NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

BAL-002-2 Background Document

September~~July~~ 2015

RELIABILITY | ACCOUNTABILIT




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Introduction

The revision to NERC Policy Standards in 1996 created a Disturbance Control Standard (DCS). It replaced B1 [Area Control Error (ACE) must return to zero within 10 minutes following a disturbance] and B2 (ACE must start to return to zero in 1 minute following a disturbance) with a standard that states: ACE must return to either zero or a pre-disturbance value of ACE within 15 minutes following a reportable disturbance. Balancing Authorities were required to report all disturbances equal to or greater than 80% of the Balancing Authority's Most Severe Single Contingency (MSSC).

BAL-002 was created to replace portions of Policy 1. It measures the ability of an applicable entity to recover from a reportable event with the deployment of reserve. The reliable operation of the interconnected power system requires that adequate capacity and energy be available to maintain scheduled frequency and avoid loss of firm load following loss of transmission or generation contingencies. This capacity (Contingency Reserve) is necessary to replace capacity and energy lost due to forced outages of generation or transmission equipment. The design of BAL-002 and Policy 1 was predicated on the Interconnection's operating under normal conditions, and the requirements of BAL-002 assured recovery from single contingency (N-1) events.

This document provides background on the development and implementation of BAL-002-2 - Contingency Reserve for Recovery from a Balancing Contingency Event. This document explains the rationale and considerations for the requirements and their associated compliance information. BAL-002-2 was developed to fulfill the NERC Balancing Authority Controls (Project 2007-05) Standard Authorization Request (SAR), which includes the incorporation of the FERC Order 693 directives. The original SAR, approved by the industry, presumes there is presently sufficient Contingency Reserve in all the North American Interconnections. The underlying goal of the SAR was to update the standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group, such that the parties would better understand the use of Contingency Reserve to balance resources and demand following a Reportable Balancing Contingency Event.

Currently, the existing BAL-002-1 standard contains Requirements specific to a Reserve Sharing Group which the drafting team believes are commercial in nature and a contractual arrangement between the reserve sharing group parties. BAL-002-2 is intended to measure the successful deployment of contingency reserve by responsible entities. Relationships between the entities should not be part of the performance requirements, but left up to a commercial transaction.

Clarity and specifics are provided with several new definitions. Additionally, the BAL-002-2 eliminates any question about who is the applicable entity and assures that the applicable entity is held responsible for the performance requirement. The drafting team's goal was to have BAL-002-2 be solely a performance standard. The primary objective of BAL-002-2 is to ensure that the applicable entity is prepared to balance resources and demand and to return its ACE to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

As proposed, this standard is not intended to address events greater than a Responsible Entity's Most Severe Single Contingency. These large multi-unit events, although unlikely, do occur. Many interactions occur during these events and Balancing Authorities (BAs) and Reserve Sharing Groups must react to these events. However, requiring a recovery of ACE within a specific time period is much too simple a methodology to adequately address all of these interactions. The suite of NERC Standards work together to ensure that the Interconnections are operated in a safe and reliable manner. It is not just one standard, rather it is the combination of the BAL-001-2 standard (in which R2 requires operation within an ACE bandwidth based on interconnection frequency), TOP-007, and EOP-002, which collectively address issues when large events occur.

- The Balancing Authority ACE Limit (BAAL) in R2 of BAL-001-2 looks at Interconnection frequency to provide the BA a range in which the BA should strive to operate as well as a 30-minute period to address instances when the BA is outside of that range. If an event larger than the BA's MSSC occurs, the BAAL will likely change to a much tighter control limit based on the change in interconnection frequency. The 30-minute limit under the BAAL allows the BA (and its RC) time to quickly evaluate the best course of action and then react in a reasonable manner. BAAL also ensures the Responsible Entity balances resources and demand when events occur of less magnitude than a Reportable Balancing Contingency. In addition R1 of BAL-001-2 requires the BA to respond to assure Control Performance Standard 1 (CPS1) is met. This may prompt the BA to respond in some circumstances in less than 10 minutes.
- The TOP-007 standard addresses transmission line loading. Members of the BAL-002-2 drafting team are aware of instances (typically N-2 or less) that could cause transmission overloads if certain units were lost and reserves responded.
- Under EOP-002, if the BA does not believe that it can meet certain parameters, different rules are implemented.

Because of the potential for significant unintended consequences that could occur under a requirement to activate all reserves, the drafting team recommends to the industry that the revised BAL-002-2 address only events which are planned for (N-1) and not any loss of resource(s) that would exceed MSSC. Therefore, the definitions and Requirements under BAL-002-2 exclude events greater than the MSSC. This provides clarity of Requirements, supports reliable operation of the Bulk Electric System and allows other standards to address events of greater magnitude and complexity.

Within NERC's State of Reliability Report, ALR2-5 "Disturbance Control Events Greater Than the Most Severe Single Contingency" has been tracked and reported since 2006. For the period 2006 to 2011 there were 90 disturbance events that exceeded the MSSC, with the highest in any given year being 24 events. Evaluation of the data illustrates events greater than MSSC occur very infrequently, and the drafting team believes their exclusion will not have any adverse impact on reliability.

The metric reports the number of DCS events greater than MSSC, regardless of the size of a Balancing Authority or RSG and of the number of reporting entities within a Regional Entity. A small Balancing Authority or RSG may have a relatively small MSSC. As such, a high number of DCS events greater than MSSC may not indicate a reliability problem for the reporting Regional Entity, but may indicate an issue for the respective Balancing Authority or RSG. In addition, events greater than MSSC may not cause a reliability issue for a BA, RSG or Regional Entity that has more stringent standards which require contingency reserve greater than MSSC.

Background

Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

Balancing Contingency Event

BAL-002-2 applies during real-time operations to ensure the Balancing Authority or Reserve Sharing Group balance resources and demand by returning its Area Control Error to defined values following a Reportable Balancing Contingency Event.

The drafting team included a specific definition for a Balancing Contingency Event to eliminate any confusion and ambiguity. The prior version of BAL-002 was broad and could be interpreted in various ways leaving the ability to measure compliance in the eye of the beholder. Including the specific definition allows the Responsible Entity to fully understand how to perform and meet compliance. Also, FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation. By developing a specific definition that depicts the events causing an unexpected change to the Responsible Entity's ACE, the necessary response requirements assure the intent of the FERC requirement is met.

The definitions of Reportable Balancing Contingency Event and Contingency Event Recovery Period work together to specify the timing requirements for recoveries from Reportable Balancing Contingency Events. A Balancing Contingency Event that is not a Reportable Balancing Contingency Event may impact the compliance requirement for the Reportable Balancing Contingency Event which occurs after it, because the megawatts lost for both may exceed the Most Severe Single Contingency. Also, a subsequent Balancing Contingency Event may occur during the Contingency Event Recovery Period of a Reportable Balancing Contingency Event, affecting the ACE recovery requirement of the initial event. The drafting team struggled with associating any specific time window for the megawatt loss to occur within for an event to qualify as a Balancing Contingency Event. The term sudden implies an unexpected occurrence in the definition of a Balancing Contingency Event, and the Responsible Entity should use its best judgment in applying any time criterion to Balancing Contingency Events that do not qualify as Reportable Balancing Contingency Events.

