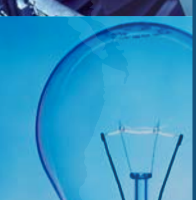
NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2011 Risk Assessment of Reliability Performance



to ensure the reliability of the bulk power system

July 2011

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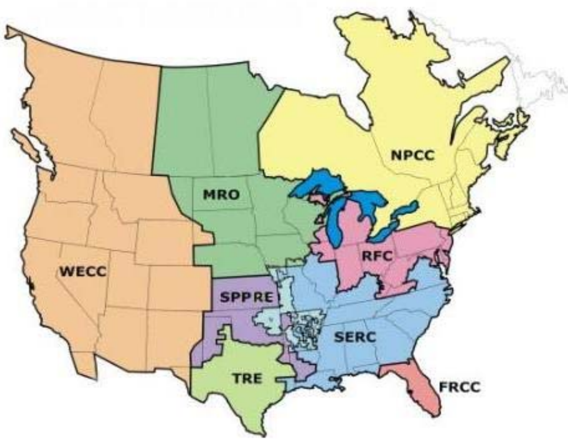
NERC's Mission

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 adequacy annually via a ten-year forecast and winter and summer forecasts; 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.[1]

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



Note: The highlighted area between SPP RE 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 Regional Entities	
FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corporation
MRO Midwest Reliability Organization	**SPP RE** Southwest Power Pool Regional Entity
NPCC Northeast Power Coordinating Council	**TRE** Texas Reliability Entity
RFC Reliability*First* Corporation	**WECC** Western Electricity Coordinating Council

[1] 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. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

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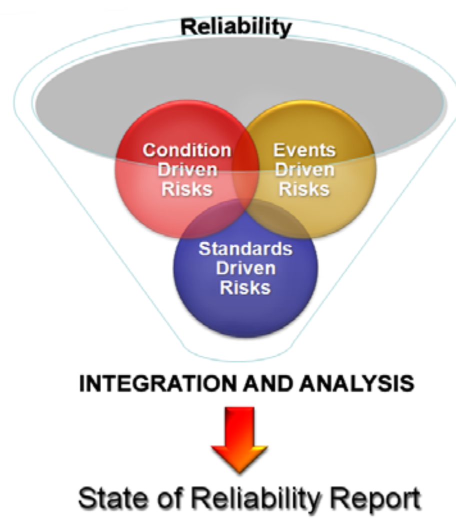
Executive Summary

2011 Transition Report

The *2011 Risk Assessment of Reliability Performance* is a foundational report, with the goal to provide a view of risks to reliability based on historic performance. The objective is to integrate many ongoing efforts underway providing technical analysis and feedback on risk attributes and reliability trends to stakeholders, regulators, policymakers and industry. The joint report development was led by NERC staff in collaboration with several groups independently analyzing specific aspects of bulk power system reliability, including the Reliability Metrics Working Group (RMWG), Transmission Availability Data System Working Group (TADSWG), Generating Availability Data System Task Force (GADSTF), and Event Analysis Working Group (EAWG).

Figure ES1: State of Reliability



Since its inaugural report,[2] the RMWG has advanced the development and understanding of risk attributes impacting reliability performance and the corresponding metrics that provide insight to the performance of the bulk power system. As this work proceeds, industry continues to investigate those risk attribute areas which enhance the understanding and insights that can be drawn for system reliability (Figure ES1). Other committees, working groups, and task forces, in addition to NERC staff, are undertaking additional reliability analysis of the system. These efforts have resulted in an evolving body of work.

The *2011 Risk Assessment of Reliability Performance* begins a transition from a 2009 metric performance assessment to a more complete risk impact evaluation of reliability. This transition is expected to crystallize as more data becomes available and understanding of the data and trends matures. The annual *Risk Assessment of Reliability Performance* report will provide a technically sound platform to ultimately communicate the effectiveness of ERO (Electric Reliability Organization) reliability programs, set the foundation of a learning and accountable ERO, and present an overall view of risk impacts affecting reliability performance.

By addressing the key, measurable components of bulk power system reliability, the *Risk Assessment of Reliability Performance* report will provide insights, guidance, and direction to those areas in which reliability goals can be more effectively and sustainably achieved. Also, the report will serve as a foundation to streamline and align the data and information reporting arising from multiple technical

[2] http://www.nerc.com/docs/pc/rmwg/RMWG_Metric_Report-09-08-09.pdf

groups, thereby providing efficient data and information transparency. The key findings and recommendations are envisioned as input to NERC's Reliability Standards and project prioritization, compliance process improvement, event analysis, reliability assessment, and critical infrastructure protection.

The ultimate goal of the State of Reliability report is twofold. First, the report will illuminate the historical, overall bulk power system reliability picture. By using robust data, the reliability of the system can be explained and documented. Currently, there are no measures, datasets, or reports that explicitly and completely state the historical performance of the system.

Second, the report will help identify risk clusters, prioritize, and create actionable results for reliability improvement. Once a risk universe has been found, it can be parsed into component clusters.[3] These significant risk clusters can be selected as priority projects to develop coordinated and multifunctional solutions to relevant problems. The State of Reliability report will provide an industry reference for historical bulk power system reliability, analytical insights with a view to action, and will enable the discovery and prioritization of specific, actionable risk control steps.

Key Findings and Recommendations

Reliability Metrics Performance

The Operating and Planning Committees approved eighteen metrics that address the characteristics of an adequate level of reliability (ALR), the following seven metrics are improving based on metric trends, indicating the bulk power system is performing better during the time frame analyzed:

- ALR1-3: Planning Reserve Margin
- ALR1-4: BPS Transmission Related Events Resulting in Loss of Load
- ALR2-5: Disturbance Control Events Greater than Most Severe Single Contingency
- ALR6-2: Energy Emergency Alert 3 (EEA3)
- ALR6-3: Energy Emergency Alert 2 (EEA2)
- ALR6-11: Automatic Transmission Outages Initiated by Failed Protection System Equipment
- ALR6-13: Automatic Transmission Outages Initiated by Failed AC Substation Equipment

The remaining metrics do not have sufficient data to derive useful conclusions, or currently lack data. With a more thorough data matrix for these metrics, more conclusions about reliability will be ascertained. All metrics will be evaluated on a regular basis to determine each metric's contribution to quantitative reliability measurement.

[3] Malcolm K. Sparrow, *The Regulatory Craft*, The Brookings Institution, 2000.

Transmission Availability Performance

On a NERC-wide average basis, the automatic transmission outage rate has improved from 2008 to 2010. Considering both automatic and non-automatic outages, 2010 records indicate transmission element availability percentage exceeds 95%.

Unexpectedly, almost one-third of all sustained, automatic outages are dependent or common mode events. Though a number of protection systems are intended to trip three or more circuits, many events go beyond their design basis. In addition, a number of multiple outage events were initiated by protection system misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry. More focus into this problem would improve the design basis assumed for reliable operation of the system. A joint team should be formed to analyze these outages.

Generating Availability Performance

On the average, units appear to require maintenance with increasing regularity to meet unit availability goals. In the last three years, the Equivalent Forced Outage Rate – Demand (EFORd) increased, indicating a higher risk that a unit may not be available to meet generating requirements due to forced outages or de-ratings. From 2009 to 2010, the average maintenance hours increased by 24 hours per unit. The three leading root causes for multiple unit forced trips are transmission outages, lack of fuel, and weather. Detailed analysis is needed to identify the root causes of increasing forced outage rate.

Disturbance Events

One of most important bulk power system performance measures is the number of significant disturbance events and their impact on system reliability. The trends have been captured in the severity risk curve analysis featured in the reliability metrics assessment.

Since the event analysis field test commenced in October 2010, a total of 42 events within five categories were reported through the end of 2010. Equipment failure is the number one cause identified from the event analyses completed from 2010. This suggests more data and analysis into equipment failure may prove fruitful. However, with such a small dataset, no conclusions can be drawn.

Report Organization

Following the introductory chapter, the second chapter details results for 2010 RMWG approved performance metrics and lays out methods for integrating the variety of risks into an integrated risk index. This chapter also addresses concepts for measuring bulk power system events. The third chapter outlines transmission system performance results that the TADSWG have endorsed using the three-year history of TADS data. Reviewed by the GADSTF, the fourth chapter provides an overview of generating availability trends for 72 percent of generators in North America. The fifth chapter provides a brief summary of reported disturbances based on event categories described in the EAWG's enhanced event analysis field test process document.

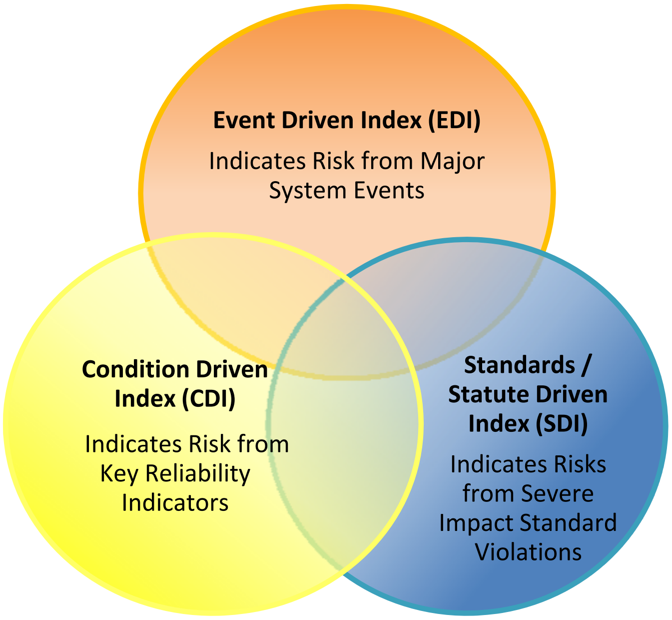
Introduction

Metric Report Evolution

The NERC Reliability Metrics Working Group (RMWG) work has progressed since its formation and following the release of the initial reliability metric whitepaper in December 2007[4]. Since that time, a metric development process has been built with the use of SMART[5] ratings (Specific, Measurable, Attainable, Relevant and Tangible) featured in the 2009 report,[6] expanding the approved metrics to eighteen, and identifying the need for additional data by issuing a data request for ALR3-5: Interconnection Reliability Operating Limit/System Operating Limit (IROL/SOL) Exceedances.

The first annual report published in June 2010 provided an analysis of seven. In August 2010, the RMWG released its *Integrated Bulk Power System Risk Assessment Concepts* paper[7] introducing new concepts, such as the "universe of risk" of the bulk power system. In the concepts paper, a method to assess "event-driven" risks was introduced and the Severity Risk Index (SRI) was established to quantify the impact of various events of the bulk power system. The concepts paper was subsequently endorsed by NERC's Operating (OC) and Planning Committees (PC).

Figure 1: State of Reliability Concepts



Subsequently, a conceptual model was developed to be used to provide an integrated reliability assessment of bulk power system performance. This year's report builds on previous work towards establishing a single Integrated Reliability Index (IRI) comprised of three components: event driven index (EDI), condition driven index (CDI), and standards/statute driven index (SDI) as shown in Figure 1.

These individual components will be used to develop a reliability index to assess the current state of reliability. This is an ambitious undertaking, and it will continue to evolve as an understanding of what factors contribute to, or indicate the level of, reliability develops. In the coming years, analysis of the SRI will expand to an integrated reliability index (IRI) with deeper analysis of the approved reliability

[4] The initial reliability metrics whitepaper is located at http://www.nerc.com/docs/pc/rmwg/Reliability_Metrics_white_paper.pdf.

[5] SMART rating definitions are located at: http://www.nerc.com/docs/pc/rmwg/SMART_%20RATING_8.26.pdf.

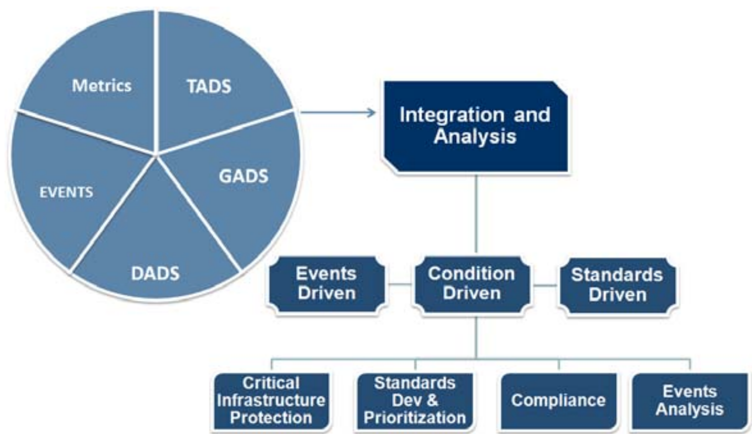
[6] 2009 Bulk Power System Reliability Performance Metric Recommendations can be found at http://www.nerc.com/docs/pc/rmwg/RMWG_Metric_Report-09-08-09.pdf.

[7] http://www.nerc.com/docs/pc/rmwg/Integrated_Bulk_Power_System_Risk_Assessment_Concepts_Final.pdf

metrics, and establish the cornerstones for developing an IRI. Chapter two of this report elaborates on recommendations for next steps to better refine and weigh the components of the IRI, as well as its use to establish a "State of Reliability" for the bulk power system in North America.

For this work to be effective and useful to stakeholders, it must use existing data sources, align with other industry analyses, and integrate with other initiatives as shown in Figure 2. NERC's data resources are introduced in this report: Transmission Availability Data System (TADS), Generating Availability Data System (GADS), Event Analysis database, and, in the future, Demand Response Availability Data System (DADS).[8]

Figure 2: Data Source Integration and Analysis



An open development process is used, incorporating continuous improvement through leveraging industry expertise and technical judgment. As new data becomes available, more concrete conclusions from the reliability metrics will be drawn and recommendations for reliability standards and compliance process improvement will be developed.

This evolution will take time, and the first assessment of ongoing reliability using the three components of an integrated reliability assessment is expected in the 2012 Annual Report. The goal is not only to measure performance, but to highlight areas for improvement as well as reinforcing and measuring industry success. As this view of reliability is developed, the quarterly performance metrics will be updated as illustrated in Figure 3 on a Reliability Indicators dashboard at NERC's website.[9] Industry will be kept informed of the evolution through yearly webinars, providing quarterly data updates, and publishing its annual report.

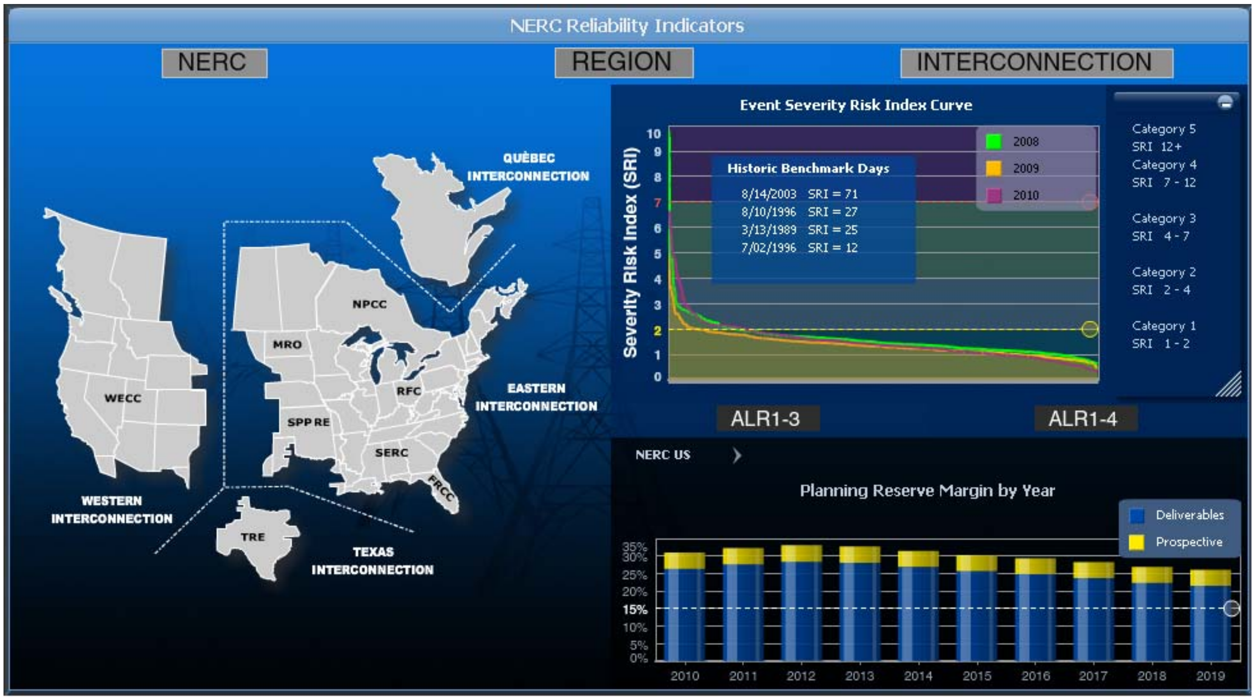
Roadmap for the Future

As shown in Figure 4, the 2011 Reliability Performance Analysis report begins a transition from a metric performance assessment to a "*State of Reliability*" report by collaborating with other groups to form a unified approach to historical reliability performance analysis. This process will require engagement with a number of NERC industry subject matter experts to develop a broad picture of the bulk power system's historic reliability.

[8] DADS will begin mandatory data collection from April 2011 through October 2011, with data due on December 15, 2011.

[9] Reliability Indicators' dashboard is available at: http://www.nerc.com/page.php?cid=4|331.

