NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2010 Annual Report on Bulk Power System Reliability Metrics

June 2010

to ensure
the reliability of the
bulk power system

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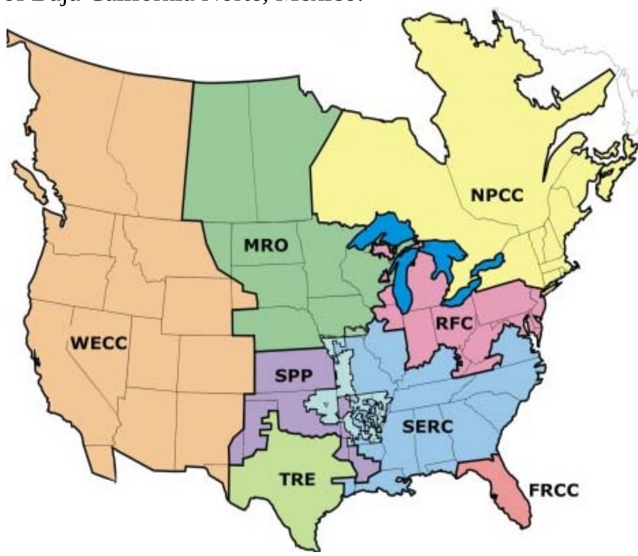
NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority for 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 a self-regulatory organization, 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 divided into the eight Regional Areas as shown on the map below (See Table A).[2] 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 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.*

Table A: NERC Regional Entities	
FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corporation
MRO Midwest Reliability Organization	**SPP** Southwest Power Pool, Incorporated
NPCC Northeast Power Coordinating Council, Inc	**TRE** Texas Regional 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 BPS, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of Ontario, New Brunswick, Nova Scotia, Québec and Saskatchewan, and with the Canadian National Energy understanding in place with provincial authorities in 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 a framework in place for reliability standards to become mandatory and enforceable. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

[2] Note ERCOT and SPP are tasked with performing reliability self-assessments as they are regional planning and operating organizations. SPP-RE (SPP – Regional Entity) and TRE (Texas Regional Entity) are functional entities to whom NERC delegates certain compliance monitoring and enforcement authorities.

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Executive Summary

This first annual report of the RMWG is designed to document both the performance of approved metrics and the introduction of new proposed metrics under consideration. As time advances, the RMWG will also undertake a review of the value of each approved metric. In the event that the RMWG concludes that a metric is no longer useful, the metric will be withdrawn and posted as a considered but not advanced metric, or a metric may be modified if there are shortcomings in its ability to convey an aspect of the Adequate Level of Reliability.[3]

In 2009, the RMWG developed a process for decision-making and continual improvement which has been applied to a wide variety of metric proposals[4]. As a NERC stakeholder body, the RMWG is carrying out the duties outlined in its scope within the principles sponsored in the creation of the ERO; namely the application of industry expertise and use of technical judgment to understand the characteristics of reliability and concentrate on its improvement.

An important question that we should try to answer is whether the current design of the bulk power system is appropriate to achieve the level of reliability we desire. In order to answer this question, performance measurements need to be conducted to develop models that link detailed measures of performance to desired results. Performance measurement is an essential tool for achieving the alignment between organizations, people, and technology; evaluating where gains have been achieved and diagnosing where improvements are needed.

This report provides an overview of the assessments of seven metrics approved in 2009. Highlights of the 2010 report include:

- Planning Reserve Margin increased from 2009 to 2012;
- BPS Transmission Related Events Resulting in Loss of Load decreased from the period of 2005 to 2008;
- The 2009 EE3 issuance has increased significantly in Arcadiana Load Pocket within SPP. The need for upgrade of electric transmission system in this area is being addressed. RMWG will continue to monitor and follow the issuance of EEA3 in SPP.

While the assessments offer a useful starting point, in many cases the data is still too sparse, thus requiring additional years of data in order to draw any specific conclusions. Also, certain metrics have captured the best available data, and recommendations have been made for their improvement.

Reliability metrics help stakeholders identify areas of focus where improvements may be necessary and can be used to evaluate whether changes produce the desired outcome. In addition, trends can indicate potential problems, which allow for informed individuals to make course corrections.

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[3] *Definition of Adequate Level of Reliability* is available at http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

[4] The RMWG report "*2009 Bulk Power System Reliability Performance Metrics Recommendations*" is available at http://www.nerc.com/docs/pc/rmwg/RMWG_Metric_Report-09-08-09.pdf

By applying the metric development process outlined in Section 2 of this report, the RMWG developed the following set of metrics and requests feedback on these nine new proposals from the Operating Committee and Planning Committee in June 2010. The detailed specifications for each metric are presented in Section 5 of this report.

ALR1-5	System Voltage Performance
ALR1-12	Interconnection Frequency Response
ALR2-3	Activation of Under Frequency or Under Voltage Load Shedding
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 Transmission Outages Initiated by Failed AC Circuit Equipment
ALR6-15	Element Availability Percentage (APC)
ALR6-16	Transmission System Unavailability due to Automatic Outages

In addition, The RMWG recommends:

1. The metric ALR4-1 (Percent of Automatic Transmission Outages caused by Failed Protection System Equipment) change back to its original definition – Correct Protection System Operations. The proposed metric ALR6-11 (Automatic AC Transmission Outages Initiated by Failed Protection System Equipment) replaces the current metric ALR4-1 (Percent of Automatic Transmission Outages caused by Failed Protection System Equipment).

2. Replace the word “Excursion” in ALR3-5 (IROL/SOL Excursion) with the word “Exceedance”.

1. Introduction

This annual report continues to evaluate and track reliability performance of the metrics with the goals specified in the NERC's *Rules of Procedure*;[5] Section 809 requires NERC to:

> ***"Identify and track key reliability indicators as a means of benchmarking reliability performance and measuring reliability improvements. This program will include assessing available metrics, developing guidelines for acceptable metrics, maintaining a performance metrics "dashboard" on the NERC Web site, and developing appropriate reliability performance benchmarks."***

The NERC Operating and Planning Committees have promoted the development of performance metrics for North America's bulk power system (BPS) through the formation of the Reliability Metrics Working Group (RMWG). The intent of this program is to provide metrics, which can yield an overall assessment of the reliability of the North American BPS based on its historical performance. The RMWG's charge is to do so within the context of the "Adequate Level of Reliability" (ALR) framework, as set out in the December 2007 report *Definition of "Adequate Level of Reliability."*[6]

This is the first annual report from the RMWG. The RMWG was established for NERC to develop meaningful metrics and relative reliability measures for the bulk power system.

In 2009, the RMWG proposed a group of nine metrics that were approved by NERC's Planning Committee.[7] These metrics were developed in the context of NERC's Adequate Level of Reliability (ALR) characteristics. This initial report contains the performance results and trends for a subset of the nine metrics for which seven have data available. Each of these metrics is discussed along with its future value to measure reliability of the bulk power system. This report establishes a continual process for annual review and refinement of existing and proposed metrics.

The RMWG has developed a well-defined process for identifying and evaluating proposed metrics. This report will further fulfill that process by adding the final step of continuous improvement. Each approved metric will be reviewed annually to determine if it meets the overarching goal of measuring relative reliability of the bulk power system. When refinements are identified to make a specific metric more effective or it is no longer useful, a recommendation will be brought to NERC's Operating and Planning Committees to revise or eliminate the metric.

This report also identifies proposed metrics under consideration, along with those that have been evaluated, but not advanced in 2009 as summarized in Appendix I. These are included to inform industry about the number and metric categories that are being considered through the development process.

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[5] The details of Section 809 is available at http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20100205.pdf.

[6] *Definition of Adequate Level of Reliability* is available at http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

[7] 2009 Bulk Power System Reliability Performance Metric Recommendations http://www.nerc.com/docs/pc/rmwg/RMWG_Metric_Report-09-08-09.pdf.

2. Metric Development

The RMWG realizes the importance of incorporating the stakeholder's proposals and comments into the metric development. It is vital to consider and address them in a systematic approach. This section outlines the metric development process, which includes details of submission, evaluation, response, review and feedback for current and future metrics.

Submission:
On an ongoing basis, the RMWG expects to receive requests to consider new metrics. New metric proposals can be submitted through metrics@nerc.net. The requestor is asked to submit information for each of the proposed metrics to include Metric Description, Purpose and Formula for calculation, along with additional details.

Evaluation:
After receiving the proposed metric, the RMWG uses the SMART (Specific, Measurable, Attainable, Relevant and Tangible) criteria to rank each proposed metric against various reliability characteristics. This consistent ranking process is used to prioritize the metrics and institute a pilot phase.

Formal Response:
The RWMG provides a written response of the metric assessment. All submitted metrics and a detailed summary of RMWG's response are maintained on NERC's web site.[8]

Ongoing Review:
RMWG reviews each metric annually to assess whether it provides useful information about bulk power system reliability in the context of the ALR definition. Based on this assessment, the metric may be rescinded unless the information is being used to support other metrics.

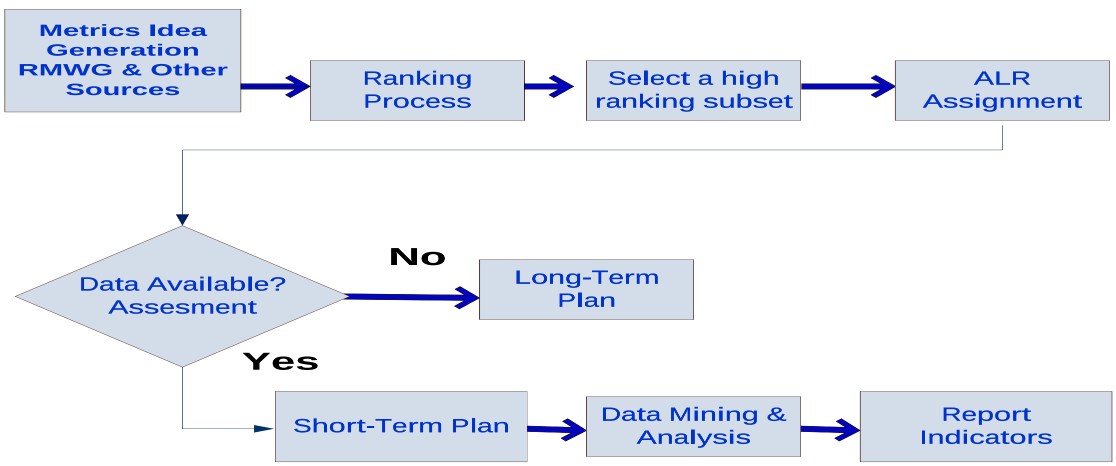
The six ALR characteristics[9] are defined as:

1) The System is controlled to stay within acceptable limits during normal conditions;
2) The System performs acceptably after credible Contingencies;
3) The System limits the impact and scope of instability and cascading outages when they occur;
4) The System's Facilities are protected from unacceptable damage by operating them within Facility Ratings;
5) The System's integrity can be restored promptly if it is lost; and
6) The System has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.

