NERC

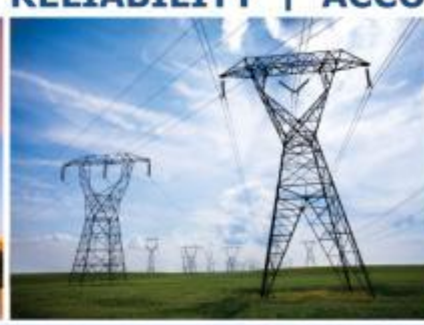
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

State of Reliability 2013

May 2013

RELIABILITY | ACCOUNTABILITY



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Preface

The North American Electric Reliability Corporation (NERC) has prepared the following assessment in accordance with the Energy Policy Act of 2005, in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the bulk power system of North America.[1,2] NERC operates under similar obligations in many Canadian provinces, as well as a portion of Baja California Norte, México.

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to evaluate reliability of the bulk power system in North America. NERC develops and enforces reliability standards; assesses reliability annually via a 10-year assessment, and winter and summer seasonal assessments; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the Electric Reliability Organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[3]

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

Note: The highlighted area between SPP and SERC denotes overlapping Regional area boundaries. For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into several assessment areas within the eight Regional Entity boundaries, as shown in the map and corresponding table above. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, México.

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[1] H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005: http://www.gpo.gov/fdsys/pkg/BILLS-109hr6enr/pdf/BILLS-109hr6enr.pdf

[2] The NERC Rules of Procedure, Section 800, further detail the Objectives, Scope, Data and Information requirements, and Reliability Assessment Process requiring annual seasonal and long-term reliability assessments.

[3] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the “electric reliability organization” under Alberta’s Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l’énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. Nova Scotia and British Columbia also have frameworks in place for reliability standards to become mandatory and enforceable.

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Notice

Many datasets and analyses conducted in the *State of Reliability 2013* report are still in an early stage. The defined characteristics of an Adequate Level of Reliability are currently being reviewed and refined. This report presents metrics and trends derived from the data available at the time of publication and may be modified pending further review and analysis.

Executive Summary

Introduction

The North American Electric Reliability Corporation (NERC) *State of Reliability 2013* report represents NERC's independent view of ongoing bulk power system (BPS) trends to objectively analyze its state of reliability based on metric information and provide an integrated view of reliability performance. The key findings and recommendations serve as technical input to NERC's Reliability Standards project prioritization, compliance process improvement, event analysis, reliability assessment, and critical infrastructure protection. This analysis of BPS performance not only provides an industry reference for historical BPS reliability, it also offers analytical insights toward industry action and enables the identification and prioritization of specific steps that can be implemented in order to reduce and manage risks to reliability.

The 2013 report further advances risk issue identification methods—in a consistent and predictable manner—that have the potential to improve reliability and promote efficiency. The methods, which are supported by data, extend traditional deterministic approaches by:

- Considering a broader set of factors that have a negative effect on reliability, and
- Providing a logical means for prioritizing these factors based on risk significance.

This report was prepared by NERC staff and the NERC Performance Analysis Subcommittee[4] (PAS) under the direction of the Operating and Planning Committees, in collaboration with many stakeholder groups,[5] including:

- Operating Committee (OC):
  - Resources Subcommittee (RS)
  - Frequency Working Group (FWG)
  - Event Analysis Subcommittee (EAS)
  - Operating Reliability Subcommittee (ORS)
- Planning Committee (PC)
  - Reliability Assessment Subcommittee (RAS)
  - System Protection and Control Subcommittee (SPCS)
  - Protection System Misoperations Task Force (PSMTF)
  - Transmission Availability Data System Working Group (TADSWG)
  - Generating Availability Data System Working Group (GADSWG)
  - Demand Response Availability Data System Working Group (DADSWG)
  - Spare Equipment Database Working Group (SEDWG)
- Compliance and Certification Committee (CCC)

Since the initial 2010 annual reliability metrics report,[6] the PAS (formerly the Reliability Metrics Working Group)[7] has enhanced data collection and trend analysis for 18 reliability indicators[8] through NERC's voluntary or mandatory data requests. This year's report also includes detailed trend analysis of frequency response and protection system misoperations metrics.

[4] Performance Analysis Subcommittee (PAS), http://www.nerc.com/filez/pas.html
[5] NERC Committees, http://www.nerc.com/page.php?cid=1|117
[6] 2010 Annual Report on Bulk Power System Reliability Metrics, June 2010, http://www.nerc.com/docs/pc/rmwg/RMWG_AnnualReport6.1.pdf
[7] Reliability Metrics Working Group (RMWG), http://www.nerc.com/filez/rmwg.html
[8] Reliability Performance Metric, http://www.nerc.com/filez/Approved_Metrics.html

2013 State of Reliability

The BPS remains adequately reliable, as reflected in metrics that show no significant upward or downward trends for the 2008–2012 period. The severity risk index (SRI) [9] and 18 metrics that measure characteristics of adequate level of reliability (ALR) indicate that the BPS is within acceptable ALR conditions. The system achieves an ALR when it meets the following six characteristics:[10]

1. Controlled to stay within acceptable limits during normal conditions;
2. Performs acceptably after credible contingencies;
3. Limits the impact and scope of instability and cascading outages when they occur;
4. Protects facilities from unacceptable damage by operating them within facility ratings;
5. Promptly restores integrity if it is lost; and
6. Has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.

The definition of ALR is being improved[11] to enable the analysis of trends, risk control measures, and continued understanding of the factors that indicate the overall level of reliability. Further, the cause-effect model will be expanded to include deeper insights of underlying factors that affect reliability.

Bulk Power System Reliability Remains Adequate

From 2008 through 2012, excluding the events caused by factors external to the performance of the transmission system (e.g., Weather-initiated events), the number of BPS transmission-related events resulting in loss of firm load decreased from an average of nine in 2008–2011 to two in 2012. The daily severity risk index (SRI)[12] value, which measures risk impact or "stress" from events resulting in the loss of transmission, generation, and load, has been stable from 2008 to 2012. Including weather-initiated events, 2012 had three high-stress days (an SRI greater than 5.0): October 29 and 30 during Hurricane Sandy, and June 29 during Thunderstorm Derecho. This is within the range of zero to seven days experienced during 2008–2011.

Risk from Standards Violations Reduced

NERC has continuously enhanced the Compliance Monitoring and Enforcement Program since 2008, providing more certainty on actions, outcomes, and reliability consequences. As of the end of 2012, 5,115 confirmed violations were processed for the period beginning June 18, 2007. Of these violations, 85 percent had minimal impact to reliability, 13 percent had moderate impact, and 2 percent had serious impact. The five-year assessment of the Key Compliance Monitoring Index[13] (KCMI) indicates that the risk to BPS reliability based on the number of violations of NERC's Standards has trended lower from 2008 to 2012.

Transmission Availability Performance is High

As shown from the transmission performance data, the availability of the bulk transmission system continues to remain high with no statistically significant change from 2008 to 2012. The ac circuit availability is above 97 percent, and the transformer availability is above 96 percent for the 2010–2012 period.

Frequency Response is Steady with No Deterioration

As recommended in the *2012 State of Reliability* report,[14] statistical tests have been applied to interconnection frequency response datasets. Additional analyses on time of year, load levels, and other attributes were conducted. From 2009 to 2012, the Eastern Interconnection (EI), ERCOT Interconnection, Québec Interconnection (QI), and Western Interconnection

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[9] SRI is a "stress" index, measuring risk impact from events resulting in transmission loss, generation loss, and load loss.
[10] Definition of "Adequate Level of Reliability", Dec 2007, http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC- mtgs.pdf
[11] Adequate Level of Reliability Task Force (ALRTF), http://www.nerc.com/filez/alrtf.html
[12] Integrated Risk Assessment Approach – Refinement to Severity Risk Index, May 6, 2011, http://www.nerc.com/docs/pc/rmwg/pas/index_team/SRI_Equation_Refinement_May6_2011.pdf
[13] Standards Driven Index, 06/06/2012, http://www.nerc.com/docs/pc/rmwg/pas/index_team/SDI_Whitepaper.pdf
[14] 2012 State of Reliability Report, May 2012, http://www.nerc.com/files/2012_SOR.pdf

(WI) have had steady frequency response performance. The expected frequency response for each interconnection remains higher than the recommended interconnection frequency response obligation.[15]

Protection System Misoperations are a Significant Contributor to Disturbance Events and Automatic Transmission Outage Severity

In support of making risk-informed decisions, enabling prioritization of issues, and aligning resources to address them, NERC uses disturbance event and equipment availability datasets to identify significant risk clusters. The risk concentration areas can be used to determine priority projects and then develop coordinated and effective solutions to relevant problems. Stakeholders can respond to the reliability issues by adjusting NERC's Reliability Standards Development Plan and focusing on compliance monitoring and enforcement activities, if necessary.

Chapter 3 of this report discusses that protection system misoperations had the largest positive correlation with automatic transmission outage severity in 2012. The correlation is statistically significant: a pattern and underlying dependency exists between misoperations and transmission outage severity. On average, transmission events with misoperations were more impactful than transmission events without misoperations. They were also, in aggregate, the largest contributor to transmission severity. The relative risk of misoperations is the highest among all cause codes, excluding Weather and Unknown initiating causes. These facts indicate that a reduction of misoperations would lead to a great improvement in reliability.

NERC has collected nearly two years of protection system misoperations data using a uniform misoperations reporting template across the eight Regional Entities. The quarterly protection system misoperation trending by NERC and the Regional Entities is posted on NERC's website.[16] The following two reliability metrics have been used to measure performance changes:

- ALR4-1[17] - Automatic AC Transmission Outages Caused by Protection System Equipment-Related Misoperations
- ALR6-11[18] - Automatic AC Transmission Outages initiated by Failed Protection System Equipment

As recommended in the *2012 State of Reliability* report,[19] a more thorough investigation into the root causes of protection system misoperations was a high priority. Under the NERC Planning Committee's direction, the Protection System Misoperation Task Force[20] (PSMTF) started to analyze misoperations in March 2012 and has completed its analysis.

PSMTF reviewed and evaluated misoperations records collected from January 1, 2011 to June 30, 2012. Approximately 65 percent of misoperations have the following three cause codes:

- Incorrect settings/logic/design errors
- Relay failures/malfunctions
- Communication failures

Recommendation

The PSMTF developed targeted, actionable solutions to reduce the amount of future misoperations, as summarized in Figure 1.7. PSMTF also proposed several changes to the data collection process that may improve the usefulness of future data. Since some entities already perform one or more of these activities, they should consider these suggestions (based on their particular circumstances).

[15] Frequency Response Initiative Report, 10/30/2012, http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf
[16] Reliability Indicators: Protection System Misoperations, http://www.nerc.com/page.php?cid=4|331|400
[17] ALR4-1, February 2009, http://www.nerc.com/docs/pc/rmwg/ALR_4-1Percent.pdf
[18] ALR6-11, March 2010, http://www.nerc.com/docs/pc/rmwg/ALR6-11.pdf
[19] 2012 State of Reliability Report, May 2012, http://www.nerc.com/files/2012_SOR.pdf
[20] Protection System Misoperations Task Force (PSMTF), http://www.nerc.com/filez/psmtf.html

AC Substation Equipment Failures are a Second Significant Contributor to Disturbance Events and Automatic Transmission Outage Severity

As recommended in the *2012 State of Reliability* report, additional data was gathered on equipment failure, including secondary cause codes and the type of equipment failure experienced. Resulting analysis found that Failed AC Substation Equipment was statistically significant and positively correlated to 2008–2012 automatic transmission outage severity. Among all cause codes, Failed AC Substation Equipment was also the second largest contributor to the 2012 transmission severity, with relative risk the second highest, excluding Weather and Unknown initiating causes. Analysis of the transmission outage and disturbance event information shows that circuit breakers are the most common type of ac substation equipment failure.

Recommendation

A thorough investigation into the root causes of circuit breaker failures that contribute to disturbance events is a high priority for 2013. A small subject matter expert technical group should be formed to further probe the ac substation equipment failures, particularly circuit breaker failures, and provide risk control solutions to improve performance.

To increase awareness and transparency, NERC developed the adequate level of reliability metric, ALR6-13 AC Transmission Outages Initiated by Failed AC Substation Equipment, to measure performance changes in Failed AC Substation Equipment. The metric trending by NERC and the Regional Entities can be viewed on NERC's website.[21]

Transmission Events with Unknown Cause Warrants Analysis

Transmission outage events with the cause code Unknown are areas where more analysis is needed. From 2008 to 2012, Unknown as an initiating cause represents 19 percent of the total number of reported events with momentary and sustained duration. Approximately 10 percent of the total events in the Unknown category are identified as Common/Dependent Mode events. These have greater transmission severity, on average, than single mode outage events.

Recommendation

A small subject matter expert technical group should be formed to further study the data collection assumptions when assigning the Unknown cause code.

Future Advancements

The *State of Reliability 2013* report is a vital step toward defining an overall view of BPS reliability risk. The goal is to quantify risk and performance, highlight areas for improvement, and reinforce and measure success in controlling these risks. A number of activities are in place to further these objectives.

In 2011, the Sandia National Laboratories (SNL)[22] provided technical support to identify and monitor areas for improving the value of reliability indices such as the SRI. Based on the recommendations, the PAS will continue applying risk cluster and other statistical analyses to identify significant initiating events and quantify their impacts, including weather related events. The resulting model could be used to characterize and monitor the state of BPS reliability, and cause-effect relationships may emerge.

Under the direction of the Critical Infrastructure Protection Committee (CIPC), the PAS is collaborating with the Bulk Electric System Security Metrics Working Group to develop security performance metrics. At the present time, the defined characteristics of ALR are being reviewed and refined. Once the enhanced definition becomes final, the PAS will evaluate the current ALR metrics and modify them accordingly.

Report Organization

Chapter 1 outlines key findings and conclusions, and Chapter 2 details the severity risk index trend analysis. Chapter 3 presents a framework and statistical analysis studies that identify the top risks to the BPS using transmission outage data. Chapter 4 provides assessment for a set of reliability metrics. Chapter 5 outlines key compliance monitoring index (KCMI) trending. Chapter 6 provides an overview of 2011–2012 winter and 2012 summer operations. Chapter 7 highlights the NERC Spare Equipment Database program.

[21] Reliability Indicators: Protection System Misoperations, http://www.nerc.com/page.php?cid=4|331|400

[22] Sandia National Labs Statistical Reliability Measure Recommendations, 03/19/2012, http://www.nerc.com/docs/pc/rmwg/pas/Mar_2012_OCPC/Final_Memo_Sandia.pdf

Chapter 1 – Key Findings and Conclusions

2012 Overall Reliability Performance

BPS reliability is stable, as evidenced by no significant upward or downward trends in the metrics for the 2008–2012 period. The severity risk index (SRI) and 18 metrics that measure the characteristics of an adequate level of reliability (ALR) indicate the BPS is within the defined acceptable ALR conditions. Based on the data and analysis in the latter chapters of this report, the following six key findings were identified:

1. BPS reliability remains adequate.
2. Risks to reliability from violations of reliability standards have been reduced.
3. Frequency response continues to be stable with no deterioration.
4. Protection system misoperations are a significant contributor to disturbance events and automatic transmission outage severity. Incorrect settings/logic/design errors, relay failures/malfunctions, and communication failures are the three primary factors that result in such misoperations.
5. AC substation equipment failure, particularly circuit breaker failure, has been identified as another significant contributor to disturbance events and automatic transmission outage severity.
6. Automatic transmission outage events with Unknown cause codes warrant analysis. Unknown as a sustained cause code is found in 34 percent of common/dependent mode (CDM) outages.

Key Finding 1: Bulk Power System Reliability Remains Adequate

Daily Performance Severity Risk Assessment

Based on the severity risk index[23] (SRI) and 18 metrics that measure the characteristics of an adequate level of reliability (ALR), BPS reliability is adequate and within the defined acceptable ALR conditions. The top 10 most severe events in 2012 were all initiated by weather. There were only three high-stress days (SRI greater than 5.0) in 2012 compared to six days in 2011.

Figure 1.1 captures the daily SRI[24] value from 2008 to 2012, including the historic significant events. The SRI is a daily, blended metric where transmission loss, generation loss, and load loss events are aggregated into a single value that represents the performance of the system. Accumulated over one year, these daily performance measurements are sorted in descending order to evaluate the year-on-year performance of the system. Since there is a significant difference between normal days and high-stress days in terms of SRI values, the curve is depicted using a logarithmic scale.

In 2012, there were three days (Hurricane Sandy on 10/29 and 10/30 and Thunderstorm Derecho on 6/29) when the system was highly stressed in comparison to 2011. For remaining high-stress days on system, SRI values in 2011 were larger than 2012 and prior years. Table 1.1 lists the 10 event dates with highest daily SRI values in 2012. A Department of Energy (DOE) OE-417 form[25] was filed for each of these weather-influenced events.

[23] SRI is a "stress" index, measuring risk impact from events resulting in transmission loss, generation loss, and load loss.
[24] Integrated Risk Assessment Approach – Refinement to Severity Risk Index 05/06/2011, http://www.nerc.com/docs/pc/rmwg/pas/index_team/SRI_Equation_Refinement_May6_2011.pdf
[25] OE-417 E-Filing System Training Reference Guide, https://www.oe.netl.doe.gov/docs/OE417_submission_instructions.pdf

Figure 1.1: NERC Daily Severity Risk Index (SRI) Sorted Descending by Year with Historic Benchmark Days

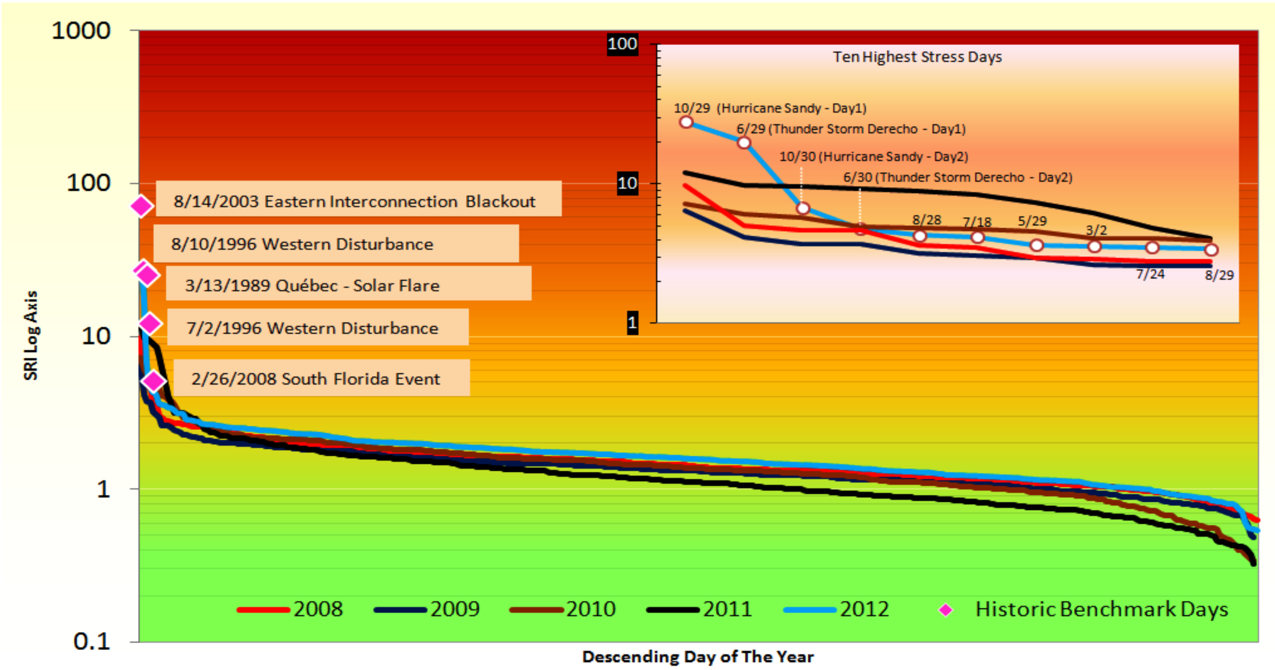


Table 1.1: 2012 NERC Top 10 SRI Days

Date	NERC SRI & Components				Weather-Influenced?	Cause Description	Interconnection
	SRI	Generation	Transmission	Load Loss			
Oct 29	27.89	1.95	1.78	24.16	✓	Hurricane Sandy	Eastern
Jun 29	19.94	2.49	1.37	16.08	✓	Thunderstorm Derecho	Eastern
Oct 30	6.63	2.76	3.35	0.51	✓	Hurricane Sandy	Eastern
Jun 30	4.71	1.62	1.96	1.13	✓	Thunderstorm Derecho	Eastern
Aug 28	4.21	1.65	0.32	2.23	✓	Hurricane Isaac	Eastern
Jul 18	4.07	1.90	1.60	0.57	✓	Severe Thunderstorm	Eastern
May 29	3.55	1.83	1.36	0.36	✓	Severe Thunderstorm	Eastern
Mar 2	3.51	0.98	1.54	0.99	✓	Severe Weather Tornadoes	Eastern
Jul 24	3.44	1.65	1.13	0.65	✓	Severe Thunderstorm	Eastern
Aug 29	3.35	1.28	1.40	0.66	✓	Hurricane Isaac	Eastern

Steady Transmission System Availability and Metrics

Reliability of the transmission system continues to remain high with no statistically significant change in performance from 2008 to 2012. Operated at 200 kV and above, ac circuit availability is more than 97 percent, and transformer availability is above 96 percent for the period 2010–2012, the only years planned outage data (an integral component in total availability) is available. This availability includes both planned and unplanned outages. Planned outages for maintenance and construction have a long-term positive impact on transmission system reliability. AC circuit and transformer unavailability was well below 5 percent, as shown in Figure 1.2. The unavailability due to automatic sustained outages was less than 0.22 percent for ac circuits, and less than 0.50 percent for transformers. These relative percentages provide an indication of the overall availability of the transmission system operated at 200 kV and above.

Figure 1.2: NERC Transmission System Unavailability by Element Type and Outage Type (2010–2012)

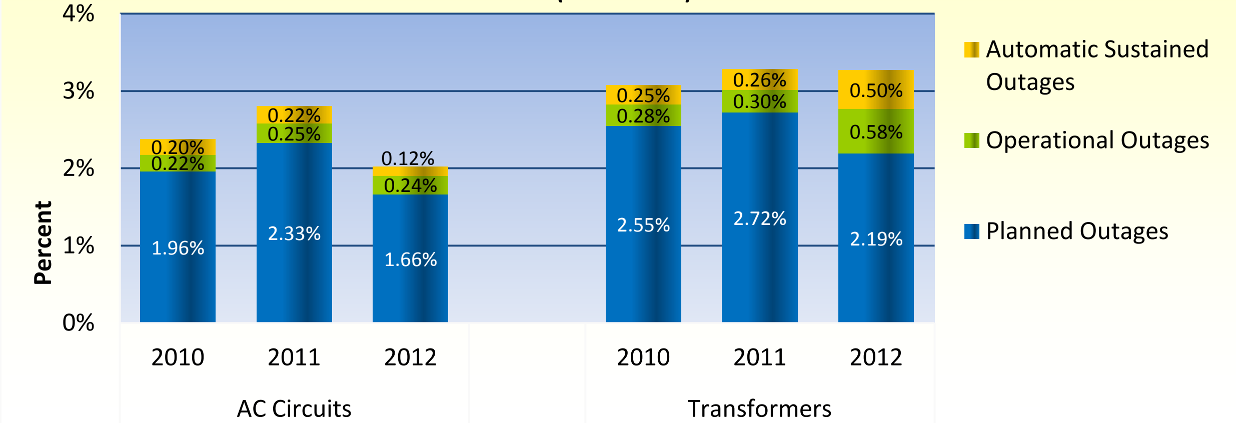
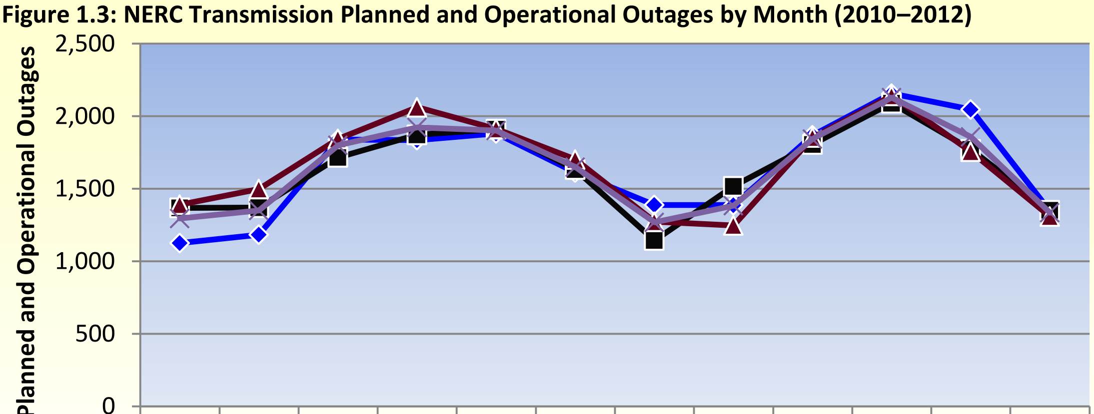


Figure 1.3 illustrates that during winter (December, January, and February) and summer months (June, July, and August), the number of transmission planned and operational outages are lower compared to other months of the year, when most construction and maintenance work occurs.

Figure 1.3: NERC Transmission Planned and Operational Outages by Month (2010–2012)



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010	1,126	1,184	1,839	1,836	1,882	1,613	1,389	1,387	1,869	2,156	2,047	1,347
2011	1,369	1,370	1,717	1,872	1,911	1,633	1,144	1,517	1,806	2,090	1,772	1,352
2012	1,391	1,499	1,845	2,062	1,913	1,702	1,273	1,248	1,854	2,141	1,756	1,309
3 Year Average	1,295	1,351	1,800	1,923	1,902	1,649	1,269	1,384	1,843	2,129	1,858	1,336

Month

In addition to ac circuit and transformer availability and unavailability, the performance indicators include four transmission availability-related metrics that measure outage rates for areas deemed important to reliability. Each metric is statistically analyzed to determine improvement or deterioration. The four metrics are:

- ALR 6-11: Automatic ac transmission outages initiated by Failed Protection System Equipment,
- ALR 6-12: Automatic ac transmission outages initiated by Human Error,
- ALR 6-13: Automatic ac transmission outages initiated by Failed AC Substation Equipment, and
- ALR 6-14: Automatic ac transmission outages initiated by Failed AC Circuit Equipment.

The statistical significance of the four transmission reliability metrics was tested for year-to-year trends. There are no statistically significant changes in performance of these metrics from 2008 to 2012. The detailed analyses and assumptions used are included in Appendix A.

Key Finding 2: Reduced Standards Violations Risks

The NERC Compliance Monitoring and Enforcement Program (CMEP) was developed in 2008 and has since been enhanced to provide more certainty on actions, outcomes, and reliability consequences. Between June 18, 2007 and December 31, 2012, 5,115 confirmed standards violations[26] have been processed.[27] Of these, 85.3 percent had minimal impact to reliability, 13.1 percent had moderate impact, and 1.6 percent had serious impact, as shown in Table 1.2.