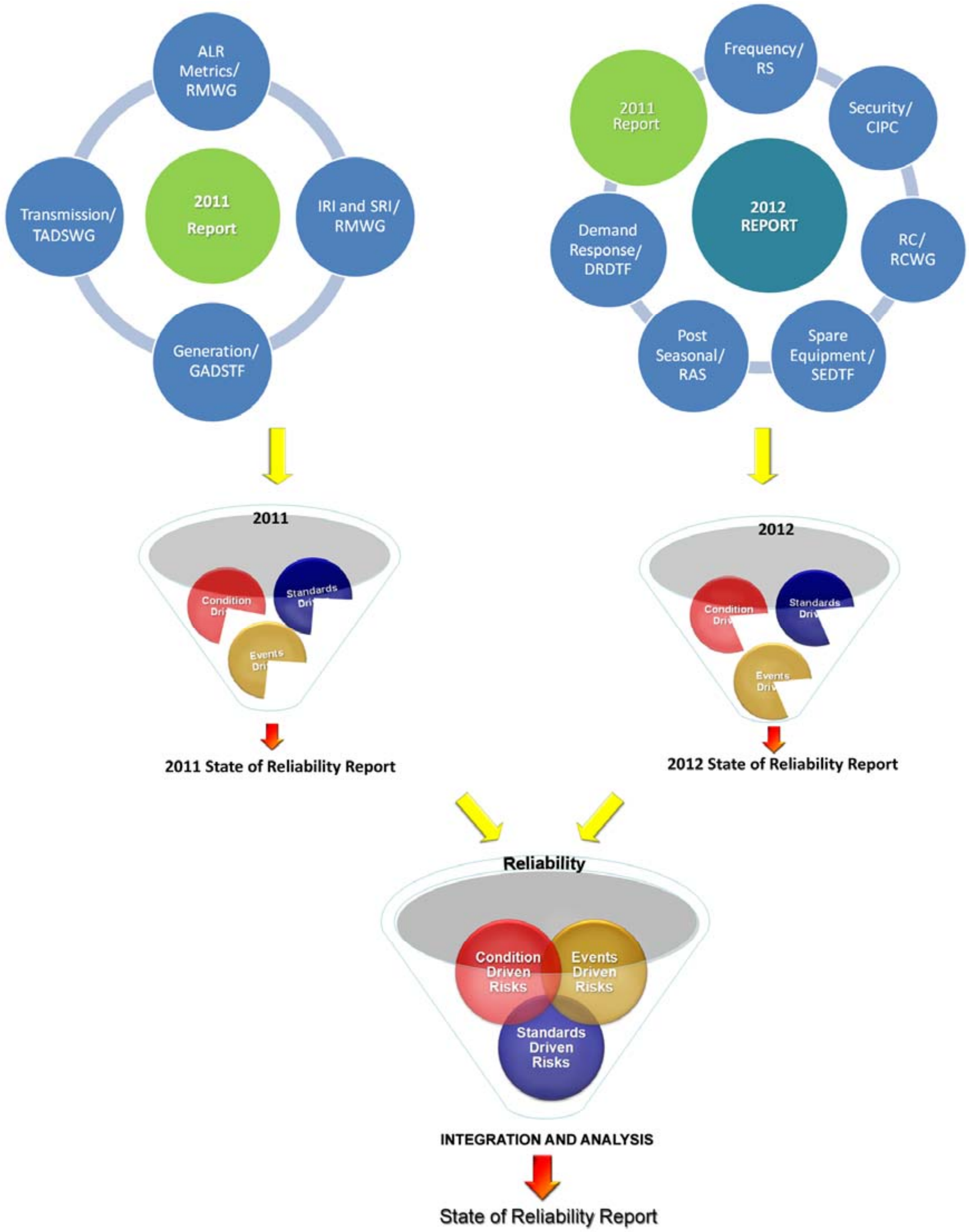
Figure 3: NERC Reliability Indicators Dashboard



Alignment to other industry reports is also important. Analysis from the frequency response completed by the Resources Subcommittee (RS), physical and cyber security assessment provided by the Critical Infrastructure Protection Committee (CIPC), the wide area reliability coordination conducted by the Reliability Coordinator Working Group (RCWG) , the spare equipment availability system enhanced by the Spare Equipment Database Task Force (SEDTF), the post seasonal assessment developed by the Reliability Assessment Subcommittee (RAS), and demand response deployment summarized by the Demand Response Data Task Force (DRDTF), will provide a significant foundation from which this report draws. Collaboration derived from these stakeholder groups further refines the metrics; and use of additional datasets will broaden the industry’s tool-chest for improving reliability of the bulk power system.

The annual S*tate of Reliability* report will be aimed to communicate the effectiveness of NERC, by presenting an integrated view of reliability performance. A platform will be created for sound technical analysis and a way to provide feedback on reliability trends to stakeholders, regulators, policymakers, and industry. The key findings and recommendations will ultimately be used as input to standards changes and project prioritization, reliability assessment, compliance process improvement, event analysis, and critical infrastructure protection areas.

Figure 4: Overview of the Transition to the 2012 State of Reliability Report



Reliability Metrics Performance

Introduction

Building upon last year's metric review, the results of eighteen performance metrics continue to be assessed. Due to 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).This will be an important improvement in the future. At this time, the number of metrics is expected to remain constant; however, other metrics may supplant existing metrics which may have more merit. In spite of the potentially changing mix of approved metrics, historical and current assessments will still be possible.

These metrics exist within an overall reliability framework, and, in total, the performance metrics being considered address the fundamental characteristics of an adequate level of reliability (ALR).[10] Each of the elements being measured by the metrics should be considered in aggregate when making an assessment of the reliability of the bulk power system, with no single metric indicating exceptional or poor performance of the power system.

Importantly, due to regional differences (size of the region, operating practices, etc.), 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 others, and assessment may not be strictly mathematical, rather more subjective. Finally, choosing one region's best metric performance to define targets for other regions is also inappropriate.

Another key principle is to retain anonymity of any individual reporting organization. Thus, granularity will be attempted to the point that such action might compromise anonymity of any given reporting entity. Certain reporting entities may appear inconsistent, but they have been preserved to maintain maximum granularity while balancing individual organization anonymity.

Although assessments have been made in a number of the performance categories, others do not have sufficient data to derive conclusions from the metric results. Continued assessment of these metrics should continue until sufficient data is available. Each of the eighteen performance metrics are presented, in summary, with their trend ratings in Table 1. The table provides a summary view of the metrics with an assessment of the current metric trends.

[10] http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

Table 1: Metric Trend Ratings

ALR	Improvements	Trend Rating
1-3	Planning Reserve Margin	
1-4	BPS Transmission Related Events Resulting in Loss of Load	
2-5	Disturbance Control Events Greater than Most Severe Single Contingency	
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	
6-13	Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment	
	Inconclusive	
2-3	Activation of Under Frequency Load Shedding	
2-4	Average Percent Non-Recovery Disturbance Control Standard Events	
4-1	Automatic Transmission Outages Caused by Failed Protection System Equipment	
6-12	Automatic AC Transmission Outages Initiated by Human Error	
6-14	Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment	
	New Data	
3-5	Interconnected Reliability Operating Limit/ System Operating Limit (IROL/SOL) Exceedance	
6-1	Transmission Constraint Mitigation	
6-15	Element Availability Percentage (APC)	
6-16	Transmission System Unavailability	
	No Data	
1-5	System Voltage Performance	
1-12	Interconnection Frequency Response	

Trend Rating Symbols	
Significant Improvement	
Slight Improvement	
Inconclusive	
Slight Deterioration	
Significant Deterioration	
New Data	
No Data	

2010 Performance Metrics Results and Trends

ALR1-3 Planning Reserve Margin

Background

The Planning Reserve Margin[11] is a measure of the relationship between the amount of resource capacity forecast and the expected demand in the planning horizon.[12] Coupled with probabilistic analysis, calculated Planning Reserve Margins is an industry standard used by system planners for decades as an indication of system resource adequacy.

Planning Reserve Margin is the difference between forecast capacity and projected peak demand (50/50 forecast[13]), normalized by projected peak demand and shown as a percentage. Based on experience, for portions of the bulk power system that are not energy-constrained, Planning Reserve Margin indicates the amount of capacity available to maintain reliable operation, while meeting unforeseen increases in demand (e.g., extreme weather) and unexpected unavailability of existing capacity (e.g., long-term generation outages). Further, from a planning perspective, Planning Reserve Margin trends identify whether capacity additions are projected to keep pace with demand growth.

Assessment

Planning Reserve Margins, considering anticipated capacity resources and adjusted potential capacity resources,[14] decrease in the latter years of the 10-year forecasts in each of the four interconnections for both the 2009[15] and 2010 resource projections. Typically, the early years provide more certainty since new generation is either in-service or under construction with firm commitments. In the later years, there is less certainty about the resources that will be needed to meet peak demand. Declining Planning Reserve Margins are inherent in a conventional forecast (assuming load growth) and do not necessarily indicate a trend of a degrading resource adequacy. Rather, they are an indication of the potential need for additional resources. In addition, key observations can be made about the Planning Reserve Margin forecast, such as short-term assessment comparison to target margins, rate of margin change through the assessment period, identification of margins that are approaching or below a target requirement, and comparisons from year-to-year forecasts.

While resource planners are able to forecast the need for resources, the type of resource that will actually be built or acquired to fill the need is less certain. For example, in the northeast U.S. markets, with a three to five year forward capacity market, firm commitments are not made in the long-term. However, resource planners do recognize the need for resources in their long-term planning and

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[11] Detailed calculations of Planning Reserve Margin are available at: http://www.nerc.com/page.php?cid=4|331|333.

[12] The Planning Reserve Margin indicated here is not the same as an operating reserve margin that system operators use for near-term operations decisions.

[13] These demand forecasts are based on "50/50" or median weather (a 50 percent chance of the weather being warmer and a 50 percent chance of the weather being cooler).

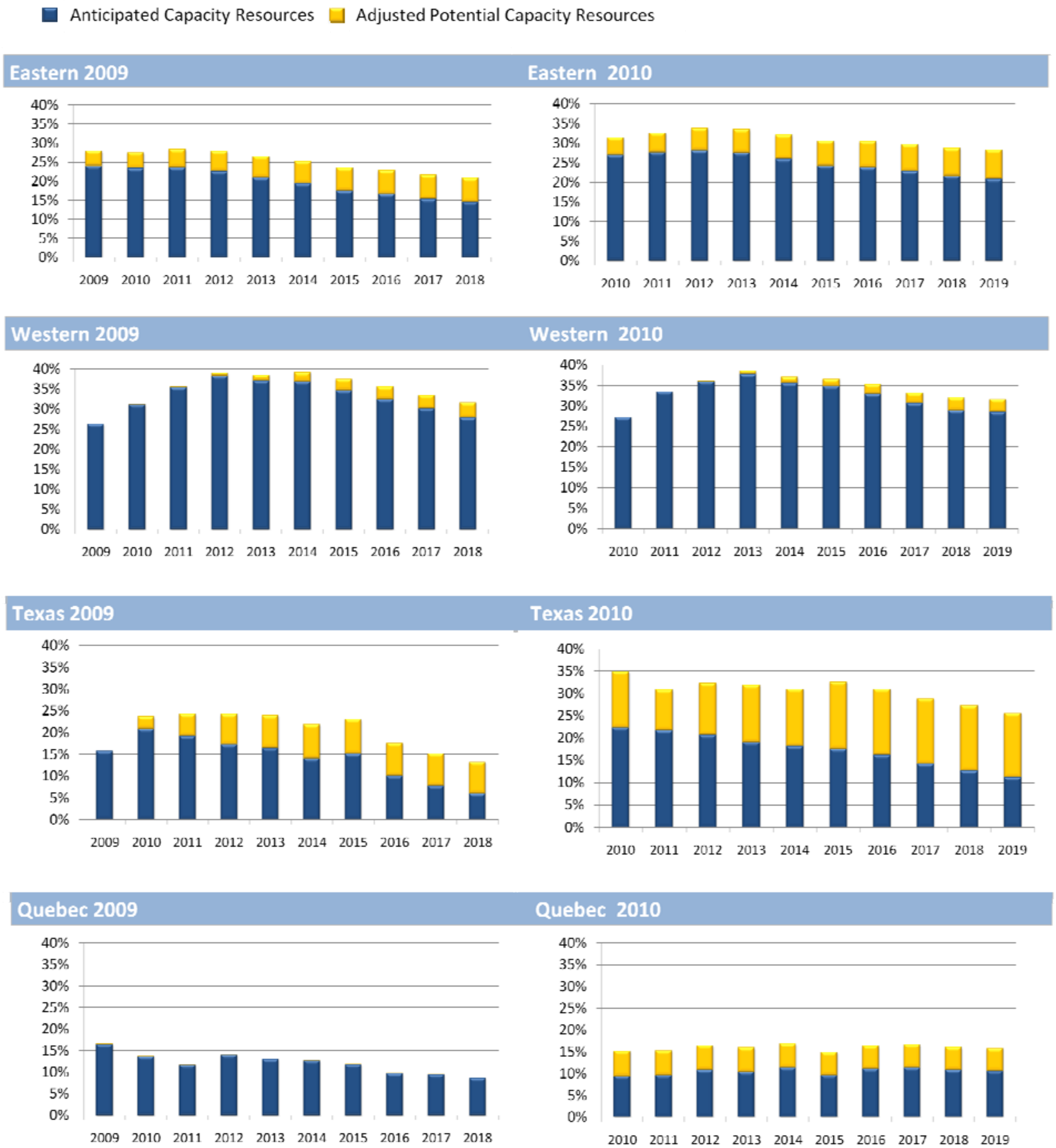
[14] See Terms Used in this Report of the *2010 Long-Term Reliability Assessment*, http://www.nerc.com/files/2010_LTRA_v2-.pdf.

[15] 2009 Long-Term Reliability Assessment, http://www.nerc.com/files/2009_LTRA.pdf.

account for these resources through generator queues. These queues are then adjusted to reflect an adjusted forecast of resources—pro-rated by approximately 20 percent, depending on the assessment area.

When comparing the assessment of planning reserve margins between 2009 and 2010, the interconnection Planning Reserve Margins are slightly higher, on an annual basis, in the 2010 forecast compared to those of 2009, as shown in Figure 5.

Figure 5: Planning Reserve Margin by Interconnection and Year



This conclusion results from slightly higher capacity forecasts and slightly lower demand forecasts. Importantly, the pace of any economic recovery will affect future comparisons.[16] This metric can be used by NERC to assess the individual interconnections in the ten-year long-term reliability assessments. If a noticeable change occurs, further investigation is necessary to determine the causes and likely effects on reliability, and the potential need for additional resources.

Special Considerations

The Planning Reserve Margin is a capacity-based metric. Therefore, it does not provide an accurate assessment of performance in energy-limited systems (e.g., hydro capacity with limited water resources or systems with significant variable generation penetration). In addition, the Planning Reserve Margin does not provide a measure of potential transmission constraints internal to their respective assessment areas. Planning Reserve Margin data, shown in Figure 5, is used for NERC's seasonal and long-term reliability assessments as the primary metric to determine the resource adequacy of assessment areas.

The North American bulk power system is divided into four distinct interconnections. These interconnections are loosely connected with limited ability to share capacity or energy across the interconnection. To reflect this limitation, the Planning Reserve Margins are calculated in this report based on interconnection values rather than by national boundaries, as is the practice of the Reliability Assessment Subcommittee (RAS).

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

Background

This metric measures bulk power system 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, and results in the loss of firm system demand for more than 15 minutes. The reporting criteria for such events are outlined below:[17]

[16] *Potential Reliability Impacts of Swift Demand Growth after a Long-Term Recession,* http://www.nerc.com/files/NERC_Swift_Scenario_Aug_2010.pdf

[17] Details of event definitions are available at: 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 bulk power system reliability.

Assessment

Figure 6 illustrates that the number of bulk power system transmission-related events resulting in loss of firm load from 2002 to 2010 is relatively constant and suggests an average of between 10 to 12 events per year are experienced. Except 2008, the magnitude of load loss, shown in Table 2, associated with these events appears to range from 2,000 MW to 5,000 MW since 2006. Further analysis and continued assessment of the trends over time is recommended.

Figure 6: Bulk Power System Transmission Related Events Resulting in Loss of Load (2002-2010)

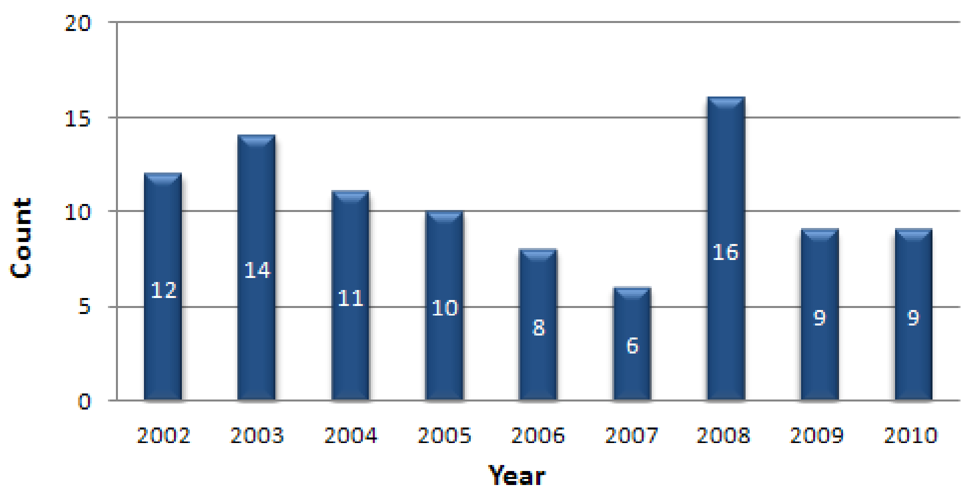


Table 2: Bulk Power System Transmission Related Events Resulting in Loss of Load (2002-2010)	
Year	**Load Loss (MW)**
2002	7,085
2003	64,850
2004	4,950
2005	8,942
2006	3,763
2007	2,249
2008	11,045
2009	4,432
2010	4,402

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 load loss should be conducted.

ALR1-12 Interconnection Frequency Response

Background

This metric is used 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 bulk power system, particularly during disturbances and restoration. The metric measures the average frequency response for all events where frequency drops more than 35 mHz within a year.

Assessment

During the study period, there was no formal, established data collection process for ALR1-12. Therefore, no assessment was possible. Full use of data being gathered from the frequency response project should be used to derive this metric.

ALR2-3 Activation of Under Frequency Load Shedding

Background

The purpose of Under Frequency Load Shedding (UFLS) is to balance generation and load in an island following an extreme event. The UFLS activation metric measures the number of times it is activated and the total MW of load interrupted in each Regional Entity and NERC-wide.

Assessment

Figure 7 and Table 3 illustrate a history of UFLS events from 2006 through 2010. Notably, single events had a load shedding range from 15 MW to 2,273 MW. The activation of UFLS is the last automated reliability measure associated with a decline in frequency in order to rebalance the system. Further assessment of the MW loss for these activations is recommended.

Because of the large range of load lost in UFLS events, the need to establish a UFLS total load loss threshold is under evaluation. The significance of a UFLS activation compared to the total load loss of the activation will be assessed over time.