Most Severe Single Contingency

The Most Severe Single Contingency (MSSC) term has been widely used within the industry; however, it has never been defined. In order to eliminate a wide range of definitions, the drafting team has included a specific definition designed to fulfill the needs of the standard. In addition, in order to meet FERC Order No. 693 (at P356), to develop a continent-wide contingency reserve policy, it was necessary to establish a definition of MSSC.

When an entity determines its MSSC, the review needs to include the largest loss of resource that might occur for either generation or transmission loss. If the loss of transmission causes the loss of generation and load, the size of that event would be the net change. Since the size of an event where both load and generation are lost due to the loss of the transmission would be less than just the loss of the generator, this event is unlikely to be the entity’s MSSC. Also, note here that the drafting team removed the previous requirement to review the MSSC at least annually. An entity should know what its MSSC is at all times. Therefore, an annual review is no longer required

Contingency Reserve

Most system operators generally have a good understanding of the need to balance resources and demand and return their Area Control Error to defined values following a Reportable Balancing Contingency Event. However, the existing Contingency Reserve definition is focused primarily on generation and not sufficiently on Demand-Side Management (DSM). In order to meet FERC Order No. 693 (at P 356) to include a requirement that explicitly allows DSM to be used as a resource for contingency reserve, the drafting team elected to expand the definition of Contingency Reserve to explicitly include capacity associated with DSM.

Additionally, conflict existed between BAL-002 and EOP-002 as to when an entity could deploy or restore its contingency reserve. EOP-002 also applies during the real-time operations time horizon and addresses capacity and energy emergencies. Given that an entity and/or event can transition suddenly from normal operations (BAL-002) into emergency operations (EOP-002), this transitional seam must be explicitly addressed in order to provide clarity to responsible entities regarding the actions to be taken.

To eliminate the possible conflict and to assure BAL-002 and EOP-002 work together and complement each other, the drafting team clarified the existing definition of Contingency Reserve. The conflict arises since the actions required by Energy Deficient Entities before declaring either an Energy Emergency Alert 2 or an Energy Emergency Alert 3 include deployment of all Operating Reserve which includes Contingency Reserve. Conversely, an Energy Deficient Entity may need to declare either an Energy Emergency Alert 2 or an Energy Emergency Alert 3, before incurring a Balancing Contingency Event. The definition of Contingency Reserve now allows for deploying capacity to respond to a Balancing Contingency Event and other contingency requirements such as Energy Emergency Alerts. Readiness to reduce Firm Demand during the Contingency Reserve Restoration Period during an Energy Emergency Alert should another Contingency Event occur is proposed for inclusion in the definition of Contingency Reserve. The Responsible Entity should have processes and procedures for direct control over the Firm Demand in place for it to be considered Contingency Reserves prior to the event during an Energy Emergency Alert.

For additional technical justification for exemption from R1 to facilitate transitioning from normal operations into emergency operations please refer to Attachment 2.

Reserve Sharing Group Reporting ACE

The drafting team elected to include this definition to provide clarity for measurement of compliance of the appropriate Responsible Entity. Additionally, this definition is necessary since the drafting team has eliminated R5.1 and R5.2 that are in the existing standard. R5.1 and R5.2 mix definitions with performance. The drafting team has included all the performance requirements in the proposed standards R1 and R2, and therefore has added the definition of Reserve Sharing Group Reporting ACE.

Other Definitions

Other definitions have been added or modified to assure clarification within the standard and requirements.

Rationale by Requirement

Requirement 1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall:

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if:

1.3..1 the Responsible Entity ~~is~~:

- is a Balancing Authority experiencing a Reliability Coordinator declared Energy Emergency Alert Level or is a Reserve Sharing Group whose member, or members, are experiencing a Reliability Coordinator declared Energy Emergency Alert level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- ~~the Responsible Entity~~ has depleted its Contingency Reserve to a level below its Most Severe Single Contingency

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

Background and Rationale

Requirement R1 reflects the operating principles first established by NERC Policy 1. Its objective is to assure the Responsible Entity balances resources and demand and returns its Reportable Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

By including new definitions, and modifying existing definitions, and the above R1, the drafting team believes it has successfully fulfilled the requirements of FERC Order No. 693 (at P 356) to include a requirement that explicitly allows DSM to be used as a resource for Contingency Reserve. It also recognizes that the loss of transmission as well as generation may require the deployment of Contingency Reserve.

Additionally, R1 is designed to assure the applicable entity uses reserve to cover a Reportable Balancing Contingency Event or the combination of any previous Balancing Contingency Events that have occurred within the specified period, to address the Order's concern that the applicable entity is responding to events and performance is measured. The Reportable Balancing Contingency Event definition, along with R1, allows for measurement of performance.

In addition, the standard drafting team (SDT) through R1 Part 1.3 has clearly identified when R1 is not applicable. By including R1 Part 1.3.1, the proposed standard eliminates the existing conflict with the EOP Standards and further addresses the outstanding interpretation. By clearly stating when R1 is not applicable or does not apply, it eliminates any auditor interpretation and allows the Responsible Entity to perform the function in a reliable manner. Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to load while managing reliability. Also, the SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

The drafting team used data supplied by the Consortium for Electric Reliability Technology Solutions (CERTS) to help determine all events that have an impact on frequency. Data that was compiled by CERTS to provide information on measured frequency events is presented in Attachment 1. Analyzing the data, reveals events of 100 MW or greater would capture all frequency events for all interconnections. However, at a 100 MW reporting threshold, the number of events reported would significantly increase with no reliability gain since 100 MW is more reflective of the outlying events, especially on larger interconnections.

The goal of the drafting team was to design a continent-wide standard to capture the majority of the events that impact frequency. After reviewing the data and industry comments, the SDT elected to establish reporting threshold minimums for each respective Interconnection. This assures the requirements of FERC Order No. 693 are met. The reportable threshold was selected as the lesser of 80% of the applicable entity's Most Severe Single Contingency or the following values for each respective Interconnection:

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Additionally, the drafting team used only loss of resource events for purposes of determining the above thresholds.

Violation Severity Levels

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the percentage of desired recovery achieved.

Compliance Calculation

It is important to note that R1 adjusts the required recovery value of Reporting ACE for any other Balancing Contingency Events that occur during the Contingency Event Recovery Period. However, to determine compliance score for compliance with R1, the measured contingency reserve response (instead of the required recovery value of Reporting ACE) is adjusted for any other Balancing Contingency Events that occur during the Contingency Event Recovery Period. Both methods of adjustment are mathematically equivalent. Accordingly, the measured contingency reserve response is computed and compared with the MW lost as follows (assuming all resource loss values, i.e. Balancing Contingency Events, are positive) to measure compliance[1]:

- The measured contingency reserve response is equal to one of the following:

[1] In adjusting for the adverse impact of rapidly succeeding (i.e. "near") Events on a Responsible Entity's Recovery from an Event, the SDT thought it more prudent to adjust for future near Events rather than for past near Events because the future Events place an added burden on performance, while adjusting for the past Events instead lowers the performance requirement. To adjust for both future and past Events amounts to double dealing because an Event is subsequent to a prior near Event, and both Events would be serving to relieve Recovery from each other. The SDT allowed only for the extreme case of exempting from recovery prior near Events that combined exceed MSSC.

