of times and the duration that an IROL is exceeded. An IROL is a SOL that, if violated, could lead to instability, uncontrolled separation, or cascading outages.[190] Each RC is required to operate within the IROL limits and minimize the duration of such exceedances. IROL exceedance data are reported per quarter and uses four duration intervals as shown in Figure F.3 through Figure F.5.

[190] T_v is the maximum time that an Interconnection reliability operating limit can be violated before the risk to the Interconnection or other RC area(s) becomes greater than acceptable. Each Interconnection reliability operating limit's T_v shall be less than or equal to 30 minutes.

Assessment

Figure F.3 demonstrates the performance for the EI from 2011–2017. In 2017, the two ranges that were impacted were the 10 second to 10 minute range and the 10 minute to the 20 minute range. For the 10 second to 10 minute range, compared to the prior year's performance (by quarter), the number of exceedances increased for the first quarter; however, it declined for the remaining quarters. For the 10 minute to 20 minute range, compared to the prior year's performance (by quarter), the number of exceedances increased for the first quarter and second quarter; however, it declined for the third and fourth quarters.

Figure F.3: Eastern Interconnection—IROL Exceedances

Figure F.4 demonstrates the performance of the ERCOT Interconnection from 2011–2017. The trend has been stable at no exceedances since the second quarter of 2013.

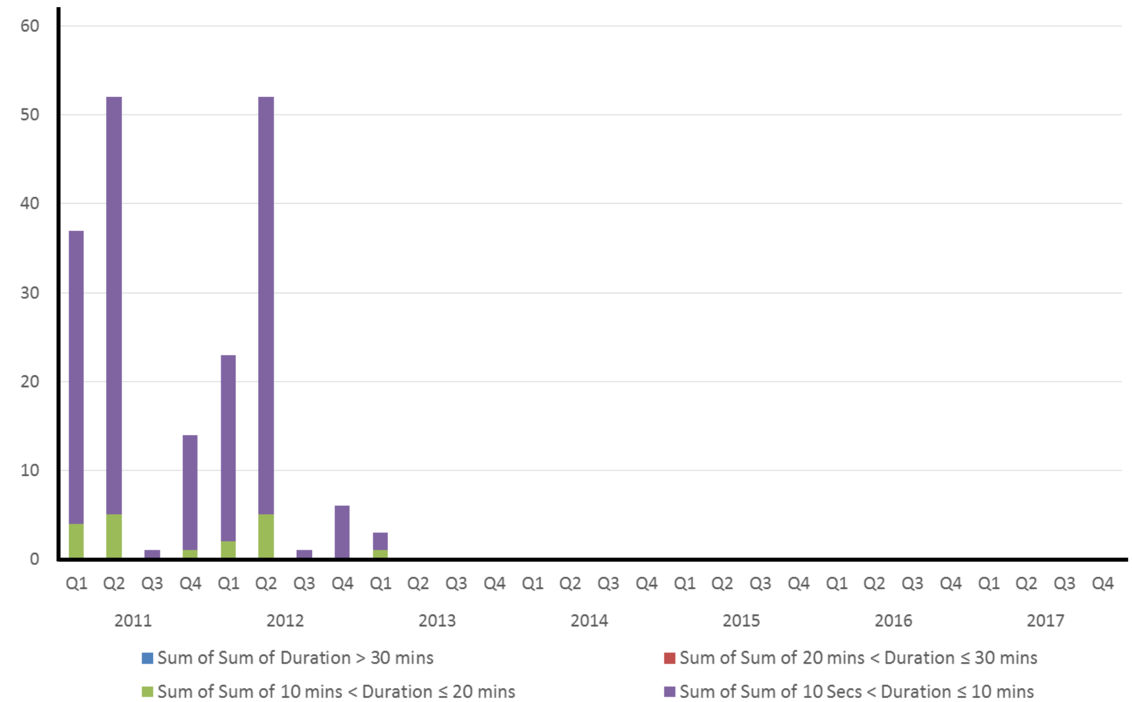


Figure F.4: ERCOT Interconnection—IROL Exceedances

Figure F.5 demonstrates performance for the WI from 2011–2017. The *State of Reliability 2015*[191] noted changes in data reporting for the WI that led to the reporting of IROLs. Prior to 2014, only SOLs were reported. Since 2014, the trend has been stable with no IROL exceedances reported.

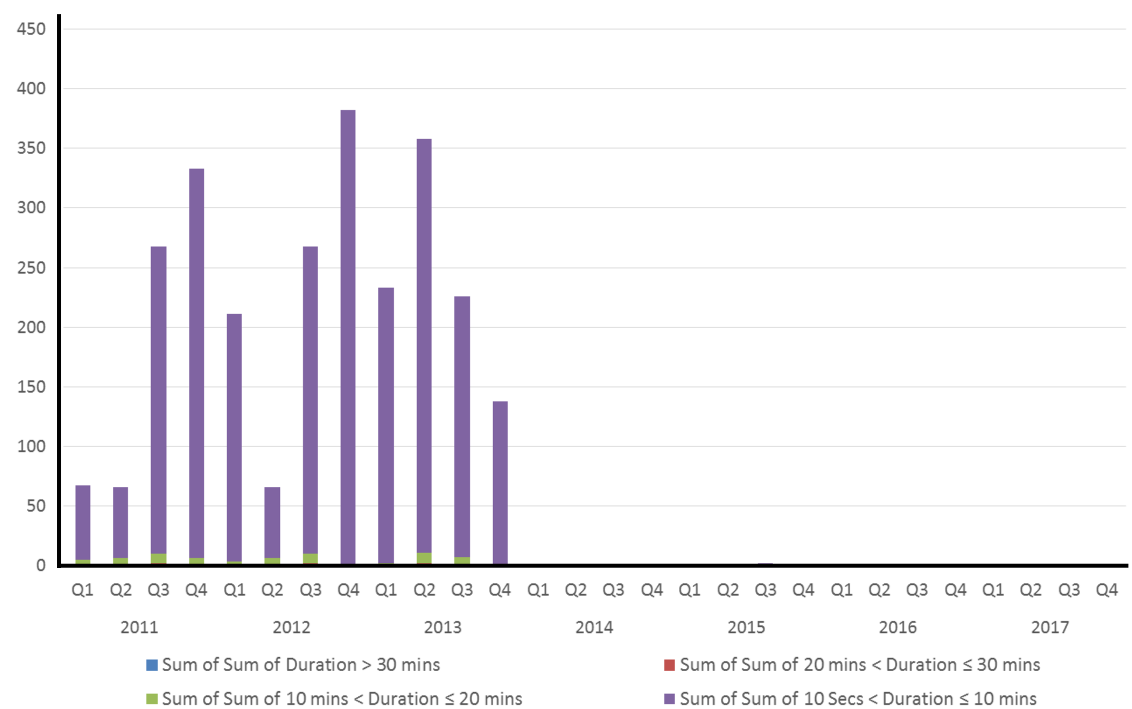


Figure F.5: Western Interconnection—SOL/IROL Exceedances

191 The *State of Reliability 2015* can be found at the following location: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2015%20State%20of%20Reliability.pdf

M-9 Correct Protection System Operations

Background

Protection system misoperations were identified as an area that required further analysis in past *State of Reliability* reports. The improvements to the data collection process, that the SPCS proposed, were implemented and have improved the accuracy of misoperation reporting. At the recommendation of the SPCS, the respective protection system subcommittees (within each RE) began misoperation analysis in early 2014 and have continued to conduct such analysis on an annual basis. In 2017, NERC deployed a portal application that allows entities to securely upload and view their reported data.

Assessment

Figure 3.4 shows the correct operations rate for NERC during the reporting period. Total protection system operations were first requested with fourth quarter 2012 misoperation data. This is to reflect the updated metric M-9 Correct Protection System Operations. The rate provides a consistent way to trend misoperations and to normalize for weather and other factors that can influence the count. Incremental improvements continue to be seen.

Figure F.6 shows the count of misoperations by month through the third quarter of 2017. The counts can show variability or similarity by year for each month and seasonal trends. For example, the chart shows higher numbers of misoperations in summer than the rest of the year.

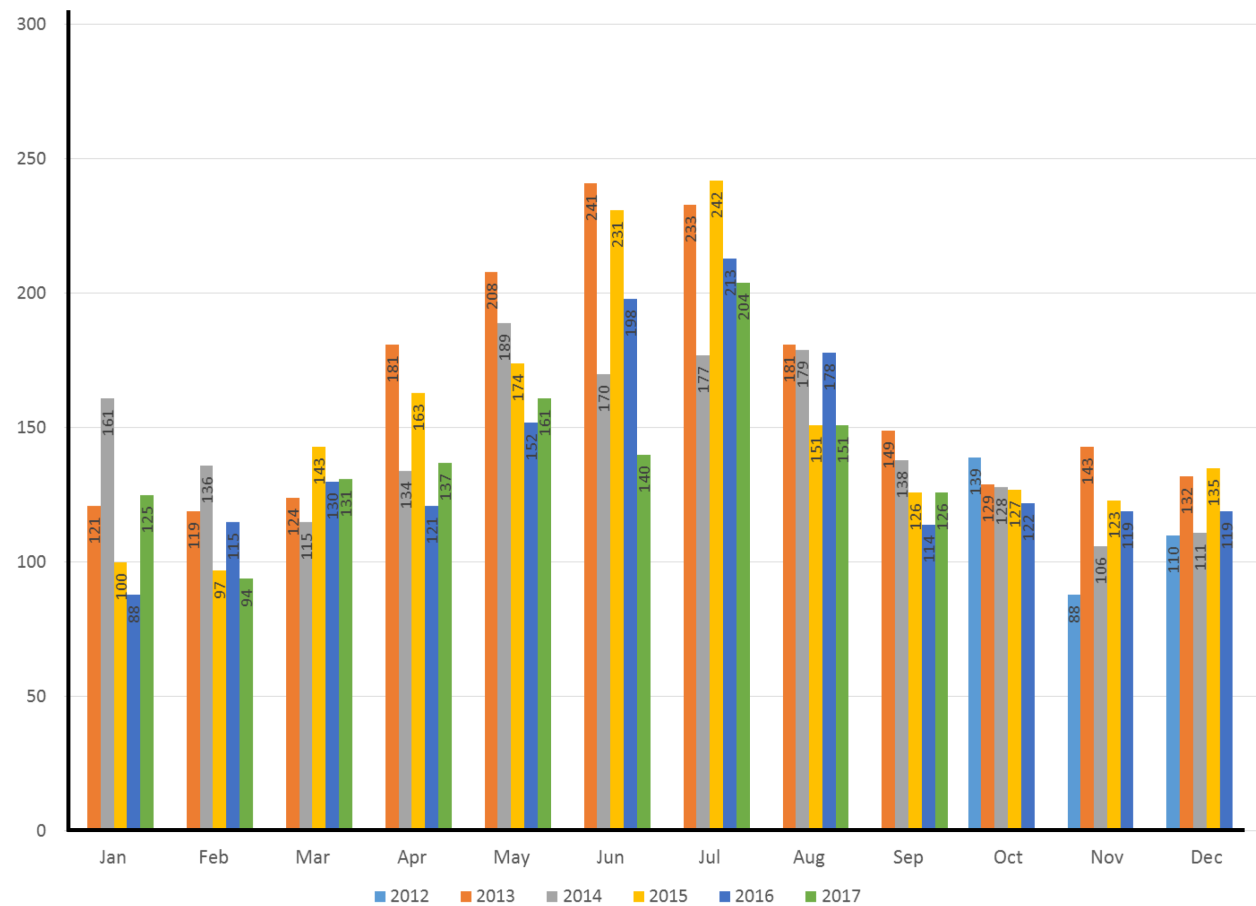


Figure F.6: Protection System Misoperations by Month (4Q 2012 through 3Q 2017)

Figure F.7 illustrates misoperations by cause code where the top three causes continue to be Incorrect Setting, Logic, or Design Error; Relay Failures/Malfunctions; and Communication Failure. These cause codes have consistently accounted for more than 60 percent of all misoperations since data collection started in 2011. Recent reporting updates has broken down the single "Incorrect Setting, Logic, or Design Error" cause code into separate cause codes of "Incorrect Settings," "Logic Errors," and "Design Errors" as seen in the **Figure F.7**. The separation allows analysis at a higher granularity to address issues that may exist in one of the cause code subgroups.