Figure 7: ALR2-3 Count of Activations by Year and Regional Entity (2006-2010)

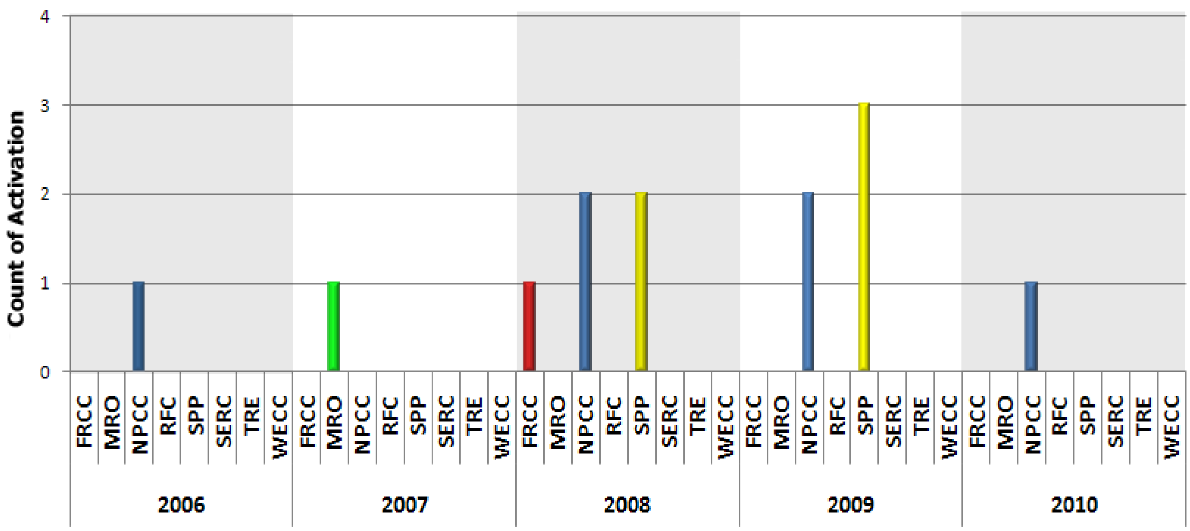


Table 3: ALR2-3 Under Frequency Load Shedding					
MW Loss					
	2006	**2007**	**2008**	**2009**	**2010**
FRCC	-	-	2,273	-	-
MRO	-	486	-	-	-
NPCC	94	-	63	20	25
RFC	-	-	-	-	-
SPP	-	-	672	15	-
SERC	-	-	-	-	-
TRE	-	-	-	-	-
WECC	-	-	-	-	-

Special Considerations

The use of a single metric cannot capture all of the relevant information associated with UFLS events as the events relate to each respective UFLS plan. Namely, use of UFLS as designed is a successful measure of system performance. The ability to measure the reliability of the bulk power system is directly associated with how it performs compared to what is planned.

ALR2-4 Average Percent Non-Recovery Disturbance Control Standards (DCS)

Background

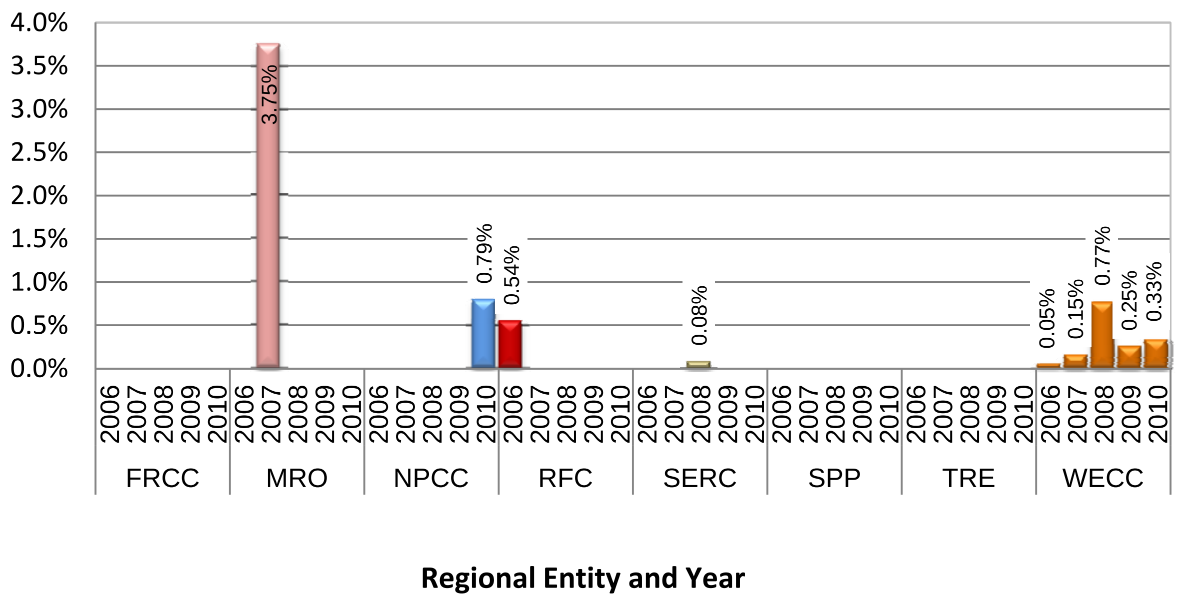
This metric measures the Balancing Authority's (BA) or Reserve Sharing Group's (RSG) ability to balance resources and demand with the timely deployment of contingency reserve, thereby returning the interconnection frequency to within defined limits following a Reportable Disturbance.[18] The relative percentage provides an indication of performance measured at a BA or RSG.

Assessment

Figure 8 illustrates the average percent non-recovery of DCS events from 2006 to 2010. The graph provides a high-level indication of the performance of each Regional Entity. However, a single event may not reflect all the reliability issues within a given RE. In order to understand the reliability aspects, it may be necessary to request individual Regional Entities to further investigate and provide a more comprehensive reliability report. Further investigation may indicate that sufficient contingency reserve were available, but, through their implementation process, failed to meet DCS recovery.

Continued trend assessment is recommended. Where trends indicated potential issues, the Regional Entity will be requested to investigate and report their findings.

Figure 8: Average Percent Non-Recovery of DCS Events (2006-2010)



[18] Details of the Disturbance Control Performance Standard and Reportable Disturbance definitions are available at: http://www.nerc.com/files/BAL-002-0.pdf.

Special Considerations

This metric aggregates the number of events based on reporting from individual Balancing Authorities or Reserve Sharing Groups. It does not capture the severity of the DCS events. Most Regional Entities use 80 percent of the Most Severe Single Contingency to establish the minimum threshold for reportable disturbance, while others use 35 percent.[19]

ALR2-5 Disturbance Control Events Greater Than Most Severe Single Contingency

Background

This metric represents the number of disturbance events that exceed the Most Severe Single Contingency (MSSC), and is specific to each BA. Each Regional Entity reports disturbances greater than the MSSC on behalf of the BA or Reserve Sharing Group (RSG). The result validates current contingency reserve requirements. The MSSC is determined based on the specific configuration of each BA or RSG and can vary in significance and impact on the BPS.

Assessment

Figure 9 represents the number of DCS events within each RE that are greater than the MSSC from 2006 to 2010. This metric and resulting trend can provide insight regarding the risk of events greater than the MSSC and the potential for loss of load.

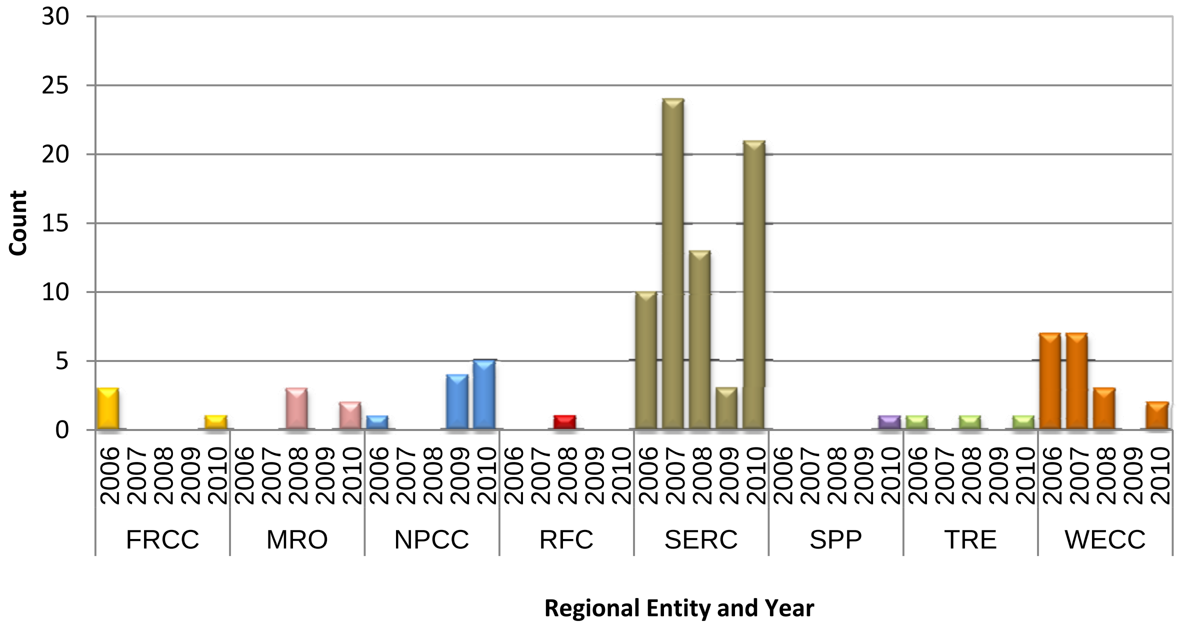
In 2010, SERC had 16 BAL-002 reporting entities; eight Balancing Areas elected to maintain Contingency Reserve levels independent of any reserve sharing group. These 16 entities experienced 79 reportable DCS events—21 of which were categorized as greater than their most severe single contingency. Every DCS event categorized as greater than the most severe single contingency occurred within a Balancing Area maintaining independent Contingency Reserve levels. Significantly, all 79 Regional Entities reported compliance with the Disturbance Recovery Criterion, including for those Disturbances that were considered greater than their most severe single contingency. This supports a conclusion that regardless of the size of the BA or participation in a Reserve Sharing Group, SERC's BAL-002 reporting entities have demonstrated the ability in 2010 to use Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following Reportable Disturbances.

If the SERC Balancing Areas without large generating units and who do not participate in a Reserve Sharing Group change the determination of their most severe single contingencies to effect an increase in the DCS reporting threshold (and concurrently the threshold for determining those disturbances which are greater than the most severe single contingency), there will be a reduction in both the gross count of DCS events in SERC and in the subset considered under ALR2-5. Masking the discrete events which cause Balancing Area to respond may not reduce "risk" to the system. However, it is desirable to maintain a reporting threshold which encourages the Balancing Authority to respond to any unexplained

[19] http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=69&Source=/Standards/Development/Pages/WECCStandardsArchive.aspx.

change in automatic control error (ACE) in a manner which supports Interconnection frequency based on demonstrated performance. SERC plans to continue to monitor DCS performance and will continue to evaluate contingency reserve requirements but does not consider 2010 ALR2-5 performance to be an adverse trend in "extreme or unusual" contingencies but, rather, within the normal range of expected occurrences.

Figure 9: Disturbance Control Events Greater Than Most Severe Single Contingency (2006-2010)



Special Considerations

The metric reports the number of DCS events greater than MSSC, most severe single contingency, without regards to the size of a BA or RSG and without respect to the number of reporting entities within a Regional Entity. Because of the potential for differences in the magnitude of MSSC and the resultant frequency of events, trending should be within each Regional Entity to provide any potential reliability indicators. Each Regional Entity should investigate the cause and relative effect on reliability of the events within their footprints. A small BA or RSG may have a relatively small value of DCS events. As such, a high number of DCS events greater than MSSC may not indicate a reliability problem for the reporting RE but may indicate an issue for the respective BA or RSG. In addition, events greater than MSSC may not cause a reliability issue for some BA, RSG or RE if they have more stringent standards which require contingency reserves greater than MSSC.

ALR 1-5 System Voltage Performance

Background

The purpose of this metric is to measure the transmission system voltage performance (either absolute or per unit of a nominal value) over time. This should provide an indication of the reactive capability available to the transmission system. The metric is intended to record the amount of time that system voltage is outside a predetermined band around nominal.

Special Considerations

With a pilot program specified in early 2011, NERC's Operating and Planning Committees approved a voluntary data request letter for respective Transmission Owners (TOs) to submit relevant data on key buses. The number of buses, the monitored voltage levels, and the acceptable voltage ranges may vary by reporting entities. Based upon the usefulness of the data collected in the pilot program, additional data needs will be reviewed in the future.

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 in a timely manner to return the system to within normal operating limits. Also, exceeding the limits may not directly lead to an outage, but it puts the system at risk if an outage were to occur during the time the system is outside it limit.

This metric was approved by NERC's Operating and Planning Committees in June 2010 and a data request was subsequently issued in August 2010 to collect the data for this metric. Based on the results of the pilot conducted in the third and fourth quarter of 2010, there is merit in continuing measurement of this metric. The reporting of IROL/SOL exceedances became mandatory in 2011, and data collected in Table 4 for 2010 has been provided voluntarily.

Table 4: ALR3-5 IROL/SOL Exceedances

	3Q2010	4Q2010	1Q2011
Number of Reporting RCs	9	10	15
≤ 10 minutes	123	226	124
10 minutes < Duration ≤ 20 minutes	10	36	12
20 minutes < Duration ≤ 30 minutes	3	7	3
> 30 minutes	0	1	0

ALR4-1 Automatic Transmission Outages Caused by Protection System Misoperations

Background

Originally titled *Correct Protection System Operations*, this metric has undergone a number of changes since its initial development. To ensure that it best portrays how misoperations affect transmission outages, it was necessary to establish a common understanding of misoperations and the data needed to support the metric. NERC's ERO-Reliability Assessment and Performance Analysis (ERO-RAPA) group evaluated several options of transitioning from existing procedures for the collection of misoperations data to a consistent approach which was introduced at the beginning of 2011. With the NERC System Protection and Control Subcommittee's (SPCS) technical guidance, NERC and the Regional Entities have agreed upon a set of specifications for misoperations reporting including format, categories, event type codes, and reporting period to have a final consistent reporting template.[20] Only automatic transmission outages 200 kV and above, including AC circuits and transformers, will be used in the calculation of this metric.

Special Considerations

Data collection will begin in the third quarter of 2011 for the second quarter of misoperation events. As revised, this metric cannot be calculated for this report at the current time. The revised title and metric form can be viewed at the NERC website.[21]

ALR6-11 – ALR6-14

ALR6-11	**Automatic AC Transmission Outages Initiated by Failed Protection System Equipment**
ALR6-12	**Automatic AC Transmission Outages Initiated by Human Error**
ALR6-13	**Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment**
ALR6-14	**Automatic AC Circuit Outages Initiated by Failed AC Circuit Equipment**

Background

These metrics evolved from the original ALR4-1 metric for correct protection system operations and now illustrate a normalized count (on a per element basis) of AC transmission element outages (i.e., TADS momentary and sustained automatic outages)[22] that were initiated by: Failed Protection System

[20] The current Protection System Misoperation template is available at: http://www.nerc.com/filez/rmwg.html.
[21] The current metric ALR4-1 form is available at: http://www.nerc.com/docs/pc/rmwg/ALR_4-1Percent.pdf.
[22] Definitions for TADS outages are located on page 4 of http://www.nerc.com/docs/pc/tadswg/Appendix%207%2020101202a%20clean.pdf.

Equipment, (ALR6-11); Human Error (ALR6-12); Failed AC Substation Equipment (ALR6-13); and Failed AC Circuit Equipment (ALR6-14). These metrics are all related to the non-weather related initiating cause codes for automatic outages of AC circuits and transformers operated 200 kV and above.

Assessment

Figure 10 through Figure 13 show the normalized automatic outages per circuit or per 100 circuit-miles and automatic outages per transformer for facilities operated at 200 kV and above. As shown in all eight of the charts, there are some regional trends in the three years of outage data. However, some Regional Entity's values have increased from one year to the next, stayed the same, or decreased with no discernable regional trends. For example, ALR6-11 computes the automatic AC Circuit automatic outages initiated by failed protection system equipment.

There are some trends to the ALR6-11 to ALR6-14 data, but many Regional Entities do not have enough data for a valid trend analysis to be performed. NERC's outage rate seems to be improving every year. On a regional basis, metric ALR6-11, along with ALR6-12 through ALR6-14 may not be statistically significant, and will require confidence intervals[23] are calculated. ALR metric outage frequency rates and regional equipment inventories that are smaller than others are likely to require more than 36 months of outage data. Some numerically larger frequency rates and areas with larger equipment inventories (such as NERC) may not require more than 36 months of data to obtain a reasonably narrow confidence interval.

While more data is still needed on a regional basis to determine if each Regional Entity's bulk power system is becoming more reliable year-to-year; there are areas of potential improvement which include power system condition, protection performance, and human factors. The industry can benefit from detailed analysis of these outage causes by identifying lessons learned and rolling average trends of NERC-wide performance. With a confidence interval of relatively narrow bandwidth, changes in statistical data can be determined to be primarily due to random sampling error or if they are significantly different due to performance.

[23]The detailed Confidence Interval computation is available at: http://www.nerc.com/docs/pc/tadstf/TADS_Nov_2_2007APPENDIX_C_Confidence_Interval.pdf.

ALR 6-11 – Automatic Outages Initiated by Failed Protection System Equipment

Automatic outages with an initiating cause code of failed protection system equipment are in Figure 10.

Figure 10: ALR6-11 by Regional Entity (Includes NERC-Wide)

**Note: TRE has no transformers with low-side voltages at 200 kV and above.*

***Note: MRO has no transformer outage occurrences.*

This code covers automatic outages initiated by the failure of protection system equipment. This includes any relay and/or control misoperations, except those that are caused by incorrect relay or control settings that do not coordinate with other protective devices.

ALR6-12 – Automatic Outages Initiated by Human Error

Figure 11 shows the automatic outages with an initiating cause code of human error. This code covers automatic outages initiated by any incorrect action traceable to employees and/or contractors for companies operating, maintaining, and/or providing assistance to the Transmission Owner.

Figure 11: ALR6-12 by Regional Entity (Includes NERC-Wide)

**Note: TRE has no transformers with low-side voltages at 200 kV and above.*
***Note: SPP has no transformer outage occurrences.*

Also, any human failure or interpretation of standard industry practices and guidelines that initiate an automatic outage will be reported in this category.