- If the Pre-Reportable Contingency Event ACE Value is greater than or equal to zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of the subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event.
- If the Pre-Reportable Contingency Event ACE Value is less than zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event, minus (d) the Pre-Reportable Contingency Event ACE Value.

- Compliance is computed as follows on CR Form 1 in order to document all Balancing Contingency Events used in compliance determination:
  - If the measured contingency reserve response is greater than or equal to the megawatts lost, then the Reportable Balancing Contingency Event Compliance equals 100 percent.
  - If the measured contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 0 percent.
  - If the measured contingency reserve response is less than the megawatts lost but greater than zero, then the Reportable Balancing Contingency Event Compliance equals 100% * (1 – ((megawatts lost – measured contingency reserve response) / megawatts lost)).

The above computations can be expressed mathematically in the following 5 sequential steps, labeled as [1-5], where:

ACE_BEST – most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)

ACE_PRE - Pre-Reportable Contingency Event ACE Value (MW)

COMPLIANCE - Reportable Balancing Contingency Event Compliance percentage (0 - 100%)

MEAS_CR_RESP - measured contingency reserve response for the Reportable Balancing Contingency Event (MW)

MSSC – Most Severe Single Contingency (MW)

MW_LOST - megawatt loss of the Reportable Balancing Contingency Event (MW)

SUM_SUBSQ - sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event (MW)

If ACE_PRE is greater than or equal to 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ **[1]**

If ACE_PRE is less than 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ – ACE_PRE **[2]**

If MEAS_CR_RESP is greater than or equal to MW_LOST, then

COMPLIANCE = 100 **[3]**

If MEAS_CR_RESP is less than or equal to 0, then

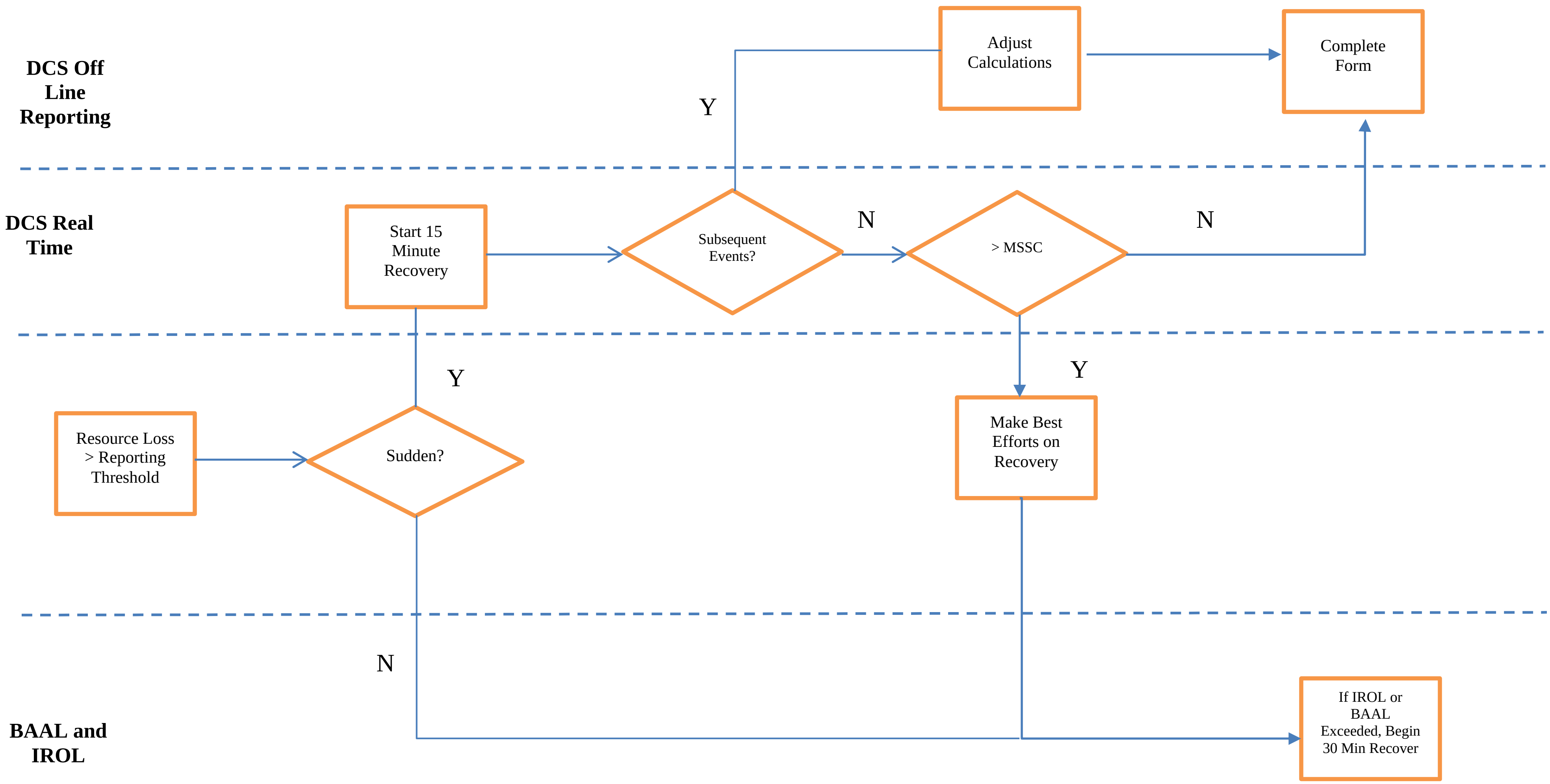
COMPLIANCE = 0 **[4]**

If MEAS_CR_RESP is greater than 0, and, MEAS_CR_RESP is less than MW_LOST, then

COMPLIANCE = 100 * (1 – ((MW_LOST – MEAS_CR_RESP)/ MW_LOST)) **[5]**

The Decision Tree flow diagram for DCS below, provides a visualization of the logic flow for a Reportable Balancing Contingency Event. It includes decision blocks for initial event determination, subsequent event determination, and checking for MSSC exceedance which should assist the Responsible Entity with Event Recovery and analysis.

Decision Tree for DCS



Requirement 2

R2. Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability.

Background and Rationale

R2 establishes a uniform continent-wide contingency reserve policy in the form of a requirement that a Responsible Entity implement an Operating Plan that assures Contingency Reserve be at least equal to the applicable entity's Most Severe Single Contingency and a definition of Most Severe Single Contingency. Its goal is to assure that the Responsible Entity will have sufficient Contingency Reserve that can be deployed to meet R1.