[8] See considered but not advanced metrics summary at http://www.nerc.com/filez/New_Metric_Proposals.html.
[9] *Definition of Adequate Level of Reliability* http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf

Stakeholder Feedback on Approved Metrics:
Industry feedback on approved metrics is welcome and valued. The comments can be submitted through email to metrics@nerc.net. The feedback can also be gathered via an electronic form available on NERC's web site. The RMWG summarizes the comments received and publish its responses[10] regularly.

Metric Generation Flow Process



[10] Sample RMWG survey is at https://www.nerc.net/nercsurvey/Survey.aspx?s=f1f39c54ff1b49a7a7f3e1f19fb9c01b.

3. Performance Results and Trends

3.1 Approved Metrics

Carefully selected and vetted metrics have the potential for indicating relative reliability trends and performance. Further, root cause analysis can be performed by NERC's Engineering and Operations department, based on relative trend analysis.

The trends for seven metrics where historical data is available and approved by the Planning Committee in 2009 are included in this report:

ALR1-3	Planning Reserve Margin
ALR1-4	BPS Transmission Related Events Resulting in Loss of Load
ALR2-4	Average Percent Non-Recovery of Disturbance Control Standard (DCS) Events
ALR2-5	Disturbance Control Events Greater than Most Severe Single Contingency (MSSC)
ALR4-1	Percent of Automatic Transmission Outages caused by Failed Protection System Equipment
ALR6-2	Energy Emergency Alert 3 (EEA3)
ALR6-3	Energy Emergency Alert 2 (EEA2)

Numerous committees/subgroups within NERC are reviewing these and other metrics to monitor reliability performance trends for the bulk power system. While the metrics may show trends or variances from year-to-year, no determination has been made as to what indicates an "acceptable" level of performance. Rather, relative trends can provide averages around which random sampling error can be determined and the likelihood of performance changes can be measured.

Importantly, it is incorrect to compare calculated metrics between regions or subregions. Comparative analysis is not useful between regions or subregions because bulk power system characteristics and market structures differ significantly. For example, the number of facilities, miles of line, system expansion, design approaches, and simple physical, geographic, and climatic conditions vary significantly. A more valuable approach is to compare regional or subregional trends individually, that is, reviewing metrics annually for each region/subregion individually to determine significant trends. Then NERC can focus on the causes for these annual trends, recommend further analysis to determine root causes, and develop lessons learned shared with all participants to support relative reliability improvements.

A. ALR1-3 Planning Reserve Margin

Background

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.

Generally, the projected demand is based on a 50/50 forecast.[13] Planning Reserve Margin is the difference between forecast capacity and projected peak demand, 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 (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.

Special Considerations

As the Planning Reserve Margin is a capacity based metric, 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. Data used here is the same data used for NERC's Reliability Assessments for both the seasonal and *Long-Term Reliability Assessments*.[14] The Resource Issues Subcommittee (RIS), under the direction of the NERC PC, is investigating a new metric proposal to consider energy-limited systems.

Assessment

Planning Reserve Margins in United States and Canada appear to increase from 2009 to 2012 then decrease through 2018 (Figures Metrics 1 and 2). Planning Reserve Margins in Canada decline to 9 percent in 2018 and fall below the NERC Reference Reserve Margin Level of 10 percent[15] for predominantly hydro based systems. The early years provide more certainty since new generation is under construction during this period; while the later years reflect proposed generation with less certainty. NERC uses this metric in the ten-year long-term reliability assessments. If a noticeable change occurs within the trend, further investigation is necessary to determine the causes and likely affects on reliability.

RMWG recommends continued observation of annual trends.

[11] Detailed calculations of Planning Reserve Margin is 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] 2009 LTRA is available at http://www.nerc.com/page.php?cid=4|61

[15] The definition of the NERC Reference Reserve Margin Level can be viewed in the section Terms Used in This Report of "*2009 Long Term Reliability Assessment*", available at http://www.nerc.com/files/2009_LTRA.pdf .

Figure Metrics 1

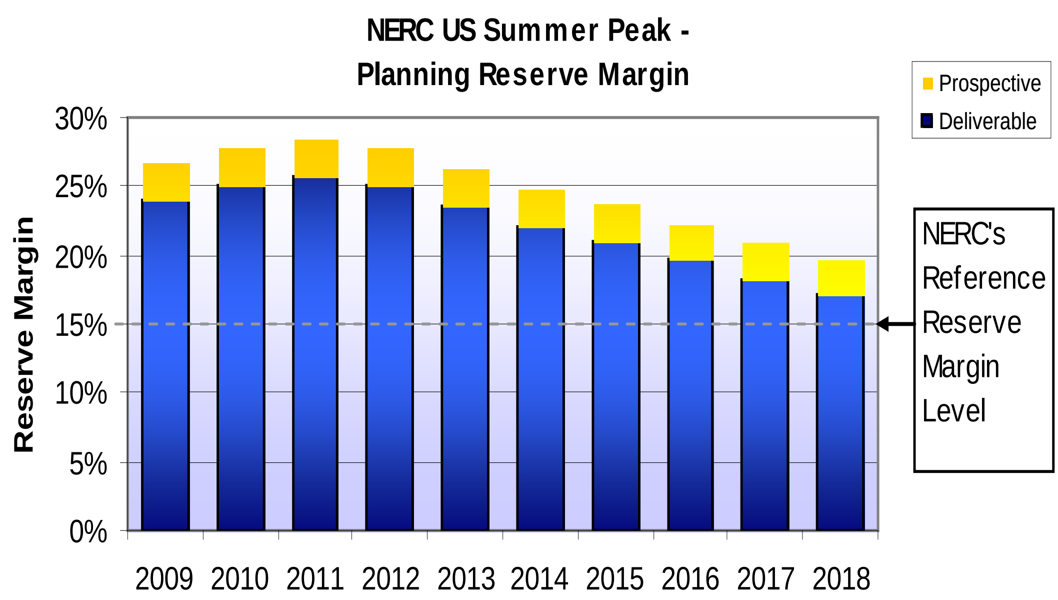
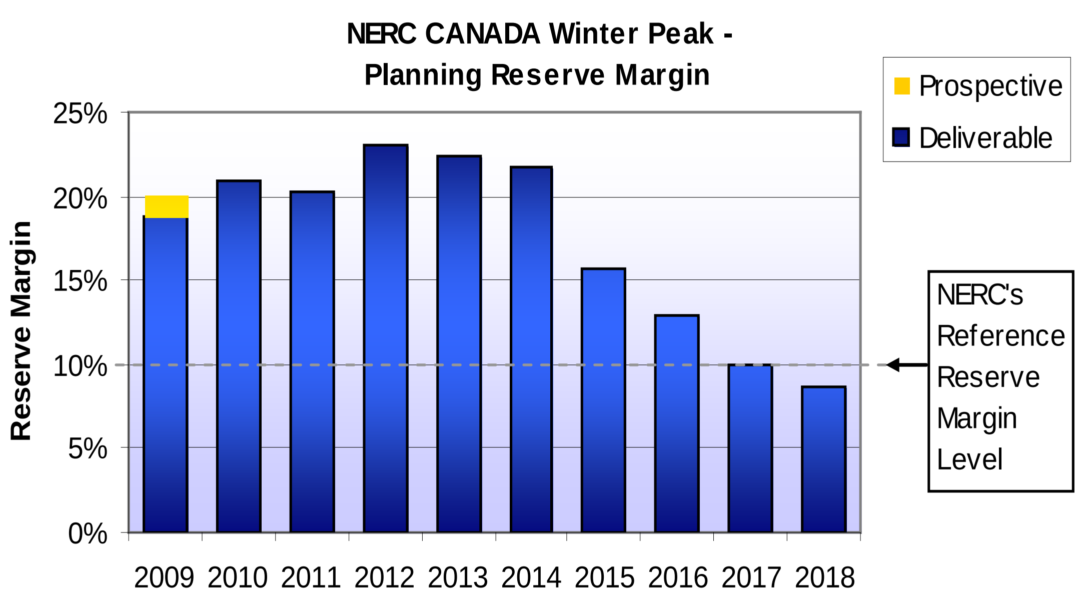


Figure Metrics 2



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

Background

This metric measures bulk power system transmission-related events resulting in loss of load. 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, which result in the loss of firm system demand for more than 15 minutes, as described below:[16]

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

Special Considerations

A single metric cannot capture all the relative data. Hence, this metric counts the number of the events within a year and, therefore, does not provide an indication of the severity or impact, namely, the extent of the transmission disturbance, the total megawatt of load interrupted or the duration of events are not reflected. The relative trend from year-to-year is the leading indicator. If the trend increases, further investigation will be required.

Assessment

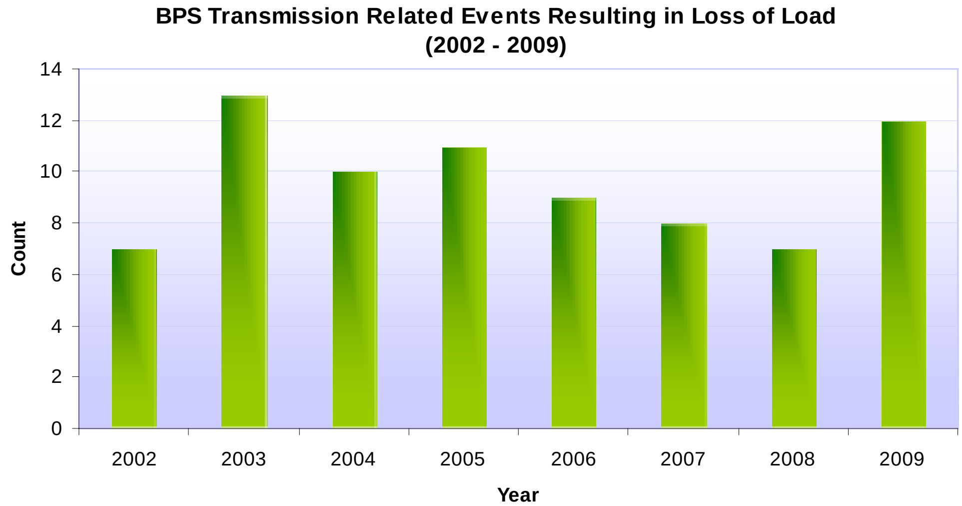
Figure Metrics 3 shows the number of BPS transmission-related events resulting in loss of firm load[17] from 2002 to 2009. The total number of the events has decreased from 2005 to 2008. Since the sample size is small, caution should be used on drawing conclusions.