Reliability Metrics Performance

ALR6-13 – Automatic Outages Initiated by Failed AC Substation Equipment

Figure 12 shows the automatic outages with an initiating cause code of failed AC substation equipment. This code covers automatic outages initiated by the failure of AC Substation; i.e., equipment "inside the substation fence" including transformers and circuit breakers but excluding protection system equipment.[24]

Figure 12: ALR6-13 by Regional Entity (Includes NERC-Wide)

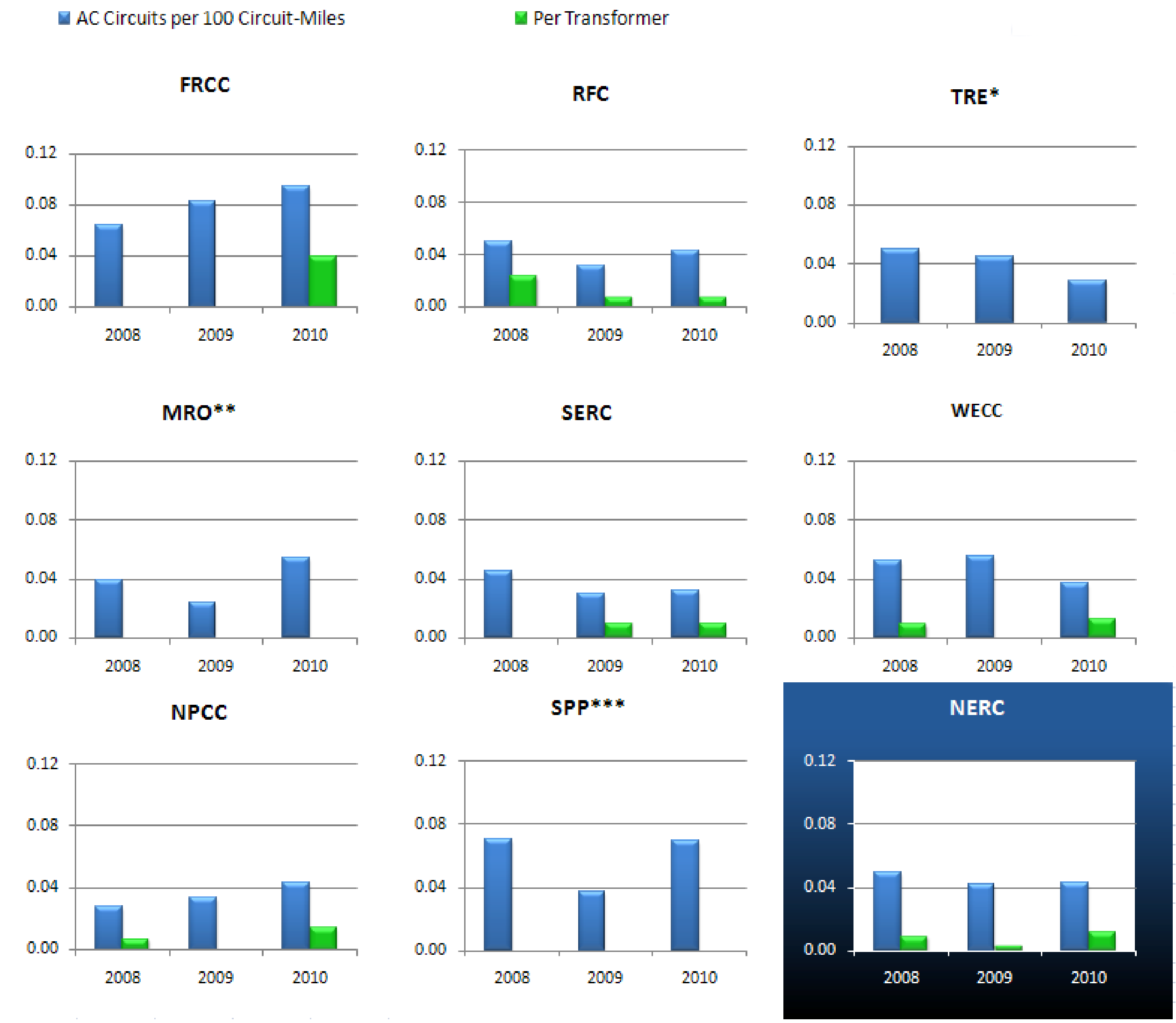
**Note: TRE has no transformers with low-side voltages at 200 kV and above.*

[24] TADS Initiating Cause Code definitions are located at: http://www.nerc.com/docs/pc/tadswg/TADS_Definitions_Appendix_7_092909.pdf.

ALR6-14 Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment

Figure 13 shows the automatic outages with an initiating cause code of failed AC circuit equipment. These automatic outages are initiated by the failure of AC Circuit equipment, i.e., overhead or underground equipment “outside the substation fence.” [25]

Figure 13: ALR6-14 by Regional Entity (Includes NERC-Wide)



**Note: TRE has no transformers with low-side voltages at 200 kV and above.*

***Note: MRO and SPP have no transformer outage occurrences.*

[25] TADS Initiating Cause Code definitions are located at: http://www.nerc.com/docs/pc/tadswg/TADS_Definitions_Appendix_7_092909.pdf.

ALR6-15 Element Availability Percentage (APC)

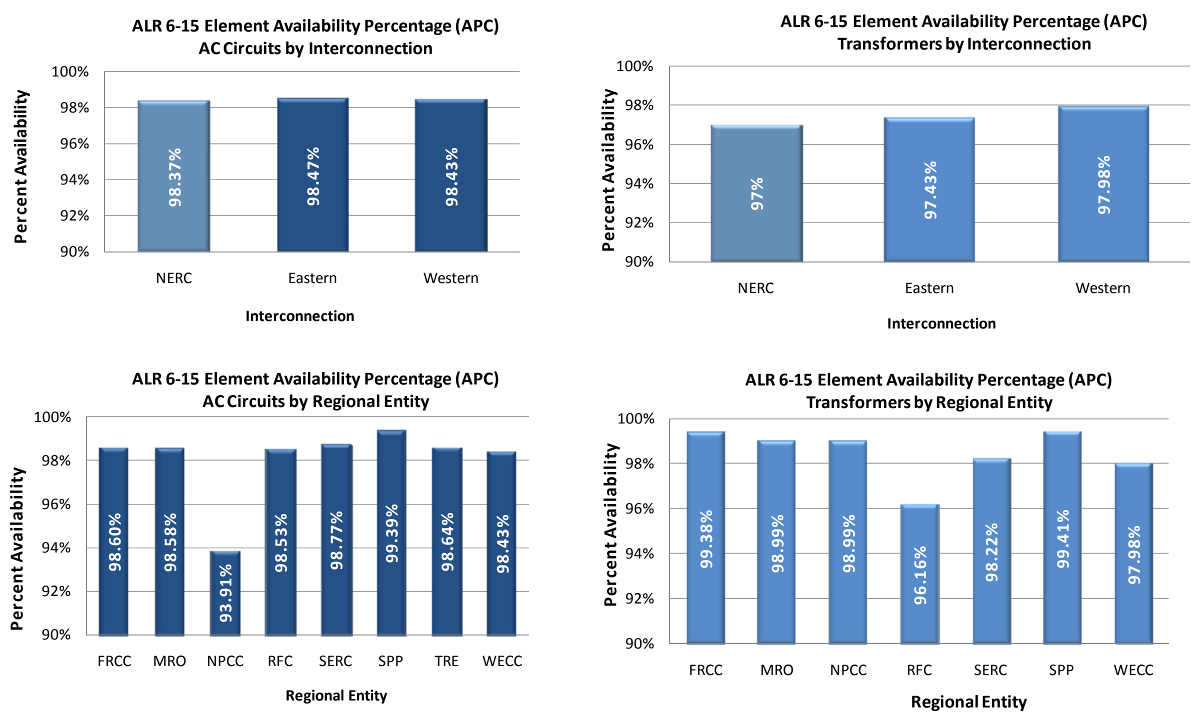
Background

This metric uses data and calculations directly from the NERC TADS effort and provides the overall percent of time the aggregate of transmission elements are available and in service. This is an aggregate value using sustained outages (automatic and non-automatic) for both AC Circuits and transformers operated at 200 kV and above for each Regional Entity, Interconnection, and for NERC.

Assessment

Figure 14 shows the aggregate element availability percentage (APC) for AC circuits and transformer facilities operated at 200 kV and above. The values are all over 90 percent. Continued metric assessment is required for at least a few more years in order to determine the value of this metric.

Figure 14: ALR6-15 Element Availability Percentages (2010)



Notably, the Eastern Interconnection does not include Québec or ERCOT. TRE does not have transformers with low-side voltages at 200 kV and above.

Special Consideration

The non-automatic outage data needed to calculate this metric was first collected for the calendar year 2010 as part of the TADS process.

ALR6-16 Transmission System Unavailability

Background

This metric uses data and calculations directly from the NERC TADS effort and shows the overall percent of time that AC circuit and transformer TADS elements are unavailable due to sustained automatic and non-automatic outages. This is a value using sustained outages for both AC circuits and transformers operated at 200 kV and above for each Regional Entity, Interconnection, and consolidated values for NERC.

Assessment

Figure 15 and Figure 16 illustrate the 2010 unavailability percentage for AC circuits and transformer facilities operated at 200 kV and above. The values for AC circuits are all under 3 percent.

Continued metric assessment is recommended in order to determine the value of this metric.

Special Consideration

The non-automatic outage data needed to calculate this metric was first collected for the calendar year 2010 as part of the TADS process.

Figure 15: ALR6-16 Transmission System Unavailability (2010)

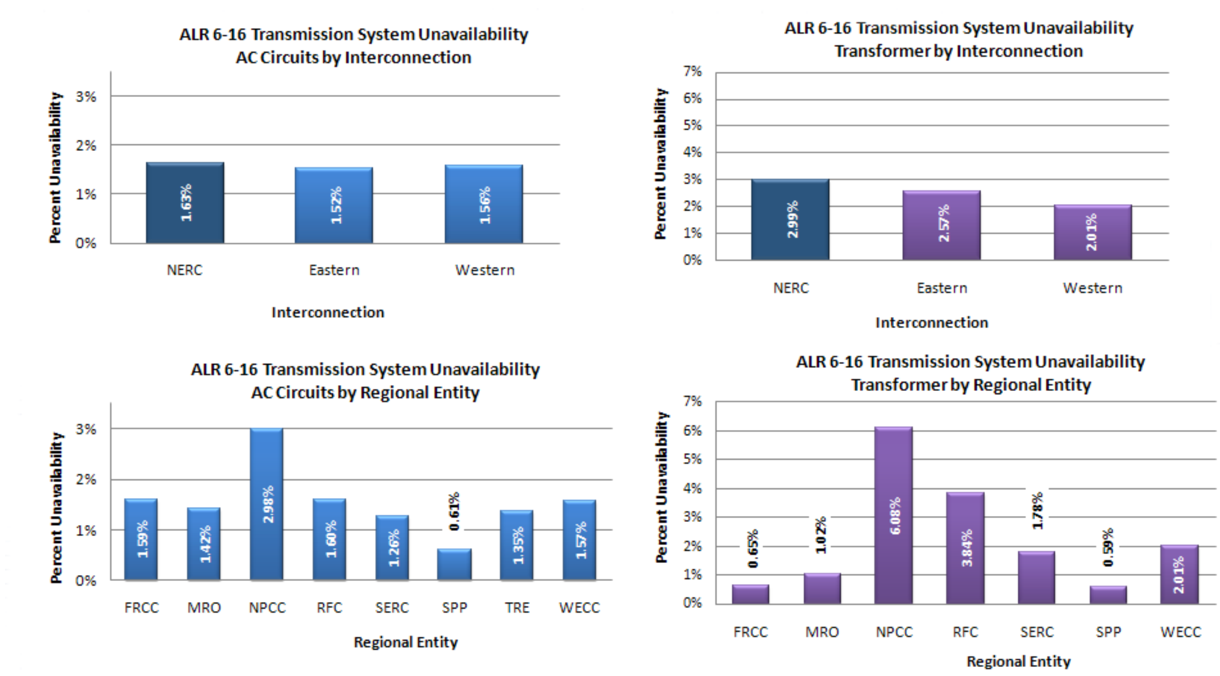
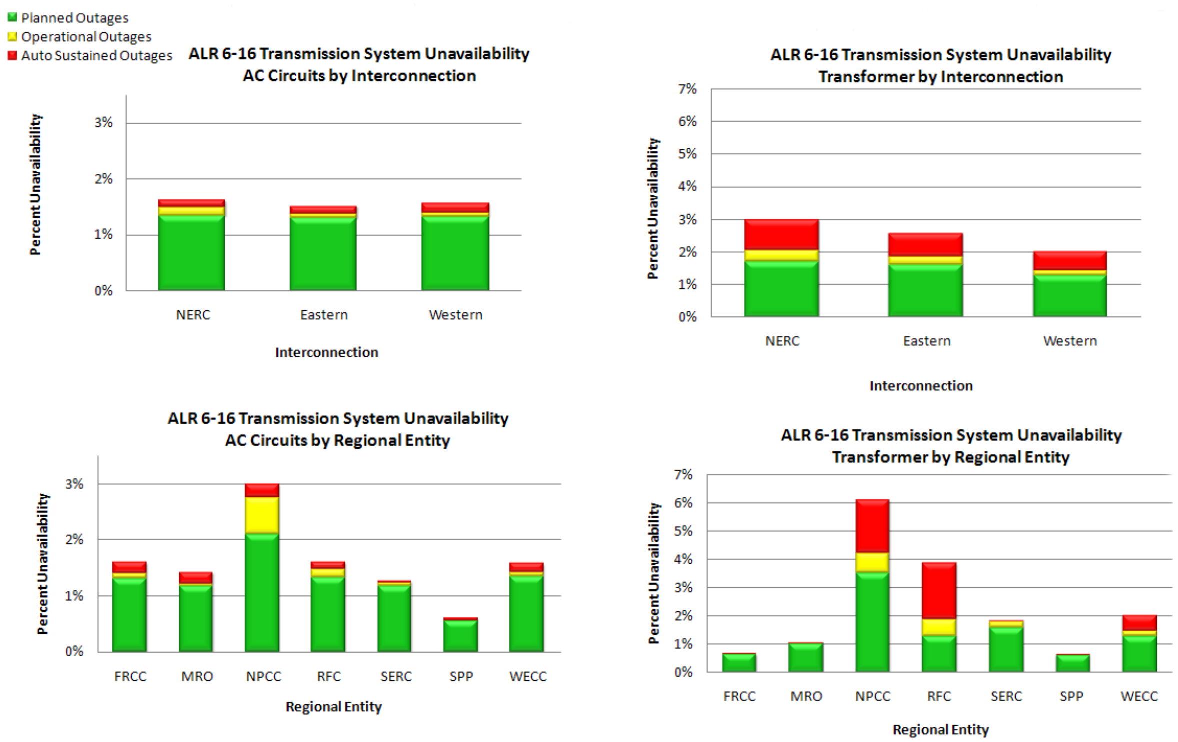


Figure 16: ALR6-16 Transmission System Unavailability by Outage Type (2010)



Notably, the Eastern Interconnection does not include Québec or ERCOT. Also, TRE does not have any transformers with low-side voltages at 200 kV and above.

ALR6-2 Energy Emergency Alert 3 (EEA3)

Background

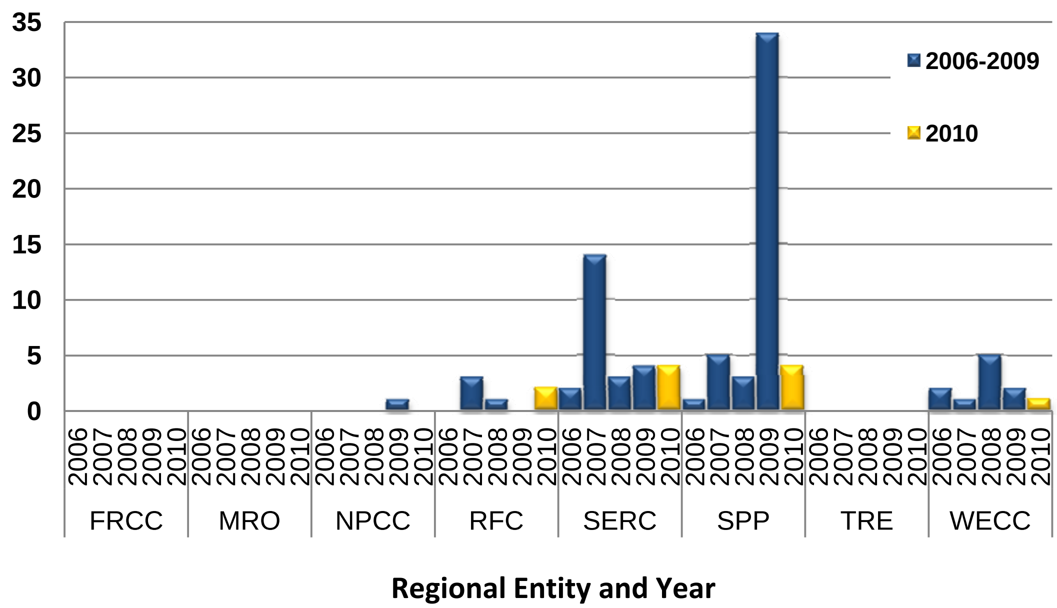
This metric identifies the number of times Energy Emergency Alerts Level 3 (EEA3) is issued. EEA3 events are firm-load interruptions due to capacity and energy deficiency and is currently reported, collected and maintained in NERC's Reliability Coordinator Information System (RCIS), defined in the NERC Standard EOP-002.[26] The 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 adequacy of the electric supply system. This metric can also be considered in the context of 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 bulk power system requiring review of resources.

[26] The latest version of EOP-002 is available at: http://www.nerc.com/page.php?cid=2|20.

Assessment

Figure 17 shows the number of EEA3 events from 2006 to 2010 at a Regional Entity level. An interactive presentation is available at the Reliability Indicator's page.[27] The number of EEA3s declared in 2010 was significantly reduced. The reason the EEA volume decreased from 2009 to 2010 in SPP was because the SPP ICT RC[28] coordinated an operating agreement between the five operating companies in the Acadiana Load Pocket (ALP). The operating agreement included a cost sharing re-dispatch that alleviated the need of a Transmission Loading Relief (TLR-5) declaration[29]. During 2009, there was no operating agreement; therefore, an entity had to provide Network and Native Load (NNL) relief when a TLR-5 was called by the ICT RC. When the TLR-5 was the primary tool to control the post contingent loading in the ALP, some of the BAs would have their firm transmission curtailed to the point where they could no longer serve their load; therefore, the EEA 3 was needed to communicate a capacity/reserve deficiency.

Figure 17: ALR6-2 Energy Emergency Alert 3 (EEA3) Counts by Regional Entity (2006-2010)



Cleco Power, Entergy and Lafayette Utilities System (LUS) are currently constructing an estimated $200 million transmission infrastructure improvement project to mitigate transmission constraints into ALP. Construction of the project is scheduled to be complete in 2012. Completion of the project should help alleviate some of the transmission congestion in this area.