Table 1.2: NERC Confirmed Violations by Assessed Risk (June 18, 2007 – December 31, 2012)

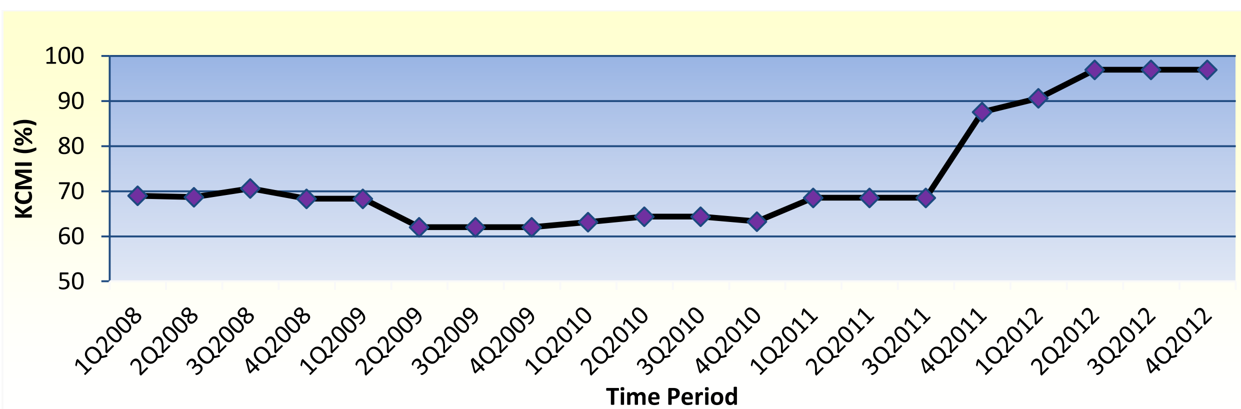
Assessed Risk	BAL	CIP	COM	EOP	FAC	INT	IRO	MOD	NUC	PER	PRC	TOP	TPL	VAR	ALL	
Minimal	80	1806	56	242	515	26	64	34	1	99	853	193	125	268	4362	85.30%
Moderate	2	410	13	27	24	1	4			11	116	34	3	27	672	13.10%
Serious		31	2	3	6		2			3	23	7		4	81	1.60%
Total	82	2247	71	272	544	27	71	34	1	113	992	234	128	299	5115	100%

A five-year assessment of the Key Compliance Monitoring Index (KCMI) indicated improvement in compliance with a set of 26 standards requirements, shown in Table 1.3. The index has increased since the fourth quarter of 2010, suggesting that compliance progressively improved from then through the fourth quarter of 2012, as shown in Figure 1.4. The violations included in KCMI have high violation risk factors and pose actual/potential serious reliability impacts. This improved compliance trend indicates a reduced risk to BPS reliability. Details of serious violations in the KCMI trend, as well as their discovery method, can be found in Chapter 5.

Table 1.3: Standard Requirements

EOP-001-0 R1	PER-002-0 R1	TOP-001-1 R6
EOP-003-1 R7	PER-002-0 R2	TOP-001-1 R7
EOP-005-1 R6	PER-002-0 R3	TOP-002-2 R17
EOP-008-0 R1	PER-002-0 R4	TOP-004-2 R1
FAC-003-1 R1	PRC-004-1 R1	TOP-004-2 R2
FAC-003-1 R2	PRC-004-1 R2	TOP-006-1 R1
FAC-009-1 R1	PRC-005-1 R1	TOP-008-1 R2
IRO-005-2 R17	PRC-005-1 R2	VAR-001-1 R1
PER-001-0 R1	TOP-001-1 R3	

Figure 1.4 Key Compliance Monitoring Index Trend by Quarter (2008–2012)



Key Finding 3: Steady Frequency Response

As recommended in the *2012 State of Reliability* report,[28] NERC applied statistical tests to interconnection frequency response datasets,[29] and additional analyses on time of year, load levels, and other attributes were conducted. From 2009 to 2012, the EI, ERCOT Interconnection, QI,[30] and WI have shown steady frequency response performance, with year-to-year time trends as shown in Figure 1.5. The expected frequency response for each interconnection has been higher than the recommended interconnection frequency response obligation. The study methods and statistical results are summarized in Chapter 4.

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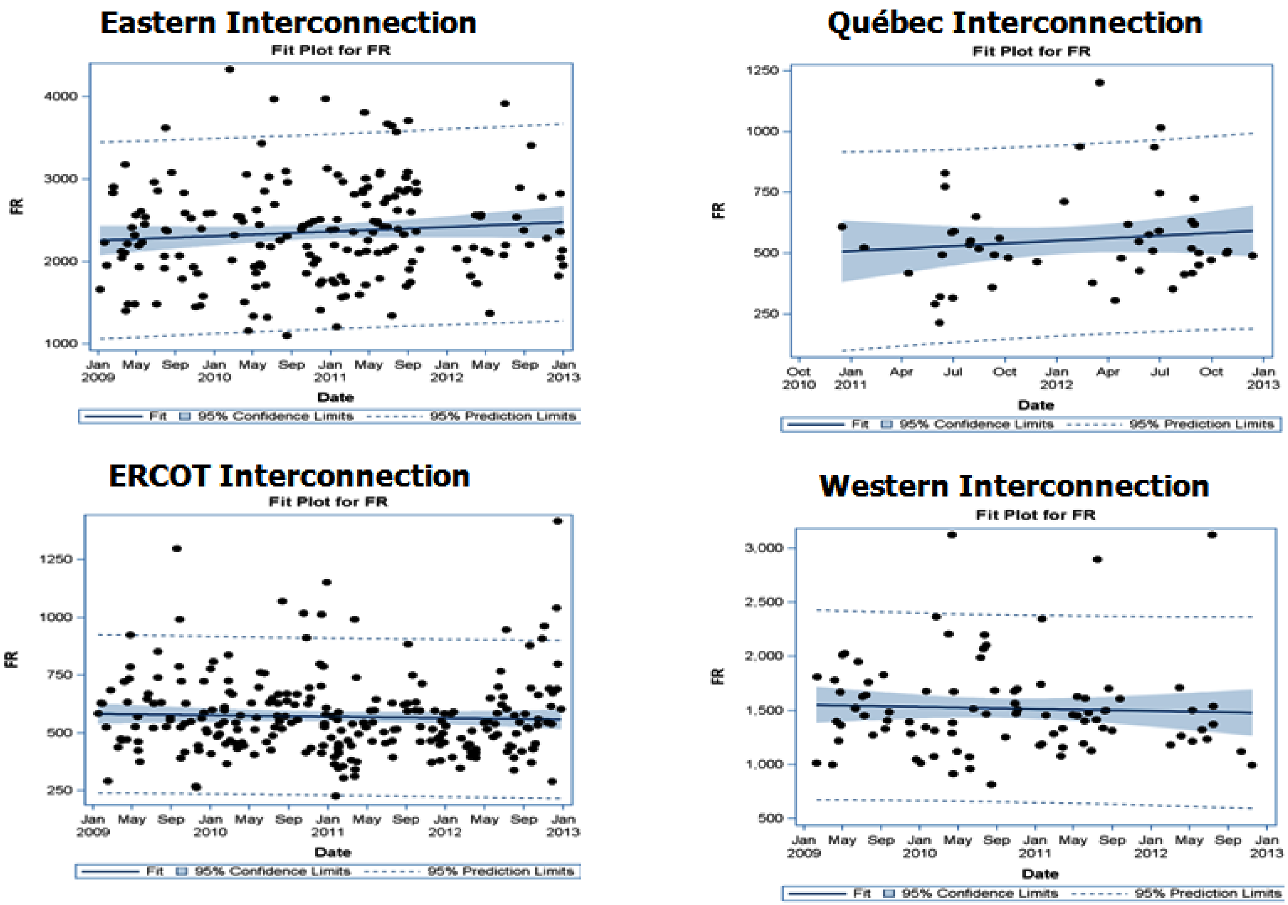
[26] Enforcement Actions, Details of confirmed violations can be viewed at http://www.nerc.com/filez/enforcement/index.html
[27] As of December 31, 2012
[28] 2012 State of Reliability Report, May 2012, http://www.nerc.com/files/2012_SOR.pdf
[29] Frequency Response Initiative Report, 10/30/2012, http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf
[30] Only Québec Interconnection 2011 and 2012 frequency response data is available.

Figure 1.5: Interconnection Frequency Response Trend (2009–2012)



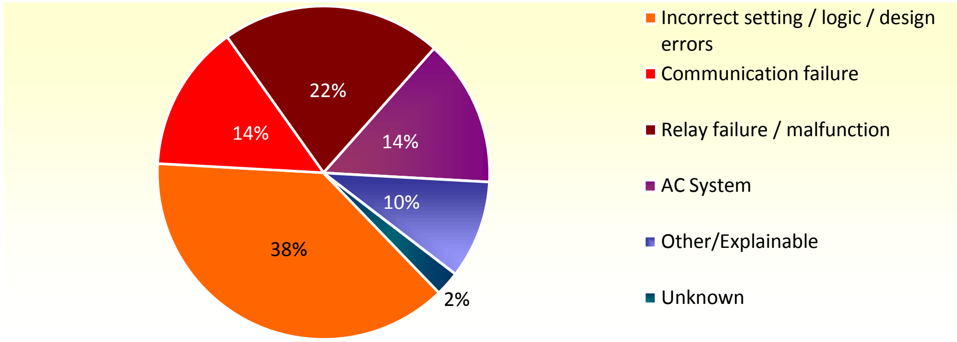
Key Finding 4: Protection System Misoperations are a Significant Contributor to Disturbance Events and Automatic Transmission Outage Severity

Based on the 2012 event analysis and 2008–2012 automatic transmission outage data, protection system misoperations are identified as the leading initiating cause to disturbance events (other than Weather and Unknown). The NERC Event Analysis program has recorded and analyzed events with misoperations as either an event cause or a contributing factor from 2011 to 2012. Out of 86 cause-coded, qualified events[31] in 2012, misoperations were involved in 33 events, equipment failures in 27 events, individual human performance in 11 events, and management or organizational issues[32] in 26 events. The cause codes for the 33 events associated with misoperations are shown in Figure 1.6. Primarily, these misoperations result from incorrect settings/logic/design errors, communication failure, and relay failure or malfunction. Most of these misoperations contribute to increasing the SRI and indicate that the number of transmission element outages increases.

[31] Qualified events meet the criteria defined in the NERC ERO Event Analysis Process Document, http://www.nerc.com/files/ERO_Event_Analysis_Process_Document_Version_1_Feb_2012.pdf, p.24, accessed April 15, 2013.

[32] NERC Event Analysis Cause Code Assignment Process, http://www.nerc.com/files/NERC_Cause_Code_Assignment_Process_February_2013.pdf, p.47, February 2013.

Figure 1.6: Misoperations in 2012 Cause-Coded Disturbance Events (42 Misoperations within 33 Qualified Events)



As described in Chapter 3, misoperations were positively correlated with 2012 automatic transmission outage severity. The correlation was also statistically significant. This reveals a pattern and underlying relationship between misoperations and transmission severity. The higher severity values observed for transmission outage events with misoperations did not occur by chance. Transmission events in 2012 with misoperations, on average, are more impactful to SRI than transmission events without misoperations. They are also, in aggregate, the largest contributor to the severity of transmission outages. Among all cause codes, the relative risk of misoperations is the highest, excluding Weather and Unknown initiating causes, as shown in Table 3.3. This indicates that a reduction of misoperations would provide the greatest improvement in reliability.

NERC has initiated several efforts to minimize protection system misoperations. These efforts include conducting industry webinars[33] on protection systems, issuing lessons learned, and documenting success stories on how Generator Owners and Transmission Owners are achieving high protection system performance. NERC is also in the process of revising a number of reliability standards that involve protection system misoperations.[34]

To understand misoperations' root causes, NERC has collected nearly two years of protection system misoperations data using a uniform reporting template across the eight Regional Entities. The quarterly protection system misoperation trending by NERC and the Regional Entities can be viewed on NERC's website.[35] The following two reliability metrics have been used to measure performance changes:

- ALR4-1 Protection System Misoperation Rate
- ALR6-11 Automatic AC Transmission Outages Initiated by Failed Protection System Equipment

The *2012 State of Reliability* report recommended as a high priority a more thorough investigation into the root causes of protection system misoperations. Under the NERC Planning Committee's direction, the Protection System Misoperation Task Force (PSMTF) started to analyze misoperations in March 2012 and has since completed its analysis.[36] The PSMTF reviewed over 1,500 misoperation records collected from January 1, 2011 to June 30, 2012 across all eight Regions. Additionally, a summary of each Region's misoperation process and observations and conclusions from data collected prior to January 1, 2011 were evaluated. Approximately 65 percent of misoperations have the following three cause codes:

- Incorrect settings/logic/design errors
- Relay failures/malfunctions
- Communication failures

The PSMTF has developed targeted, actionable solutions to reduce the amount of future misoperations, as summarized in Figure 1.7. Since some entities already perform one or more of these activities, they should consider these suggestions based on their particular circumstances.

The PSMTF proposed several improvements to the data collection process that may improve the usefulness of future data. Further, the PSMTF and NERC's System Protection Control Subcommittee (SPCS) recommended that misoperation analysis

[33] http://www.nerc.com/files/misoperations_webinar_master_deck_final.pdf, December 1, 2011.
[34] http://www.nerc.com/filez/standards/Project2010-05_Protection_System_Misoperations.html
[35] Reliability Indicators: Protection System Misoperations, http://www.nerc.com/page.php?cid=4|331|400
[36] http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf, April 1, 2013, p. 36.

be continued on an annual basis by the respective protection system subcommittees within each Regional Entity. This analysis will be forwarded to the NERC SPCS and NERC Performance Analysis Subcommittee (PAS) for trending and metrics reporting. A measurable reduction will only be possible by industry's taking action.

Figure 1.7: Suggested Actionable Solutions to Reduce Misoperations

Incorrect Setting/Logic/Design Errors

- Applications requiring coordination of functionally different relay elements should be avoided. This type of coordination is virtually always problematic and is the cause of numerous misoperations reported in the study period.
- Misoperations due to setting errors can potentially be reduced, and there are several techniques, including:
  - Peer reviews
  - Increased training
  - More extensive fault studies
  - Standard templates for setting standard schemes using complex relays
  - Periodic review of existing settings when there is a change in system topography

Relay Failure/Malfunction

- Microprocessor-based Relay Firmware
  - Entities should evaluate the need to apply updated firmware.
  - While many firmware updates may not be critical to the relay protection functions, updated firmware that corrects critical protection functions should be given priority.

Communication Failure

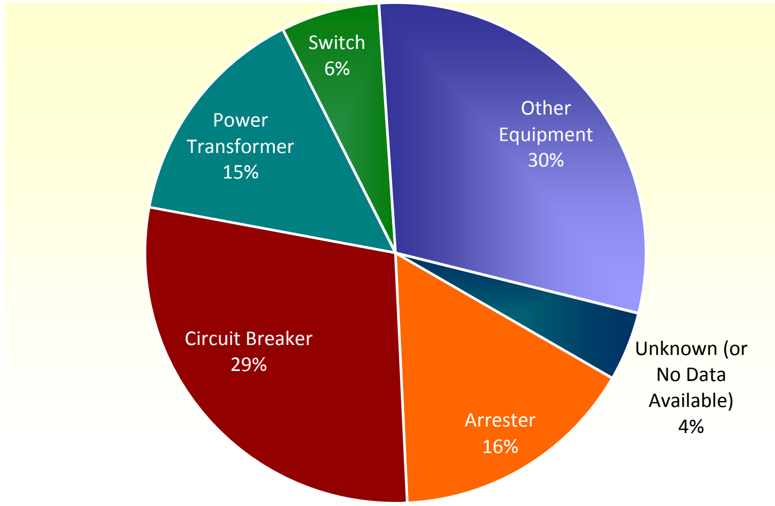
- Spark gaps need to be inspected for build-up and the proper gap required by the manufacturers.
- Modern check-back equipment is helpful for detecting the failure to perform a carrier test, and it also provides a better indication of communication scheme condition (by sending codes at various power levels) than many older check-back test schemes. Alternatively, frequency shift keying (FSK) carrier can be used with microprocessor-based relays with little loss of speed.

Key Finding 5: AC Substation Equipment Failures are a Second Significant Contributor to Disturbance Events and Automatic Transmission Outage Severity

The *2012 State of Reliability* report recommended that additional data be collected to analyze equipment failure, including secondary cause codes. The analysis showed that Failed AC Substation Equipment was positively correlated with the 2008–2012 automatic transmission outage severity. The correlation was statistically significant, as well. Failed AC Substation Equipment is the second largest contributor to transmission severity in 2012. Among all cause codes, the relative risk of Failed AC Substation Equipment is the second highest, excluding Weather and Unknown initiating causes, as shown in Table 3.6.

A recent voluntary survey of 2012 transmission outages initiated by Failed AC Substation Equipment indicates 29 percent of these outages involved circuit breaker failures, 16 percent were due to arrester failures, and 15 percent were due to power transformer failures, as shown in Figure 1.8. As shown in the figure, circuit breakers are the most common type of Failed AC Substation Equipment within these transmission outages.

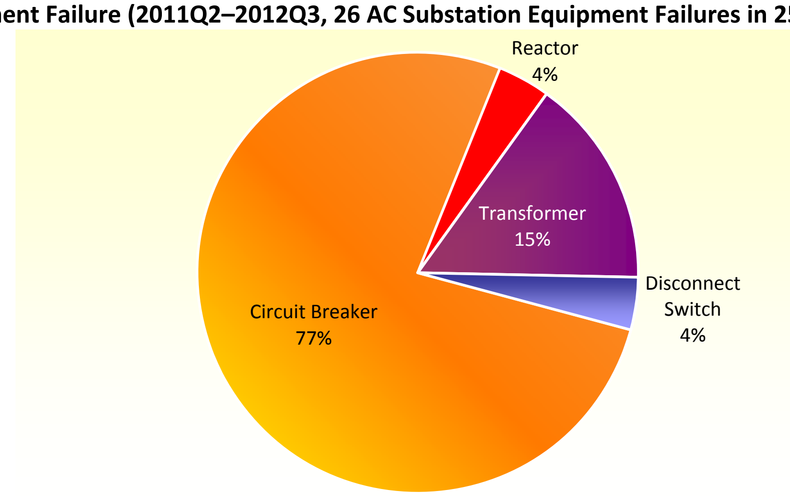
Figure 1.8: Failed AC Substation Equipment Survey Results (58 of 193 TADS Reporting TOs)



In addition to the voluntary survey data, NERC has collected more than one year of event data to analyze disturbance event root causes and develop reduction solutions. From the beginning of second quarter 2011 to the end of third quarter 2012, 121 disturbance events with transmission outages were reported. For each of the 26 AC substation equipment failures within these 121 events, Figure 1.9 shows the type of AC substation equipment failure. Approximately 79 percent of the disturbance events with transmission outages reported no AC substation equipment failure. These events were due to other factors, such as misoperations. The remaining 21 percent of disturbance events with transmission outages reported AC substation equipment failure involvement. Of the disturbance events with transmission outage and circuit breaker failure indicated, approximately half were the initiating event, and one-third were contributory to increasing the event's severity. NERC recommends that a small subject matter expert technical group be formed to further validate the findings and root causes to understand the contributing factors to circuit breaker failures and provide risk control solutions to improve performance.

NERC has developed an adequate level of reliability metric, ALR6-13 AC Transmission Outages Initiated by Failed AC Substation Equipment, to measure performance changes in Failed AC Substation Equipment.[37]

Figure 1.9: AC Substation Equipment Type Reported in Disturbance Events with Transmission Outage and AC Substation Equipment Failure (2011Q2–2012Q3, 26 AC Substation Equipment Failures in 25 events)

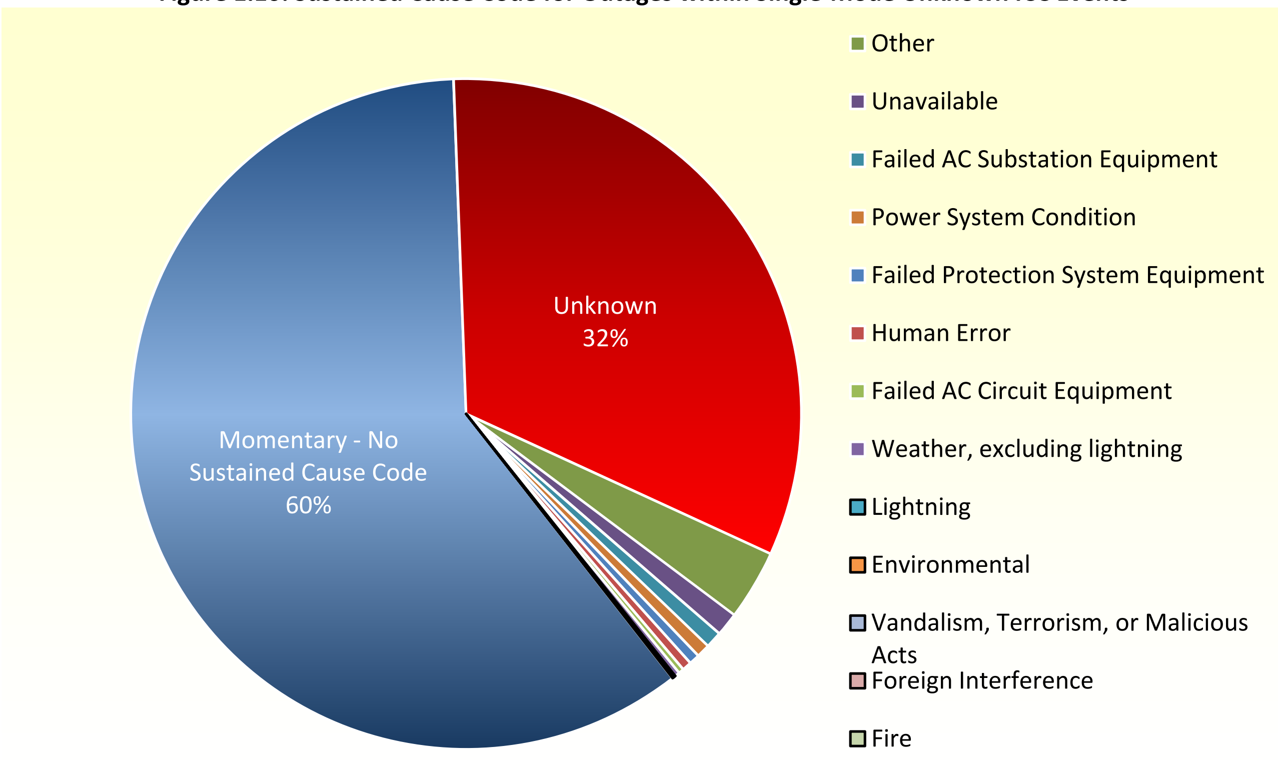


[37] Reliability Indicators: Protection System Misoperations, http://www.nerc.com/page.php?cid=4|331|400

Key Finding 6: Automatic Transmission Events with Unknown Cause Necessitate Analysis

A total of 3,903 automatic transmission events were reported with Unknown as an initiating cause code (ICC) from 2008 to 2012, comprising 19 percent of all events with automatic outages. This may be an area where more analysis is needed. Table 3.4 shows Unknown second only to Lightning in the number of reported events from 2008 to 2012. Approximately 90 percent of these Unknown cause code events are single mode, and 10 percent are Common/Dependent Mode (CDM). Figure 1.10 breaks down the outages within single-mode Unknown ICC events by sustained cause code. Of the single-mode events, 60 percent of the outages are momentary, and 32 percent have an Unknown sustained cause code.

Figure 1.10: Sustained Cause Code for Outages within Single-Mode Unknown ICC Events



The CDM events have greater transmission severity, on average, than single-mode events. Table 3.7 indicates that CDM events with a cause code of Unknown have a relative risk of 2.7 percent, the fourth largest category. As shown in Table 1.4, approximately 34 percent of outages within CDM Events with an Unknown ICC have a sustained cause code of Unknown. More investigation would provide insight on the high amount of relative risk associated with these events. Additional guidance may be needed for entities to provide consistency in reporting these events.

Table 1.4: CDM Events with Unknown ICC (2008–2012)

Description	Percent
Momentary Outage – No Sustained Cause Code	45.6%
Sustained Outage with Unknown Cause Code	34.2%

Chapter 2 – Daily Performance Severity Risk Assessment

Overview

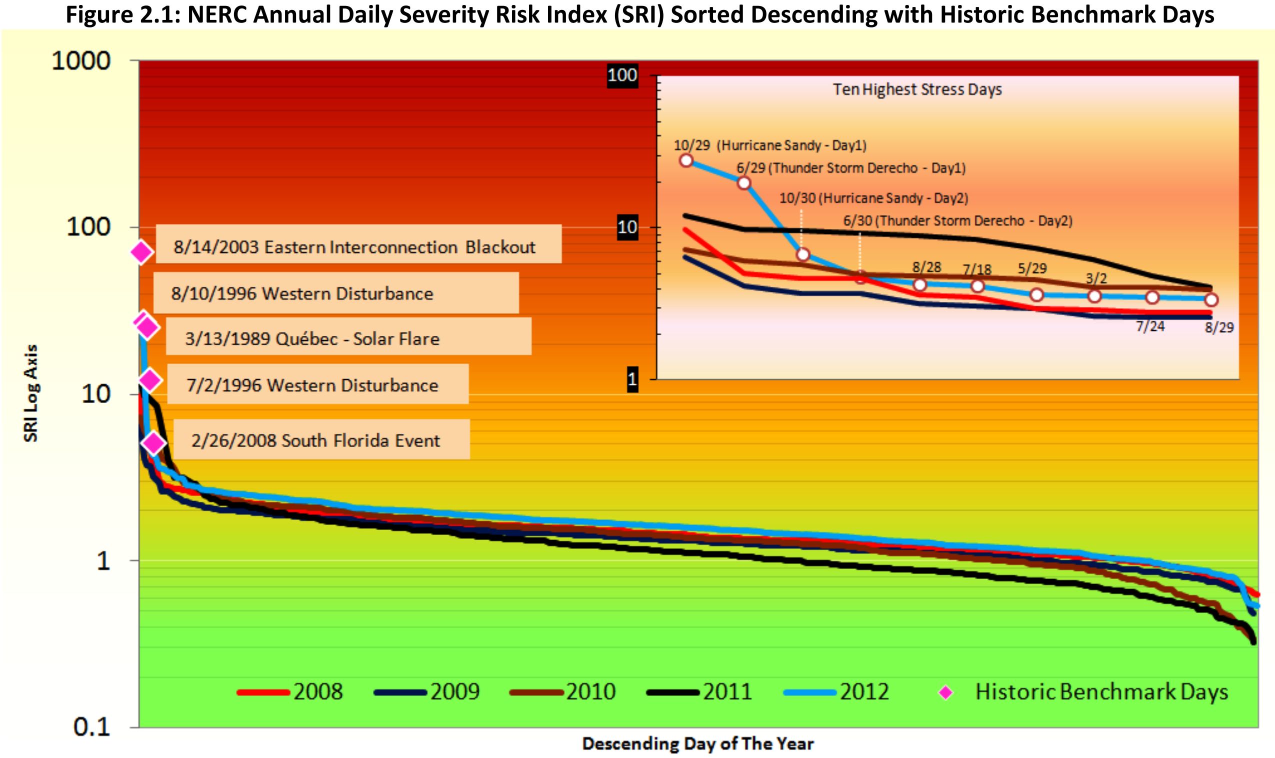
The severity risk index (SRI) was calculated from 2012 data and was then compared to the SRI for the years 2008–2011. Key conclusions were:

- There were several high-stress days resulting from extreme Weather events. In general, the SRI correctly correlated with those events, and the power system—while stressed—responded well.
- The top-10 most severe days in 2012 were all initiated by Weather.
- In 2012, there were three days (Hurricane Sandy on 10/29 and 10/30 and Thunderstorm Derecho on 6/29) when the system was highly stressed in comparison to 2011.
- There were fewer high-stress days (SRI greater than 5.0) in 2012, with three days, compared to 2011, with six days.
- For SRI values less than 5.0, 2011 had better average performance than 2012.

NERC Assessment

Figure 2.1 captures the daily SRI[38] values from 2008 to 2012, and it includes historically significant events to provide relative reliability perspective. An inset highlights the highest stress days experienced in 2012 from the left side of the SRI curve.

Figure 2.1: NERC Annual Daily Severity Risk Index (SRI) Sorted Descending with Historic Benchmark Days



As the year-to-year performance is evaluated in Figure 2.1, certain portions of the graph become relevant for specific analysis. First, the left side of the graph, where the system has been substantially stressed, should be considered in the context of the historically significant event days. Next, the slope of the central part of the graph may reveal year-to-year changes in performance for the majority of the days of the year and demonstrate routine system resilience. Finally, the right portion of the curve may also provide useful information about how many days with lower SRIs occurred during any year compared to other years.

[38] Integrated Risk Assessment Approach – Refinement to Severity Risk Index, 05/06/2011, http://www.nerc.com/docs/pc/rmwg/pas/index_team/SRI_Equation_Refinement_May6_2011.pdf

The inset shown in Figure 2.1 indicates that in 2012, there were three days (Hurricane Sandy on 10/29-30 and Thunderstorm Derecho on 6/29) when the system was highly stressed in comparison to 2011. For the remaining high-stress days on the system, 2012 had comparable performance to 2011 and was similar to prior years. Table 2.1 lists the 10 event dates with highest daily SRI values in 2012. Every event that occurred on the date filed Form OE-417.[39] The top-10 SRI days (eight events) were all weather-influenced.