RMWG recommends continued assessment of the trends over time.

[16] Details of event definitions are available at http://www.nerc.com/files/EOP-004-1.pdf.

[17] The metric source data may require adjustments to accommodate all the different groups for measurement and consistency as OE-417 is only used in the US.

Figure Metrics 3



C. ALR2-4 Average Percent Non-Recovery of Disturbance Control Standard (DCS) Events

Background

The DCS Failures metric measures the Balancing Authority's (BA) or Reserve Sharing Group's (RSG) ability to balance resources and demand with contingency reserve, thereby returning the interconnection frequency within defined limits, following a Reportable Disturbance.[18] The relative percentage provides an indication of performance measured at a BA or RSG. NERC Standard BAL-002 requires that a BA or RSG evaluate contingent BA or RSG performance for all reportable disturbances and report findings quarterly to NERC.

Special Consideration

A single metric cannot capture all the relative data. 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.

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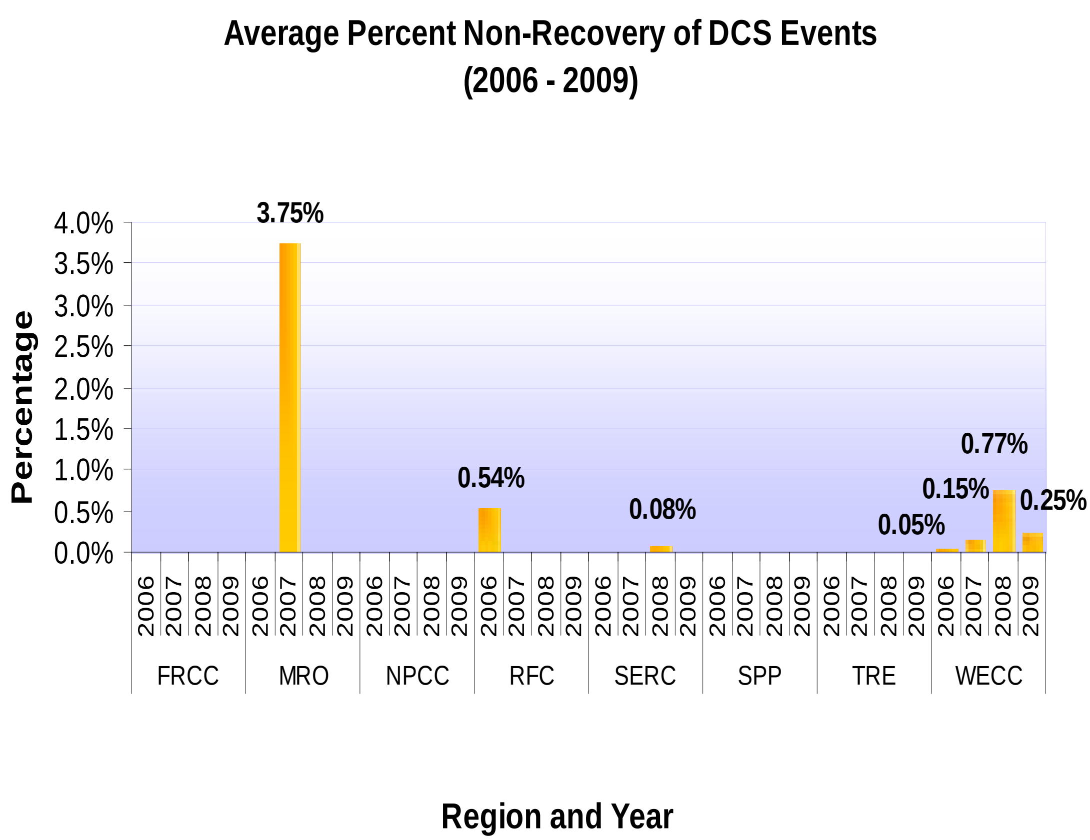
[18] Details of the Disturbance Control Performance Standard and Reportable Disturbance definition are available at http://www.nerc.com/files/BAL-002-0.pdf.

Assessment
Figure Metrics 4 shows the average percent non-recovery of DCS events from 2006 to 2009. Since the reporting threshold varies from Regional Entity (RE) to RE these numbers are not comparable between REs. For instance, some REs use 80 percent of the Most Severe Single Contingency to establish the minimum threshold for Reportable Disturbance, while other uses 35 percent.[19] Therefore, some REs will report few disturbances, while others report many.

The graph provides a high-level indicator for each respective RE. 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 REs to further investigate and provide a more comprehensive reliability report. Further investigation may indicate the entity had sufficient contingency reserve, but, through their implementation process, failed to meet DCS recovery.

RMWG recommends continued trend assessment. Where trends indicated potential issues, the RE will be requested to investigate and report their findings.

Figure Metrics 4



[19] WECC RE requested for a 35 percent reporting threshold for DCS http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=69&Source=/Standards/Development/Pages/WECCStandardsArchive.aspx

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

Background

Disturbance control events greater than Most Severe Single Contingency[20] (MSSC) metric identifies the number of disturbance events that exceed (MSSC), and is specific to each BA. Each BA or RSG reports disturbances greater than the MSSC as the results help validate current contingency reserve requirements. The MSSC is determined based on the specific configuration of each system and can vary in significance and impact on the BPS.

Special Consideration

This metric reports the number of DCS events greater than MSSC without regards to the size of a BA or RSG, and without respect to the number of reporting entities within a given RE. Therefore, trends within an RE will provide the potential reliability indicators.

Assessment

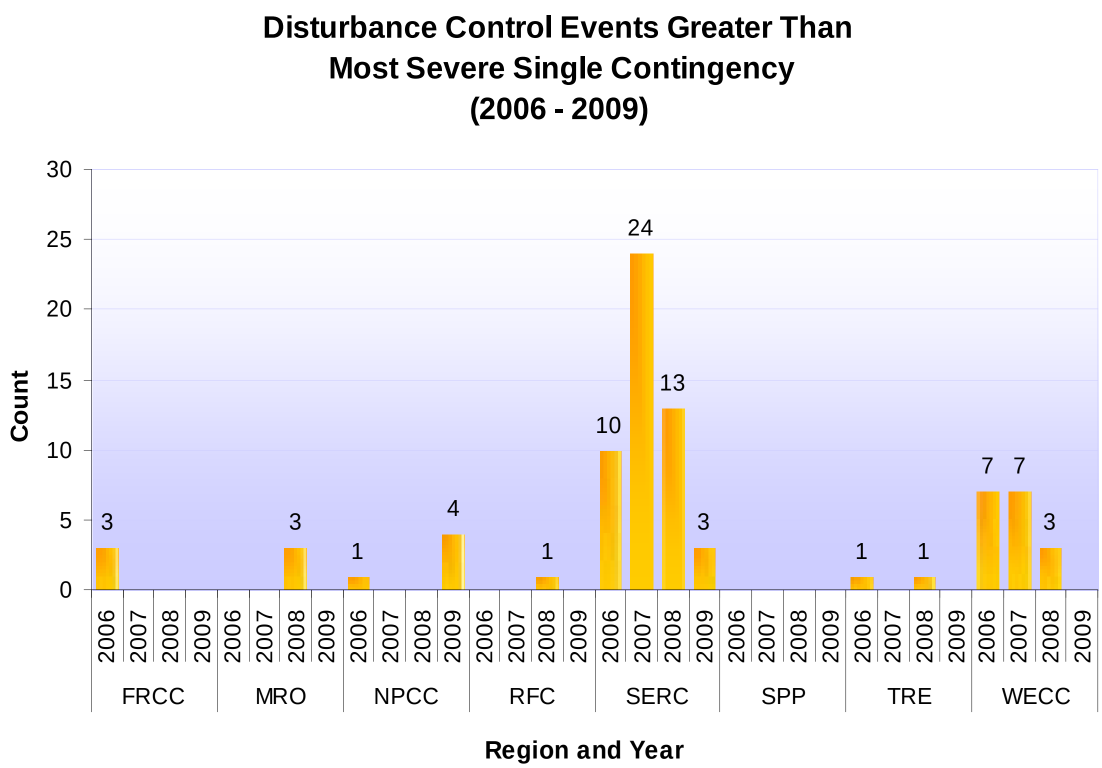
Figure Metrics 5 represents the number of DCS events that are greater than the MSSC from 2006 to 2009. Since each RE is different, a trend provides an indicator. With this trend, the respective RE must investigate to determine the cause and relative effect on reliability. A small reporting threshold may not indicate a reliability problem for the reporting RE; however, it may indicate an issue for the respective BA.

In addition, events greater than MSSC may not cause a reliability issue, since some REs have more stringent standards which may require additional contingency reserve greater than MSSC; in their scenarios, the minimum requirement for contingency reserve is MSSC. These metric and resulting trends provide insight exposure to events greater than MSSC, and the potential for loss of load.

The RMWG recommends continued metric assessment.

[20] Details of the most severe single contingency determination process are available at http://www.nerc.com/files/BAL-002-0.pdf.

Figure Metrics 5



E. ALR4-1 Percent of Automatic Outages caused by Failed Protection System Equipment

Background

The percent of Automatic Outages caused by Failed Protection System Equipment metric, measures the relative performance of protection systems (both generator and transmission) on the BPS. The percentage of automatic transmission outages caused by failed protection systems provides an indication of the relative performance of protection system operations, when specifically compared to correct protection system operations as a ratio of total protection system operations. This metric could be expanded in the future to track human error and equipment failure misoperations.

To determine if a misoperation has occurred requires that all operations be reviewed by transmission and generator owners. Therefore, the total number of operations should already be known, and reported (in total or possibly broken down further by voltage class). Misoperations are currently reported to the Regional Entities to comply with NERC Standards PRC-003[21], 004[22] and 016[23], but the total number of operations is not. The total number of operations should

[21] Standard PRC-003 is available at http://www.nerc.com/files/PRC-003-1.