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

[28] Southwest Power Pool (SPP) Independent Coordinator of Transmission (ICT) Reliability Coordinator (RC)

[29] More information on Transmission Load Relief is contained in the IRO-006 standard which is located at: http://www.nerc.com/files/IRO-006-4.pdf. In particular, TLR-5 definitions are referenced on page 16 and 17.

SPP RTO continues to coordinate operating plans with the operating entities in this area. Mitigation plans and local operating guides in place are expected to provide sufficient flexibility should issues arise. NERC will continue to monitor this area for reliability impacts and coordinate any actions with the SPP Reliability Coordinator and SPP Regional Entity.

Special Considerations

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

ALR 6-3 Energy Emergency Alert 2 (EEA2)

Background

The Energy Emergency Alert 2 (EEA2) metric measures the number of events that BAs declare for deficient capacity and energy during peak load periods. The number of EEA2 events, and any trends in their reporting, indicates how robust the system is in supplying aggregate load requirements. The EEA2 declarations may also serve as a leading indicator of energy and capacity shortfall in the adequacy of the electric supply system. EEA2 declarations provide a sense of the frequency of precursor events to more severe EEA3 declarations. This metric measures the number of events that Balancing Authorities declare for deficient capacity and energy during peak load periods. At this time, however, this data reflects inclusion of Demand Side Resources that would not be indicative of inadequacy of the electric supply system.

Demand response is a legitimate resource to be called upon by balancing authorities and does not indicate a reliability concern. The historical record may include demand response activations and non-firm load interruptions, per applicable contracts, within the EEA alerts.[30] EEA2 events called solely for activation of demand response or interruption of non-firm load per applicable contracts should be excluded from this metric.

This metric can also be considered in the context of the Planning Reserve Margin. Significant increases or decreases in EEA2 events with relatively constant Planning Reserve Margins could indicate volatility in the actual loads compared to forecasted levels or changes in the adequacy of the bulk power system required to meet load demands. As more data is gathered, there might be an indication of either decreasing or increasing adequacy in the electric supply system's Planning Reserve Margins.

Assessment

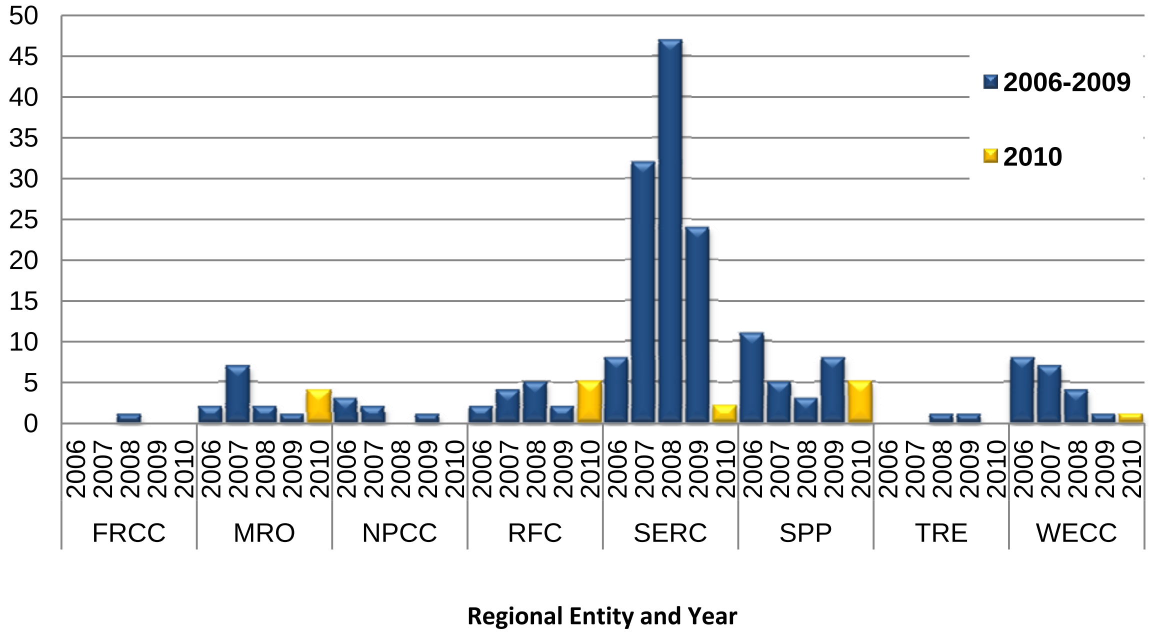
Figure 18 shows the number of EEA2 events by Regional Entity from 2006 to 2010 from the EEA2 interactive reports available online.[31] The general trend continues to show improved performance which may have been influenced by the overall reduction in demand throughout NERC caused by the economic downturn.

[30] The EEA2 is defined at http://www.nerc.com/files/EOP-002-2.pdf.

[31] EEA2 interactive version located at: http://www.nerc.com/page.php?cid=4|331|341.

There two issues that should be assessed further for the EEA2 metric. To begin, specific performance for any one region should be investigated for issues or events that may affect the results. Secondly, determining whether performance reported includes those events resulting from the economic operation of DSM and non-firm load interruption should also be investigated.

Figure 18: ALR6-3 Energy Emergency Alert 2 (EEA2)



Special Considerations

The intent of this metric is to measure only EEAs that are called for reliability reasons and not for economic factors, such as demand side management (DSM) and non-firm load interruption. The historical data for this metric may include events that were called for economic factors. However, recent data should only include EEAs called for reliability reasons.

ALR 6-1 Transmission Constraint Mitigation

Background

The intent of this metric is to identify trends in the number of mitigation measures (Special Protection Schemes (SPS), Remedial Action Schemes (RAS), and Operating Procedures) required to meet Transmission Planning (TPL)[32] reliability requirements. By their nature, SPS do not indicate an inherent weakness in the bulk power system; they are an indication of methods that are taken to operate the system through the range of conditions it must perform.

[32] In particular, the standard is TPL-005-0 and is located at http://www.nerc.com/files/TPL-005-0.pdf.

Assessment

A pilot with four Regional Entities was completed and, based on the results, the pilot data collection was expanded to all regions. The initial results of the data collection are shown in Figure 19 and Table 5. Per Regional Entity, there are a relatively constant number of regional mitigation measure plans over the data collection time period.

Figure 19: ALR6-1 Transmission Constraint Mitigation by SPS/RAS (2009-2014)

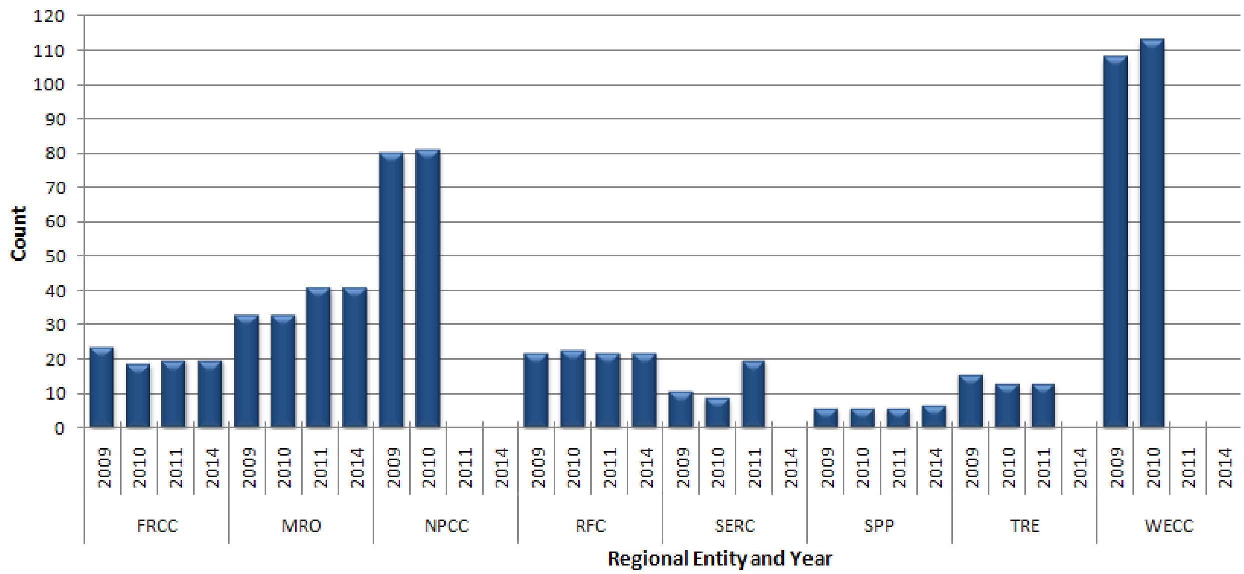


Table 5: ALR6-1 Transmission Constraint Mitigation by Operating Procedure/Guides (2009-2014)				
	2009	**2010**	**2011**	**2014**
FRCC	-	107	75	66
MRO	79	79	81	81
NPCC	-	-	-	-
RFC	2	1	3	4
SPP	39	40	40	40
SERC	6	7	15	-
TRE	29	25	25	-
WECC	110	111	-	-

**”-“ data is not available.*

Special Considerations

This metric is only intended to evaluate the trend use of these plans, and whether the metric indicates robustness of the transmission system is increasing, remaining static, or decreasing. A certain number of SPS mitigation plans may be necessary to support reliable operation of the system. An increase of SPS may indicate additional, required transmission capacity is required. Correspondingly, a reduction in the number of SPS may be an indicator of increased generation or transmission facilities being placed in-service, which may imply greater robustness of the bulk power system.

In general, mitigation plans are a viable and valuable tool for effective operation of the bulk power system. In power system planning, reliability, operability, capacity and cost-efficiency are simultaneously considered through a variety of system scenarios. Mitigation measures are a method for optimizing a power system across these scenarios.

Integrated Bulk Power System Risk Assessment

Introduction

In developing eighteen metrics to measure adequate level of reliability, any such measurement of reliability must include consideration of the risks present within the bulk power system to appropriately prioritize and manage these system risks. This approach not only can be used to measure risk reduction over time. Also, a uniform event analysis process can be applied to identify significant events for further detailed review.

The Operating Committee (OC) and Planning Committee (PC) endorsed the concepts and framework[33] of the risk-based approach in their September 2010 meetings and further supported the event severity risk index (SRI) calculation[34] in March 2011.

Recommendations

- NERC should embrace the use of risk assessment to identify trends and lessons learned to improve bulk power system reliability.
- The SRI should be integrated into the event analysis process and root cause analysis.
- As trend evaluations increase the knowledge of risks to the bulk power system, data required to support additional assessment should be gathered.

Event Severity Risk Index (SRI)

Risk assessment is an essential tool for achieving the alignment between organizations, people and technology. This will assist in quantifying inherent risks, identifying where potential high risks exist, and evaluating where the most significant risk reduction can be achieved. NERC, the Regional Entities, and registered entities can use this tool to focus on the areas of highest reliability risk to provide a sound basis for development of results-based standards and compliance programs. Risk assessment also serves to engage all stakeholders in a dialogue about specific risk factors and a strategic plan for risk reduction and early detection.

[33] http://www.nerc.com/docs/pc/rmwg/Integrated_Bulk_Power_System_Risk_Assessment_Concepts_Final.pdf
[34] http://www.nerc.com/docs/pc/rmwg/SRI_Equation_Refinement_May6_2011.pdf

The SRI is a daily, blended metric where transmission loss, generation loss, and load loss events are aggregated into a single value that represents risk to the system. Each element (transmission, generation, and load loss) is weighted by the inventory for that element to rate significant events appropriately. On a yearly basis, these daily performance measurements are sorted in descending order to evaluate the year-on-year performance of the system.

To pilot the concepts, SRI values were derived for historically memorable days. Once these calculations were complete, they were reviewed and evaluated by various stakeholders for validation. Based upon feedback, modifications to the calculation were made and assessed against the historic days. This iterative process finalized the details for the calculation of SRI with a range of zero (normal operation) to 1,000 (a theoretical condition in which every transmission line, all generation units and all load lost across the system in a single day).

Figure 20 captures the daily severity risk index value from 2008 to 2010 including the historic significant events used to pilot the calculation. Since there is significant disparity between normal days and events in terms of SRI values, the curve is depicted using a logarithmic scale. Each year's data is sorted in descending order. At the left-side of the curve, the days that the system is severely stressed are plotted. The central, more linear portion of the curve identifies the routine daily performance. Finally, the far, right side of the curve shows the values plotted for days when the system is operating normally.

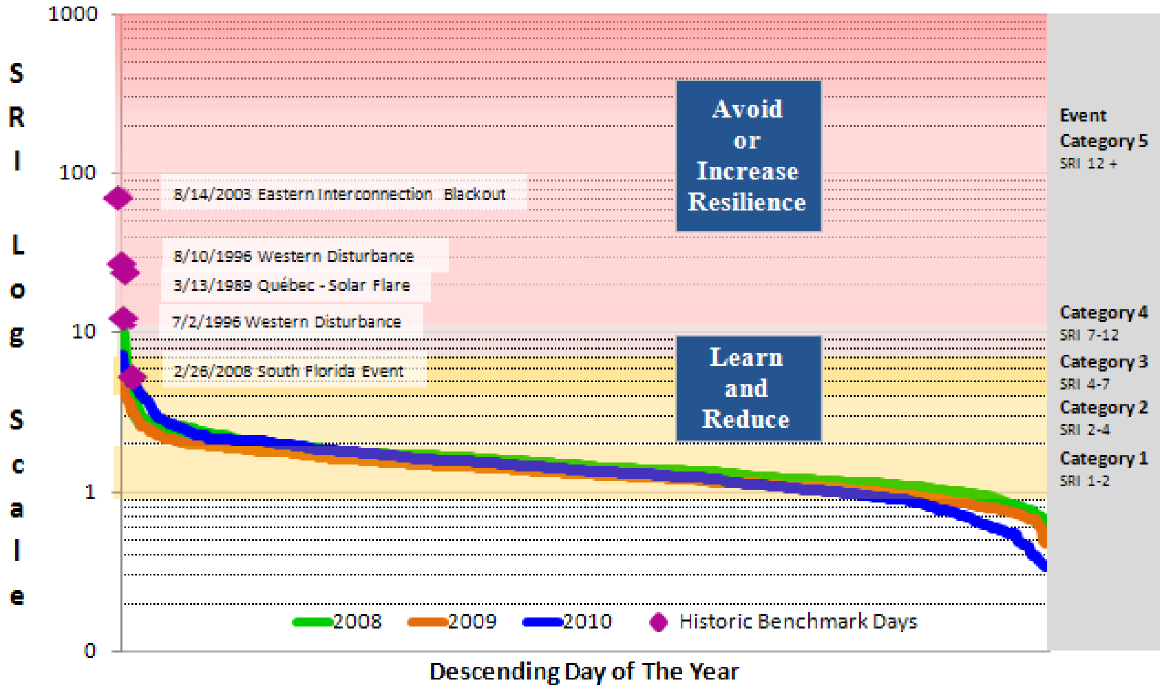
Based on the SRI, 2009 and 2010 had fewer extreme days than 2008. Routine daily performance remains consistent across all three years. Figure 20 captures the days for each year benchmarked with historically significant events.

In Figure 20, the NERC event categories and SRI ratings are directly related. As the SRI increases, the category, or severity, of the event increases. Historical events are shown to give a perspective of how a well-known event would register on the SRI scale.

The event analysis process[35] benefits from the SRI as it enables a numerical comparison of events. By using this measure, an event can be prioritized by its severity. In a severe event, this is unnecessary. For most events, however, this prioritization can be a challenge. By using the SRI, the event analysis process can see which events to learn from and reduce, which events to avoid, and when resilience needs to be increased under high impact, low frequency events.

[35] http://www.nerc.com/page.php?cid=5|365

Figure 20: NERC Annual Daily Severity Risk Index (SRI) Sorted Descending with Historic Benchmark Days



Other factors that impact severity of a particular event to be considered in the future include whether equipment operated as designed and resulted in loss of load from a reliability perspective (intentional and controlled load-shedding). Also, mechanisms for enabling ongoing refinement to include the historic and simulated events for future severity risk calculations are being explored.

While the SRI curves have become useful in characterizing the performance of the bulk power system, there are enhancements which would provide further benefit to the industry. Namely, the curve could provide greater value in assessing the performance of the system if the viewer were able to distinguish which days were fundamentally driven by causes outside the control of the industry, namely weather, and the extent to which the day's score was the result of the system operating as designed. This could result in particular data points being shown as a range of performance, with the "as experienced" performance could be compared against a calculated "as designed" performance.

Reliability Metrics Conclusions and Recommendations

Among the eighteen metrics that address the characteristics of an adequate level of reliability (ALR), trends indicate the system is performing better in the following seven areas:

- ALR1-3 Planning Reserve Margin
- ALR1-4 BPS Transmission Related Events Resulting in Loss of Load
- ALR2-5 Disturbance Control Events Greater than Most Severe Single Contingency
- ALR6-2 Energy Emergency Alert 3 (EEA3)
- ALR6-3 Energy Emergency Alert 2 (EEA2)
- ALR6-11 Automatic Transmission Outages Initiated by Failed Protection System Equipment
- ALR6-13 Automatic Transmission Outages Initiated by Failed AC Substation Equipment

Many of the remaining metrics do not have sufficient data to derive useful conclusions. With a more thorough data matrix, more conclusions about reliability could be drawn. All metrics will be assessed on a regular basis to determine their contribution to quantitative reliability measurement. In addition to further collection, an investigation into the data collection processes for some metrics will also be investigated. In particular, a study should be conducted to determine the usefulness of a 100 MW load loss threshold for ALR2-3.

For the IRI, more investigation is needed to determine the overlap of the components (CDI, EDI, and SDI). At this time, components of the IRI should be solidified before the IRI will be useful. In particular, the CDI should be more thoroughly understood as an index by collecting more data over time.