The more pronounced downward slope of the graph's left side in Figure 2.1 demonstrates that 2012's performance improved, compared to previous years. The central and right portions of the graph show year-to-year improvement up to 2011.[40]

Table 2.1 lists the historical days with SRI greater than 10 in descending order with a breakdown of power system component severity. Seven historical days with SRI greater than 10 were recorded. The 2003 Eastern Interconnection (EI) blackout remains on top, and 2012 had two days (10/29 and 6/29) with SRI greater than 10.

Table 2.1: Historical Days with SRI greater than 10

Date	NERC SRI and Components				Weather Influenced?	Description	Interconnection
	SRI	Generation	Transmission	Load Loss			
Aug 14 2003	71.28	7.8	8.62	54.86		Eastern Interconnection Blackout	Eastern
Oct 29 2012	27.89	1.95	1.78	24.16	✓	Hurricane Sandy	Eastern
Aug 10 1996	27.13	4.25	4.22	18.67		Western Disturbance	Western
Mar 13 1989	25.01	2.65	12.66	9.7	✓	Québec - Solar Flare	Québec
Jun 29 2012	19.94	2.49	1.37	16.08	✓	Thunderstorm Derecho	Eastern
Jul 2 1996	12.17	2.88	1.39	7.9		Western Disturbance	Western
Oct 29 2011	12.08	0.57	0.61	10.9	✓	Severe Weather Northeast Snowstorm	Eastern

Figure 2.2 shows annual cumulative performance of the BPS. If a step change occurs on the graph, it represents a stress day as measured by the SRI. However, without additional analysis and review of completed events analyses, no trends about the time of the year could be concluded.

Figure 2.2: NERC Cumulative SRI (2008–2012)

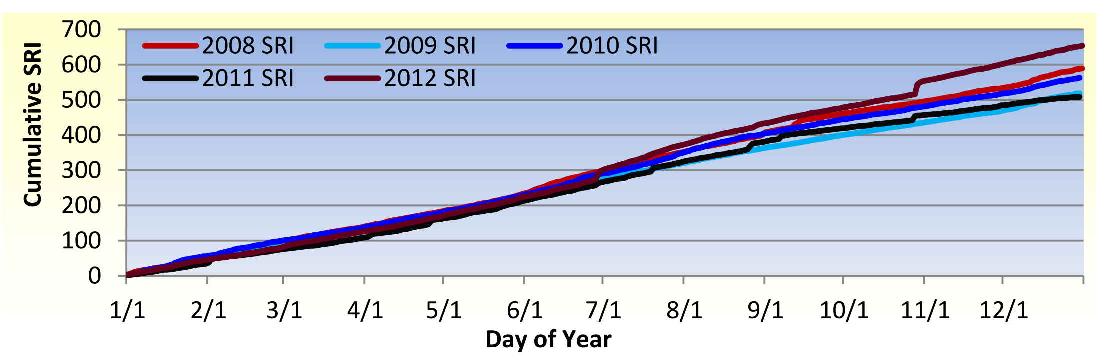
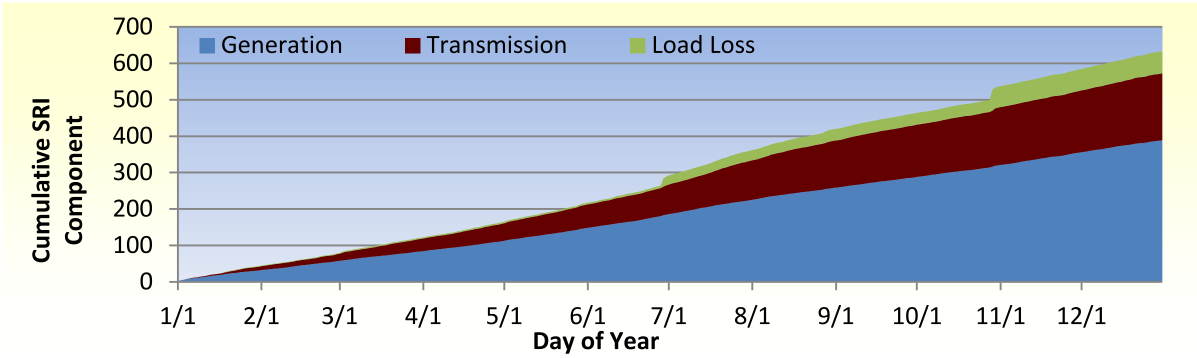


Figure 2.3 breaks down the 2012 cumulative performance by BPS segment. The largest components are generation, transmission, and load loss, in that order. In Figure 2.3, the load-loss component exhibits step changes, which is attributed to the higher stress days in 2012. In addition to the mechanism used to capture load-loss events, only OE-417 forms are associated with significant load loss events.

39 OE-417 E-Filing System Training Reference Guide, https://www.oe.netl.doe.gov/docs/OE417_submission_instructions.pdf

40 Generation availability data reporting became mandatory in 2012. Prior to 2012, only 72 percent or fewer unit outages were reported.

Figure 2.3: NERC Cumulative SRI by Component for 2012



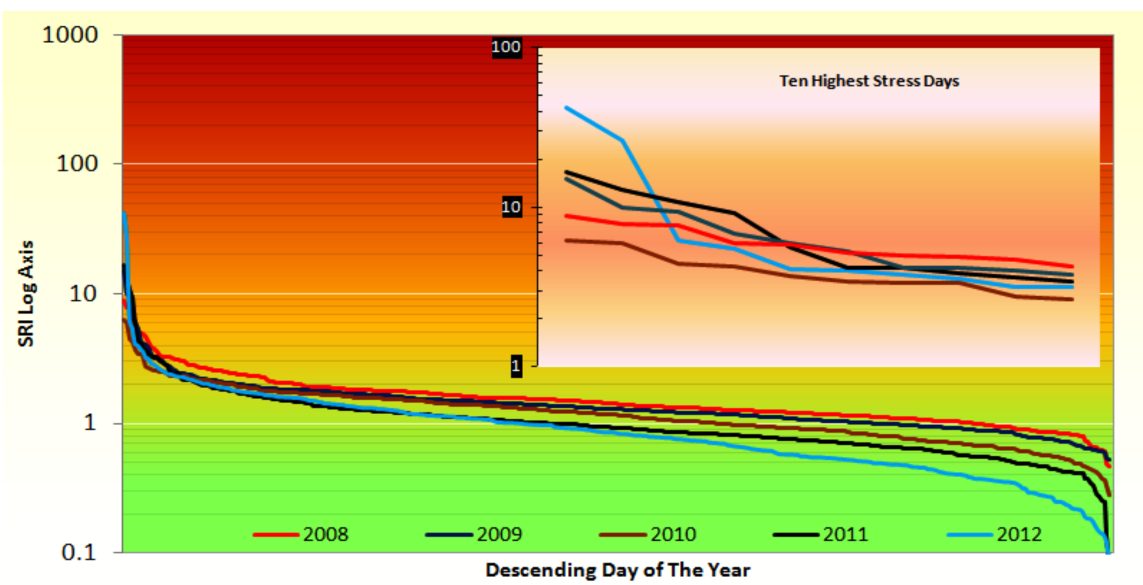
Interconnection Assessments

A feature of SRI is its applicability to various levels of the BPS. Interconnection assessments based on SRI provide a meaningful snapshot of performance within each interconnection. As each interconnection is analyzed, the severity of given events will vary substantially based on the size of the interconnection. The largest interconnections are the EI, Western Interconnection (WI), and the ERCOT Interconnection, in that order. A smaller interconnection usually displays much greater volatility in daily results than either a larger interconnection or when blended together into the NERC daily performance. While a day's performance may not have been noteworthy on an NERC-wide scale, at an interconnection level, analysis of that day may yield opportunities to learn and improve future performance of the particular interconnection.

Eastern Interconnection

Figure 2.4 shows that 2012's highest stress days were more severe than those in 2011. The average performance was better than in previous years.

Figure 2.4: Eastern Interconnection Annual Daily Severity Risk Index (SRI) Sorted Descending



In Figure 2.5, annual cumulative SRI performance of the EI is shown. If a step change occurs on the graph, it represents a stress day as measured by the SRI. However, without additional analysis and review of any completed events analyses, no trends about the time of the year could be concluded.

Figure 2.5: Eastern Interconnection Cumulative SRI (2008–2012)

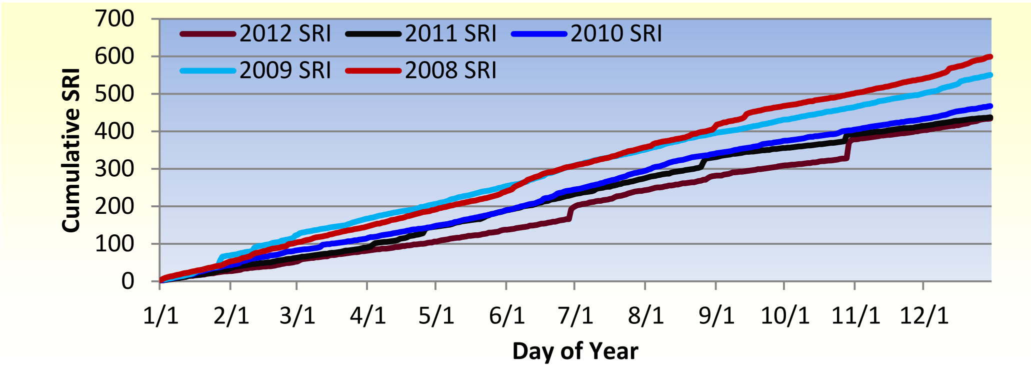
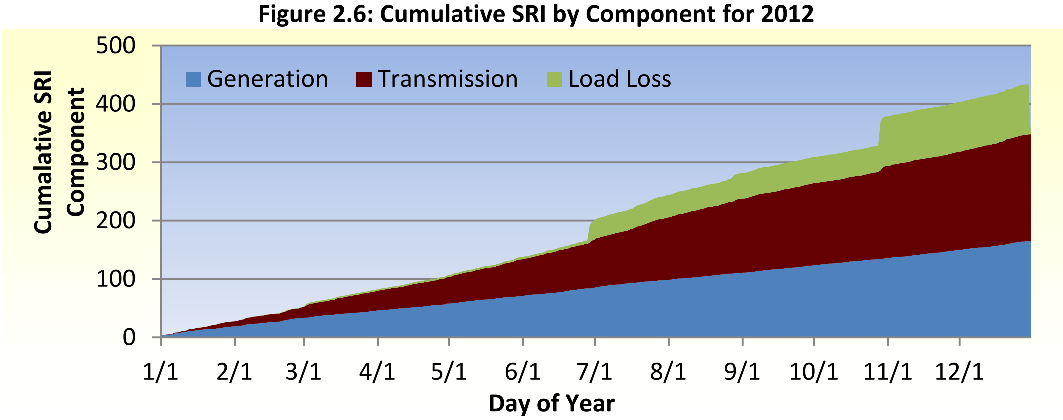


Figure 2.6 separates the cumulative SRI performance by the BPS components. The largest components are the generation, transmission, and load loss component, in that order. Notably, the load loss component exhibits several step changes that are attributable to the high stress days in 2012 (Hurricane Sandy and Thunderstorm Derecho).

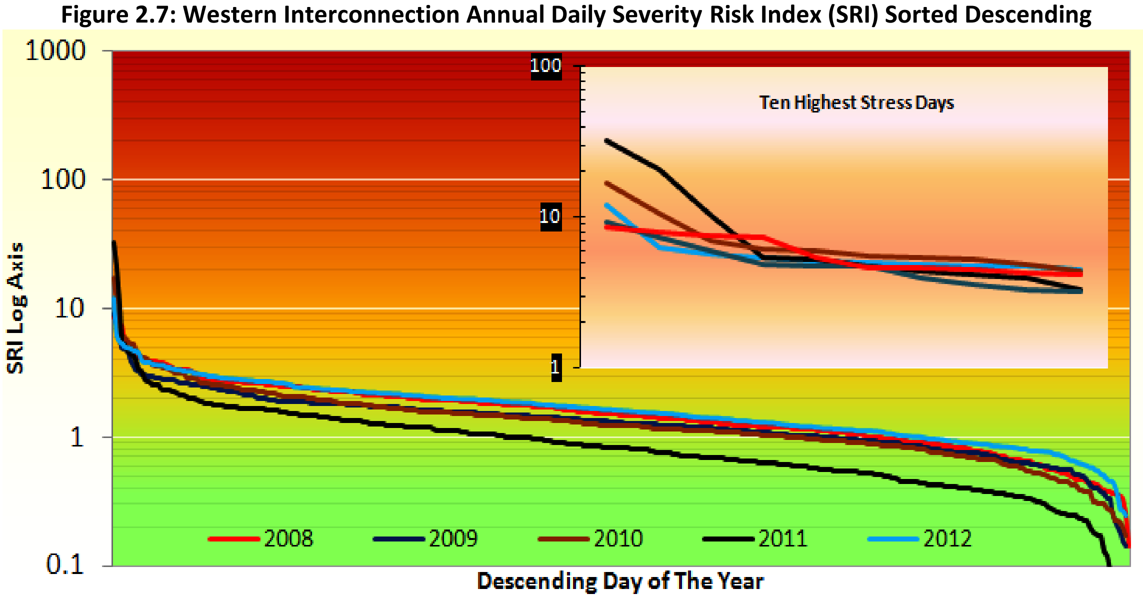
Figure 2.6: Cumulative SRI by Component for 2012



Western Interconnection

In Figure 2.7, the highest stress days in 2012 had lower severity than comparable days in 2011, and the average performance was substantially better in 2011 when compared to 2012.

Figure 2.7: Western Interconnection Annual Daily Severity Risk Index (SRI) Sorted Descending



In Figure 2.8, annual cumulative SRI performance of the WI is shown. If a step change occurs on the graph, it represents a stress day as measured by the SRI. However, without additional analysis and review of completed events analyses, no trends about the time of the year could be concluded.

Figure 2.8: Western Interconnection Cumulative SRI (2008–2012)

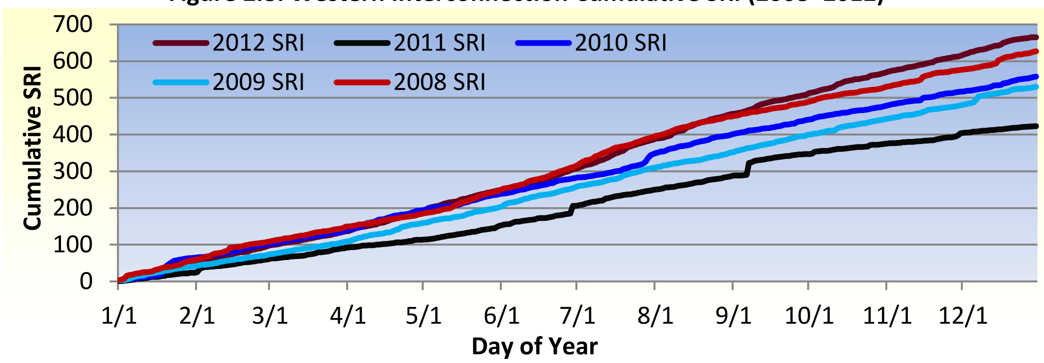
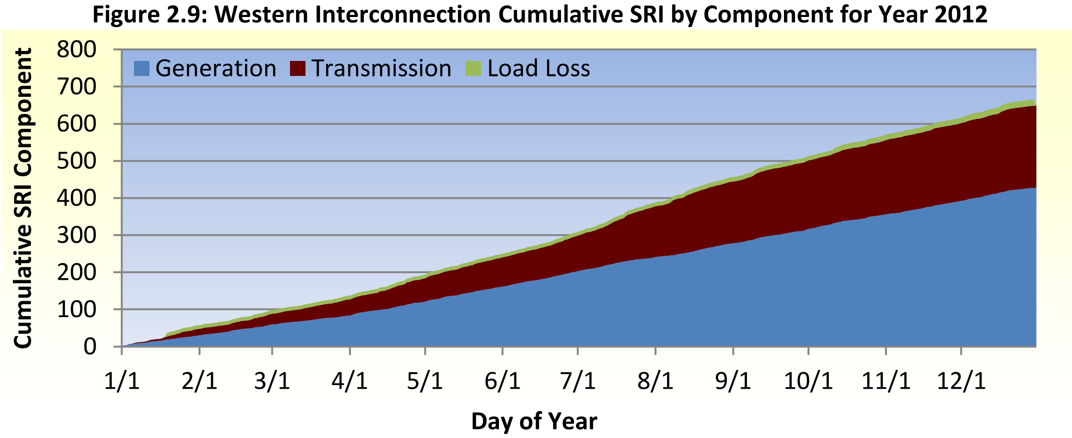


Figure 2.9 breaks the cumulative SRI performance into the bulk power system components. The generation component is the largest followed by the transmission component and then the load loss component, which is very low. Notably, the load loss component in Figure 2.9 is less than the other components, due to fewer occurrences of load-loss events and high-stress days.

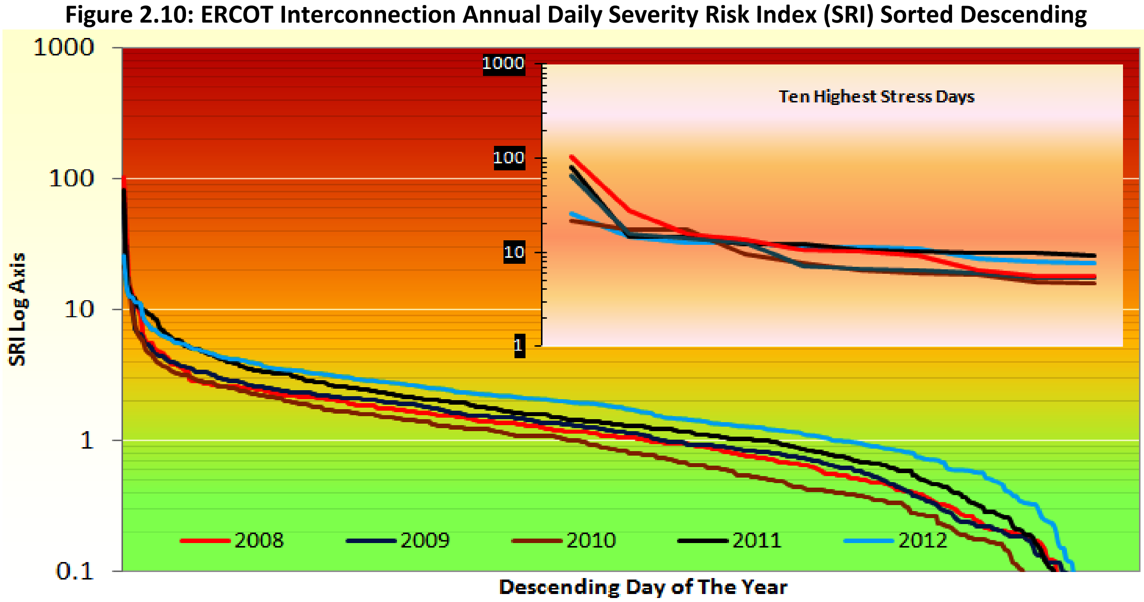
Figure 2.9: Western Interconnection Cumulative SRI by Component for Year 2012



ERCOT Interconnection

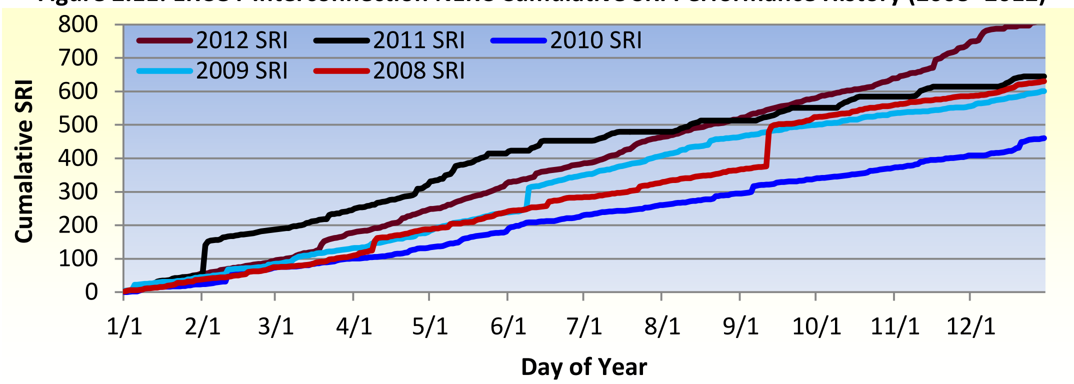
Figure 2.10 shows that 2012's highest stress days were less severe than those in 2011, and the average performance was slightly better in 2011 when compared to 2012.

Figure 2.10: ERCOT Interconnection Annual Daily Severity Risk Index (SRI) Sorted Descending



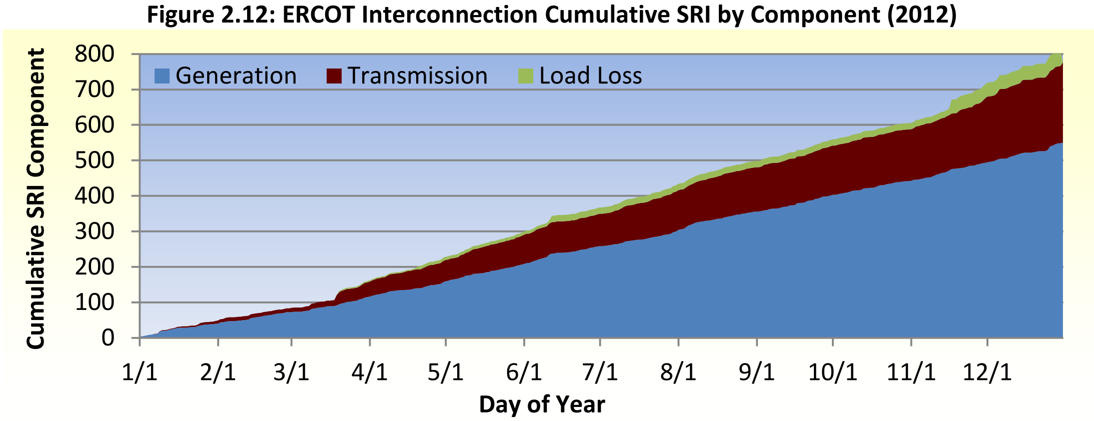
In Figure 2.11, annual cumulative SRI performance of the ERCOT Interconnection is shown. If a step change occurs on the graph, it represents a stress day as measured by the SRI. However, without additional analysis and review of completed events analyses, no trends about the time of the year could be concluded.

Figure 2.11: ERCOT Interconnection NERC Cumulative SRI Performance History (2008–2012)



The figure 2.12 breaks the cumulative SRI performance into the BPS components. The generation component is the largest, followed by transmission and load loss, which is very low. Some small step changes can be seen in the load-loss component due to severe Weather events from the second to fourth quarters of the year.

Figure 2.12: ERCOT Interconnection Cumulative SRI by Component (2012)



Québec Interconnection

There is insufficient historic daily generation outage data for QI. The QI SRI assessment will be provided in a future report.

Chapter 3 – Risk Issue Identification

Overview

In support of making risk-informed decisions, enabling prioritization of issues, and aligning resources to address them, NERC uses disturbance event and equipment availability datasets to identify significant risk clusters. The risk concentration areas can be selected as priority projects to develop coordinated and effective solutions to relevant problems. The stakeholders can respond to the reliability issues, including adjusting NERC's Reliability Standards Development Plan, and focusing compliance monitoring and enforcement activities, if necessary. This chapter presents a conceptual framework and statistical analysis studies that identify the top risks to the BPS using transmission outage data. This framework and these risk analysis methods can be applied using other reliability datasets to discover risk concentration areas.

Based on the 2011–2012 event analysis and 2008–2012 automatic transmission outage data, the two significant risk clusters identified in this chapter are:

1. Protection system misoperations
2. AC substation equipment failure, particularly circuit breaker failure

Due to the historical proportion of disturbance events with misoperation contribution, the NERC Event Analysis program recorded and analyzed all 2012 events with misoperations as an event cause or event contribution. As shown in Figure 1.6, approximately 34 percent of 2012 qualified events[31] involved protection system misoperations. The majority of these misoperations resulted from incorrect settings/logic/design errors, communication failure, and relay failure/malfunction. Additional analysis should be performed to determine if misoperations in the disturbance events were causal or added to the impact of a separate initiating mechanism. Protection system misoperations should be prevented or their impacts mitigated in cases where it is not feasible to prevent the misoperation.

NERC is in the process of revising a number of reliability standards involving protection system misoperations.[41] Also, NERC conducts industry webinars[42] on protection systems. Also, success stories on how Generator Owners and Transmission Owners (TOs) achieve high protection system performance are documented.

Misoperations (as an augmented initiating cause code) were found to have the largest, positive, and statistically significant correlation with 2012 automatic transmission outage severity. Excluding Weather-related and Unknown events, events initiated by misoperations were the largest contributor to transmission severity and transmission severity relative risk.

TADS data collection does not include secondary cause codes. However, the TADSWG conducted a voluntary survey of TOs asking for a breakdown of Failed AC Substation Equipment data by several typical types of equipment for 2012 data. Figure 1.8 illustrates the results received from the 60 responding TOs with TADS Failed AC Circuit Equipment outages during 2012. Circuit breaker failure is the single largest cause of outages in this survey data, followed by arresters and transformers.

In addition to the survey, NERC collected more than one year's worth of event data to analyze disturbance event root causes. From the second quarter of 2011 to the third quarter of 2012, 121 disturbance events were reported with transmission outages.

A deeper investigation into the root causes of circuit breaker failures that contribute to disturbance events is a high priority. NERC recommends that a subject matter expert technical group be formed to further study the contributing factors to ac substation equipment failures, particularly circuit breaker failures, and to propose solutions to improve performance.

Failed AC Substation Equipment as an initiating cause code was found statistically significant and positively correlated to 2008–2012 automatic transmission outage severity. Events initiated by Failed AC Substation Equipment are the second biggest contributor to the 2008–2012 transmission severity if the weather-related and Unknown events are excluded. From the second quarter of 2011 to the third quarter of 2012, 121 disturbance events had automatic transmission outages. Of those, circuit breaker failures were reported as the most often failed equipment inside the ac substation.

[41] http://www.nerc.com/filez/standards/Project2010-05_Protection_System_Misoperations.html
[42] http://www.nerc.com/files/misoperations_webinar_master_deck_final.pdf, December 1, 2011.

A deeper investigation into the root causes of circuit breaker failures that contribute to disturbance events is a high priority. A subject matter expert technical group should be formed to delve into the problem of ac substation equipment failures, particularly circuit breaker failures, and provide risk control solutions to improve performance.

Study Method

Defining BPS Impact

To define the impact, or severity, of each transmission event, a measure based on data must be introduced to quantitatively compare events. The TADS outage data is used to populate the statistical analysis study. For this analysis, the transmission outage impact component of the SRI quantifies BPS impact. Since transmission outages are a significant contributor to overall SRI, this chapter focuses on breaking down individual transmission event causes based on a method derived from TADS outage initiating cause codes.

The SRI presented in Chapter 2 consists of several weighted risk impact components: generation, transmission, and load loss.[43] The transmission outage impact component is defined as $w_T \times N_T$ where w_T is a weighting factor of 30 percent and N_T is the severity impact of transmission outages on the BPS based on TADS outages over the period. The severity of the transmission outages is assessed based on their effect on the power flow through ac transmission circuits.

In order to assess the impact that transmission events have on the BPS, a transmission severity measure was developed. This measure is based on the SRI transmission severity component as shown in Equation 3.1. An approximate average MVA value for each voltage class is used to determine the transmission event severity. The average MVA values, or equivalent MVA values, shown in Table 3.1 are used in the transmission severity definition to assess the severity of transmission outage events on the BPS. These equivalent MVA values are also applied to the transmission severity denominator to normalize the function.