FERC Order 693 (at P356) directed BAL-002 to be developed as a continent-wide contingency reserve policy. R2 fulfills the requirement associated with the required amount of contingency reserve a Responsible Entity must have available to respond to a Reportable Balancing Contingency Event. Within FERC Order 693 (at P336) the Commission noted that the appropriate mix of operating reserve, spinning reserve and non-spinning reserve should be addressed. However, the Order predated the approval of the new BAL-003, which addresses frequency responsive reserve and the amount of frequency response obligation. With the development of BAL-003, and the associated reliability performance requirement, the SDT believes that, with R2 of BAL-002 and the approval of BAL-003, the Commission's goals of a continent-wide contingency reserves policy is met. The suites of BAL standards (BAL-001, BAL-002, and BAL-003) are all performance-based. With the suite of standards and the specific requirements within each respective standard, a continent-wide contingency policy is established.

The Responsible Entity's Operating Plan will address the process by which Contingency Reserves greater than or equal to the Most Severe Single Contingency are available in Real-time. Once an entity utilizes its contingency reserve, Requirement R3 addresses restoration of the reserves.

Requirement 3

R3. Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration period resets the beginning of the Contingency Event Recovery Period.

Background and Rationale

Requirement R3 establishes the restoration of Contingency Reserves following Reportable Balancing Contingency Events. This requirement addresses the need to be prepared for future Balancing Contingency Events. Contingency Reserves must be restored to at least the minimum required amount, the Most Severe Single Contingency, to assure that the next event for which an entity plans is expected to be covered if the event occurs. Contingency Reserves must be restored within the Contingency Reserve Restoration Period which is defined as a period not exceeding 90 minutes following the end of the Contingency Event Recovery Period, which is 15 minutes.