[22] Analysis and Mitigation of Transmission and Generation Protection System Misoperations http://www.nerc.com/files/PRC-004-1.pdf

[23] Special Protection System Misoperations http://www.nerc.com/files/PRC-016-0_1.pdf

become available for use in this metric when the three PRC standard revisions become effective as endorsed by the PC.[24]

Special Consideration

In the interim, since the NERC Transmission Availability Data System (TADS)[25] reveals only the total number of automatic transmission system outages and the number of outages caused by failed protection system equipment[26] for 200 kV and above, this metric is currently defined as the Percent of Automatic Outages caused by Failed Protection System Equipment. The final metric for correct protection system operations will be used once the total number of protection system operations can be gathered. However, after considering a proposal for additional metrics using the NERC TADS (specifically, proposed metrics ALR6-11, -12, -13, and -14), the RMWG is recommending that this metric revert back to its original language because the proposed metric ALR6-11 (Automatic AC Transmission Outages Initiated by Failed Protection System Equipment) would replace the interim metric ALR4-1, pending the Operating and Planning Committees' approval.

Assessment

Figure Metrics 6 shows the percent of automatic outages caused by failed protection system equipment reported for outages in the calendar year 2008. This chart covers alternating current (AC) transmission circuits and transformers operated at 200 kV and above as reported in TADS. Both monetary and sustained outages are included and the failed protection system equipment is either an initiating cause or a sustained cause. Since the TADS effort contains a single year of data, the statistical sample is small and caution should be used in drawing any conclusions. The stand-alone chart below shows a single cause category for AC transmission circuit and transformer outages. Three to five years of data will be needed to develop a rolling average to represent any meaningful statistical trend.

In the TADS report, the outage cause category may not necessarily correlate completely to misoperations, which has no common formal definition. The TADS definition includes failed protection system equipment, relay or control operations; not including misoperations that are caused by incorrect relay or control settings and do not coordinate with other protective devices. These misoperations caused by human error are reported under separate Human Error cause code. Currently the metric ALR4-1 does not capture those misoperations caused by human error. However, when the standards reflect the referenced changes, these Human Error type outages will be counted and included in the report.

In 2008, for AC circuits and transformers operating between 200-799 kV, several other categories were responsible for more monetary and sustained outages than failed protection systems (6.9 percent).[27] The "unknown" category was responsible for 19.7 percent of the

[24] The recommended changes by the Special Protection and Control Subcommittee (SPCS) can be viewed at http://www.nerc.com/docs/pc/Draft_PC_Minutes_June_2009_06-23-09.pdf.

[25] http://www.nerc.com/filez/tadswg.html

[26] TADS Data Reporting Instruction Manual can be viewed at http://www.nerc.com/docs/pc/tadstf/Ph_I_Data_Reporting_Instr_Manual_112108.pdf.

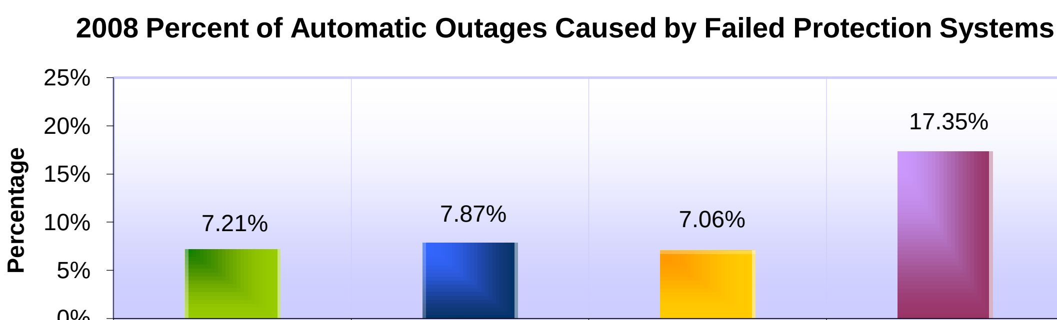
[27] 2008 TADS Report is available at http://www.nerc.com/docs/pc/tadswg/Draft_NERC_Updated_2008_TADS_Report.pdf.

automatic outages, "failed AC circuit equipment" category accounted for 8.2 percent, "unavailable" category accounted for 6.6 percent, and the "other" category accounted for 5.5 percent.

AC circuits and transformers operating between 600-799 kV had more than double the percentage of outages caused by failed protection system equipment, than all of the other voltage classes. There are 81 outages in 2008 compared with the other voltage classes, which have more than 4,500 reported outages combined and over 343 protection equipment failures. As only one year of data has been collected, it is too early to suggest this difference may be anything but random sampling error.

This metric is undergoing continued assessment and coincides with the proposed new metric ALR6-11 (Automatic AC Transmission Outages Initiated by Failed Protection System Equipment). It is anticipated that this metric will revert back to its original description for correct protection system operations, which will require NERC Reliability Standards revisions before implementation can begin.

Figure Metrics 6



	200-299 kV	300-399 kV	400-599 kV	600-799 kV
Failed Protection Outages	189	122	45	17
Other Automatic Outages	2434	1429	592	81
Percentage	7.21%	7.87%	7.06%	17.35%

F. ALR6-2 Energy Emergency Alert 3 (EEA3)

Background

Energy Emergency Alert 3 (EEA3) identifies the number of times EEA3s are issued. EEA3 events are firm-load interruptions due to capacity and energy deficiency. EEA3 is currently reported, collected and maintained in NERC's Reliability Coordination Information System (RCIS). EEA3 is defined in Attachment 1 of the NERC Standard EOP-002.[28]

The number of EEA3s per year provides a relative indication of performance measured at a BA or interconnection level. As historical data is gathered, trends in future reports will provide an

[28] The latest version of Attachment 1 for EOP-002 is available at http://www.nerc.com/page.php?cid=2|20

indication of either decreasing or increasing adequacy in the electric supply system. This metric can also be compared to the Planning Reserve Margin. Significant increases or decreases in EEA3 events with relatively constant Planning Reserve Margins could indicate volatility in the actual loads compared to forecast levels or changes in the adequacy of the bulk power system required to meet load demands.

Special Considerations

The metric counts the number of EEA3 declarations. The intent is to measure only EEAs that are called for reliability reasons and not for economic factors. RMWG made their recommendation to Reliability Coordinator Working Group (RCWG) to consider and revised EEA declarations to exclude economic factors.

Assessment

Figure Metrics 7 shows the number of EEA3 events during 2006 to 2009 at a Regional level. Specific issues or events at a Regional level may exist that should be investigated further by the RE before any conclusions are drawn.

Southwest Power Pool (SPP)

The SPP Reliability Coordinator (RC) issued more EEA3s in 2009 than previous years due to events in the Acadiana Load Pocket.[29] As a long-term solution, the SPP ICT (Independent Coordinator Transmission) facilitated an agreement to expand and upgrade electric transmission in the area.[30] The joint project includes upgrades to certain existing electric facilities as well as the construction of new substations, transmission lines, and associated equipments. All upgrades are expected between 2010 and 2012. When completed, these upgrades will address the higher potential for EEA3s.

SERC

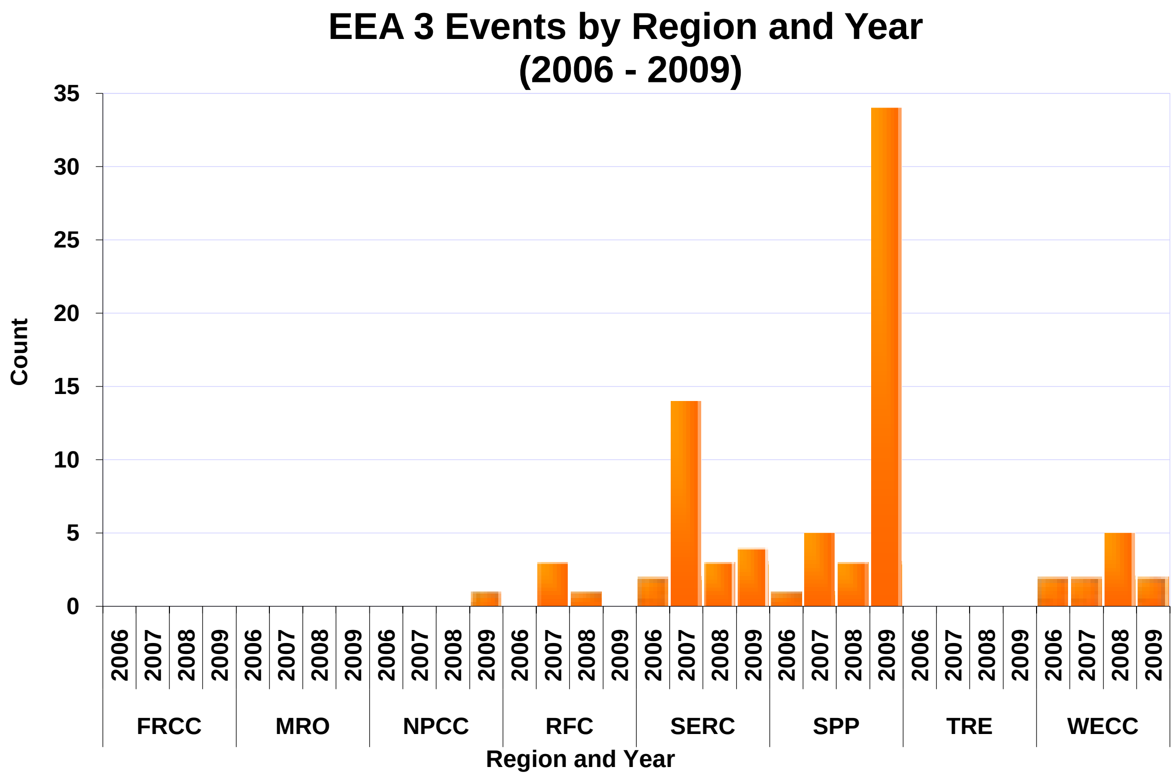
The high numbers of EEA3s for SERC in 2007 were the result of peak system conditions, which have not been repeated in recent years. Summer 2007 was also when the last Regional peak occurred. SERC contains a number of relatively small Balancing Authorities compared to other regions and is one reason why this metric cannot be compared between regions. The metric trend for SERC continues to improve.

The RMWG recommends continued metric assessment.

[29] For more details of adequacy issues in the Acadiana Load Pocket, see SPP's Regional Assessment in *2009 Long-Term Reliability Assessment*, available at http://www.nerc.com/files/2009_LTRA.pdf.

[30] The detailed upgrade information is available at http://www.spp.org/publications/SPP_Acadiana_news_release_1-19-09.pdf.

Figure Metrics 7



G. ALR 6-3 Energy Emergency Alert 2 (EEA2)

Background

Energy Emergency Alert 2 (EEA2) metric measures the number of events BAs declare for deficient capacity and energy during peak load periods, which may serve as a leading indicator of energy and capacity shortfall in the adequacy of the electric supply system. It provides a sense of the frequency or precursor events to the more severe EEA3 declarations.