For normalization, the total number of ac circuits from the same year as the outage is multiplied by each voltage class's equivalent MVA rating. For example, if an outage occurred in 2008, the normalization would use the total ac circuits in 2008. This allows comparison of TADS events across years while taking into account the changing amount of circuits within the BPS. The only difference between the calculated transmission severity discussed in this chapter and that of the previous chapter on SRI is that the SRI transmission component is multiplied by the 30 percent weighting factor and a scaling factor of 1,000.

$$Transmission\ Severity_{Trans} = \frac{\sum_{Voltage\ Class}(MVA_{avg} \times AC\ Circuits\ Outages)}{\sum_{Voltage\ Class}(MVA_{avg} \times Total\ AC\ Circuits)} \quad \text{(Equation 3.1)}$$

Table 3.1: Transmission Severity Equivalent MVA Values

Voltage Class	Equivalent MVA Value
200–299 kV	700
300–399 kV	1,300
400–599 kV	2,000
600–799 kV	3,000

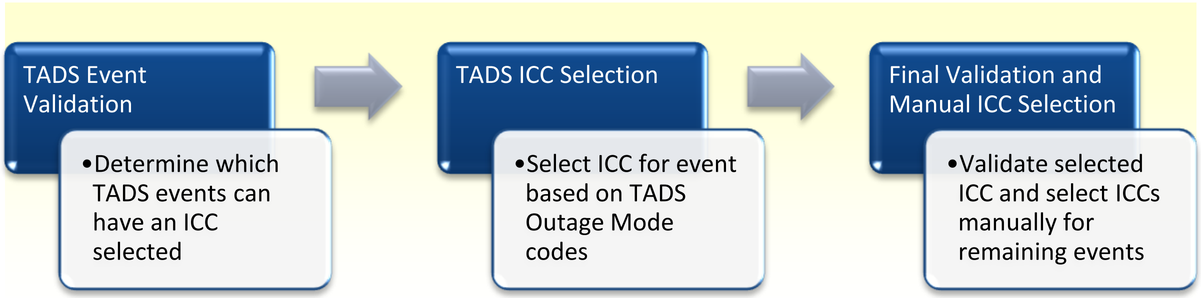
Determining Initiating Causes and Probability

TADS events are categorized by initiating cause codes[44], or ICCs. These ICCs allow analysis to study cause-effect relationships between each event's ICC and the event severity. As shown in Figure 3.1, for single-mode outage TADS events, the outage ICC is selected for the event's ICC. For Common or Dependent Mode TADS events, logical rules were applied to determine the initiating outage. The initiating cause code is used to determine the event's ICC.

[43] http://www.nerc.com/docs/pc/rmwg/pas/index_team/SRI_Equation_Refinement_May6_2011.pdf, pp. 2-3.

[44] For detailed definitions of TADS cause codes, please refer to: http://www.nerc.com/docs/pc/tadswg/2012_TADS_Definitions.pdf, January 14, 2013, pp. 19-20.

Figure 3.1 TADS Event Initiating Cause Code Selection Procedure

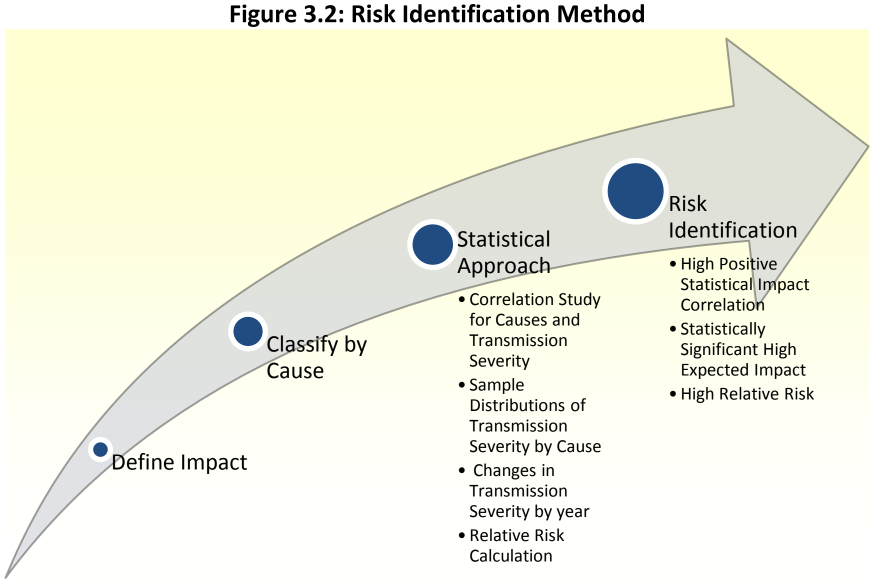


For the TADS event groups initiated by a common cause, the probability[45] of observing the event in an hour is estimated by the corresponding event occurrences reported. Namely, the probability is the total event count during the study period divided by the total number of hours in the same period. Therefore, the sum of the estimated probabilities over all groups is equal to the estimated probability to observe any outage event during a given hour. With the development of the transmission severity and TADS event initiating cause code, it is possible to statistically analyze the five years of TADS data (2008–2012). The statistical analysis shows which initiating cause codes result in the most transmission severity and the ICCs where the transmission severity indicates a trend over time.

Determining Relative Risk

Each study followed a similar approach, as shown in Figure 3.2. To begin, a study was performed to determine the correlation between each ICC and transmission severity, and whether a statistically significant confidence level is 95 percent or higher. Second, a sample distribution was created to determine any statistically significant pair-wise differences in expected transmission severity between ICCs. Also, a time trend analysis was performed where applicable. Finally, relative risk was calculated for each ICC group.

Figure 3.2: Risk Identification Method



A correlation study between transmission severity and the indicator function of a given ICC was performed to test a null statistical hypothesis on zero correlation at significance level 0.05. If the test resulted in rejection of the hypothesis, there was a statistically significant positive or negative correlation between ICC and transmission severity.

Distributions of transmission severity for the entire dataset were examined separately for events with a given ICC. A series of t-tests were performed to compare the expected transmission severity of a given ICC with the expected severity of the

[45] Probability is estimated using event occurrence frequency of each ICC type without taking into account the event duration.

rest of the events at significance level of 0.05. Then, Fisher's Least Square[46] difference method was applied to determine statistically significant[47] differences in the expected transmission severity for all pairs of ICCs.

Where applicable, a time trend analysis was performed. Statistically significant differences in the expected transmission severity for each ICC group were analyzed for each year of data. This showed if the average transmission severity for a given ICC group had changed over time.

Finally, relative risk was calculated for each ICC group. The impact of an outage event was defined as the expected transmission severity associated with a particular ICC group. The risk per hour of a given ICC was calculated as the product of the probability to observe an event with this ICC during an 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 the ICC in the total (combined for all events) risk per hour.

Risk Identification Findings

2012 Study with New Event Types

TOs have provided transmission performance information within NERC through the NERC TADS process. The data used in the studies includes momentary and sustained ac automatic outages of ac circuits (overhead and underground) that operate at voltages greater than or equal to 200 kV with the criteria specified in the TADS process, as shown in Table 3.1.

In 2012, TADS event type reporting was modified to further distinguish normal clearing events from abnormal clearing events. To introduce the additional data into this study where this level of disaggregation is not available for prior years, TADS events with protection system misoperations—event types 61 dependability[48] (failure to operate) and 62 security[49] (unintended operation)—are included with the initiating cause codes (ICC) as shown in Table 3.2. The new ICCs developed are analogous to protection system misoperations, which are comprised of Failed Protection System Equipment (FPSE) and Human Error with event type 61 or 62, as shown in Table 3.1. Table 3.2 lists counts of the 2012 TADS events by augmented ICC. Events initiated by misoperations comprise 8.6 percent of all events and represent the fourth-largest group of events (after weather-related and Unknown ICCs.)

Table 3.2: 2012 TADS Outage Events by Augmented ICC

Initiating Cause Code	TADS Events
Lightning	**852**
Unknown	**710**
Weather, Excluding Lightning	**446**
Misoperations	**321**
Failed Protection System Equipment (FPSE)	226
Human Error w/ Type 61 or 62	95
Failed AC Circuit Equipment	**261**
Failed AC Substation Equipment	**248**
Human Error w/o Type 61 or 62	**212**
Foreign Interference	**170**
Contamination	**160**
Fire	**106**
Other	**104**
Power System Condition	**77**
Vegetation	**43**

[46] For Fisher's least significance difference (LSD) method or test, D. C. Montgomery and G. C. Runger, Applied Statistics and Probability for Engineers. Fifth Edition. 2011. John Wiley & Sons. Pp. 524-526.

[47] At significance level of 0.05.

[48] 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, or
- In the absence of a fault, failure to operate as intended within its designed operating time.

[49] 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.

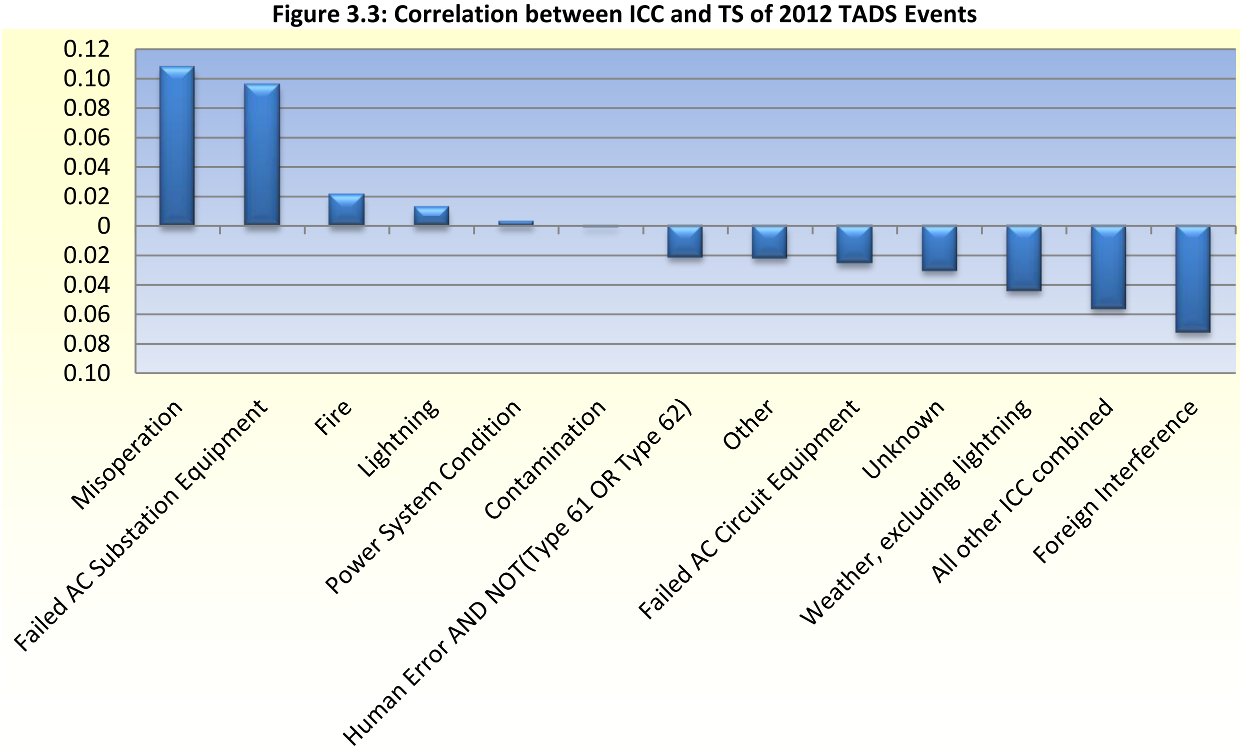
Table 3.2: 2012 TADS Outage Events by Augmented ICC	
Initiating Cause Code	**TADS Events**
Vandalism, Terrorism, or Malicious Acts	**10**
Environmental	**4**
Failed AC/DC Terminal Equipment	**0**
All in TADS	**3753**
All with ICC assigned	**3724**

The Human Error with event type 61 or 62 ICC corresponds to two misoperation causes:[50] incorrect setting/logic/design error or as-left personnel error. However, these events include Human Error during testing and maintenance activities that would not be classified as a misoperation. Human Error during testing and maintenance resulting in protection system activation has contributed to large disturbance events. Therefore, these events were included to capture this risk. After removing 95 events initiated by misoperations, Human Error now accounts for 5.6 percent of all 2012 TADS events.

Figure 3.3 shows the correlations between calculated transmission severity and the given ICC. A positive correlation of initiating cause code to transmission outage severity would indicate a higher likelihood that an event with this ICC will result in a higher transmission outage severity. A negative correlation indicates the contrary; in this case, a lower transmission outage severity would be likely. No existing correlation indicates the absence of a linear relationship between ICC and the transmission outage severity, and that the events with this ICC have the expected transmission severity similar to all other events from the database.

Misoperations were found to have the largest positive correlation with 2012 automatic transmission outage severity. The correlation was also statistically significant. Relative risk of the 2012 TADS events by augmented ICC is listed in Table 3.3. Excluding Weather-related and Unknown events, events initiated by misoperations were the largest contributor to transmission severity and transmission severity relative risk.

Figure 3.3: Correlation between ICC and TS of 2012 TADS Events



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[50] http://www.nerc.com/docs/pc/rmwg/pas/templates/Protection_System_Misoperation_Reporting_Template_Final.xlsx, January 16, 2013.

Table 3.3: Relative Risk by Augmented ICC (2012)				
Group of TADS events (Based on Augmented ICC)	Probability [51] to have an event from a group per hour in 2012	Expected impact (expected transmission severity of an event)	Risk associated with a group per hour 2012	Relative risk per hour associated with a group in 2012
All TADS events	0.427	0.163	0.07	1
All with ICC assigned	0.424	0.162	0.069	0.983
Lightning	0.097	0.164	0.016	0.228
Unknown	0.081	0.155	0.013	0.18
Weather, Excluding Lightning	0.051	0.149	0.008	0.109
Misoperation	0.037	0.198	0.007	0.104
Failed AC Substation Equipment	0.028	0.199	0.006	0.081
Failed AC Circuit Equipment	0.03	0.152	0.005	0.065
Human Error AND NOT (Type 61 OR Type 62)	0.024	0.153	0.004	0.053
Contamination	0.018	0.161	0.003	0.042
Foreign Interference	0.019	0.127	0.002	0.035
Fire	0.012	0.174	0.002	0.03
Other	0.012	0.148	0.002	0.025
Power System Condition	0.009	0.164	0.0014	0.021
Combined Smaller ICC Groups	0.006	0.115	0.0007	0.011

Focusing the statistical analysis of the 2012 TADS data on the transmission severity and initiating causes of TADS events, and aligning that information with misoperations, yields the following results and observations:

- Among focus area-augmented ICCs, misoperations and Failed AC Substation Equipment are the two biggest contributors to the transmission severity risk.
- TADS events initiated by either of these causes statistically have significantly greater expected severity than the rest of TADS events.
- No other single augmented ICC has a statistically significant positive correlation with transmission severity risk.

2008–2012 Combined Study

Table 3.4 lists a total count of TADS events by ICC for 2008–2012. The three biggest groups of events correspond to ICCs: Lightning, Unknown, and Weather Excluding Lightning. The next four groups of events are initiated by Human Error, Failed AC Circuit Equipment, Failed AC Substation Equipment, and Failed Protection System Equipment.

Table 3.4: TADS Outage Events by ICC (2008–2012)						
Initiating Cause Code	2008	2009	2010	2011	2012	2008–2012
Lightning	949	789	741	822	852	4,153
Unknown	917	673	821	782	710	3,903
Weather, Excluding Lightning	662	534	673	539	446	2,854
Human Error (HE)	301	291	305	291	307	1,495
Failed AC Circuit Equipment	307	257	277	306	261	1,408
Failed AC Substation Equipment	253	266	238	289	248	1,294
Failed Protection System Equipment (FPSE)	282	229	234	234	226	1,205
Foreign Interference	181	199	173	170	170	893
Contamination	97	96	145	132	160	630
Power System Condition	109	112	74	121	77	493
Other	104	107	84	91	104	490
Fire	119	92	84	63	106	464
Vegetation	60	29	27	44	43	203

[51] As estimated from the frequency of the events of each type without taking into account the event duration

Table 3.4: TADS Outage Events by ICC (2008–2012)						
Initiating Cause Code	**2008**	**2009**	**2010**	**2011**	**2012**	**2008–2012**
Vandalism, Terrorism, or Malicious Acts	15	4	6	5	10	40
Environmental	2	5	11	5	4	27
Failed AC/DC Terminal Equipment	1	1	2	0	0	4
All in TADS	4,390	3,705	3,918	3,934	3,753	19,700
All with ICC assigned	4,359	3,684	3,895	3,894	3,724	19,556

Almost all ICC groups have a sufficient sample size to be used in a statistical analysis. Four ICCs (Vegetation; Vandalism, Terrorism, or Malicious Acts; Environmental, and Failed ac/dc terminal equipment) will be grouped together in this report and labeled "Combined smaller ICC groups" for statistical analysis and will then be compared to other ICC groups and studied with respect to annual changes of transmission severity.

The cause-effect relationship that defines initiating cause code for a TADS event allows ICC assignment to a majority of TADS events. These 19,546 events comprise 99.2 percent of the total number of TADS events for the years 2008–2012 and 98.6 percent of the total transmission severity of the database. Table 3.5 provides the corresponding statistics by year.

Table 3.5: TADS Event Summary (2008–2012)						
Summary	**2008**	**2009**	**2010**	**2011**	**2012**	**2008–2012**
Number of TADS events	4,390	3,705	3,918	3,934	3,753	19,700
Number of events with ICC assigned	4,359	3,684	3,895	3,894	3,724	19,546
Percentage of events with ICC assigned	99.30%	99.40%	99.40%	99.00%	99.20%	99.20%
Transmission severity all TADS events	793.7	643.79	676	665.7	612.4	2,779.2
Transmission severity of events with ICC assigned	782	636.8	667.5	654.6	602.1	3343
Percentage of transmission severity of events with ICC assigned	98.50%	98.90%	98.70%	98.30%	98.30%	98.60%

As shown in Table 3.6, events related to Weather represent the largest percentage of transmission severity. These are provided into two ICC groups in TADS: Lightning, and Weather Excluding Lightning. TADS events with an ICC of Lightning result in the greatest combined transmission severity for all TADS events. Therefore, Lightning event impacts on SRI are significant but may not be a large contributor to overall system reliability. These Lightning events are typically momentary, single-mode outages and restore quickly.

Among non-weather-related known ICCs, Human Error and Failed AC Substation Equipment are the two greatest contributors to the transmission severity. These two are also tracked through closely related adequate level of reliability (ALR) metrics. Moreover, TADS events initiated by either of these two causes have statistically significantly greater expected severity than TADS non-Weather ICC events. This is likely because a single substation element (equipment) failure may lead to multiple line outages on lines emanating from the same substation bus or end point. Therefore, the equipment failure would have the potential to substantially impact the network in that location.

Table 3.6: Evaluation of ICC Relative Risk (2008–2012)				
Group of TADS events	**Probability[47] above to have an event from a group per hour**	**Transmission severity (expected impact of an event)**	**Risk associated with a group per hour**	**Relative risk per ICC group**
All TADS events	0.449	0.172	0.077	**100.0%**
All TADS with ICC assigned	0.446	0.171	0.076	**98.6%**
Failed AC Substation Equipment	0.030	0.200	0.006	**7.6%**
Human Error	0.034	0.179	0.006	**7.9%**
Failed AC Circuit Equipment	0.032	0.153	0.005	**6.4%**
Failed Protection System Equipment	0.027	0.180	0.005	**6.4%**
Lightning	0.095	0.171	0.016	**20.9%**
Weather, Excluding Lightning	0.065	0.167	0.011	**14.1%**
Unknown	0.089	0.167	0.015	**19.2%**

Table 3.6: Evaluation of ICC Relative Risk (2008–2012)				
Group of TADS events	Probability[47] above to have an event from a group per hour	Transmission severity (expected impact of an event)	Risk associated with a group per hour	Relative risk per ICC group
Contamination	0.014	0.198	0.003	**3.7%**
Foreign Interference	0.020	0.138	0.003	**3.6%**
Power System Condition	0.011	0.162	0.002	**2.4%**
Other (as defined in TADS)	0.011	0.166	0.002	**2.4%**
Fire	0.011	0.202	0.002	**2.8%**
Combined Smaller ICC Groups	0.006	0.152	0.001	**1.2%**

Common/Dependent Mode Event ICC Study (2008–2012)

TADS data also provides information to classify outages as single-mode or Common/Dependent Mode (CDM) events that should be evaluated separately. CDM events are those that result in multiple transmissions element outages. It is important to monitor and understand CDM events due to their potential risk to system reliability.

Analysis of the TADS CDM events indicated that events with ICCs of Failed AC Substation Equipment and Human Error are the two largest contributors to transmission severity. CDM events initiated by Failed AC Substation Equipment have statistically greater expected severity than other CDM events; however, the difference in transmission severity of CDM events initiated by Human Error and all other CDM events is not statistically significant. In other words, CDM events initiated by Human Error on average have the same transmission severity as all the other CDM events that occurred in 2008–2012. CDM events are a subset of the TADS events considered previously. Table 3.7 indicates that 27.3 percent of total transmission severity in TADS is due to CDM events, and it provides a breakdown of relative risk of CDM events by ICC.

Table 3.7: Evaluation of CDM Event ICC Contributions to SRI (2008–2012)				
Group of TADS events	Probability[51] to have an event from a group per hour	Transmission severity (expected impact of an event)	Risk associated with a group per hour	Relative risk per CDM ICC group as a % of all TADS ICCs
All TADS events	0.449	0.172	0.077	**100.0%**
CDM events	0.085	0.249	0.021	**27.3%**
CDM with ICC assigned	0.082	0.246	0.020	**26.1%**
CDM Failed AC Substation Equipment	0.011	0.271	0.003	**3.8%**
CDM Failed AC Circuit Equipment	0.005	0.242	0.001	**1.4%**
CDM Human Error	0.007	0.251	0.002	**2.4%**
CDM Failed Protection System Equipment	0.008	0.235	0.002	**2.3%**
CDM Lightning	0.016	0.255	0.004	**5.3%**
CDM Weather, Excluding Lightning	0.009	0.265	0.002	**3.1%**
CDM Unknown	0.009	0.244	0.002	**2.7%**
CDM Power System Condition	0.008	0.158	0.001	**1.7%**
CDM Other (as defined by TADS)	0.003	0.261	0.001	**1.0%**
CDM Fire	0.002	0.300	0.001	**0.9%**
CDM Contamination	0.002	0.324	0.0005	**0.6%**
CDM Foreign Interference	0.002	0.207	0.0005	**0.6%**
CDM Combined smaller ICC groups	0.001	0.285	0.0003	**0.3%**

Chapter 4 – Reliability Indicator Trends

Overview

Building upon last year's metric review, the results of 18 performance metrics continue to be assessed. Each metric is designed to show a measure for a given ALR characteristic. In Table 4.1, each metric is placed into a grid showing which ALR characteristic it represents. Also, the standard objective areas are shown for each ALR metric to provide a connection between standard objectives and ALR characteristics.

Due to varying data availability, each of the performance metrics does not address the same time periods (some metrics have just been established, while others have data over many years). At this time, the number of metrics is expected to remain constant; however, other metrics may supplant existing metrics that may have more merit. An overview of the ALR metric ratings for 2011 and 2012 is provided in Table 4.2. Although a number of performance categories have been assessed, some do not have sufficient data to derive conclusions from the metric results. Assessment of these metrics should continue until sufficient data is available to determine if the metric is a good indicator of the ALR objective it is meant to measure.

Table 4.1: Adequate Level of Reliability Characteristics[52]

Standard Objectives	Boundary	Contingencies	Integrity	Protection	Restoration	Adequacy
Reliability Planning and Operating Performance		ALR1-4	ALR3-5	ALR4-1		ALR1-3 ALR6-1 ALR6-11 ALR6-12 ALR6-13 ALR6-14 ALR6-15 ALR6-16
Frequency and Voltage Performance	ALR1-5 ALR1-12	ALR2-4 ALR2-5		ALR2-3		
Reliability Information						
Emergency Preparation						ALR6-2 ALR6-3
Communications and Control						
Personnel						
Wide-area View						
Security						

These metrics exist within a reliability framework and overall, the performance metrics being considered address the fundamental characteristics of an ALR.[53] Each of the performance categories being measured by the metrics should be considered in aggregate when making an assessment of the reliability of the BPS with no single metric indicating exceptional or poor performance of the power system. Due to regional differences (size of the Region, operating practices, etc.) it is important to keep in mind that comparing the performance of one Region to another would be erroneous and inappropriate. Furthermore, depending on the Region being evaluated, one metric may be more relevant to a specific Region's performance than another, and assessments may be more subjective than a purely mathematical analysis. Finally, choosing one Region's best metric performance to define targets for other Regions is also inappropriate.

Another metric reporting principle is to retain anonymity of any individual reporting organization. Thus, details will be presented only to a point that does not compromise anonymity of any individual reporting organization.

[52] The blank fields indicate no metrics have been developed to assess related ALR characteristics at this time.

[53] Definition of "Adequate Level of Reliability," Dec 2007, http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf

Table 4.2: Metric Trend Ratings

ALR	Boundary	Trend Rating
1-5	System Voltage Performance	◑**
1-12	Interconnection Frequency Response	◑
	Contingencies	
1-4	BPS Transmission Related Events Resulting in Loss of Load	●
2-4	Average Percent Non-Recovery Disturbance Control Standard Events	◕
2-5	Disturbance Control Events Greater than Most Severe Single Contingency	◑*
	Integrity	
3-5	Interconnected Reliability Operating Limit/ System Operating Limit (IROL/SOL) Exceedances	◑*
	Protection	
2-3	Activation of Underfrequency Load Shedding	◑
4-1	Automatic Transmission Outages Caused by Failed Protection System Equipment	◑**
	Adequacy	
1-3	Planning Reserve Margin	◑*
6-1	Transmission Constraint Mitigation	◑
6-2	Energy Emergency Alert 3 (EEA3)	◑
6-3	Energy Emergency Alert 2 (EEA2)	◑
6-11	Automatic AC Transmission Outages Initiated by Failed Protection System Equipment	◑
6-12	Automatic AC Transmission Outages Initiated by Human Error	◑
6-13	Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment	◑
6-14	Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment	◑
6-15	Element Availability Percentage	◑
6-16	Transmission System Unavailability	◑

Trend Rating Symbols	
Significant Improvement	●
Slight Improvement	◕
No Change	◑
Inconclusive/Mixed	◑*
Slight Deterioration	◔
Significant Deterioration	○
New Data	◑**

This chapter provides a discussion of the ALR metric trend ratings and activity on certain key metrics. The full set of metrics and their descriptions, along with the results and trending are on the NERC public website.[54]

ALR1-4 BPS Transmission-Related Events Resulting in Loss of Load

Background

This metric measures BPS transmission-related events resulting in the loss of load, excluding weather-related outages. Planners and operators can use this metric to validate their design and operating criteria by identifying the number of instances when loss of load occurs. For the purposes of this metric, an "event" is an unplanned transmission disturbance that produces an abnormal system condition due to equipment failures or system operational actions, that results in the loss of firm system demand for more than 15 minutes. The reporting criteria for such events are outlined below:[55]

[54] Assessments & Trends: Reliability Indicator, http://www.nerc.com/page.php?cid=4|331

[55] Disturbance Reporting, 01/01/2007, http://www.nerc.com/files/EOP-004-1.pdf

- Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demand totaling more than 300 MW.
- All other entities are required to report all such losses of firm demands totaling more than 200 MW or 50 percent of the total customers being supplied immediately prior to the incident, whichever is less.
- Firm load shedding of 100 MW or more used to maintain the continuity of the BPS reliability.

Assessment

Figure 4.1 shows that the number of BPS transmission-related events resulting in loss of firm load from 2002 to 2011 is relatively constant. The year 2012 was better in terms of transmission-related load loss events, with only two events having resulted in total load loss of 1,055 MW. On average, eight to 10 events are experienced per year prior to 2012. The top three years in terms of load loss are 2003, 2008, and 2011, as shown in Figure 4.2. 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. Further analysis and continued assessment of the trends over time is recommended.