Attachment 1

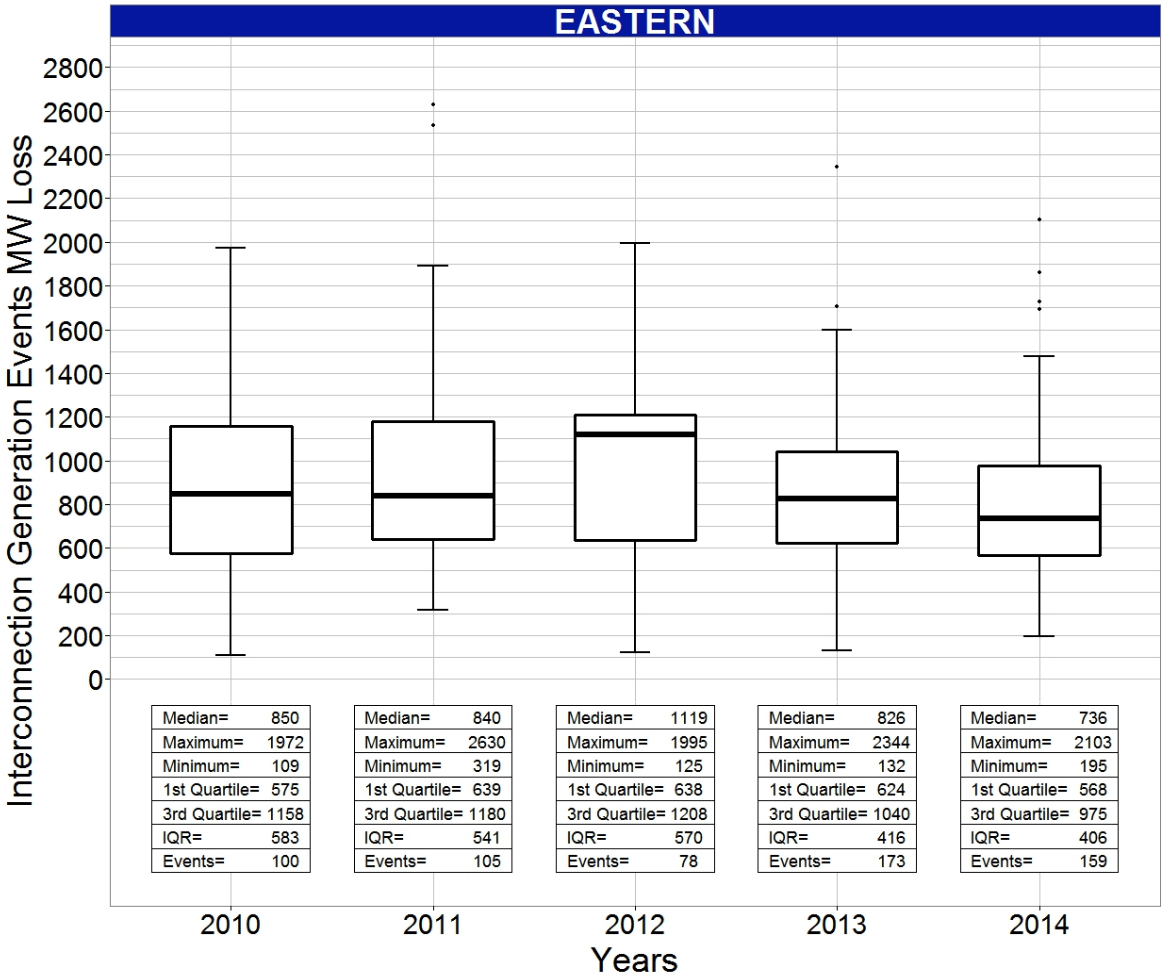
NERC Interconnections 2009-2013

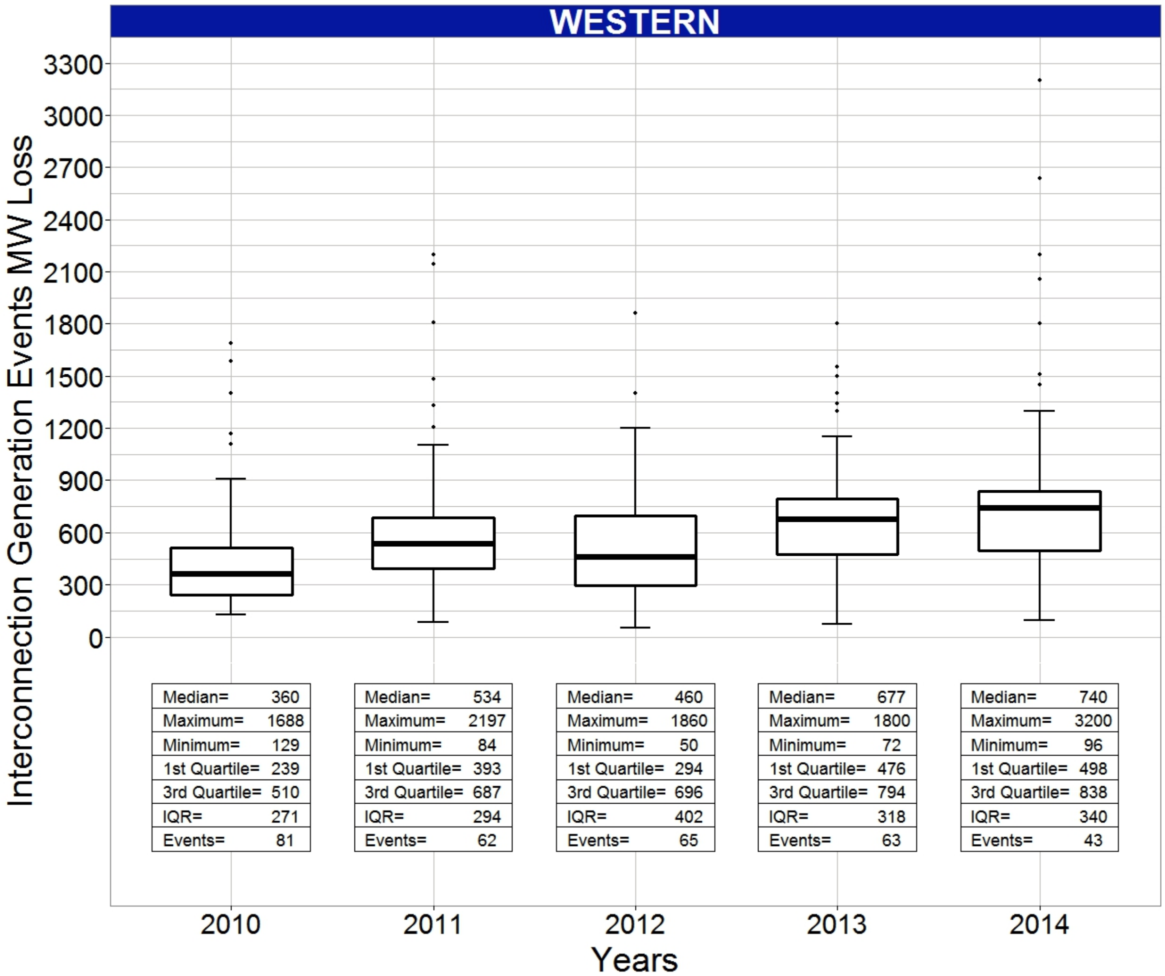
Frequency Events Loss MW Statistics

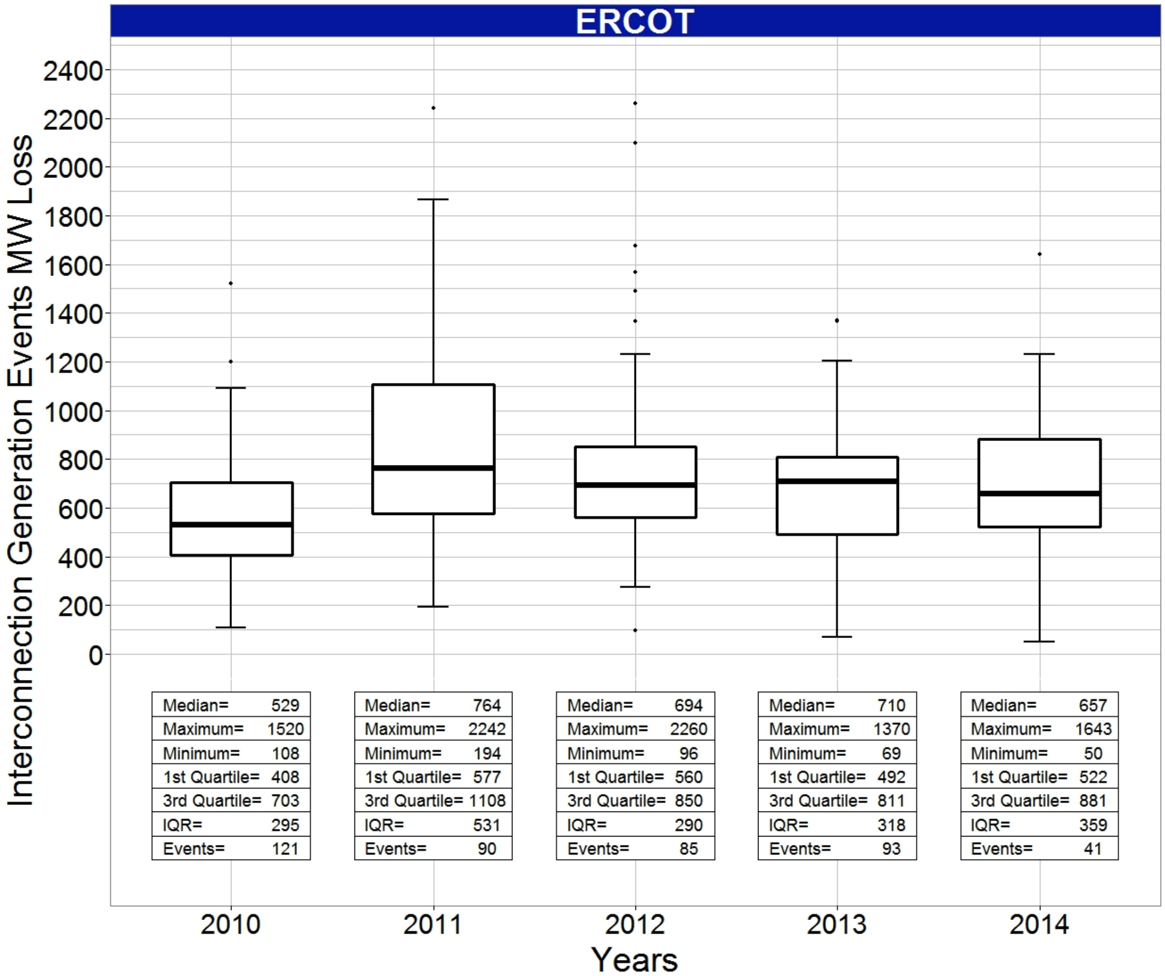
For: NERC BARC Standard Drafting Team

Prepared by: CERTS

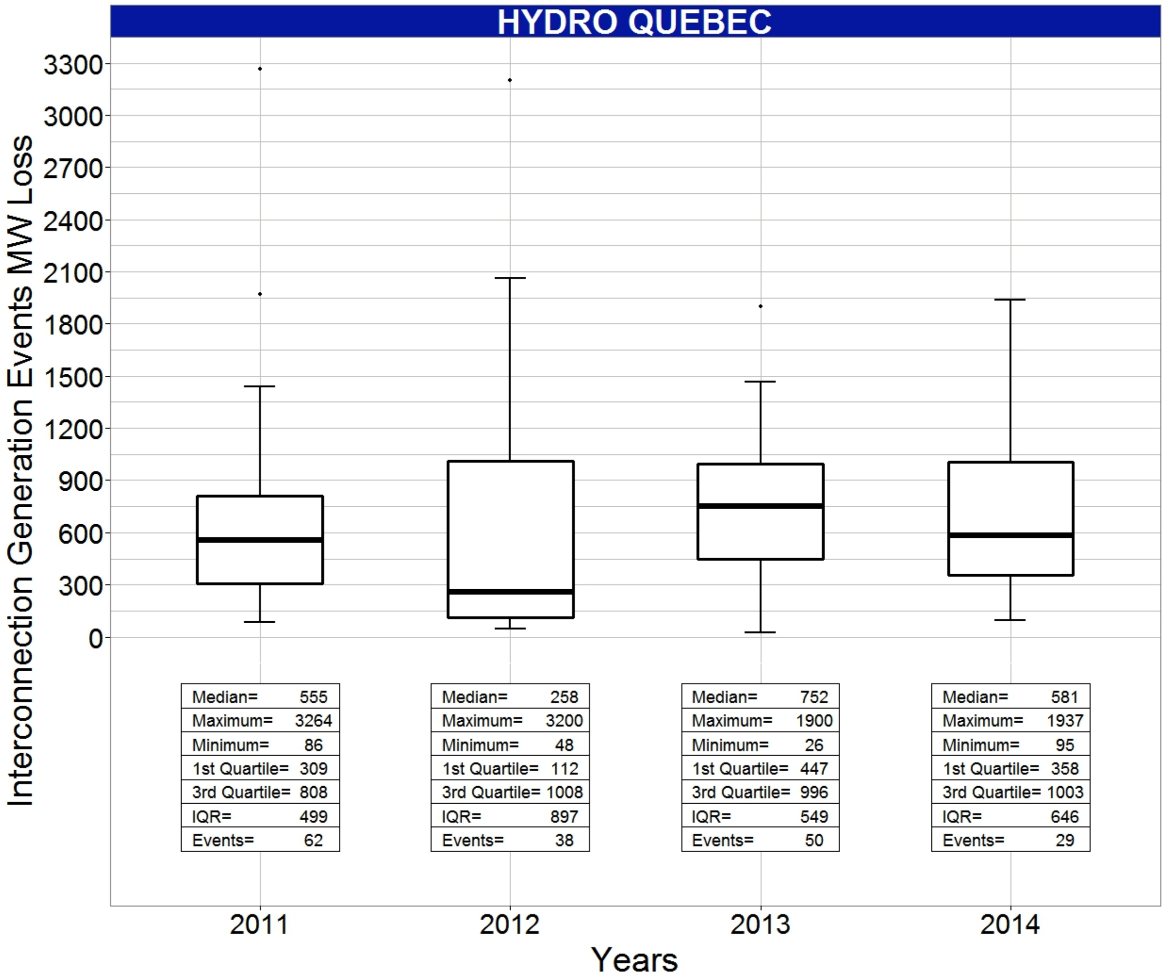
Date: October 15, 2013


EASTERN
Interconnection Generation Events MW Loss
2800
2600
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
Median= 850
Maximum= 1972
Minimum= 109
1st Quartile= 575
3rd Quartile= 1158
IQR= 583
Events= 100
Median= 840
Maximum= 2630
Minimum= 319
1st Quartile= 639
3rd Quartile= 1180
IQR= 541
Events= 105
Median= 1119
Maximum= 1995
Minimum= 125
1st Quartile= 638
3rd Quartile= 1208
IQR= 570
Events= 78
Median= 826
Maximum= 2344
Minimum= 132
1st Quartile= 624
3rd Quartile= 1040
IQR= 416
Events= 173
Median= 736
Maximum= 2103
Minimum= 195
1st Quartile= 568
3rd Quartile= 975
IQR= 406
Events= 159
2010
2011
2012
2013
2014
Years


WESTERN
Interconnection Generation Events MW Loss
3300
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
Median= 360
Maximum= 1688
Minimum= 129
1st Quartile= 239
3rd Quartile= 510
IQR= 271
Events= 81
Median= 534
Maximum= 2197
Minimum= 84
1st Quartile= 393
3rd Quartile= 687
IQR= 294
Events= 62
Median= 460
Maximum= 1860
Minimum= 50
1st Quartile= 294
3rd Quartile= 696
IQR= 402
Events= 65
Median= 677
Maximum= 1800
Minimum= 72
1st Quartile= 476
3rd Quartile= 794
IQR= 318
Events= 63
Median= 740
Maximum= 3200
Minimum= 96
1st Quartile= 498
3rd Quartile= 838
IQR= 340
Events= 43
2010
2011
2012
2013
2014
Years



	2010	2011	2012	2013	2014
Median=	529	764	694	710	657
Maximum=	1520	2242	2260	1370	1643
Minimum=	108	194	96	69	50
1st Quartile=	408	577	560	492	522
3rd Quartile=	703	1108	850	811	881
IQR=	295	531	290	318	359
Events=	121	90	85	93	41


HYDRO QUEBEC
Interconnection Generation Events MW Loss
Years
2011
Median= 555
Maximum= 3264
Minimum= 86
1st Quartile= 309
3rd Quartile= 808
IQR= 499
Events= 62
2012
Median= 258
Maximum= 3200
Minimum= 48
1st Quartile= 112
3rd Quartile= 1008
IQR= 897
Events= 38
2013
Median= 752
Maximum= 1900
Minimum= 26
1st Quartile= 447
3rd Quartile= 996
IQR= 549
Events= 50
2014
Median= 581
Maximum= 1937
Minimum= 95
1st Quartile= 358
3rd Quartile= 1003
IQR= 646
Events= 29

Attachment 2

Technical Justification for Applicability of BAL-002 During Emergency Alerts