The number of EEA2 events, and any trends in their reporting, indicates how robust the system is in being able to supply the aggregate load requirements. The historical records may include demand response activations and non-firm load interruptions per applicable contracts within the EEA alerts, per its definition[31]. Demand response is a legitimate resource to be called upon by BAs and are not a reliability concern. As data is gathered in the future, reports will provide an indication of either decreasing or increasing adequacy in the electric supply system. EEA events called solely for activation of demand response (controllable or contractually prearranged demand-side dispatch programs) or interruption of non-firm load per applicable contracts should be excluded. This metric can also be compared to 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 forecast levels or changes in the adequacy of the bulk power system required to meet load demands.

[31] EEA2 as defined from the Reliability Indicator page http://www.nerc.com/page.php?cid=4|331|341

Special Considerations

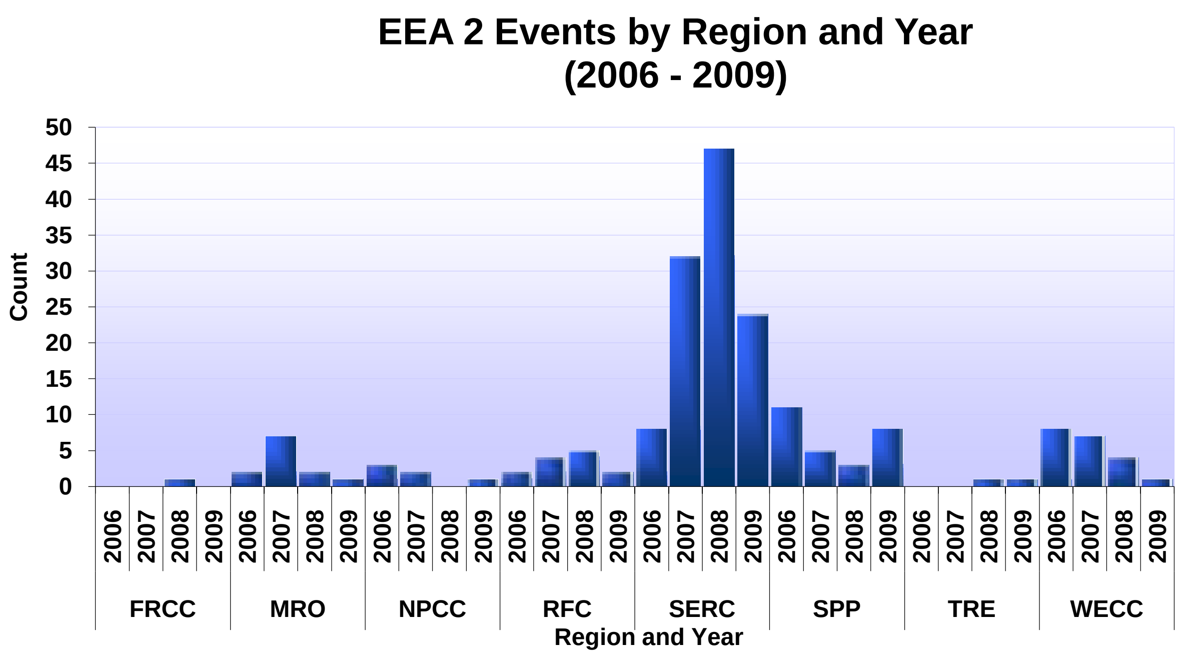
The target is to measure only EEAs that are called for reliability reasons and not for economic factors such as DSM and non-firm load interruption. RMWG submitted recommendations to the Reliability Coordinators Working Group (RCWG), to consider excluding economic factors from EEA reported by NERC's Reliability Coordinator Information System (RCIS).

Assessment

Figure Metrics 8 shows the number of EEA2 events by Region during 2006 to 2009. Specific performance by any one region should be investigated further for issues or events that may affect the results. As mentioned above, economic factors will be excluded when new data becomes available.

The RMWG recommends continued metric assessment.

Figure Metrics 8



3.2 Approved Metrics Still Under Development

In addition to the seven metrics discussed in the previous section, the NERC Planning Committee approved two additional metrics that are still under development. The following is status of each metric.

ALR3-5	IROL/SOL Excursion
ALR6-1	Transmission Constraint Mitigation

ALR3-5 IROL/SOL Excursion

The RMWG issued a NERC Rules of Procedure Section 1600 data request for this metric. On March 5, 2010, NERC sent out a solicitation for public comment on the data request, resulting in the submittal of eight sets of comments. The RMWG has considered and discussed each comment. For the comments that were not accepted, the RMWG provided corresponding explanations.32 Others made comments that were favorable and supportive of the data request or comments that did not require a response. The RMWG did not respond to those comments. Several comments suggested changing the word "Excursion" to "Exceedance". The RMWG adopted the suggestion and recommends the word change to OC and PC for approval.

After the endorsement from OC and PC, NERC will present this proposed data request to the NERC Board of Trustees for approval, as required by Section 1602 of the NERC's *Rules of Procedure*. Upon NERC Board of Trustees' approval, this data request will become mandatory for all Reliability Coordinators (RCs) in the U.S. who are registered on the NERC Compliance Registry. Non-U.S. RCs who are NERC members are also required to comply with NERC's *Rules of Procedure*. Therefore, because this data is being requested in accordance with Section 1600, non-U.S. RCs that are NERC members must also provide the requested IROL/SOL data.

ALR6-1 Transmission Constraint Mitigation

The RMWG completed a pilot data run with four regions and recommended expanding the pilot data collection to all regions. Regional data submissions are due by August 15, 2010. This metric will be re-evaluated once data is collected. Details on this metric can be found in the 2009 RMWG report[33].

[32] ALR3-5 data request comments and responses can be viewed at http://www.nerc.com/docs/pc/rmwg/ALR3-5_Data_Request_Comments_and_Responses6.1.pdf.

[33] 2009 Bulk Power System Reliability Performance Metric Recommendations http://www.nerc.com/docs/pc/rmwg/RMWG_Metric_Report-09-08-09.pdf.

3.3 New Development That Resulted in ALR4-1 Metric Changes

The approved ALR4-1 was originally defined as Correct Protection System Operations. Since the total number of protection system is not available, this metric is currently defined as Percent of Automatic Outages caused by Failed Protection System Equipment. NERC Transmission Availability Data System (TADS)[34] reveals the total number of automatic transmission system outages and the number of outages caused by failed protection system equipment[35] for 200 kV and above. The final metric for correct protection system operations will be used once the total number of protection system operations can be gathered. However, after considering a proposal for additional metrics using the NERC TADS (specifically, proposed metrics ALR6-11, -12, -13, and -14), the RMWG is recommending that this metric revert back to its original language because the proposed metric ALR6-11 (Automatic AC Transmission Outages Initiated by Failed Protection System Equipment) will replace the current metric ALR4-1, pending the Operating and Planning Committees' approval.

The original ALR4-1 metric template is shown below.

[34] http://www.nerc.com/filez/tadswg.html

[35] TADS Data Reporting Instruction Manual can be viewed at http://www.nerc.com/docs/pc/tadstf/Ph_I_Data_Reporting_Instr_Manual_112108.pdf.

	ALR4-1 Correct Protection System Operations
Metric Number	ALR4-1
Submittal Date	February 27, 2009
Sponsor Group (OC, PC or subgroup name)	RMWG
Short Title	Correct Protection System Operations
Metric Description	Percent of correct protection system operations (i.e. automatic facility trips) that properly cleared faults; compared to all operations (including misoperations)
Purpose	The purpose of this metric is to gauge the performance of protection systems (both generator and transmission) on the bulk power system.
How will it be suited to indicate performance?	The relative percentage provides an indication of the relative performance of protection system operations, specifically correct protection system operations as a ratio of total protection system operations. In the future after a few years of data collection, a benchmark percentage could be established.
Formula	Percent correct trips = number of correct trips divided by the total number of trips (which = correct trips + misoperations)
Time Horizon	Historical perspective
Metric Start Time or Baseline and Roll Up	The first year data becomes available
Data Collection Interval and Roll Up	To determine if a misoperation has occurred requires that all operations be reviewed by Transmission/Generator Owners. Therefore, the total number of operations should already be known, and could be reported (in total or possibly broken down further by voltage level). Misoperations are currently reported to the Regional Entities for compliance to standards PRC-003, 004 & 016, but the total number of operations currently is not. The total number of operations should be available when these three PRC standards are revised through the NERC standards process and become effective.
Ease of Collection	Each Regional Entity collects misoperation data regularly per PRC-003, -004 and -016. The number of operations will be collected upon after the standards requirements are revised.
Aggregation	Results could be presented by voltage level on a Regional Entity and/or Interconnection basis.
Linkage to NERC Standard	PRC-003, -004, and -016
Linkage to Data Source	Use of the Regional Entities' misoperation databases.

Need for Validation or Pilot	Yes, need to validate completeness and consistency of historical data across each Regional Entity. A pilot run should be performed.					
Data Submitting Entity	Transmission Owner and Generator Owner					
SMART Rating	Total Score 15	Specific/ Simple 3	Measurable 3	Attainable 3	Relevant 3	Tangible/ Timely 3
Reporting						
Style (look and feel)	Bar charts					
Publications and Documentation	This metric will be included in NERC RMWG reports, and may be included in the annual NERC LTRA report.					

4. Accuracy and Completeness

4.1 Consultation with Stakeholders

NERC functional entities have a role in supporting reliable performance of the bulk power system. Therefore, the RMWG engaged many of the subgroups of the Operating and Planning Committees to solicit their ideas and contributions. Appendix III outlines the collaborative effort of the RMWG through the NERC stakeholder bodies.

To help ensure all metric suggestions are considered, the chairs of the Operating and Planning Committees sent a letter along with a template providing the necessary details on April 6, 2009[36] to subgroup chairs requesting contributions. The RMWG reviewed each proposed metric and provided feedback to the contributors describing the specifications of their proposed metric. The RMWG encourages all subgroups to submit any new reliability metric proposals. NERC subgroups are expected to provide subject-matter expertise during the metric evaluation, development and implementation processes.

4.2 Metrics Framework

Reliability metrics are linked not only to ALR, but also to the NERC Standards objectives.[37] The table below provides an overview of how each metric is related to the six ALR characteristics and eight Standards objectives.

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

*Approved Metrics

[36] PC and OC letter to solicit feedback for the RMWG at http://www.nerc.com/docs/pc/rmwg/RMWG_Letter_Metrics_Development.pdf.