Future Advancements: Integrated Reliability Index

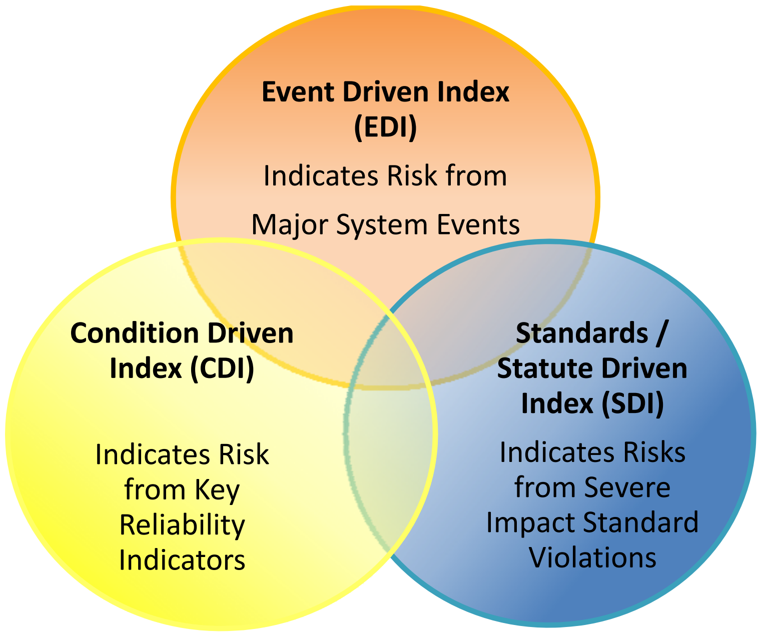
As the next step to the severity risk index, an integrated reliability index (IRI) is under development to provide a more complete bulk power system reliability picture. Currently, the concept of the IRI is in a whitepaper status.[36] Upon completion, the IRI should peer beyond the severity risk index's narrow, event based scope and illuminate a broader, quantitative picture of total bulk power system reliability.

The IRI is composed of three component indices that attempt to capture different families of risk to the bulk power system. These are the Event Driven Index (EDI), Standards/Statute Driven Index (SDI), and Condition Driven Index (CDI) as shown in Figure 21.

The ultimate goal of the IRI is to provide the industry meaningful trends of the bulk power system's performance and guidance on how the industry can improve reliability and support risk-informed decision making. The development of these composite indices aims to inform, increase transparency, and quantify the effectiveness of risk reduction or mitigation actions. Also, these metrics will facilitate unitary assessment of risks which impacted reliability of the bulk power system.

[36] http://www.nerc.com/docs/pc/rmwg/Integrated_Reliability_Index_WhitePaper_DRAFT.pdf

Figure 21: Risk Model for Bulk Power System

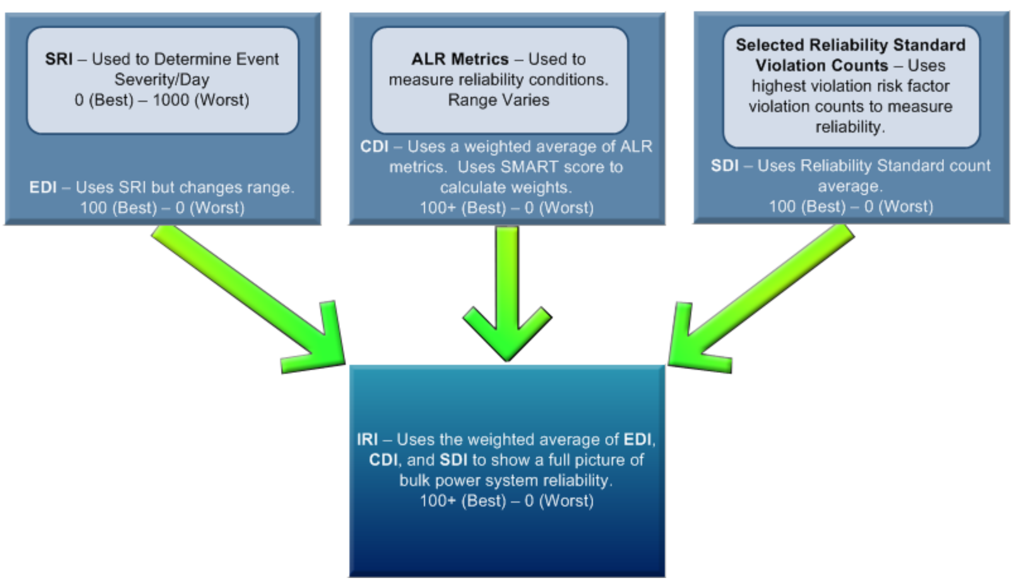


The integrated model of event-driven, condition-driven, and standards/statute-driven risk information can be constructed to illustrate all possible logical relations between the three risk sets. Due to the nature of the system, there is some overlap among the components. This overlap and its implications to blended metric calculations will be explored in the future.

The Three Components of the IRI

The three components of the IRI work together as shown in Figure 22 to comprise a full picture of the state of reliability.

Figure 22: An overview of the components that comprise the Integrated Reliability Index (IRI)



Event-Driven Index (EDI)

The Event-Driven Index provides a basis for the prioritization of events, based on bulk power system integrity, equipment performance, and engineering judgment. This indicator can serve as a high value risk assessment tool to investigate disturbance history and measure the severity of events. Currently, the EDI is a derivative of SRI results for a specific time period, but it transforms that performance into a form of an availability index. However, the specific formula for the EDI is under development.

Condition-Driven Indicators (CDI)

The Condition-Driven Indicators focus on a set of measurable system conditions (performance measures) to assess bulk power system reliability. The CDI will use metrics that directly tie to adequate level of reliability (ALR) characteristics. These metrics will cover most areas of reliability and provide the majority of the IRI component data.

However, there is not yet a comprehensive set of metrics for each of the characteristics of reliability, nor is there sufficient history to know what the benchmark for any of these values should be. In the interim, this composite metric should be lessened in importance, but continue to be explored to achieve its long-term value to the industry.

Standards/Statute-Driven Indicators (SDI)

The Standards/Statute-Driven Indicator measures the success of compliance, based upon the subset of high-value standards, and is divided by the number of participants who could have received the violation within the time period considered. Also, based on these factors, known unmitigated violations of elevated risk factor requirements are weighted higher than lower risk factors. The index decreases if the compliance improvement is achieved over the trending period.

IRI Index Calculation

At this time, three individual components should be strengthened separately and should be blended into a single metric. The final integration should only occur after each component index bears sufficient relevance to actual reliability. To perform integration of the component indices, each component would be weighted and a combining formula would be used to calculate IRI.

The conceptual model for developing a single IRI would inherently include future modification. This modification would be necessary after gaining experience with the new metric and consideration of the industry's feedback. The IRI is intended to be a composite metric which integrates several forms of individual risks to the bulk power system. Since the three components range across many stakeholder organizations, any integrating formula is only a starting point for continued study and evaluation.

IRI Recommendations

For the IRI, more investigation should be performed to determine the best way to integrate EDI, CDI, and SDI into an Integrated Reliability Index (IRI) that quantitatively represents the reliability of the bulk power system. To this end, study into determining the amount of overlap between the components is necessary. Also, the CDI component of the IRI needs to be solidified. More accurate metric data is needed to paint a fuller picture of system conditions. Many of the metrics used to calculate the CDI are new, or have limited supporting data. Compared to the SDI, which measures well-known violation counts, and the EDI, which uses the well-defined SRI, the CDI lacks the depth of rigor and should be improved with further investigation.

Transmission Equipment Performance

Introduction

The Transmission Availability Data System (TADS) was launched with the establishment of a TADS task force by the NERC Planning Committee in October 2006[37]. On October 27, 2007, the NERC Board of Trustees approved the collection of automatic transmission outage data beginning in calendar year 2008 (Phase I). Subsequently, on October 29, 2008, the NERC Board of Trustees approved the collection of non-automatic outage data beginning in calendar year 2010 (Phase II).

This chapter focuses on automatic outage trends from calendar year 2008 to 2010. Since only one year of non-automatic outages has been collected, insufficient information is available for use in this report.

When calculating bulk power system performance, care must be exercised when interpreting results. Misinterpretation can lead to erroneous conclusions regarding system performance. A mathematical confidence interval technique was applied to determine the relevance of trending for transmission metrics.[38] On a regional basis, there was not enough data to perform statistically relevant trending. On a NERC-wide basis, however, there is enough information to accurately determine whether the yearly outage variation compared to the average is due to random statistical variation, or the particular year in question is significantly different in performance.

Performance Trends

Transmission performance information has been provided by Transmission Owners (TOs) within NERC through the NERC TADS process. The data presented reflects momentary and sustained AC automatic outages of transmission elements that operate at voltages greater than or equal to 200 kV with the criteria specified in the TADS process. The following elements listed below are included:

- AC Circuits ≥ 200 kV (Overhead and Underground Circuits). Radial circuits are included;
- DC Circuits with ≥ +/-200 kV DC voltage;
- Transformers with ≥ 200 kV low-side voltage; and
- AC/DC Back-to-Back (BTB) Converters with ≥ 200 kV AC voltage, on both sides.

[37]For additional details on TADS, the Data Reporting Instruction Manual is located at: http://www.nerc.com/docs/pc/tadswg/Data%20Reporting%20Instr%20Manual%2020101202a%20clean.pdf.

[38]The detailed Confidence Interval computation is available at: http://www.nerc.com/docs/pc/tadstf/TADS_Nov_2_2007APPENDIX_C_Confidence_Interval.pdf.

AC Element Outage Summary and Leading Causes

Table 6 shows the 2008, 2009, and 2010 NERC total AC transmission element inventory and a summary of the associated outages. The number of circuits increased from year-to-year due to new construction or reconstruction to higher voltages. For every outage experienced on the transmission system, cause codes are recorded according to the TADS process.[39] Causes of both momentary and sustained outages have been indicated. These causes are analyzed to identify trends, similarities, and to provide insight into what could be done to prevent future occurrences.

Figure 23 and Figure 24 describe the top ten initiating cause codes for sustained and momentary automatic outages from 2008 to 2010. Based on the two figures, the relationship between the total number of outages and total outage hours are provided. Failed AC Substation Equipment and Failed AC Circuit Equipment are the top two causes of sustained outage hours with 65 percent of the total outage hours. The two largest causes of momentary outage hours within NERC are “Lightning” and “Weather, excluding Lightning”.

Importantly, Human Error, Failed Protection System Equipment, and Failed AC Circuit Equipment initiating cause codes have very similar totals numbers of outages and should all be considered significant focus points in reducing the number of sustained automatic outages for all elements.

[39]Please refer to section F in http://www.nerc.com/docs/pc/tadswg/Appendix%207%2020101202a%20clean.pdf for TADS automatic outage codes.

Table 6: NERC - All AC Elements Sustained and Momentary Outage Performance Summary*						
2008 Number of Outages						
AC Voltage Class	No of Circuits	Circuit Miles	Sustained	Momentary	Total Outages	Total Outage Hours
200-299kV	4,369	102,131	1,560	1,062	2,622	56,595
300-399kV	1,585	53,631	793	753	1,546	14,681
400-599kV	586	31,495	389	196	585	11,766
600-799kV	110	9,451	43	40	83	369
All Voltages	6,650	196,708	2,785	2,051	4,836	83,626
2009 Number of Outages						
AC Voltage Class	No of Circuits	Circuit Miles	Sustained	Momentary	Total Outages	Total Outage Hours
200-299kV	4,468	102,935	1,387	898	2,285	28,828
300-399kV	1,619	56,447	641	610	1,251	24,714
400-599kV	592	32,045	265	166	431	9,110
600-799kV	110	9,451	53	38	91	442
All Voltages	6,789	200,879	2,346	1,712	4,038	63,094
2010 Number of Outages						
AC Voltage Class	No of Circuits	Circuit Miles	Sustained	Momentary	Total Outages	Total Outage Hours
200-299kV	4,567	104,722	1,506	918	2,424	54,941
300-399kV	1,676	62,415	721	601	1,322	16,043
400-599kV	605	31,590	292	174	466	10,442
600-799kV	111	9,477	63	50	113	2,303
All Voltages	6,957	208,204	2,582	1,743	4,325	83,729

**Note: The NERC table does not show redacted outages, DC Circuit outages, Transformer outages, or AC/DC converter outages.*

Figure 23: NERC - Top Ten Momentary Automatic Outage Hours by Cause Code

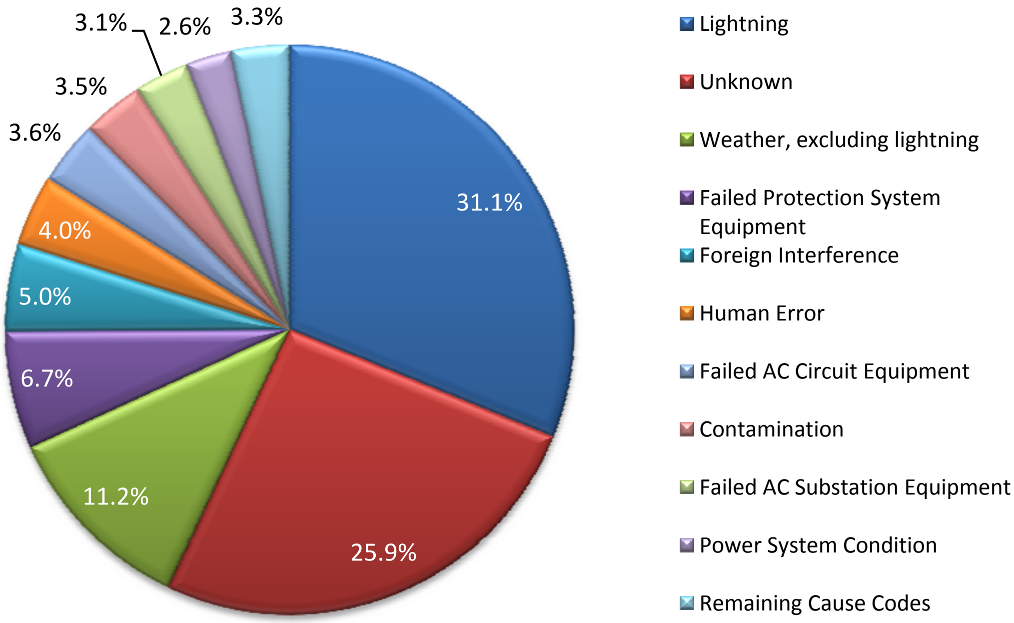
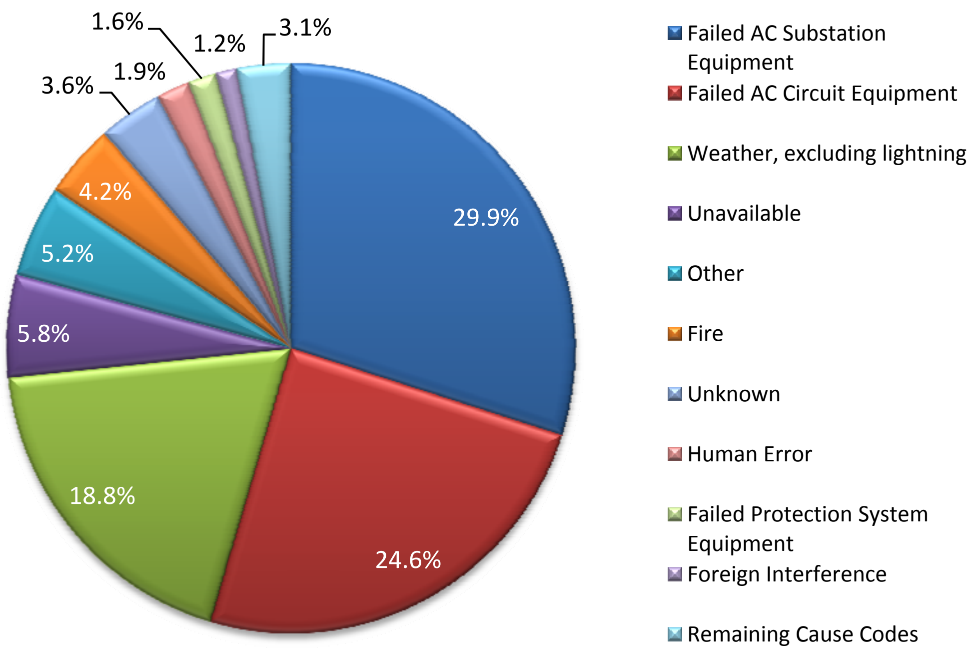


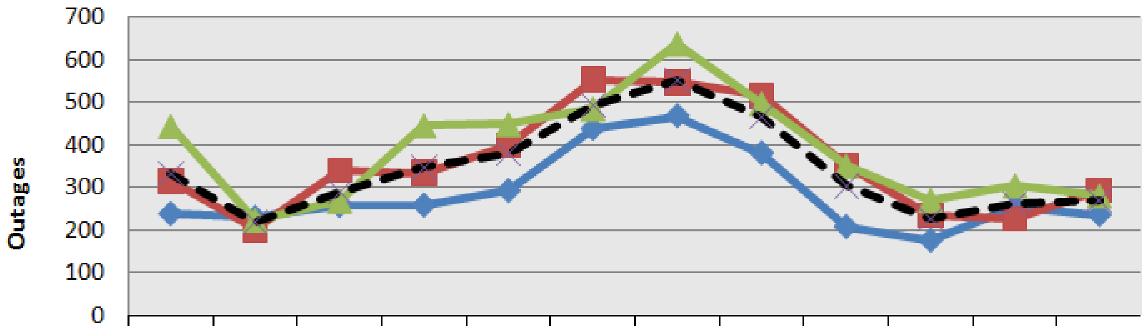
Figure 24: NERC - Top Ten Sustained Automatic Outage Hours by Cause Code



Transmission Monthly Outages

Figure 25 displays the total number of automatic outages on a monthly basis. The three months with the highest total of automatic outages were June, July, and August. From a seasonal perspective, winter, November 1 to the end of February, had a monthly, 3-year average of 271 outages. Summer, June 1 through September 30, had a monthly, 3-year average of 453 outages.

Figure 25: Number of Automatic Outages by Month for AC Circuits (2008-2010)*



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2008	238	229	257	258	292	437	467	380	208	176	255	236
2009	315	201	339	334	398	553	546	515	351	235	226	294
2010	444	224	269	446	449	486	639	498	351	271	305	281
3 Year AVG	332	218	288	346	380	492	551	464	303	227	262	270

**This figure does not show redacted outages, DC Circuit outages, Transformer outages, or AC/DC Converter outages.*

Outage Initiation Location

For every outage experienced on the transmission system, the outage initiation code is identified and recorded. The outage initiation code can be measured to identify trends and similarities and provide insight into areas for improvement.

The "Outage Initiation Code" describes where an automatic outage was initiated on the power system. The five codes are as follows:

- Element-Initiated
- Other Element-Initiated
- AC Substation-Initiated
- AC/DC Terminal-Initiated (for DC circuits)
- Other Facility Initiated: any facility not included in any other outage initiation code

Notably, the protection system is not part of an "AC Substation" or an "AC/DC Terminal". If a protection system misoperates and initiates an outage, it will be classified as "Other-Facility Initiated". Figure 26 and Figure 27 show the initiating location of sustained and momentary automatic outages from 2008 to 2010.

With both momentary and sustained automatic outages taken into account; the outage was initiated on the TADS element – AC circuit or transformer – more than 60 percent of the time, as shown in Figure 26 and Figure 27.