Technical Justification for Applicability of BAL-002 During Energy Emergency Alerts

I. INTRODUCTION

The Balancing Authority Reliability-based Controls standard drafting team (BARC SDT) has identified a conflict between NERC Reliability Standards BAL-002 and EOP-002 that unnecessarily requires arbitrary interruption of Firm Load. In order to address this issue, the BARC SDT is recommending that Standard BAL-002-2 not be enforceable during an Energy Emergency Alert (EEA) event where the EEA process requires the use of Contingency Reserve to maintain load service.[2] This document provides support for this recommendation and an overview of reliable frequency management on the North American Interconnections.

II. BACKGROUND

Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

Reliability Standard BAL-002 applies during the real-time operations time horizon and addresses the balancing of resources and demand following a disturbance. Reliability Standard EOP-002 also applies during the real-time operations time horizon and addresses capacity and energy emergencies. Given that an entity and/or event can transition suddenly from normal operations into emergency operations (EOP-002) where Contingency Reserve maintained under BAL-002 may be utilized to serve Firm Load, this transitional seam must be explicitly addressed in order to provide clarity to responsible entities regarding the actions to be taken. The proposed applicability of BAL-002 is designed to address this issue.

III. LEGACY REQUIREMENTS

The Resource and Demand Balancing (BAL) standards include both requirements that have a sound technical basis and legacy requirements that the industry has used for years but fail to

[2] The proposed applicability section states: "Applicability is determined on an individual Reportable Balancing Contingency Event basis, but the Responsible Entity is not subject to compliance during periods when the Responsible Entity is in an Energy Emergency Alert Level under which Contingency Reserves have been activated."

have a sound technical basis. NERC began replacing these legacy requirements with technically based requirements starting with the Control Performance Standard1 (CPS1). Both Control Performance Standard2 (CPS2) and the Disturbance Control Standard (DCS) remain in the legacy category. The following are specific concerns associated with these requirements.