[37] Other future ALR reliability metrics will be linked to the Standard objectives. Metrics under consideration are available at http://www.nerc.com/docs/pc/rmwg/Currentand_Future_Metric_List.pdf.

4.3 Accountability for Analysis

The metrics provide information expected to prompt NERC, Regional Entities, and other responsible entities to understand the high-level information, and how the data contributes to the results. As described in this report, the RMWG is responsible for developing and maintaining ALR metrics, and will strive to consciously limit any burden on the industry for the data needed for each metric and as part of any data requested by NERC under Section 1600 of the *Rules of Procedure*.[38] As a result, NERC may not have the detailed data required for further analysis to validate its accuracy or completeness, or determine underlying causes. The RMWG may recommend the Operating Committee or Planning Committee undertake initiatives to provide more detailed data and analysis of the metrics.

The Operating Committee or Planning Committee may choose to assign subcommittees, task forces, or working groups to assess the causes of the observed trends and underlying data. As these metrics will be reported at the Regional level, Regional Entities are encouraged to work with the responsible entities through existing collaborative mechanisms to understand the results, and take any necessary action. Reporting entities are responsible for submitting valid data as defined by the metric. No detailed validation will be performed by the RMWG or NERC. It is anticipated that Regional Entities may be interested in understanding how the reported data contributes to overall metrics results, and may take any additional necessary action.

4.4 Review and Validation

The data review and validation is vital to ensure trend analysis to provide meaningful and accurate results. Following the tabulation of data, the results are provided to the Regional Entities for review. This way, the metrics may be validated and areas for improvement and corrections can be identified through information exchange between NERC and the Regional Entities.

[38] The detail of Section 1600 is available at http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20100205.pdf.

5. 2010 Metric Proposals

The result of the RMWG's metric selection process developed in 2009 brings a new list of nine metrics for 2010. These metrics went through the same process of solicitation, ranking, reviewing, and testing. The RMWG requests feedback on the following nine new proposals from the Operating Committee and Planning Committee in June 2010, desiring approval in September 2010.

ALR1-5	System Voltage Performance
ALR1-12	Interconnection Frequency Response
ALR2-3	Activation of Under Frequency or Under Voltage Load Shedding
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 Transmission Outages Initiated by Failed AC Circuit Equipment
ALR6-15	Element Availability Percentage (APC)
ALR6-16	Transmission System Unavailability due to Automatic Outages

This section provides detailed specifications for each metric, including metric description, formula, and data sources. The following are the detailed metric templates for each of these nine proposals.

ALR1-5 System Voltage Performance	
Metric Number	ALR1-5
Submittal Date	May 8,2009
Sponsor Group	RMWG
Short Title	Transmission System Voltage Profile
Metric Description	Measure the transmission system voltage performance over time
Purpose	Measure the transmission system voltage performance (either absolute or per unit of a nominal value) over time which provides an indication of the reactive capability applied to the transmission system. Record the amount of time that system voltage is outside a predetermined band around nominal.
How will it be suited to indicate performance?	Measuring the transmission system voltage level over time provides an indication of the capability of reactive resources (both static and dynamic) applied to the transmission system. Wide fluctuations in voltage levels during off peak to on peak load cycles may indicate inadequate reactive resources necessary to maintain stable voltage profiles.
Formula	At select transmission system nodes (e.g., busses), record node (bus) voltage level in one minute time increments. Record the number of minutes the actual voltage level is outside a predetermined range around nominal. Guidance would be necessary to establish a measurement process. It would be done at a Region level. The Region would define the nodes for measurement and establish the acceptable bandwidth. The Regions would provide the data and results to NERC.
Time Horizon	Real time, operating horizon
Metric Start Time or Baseline	Start when the guidance document has been developed and data is first available
Data Collection Interval and Roll Up	Voltage readings recorded in one minute intervals. Graphs plotted with voltage vs. time for each bus monitored. Number of minute's voltage outside the predetermined range of nominal totaled per reporting period. This would be further developed and documented by Regions.
Ease of Collection	Each Region to designate critical nodes (busses) to monitor and data collected through EMS and/or SCADA system readings. Data archived for reporting on a monthly basis.
Aggregation	Total minutes node (bus) voltage is outside the range of nominal is aggregated per node (bus) and by voltage class. No aggregation possible for actual node (bus) voltage, but critical nodes (busses) can be identified that provide maximum indication of system voltage performance.
Linkage to NERC Standard	VAR-001
Linkage to Data Source	EMS and/or SCADA system data readily available. Recording and storage system may be required but should be available.
Need for Validation or Pilot	No pilot necessary, validation of data and results is critical. Questionnaires were sent to RCWG to define number of busses and specific bandwidths.

Data Submitting Entity	Transmission Operators (TOPs)					
SMART Rating	Total Score 14	Specific/ Simple 3	Measurabl e 3	Attainable 3	Relevant 3	Tangible/ Timely 2
Reporting						
Style (look and feel)	Line graphs of actual values or deviations from nominal. Bar charts for total time outside a range of nominal.					
Publications and Documentation	This metric will be included in NERC RMWG reports					

ALR1-12 Interconnection Frequency Response	
Metric Number	ALR1-12
Submittal Date	June 18, 2009
Sponsor Group (OC, PC or subgroup name)	Resources Subcommittee
Short Title	Interconnection Frequency Response
Metric Description	The metric is to track and monitor Interconnection Frequency Response.
Purpose	There is evidence of continuing decline in Frequency Response in the three Interconnections over the past 10 years, but no confirmed reason for the apparent decline. The metric data trends and analysis will assist in identifying root causes of decline.
How will it be suited to indicate performance?	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.
Formula	Average frequency responses for all events where frequency drops more than 35 MHz within a year
Time Horizon	Historic view
Metric Start Time or Baseline	1999 or when data is first available
Data Collection Interval and Roll Up	Quarterly
Ease of Collection	Available from ARR report[39]
Aggregation	Interconnection
Linkage to NERC Standard	BAL-003
Linkage to Data Source	Resource Adequacy Application
Need for Validation or Pilot	No
Data Submitting Entity	Balancing Authorities

SMART Rating	Total Score	Specific/ Simple	Measurable	Attainable	Relevant	Tangible/ Timely
	11	2	2	2	3	2

Reporting

[39] The CERTS/EPG Automatic Reliability Report (ARR) application provides a summary of historical load-generation, resource adequacy and control performance for the three NERC interconnections (Eastern, Western, and ERCOT).

Style (look and feel)	Line graphs of actual values or deviations from nominal.
Publications and Documentation	This metric will be included in NERC RMWG reports

ALR2-3 Activation of Under Frequency or Under Voltage Load Shedding						
Metric Number	ALR2-3					
Submittal Date	May 8, 2009					
Sponsor Group (OC, PC or subgroup name)	Originally proposed by RMWG-Team 1					
Short Title	UFLS/UVLS Activation					
Metric Description	Number of activation of UFLS and/or UVLS by each region and total MW of load interruption by each region and NERC wide.					
Purpose	The purpose of the Under Frequency or Under Voltage Load Shedding (UFLS or UVLS) is mitigation for when the System does not perform in an acceptable manner after a credible Contingency.					
How will it be suited to indicate performance?	By utilizing a known standard and the value of success, the industry can focus on technically based and practical application based perspective on both reliability metric and operational planning.					
Formula	Number of activation of UFLS and/or UVLS by each region and total MW of load interruption by each region and NERC wide.					
Metric Start Time or Baseline	Start with pilot data for last 10 year (1999 – 2009)					
Time Horizon	Operations					
Data Collection Interval and Roll Up	Yearly					
Ease of Collection	Data is available in Regional Entities per PRC-020 and PRC-006.					
Aggregation	At regional level					
Linkage to NERC Standard	PRC-020 and PRC-006					
Linkage to Data Source	UVLS and UFLS database at each region					
Need for Validation or Pilot	Data pilot and validation are required.					
Data Submitting Entity	Regional Entities					
SMART Rating	Total Score 10	Specific/ Simple 3	Measurable 2	Attainable 1	Relevant 2	Tangible /Timely 2
Reporting						

Style (look and feel)	Line or bar chart
Publications and Documentation	RMWG annual report and Reliability Indicators webpage

ALR6-11 Automatic AC Transmission Outages Initiated by Failed Protection System Equipment	
Metric Number	ALR6-11
Submittal Date	March 31, 2010
Sponsor Group (OC, PC or subgroup name)	NERC
Short Title	AC Transmission Outages - Failed Protection System Equipment
Metric Description	Normalized count (on a per circuit basis) of 200kV and above AC Transmission Element outages (i.e. TADS momentary and sustained Automatic Outages) that were initiated by Failed Protection System Equipment. This metric will use the TADS data and definition of *Failed Protection System Equipment. Transmission Elements* in this metric includes AC Circuits and Transformers.
Purpose	The purpose of this metric is to gauge Failed Protection System Equipment as one of many factors in the performance of AC transmission system Automatic Outages.
How will it be suited to indicate performance?	The normalized count provides an indication of the relative protection system equipment performance, specifically the AC Transmission Element outage rate for momentary and sustained outages initiated by Failed Protection System Equipment. Failed Protection System Equipment is one of the highest causes for initiating automatic transmission system outages.
Formula	Automatic AC Outages initiated by Failed Protection System Equipment = Number of Momentary and Sustained Automatic AC Element Outages initiated by Failed Protection System Equipment / Total Number of AC Elements (AC Circuits or Transformers). For example on a NERC-wide basis the 2008 calculation = 182 / (6653 AC Circuits) = 0.0274 outages per circuit. (Preliminary 2009 calculation = 154 / (6805.7 AC Circuits) = 0.0226 outages per circuit).
Metric Start Time or Baseline	Year 2008 and 2009 TADS data initially and eventually on a 5 year rolling average.
Time Horizon	Historical time frame
Data Collection Interval and Roll Up	The TADS data provides the total number of automatic transmission system outages and the number of outages initiated by failed protection system equipment[40] for 200 kV and above.
Ease of Collection	Data is already being collected via the NERC TADS process.
Aggregation	Results could be presented by normalized counts on a Regional Entity basis, Interconnection basis, or NERC wide basis.
Linkage to NERC Standard	None
Linkage to Data Source	The NERC TADS definitions and data.

[40] TADS Data Reporting Instruction Manual can be viewed at http://www.nerc.com/docs/pc/tadstf/Ph_I_Data_Reporting_Instr_Manual_112108.pdf.