Figure 4.1: ALR1-4 BPS Transmission-Related Events Resulting in Load Loss (2002–2012)

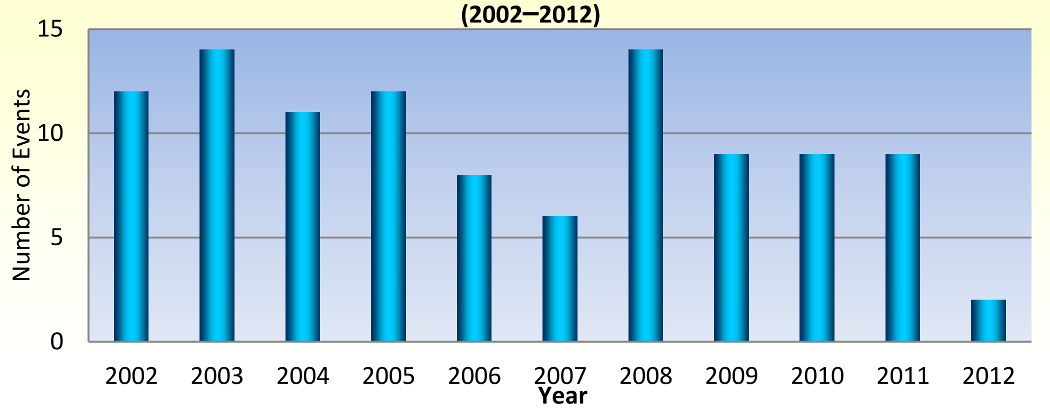
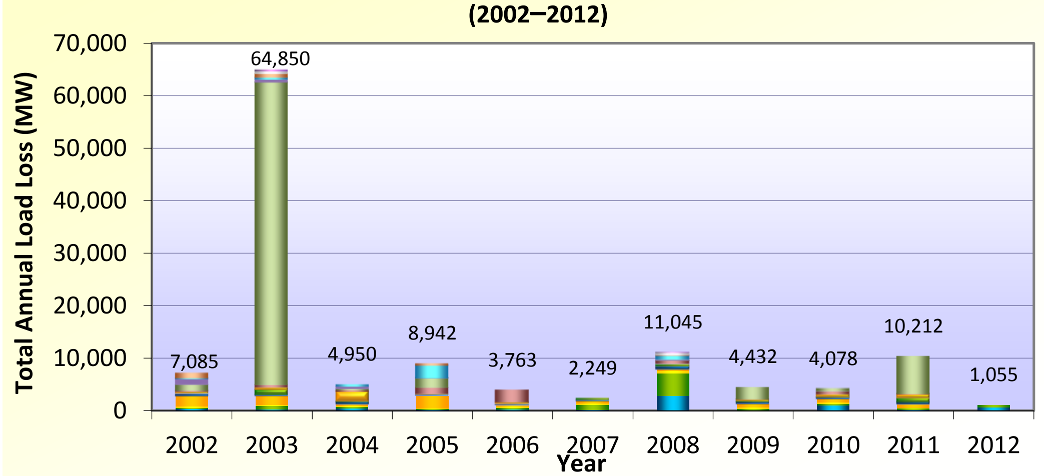


Figure 4.2: ALR1-4 BPS Transmission-Related Events Resulting in Load Loss (2002–2012)



Special Considerations

The collected data does not indicate whether load loss during an event occurred as designed or not as designed. Further investigation into the usefulness of separating load loss as designed and unexpected firm load loss should be conducted. Also, differentiating between load loss as a direct consequence of an outage compared to load loss as a result of operation action to mitigate an IROL/SOL exceedance should be investigated.

ALR1-12 Metric Interconnection Frequency Response

Background

This metric is to track and monitor interconnection frequency response. Frequency response is a measure of an interconnection's ability to stabilize frequency immediately following the sudden loss of generation or load. It is a critical component to the reliable operation of the BPS, particularly during disturbances. The metric measures the average frequency response for all events where frequency deviates more than the interconnection's defined threshold as shown in Table 4.3.

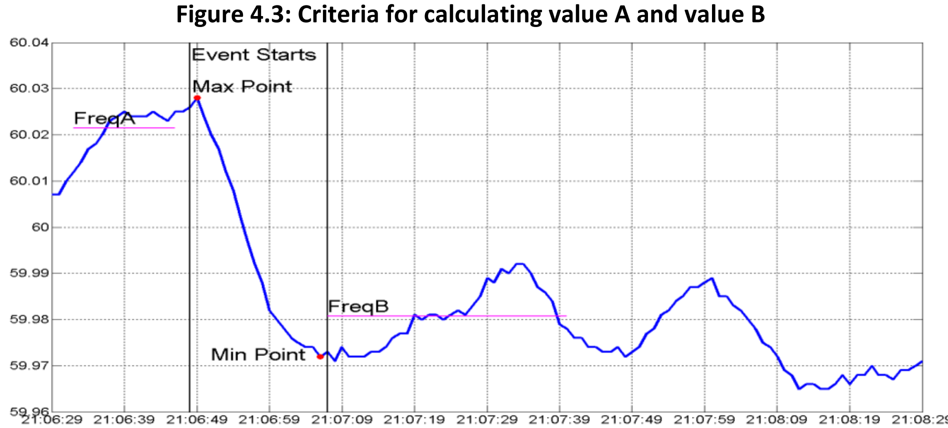
The following are frequency response calculations of Eastern Interconnection (EI), Western Interconnection (WI), ERCOT Interconnection, and Québec Interconnection. The frequency response should not be compared between interconnections, because their BPS characteristics differ significantly in terms of number of facilities, miles of line, operating principles, and simple physical, geographic, and climatic conditions. Figure 4.3 shows the criteria for calculating average values A and B used to report frequency response. The event starts at time t±0. Value A is the average from t-16 to t-2 seconds, and Value B is the average from t+20 to t+52 seconds. The difference of value A and B is the change in frequency[56] used for calculating frequency response.

The monthly frequency event candidate lists are posted on the NERC Resources Subcommittee[57] website. These lists are vetted by the NERC Frequency Working Group and the final list is chosen on a quarterly basis. The data is used to support Frequency Response Standard (FRS) BAL-003. The frequency event data collection process is described in the BAL-003 Frequency Response Standard Supporting Document.[58]

Table 4.3: Frequency Event Triggers

Interconnection	ΔFrequency (mHz)	MW Loss Threshold	Rolling Windows (seconds)
Eastern	40	800	15
Western	70	700	15
ERCOT	90	450	15
Québec	300	450	15

Figure 4.3: Criteria for calculating value A and value B



The actual megawatts (MW) loss for the significant frequency events is determined jointly by NERC and Regional Entity situation awareness staff. Both the change in frequency and the MW loss determine whether the event qualifies for further consideration in the monthly frequency event candidate list. The final monthly datasets are used to analyze the

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[56] ALR1-12 Frequency Response Data Collections Process, Slide 18 of Presentation 1, 10/26-27/2011 http://www.nerc.com/docs/oc/rs/RS_Presentation_October_2011.pdf

[57] Resource Subcommittee (RS), http://www.nerc.com/filez/rs.html

[58] BAL-003-1 Frequency Response & Frequency Bias Setting Standard, 07/06/2011, http://www.nerc.com/docs/standards/dt/Attachment%20A%20%20Frequency%20Response%20Standard%20Supporting%20Document%20-%20RL-%202011%2007%2011.pdf

interconnection frequency response performance. Table 4.4 shows the number of frequency events per year for each interconnection.

Table 4.4: Yearly Number of Frequency Events				
Interconnection	2009	2010	2011	2012
Western	25	29	25	12
Eastern	44	49	65	28
ERCOT	51	67	65	63
Québec	-	-	20	28

Assessment

Based on the recommendations from the *2012 State of Reliability* report, statistical significance tests have been applied to interconnection frequency response datasets, and additional analysis on time of year, load levels, and other attributes were also conducted. The overall observations and test results are summarized below:

- The EI frequency response was stable from 2009 through 2012.
- The ERCOT Interconnection frequency response was stable from 2009 through 2012.
- The QI frequency response was stable from 2011 through 2012.[59]
- The WI frequency response was stable from 2009 through 2012.

Figure 1.5 illustrates the interconnection trends using a linear regression method. The statistical significance analysis of the observed trends can be found in Appendix B.

Special Considerations – Explanatory Variables

As recommended in the *2012 State of Reliability* report, specific attributes should be studied in order to understand their influence on severity of frequency deviation events. For each interconnection, a set of six attributes was selected as candidates to be included as explanatory variables (regressors) in the multiple regression models that describe the interconnection frequency response. These variables are not pair-wise uncorrelated, and some pairs are strongly correlated; however, all of them are considered as the candidates to avoid loss of an important contributor to the frequency response variability. The model selection methods help remove highly correlated regressors and run a multicollinearity diagnostic (variance inflation diagnostic) for the selected multiple regression model. The following six specific attributes are included in the studies. Each of these variables was tested for the frequency response data of each interconnection. The details of this analysis can be found in Appendix B.

- Summer
- Winter
- High Pre-Disturbance Frequency
- On-peak Hours
- Time
- Interconnection Load Level

For the EI, load level has the biggest impact on frequency response, followed by the indicator of High Pre-disturbance Frequency and Time. Interconnection Load and Time[60] are positively correlated with frequency response. High Pre-disturbance Frequency is negatively correlated with frequency response.

[59] Only 2011 and 2012 data is available for Québec Interconnection.

[60] Note that the correlation between time and frequency response is positive and this is equivalent to the fact that the slope is positive and the trend line is increasing function. However, the correlation is not statistically significant. This leads to the failure to reject the

For the WI, the indicator of High Pre-disturbance Frequency has the biggest impact on frequency response, followed by the Interconnection Load. The indicator is negatively correlated with frequency response, while the Interconnection Load is positively correlated with frequency.

For ERCOT, the indicator of High Pre-disturbance Frequency has the biggest impact on frequency response, followed by the indicator of Winter. Both indicators, High Pre-disturbance Frequency and Winter, are negatively correlated with frequency response.

For Hydro Quebec, the indicator of Winter has the biggest impact on frequency response, followed by the indicator of On-peak Hours and the Interconnection Load. Indicators Winter and On-peak Hours, and Interconnection Load are positively correlated with frequency response.

ALR3-5 Interconnection Reliability Operating Limit/ System Operating Limit (IROL/SOL) Exceedances

Background

This metric measures the number of times that a defined Interconnection Reliability Operating Limit (IROL) or System Operating Limit (SOL) was exceeded and the duration of these events. Exceeding IROL/SOLs could lead to outages if prompt operator control actions are not taken to return the system to within normal operating limits. In addition, exceeding the limits may not directly lead to an outage, but it puts the system at unacceptable risk if the operating limits are exceeded beyond T_v.[61] To monitor how quickly IROL/SOLs are returned to within normal limits, the data are grouped into four time segments, as shown in Table 4.5.

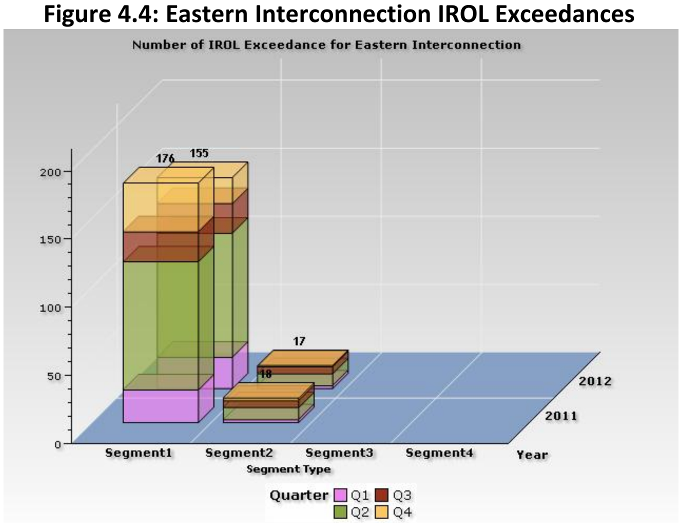
Table 4.5: Exceedance Duration Segment

Segment Type	IROL/SOL Duration
Segment1	10 secs < Duration ≤ 10 mins
Segment2	10 mins < Duration ≤ 20 mins
Segment3	20 mins < Duration ≤ 30 mins
Segment4	Duration > 30 mins

Eastern Interconnection

Figure 4.4 shows the number of IROL exceedances separated by quarter and segment type for the EI for 2011 and 2012. The second quarter shows the most exceedances for the EI in both years that were due to planned transmission outages and that caused congestion and higher flows on limited number of paths.

Figure 4.4: Eastern Interconnection IROL Exceedances



null hypothesis of zero correlation. So even though the slightly increasing trend for frequency response in time was observed, there is a high probability that the positive correlation and the positive slope occurred by chance.

[61] T_v is the maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes.

Western Interconnection

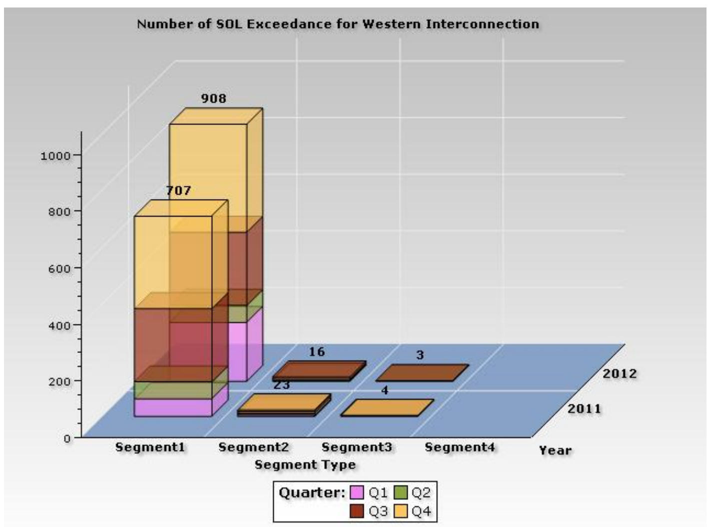
"Path Limits" in the WI are generally called SOLs and can be more conservative than the path limits used in the Eastern and ERCOT Interconnections. Many of the WI path limits have been calculated using N-2 outage conditions and have identified reactive margins. Exceedance of these SOLs does not represent an insecure N-1 system state. Figure 4.5 shows the number of SOL exceedances separated by quarter and segment type for the WI for 2011 and 2012.

The number of SOL exceedance has increased in the fourth quarter of 2012 due to the following reasons:

- Reduced SOLs due to transmission outages concurrent with increased path utilization
- Scheduled and forced generator outages in the Desert Southwest and Pacific Northwest subregions
- Limited ability to control unscheduled flow due to water flow qualified phase shifting transformer outage

There were no existing identified IROLs in the WI. As part of a continuing review of the September 8, 2011 Southwestern blackout event, WECC is examining the operating limit setting methodology for potential changes.

Figure 4.5: Western Interconnection ALR3-5 SOL Exceedances

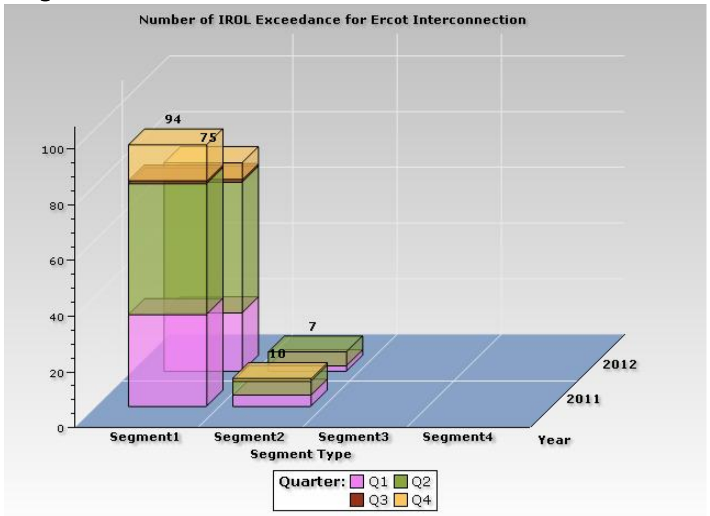


ERCOT Interconnection

Figure 4.6 shows there were fewer exceedances in 2012 than 2011. Most of this-year-to year change is the result of adjusting to ERCOT's new nodal dispatch system, which was implemented in late 2010. Other contributions to the improved performance are smoother transitions in limit values due to the implementation of real-time analysis tools, and more available transmission. Improved transmission resulted in another major drop in exceedances between 2012Q1 and 2013Q1, with the expectation that with additional transmission, the IROL will cease to exist by 2013Q4.

More dynamic wind generation during the fall (Q4), winter (Q1), and spring (Q2), as compared to the summer (Q3) is a result of seasonality. This seasonal rise in exceedances is also reflective of prompt changes in generation patterns to accommodate shifting load demand. In Q3 the outages were still prevalent (especially compared to Q1), but the wind and generation changes are less dramatic and more manageable.

Figure 4.6: ERCOT Interconnection ALR3-5 IROL Exceedances



Québec Interconnection

The data is available for the assessment of Québec Interconnection, but being singleton in nature, this information is considered confidential and not to be mentioned in this report.

ALR4-1 Protection System Misoperations

Background

Protection system misoperations were identified as one of the problem areas in the *2012 State of Reliability* report. Since 2012, additional misoperation data has been collected. The Protection System Misoperations Task Force (PSMTF) was also formed to identify areas to reduce protection system misoperations. The PSMTF analyzed protection system misoperation data, researched possible root causes, and developed observations, conclusions, and recommendations to help registered entities manage risk by reducing the most frequent causes of protection system misoperations.

Assessment

Figure 4.7 shows misoperations on a monthly basis from April 1, 2011 to September 30, 2012. Overall, the trend is periodic, with peaks in June 2011 and July 2012. Figure 4.8 illustrates the top three cause codes assigned to misoperations: incorrect setting, logic, or design error; relay failures/malfunctions; and communication failure.

Figure 4.7: NERC Misoperations by Month (2Q2011–3Q2012)

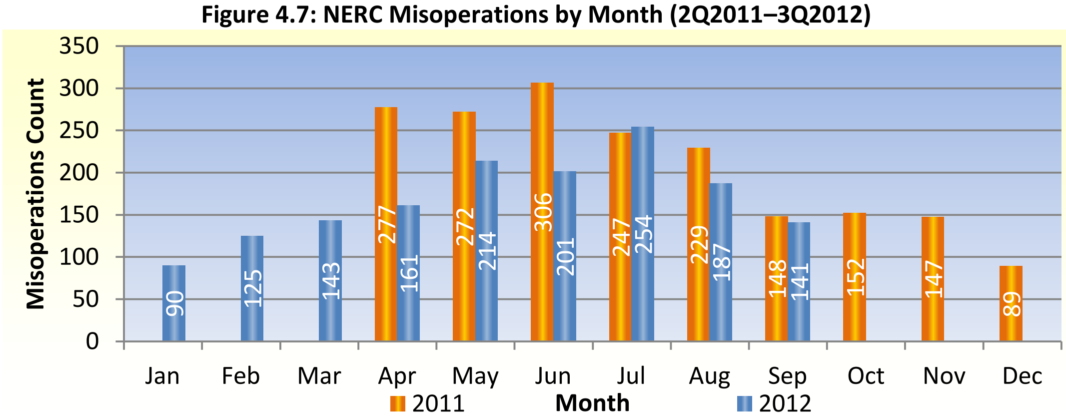
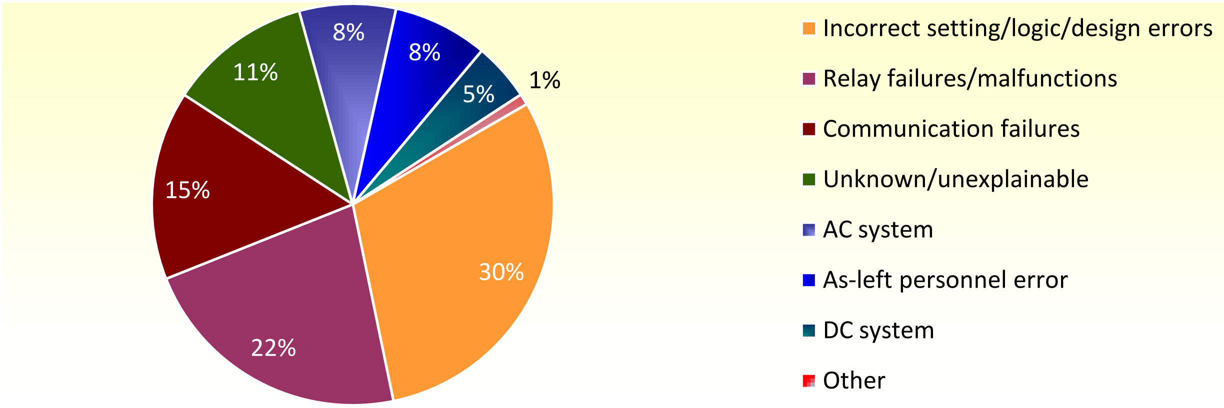


Figure 4.8: NERC Misoperations by Cause Code from 2011Q2 to 2012Q3



The NERC Event Analysis group has recorded and analyzed all 2012 events with misoperations as an event cause or event contribution. As shown in Figure 1.6, approximately 27 percent of 2012 qualified events[31] involved protection system misoperations. The majority of these misoperations resulted from incorrect settings/logic/design errors, communication failure, and relay failure/malfunction. Additional analysis should be performed to determine if misoperations in the disturbance events were causal or added to the impact of a separate initiating mechanism. Protection system misoperations should be prevented or their impacts mitigated in cases where it is not feasible to prevent the misoperation.

NERC is in the process of revising a number of reliability standards involving protection system misoperations.[62] To increase awareness and transparency, NERC will continue to conduct industry webinars[63] on protection systems and document success stories on how Generator Owners and Transmission Owners are achieving high protection system performance. The quarterly protection system misoperation trending by NERC and the Regional Entities can be viewed on NERC's website.[64]

PSMTF analyzed over 1,500 misoperations from 2011 to 2012Q2 with a focus on the top three causes. After analyzing the misoperation data, the PSMTF found ways to potentially reduce the amount of future misoperations. These results are summarized in Figure 1.7. Since some entities already perform one or more of these activities, entities should consider these suggestions for improvement based on their particular circumstances.

There are several areas, as shown in the figure above, where misoperation reduction is possible for entities. First, relay applications requiring coordination of functionally different relay elements should be avoided. Secondly, misoperations due to setting errors can potentially be reduced. Techniques that could be used to reduce the application of incorrect settings include peer reviews, increased training, more extensive fault studies, standard templates for setting standard schemes using complex relays, and periodic review of existing settings when there is a change in system topography. Finally, firmware updates may affect relay protection settings, logic, communications, and general information stored and reported by the relay. Entities should be aware of what version of firmware they have on their microprocessor-based relays. Entities should also monitor if the relay vendor has issued updated relay firmware.

Special Considerations

NERC undertook an effort to collect total protection system operations to create a more useful metric to monitor protection system misoperation performance. This will first be requested with the 2012Q4 misoperation data. Having the total number of operations will allow an easy way to normalize and trend protection system misoperations over time.

ALR6-2 Energy Emergency Alert 3 (EEA3)

Background

This metric identifies the number of times Energy Emergency Alert Level 3 (EEA3) is issued. EEA3 events are firm-load interruptions imminent or in progress due to capacity or energy deficiencies. EEA3 events are currently reported, collected, and maintained in NERC's Reliability Coordinator Information System (RCIS), defined in the NERC Standard EOP-002.[65] The

[62] http://www.nerc.com/filez/standards/Project2010-05_Protection_System_Misoperations.html
[63] http://www.nerc.com/files/misoperations_webinar_master_deck_final.pdf
[64] http://www.nerc.com/page.php?cid=4|331|400
[65] The latest version of EOP-002 is available at: http://www.nerc.com/files/EOP-002-3_1.pdf.

number of EEA3s per year provides a relative indication of performance measured at a Balancing Authority or interconnection level. As historical data is gathered, trends provide an indication of either decreasing or increasing use of EEA3s, signaling real-time adequacy of the electric supply system. This metric can also be considered in the context of the Planning Reserve Margin. Significant increases or decreases in EEA3 events with relatively constant ALR1-3 Planning Reserve Margins could indicate changes in the adequacy of the BPS that would require a review of resources. However, lack of fuel and dependence on transmission for imports into constrained areas can also contribute to increased EEA3 events.

Assessment

Table 4.6 shows the number of EEA3 events from 2006 to 2012 at a regional entity level. An interactive quarterly trending is available at the Reliability Indicator's page.[66] Due to the large number of EEA3s in the Acadiana Load Pocket region, the SPP RC coordinated an operating agreement in 2009 with the five operating companies in the ALP to improve reliability performance as an interim step while a $200 million transmission construction program was initiated by Cleco Power, Entergy, and Lafayette Utilities. These construction projects, including several 230 kV lines, were completed by summer of 2012 and as a result, there were no EEAs issued for the area in 2012.

Table 4.6: Energy Emergency Alert 3

Number of Events	Year						
	2006	2007	2008	2009	2010	2011	2012
NERC (Total)	7	23	12	41	14	23	20
FRCC	0	0	0	0	0	0	0
MRO	0	0	0	0	0	0	0
NPCC	0	0	1	1	0	0	0
RFC	0	3	1	0	2	0	1
SERC	4	14	2	3	4	2	11
SPP RE	1	5	3	35	4	15	6
TRE	0	0	0	0	0	1	0
WECC	2	1	5	2	1	5	1

Within SERC-SE Assessment Area, EEA3s were declared in June and July due to Level 5 Transmission Loading Relief conditions for a flowgate outside of the SERC-SE Assessment Area. By previous agreement with the neighboring SERC RC, dynamic schedule curtailments could be exempted from the TLR curtailment on a remote flowgate if the curtailment would cause an EEA3 condition. In this case, the EEA3 entity had plenty of generation capacity to serve the load but would not have been able to use it if the dynamic schedule had been curtailed. The curtailments were exempted and no load was shed.

Special Considerations

The need to include the magnitude and duration of the EEA3 declarations in this metric is under evaluation.

[66] The EEA3 interactive presentation is available on the NERC website at: http://www.nerc.com/page.php?cid=4|331|335.

Chapter 5 – Key Compliance Monitoring Indicator Trend

Overview

With the beginning of the sixth year of mandatory and enforceable reliability standards, the need for measuring and reporting on compliance trends and their impact on reliability from the implementation of the NERC Compliance Monitoring and Enforcement Program (CMEP) is necessary. The objective is to create a set of metrics that provide reliability trends and industry feedback that resulted from NERC's CMEP. These performance measures focus on reliability impacts and provide a basis for informed decision making. They also effectively engage stakeholders in a dialogue about high risk violations, and help guide a strategic plan for risk reduction and reliability improvement.

Under the direction of the NERC Operating and Planning Committees, a Key Compliance Monitoring Index[67] (KCMI) was developed and endorsed by the NERC Compliance and Certification Committee (CCC). The five-year assessment of the KCMI indicates that the risk to BPS reliability—based on the number of NERC Standards violations that have severe risk impact—has trended lower. In addition, the CMEP's processes have been developed and enhanced since 2008, to provide more certainty on actions, outcomes, and reliability consequences. As of December 31, 2012, 5,115 confirmed violations have been processed for the period June 18, 2007 through December 31, 2012. Of these violations, 85.3 percent had minimal impact to reliability, 13.1 percent had moderate impact, and 2 percent had serious impact, as shown in Table 5.1.

Table 5.1: NERC Confirmed Violations by Assessed Risk* (June 18, 2007 – Dec. 31, 2012)

Assessed Risk	BAL	CIP	COM	EOP	FAC	INT	IRO	MOD	NUC	PER	PRC	TOP	TPL	VAR	ALL	
Minimal	80	1806	56	242	515	26	64	34	1	99	853	193	125	268	4362	85.3%
Moderate	2	410	13	27	24	1	4			11	116	34	3	27	672	13.1%
Serious		31	2	3	6		2			3	23	7		4	81	1.6%
Total	82	2247	71	272	544	27	71	34	1	113	992	234	128	299	5115	

**This table does not include the 92 standards violations included in FERC's stipulation and consent agreements.*[68]

The confirmed violations were separated into 14 standard categories and three types of risk impact levels: minimal, moderate, and serious. There were 81 confirmed violations assessed to be of serious risk to reliability, and these violations constitute 1.6 percent of all confirmed violations. Among these 81 violations, the majority were for CIP and PRC standards.