- When CPS1 was implemented to replace A1/A2, previous requirements were modified so that CPS1 would apply at all times including the (disturbance) periods where DCS is applicable, not just during normal operations/periods. So DCS is not the only standard governing disturbance conditions.
- The Disturbance Control Standard (DCS) and its precursor B1/B2 have been unique in requiring immediate action by the Balancing Authority (BA), in this case to address unexpected imbalances within defined limits.
- DCS, albeit results-based in its current form, was initially designed to measure the utilization of Contingency Reserve to address a loss of resource within the defined limits. In its results-based form it assumed that implementing sufficient Contingency Reserves as needed to comply with the recovery requirement would be a reasonably equitable minimum quantity for all BAs participating in interconnected operation.
- DCS is based upon ACE recovery to the lower of pre-disturbance ACE or zero. A Balancing Authority which might be under-generating prior to a generation loss, could lose a generating unit and under DCS be deemed compliant if it returned ACE to its pre-disturbance state, though it could still be depressing Interconnection frequency.
- As DCS recovery from a reportable event must occur within a 15-minute period, it is possible for a Balancing Authority's ACE to again go negative after that time, with a similar impact on Interconnection frequency.
- Since CPS2 allows a BA to be unaccountable for approximately 74 hours of operation in a 31-day month, an imbalance condition may persist and negatively impact Interconnection frequency for many hours[3].
- When ACE is modulated by frequency, "significant" losses are defined not only by the size of the event causing an ACE deviation, but also contingent on the deviation of Interconnection frequency from Scheduled Frequency.

IV. TIE-LINE BIAS FREQUENCY CONTROL AND ACE

[3] Reliability-Based Control v3, Standard Authorization Request Form, November 7, 2007.

Tie-Line Bias Frequency Control is implemented on the North American Interconnections through the use of the ACE Equation.[4] In general, ACE is the term used to determine the load-generation imbalance that is being contributed by each Balancing Authority (BA) on an Interconnection. ACE is a powerful indicator, because it indicates the imbalance within the boundaries of a single BA, thus defining the Secondary Control responsibilities for that BA and, therefore, the control action that would return ACE to zero. ACE includes the Frequency Bias Setting term, which allows the Primary Frequency Control to be a shared service throughout a multi-BA Interconnection, while assigning to each individual BA the specific responsibilities of maintaining its own Secondary Frequency Control.

In summary, ACE only provides guidance with respect to Secondary Frequency Control and does not indicate or provide any direct measure of Primary Frequency Control, and only reflects the estimated Frequency Response as represented by the Frequency Bias Setting term. NERC Requirements and supporting documentation for Frequency Response (Primary Frequency Control) are included in BAL-003-1 Frequency Response and Frequency Bias Setting standard. More detail on Tie-Line Bias Frequency Control and ACE is attached.[5]

V. CONTROL PERFORMANCE STANDARD1 (CPS1)

Prior to the development of CPS1, the industry assumed that, "It is impossible, however, to use frequency deviation to identify the specific control area (sic, i.e. BA) with the under- or over-generation creating the frequency deviation…".[3] In the 1990's the development of CPS1 demonstrated that not only was it possible to identify the specific BA creating the frequency deviation, but that it is also possible not only to determine the relative contribution by each BA to the magnitude of the frequency deviation[6], but also to determine the relative contribution of each BA to the reliability risk caused by that deviation. In addition, the CPS1 Requirement provided a guarantee: "If all BAs on an interconnection complied with the CPS1 Requirement,

[4] Illian, Howard F., Understanding ACE, CPS1 and BAAL, Prepared for the NERC BARC Standard Drafting Team, September 10, 2010 rev. August 19, 2014, Section 2, pp. 1-4, for a derivation of the ACE Equation and the requirements for implementing it that are included in the definition of ACE appearing in the NERC Glossary.

[5] Illian, Howard F., Frequency Control Performance Measurement and Requirements, Ernest Orlando Lawrence Berkeley National Laboratory, December 2010, for a discussion of the history of Frequency Control and Performance Measurement.

[6] Illian, Howard F., Understanding ACE, CPS1 and BAAL, Section 2, pp. 5-10 for a derivation of the CPS1 requirement.

the Root Mean Squared[7] value of the frequency deviation for that Interconnection would be less than the epsilon1[8] frequency deviation limit for that Interconnection."

CPS1 is a rolling annual average of individual measurements each averaged over one-minute, and is assessed monthly. CPS1 measures the covariance between the ACE of a BA and the frequency deviation of the Interconnection which is equal to the sum of the ACEs of all of the BAs. CPS1 has the great value of using the Interconnection frequency to determine the degree to which ACE among the BAs on a multiple BA Interconnection is harming or helping interconnection frequency. Since the frequency deviation is a measured value, the ACE of a BA will directly affect only the CPS1 of the BA with the ACE and not the CPS1 measure of other BAs.

VI. BALANCING AUTHORITY ACE LIMIT (BAAL)

When the Balancing Resources and Demand (BRD) standard drafting team recognized the need for a control measure over a shorter time horizon than either CPS1 (annual) or Control Performance Standard 2[9] (CPS2, monthly) provided, it began looking for a measure that would allow a window for common imbalance events like a unit trip, while providing a limit on how much frequency deviation should be allowed over that short period. After considering numerous alternatives, BAAL was selected as the appropriate short-term measure.[10,11]

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7 "Root Mean Squared" means the square root of the mean of the squared errors, so that positive and negative errors do not offset each other and any shift in the mean is counted as error.

8 "Epsilon1" is the frequency deviation limit determined for each North American Interconnection and used by CPS1 to bound the Root Mean Squared frequency deviation. It is 18 mHz on the Eastern, 22.8 mHz on the Western, 30 mHz on the ERCOT, and 21 mHz on the Quebec Interconnections.

9 Proposed to be replaced by BAAL under BAL-001-2, CPS2 requires the BA to move its ACE within predefined L10 bounds when it is binding (during only 90% of the ten-minute periods per month) without regard to whether such action helps or hurts Interconnection frequency.

10 Illian, Howard F., Meeting the Discrete Event Measure (DEM) Objectives with the Abnormal Operations Measure (AOM), Prepared for the NERC Balancing Resources and Demand Standard Drafting Team, March 20, 2004.

11 Illian, Howard F., Setting the Balancing Authority ACE Limit (BAAL) for the NERC Abnormal Operations Measure (AOM), Prepared for the NERC Balancing Resources and Demand Standard Drafting Team, March 28, 2004.

Considerable evaluation and Field Trials have shown that BAAL[12] is a better indicator of contributions to reliability risk of an interconnection than the magnitude of ACE alone. This superiority, like CPS1's, derives from the concurrent use of both ACE and frequency error in the BAAL measure. Thus BAAL captures the relative contribution to reliability by all of the ACEs on an interconnection and indicates where each BA stands relative to its secondary control responsibilities and the current state of the interconnection as indicated by the frequency error for both under- and over-frequency conditions.