Figure 26: Sustained Automatic Outage Initiation Code

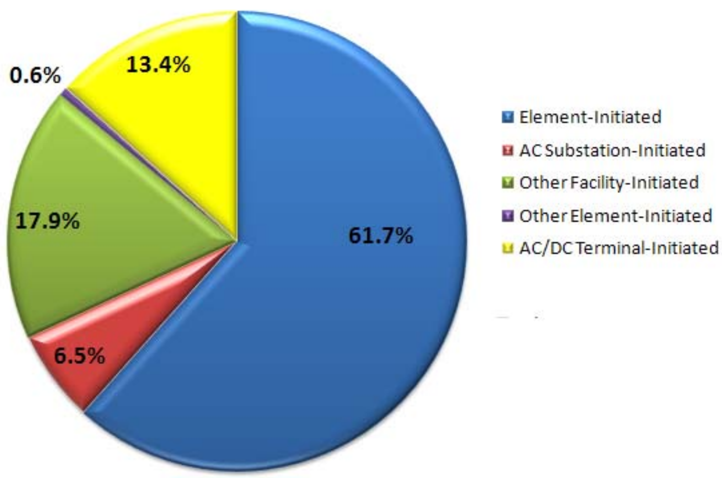
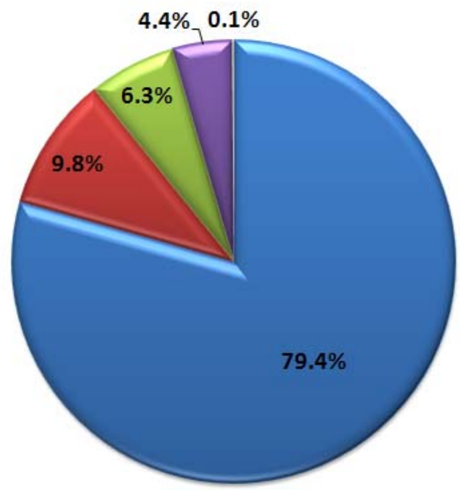


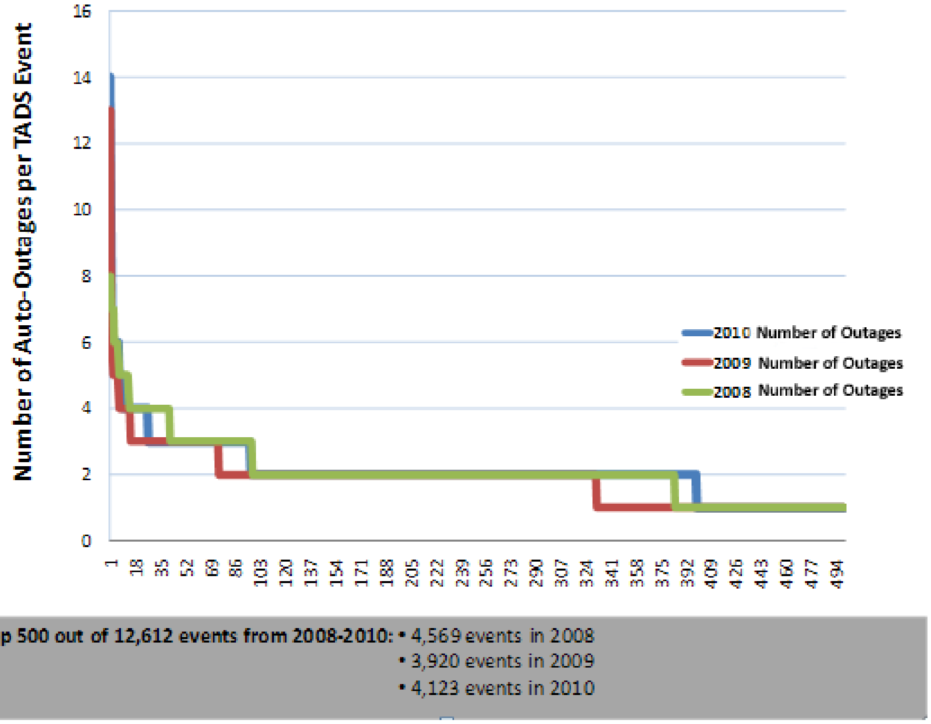
Figure 27: Momentary Automatic Outage Initiation Code



Transmission Outage Events

Figure 28 illustrates the relationship between the numbers of automatic outages per TADS event. All three years, 2008, 2009, and 2010, follow a similar trend. The largest number of automatic outages per event is fourteen in 2010, thirteen in 2009, and eight in 2008. There are around 70 to 100 events that contain between fourteen and three automatic outages (see below). There are around 330 to 400 events that contain two or more automatic outages. Each of the other events contains only one automatic outage. In the figure, the total number of events in 2008 to 2010 ranged from 3,920 to 4,569 events per year. In 2010, over 90 percent of TADS events contained at least one automatic outage.

Figure 28: Event Histogram (2008-2010)



Transmission Outage Modes

Figure 29 and Figure 30 show the percentage of outage modes. The "outage mode code" relates one automatic outage to other automatic outages. A definition of each outage mode code is provided in Table 7.

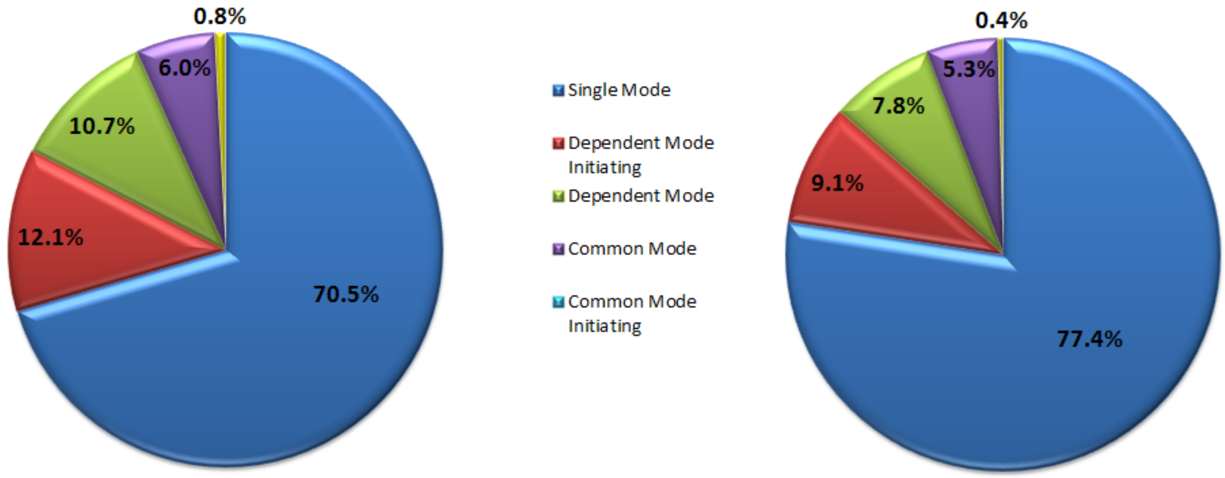
Table 7: Outage Mode Codes	
Outage Mode Code	**Automatic Outage Description**
Single Mode	A single element outage which occurs independently of another automatic outage
Dependent Mode Initiating	A single element outage that initiates at least one subsequent element automatic outage
Dependent Mode	An automatic outage of an element which 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

Over 70% of sustained and momentary automatic outages are single mode. This reinforces the long held belief that the majority of all sustained and momentary automatic outages are single mode. However, a significant percent of automatic outages, 29.6% sustained and 22.6% momentary, are in the dependent or common mode family. Based on the design criteria of withstanding single mode outages, the discovery of significant non-single mode outages might be a reliability risk.

An investigation into the root causes of dependent and common mode events which include three or more automatic outages, identified in the 2008 to 2010 data, is a high priority. Some protection systems are designed to trip three or more circuits, but some events go beyond what is designed. In addition, protection system misoperations are associated with a number of multiple outage events.

Figure 29: Sustained Automatic Outage Mode Code (2008-2010)

Figure 30: Momentary Automatic Outage Mode Code (2008 -2010)



Conclusions

On a NERC-wide average basis, the automatic transmission outage rates are improving from 2008 to 2010. For 2010, the data indicates that the transmission element availability percentage exceeded 95%.

There are two potential improvements to reliability based on the data. Firstly, the cause codes of Human Error, Failed Protection System Equipment, and Failed AC Circuit should be a focal point to reduce the number of sustained automatic outages for all elements. Secondly, a deeper investigation into the root causes of dependent and common mode events which include three or more automatic outages is a high priority. Therefore, a joint team should be formed to analyze dependent and common mode events. These events, which go beyond design criteria, represent a tangible threat to reliability. More analysis would improve the design basis assumed for reliable operation of the system.

Generation Equipment Performance

Introduction

The development of the Generating Availability Data System (GADS) began in 1982. This data system collects, records, and retrieves voluntarily provided operating information. By pooling individual unit information, generating unit availability performance is calculated. Also, the information supports equipment reliability, availability analyses and risk-informed decision-making to relevant parties. Finally, reports and information resulting from the data collected through GADS are now used for benchmarking and analyzing electric power plants.

Currently, the data collected through GADS contains 72 percent of North American generating units with generating capacity of 20 MW or higher.[40] However, many newer combined-cycle plants are not reporting information, and a full view of each unit type is not presented. Rather, a sample of all the units in North America that fit a given, more general category is provided[41] for the 2008 to 2010 assessment period.

Generation Key Performance Indicators

Three key performance indicators[42] used to measure the availability of generating units are Equivalent Availability Factor (EAF), Net Capacity Factor (NCF), and Equivalent Forced Outage Rate – Demand (EFORd). In Table 8, the North American fleet average EAF, NCF, and EFORd compared to unit age for all generating units with a capacity of 20 MW and higher is provided for the years 2008-2010. For this period, the same group of units was used, so a true measure of comparable trending could be completed. During the last three years, the EAF has declined, NCF dropped in 2008 and has partly recovered in 2010, and EFORd has increased. Overall, the fleet of units reported to GADS is aging overall. On a three-year average, fossil units are around 12 years older than the rest of the fleet.

During this three-year period, the average FOH was 287 hours, average MOH (including extensions to MO) was 171 hours, and the average POH (with extensions of PO) was 470 hours as shown in Figure 31.

Table 8: General Availability Review of GADS Fleet Units by Year*

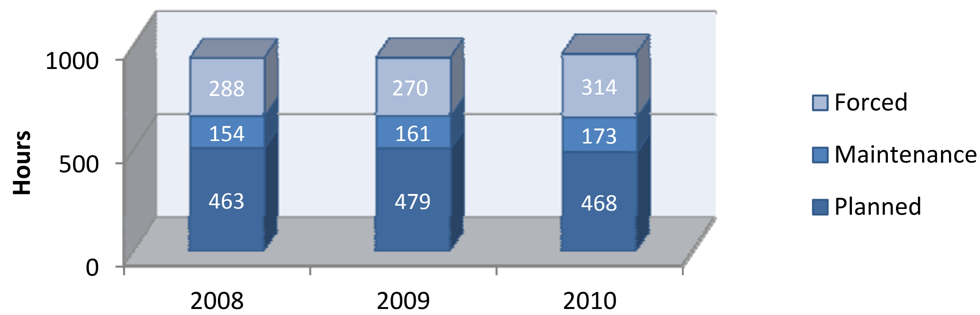
	2008	2009	2010	Average
Equivalent Availability Factor (EAF)	87.52	87.53	86.38	87.15
Net Capacity Factor (NCF)	50.49	46.87	48.30	48.55
Equivalent Forced Outage Rate - Demand (EFORd)	5.66	5.57	6.24	5.82
Number of Units ≥20 MW	3,991	3,991	3,991	3,991
Average Age of the Fleet in Years (all unit types)	31.1	31.9	33.0	32.0
Average Age of the Fleet in Years (fossil units only)	42.2	43.2	44.3	43.2

**Includes only GADS reporting units with greater than 20MW generation capability*

[41] GADS contains 1,500+ units under 20 MW that are not included in this report.

[42] http://www.nerc.com/page.php?cid=4|43

Figure 31: Average Outage Hours for Units > 20 MW



Forced outage hours jumped from 266 to 310 hours per unit between 2009 and 2010. At the same time, maintenance events also increased by 24 hours per unit. Planned outage events experienced a slight increase. More planned outage time is needed to repair the generating fleet. Whether age is the cause of the increased need for planned outage time remains unknown, and further investigation into the cause for longer planned outage time is warranted, if the trend continues.

Multiple Unit Forced Outages and Causes

Multiple unit forced outages constitute a reliability risk, and the trend of multiple unit outages is tracked. Table 9 provides the annual multiple-unit forced outage trips resulting from the same cause for each of the assessment years, 2008 to 2010. The "single unit" trips are large units with a Net Dependable Capacity of 750 MW or more. The trip of "two units" or more is any combination of unit capacity with the total amount of lost capacity more than 750 MW.

Table 9 also presents more information on a particular pattern of outages. During 2008-2010, there were a large number of double-unit outages resulting from the same event. Investigations show that some of these trips were at a single plant, caused by common control and instrumentation for the units. The incidents occurred several times for several months and are a common mode issue internal to the plant.

Table 9: Number of Multiple Unit Forced Outages and Frequency/Year*

	2008			2009			2010		
Type of Unit Trip	**# of Trips**	**Avg Outage Hr/ Trip**	**Avg Outage Hr/ Unit**	**# of Trips**	**Avg Outage Hr/ Trip**	**Avg Outage Hr/ Unit**	**# of Trips**	**Avg Outage Hr/Trip**	**Avg Outage Hr/ Unit**
Single	591	58	58	284	64	64	339	66	66
Two	281	43	22	508	96	48	206	41	20
Three	74	48	16	223	146	48	47	109	36
Four	12	77	19	111	112	28	40	121	30
Five	11	1,303	260	60	443	88	19	199	10
> Five	20	166	16	93	206	50	37	246	6

**Loss of ≥ 750 MW per Trip*

Generation Equipment Performance

In 2008, the high five-unit average outage hours/trip is attributed to damage and cleanup from Hurricane Ike hitting the Gulf Coast. The highest total number of multiple unit trips occurred in 2009. The majority of 2009 multiple unit trips have three main causes, transmission, lack of fuel, and storms. A summary of the three categories for single and multiple unit outages are reflected in Table 10.

Table 10: Top Three Causes of Multiple Unit Forced Outages (2009)*

Cause	Number of Events	Average MW Size of Unit
Transmission	1,583	16
Lack of Fuel (Coal Mines, Gas Lines, etc.) Not in Operator Control[43]	812	448
Storms, Lightning, and Other Acts of Nature	591	112

**Includes all unit capacities*

In 2009, many of the storm-based, transmission outages were caused by the same reasons because the storms may have caused transmission interference. However, the plants reported the problems inconsistently with either the transmission interference or storms cause code. Therefore, they are depicted as two different causes of forced outage. Transmission caused outages were much higher than the number two and three causes. Thirty-five percent came from one utility with a large number of hydroelectric units. The company related the trips to various problems including weather (lightning, storms), wildlife, "line bumps", and problems on the receiving end of the transmission line. Nine hundred and eighty-five transmission trips (62 percent) were from hydroelectric units.[44]

In 2009, only ten transmission trips resulted in a loss of 750 MW or more per trip. Twenty two generating plants were affected by the ten trips. Causes for the trips include feeder line trips (1 trip), breakers in the switchyard (8 trips), personnel errors (2 trips), and unknown (10 trips.)

The "Lack of Fuel" outages are of interest as these events occur when a unit is available to operate, but there is an interruption in fuel to operate the unit. These events do not include interruptions of fuel due to contracts. The "Lack of Fuel" cause code only takes into account units that are expecting fuel that do not receive it when requested. Table 11 presents the distribution of "Lack of Fuel" events by NERC Regional Entity.

[43] One company contributed to the majority of oil-fired lack of fuel events. The units need gas to start when running on oil. Upon shutdown, the units must switch to gas to clean themselves. Due to a gas restriction, the units cannot start, and the units go on a forced outage. Until the restriction is lifted, the two units will continue to be on a forced outage cycle.

[44] The average size of the hydroelectric units were small – 3.35 MW.

Table 11: Forced Outages Due to Lack of Fuel by Regional Entity	
Regional Entity	**Number of Lack of Fuel Problems Reported**
FRCC	0
MRO	3
NPCC	24
RFC	88
SERC	17
SPP	3
TRE	7
WECC	29

Event records also provide descriptions of why the unit was without fuel with the majority of descriptions being:

- Temperatures affecting gas supply valves
- Unexpected maintenance of gas pipe-lines
- Compressor problems/maintenance

Table 12 provides the top causes of forced outage for several major generating unit types.

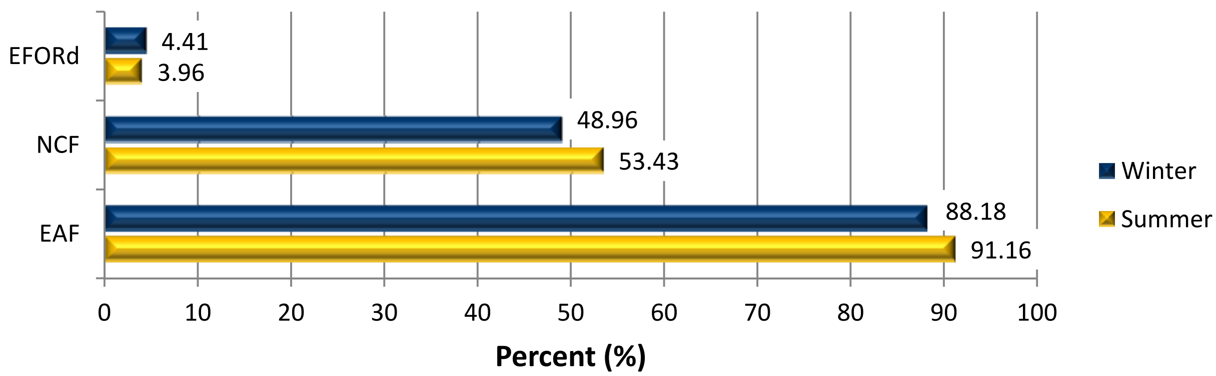
Table 12: Causes of Forced Outage for Different Unit Types (2008-2010)						
Fossil - all MW sizes; all fuels						
Rank	**Description**	**Occurrence per Unit-year**	**MWH per Unit-year**	**Average Hours To Repair**	**Average Hours Between Failures**	**Unit-years**
1	Waterwall (furnace wall)	0.64	14,735	59.5	13,484	3,984
2	Second Superheater Leaks	0.20	5,660	63.2	44,446	3,984
3	First Reheater Leaks	0.17	5,221	65.1	49,112	3,984
Combined-Cycle Blocks						
Rank	**Description**	**Occurrence per Unit-year**	**MWH per Unit-year**	**Average Hours To Repair**	**Average Hours Between Failures**	**Unit-years**
1	HP Turbine Buckets Or Blades	0.02	4,663	1,830	1,839,600	466
2	Turbine Control Valves	0.04	2,777	100	216,424	466
3	Gas Turbine Compressor - High Pressure Shaft	0.01	2,266	663	613,200	466
Nuclear Units - all reactor types						
Rank	**Description**	**Occurrence per Unit-year**	**MWH per Unit-year**	**Average Hours To Repair**	**Average Hours Between Failures**	**Unit-years**
1	LP Turbine Buckets or Blades	0.01	26,415	8,760	153,042	288
2	Containment Structure	0.01	9,233	1,226	200,132	288
3	Main Transformer	0.07	7,881	101	108,495	288
Simple-Cycle Gas Turbine Jet Engines						
Rank	**Description**	**Occurrence per Unit-year**	**MWH per Unit-year**	**Average Hours To Repair**	**Average Hours Between Failures**	**Unit-years**
1	Main Transformer	0.03	1,611	1,016	138,023	4,181
2	Other Gas Turbine Controls And Instrument Problems	0.12	428	70	64,137	4,181
3	Other Gas Turbine Problems	0.09	400	119	81,961	4,181

2008-2010 Review of Summer and Winter Availability

To address seasonality of unit availability from 2008 to 2010, unit information for the months of June to September (summer) and December through February (winter) were pooled to calculate forced outage events.[45] Figure 32 shows the average Equivalent Availability Factor (EAF) is three percentage points higher, and the average Equivalent Forced Outage Rate - Demand (EFORd) is slightly under one-half of a percentage point lower in the summer period than in the winter period. The units were more reliable with less forced events during high-demand times during the summer season than the winter season. On average, units have a higher Net Capacity Factor (NCF) of 4.5 percentage points in the summer season.