Key Compliance Monitoring Index (KCMI)

Background

The Key Compliance Monitoring Indicator (KCMI) is a historical measure that is useful for trending. The KCMI does not address real-time or forward-looking compliance performance. It measures compliance improvement based on a set of 26 key reliability standards requirements, shown in Table 5.2. The index increases if the compliance improvement is achieved over a trending period. The violations included in KCMI all have high violation risk factors (VRFs) and actual or potential serious reliability impacts. Based on these two dimensions, known unmitigated violations are normalized over the number of applicable registered entities subject to a particular standard requirement, as shown in Equation 5.1.

$$KCMI = 100 - \sum \frac{w_v \times N_V}{N_R} \quad \text{(Equation 5.1)}$$

Where,

KCMI is the integrated index for a specific period (presently specified as quarters)

W_V is the weighting of a particular requirement violation (presently specified as $1/26$

N_V is the number of known unmitigated violations for the selected requirement

N_R is the number of registered entities required to comply with the requirement obtained from the NERC Compliance Registry

67 http://www.nerc.com/docs/pc/rmwg/pas/index_team/SDI_Whitepaper.pdf

68 http://www.ferc.gov/enforcement/civil-penalties/actions/civil-penalty-action-2011.asp

The reliability risk impact assessment and VRF are used as selection criteria to identify the subset of standard requirements to be included in the KCMI. The risk impact assessment is to evaluate risk to the BPS when a requirement is violated, as determined by the Regional Entity and NERC. The factors considered in the risk assessment include but not limited to the following:

- Time horizon
- Relative size of the entity
- Relationship to other entities
- Possible sharing of responsibilities
- Voltage levels involved
- Size of generator or equipment involved
- Ability to project adverse impacts beyond the entity's own system

Table 5.2: Standard Requirements
EOP-001-0 R1
EOP-003-1 R7
EOP-005-1 R6
EOP-008-0 R1
FAC-003-1 R1
FAC-003-1 R2
FAC-009-1 R1
IRO-005-2 R17
PER-001-0 R1
PER-002-0 R1
PER-002-0 R2
PER-002-0 R3
PER-002-0 R4
PRC-004-1 R1
PRC-004-1 R2
PRC-005-1 R1
PRC-005-1 R2
TOP-001-1 R3
TOP-001-1 R6
TOP-001-1 R7
TOP-002-2 R17
TOP-004-2 R1
TOP-004-2 R2
TOP-006-1 R1
TOP-008-1 R2
VAR-001-1 R1

Assessment

Table 5.3 shows 54 violations with the 26 standards requirements that are included in the KCMI trending. NERC and the Regional Entities processed 31 of them, and the remaining 23 were found in FERC's stipulation and consent agreements.[69]

Table 5.3: Violations Included in KCMI* (June 18, 2007 – December 31, 2012)

	BAL	CIP	COM	EOP	FAC	INT	IRO	MOD	NUC	PER	PRC	TOP	TPL	VAR	ALL
Assessed Risk - Serious					5					1	22	3			31
In FERC's stipulation and consent agreements				8	1					7	6	1			23

* *Major violations with 26 requirements that were issued by FERC are included in this table, e.g., the February 2008 blackout.*

Figure 5.1 shows the quarterly KCMI trend from 2008 to 2012, which has continuously improved since the fourth quarter of 2010, indicating an improvement in the number of compliance violations with serious impact. Note that CIP violations in Table 5.1 are not considered in the standards shown in Table 5.2, which are used in calculating KCMI.

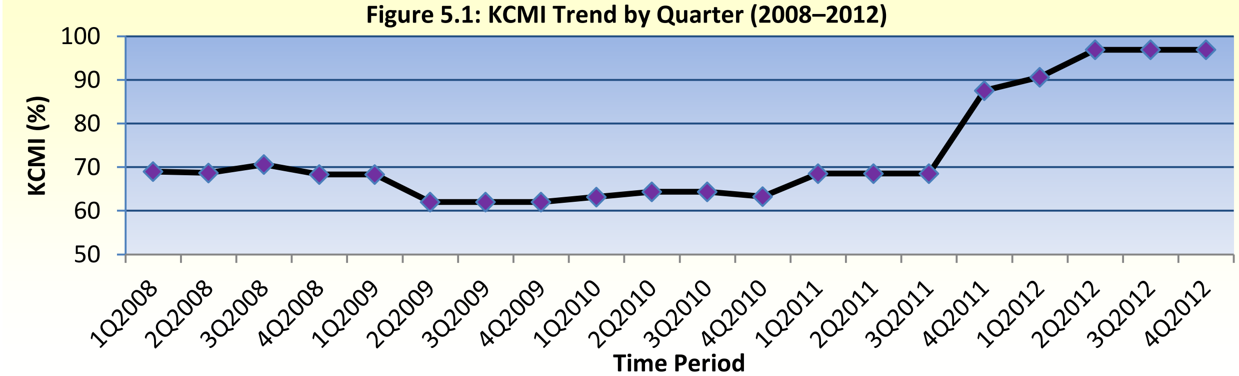


Figure 5.1: KCMI Trend by Quarter (2008–2012)

Table 5.4 shows the 81 serious violations separated by Regions, standards, and discovery method. Most of the PRC and CIP violations were self-reported. Of particular interest are the 10 violations that were discovered by two compliance investigations. They were triggered by an energy emergency event that occurred February 26, 2008, and a Category 2 disturbance event on November 7, 2008. Nine violations[70] during the energy emergency event posed a serious risk to reliability, because they subjected the BPS to unnecessary and avoidable high levels of reliability risk and could have

[69] http://www.ferc.gov/enforcement/civil-penalties/actions/civil-penalty-action-2011.asp
[70] http://www.nerc.com/filez/enforcement/FinalFiled_NOP_NOC-894.pdf

potentially led to widespread and severe system disturbance. One serious violation[71] was discovered from the Category 2 event where a system operating limit (SOL) was exceeded for a total of 47 minutes, or 17 minutes outside the required time frame.

Table 5.4: Serious Violations by Discovery Method, Standard and Region

Discovery Method	Region	BAL	CIP	COM	EOP	FAC	INT	IRO	MOD	NUC	PER	PRC	TOP	TPL	VAR	Total
Self-Report	**MRO**					1										1
	NPCC*											8			2	10
	RFC		2			3										5
	SERC*		13	1								2				16
	SPP RE											2				2
	WECC		7			1						2				10
Investigation	**WECC**												1			1
	TRE			1	2			2			3		1			9
Spot-Check	**NPCC***											8				8
	SERC*		6													6
	WECC		1													1
Audit	**NPCC**		1													1
	RFC		1													1
	SPP RE												5		2	7
	TRE				1			1								2
	WECC											1				1
Total	**NERC**	0	31	2	3	5	0	3	0	0	3	23	7	0	4	81

** 16 PRC violations in NPCC were from one entity with the 8 subsidiaries registered in NERC compliance registry.[72] 15 CIP violations in SERC were from one entity.[73]*

Special Consideration

As reliability standards change and their violation risk factors evolve over time, the number of requirements included in KCMI, and the specific requirements that are included, will change, too. KCMI calculations will have to link old and new performance to create a sustainable long-term view of compliance performance. An enhancement is currently being considered to use a smoothing method when adding and removing requirements. When a new standard is approved, one or more requirements might be added. A requirement that is retired, or that has a change in its violation risk factor, may be removed from KCMI. It is necessary to smooth out the effects of these additions or requirement changes in order to reflect real system conditions and avoid drops and jumps in the KCMI integrated value. Preliminary studies show that the divisor adjustment class[74] of methods can effectively smooth the KCMI for these transitions.

The NERC Compliance and Certification Committee (CCC) and PAS have established a review process to validate quarterly trends and the standard requirements used in the KCMI. This process includes:

1. Validating standard requirements designated as those that likely provide leading reliability indicators, and
2. Validating quarterly KCMI performance results and providing contextual trend information.

[71] http://www.nerc.com/filez/enforcement/FinalFiled_NOP_NOC-1773.pdf
[72] http://www.nerc.com/filez/enforcement/FinalFiled_NOP_NOC-135.pdf
[73] http://www.nerc.com/filez/enforcement/Public_Finalfiled_NOP_NOC-1531.pdf
[74] The Dow Divisor is used to maintain the historical continuity of the Dow index when constituents' stock splits, spins off, and changes.

Chapter 6 – Post-Seasonal Assessment

Background

Based on recommendations from industry representatives as well as approval from the NERC Planning Committee, assessment boundaries were reconstructed beginning in 2011 to represent existing operating boundaries used in the planning process.[75] Prior to 2011, Regional Entity boundaries were used for NERC assessments; however, these borders do not necessarily signify that planning and operations occur within a single Regional Entity. Therefore, assessment boundaries (shown in Figure 6.1 and Table 6.1) are now based on existing operational and planning boundaries versus traditional NERC Regional Entity boundaries.

Figure 6.1: NERC Assessment Area Map

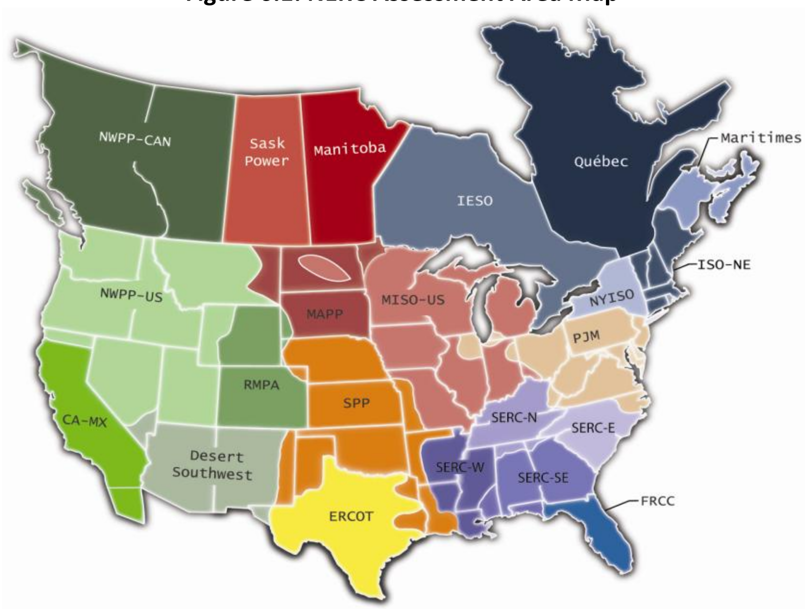


Table 6.1: 2010 and 2011 Assessment Boundary Differences

2010 Assessment Areas	2011 Assessment Areas	NERC Regional Entity	Description of Change
New England	ISO-NE	NPCC	Area name changed
New York	NYISO	NPCC	Area name changed
Ontario	IESO	NPCC	Area name changed
Québec	Québec	NPCC	No change
Central	SERC-N	SERC	Removed PJM RTO members
Delta	SERC-W	SERC	Removed SPP RTO members
Gateway	—	—	Removed part of the MISO RTO
Southeastern	SERC-SE	SERC	No change to boundary
VACAR	SERC-E	SERC	Removed PJM RTO members
SPP	SPP	SPP RE	SPP RTO and SPP RE members

NERC and industry stakeholders performed detailed data checking on the reference information received by the Regions, as well as a review of all self-assessments, to form an independent view of post-seasonal assessments for 2011–2012 winter and 2012 summer assessment seasons. During the 2011–2012 winter and 2012 summer, system operators across NERC maintained BPS reliability. Day-ahead and seasonal forecasted peak demands exceeded actual peak demands in many areas, as shown in Tables 6.2 and 6.4.

[75] http://www.nerc.com/docs/pc/ras/Reliability%20Assessments%20-%20Subregional%20Restructuring.pdf

Peak Load

Data for each assessment area's load and capacity[76] for the winter season is included in Tables 6.2 and 6.3. No assessment area reported any significant issues with supplying their system load during the winter season. Data for the summer season are also included in tables 6.4 and 6.5. Some assessment areas experienced all-time peak loads, and some assessment areas reported issues related to peak loads and weather. The more significant issues are discussed in the remainder of this chapter.

MISO experienced a new all-time peak load of 98,576 MW on July 23 hour ending 15. With substantially more generation available than other times of the summer season, due to decreased outages and increased wind output, MISO was able to effectively manage the 2012 summer peak day without implementing maximum generation procedures.

ERCOT broke the all-time monthly June and July peak demand records in 2012. The summer season peak of 66,548 megawatts (MW) occurred on June 26, 2012 and was 3,604 MW above the 2011 June peak demand. Available operational generation capacity was 71,000 MW at the time of the summer peak demand. ERCOT's all-time peak demand occurred on August 3, 2011, when electric use in ERCOT topped out at 68,305 MW.

Table 6.2: 2011–2012 Winter Actual Load Peak & Seasonal Peak Forecast

Assessment Area	Actual Peak Demand (MW)	Winter Peak Demand Forecast (MW)	Winter Month of Peak Demand (MW)	All-Time Winter Peak Demand (MW)
ERCOT	50,046	53,562	December	57,265
FRCC	39,668	47,613	January	52,368
MISO	72,850	79,994	January	76,197
ISO-NE	19,905	22,255	January	22,818
Maritimes (NBSO)	4,963	5,552	January	5,716
NYISO	23,901	24,533	January	25,541
Ontario	21,847	22,311	January	24,979
Québec	35,481	37,153	January	37,717
PJM	122,567	128,804	February	134,551
SaskPower	3,314	3,596	December	3,314
SERC-E	40,151	42,459	January	43,258
SERC-N	39,580	47,123	February	46,819
SERC-SE	42,811	44,259	February	48,742
SERC-W	19,868	19,931	January	22,042
SPP	37,148	42,394	December	42,045
WECC	126,337	123,171	December	131,708
CA-MX	38,709	37,681	December	43,336
NWPP RSG	62,462	60,219	January	63,623
RMRG	10,315	9,669	December	
SRSG	16,853	17,889	December	18,652

Consistent with the NERC seasonal assessments,[77] the following definitions are used in Tables 6.3 through 6.5.

- Total Available Capacity = Total Available Generation[78] + Demand Response Capacity
- Actual Reserve = Total Available Capacity – Actual Peak Demand

[76] The SPP data shown in Tables 6.2, 6.3, 6.4 and 6.5 is reported for the SPP RC footprint. SPP's 2012 summer, 2012 LTRA and 2012/2013 Winter Assessment data is reported on the SPP RE + Nebraska footprint. Any other data differences are explained in the individual assessments.
[77] http://www.nerc.com/page.php?cid=4|61
[78] Note that the Total Available Generation does not include firm exports or imports, scheduled, forced outages or derate.

Table 6.3: 2011–2012 Winter Total Available Capacity & Reserve		
Assessment Area	Total Available Capacity (MW)	Actual Reserves (MW)
ERCOT	56,090	6,044
FRCC	53,315	13,647
MISO	101,565	28,715
ISO-NE	30,403	3,106
NYISO	25,988	2,087
Ontario	27,665	5,818
Maritimes (NBSO)	7,696	2,733
SaskPower	3,671	428
Quebec	38,191	2,710
PJM	173,752	38,192
SERC-E	56,087	2,613
SERC-N	59,110	3,892
SERC-SE	66,636	4,603
SERC-W	37,418	1,677
SPP	51,441	2,321
WECC	145,599	19,262
CA-MX	42,594	3,885
NWPP RSG	74,105	11,643
RMRG	11,808	1,493
SRSG	20,119	3,266

Table 6.4: 2012 Summer Actual Load Peak and Seasonal Forecast				
Assessment Area	Actual Peak Demand (MW)	Peak Demand Forecast (MW)	Month of Peak Demand (MW)	All-Time Peak Demand (MW)
ERCOT	66,548	67,492	June	68,305
FRCC	43,459	45,613	August	46,525
MISO	98,576	94,395	July	98,576
ISO-NE	25,880	27,440	June	28,130
Maritimes (NBSO)	3,169	3,392	July	3,576
NYISO	32,439	33,295	July	33,939
Ontario	24,636	23,298	July	27,005
Québec	21,413	20,988	June	22,092
PJM	156,339	153,752	August	165,127
SaskPower	3,079	3,034	July	3,079
SERC-E	42,832	43,255	July	43,253
SERC-N	44,799	45,102	June	45,579
SERC-SE	47,053	48,895	June	50,309
SERC-W	24,959	25,403	June	25,585
SPP	53,984	54,974	August	54,949
WECC	152,901	153,021	August	159,182
CA-MX	54,740	55,435	August	65,049
NWPP RSG	59,821	58,771	July	59,821
RMRG	12,332	12,057	June	12,099
SRSG	29,630	28,604	August	29,192

Table 6.5: 2012 Summer Total Available Capacity and Reserve		
Assessment Area	Total Available Capacity (MW)	Actual Reserves (MW)
ERCOT	71,000	5,988
FRCC	53,327	9,868
MISO	103,109	4,533
ISO-NE	30,484	3,026
NYISO	35,055	2,616
Ontario	29,394	4,758
Maritimes (NBSO)	7,426	762
SaskPower	3,338	336
Québec	30,217	3,214
PJM	173,752	19,996
SERC-E	51,455	2,480
SERC-N	59,764	2,299
SERC-SE	66,116	4,603
SERC-W	37,156	1,812
SPP	60,385	2,425
WECC	173,463	20,562
CA-MX	59,743	5,003
NWPP RSG	71,001	11,180
RMRG	14,016	1,684
SRSG	32,971	3,341

Demand Response Realization

The 2011-2012 winter demand response events for all assessment areas are given in Table 6.6.

Table 6.6: Demand Response Event Information for 2011–2012 Winter by Region (October 2011 – March 2012)			
Region	Total events	Total dispatched (MW)	Average sustained response period
FRCC	6	902	20 min, 19 sec
MRO	2	100	1 hr, 52 min
NPCC	18	1,410	3 hr, 29 min
RFC	2	62	30 min
SERC	67	4,909	1 hr, 59 min
SPP	0	0	0
TRE	1	830	14 min, 54 sec
WECC	42	3,043	49 min, 20 sec
NERC Total	137	10,426	1 hr, 44 min

Fuel Situations

SERC experienced several fuel situations, but none posed any risk to BPS reliability. Due to significant rainfall, a limited number of plants within SERC-SE experienced wet coal conditions, which resulted in a reduction in plant output. Various plants within SERC-W encountered pipeline and weather-related events that limited fuel supply. As a result of these situations, other fuel options, such as the use of alternate pipelines, the purchase of additional gas, and the utilization of fuel oil, were employed to maintain fuel reliability of the BPS. On June 29, ISO New England forecasted a peak load of 23,805 MW. This total was approximately 1,000 MW greater than the prior operating day, during which minimal coal-fired generation was used to meet demand. System assessments determined possible regional gas-transmission constraints from west to east and possible limits on natural gas generation. As a result, a significant amount of non-gas-fired generation was utilized to supply load and maintain reliability during the period.

Variable Generation Integration

There were no significant reliability challenges reported in the 2011–2012 winter and the 2012 summer periods that resulted from the integration of variable generation resources. More improved wind forecast tools and wind monitoring displays are being used to help system operators manage integration of wind resources into real-time operations.

Transmission Availability

Tables 6.7 and 6.8 summarize monthly transmission unavailability rates due to planned, operational, and automatic sustained outages for ac circuits operated at 200 kV and above. The total unavailability was under 3 percent.

Table 6.7: Winter 2011–2012

Month	Monthly Transmission System Unavailability % Due to Automatic Outages	Monthly Transmission System Unavailability % Due to Operational Outages	Monthly Transmission System Unavailability % Due to Planned Outages
11-Oct	0.03	0.24	2.60
11-Nov	0.09	0.24	1.60
11-Dec	0.02	0.11	0.70
12-Jan	0.24	0.40	2.00
12-Feb	0.02	0.52	1.90
12-Mar	0.35	0.34	2.20

Table 6.8: Summer 2012

Month	Monthly Transmission System Unavailability % Due to Automatic Outages	Monthly Transmission System Unavailability % Due to Operational Outages	Monthly Transmission System Unavailability % Due to Planned Outages
12-Apr	0.03	0.44	2.40
12-May	0.05	0.08	1.50
12-Jun	0.13	0.18	0.80
12-Jul	0.10	0.26	0.60
12-Aug	0.09	0.09	1.00
12-Sep	0.07	0.26	2.20

Generation Availability

The 2012 summer Equivalent Forced Outage Rate demand[79] (EFORd) for each Region is listed in Table 6.9.

Table 6.9: EFORd Summer 2012

Region	EFORd Monthly Average
FRCC	2.19
MRO	4.29
NPCC	6.21
RFC	5.91
SERC	3.24
SPP	5.55
TRE	4.04
WECC	3.57

[79] This is Equation 57 of Data Reporting Instructions (DRI) in Appendix F, at http://www.nerc.com/page.php?cid=4|43|45.

Chapter 7 – Spare Equipment Database (SED) Initiative

Background

In June 2010, NERC issued a report titled "High-Impact, Low-Frequency Event Risk to the North American Bulk Power System."[80] In a postulated high-impact low-frequency (HILF) event, such as a coordinated physical or cyber attack or a severe geo-magnetic disturbance (GMD), long lead time electric transmission system equipment may be damaged. This could adversely impact significant areas of the BPS for a relatively long period.

If a HILF event takes place, increased intercompany coordination to maximize use of existing long lead time transmission system equipment will increase the resiliency of the system. This chapter discusses efforts to increase resiliency through a database that can facilitate timely communications when locating available spares from unaffected entities.

Purpose

To facilitate this effort, the NERC Planning Committee formed the Spare Equipment Database Task Force (SEDTF) during the fourth quarter of 2010. The purpose of SEDTF is to recommend a uniform approach for collecting information on long lead time and electric transmission system critical spare equipment, and to recommend a means for obtaining and communicating this information to the electric industry.[81] Data collection is supported by the Spare Equipment Database (SED).

This database is not meant to replace or supersede any other transformer sharing agreements (such as the Edison Electric Institute's Spare Transformer Equipment Program (STEP))[82] or other neighboring or regional utility arrangements. The SED is a 24–7 operational, web-based tool populated and managed by participating NERC-registered Transmission Owner (TO) and Generator Owner (GO) organizations regardless of whether they have spare equipment available. SED helps facilitate timely communications between entities that need long lead time equipment and equipment owners who may have spare assets to share.

Initial Focus

The SEDWG reviewed various types of long lead time equipment which, if lost as the result of HILF events, could have a significant reliability impact to the BPS. Long lead time is herein defined as equipment that under normal circumstances consistently takes more than six months to manufacture and deliver. One such type of long lead time equipment is large power transformers. In addition, large power transformers require substantial capital to secure. For these reasons, transformer owners maintain an appropriate and limited number of spares in the event a transformer fails. However, during a HILF event, numerous transformers may be damaged and rendered unusable. Therefore, SEDTF's initial focus is on spare transmission transformers and spare generator step-up (GSU) transformers.

In 2012, the task force was changed to a working group (SEDWG). In the future, SEDWG will review the possibility of expanding SED to include other long lead time equipment (e.g., circuit breakers, capacitor banks, dynamic reactive power, FACTS devices, phase-shifting transformers, transmission cable, underground cable, shunt reactors, etc.). Participating organizations will voluntarily identify and report spare equipment that meets predefined criteria in the database.

Confidentiality

Though kept confidential, asset owner entity information will be required to facilitate swift communications subsequent to a HILF event. The database will contain the entity's NERC Registry name and primary and secondary contact information. Additionally, an SED data manager for each reporting organization is recommended. Required data fields will include nameplate information such as high- and low-voltage ratings, nameplate MVA ratings, impedance, number of phases, connection information, and any vital comments associated with the spare. These data fields will provide essential

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[80] High Impact, Low Frequency Event Risk to the North American Bulk Power System, June 2012, http://www.nerc.com/files/HILF.pdf

[81] This task force will support the Electricity Sub-sector Coordinating Council's Critical Infrastructure Protection Roadmap, work plan items: 1) G - Critical Spares, and 2) P- GMD – Restore the Bulk power System.

[82] STEP is a voluntary "electric industry program that strengthens the sector's ability to restore the nation's transmission system more quickly in the event of a terrorist attack". Spare Transformers, http://www.eei.org/ourissues/ElectricityTransmission/Pages/SpareTransformers.aspx

information that would enable automated queries to be performed of the available assets, and allow users to contact the asset owner's entities subsequent to a HILF event.

The overall SED effort is directed at documenting all possible spares, including those with sharing agreements and those jointly owned. The SED information submittal forms will ask if the reported spare is jointly owned by two or more entities and if the joint owners will be uniquely identified in the submittal form. NERC will review the individual SED submittals to eliminate duplicate counting of these spares. Working with each of the affected SED participants, NERC will attempt to assure the reporting is done only by the entity that has physical responsibility for the spare. The SED Instruction Manual will also provide reporting instructions and examples.

A complete description of the SED Search Process and a Special Report on Spare Equipment Database can be found on NERC's website.[83]

SED Participation Benefits

Participating in SED is beneficial to equipment owners, because it:

1. allows entities to confidentially seek spares,
2. provides a means to achieve faster restoration following an event,
3. fosters entity cooperation,
4. allows for a targeted communication approach to entities with applicable spares, and
5. balances risk mitigation and freedom via:
    - voluntary participation,
    - double-blind requests, and
    - entities not being forced to commit spares.

Monitoring Procedures – In the SED's initial year, quarterly reports will be provided to the Standing Committees on participation and implementation. Exercises will also be conducted to measure the effectiveness of the SED. After the initial year, the SED effectiveness will be assessed on an annual basis.

Registration and Contact Information

- Sign the Mutual Confidentiality Agreement, which can be found at: http://www.nerc.com/docs/pc/sedtf/Confidentiality_Agreement.pdf.
- Once signed, submit agreement to SEDRegistration@nerc.net. After submission, NERC staff will contact you with next steps.
- For further information related to SED program, please visit http://www.nerc.com/filez/sedtf.html.
- Contact info:
    - Email: SEDRegistration@nerc.net
    - To learn more about Spare Equipment Database, contact Naved Khan at Naved.Khan@nerc.net; (404) 446-9730

[83] Special Report: Spare Equipment Database System, October 2011, http://www.nerc.com/docs/pc/sedtf/SEDTF_Special_Report_October_2011.pdf

Appendix A – Statistical Analysis for Chapter 3

Overview

This appendix supports the observations and conclusions documented in Chapter 3.

The procedure illustrated in Figure 3.1 is used to determine a TADS event's Initiating Cause Code, or ICC. The procedure that defines ICC for a TADS event allows ICC assignment to a majority of system events recorded in TADS. There are 19,556 events with ICCs assigned, comprising 99.2 percent of the total number of TADS events for the years 2008–2012. These events reflect 98.6 percent of the total calculated transmission severity of the database. Table 3.4 provides the corresponding available event data by year.

Table A.1 lists annual counts and hourly event probability of TADS events by ICC. The three ICCs with the largest number of events are initiated by Weather (with and without lightning), Unknown, and a group defined as Reliability Metrics (composed of ICCs of Human Error, Failed AC Circuit Equipment, Failed AC Substation Equipment, and Failed Protection System Equipment). The four ICCs grouped as Reliability Metrics are related to ALR6-12, ALR6-14, ALR6-13 and ALR6-11 and are combined in one section of the table. Metrics are provided for each of the ICCs in the group, as well as for the group as a whole.

Almost all TADS ICC groups have sufficient data available to be used in a statistical analysis. Only four ICCs (Vegetation; Vandalism, Terrorism, or Malicious Acts; Environmental; and Failed AC/DC terminal equipment) do not have enough data. These are combined into a new group, named "Smaller ICC groups combined," that can be statistically compared to every other group and also studied with respect to annual changes of transmission severity.