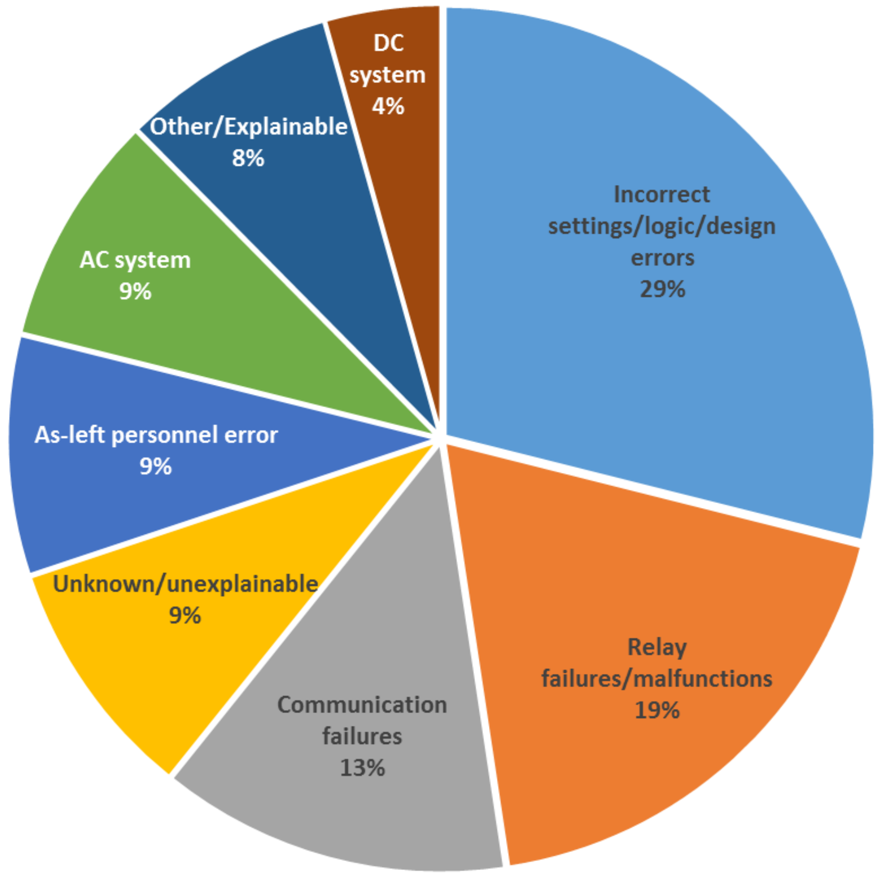


Figure F.7: NERC Misoperations by Cause Code (4Q 2012 through 3Q 2017)

Linkage between Misoperations and Transmission-Related Qualified Events

An analysis of misoperation data and events in the EA Process found that in 2015 there were 50 transmission-related system disturbances that resulted in a qualified event. Of those 50 events, a total of 34 events, or 68 percent, had associated misoperations. Of the 34 events, a total of 33 of them, or 97 percent, experienced misoperations that significantly increased the severity of the event. There were four events where one or more misoperations and a substation equipment failure occurred in the same event. The relay ground function accounted for 11 misoperations in 2014, causing events that were analyzed in the EA Process. This was reduced to six events in 2015. It was further reduced to only one event in 2016. The focus on the relay ground function has been attended by a reduction in its involvement in qualified events. It is not clear if any statistical basis will be able to confirm that its role in relay misoperations has been similarly decreasing.

Actions to Address Misoperations

To increase awareness and transparency, NERC and the REs will continue to conduct industry webinars[192] on protection systems and document success stories on how GOs and TOs are achieving high levels of protection system performance. The quarterly protection system misoperation trend can be viewed on NERC's website.[193]

NERC introduced MIDAS in 2016, a data collection site for misoperations. In 2017, NERC replaced the data collection site with an application that allows the users to review, create, or update existing records with improved data validation and reporting through a secure portal integrated with NERC's ERO User Management System. NERC collaborates closely with the Regions to impart best practices and improve data collection.

Summaries of Individual Regional Entity Initiatives

FRCC

The FRCC SPCS continues to conduct peer reviews of protection system misoperations prior to the protection system owner submitting the data to NERC MIDAS. The FRCC SPCS is a Member Services subcommittee but includes FRCC RE staff as part of the review. In 2017 the FRCC SPCS established a temporary Misoperations Task Force made up of subject matter experts from the FRCC SPCS and FRCC RE staff to develop a misoperations assessment. The purpose of the assessment was to identify key focus areas and lay a path forward with recommendations and conclusions that will aid in reducing the risk to reliability related to the annual rate of misoperations. There were five recommendations that were included in the report; the first three focused on improving the misoperations reporting by completing the optional fields in the MIDAS form (more thorough reports, including one-line diagrams and/or pictures) provided when warranted) and conducting monthly reviews when reports are available to help keep all engaged. The last two recommendations were focused on correcting a data error that was found and reviewing the report for metrics to track going forward.

The 2017 Assessment showed that FRCC entities made steady progress in reducing the misoperation rate. Implementing the recommendations will ensure that focus remains on continuing to reduce the risk to reliability related to the annual rate of misoperations.

MRO

In 2017, the MRO Protective Relay Subcommittee prepared and published a second white paper to discuss high impact misoperations and identify ways to increase the reliability (both security and dependability) of these misoperation types to minimize their occurrences. This second white paper addressed two types of misoperations, which are observed to have the most egregious impact on reliability: misoperations associated with bus differential and breaker failure relays.[194]

The MRO has also been focusing on accurate and consistent reporting of misoperations in order to acquire good data, which will allow for better attention to causes and (ultimately) solutions to misoperations. This is accomplished by reviewing submittals into MIDAS and working directly with entities to assure operations and misoperations are accurately recorded. MRO has also embraced the misoperation webinars that WECC will be hosting throughout 2018 by encouraging all of our MRO MIDAS data submitters to register and participate on these webinars.

---

[192] Information on misoperations industry webinars can be found at the following location: http://www.nerc.com/files/misoperations_webinar_master_deck_final.pdf

[193] Quarterly protection system misoperation trend can be found at the following location: http://www.nerc.com/pa/RAPA/ri/Pages/ProtectionSystemMisoperations.aspx

[194] Both of MRO's white papers addressing protection system misoperations can be found at the following location: MRO PRS Committee Technical Papers.

NPCC

The NPCC has instituted a procedure for peer review and analysis of all NPCC protection system misoperations. The NPCC review process is intended as a feedback mechanism that promotes continuous improvements based on lessons learned from reported protection system misoperations. The NPCC task force on system protection reviewed NERC lessons learned and NPCC-reported protection system misoperations while providing regional perspectives for entities' use to further improve performance and reduce misoperations.

NPCC collected additional data on microprocessor-based relay misoperations to develop potential measures that address misoperations caused by Incorrect Setting/Logic/Design Errors and to share knowledge of identified relay vendor specific product concerns along with the vendor recommended mitigations.

NPCC and SERC shared experiences identifying leading causes of protection system failures and misoperations as well as metrics used to measure performance. The two Regions shared best practices, processes, and criteria that support reducing protection system misoperations. NPCC also shared best practices and experience identifying leading causes of protection system failures and misoperations with MRO and RF. NPCC also completed comparative analyses of its protection system operation/misoperations data with SERC, MRO, and RF, using data submitted via MIDAS. The results were shared with SERC, MRO, and RF.

NPCC conducted a session on MIDAS Portal and areas of the Protection System Misoperation Review Working Group at the NPCC Fall Compliance/Standard Workshop in November 2017.

RF

RF continues to address the NERC misoperation reduction goal by providing training opportunities on protection topics to RF's member entities and through other staff activities. The RF Protection Subcommittee has an annual training session provided by SEL for various aspects of microprocessor relays. Topics have included design concepts for protection communication systems and polarization techniques associated with protection system settings. Starting in 2015, RF began hosting an annual workshop for field protection engineers and technicians; these are the personnel directly responsible for the installation and (commissioning) testing of protection system equipment, and they ensure that these protection systems are installed and function as designed. Topics for these annual workshops have included power line carrier equipment, protection system commissioning and testing, consideration of HP in protection system design, and protection system drawings in 2018. The 2017 spring Reliability Workshop also dedicated a full day of activities to the topic of misoperations. RF will continue to offer these opportunities and has invited the other Regions to participate.

Beginning in 2016, RF implemented a misoperations peer review process utilizing members of the RF Protection Subcommittee to analyze the reported misoperations and to offer feedback on analysis and mitigation techniques. This process leverages the expertise and experiences of the Protection Subcommittee to help entities in the Region reduce their misoperations.

In 2015, RF staff conducted an internal controls evaluation on a large entity related to misoperations and continue to track that entity's progress on a regular basis. In 2016 and 2017, RF conducted a verification effort for short circuit values on tie lines between TOs. This effort was conducted to enhance coordination between TOs for their internal short circuit models. RF will continue to conduct this exercise every other year.

In 2018, RF will visit with three entities to discuss their misoperation performance and related activities to help reduce misoperations. RF conducted six similar visits in 2012. RF has also authored many lessons learned associated with misoperations.[195]

[195] The RF lessons learned regarding misoperations are posted on the RF public web site: https://www.rfirst.org/KnowledgeCenter/Risk%20Analysis/Misops/Pages/Misops.aspx .