During the spring season (March-May), 77 percent of the units took a planned outage (PO) for an average 231 hours, 9.6 days. In fall (October-November), only 42 percent of the units experienced a PO, and the average duration was a shorter 134 hours, 5.6 days. Some units took both spring and fall planned outages, although this is rare. Based on this assessment, generating units are prepared for the summer peak demand. The resulting availability indicates that spring and fall maintenance was, on average, successful. This is measured by an increased EAF and a lowered EFORd.

Figure 32: Summer-Winter Average EAF, NCF, and EFORd (2008-2010)



Conclusions

During 2008-2010, the average Equivalent Availability Factor (EAF), which measures the overall availability of generating units, decreased. At the same time, the average Net Capacity Factor (NCF), an indicator of energy production, decreased in 2009 and rebounded in 2010. The average number of forced outages in 2010 is greater than in 2008, while at the same time, the average planned outage times have slightly increased. As a result, the Equivalent Forced Outage Rate – Demand (EFORd) also increased illustrating that more units have experienced forced events during peak-demand times in 2010, than in the previous two years. Potentially, with shorter planned outage periods in 2010, there may be less time to repair equipment

[45] A study of peak periods was conducted by the NERC Generating Availability Trend Evaluation (GATE) Working Group several years ago, see http://www.nerc.com/files/Seasonal-Performance-Trends.pdf

and prevent forced unit outages. Detailed analysis to delve into the root causes of increasing forced outage rate should be performed.

In the last three years, there has been an increase in Equivalent Forced Outage Rate – Demand (EFORd). This indicator measures the rate of forced outage events on generating units during periods of load demand. Forced outage hours jumped from 266 to 310 hours per unit between 2009 and 2010. At the same time, maintenance events also increased by 24 hours per unit. Planned outage events increased slightly over the three-year period. The resulting conclusions from this trend are:

- More or longer planned outage time is needed to repair the generating fleet. Whether age is the cause of the increased need for planned outage time remains unknown, and further investigation into the cause for longer planned outage time is warranted, if the trend continues.
- From 2008 to 2010, there were a large number of double-unit outages resulting from the same event. Investigations show that some of these trips were at a single plant, and the trips were caused by common control and instrumentation for the units.

In addition, there are many multiple unit forced outages due to lack of fuel. The majority of multiple unit trips have three main causes: transmission, lack of fuel, and storms. With special interest in the forced outages due to “Lack of Fuel,” additional analysis revealed that 77 percent of the units experiencing unexpected fuel stoppage are oil-fired fossil units while gas-fired units experienced 15 percent of the unexpected fuel stoppages.

Finally, based on the information assessed, generating units continue to be more reliable during the peak summer periods.

Disturbance Event Trends

Introduction

The purpose of this section is to report event analysis trends from the beginning of the event analysis field test,[46] October 25, 2010, to the end of 2010. One of the companion goals of the event analysis program is the identification of trends in events and their associated causes. These causes could include human error, equipment failure, protection system misoperation, or a multitude of other causes. The information provided in the event analysis database (EADB) and various event analysis reports have been used to track and identify trends in bulk power system events, in conjunction with other databases (TADS, GADS, metric and benchmarking database.)

The Event Analysis Working Group (EAWG) continuously gathers event data and works towards an integrated approach to analyzing data, assessing trends and communicating the results to the industry.

Performance Trends

The event category is classified[47] as shown in Figure 33. Figure 34 depicts disturbance trends in Category 1 to 5 system events from the beginning of event analysis field test to the end of 2010.[48] From the figure, November and December had substantially events than October. This is due to the field trial starting on October 25, 2010.

Figure 33: BPS Event Category

Category 1: An event resulting in one or more of the following:

a. Unintended loss of three or more BPS elements caused by common mode failure.
b. Intended and controlled system separation by the proper operation of a Special Protection System Scheme (SPS) / Remedial Action Scheme (RAS) in Alberta from the Western Interconnection, New Brunswick or Florida from the Eastern Interconnection.
c. Failure or misoperation of an SPS/RAS.
d. System-wide voltage reduction of 3% or more.
e. Unintended BPS system separation resulting in an island of 100 MW to 999 MW.
f. Unplanned evacuation from a control center facility with BPS SCADA functionality for 30 minutes or more.

Category 2: An event resulting in one or more of the following:

a. Complete loss of all BPS control center voice communication system(s) for 30 minutes or more.
b. Complete loss of SCADA, control or monitoring functionality for 30 minutes or more.
c. Voltage excursions equal to or greater than 10% lasting more than five minutes.
d. Loss of off-site power (LOOP) to a nuclear generating station.
e. Unintended system separation resulting in an island of 1,000 MW to 4,999 MW.
f. Unintended loss of 300MW or more of firm load for more than 15 minutes.
g. Violation of an Interconnection Reliability Operating Limit (IROL) for more than 30 minutes.

Category 3: An event resulting in one or more of the following:

a. The loss of load or generation of 2,000 MW or more in the Eastern Interconnection or
b. Western Interconnection, or 1,000 MW or more in the ERCOT or Québec Interconnections.
c. Unintended system separation resulting in an island of 5,000 MW to 10,000 MW.
d. Unintended system separation resulting in an island of Florida from the Eastern Interconnection.

Category 4: An event resulting in one or more of the following:

a. The loss of load or generation from 5,001 MW to 9,999 MW.
b. Unintended system separation resulting in an island of more than 10,000 MW (with the exception of Florida as described in Category 3c).

Category 5: An event resulting in one or more of the following:

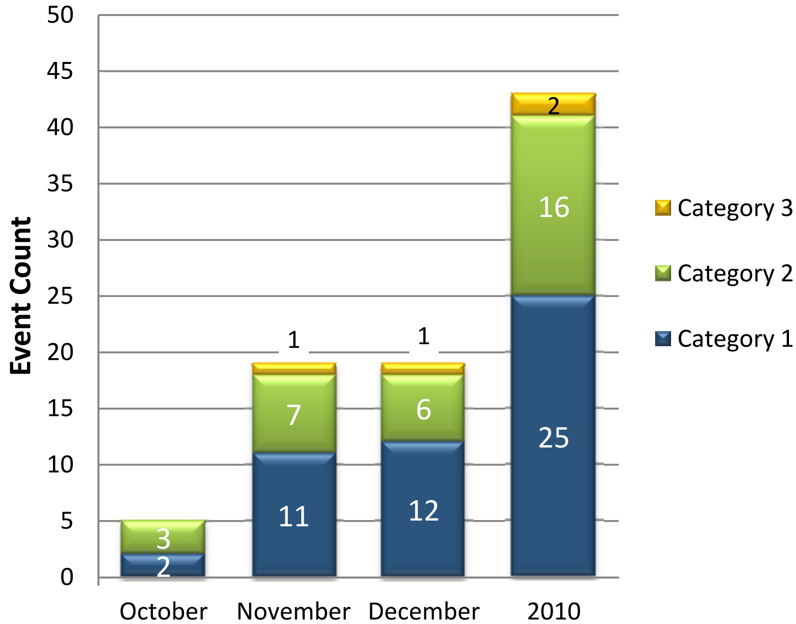
a. The loss of load of 10,000 MW or more.
b. The loss of generation of 10,000 MW or more.

[46] http://www.nerc.com/docs/eawg/Galloway-Industry-EA-Field-Test-102210.pdf

[47] http://www.nerc.com/files/2011-05-02%20Event_Analysis_Process_Phase%202%20Field%20Test%20Draft%20-%20Final%20-%20For%20posting.pdf

[48] Documents for the EA Field Test are located at: http://www.nerc.com/page.php?cid=5|365.

Figure 34: Event Category by Month (October 25, 2010 – December 31, 2010)



In addition to the category of the events, an event's status plays a critical role in data accuracy. By examining Figure 35, over 80% of the events reported in 2010 have been closed, meaning the category, root cause, and other important information have been sufficiently finalized in order for analysis to be accurate for each event. At this time, there is not enough data to draw any long-term conclusions about event analysis performance.

Figure 35: Event Count by Status

(October 25, 2010 – December 31, 2010)

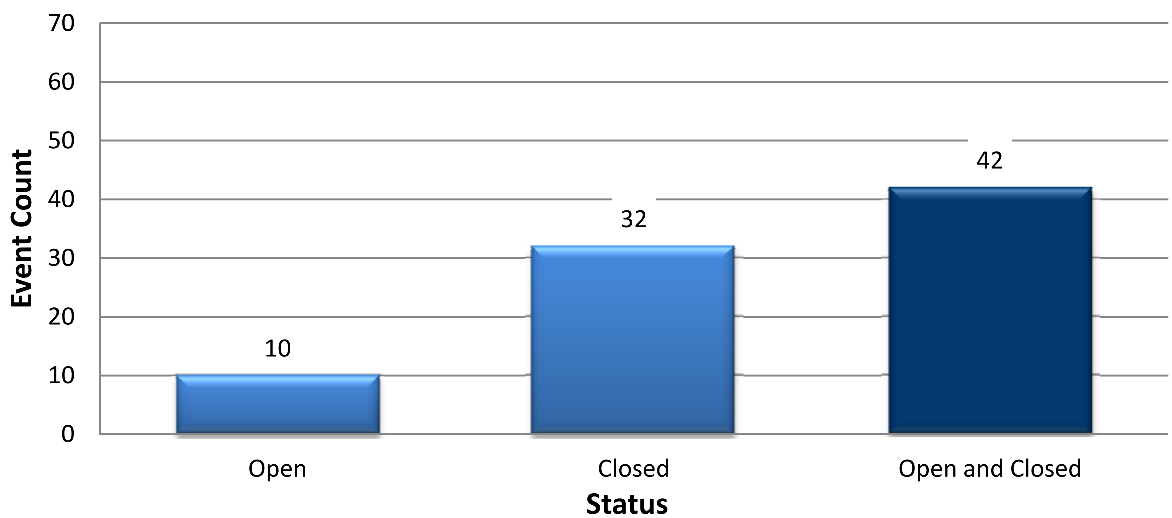
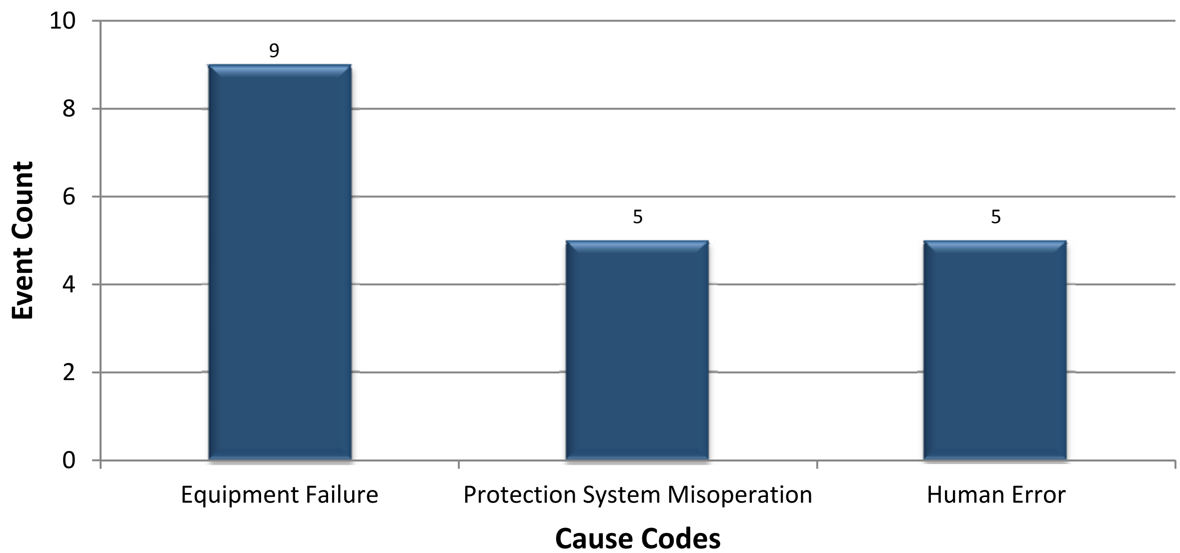


Figure 36 shows the top 3 event causes: equipment failure and protection system misoperation. Because of how new and limited the data is, however, there may not be statistical significance for this result. Further trending of cause codes for closed events and the development of a richer dataset is needed to assess trends between event cause codes and event counts.

Figure 36: Top 3 Event Counts by Cause Code for all 2010 Closed



Conclusions

Due to the relatively new process for events analysis and categorization, more time is required before conclusive recommendations may be obtained. Further analysis and data will provide valuable statistics in the future.

Abbreviations Used in This Report

Acronym	Definition
ALP	Acadiana Load Pocket
ALR	Adequate Level of Reliability
ARR	Automatic Reliability Report
BA	Balancing Authority
BPS	Bulk Power System
CDI	Condition Driven Index
CEII	Critical Energy Infrastructure Information
CIPC	Critical Infrastructure Protection Committee
CLECO	Cleco Power LLC
DADS	Future Demand Availability Data System
DCS	Disturbance Control Standard
DOE	Department Of Energy
DSM	Demand Side Management
EA	Event Analysis
EAF	Equivalent Availability Factor
ECAR	East Central Area Reliability
EDI	Event Drive Index
EEA	Energy Emergency Alert
EFORd	Equivalent Forced Outage Rate, Demand
EMS	Energy Management System
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
ESAI	Energy Security Analysis, Inc.
FERC	Federal Energy Regulatory Commission
FOH	Forced Outage Hours
FRCC	Florida Reliability Coordinating Council
GADS	Generation Availability Data System
GOP	Generation Operator
IEEE	Institute of Electrical and Electronics Engineers
IESO	Independent Electricity System Operator
IROL	Interconnection Reliability Operating Limit

Acronym	Definition
IRI	Integrated Reliability Index
LOLE	Loss of Load Expectation
LUS	Lafayette Utilities System
MAIN	Mid-America Interconnected Network, Inc
MAPP	Mid-continent Area Power Pool
MOH	Maintenance Outage Hours
MRO	Midwest Reliability Organization
MSSC	Most Severe Single Contingency
NCF	Net Capacity Factor
NEAT	NERC Event Analysis Tool
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OC	Operating Committee
OL	Operating Limit
OP	Operating Procedures
ORS	Operating Reliability Subcommittee
PC	Planning Committee
PO	Planned Outage
POH	Planned Outage Hours
RAPA	Reliability Assessment Performance Analysis
RAS	Remedial Action Schemes
RC	Reliability Coordinator
RCIS	Reliability Coordination Information System
RCWG	Reliability Coordinator Working Group
RE	Regional Entity
RFC	Reliability First Corporation
RMWG	Reliability Metrics Working Group
RSG	Reserve Sharing Group
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SDI	Standard/statute Driven Index
SERC	SERC Reliability Corporation

Acronym	Definition
SRI	Severity Risk Index
SMART	Specific, Measurable, Attainable, Relevant and Tangible
SOL	System Operating Limit
SPS	Special Protection Schemes
SPCS	System Protection and Control Subcommittee
SPP	Southwest Power Pool
SRI	System Risk Index
TADS	Transmission Availability Data System
TADSWG	Transmission Availability Data System Working Group
TO	Transmission Owner
TOP	Transmission Operator
WECC	Western Electricity Coordinating Council

Contributions

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NERC Industry Groups

Table 13 lists the NERC industry group contributors.

Table 13: NERC Industry Group Contributions[49]		
NERC Group	**Relationship**	**Contribution**
Reliability Metrics Working Group (RMWG)	Reports to the OC/PC	• Lead Development of Report • Provide Reliability Metrics Data • Responsible for Reliability Metrics Performance Chapter
Transmission Availability Working Group (TADSWG)	Reports to the PC	• Provide Transmission Availability Data • Responsible for Transmission Equipment Performance Chapter • Content Review
Generation Availability Data System Task Force (GADSTF)	Reports to the PC	• Provide Generation Availability Data • Responsible for Generation Equipment Performance Chapter • Content Review
Event Analysis Working Group (EAWG)	Reports to the OC/PC	• Provide Events Data • Responsible for Disturbance Events Trends Chapter • Content Review

[49] Rosters for RMWG, TADSWG, GADSTF, and EAWG are available at http://www.nerc.com/files/roster.pdf.

Regional Entity Staff

Table 15 provides a list of the Regional Entity staff who provided the data and content review.

Table 14: Contributing Regional Entity Staff

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NERC Staff

Table 15 provides a list of the NERC staff who contributed to this report.

Table 15: Contributing NERC Staff

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Errata

October 4, 2011

Page 55, Paragraph 1, Sentence 1: Changed October 25, 2011 to October 25, 2010.

Page 13, Figure 6: Corrected values for figure 6.

Page 13, Table 2: Corrected values for table 2.

to ensure
the reliability of the
bulk power system