Table A.1: TADS Events and Hourly Event Probability by Initiating Cause Code[84]

Initiating Cause Code	2008	2009	2010	2011	2012	2008–2012	Event probability/hour
All in TADS	4,390	3,705	3,918	3,934	3,753	19,700	0.45
All TADS with ICC assigned	4,359	3,684	3,895	3,894	3,724	19,556	0.45
Reliability Metrics	1,143	1,043	1,054	1,120	1,042	5,402	0.12
Human Error	301	291	305	291	307	1,495	0.03
Failed AC Circuit Equipment	307	257	277	306	261	1,408	0.03
Failed AC Substation Equipment	253	266	238	289	248	1,294	0.03
Failed Protection System Equipment	282	229	234	234	226	1,205	0.03
Weather							0.16
Lightning	949	789	741	822	852	4,153	0.10
Weather, Excluding Lightning	662	534	673	539	446	2,854	0.07
Unknown	917	673	821	782	710	3,903	0.09
Foreign Interference	181	199	173	170	170	893	0.02
Contamination	97	96	145	132	160	630	0.01
Power System Condition	109	112	74	121	77	493	0.01
Other (as defined in TADS)	104	107	84	91	104	490	0.01
Fire	119	92	84	63	106	464	0.01
Combined Smaller ICC groups	78	39	46	54	57	274	0.01
Vegetation	60	29	27	44	43	203	
Vandalism, Terrorism, or Malicious Acts	15	4	6	5	10	40	
Environmental	2	5	11	5	4	27	
Failed AC/DC Terminal Equipment	1	1	2	-	-	4	

Correlation between ICC and Transmission Severity

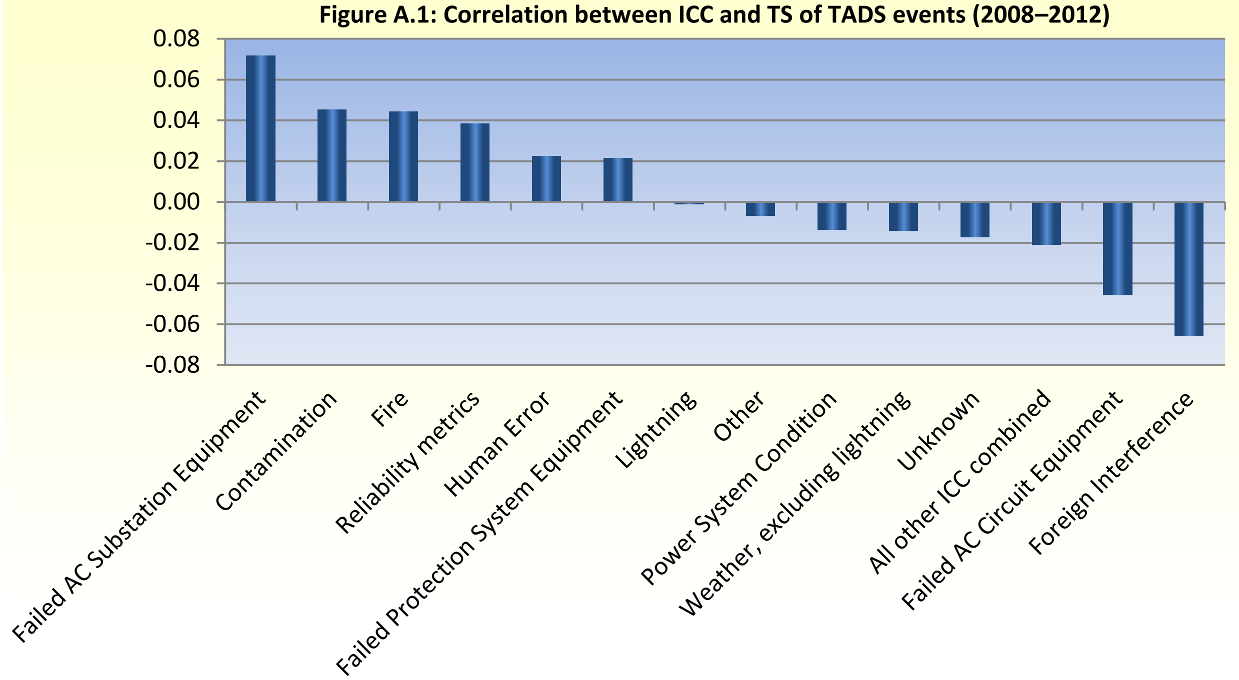
Figure A.1 shows the correlations between calculated transmission severity and the given ICC. In each case, a null statistical hypothesis on zero correlation at significance level 0.05 was tested. If the test resulted in rejection of the hypothesis, it is concluded that a statistically significant positive or negative correlation between an ICC and transmission severity exists. A

[84] For detailed definitions of TADS cause codes, please refer to: http://www.nerc.com/docs/pc/tadswg/2012_TADS_Definitions.pdf, January 14, 2013, pp. 19-20.

positive correlation of initiating cause code to transmission outage severity would indicate a greater likelihood that an event with this ICC would result in a higher transmission outage severity. A negative correlation would indicate the contrary; in this case, a lower transmission outage severity would be likely. If no correlation is found, it indicates the absence of a linear relationship between ICC and the transmission outage severity, and that the events with this ICC have an expected transmission severity similar to all other events from the database.

There were three key outcomes of all the tests. To begin, Failed AC Substation Equipment, Contamination, Fire, Reliability metrics, Human Error, and Failed Protection System Equipment have statistically significant positive correlation with transmission severity. The expected severity of events with each of these ICCs is greater than the expected severity compared to other ICC events. Secondly, Foreign Interference, Failed AC Circuit Equipment, Smaller ICC groups combined, Unknown, and Weather Excluding Lightning, have statistically significant negative correlation with transmission severity. The expected severity of events initiated by these causes is smaller than the expected transmission severity of the remaining dataset. Finally, for each of the remaining groups (Power System Condition, Lighting, Other), the difference between transmission severity for the group and for its complement is not statistically significant, because the hypotheses on zero correlation cannot be rejected at the given significance level.

Figure A.1: Correlation between ICC and TS of TADS events (2008–2012)



Distribution of Transmission Severity by ICC

Next, the distribution of transmission severity for the entire dataset was studied separately for events with a given ICC. The transmission severity of the 2008–2012 dataset has the sample mean of 0.172 and the sample standard deviation of 0.112. The sample statistics for transmission severity by ICC are listed in Table A.2.

The groups of events initiated by Fire and Failed AC Substation Equipment not only have statistically[85] greater expected severity than the rest of the events; the variance of transmission severity (and its standard deviation) for these groups is also statistically greater than for its complement. The greater variance is an additional risk factor since it implies more frequent occurrences of events with high transmission severity.

Table A.2 provides a column that indicates which other ICCs are statistically less than a given ICC reference by the table's column 1 index. For example, transmission severity for Human Error (#5) is statistically significantly less than Fire (#1), while Contamination (#3) is not statistically significantly less than Fire.

[85] At significance level 0.05

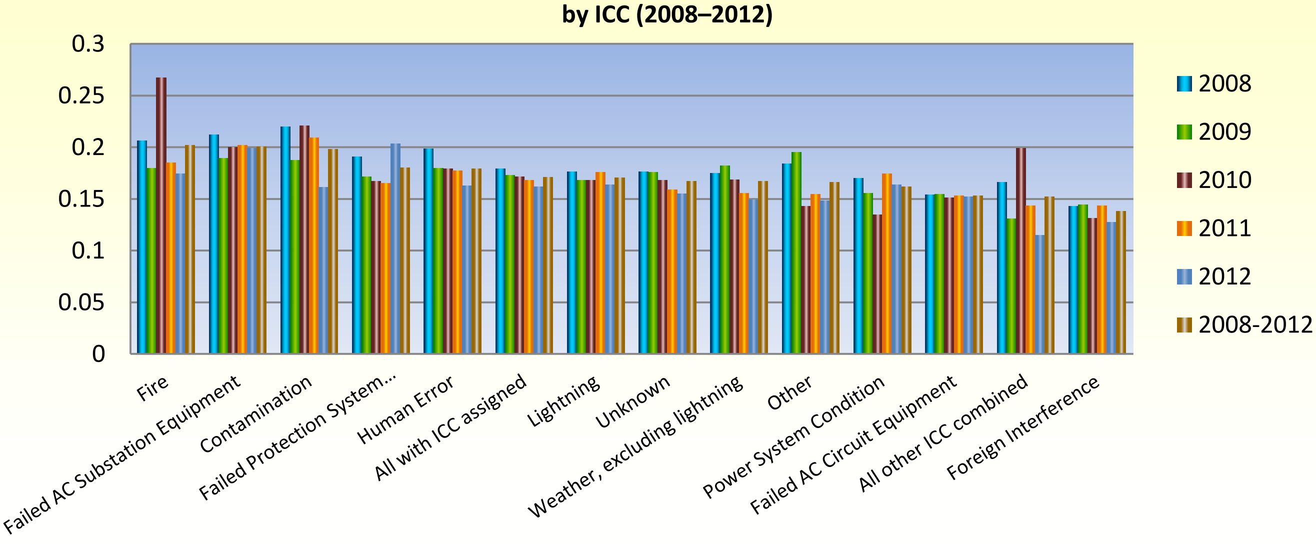
#	Initiating Cause Code (ICC)	Average TS for Events with the ICC 2008-2012	Is Expected TS statistically significantly[86] bigger than for the rest of the events?	ICC with statistically significantly[87] smaller Transmission severity	Standard deviation of transmission severity 2008–2012
1	Fire	0.202	Yes	4, 5, 6, 7, 8, 9, 10, 11, 12	0.143
2	Failed AC Substation Equipment	0.2	Yes	4, 5, 6, 7, 8, 9, 10, 11, 12	0.142
3	Contamination	0.198	Yes	4, 5, 6, 7, 8, 9, 10, 11, 12	0.112
4	Failed Protection System Equipment	0.18	Yes	6, 7, 8, 9, 10, 11, 12	0.125
5	Human Error	0.179	Yes	6, 7, 8, 9, 10, 11, 12	0.108
	All TADS events	0.172	N/A	N/A	0.111
	All TADS with ICC assigned	0.171	N/A	N/A	0.109
6	Lightning	0.171	No	11, 12, 13	0.098
7	Weather, Excluding Lightning	0.167	No	11, 12, 13	0.101
8	Unknown	0.167	No	11, 12, 13	0.078
9	Other (as defined by TADS)	0.166	No	13	0.211
10	Power System Condition	0.162	No	13	0.187
11	Failed AC Circuit Equipment	0.153	No	13	0.082
12	Combined Smaller ICC groups	0.152	No	none	0.134
13	Foreign Interference	0.138	No	none	0.064

Table A.2: Distribution of Transmission Severity (TS) by ICC

Average Transmission Severity by ICC: Annual Changes

Year-over-year changes in calculated transmission severity by ICC were reviewed next. Figure A.2 shows changes in the average severity for each ICC and for the 2008–2012 dataset. The groups of ICC events are listed from left to right by descending average transmission severity for the five-year data. The single highest average transmission severity is observed for 2010 events initiated by fire. NERC's investigation revealed that two wildfires[88] initiated the most severe events in this category.

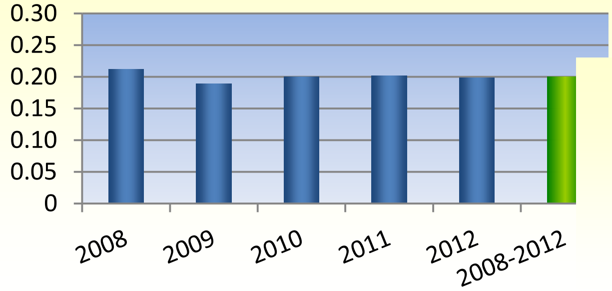
Figure A.2: Average Transmission Severity of TADS Events by ICC (2008–2012)



[86] At significance level of 0.05
[87] At significance level of 0.05
[88] Québec wildfires June 22-23, 2010, and Sequoia National Forest fire in California, July 29-30, 2010

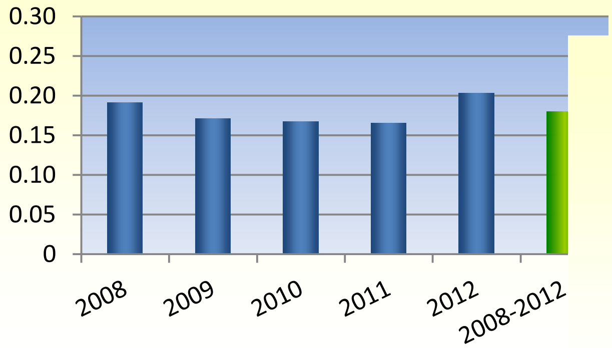
The following series of graphs shows changes in the average transmission severity by year for four groups of ICCs. For each group, the graph accompanies a list of statistically significant[89] changes (decreases and increases).

Figure A.3: Average Transmission Severity of Events Initiated by Failed AC Substation Equipment (2008–2012)



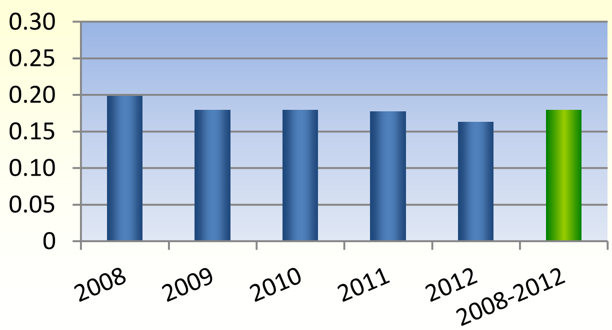
- Statistically significant year-over-year increases
  - none
- Statistically significant year-over-year decreases
  - none

Figure A.4: Average Transmission Severity of Events Initiated by Failed Protection System Equipment (2008–2012)



- Statistically significant year-over-year increases
  - 2009 vs. 2012
  - 2010 vs. 2012
  - 2011 vs. 2012
- Statistically significant year-over-year decreases
  - 2008 vs. 2010
  - 2008 vs. 2011

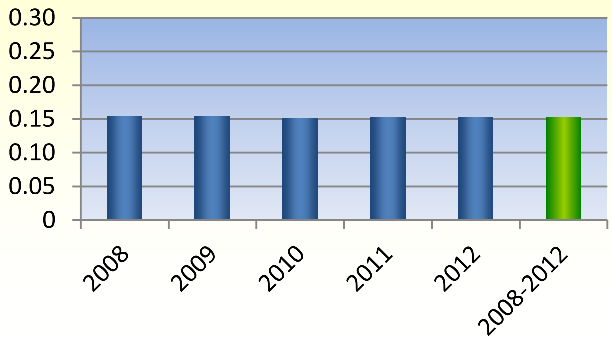
Figure A.5: Average Transmission Severity of Events Initiated by Human Error (2008–2012)



- Statistically significant year-over-year increases
  - none
- Statistically significant year-over-year decreases
  - 2008 vs. 2009
  - 2008 vs. 2010
  - 2008 vs. 2011
  - 2008 vs. 2012

89 This summary lists only changes that are statistically significant at the 0.05 level.

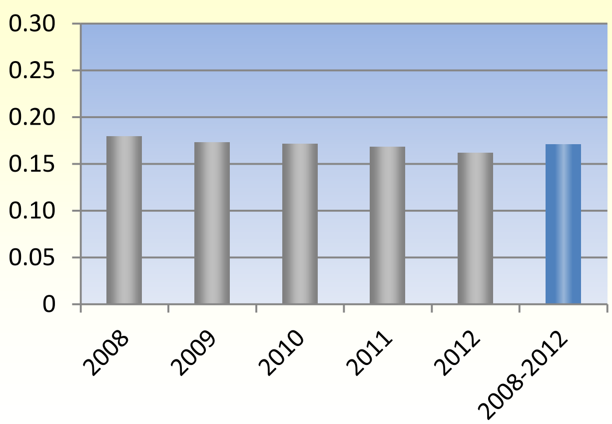
Figure A.6: Average Transmission Severity of Events Initiated by Failed AC Circuit Equipment (2008–2012)



- Statistically significant year-over-year increases
    - none
- Statistically significant year-over-year decreases
    - 2008 vs. 2009
    - 2008 vs. 2010
    - 2008 vs. 2011
    - 2008 vs. 2012

Finally, for the 2008–2012 set of TADS events, changes in the average transmission severity by year are as follows:

Figure A.7: Average Transmission Severity of TADS events (2008–2012)



- Statistically significant year-over-year increases
    - none
- Statistically significant year-over-year decreases
    - 2008 vs. 2009
    - 2008 vs. 2010
    - 2008 vs. 2011
    - 2008 vs. 2012
    - 2009 vs. 2012
    - 2010 vs. 2012
    - 2011 vs. 2012

Total (Combined) Transmission Severity by ICC: Annual Changes

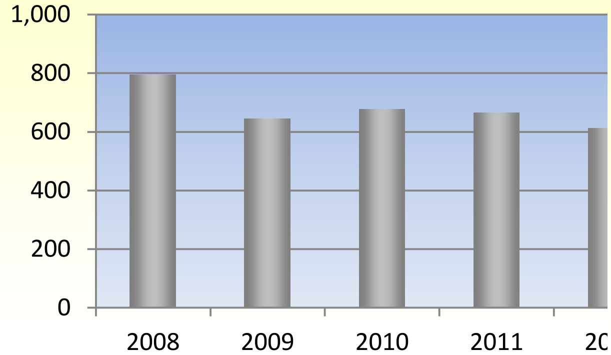
Total annual transmission severity associated with each ICC by year is listed in Table A.3.

Table A.3: Annual Transmission Severity

Group of TADS events	2008	2009	2010	2011	2012
All TADS events	793.7	643.8	676.0	665.7	612.4
All with ICC assigned	782.0	636.8	667.5	654.6	602.1
Reliability metrics	214.7	191.4	200.6	197.9	202.6
Human Error	59.7	52.3	54.7	51.5	50.0
Failed AC Substation Equipment	53.7	50.4	47.6	58.3	49.3
Failed Protection System Equipment	53.9	39.3	39.1	38.7	46.0
Failed AC Circuit Equipment	47.4	39.8	41.8	46.8	39.7
Weather	283.4	230.0	238.0	228.4	206.3
Lightning	167.5	132.7	124.4	144.5	139.8
Weather, Excluding Lightning	115.9	97.2	113.6	83.9	66.6
Unknown	161.7	118.4	137.9	124.2	110.2
Contamination	21.4	18.0	32.0	27.6	25.8
Foreign Interference	25.9	28.8	22.7	24.4	21.6
Fire	24.6	16.5	22.4	11.7	18.5
Other (as defined in TADS)	19.1	20.9	12.0	14.1	15.4
Power System Condition	18.6	17.4	10.0	21.1	12.6
Combined smaller ICC groups	14.1	5.1	9.4	7.8	6.5

Figure A.8 shows changes in the total transmission severity of TADS events by year.

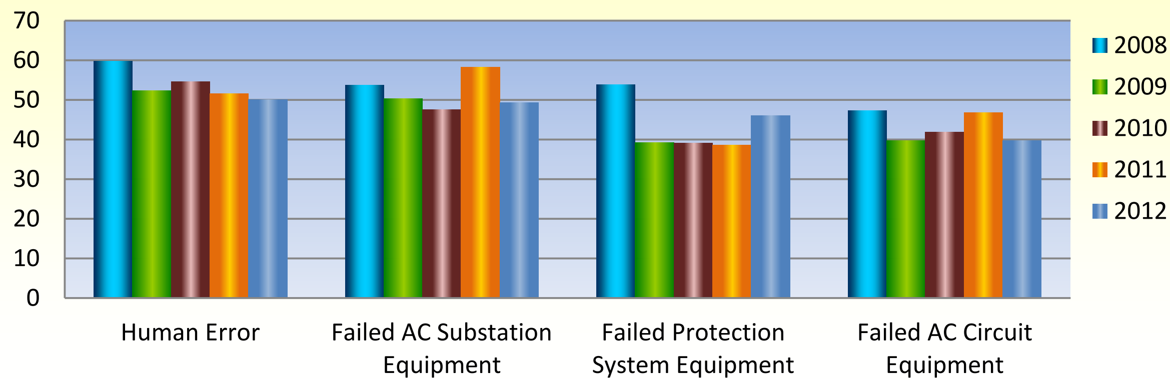
Figure A8: Total Transmission Severity of TADS Events by Year



- Statistically significant year-over-year increases
  - none
- Statistically significant year-over-year decreases
  - 2008 vs. 2009
  - 2008 vs. 2010
  - 2008 vs. 2011
  - 2008 vs. 2012
  - 2010 vs. 2012
  - 2011 vs. 2012

In particular, changes in the total transmission severity of events with a common ICC related to one of the ALR metrics are shown in Figure A.9.

Figure A.9: Total Transmission Severity by Year

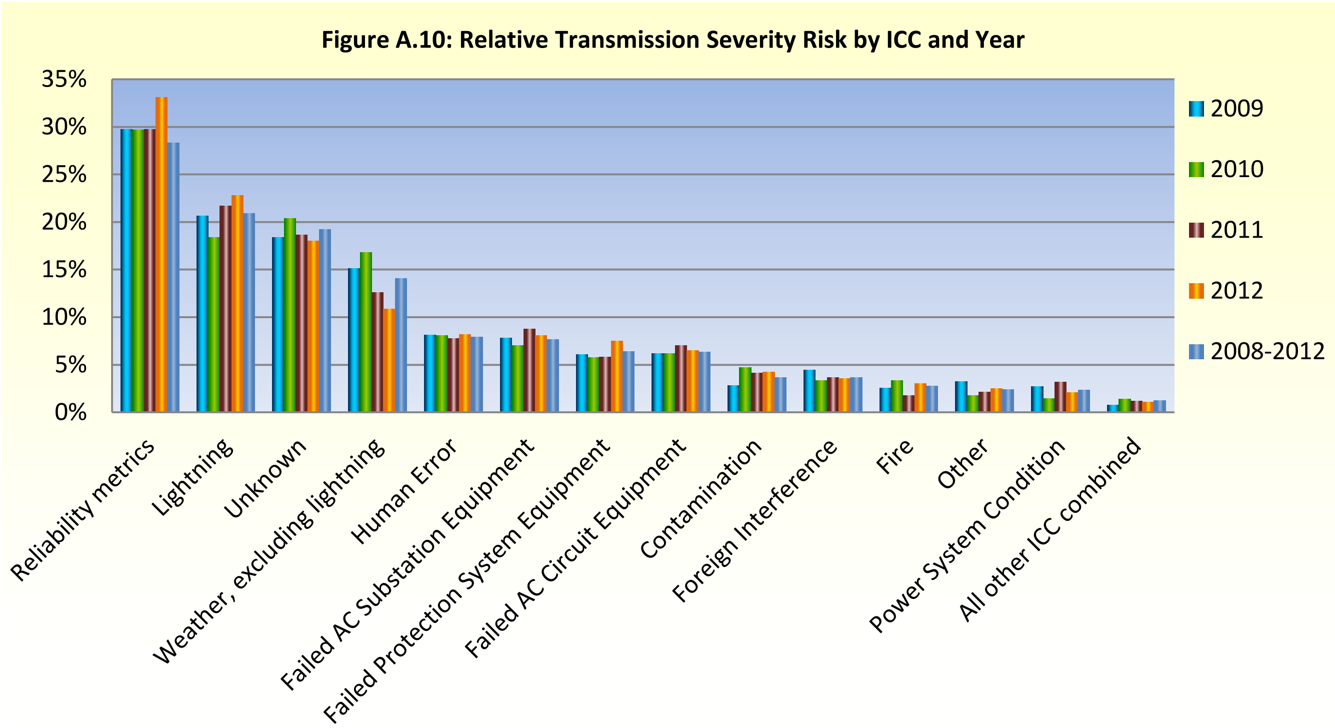


There were several statistically significant increases and decreases over time for ICCs related to Adequate Level of Reliability (ALR) metrics. The total transmission severity of TADS events initiated by Human Error had no statistically significant increases or statistically significant[90] decreases from 2008 to 2009, from 2008 to 2011, and from 2008 to 2012. The total transmission severity of TADS events initiated by Failed AC Substation Equipment had no statistically significant changes. The total transmission severity of TADS events initiated by Failed Protection System Equipment had statistically significant increases from 2009 to 2012, from 2010 to 2012, and from 2011 to 2012; and statistically significant decreases from 2008 to 2009, from 2008 to 2010, and from 2008 to 2011. Finally, the total transmission severity of TADS events initiated by Failed AC Circuit Equipment had no statistically significant changes.

Transmission Severity Risk and Relative Risk of TADS Events by ICC

The risk of each ICC group can be defined as the total transmission severity associated with this group; its relative risk is equal to the percentage of the group transmission severity in the 2008–2012 data base. Equivalently, the risk of a given ICC per hour can be defined as the product of the probability to observe an event with this ICC during an hour and the expected severity (impact) of an event from this group. For any ICC group, the relative risk per hour is the same as the relative risk for five years (or any other time period). Table 3.6 shows relative risk by ICC, with the ICC groups listed from the biggest relative risk to the smallest. Figure A.10 shows year-over-year changes in the relative risk of TADS events by ICC; light blue bars correspond to the values listed in the last column of Table 3.5.

[90] At significance level 0.05



CDM Events: Definitions and Breakdown by ICC

As part of the analysis, a breakdown of ICC was performed for TADS events containing Common or Dependent Mode outages. These TADS events have more transmission severity than TADS events with one single-mode outage. TADS events were separated into two types: single-mode events and Common Dependent Mode (CDM) events. A single-mode event is defined as a TADS event with one single-mode outage. A CDM TADS event is a TADS event where all outages have one of the modes (other than single) in Table A.4.

Table A.4: Outage Mode Codes

Outage Mode Code	Automatic Outage Description
Single Mode	A single-element outage that occurs independently of another automatic outage
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 initiating cause code 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

Based on this definition, every TADS event was categorized as either a single-mode event or a CDM event. Some TADS events combined single-mode outages with other outage modes. These events were manually examined to determine if the event was single mode or CDM. For some events, it was not possible to determine whether the event was single-mode or CDM, nor was it possible to tell the ICC for the event. These events, approximately 0.7 percent of all TADS events, were removed from the study.

Table A.5 lists CDM events by ICC in the 2008–2012 database and their percentages with respect to all TADS events with a given ICC. Similar to all TADS events, Lightning initiated the biggest number of CDM events. CDM events initiated by Failed AC Substation Equipment comprise the second biggest group, followed by Weather Excluding Lightning, and Unknown. Overall, 3,718 CDM events made up 18.9 percent of all TADS events from 2008 to 2012. Out of these, 3,604 are assigned to one of the 17 ICCs.

Almost all ICC groups of CDM events for five years have a sufficient sample size to be used in a statistical analysis, but the sample size is not enough to track statistically significant year-over-year changes in transmission severity. Four ICCs (Vegetation; Vandalism, Terrorism, or Malicious Acts; Environmental, Failed AC/DC Terminal Equipment) must be combined to comprise a new group, Smaller ICC Groups Combined, that can be statistically compared to every other group.

Table A.5: CDM Events and Hourly Event Probability by Initiating Cause Code

Initiating Cause Code	ALL TADS events	CDM events	CDM as % of ALL	Event probability per hour
All with ICC assigned	19,556	3,604	0.18	0.09
In TADS	19,700	3,718	0.19	0.46
Reliability Metrics	5,402	1,332	0.25	0.03
Failed AC Substation Equipment	1,294	476	0.37	0.01
Failed Protection System Equipment	1,205	331	0.28	0.01
Human Error	1,495	324	0.22	0.01
Failed AC Circuit Equipment	1,408	201	0.14	0.01
Lightning	4,153	703	0.17	0.02
Weather, Excluding Lightning	2,854	398	0.14	0.01
Unknown	3,903	377	0.10	0.01
Power System Condition	493	364	0.74	0.01
Other	490	124	0.25	0.00
Foreign Interference	893	102	0.11	
Fire	464	98	0.21	0.00
Contamination	630	67	0.11	0.00
Smaller ICC groups combined	274	39	0.14	0.00
Vegetation	203	23	0.11	
Environmental	27	11	0.41	
Failed AC/DC Terminal Equipment	4	3	0.75	
Vandalism, Terrorism, or Malicious Acts	40	2	0.05	

CDM Events: Correlation between ICC and Transmission Severity

To study correlation, a null statistical hypothesis was tested for zero correlation at significance level 0.05. If the test resulted in rejection of the hypothesis, a statistically significant positive or negative correlation between ICC and transmission severity was concluded. There were three key results of all the tests. First, Contamination, Failed AC Substation Equipment, Fire, and Weather Excluding Lightning have statistically significant *positive* correlation with transmission severity (events with each of these ICC have, on average, bigger transmission severity than the rest of events). Second, Power System Condition and Foreign Interference have statistically significant *negative* correlation with transmission severity. Finally, the smaller ICC groups combined (as shown in the previous figure), Reliability Metrics, Lightning, Other, Human Error, Unknown, Failed AC Circuit Equipment, and Failed Protection System Equipment categories have essentially the same transmission severity as the rest of events.