SERC

The SERC Protection and Controls Subcommittee (PCS) has a very robust program to review quarterly misoperations and provide feedback to the entities. In 2016 SERC PCS created a SERC *Regional Best Practices for Protection System Misoperations Reduction*[196] paper for entities to reference. In order to evaluate the risk to the reliability of BES due to protection system misoperations, SERC PCS developed a metric to measure risk based on cause, category, voltage, misoperation rate, and corrective action plan (CAP) response time. The paper describing the methodology is posted on the SERC website. SERC trends the risk and shares its semiannually with SERC Engineering Committee to provide visibility of progress. In 2018, SERC plans to use the SERC data analytics program to develop insights to the misoperations in the SERC Region. The snapshot of the dashboard developed by SERC PCS in conjunction with SERC analytics team will be posted on SERC website. SERC closely monitors the CAP completion duration and routinely contacts the entity for the CAP open for more than two years. SERC PCS will continue to build on the solid foundation and develop new tools to improve the risk to reliability of BES caused by misoperations.

SPP RE

The SPP System Protection and Control Working Group (SPCWG) has prepared a white paper discussing misoperations caused by communication failures,[197] a leading cause of misoperations in the SPP Region. The System Protection and Control Working Group is currently working on a white paper that discusses misoperations caused by Incorrect Settings/Logic/Design Errors, the second leading cause of misoperations in the SPP Region. These white papers then identify effective approaches to reduce misoperation occurrences.

Texas RE

Texas RE continues to work with ERCOT's System Protection Working Group (SPWG) on the following:

- Monitoring of multiple metrics and historical trends for misoperations by voltage class, cause, corrective action plan completion rates, etc.
- Monitoring HP issues as it relates to the cause of misoperations
- Sharing NERC lessons learned and event cause codes from protection system misoperation events
- Presenting the analysis of quarterly protection system misoperation data and historical trends at each SPWG meeting
- Conducting the 2018 workshop that is planned in conjunction with a quarterly SPWG meeting to focus and brainstorm on high level best practices and mitigation strategies for misoperation reduction

Texas RE also tracks and trends misoperation performance in its annual Assessment of Reliability Performance for the Interconnection and is conducting an in-depth analysis to identify the key focus areas to reduce misoperations. In both 2016 and 2017, As-Left Personnel Errors replaced Communication Failures as the third highest cause for misoperations. This has led to a renewed focus on the HP causal factors for misoperations as well as operational processes and procedures for the commissioning and maintenance of protection systems.

WECC

In 2017, WECC worked with a team of stakeholders to develop a strategy to reduce misoperations in the WI. This effort was aided by analysis performed by WECC's Relay Working Group (RWG) as well as analysis performed with WECC's Performance Analysis department. This team identified several areas where improvements could help reduce misoperations, and actions were assigned to WECC, the RWG, and registered entities. This effort was shared with

[196] The *Regional Best Practices for Protection System Misoperations Reduction* can be found at the following location: http://www.serc1.org/docs/default-source/committee/ec-protection-and-control-subcommittee/serc-regional-best-practices-for-protection-system-misoperations-reduction-8-19-2016.pdf

[197] The SPCWG white paper can be found at the following location: https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.spp.org%2Fdocuments%2F23167%2Fspcwg_commmisops_white paper_final_mopc.doc

industry with as part of WECC's first Misoperations Workshop, held in August 2017. Feedback from workshop participants was incorporated and the strategy was finalized. The timeline for this effort extends across multiple years as some of the tasks require time to implement and for improvement to be realized. In Q2 2018, WECC will publish this reduction strategy in an interactive online format that will be updated as progress is made on each of the tasks. WECC encourages entities to evaluate their individual systems and apply the recommendations that will be the most impactful to their operation.

During the Misoperation Workshop of 2017, WECC identified an inconsistency in the way operations and misoperations are being reported into the MIDAS Portal. To help bring consistency to this issue, WECC will host six webinars through 2018 that will help bring consistency to this reporting. The scenarios shared on the webinar are vetted through the ERO Enterprise and the RWG to ensure a consistent stance on each scenario. WECC feels this effort is important because the reduction of misoperations is based on a calculated misoperation rate. If this rate is inaccurate due to inconsistent reporting, the success of the strategy cannot be accurately measured.

WECC will host another Misoperations Workshop in June 2018. The content of this workshop is based on the topics identified in the reduction strategy.

Misoperations Analysis

Misoperation Rate by Region and for NERC

Table F.2 lists the NERC operation and misoperation counts and the corresponding misoperation rates by Region and for NERC with the 16 available quarters (Q4 2012 through Q3 2017). NERC's numbers are based on the combined data for the Regions available for the respective time periods.

Table F.2: Operations and Misoperations by Region from Q4 2012 Through Q3 2017

Region	Operations	Misoperations	Misoperation Rate
FRCC	3,831	328	8.6%
MRO	7,339	763	10.4%
NPCC (Q1 2013 to Q3 2017)	12,568	916	7.3%
RF	13,186	1,741	13.2%
SERC	20,861	1,703	8.2%
SPP	10,193	1,109	10.9%
Texas RE	11,307	809	7.2%
WECC (Q2 2016 to Q3 2017)	9,280	469	5.1%
NERC	**88,565**	**7,838**	**8.8%**

Comparison of Regional Misoperation Rates

Regional misoperation and operation data were analyzed to find statistically significant differences[198] in misoperation rates between Regions based on the five-year data (except for Q1 2013 through Q3 2017 for NPCC and Q2 and Q3 2017 for WECC).

Figure F.8 lists the average five-year misoperation rate by Region ordered from highest (RF's rate of 13.2 percent) to the lowest (WECC's rate of 5.1 percent) and summarizes results of Duncan's grouping test[199] for the misoperation rates. Each bar connects Regions with similar (not statistically significantly different) expected misoperation rates.

[198] Large sample test on population proportions at the 0.05 significance level
[199] At significance level of 0.05.

For example, differences in misoperation rate between SPP and MRO, connected by a red bar, are not significant, meaning that the percentage of operations resulting in misoperations in these two Regions are expected to be close.

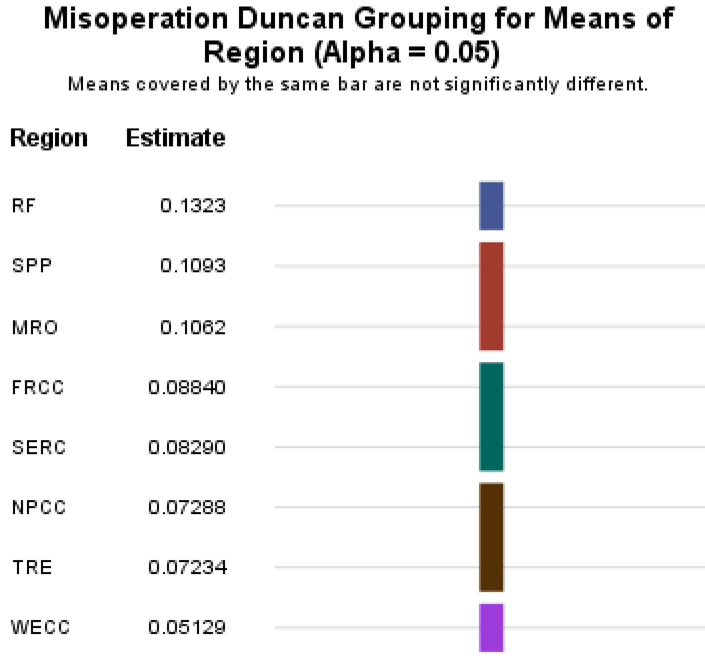


Figure F.8: Misoperation Rate by Region (2Q 2012 through 3Q 2017) and Regional Grouping by Expected Misoperation Rate

M-10 Transmission Constraint Mitigation

This metric was approved for retroactive retirement by the PC in June of 2017. The metric measured the number of mitigation plans that included SPSs, RASs, and/or operating procedures developed to meet reliability criteria.

M-11 Energy Emergency Alerts

Background

To ensure that all RCs clearly understand potential and actual energy emergencies in the Interconnection, NERC has established three levels of energy emergency alerts (EEA). This metric measures the duration and number of times EEAs of all levels are issued and when firm load is interrupted due to an EEA Level 3 event. EEA trends may provide an indication of BPS capacity. This metric may also provide benefits to the industry when considering correlations between EEA events and planning reserve margins.

When an EEA3 alert is issued, firm-load interruptions are imminent or in progress. The issuance of an EEA3 may be due to a lack of available generation capacity or when resources cannot be scheduled due to transmission constraints.

Assessment

Table F.3 shows the number of EEA3 events declared from 2006–2017. Six EEA3's were declared in 2017, four more than the previous year. The increase in EEA3s can mainly be attributed to the new EOP-011-1 that consolidated requirements from three standards: EOP-001-2.1b, EOP-002-3.1, and EOP-003-2. EOP-011-1 became effective April 1, 2017. The load loss is reduced from all years since 2013.

Table F.3: 2017 Energy Emergency Alert 3												
Region	**Number of Events**											
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
NERC	**5**	**26**	**13**	**38**	**7**	**23**	**14**	**6**	**4**	**1**	**2**	**6**
FRCC	0	0	0	0	0	0	0	1	2	0	0	0
MRO	0	0	0	0	0	0	0	0	0	0	0	0
NPCC	0	0	0	1	0	0	0	0	1	0	0	0
RF	0	0	0	0	0	0	0	0	0	0	0	0
SERC	2	14	2	0	3	2	7	0	1	0	0	0
SPP	1	9	8	37	4	15	6	2	0	0	0	0
Texas RE	0	0	0	0	0	1	0	0	0	0	0	0
WECC	2	3	3	0	0	5	1	3	0	1	2	6

Table F.4 shows the number of all EEAs declared in 2017, broken out by Region as well as event level.

Table F.4: 2017 EEA Level by Region				
Region	**EEA1**	**EEA2**	**EEA3**	**Total**
FRCC	1	1	0	2
MRO	7	3	0	10
NPCC	2	0	0	2
RF	0	0	0	0
SERC	5	2	0	7
SPP	0	0	0	0
WECC	6	5	6	17
Texas RE	0	0	0	0
Grand Total	**21**	**11**	**6**	**38**

In **Figure F.9**, a graph is provided for 2013–2017, showing the duration and amount of load shed during an EEA, if any. The six EEA3's declared lasted 3.37 hours, and 0 MW of load was shed during the six EEA3 events that were declared.