VII. INTERACTION BETWEEN STANDARDS

The drafting team has identified as an issue the existence of points where the standards are in conflict with each other. The drafting team has attempted to address the conflicts identified, as follows:

NERC standard EOP-002 requires a BA to use all its reserves during an Energy Emergency Alert 2 (EEA2) or higher. The following language is found in EOP-002 Attachment 1-EOP-002:

> **2.6.4 Operating Reserves.** Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

The current BAL-002 specifies a minimum level reserve requirement at all times unless a qualifying event has occurred. The drafting team noted that in the EEA process an entity is driven to request an EEA rarely as the result of a single unit loss. In fact, an EEA declaration by the Reliability Coordinator might result from issues that include no event that would qualify as a Disturbance and the EEA situation could last longer than the reserve recovery period of 90 minutes. For this reason, the drafting team recommends significant changes to the standards in question.

In addition to the identified conflict, other standards can require the activation of contingency reserve. These include other BAL standards, IRO standards and TOP standards. Compared to those standards, the BAL-002 standard provides the least direct measure of reliability. Therefore, an entity should never be conflicted between applying the requirements of BAL-002 and complying with the other standards.

[12] Illian, Howard F., Understanding ACE, CPS1 and BAAL, Prepared for the NERC BARC Standard Drafting Team, September 10, 2010 rev. August 19, 2014, Section 2, pp. 10, for a derivation of the BAAL requirement.

Finally, there is one overarching principal not reflected in the discussion up to this point, namely keeping the lights on if possible. If there is a requirement to bring ACE back no matter what, then that requirement will have the unintended consequence of shedding Firm Load, especially during an EEA. During the EEA process, the expectation is that a BA will have firm load ready to shed in order to meet its reserve requirement under R2 of the proposed BAL-002 standard. However, if the BAL-002 standard also requires the entity to meet R1 during the EEA, entities will shed firm load to restore ACE to its pre-contingency level, regardless of the lack of any reliability issues. In other words, frequency could be settling at or very near 60 Hz, no transmission lines are overloaded as determined by the TOP standards, and the entity is operating within the parameters defined in BAL-001, but firm load would be interrupted simply to bring the entity's ACE back to what it was prior to the loss of the unit. Since the industry has defined reliability as frequency at or near 60 Hz and transmission lines operating within their limits, there is no reason to interrupt firm load.

Instead, the BARC SDT is recommending that Standard BAL-002-2 not be enforceable during an EEA event where the EEA process requires the use of Contingency Reserve to maintain load service. Instead, the Reliability Coordinator, Transmission Operators and the impacted Balancing Authorities should use real-time situational awareness, taking into account issues addressed in BAL-001, BAL-003, the IRO suite of standards and the TOP suite of standards, to determine what actions are appropriate when conditions are abnormal. This process would allow continued load service without arbitrarily requiring interruption of firm load.

This concern arises because the other standards look at specific reliability issues other than just balancing between scheduled and actual interchange. BAL-001-2 and BAL-003-1 look at interconnection frequency to determine whether the Balancing Authority is helping or hurting reliability. During an EEA event, curtailing load to move ACE back to a pre-event level could adversely affect frequency. If frequency goes up from 60 Hz when a Balancing Authority interrupts load, the impact is detrimental to the interconnection. Under the TOP standards, if flows on transmission lines are within the limits specified, there is no need to alter the flows on the transmission system by interrupting load.

Finally, the Reliability Coordinator has a wide area view of the electric system as required under the IRO standards. The IRO standards clearly state the Reliability Coordinator's responsibilities during the EEA process. If the Reliability Coordinator has not identified a reliability concern in its near term operations evaluation, actions such as interruption of firm load should not occur simply to balance load and resources within the BA. During abnormal (emergency) situations, taking significant actions with a narrow view will not be beneficial for Interconnection reliability.

EXAMPLES

- Example 1

  On an usually cold day in February 2011, at 06:22, a Balancing Authority Area (BAA) experienced a 350 MW generation loss when a 750 MW joint ownership unit tripped off-line. Earlier in the day the BAA operator experienced loss of several generating units with a total capacity of 1050 MW, the latest loss being just 38 minutes prior to the 350 MW loss. When the 350 MW event occurred the BAA operator requested reserve/emergency assistance, shed 300 MW of customer load to restore contingency reserve, and requested the RC post an EEA3. The EEA3 was posted. Although the frequency only touched 59.91 Hz, averaging 59.951 Hz in the first minute of the outage, was it really necessary to cut load and leave people in the cold, dark of that morning to restore contingency reserve? Having idle generation, when the Interconnection is operating reliably, does not warrant shedding customer load.
- Example 2

  In June 2012, at 17:08, a BAA experienced an 800 MW generation loss. The BA and the reserve sharing group (RSG) it participates in were in the process of replacing the lost generation when, in the thirteenth minute of the recovery when there were no identified frequency, voltage or loading threats to reliability, the BAA was directed by its Reliability Coordinator (RC) to shed 120 MW of customer load. Although the combined Area Control Error (ACE) of the RSG participants was positive, the RC focused on the ACE of the BAA that lost the generation – which was still negative – ignoring the fact that the Interconnection frequency (59.96 Hz) was above the Frequency Trigger Limit (59.932 Hz). The needless shedding of customer load when system reliability is not threatened attracted the attention of state regulators who were not happy with the action. This demonstrates that focusing solely on a BAA's ACE and not on the true Interconnection reliability indicators can cause actions that do not support reliability.
- Example 3

  In June 2004, at 0741, a series of events led to a generation loss of over 4,600 MW. In spite of the event size, the Interconnection frequency was arrested without triggering automatic underfrequency load shedding, thanks to governor action, frequency sensitive load and deployment of Contingency Reserve (as required by BAL-002). Some transmission elements exceeded their limits for a short time (as permitted by the EOP standards), And, prior to the disturbance, the frequency was in the normal operating range due to automatic generation control (AGC) operation (as required by BAL-001). During the event almost 1,000 MW of interruptible customer load was shed throughout the interconnected systems by devices that automatically operated to protect various parts of the system (as determined by the TPL and TOP Standards). This demonstrates how the suite of standards defined by NERC work together to efficiently protect the system and minimize customer interruptions.

VIII. CONCLUSIONS

There are important conclusions that can be drawn from this work and the mathematical guarantees that it provides:

- The Disturbance Control Standard (DCS) as currently configured only looks at ACE, the imbalance contribution of a single BA, and does not include a specific frequency error component that indicates the BA's contribution relative to the condition of the interconnection to which the BA is connected.

- As the DCS measure does not have a specific frequency component, compliance to DCS at times conflicts with the overall goal of targeting operation within predefined Interconnection frequency limits. For example, DCS recovery initiated from above Scheduled Frequency has a detrimental impact on Interconnection frequency.

- The focus on ACE alone is insufficient to control frequency on a multiple BA Interconnection. The correlation of the ACEs among the BAs on the Interconnection will affect the quality of frequency control independent of how any individual ACE is controlled.

- Adequate control of Interconnection frequency requires the use of both ACE (individual BA balancing error) and frequency deviation.

- Adequate control of reliability risk on an Interconnection requires the use of ACE, frequency deviation and available frequency response.

- BAAL addresses all events impacting Interconnection frequency, both above and below scheduled frequency.

BAAL addresses all of the above issues in its time domain without requiring response to or measurement of events that fail to raise reliability concerns. For these reasons, the proposed applicability of BAL-002 is a reasonable and technically-justified approach that addresses the seam with EOP-002.