CDM Events: Distribution of Transmission Severity by ICC

Next, the distribution of transmission severity for CDM events with a given ICC was studied. The transmission severity for CDM events has a sample mean of 0.249 and a sample standard deviation of 0.187. The sample statistics for transmission severity by ICC are listed in Table A.6. The CDM events initiated by Contamination have the biggest average transmission severity of 0.324, followed by Fire, All other ICCs Combined, and Failed AC Substation Equipment (with the expected transmission severity of 0.300, 0.285, and 0.271, respectively). The events initiated by Power System Condition have the smallest average severity of 0.158. Interestingly, the All Other ICCs Combined and Fire did not occur often, but upon occurrence, resulted in significant transmission severity. Because CDM events typically have more outages per event than single-mode events, on average CDM events have higher transmission severity than TADS events.

Table A.6 provides a column that indicates which other ICCs are statistically smaller than a given ICC referenced by the table's column 1 index. For example, transmission severity for Human Error (#8) is statistically significantly smaller than Contamination (#1), while Fire (#2) is not statistically significantly smaller than Contamination.

Table A.6: Distribution of CDM Transmission Severity (TS) by ICC					
#	Initiating Cause Code (ICC)	Average transmission severity for the events with the ICC 2008–2012	Is expected transmission severity statistically significantly[90] bigger than for the rest of the events?	ICC with statistically significantly[90] smaller transmission severity	Standard deviation of transmission severity 2008–2012
1	Contamination	0.324	Yes	4, 5, 6, 7, 8, 9, 10, 11, 12, 13	0.234
2	Fire	0.3	Yes	7, 8, 9, 10, 11, 12, 13	0.213
3	Smaller ICC groups combined	0.285	No	12, 13	0.287
4	Failed AC Substation Equipment	0.271	Yes	9, 11, 12, 13	0.189
5	Weather, Excluding Lightning	0.265	No	11, 12, 13	0.156
6	Other	0.261	No	12, 13	0.388
7	Lightning	0.255	No	12, 13	0.144
	Reliability metrics	0.253	No	N/A	0.177
8	Human Error	0.251	No	12, 13	0.158
	All CDM events	0.249	N/A	N/A	0.187
	All CDM with ICC assigned	0.246	N/A	N/A	0.185
9	Unknown	0.244	No	13	0.132
10	Failed AC Circuit Equipment	0.242	No	13	0.13
11	Failed Protection System Equipment	0.235	No	13	0.196
12	Foreign Interference	0.207	No	none	0.091
13	Power System Condition	0.158	No	none	0.212

Transmission Severity Risk and Relative Risk of CDM Events by ICC

If the transmission severity risk of each ICC group is simply the total transmission severity associated with the group, then its relative risk is equal to the percentage of the group transmission severity in the 2008–2012 dataset. Equivalently, the risk of a given ICC per hour can be defined as the product of the probability to observe an event with this ICC during an hour and the expected severity, or impact, of an event from this group. Then for any ICC group, the relative risk per hour is the same as the relative risk for five years or any other time period. Table 3.6 lists relative risk by ICC with the ICC groups of CDM events in order from the biggest relative risk to the smallest.

Appendix B – Statistical Analysis for Chapter 4

Overview

This appendix provides details and documentation for the summary results found in Chapter 4.

Interconnection Frequency Response: Time Trends

Eastern Interconnection

The time trend analysis uses the EI frequency response datasets for 2009–2012. The values in the graph below represent the observed values of frequency response (FR) for events since 2009 in the EI. In this section, relationships between FR and the explanatory variable T (time: year, month, day, hour, minute, second) are studied.

Even though a linear trend line for the scatter plot connecting T and FR shown in Figure 1.5 has a small positive slope at 0.00000175, the linear regression is not statistically significant and on average, the EI frequency response[91] has been stable from 2009 through 2012.

ERCOT Interconnection

The time trend analysis uses the ERCOT frequency response datasets for 2009–2012. The frequency response values represent the observed values of the analysis (response) variable frequency response (FR) of ERCOT. In this section, the relationship is investigated between FR and the explanatory variable T, when a frequency response event happened.

There is a negative correlation of -0.04 between T and FR; however, the statistical test on the significance of the correlation (and the equivalent test of the significance of a linear regression) fails to reject the null hypothesis about zero correlation at a standard significance level (p-value of both tests is 0.53). This result suggests a high probability that the negative correlation could have occurred simply by chance. It implies that even though a linear trend line for the scatter plot connecting T and FR shown in Figure 1.5 has a small negative slope (-0.000000193141), the linear regression is not statistically significant, and on average, the ERCOT Interconnection frequency response has been stable from 2009 through 2012.

Québec Interconnection

The time trend analysis uses the Québec frequency response datasets for 2011–2012. The frequency response values represent the observed values of the analysis (response) variable FR of the Hydro Québec (HQ) frequency response. In this section, the relationship is investigated between FR and the explanatory variable T, when a frequency response event happened.

There is a positive correlation of 0.12 between T and FR; however, the statistical test on the significance of the correlation (and the equivalent test of the significance of a linear regression) fails to reject the null hypothesis about zero correlation at a standard significance level (p-value of the both tests is 0.41). This result leads to the conclusion that with high probability the positive correlation could occur simply by chance. It implies that even though a linear trend line for the scatter plot connecting T and FR shown in Figure 1.5 has a small positive slope (0.00000134), the linear regression is not statistically significant, and on average, the QI frequency response has been stable from 2010 through 2012.

Western Interconnection

The time trend analysis uses the Western Interconnection (WI) frequency response datasets from 2009 through 2012. The frequency response values represent the observed values of the analysis (response) variable FR, the WI frequency response. In this section, the relationship is investigated between FR and the explanatory variable T, when a frequency response event happened.

There is a negative correlation of -0.04 between T and FR; however, the statistical test on the significance of the correlation (and the equivalent test of the significance of a linear regression) fails to reject the null hypothesis about zero correlation at

[91] There is a positive correlation of 0.10 between T and FR; however, the statistical test on significance of the correlation (and the equivalent test of the significance of a linear regression) fails to reject the null hypothesis about zero correlation at a standard significance level (p-value of the both tests is 0.19). This implies the slight increase in frequency response since 2009 could just be chance.

a standard significance level (p value of the both tests is 0.67). This result leads to the conclusion that the negative correlation could have occurred simply by chance. It implies that even though a linear trend line for the scatter plot connecting T and FR shown in Figure 1.5 has a small negative slope (-0.000000604286), the linear regression is not statistically significant, and on average, the WI frequency response has been stable from 2009 through 2012.

For the WI, the data for the years 2009 through 2010 are not very reliable. The value of B was calculated within the first 10 seconds in 2009 and 2010. The other reason the frequency response is much higher for these years is because the capacity of the unit—rather than the net MW loss to the interconnection—was reported. In recent years, such as from 2011 through 2012, better tools have been put in place to detect frequency events and their underlying causes. There are also more systematic procedures to document and verify these events.

Interconnection Frequency Response: Year-to-Year Changes

Eastern Interconnection

The time trend analysis uses the Eastern Interconnection (EI) frequency response datasets from 2009 through 2012. The sample statistics by year are listed in Table B.1.

Table B.1: Sample Statistics for Eastern Interconnection

Year	Number of values	Mean of Frequency Response	Std. Dev. of Frequency Response	Minimum	Maximum
2009–2012	186	2,360	599	1,103	4,336
2009	44	2,258	522	1,405	3,625
2010	49	2,336	698	1,103	4,336
2011	65	2,468	594	1,210	3,815
2012	28	2,314	524	1,374	3,921

After the analysis, Fisher's least significant difference test is used to analyze all pair-wise changes in frequency response. These tests result in the conclusion that there are no statistically significant changes in the expected frequency response by year for the EI.

ERCOT Interconnection

The time trend analysis uses the ERCOT frequency response datasets from 2009 through 2012. The sample statistics by year are listed in Table B.2.

Table B.2: Sample Statistics for ERCOT Interconnection

Year	Number of values	Mean of Frequency Response	Std. Dev. of Frequency Response	Minimum	Maximum
2009–2012	246	570	172	228	1,418
2009	51	595	185	263	1,299
2010	67	610	165	368	1,153
2011	65	510	131	228	993
2012	63	571	192	290	1,418

Next, Fisher's least significant difference test is applied to analyze all pair-wise changes in frequency response. These tests find two statistically significant decreases in the expected frequency response (2009–2011 and 2010–2011) and one statistically significant increase (2011–2012). However, the change in the expected frequency response from 2009 to 2012 is not statistically significant.

Québec Interconnection

The time trend analysis uses the Québec frequency response datasets for the years 2011 through 2012. The sample statistics by year are listed in Table B.3.

Table B.3: Sample Statistics for Québec Interconnection					
Year	Number of values	Mean of Frequency Response	Std. Dev. of Frequency Response	Minimum	Maximum
2010–2012	48	555	192	215	1,202
2011	20	499	154	215	830
2012	28	593	212	306	1,202

Next, Fisher's least significant difference test is applied to analyze all pair-wise changes in frequency response. These tests result in the conclusion that there are no statistically significant changes in the expected frequency response by year for Québec Interconnection.

Western Interconnection

The time trend analysis uses the WI frequency response datasets for 2009–2012. The sample statistics are listed by year in Table B.4.

Table B.4: Sample Statistics for Western Interconnection					
Year	Number of values	Mean of Frequency Response	Std. Dev. of Frequency Response	Minimum	Maximum
2009–2012	91	1,521	430	817	3,125
2009	25	1,514	296	1,000	2,027
2010	29	1,572	512	817	3,125
2011	25	1,497	392	1,079	2,895
2012	12	1,467	557	997	3,123

It is impossible to statistically analyze pair-wise annual changes in the WI frequency response due to small sample sizes for each year.

Explanatory Variables for Frequency Response and Multiple Regression

Explanatory Variables

In the *2012 State of Reliability* report, Key Finding #2 proposed further work to see if specific indicators could be tied to severity of frequency deviation events. For each interconnection, the following set of six variables is included as explanatory variables (regressors) in the multiple regression models that describe the interconnection frequency response. These variables are not 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. Model selection methods help ensure the removal of highly correlated regressors and run multicollinearity diagnostic (variance inflation diagnostic) for a multiple regression model selected.

Summer (Indicator Function) – Defined as 1 for frequency response events that occur in June through August and 0 otherwise.
Winter (Indicator Function) – Defined as 1 for frequency response events that occur from December through February and 0 otherwise.
High Pre-Disturbance Frequency (Indicator Function) – Defined as 1 for frequency response events with pre-disturbance frequency (point A)>60 Hz, and 0 otherwise.
On-peak Hours (Indicator Function) – Defined as 1 for frequency response events that occurred during On-peak Hours and 0 otherwise. On-peak Hours are designated as follows: Monday to Saturday hours from 0700 to 2200 (Central Time) excluding six holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.
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 FR event. This is used to determine trends over the study period.
Interconnection Load Level – Measured in MW. For the Eastern and Western Interconnections, the data are unavailable for the 2012 events; thus, the multivariate statistical analysis for them involves 2009–2011 data only (158 observations for the EI and 79 observations for WI). For ERCOT the analysis covers the four-year data and for Québec, the 2011–2012 data.

For each Interconnection, Table B.5 lists the ranks of statistically significant variables of interconnection frequency response. "Positive" indicates positive correlation, "negative" indicates negative correlation, and a dash indicates no statistically significant insights.

Table B.5: Observation Summary				
	EI	WI	ERCOT	HI
Summer	-	-	-	-
Winter	-	-	2 (negative)	1 (positive)
Pre-disturbance freq.	2 (negative)	1 (negative)	1 (negative)	-
On-peak Hours	-	-	-	2 (positive)
Time	3 (positive)	-	-	-
Load Level	1 (positive)	2 (positive)	-	3 (positive)

Eastern Interconnection: Multivariate Analysis and Model

Descriptive statistics for the six explanatory variables and the EI frequency response are listed in Table B.6.

Table B.6: Descriptive Statistics					
Variable	N	Mean	Std Dev	Minimum	Maximum
Time92	158	1,597,049,962	26,033,859	1,546,788,406	1,633,537,560
Summer	158	0	0	-	1
A>60	158	0	1	-	1
On-peak Hours	158	1	0	-	1
Interconnection Load	158	342,071	63,846	217,666	540,366
Winter	158	0	0	-	1
FR	158	2,369	612	1,103	4,336

The correlation and a single regression analysis result in the hierarchy of the explanatory variables for the Eastern Interconnection frequency response shown in Table B.7. The value of a coefficient of determination R^2 indicates the percentage in variability of frequency response that can be explained by variability of the corresponding explanatory variable. Out of the six parameters, Interconnection Load has the biggest impact on frequency response, followed by the indicator of High Pre-disturbance Frequency and Time. Interconnection Load and Time are positively correlated with frequency response (they increase or decrease together, on average) while High Pre-disturbance Frequency is negatively correlated with frequency response. The events with A>60 MW/0.1 Hz have smaller frequency response than the events with A≤60 MW/0.1 Hz.

The other three variables do not have a statistically significant linear relationship with frequency response. Both Stepwise selection algorithm[93] and backward elimination algorithm[93] result in a multiple regression model that connects the EI frequency response with the following regressors: Interconnection Load, High Pre-disturbance Frequency, and On-peak Hours (the other three variables are not selected or were eliminated[94]). The models' coefficients are listed in Table B.8.

Table B.7: Correlation and Regression Analysis			
Explanatory Variable	Correlation with FR	Statistically Significant[95] (Yes/No)	Coefficient of Determination of Single regression (If SS)
Interconnection Load	0.36	Yes	13.3%
A>60	-0.26	Yes	6.9%
Time	0.16	Yes	2.6%
On-Peak hours	0.09	No	N/A
Summer	0.08	No	N/A
Winter	-0.08	No	N/A

[92] 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 FR event.

[93] For Stepwise regression algorithm and Backward Elimination algorithm

D. C. Montgomery and G. C. Runger. Applied Statistics and Probability for Engineers. Fifth Edition. 2011. John Wiley & Sons. Pp. 499-501.

[94] Regressors in the final model have p-values not exceeding 0.1.

[95] At significance level 0.1

The coefficient of multiple determination of the model is 21.5 percent; the model is statistically significant ($p<0.0001$). The random error has a zero mean and the sample deviation σ of 548 MW/0.1 Hz. Variance inflation factors for the regressors do not exceed 1.32, which confirms an acceptable level of multicollinearity that does not affect a general applicability of the model.

Table B.8: Coefficients of Multiple Models						
Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variance Inflation
Intercept	1	1,224	249	5	<.0001	0
A>60	1	(333)	88	(4)	-	1.01
On-peak Hours	1	(180)	104	(2)	0	1.31
Interconnection Load	1	0	0	5	<.0001	1.3

Frequency responses in the EI are higher due to the large number of disturbances in the dataset in which frequency changes were greater than the generator dead-bands. Also, in earlier studies, the gross output of the unit trip was reported, rather than the net generation[96] MW loss to the interconnection.

ERCOT: Multivariate Analysis and Model

Descriptive statistics for the six explanatory variables and the ERCOT frequency response are listed in Table B.9.

Table B.9: Descriptive Statistics					
Variable	N	Mean	Std Dev	Minimum	Maximum
Time[97]	246	1,644,212,680	16,758,218	1,611,465,058	1,670,906,162
Winter	246	0	0	-	1
Summer	246	0	0	-	1
A>60	246	0	1	-	1
On-peak Hours	246	1	0	-	1
Interconnection Load	246	38,361	9,949	22,243	64,744
FR	246	570	172	228	1,418

The correlation and a single regression analysis result in the hierarchy of the explanatory variables for the ERCOT frequency response shown in Table B.10.

Table B.10: Correlation and Regression Analysis			
Explanatory Variable	Correlation with FR	Statistically Significant[98] (Yes/No)	Coefficient of Determination of Single regression (If SS)
A>60	-0.35	Yes	12.3%
Winter	-0.11	Yes	1.3%
Time	-0.04	No	N/A
Summer	0.01	No	N/A
On-Peak hours	-0.01	No	N/A
Interconnection Load	-0.01	No	N/A

As previously stated, an R^2 coefficient is the percentage in variability of frequency response that can be explained by variability of the corresponding explanatory variable. Out of the six parameters, the indicator of High Pre-disturbance Frequency has the biggest impact on frequency response, followed by the indicator of Winter. Both High Pre-disturbance Frequency and Winter are negatively correlated with frequency response (the events with A>60 MW/0.1 Hz have smaller frequency response than the events with A≤60 MW/0.1 Hz, and the Winter events have smaller frequency response than other events). The other four variables do not have a statistically significant linear relationship with frequency response.

Finally, both Stepwise selection algorithm and backward elimination algorithm result in a multiple regression model that connects the ERCOT Interconnection frequency response with High Pre-disturbance Frequency and Winter (the other four

[96] There could be a coincident loss of load also.
[97] 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 an FR event.
[98] At significance level 0.1

variables are not selected or were eliminated[99]) as regressors. The coefficients of the multiple models are listed in Table B.11.

The coefficient of multiple determination of the model is 14.6 percent; the model is statistically significant ($p<0.0001$). The random error has a zero mean and the sample deviation σ of 160 MW/0.1 Hz. Variance inflation factors for the regressors do not exceed 1.02, which confirms an acceptable level of multicollinearity that does not affect a general applicability of the model.

Table B.11: Coefficients of the multiple model						
Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variance Inflation
Intercept	1	643	15	42	<.0001	0
Winter	1	(60)	23	(3)	0	1.01
A>60	1	(127)	21	(6)	<.0001	1.01

In the past in ERCOT when Load Resource has tripped, the interconnection measured the tripped MW[100] level of the Load Resource and subtracted the total tripped Load Resource from the generator MW net loss. If a 1000 MW generator trips and 200 MW Load Resource tripped, frequency response will be calculated using 800 MW net losses. Load Resource can be regarded as a dummy variable in the calculation of frequency response as (Unit MW Loss – Load Resource MW)/10*(Change in Frequency). The ERCOT event list contains the Load Resource MW data if any tripped during the event. For runback events, only the ones that ran back within the A-to-B measure would be used. The MW net loss or change during that same time period would be used. Longer period runbacks would not be included.

Several factors contributed to the frequency response performance in ERCOT over the past couple of years. One was the drop in natural gas prices and the change in dispatch. The price change caused many of the large coal generators to shut down, and frequency response from these generators had been excellent. The combined-cycle facilities that replaced these units had difficulty getting frequency response to work consistently and correctly. Since the fall of 2012, frequency response from combined-cycle facilities has improved due to efforts of the Texas Reliability Entity (TRE) to work with these generators to improve their performance. Another contributing factor was the continued increase in wind generation that typically operates at maximum output. Without margin in the up direction, the interconnection only receives benefit by curtailing wind generators during high-frequency excursions from these generators. When low-frequency excursions occur, the wind generators cannot provide additional output to increase interconnection frequency.

Finally, ERCOT has a small hydro fleet that suffered significantly due to the extreme drought of 2011. There was some relief in 2012, but not in the geographical area of these hydro facilities. Additionally, the owners of the facilities have changed the facilities' operation. Prior to the ERCOT nodal market implementation in December 2010, many of these facilities were operated as frequency responsive reserves. They were on-line in synchronous condenser mode and ramped to full output in about 20 seconds anytime frequency dropped to 59.900 Hz or below. This provided from 50 to 240 MW of frequency response during the first 20 seconds of any disturbance. Since early 2011, this service has been discontinued.

Québec: Multivariate Analysis and Model

Descriptive statistics for the six explanatory variables and the Québec frequency response are in Table B.12.

Table B.12: Descriptive Statistics					
Variable	N	Mean	Std Dev	Minimum	Maximum
Time101	48	1,644,212,680	16,758,218	1,611,465,058	1,670,906,162
Winter	48	0	0	-	1
Summer	48	0	0	-	1
A>60	48	1	1	-	1
On-peak Hours	48	1	1	-	1
Interconnection Load	48	19,389	3,766	14,330	31,931
FR	48	554	194	215	1,202

[99] Regressors in the final model have p-values not exceeding 0.1.
[100] This is AGC scan rate data from the supplier of the Load Resource.
[101] 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 an FR event.

The correlation and a single regression analysis result in the hierarchy of the explanatory variables for the Québec frequency response shown in Table B.13.

Table B.13: Correlation and Regression Analysis			
Explanatory Variable	**Correlation with FR**	**Statistically Significant[102] (Yes/No)**	**Coefficient of Determination of Single regression (If SS)**
Winter	0.30	Yes	9.1%
On-Peak hours	0.29	Yes	8.2%
Time	0.14	No	N/A
Summer	-0.12	No	N/A
A>60	0.12	No	N/A
Interconnection Load	0.24	No	N/A

The value of a coefficient of determination R^2 indicates the percentage in variability of frequency response that can be explained by variability of the corresponding explanatory variable. Out of the six parameters, the indicator of Winter has the biggest impact on frequency response, followed by the indicator of On-peak Hours and Interconnection Load. Winter and On-peak Hours and the Interconnection Load are positively correlated with frequency response (the Winter events have higher frequency response than other events; the on-peak hour events have higher frequency response than the off-peak hour events, and, finally, the events with higher Interconnection Load have bigger frequency response).

Finally, both Stepwise selection algorithm and backward elimination algorithm result in a multiple regression model that connects the Québec Interconnection (QI) frequency response with regressors Winter and On-peak Hours (other four variables are not selected or were eliminated). The coefficients of the multiple models are in Table B.14.

Table B.14: Coefficients of the Multiple Model						
Variable	**DF**	**Parameter Estimate**	**Standard Error**	**t Value**	**Pr > |t|**	**Variance Inflation**
Intercept	1	483	39	13	<.0001	0
Winter	1	159	80	2	0	1.01
On-peak Hours	1	99	53	2	0	1.01

The coefficient of multiple determination of the model is 15.6 percent; the model is statistically significant ($p=0.02$). The random error has a zero mean and the sample deviation σ of 182 MW/0.1 Hz. Variance inflation factors for the regressors do not exceed 1.02, which confirms an acceptable level of multicollinearity that does not affect a general applicability of the model.

The main reason that winter events have a better frequency response is because winter is the peak usage season in the Québec Interconnection. 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.

[102] At significance level 0.1

Western Interconnection: Multivariate Analysis and Model

Descriptive statistics for the six explanatory variables and the WI frequency response are listed in Table B.15.

Table B.15: Descriptive Statistics

Variable	N	Mean	Std Dev	Minimum	Maximum
Time103	79	1,591,586,534	24,880,470	1,549,711,475	1,632,393,394
Summer	79	0	0	-	1
Winter	79	0	0	-	1
A>60	79	0	1	-	1
On-peak Hours	79	85,783	13,640	60,188	113,495
Interconnection Load	79	1	1	-	1
FR	79	1,530	412	817	3,125

The value of a coefficient of determination R^2 indicates the percentage in variability of frequency response that can be explained by variability of the corresponding explanatory variable. Out of the six parameters, the indicator of High Pre-disturbance Frequency has the biggest impact on frequency response, followed by Interconnection Load. The indicator is negatively correlated with frequency response (the events with Pre-disturbance frequency greater than 60 Hz have smaller frequency response on average), while the Interconnection Load is positively correlated with frequency response (the the events with higher Interconnection Load have bigger frequency response). Other four variables are not statistically significantly correlated with frequency response.

The correlation and a single regression analysis result in the hierarchy of the explanatory variables for the WI frequency response shown in Table B.16.

Table B.16: Correlation and Regression Analysis

Explanatory Variable	Correlation with FR	Statistically Significant[104] (Yes/No)	Coefficient of Determination of Single regression (If SS)
Summer	-0.18	No	N/A
Time	-0.18	No	N/A
Winter	0.10	No	N/A
Interconnection Load	-0.08	No	N/A
On-Peak hours	-0.07	No	N/A
A>60	-0.02	No	N/A

Finally, both Stepwise selection algorithm and backward elimination algorithm result in a single regression model that connects the WI frequency response with regressor indicator of High Pre-disturbance Frequency (other five variables are not selected or were eliminated). The coefficients of the single model are listed in Table B.17.

Table B.17 : Coefficients of the Multiple Model

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variance Inflation
Intercept	1	1,725	54	32	<.0001	0
A>60 Hz	1	(429)	80	(5)	<.0001	1

The coefficient of determination of the model is 27.2 percent; the model is statistically significant ($p<0.0001$). The random error has a zero mean and the sample deviation σ of 353 MW/0.1 Hz. Since the multiple models for the WI frequency response are reduced to a single model, no multicollinearity diagnostics are needed.

[103] 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 FR event.

[104] At significance level 0.1

Abbreviations Used in This Report

Acronym	Description
ALR	Adequate Level of Reliability
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Common/Dependent Mode
EEA	Energy Emergency Alert
EFORd	Equivalent Forced Outage Rate, Demand
EI	Eastern Interconnection
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
ICC	Initiating Cause Code
IROL	Interconnection Reliability Operating Limit
ISO	Independent System Operator
ISO-NE	ISO New England
KCMI	Key Compliance Monitoring Index
MRO	Midwest Reliability Organization
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent Service Operator
PAS	Performance Analysis Subcommittee
PSMTF	Protection System Misoperation Task Force
QI	Québec Interconnection
RC	Reliability Coordinator
RE	Regional Entities
RFC	Reliability*First* Corporation
RSG	Reserve Sharing Group
SERC	SERC Reliability Corporation
SNL	Sandia National Laboratories
SOL	System Operating Limit
SPS	Special Protection Schemes
SPCS	System Protection and Control Subcommittee
SPP	Southwest Power Pool
SRI	Severity Risk Index
TADS	Transmission Availability Data System
TADSWG	Transmission Availability Data System Working Group
TO	Transmission Owner
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council
WI	Western Interconnection

Contributions

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NERC Industry Groups

Table 1 lists the NERC industry group contributors.

Table 1: NERC Group Acknowledgements	
Group	Officers
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Performance Analysis Subcommittee	Chair: Bill Adams, Georgia Power Vice Chair: Melinda Montgomery, Entergy
Demand Response Availability Data System Working Group	Chair: Bob Collins, TRE Vice Chair: Mike Jaeger, ISO-NE
Events Analysis Subcommittee	Chair: Sam Holeman, Duke Energy Vice Chair: Hassan Hamdar, FRCC
Generation Availability Data System Working Group	Chair: Gary Brinkworth, TVA Vice Chair: Leeth DePriest, Southern Company
Transmission Availability Data System Working Group	Chair: Jake Langthorn, Oklahoma Gas and Electric Co. Vice Chair: Jeff Schaller, Hydro One Networks, Inc.
Resources Subcommittee	Chair: Don Badley, Northwest Power Pool Corp. Vice Chair: Gerald Beckerle, Ameren Services
Operating Reliability Subcommittee	Chair: Colleen Frosch, ERCOT Vice Chair: Joel Wise, TVA
Frequency Working Group	Chair: Sydney Niemeyer, NRG Energy
Operating Committee	Chair: Tom Bowe, PJM Interconnection, LLC Vice Chair: James D. Castle, Duke Energy
Planning Committee	Chair: Jeffery L. Mitchell, RFC Vice Chair: Ben Crisp, SERC Reliability Corporation
Reliability Assessment Subcommittee	Chair: Vince Ordax, FRCC Vice Chair: Layne Brown, WECC
System Protection and Control Subcommittee	Chair: William J. Miller, Exelon Corporation Vice Chair: Philip B. Winston, Southern Company
Protection System Misoperations Task Force	Chair: John Seidel, Midwest Reliability Organization
Spare Equipment Database Working Group	Chair: Dale Burmester, American Transmission Company, LLC Vice Chair: Mark Westendorf, Midwest ISO, Inc.
Compliance and Certification Committee	Chair: Terry Bilke, Midwest ISO, Inc. Vice Chair: Patricia E. Metro, National Rural Electric Cooperative Association

Regional Entity Staff

Table 2 provides a list of the Regional Entity staff that provided data and content review.

Table 2: Contributing Regional Entity Staff	
Name	Regional Entity
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Phil Fedora	NPCC
Paul Kure	RFC
John Johnson	SERC
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NERC Staff

Table 3 provides a list of the NERC staff who contributed to this report.

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