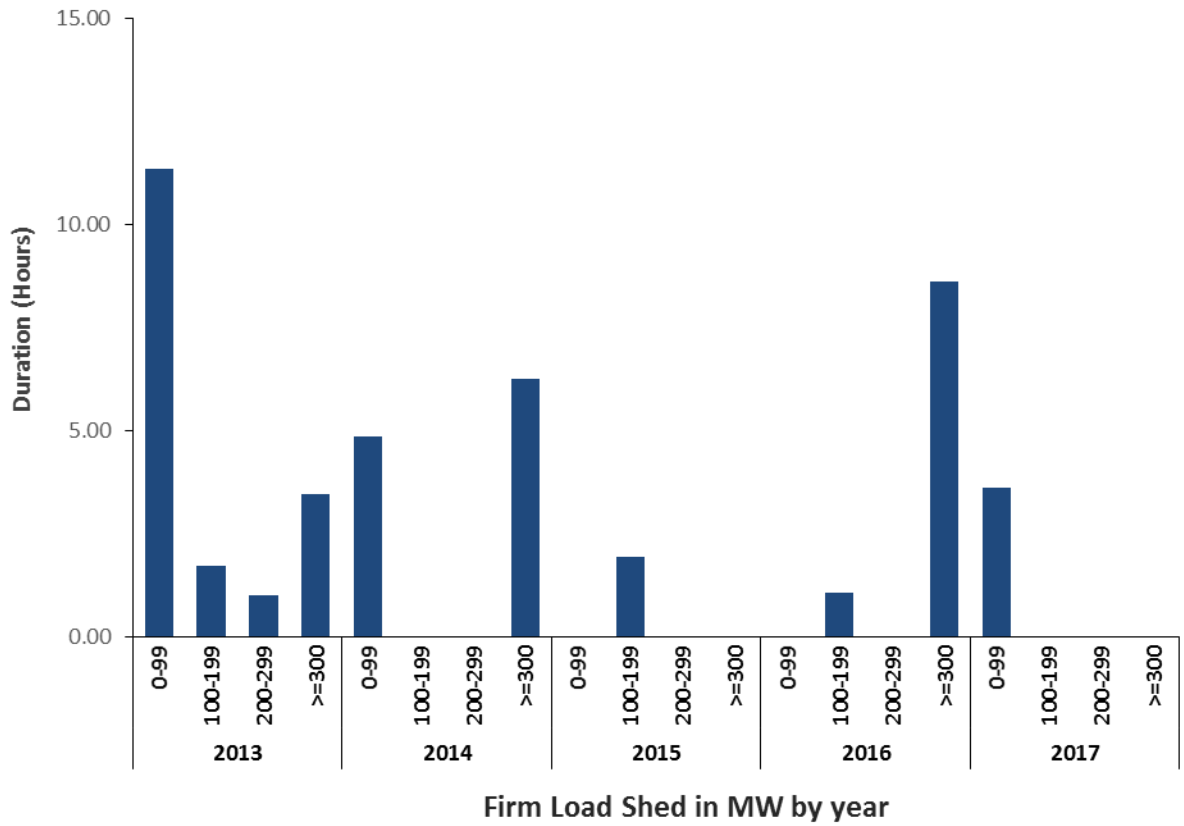


Figure F.9: Firm Load Shed and Duration Associated with EEA3 Events by Year

Appendix G: Event Analysis

This appendix highlights some event analysis activity not included in Chapter 6. Then it describes the EA Process, speaks to types and causes of events, and details the impacts of system protection misoperations on 2017 events. Finally, it augments information regarding Hurricanes Harvey and Irma presented in **Chapter 5** and provides a summary of the work of the EAS, NERC EA group, and larger ERO Enterprise EA groups.

Energy Management System Working Group

Fifth Annual Monitoring and Situational Awareness Conference

The EMSWG analyzes the events and data that are being collected about EMS outages and challenges. From the EA reports and the work of the EAS, NERC published multiple lessons learned specifically about EMS outages and worked to build and support an industry-led EMSWG to support the EAS. The hard work and active sharing of this group has reduced some of the residual risk associated with this potential loss of situation awareness and monitoring capability that comes with an EMS outage, and they will continue to provide valuable information to the industry.

Risks and Mitigations for Losing EMS Functions Reference Document

The industry's voluntary ERO EA Process provides information to the ERO and industry on the categories and causes of qualifying events. Review and analysis of both EMS and non-EMS events can identify potential reliability risks or vulnerabilities to the BPS that need to be mitigated. Secondly, there are several major initiatives underway in EA to improve reliability: HP improvement, analysis of the 2016–2017 winter season's effect on resource availability, and the publishing of lessons learned throughout 2017.

NERC hosted its fifth annual Monitoring and Situational Awareness Conference on October 3–4, 2017, at the Georgia Power Company Corporate Headquarters in Atlanta, GA. The conference brought together more than 120 operations and EMS experts from registered entities, government regulators, and a variety of vendors and consultants from all Regions and Canada. The focus was on energy management systems quality, including modeling and real-time assessments. William Ball, chief transmission officer and executive vice president of Southern Company, delivered the keynote presentation and spoke on the importance of continued development of elegant EMS tools and systems with built-in security and resiliency to face the challenges of the future. Conference highlights include a presentation on the Modeling and Real-Time Assessment Tool, a presentation of lessons learned from recent EMS outages, and several panel discussions led by industry experts and EMS vendors. The conference presentations are available on the NERC website.[200]

Reference Document on EMSWG Risks and Mitigations for Losing EMS Functions

The EMSWG released a reference document[201] about risks and mitigations for losing EMS functions. The reference document briefly describes what an EMS is, the various parts of it, and the dependency between the parts; then the reference document analyzes 318 EMS events reported by 130 NERC registered entities between October 2013 and April 2017 through the ERO EA Process. Based on the analysis, the reference document identifies and discusses the risk of losing EMS functions, analyzes the causes of reported EMS events, and shares mitigation strategies to reduce these risks.

[200] Conference presentations can be found at the following location: http://www.nerc.com/pa/rrm/Resources/Pages/Conferences-and-Workshops.aspx

[201] The reference document can be found at the following location: http://www.nerc.com/comm/OC/ReferenceDocumentsDL/Risks_and_Mitigations_for_Losing_EMS_Functions_Reference_Document_20171212.pdf

The following are concluded in the reference document:

- According to the available data, although the number of events seems significant, it was observed that the actual EMS availability was 99.99 percent during the term (between October 2013 and April 2017).
- Software and telecommunications failure are major contributors to the loss of EMS functions.
- The loss of EMS functions has not directly led to the loss of generation, transmission lines, or customer load. However, it is important to note that the loss of EMS functionality has contributed to events because it limited system operators' capability to maintain situational awareness.
- Mitigating actions have been effective during EMS events to manage risks within acceptable levels.

Event Analysis Process

Since its initial implementation in October of 2010, the EA Process has collected 1,080 qualified events and yielded 134 lessons learned, including nine published in 2017.[202]

The first step in the ERO EA Process is BPS awareness and the monitoring of the BPS for reliability incidents. BPS conditions provide recognizable signatures through automated tools, mandatory reports, voluntary information sharing, and third-party publicly available sources. The majority of these signatures represents conditions and occurrences that have little or no reliability impact. The ERO Enterprise monitors these signatures for significant occurrences and emerging risks and threats across North America.

Registered entities continue to share information and collaborate with the ERO well beyond any mandatory reporting in order to maintain and improve the overall reliability of the grid. Only a small subset of the reported occurrences rise to the level of a reportable event. **Table G.1** provides details on the 2017 mandatory reports and other information that is translated into products that address reportable events.

Table G.1: Situational Awareness Inputs for 2017 Products

Information Received	Products
Mandatory Reports	228 daily reports
153 DOE OE-417 Reports	14 special reports for significant occurrences
334 EOP-004-3 Reports	
0 EOP-002-3 Reports (Retired in 2017)	2 reliability-related NERC Advisory (Level 1) Alerts
Other Information[203]	683 new EA entries (known as "Notifications" and associated with the 181 qualified events and the 310 nonqualified occurrences)
3,136 Intelligent Alarms Notifications	2 reliability-related NERC Recommendation (Level 2) Alerts
4,238 FNet/Genscape Notifications and 250 Daily Summaries	
357 Peak Reliability Messages (PRM)	
1,506 RCIS Messages	
2,360 Space Weather Predictive Center Alerts	
1,075 Assorted US Government Products	
5,689 Assorted Confidential, Proprietary, or Nonpublic Products	
2,205 Reliability Coordinator (RC) and ISO/RTO Notifications	

[202] The link to the NERC Lessons Learned page: http://www.nerc.com/pa/rrm/ea/Pages/Lessons-Learned.aspx
[203] Information sources are listed in no particular order or priority and not limited to these resources.

Reported Events

Using automated tools, mandatory reports, voluntary information sharing, and third-party publicly available sources, disturbances on the grid are categorized by the severity of their impact on the BPS. Table G.2 contains the count of reportable events. Additional information on the EA Process can be found on the NERC website.[204] As of January 1, 2017, a new EA Process version became effective.[205]

Table G.2: Events Analysis Event Summary—2017			
Event Category	**Count - Total**	**Count**	**Comments**
CAT 1	890	176	58—3 or more BPS facilities lost (1a) 7—BPS SPS/RAS Misoperation (1c) 1—Voltage reduction > 3% (1d) 1—Unintended Islanding (1e) 3—Unintended loss 1,000-1,999MW generation in ERCOT (1g) 106—EMS (1h)
CAT 2	165	3	2—Unintended loss of load (2f) 1—IROL Violation
CAT 3	18	0	
CAT 4	3	0	
CAT 5	4	2	Hurricane Harvey Hurricane Irma
Total CAT 1–5 Events	**1,080**	**181**	
Nonqualified Occurrences Reported	**2,844**	**310**	

Energy Management System Events

EMS is a system of computer-aided tools used by System Operators to monitor and control the BES. The EMS provides situational awareness and allows System Operators to make efficient and effective decisions.

The EA process is an effective tool for analyzing reported events and identifying risks; however, the distinct differences in EMS (1h events) and non-EMS events required the ERO Enterprise to evaluate the event separately.

The EMSWG analyzes the events and data collected about EMS outages and challenges. From the EA reports and the work of the EAS, supported by the EMSWG, NERC published multiple lessons learned specifically about EMS outages. The hard work and the active sharing from the EMSWG is attempting to reduce some of the residual risk associated with the potential loss of situational awareness and monitoring capability that comes with this type of event, and

[204] EA process in effect through the end of 2016: http://www.nerc.com/pa/rrm/ea/EAProgramDocumentLibrary/ERO_EAP_V3_final.pdf

[205] EA Process in effect as of January 1, 2017: http://www.nerc.com/pa/rrm/ea/ERO_EAP_Document/ERO_EAP_v3.1.pdf

they will continue to provide valuable information to the industry. The EMSWG published a reference document, *Risks and Mitigations for Losing EMS Functions Reference Document,*[206] to identify and discuss the risk(s) of losing EMS functions, analyze the causes of EMS events, and share mitigation strategies to reduce the risks.