Need for Validation or Pilot	No, the data and results are already being reported via the TADS process.					
Data Submitting Entity	Transmission Owners via TADS procedures.					
SMART Rating	Total Score	Specific/ Simple	Measurable	Attainable	Relevant	Tangible/ Timely
	14	3	3	3	3	2
Reporting						
Style (look and feel)	Bar charts					
Publications and Documentation	The statistics needed to compute this ALR metric are currently shown in the TADS reports. This metric may be included in the annual NERC LTRA report, at the discretion of the NERC Planning Committee.					

ALR6-12 Automatic AC Transmission Outages Initiated by Human Error	
Metric Number	ALR6-12
Submittal Date	March 31, 2010
Sponsor Group (OC, PC or subgroup name)	NERC
Short Title	AC Transmission Outages - Human Error
Metric Description	Normalized count (on a per circuit basis) of 200kV and above AC Transmission Element outages (i.e. TADS momentary and sustained Automatic Outages) that were initiated by Human Error. This metric will use the TADS definition of *Human Error*, which states "Automatic Outages caused by any incorrect action traceable to employees and/or contractors for companies operating, maintaining, and/or providing assistance to the Transmission Owner will be identified and reported in this category. Also, any human failure or interpretation of standard industry practices and guidelines that cause an outage will be reported in this category." *Transmission Elements* in this metric includes AC Circuits and Transformers.
Purpose	The purpose of this metric is to gauge Human Error as one of many factors in the performance of AC transmission system Automatic Outages.
How will it be suited to indicate performance?	The normalized count provides an indication of the relative human factor performance, specifically the AC Transmission Element outage rate for momentary and sustained outages initiated by Human Error. Human Error is one of the highest causes for initiating automatic transmission system outages.
Formula	Automatic AC Outages initiated by Human Error = Number of Momentary and Sustained AC Element Automatic Outages initiated by Human Error / Total Number of AC Elements [AC Circuits or Transformers]. For example on a NERC wide basis the 2008 calculation = 284 / (6653 AC Circuits) = 0.0427 outages per circuit. (Preliminary 2009 calculation = 234 / (6805.7 AC Circuits) = 0.0344 outages per circuit).
Metric Start Time or Baseline	Year 2008 and 2009 TADS data initially and eventually on a 5 year rolling average.
Time Horizon	Historical time frame
Data Collection Interval and Roll Up	The TADS data provides the total number of automatic transmission system outages and the number of outages initiated by Human Error[41] for 200 kV and above.
Ease of Collection	Data is already being collected via the NERC TADS process.
Aggregation	Results could be presented by normalized counts on a Regional Entity basis, Interconnection basis, or NERC wide basis.

[41] TADS Data Reporting Instruction Manual can be viewed at http://www.nerc.com/docs/pc/tadstf/Ph_I_Data_Reporting_Instr_Manual_112108.pdf.

Linkage to NERC Standard	None.
Linkage to Data Source	The NERC TADS definitions and data.
Need for Validation or Pilot	No, the data and results are already being reported via the TADS process.
Data Submitting Entity	Transmission Owners via TADS procedures.

	Total Score	Specific/ Simple	Measurable	Attainable	Relevant	Tangible/ Timely
SMART Rating	14	3	3	3	3	2

Reporting	
Style (look and feel)	Bar charts
Publications and Documentation	The statistics needed to compute this ALR metric are currently shown in the TADS reports. This metric may be included in the annual NERC LTRA report, at the discretion of the NERC Planning Committee.

ALR6-13 Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment	
Metric Number	ALR6-13
Submittal Date	March 31, 2010
Sponsor Group (OC, PC or subgroup name)	NERC
Short Title	AC Transmission Outages – Failed AC Substation Equipment
Metric Description	Normalized count (on a per circuit basis) of 200kV and above AC Transmission Element outages (i.e. TADS momentary and sustained Automatic Outages) that were initiated by failed AC substation equipment. This metric will use the TADS definition of "*Failed AC Substation Equipment*", which states "Automatic Outages caused by the failure of AC Substation; i.e., equipment "inside the substation fence" including Transformers and circuit breakers but excluding Protection System equipment. The TADS definition of "*AC Substation*" states "An AC Substation includes the circuit breakers and disconnect switches which define the boundaries of an AC Circuit, as well as other facilities such as surge arrestors, buses, transformers, wave traps, motorized devices, grounding switches, and shunt capacitors and reactors. Series compensation (capacitors and reactors) is part of the AC Substation if it is not part of the AC Circuit. See the explanation in the definition of "AC Circuit." Protection System equipment is excluded." *Transmission Elements* in this metric include AC Circuits and Transformers.
Purpose	The purpose of this metric is to gauge failed substation equipment as one of many factors in the performance of transmission system Automatic Outages.
How will it be suited to indicate performance?	The normalized count provides an indication of the relative substation equipment performance, specifically the AC Transmission Element outage rate for momentary and sustained outages initiated by AC substation equipment. AC substation equipment is one of the highest causes for initiating automatic transmission system outages.
Formula	Automatic AC Outages initiated by Failed AC Substation Equipment = Number of Momentary and Sustained Automatic AC Element Outages initiated by Failed AC Substation Equipment / Total Number of AC Elements (AC Circuits or Transformers). For example on a NERC-wide basis the 2008 calculation = 328 / (6605 AC Circuits) = 0.05 outages per circuit. (Preliminary 2009 calculation = 305 / (6756.7 AC Circuits) = 0.05 outages per circuit).
Metric Start Time or Baseline	Year 2008 and 2009 TADS data initially and eventually a 5 year rolling average.
Time Horizon	Historical time frame
Data Collection Interval and Roll Up	The TADS data provides the total number of automatic transmission system outages and the number of outages initiated by Failed AC Substation Equipment[42] for 200 kV and above.

[42] TADS Data Reporting Instruction Manual can be viewed at http://www.nerc.com/docs/pc/tadstf/Ph_I_Data_Reporting_Instr_Manual_112108.pdf.

Ease of Collection	Data is already being collected via the NERC TADS process.
Aggregation	Results could be presented by normalized counts on a Regional Entity basis, Interconnection basis, or NERC wide basis.
Linkage to NERC Standard	None
Linkage to Data Source	The NERC TADS definitions and data.
Need for Validation or Pilot	No, the data and results are already being reported via the TADS process.
Data Submitting Entity	Transmission Owners via TADS procedures.

	Total Score	Specific/ Simple	Measurable	Attainable	Relevant	Tangible/ Timely
SMART Rating	14	3	3	3	3	2

Reporting	
Style (look and feel)	Bar charts
Publications and Documentation	The statistics needed to compute this ALR metric are currently shown in the TADS reports. This metric may be included in the annual NERC LTRA report, at the discretion of the NERC Planning Committee.

ALR6-14 Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment	
Metric Number	ALR6-14
Submittal Date	April 12, 2010
Sponsor Group (OC, PC or subgroup name)	NERC
Short Title	AC Transmission Outages – Failed AC Circuit Equipment
Metric Description	Normalized count (on a per 100 circuit-mile basis) of 200kV and above AC Transmission Element outages (i.e. TADS momentary and sustained Automatic Outages) that were initiated by failed AC circuit equipment. This metric will use the TADS definition of "*Failed AC Circuit Equipment*", which states "Automatic Outages related to the failure of AC Circuit equipment, i.e., overhead or underground equipment 'outside the substation fence.' Refer to the TADS definition of "*AC Circuit*", which states "A set of AC overhead or underground three-phase conductors that are bound by AC Substations. Radial circuits are AC Circuits." *Transmission Elements* in this metric include AC Circuits only.
Purpose	The purpose of this metric is to gauge failed AC circuit equipment as one of many factors in the performance of transmission system Automatic Outages.
How will it be suited to indicate performance?	The normalized count provides an indication of the relative transmission circuit equipment performance, specifically the AC Transmission Element outage rate for momentary and sustained outages initiated by AC circuit equipment. AC circuit equipment is one of the highest causes for initiating automatic transmission system outages.
Formula	Automatic AC Outages caused by Failed AC Circuit Equipment = Number of Momentary and Sustained Automatic AC Element Outages initiated by Failed AC Circuit Equipment / Total Number of AC Elements (AC Circuits or Transformers). For example on a NERC-wide basis the 2008 calculation = 326 / (6605 AC Circuits) = 0.05 outages per circuit. (Preliminary 2009 calculation = 277 / (6756.7 AC Circuits) = 0.04 outages per circuit).
Metric Start Time or Baseline	Year 2008 and 2009 TADS data initially and eventually a 5 year rolling average.
Time Horizon	Historical time frame
Data Collection Interval and Roll Up	The TADS data provides the total number of automatic transmission system outages and the number of outages initiated by Failed AC Circuit Equipment[43] for 200 kV and above.
Ease of Collection	Data is already being collected via the NERC TADS process.
Aggregation	Results could be presented by normalized counts on a Regional Entity basis, Interconnection basis, or NERC wide basis.
Linkage to NERC Standard	None

[43] TADS Data Reporting Instruction Manual can be viewed at http://www.nerc.com/docs/pc/tadstf/Ph_I_Data_Reporting_Instr_Manual_112108.pdf.

<table>
<tr><td>Linkage to Data Source</td><td colspan="6">The NERC TADS definitions and data.</td></tr>
<tr><td>Need for Validation or Pilot</td><td colspan="6">No, the data and results are already being reported via the TADS process.</td></tr>
<tr><td>Data Submitting Entity</td><td colspan="6">Transmission Owners via TADS procedures.</td></tr>
<tr><td rowspan="2">SMART Rating</td><td>Total Score</td><td>Specific/ Simple</td><td>Measurable</td><td>Attainable</td><td>Relevant</td><td>Tangible/ Timely</td></tr>
<tr><td>14</td><td>3</td><td>3</td><td>3</td><td>3</td><td>2</td></tr>
<tr><th colspan="7">Reporting</th></tr>
<tr><td>Style (look and feel)</td><td colspan="6">Bar charts</td></tr>
<tr><td>Publications and Documentation</td><td colspan="6">The statistics needed to compute this ALR metric are currently shown in the TADS reports. This metric may be included in the annual NERC LTRA report, at the discretion of the NERC Planning Committee.</td></tr>
</table>

ALR6-15 Element Availability Percentage (APC)	
Metric Number	ALR 6-15
Submittal Date	May 8, 2009
Sponsor Group (OC, PC or subgroup name)	SERC Reliability Corporation
Short Title	
Metric Description	Overall percent of time the aggregate of transmission system facilities (i.e., AC lines and transformers operated at 200 kV and above) are available for service. This includes outages caused by both automatic and non-automatic events. Momentary outages are not included in this calculation.
Purpose	To determine the percent of time that the transmission system operated at 200 kV and above is available when outages due to automatic and non-automatic events are considered. This value may be trended over time to gauge increasing or decreasing performance.
How will it be suited to indicate performance?	The overall availability is the percentage of time the transmission system is available (i.e., in service) for the transmission of electricity. The relative percentage provides an indication of the overall availability of the transmission system operated at 200 kV and above, which indicates reliability performance.
Formula	The percent of time the interconnected transmission system (AC circuits and transformers) operated at 200 kV and above is available due to sustained automatic and non-automatic outages, is calculated as follows: $\text{APC (in \%)} = \left(1 - \frac{\text{Total Sustained Outage Hours}}{\text{Total Element Hours}}\right) \times 100$ where, The APC, the Total Sustained Outage Hours and the Total Element Hours are defined and calculated in the TADS report[44].
Time Horizon	Historical perspective
Metric Start Time or Baseline and Roll Up	Year 2010, the first year of TADS data collection that includes Non-automatic outages
Data Collection Interval and Roll Up	Data collection is through the NERC TADS procedure. Metric calculation is one value for each Interconnection (Eastern, Western, Texas, and Québec) for the aggregate of facilities 200 kV and above. The metric would be reported on the same interval as TADS reports.