Statistical Process Control

For trending of the number of events, NERC uses a standard Statistical Process Control method that results in control charts. The control chart provides control limits that are calculated by using an Individuals-Moving Range calculation. In this way, there is no unnecessary reaction to what would be considered normal variation in the numbers of events reported. This also helps determine what "normal" looks like when determining if any anomalies have occurred.

Figure G.1 is the control chart for the 1080 Qualified Events through 2017. In October 2013, when Version 2 of the EA Process introduced a new category of events, collectively known as Category 1h: Partial Loss of the EMS, occurrences that were not previously reported became visible and a shift in the control limits occurred. The control chart of events in 2017 shows the numbers of events were stable and predictable until a rash of EMS events in October (as shown in **Figure G.2** and **Figure G.3**). These multiple events were the result of the inability to resolve problems quickly with a newly installed (system change out) EMS system, and (for one entity) simply not identifying the cause of a problem until it had occurred multiple times.

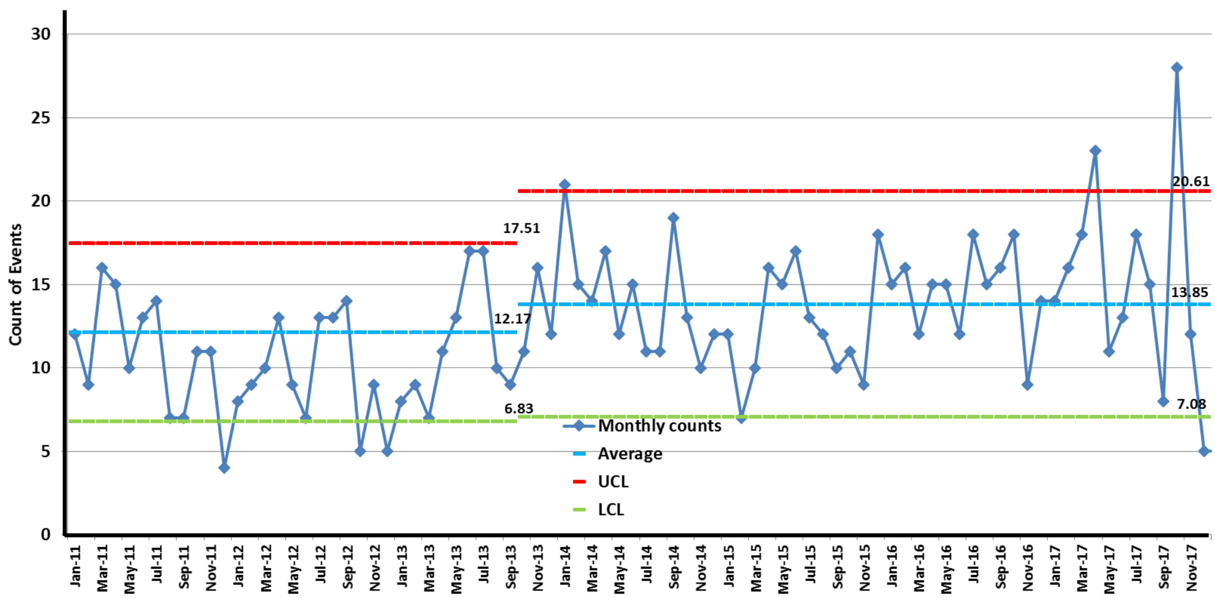


Figure G.1: Control Chart for the Number Events (Per Month) Over Time

[206] *Risks and Mitigations for Losing EMS Functions Reference Document* can be found at the following location: http://www.nerc.com/comm/OC/ReferenceDocumentsDL/Risks_and_Mitigations_for_Losing_EMS_Functions_Reference_Document_20171212.pdf

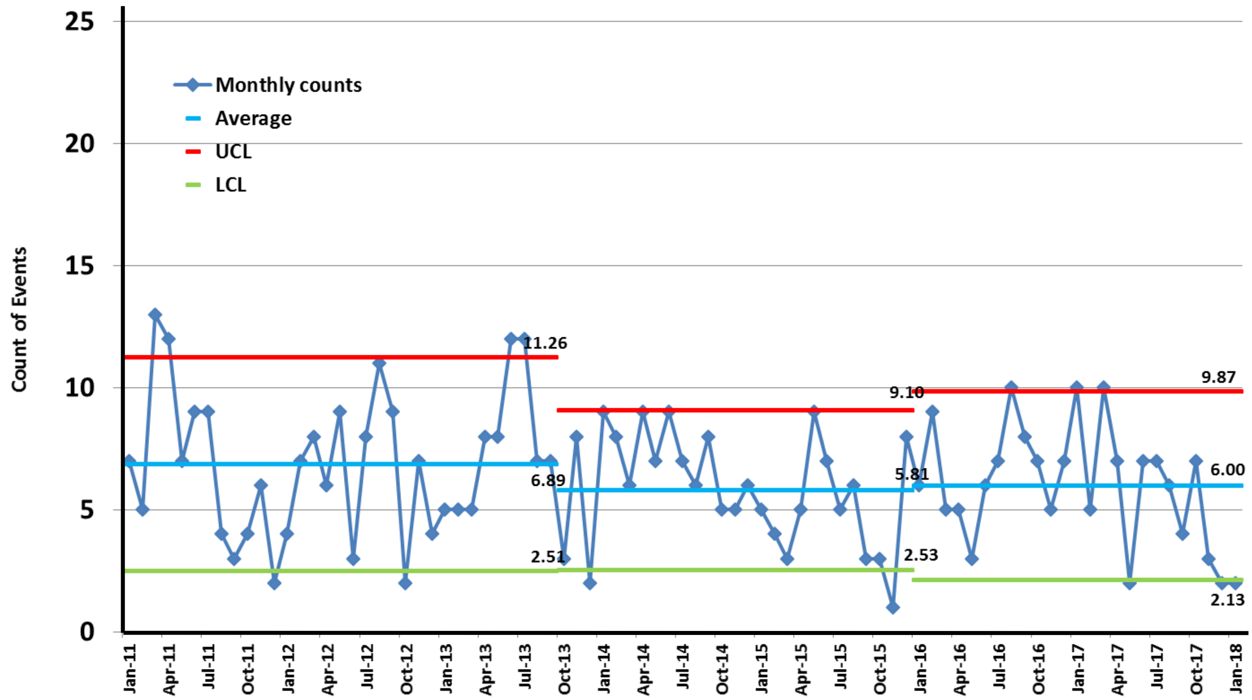


Figure G.2: Control Chart for the non-EMS Events (Per Month) Over Time

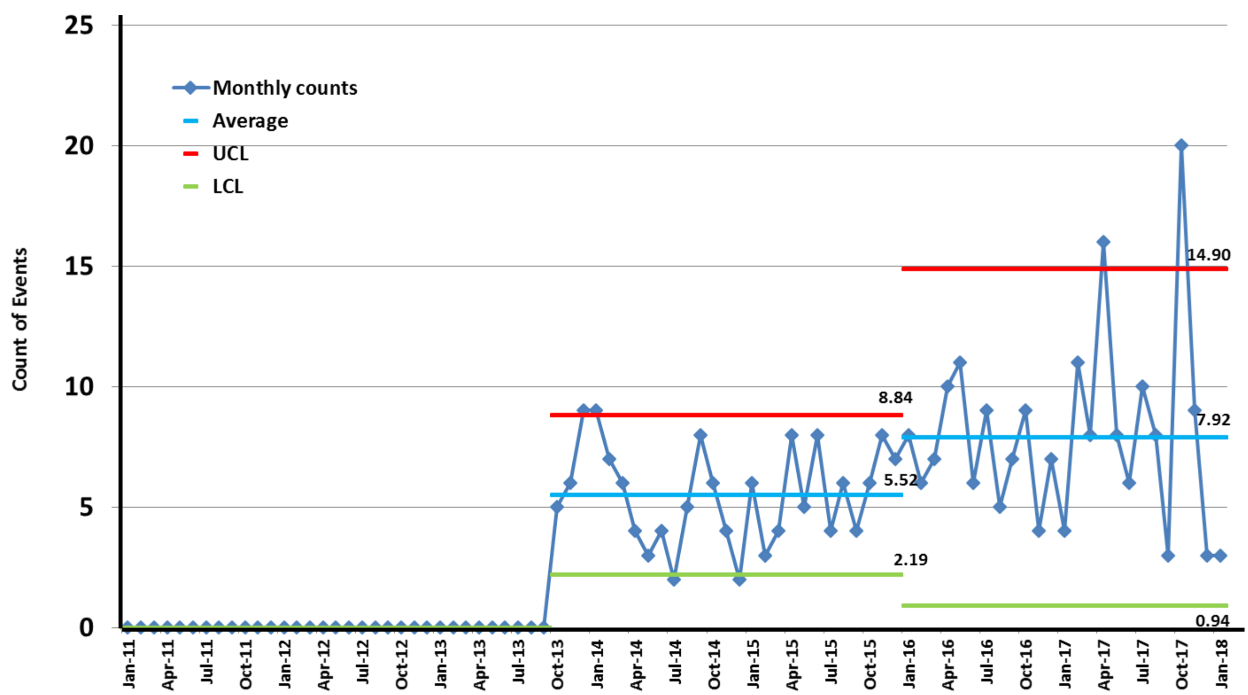
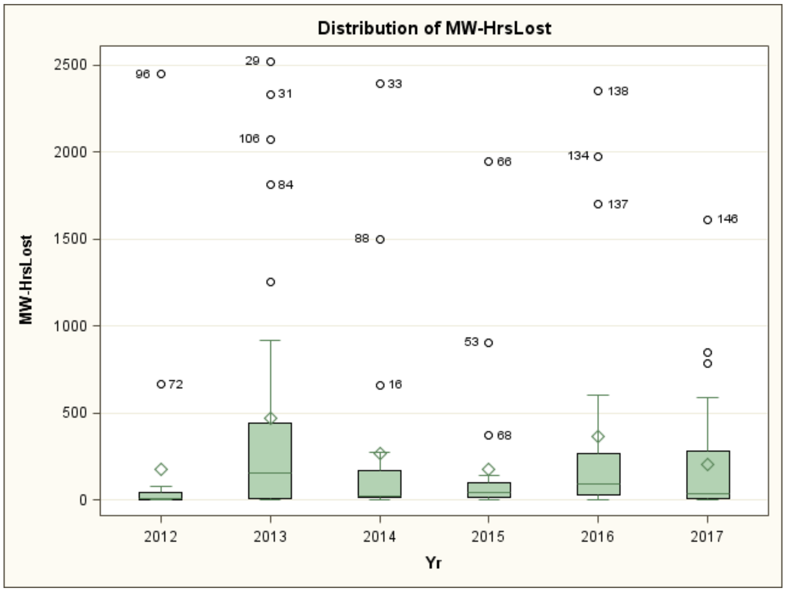


Figure G.3: Control Chart for the EMS Events (Per Month) Over Time

Reviewing the events for which firm load loss was reported, from 2012–2017 (excluding 2011, the first full year of reporting for a new process), the years appear to be similar (not statistically different, when analyzed), as shown in **Figure G.4**. If a load loss event occurs, looking at the full set of load loss events (151 events, out of 931 reported events, 2012–2017) the average outage is 288 MWh, but there is a great deal of variation (572MWh) in the sample. Therefore, a better evaluation is the median, which is 54 MWh.

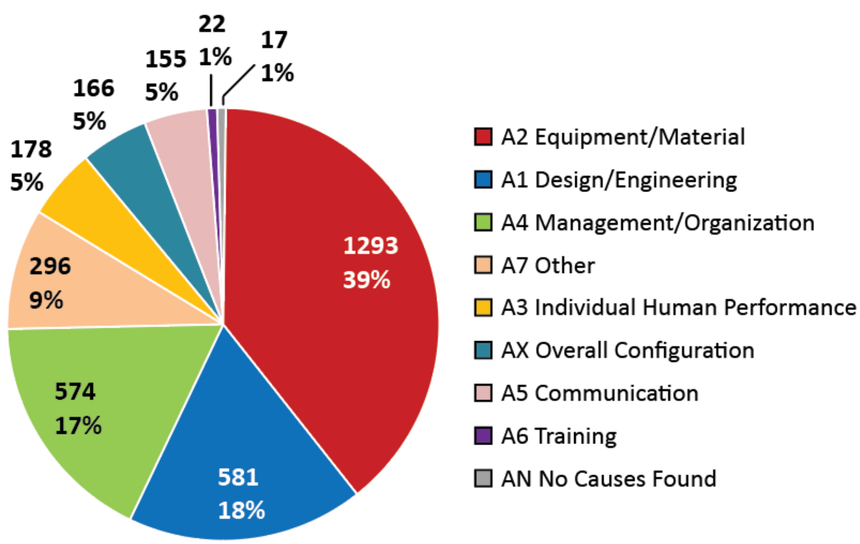


Year	Number of Events	MWh Lost	
		Mean	Std Dev
2012	19	179.04	569.84
2013	33	469.63	719.23
2014	21	269.32	594.55
2015	24	173.01	421.78
2016	24	363.53	657.42
2017	30	203.21	353.67

Figure G.4: Analysis of Firm Load Loss events by Year

Causes of Events

Through the EA Process, cause codes were assigned to 943 of the 1080 events, leading to 3,282 root or contributing cause codes being identified. The root cause of every event cannot be determined though many of the contributing causes or failed defenses can be established. **Figure G.5** shows the overall breakdown of the identified cause codes of events.



943 events have been cause coded with 2279 identified causes

Figure G.5: The Percentage of Contributing Causes by Major Category

Identification of these areas of concern allows for the prioritization and search for actionable threats to reliability. Following recommendations from the AC Substation Equipment Task Force (ACSETF) report, an addendum was developed for the types of information needed to support the EA Process when failed equipment is identified.[207] For example, NERC EA has created a template to collect additional information for substation equipment failures and will continue to analyze the data for common themes. NERC published a lessons learned in March 2017, *Slow Circuit Breaker Operation Due to Lubrication Issues*.[208]

Events with Misoperations and Substation Equipment Failure

Another analysis performed to provide information needed to support the EA process regarding failed equipment is the historical review of non-EMS events for those initiated or that had increased severity due to a Misoperation or Substation Equipment Failure. This analysis has been performed and outlined in NERC's annual *State of Reliability* reports since 2015, and the results are outlined in **Table G.3** and **Table G.4**.

Out of the 75 non-EMS events in 2017, a total of 39 of these events (52 percent) experienced one or more misoperations. In 38 of these events, the misoperations exacerbated the severity of the event. Of these 39 events with misoperations involved, 11 events (28 percent) experienced a breaker failure scheme misoperation or bus differential misoperation. These types of misoperations typically have a high impact on the BPS, particularly when they clear a straight bus with multiple facilities. The table also includes the total misoperations reported MIDAS

Table G.3: Historical Data for Protection System Misoperations Associated with Events

	2015	2016	2017	Total
Non-EMS Events	50	85	75	210
Events with Misoperations	34	55	39	128
Percentage of Non-EMS Events with Misoperations	68%	65%	52%	61%
Number of Breaker Failure/Bus Differential Misoperations	14	27	11	52
Total Reported Misoperations in MIDAS	1,492*	1,590	1,599	4,681
Percentage of Misoperations that rise to a Reportable Event	2.3%	3.4%	2.4%	2.7%

*2015 MIDAS misoperations count does not include WECC.

Of the 75 non-EMS events in 2017, a total of 26 (35 percent) experienced substation equipment failures. These substation equipment failures were either the initiating cause of the event or they subsequently increased the severity of the event. The substation equipment failures were as follows:

Table G.4: Historical Data for Substation Equipment Failures Associated with Events

	2015	2016	2017	Total
Non-EMS Events	50	85	75	210
Events with Substation Equipment Failures	12	29	26	67
Percentage of Non-EMS Events with Substation Equipment Failures	24%	34%	35%	32%
TADS outages initiated by Substation Equipment Failures	667	639	611	1,917
Percentage of Reportable SSE Events versus TADS SSE outages	1.8%	4.5%	4.3%	3.5%
Types of Substation Equipment Failures				
• Breaker Failures	6	10	13	29
▪ Slow or Stuck Breakers		8	10	18
• Relay/Protection System Failures		1	11	12

[207] The EA Process documents can be found at the following location: http://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx
[208] The lesson learned can be found at the following location: http://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20170301_Slow_Circuit_Breaker_Operation_Due_to_Lubrication_Issues.pdf

Table G.4: Historical Data for Substation Equipment Failures Associated with Events				
	2015	2016	2017	Total
• Current Transformer/Voltage Transformer Failures	1	2	4	7
• Circuit Switcher Failures		3	3	6
• Insulator Failures		1	3	4
• Surge Arrestor Failures	2	2		4
• Shunt Capacitor/Shunt Reactor Failures	2	2		4
• Other Equipment (Static Wire, Bushings, Transformers)	3	1	2	6

NERC EA began a new initiative in 2017, identifying Failure Modes and Mechanisms (FMM) as they apply to substation equipment failures. Detailed FMM diagrams for eight types of common substation equipment have been drafted and sent out for industry review. The top tiers on the diagrams will be the basis for equipment failure codes, similar in format to the current EA cause codes. The capture of data for the equipment FMM codes will be performed in the EA process using an enhanced Failed Substation Equipment Addendum. These new codes will be used in future years for finding patterns in and trending physical causes of equipment failures and provide the data detail that was missing in the ACSETF effort.[209]

Asset management and maintenance was identified as a low-priority risk by the Reliability Issues Steering Committee.[210] Low-priority risks do not mean that possible reliability impact is small but rather the profiles are understood with clearly identifiable steps that can be taken to manage risk. The failure to properly commission, operate, maintain, and upgrade BES assets could result in more frequent or more severe outages as equipment failures initiate or exacerbate events.

A related area, Configuration Management, was highlighted by an event where digital controls were not updated in line with physical plant changes over time. This was described in lessons learned: *Generator Trip While Performing Frequency Response*.[211]

A similar identification of trends can be observed in the large contribution of “less than adequate” or “needs improvement” cause factors in management and organizational practices that have been seen to contribute to events. Many of these threats can be identified and shared with the industry for awareness. For example, see **Figure G.6** where the identification of some of the challenges to organization and management effectiveness are identified.

---

[209] The ACSETF report can be found at the following location:
https://www.nerc.com/comm/PC/AC%20Substation%20Equipment%20Task%20Force%20ACSETF/Final_ACSETF_Report.pdf

[210] The RISC report can be found at the following location:
http://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO_Reliability_Risk_Priorities_RISC_Reccommendations_Board_Approved_Nov_2016.pdf

[211] The lesson learned can be found at the following location:
http://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20170601_Generator_Trip_While_Performing_Frequency_Response.pdf

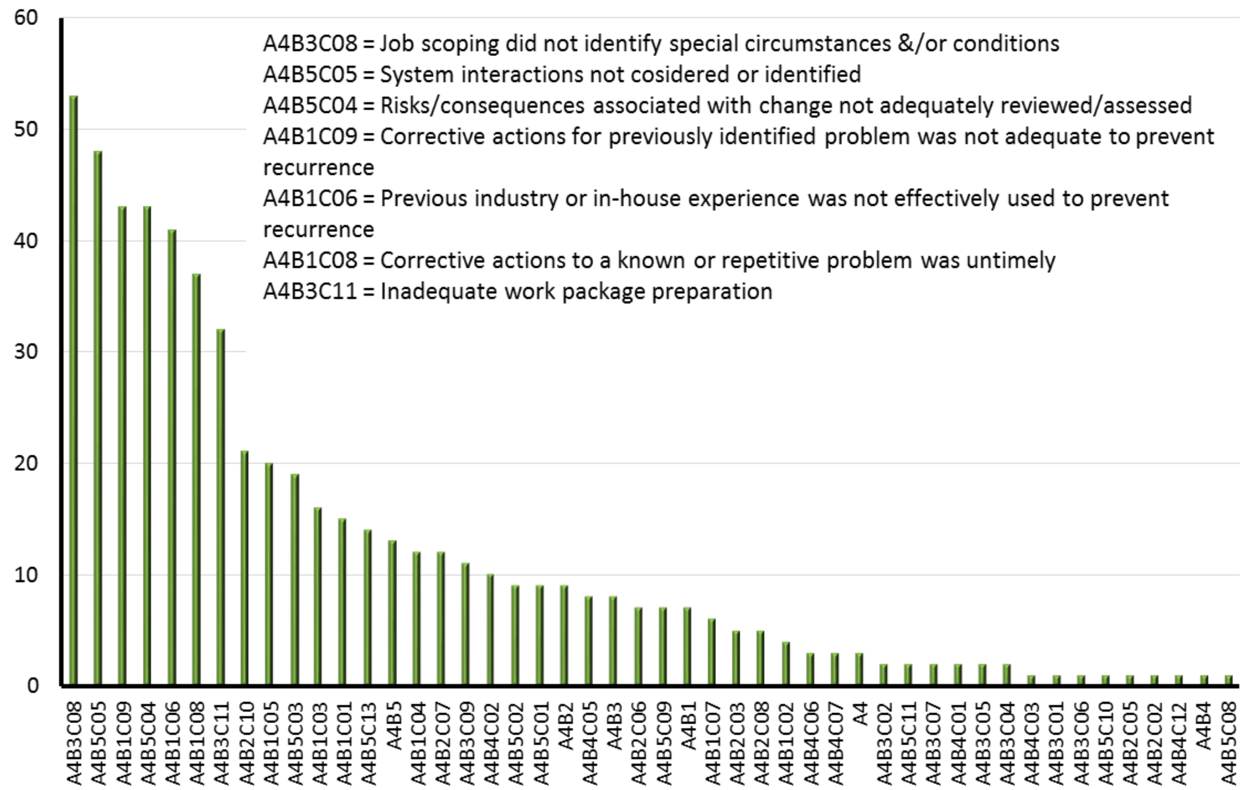


Figure G.6: Management or Organization Challenges Contributing to an Event

Major Initiatives in Event Analysis

Human Performance

EA has identified work force capability and HP challenges as possible threats to reliability. HP and a skilled workforce was also identified as a priority by the RISC. Workforce capability and HP is a broad topic but can be divided into management, team, and individual levels. NERC held its sixth annual HP conference in Atlanta, Improving Human Performance and Increasing Reliability on the BPS, at the end of March 2017.[212] Equipment Failure Modes and Mechanisms were introduced as a new topic for cause analysis training in 2017.