[44] The APC is defined on page 20 of the 2009 TADS Phase II Final Report, available at http://www.nerc.com/docs/pc/tadstf/TADS_Phase_II_Final_Report_091108.pdf.

Ease of Collection	The TADS database makes this metric easily reportable on a uniform basis.					
Aggregation	Reported on an aggregate basis by Regional Entity, Interconnection (Eastern, Western, Texas, and Québec) and NERC.					
Linkage to NERC Standard	None					
Linkage to Data Source	NERC TADS data base http://www.nerc.com/docs/pc/tadswg/Data_Reporting_Instr_Manual_09-29-09.pdf					
Need for Validation or Pilot	No, the data and results will be reported via the TADS process when it becomes available. [Note: The former ECAR, MAIN, and MAPP regions had collected and reported similar data and statistics in the past and could be used for reference.]					
Data Submitting Entity	Transmission Owner via TADS reporting procedure					
SMART Rating	Total Score	Specific/ Simple	Measurable	Attainable	Relevant	Tangible/ Timely
	13	3	3	3	2	2
Reporting						
Style (look and feel)	Bar charts, with possible trend lines added in the future					
Publications and Documentation	This metric is defined in TADS report as well and will be tracked in NERC metrics reports.					

ALR6-16 Transmission System Unavailability due to Automatic Outages	
Metric Number	ALR6-16
Submittal Date	May 8, 2009
Sponsor Group (OC, PC or subgroup name)	SERC Reliability Corporation
Short Title	Transmission System Unavailability due to Automatic Outages
Metric Description	Overall percent of time the aggregate of transmission system facilities (i.e., AC circuits and transformers 200 kV and above) are unavailable for service (out of service) due to sustained automatic outages. Planned outages are not included in this metric. Momentary outages would not be included in this calculation.
Purpose	To determine the percent of time that the transmission system operated at 200 kV and above is unavailable due to sustained automatic outages. This value may be trended over time to gauge increasing or decreasing performance.
How will it be suited to indicate performance?	The unavailability is the percentage of time the entire transmission system is not available (i.e., out of service) for the transmission of electricity due to sustained automatic outages. The relative percentage provides an indication of the overall unavailability of the transmission system operated at 200 kV and above, which indicates reliability performance.
Formula	The percent of time the interconnected transmission system (AC circuits and transformers) operated at 200 kV and above is unavailable due to sustained automatic outages is calculated as follows: $\text{Unavailability (in \%)} = \dfrac{\text{Total hours out-of-service due to automatic outages}}{\text{Total facility-hours}} \times 100$ where, Total facility-hours = hours in a year X number of facilities reported Total hours out-of-service = A summation of the hours out-of-service during the year for all of the facilities (i.e. AC circuits and transformers) Example: For a year with 365 days (or 8,760 hours) and a system with 90 facilities (AC circuits and transformers) that had 5,000 total facility-hours out-of-service due to sustained automatic outages, Total facility-hours = (8,760 hours in a year) X (90 facilities) = 788,400 $\text{Unavailability} = \dfrac{5{,}000}{788{,}400} \times 100 = 0.63\%$
Time Horizon	Historical perspective

<table>
<tr><td>Metric Start Time or Baseline and Roll Up</td><td colspan="6">Year 2008, the first year of TADS</td></tr>
<tr><td>Data Collection Interval and Roll Up</td><td colspan="6">Data collection is through the NERC TADS procedure. Metric calculation is one value for each Interconnection (Eastern, Western, Texas, and Québec) for the aggregate of facilities 200 kV and above. The metric would be reported on the same interval as TADS reports.</td></tr>
<tr><td>Ease of Collection</td><td colspan="6">The TADS database makes this metric easily reportable on a uniform basis.</td></tr>
<tr><td>Aggregation</td><td colspan="6">Reported on an aggregate basis by Regional Entity, Interconnection (Eastern, Western, Texas, and Québec) and NERC.</td></tr>
<tr><td>Linkage to NERC Standard</td><td colspan="6">None</td></tr>
<tr><td>Linkage to Data Source</td><td colspan="6">NERC TADS database
http://www.nerc.com/docs/pc/tadswg/Data_Reporting_Instr_Manual_09-29-09.pdf</td></tr>
<tr><td>Need for Validation or Pilot</td><td colspan="6">No, the data and results is already being reported via the TADS process. [Note: The former ECAR, MAIN, and MAPP regions had collected and reported similar data and statistics in the past and could be used for reference.]</td></tr>
<tr><td>Data Submitting Entity</td><td colspan="6">Transmission Owner via TADS reporting procedure</td></tr>
<tr><td rowspan="2">SMART Rating</td><td>Total Score</td><td>Specific/ Simple</td><td>Measurable</td><td>Attainable</td><td>Relevant</td><td>Tangible/ Timely</td></tr>
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<tr><th colspan="7">Reporting</th></tr>
<tr><td>Style (look and feel)</td><td colspan="6">Bar charts, with possible trend lines added in the future</td></tr>
<tr><td>Publications and Documentation</td><td colspan="6">This metric is recommended to be added to the NERC TADS report and included in NERC metrics reports.</td></tr>
</table>

Appendix I: Considered But Not Advanced Metrics

The following eleven metrics were considered, but not advanced for implementation in 2010:

Considered But Not Advanced	
Metric Name	**Reasons**
Average Frequency	Summary
Daily Frequency Outliers Noise	Summary
Breaker Failures	Summary
Exposure to Cascading	Summary
Magnitude of IROL Exceedance	Summary
Simultaneous EEAs	Summary
Simultaneous TLRs	Summary
Integral of Negative Frequency Excursions	Summary
LMP Divergence	Summary
Maintaining The Required Amount of Reserve	Summary
SPS Operation	Summary

Appendix II: RMWG Scope

Purpose and Deliverables

The Group will provide input to and support the objectives of the NERC Reliability Assessment and Performance Analysis Program[45], including the development and improvement of NERC's risk indices and key reliability metrics. Specific activities will include:

1. Develop general metrics[46] measuring the characteristics of an Adequate Level of Reliability (ALR);[47]
2. Develop and implement a risk-based approach to assess reliability trends;
3. Define and report reliability measures and risk assessments including formulae or methods for identification and calculations;
4. Define data collection and reporting guidelines;
5. Publish quarterly website updates and annual report on bulk power system reliability metrics.

The Group will report its progress at each joint meeting of the Operating Committee (OC) and Planning Committee (PC).

Membership

- NERC will seek membership from industry experts in operations, planning, and risk assessment including members from OC and PC, in the areas of performance metrics, benchmarking and risk analysis, with final selection agreed to by the chairs of the OC and PC.
- Members must be willing to commit their time to participate in the Group's discussions, including the development of reports.

Governance

The Group reports to the OC and PC. The OC and PC will endorse the recommendations by the Group of reliability measures and risk-based assessments, data collection guidelines and the implementation plan. The OC and PC will review the scope and need for the group every two years. The Group Chair is appointed by the OC and PC chair.

Meetings

Meetings and conference calls as needed.

[45] Defined in Section 806 of the NERC *Rules of Procedure*, available at http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20100205.pdf
[46] Metrics covering both operations (real-time) and future reliability.
[47] http://www.nerc.com/files/Adequate_Level_of_Reliability_Definition_05052008.pdf

Appendix III: Coordination and Outreach Efforts

RMWG Coordination and Outreach Efforts	
Committee	**Subgroup**
Operating Committee	Operating Reliability Subcommittee
	Resource Subcommittee
	Reliability Coordinator Working Group
	Reliability Fundamentals Working Group
Planning Committee	Reliability Assessment Subcommittee
	Resource Issues Subcommittee
	Transmission Issues Subcommittee
	System Protection and Control Subcommittee
	Transmission Availability Data System Task Force
	Data Coordination Subcommittee
	Demand Response Data Task Force
	Integration of Variable Generation Task Force
	G and T Reliability Planning Models Task Force
Standards Committee	
Transmission Forum	
Canadian Electricity Association	

Appendix IV: RMWG Roster

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Appendix V: Abbreviations Used in This Report

Abbreviations	
ALR	Adequate Level of Reliability
ARR	Automatic Reliability Report
BA	Balancing Authority
BPS	Bulk Power System
CEII	Critical Energy Infrastructure Information
DCS	Disturbance Control Standard
DOE	Department Of Energy
EA	Event Analysis
ECAR	East Central Area Reliability
EEA	Energy Emergency Alert
EMS	Energy Management System
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
ESAI	Energy Security Analysis, Inc.
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GOP	Generation Operator
IEEE	Institute of Electrical and Electronics Engineers
IESO	Independent Electricity System Operator
IROL	Interconnection Reliability Operating Limit
LOLE	Lost of Load Expectation
MAIN	Mid-America Interconnected Network, Inc
MAPP	Mid-continent Area Power Pool
MRO	Midwest Reliability Organization
MSSC	Most Severe Single Contingency
NEAT	NERC Event Analysis Tool
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OC	Operating Committee
OL	Operating Limit
PC	Planning Committee
RC	Reliability Coordinator
RCIS	Reliability Coordination Information System
RCWG	Reliability Coordinator Working Group
RE	Regional Entities
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
SERC	South Eastern Electric Reliability Council
SMART	Specific, Measurable, Attainable, Relevant and Tangible
SOL	System Operating Limit
SPP	Southwest Power Pool
TADS	Transmission Availability Data System
TADSWG	Transmission Availability Data System Working Group
TOP	Transmission Operator