NERC continues to conduct cause analysis training with staff from the Regions and registered entities. As of December 2017, personnel from all eight Regions, and approximately 1,403 people (1,476 class students, if you don't eliminate duplicates, where a person has attended more than once) from 322 different registered entities have received cause analysis training, roughly 11,000 hours of training.

NERC hosted its fifth annual Monitoring and Situational Awareness Conference on October 3–4, 2017, at the Georgia Power Company Corporate Headquarters in Atlanta, GA. The conference brought together more than 120 operations and EMS experts from registered entities, government regulators, and a variety of vendors and consultants from all Regions and Canada. The focus was on energy management systems quality, including modeling and real-time assessments. William Ball, chief transmission officer and executive vice president of Southern Company, delivered the keynote presentation and spoke on the importance of continued development of elegant EMS tools and systems with built-in security and resiliency to face the challenges of the future. Conference highlights include a presentation

[212] HP Conference information can be found at the following location: http://www.nerc.com/pa/rrm/hp/Pages/default.aspx

on the Modeling and Real-Time Assessment Tool, a presentation of lessons learned from recent EMS outages, and several panel discussions led by industry experts and EMS vendors. The conference presentations are available on the NERC website.[213]

2017–2018 Winter Weather Review

NERC scheduled and recorded a Winter Preparation for Severe Weather Events webinar originally scheduled for September 7, 2017. Due to the large number of entities impacted by Hurricanes Harvey and Irma, the webinar was postponed to support continuing recovery efforts. The presentation and recorded streaming webinar were turned into a multimedia presentation and posted on the NERC website to allow industry stakeholders to review the webinar at their convenience.[214]

The Winter Preparation for Severe Weather Events webinar provided the industry reports and material in preparation for the upcoming for Winter 2017–2018. The objective of the webinar was to remind industry of the need to continue to appropriately prepare for the upcoming winter weather forecasts. The webinar highlighted the recently revised *Reliability Guideline: Generating Unit Winter Weather Readiness* that was approved by the OC and posted on Reliability Guideline webpage.[215] Information was shared from 2017–2018 Winter Reliability Assessment. The winter preparation materials can be found on NERC's website.[216]

2017 Lessons Learned

Sometimes events of interest do not qualify for the EA Process Category 1–5 classification. Some non-qualifying occurrences were used in generating two significant lessons learned in 2017:

- *Loss of Wind Turbines due to Transient Voltage Disturbances on the Bulk Transmission System:*[217] reviewed a significant event from South Australia and examined some similar events in Texas for common issues and lessons learned.
- *Dispatched Reduction in Generation Output Causes Frequency Deviation:*[218] discusses an event in which marketing software drove generation down significantly, requiring operator intervention.

Hurricane Harvey

Hurricane Harvey made landfall as Category 4 hurricane on August 25, 2017, at 10:00 pm Central Daylight Time (CDT), with winds in excess of 130 MPH and record-breaking storm surge. The storm inflicted massive disruptions on the electric power system in Corpus Christi, Houston/Galveston, and Beaumont/Port Arthur areas of Texas. As Harvey moved inland, the storm stalled, causing excessive rain (40–50 inches) in parts of southeastern Texas, flooding large areas of Houston and inland as far as Austin.

---

[213] Conference presentations can be found at the following location: http://www.nerc.com/pa/rrm/Resources/Pages/Conferences-and-Workshops.aspx

[214] The webinar presentation can be found at the following location: https://www.nerc.com/pa/rrm/Webinars%20DL/NERC_Winter_Prep_Webinar_20170907.pdf; for more training and outreach videos on this and similar topics, see https://www.nerc.com/pa/rrm/Pages/Webinars.aspx

[215] The reliability guideline can be found at the following location: https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx

[216] The Cold Weather Training Materials can be found at the following location: http://www.nerc.com/pa/rrm/ea/Pages/Cold-Weather-Training-Materials.aspx

[217] The lesson learned can be found at the following location: http://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20170701_Loss_of_Wind_Turbines_due_to_Transient_Voltage_Disturbances.pdf

[218] The lesson learned can be found at the following location: http://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20170401_Dispatched_Reduction_in_Generation_Output_Causes_Frequency_Deviation.pdf

Preparation for the storm included the continual monitoring weather developments and the ongoing communications, including the exchanging of projections between NERC REs, Independent System Operators (ISOs), and the potentially affected registered entities. Lines and generators on maintenance were returned to service. Unit commitment and generator dispatch decisions were made to posture the system to withstand the impact of the storm and recover promptly afterward. Equipment status and capabilities were confirmed. TOs and Transmission Operators (TOPs) reported several local load networks were preemptively shut down in a controlled fashion to prevent damage to equipment and speed restoration. GOs reported that fossil-fueled and wind generating units in the path of the storm were shut down or evacuated.

Hundreds of high-voltage transmission lines, including seven 345-kV lines and more than 200 138-kV and 69-kV lines experienced storm-related forced outages. Most of these transmission facilities were located in the immediate area along the Gulf Coast of Texas where the hurricane made landfall, but some were in the Houston area, where transmission facilities were damaged by flooding.

Wind turbines are commonly shut off at wind speeds of about 55 MPH and higher to protect them from damage, and several turbines in ERCOT's coastal area were shut off while high winds from the storm passed. ERCOT's southern area saw increased levels of wind generation during the four days after landfall when wind speeds were relatively high but below 55 MPH.

The recovery effort was initiated by the transmission, distribution, and generation asset owners when it was safe for crews to enter the impacted areas. The initial recovery consisted of inspections and asset assessments. The equipment owners' initial assessments were greatly hampered by flooding and the unavailability of roads. The priority, as communicated by the utilities, was to the restore transmission assets to generating facilities needed for distribution load recovery. While there was sufficient generation capacity available to meet the load as restoration progressed, there were some cases where customer restoration was hindered by local area transmission outages. This includes instances in which substations were so severely damaged that they did not allow power to be delivered to the distribution system.

Most entities returned 95 percent or more of their customers to service between August 26, 2017, and September 2, 2017. Due to flooding in Houston, one of the hardest hit areas, power restoration was not completed until September 8, 2017.

The extensive, and longer-than anticipated, flooding and storm debris presented many challenges to the recovery process. Utilities overcame these issues by using approaches that have not been used in previous weather-related events:

- Unmanned aerial drones were used to perform damage assessments on inaccessible transmission and distribution lines
- Amphibious vehicles and airboats were used to access flooded areas

The following good industry practices were identified for Hurricane Harvey:

- Pre-staging of equipment outside of flood-prone areas made the restoration process more effective.
- Collaborative efforts with other Texas utilities, ERCOT, and regional mutual assistance groups worked well during this event. It is important to touch base with contract resources and adjacent utilities prior to the storm event to establish communication chains.
- Establishment of contacts with State and Local Emergency Management coordinators and key stakeholders was key in maintaining continuity and prioritization of the recovery effort.

- Use of advanced meters and intelligent grid devices was effective to pinpoint outages, operate equipment remotely, and increase efficiency.
- Use of Facebook, Twitter, Power Alert Service, and text messages was effective in keeping customers informed.
- Use of utility-directed aerial drones were effective to assess damage, evaluate work conditions, and enable real-time situational awareness. Infrared capabilities helped identify equipment that needed further inspection.
- Preventive actions taken, such as pausing wind turbines prior to experiencing high wind cut-out speeds helped avoid individual turbine faults, stop yawing, and allow the turbines to continuously pitch into the wind as long as possible.
- The use of detailed pictures of transmission structures facilitated a rapid design response allowing materials to be marshalled and a high-level scope developed to mobilize construction resources.
- ERCOT's Forced Outage Detector application was instrumental in helping operators and support engineers identify undocumented outages.
- ERCOT's Grid Applications Support Operations Engineers were able to utilize the State Estimator Statistical application to quickly identify MW/MVAR mismatches and topology issues.
- Having on-site Engineering Support from the Advanced Network Analysis and Operations Support departments ensured quick evaluations of issues with ERCOT applications.

Hurricane Irma

Hurricane Irma made initial landfall in the United States on Cudjoe Key (20 miles north of Key West) in the Florida Keys at 9:34 am EST on September 10, 2017, as a Category 4 storm with sustained winds of 130 mph. Later that same day Irma weakened to a Category 3 storm with sustained winds of 115 mph and made a second landfall near Marco Island in southwest Florida at 3:35 pm EDT. Irma moved quickly northward, just inland from the west coast of Florida on September 10 and 11. As Irma hit Florida, tropical storm force winds extended outward up to 400 miles from the center, and hurricane force winds extended up to 80 miles. Hurricane force wind gusts (i.e., 74 mph or more) were reported along much of the east coast of Florida, from Jacksonville to Miami. In addition to the prolonged periods of heavy rain and strong winds, storm surge flooding also occurred well away from the storm center, including the Jacksonville area, where strong and persistent onshore winds had been occurring for days before Irma's center made its closest approach.

When Hurricane Irma reached northwest Florida (on the morning of September 11), the wind gusts were generally in the 45 to 60 mph range. Dry southwest winds made the storm system irregular and conditions improved rapidly once the storm center passed over Florida. Irma weakened to a tropical storm in south Georgia in the afternoon of September 11 and was downgraded to a tropical depression while moving north across central Georgia in the evening.

As Hurricane Irma approached Florida, NERC, REs, and the potentially affected registered entities continually monitored weather developments and exchanged information. Prior to the storm's landfall the RC initiated daily calls with the TOPs and BAs in the FRCC Region. The TOPs and BAs reported that the lines and generators that were previously shut down for maintenance were returned to service. The BAs reported that several generating units (approximately 2,500 MW) were placed into preemptive shutdown condition to further protect assets from long-term damage due the high winds and the predicted storm surge.

Over 100 high-voltage transmission lines, including one 500 kV line, a total of 48 230 kV lines and 69 138 kV lines and 115 kV lines experienced storm-related forced outages. Several transmission lines (two 500 kV lines and five 230 kV

Lines) were shut down in a controlled fashion to address high voltage conditions. Numerous generation facilities (approximately 6,500 MW) were shut down in a controlled fashion to minimize storm related damage. A total of 3,355 MW of generation experienced storm-related forced outages, primarily from high winds, sustained storm surges, and as a result of transmission line forced outages. Customer outages exceeded six million.

The recovery effort was initiated by the transmission, distribution, and generation registered entities. The initial recovery consisted of inspections and asset assessments. The registered entities initial assessments were greatly hampered by storm surge, storm damage, and the lack of accessibility into deep right-of-ways due to localized flooding and storm debris. The priority, as communicated by the RC and the TOPs, was to the restore transmission assets to generating facilities needed for distribution load recovery. While there was sufficient generation capacity available to meet the load as restoration progressed, there were some cases where customer restoration was hindered by local area transmission and distribution outages.

Most entities returned 95 percent of their customers to service between September 12 and 15, 2017. Areas along the southern and eastern coastlines, which were the areas experiencing the largest sustained storm surges, reported having prolonged restoration times beyond September 15, 2017.

Due to the unprecedented number of pole-mounted distribution transformers damaged, mutual aid and other non-conventional means were utilized to acquire enough units to complete restoration. Additionally, the extensive, and longer-than anticipated, storm surge along with storm debris presented many challenges to the recovery process.

The registered entities overcame these issues by using approaches that have not been used in previous weather-related events occurring in the Region:

- Unmanned aerial drones were used to perform damage assessments on inaccessible transmission and distribution lines.
- Amphibious vehicles and airboats were used to access flooded areas.
- Innovative Damage Assessment Process utilizing a mobile application in which damage can be reported: sent back to the office (automatically creating a map) and then issued to line workers in real time.

The following good industry practices were identified for Hurricane Irma:

- Pre-staging of equipment outside of hurricane's projected path made the restoration process more effective.
- Preemptively removing generation prior to the hurricane making landfall protected equipment from damage and significantly shortened restoration times.
- Continuous communications between the RC, TOPs, and BAs in the FRCC Region ensured coordinated efforts throughout the event and the subsequent restoration.
- Advanced meters and intelligent grid devices were effective to pinpoint outages, operate equipment remotely, and increase efficiency.
- Installation of flood monitors in substations located within the 100 year flood plain resulted in the ability to de-energize substations at notification of rising water and avoiding catastrophic damage to sensitive station equipment.
- Leveraging social media enabled first ever communications with Facebook live and other platforms providing customers with the most current outage and restoration information.
- Aerial drones were effective to assess damage, evaluate work conditions, and enable real-time situational awareness. Infrared capabilities helped identify equipment that needed further inspection.

- Hardening and resiliency programs implemented prior to the hurricane significantly reduced the storm damage sustained due to high winds and storm surge.

Summary

The EA Process continues to provide valuable information for the industry to address potential threats or vulnerabilities to the reliability of the BPS. The ability to identify specific pieces of equipment that are potential threats as well as emerging trends that increase risk to the system illustrates the value of the EA Process. These outcomes, coupled with the ability to actively share the information through lessons learned, webinars, technical conferences, and related venues, remain critical to the sustainment of high reliability.

Appendix H: Abbreviations Used in this Report

Table H.1: Abbreviations Used in this Report	
Abbreviation/Acronym	**Name**
ACSETF	AC Substation Equipment Task Force
ALR	Adequate Level of Reliability
APT	advanced persistent threat
BA	Balancing Authority
BES	Bulk Electric System
Board	Board of Trustees
BPS	bulk power system
CAP	Corrective Action Plan
CDM	common or dependent mode
CIP	Critical Infrastructure Protection
CIPC	Critical Infrastructure Protection Committee
CMEP	Compliance Monitoring and Enforcement Program
CP	Compliance Process
CRISP	Cyber Security Risk Information Sharing Program
DADS	Demand Availability Data System
DADSWG	Demand Availability Data System Working Group
DCS	disturbance control standard
DGL	daily generation loss
DHS	Department of Homeland Security
DOE	Department of Energy
DRI	data reporting instruction
DTL	daily transmission loss
EEA	Energy Emergency Alert
EACMS	Electronic Access Control or Monitoring Systems
EI	Eastern Interconnection
E-ISAC	Electricity Information Sharing and Analysis Center
ERO	Electric Reliability Organization
ERS	essential reliability services
FBI	Federal Bureau of Investigation
FERC	Federal Energy Regulatory Commission
FMM	Failure Modes and Mechanisms
FP&L	Florida Power & Light
FPSC	Florida Public Service Commission
GADS	Generation Availability Data System
GO	Generator Owner
HE	Hour Ending
HP	Human Performance
Hz	hertz
ICC	initiating cause codes

Table H.1: Abbreviations Used in this Report

Abbreviation/Acronym	Name
IFRM	Interconnection Frequency Response Performance Measure
IFRO	interconnection frequency response obligation
IROL	Interconnection Reliability Operating Limit
IRPTF	Inverter-based Resource Performance Task Force
JAR	Joint Analysis Report
mHz	mega hertz
MIDAS	Misoperations Information Data Analysis System
MSSC	most severe single contingency
MVA	megavolt ampere
MW	megawatt
NAGF	North American Generator Forum
NATF	North American Transmission Forum
NERC	North American Electric Reliability Corporation
OC	Operating Committee
PAS	Performance Analysis Subcommittee
PC	Planning Committee
PCS	Protection and Controls Subcommittee
PV	photovoltaic
QI	Quebec Interconnection
RAS	remedial action scheme
RC	Reliability Coordinator
RCC	Resource Contingency Criteria
RE	Regional Entity
RS	Resources Subcommittee
RSG	reserve sharing group
RWG	Reserves Working Group
SAMS	Systems Analysis and Modeling Subcommittee
SAR	Standard Authorization Request
SC	Standards Committee
SCC	sustained cause codes
SIS	Safety Instrumented Systems
SMB	Server Message Blok
SOL	System Operating Limit
SOR	State of Reliability
SPCS	System Protection Control Subcommittee
SPS	special protection systems
SPWG	System Protection Working Group
SRI	Severity Risk Index
SWMG	Security Metrics Working Group
TADS	Transmission Availability Data System
TADSWG	Transmission Availability Data System Working Group

Table H.1: Abbreviations Used in this Report	
Abbreviation/Acronym	**Name**
TI	Texas Interconnection
TLP	Threat Level Protocol
TOP	Transmission Operators
TOS	Transmission Outage Severity
TO	Transmission Owner
UFLS	under-frequency load shed
WEFOR	weighted equivalent forced outage rate
WI	Western Interconnection

Appendix I: Contributions

NERC would like to express its appreciation to the many people who provided technical support and identified areas for improvement.

Table I.1: NERC Industry Group Acknowledgements	
Group	**Officers**
Planning Committee	Chair: Brian Evans-Mongeon, Utility Services, Inc. Vice Chair: Noman Williams, GridLiance
Operating Committee	Chair: Lloyd Linke, WAPA Vice Chair: David Zwergel, MISO
Critical Infrastructure Protection Committee	Chair: Marc Child, Great River Energy Vice Chair: David Revill, GTC Vice Chair: David Grubbs, City of Garland
Bulk Electric System Security Metrics Working Group	Chair: Larry Bugh, Reliability*First*
Performance Analysis Subcommittee	Chair: Paul Kure, Reliability*First* Vice Chair: Maggie Peacock, WECC
Demand Response Availability Data System Working Group	James McAnany, PJM
Events Analysis Subcommittee	Chair: Rich Hydzik, Avista Corporation Vice Chair: Vinit Gupta, ITC
Generation Availability Data System Working Group	Chair: Leeth DePriest, Southern Company Vice Chair: Steve Wenke, Avista Corporation Additional Support: Ron Fluegge, GADSOS
Transmission Availability Data System Working Group	Chair: Kurt Weisman, ATC Vice Chair: Brian Starling, Dominion
Resources Subcommittee	Chair: Tom Pruitt, Duke Energy Vice Chair: Sandip Sharma, ERCOT
Operating Reliability Subcommittee	Chair: Dave Devereaux, IESO Vice Chair: Chris Pilong, PJM
Frequency Working Group	Chair: Danielle Croop, PJM
Reliability Assessment Subcommittee	Chair: Tim Fryfogle, Reliability First Vice Chair: Lewis DeLarosa, Texas RE
System Protection and Control Subcommittee	Chair: Mark Gutzmann, Xcel Energy Vice Chair: Jeff Iler, AEP
Compliance and Certification Committee	Chair: Patricia E. Metro, NRECA Vice Chair: Jennifer Flandermeyer, KCP&L

Table I.2: NERC Staff	
Name	**Title**
Mark Lauby	Senior Vice President and Chief Reliability Officer
James Merlo	Vice President and Director, Reliability Risk Management
David Till	Senior Manager, Performance Analysis
Brad Gordon	Manager, Performance Analysis, Balancing and Frequency Control
Svetlana Ekisheva	Senior Manager, Statistical Analysis and Outreach
Jack Norris	Engineer, Performance Analysis

Table I.2: NERC Staff	
Name	**Title**
Margaret Pate	Reliability Risk Control Liaison, Performance Analysis
Donna Pratt	Manager, Performance Analysis, Data Analytics
Elsa Prince	Principal Advisor, Performance Analysis
Lee Thaubald	Technical Analyst, Performance Analysis
Matthew Varghese	Senior Engineer, Performance Analysis
Rich Bauer	Associate Director, Event Analysis
Laura Brown	Director, Programs and Engagement
Terry Campbell	Manager of Technical Publications
Alex Carlson	Senior Technical Publications Specialist
Sam Chanoski	Director, Threat Intelligence and Countermeasures
Thomas Coleman	Director, Reliability Assessments
Bob Cummings	Senior Director, Engineering and Reliability Initiatives
Howard Gugel	Senior Director, Standards
Aaron Hornick	Senior Enforcement Analyst, Enforcement
Ed Kichline	Senior Counsel and Director of Enforcement
Mani Mardhekar	Senior Engineer, Bulk Power System Awareness
Kimberly Mielcarek	Senior Director of Communications
John Moura	Director of Reliability Assessment and Systems Analysis
Steve Noess	Director of Compliance Assurance and Program Oversight
Ryan Quint	Senior Manager, System Analysis
Janet Sena	Senior Vice-President, Policy and External Affairs
Sandy Shiflett	Senior Program Specialist
Jule Tate	Associate Director, Events Analysis
Ganesh Velummylum	Senior Manager, System Analysis
Warren Wu	Senior Engineer of Balancing Operations and Analysis